POWER GENERATION AND ITS IMPACT ON ELECTRICITY TARIFF: A CASE STUDY OF SIERRA LEONE.

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This work is dedicated to my beloved wife, Alice M. Tarawalie, and children – Michaela, Marina and Christina. I miss you all during my studies in South Africa.

DECLARATION.

I declare that this dissertation is essentially my own work. It is being submitted in partial fulfilment of the requirements for Masters of Science in Engineering degree at the University of Cape Town and has not been submitted in this form or any other form for a degree at any other university.

Michael Abu Conteh.

Signed by candidate

Date: 8/10/03

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To God be the glory and honour for His wonderful gift of life and strength to pursue my educational carer up to this level. To my mum, I owe you everything in this world.

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ABSTRACT

Electricity tariffs are generally high in African countries, but a significant share of it is due to inefficiencies in power generation and supply. This work looked at a case study of the Sierra Leone national utility's power generation and its impact on the tariff system. Sierra Leone is a relatively small country along the west coast of Africa. It is one of the least developed countries in the world, but its electricity tariffs are one of highest in Africa. This is largely due to its inefficient power generation. A significant energy input is wasted and there are high energy output losses in the system. About 10% of the energy input is lost because of poor housekeeping and operating practices. On the average 6% of the power generated is consumed by the plant auxiliaries and the station due to old and inefficient equipments. The technical and non-technical losses of the system are alarmingly high averaging about 38% in recent years. Normally, the level of electricity rates is based on revenue requirement, which depends on the operating cost. The average electricity price in Sierra Leone in 2002 was about US$ 0.18. This high tariff is due to cost associated with the above inefficiencies, which increases the operating costs and the type and age of the generating plants. Besides, on the average there is a net decline on the generation output while operating expenses continue to increase. Using the rate-of-return methodology the tariffs were found to be well below the existing utility tariffs if the fuel is imported from the OECD countries.

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ACRONYMS AND ABBREVAITIONS

DSM	Demand side management
EE	Energy efficiency
EMCS	Energy management control systems
EPRI	Electric power research institute
ERI	Energy research institute
ESI	Electricity supply industry
FLRs	Filters, lubricators and regulators
GDP	Gross domestic product
GNI	Gross national income
GW	Gigawatt
GWh	Gigawatt - hour
HAWT	Horizontal axis wind turbine
HPT	High-pressure turbine
HRSG	Heat recovery steam generator
IAEA	International atomic energy agency
IC	Internal combustion
IEA	International energy agency
IPT	Intermediate pressure turbine
KW	Kilowatt
KWh	Kilowatt - hour
LPT	Low pressure turbine
LRMC	Long run marginal cost
m/s	meters per second
MW	Megawatt
MWh	Megawatt-hour
NEI	Nuclear energy institute
NPA	National power authority
OECD	Organisation of economic and community development
PB	Performance based
PC	Price cap
pf	Power factor
PPP	Purchasing power parity
PWR	Pressurised water reactor
RC	Revenue cap
ROR	Rate of return
SRMC	Short run marginal cost
SS	Sliding scale
TDS	Total dissolved solids
TWh	Terawatt - hour
VAD	Value added for distribution
VAWT	Vertical axis wind turbine
WEM	Wholesale electricity market

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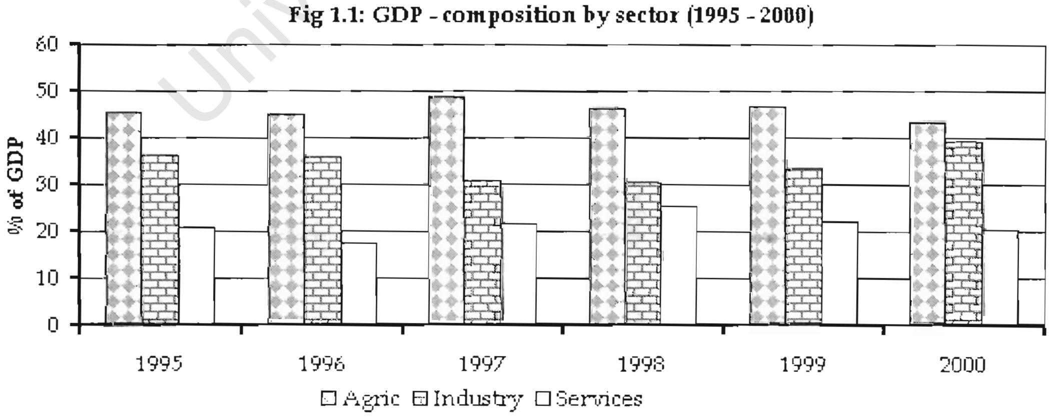
CHAPTER 1
INTRODUCTION

1.0 BACKGROUND OF STUDY

Sierra Leone is relatively a small (72,000 km^2) tropical country along the west coast of Africa and borders the Atlantic Ocean and lies between Guinea and Liberia (see appendix A, fig. A1). It has 3 provinces with 12 districts and the western area where the capital is located. The population is about 5 million with a gross national income (GNI) per capita of US$ 140 and low levels of social development: life expectancy is only 43 years, with infant mortality at 15%, about 90% of the population have no access to electricity (World Bank; The World Factbook, 2002). Sierra Leone has substantial mineral, agricultural and fishery resources that form the major source of its export earnings, but is one of the least developed countries in the world. This is largely due to the undeveloped economic and social infrastructures, serious social disorders and the recent 10-year civil war, and these factors continue to hinder economic activities. Manufacturing consists mainly the processing of raw materials and light manufacturing for the domestic market. According to the World Fact Book (2002), the 2002 gross domestic product (GDP) was $2.8 billion with a growth rate of 5%. Figure 1.1 below gives the gross domestic product composition by sector between 1995 and 2000. Agriculture contributes about 43%, industry 32% and services 19.3%.

Fig 1.1: GDP - composition by sector (1995 - 2000)

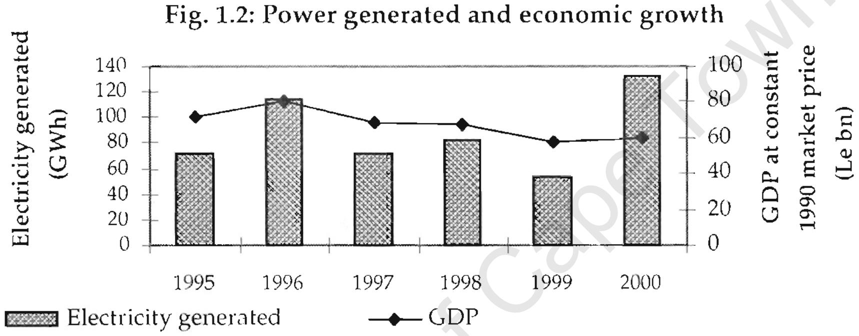


Source: Adapted from Annual Statistics Digest - 2001.

Power generation in Sierra Leone started significantly in the early 1950's and currently consists of 90% thermal and 10% non-thermal (hydroelectric). As reported by Lahmeyer International in 1996, there are 13 power stations with small diesel engine-generator units scattered all over the country (see appendix A). The current total installed and operating capacity in the country (excluding auto producers) is estimated at 42 MW. The only operating hydropower capacity is the Goma hydroelectric plant in the Kenema District of the Eastern Province that has a capacity of 4 MW.

Recent experiences show that power generation and economic development have had close interactions. Electricity, if articulated with other development factors, can boost economic development tremendously. Fig. 1.2 gives the Sierra Leone economic growth-electricity supply nexus.

Fig. 1.2: Power generated and economic growth



On the average, both power generation and economic growth have been on a downward spiral from 1995 - 1999. The low level and declining power generation is one of the main barriers to the lack of high-energy intensity and heavy manufacturing industries in the country. The civil war between 1991 and 2001 affected the export earnings significantly. The lack of foreign exchange reduces petroleum imports, dislocating transportation and limits the operation of oil based electrical power plants. Furthermore, shortages of imported spare parts have restricted essential maintenance, increase power losses and reduce operating capacity.

The overall performance of the national utility - National Power Authority (NPA) is far from satisfactory. About 30-45% of the electricity generated is lost, and those having access to electricity are experiencing prolonged supply interruptions. The utility is not autonomous and there are difficulties in getting government approval for certain decisions. From 1996 - 2000 the average tariffs were below the consumer price index (CPI), but are very high according to international standards. This affects the quality of life in the country due to the importance of electricity to the overall economy.

Electricity is the pivot of all modern economic and development activities in any country. It is very essential particularly in the manufacturing, agriculture, and commercial sectors and for a satisfactory quality of life. So, the most important issues are its affordability, reliability and quality of service. One way of reversing this situation is to investigate energy efficiency opportunities. Energy efficiency (EE) practices are economic and technical instruments for improving the productivity and profitability of any industry. They focus on how much energy is used relative to the service demanded. Therefore, this work will look at the energy efficiency of power generation of the National Power Authority (NPA) - Sierra Leone and investigate its impact on tariff.

1.2 THE PROBLEM STATEMENT

Depending on the structure of the electricity supply industry (ESI) an electricity tariff, the cost per unit energy or demand charged to the final consumer consists of the different cost components: generation, transmission, distribution and value added for distribution (VAD). Generally, generation consists of about 75% of the total operating costs depending on the type of plant. Therefore its efficiency has significant impact on tariff; the higher the operating costs, the higher the tariff.

NPA's electricity generation is very inefficient. A significant energy input is wasted and there are high energy output losses in the system. From interviews conducted with key personnel and personal data analysis, about 10% of the energy input is lost because of poor housekeeping and operating practices. On the average 6% of the power generated is consumed by the plant auxiliaries and the station due to old and inefficient equipments. The technical and non-technical losses of the system are alarmingly high - about 38%. These inefficiencies are sources of revenue loss and increased expenses.

The physical and financial aspects of the national utility (NPA) are deteriorating. The utility is overstaffed. The credit billing system and methods of revenue collection are inefficient. The billing cycle up to 2001 was 90 days. These with poor management resulted in NPA being in serious financial difficulties. The weak financial base coupled with the lack of foreign exchange to purchase spare parts and the slow response of government to the problems of the utility, make it very difficult for NPA to maintain the existing generating units. Hence the electricity demand of the nation cannot be met. From a personal communication with the system-planning officer of NPA, the electricity access in the country is between 6 - 10%. Those who have access to electricity are experiencing prolonged outages due to the frequent breakdown of the generating units.

Normally, the level of electricity rates is based on cost of service and a fair return on capital assets. The average tariff in the country is extremely high. The average electricity price in Sierra Leone in 2002 was about US$ 0.18. This high tariff is due mainly to the high operating costs, which is a result of the above inefficiencies and the type and age of the generating plants. Besides, on the average there is a net decline on the generation output while operating expenses continue to increase.

1.3 OBJECTIVES

The general aim of this work is to suggest ways of improving the energy efficiency in generating power and the operational and financial efficiencies of NPA. To achieve these specific objectives that will be addressed are:

1. Establish the efficiency of the generation.
2. Identify and suggest corrective measures of how to improve the generation inefficiencies of the utility.
3. Suggest ways of improving the revenue management of the utility.

1.4 SCOPE AND LIMITATION OF STUDY

Presently, electric power generation implies large-scale production of electric power in stationary plants designed for the purpose. Most electric generators are either driven hydraulic turbines or steam and gas turbines. Limited use is being made of wind, geothermal and solar energies. The three significant types of generating plants are hydroelectric, fossil-fuel-electric and nuclear electric. Fossil fuel fired electric plants or thermal plants can either be externally (as in steam and gas turbines) or internally (as in internal combustion engines) fired. About 85% of NPA's installed capacity is located in Freetown and over 70% of the power generated from internal combustion engines running on heavy fuel oil (HFO). Therefore, this study is limited to thermal plants with particular attention to internal combustion diesel generators and the Kingtom power station in Freetown.

1.5 METHODOLOGY

Methods used in this study can be summarised as follows:

- Literature survey of the various ways electric power is produced, energy efficiency practices and tariff setting methods;
- Field visit to the power utility in Freetown, Sierra Leone and discussions with some heads of department at NPA;
- Analysis of data; and,
- Suggestions from result of the analysis.

1.6 LAYOUT OF WORK

This report is structured in seven chapters. Chapter 1 gives an introduction to the background of the work, the statement of the research problem and the objectives, limitation and methodology.

Chapter 2 is a description of the operation of power production systems. It includes both thermal and non-thermal power plants and their expected thermal efficiencies and production costs.

Chapter 3 discusses the energy efficiency practice in power production and how it can be improved.

Chapter 4 describes the general regulatory methods of determining electricity tariff and few international experiences.

Chapter 5 gives a report of the field visit and how the data were obtained. It is structured into three sections. The first section gives a brief description of the electricity supply industry of the country and the Kingtom power station. The second section gives the numerical data collected and the third section presents personal observations of the operations of NPA.

Chapter 6 is the analysis and discussions. This chapter is structured into three sections. The first section is the technical analysis of the power system and section two is the tariff analysis using the rate of return (ROR) or revenue requirement methodology. Section three gives a comparison of some selected performance indicators of NPA and other power utilities in Africa.

Chapter 7 gives the conclusion of the work and some recommendations. The recommendations given are both for short and long terms implementation. The short-term recommendations address the current operational inefficiencies of the utility so at to reduce its operational expenses, which will invariably result to a reduction of the tariffs. The long-term recommendations address the future operational improvement of the utility.

CHAPTER 2
POWER PRODUCTION SYSTEMS

2.0 INTRODUCTION

Generally, power plants fall into three categories and these are:

- Electric power plants that generate electricity to supply a national grid;
- Heat power plants that generate heat for district heating; and,
- Cogeneration power plants that generate both electricity and heat.

This work will be only confined to the first type. Such power plant consists of a prime mover (turbine or internal combustion engine) and a generator. The prime mover provides the mechanical power in rotary motion from the heat energy of an energy source or the kinetic energy of a moving fluid to drive the generator, which converts this energy into electricity.

Power plants are characterised by the input energy source and are broadly divided into thermal and non-thermal. This chapter gives a brief description and operation of such power plants in central power stations and their respective production costs.

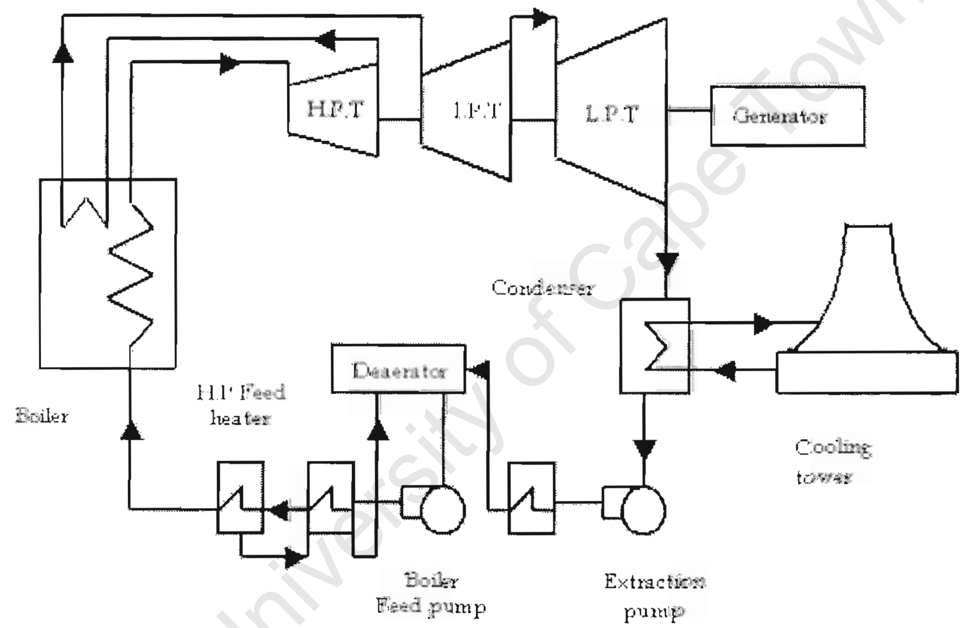
2.1 THERMAL POWER PLANTS

Thermal power plants use heat energy from a fuel to drive a prime mover. These can be further divided into fossil fuel-fired plants and nuclear plants. About 90-95% of thermal plants use fossil fuel (solid, liquid and gas), solar or biomass to produce the mechanical energy required to drive a generator and produce electrical energy from steam raised in a boiler (as in turbine plants) or the combustion of a fuel-air mixture (as in diesel internal combustion engine). A nuclear power plant is one in which a nuclear reactor acts as a boiler and the thermal energy is produced by the fission reaction of uranium. There are various types of fossil fuel-fired thermal power plants. These are steam turbine, gas turbine, combined cycle and diesel power plants. These are described below.

2.1.1 Fossil fuel steam turbine power plants

A steam turbine is a heat engine that is taking heat from a high temperature source, converting part of it into mechanical energy and rejecting the remainder at a low temperature. The working fluid (steam) operates in a closed Rankine cycle and is produced externally in a boiler using fossil fuels (coal, oil or gas), solar energy or geothermal source. The diagram below is a simplified configuration of a typical central electricity steam turbine plant, which is fossil fuel-fired.

Fig. 2.1: Central electricity thermal plant



Heat from the energy source is transferred to the water in the boiler producing high pressure, high temperature steam. The steam is admitted into the high-pressure turbine (HPT) where its kinetic energy is transferred to the blades causing rotation of the turbine shaft that, in turn, drives the electric generator. It will expand to an intermediate pressure after which most of it is returned to the boiler for reheating. The balance steam is led to the high-pressure feedheaters to heat the boiler feedwater. The reheated steam is led to the intermediate pressure turbine (IPT) and then to the low-pressure turbine (LTP) for further expansion. After passing through the turbines, the low-pressure steam is exhausted to the condenser where it is condensed. The extraction pump extracts the condensate and it is pumped back to the boiler through the high-pressure feedheaters by the boiler feedpump, which increases its pressure. The deaerator removes any condensed gases from the system.

The efficiency of such a system is in the range of 35-40% (Loftness R L, 1978:384). Large steam turbine power plants are generally operated as base-load plants, that is, continuous operation at or near full capacity.

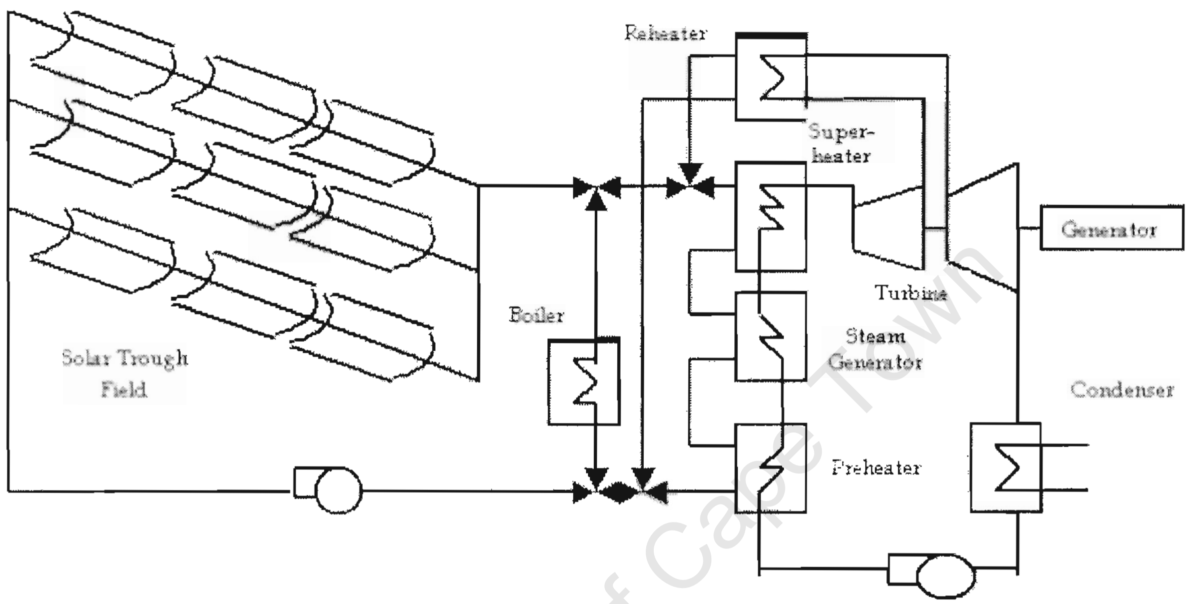
2.1.2 Solar steam turbine power plants

The global installed capacity of solar thermal plants in 2000 was 0.4 GW (IEA, 2002). These are facilities that use solar radiation to produce electrical energy. The process is carried out using photothermal on a Rankine cycle. The solar radiation heats up a fluid and produces steam, which is sent to the turbine to produce electrical energy. To attain a high steam temperature that will operate the cycle efficiently, concentrating collectors (parabolic troughs or power tower) are used. Concentrating solar thermal power technologies consist of four basic key elements. These are the concentrator, receiver, transport - storage, and power conversion. The concentrator captures and concentrates solar radiation, which is delivered to the receiver. This absorbs the concentrated sunlight, transferring its heat energy to a working fluid. The transport - storage system passes the fluid from the receiver to the power conversion system, which can be a Rankine, Brayton, combined or Stirling cycles.

Fig. 2.2 below shows the principle of the parabolic trough. The concentrating collectors are large parabolic mirrors that track and concentrate the sunlight on a line focus. A metal absorber pipe with a selective coating to lower the emission losses is situated at the line focus. The fluid that runs through the tube is water or special thermal oil. The concentrated sunlight heats the fluid up to nearly 400°C and this will evaporate the water into steam that drives the turbine. The low-pressure steam from the turbine is condensed into water in the condenser and then returned to the cycle. During periods of bad weather or at night the boiler or burner can be used to operate the water-steam cycle.

For very large installations, the power tower is more favoured. This consists of a receiver at the top of a central tower surrounded by hundreds of mirrors. In this configuration, the concentrated sunlight can heat an absorber up to about 1000°C. Air or molten salt transport the heat to produce steam for steam turbines or for the direct use of a gas turbine.

Fig. 2.2: Parabolic trough solar thermal power plant.



Source: Quaschning & Blanco, 2001:2

2.1.3 Geothermal steam turbine power plants

The global installed geothermal generating capacity to produce electricity as at 2000 was 7,974.06 MW of which the OECD countries accounted for about 70% (International Geothermal Association, 2002; IEA, 2002). There are various technologies of geothermal plants and include among others direct-steam plants, flash-steam plants and binary plants.

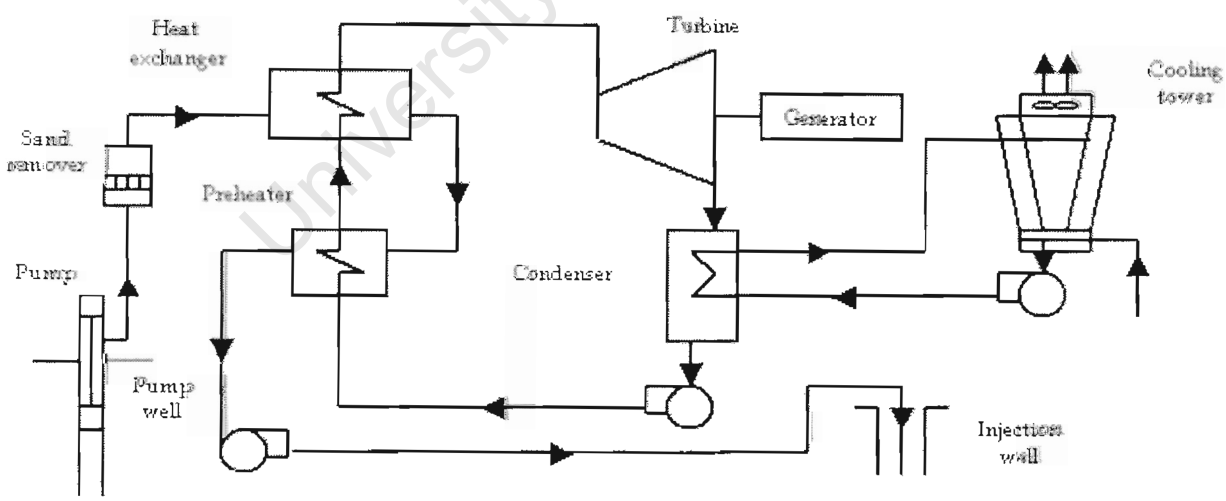
In direct-steam plants, dry saturated or slightly superheat steam produced from underground wells is directly transmitted to the turbine. Particulates and condensate in the steam are respectively removed by cyclone separators and drain pots. A moisture remover removes the moisture from the steam before it is admitted to the turbine. Non-condensable gases are removed from the system by the condenser. The condensate is used as makeup water for the cooling system and the excess is injected back into the reservoir.

Most geothermal reservoirs produce a two-phase fluid (vapour and liquid). The vapour is separated from the mixture by a highly efficient cyclone separator and the high-pressure steam utilised by the turbines. The liquid from the separator is injected, used for some direct heat applications or flashed to a lower pressure to produce additional steam for low-pressure turbine. Flash-steam plants are of two types and these are:

- Single-flash plants: these are plants that utilise the primary high-pressure steam from the separator.
- Double-flash plants: these are plants using both high- and low-pressure steam.

Binary plants operate on a closed conventional Rankine cycle. In this type, the geothermal energy of the fluid from the reservoir is transferred through a heat exchanger to a secondary working fluid. The suitable working fluids are hydrocarbons (isobutene, isopentane and propane) and certain refrigerants. Fig. 2.3 shows a schematic diagram of a binary geothermal power plant.

Fig. 2.3: Basic geothermal power plant



Source: DiPippo R, 1999:4.

The geofluid remains in the liquid state throughout the plant from extraction to injection. It is extracted by the pump and transferred to the heat exchanger through the sand remover. The working fluid is evaporated in the heat exchanger and then led to the turbine. After passing through the turbine, it is condensed and cooled in the condenser and then pumped to the evaporator through a preheater. If the turbine exhaust contains significant superheat, a heat recuperator is utilised to extract more heat from it to preheat the working fluid.

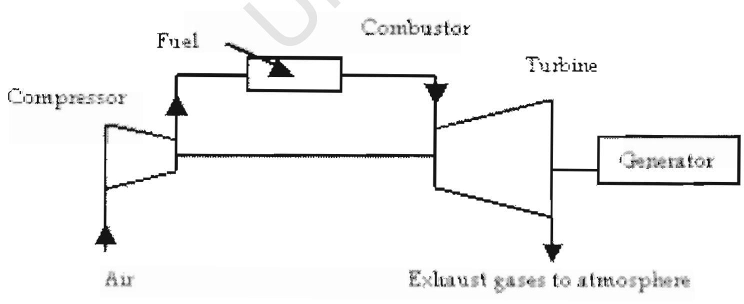
2.1.4 Gas turbine power plants

A gas turbine/combustion turbine power plant can burn either oil or natural gas and its principle of operation is the same as a jet engine. Basically, it consists of three components and these are:

- Compressor - this acts as a fan to drive the working fluid, which is normally air, into the heating system. It compresses the incoming air to high pressure;
- Combustor - this is the heating system, which burns the fuel/air mixture and produces high-pressure, high-velocity gas; and,
- Turbine - this extracts the energy from the high-pressure, high-velocity gas flowing from the combustion chamber to drive the compressor and generator.

Figure 2.4 shows a simple configuration of a gas turbine power plant.

Fig. 2.4: A simple theoretical gas turbine power plant



Air at an ambient temperature is drawn into and compressed in the compressor. Fuel and compressed air are introduced into the combustion chamber and the mixture ignited. The high temperature and pressure combustion gasses expand in and drive the turbine. They are exhausted into the atmosphere after passing through the turbine. The efficiency of this type of plant falls within the range of 27 - 38% (Loftness R L, 1978:384).

Some of the advantages of Gas turbine plants are: no requirement for cooling water; quick start ability and can attain full capacity within a short period of time; they have lower construction cost and time than steam turbines, but higher fuel cost; they can be distributed in medium sizes, being located near the demand and thereby minimising transmission losses.

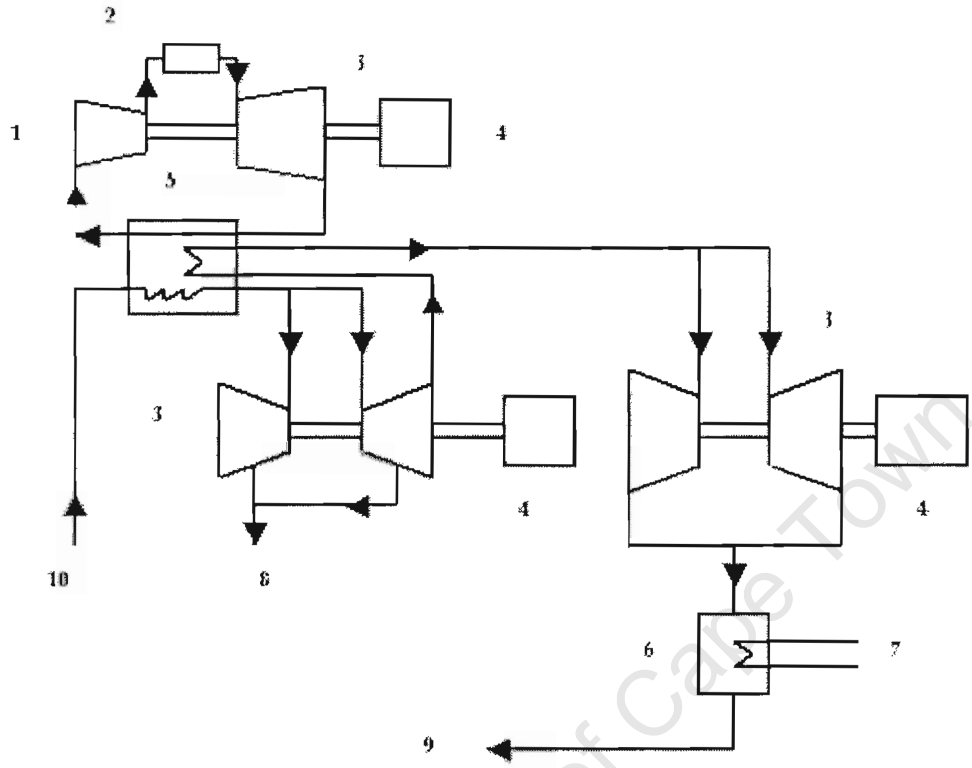
2.1.5 Combined cycle power plants

The rationale of combined cycles is to utilise the high-energy content in the high temperature exhaust gases from gas turbine power plants that would otherwise be wasted and the difficulty of attaining better performance from conventional steam power cycles through higher temperatures and pressures. They are generally a combination of a gas turbine generator, a heat recovery steam generator (HRSG) and a steam turbine generator. The three basic types of combined cycle are supercharged boiler cycle, exhaust-fired boiler cycle and the hot-air turbine cycle (Bennett KF, 2002). Fig. 2.5 below is a schematic diagram of a combined cycle power plant.

In the supercharged-boiler combined cycle, the boiler replaces the combustor in the conventional gas turbine. The air heater first preheats the high-pressure air from the compressor before entering the boiler where it is fired. The high-pressure gases from the boiler then expand in and drive the gas turbine. The remaining heat in the exhaust gases is recovered in the air heater, economiser, and stack-gas cooler. The combustor is maintained in the exhaust-fired-boiler combined cycle. The exhaust gases from the gas turbine are blown directly into the boiler. The final recovery of the low-temperature heat is similar to the supercharged-boiler cycle. In the hot-air-turbine combined cycle, hot high-pressure air that is first preheated by the air heater and then heated in the boiler is blown directly to the gas turbine. The exhaust air from the turbine then passes again through the combustion area of the boiler and then to stack. The low-temperature is recovered as in the other two combined cycles.

The thermal efficiencies of combined cycles can range up to 55% (Loftness R L, 1978:384).

Fig. 2.5: Schematic diagram of a basic combined cycle

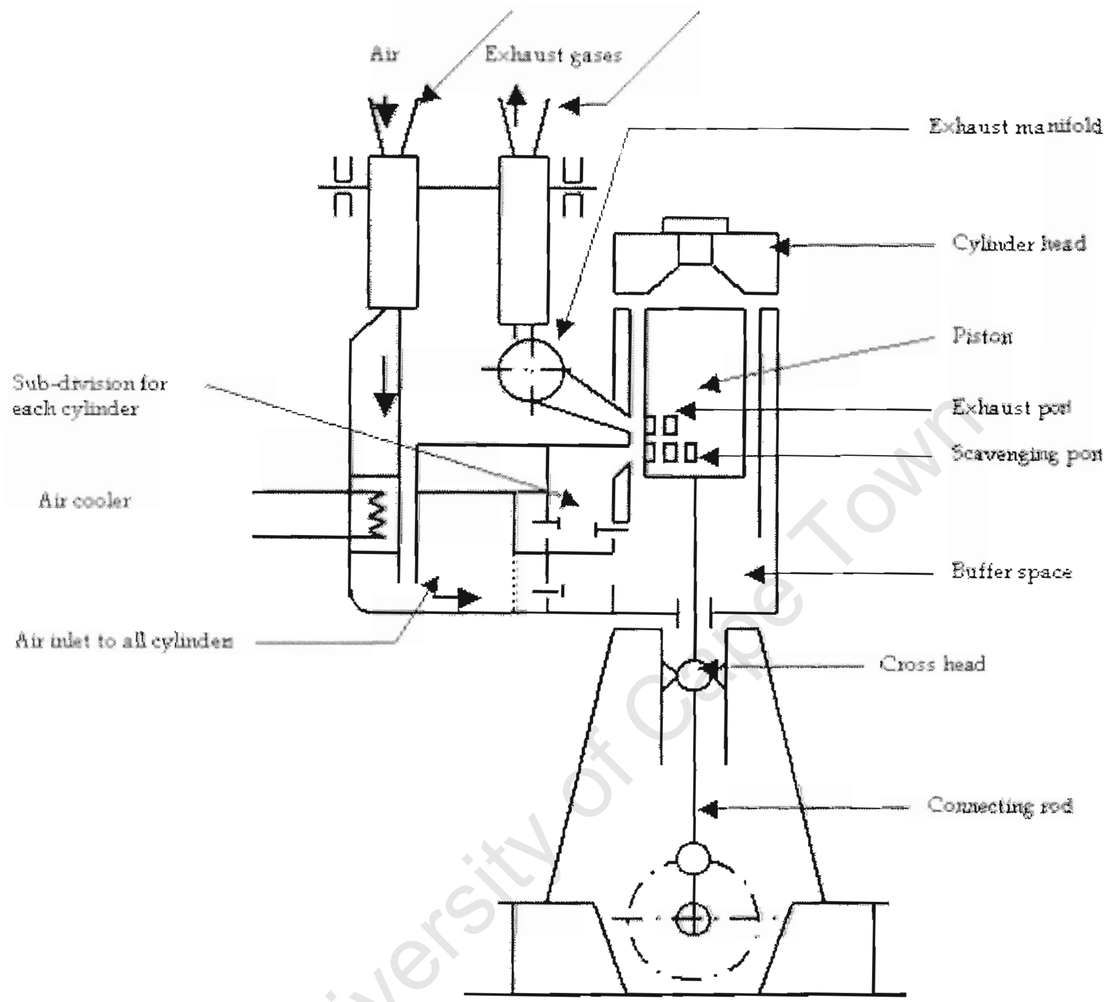


2.1.6 Diesel power plants

Diesel power plants are internal combustion (IC) engines that derive propulsive power through the ignition of a fuel-air mixture within a cylinder to generate combustible gases at high pressure that move a piston attached to a drive shaft to which the generator is connected. They are single acting and reversible two-stroke marine engines available in different sizes up to 10 MW. Fig. 2.6 is a sectional view of a typical diesel engine power plant.

When the piston is at the top dead centre, the scavenging and exhaust ports are closed by the lower part of the piston. Fuel is injected and combustion takes place. The piston will move down under the influence of the combustion gases. The air present in the buffer space is compressed. On it downward motion, the exhaust ports are uncovered, while the scavenging port are still closed the exhaust gases flow to the exhaust manifold. Further downward movement uncovers the scavenging port and the compressed air in the buffer space flows into the cylinder through the scavenging ports.

Fig. 2.6: Marine diesel engine power plant



Source: Service instruction manual for Sulzer diesel engine, Volume 185

The pressure in the exhaust manifold prevents escape of air in the cylinder through the exhaust ports. In the upward movement of the piston, the pressure in the buffer space drops and fresh air enters. The turbocharger, operated by the exhaust gases, supplies compressed air in an uninterrupted flow through the air cooler.

The efficiencies of diesel IC engine power plants are around 35%.

2.1.7 Nuclear power plants

As reported in 2001 by the Nuclear Energy Institute (NEI), the global nuclear power generating capacity was 348,414 MWe. According to the International Atomic Energy Agency (IAEA) power Reactor Information System, the total net installed capacity as of 1st January 2003 was 359 GWe with a world nuclear electricity generation of 2,574 TWh. The United States of America, with the highest installed capacity, accounts for about 28%, followed by France - 18% and Japan - 13%.

The energy source used in almost all nuclear power plants is uranium-235 (U^{235}), which is found in natural uranium. Natural uranium contains 0.7% of U^{235} and 99.3% of uranium-238 (U^{238}). However, for electricity power production, U^{235} is enriched to about 3%. Other energy sources used in nuclear power plants are plutonium-239 (which can be produced by bombarding U^{238}) and a mixture of plutonium and uranium.

A nuclear power plant is a thermal plant in which a nuclear reactor acts as a boiler. Fission reaction in the nuclear fuel produces the thermal energy. The fuel is located inside the reactor, which is hermetically sealed. The heat generated in the reactor and transmitted to a coolant is used to produce steam that is admitted to and drives the turbine where its energy is transformed into electrical energy.

Nuclear power plants are classified according to their reactors. Different types of reactors exist characterised by their three main components: fuel, coolant and moderator. The fuel provides the thermal energy, which is removed from the reactor by the coolant. The moderator controls the reaction of the fissile material in the reactor. The most common moderator materials are light water (normal), heavy water (water molecule consists of deuterium instead of hydrogen) and carbon (graphite). However, the most common reactors used for electricity production are shown in the table 2.1 below with their characteristics.

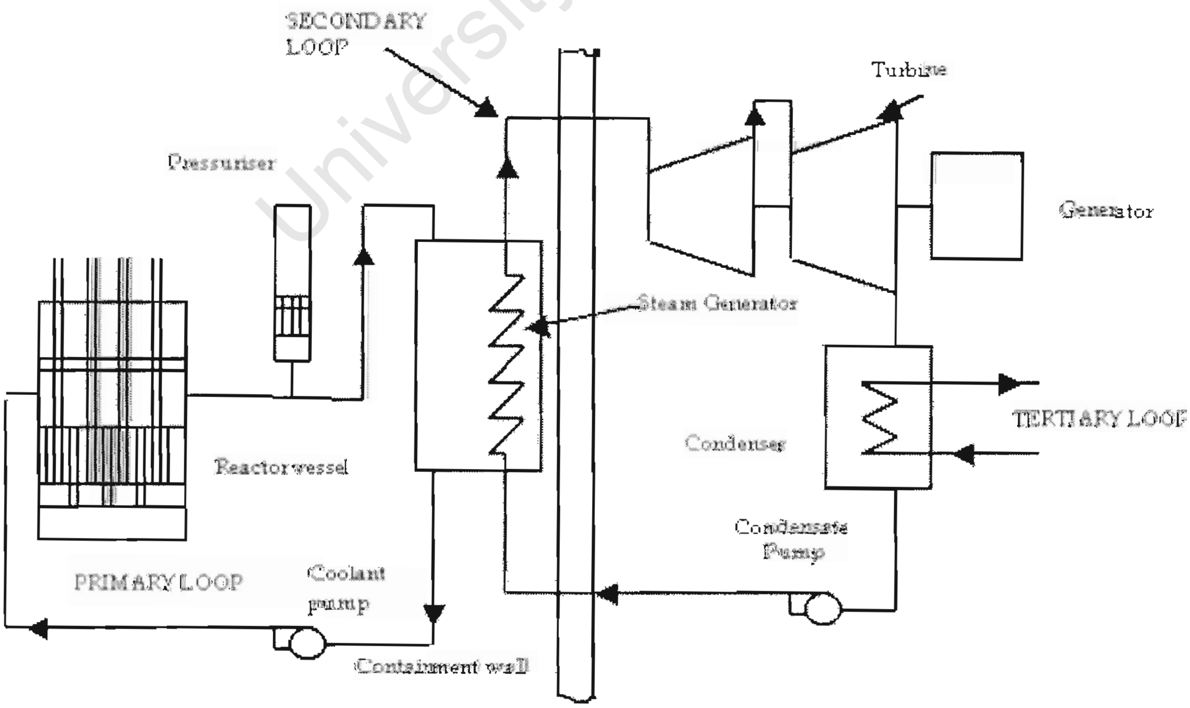
Fig. 2.7 is a typical pressurised water reactor (PWR) nuclear plant. It consists of the basic equipments of a fossil fired power plant and the reactor. It operates on three separate water systems. The primary and secondary loops are closed systems. The primary loop contains the coolant, which is very radioactive. It transfers the heat produced in the reactor to the steam generator where the steam is produced. The coolant pump again pumps the coolant to the reactor. The coolant is not allowed to boil and kept in the liquid state throughout by the pressuriser.

Table 2.1: Characteristics of some reactors

Reactor	Coolant	Moderator
Light-Water reactor: Bioling water reactor (BWR)	Water	Water
: Pressurised water reactor (PWR)	Water	Water
Heavy-Water reactor	Heavy water	Heavy water
Gas-cooled: Magnox reactor	Carbon dioxide	Graphite
: Advanced gas-cooled reactor	Carbon dioxide	Graphite
: Pebble Bed Modular Reactor (PBMR)	Helium	Graphite
Fast Breeder Reactor	Sodium	None

The secondary loop contains water that is pumped to the steam generator. This water is allowed to boil and form steam, which is then led to drive the turbines and generator. Once the steam has driven the turbines it flows to the condensers where it is cooled back to water and circulated back to the steam generator. The tertiary loop is seawater and it cools the condenser.

Fig. 2.7: PWR nuclear electric plant



2.2 NON-THERMAL PLANTS

Non-thermal power plants use the kinetic energy of falling water or air to drive a turbine. They are hydroelectric plants and wind electric power plants. The two types are described below.

2.2.1 Hydroelectric power plants

Hydropower is by far the largest source of renewable electricity generation and represents the third largest provider of total electricity in the world. The total technical potential of hydropower in the world is about 14,000 TWh/year with a current installed generating capacity in the range of 675 – 692 GW and a further 110 GW under construction (Bonsor K; Lafitte R, undated). Lafitte also stated that the share of hydropower to world's electricity production, at present, is about 19% (2,650 TWh/yr). Canada, with an installed capacity of 65,678 MW, is the world's largest hydropower producer and accounting for more than 13% of the world's production (Canada Hydropower Association). But the largest hydroelectric plant is the Itaipu power plant (12.6 GW) jointly owned by Brazil and Paraguay followed by the Guri power plant (10.3 GW) in Venezuela (Bonsor K, undated). The Three Gorges hydro project in China, if completed in 2009 will be the world's largest hydroelectric plant with a capacity of 18 GW.

Hydroelectric plants are divided into conventional plant (dam and run-of-river types) and pumped storage. A conventional hydroelectric plant consists the following components:

- A dam to control the flow of water and increases the elevation to create the head;
- Penstock, which is a pipe or tunnel, conveys the water under pressure from the reservoir to the turbine in the power station;
- Surge tank: this is a concrete shaft or steel tank located along the penstock to prevent excessive pressure changes due to load changes to affect the penstock;
- Turbine provides the mechanical energy from the force of the water pushing against its blades to drive the generator. The most common turbine for hydro plants is the Francis turbine;
- Generator produces the electrical energy; and,

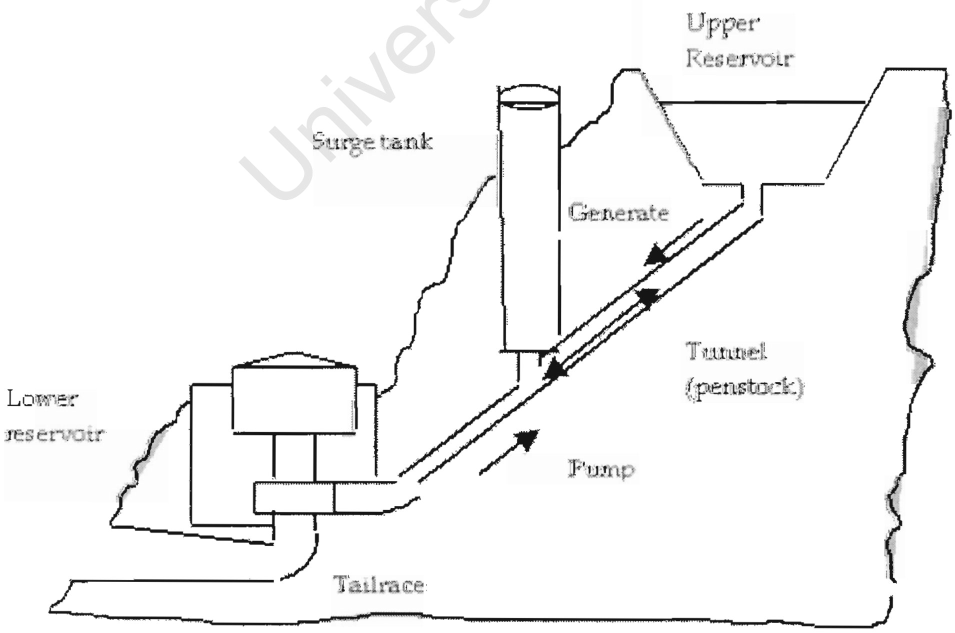
- Tailrace is a channel leading back to the river situated below the power station into which the turbine discharge.

Conventional hydroelectric plants are normally built on a river course, where a dam is created to retain water. The mass of dammed water is conducted through the penstock to the blades of the turbine, where its kinetic energy is converted into mechanical energy and electrical energy. The turbine is usually located at the foot of the dam. After passing through the turbine, the water is discharged into the tailrace, exit and carried downstream.

Fig 2.8 is schematic diagram of a pumped storage facility. It consists of two reservoirs (upper and lower) of essentially equal volumes. These are connected by the penstock along which a pumping-generating station is located.

The principal equipment of the station is the pumping-generating unit, which is a reversible machinery designed to function as a motor-pump in one direction of rotation and as a turbine-generator in the opposite direction of rotation. In the generation mode, water is released from the upper reservoir through the turbine to the lower reservoir. During periods of low demand, the turbine-generator will operate in the reverse mode and pump the water to the upper reservoir.

Fig. 2.8: A pumped storage hydroelectric plant.



Pumped storage facilities are normally used as peaking plants.

2.2.2 Wind electric power plants

A wind electric power plant is one in which the kinetic energy of air in motion is transformed into mechanical rotation energy to drive a generator. Modern wind turbines are divided into two types. These are:

- Horizontal axis wind turbine (HAWT); and,
- Vertical axis wind turbine (VAWT).

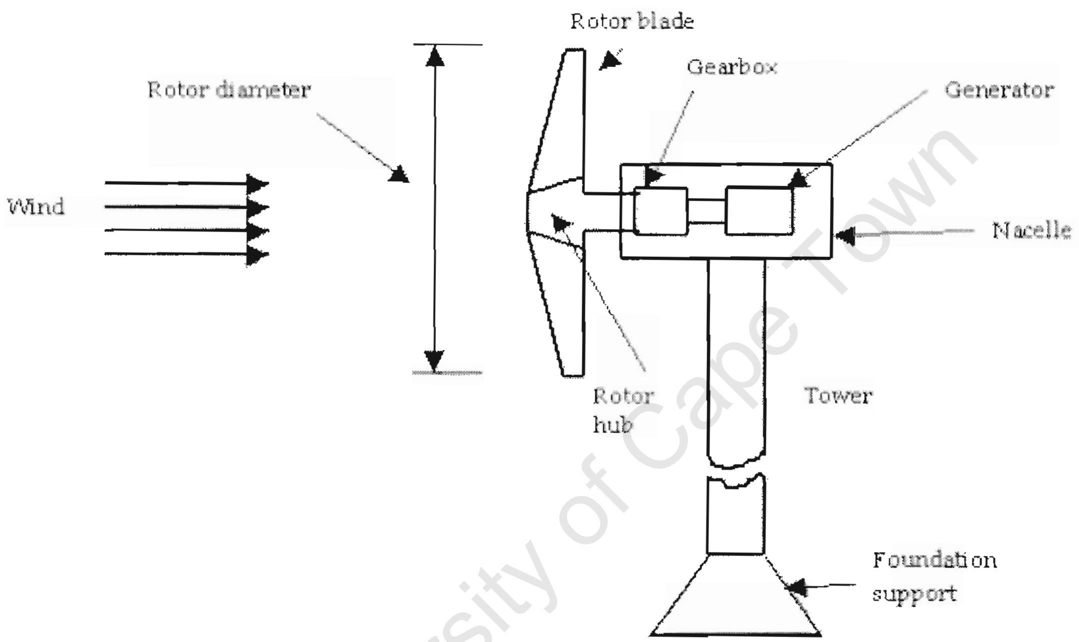
Both HAWT and VAWT are made up of several systems. These are:

I. The rotor system: this contains the assembly of blades, hub and shaft. Modern rotor systems are usually made up of two or three blades (up to about 65 m) designed to extract energy from upstream flow of the wind. Most HAWT consists of two or three blades while VAWT are made up of two blades.
II. The tower: this supports the rotor system and drive train in the case of the HAWT. The height of the tower can be up to between 25 and 80 m.
III. The drive train: it consists of the gearbox, a breaking mechanism and the generator.
IV. Miscellaneous: these include the control and safety system, electrical connections, service facilities and supporting structure.

The diagram below shows a simplified version of a HAWT. The wind turns the impellers round; this spins a shaft inside the nacelle. The shaft connects to the generator through the gearbox, which increases the rotational speed. The generator then converts the rotational energy into electrical energy. The control systems are fitted on top of the nacelle. When there is a change in wind direction, the nacelle and rotor are turn around to face the wind by motors. The nacelle is also fitted with brakes, so that the turbine can be shut down at very high wind speeds.

The output of a wind turbine depends on the wind regime where it is located. Wind turbines start to operate at wind speeds of 4 to 5 metres/second (m/s) and can reach maximum power output at around 15 m/s. At gale force winds (25+ m/s), wind turbines will be shut down by the power control system. Its normal capacity factor and efficiency are in the region of about 30% respectively.

Fig. 2.9: Simplified version of a HAWT



Source: Ndyeshobola A et al (eds.), 1996:18

HAWT accepts wind in one direction and thus requires a control mechanism to continuously track the wind direction while VAWT accepts wind from any direction. But VAWT blades lose energy as they turn out of the wind, while HAWT blades work all the time. Wind speeds increase with altitude and this gives an advantage to tall HAWT. VAWT is less costly and easier to maintain because of its small tower and ground-mounted generators.

The current global installed wind electric power plant is 30 GW (American Wind energy Association) with an average annual growth of 32% between 1998 and 2002. According to Gipe's (2000) analyses of the BTM consultant one time report of the wind industry, today's state-of-the-art wind turbine cost about US$ 1000/kW and operating and maintenance (OM) costs are averaging between US$ 0.006 and

US$ 0.01 per kWh. He further noted that after 10 years of service, OM costs will rise very little to US$ 0.015 - 0.02/kWh.

2.3 ELECTRICITY PRODUCTION COSTS

Table 2.2 shows an estimated electricity production costs for the different energy sources. As shown, solar thermal has the highest production cost. But due to the improved production methods, costs have been falling at an annual average rate of about 5% in real terms (Appleby P, 1999:56). According to Quaschning and Blanco (2001), the levelised cost of solar electricity has reduced from 0.27 US$/kWh in the first power plant to about 0.12-0.14 US$/kWh in the last installed system. So, solar electricity will become very competitive in the near future. Other renewable energy sources, especially hydro and most geothermal, are already competitive with fossil and nuclear sources.

Table 2.2: Estimated electricity production costs from different energy sources

Energy source	Production cost (US cents/kWh)
Fossil/nuclear	2 – 6[a]
Solar thermal	12 – 20[b]
Geothermal	1.5 – 6.5[b]
Wind	5 – 11[a]
Biomass	8 – 11[a]

[a] *1998 estimate.* [b] *2000 estimate.*

Source: Appleby P, 1999: 54; Barbier E, 1999: 153; Lund J, 2000:124; Geyer M, 2000:184

CHAPTER 3
POWER PRODUCTION ENERGY EFFICIENCY PRACTICES

3.0 INTRODUCTION

Energy efficiency (EE) is a practice to reduce energy inputs for the same products, processes, services, procedures and facilities or increasing output for the same energy input. In other words, energy efficiency concerns how much energy is used or saved relative to the service demanded. EE includes energy conservation, which deals with the amount of energy consumed. Hence, the application of energy efficiency should focus on the technological aspect of energy use and human or institutional behaviours that drive energy consumption.

Energy efficiency is a proven energy resource. The maximum demand on any power system is seldom constant; rather it varies throughout. This demand increases as the customer base increases and it peaks more in high demand such as colder months. The cost of generating power to meet this peak demand will also increase. It may require the addition of new generating plants when the maximum peak is about 80 - 85% of the total installed capacity. The application of EE practices on the demand side can reduce the peak and hence prevent the construction of new power plants in cases where there is saturated demand.

Energy efficiency can be an economic instrument of increasing the profitability of the utility. With increases in fuel costs and electricity, appreciable financial rewards may be gained by using the four categories of energy cost savings - housekeeping, low cost modification and improvement of systems, retrofits and major capital expenditure (ERI, 2000a). In most cases, the payback period on investment made to improve the EE may be less than a year.

The application of EE measures has some environmental benefits through the reduction of adverse emissions from electricity sources, as electric power generation is one of the major sources of atmospheric pollutions. Thermal plants emit more greenhouse gases and particulate matter than other types of plants. These pollutants have considerable effect on the ecosystem and human health. As pointed out above, cutting down peak demand can reduce fuel input and postponing or avoiding the building of new power plants.

This chapter explains the energy efficiency practices in power production and how to improve them. EE in the power industry involves getting the most usable energy out of the fuel that supplies the power plant (US DOE). O'callaghan (1981:22) noted that the energy cost of a product depends upon the energy usage during manufacture, including that used to maintain a comfortable thermal working environment. Therefore, the total energy input to produce electric power is the fuel input plus the energy consumed by the plant auxiliaries and that to maintain a comfortable working environment. According to Scott Rouse (undated), EE in energy generation could be measured in two ways:

1) A reduction in station service, e.g., reducing the energy (kWh) used in making energy; and,
2) A production increase (thermal efficiency), e.g., more energy (kWh) out for the same amount of fuel.

These are described below.

3.1 REDUCING THE STATION/PLANT AUXILIARIES' ENERGY CONSUMPTION

The basic energy consuming systems in a power plant are:

- Inductive loads;
- Compressed air;
- Process heat;
- Steam; and,
- Lighting.

Inductive loads

In general inductive motors and other inductive loads (for instance, induction furnaces and arc welding plants) consume most of the auxiliaries' energy input in electric power generating plants. About 50-60%

of the total electricity used is consumed by electric-drive systems (US DOE, 1996a). The major source of energy consumption in motor-driven systems is low power factor (pf), which is adversely affected by low loading. The maximum efficiency of a motor is usually near 75% of its rated output and it reduces dramatically below 50% while its power factor will start to drop off at about 65% of full-load amperage (US DOE, 1996b). Fully loaded induction motors can have power factors below 0.6 and on low loads power factors can approach 0.1 (UK Department of Environment 1997a).

Electrical equipments operating at low pf use excess current and this has an impact on the utility, as this will increase its production cost. In addition, excess current can cause overheating and premature failure of the motor. Furthermore, it has an effect on the size and cost of equipment used to supply energy to the motor. For instance, the sizes of switchgears, cables and transformer need to be increased to handle the excess current. Depending on the country, many utility companies charge additional fees for pf less than the allowed minimum. The allowed operating power factor in the United States of America is 0.95 while Ghana is 0.9. In South Africa the allowed operating pf is a 30% band below 0.98. In many countries the tariff for industry is made to penalise low pf.

The appropriate method to reduce energy consumption in inductive loads is to correct the pf. For motors, individual pf correction is necessary for constant loads. If a capacitor is fitted there is no need for additional switchgear. Other efficient measures to operate a motor are: the use of variable speed drives for varying loads and controls to turn off idling motors. Idling motors can take up to 50% full load current (UK Department of Environment 1997a).

Compressed air system

In power generation, compressed air is used to start internal combustion diesel engines and operating hand tools (pneumatic spanners) needed for machine jobs. Energy consumption is negligible because the system is not often used.

The means of increased energy consumption are:

- Leaks: they can cause pressure drop in the system, excess compressor capacity and increased run time that can lead to decreased service life. The consequence of pressure drop is additional generated pressure to cover losses and hence more energy consumption. Therefore leaks are means of wasting energy and this can be as much as 20-30% of the compressor output (ERI, 2000b). Common areas of leaks are couplings, hoses, tubes, fittings, pipe joints, flanges, packings, thread sealants, FLRs (filters, regulators and lubricators) and point of use devices. Table 3.1 below shows the power wastage through leaks as a function of hole diameter and pressure.

Table 3.1: Power wasted through leaks

Hole diameter (mm)	Air leakage at 7 bar (l/s)	Power required to compress air being wasted (kW)
0.4	0.2	0.1
1.6	3.1	1.0
3.0	11.0	3.5

Source: Adapted from ERI, 2000b.

- Air filters: an improper sized air filter in relation to pipe network and a dirty or clogged filter will also cause pressure drops in the system.
- Dryers: depending on the type of dryer used the energy consumed can be in the range of 3% - 5% of compressed air or electrical equivalent [ERI, 2000b: 24-25].

Therefore, to improve the energy efficiency of a compressed air system is to reduce or eliminate leaks, utilising properly sized and clean air filters and efficient dryers.

Process heating

To raise steam in fossil fuel fired turbine plants for process heating, about 90% of the energy input is consumed. When an HRSG is used, process heating can account for between 10% and 20% of the energy input due to the addition of an auxiliary oil fired boiler.

Process heating systems in power stations include heating devices (boilers, feedwater heaters and deaerators), heat transfer devices and heat recovery devices (heat exchangers - economisers and recuperators). In most applications, fuel-fired, steam heating or electric heating supplies heat. Factors such as process temperature, equipment design and operation, and the type of heat recovery system used determine the energy efficiency of the process heating system. With the use of advanced technologies and operating practices, process heat energy consumption could be reduced by 5 - 20%.

In boilers, heat is produced mainly by the combustion of fossil fuels. The heat is then transferred to the water to produce steam. The heat discharged from the stack accounts for the largest loss in fuel fired boilers and it has the following components:

- Energy loss due to unburned carbon: this is a loss of potential heat in the fuel. It is less significant for gas and oil fired installations.
- Energy loss due to the dry flue gas: this is the loss as a result of nitrogen entering at ambient temperature and leaving at higher temperature.
- Energy loss due to the presence of water vapour in the fuel, combustion air and that produced by the combustion process: this is the energy wasted in heating the water to the temperature at which the flue gases leave the boiler.
- Energy loss due to incomplete combustion: this is due to the imperfect mixing of stochiometric air and fuel or ineffective atomisation of the fuel. The minimum amount of excess air required depends on the fuel and the mixing efficiency. If less than the minimum quantity of air is supplied, some of the fuel will not burn completely which is a waste and too much excess air is also a waste as the excess air has to be heated and passed out in the flue.

In practice this loss varies between 8 - 50% depending on the fuel.

The quantity of total dissolved solids (TDS) and the quality of the make-up water affect the performance of boilers. Blowdown is an important boiler operation to remove sludge that builds up on the boiler furnace tubes. But when the quantity of blowdown exceeds the minimum necessary, then it becomes another source of energy loss. The installation of a blowdown heat recovery system, the correct checking and maintenance of feedwater and boiler water quality can reduce the energy loss, at the same time maintaining or improving the performance of the boiler.

The heating transfer rate of steam in process heating is greatly impaired by fouling, which is a loss of energy. Generally, fouling of tubes is due to sedimentation, scaling, reaction, corrosion and biological growth. Regular cleaning of inside tube surfaces is very necessary.

Steam utilisation

The main use of steam in power generation is to provide energy to drive the turbine in steam turbine plants or to heat the high viscous heavy fuel oil in diesel power plants. Energy losses in transmitting steam from the point of generation to end-use are due to lack or poor insulation, steam leaks, pressure drops along the pipe lines and fittings, improper sizing of pipes and the presence of air in the pipe lines.

Depending on the process temperature and length of the bare steel pipe, the amount of energy loss due to the absence of insulation can be very significant. For instance, the energy loss from a NPS 4 uninsulated pipe transmitting steam at 135°C is approximately 600 Wh/m (ERI, 2000c: 47). This can be a huge loss if the pipe is left uninsulated throughout the year. Heat loss increases as the surface area increases. So, an oversized pipe increases energy loss.

The temperature of a process steam depends on its pressure. Steam flowing through a series of pipefittings and bends suffers considerable pressure loss. Table 3.2 below shows the pressure drop through various fittings expressed in terms of equivalent straight length of pipe. Depending on the number of bends and valves and the distance of transmission, the pressure loss can be significant. This is an energy loss because more fuel will be consumed to increase the pressure to compensate the pressure loss to meet the required temperature of the process.

When steam is turned off and allowed to cool, air will enter the system. If in the next operation this air is not aspirated, it will mix with the steam and lowers its temperature. The effect is more drastic due the high thermal resistance of air. Again, the pressure has to be increased to meet the heating temperature.

Table 3.2: Resistance of standard pipefittings measured as equivalent pipe length (meters)

Pipe size (mm)	Standard elbow (90°)	Standard bend (90°)	Tee (flow through branch)	Gate valve (open)	Globe valve (open)
50	1.5	0.6	3.0	0.7	17
65	2.0	0.8	4.0	0.85	22
80	2.4	1.0	4.8	1.0	27
100	3.0	1.2	6.0	1.3	34
125	3.75	1.5	7.5	1.6	43
150	4.5	1.8	9.0	2.0	51
200	6.0	2.4	12.0	2.6	68

Source - ERI, 2000d: 12

The effective way to reduce the energy consumption in steam utilisation is to determine the correct pressure of the process and using the right size of pipe and insulation, steam traps and air vents.

Lighting

Lighting is very important in power stations for a better working environment. Depending on the types of lamps and electrical fittings used, the amount of energy consumed and maintenance costs can be significant. Upgrading the lighting system with advanced technologies (high intensity discharge lamps, electronic ballasts and compact fluorescent lamps and metal halide fixtures) and controls (photo cells and occupancy sensors), considerable energy consumption can be reduced.

3.2 INCREASING THE THERMAL EFFICIENCY AND CAPACITY OF PLANT

Maintenance

Maintenance, as defined according to BS 3811, is work undertaken to keep or restore a facility to an acceptable standard (Parrish A, 1980:20-96). An electric plant is a complex assembly of off-the-shelf components and custom-engineered equipment. Its reliability and safety throughout its useful life is very crucial. The components and equipment of a power plant are faced with a wide range of operating environment and service conditions (highly corrosive gases; deposition of corrosive solid material; erosion caused by high-velocity, abrasive solid materials; high temperatures; etc). Thus, their service life defers considerably and this will affect the ability to maintain reliable integrated operation. Failure of a component, or its failure to meet performance specification, results in the inability of the plant to perform efficiently or to generate at designed output.

There are many circumstances under which Power systems may fail to meet their performance and reliability expectations. For instance, imperfect information regarding conditions of service can result in exposure to stresses higher than the designed stresses; unexpected trace materials in the fuel supply can result in higher corrosion; improper operation or failure of control components may also shorten components lives. Air in-leakage affects the steam turbine output by increasing the backpressure. It also affects the performance of the condenser due to increased dissolved oxygen (O_2) and carbon dioxide (CO_2) that will enhance corrosion. An increase of 1 in-Hg backpressure can reduce the turbine capacity by 2% and the corresponding heat rate increase is severe. For every 0.1 in-Hg increase in turbine backpressure the corresponding heat rate increase is approximately 16 Btu/kWh (www.platts.com/engineering/issues/Power/0201/0201pwr_fom.shtml).

Therefore maintenance is very necessary to achieve the reliable and safe operation of any generating unit. Inadequate maintenance accelerates depreciation and leads to excessive damage at an exceedingly high cost in both repairs and down time. Such loses can be prevented. Generally, maintenance of electric generating units falls into three categories. These are proactive, reactive and predictive (Sullivan GP et al, 2002:5.1-5.4).

Proactive maintenance is planned maintenance and it is an action performed based on fixed calendar schedules or hours of service (regardless of the condition of equipment) that spot, prevent, or moderate degradation of component or system with the aim of extending its useful life. Actions like regularly changing of lubricants, replacements of seals, major overhauls that are done according to manufacturers' recommendations or utility' experience can extend equipment life and increase reliability.

Reactive maintenance is an unplanned maintenance. This is carried out when components or systems fail or experience performance deterioration. This involves the replacement of an identical part or an improved design or material. This type of maintenance can also be initiated by discovery of situations that lead to component failure if not corrected.

Predictive maintenance is "measurements that detect the onset of a degradation mechanism, thereby allowing casual faults to be eliminated or controlled prior to any significant deterioration in the component physical state" (Sullivan GP et al, 2002:5.3). It is used to define needed maintenance task based on equipment condition. Predictive capability (monitoring equipment) allows threatening conditions to be exposed and alleviate prior to failure. This can avoid the cost of lost generation, wear and tear on equipment that occur during the shutdowns and start-ups and safety risks associated with failure.

Utilising combined cycles

The relative low efficiency of gas turbine can be due to either low temperature input or high temperature in the exhaust gases. The heat in the exhaust gases may be used to raise the efficiency by regeneration - heating the compressed air before the combustion process. Using the appropriate plant, the heat may be used more effectively to raise steam by feeding the engine exhaust gases into a boiler, to drive a steam turbine and generate more power. Steam-turbine-gas-turbine combined cycle offers an effective method of increasing the heat rate and power output of steam turbines. With such a combination, the heat rate and power output improvement can range between 1.8 - 6.5% and 5.8 - 21% respectively (Bennett K F, 002).

Gas-turbine upgrade

The use of gas turbines in hot climates has a major disadvantage. Its output decreases significantly as the ambient inlet air temperature increases. The lower density of the warm air reduces the mass flow through the gas turbine. According to Hicks (1998), the three most common methods to handle such problem and increase the output include:

1. Injecting water or steam into the combustor. This can significantly increase power output, but the overall combined cycle efficiency will be affected. For steam injection, steam can be extracted either from the high-pressure turbine or HRSG section.

2. Precooling using evaporative coolers, mechanical chillers or absorption coolers. This involves spraying water into the inlet air stream to cool the air near the ambient wet-bulb temperature. It is a technique that boosts the gas turbine output by increasing the density and mass flow of the air entering the unit. The overall output can be increased by about 4%-5%, and the incremental cost can be about $200/kw.
3. Supplementary firing of the HRSG. This method lowers the cycle efficiency and has a higher emissions and costs for larger plants.

The choice of any option has to be balanced between capital investment and overall performance of the system as the addition and operation of other components will be affected.

Phillips and Levine (2002) show that supercharging and coating of gas turbine internal components and compressor blades can upgrade gas turbine performance. Supercharging of a gas turbine requires the addition of a fan to boost the pressure of the air entering the inlet compressor, its impact is more significant if it is coupled with inlet precooling downstream of the fan. Supercharging and precooling could increase output by 24% while improving the heat rate by 4%. Applying thermal barrier coating provides an insulating barrier between the hot combustion gases and the metal parts. This will allow increased firing temperature and longer component life. Coating of gas turbine compressor blades provides smoother, aerodynamic surfaces that increase compressor efficiency since smoother surfaces tend to resist fouling.

3.3 DEMAND SIDE MANAGEMENT (DSM)

However, reducing the station services and improving the thermal efficiency of the plant are just two ways to pursue EE in power production from the supply end. Demand side management (DSM) is an effective programme that also contributes to the efficient operation of power plants as it involves the end user.

Swisher (undated), as quoted from Electric Power Research Institute (EPRI), defines DSM as the planning, implementing and monitoring of those utility activities designed to influence the customers amount and timing of electricity demand in ways that will increase his/her satisfaction and produce desired changes in the utility's load shape. Due to the inability and/or cost to store electricity, it is only generated at the moment it is needed. As a result during periods of low demand, utilities operate plants below rated output, which is very inefficient. Storing electricity during period of low demand can improve the efficiency and reliability of the electric utility system. This can reduce energy wasted in keeping spinning reserves to meet peak power demand and running base load efficiently, i.e., running them at full capacity.

Changing the normal load shape to the utility's desired one can cut fuel input, postpone or avoid the construction of new plants. DSM is a programme that benefits residential, commercial and industrial sectors, utilities and including society. The following are some of its benefits:

- It reduces customers' energy bills;
- It reduces emissions that cause global warming and acid rain through the utility's use of less fuel and avoidance or postponement of new power plant;
- It can reduce maintenance and equipment replacement costs;
- It enhances national security by easing dependence on foreign energy sources.

Generally, utility DSM activities fall into two categories: load levelling and load reduction.

Load levelling

Load levelling involves redistributing energy demand to spread more evenly throughout the day - load shifting. Energy management control systems (EMCS) can enable the utility to control end-user equipment (typically applied to heating, cooling and ventilation) and also invoke on-site generators. The following are some innovative rates the utility can use to influence consumers' patterns of electricity use:

i. Time-Of-Use rate: this is rate option that considers on-peak and off-peak hours in the calculation of energy bills. It offers reduced rates for usage and demands during off-peak periods. This is an incentive measure for end-users to shift demand to off-peak hours. This can benefit both the utility and the customers.

ii. Interruptible rates: this option offers discount (generally on maximum demand charge for large users) in exchange for the right to reduce customer's electricity demand when requested by the utility.

iii. Power factor charge: this is a charge for industrial and commercial customers that are operating below the stipulated pf. It is a negative incentive to discourage them from partially loading their electrical equipment, as this is one of the major causes of low pf.

Load factor is defined as the ratio of the average load to the actual maximum load. Its optimisation offers opportunities for industrial and commercial sectors to use the same amount of energy and maintain the same average load. This is achieved by reducing the maximum demand - moving loads to period of low demand - since it is normally regarded as twice the highest load taken during any half hour in any month (UK Department of Environment 1997). Load factor controls consist of simple alarms or indicators. These will notify energy managers when a predetermined energy demand, which is below the maximum demand, is reached to shift operations.

Load reduction

Load reduction is energy conservation programmes to reduce electricity use. For instance, programmes to improve the efficiency of equipment (energy-efficient lighting, appliance and motors), buildings and industrial processes.

CHAPTER 4
THEORETICAL CONSIDERATIONS OF ELECTRICITY TARIFF

4.0 INTRODUCTION

Ideally the revenue generated by any electric utility must in the long run be enough to cover the entire costs of service although this might not be the case in situations where electricity production is subsidised. This revenue or revenue requirement is obtained from two kinds of charges: an energy charge and a demand charge. Therefore, setting of tariff should reflect the costs of service and meet the following objectives (USAID, undated: 46):

- To collect adequate revenue to operate the electric system reliably and to attract the necessary capital for maintenance and expansion;
- To send efficient price and consumption signals to electric consumers; and,
- To allocate costs of the system fairly among customers.

The design of tariff should enable utilities to recover their annual production costs and have a fair return on their capital investments, but at the same time customers should not be overpriced.

Electricity bills received by consumers consists of both tariff and non-tariff charges. The tariff charges are energy and capacity charges. The energy charge is intended to recover the annual generation and supply costs while the capacity charge is intended to recover the capital costs. Non-tariff charges are customer specific. These are administrative costs to provide the customer with electricity. The payment of these costs depends on the utility methodology of collecting revenue.

Any electric utility has different customer categories and tariff structure. The actual allocation of costs to the different customer groups is not ideal. There are cross subsidies between energy and capacity charges among the different customer categories. In many countries, industrial and commercial customers subsidise the residential customers. This is to make provision for the affordability of the tariff rate. In other cases, the reverse is done to boost industrial development, especially emerging industrialising countries.

The purpose of this chapter is to give a brief overview of how average tariff can be determined. The allocation of the average tariff depends on the individual utility methodology.

4.1 REGULATORY METHODS OF TARIFF SETTING.

The presence of a regulatory body in the ESI is very necessary. This is due to the characteristics of the industry and usually the transmission and distribution functions are normally monopolies. The basic functions of a regulator in the electricity market are to control market power for a fair competition in a competitive situation, to allow investors a fair rate of return and to protect the end-users. The mechanisms used are based on either of the following methods: rate-of return (ROR) and performance based (PB) pricing. PB pricing tools can be price-cap (PC), revenue cap (RC) and sliding scale (SS).

4.1 Rate-of-return (ROR)

Rate-of-return (ROR) is also known as revenue requirement. According to Jamison (2001) this type of pricing mechanism is used for the following:

- To constantly monitor the utility earnings and allow price adjustment to keep the realised rate of return in line with what is allowed;
- To adjust price levels in a rate case setting;
- To review past efficiency assumptions during a price review;
- To set initial price for price cap regulation; and,
- To set net present value (NPV) of cash flows earning a particular rate of return.

The prices are set to enable the utility to generate an allowed rate of return on all capital investments used and useful in delivering service and its operating costs including depreciation and other taxes. The following formula is used to determine the total revenue requirement necessary to meet demand for service:

$$RR = [(V-D)*r] + E + d + T \text{ --------------------(4.1)} \qquad \text{(USAID, undated: 32)}$$

Where:

- RR = Revenue requirement;
- V-D = Book value of the useful fixed asset (rate base);
- V = original book value of plant in service;
- D = accumulated depreciation;
- r = allowed rate of return (weighted average cost of capital);
- E = operating expenditure;
- d = annual depreciation expenses; and,
- T = taxes.

Fixed assets are the useful assets used by the utility in generating and delivering electricity. They include generating plant, buildings, vehicles, poles, wires, computers, etc. There are various methods to value the rate base. Methods such as historical cost, replacement cost and concession bid are most commonly used. The choice of method will depend on the regulatory regime. Operating costs include production and delivery costs, wages, salaries, maintenance, billing, administration and general expenses.

Depreciation is the annual accounting charge for wear, tear and the obsolescence of the plant. It is an expense though non-cash. Different methods can be used to estimate depreciation but straight-line method is always used, by accounting conventions, to calculate book-depreciated expenses in the income statement. This method assumes the value of an asset to decrease at a constant rate and the depreciation at any year is given as:

$$D_t = \frac{P - F}{n} \quad \text{-------------------(4.2)} \qquad \text{(Thuesen and Fabrycky, © 1998)}$$

Where:

- D_t = the depreciation charge in year t;
- P = original cost of asset;
- F = salvage value; and,
- n = estimated life.

Generally, the value of a plant decreases more rapidly in the first few years in service. So, other accounting methods that depreciate the assets rapidly can also be used. These are sum-of-the-year's digits and declining balance. Sum-of-the year's digit depreciation assumes the asset value decreases at a decreasing rate and the depreciation at any year t is given as:

$$D_t = \frac{n-t+1}{n(n+1)/2}(P-F) \text{ --------------------(4.3)} \qquad \text{(Thuesen and Fabrycky, © 1998)}$$

Where P, F and n have the same meaning as above.

Declining-balance method depreciates the asset based on the net book value, which decreases over time. The general expression for the depreciated charge for any point in time is given as:

$$D_t = \alpha(1-\alpha)^{t-1} * P \text{ --------------------(4.4)} \qquad \text{(Thuesen and Fabrycky, © 1998)}$$

Where α = fixed depreciation rate.

The allowed rate of return (r) is determined based on weighted average cost of capital (WACC). This is due to the fact that the asset of a utility, in most cases, is financed by both equity and debt capitals. The choice of the allowed rate is very crucial as this can cause over investment for allowed rates greater than the cost of capital and vice versa. The actual average tariff is given by:

$$Ave.price = \frac{\text{Re}\,venue\,\text{Re}\,quirement}{TotalSaleVolume(kW/h)} \text{ --------------------(4.5)}$$

The amount obtained will reflect recent changes in the market condition and future tariffs are updated on a regular basis. ROR pricing mechanism guards against excessive earnings by the utility. It provides limited incentive for operational and financial efficiencies, because all costs are passed on to the end-user. Thus, the customer bears the market risk and not the utility when using ROR to set tariffs.

4.1.2 Performance based (PB)

Performance based (PB) pricing methods are more appropriate for price increases in successive years. This method provides strong incentives for efficiency improvements (cost containment or reduction, innovations, encourages increased energy efficiency in supply and end-use, and increase service quality). The crucial issue is to get the numbers used in the computation to be right. If these are wrong, then the utility will be enriched or jeopardised. Prices are set arbitrarily for a relatively long period and then allow the regulated utility to reveals its true cost.

Price Cap (PC)

This type of pricing is based on LRMC or average cost. Price caps are often set using the same formula as in rate-of-return, but the difference is that the regulatory body has a target rate of return; r. Future prices are adjusted according to the formula given below:

$$\%\Delta P_R = I - X \quad \text{--------------------(4.6)} \qquad \text{(Sapington D, undated)}$$

Where:

- $\%\Delta PR$ = average % change in the regulated price;
- I = Inflation index; and,
- X = Productivity factor.

Productivity factor measures the extent to which the utility's costs are rising faster or slower than the inflation. Its choice in calculations is very crucial: too small factor will earn the utility excessive profit while too large factor will threaten its financial position. Wars and storms can affect or damage useful capital assets of the utility. Such exogenous factors are outside the control of the utility expense, but have to be incurred for smooth running. When these are considered, the PC adjusting factor is given as:

$$\%\Delta PR = I + X \pm Z \quad \text{-------------------(4.7)} \qquad \text{(Sapington D, undated)}$$

Where Z = cost items that falls outside the scope of normal operation.

Future prices are given as:

$$PCI^t = PCI^{(t-1)} [1 + I^t - X^t] \quad \text{-------------------}(4.8) \quad \text{(Sapington D, undated)}$$

Where:

- PCI^t = future price cap in year t;
- $PCI^{(t-1)}$ = price cap in year t-1;
- I^t = inflation index in year t; and,
- X^t = productivity factor for year t.

Revenue Cap (RC)

This is a type of tariff setting that gives incentive for a utility to improve on its productivity efficiency. It is set using the same formula as ROR and PC such that the revenue capped equals rate of return plus cost, and it allows a fixed amount of revenue. The basic formula for future revenue cap changes is given as:

$$Cap_1 = Cap_2 (I - X) \pm Z \quad \text{------------------}(4.9) \quad \text{(USAID, undated: 53)}$$

Where

- Cap_1 = future revenue cap; and,
- Cap_2 = existing revenue cap.

RC and PC are identical for the fact that they are incentives regulatory mechanisms. Their main difference is that with RC there is a room to invest in energy efficiency while PC encourages increased volume sales and hence discourages end-use energy efficiency.

Sliding scale (SS)

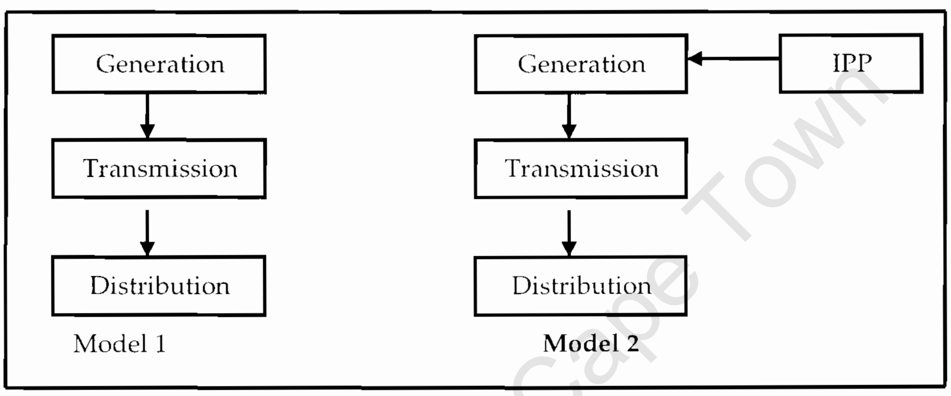
This is a type of tariff set in which excessive profit or abnormal loss by the utility is shared between the utility and the tariff payer in the form of either a decrease or increase in tariff.

There are two types of electricity supply industries (ESI) namely, vertically integrated and unbundled industries. The tariff setting in these industries can be different and are discussed below.

4.2 TARIFF DETERMINATION IN A VERTICALLY INTEGRATED ESI

In a vertical integrated ESI, all the three functions of generation, transmission and distribution are operated by the utility and ownership in most cases is dominated by the public sector. Fig 4.1 shows the two models of vertical integration. Model 1 is a complete public ownership and operation with no competition. In model 2 there is private participation in generation, but the independent power producer generates and sells to the existing utility, which also generates and distributes.

Fig. 4.1: Vertical integrated ESI.



Tariffs in a vertically integrated ESI are determined by the utility but regulated by the government through the sector ministry or parliament. If there is an independent regulatory body, then the setting of the tariff is the prerogative of that body. The formula or method used to set tariff varies from one country to another. Ideally, it should be based on the cost of service and involves several stages.

First, a forecast of generation and sales are made. The operating cost is then estimated based on costs of spare parts and materials, fuels and lubricating oils, labour and administration, debt services, depreciation and return on capital. Then, the operating cost is divided by the sales (kWh) to give the average cost of tariff. This average cost is distributed according to the various customer categories. The distribution of this cost depends on the individual utility methodology.

4.2.1 The Sierra Leone experience

From a personal discussion with the Commercial Director of NPA – Sierra Leone, the tariff determination of an integrated utility consists of the following:

- **The variable generation cost**: this is calculated by taking into account the following; fuel, lubricating oil, cooling water (and any treatment chemical), repairs and maintenance, operation cost (starting, stepping and controlling running plant), power used on plant (directly associated with production) and any other costs directly associated with generation. Then, the generation variable cost is given as:

$$Generation\ variable\ cost/_{Unit} = \frac{TotalAnnual\ variable\ cost}{TotalAnnual\ Production} \quad \text{-------------------(4.10)}$$

If there is a difference between energy produce and sold, then

$$Generation\ variable\ cost/_{Unit} = \frac{TotalAnnual\ variable\ cost}{TotalAnnualPurchasedSales} \quad \text{--------------------(4.11)}$$

- **Revenue cost of running the organisation**: this includes the following costs;

i. Supply cost - meter repairs/calibration, meter reading, billing and settlement, customer services, etc; and; and,

ii. Distribution cost - wages and salaries, cables and lines repair, pole replacement, transformer repairs/maintenance, etc.

Added to the above is any other cost associated in delivering power to the end-user.

If all unit generated is to bear an equal share of the revenue costs, then the second stage above should be divided by the costs of annual production (or purchased sales). This will give an "added" cost per unit. Then this "added" cost is apportioned according to customer categories. The above calculations should have accounted for the operating costs of the organisation. But if this is made as the sale price, then there will be no reserve funds to purchase capital equipment.

To make provision for capital equipment, two techniques are employed:

1. Depreciating the existing asset base over sensible period of years and adding this depreciation to the operating "added" costs.
2. Forecasting what the future capital expenditure will be and assuming that the utility recovers a profit margin sufficient to fund this expenditure.

Therefore, the average cost of the tariff is the summation of the generating and added costs plus depreciation. The initial rate is then set at long-run marginal cost (LRMC). Future tariffs are adjusted to accommodate short-run marginal cost (SRMC) changes.

4.2.2 South African experience

The South African ESI is mainly in the public sector. The National Electricity Regulator (NER) regulates the industry. Eskom, a vertical integrated utility and state owned corporation, owns 96% of the generating capacity. It had an installed generating capacity of 41,812 MW and an available capacity of 38,389 MW in 2001 in the country. The average availability of its generating plants is 93.6% (Eskom - South Africa). Private generation is only 4% and Eskom owns 100% the transmission grid. The current licensed distributors, including Eskom, are 237 (NER journal 3rd quarter, 2002). Municipal distributors are buying electricity from Eskom and put a mark-up on Eskom's price.

Setting of tariff is the responsibility of NER, and Eskom has to submit an application to NER for an increase in its tariff. The tariff and pricing committee will then evaluate the application and make recommendations to the Board. The Board will then issue the approval if necessary.

According to the Contact Trust Report on the parliamentary portfolio committee on Mineral and Energy meeting held on the 9/4/2003, NER had been using various regulatory methodologies to approve tariff increase. Revenue Requirement method was applied from 1996 - 2000. In 2001, incentive based regulation method was used. From 2002 to present, the ROR method is being applied. In the use of ROR methodology, NER made a provision for an allowance for working capital. The rationale for this allowance is to compensate the time of payment and receipt of income on electricity sales. The ROR formula used by NER is:

$$R = E + (V - d + w) * r \text{ -------------------(4.12)} \qquad \text{(NER, 2002:7)}$$

Where:

- R = Revenue Requirement;
- E = operating expenses or cost of supply;
- V = Value of qualifying property;
- d = accumulated depreciation;
- w = Allowance for working capital; and,
- r = rate of return computed from WACC.

The computation of the above parameters is contingent on the regulatory body. NER values the asset base based on historical cost and depreciation is also based on historical cost on a straight-line basis. The rate of return is determined on the bases of WACC using the formula given below:

$$WACC = [K_d * G(1 - t_c)] + [K_e(1 - G)] \text{ --------------------(4.13)} \qquad \text{(NER, 2002:12)}$$

Where:

- K_d = cost of debt;
- G = level of gearing;
- K_e = cost of equity; and,
- t_c = company tax rate.

The allowance for working capital, w, is computed as follows:

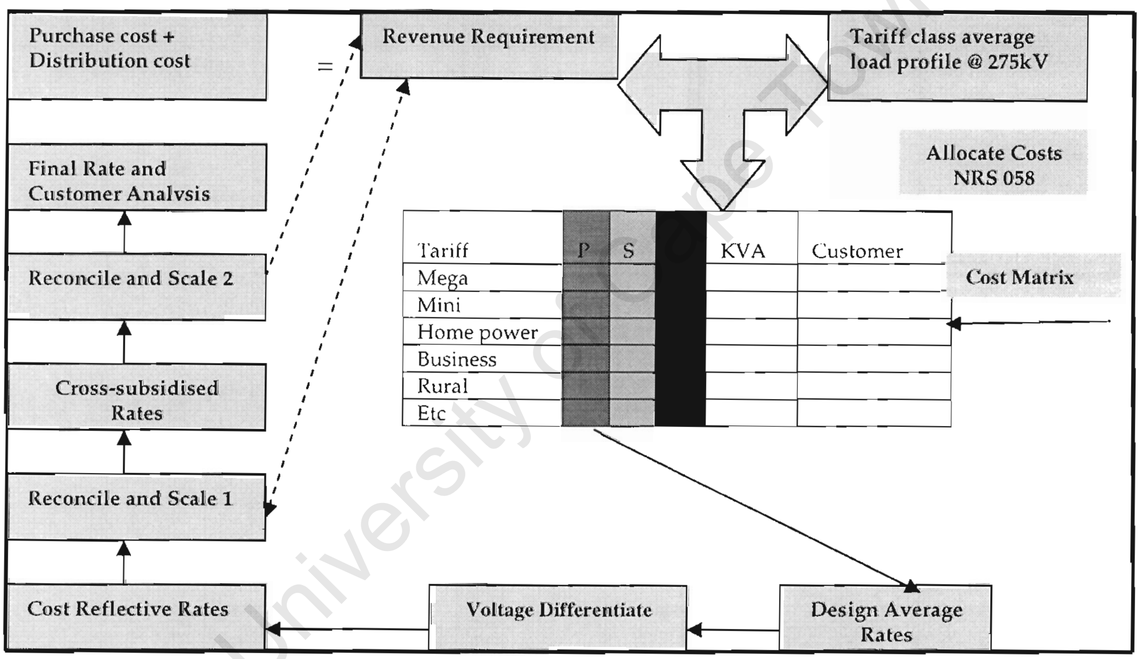
$$\mathbf{W = Es * \frac{45}{365} - C_o * \frac{30}{365}} \text{ --------------------(4.14)} \qquad \text{(NER, 2002:12)}$$

Where:

- Es = total revenue from electricity sales; and,
- Co = operating cost.

The diagram below (fig. 4.2) shows the rate calculation and cost allocation matrix of Eskom. The revenue requirement, which is the summation of purchase and distribution costs, is allocated in the cost matrix according to the NRS 058 methodology and a tariff class load profile of 275 kV. The costs are allocated into energy cost according to the customer load profile, capacity based on average and excess method[1] and per account/point of delivery. This provides the cost matrix that gives the identified cost for each customer category. From the cost matrix, the average rates are designed by adding the appropriate cost components of each customer and this is the rate at 275 kV. The voltage level rates are then determined and added to the average rate to approach cost reflective.

Fig. 4.2: Eskom's rate matrix.



Source: Eskom - South Africa.

A first reconciliation between this calculated cost and Eskom's revenue requirement is done at this stage. Among the aims of tariff design is affordability, then cross subsidisation between energy and capacity charges and among customer categories is executed after the first reconciliation and scaling. A

[1] RE_c = RET – (30% * kWh), where RE_E = excsee reactive energy, RET = total reactive energy and kWh = active energy consumption. **Source: Eskom, 2002 Pricing Plan Bridge Workshop.**

second reconciliation and scaling is done to ensure that the revenue requirement of the utility is actually recovered. This gives the final tariff for each customer.

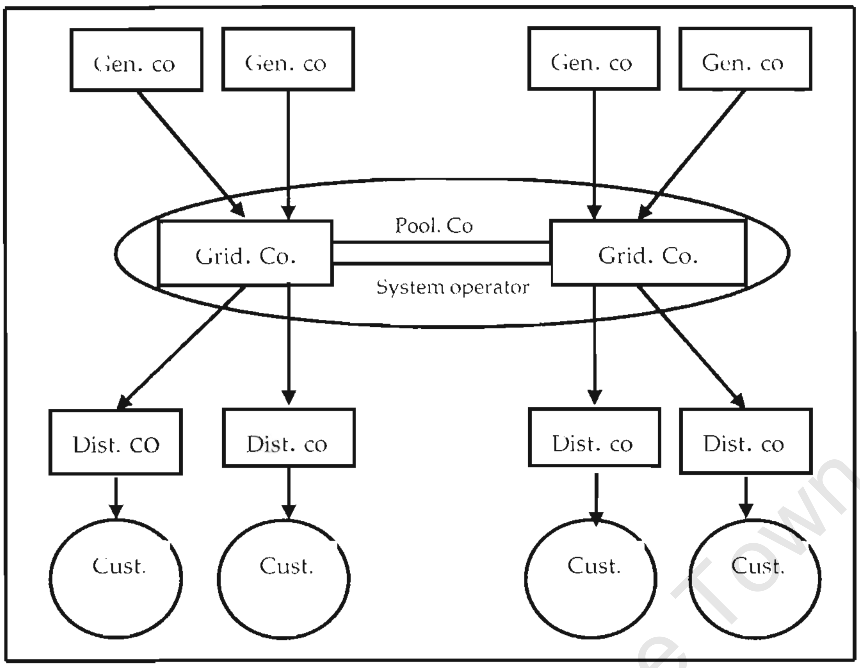
4.3 TARIFF DETERMINATION IN AN UNBUNDLED ESI

The restructuring of the power sector is a functional unbundling of the vertically integrated system into separate entities: generation, transmission and distribution. This creates the potential for competition in generation and retail services while transmission and distribution wires remain a monopoly. Open access to the transmission grid becomes an essential requirement. The diagram below shows a competitive market structure: the various functions of generation, transmission and distribution are completely unbundled and ownership is private sector dominated.

A competitive electricity market is a pool-based market with spot sales and long-term supply contracts. Given the economic difficulty of storing electricity, supply must meet demand at all times. Thus, a spot electricity market requires a pool operator that plans the actual dispatch of generating plants in the very short term so as to maintain the reliability of the system and assists in the price determination. Assuming the structures and facilities to generate and deliver power are in place, the tariff calculation will be focused on short-run market pricing. Long-run contract market pricing can easily be mirrored from the short-run market.

Tariffs in an unbundled ESI are market-determined and approach the short run marginal cost (SRMC). They consist of the following costs: generation, transmission, and distribution plus a value added for distribution (VAD). They are regulated based on the existing regulation regimes; generation prices may be regulated or not, transmission and distribution prices are regulated due to their characteristics of being natural monopolies and retail prices are either regulated or not. The calculation of the above parameters varies from one country to another.

Fig. 4.3: Competitive electricity market structure



Source: Hogan W.W. (undated: 2)

Generation cost consists of two components: energy and capacity. Depending on the regulatory system of the country, generating companies are free to make bids on energy and available capacity; otherwise the offer price is the SRMC of generation, which is determined by the regulator (Fischer R, 2000). In most cases generators are allowed to bid their products. There are different bidding systems with various degrees of complexity. Bids can be energy and capacity or energy only and capacity paid for separately. Usually, these bids are collected by the pool operator and ranked. Based on merit order dispatch, a market-clearing price will then be established, which depends on the last most expensive dispatched plant. If demand participation is allowed in the pool operation, the clearing price is determined from the supply and demand graphs. The intersection of the two graphs gives the energy price and this will be the pool price to be received by all dispatched plant. Constrained plants, in this case, can recover their capital investments through the capacity charge, which will be received by all participating generators.

The wheeling of power from the generating units to the end-user encounters losses due to the resistance of the wires and congestion in the network. To make provision for this anomaly, locational prices are determined by the pool operator. Congestion in the system is managed by using a nodal or zonal pricing system. With the sport market being the reference point, different locational prices will evolve. The difference in the locational prices between the source and destination is the transmission price or rent for transmission usage.

The locational price plus a mark up for other ancillary services gives the pool-selling price. The final average tariff for the end users will be the pool purchase price plus VAD. VAD is meant to cover distribution system operating costs, taxes and it includes an incentive for efficiency gains. The distribution of the final average tariff depends on the methodology used by the distribution company. Performance based regulation is used in computing the VAD.

The calculation of the above costs varies from one country to another. Few countries, such as Argentina, England and Wales, and the Scandinavian countries, operating power pools in an unbundled electricity supply industry are reviewed below.

4.3.1 Experiences in other countries

Argentina

The ESI in Argentina was unbundled in January 1992 and operating a wholesale electricity market (WEM). A nodal pricing system is used in the country. Each node has a price for energy and capacity. The tariff for the end-user is the sum of the nodal price and VAD.

The wholesale electricity operator company, CAMMESA, calculates the energy price (PEi) at a node i using the formula given below in my own symbols:

$$P_{Ei} = P_M * \lambda_i \text{ --------------------(4.15)} \qquad \text{(Vignolo M, 2000:8)}$$

Where:

- P_{Ei} = energy price at node i;
- P_M = energy market price; and,
- λ_i = nodal factor at node i.

When a local market is not directly linked to the wholesale electricity market (which is the reference point) the nodal factor is given as:

$$\lambda_i = 1 + \frac{d(losses)}{d(Pdi)} \text{-------------------}(4.16.1) \qquad \text{(Vignolo M, 2000:7)}$$

Where $d(losses)/d(Pdi)$ = derivative of the losses in the link between the WEM and the node i with respect to the power demand at the node.

For a direct link to the WEM, the nodal factor is given as:

$$\lambda_i = \lambda_{Li} * \lambda \text{ -------------------}(4.16.2) \qquad \text{(Vignolo M, 2000:8)}$$

Where:

- λ_i = Nodal factor of node i with respect to WEM node;
- λ_{Li} = Nodal factor of the node i with respect to the local market; and,
- λ = Nodal factor of the local market with respect to the WEM when there is no constraint.

The capacity price is given by the formula:

$$P_{Ci} = P_{CM} * \beta_i \text{ ------------------}(4.17) \qquad \text{(Vignolo M, 2000:10)}$$

Where:

- P_{Ci} = capacity price at node i;
- P_{CM} = capacity price at the WEM; and,
- β_I = an adaptation factor at node i.

The adaptation factor is a measure of the reliability of the link between the WEM and a specific node. It is the ratio of the capacity prices at the node and the WEM. Therefore, it is considered as a cost, which they call an "over-cost", due to a failure at the node of the end-user. The adaptation factor is computed as follows:

$$\beta_I = 1 + [\textstyle\sum_l OPi\_l \,/\, P_{CM}] \text{ --------------------}(4.18) \qquad \text{(Vignolo M, 2000:10)}$$

Where:

- $\sum_l OPi\_l$ = Over-cost at node i due to the reliability of the transmission line l linking node i. It is the annual over-cost due to the two types of failures (long and short durations) along the line. It is given as:

$$OP_{i\_l} = (OP_{L\_l} + OP_{S\_l}) / (W_{AVE\_l} * n) \text{ ----------(4.19)} \qquad \text{(Vignolo M, 2000:10)}$$

Where:

- OP_{L_l} = over-cost due to failure for long duration;
- OP_{S_l} = over-cost due to failure for short duration;
- W_{AVE_l} = average power linked through line l; and,
- n = number of non-valley hours during the working days in the two seasonal periods in consideration.

- P_{CM} = capacity price at the WEM.

England and Wales

The England and Wales pool is a spot electricity market, organised a day in advance. All generating companies bid into the pool and the system operator converts them into a system marginal price based on merit order. The market-clearing price becomes the energy price. The capacity charge is based on the probability of power cuts and this is set at:

Capacity charge = probability of a power cut * expected cost.

$$= LOLP * (VOLL - SMP).\text{------------------(4.20)} \qquad \text{(Green R, 1998:5).}$$

Where:

- LOLP = Loss of load probability;
- SMP = system marginal price; and,
- VOLL = value of lost load.

LOLP is a reliability index that describes the state of the electric system. In generation planning it is defined as the average number of days over a long period, during which the daily peak is expected to exceed the available generating capacity (Munasinghe, 1979).

Therefore, the actual pool-purchasing price is given as:

$$PPP = (1 - LOLP) * SMP + (LOLP * VOLL) \text{--------(4.21)} \quad \text{(Green Richard, 1998:5).}$$

Where PPP = Pool purchasing price and the other symbols having the same meaning as above.

Nordic pool

National grid companies in Finland, Norway and Sweden operate this pool. It is also a spot electricity market and demand participation is allowed. Both supply and demand bids are made every hour and a system price without constraints is established. A single price is set for the 24 hours of the day. To manage congestion problems, locational prices are adjusted such that areas with surplus generation will experience reduced price and deficit areas will experience increased price. If there is no constraint in the link between two bidding areas, the capacity price is zero and the system price becomes the generation and transmission price. When there is a constraint and price adjustment is done, the capacity fee becomes the difference between the system price and the locational or area price as shown below.

$$C_f = P_s - P_a \text{-------------------(4.22)} \qquad \text{(Nord Pool)}$$

Where C_f = capacity fee, P_s = system price and P_a = area price.

CHAPTER 5
OPERATIONS OF THE NATIONAL POWER AUTHORITY: SIERRA LEONE

This chapter is the report of the field visit and it is structured into three sections. The first section gives a brief description of the electricity supply industry of the country and the Kingtom power station. The second section gives the numerical data collected during this visit and the third section presents observations of the operations of NPA.

5.1 INTRODUCTION

The fieldwork was made to Freetown, Sierra Leone and the power utility and the oil companies were visited. Data were obtained through the utility records, observations and personal discussions with relevant personnel and taking measurements. The utility numerical data in Appendix B were compiled from the monthly generation reports and generation log sheets and financial statements. With the assistance of the Generation Manager and site engineers, a detailed walk trough of the power station was made. This enables me to identify some inefficient generation operations and the physical state of auxiliaries and other practices carried out in the station. The macroeconomic indicators of the country were obtained through Internet search of the Central Statistics office (CSO) of Sierra Leone and the Bank of Sierra Leone. The objective of data collected is to establish the energy efficiency of the power generation and the operational efficiency of the utility and their relation with the electricity tariff.

The condition of the steam wasted at the power station was personally measured, but with great difficulties to establish its mass flow rate. This would have helped to quantify the exact magnitude of the energy wasted and then express it in monetary terms. Generally, energy data collection, management and storage are serious problems in Africa, because data is not usually available. This is due to the lack of well-organised energy information system in many African utilities, with Sierra Leone not being an exception. Owing to the rebel invasion of Freetown in 1999, some of the main offices of the utility were burnt down and the Management Account Offices was one of them. Besides, it the Authority was only able to get a data storage system (computers) in 2000. So, it was difficult to get comprehensive data of NPA. However, seven-year data (1996 - 2002) were collected.

5.1.1 The electricity supply industry (ESI)

The power utility of Sierra Leone is state-owned. It is vertically integrated and small in size relative to many African countries. Table 5.1 below shows the original installed capacity in the country up to 1995, which excludes private capacity. Owing to the poor performance of the utility coupled with the 10-year war situation in the country, almost all the provincial thermal plants, with the exception of two - Bonthe and Moyamba, have either deteriorated beyond economic repair or were completely destroyed.

Table 5.1: Original thermal plants up to 1995.

Power station	Rated output (MW)
Western Area	
Kingtom	18.4
Falcon Bridge	1.20
Provincial Towns	
Port Loko	0.14
Lunsar	0.10
Rokupr	0.10
Kambia	0.40
Lungi	1.20
Bo	5.03
Njala	0.88
Bonthe	0.16
Koidu	1.00
Makeni	1.00
Moyamba	0.20
Kabala	0.25
Total	30.06

Source: NPA - Lahmeyer International, 1996 Report

Due to increased demand, the current total installed capacity excluding auto-producers (mining, industrial and commercial) is 41.13 MW of which 37.74 MW is located in Freetown, and the original capacities in Bo, on the and Moyamba. The Falcon Bridge plant is currently operated as a black start facility for the Kingtom generating units. Between 1996 and 2002, the total registered private generating capacity in Freetown was 73.23 MW (Research findings - NPA files). The actual private capacity is higher than this value due to the non-registering of some generating sets by many other Ministries, Embassies and few other households. All existing power plants are operating on heavy fuel oil (HFO) and straight-run diesel fuel oil (DFO).

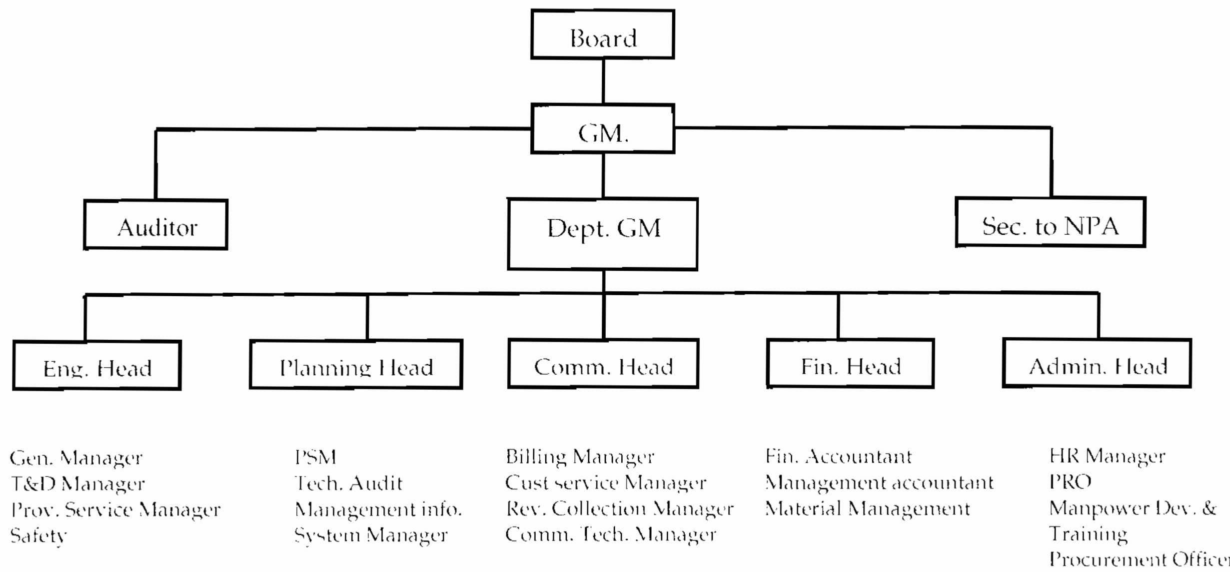
The existing and operating hydro power plant is a 4 MW run-of-river type with a small reservoir. It is located in the Eastern province. A 50 MW hydro power plant is presently under construction with a firm generating capacity of 157 GWh. However, the estimated hydropower potential of the country is 1,513 MW scattered over 27 sites (NPA).

The public utility system consists of the Western Area Grid centred in Freetown and originally twelve isolated provincial systems in the rest of the country. The National Power Authority (NPA) and two semi-autonomous commercial utilities (Bo/Kenema Power Services - BKPS and Lungi) manage the ESI. The largest plants (6 - 9.2 MW) are located in Freetown.

The ESI is sector regulated through the Minister of Energy and Power (MEP). This Ministry was created in 1974 for establishing and implementing policy in the sub-sector. In carrying out its role, the Minister appoints a Board of Governors to run the Authority. The Board then appoints the General Manager who also serves as an ex-officio member in the Board. The 1982 Electricity Act gave NPA a high degree of autonomy through an independent Board, but this is not operating in practice. The purchase of spare parts for the generators, other major expenditures and decisions has to get the approval of the government.

Fig. 5.1 below shows the recently adopted structural organisation of NPA after the expiration of a management contract in June 2002. It consists of a General Manager and departmental heads covering engineering, planning, commercial, finance, and administration. The total work force of the utility as at the end of February 2003 was 617, which constitutes 586 permanent workers and 85 on contracts.

Fig. 5.1: Current structural organisation of NPA



Source: NPA - Sierra Leone

5.1.2 The Kingtom power station

The Kingtom power station was established in 1964 with two 6.2 MW MAN-AEG generating sets. The station was formally commissioned in 1965. In 1970 another 6.2 MW MAN - AEG generating set was added. As a result of some technical problems, they were decommissioned. Due to the increase in power demand, the station is currently having a total installed and operating capacity of 36.54 MW. This capacity is made up of the following generating units:

- 2 x 9.2 MW Sulzer - BBC generating sets commissioned in 1978 and 1981. Both have exceeded their 20-year economic life.
- 4 x 3 MW KHD generating sets commissioned in 1985. Currently, one is operational but occasionally operated.
- 1 x 5.0 MW Mitsubishi Heavy Industries (MHI) generating set commissioned in 1995.
- 1 x 6.3 MW Mirrless generating set commissioned in 2001.
- 3 x 1.28 MW Caterpillar generating set commissioned in 2001.

The station has one central workshop and a training school.

5.2 NUMERICAL DATA COLLECTED

These data are presented in tabular form because of their numerical nature. Table 5.2 illustrates the annual statistics of the energy generated, auxiliaries and station energy consumption, fuel consumed by generating units and their hours run. TableB1 (Appendix B) gives the monthly statistics of the above quantities. These were obtained from the generation report log sheets. The objective of this data is to establish the heat rate (thermal efficiency) of the plant as a whole.

Table 5.2: Annual energy generated, auxiliaries and station energy consumption and hours of run.

Year	Energy gen. (kWh)	Auxiliaries and station consumption (kWh)	Fuel consumed (Imperial gallons)		Expected hours run[a] (hrs)	Hours run (hrs)
			HFO	DFO		
1996	114,241,941	4,071,424	6,521,992	95,247	25,632	18,000.4
1997	71,439,200	3,020,690	4,369,547	107,743	26,304	13,064.4
1998	82,335,520	5,089,051	5,197,694	59,171	20,160	14,642.85
1999	51,899,100	4,284,612	3,674,950	47,961	12,384	8,466.8
2000	61,405,188	3,608,974	3,371,758.8	807,859	14,688	11,870.74
2001	106,312,032.5	5,706,610	6,127,653.4	911,910.6	51,096	41,122.9
2002	123,499,068.2	6,562,780	7,191,226.5	710,165.6	56,952	45,566.3

[a] *This is the total expected hours run for all generating units.*

Source: NPA, Sierra Leone.

From observations, the values of the fuel consumption may have some errors. These may arise from fuel leakages beyond the flow meter (e.g. injection pump and along the pipelines). Therefore, the flow meter readings cannot give a 100% true values of the engine consumption. However, the difference is negligible and no adjustment was done in flow meter readings.

Table 5.3 gives the operating costs (which include generation and transmission costs, supply cost and administrative charges), book value of the useful fixed assets of the utility and the equity and debt capitals. Table B3 shows the various tariffs and tariff structure of NPA between 1996 and 2002. Table B4 shows some macroeconomic indicators of the country. The aim of these data is to compare NPA's tariff using another method (rate of return) of tariff computation.

Table 5.3: Operating costs, book value of fixed assets and capital of NPA

Details	1996	1997	1998	1999	2000	2001	2002
	Le '000	Le '000	Le '000	Le '000	Le '000	Le '000	Le '000
Value of fixed assets	22,834,924	23,577,566	24,709,810	24,255,596	24,325,461	41,480,897	
Accumulated depreciation	1,287,550	3,186,184	5,104,480	6,658,992	8,515,829	10,542,545	
Operating costs	8,578,233	12,633,554	10,598,217	14,194,992	14,979,585	25,424,200	
Capital	36,367,257	39,445,277	62,921,619	65,111,006	82,508,879	104,430,579	
Equity	9,223,573	9,223,573	9,223,573	9,223,573	9,223,573	9,479,738	
Debt	27,143,684	30,221,704	53,698,046	55,887,433	73,285,306	94,950,841	
Int. rate[2] (%) - debt	2 – 7.5	2 – 7.5	2 – 7.5	2 – 7.5	2 – 7.5	2 – 7.5	2 – 7.5

Note: *2002 data are not available, as the financial statement was still not audited at the time of data collection.*
Source: NPA, Sierra Leone.

5.3 OPERATIONS OF NPA

Fuel procurement and transportation

The fuel (HFO and straight-run DFO) used by the generators is mostly imported from Cote d'Ivoire by the oil companies in the country as the country closed down its refinery several years ago. These are National Petroleum - NP, Mobil and Safecon; NP being the largest importer. Currently, any HFO bought from other West African country has to pass through Cote d' Ivory for processing before it is brought into the country. On the arrival of the fuel, NPA sends a sample to the West Africa oil refinery company for verifications to authenticate if it meets the engine manufacturer's specifications.

The purchase of the fuel is mainly from the NP Company on a local purchase order. The other oil companies are not in the financial position to operate as NP because NPA receives the fuel on loan and pays at the end of the month. The average daily purchase of HFO is about 70 tons. The history of the average HFO costs from 1996 - 2002 is given in table 5.2.

Three vehicles of 15 tons capacity transport the fuel from the oil terminal. During transportation the quantity lost due to evaporation and spillage is about 6 imperial gallons. One ton HFO is equivalent to

[2] The utility is a non-profit organisation and hence on payment of dividend. So, the rate of return on equity capital is zero.

236 imperial gallons. Each vehicle consumes 22 imperial gallons of straight run diesel oil for nine shuttles between the station and the oil terminal.

Table 5.4: HFO cost in Sierra Leone (1996 -2002)

	1996	1997	1998	1999	2000	2001	2002
Cost (US \$/$\text{gallon}_{\text{imperial}}$)	1.19	1.22	0.96	0.99	0.98	1.11	1.05
Cost (US \$/tonne)	281.94	288.42	227.23	233.50	232.35	262.04	246.72

Note: The costs received from NPA were in the local currency and were converted to US\$ using the average official exchange rates for the respective years.

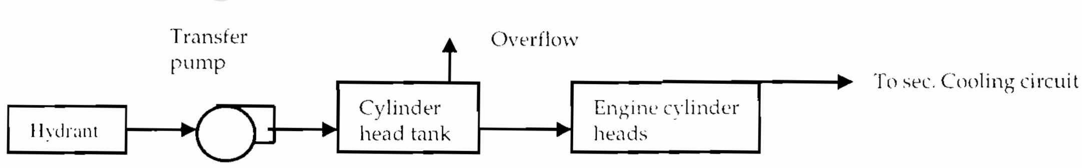
Source: NPA - Sierra Leone.

Water consumption

The main use of water at the station is to generate steam and the cooling of the engines. Water is obtained from the national water company (Guma) in Freetown. Originally there was a flow meter that measured the station's water consumption. During observation of the station this meter was not in working order. Currently, there is no verification of the water bills for the station.

Fig. 5.2 is a simplified schematic diagram of the cylinder head cooling circuit. Water is tapped from the hydrant by the transfer pump and sent to the cylinder head tank and then on to the cylinder heads. The cylinder head tank is supposed to have a regulator to regulate the maximum and minimum water levels in the tank so as to maintain a continuous supply to the cylinder heads. But due to negligence and poor maintenance, this regulator is out of working order. So, to ensure the continuous water supply to the cylinder heads, the maximum level is maintained by allowing the transfer pump to be sending water continuously. Hence, water is overflowing through the overflow pipe continuously wasting a significant quantity.

Fig. 5.2: Cylinder head cooling circuit



The cooling circuit of the injectors is also another source of water wastage. The injectors get its cooling water from a tank in the basement and discharge the hot water to the same tank. Since there is no cooling system (heat exchangers) to cool the cooling water for this circuit, the tank is intermittently flushed with fresh water. Again, significant quantity of water is wasted in this way; an unsustainable practise as it increases the water bills and hence the operating expenses.

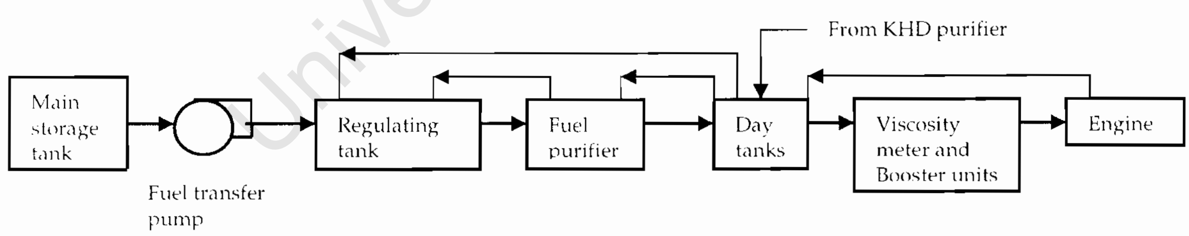
Oil flow to the engine

Figure 5.3 below illustrates a simplified schematic diagram of the flow path of the fuel from the main storage tank to the engine. All the pipelines including those from the auxiliary boiler and steam drum are steam traced with the exception of the return pipelines.

The main source of fuel wastage is its transfer from one tank to anther during its purification process. The purified fuel is transferred to the day tank and then on to the engine through a viscosity meter and booster unit. The viscosity meter checks and regulates the viscosity of the fuel that goes to the engine while the booster unit increases its pressure to the correct operating pressure. The transfer of fuel between the purifier and the day tank is such that if the purified fuel is sent to the day tank while its valve is closed, the fuel will return to the regulating tank.

If a day tank is filled while its valve is still open and the valves of the other day tanks are closed, the fuel will return to the regulating tank via the purifying unit. Unused fuel by the engine is returned to the day tank. Thus, there is a great possibility for the fuel to overflow at the regulating tank.

Fig. 5.3: Flow path of fuel.



According to the manufacturer's instructions, the engine should be started and shut down on straight-run diesel. If started on HFO, then it should be at its correct viscosity, which is in the range of 13 - 17 cSt, otherwise excessive pressure will develop at the relief valve of the injector pump causing it to open and discharge a significant amount of fuel. In addition, the atomisation of the fuel by the injector will be impaired causing improper combustion and loss of energy input.

At present the engine is started and shut down on HFO, which is possible if the fuel has its correct viscosity. The following were observed during the field visit to the station:

- Frequent overflow of fuel at the regulating and viscosity tanks and fuel filter;
- Viscosity meter is out of working order;
- Occasional discharge of fuel at the relief valve;
- Leakages along the fuel pipeline to the engine.

Steam generation and use

The main use of the steam is to heat the fuel pipeline for easy flow of the fuel. It is generated through the exhaust boilers of the generators and an auxiliary boiler that uses straight-run diesel fuel oil. As observed during the field visit, the two exhaust boiler of the two Sulzer units were out of use due to technical reasons; probably excessive leakage of water in the boiler. The exhaust boilers of the other units (MHI and Mirrless units) were in excellent working order.

When the two-Sulzer units are in operation the auxiliary boiler is used to provide steam for the required heating. In the case of either the MHI unit or the Mirrless unit operating with a Sulzer unit or the two units are operating alone, a significant amount of steam is continuously discharged to the surroundings, which is at an ambient temperature of about 30°C. The quantity of steam discharge depends on the load on the generators. The more the load, the more exhaust gases are produced and hence more steam is produced and wasted. The condition of the exhausted steam is at a temperature of 104°C and a pressure of 5.1 - 5.8 bars. From the generation log sheet it is observed that the exhaust gas temperatures range between 394°C and 470°C. Therefore, a huge amount of useful energy is wasted.

The following were observed points of steam leakage:

- About 50 cm from the steam outlet from the auxiliary boiler;
- About 1 m before the steam distribution unit and the inlet of the unit;
- The steam condensate tank;
- The viscosity unit and delivery pipeline to the engine.

Billing and revenue collection

The utility has a customer base of 45,000 of which 40,000 are active customers while 5,000 are inactive. The exact number of active customers is probably less than the given figure. This is due to the duplication of accounts and other causes. The duplication of accounts is due to poor customer information system and management and the following:

- Accumulation of high bills that are not paid;
- Establishment of a new account using the same meter; and,
- The reuse of stolen meters.

The inactive customers are a result of burnt meters during the rebel incursion in Freetown or fire accident, vacation meters and withdrawn meters due to non-payment.

The billing was found to be 60-90 days late. This problem was up to 2000 due to lack of in-house computers and the appropriate billing software. In the late 1980's, customer data were sent to Liberia for billing process (World Bank report) and this was causing too much delay. The problem is now reduced to 30 days and more effort is being done to stop the practice completely.

Account receivable is an indicator of efficient billing and revenue collection expressed as the delay in payment - months of sales. This was found to be indefinite until a customer accumulates a debt that will warrant disconnection. Originally the payment of bills was done at NPA head office. Owing to poor salaries the direct handling of money by staff members was an opportunity for it to be stolen. Besides, this was creating a lot of inconveniences for customers that are far off from the head office and long-our queues. This single revenue collection point is inefficient and might be one of the reasons for delay payment or non-payment by some customers. Recently, other revenue collection centres have been established all over the city. These include the utility branch at Blackhall road and some selected banks (Sierra Leone Commercial and its branches, Rokel commercial, Union Trust and National Guarantee). May be due to poor advertisement the system is not yet effective. About 90% collection is still done at the head office.

CHAPTER 6
ANALYSES AND DISCUSSIONS

This chapter is structured into three sections. The first section gives the technical analysis of the power system, section two is on the tariff analysis using the rate of return (ROR) or revenue requirement and the third section gives a comparison of some selected performance indicators of NPA and other power utilities in Africa.

6.1 TECHNICAL ANALYSIS

6.1.1 Heat rate of generating plant

The performance of any electric power plant is generally expressed in terms of heat rate. It is a measurement of how efficiently a generator uses heat energy. Heat rate gives a reasonably accurate estimate of the amount of fuel intake of any type used per MW of electrical load. It is an indicator of fuel consumption that measures the number of kilojoules (kJ) consumed to produce one kilowatt-hour (kWh) of electricity, which is expressed in kJ/kWh. When this is compared to the actual energy produced, it can tell how efficiently the generator converts the fuel into electrical energy. Heat rate is converted to thermal efficiency (η_{th}) using the expression given below:

$$\eta_{th}(\%) = \frac{1}{HeatRate\left(kJ/_{kWs}\right)} * 100 \text{ ---------(6.1)} \qquad \text{(Avallone and Baumister, 1996:9-17)}$$

$$= \frac{360}{HeatRate\left(kJ/_{kWh}\right)}$$

The heat rate of a generator depends on the type of technology, its size, age, the quality and type of fuel used, capacity factor and operating conditions and practices. Its improvement can give a better unit efficiency, which invariably increases reliability and better capacity factor, reduces generation variable costs and increases plant profitability.

$$HeatRate = \frac{EnergyInput(kJ)}{EnergyOutput(kWh)} \quad \text{-------------------(6.2)}$$

Since the plant consumes two type fuels, the energy input is given as:

$$EnergyInput = 4.54 * 10^{-3}[D_1V_1C_1 + D_2V_2C_2] \quad \text{------------------(6.3)}$$

Where:

- D = density of fuel (kg/m^3);
- V = volume of fuel consumed by generating units (imperial gallons);
- C = calorific value of fuel (MJ/kg); and,
- The subscripts 1 and 2 represent HFO and DFO respectively.

1 imperial gallon = $4.54*10^{-3}$ m^3

D_1 = 939 kg/m^3 (NPA test result value), D_2 = 840 kg/m^3, C_1 = 40.9 MJ/kg and C_2 = 42.9 MJ/kg (IEA)

Using 2002 data from table 5.2 and equation 6.3, the energy input is given as:

Energy input = 4.54*10-3[(939*7,191,226.5*40.9) +(840*710,165.6*42.9)] = 1,370,041,704 kJ

Therefore, applying equation 6.2, the heat rate for 2002 becomes:

$$HeatRate = \frac{1,370,041,704}{123,499,068.2} = 11.09 kJ / kWh$$

The results of the heat rate calculation are shown in appendix C and the annual values are given in table 6.1 below.

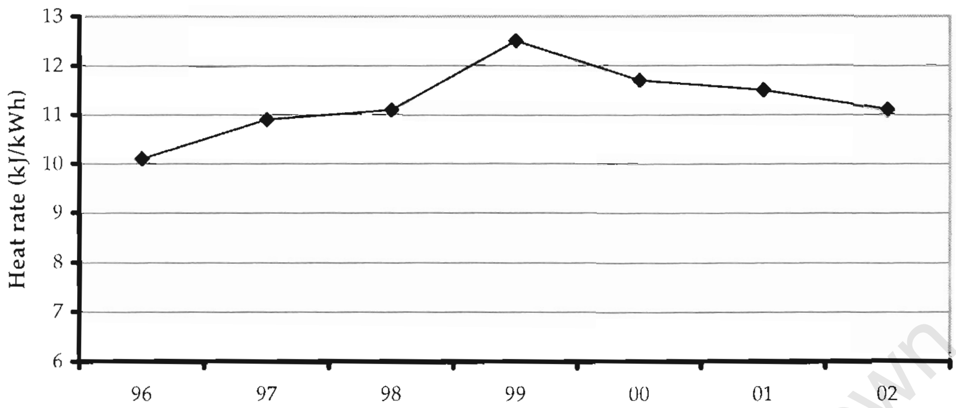
Table 6.1: Annual heat rates of kingtom power plant

	1996	1997	1998	1999	2000	2001	2002
Heat rate (KJ/kWh)	10.09	10.91	11.12	12.50	11.73	11.45	11.09

Fig. 6.1 below shows the trend of the average annual gross heat rates of the Kingtom power plant from 1996 - 2002. They increase gradually from 10.1 in 1996, peaks to 12.5 in 1999 and then fall to 11.1 in 2002. The average heat rate in this period was 11.27 kJ/kWh, which is equivalent to a thermal efficiency of 31.94%. This is within the efficiency range of an IC engine-generator unit, which lies between 30% and 35%. From table C1 (see Appendix C), the monthly heat rate fluctuations have been between 8.68 kJ/kWh in June 1998 and 15.05 kJ/kWh in May 2002. The gradual average annual increase is a reflection of the age of the generators, poor maintenance and operating practices (low capacity factors). The peak in 1999 is the cumulative effect of the above factors and the war situation in the country when

the station was forced to use the recycled fuel, which is of poor quality. The declining heat rate showed improved maintenance due to the change of the old management in January 2000.

Fig. 6.1: Average annual heat rate (1996 - 2002)



6.1.2 Auxiliaries and station energy consumption

The energy use of a modern utility is expected to be around 2 - 3%. This should include energy consumption of the plant auxiliaries, central workshop and buildings of the utility. The system energy use is accounted as the difference between the energy generated and what is available for billing.

The values of the energy consumed by the auxiliaries and station were obtained from records. From table 5.2, expressing the 2002 auxiliaries and station energy consumption as a percentage of the energy generated gives:

$$\text{Energy consumed (\%)} = \frac{6{,}562{,}780}{123{,}499{,}068.2} * 100 = 5.31$$

Table 6.2 shows the annual station energy consumption.

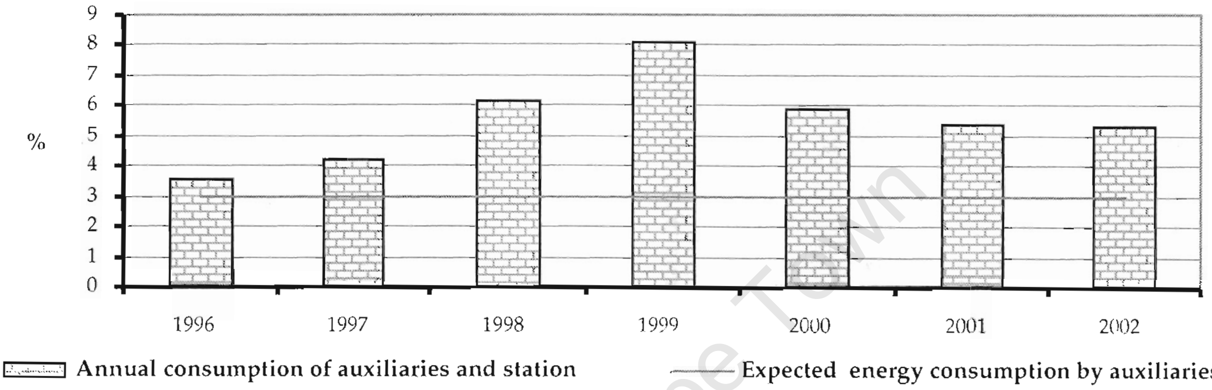
Table 6.2: Annual auxiliaries and station energy consumption.

	1996	1997	1998	1999	2000	2001	2002
Energy consumption (%)	3.56	4.23	6.18	8.10	5.88	5.37	5.31

Fig. 6.2 is an illustration of the average annual system energy consumption and the expected system consumption. The annual energy consumption exceeds the expected value in all the years. It exceeds the expected energy use by 20% in 1996 and 170% in 1999. The average energy use between 1996 and 2002 was 5.52%, which exceeds the expected value by 84%. This is very high and it reduces the units

available for sale, which is a huge loss in monetary terms. The high consumption may be due to old and inefficient equipment, low loading of and many idle motors and other technical and non-technical factors. All inductive loads are operating between at 0.80 and 0.85 pf. Private jobs, for instance welding and lathe turning, done in the central and training school workshops contribute significantly to the system energy consumption. Strict measures should be put in place to reduce this anomaly.

Fig. 6.2: Average annual auxiliaries and station energy consumption



6.1.2 Plant availability

Plant availability is a measure of the amount of time a given plant is available to produce power. It is given as:

$$P_A = \frac{T_u}{T_U + T_D} \text{------------------}(6.4) \qquad \text{(Munasinghe, 1979: 203)}$$

Where:

- T_U = Time generating unit is ready and available for use; and,
- T_D = Time unit is off-line and unavailable for use.

Considering planned and forced outages and reserve capacity for peaking periods, the availability of a modern thermal plant is expected in the range of 85 - 90%. From table 5.2, the 2002 availability is computed as follows:

$$Availability(\%) = \frac{HoursRun}{ExpectedHoursRun} * 100 = \frac{45{,}566.3}{56{,}952} * 100 = 80\%$$

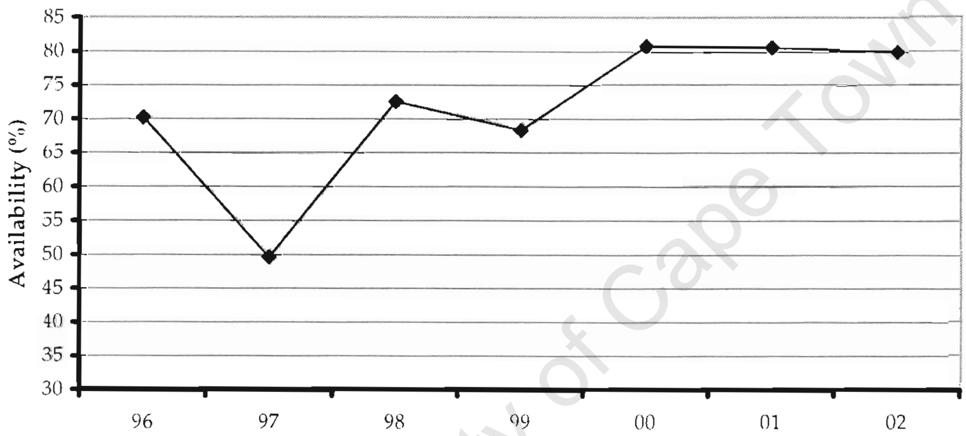
Table 6.3 shows the annual availability of the kingtom plant.

Table 6.3: Annual availability of the kingtom power plant.

	1996	1997	1998	1999	2000	2001	2002
Availability (%)	70.22	49.67	72.63	68.37	80.82	80.48	80.00

Fig. 6.3 shows the average annual availability of the Kingtom power plant between 1996 and 2002. The average availability in this period was 71.8%, which is far below the expected range. This decreases the forecast energy to be generated. The low average availability in 1997 was due to the political impasse in the country when the Armed Force Revolutionary Council (AFRC) overthrew the democratically elected government. There was an economic embargo that caused serious fuel shortages in the country.

Fig. 6.3: Average annual plant availability (1996 - 2002).



However, the monthly availability is not good because it varies widely between 30% in February 1998 to 96% in May 2002. The overall low availability can be attributed to the following:

- Unplanned shut down due to frequent engine breakdowns and other technical problems;
- Long waiting periods of spare parts from outside the county;
- Frequent forced shut downs as a result of the ripple effect of excess load on the generators due to poor coordination between the control room and the distribution substation operators; and,
- Fuel shortages due to delays in supply.

6.1.4 Technical and non-technical losses

The generation, transmission and distribution of electricity from the point of generation to the end user encounter considerable losses. These are due to both technical and non-technical losses (commercial losses). Technical losses are due to the following:

- Losses due to generator efficiency;
- Line losses due the resistance of the wire; and,
- Voltage related losses.

Non-technical losses are due to the following:

- Unmetered consumption of electricity;
- The existence of illegal connections (theft). The impact of theft is not only limited to revenue loss, it also affect power quality resulting in low voltage and dips;
- Inadequate metering;
- Inaccurate billing and collection; and,
- Faulty meters.

The total network losses are a combination of the transmission and distribution technical losses and non-technical losses. These are measured by taking the difference between the energy available for billing and what is sold. The total network losses of any grid are expected to be about 10% (Bhagavan, ed., 1999: 338). Table 6.4 below is a report of a study carried by EPRI on the T&D system. It gives an estimate of the unavoidable technical losses in the system.

There exist computer programs that can estimate the theoretical technical losses of any network. The actual technical loss is then calculated from the total technical losses assuming maximum current to flow through during the whole period by introducing a load loss factor (LLF). The formula below is an empirical relation between LLF and load factor (LF):

$$LLF = 0.3LF + 0.7LF^2 \text{ -----------(6.5)} \qquad \text{(AGL electric limited, 2003: 10)}$$

Where:

$$LF = \frac{TotalEnergyDelivered - EnergySold}{Peakload * Hour\sin period} * 100\% \text{ -------------(6.6)} \quad \text{(Davidson et al, 2002: 58)}$$

The non-technical loss is then given as:

Non-technical loss = Network loss - Technical loss ---------(6.7)

Table 6.4: Transmission and distribution losses

System element	Power losses (%)	
	Minimum	**Maximum**
Step-up transformer & EHV transmission system	0.5	1.0
Transformation to intermediate voltage level, transmission system & step down to sub-transmission voltage level	1.5	3.0
Sub-transmission system & step down to distribution voltage level	2.0	4.5
Distribution lines and service connections	3.0	7.0
Total losses	7.0	15.5

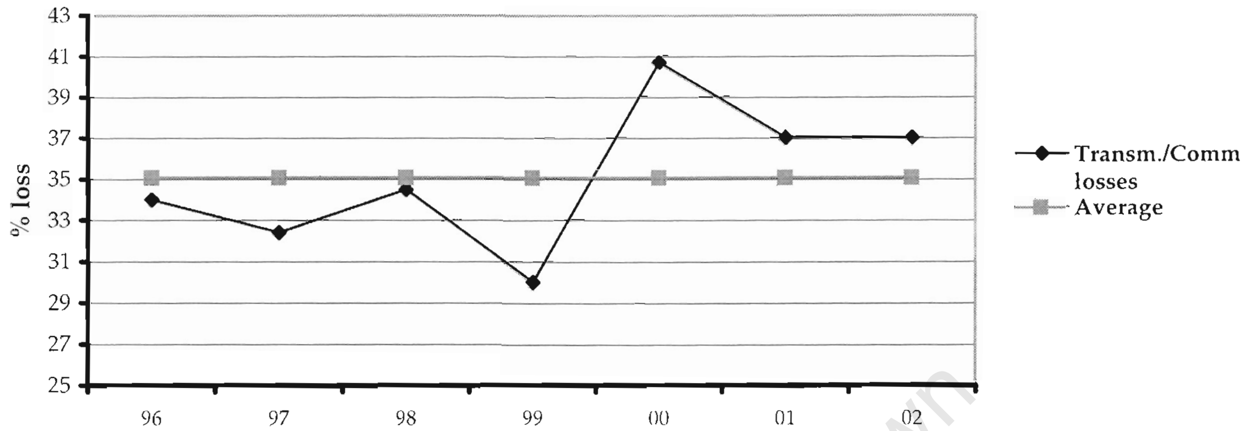
Source: Bhalla (undated: 2)

Table 6.5: Average annual system losses

	1996	1997	1998	1999	2000	2001	2002
Losses (%)	34.0	32.0	35.0	30.0	41.0	37.0	37.0

Table 6.5 above gives the average annual system losses of NPA from 1996 – 2002. The annual system losses and the average losses in this period are shown in fig. 6.4 below. They vary from 34% in 1996, decline to 30% in 1999, peak to 41% in 2000 and then stabilise to 37% from 2001 - 2002. From table C1 (Appendix C), the average monthly variations are very high. They are from 14% in November 1999 to 52% in March 1998. These losses are a result of the age of the network, lack of maintenance, illegal connections and the lack of enforcement and ability to disconnect delinquent customers.

Fig. 6.4: Average annual Transmission and Commercial losses (1996-2002)



System losses are an indication of the quality of service. The high level of losses is very unsustainable as they represent a huge revenue loss to the utility. The cost of these losses is often passed on to the consumers. As noted by Davidson (2002:16), losses signify considerable operating cost and this can add about 6 to 8% to the cost of electricity. The economic operation of power network should therefore entail minimising generation costs, and transmission and distribution losses.

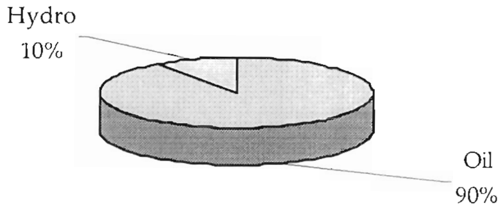
The following are major reasons for the high technical losses in the country:

- The age of the network;
- Little or no investment on the transmission and distribution systems;
- Overloading of the network due to the new connections without upgrading the network;
- Improper load management; and,
- Poor quality equipment used in industrial loads.

6.1.5 Energy mix and fuel costs

The energy mix for power production in the country is very limited. As shown in fig 6.5 below about 90% of the electricity is produced from oil, which is imported. The remaining 10% is produced from hydro. Hydropower is affected by seasonal variations. High evaporation and low rainfall will lower the dam level, which will affect the power output. This limited energy mix poses energy insecurity for the utility and this is exacerbated by the fuel supply method.

Fig. 6.5: Energy souces for power production in Sierra Leone.



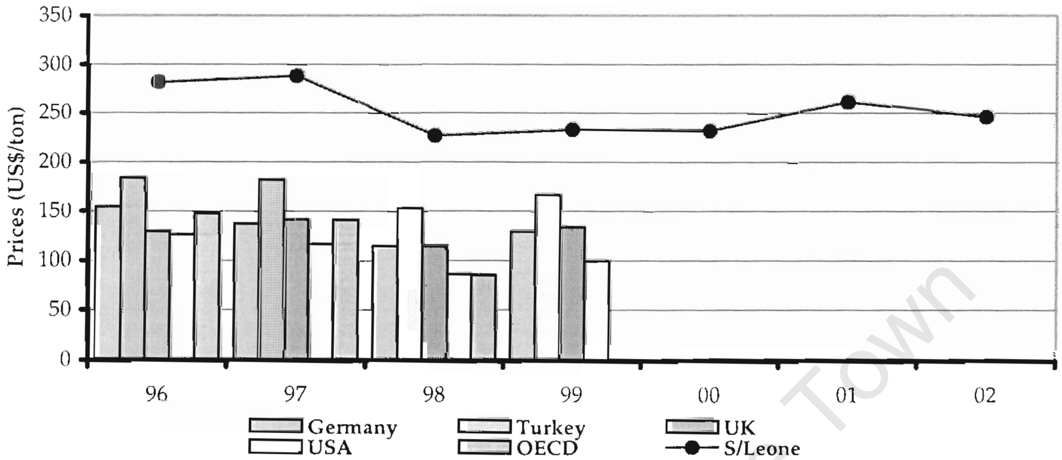
Although the oil companies in the country are importing oil from few West African countries, the major source and only route of fuel import is Cote d'Ivoire. A single route supply chain could be unreliable and inefficient. This was demonstrated by the recent political impasse in Abidjan and it created a shortage of HFO in the country, which affects the productivity of the utility.

The wastage of HFO during transportation is considered negligible by the utility as no measures are taken to address the situation, but the cumulative effect for a year can be significant. The average 6 gallons wastage per trip for three vehicles is equivalent to about 84 tons at the end of the year. In monetary terms, this is a loss worth Le 45.853 million (US$ 20,724) at 2002 prices. Added to this is the annual fuel consumption of the three vehicles transporting the HFO from the oil terminal to the power station. The total consumption is about 8,052 gallons and this is worth about Le 38.65 million (US$ 17,469) at 2002 prices. The total amount is worth to be invested on a pipeline between the station and the oil terminal, which can reduce or eliminate the fuel wastage. Payback period of such investment is about one or two years.

Fig. 6.6 below shows the prices of heavy fuel oil (HFO) for electricity generation in Sierra Leone and some OECD countries. The HFO prices were converted to US dollars using absolute purchasing power parity, which refers to the equalisation of price levels across countries in terms of exchange rates. Fig. 6.6 clearly shows that NPA purchasing prices were relatively very high. Between 1996 and 1999, the price per tonne in Sierra Leone was about 65% higher than Turkey, which is the highest among the

OECD countries shown in the figure. The current price is US$ 246.72/ton. Hence, in US dollar terms Sierra Leone is paying 60% above the current price.

Fig. 6.6: HFO prices for electricity generation (1996-2002).



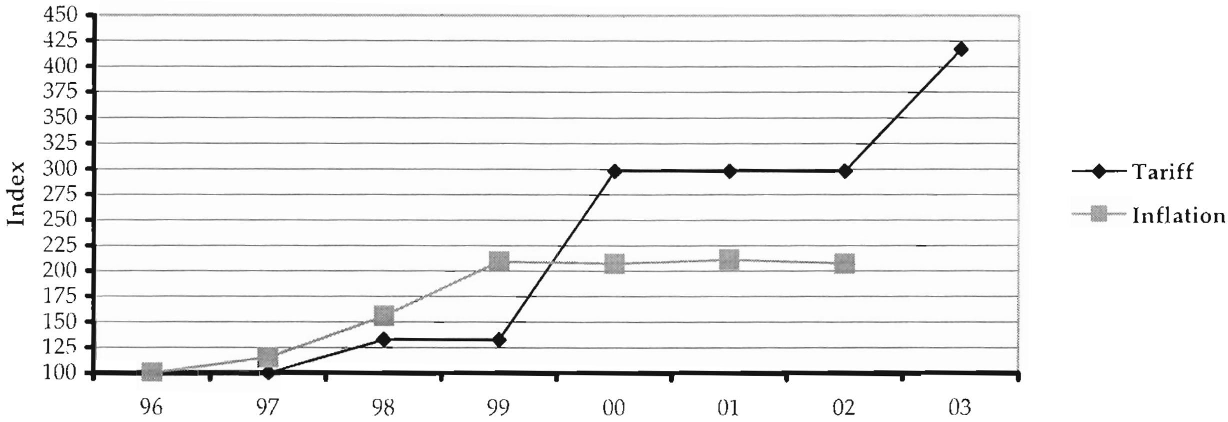
6.2 TARIFF ANALYSIS

6.2.1 Tariff and inflation growth

Fig 6.7 is a comparison between the tariff growth and the economy wide inflation. Tariff increase from 1996 - 2002 has been twice (1998 and 2000) and the 2003 proposed increase, while inflation increases every year. May be it is the reluctance or delay on government to approve tariff increase, which can be attributed to it being disappointed with the utility's poor performance.

The tariff growth from 1996 - 1999 was about 70% below inflation rate. Within this period, power generation was steadily declining and that affects economic activities in the country. Furthermore, the currency devaluation within the same period was about 100%. Between 1999 and 2002 there was a dramatic increase in tariff growth that surpasses inflation by almost 95%. 1999-200 was the period the utility was at its worst performance. The 2003 price is still under consideration, but if implemented will widen the gap tremendously.

Fig. 6.7: Average tariff and inflation (1996 = 100)



6.2.2 Comparison of tariff with the rate of return method

The formula used by NPA for tariff increase is shown below:

$$\frac{T_1}{T_2} = A + B\frac{E_1}{E_2} + C\frac{F_2}{F_1} \text{ --------------------(6.8)} \qquad \text{(NPA - Sierra Leone)}$$

Where:

- T1 and T2 = tariff before and after indexation;
- E1 and E2 = foreign exchange before and after variation of exchange rate;
- F1 and F2 = fuel costs before and after change in cost;
- A = local (Sierra Leone) cost;
- B = sum of projected foreign exchange related expenditure for the year/ revenue projected for the year;
- C = sum of projected fuel costs for the year/revenue projected for the year; and,
- A + B + C = 1.

The rationale for the use of the above formula is that almost all expenditures are import related. It takes into consideration adjustments for fuel costs, foreign exchange and the macroeconomic indicators of the country.

The above formula, which was recommended by the World Bank, has no provision for asset value recovery that will enable the utility to meet future sustainability. It is just an immediate recovery of fuel costs and foreign related expenditure for continued operation. Applying equation 6.8 to the 2002 tariff rates (see appendix B, table B3) for the proposed 2003 rates increase gives a 33% increase, which is a high increase. In the Lahmeyer International report of 1995, it was recommended that NPA should base their tariffs on LRMC. This is because of the tariffs are not cost reflective.

However, the rate of return method of tariff rate setting is used to analyse the tariffs in the country. This is based on the revenue requirement of the utility and is determined using a calculated rate of return on capital. It is a formula (see equation 4.1) that gives any utility the opportunity to recover all its expenditures (both local and foreign) and a fair return on the cost of capital. With good management, it gives a scope for future expansion and continued operation.

Performance Based method will not be used because the determination of the X-factor and the selection of the exogenous factor are very crucial in the calculation. The consequence of wrong numbers in the formula has an adverse effect either on the utility or the ratepayers. Moreover, it is suitable in a competitive situation as it serves as an incentive for improved performance and delivery of good services. The situation in Sierra Leone is far from ideal, because there is no competition and performances are deteriorating.

Using the parameters in equation 4.1 and 2001 values from tables 5.2 and 5.3, V = Le 41,480,897,000, D = 10,542,545,000, E = Le 25,424,200,000, d = 2,026,716,000, return on debt = 7% equity/capital = 0.254, debt/capital = 0.746, Energy available for sale = 88.533 GWh and US$ 1 = Le 1,985.89.

Since the utility is not paying any dividend to government, the return on equity is supposed to be zero. To make provision for equity capital investment recovery, an average 16% is selected for the computation as the national bank interest rates between 1996 and 2002 range between 12% and 18%. The energy available for sale is the difference between what is generated and the sum of the auxiliaries and station energy consumption.

The rate of return on capital used in equation 4.1 was calculated as follows:

$$r = (\%equity * \frac{equity}{capital}) + (\%debt * \frac{debt}{capital}) = (0.16 * 0.091) + (0.07 * 0.909) = 0.078$$

Using equation 4.1, revenue requirement is given as:

$$RR = (41{,}480{,}897{,}000 - 10{,}542{,}545{,}000) * 0.078 + 25{,}424{,}200{,}000 + 2{,}026{,}716{,}000$$

$$= 2{,}413{,}191{,}456 + 27{,}450{,}916{,}000 = Le29{,}864{,}107{,}456$$

Average tariff = RR/ unit available for sale

$$= \frac{29{,}864{,}107{,}456}{100{,}184{,}379.1} = 298.09 Le / kWh$$

Using the official exchange rate (Table B3, Appendix B), this average price is equivalent to 15.01 US cents/kWh. Table 6.6 shows the ROR method computed results (see Appendix C, table C2) compared to NPA tariffs rates. Since the revenue requirement of any utility is expected to increase every year, the computed rates using ROR methodology increase annually. The nominal tariff increases in US $ shown in the table were opposed by the fluctuation of the local currency, which depreciated by 128% from 1996 - 2000, appreciated by 5% in 2001 and depreciated again by 11% in 2002.

Table 6.6: ROR computed rates compared to NPA's previous tariffs (1996 - 2001)

	1996	1997	1998	1999	2000	2001	2002	2003[a]
ROR rates (US cents/kWh)	11.97	24.88	11.77	19.62	14.87	15.01	-	-
NPA rates (US cents/kWh)	14.23	13.34	11.17	9.56	18.59	19.64	17.63	24.62

[a] *This is a proposed tariff (at the time of writing) and it is still waiting for approval.*

Between 1996 and 1997 the ROR average prices rose by 125%, fell by 50% in1998 and then peaked by 250% in 1999 as shown in fig. 6.8. Thereafter they show a downward trend. NPA average prices were constant between 1996 and 1997 and then rose steadily. In 2000, NPA's tariffs exceed the ROR rates by 25%. The high level of the ROR rates from 1997 - 1999 can be attributed to the poor performance of the utility or the imbalance between the operating expense and the energy generated. Table 6.7 below shows the annual growth of the utility's operating expenses and energy generated. The two quantities are inversely proportional; while operating expenses are increasing, productivity is decreasing. Operating expenses in 1997 rose by 47% while the energy generated fell by 37%. The worst situation was in 1999; operating expenses increased by 65% with reference to the base year (1996) while production decreased by 55%. Revenue requirement depends on the operating expenses. If operating expenses do not increase with the energy generated, the computed tariff using ROR will increase.

Fig. 6.8: NPA tariffs compared to ROR computed rates (1996 = 100)

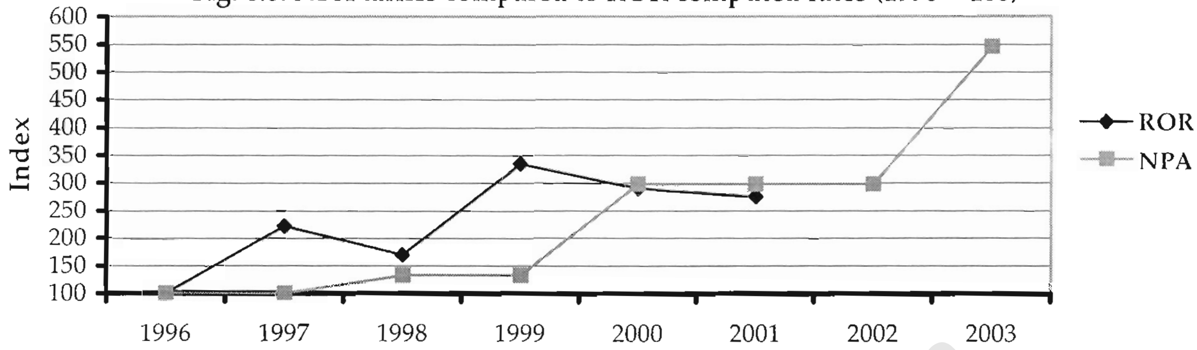


Table 6.7: Operating expenses and productivity 1996 = 100

	1996	1997	1998	1999	2000	2001	2002
Operating expenses	100	147	124	165	175	296	
Energy generated	100	63	72	45	54	93	108

There was a slight improvement in production between 2000 and 2002. This might be due to the change in management or the increased generating capacity (three 1.28 MW Caterpillar generating sets and the 6.3 MW Mirrless generating set) respectively. Within that period, the ROR tariffs were below the existing NPA tariff. This demonstrates that if the utility can match operating expenses with production, the use of ROR method to set tariff will bring about realistic low tariffs.

Fig 6.9 shows the cost of production and tariff. It can also be used to explain why the ROR computed tariffs in 1997 and 1999 are higher than the existed NPA tariffs. In those two years the tariffs were really below the cost of production, while the ROR computed tariffs are supposed to be the actual tariffs.

Fig. 6.9: Cost of production compared to tariff (1996 - 2001)

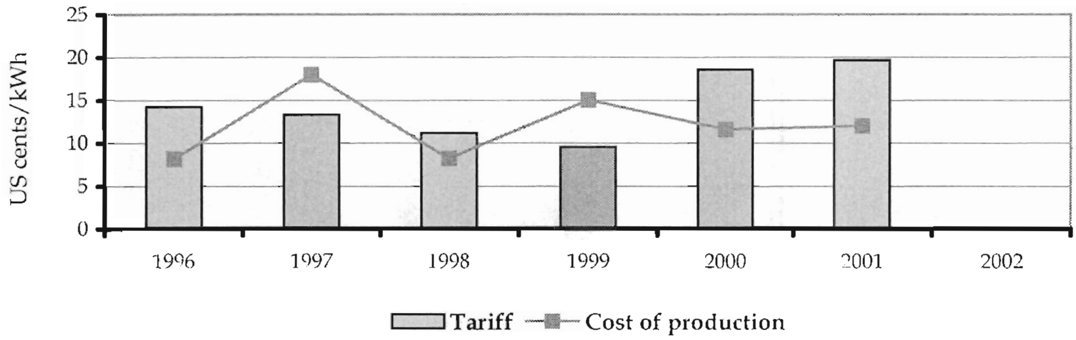
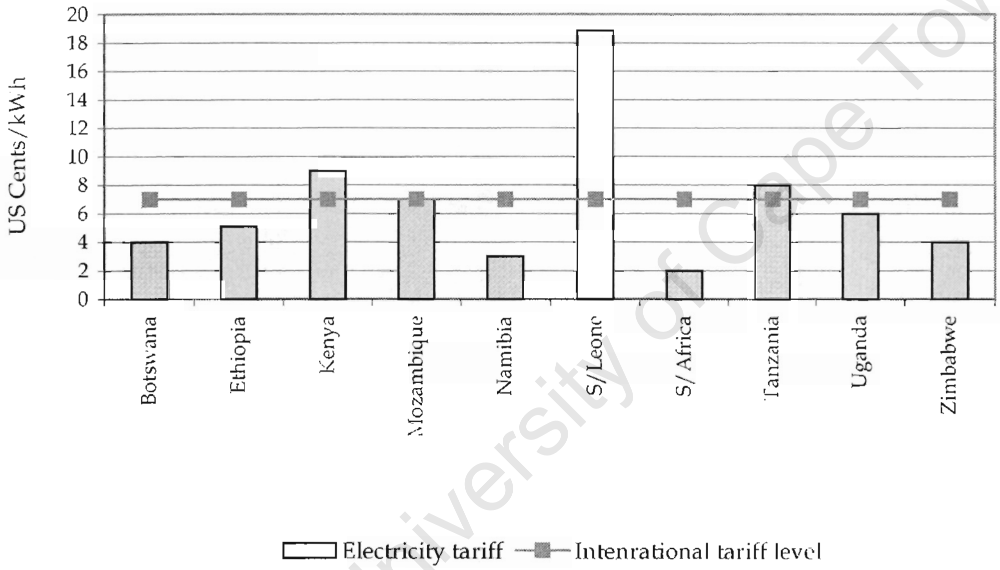


Fig. 6.10: Average electricity tariff in some African contries compared to Sierra Leone (2000)



Source: Adapted from Eberhard, 2002; Teferra M et al. (eds.), 2002 and NPA – Sierra Leone

The electricity tariff in the country is very high. Figure 6.10 above shows the average electricity tariff in the country compared to some African countries. It is 100% higher than Kenya, which is the highest in the Southern and Eastern region in 2000. Figures 6.11 - 6.13 illustrate a comparison of the tariff levels of the major electricity consuming sectors - domestic, commercial and industrial sectors. On the average, Sierra Leone has the highest tariffs.

Fig. 6.11: Domestic tariffs (1996 - 2002).

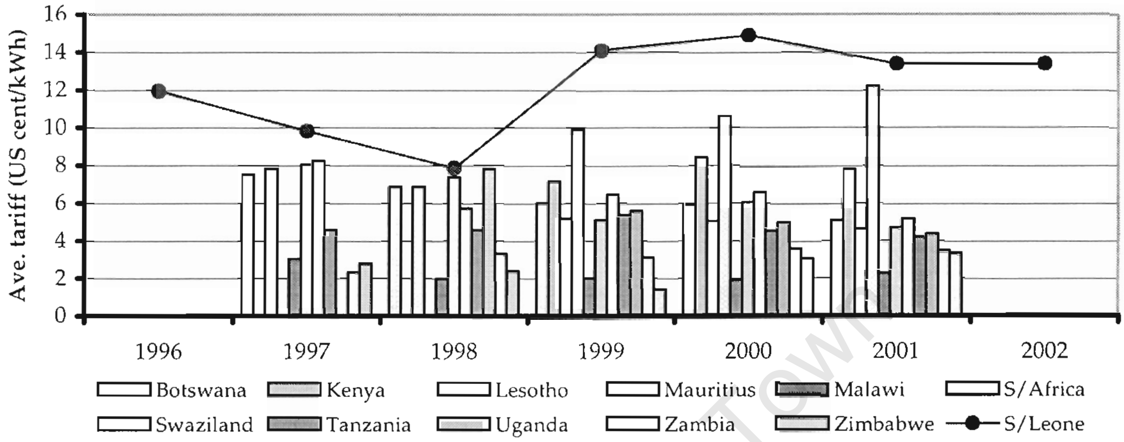


Fig. 6.12: Commercial tariffs (1996 - 2002)

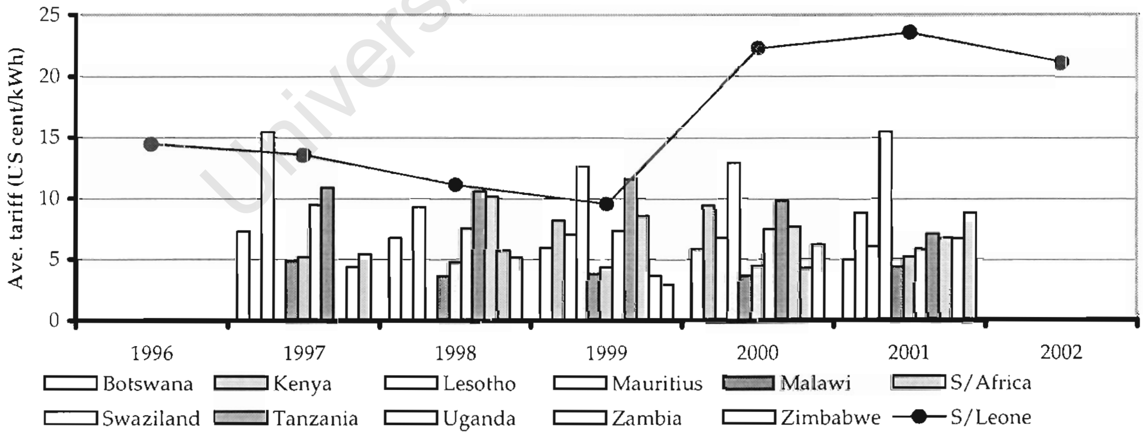
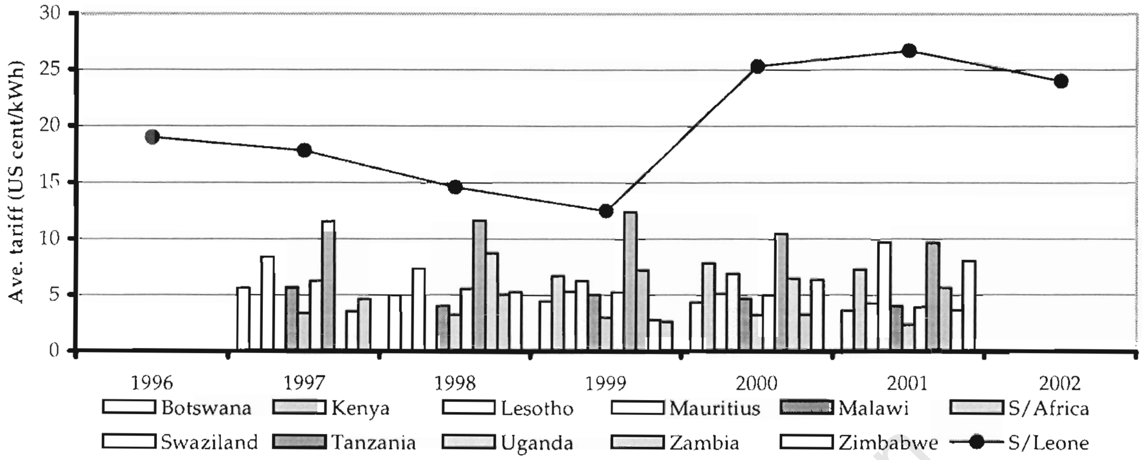


Fig. 6.13: Industrial tariffs (1996 - 2002)



The normal average tariff for countries in Sub-Saharan Africa is 7 US cent/kWh. Kenya and Tanzania are about 28% and 14% respectively above the normal tariff level while Sierra Leone is about 170% above (see fig. 6.10).

6.2.3 Sensitivity analysis

About 50 - 90% of a utility's cost of operation can represent production and delivery costs (USAID, undated). Fig 6.14 below shows the operating cost composition in 2002. The breakdown of the operating cost for the other years is unavailable. The operating cost (excluding supply and administration costs) of NPA in 2002 was Le 26.45 billion (about US$ 12 million). The fuel costs represent about 78%. Based on this significant contribution of the fuel expenses, the operating cost was used as a parameter for the sensitivity analysis.

The 2001 average tariff based on the ROR calculations was tested using a range of -10 and +25%. Figure 6.15 shows the impact of the changes with respect to the average tariff. The effect of increasing the fuel prices, while the other variables in the operating cost remain constant, demonstrates a significant impact on the average price. It shows a direct linear variation. In the above situation, 1% increase in the fuel cost corresponds to an increase of approximately US$ 0.0014 in the tariff. To breakeven at the existing price, the fuel price has to increase by 18%.

Fig. 6.14: Composition of production cost (2002).

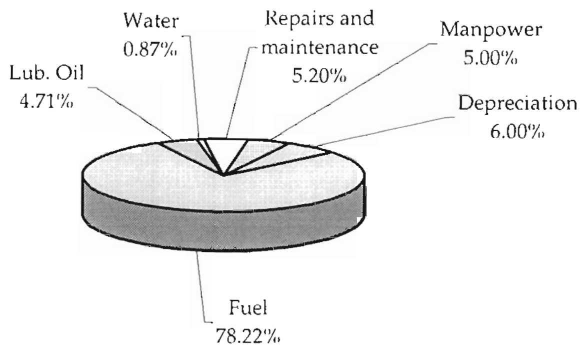
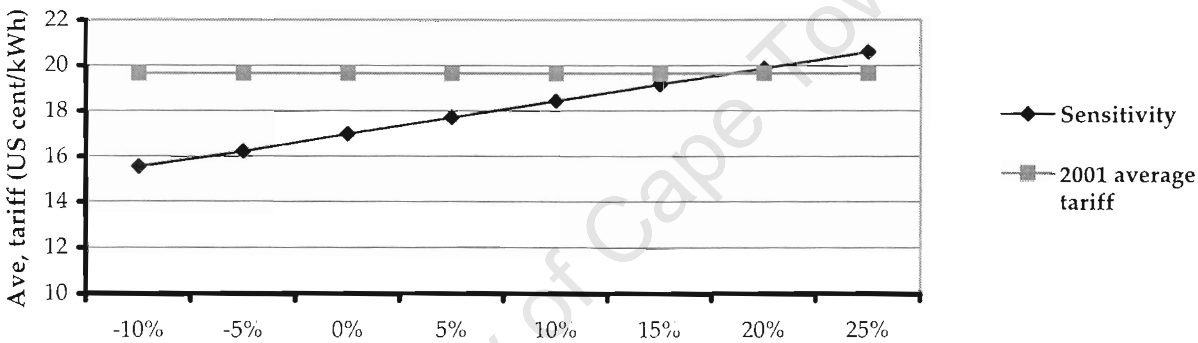


Fig. 6.15: Impact of changes in operating costs on average tariff - 2001.



From fig. 6.6, it is deduced that the cost at which the utility is buying the fuel is about 65% higher than the OECD countries and from fig. 6.11 it can be seen that the fuel expenditure in 2002 constitutes 78% of the total operating expenses. Assuming the fuel expenses from 1996 – 2002, on the average, constitute 70% of the operating expenses and the fuel cost is reduced by 65% then the operating expenditure becomes 0.55E. Since, the national utility is not paying tax, equation 4.1 can be adjusted to give the expression below.

$$RR = (V - D) * r + 0.55E + d \text{ -----------------------(6.9)}$$

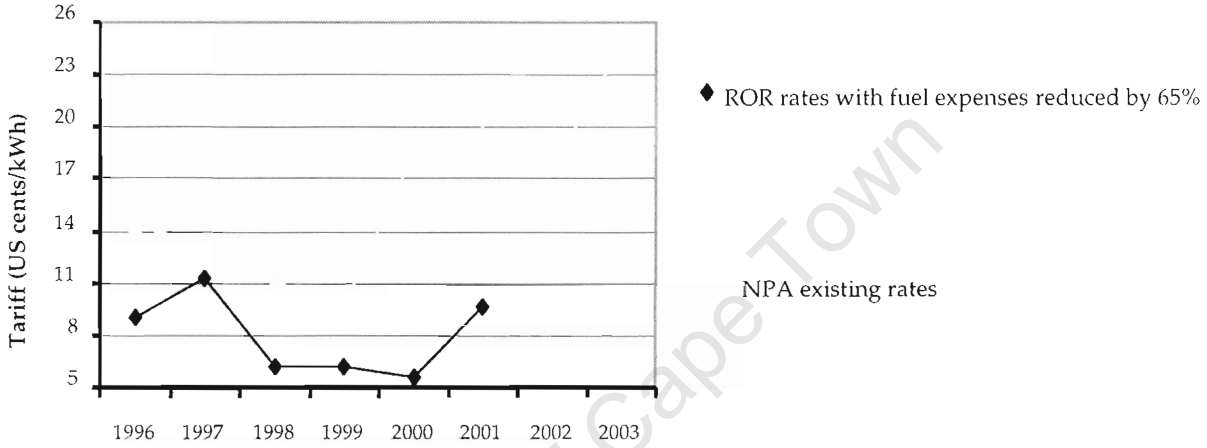
Using equation 6.9 and assuming all parameters to remain constant, the average tariffs are given in table 6.8.

Table 6.8: Average tariffs, assuming fuel costs reduced by 65%

	1996	1997	1998	1999	2000	2001
ROR rates (US cents/kWh)	8.97	11.24	6.21	6.14	5.59	9.57
NPA rates (US cents/kWh)	14.23	13.34	11.17	9.56	18.59	19.64

Fig. 6.16 is a comparison of NPA's existing tariffs and ROR rates assuming the fuel is purchased from the OECD countries. This is a clear manifestation that the tariffs in the country are high. If the fuel is procured from any of the OECD countries, the tariffs will be at international accepted level and the mark up freight cost on the tariffs will not increase the tariffs by 10 - 15%. This is not realised because management lack business thinking to optimise profit.

Fig. 6.16: Comparison of tariffs



6.3 PERFORMANCE INDICATORS

Table 6.9 is an illustration of some performance indicators of NPA and other utilities in Africa in 2000. The international target of system losses is between 10% and 11%, customer/employee ratio is about 160 and access to electricity is 80% (Bhagavan, ed, 1999: 337-338). According to Teferra and Karekezi (2002:23) a well run utility in a developing African context should have a maximum system losses of 12%, maximum employees/MW installed capacity ratio of 5, a minimum customers/employee ratio of 125 and a maximum employees/GWh produced of 2. It is very glaring that the performance of NPA is very inefficient. The average system losses are extremely high. Translating the 2002 average losses into monetary terms gives an equivalence of about Le 7.7 billion4 (US$ 3.5 million). This is a significant amount, which could have added great value to the utility. But due to poor management and maintenance, this was lost.

Considering the ideal staffing ratio in the African context, the 2002 data shows that NPA is about 200% overstaffed. This is source of increased operating expenditure. Despite the 2002 operating costs are not yet available, one can make an intelligent guess that there is a significant increase in operating expenses between 2002 and 2003.

Table 6.9: Some selected performance indicators - 2000

	Ave. total losses (%)	Employees/ MW installed capacity	Customer/ Employee	Employee/ GWh produced	Access to electricity (%)
Cote d'Ivoire (CIE)	13.00	3.20[a]	159.50[a]	1.70[a]	21.00[a]
Botswana (BPC)	11.12	13.16	44.00	1.00	NA
Ethiopia (EEPCO)	17.00	19.40	72.00	4.80	13.00
Ghana (ECG & VRA)	26.00	1.30[a]	125.70	0.40[a]	45.00
Kenya (KPLC)	21.45	5.80	73.00	1.60	20.00
Malawi (ESCOM)	15.31	10.00	37.00	2.17	5.00
Mauritius (CEB)	10.20	5.00	184.00	2.00	87.00
Nigeria (NEPA)	40.00	6.30	66.40[a]	2.40	39.00
Senegal (SENELEC)	17.00	4.00	234.00	1.30	30.40
S/Leone (NPA)	41.00	17.90	59.60	5.40	6 – 10
S/Africa (Eskom)	5.00	0.84	95.00	0.17	70.00
Swaziland (SEB)	14.80	13.70	53.00	0.81	NA
Tanzania (Tanesco)	23.80	12.50	57.00	3.40	7.00
Uganda (UEB)	39.00	7.24	93.00	1.24[b]	5.00
Zambia (ZESCO)	17.30	2.30	49.00	0.50	20.00
Zimbabwe (ZESA)	12.80	3.55	72.00	1.80	40.00

[a] This is 1995 data. [b] This is 1999 data. NA = Not Available

Source: Teferra and Karekezi, 2002: p24, 95,148,207,255; SAD-ELEC, 2001; NPA - Sierra Leone.

CHAPTER 7
CONCLUSION AND RECOMMENDATIONS

This chapter consists of conclusion and recommendations. The recommendations are a combination of both short and long terms. The short-term recommendations address the current operational inefficiencies of the utility, aimed at improving its financial viability, which invariably will result in a reduction of the high tariffs. The long-term recommendations are considerations to be implemented in the long term.

7.1 CONCLUSION

NPA's power production is energy inefficient and the overall performance is far from satisfactory. There is too much energy wasted, high network losses, poor management and the utility is also overstaffed. Besides, production continually declines while operating expenses increase steadily. These inefficiencies contribute to the high operating cost incurred by the utility and are passed on to the consumers. Therefore, whatever method is used to compute the average tariff, this will always be very high compared to international standards.

The above inefficiencies are some of the factors that affect the financial weakness of the utility. Other factors are delays in tariff increase approval and billing, the depreciation of the national currency and non-payments.

The recommendations given below if adopted will go a long way to help the utility in reducing its financial losses, enabling it to improve its revenue. With good management, the utility will be able to invest more towards improvement of the T&D facilities that will result in lower network losses. This in turn will further improve the revenue earning and enable the utility to import the latest technology, procure adequate quantity of quality spare parts, and machinery and equipments. Consequently, this will lead to the reduction of the unit production cost and hence low tariffs.

7.2 RECOMMENDATIONS

7.2.1 Short-term recommendations

Network loss reduction.

Technical losses are inherent in any network and can be reduced to their optimal levels. The tolerable maximum losses in a network should be between 11% and 15%. If the losses can be reduced to the minimum (7%), this will boost the financial gains of the utility with a huge social benefit; it will lower the cost of delivering power and consequently lower electricity cost.

The first step in the direction of reducing the network losses is to have a clear understanding of the magnitude of the technical and non-technical losses. To achieve this a detailed network documentation and a system of energy accounting should be put in place.

Some of the measures to reduce network losses are as follows:

- Strengthening the sagging wire;
- Realigning the lines to reduce line mileage and using small distance transformers to reduce the length of low voltage lines. This is due to the fact that excess load on the T&D lines can lead to power loss and it is also true for overextended lines from transformers;
- Improving the efficiency of the various system components. Replacing the existing transformers with high efficient ones, for instance improved silicon steel transformers and amorphous core transformers, can reduces the losses;
- Establishing a standard power factor (pf) at which industries commercial sectors should operate and charging a fee for those that will operate below the stipulated pf.
- Since resistance is inversely proportional to the cross-section of the conductor (feeders and transmission lines), replacing existing conductors with larger diameter conductors will also reduce the technical losses;
- Setting up vigilant squads and intensifying surprise inspections to detect cases of malpractices (meter tampering and bypassing, illegal tapping of power, etc);

- Imposing severe penalties on culprits;
- Enclosing the meter such that it cannot be tampered; and,
- Providing adequate meter testing and scheduling a time bound program for checking the meters.

Offering the utility to concessions

Since the electricity market in the country is very small to support effective competition, competitive awarded concession is the best option. It creates competition for the market and has the following benefits:

- Lower electricity prices as the concession will be awarded to the bidder who offers the lowest price.
- Improved efficiency: this encourages the utility to produce the electricity cheaply and to sell the electricity at a price that will cover its cost but not much more - just as ordinary competition keeps prices down and limit profits.
- Improved service delivery: concessions generally have a limited term, at the end of which they are put to a bid again. When the incumbent concessionaire has the opportunity to compete in the re-bidding, it has an extra incentive to perform well. In this way, it improves the chances of being awarded the concession again.

There are three types of concessions:

1. **Management contracts with incentive payments**. In this type of concession the government get some financial returns and bears part of the operating risk. The other part of the operating risk is on the concessionaire, since his profit depends on the operating performance of the utility.
2. **Lease**. In this case the concessionaire pays no fee to the government, but his profit depends directly on the operating profits of the utility. Operating risk is fully on the concessionaire and investment risk is on the government.
3. **Build-operate-transfer (BOT) and rehabilitate-operate-transfer (ROT)**. In such arrangements the concessionaire bears both investment and operating risks.

The type of concession to use depends on the government's intention of the utility. Since the national utility is not paying dividend to the government, then it is better the utility is lease to a private company.

Workforce reduction

As shown in table 6.9 NPA is too overstaffed. According to the staffing ratio of a well-run African utility, the required number of staff for the installed and operating capacity is about 210. To achieve this requires a 67% reduction in the workforce of the utility. An employees-installed capacity ratio of 7 is satisfactory and hence recommended. Therefore, NPA requires 300 employees for its installed capacity. Although this will have a short-term social impact, as about 53% will loose their job, it is very necessary to improve the financial and operation efficiencies of the utility. Further more, this will improve the reliability of the power supply and this will encourage the establishment of other enterprises, thus creating other jobs.

Decrease of fuel wastage

The short-term measure to address the power station fuel wastage is to improve the house keeping. This will involve the following:

- Mending the leaking pipes;
- Permanently relegating the duty of transferring and treatment of the fuel to one dedicated individual;
- Replacing the viscosity meter.

Publication of financial statements

The Authority is a public utility and hence belongs to everyone in the country. The public is completely disturbed about the operational inefficiency of the utility. Although, every week or two, one or two members of the administration will come in the air to explain the problems of the utility, there is one important aspect that is never disclosed to the public. This is the financial statement of the utility. Almost all international power utilities (both public and private) are publishing their financial statements annually through annual reports and financial newspapers. Therefore, it is expedient for NPA to be publishing its financial statements. They ought to be promptly prepared and audited though at the time of writing the 2002 financial statement has not been audited. In this way, the public will know the profit or loss created by the utility, its financial status and be able to make useful suggestions as to how to develop and expand the ESI.

Testing of the sump oil

As shown in fig. 6.11, lubricating oil contributes about 5% of the operating costs. The usual disposal of the sump oil at the end of the scheduled 10,000 hours of run for maintenance with no concern of its condition and performance capability is another source of revenue loss or added expenditure. Owing to the low availability of the plant, there is a possibility of the oil not completely loosing its lubricating properties. Periodic testing of the sump oil will reveal its actual condition and lubricating properties and might be possible to extend the period of change to another 1000 - 2000 hours. This will increase the financial savings and reduce operating costs. The implementation of this recommendation requires some investment whose payback period can be one or two years.

7.2.2 Long-term recommendations

Need for new power plants.

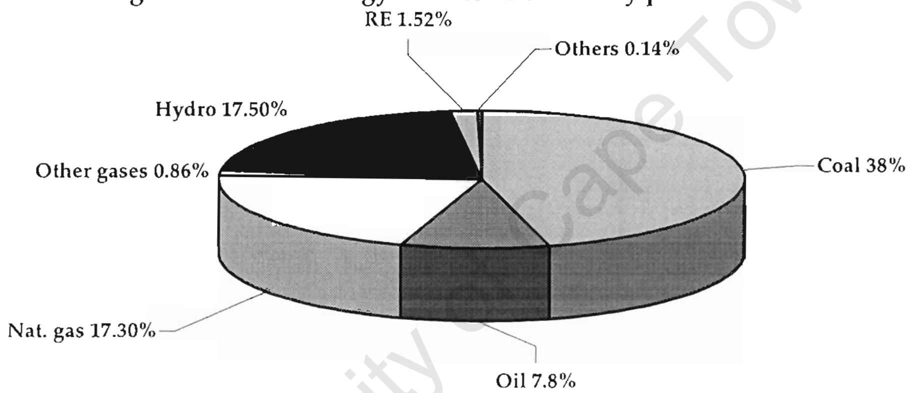
Currently, there is a general trend of growth in demand for electricity. New connections and the potential of overall economic growth will result in increasing demand in the country. As a rough estimate the growth projection for the immediate future is in the range of 800 - 1000 MW. The Bumbuna hydroelectric if commissioned in 2004 to supplement the existing capacity will not meet the projected demand. Besides, the two largest generating units at the Kingtom power station have gone beyond their 20-year economic lives and will soon reach decommission. If decommissioned, new plants must be built to replace them. With the growing concern of environmental issues, the direct capital cost (including plant cost and installation) of a coal-fired plant with flue gas desulphurisation (FGD) is about US$ 800/kW (International Atomic Energy Agency- IAEA, 1984). Therefore, an 800 MW plant will cost US$ 640 million.

DSM, as an energy efficiency measure, can help utility to manage its demand load and postponed the construction of new plants. With the situation of Sierra Leone, implementing DSM will reduce the estimated new capacity. Therefore it is timely for the utility think and implement DSM.

Increase the energy mix

A number of different energy sources are used worldwide to produce electricity. These include fossil fuels and renewables. Figure 7.1 below shows the shares of the different energy sources of electricity generation in 2000. Coal, which has a share of 38%, is the major source of electricity production followed by hydro (17.5%) and natural gas (17.3%).

Fig. 7.1: Share of energy sources of electricity production - 2000.

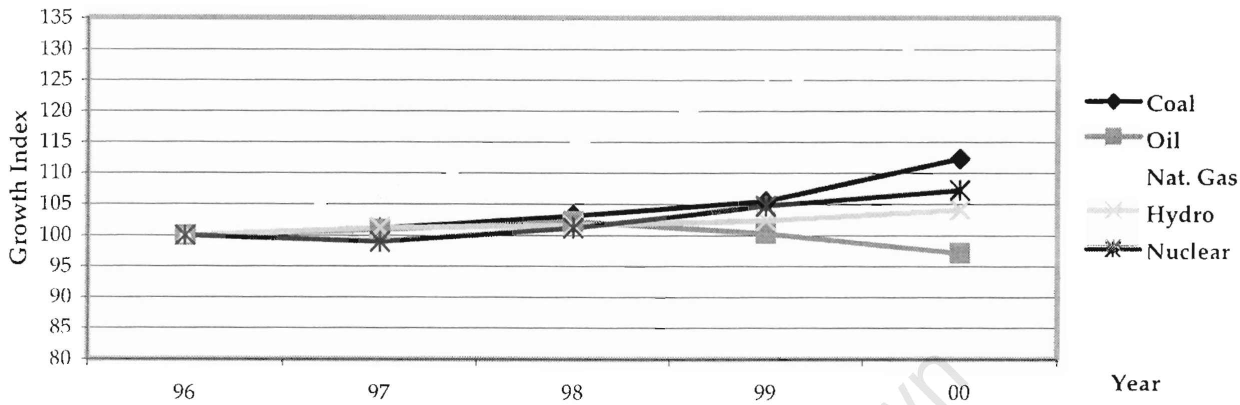


Note: RE = Renewables (solar, geothermal, tide, wave and ocean, wind, and biomass); other gases include biogas and manufactured gas; coal includes hard coal, sub-bituminous, lignite/brown and peat.

Source: International Energy Agency (IEA).

Figure 7.2 shows the growth rate of the major energy sources. Despite its fuel cost, natural gas shows a marked increase over the years with an average annual growth rate of about 6.5%, followed by coal (2.5%) and nuclear (1.5%). Oil increases at an annual average rate of about 0.6% between 1996 and 1999 and then declines at 1.6%. The increased growth of gas can be attributed partly to climate change mitigation measures and the electricity industry deregulation that is bringing in more independent power producers. Besides, the cost of the gas turbines is relatively cheap and has a short installation time.

Fig. 7.2: Growth of major energy sources of electricity production - (1996 -2000).
Index: 1996 = 100



With the oil exploration about to take place in the country, it is timely NPA management start to think about the use of gas to increase it energy mix for power production. But since it is yet unknown about the quantity of gas in the country, there is also the opportunity to tap the gas from the West African Gas Pipeline (WAGP) that is scheduled to come on stream by June 2005 (Asamoah, 2002:19). This WAGP will feed its source country (Nigeria) and three neighbouring countries (Togo, Ghana and Abidjan). With such development and the plan for NPA to join the WAGP, the pipeline can easily be extended to Sierra Leone from Cote d'Ivoire through Liberia.

The construction of the gas pipeline is capital intensive. The implementation of the short-term recommendations can boost the financial standing of the utility. This will be possible with dedicated and co-operate minded management.

The use of combined cycles

The steam discharged to the surroundings of the power station is significant and the exhaust gases temperature is fairly high. This is energy wasted. The steam can be utilised by integrating the existing generators with a steam turbine. In this way the efficiency of the plant can be improved while increasing the installed capacity. This will require an external superheater as the condition of the steam wasted is almost at its saturation temperature. Otherwise, the steam flow system should be redesigned such that the energy in the exhaust gases is utilised to superheat the steam.

The high mean temperature is an indication of high solar radiation. Therefore, another option is to install a solar thermal plant (STP) and integrate it into the existing plant. The STP can be used as a base load plant while the diesel thermal plant can be as a peaking plant or reserve capacity for bad weather and night periods.

STP projects are capital intensive. With worldwide dramatic interest to reducing anthropogenic greenhouse gases and other associated power production pollutants, funds for such projects can be sourced through the Global Environmental Facility (GEF) and Green Power Development Fund from Europe. In 2000, GEF approved grants for the first solar thermal projects in Egypt, Mexico and Morocco.

Billing and revenue collection

Billing process involves the following: data collection, data processing, bill production process, mailing, customer service, and payment collection. This can be a source through which revenue can be lost if meters are not read correctly, data are not processed correctly and bills produced timely. Due to lack of the necessary infrastructure, incompetent personnel and poor management NPA outsource meter reading and delays the bills production. As a result of poor customer service they are experiencing delayed payments by large customers and other non-payments, which is due to the credit system.

There are many possible options to overcome these problems due to recent technological advances. Integrating an automated meter reading (AMR) system with radio frequency communication, it is possible to read meters directly from a central location, thus avoiding contracting the process. Current utility customer relationship management (CRM) software packages expedite bill processing. Although this needs a huge investment, it is possible if the above short term measures are corrected. The following are some recommended options:

- Overhauling the whole metering system and replace it with AMR system or prepaid system.
- Improving the communication facilities and introducing Internet billing.

- Training of personnel
- Expanding the current revenue collection centres by including shopping centres.

The above options require massive investment to overhaul the whole metering system. The first two options require constant power supply and the Internet billing is only possible with customers connected to the Internet.

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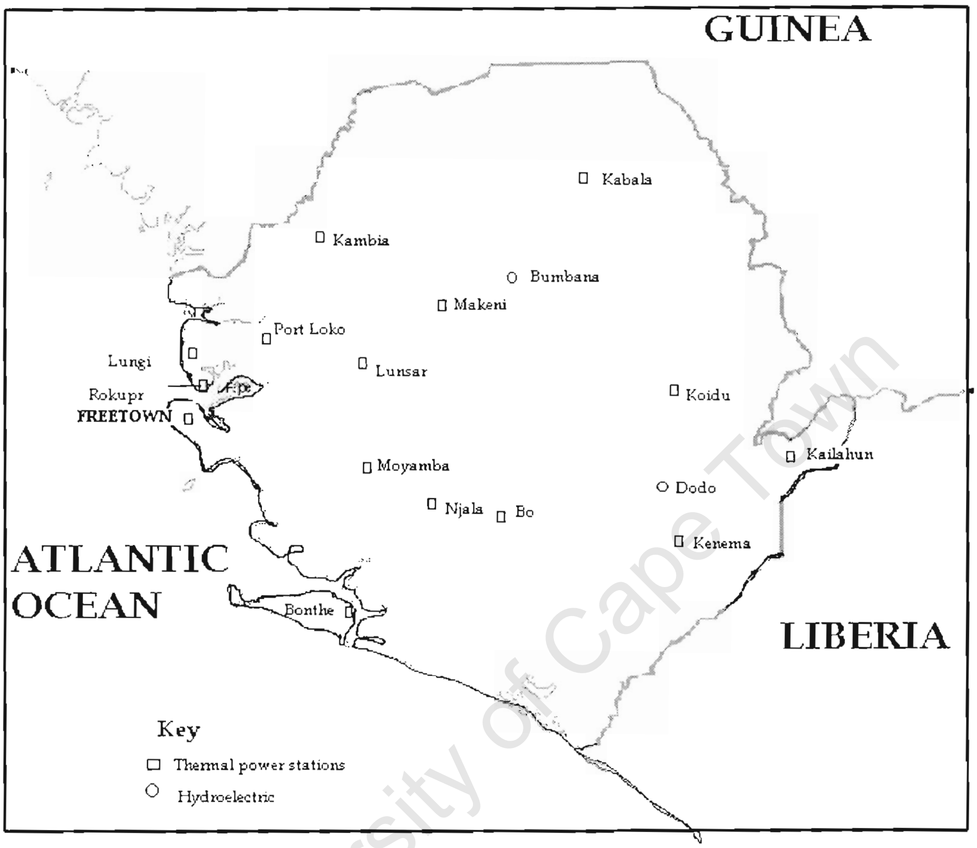
APPENDICES

APPENDIX A

Fig. A1: Location of Sierra Leone in Africa.

Fig. A.2: Location of power plants



APPENDIX B.

Table B1: Fuel consumption, energy generated and availability of Kingtom power plant (1996 – 2002). Source: NPA, Sierra Leone.

Year	Month	Energy gen. (kWh)	Station energy use (kWh)	Fuel consumed (Imp. gal.)		Expected Hours run[3] (hrs)	Hours run (hrs)
				HFO	DFO		
2002	Jan	7,874,240	515,350	420,578	84,520	4,464	3220.97
	Feb	8,822,599	493,290	517,080.4	59,762.58	4,032	3,057.7
	Mar	11,361,265	596,140	541,268	93,627.7	4,464	4,045.2
	Apr	10,110,821	560,520	403,964.2	101,700.5	5,040	3,863.8
	May	11,746,011	534,830	968,058.8	48,699.5	4,464	4,278.7
	Jun	10,765,711.2	491,660	575,012.4	33,813.5	4,320	3,971.2
	Jul	11,192,308	536,570	666,777.3	31,727.46	4,464	4,031.6
	Aug	8,384,401	489,530	438,504.5	59,766.6	5,208	3,257.2
	Sep	12,391,118	626,760	771,508	37,656	5040	4,272.4
	Oct	9,045,379	540,040	426,762	51,589	5,208	3,525
	Nov	10,345,850	549,700	616,675.6	56,315.25	5040	3922.9
	Dec	11,459,365	628,390	853,073.3	50,987.37	5,208	4,119.6
	Total	**123,499,068.2**	**6,562,780**	**7,191,226.5**	**710,165.6**	**56,952**	**45,566.3**
2001	Jan	10,524,490	409,200	582,804	79,973	4,464	4,034.3
	Feb	7,323,880	375,910	402,046	88,581.17	4,032	3,048.7
	Mar	10,157,795	474,820	585,100	103,794.1	4,464	3,532.1
	Apr	8,320,242	426,390	443,380	94,632.65	4,320	3,409.7
	May	7,425,867	430,350	365,915.7	119,609.7	4,464	3,027.8
	Jun	8,974,873	500,490	543,365	46,099.87	4,320	3,497.6
	Jul	9,384,772	538,270	546,063.5	31,942	4,464	3,206.2
	Aug	9,341,939	538,870	548,174.2	50,113.2	4,464	3,533
	Sep	8,281,885.5	498,470	505,059.3	48,578.9	3,600	3,380.4
	Oct	8,608,876	478,890	533,634.4	59,093.71	3,720	3,418.4
	Nov	8,111,426	488,760	493,684.6	88,345.9	4320	3,280.3
	Dec	9,855,987	546,190	578,426.7	101,146.4	4,464	3,754.4
	Total	**106,312,032.5**	**5,706,610**	**6,127,653.4**	**911,910.6**	**51,096**	**41,122.9**
2000	Jan	3,764,400	332,290	247,951	6,057	744	663.25
	Feb	4,603,000	330,720	272,987	5,590	696	659.55
	Mar	5,511,700	349,931	177,104	171,947	744	720.15
	Apr	4,873,700	344,759	300,396	26,467	720	667.38
	May	4,394,600	323,352	284,496	8,252	744	661.75
	Jun	3,664,600	260,772	243,760	8,240	720	542.17
	Jul	5,039,100	321,150	321,040	9,278	744	704.17
	Aug	5,024,600	296,820	331,776	9,743	744	684
	Sep	4,785,181	262,950	278,356.8	43,013	720	589.62
	Oct	6,960,795	268,480	324,967	138,141	1488	1,408.4
	Nov	6,499,802	269,560	310,999	269,560	2160	1,335.9

[3] This is the total expected hours run for all generating units.

Year	Month	Energy gen. (kWh)	Station energy use (kWh)	Fuel consumed (Imp. gal.)		Expected Hours run (hrs)	Hours run (hrs)
				HFO	DFO		
	Dec	6,283,710	248,190	277,926	111,571	4,464	3,234.4
	Total	**61,405,188**	**3,608,974**	**3,371,758.8**	**807,859**	**14,688**	**11,870.74**
1999	Jan	3,780,700	333,490	251,725	1,488	1488	714
	Feb	5,255,500	390,390	337,628	200	1,344	939.20
	Mar	5,888,600	427,780	374,647	1,570	1,488	943.45
	Apr	6,271,700	411,390	412,663	3,434	1,440	934.25
	May	5,374,400	381,520	376,731	4,930	1,488	709.35
	Jun	4,493,100	348,400	322,502	5,514	720	661
	Jul	3,485,200	431,802	253,291		744	592.5
	Aug	3,798,400	328,040	266,451	7,183	744	606.5
	Sep	3,945,300	345,290	281,367	6,000	720	653.5
	Oct	3,602,100	306,240	262,113	5,600	744	594.15
	Nov	4,128,300	327,930	295,636	5,793	720	634.45
	Dec	2,875,800	252,340	204,196	6,249	744	484.45
	Total	**51,899,100**	**4,284,612**	**3,674,950**	**47,961**	**12,384**	**8,466.8**
1998	Jan	5,451,580	363,920	366,850	896	2,976	1,136.3
	Feb	3,404,280	270,000	212,976	Nil	2,016	604.35
	Mar	6,864,660	415,370	476,996	933	2,976	1,259.5
	Apr	8,432,300	452,090	522,092	5,379	2,160	1,481.1
	May	8,227,400	477,190	508,278	2,714	2,232	1,534.2
	Jun	7,528,800	464,550	367,742	7,371	2,160	1,393.5
	Jul	6,973,700	481,080	462,290	11,858	2,232	1,292.4
	Aug	4,796,300	346,210	320,530	14,717	1,488	896
	Sep	7,040,700	430,331	472,830	10,201	2,160	1,334.4
	Oct	9,075,100	496,530	558,998	2,861	2,232	1,532.2
	Nov	6,643,800	443,760	415,904	Nil	1,440	1,029.4
	Dec	7,896,900	448,020	512,208	2,241	1,488	1,149.5
	Total	**82,335,520**	**5,089,051**	**5,197,694**	**59,171**	**20,160**	**14,642.85**
1997	Jan	10,634,000	402,680	633,357	14,836	2,232	1,624.2
	Feb	8,548,500	315,120	513,548	13,213	2,016	1,403.4
	Mar	8,674,600	323,530	498,844	16,887	2,232	1,432.3
	Apr	10,448,820	405,240	664,228	18,982	2880	1,705.3
	May	10,234,800	427,820	586,670	15,362	2,976	1,774.5
	Jun	6,453,080	444,240	409,558	5,969	2,880	1,414.3
	Jul	5,757,200	371,610	366,871	5,576	2,232	1,006.1
	Aug	1,567,700	98,300	85,653	4,378	2,232	289.4
	Sep	2,720,500	33,530	182,910	4,568	720	703
	Oct	1,316,180	18,910	102,143	3,712	1,488	356.4
	Nov	1,016,300	18,270	72,911	1,439	1,440	341.1
	Dec	4,067,520	161,440	252,854	2,821	2,976	1,012.4
	Total	**71,439,200**	**3,020,690**	**4,369,547**	**107,743**	**26,304**	**13,064.4**
1996	Jan	9,811,970	298,068	537,348	6,428	2,232	1,470.6
	Feb	9,607,660	292,325	534,786	3,135	2,088	1,382.4
	Mar	10,243,140	310,803	557,315	5,775	2,232	1,539.3
	Apr	9,682,580	253,770	551,142	7,582	2,160	1,545.3
	May	10,208,800	376,540	572,852	9,746	2,232	1,606.1
	Jun	9,544,300	381,240	535,505	5,477	2,160	1,452.3
	Jul	9,168,911	360,450	535,051	11,438	2,232	1,548.6
	Aug	9,254,700	375,150	535,540	10,339	2,232	1,526.1
	Sep	8,008,400	295,820	480,530	8,780	2,160	1,462.5
	Oct	8,528,300	311,910	493,496	10,317	2,232	1,482.5

Year	Month	Energy gen. (kWh)	Station energy use (kWh)	Fuel consumed (Imp. gal.)		Expected Hours run (hrs)	Hours run (hrs)
				HFO	DFO		
	Nov	9,723,510	394,540	577,492	3,894	1,440	1,378.3
	Dec	10,459,670	420,808	610,935	12,336	2,232	1,606.4
	Total	**114,241,941**	**4,071,424**	**6,521,992**	**95,247**	**25,632**	**18,000.4**

Table B2: Tariff structure and increment over the years (1996 – 2002). Source: NPA, Sierra Leone.

Tariff structure and energy consumption levels		Energy charge (Le/kWh[4])			
		Year			
		1996	1998	2000	2003[5]
TARIFF 1	DOMESTIC				
	0 – 30	90	117	205	287
	31 – 150	110	143	293	410
	Above 150	130	169	389	544
	Min. charge	2,500	3,250	6,143	8,600
	Fixed charge	1,000	1,300		
TARIFF 2	NON-DOMESTIC (below 150 kW)				
	0 – 30	100	130	358	510
	31 – 150	120	156	429	600
	Above 150	130	169	465	651
	Min. charge	3,000	3,900	10,725	15,015
	Fixed charge	1,500	1,950		
TARIFF 3	STATE RUN INSTITUTIONS			INSTITUTIONS	
	All units	100	130	429	600
	Min. charge	5,000	6,500	17,875	25,025
	Fixed charge	2,000	2,600		
TARIFF 3A	OTHERS				
	All units	120	156		
	Min. charge	5,000	6,500		
	Fixed charge	2,000	2,600		
TARIFF 4	COMMERCIAL/ INDUSTRIAL (above 15 kW)				
	All units	150	195	517	723
	Min. charge	50,000	65,000	65,000	91,000
	Fixed charge	20,000	26,000		
TARIFF 5	STREET LIGHTING				
	All units	120	156	435	609
	Min. charge	7,500	9,750	796	1,114
	Fixed charge	4,000	5,200	14,625	20,475
TARIFF 6	TEMPORARY SUPPLIES				
	All units	200	260	-	400
	Min. charge	5,000	6,500	-	10,000
	Fixed charge	4,000	5,200		
TARIFF 7	WELDERS				
	All units	200	260	546	764
	Min. charge	10,000	13,000	19,500	27,300
	Fixed charge	10,000	13,000		
	Demand above 15 kW[6]	455/kW per month			
	Operation at pf < 0.9	65 /kVArh per month			
AVE. PRICE		**131**	**174**	**390**	**546**

[4] The minimum and fixed charges are charged per month

[5] At the time of writing, these are proposed tariffs.

[6] This is for tariffs 4 and 7.

Table B3: Macroeconomic indicators.

Year	CPI	Inflation[a] (%)	Annual growth rate of GDP (%)	Average exchange rate (Le/US$)	
				Official	Parallel Market
1996	246.40	0.00	6.1	920.75	956.98
1997	283.03	14.87	- 17.6	981.91	1,220.64
1998	383.92	35.65	- 0.8	1,557.90	1,820.05
1999	514.63	34.05	- 8.1	1,819.27	2,946.23
2000	509.94	- 0.9	3.8	2,097.45	2,314.77
2001	521.06	2.18	5.4	1,985.89	
2002				2,212.47	

[a] *1996 is taken as the base year.*

Source: Central Statistics Office, Sierra Leone; Bank of Sierra Leone

APPENDIX C.

Table C1: Heat rate and auxiliaries' consumption of plant and losses of the system.

1 kWh = 3.6 MJ 1 Imperial gallon = 4.54 litres = $4.54 * 10^{-3}$ m^3
Energy input = $4.54 * 10^{-3}$ (DVC) kJ, where D = density of fuel in Kg/m^3; V = Volume of fuel in imperial gallons and C = Calorific value in MJ/Kg.
D_{HFO} = 939 kg/m^3 (NPA test report value), C_{HFO} = 40.9 MJ/Kg; D_{DFO} = 840 Kg/m^3; C_{DFO} = 42.9 MJ/Kg.

Year	Month	Energy gen. (kWh)	Energy input (kJ)	Heat rate[7] (kJ/kWh)	Station energy use (%)	Tech. and non-tech Losses. (%)[8]	Availability (%)
2002	Jan	7,874,240	87,159,387.02	11.07	6.52	25	72.15
	Feb	8,822,599	99,935,064.77	11.33	5.59	43	75.84
	Mar	11,361,265	109,692,844.40	9.65	5.25	33	90.62
	Apr	10,110,821	87,073,407.81	8.61	5.54	36	76.67
	May	11,746,011	176,757,319.1	15.05	4.55	41	95.85
	Jun	10,765,711.2	105,790,680.50	9.83	4.57	40	91.93
	Jul	11,192,308	121,449,447.50	10.85	4.79	33	90.31
	Aug	8,384,401	86,235,295.00	10.29	5.84	29	62.54
	Sep	12,391,118	140,680,133.30	11.35	5.06	48	84.77
	Oct	9,045,379	82,849,999.15	9.16	5.97	27	67.68
	Nov	10,345,850	116,736,405.50	11.28	5.31	44	77.84
	Dec	11,459,365	157,082,484.00	13.71	5.48	45	79.1
	Total	**123,499,068.2**	**1,370,041,704**	**11.09**	**5.31**	**Ave. = 37**	**80.00**
2001	Jan	10,524,490	114,701,070.30	10.90	3.89		90.37
	Feb	7,323,880	84,592,584.56	11.55	5.13		75.61
	Mar	10,157,795	118,998,612.8	11.72	4.67		79.12
	Apr	8,320,242	92,789,588.78	11.15	5.12	31	78.93
	May	7,425,867	83,369,310.26	11.23	5.80	34	67.82
	Jun	8,974,873	102,282,759.00	11.40	5.58	33	80.94
	Jul	9,384,772	100,436,991.00	10.70	5.74	44	71.82
	Aug	9,341,939	103,777,881.7	11.11	5.72	38	79.14
	Sep	8,281,885.5	96,009,387.42	11.59	6.02	38	93.90
	Oct	8,608,876	102,711,976.80	11.93	5.56	33	91.89
	Nov	8,111,426	100,532,122.3	12.39	6.03	40	75.93
	Dec	9,855,987	117,401,889.00	11.91	5.54	45	84.10
	Total	**106,312,032.5**	**1,217,604,174.00**	**11.45**	**5.37**	**Ave. = 37**	**80.48**
2000	Jan	3,764,400	44,223,472.63	11.75	8.83	40	89.15
	Feb	4,603,000	48,512,325.6	10.54	7.18	37	94.76
	Mar	5,511,700	59,010,824.31	10.71	6.35	45	96.79
	Apr	4,873,700	56,706,884.67	11.64	7.07		92.69
	May	4,394,600	50,954,537.46	11.59	7.36		88.94
	Jun	3,664,600	43,849,879.72	11.97	7.12		75.30
	Jul	5,039,100	57,494,175.52	11.41	6.37		94.65
	Aug	5,024,600	59,442,170.99	11.83	5.91		91.94
	Sep	4,785,181	55,571,130.92	11.61	5.50		81.89

[7] Heat rate = Energy input / Energy output.
[8] % Trans./Comm. Losses = [(Unit available for billing – Unit sold)/Unit available for billing]*100

Year	Month	Energy gen. (kWh)	Energy input (kJ)	Heat rate (kJ/kWh)	Station energy use (%)	Tech. and non-tech Losses. (%)	Availability (%)
	Oct	6,960,795	79,261,314.00	11.39	3.86		94.65
	Nov	6,499,802	98,326,465.82	15.13	4.15		61.85
	Dec	6,283,710	66,712,341.64	10.62	3.95		72.45
	Total	**61,405,188**	**720,065,523.30**	**11.73**	**5.88**	**Ave = 41**	**80.82**
1999	Jan	3,780,700	44,133,999.96	11.67	8.82	9	47.98
	Feb	5,255,500	58,901,253.13	11.21	7.43	36	69.88
	Mar	5,888,600	65,579,991.37	11.14	7.26	42	62.80
	Apr	6,271,700	72,513,385.78	11.56	6.56	36	64.88
	May	5,374,400	66,493,063.40	12.37	7.10	27	47.67
	Jun	4,493,100	57,133,285.25	12.72	7.75	39	91.81
	Jul	3,485,200	44,163,604.48	12.67	12.40	31	79.64
	Aug	3,798,400	47,633,334.45	12.54	8.64	38	81.52
	Sep	3,945,300	50,040,532.72	12.68	8.75	20	90.76
	Oct	3,602,100	46,617,980.20	12.94	8.50	34	79.86
	Nov	4,128,300	52,494,597.58	12.72	7.94	38	81.12
	Dec	2,875,800	36,625,799.71	12.74	8.77	14	65.11
	Total	**51,899,100**	**648,607,757.60**	**12.50**	**8.10**	**Ave. = 30**	**68.37**
1998	Jan	5,451,580	64,110,244.33	11.76	6.68	36	38.18
	Feb	3,404,280	37,134,315.18	10.91	7.93	19	29.98
	Mar	6,864,660	83,321,261.03	12.14	6.05	52	42.32
	Apr	8,432,300	91,911,542.33	10.90	5.36	37	68.57
	May	8,227,400	89,066,941.81	10.83	5.80	30	68.73
	Jun	7,528,800	65,325,104.97	8.68	6.17	32	64.51
	Jul	6,973,700	82,544,502.89	11.84	6.90	26	57.90
	Aug	4,796,300	58,295,091.46	12.15	7.22	31	60.22
	Sep	7,040,700	84,111,157.48	11.95	6.11	40	61.78
	Oct	9,075,100	97,934,487.81	10.76	5.47	43	68.65
	Nov	6,643,800	72,516,699.59	10.91	6.68	23	71.48
	Dec	7,896,900	89,674,788.86	11.36	5.67	47	77.25
	Total	**82,335,520**	**915,946,107.70**	**11.12**	**6.18**	**Ave. = 35**	**72.63**
1997	Jan	10,634,000	112,858,811.30	10.61	3.79	27	72.77
	Feb	8,548,500	91,703,487.07	10.73	3.69	21	69.61
	Mar	8,674,600	89,740,789.11	10.35	3.73	34	64.17
	Apr	10,448,820	118,919,752.60	11.38	3.88	37	59.21
	May	10,234,800	104,804,560.90	10.24	4.18	45	59.63
	Jun	6,453,080	72,386,735.33	11.22	6.88	21	49.10
	Jul	5,757,200	64,879,569.97	11.27	6.45	45	45.10
	Aug	1,567,700	15,650,640.48	9.98	6.27	50	12.97
	Sep	2,720,500	32,639,373.37	12.00	1.23	17	97.64
	Oct	1,316,180	18,416,863.04	13.99	1.44	(2)	23.95
	Nov	1,016,300	12,948,125.63	12.74	1.80	57	23.69
	Dec	4,067,520	44,548,934.83	10.95	3.97	38	34.01
	Total	**71,439,200**	**779,497,643.70**	**10.91**	**4.23**	**Ave. = 32**	**49.67**
1996	Jan	9,811,970	94,743,185.60	9.66	3.04	34	65.89
	Feb	9,607,660	93,757,731.32	9.76	3.04	31	66.21
	Mar	10,243,140	98,117,781.78	9.58	3.03	36	68.97
	Apr	9,682,580	97,337,094.14	10.05	2.62	34	71.54
	May	10,208,800	101,476,469.20	9.94	3.69	35	71.96
	Jun	9,544,300	94,266,254,.80	9.88	3.99	25	67.24
	Jul	9,168,911	95,162,335.85	10.38	3.93	31	69.38
	Aug	9,254,700	95,067,797.30	10.27	4.05	35	68.37

Year	Month	Energy gen. (kWh)	Energy input (kJ)	Heat rate (kJ/kWh)	Station energy use (%)	Tech. and non-tech Losses. (%)	Availability (%)
	Sep	8,008,400	85,221,242.47	10.64	3.69	33	67.71
	Oct	8,528,300	87,733,441.75	10.29	3.66	34	66.42
	Nov	9,723,510	101,328,088.40	10.42	4.06	36	95.72
	Dec	10,459,670	108,540,321.80	10.38	4.02	44	71.97
	Total	**114,241,941**	**1,152,751,744.00**	**10.09**	**3.56**	**Ave. = 34**	**80.22**

Table C2: Tariff computation using ROR .

Details.	**Year.**						
	1996	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
	Le '000	**Le '000**	**Le '000**	**Le '000**	**Le '000**	**Le '000**	**Le '000**
Value of fixed assets	22,834,924	23,577,566	24,709,810	24,255,596	24,325,461	41,480,897	
Accumulated depreciation	1,287,550	3,186,184	5,104,480	6,658,992	8,515,829	10,542,545	
Depreciation	1,287,550	1,898,634	1,918,286	1,554,442	1,856,907	2,026,716	
Operating costs [a]	8,578,233	12,633,554	10,598,217	14,194,992	14,979,585	25,424,200	
Return on equity [b]	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Return on debt	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Equity/capital	0.254	0.234	0.147	0.142	0.112	0.091	
Debt/capital	0.746	0.766	0.853	0.858	0.888	0.909	
WACC (r)	0.093	0.091	0.083	0.083	0.080	0.078	
RR = [(Book value * r) + operating costs + depreciation] * 1000[c]							
RR (Le bn)	11.867	16.389	14.144	17.210	18.101	29.864	
Units available for sale [d] **(GWh)**	107.720	67.070	77.138	48.224	58.033	100.184	
Average price (Le/kWh)	110.19	244.34	183.36	356.87	311.91	298.09	
Exchange rate (Le/US$)	920.75	981.91	1,557.90	1,819.27	2,097.45	1,985.89	
Average price (US cent/kWh)	11.97	24.88	11.77	19.62	14.87	15.01	

[a] *These include generation and transmission costs, supply cost and administrative charges.*
[b] *The national banks interest rates are from 12 – 18%. Thus, 16% was chosen for the period under consideration.*
[c] *The multiplication of the 1000 factor is due to the fact that book value, operating costs and depreciation are in thousands.*
[d] *These were calculated after accounting the system energy consumption.*

Table C3: Sensitivity analysis – Impact of changes in operating cost on 2001 average tariff.

	-10%	-5%	0	5%	10%	15%	20%	25%
ROR average tariff (Le/kWh)	308.67	323.03	337.39	351.75	366.11	380.46	394.82	404.21
US cent/kWh	15.54	16.23	16.99	17.71	18.44	19.16	19.88	20.60