5.3 Power Consumption

The availability of electricity in Kenya is generally limited to the more densely populated narrow strip running across the southern part of the country from Mombasa through Nairobi to Kisumu in parallel with the major highways, and along the coast. Other areas are not served with electricity due to scattered population except a few population centers served by independent plants. Only about 6% of the total population has access to electricity, and the average per capita consumption of electricity was estimated to be about 134 KWh in 1981, even if the electrical energy provided by private industries was included.

The average load growth in Kenya during 1970's was about 8% per annum, but thereafter it has slowed down considerably, reflecting generally slow-moving economic activities (see Table 5.3). The average load growth in the first three years of 1980's was just 5% per annum, and the growth in the following years was even slower.

According to the current five-year development plan, the electricity consumption was expected to grow at the annual rate of about 6% during 1984-88. The Kenya's economy itself was projected to expand by an average annual rate of 4.9% in the same period, starting from 3.9% in 1984 to 5.6% in 1988. It is expected that the annual growth of 6% may be attained by the end of the decade as the official development programme is aiming (see Section 2.1).

5.4 Electric Power Demand

5.4.1 National Power Demand

(1) Review of recent forecasts

A recent study on the Turkwell Gorge hydro-electric power development project made a most comprehensive review of recent demand forecasts on the electric power[6/]. It also presented its own forecast on national power demand, based on an international regression model (macro model) for per capita energy consumption and modified versions of it.

These forecasts by the Turkwell study and some of representative forecasts in recent years are compared in Figure 5.2 with respect to annual growth rates. A tendency observed from the figure is that more recent forecasts apply lower growth rates for power demand, reflecting decelerated growth of energy consumption in the past few years as a result of generally slow-moving economy.

The difference among more recent forecasts in essence is in the assumptions as to how quickly the annual growth rates will attain the 6 percent per annum level, the rate generally accepted for medium-term load growth. KP&L projected in 1983 that both the peak load and the energy demand would grow at 6 percent per annum to the year 2000, but now concedes that the growth rates for the next few years will be lower than 6 percent (probably 5 percent).

The Turkwell macro forecast, on the other hand, defers the recovery to the 6 percent level until 1993. The Turkwell study subsequently proposed, modifying its macro forecast, that the 6 percent per annum growth rate be attained by 1989 as "the median forecast".

(2) Confirmation of the Turkwell median forecast

No extensive efforts will be made in this study to present a more reasonable forecast of national power demand, as such a study has just been done, associated with the Turkwell project as outlined above, and the median forecast proposed by the study has been basically accepted by KP&L. In this subsection, simple analyses will be made based on macroeconomic observations just to check the reasonableness of the Turkwell median forecast (see Table 5.4).

GDP elasticity of energy consumption

Table 5.3 gives the data on the gross domestic products (GDP) and the total energy consumption in Kenya in the past ten years. Also shown in the table are growth rates of these quantities for different periods and the elasticity of energy consumption with respect to GDP computed from these data. It is observed from Table 5.3 that the elasticity tends to be lower when GDP growth rate is lower, but in any case it is larger than one.

On the other hand, the following remarks may be made about the growth of GDP in the recent past and the near future. The Kenya's economy grew in 1970's at the average annual rate of 5.1 percent in real terms, despite sharp increases in prices of petroleum, for which the country depends totally on imports. The growth, however, slowed down thereafter, and in 1982 it fell below the population growth (about 3.9 percent per annum), causing a decrease in the per capita GDP. The Kenya's economy is now expected to recover slowly and the current five-year development plan sets the realistic growth targets for the plan period at 4.9 percent per annum on average, starting from 3.9 percent in 1984 to 5.6 percent in 1988.

From the foregoing observations, it may be concluded that the energy consumption will grow in the next few years at about 4 percent at first and approach to 6 percent level by the end of the current five-year plan period. This implies that the Turkwell median forecast is quite reasonable.

Per capita energy use and per capita GDP

The per capita energy consumption naturally increases as the per capita GDP grows. No sophisticated model was used in this study to define the relationship between these two quantities in Kenya, but the data in the past ten years, as plotted in Figure 5.3, are suggestive. In the figure, a range is indicated in which the per capita energy consumption and GDP are likely to evolve in the next decade or so.

An apparent shift of the functional relationship between the per capita energy use and GDP from late 1970's to early 1980's may be attributable to a few factors. Major factors may be:

- change in economic structure to more energy-saving one,
- slow-moving economic activities in early 1980's, and
- suppressed demand due to insufficient power supply capacity
- or delay in extension of distribution lines.

Also it is generally observed the growth rate of per capita energy consumption tends to become lower than that of per capita GDP, as the economy passes a certain threshold of development.

It is not the purpose here to analyze in detail the reasons behind the phenomenon described above. Figure 5.3 is presented only to indicate a likely range of the per capita energy consumption and GDP.

The projection of the per capita GDP is taken from the Turkwell study. Although the figures for the per capita GDP used in this study are different from those cited in the Turkwell study, it is assumed herein that the per capita GDP will grow at the rates projected by the Turkwell study. The per capita GDP in the year 2000 is thus calculated to be 98 Kenya pounds at the constant 1975 price used here.

The per capita energy consumption in 2000, corresponding to the per capita GDP of 98 Kenya pounds, can be read from the curves in Figure 5.3 to be between 110 and 125 kWh. For the population in 2000, the official projection of 37,505 thousand is used. The figures for the per capita energy consumption correspond to the total energy demand of 4,100 GWh and 4,500 GWh, respectively. The Turkwell study, on the other hand, presents low and median forecasts in 2000 respectively as 4,379 GWh and 4,920 GWh on the "sent-out" basis. Taking account of transmission and distribution losses (about 15 percent), the Turkwell median forecast for the year 2000 falls between the two figures projected by this study.

5.4.2 Regional Power Demand

(1) Geographical distribution of power demand

The Turkwell study also analysed the maximum load by power supply region, based on the observations of consumption patterns in recent years as well as a review of the National Power Development Plan Study of 1977. This, however, is basically an analysis of trends, and may not be quite satisfactory for projection purposes when some structural change may be involved in the development of regional power demand. Such a change may be caused by shifts in government development policies that may emphasize the development of certain regions or sectors.

Geographical distribution of energy sales in the past is presented in Table 5.5. It shows that sales in the Nairobi region as a percentage of total sales have declined slightly from about 60 percent in 1976 to a level of 55 percent, while sales in the Western region have increased during the same period from about 8 percent to 12 percent. It is claimed that this change in relative importance of market areas reflects the government policy since the early 1970's to stimulate development (particularly industrial) in the Western region7/. Moreover, much demand (especially industrial) can be induced in a region where the power supply is at present a major constraint to development but high potentials exist with a variety of other development elements.

Rural electrification is another aspect which is heavily policy dependent. Although the past performance in this area has not been totally successful, increasing emphasis will be placed on this aspect in the future. In what follows, first the demand structure by region is compared to clarify the development and power supply characteristics of the Western Kenya region, and secondly the power demand is projected for this region to the year 2000.

(2) Comparison of demand structure by region

The area served by the National Power Supply System of KP&L is divided into five regions. Total electricity consumption in 1983 is broadly classified into three consumer categories -- viz. (1) domestic and small commercial, (2) industrial and large commercial, and (3) public and other -- for each region as shown in Table 5.6. The table indicates that the five regions can be divided into two distinct groups by the demand structure or more specifically the share of the domestic and small commercial consumption. For each group, the following observations can be made.

The Western Kenya and the Coast regions constitute one group, which is characterized by some 20 percent share of the domestic and small commercial category and close to 80 percent share of the industrial and large commercial consumption. The other group consists of the Rift Valley, Mt. Kenya and Nairobi regions, which have much higher shares of the domestic and small commercial consumption. If the off-peak domestic demand is included, this category accounts for about 40 percent of the total consumption for each region.

A plausible explanation for this difference in the demand structure may be as follows. Areas served by the national grid in the Nairobi, Rift Valley and Mt. Kenya regions are either centrally located or close to power sources and trunk transmission lines so that more households and the small commercial establishments are served with electricity. For the Western Kenya and the Coast regions, their peripheral locations in the entire supply area are accountable for the small shares of the domestic and small commercial consumption.

Better insights can be obtained into the demand structure, if another sidelight is provided. An attempt was made to estimate the household electrification ratio for each supply region, and the results are summarized in Table 5.7. Since the power supply regions do not coincide with administrative divisions, the data on the population and the number of households were estimated by using the data by district having larger demand centers.

The estimated figures for household electrification ratio by region reveal the following. The Western Kenya and the Coast regions, though classified above into the same group, have in fact considerably different demand structure. That is, a much larger portion of households in the Coast region are served with electricity. The small share of the domestic and small commercial consumption in the Coast region is presumably a reflection of high power demand by industries in Mombasa and neighbouring urban areas located near the major power generating facilities at Kipevu. It has been confirmed that households in the Western Kenya region are poorly served with electricity owing to its peripheral location in the national grid. The difference between these two regions comes in short from existence or non-existence of major generating facilities in respective regions.

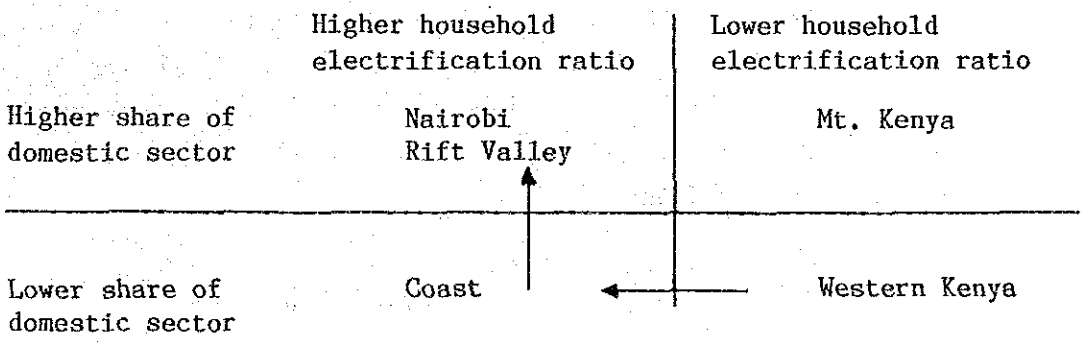
Of three regions in the other group, the Mt. Kenya region has an extremely low household electrification ratio despite its central location. However, due to the way the regional data on population and households are estimated from each supply region as mentioned above, this region includes those districts that are only marginally served by the national grid and predominantly rural. Only a few secondary towns in the central area are served with electricity, where the number of large industries are limited.

(3) Power demand projection for Western Kenya

In this subsection, the electric power demand in the Western Kenya region is projected to the year 2000 in line with the observations made above. A mid-point of the projection is taken to be the year 1993, when the Sondu hydropower project is most likely to be introduced.

General

A two-way classification of the five power supply regions is made as presented below, in accordance with the observations in the preceding subsection.



	Higher household electrification ratio	Lower household electrification ratio
Higher share of domestic sector	Nairobi Rift Valley	Mt. Kenya
Lower share of domestic sector	Coast	Western Kenya

It is inferred that the power demand in Western Kenya will develop probably following the Coast region whose demand structure, in turn, will gradually change with increasing share of the domestic and small commercial category as the power supply system is extended to more rural areas.

Domestic and small commercial

It is expected that the share of the domestic and small commercial consumption in the Western Kenya region will increase only slowly but the household electrification ratio will certainly increase significantly, particularly if major generating facilities like the Sondu hydropower plant are established within the region. It seems reasonable for the purposes of this study to assume that the household electrification ratio in the Western Kenya region will approach the present level of the Rift Valley region (6 percent) towards the end of the century. The following figures are used for the projection:

Household electrification ratio	Expected year
3 percent	by 1993
5 percent	by 2000.

The unit use of electricity per consumer in the domestic and small commercial category is calculated to be 2,092 kWh per year for Western Kenya, which may be compared with 2,159 kWh for Mt. Kenya, 2,341 kWh for Coast, 2,817 kWh for Rift Valley and 4,196 kWh for Nairobi. The value 2,100 kWh per year is taken for the projection purpose as a conservative estimate of the unit use. The projected population in the region is 10,978 thousand in 1993 and 13,967 thousand in 2000, following the official projections. Thus the total domestic and small commercial demand is calculated as follows, assuming the average size of households in the region will stay at 5.46:

Year	Total demand
1993	(10,978,000/5.46) x 0.03 x 2,100 ≒ 127 GWh
2000	(13,967,000/5.46) x 0.05 x 2,100 ≒ 269 GWh.

Public and off-peak domestic

The power consumption data for the past several years show that the ratio of the public and off-peak domestic use category to the domestic and small commercial demand has been slightly smaller than 15 percent and tends to decline as the total consumption increases (see Table 5.8). It is just assumed here that the share will be 13 percent in both 1993 and 2000 without any further sophistication, as this demand is only a small portion of the total power demand:

Year	Total demand
1993	127 x 0.13 = 17 GWh
2000	269 x 0.13 = 35 GWh.

Industrial and large commercial

As already indicated, much industrial demand is expected to be induced, if the power supply capability is improved for Western Kenya so that the demand projection by trend would not be appropriate for the industrial and large commercial category. In this study, therefore, specific industries are identified that may be established in the region in the near future, and expected load by each industry is roughly estimated.

First, there are several major industries either under construction or with a high probability of realization that are expected to be connected to the national grid by the year 1987. These are listed in Table 5.9 together with the expected loads in 1987. The total demand by these industries in about 19 MW in peak load and 81 GWh in total annual energy.

Secondly, some other industries as listed in Table 5.10 are likely to be established by and by in a medium term. The total demand of these prospective industries will be about 13 MW in peak load and some 57 GWh in annual energy. If all the prospective industries are established by the year 1993, the total demand by the new industries will be about 32 MW and 138 GWh. Including the demand of industrial and large commercial establishments existing in 1983 or 197 GWh, the total power demand in this category would be 335 GWh in 1993.

It is not very meaningful to try to identify specific industries that may be established in a longer run because of much uncertainties involved. For the period between 1993 and 2000, therefore it is assumed that the power demand by the industrial and large commercial consumers will grow at the same rate as the expected average growth rate between 1983 and 1993. Thus the power demand by this category will be about 486 GWh in the year 2000.

Total power demand

The results of the power demand projections for the Western Kenya region are summarized in Table 5.11. The total power demand will be 479 GWh in 1993 and 790 GWh in 2000 in annual energy. The shares of different consumer categories as shown in Table 5.11 indicate that the demand structure in this region will be very much similar in 1993 and 2000 to that for the whole country in 1983 (see Table 5.6). It is thus inferred that the load factor for this region will be at the same level as 1993 and 2000 as the present load factor for all the regions or about 70 percent.

By applying the load factor of 70 percent, the peak load is calculated to be about 78 MW in 1993 and 129 MW in 2000. These figures correspond very well with the regional maximum power demand for Western Kenya estimated by the Turkwell Study.

5.5 Power Supply Expansion Plan

5.5.1 On-going Power Projects

The on-going power projects which are under construction and/or committed are as follows:

Name of Project	Type	Installed Capacity (MW)	Year of Commissioning
(a) Olkaria No.3 Unit	Geothermal	15	1985
(b) Kiambere	Hydro	144	1988
Total		159	

Kiambere hydropower plant (2 x 72 MW) is located on the Tana River at about 35 km downstream of the Kindaruma power station. Upon completion of the Kiambere, about 60% of the hydro potential (approximately 800 MW) of Tana River will have been developed.

5.5.2 Planned Power Projects

The following power projects other than the Sondu Project are planned:

Name of Project	Type	Installed Capacity (MW)	Status
(a) Olkaria	Geothermal	30	Under-exploitation
(b) Turkwell	Hydro	100	F/S and appraisal completed
Total		130	

It is reported that geothermal potential in Kenya's Rift Valley is estimated to be about 170 MW according to steam exploration, of which 44% will have been developed at Olkaria with the completion of the above project. Feasibility of Turkwell in Kerio Valley was assessed by the Consulting Engineers, Preece, Cardew & Rider Ltd (PCR) and reported viable. The Turkwell hydro power plant will connect to the Lessos substation via 220 kV transmission line.

The conceivable future hydro power plants are as below, but their feasibility studies are yet to start:

Name of Project	Name of River	Installed Capacity (No. x MW)
Mutonga	Tana	2 x 35
Grand Falls	"	3 x 40*
Adamson's Falls	"	2 x 25
Korech	"	2 x 40
Kindaruma 3rd unit	"	1 x 22**
Gitaru 3rd unit	"	1 x 72***
Munyu	Athi	38
Ewaso Ngiro	Ewaso Ngiro	2 x 50

Note: * Generation and Economic Study for the Turkwell Gorge Project, PCR, July 1984

** Rating of 22 MW can be installed in the existing power station but increase only 10 GWh per year in the energy output.

*** Rating of 72 MW can be commissioned but increase only 55 MW in the installed capacity and 40 GWh per year in the energy output.

5.5.3 Planned Transmission Lines and Substations

According to the power development programme mentioned above, major transmission system is planned to be expanded and reinforced as shown in Figure 5.1 along with substations by KP&L as follows:

Transmission Line	Voltage (KV)	Circuit	Estimated Length (km)	Status
(a) Kiambere-Kamburu[1]	220	Single	39	Under construction and to be commissioned in 1988
(b) Kiambere-Rabai[1]	220	Single	41	"
(c) Nairobi-Rabai	220	Single	460	To be commissioned in 1992
(d) Turkwell-Lessos	220	Single	225	To be commissioned in 1993
(e) Lessos-Nairobi	220	Single	240	To be commissioned in 1993
(f) Kilifi-Bura	132	Single	400	To be commissioned in 1990.
Total			1,401	

Note: 1 - With completion of Kiambere power stations, 220kV transmission line will be connected to the existing 220 kV Kamburu-Rabai line.

Regarding the planned substations, no firm details of extensions and/or reinforcement are available at present.

5.6 Power Balance Study

According to the power demand forecast discussed in the previous section, power demand in the KP&L system is expected to increase from 355MW in 1985 to 454MW in 1990, 608MW in 1995 and 814MW in 2000, whilst 2,148 GWh/yr in 1985 to 2,747 GWh/yr in 1990, 3,677 GWh/yr in 1995 and 4,920 GWh/yr in 2000 in energy demand. In addition, reserve capacity is required for maintaining the system reliability. If the reserve capacity estimated to be 17% of power demand is added to the power demand estimated on the sent-out basis, the total power demand will reach 531MW in 1990, 711MW in 1995 and 952MW in 2000.

On the other hand, present power supply capacity in the KP&L system stays at 533MW in effective capacity including 15MW of Olkaria III commissioned in 1985 and 30MW imported from UEB. Kiambere and Turkwell hydropower plants with the installed capacity of 144MW and 100MW are scheduled to join the system in 1988 and 1993 respectively. The addition of these two plants is expected to meet the power demand by 1995 including reserve capacity, even if some old plants are retired.

Energy balance as well as power balance was examined based on the recorded annual average energy of hydropower plants and the energy output estimated from the presumed maximum plant factor of thermal plants. Present energy supply capacity of 2,440 GWh/yr will increase by 3,120 GWh/yr and 3,200 GWh/yr (plant retirements are included.) with the addition of Kiambere and Turkwell respectively, so that energy requirements in the system will be met through early 1990's, probably 1993. In case that the energy imported from UEB is treated as non-firm after 1988 according to KP&L's plan, energy deficits may occur before installation of Turkwell.

The results of this power balance study suggest that the installation timing of a project which comes next to the Turkwell will be the year 1993. Potential projects expected to join the system after the Turkwell are the Sondu/Miriu hydropower plant and the Olkaria IV, Eburru and Lake Bogoria geothermal plants.

Several hydropower projects have been identified including Mutonga, Grand Falls, Adamson's Falls, Korech, Munyu and Ewaso Ngiro besides Sondu/Miriu, but they are only at the level of reconnaissance or pre-feasibility study. They can not be considered as candidates for the KP&L system until feasibility studies are carried out.

Chapter 6. PLAN FORMULATION

6.1 Approach

The Sondu River is generally characterized as the river with ample flow replenished by abundant rainfall of the basin. Total hydropower potential of the Sondu River is assessed to be 187MW in firm basis, fifth largest potential out of 14 major rivers in Kenya, availing ample flow and head. The studies in the past recommended to develop 75MW of the total potential in the coming two decades by building storage dams at the proposed sites; Sondu/Miriu, Magwagwa and others.

The Sondu River basin, on the other hand, adjoins with the Kano Plain extended to about 60,000 ha, where fertile soils and topographic characteristics with little undulation promise high potentiality of agricultural development, provided that water necessary for agricultural production is sufficiently available.

In the Kano Plain, a number of water resources development plans have been contemplated aiming at efficient utilization and better management of land resources. Among six major rivers in the LBDA area, the Upper Yala and Sondu rivers besides the Nyando which drains in the Kano Plain are conceived as promising water sources for the irrigated agriculture development in the Kano Plain by means of inter-basin transfer.

Since the Sondu has much richer flow and is more amenable to inter-basin transfer than the Upper Yala, the studies in the past recommended the Sondu diversion for both of irrigation development in the vast Kano Plain and hydropower development harnessing the high head availed with the trans-basin diversion.

The primary objective in this study is, therefore, placed on searching efficient use of the diverted water of the Sondu in combination with the Nyando River water for hydropower generation and irrigated agriculture developments in the Kano Plain. In line with the study objective, water and land resources development schemes identified or elaborated so far in the Sondu River basin and Kano Plain are reviewed:

(1)	Sondu/Miriu Hydropower Scheme	IDCJ/NK, TAMS (1981) (1980)
(2)	Magwagwa Hydropower Scheme	TAMS (1980)
(3)	Sotik Water Supply Scheme	MOWD
(4)	Kano Plain Irrigation Scheme	USBR, ITALCONSULT (1967) (1982)
(5)	South Kano Irrigation Scheme	AGRAR & HYDROTECHNIK (1981)
(6)	Ahero Pilot Irrigation Scheme	ILACO/NIB (1966) (1969)
(7)	West Kano Irrigation Scheme	ILACO/NIB (1966) (1967).

The last two schemes have already been implemented by pumped irrigation from the Nyando River and Lake Victoria, respectively. There is, however, possibility to change the irrigation method to gravity irrigation, if the Sondu transfer scheme is materialized.

Prior to JICA study, under UNDP the Kano plain irrigation development was also being studied including a part of the objective area by JICA study. UNDP study elaborated water sources for the irrigation to exploit the Nyando and Sondu rivers. The results of this study were duly referred to plan formulation of the Sondu River multipurpose development plan in this Chapter.

6.2 Development Strategies

The first step to formulate the optimal development plan of the Sondu River multipurpose development project is to identify possible schemes of regulation dams and hydropower development based on the past studies and field surveys on the Sondu. A preliminary comparative study was worked out to identify such schemes that would promise the benefits from both the hydropower and irrigation.

The second step is to make development plans combining the schemes selected in the first step with the irrigation development in the Kano Plain and to find the optimal development plan that would accrue the maximum benefits for both hydropower generation and irrigation. The approach to the irrigation development plan is first to identify the possible irrigation area in the project area, secondly to formulate the plan by sub-area such as the Nyakach Plain, the south Kano Plain (left side of the Nyando) and whole Kano Plain elaborating on cropping patterns, irrigation water requirements and water availability from the Nyando River as well as the Sondu diversion.

The third step is to find the optimal installation timing of the Sondu hydropower project in the long-term installation programme of power plants newly added to the KP&L power grid to meet the increasing power and energy requirements.

6.2.1 Development Schemes

The schemes identified for hydropower generation in the Sondu River and the irrigation development in the Kano Plain as the first step are depicted in Figure 6.1, and brief explanation of each scheme is given by category; diversion, storage and irrigation schemes.

Diversion schemes are the inter-basin transfer of the Sondu River flow to the Kano Plain in order to generate hydropower using head created by trans-basin and to supply irrigation water.

The schemes contemplated are:

Scheme D-1: Sondu/Miriu diversion scheme

The diversion site is located about 18km downstream from Sondu village. A 4km long waterway heading Thurdibuoro village makes possible transfer of flow of the Sondu River and some 150m head is to be created with this diversion. A basic development plan is shown in Figure 6.2.

Scheme D-2: Nyamarimba diversion scheme

Water diverted 1km downstream from Miriu village is conveyed to Nyamarimba village with an open channel along El.1,440m contour, and then led with a 3km long penstock down the escarpment towards 1km east of Okanowach village. Created head is some 230m. A basic development plan is shown in Figure 6.3.

Scheme D-3: Sondu-Maraboi diversion scheme

Sondu River flow is diverted 2km upstream from the big bend of the Sondu near Sondu village and is conveyed to Kaplelatet village with an open channel along El.1,520m contour. A 3km long penstock leads diverted water to the Asawo River near Onywongo village. The head created with this diversion is some 240m. A basic development plan is shown in Figure 6.4.

Storage schemes are planned to increase firm discharge for power generation and to extend irrigation areas in the Kano Plain.

The impounding reservoir schemes contemplated are:

Scheme S-1: Magwagwa reservoir scheme

The site about 10km upstream from Sondu village has a topographic favour to create a large scale impounding reservoir by building a

100m high scale dam. The damsite proposed in the Interim Report was shifted to the downstream reach by some 1.5km to reduce the construction cost, although the construction of a saddle dam is necessitated for keeping the active storage required. The basic development plan is shown in Figure 6.5.

Scheme S-2: Magwagwa reservoir scheme plus waterway

This is a plan with an 8km long waterway from the Magwagwa reservoir to Pala village located 4km downstream from Sondu village, and elevation falls of 100m become available for power generation with this waterway in addition to the head created by dam. It is noted that this plan and Sondu-Maraboi diversion scheme (Scheme D-3) are mutually exclusive. The basic development plan is shown in Figure 6.6.

Scheme S-3: Sondu/Miriu reservoir with the diversion scheme

This plan is to build a reservoir at the Sondu/Miriu diversion site for making firm up and diverting the Sondu River flow. Moreover, construction of a dam makes possible the creation of additional head of nearly 80m besides elevation falls by trans-basin (Scheme D-1). The basic development plan is shown in Figure 6.7.

Irrigation schemes which are to be combined with the abovementioned schemes are contemplated as follows.

Scheme I-1: Irrigation scheme for the left bank areas of the Nyando River in the Kano Plain (15,610 ha)

The development of this scheme relies on the Sondu River flow as a water source. It is confirmed in the Appendix VII, Extensible Irrigation Area in Kano Plain, of Volume IV that irrigation water requirements of this scheme are sufficed with the natural flow of the Sondu River. In other words, the diversion plan of the Sondu

River flow (Scheme D-1 to 3) makes possible not only power generation, but also the full development of this irrigation scheme.

Scheme I-2: Irrigation scheme for the whole area of the Kano Plain (25,610 ha)

The Nyando River is a primal water source for the right bank areas of the Nyando River, but the availability of the Nyando River flow is not enough for the full development of the right bank areas of the Nyando, so that the Sondu River flow is supplementarily used to suffice water requirements.

6.2.2 Combination Plans on Development

Five combination plans were contemplated as the second step by combining the schemes by category in order to seek the optimal development of power generation and irrigation as discussed below.

Combination-A, the basic idea of which is depicted in Figure 6.8-A, is the plan to combine the best run-of-river scheme out of Scheme D-1 (Sondu/Miriu diversion) to Scheme D-3 (Sondu-Maraboi diversion) with the irrigation scheme (Scheme I-1).

Basic concepts of this combination plan are to maximize net benefits yielded from power generation and irrigation development only depending on the natural flow of the Sondu.

Combination-B is the plan to combine the Sondu/Miriu reservoir (Scheme S-3) with the irrigation development for the whole area of the Kano Plain (Scheme I-2) as shown in Figure 6.8-B.

Primary discussions of this plan are not only to find out the optimal development scale of the reservoir for power generation, but also to search the possibility of extension of irrigation areas beyond the Nyando River.

Combination-C, the basic idea of which is given in Figure 6.8-C, is the plan to combine the Magwagwa reservoir plus waterway as an impounding function (Scheme S-2) with the irrigation development for the whole area of the Kano Plain (Scheme I-2), and either of the Sondu/Miriu (Scheme D-1) and Nyamarimba (Scheme D-2) is selected as the function of trans-basin.

This plan intends to efficiently use the available head in the Sondu River with the long waterway as well as to regulate the flow of the Sondu with the Magwagwa reservoir.

Combination-D is the plan to build reservoirs in a series at Magwagwa (Scheme S-2) and Sondu/Miriu (Scheme S-3), and to supply water to the irrigation areas extended in the whole Kano Plain as shown in Figure 6.8-D.

This plan aims at developing the Sondu River as much as possible in both of head and flow.

Combination-E, of which the development idea is depicted in Figure 6.8-E, is the plan to combine the Magwagwa reservoir (Scheme S-1) with the irrigation development for the whole area of the Kano Plain (Scheme I-2), and then Sondu-Maraboi diversion (Scheme D-3) is selected as the function of trans-basin for utilizing the head of the Sondu efficiently.

6.3 Plan Optimization

Simulation models were built to suit Combination A to E for searching the optimal development plan out of Combination A to E and further for determing the optimal development scale of the selected combination. The selection of the optimal combination was made under the criteria that the combination which gains the maximum net benefit is optimal.

The optimal development plans of each combination alternative so obtained as the results of simulation study are depicted in Table 6.1 with benefits and costs accrued from both of power generation and irrigation development. Combination-C, the Magwagwa reservoir with a waterway plus the Sondu/Miriu run-of-river, was proposed as an optimal combination because of highest net benefit. The development features of it are:

<u>Magwagwa reservoir plus waterway plan</u>

Firm discharge : 24.1 m^3/sec
Plant discharge (8-hour peak operation) : 72.3 m^3/sec
Full supply level : El.1,662.9 m
Minimum operating level : El.1,606.3 m
Dam crest elevation : El.1,667.9 m
Dam height : 100.9 m
Active storage : 590.7 million m^3
Installed capacity : 94.6 MW
Firm energy : 276.2 GWh/yr
Secondary energy : 57.9 GWh/yr

<u>Sondu/Miriu run-of-river plan</u>

Firm discharge : 24.1 m^3/sec (3.3 m^3/sec)
Plant discharge : 39.9 m^3/sec (29.6 m^3/sec)
Installed capacity : 48.6 MW (32.8 MW)
Firm energy : 237.5 GWh/yr (32.0 GWh/yr)
Secondary energy : 14.9 GWh/yr (155.6 GWh/yr)

Note: Figures in parentheses are the scale of the Sondu/Miriu diversion scheme only (Scheme D-1). The preliminary design of the Sondu/Miriu run-of-river plan in this feasibility study will be done with the premise that the Magwagwa reservoir is constructed.

Outputs from both plans

Installed capacity : 143.2 MW
Firm energy : 513.7 GWh/yr
Secondary energy : 72.8 GWh/yr

Irrigation area

In the left bank of the Nyando : 15,610 ha
In the right bank of the Nyando : 10,000 ha.

The development of Combination-C is recommended not only with the highest net benefit among the combinations, but also with the merits that the Sondu/Miriu site has been investigated and the Sondu/Miriu run-of-river power plan itself is viable with the economic internal rate of return of 10.95% (Figure from Combination-A). Besides, stage development can be conceived on Combination-C in order to distribute the financial burden needed in a short time period. The possibility of stage development on Combination-C will be discussed in the subsequent planting-up study of the KP&L power system. On the other hand, the unit energy production cost is calculated to be 5.49 US¢/KWh, which is competitive against the long-run marginal cost of power supply used as a guideline for setting on electricity tariff, 5.73 US ¢/KWh (i.e. 0.86 KShs/KWh) as discussed in the subsequent Chapter 9.

Furthermore, it is noted, as merits of Combination-C, that the Magwagwa reservoir development makes possible not only irrigation schemes for the whole area of the Kano Plain, but also bears great energy of more than 500 GWh/yr in firm basis.

On the other hand, the exploitation of 24.1 m^3/sec in terms of firm discharge, around 60% of average flow (41.6 m^3/sec), may not be so large as to cause influence to river conservation in the downstream reaches of the Sondu. Furthermore, water supply to the permit holders of water abstraction in the lower reaches from the Nyakwere village is warranted by taking from the irrigation canal. Further detailed discussions are given in Appendix IV, Optimization Study, of Volume IV.

6.4 Installation Timing of the Project

6.4.1 Basic Concepts

As the third step, it was studied to search the optimal installation timing of the Sondu hydropower project so developed in the preceding section in the long-term installation programme of power plants newly added to the KP&L power grid so that increasing power and energy requirements discussed in Chapter 5 can be met. The optimal installation timing of the Sondu hydropower project was made by searching the time when the Sondu hydropower project is emerged in the least cost sequence of the long-term power plant development. Furthermore, the possibility of stage development in the Sondu hydropower project was examined for reducing impacts of heavy financial burden; first stage (Sondu/Miriu run-of-river plan) and second stage (Magwagwa reservoir plus waterway plan).

Besides the Sondu/Miriu hydropower projects, several types of plant were considered as the candidates newly added to the system as described in the preceding Section 5.6. Table 6.2 shows the list of thermal candidates except for geothermal, whilst Table 6.3 for hydro and geothermal candidates, in which the plant scale is estimated based on the site identification. In addition, the projects under construction and committed are added to the KP&L power supply system on the appointed commission date with priority; Olkaria-III (15MW) in 1985, Kiambere (144MW) in 1988 and Turkwell (106MW) at the beginning of 1993.

6.4.2 Least Cost Sequence

The least cost sequence to search the optimal installation timing of the Sondu hydropower project was so obtained using dynamic programming, a technique of Operations Research, as shown in Table 6.4, whilst the power and energy balances in the least cost sequence are illustrated in Figure 6.9.

The optimal installation timing of the Sondu/Miriu project is reckoned to be 1992 (commissioning at the beginning of 1993) for the first stage (Sondu/Miriu run-of-river plan, 48.6 MW) and 1996 for the second stage (Magwagwa reservoir plus waterway plan, 94.6 MW). Olkaria IV geothermal (30 MW) and a coal-fired (60 MW) plant emerged in 1993 follow the first stage, whilst Eburru geothermal (15 MW in 1998) and coal-fired plants (120 MW in 1998, 60 MW in 2001, 60 MW in 2002, 120 MW in 2003 and 60 MW in 2004) come after the second stage.

In case that a run-of-river project is developed as a first stage in a basin and followed by a reservoir type project of upper reaches, it is normal that firm energy generated from the first stage tremendously increases with the installation of the second stage. In such a case, simultaneous installation of both stages may be revealed in the study to search a least cost sequency due to that firm energy is only counted as available energy to meet energy demand.

Hydropower development in the Sondu River basin by the Sondu/Miriu run-of-river and Magwagwa reservoir projects is not exempted from the case mentioned above (both in 1996). The earlier installation (1992) of the Sondu/Miriu run-of-river as the first stage was, however, reckoned in the least cost sequence by fuel saving effects of secondary energy with 155.6 GWh/year; that is, fuel saving effects are greater than incremental discounted costs by shifting the installation year from 1996 (commission year of the second stage) to 1992.

A time schedule to implement both the first and second stages of the Sondu project was prepared according to the lead time necessary for finance and detailed design and construction period assumed in the study to serch the least cost sequence as shown in Figure 6.10, although a detailed implementation schedule for the first stage is discussed in the subsequent Chapter 8. In order to fix the commission date of the first stage at the beginning of 1993, the arrangement of finance shall be taken immediately after this feasibility study.

Furthermore, the planting-up study indicates that geothermal, as one of promising indigenous energy sources, shall be developed with priority; 45MW by 1998. However, it is likely due to the small plant scale compared with the growing power and energy demands that the installation of Lake Bogoria was not emerged to the system in 2000's. Current earnest exploitation of geothermal at Olkaria, Eburru and Lake Bogoria shall be continued with the consideration of making plant scale larger.

For keeping the power and energy balance, the development of 480MW is required on coal-fired plants by year 2005 besides the Sondu/Miriu and geothermal plants. Although oil-fired plants are competitive against coal-fired plants, the installation of coal-fired plants is more attractive, provided that the oil price stays at the present level.

None of hydro project than the Sondu/Miriu was emerged in the planting-up study. This may be due to uncertainties involved in the cost estimate of the project.

6.4.3 Sensitivity Tests

Sensitivity tests were carried out for assessing uncertainties involved in the future costs and assumptions applied on the planting-up study, and then the following were selected as the cases to be performed:

(1) Variation of discount rates; 5%, 8%, 12% and 15% besides the prime test discount rate of 10%

(2) Low and high demand forecasts

(3) Non-firm for the energy imported from UEB after 1988

(4) Application of cost allocation for the Sondu/Miriu project

(5) Thermal candidates only for the planting-up study; coal-fired, oil-fired, diesel and gas turbine except geothermal and hydro plants

(6) 10% capital cost up for the Sondu/Miriu project

(7) 10% fuel cost up and down for the coal-fired plant, and

(8) 10% capital cost down for the thermal plant except geothermal.

The optimal installation timing of the Sondu/Miriu project indicated to be 1992 for the first stage and 1996 for the second stage in the least cost sequence was not changed for the above test cases. Thus, the Sondu/Miriu project can be said to be a promising project to be developed, even if uncertainties are involved in the future costs and assumptions. Further detailed discussions are given in Appendix V, Power Development Programme, of Volume IV.

Chapter 7. BASIC DESIGN

7.1 General

This chapter describes the preliminary design of major structures on the proposed Sondu/Miriu run-of-river hydropower project; the first stage of Combination-C selected as the optimal plan of the Sondu River development. The design was made at a feasibility study level, to the extent required for the purpose of estimating construction cost, and with the premise that the Magwagwa reservoir plan as the second stage will come in service.

The following basic dimensions have been worked out for the project through the optimization study discussed in the previous chapter:

- Full supply level of intake pond : El.1368.0m
- Minimum operation level of intake pond : El.1355.5m
- Plant peak discharge : 39.9 m^3/sec
- Tailwater level at plant peak discharge : El.1205.4m
- Gross head at plant peak discharge : 162.6m
- Installed power capacity (2 units) : 48.6MW (24.3 MW x 2).

The project involves the construction of a 20m high gated intake weir on the Sondu River, and intake structure feeding 39.9 m^3/sec into the waterway, sand desilting basin, a 4,314m long headrace tunnel, a surge tank, a 1,092m long penstock line, and a power plant with 48.6MW installed capacity, for which the number of units was selected to be two unit considering system reliability and maintenance of turbines and generators, even if a single unit was most economical in a preliminary cost comparison. The project would also include the construction of a 40km long 132kV transmission line to deliver the generated power to the Muhoroni substation. A general layout of the project is shown in Figure 7.1.

7.2 Design of Main Structures

7.2.1 Intake Weir

The intake weir which has functions to divert the Sondu water to the Kano Plain and to create storage required for daily operation is located about 18km downstream from Sondu village, where the elevation of riverbed is El.1349.0m and average gradient of slope is 1/105. Figure 7.2 shows the general layout of the intake weir and its associated structures.

Design concepts: The intake weir and related structures were designed on the basis of following concepts:

(a) All the structural foundation is placed directly on a firm layer of granite after removing overburden.

(b) The intake weir is provided with gated orifices, and its sill elevation is set at the present riverbed level to keep the siltation level of the created pond as low as possible.

(c) Sediments to be deposited in the intake pond are flushed out by opening the gates during flood periods.

(d) Large floods are to be evacuated through bottom orifices and a overflow spillway.

(e) A sand desilting basin is provided between the intake and the headrace tunnel entrance to remove the larger sizes of suspended and rolling particles.

Intake weir and pond: The storage capacity of 1,100,000 m^3 is secured in the intake pond in order to make a joint operation with the Magwagwa power plant which will have a different operation mode; that is, the Sondu/Miriu plant is used as a base-peak plant, whilst an 8-hour peak plant for the Magwagwa.

On the above basis, the intake weir was designed to have following dimensions:

(a) Gate sill elevation : El.1349.0m (Riverbed El.)
(b) Spillway crest elevation : El.1368.0m (FSL)
(c) Weir crest elevation : El.1369.5m (FSL + 1.5m)
(d) Sand flush gates : 5.5m wide x 5.5m high x 2 nos.

The design flood for the intake weir was based on the 200-year probable flood of 655 m^3/sec (refer to Appendix III, Hydrology and Meteorology, of Volume IV). This flood would be released through the full opened flush gates and spillway with 1.5m freeboard. Water to warrant livings of riparians in the downstream reaches will be released through the steel pipe with a diameter of 10 cm equipped in the pier of intake weir.

Stability of intake weir was examined against overturning, bearing force of the foundation and sliding. The stability against overturning was checked against the vertical loads mainly composed of dead loads. Furthermore, the weir was designed to have an adequate resistance against sliding by horizontal force including seismic and water pressure loads.

River diversion for the construction of the intake weir is made by providing an open channel, which has a flow capacity of 337 m^3/sec, a 2-year flood (refer to Appendix III, Hydrology and Meteorology, Volume IV). A dry work space is ascertained by encircling with earth coffers and concrete blocks. After the construction works, the channel provided for the river diversion will be used as the stilling basin of the spillway.

Intake: The intake which leads water to the waterway is located on the right bank immediately upstream of the intake weir. The entrance sill of the intake is set at El.1353.0m, 4.0m higher than the sill of the sand flush gate in the intake weir, not to pull silted particles in. The silting level of the pond would always be kept below the entrance sill of the intake by the periodical flushing of sediments through the gates.

Sand desilting basin, 40m long and 26m wide, is connected to the intake. The average flow velocity is set at 0.3 m/sec for the plant discharge of 39.9 m^3/sec so that silted particles carried through the intake can be settled in the sand desilting basin and are not entrained to the waterway. The basin consists of two flow channels divided by a partition wall at the centre so that the periodical dredging work and maintenance can be made without stopping power generation.

7.2.2 Waterway

The waterway with total horizontal length of 5,406m is divided into two by a surge tank; a headrace tunnel of 4,314m and a penstock of 1,092m as shown in Figure 7.1, whilst further detail of the penstock is depicted in Figure 7.3. The selected route for the headrace tunnel runs through granodiorite rock which is hard and massive, even though there are some minor cross faults.

For the penstock, the route is selected on the steep slope of escarpment which covers with thin debris. An open-air type was designed for the most part of alignment for saving construction cost and easy maintenance.

Design of headrace tunnel: An economic comparison was made to determine the diameter of the headrace tunnel considering the following components;

(a) construction cost,
(b) energy loss value due to head loss in the tunnel, and
(c) operation and maintenance cost.

As the results of comparison, the economic diameter was determined to be 4.2m for the design discharge of 39.9 m^3/sec. The cross section of headrace tunnel is shown in Figure 7.1.

Surge tank is provided at the downstream end of the headrace tunnel. It is of a restricted orifice type of reinforced concrete mostly built in underground.

The principal dimensions of the surge tank structure are shown in Figure 7.4 and described below;

Port diameter : 1.7m
Shaft diameter: 10.0m
Shaft height : 51.9m

Up-surging water level : El.1381.0m (FSL + 13.0 m)
Down-surging water level: El.1343.0m (MOL - 12.5 m).

Penstock is divided into two types; a tunnel portion of 102m long and an open-air steel pipe of 1008.7m long as shown in Figure 7.3.

For the erection of tunnel portion, a working space of 60cm was kept between the steel shells and the initial concrete as shown in Figure 7.4. After installation of steel shells, this space is filled with concrete. On the other hand, the open-air type penstock is supported with anchor blocks and saddle piers. The anchor blocks and saddle piers are designed at an interval of 100 to 150m and about 15m respectively.

Design concepts and assumptions applied to determine the economic diameter of penstock at this feasibility study stage were as follows:

(a) Diameters of the penstock were estimated using the same method applied to determine the economic diameter of the headrace tunnel. However, the costs of generating equipment are included besides the construction cost of penstock and energy losses for determining the economic diameter of the penstock.

(b) In design of its plate thickness, dynamic pressure due to water hammer was computed on the following assumptions:

- "Jaeger's formula" is applied to analyze water hammer in the penstock with the orifice type surge tank.

- The closing time is limited to less than 8 seconds.

- The pressure rise is limited to less than 55% of static water head.

(c) SM class steel is used for the penstock. The allowed maximum and minimum plate thicknesses would be 25mm and 6mm.

Based on the aforesaid concepts and assumptions, economic comparison was carried out and consequently the penstock diameters vary from 3.3m to 3.0m for the change of water pressure.

7.2.3 Power Station

This subsection discusses planning and design for civil works of the powerhouse, tailrace and switchyard. Generating equipment, transmission line, metal works, etc., will be described in the subsequence sections.

The open-air type powerhouse with two units of turbine and generator, the generating capacity of which is 48.6 MW in total, is located at the foot of the Nyakach Escarpment as shown in Figures 7.5 and 7.6.

A hollow jet valve bifurcated from the penstock is provided in the power station for the exclusive irrigation use in case that all the generating equipment is out of order or stopped for maintenance. A 90-ton overhead travelling crane with an auxiliary hoist is equipped in the powerhouse.

As the water released from the power station after generation of electricity is taken into the irrigation canals to Kano and Nyakach plains, a tailrace pond which controls water level at El.1,205m with 0.4m freeboard, will be provided with the power station. At the downstream end of the pond, an ogee type weir is provided to evacuate water spilt from the tailrace pond to Lake Victoria through the outlet channel constructed by improving the small creek beside the power station.

7.3 Design of Hydro-Mechanical Facilities

7.3.1 Intake Weir

(1) Intake weir orifice gate: Two (2) sets of orifice type radial gate will be provided in the intake weir. The principal features are as follows:

Type : Orifice type radial gate
Quantity : Two (2) sets
Clear Height : 5,500 mm
Clear Span : 5,500 mm
Hoist Type : Hydraulic cylinder type hoist.

(2) Intake weir orifice stoplog: One (1) set of the stoplog will be provided at the entrance of the orifice for the maintenance of the weir orifice gates and their guide frames. The stoplog blocks are handled by a 20-ton class track crane with a lifting beam.

The principal features are as follows:

Type : Slide gate
Quantity : One (1) set of stoplog
: Two (2) sets of guide frame
: One (1) set of lifting beam
Clear Span : 5,500 mm
Clear Height : 6,000 mm
Stoplog Height : 6,200 mm (4 x 1,550 mm).

7.3.2 Intake

(1) Intake gate: Four (4) sets of the fixed wheel gates (vertical lift gate) will be provided in the intake for emergency water shutdown, inspection and maintenance of the waterway. The gate is operated with a stationary type hoist mounted on the hoist deck. The principal features are as follows:

Type : Fixed wheel gate
Quantity : Four (4) sets
Clear Span : 5,000 mm
Clear Height : 2,500 mm
Hoist Type : Stationary type wire rope hoist.

(2) Intake service gate and monorail crane: One (1) set of the service gate will be provided in the intake structure for the maintenance of the intake gates and their guide frames.

The principal features are as follows:

Type : Slide gate
Quantity : One (1) gate leaf
: Four (4) guide frames
: One (1) monorail crane
Clear Span : 5,000 mm
Clear Height : 2,500 mm
Hoist Type : Travelling type monorail hoist.

(3) Intake trashrack: One (1) set of fixed type trashrack will be provided in front of the intake structure. The principal features are as follows:

Type : Fixed type
Quantity : One (1) set
Total Width : 28.0 m
Clear Height : 3.5 m
Total Height : 16.5 m
Total Slant Length : 17.2 m
Bar Pitch : 50 mm (at inflow and pier portions)
: 100 mm (at concrete wall portion).

(4) Intake mechanical rake: One (1) set of the mobile type raking equipment will be provided in the intake structure for removing trash and debris from the surface of intake trashrack. The raking

equipment consists of the mobile type raking car with its rails and stoppers. The mobile type raking car comprises the rake and its lifting devices, trash convey device, travelling device and all other necessary devices.

The capacity of the raking equipment was decided by expected sizes and quantity of the trash and debris. The principal features are as follows:

Type	: Unguided and mobile car type
Quantity	: One (1) set
Width of Rake	: 3.0 m
Raking Capacity	: 750 kgs/3.0 m.

(5) Inlet stoplog: One (1) set of the inlet stoplog will be provided at the inlet of the headrace tunnel for the inspection and maintenance of the sand stilling basin, headrace tunnel and surge tank.

The stoplog structure consists of ten (10) stoplog blocks and two (2) guide frames. The stoplog blocks are handled by a 20-ton class track crane with a lifting beam.

The principal features are as follows;

Type	: Slide gate
Quantity	: One (1) set of stoplog : Two (2) sets of guide frame : One (1) set of lifting beam
Clear Span	: 5,000 mm
Stoplog Height	: 15.0 m (10 x 1,500 mm).

(6) Sand flush facility: One (1) set of the sand flush facility consisting of valves and steel conduits will be provided in the intake for draining water in the sand stilling basin. Principal features are as follows:

Type : Slide gate valve
Quantity : Valve : Two (2) sets
: Steel Conduit : One (1) lane
Size of Valve : 850 mm x 850 mm
Operation : Motorized spindle hoist.

7.3.3 Waterway and Power Station

(1) Penstock: One (1) complete lane of the penstock will be provided from the surge tank to the inlet valve of two (2) turbine units. The penstock with 1,110.7 m in total consists of shells proper, reducing pipes, bifurcation, expansion points, ring girder assemblies, bend pipes, manholes, seepage and thrust collars and so on.

The penstock was designed to have sufficient strength for the critical loading conditions of internal and external pressure, axial force and, earthquake or wind loads.

The principal features are as follows:

Type : Exposed and embedded type steel penstock including Wai (Y) type bifurcation
Quantity : One (1) lane
Diameter : 3.3m to 3.0m (2.1 m after bifurcation)
Length : 1,110.7m.

(2) Penstock valve: One (1) set of the butterfly valve will be provided in the penstock valve house located just downstream from the outlet of the penstock tunnel for the emergency water shutdown, inspection and maintenance of the penstock.

The principal features are as follows:

Type	: Butterfly valve
Quantity	: One (1) set
Diameter of Valve	: 3.3 m
Operation	: Hydraulic cylinder type hoist.

(3) Irrigation outlet facility: One (1) set of the irrigation outlet facility will be provided by branching off the penstock near the powerhouse for supplying 8 m^3/sec to the tailrace in case that all generating equipment is out of order or stopped for the maintenance.

The hollow jet valve was selected as the discharge control valve and one (1) slide valve will be provided as the guard valve for the emergency water shutdown, inspection and maintenance.

The principal features are as follows:

Valve Type	: Main valve: hollow jet valve : Guard valve: slide valve
Quantity	: One (1) set
Diameter of Valve	: Guard valve : 0.9 m Main valve : 0.6 m
Operation	: Hydraulic cylinder type hoist.

(4) Draft tube gate: One (1) set of the draft tube gate and monorail crane will be provided in the tailrace outlet of the power station for the inspection and maintenance of the water turbine units.

The principal features are as follows:

Type	: Slide gate
Quantity	: One (1) gate leaf : Two (2) guide frames : One (1) monorail crane
Clear Span	: 4,400 mm
Clear Height	: 2,800 mm
Hoist Type	: Travelling type monorail hoist.

(5) Irrigation intake facility: Two (2) sets of irrigation intake facility will be provided in the tailrace of the power station. Principal features are as follows:

Type : Fixed wheel gate
Quantity : Three (3) sets in total
Size of Gate : 2,500 mm x 2,500 mm (2 sets for the right canal)
(Clear Span x : 2,000 mm x 2,000 mm (1 set for the left canal)
Gate Height)
Operation : Motorized spindle hoist.

7.4 Design of Generating Equipment

7.4.1 Generating Equipment and its Auxiliary Equipment

Basic design conditions of the generating equipment are summarized below:

(1) Full supply water level of intake pond : El.1,368.0 m
(2) Minimum operating water level of intake pond : El.1,355.5 m
(3) Plant peak discharge : 39.9 m^3/sec
(4) Tail water level at plant peak discharge : El.1,205.4 m
(5) Tail water level at no flow : El.1,205.0 m
(6) Rated head : 143.1 m.

The turbines and generators were designed on the basis of the abovementioned conditions as follows:

(1) Water turbine

(a) Type : Vertical shaft, Francis
(b) Number of unit : 2
(c) Rated output : 25,000 kW
(d) Rated speed : 429 rpm

(2) Generator

(a) Type : Vertical shaft, revolving-field type
(b) Number of unit : 2
(c) Rated output : 24,300 kW
(d) Rated capacity : 27,000 kVA
(e) Rated voltage : 11 kV.

Major auxiliary equipment of the power station would include the following:

- One (1) set of 90-ton overhead travelling crane with an auxiliary hoist for handling miscellaneous equipment,
- Two (2) sets of through-flow type inlet valves of 1.8 m diameter (maximum static head: 163.0 m), and
- One (1) set of diesel engine generator for emergency power supply to the auxiliary equipment.

7.4.2 Outdoor Switchyard

The outdoor switchyard of the power station will be equipped with the following:

- 132 KV single bus
- Three (3) 132 KV transformer bays
- One (1) 132 KV transmission line bay (two bays in future).

Two (2) banks of 27,000 KVA main transformers will be provided for two (2) generators as unit system.

One (1) bank of 132/11 KV, 3,000 KVA local service transformer will also be provided for not only station supply but also local supply.

7.4.3 Transmission Line Protective Equipment and PLC Telephone Equipment

Carrier pilot relaying equipment will be provided between Sondu/Miriu power station and Muhoroni substation and between Muhoroni and Lessos substation with single phase reclosing function.

Besides, power line carrier (PLC) telephone equipment will be provided among Sondu/Miriu, Muhoroni and Lessos, in addition to the existing PLC equipment among Lessos, Kisumu and Chemosit.

7.5 Transmission Line and Substation

7.5.1 General

As explained in Chapter 5, the major load centre is concentrated in Nairobi area followed by Coastal and Western areas. The national power grid system (NPGS) comprises 220 KV and 132 KV lines as primary transmission system and 66 KV, 40 KV and 33 KV lines as secondary transmission system as shown in Figures 7.7 and 5.1. The present trunk line between Juja Road substation in Nairobi and Tororo substation in Uganda via Lessos substation in Western area is a 132 KV double circuit line with Wolf and Lynx ACSR conductor.

In Western area, the 132 KV transmission line with Wolf ACSR conductor has been extended from Lessos substation to Chemosit substation in Kericho District and Mambo Leo substation in Kisumu District via Muhoroni, and to Eldoret substation in Uasin Gishu District in 1983.

The Turkwell Gorge power station (100 MW) which will be connected with the NPGS at Lessos by 220 KV line is being implemented and will come on stream before the Sondu/Miriu Project. Construction of a new 220 KV transmission line between Lessos and Nairobi has been planned by KP&L in order to increase transmission capacity of the existing line and reliability of the NPGS.

Under these circumstances, power transmission facilities for connecting the Sondu/Miriu power station into the NPGS at Lessos substation only is considered in this study.

7.5.2 Transmission Line

The Sondu/Miriu power station will be connected to the NPGS at the Muhoroni substation by the 132 KV single circuit transmission line, utilizing the existing 132 KV transmission line between Muhoroni and Lessos as shown in Figure 7.8.

The transmission voltage is selected to be 132 KV for this line, taking into account the following:

(a) Maximum output of the Sondu/Miriu power station (2 x 27 MVA);
(b) Distance between the said power station and the nearest substation, i.e. Lessos substation (ca. 90 km); and
(c) The existing transmission line voltage in this region.

A single circuit line was selected with Wolf ACSR conductor which is the same size of the existing conductor, since its thermal rating of about 80 MVA (70°C conductor temperature) would be quite sufficient to transfer the maximum power to Muhoroni without consideration of power transfer to Mambo Leo and Chemosit substations.

The route length of the proposed line from the power station to Muhoroni substation is estimated to be about 40 km.

When Magwagwa power station (ca. 95 MW) is planned to be developed in 1996, a 132 KV double circuit transmission line with same size ACSR conductor will be connected to Lessos substation via Muhoroni, considering outage of one line out of three lines. Besides, an interconnection line between Sondu/Miriu and Magwagwa power stations will also be constructed, taking into account outage of the transmission line between Sondu/Miriu power station and Muhoroni.

7.5.3 Substation

As mentioned above, the existing switching gears in Muhoroni substation will be improved for the connection of Sondu/Miriu power station in this Project and Magwagwa power station in future.

The Muhoroni substation would be equipped with the following:

- 132 KV double bus with 1 $^{1}/3$ C.B. system
- Four (4) 132 KV transmission line bays
- One (1) local service transformer bay
- One (1) lot of 11 KV indoor cubicles for local and station supply
- One (1) lot of control boards in the building.

One (1) bank of 2,000 KVA local service transformer would be provided for local and station supply.

The general layout of Muhoroni substation is shown in Figure 7.9, taking account of future expansion of transmission line bays.

Chapter 8. CONSTRUCTION PLAN AND COST ESTIMATE

8.1 Construction Plan and Schedule

8.1.1 General

All the works of the Sondu/Miriu run-of-river project will be fundamentally executed by contractors selected by means of international competitive tender including prequalification except the engineering services. The following are modes of construction for the project works;

- Main civil works (River diversion, weir and intake, waterway, power station including building works, outlet channel and road construction) : International competitive tender
- Metal works (Weir, intake, penstock line, irrigation outlet and tailrace) : International competitive tender
- Generating equipment & transmission line (Generating equipment, substation equipment and transmission line) : International competitive tender
- Engineering services (Detailed design and construction supervision). : Direct order

8.1.2 Construction Schedule

The construction period of the project is scheduled to extend over 7 years. First 3 years are required for the arrangement of construction finance, the selection of engineering consultant, the detailed engineering services and the tendering time, and latter 4 years are required for the construction work of the project. The arrangement of construction finance shall be made by the Ministry of Energy and Regional Development/the Lake Basin Development Authority. In order to secure this target, the following basic schedule shall be kept for the implementation of the project;

a) Financial arrangement : For 9 months from January 1986 to September 1986
b) Contract for engineering services : For 3 months from October 1986 to December 1986
c) Engineering services for detailed design : For 14 months from January 1987 to February 1988
d) Tender and contract : Completion in December 1988
e) Main construction works : Commencement in January 1989 to Completion in December 1992, Within 48 months
f) Commissioning of commercial operation of power station : Beginning of January 1993.

The overall construction schedule is shown in Figure 8.1 by a bar chart. Detailed discussions on the construction schedule are given in Appendix VI, Construction Plan and Cost Estimate, of Volume IV. It is noted that the land acquisition and compensation to be claimed for the construction of the project will be settled by the Lake Basin Development Authority in advance of the commencement of the construction.

8.1.3 Construction Plan and Method

The construction plan of the project is worked out on the basis of the mode of construction and target of schedule of construction. Major construction plant and equipment for construction use are listed in Table 8.1. The construction plan for the major structures is briefly discussed as follows.

(1) River diversion

River diversion during construction of the intake weir, intake and desilting basin structures is made by the diversion channel planned at left abutment (refer to Figure 7.2). The coffers of 250m in length are placed at the downstream and upstream and along the diversion channel. Major equipment to be employed for the construction works is 7 m^3/min crawler drills, 21-ton bulldozers with ripper, 2.3 m^3 tractor shovels, 11-ton dump trucks and 5-ton vibrating rollers.

(2) Weir and intake

Earth and rock excavation and filling will be carried out using 7 m^3/min crawler drills, 21-ton bulldozers with ripper, 2.3 m^3 tractor shovels, 11-ton dump trucks and 5-ton vibrating rollers. Consolidation and curtain grouting works will be carried out using 5.5 kw rotary drills, 7.5 kw grout pumps and 200 lit x 2 grout mixers. Concrete will be produced by a 1.0 m^3 concrete plant, transported by 3.2 m^3 agitators and placed by 20-ton truck cranes with a 1 m^3 bucket and 45 m^3/h concrete pump cars. The weir orifice gate and intake gate will be fabricated at the contractor's factory in sub-assembly units. The sub-assemblies will be carried to the installation site using 20-ton trailers and handled by 20-ton truck cranes.

(3) Waterway

(a) Headrace tunnel

The headrace tunnel is a concrete-lined tunnel of 4.2 m in diameter and 4,314 m in length (refer to Figure 7.1). Two work adits of 4.0 m in width and 400 m in total length are planned to be driven at the distance of 150 m and 50 m from the downstream portal and upstream portal respectively. A full-face attack method is to be applied for the excavation and hauling of tunnel spoil is to be made by the rail method. Two tunnel faces are set up to be attacked from both ends simultaneously. Excavation works will be carried out using drill jumboes, 0.6 m^3 muck loaders and 4.5 m^3 muck cars with a 10 ton battery locomotive. The driving progress speed is planned to be 220 m per month (110 m/set x 2 faces). An arch and then invert method is applied for concrete-lining work. Concrete work will be carried out using 3.2 m^3 agitators, 3 m^3 pneumatic placers with a 4 ton battery locomotive. Concrete-lining progress is planned to be 300 m per month (150 m/set x 2 sets). Invert concrete will be placed by invert finishers in combination with 3 m^3 agitator cars with the 4 ton battery locomotive. Backfill grout and consolidation grout will be carried out using 11 kw low pressure grout pumps, leg hammers, 7.5 kw grout pumps and 200 lit x 2 grout mixers.

(b) Surge tank

A vertical shaft of 10 m in diameter and 51.9 m in height, of which underground portion is about 40 m, will be executed by a pilot shaft and enlargement method. The pilot shaft of 2 m x 2 m is excavated at the centre of shaft and will be excavated using a raise climber upward from the bottom. Enlarging to a full shaft diameter will be made by drilling and shooting with 7 m^3/min crawler drills and jackhammers. The progress per day is planned to be 1.2 m. The initial concrete-lining work will be done at every stage following drilling and shooting works of 1.2 m progress. The second concrete-lining work will be made upward from the shaft bottom, after the completion of shaft enlargement and initial concrete-lining works. The concrete work will be carried out using 20-ton truck cranes with a 1 m^3 bucket.

(c) Penstock tunnel and penstock line

A steel penstock of 3.3 to 3.0 m (2.1 m after bifurcation) in diameter and 1,110.7 m in length consists of the upper penstock tunnel portion of 102 m and inclined open portion of 1,008.7 m. The penstock tunnel excavation and concrete works will be executed in a similar way to the headrace tunnel. Open cut excavation will be carried out using 7 m^3/min crawler drills, 21-ton bulldozers with ripper, 2.3 m^3 tractor shovels and 11-ton dump trucks. Concrete placing in an open portion will be performed by 20-ton truck cranes with a 1 m^3 bucket and 45 m^3/h concrete pump cars. Penstock shell will be fabricated at the contractor's factory in piece. The steel plate segment will be welded by an automatic welding machine into 6 m long segment at the site work shop. Each pipe segment will be transported to the installation site by 20-ton trailers.

The penstock-unit will be installed using rail mounted carriers, incline machines with a carrier and 30-ton truck cranes.

(4) Power station

The powerhouse of reinforced concrete structure (21 m in length, 35.0 m in width and 24.0 m in height referred from Figure 7.5) is constructed to accommodate two units of 25 MW Francis type turbine and 27 MVA generator. Foundation excavation for the powerhouse and tailrace will be carried out using 7 m^3/min crawler drills, 21-ton bulldozers with ripper, 2.3 m^3 tractor shovels and 11-ton dump trucks.

The substructure concrete work will be completed before the installation of overhead crane. The tailrace concrete work will be made in parallel with the substructure concrete work. The draft-tube and casing will be installed using the overhead crane. Subsequently, the second stage concrete around the draft-tube and casing and the remaining concrete will be placed according to the progress of installation of the turbines and generators. The substructure concrete will be transported by 3.2 m^3 agitators and placed by 45 m^3/h concrete pump cars and 20-ton cranes with a 1 m^3 bucket. The second concrete and the remaining concrete will be placed by a 45 m^3/h concrete pump car.

8.2 Cost Estimate

8.2.1 Construction Cost

(1) General

Construction cost for the implementation of the project is estimated on the basis of the preliminary design and the proposed construction plan and schedule. The foreign and local currency portions of construction cost are estimated in US Dollar and Kenya Shilling respectively and then converted to Kenya Shilling. The basic conditions applied for the cost estimate are presented below:

a) The construction cost of the project is divided into the direct cost (contract cost) for preparatory works, main civil works, metal works, generating equipment & substation equipment and transmission line, and the indirect cost for land acquisition, administration expenses, engineering services and contingencies.

b) Prices are based on the current prices for labour, materials and equipment as of December 1984. The ruling exchange rate is 1.0 US Dollar = 15.0 Kenya Shilling = 240 Japanese Yen.

c) Cost for preparatory works is estimated at 10 percent of the sum of main civil works, metal works, generating equipment & substation equipment and transmission line.

d) Cost for main civil works is based on the expenses of labour, materials, construction equipment and the contractor's indirect cost (overhead expenses and profit).

- Labour cost is estimated based on the 8 hour shift per day.

- Most of construction materials are supplied from local market. The imported material cost is estimated on the basis of C.I.F. price and added sales tax and duties. Local supplies are to be the purchased price at the site.

- Construction equipment and plant will be purchased and owned by a contractor. The foreign currency portion includes depreciation cost, spare parts and consumable cost, while the local component includes the cost of operator mechanic labour cost for the repair and administration expenses, import fees, taxes and duties.

e) The cost for metal works, generating equipment, substation equipment and transmission line is estimated on the basis of the current international contract prices, and the tax and duties are excluded. The cost is estimated on the basis of F.O.B.

price in Japan. The cost for supply and delivery on imported items, ocean freight and insurance are considered to be foreign currency portion. The cost for unloading and other charges at Mombasa port and inland transportation is estimated by local currency.

f) All required lands and right of way shall be acquired by the Lake Basin Development Authority. The cost for land acquisition and compensation is shown in Table 8.2.

g) An allowance of 2 percent of the direct cost (contract cost) is provided for the government administration expenses of the project.

h) Cost of the engineering services for construction supervision is estimated on man-month base. The cost for detailed design and preparation of tender document on the pre-construction stage is estimated at US$ 3 million including price escalation and physical contingency.

i) Physical contingency is estimated at 10 percent of the amount of preparatory works, main civil works, land acquisition and compensation, administration expenses and engineering services. As for the metal works, generating equipment & substation equipment and transmission line, the cost for the physical contingency is estimated at 5 percent of the amount for the direct cost.

j) Price contingency is estimated by applying the inflation rate of 3 percent per annum for foreign currency portion and 9 percent of local currency portion.

(2) Construction cost

The construction cost for the project is estimated at KShs. 1,320.9 million equivalent in total, consisting of KShs. 1,004.0 million equivalent in foreign currency portion (US$ 66.9 million, 76%) and

KShs.316.9 million in local currency portion (24%). The construction cost and its detailed estimate are shown in Table 8.3 and Table 8.4 respectively.

8.2.2 Annual Disbursement Schedule

The annual disbursement of construction cost for foreign and local currencies is estimated on the basis of the construction schedule. The disbursement schedule is shown in Table 8.5 and summarized as follows:

	Foreign Currency		Local Currency	Total
Year	Mill. US$	Mill. KShs.	Mill KShs.	Mill. KShs
1987	(3.00)	45.00	–	45.00
1989	(16.66)	249.94	82.04	331.98
1990	(15.93)	238.98	110.98	349.96
1991	(23.30)	349.54	82.58	432.12
1992	(8.04)	120.58	41.27	161.85
Total	(66.93)	1,004.04	316.87	1,320.91

Chapter 9. PROJECT EVALUATION

9.1 Economic Analysis

9.1.1 Framework

Direct benefits of the Sondu River multipurpose development project will accrue both from hydropower generation and irrigated agriculture. Evaluation of economic viability separately for hydropower and irrigation components cannot be properly done, when two components are related to one another physically in realization of common use of some facilities of the project. This is usually the case with many multipurpose projects.

Therefore, the economic viability of the Sondu multipurpose project is first evaluated here, based on all the costs and benefits involved in implementing the project, combining both the hydropower and irrigation components. Secondly, the economic viability of the hydropower component is evaluated, based on power benefits alone and excluding from the total project costs those costs (called specific or direct costs) of facilities serving specifically the irrigation component.

9.1.2 Project Costs and Benefits

(1) Economic cost

In economic analysis, all the costs involved in the project have to be measured as economic costs, i.e. the real resource costs or "opportunity costs" incurred from the viewpoint of nation's economy. Thus the economic cost of any project input would depend on what other opportunities would be lost for utilizing this input, should the project be implemented.

The measurement of economic costs, therefore, depends on the assumption of how each project input would be procured — whether by increasing import, decreasing export, expanding domestic production or diverting from other potential uses. Clearly it is impracticable to trace procurement sources for all the project inputs. Thus in this study, the following principles were applied.

All equipment and materials to be newly imported for the project were costed at their C.I.F. prices. Competitive rates applicable to services provided by the expatriate were used as economic costs of foreign labour. In fact the foreign currency portion of the project costs as presented in Chapter 8 has been estimated in the ways described above. Thus it can be used as economic costs without any conversion. For tradable (exportable) goods to be procured in local markets, their F.O.B. prices represent the shadow prices to be used in economic analysis.

Shadow pricing was applied also to common labour and cement, two other important project inputs. The shadow wage of unskilled labour was calculated to be 60% of the wage used in financial analysis. The shadow price of cement was found to be about 70% of the retail price in domestic market set by the Government. Although the cement may be procured directly in the domestic market, the foreign and local currency portions of the economic price are about 50% each. Details of the calculation are included in Section 4.2, Volume VI.

Internal transfer portions have to be excluded from local currency costs of other project inputs. Whilst indirect taxes on commodities in a competitive market should not be excluded, as consumers express their willingness-to-pay by market prices including taxes, the possibility is remote that such commodities would be involved in the project. The internal transfer portions were estimated to be about 10% by inspection of data on government revenue from taxes and exercise (see Section 4.2, Volume VI).

In the present study, the combined effects of eliminating internal transfer portions and the shadow pricing mentioned above have been deduced instead of adjusting financial costs by each cost element to calculate the economic costs. That is, the local currency portion of economic costs was estimated to be approximately 85% of the financial costs.

The economic costs measured in this way consist of costs expressed in both foreign (US dollars) and local (Kenya shillings) currencies, and have to be expressed in common terms. This in essence requires to measure in the local currency the real economic value of foreign exchange, another important project input.

A prevailing or official exchange rate may in some cases be regarded as a fair reflection of the real value of foreign exchange for nation's economy. If not, a shadow exchange rate has to be assessed. Calculation by using two simple methods to assess the shadow exchange rate has confirmed that practically no over- nor under-valuation of the local currency existed after the Kenya shilling was devalued in mid-1983 (see Section 4.2, Volume VI).

It is concluded that the floating price quotations of US dollars thereafter well represent the real value of foreign exchanges in Kenya. Thus for the economic analysis, the foreign currency costs expressed in US dollars are to be converted to Kenya shillings at the rate of 1 US dollar = 15.0 Kenya shillings, the rate effective at the end of field investigation period (November 1984).

(2) Benefits

Economic analysis of a power project represents a special case in project evaluation due to its characteristics as a public utility project. Benefits of power are realized, for instance, in the form of increased production value as it is used as one of inputs to economic activities. It is difficult to measure such increased production value, to say nothing of measuring the utility value of domestic power consumption.

In general, prices of a commodity in a competitive market are regarded as reflecting consumers willingness-to-pay, a legitimate measure of benefits associated with this commodity. In the case of power, however, such a market hardly exists, and particularly in developing countries where power is developed and supplied by the government or a public enterprise like KP&L. Prices for electricity are often kept at low level for political or socio-economic reasons such as to contribute to public welfare or to promote industrialization.

On the other hand, it has been advocated that the long-run marginal cost (LRMC) of power supply should be calculated and used as a guideline for setting such an electricity tariff that would induce more efficient resource allocation from a viewpoint of nation's economy. In this study, an attempt was made to estimate the LRMC to be used as a proxy of unit power benefit.

In particular, the LRMC of power generation and transmission to a primary substation was calculated as the average incremental cost involved in most likely and cost-effective development of power supply system based on thermal generation. The average incremental cost of power generation was calculated to be 0.86 Kenya shillings per kWh. Detailed calculation as well as estimated LRMC of power supply is included in Section 4.3, Volume VI.

The irrigation benefit for the Sondu multipurpose development project is defined as the difference between the net production value with the project and the net production value without the project. The net production value under either "with the project" or "without the project" conditions is calculated by subtracting production costs from the gross value of agricultural products valued at respective economic prices. The calculation procedure for irrigation benefit is detailed in Chapter 6, Volume III.

9.1.3 Economic Rate of Return

(1) Economic cost-benefit streams

In accordance with the idea of using the LRMC as a proxy of unit power benefit, the average incremental cost of power generation, calculated to be 0.86 Kenya shillings per kWh, is multiplied by annual energy available at a primary substation to obtain annual benefit of hydropower. The annual energy generation is the same throughout the evaluation period, as the hydropower plant will be utilized in full from the first year of its operation. The annual benefit is adjusted for transmission losses up to the primary substation.

With the diverted water of the Sondu, the net area of 15,610 ha can be developed for irrigated agriculture. The benefits accruing from this entire area are included in the benefits of the Sondu project (first stage development). The irrigation benefits which were estimated and reported in Volume IV, are added to the hydropower benefit to obtain the benefit stream of this multipurpose project. The five year build-up period has been assumed for the irrigation benefits, before they reach the maximum level.

The economic costs of the project were estimated by adjusting the financial costs, presented in Chapter 8 of this volume for hydropower and in Volume III for irrigation, in the way described in the previous section. The operation and maintenance (O&M) cost of hydropower component is estimated by the following:

$$\left(\begin{array}{l}\text{Direct cost of intake}\\ \text{dam and associated works}\end{array}\right)\text{x}0.005 + \left(\begin{array}{c}\text{Direct cost of power generating}\\ \text{equipment and facilities}\end{array}\right)\text{x}0.02$$

From the cost data in Table 8.4, the annual O&M cost is calculated to be 7,057 thousand Kenya shillings, after shadow pricing. The economic cost and benefit streams are summarized in Table 9.1.

(2) ERR for multipurpose development

The internal economic rate of return (ERR) for the Sondu River multipurpose development project (first stage) was calculated from the cost and benefit streams presented in Table 9.1. The ERR was found to be 13.6 percent. In view of the opportunity cost of capital in Kenya, i.e. 10 percent return on capital, this multipurpose development is assessed to be sufficiently viable under all the assumed conditions.

The S/W for the study delineated the irrigation area bordered to the north by the Awach Kano River, instead of the entire area irrigable with the water to be diverted from the Sondu River. If only the costs and benefits of this area of 8,540 ha are included in the cost and benefit streams of the multipurpose development, the ERR becomes 12.2 percent (see Volume III for costs and benefits data corresponding to 8,540 ha).

(3) Sensitivity analysis

The economic viability of the Sondu multipurpose project was tested against major factors where uncertainties are involved. These are decrease in power and/or irrigation benefits and increase in investment costs. The results of this sensitivity analysis are summarized as follows:

Case 1	Standard	13.6%
Case 2	Power benefit decrease by 10%	13.2%
Case 3	Irrigation benefits decrease by 10%	13.0%
Case 4	Investment costs increase by 10%	12.7%
Case 5	Combination of Cases 2, 3, and 4	11.8%.

As seen from the figures above, the value of ERR is slightly more sensitive to decrease in irrigation benefits rather than that in hydropower benefit. Including the case of 10 percent increase in investment costs, the ERR is higher than the rate corresponding to the opportunity costs of capital. Even in the worst case examined, where three unfavourable conditions coincide, the ERR is 11.8 percent.

(4) ERR for hydropower development

The hydropower and irrigation components can not be really separated in evaluating the Sondu project, as it is a multipurpose project. The fact that the levels of study at this time are different for the hydropower and irrigation components makes the evaluation even more difficult. It would still be helpful in obtaining further insights to calculate the ERR for hydropower component alone. The power benefit is the same as before, and the costs of intake weir, intake, headrace, penstock, powerhouse, generating equipment and transmission are included in the cost stream. The ERR is calculated to be 10.4%, higher than the rate corresponding to the opportunity costs of capital. This result, in fact, underrates the economic viability of the Sondu project, which would also serve the irrigation.

(5) Evaluation by the Kenyan method

In Kenya, it has not become a standard practice to calculate the LRMC and to use it for evaluating power projects. Instead, the average electricity tariff that is effective at the time of project evaluation is usually taken as a conservative estimate of unit power benefit. The average electricity tariff was about 0.70 Kenya shillings per kWh at the time of field investigation, but the tariff revision in 1985 raised it to about 0.78 Kenya shillings per kWh.

The average electricity tariff is multiplied by the energy available at sales ends to obtain again a conservative estimate of power benefit. To calculate the electrical energy available at sales ends, the transmission and distribution loss is assumed to be just ten percent, somewhat lower than the overall loss ratio of the national grid. Cost of sub-transmission and distribution is calculated as follows and added to the cost stream. The total cost of transmission and distribution, including both capital costs and engineering, management and other O&M costs, is 0.26 Kenya shillings per kWh after shadow pricing, of which about 70 percent or 0.18 Kenya shillings is attributable to sub-transmission and distribution.

The benefit and cost streams thus calculated are presented in Table 9.2. In calculating the benefit in the table, it was assumed that the secondary energy has as much value as assumed for the primary energy. This assumption would be reasonable as long as the existence of sufficient demand for the secondary energy is warranted, especially since the assumed unit power benefit is only a conservative estimate of real power benefit. One possibility suggested by LBDA and discussed at the steering committee is to use such energy for pumped irrigation along the rain-shadow of Lake Victoria shores.

Effects of lower value or demand for secondary energy were also tested. The results are summarized as follows.

Value of secondary energy	ERR
100%	8.6%
80	7.2
60	5.3

It has been informed by KP&L that the ERR calculated in the same way for the Kiambere hydropower project was 10 percent, and 8 percent for the Turkwell gorge hydropower project. It may be concluded that the first stage development of the Sondu River hydropower project is economically almost as viable as the Turkwell, provided that there exist sufficient uses for the secondary energy.

9.2 Financial Analysis

9.2.1 Project Costs and Revenue

(1) Project costs

Financial costs of the Sondu multipurpose development project were estimated at the price level of December, 1984 and presented in Chapter 8 for hydropower component. In Chapter 8, price escalation was calculated by applying annual inflation rates of 3 percent for foreign currency costs and 9 percent for local currency costs, and added to the construction costs according to the disbursement schedule, but in Kenya price escalation is not included in calculating internal financial rate of return (ERR) of any power project.

Additional investment and replacement costs as well as O&M costs are also included in the cash flow without price escalation. Cost of sub-transmission and distribution is taken to be 70 percent of the total cost of transmission and distribution or 0.31 Kenya shillings per kWh, including both capital costs and engineering, management and other O&M

costs. Thus the sub-transmission and distribution cost is calculated to be 0.22 Kenya shillings per kWh.

(2) Project revenue

Revenue from energy sales is calculated based on the salable energy after deducting station use and transmission and distribution losses from the power generation schedule given in Chapter 7. The salable energy is to be multiplied by the average unit electricity tariff. Different tariff rates are assumed to calculate FRR.

9.2.2 Financial Rate of Return

(1) Financial cash flow

The financial cash flow for the Sondu hydropower development is prepared based on the investment costs, the O&M costs and revenue calculated as described above, for such average tariff level. Interests during construction on external loans, foreign or local, are not included in the cash flows.

(2) Calculation of FRR

From the cash flow data in Table 9.3, corresponding to the average tariff of 0.78 Kenya shillings per kWh, the internal financial rate of return (FRR) is calculated to be 4.2 percent. Another tariff revision, if approved would raise the average tariff again by 11 percent. Further revisions would certainly be introduced before the Sondu hydropower project is commissioned.

Thus the effects of raising the average electricity tariff have been analyzed, and the following results obtained.

Average electricity tariff	FRR	Average annual rate of tariff increase necessary
0.78 KShs/kWh	4.2%	0 %
0.90	6.6	1.8
1.00	7.6	3.2
1.10	8.7	5.5
1.25	10.1	6.1

(3) Cost allocation

Naturally the intake dam and diversion work will serve not only the hydropower generation but also the irrigation by making the Sondu River water available to the Nyakach and the Kano plains. Thus a part of the costs for these works may be borne by irrigation sector, when this multipurpose project is implemented. It is, of course, beyond the scope of this study to indicate how the total costs should be allocated between the hydropower and irrigation sectors.

Still it is meaningful to see how the financial performance of the hydropower development will be affected by the cost allocation. Thus the FRR was calculated under the condition of cost allocation. The result show that FRR will increase from 4.2 percent corresponding to the average tariff of 0.78 Kenya shillings per kWh to 4.8, 5.1 and 5.4 percent respectively, as 20, 30, 40 percent of the common costs are allocated to the irrigation sector.

One reasonable method of allocating the costs between the hydropower and the irrigation sectors is to prorate the total costs in proportion to the total flow of river water to be used by respective sectors. According to the optimization study in Chapter 6, the average annual flow used by the hydropower and the irrigation sectors is 24.1 m^3/sec and 12.5 m^3/sec, respectively. This implies that about 35 percent at the common costs may be borne by the irrigation sector.

9.2.3 Project Finance and Loan Repayability

(1) General

The implementation of the first stage hydropower development of the Sondu project will require some 66.9 million U.S. dollars in foreign currency, 316.9 million Kenya shillings in local currency and 1,320.9 million Kenya shillings equivalent in total, including price escalation. How these costs may be financed is a matter to be determined later, but in this subsection financial performance of the project is examined under assumed but realistic conditions.

(2) Terms of loans

The Sondu project is likely to be implemented by introducing external loans to cover some part of project costs. The following conditions are assumed.

(i) All the foreign currency portion of the investment costs would be financed by a loan from an international financing agency.

(ii) The terms of this external loan is assumed to be as follows.

Interest rate : 4.0 percent per annum
Grace period : Construction period (4 years)
Repayment period: 30 years including the grace period

(iii) All the repayments would be constant over the maturation period, corresponding to increasing principal repayment and decreasing interest payment

(iv) All the local portions of investment costs and annual expenses would be provided by the Government contribution.

(3) Financial statement

Gross revenue is calculated by assuming the average tariff of 1.25 Kenya shillings per kWh. This represents the 6 percent annual increase in the average electricity tariff, as mentioned in the previous subsection. On the cost side, only the project costs with price escalation are included.

Under these conditions assumed above, a simple financial statement is prepared and presented in Table 9.4. It should be noted that this is the financial statement for the project, but not the one for KP&L as other associated costs (e.g. sub-transmission and distribution cost) are not included. It is observed from the table that the annual balance would turn positive as the project starts operation in 1993 and the accumulated outstanding would become positive eight years thereafter. At the end of repayment period, the accumulated surplus would exceed one billion Kenya shillings, equivalent to about 80 percent of the initial investment costs.

9.3 Comprehensive Evaluation

9.3.1 Associated Benefits and Costs

In the preceding sections, the Sondu project was evaluated both economically and financially, based only on direct benefits or revenue respectively accruing from the electricity and agricultural products. In this section, attention is directed to secondary benefits and costs that may be associated with the project. Particularly the project is evaluated from the viewpoints of regional development and environmental quality.

(1) Effects on regional development

The Western Kenya region, where the Sondu multipurpose project is located, is one of less developed regions in Kenya, despite the fairly good development potentials with water and related land resources, fish stocks, mineral and other resources as well as human resources and its location itself (see Chapter 3 of this volume and Chapter 2 of Volume VI). The Sondu project is likely to trigger the development of this important region.

Major contribution of the Sondu project would be in the following aspects.

(i) Incentives for industrial development in general by improving the electricity supply capacity

(ii) Consolidation of basis for agro-related industries with increased agricultural products

(iii) Opportunities for new and more intensive farming practices with the provision of irrigation and drainage

(iv) Watershed protection by population re-distribution from highlands to lowlands

(v) Promotion of other development projects by LBDA, whose financial and project implementing capability would be much improved by the project

To pursue and realize these possibilities in a manner that would not disrupt the conventional lifestyles of the local people and relationships among different tribes and clans would be a challenge and responsibility of LBDA.

(2) Effects on environment

Possible effects

Possible impact of the Sondu project on the environment in and around the project site has been assessed at a preliminary level. As it is only a preliminary assessment, the possible effects have been classified into the following five ranks just to indicate if they would be beneficial, neutral or harmful to natural and human surroundings.

+H : high positive
+L : low positive
0 : no effect of negligible effect
-L : low negative
-H : high negative

Assessment results are summarized in Table 9.5.

Further studies

As shown in Table 9.5, environmental effects of the Sondu project have been assessed low negative (-L) in the aspects of sedimentation, vegetation, and fish and fisheries, and high negative (-H) in the public health aspect. Those effects assessed low negative at this time, however, may turn out to be negligible, if more detailed investigations are made into existing conditions and careful approaches are taken accordingly to project implementation.

Possible effects on public health evaluated high negative, especially prevalence of malaria and schistosomiasis, may be more serious and thus call for follow-up studies. Precedents of other similar projects and control measures on malaria and schistosomiasis are included in Chapter 3 of Volume VI for reference of the further studies.

9.3.2 Conclusions

The first stage development of the Sondu River multipurpose development project is economically viable, as the internal economic rate of return is 13.6 % based only on the direct benefits of electricity and irrigated agriculture, as reported in Section 9.1. The financial feasibility of the project is subject to future revisions of electricity tariff as well as terms of external loans to be introduced to implement the project. In order to attain the internal financial rate of return of eight percent, the average electricity tariff has to be raised by six percent per annum on average until the year 1993.

Other aspects of the project seem generally favourable; i.e. the secondary benefits will well outweigh the secondary costs. Particularly in view of the importance of the project for the development of one of less developed regions in Kenya, the implementation of the project at the earliest possible time is highly recommended.

Chapter 10. FURTHER INVESTIGATION AND STUDIES

10.1 General

As reported in the preceding chapters, the Sondu River multipurpose development project is not only economically viable but also crucially important for the development of the Western Kenya region. Its first stage development is relatively simple diversion of river water by an intake weir at Sondu/Miriu site to harness the hydropower generating head endowed by the Nyakach escarpment and to make the water available for irrigated agriculture in the Nyakach and Kano plains. This is to be followed by the second stage development of an upstream reservoir at Magwagwa, which would increase both the hydropower generation and irrigation area by significant amount.

In view of the importance of the project particularly for the development of the less developed but high potential region in Kenya, the implementation of the first stage development at the earliest possible time is highly recommended. In order to realize the commissioning of the hydropower plant in 1993 as planned by this study, it would be desirable to start detailed design by the beginning of 1987.

The irrigation development is an integral part of the Sondu project. When the present problem of food shortage in sub-Sahel region of Africa is considered, the need for increased crop production by the project would be even more urgent. At this time, only a pre-feasibility study has been carried out for the irrigation development associated with the Sondu hydropower development. The study was confined to the area bordered to the north by the Awach Kano River, although the area beyond it was also considered for planning purposes. It is imperative to upgrade this study to a feasibility study level, possibly delineating a larger area for irrigation development. The feasibility study itself may be carried out in a relatively short period of time, given the results of this and other studies recently completed, but the aerophoto mapping to a proper scale (e.g. 1 to 5,000) has to be conducted at the eariest time.

As mentioned above, the effects of the project will be very much increased with the second stage development of Magwagwa dam. The study at this time indicates that it would be ideal to have the Magwagwa dam with the time lag of about three years after the first stage development. Considering a longer period of time required for design and implementation of this major dam project, it is recommended to conduct its feasibility study within a few years time.

As the Sondu project is a major multipurpose development project, multiple government agencies will be involved in its implementation so that the cooperation of these agencies and coordination of sometimes conflicting interests are most essential. Also negotiation for financing schemes of both foreign and local currency costs should be started as soon as possible for smooth project implementation thereafter. In particular, possible cost allocation schemes between irrigation and hydropower components should be sought, including financial arrangements between KP&L and LBDA concerning generation and sales of electricity.

The completion of this feasibility study marks the first substantial step toward the implementation of this project. In addition to detailed design for the first stage development and other related studies as mentioned above, some supplemental studies would be desirable in the next planning stage, including a basic study for compensation/relocation and socio-cultural effects in general and a further study of public health aspect (see Chapter 3, Volume VI).

10.2 Detailed Design for the First Stage

10.2.1 Objective

Subsequent to the completion of this feasibility study, detailed design (D/D) for the first stage development of an intake weir, diversion waterway and a hydropower plant should be initiated. The objectives of the engineering services for D/D would be (i) to collect update/additional data and information and to review and analyze the findings and recommendation for optimization of the project, (ii) to conduct additional field investigations for obtaining essential data for design, (iii) to prepare design drawings, design report, technical specifications, pre-qualification and tender documents, cost estimate, detailed implementation programme for construction of the Sondu/Miriu hydropower project, and (iv) to transfer knowledge and technology to the LBDA staff concerned during the period of services.

10.2.2 Scope of Works

The engineering services for D/D would be carried out in close cooperation with assigned LBDA counterparts. The services would include but not necessarily be limited to the following.

(1) Review of available data

To obtain updated information, to review the feasibility study report and, if necessary, to revise the development scheme, scale, and principal features of the project.

(2) Preparation of inception report

(a) To make work schedules, with study and survey methods for this engineering service.
(b) To prepare an inception report containing results of the above review of the feasibility study and proposed work schedules and methods.

(3) Preparation of tender documents for field investigations

To prepare tender documents for the following field investigations to be executed by local consultants.

(a) Test boring and grouting
(b) Seismic exploration
(c) In-situ rock shear tests and excavation of test adits
(d) Shear test for rock materials on a large scale

(e) Soil and concrete tests including sampling and test pits in soil and aggregate borrow areas/quarries
(f) Topographic surveys
(g) Boring and penetration test

Note: Items (a) to (e) refer to the intake weir site, and item (g) to the transmission line, but item (f) to both dam and transmission sites.

(4) Field investigation and tests for detailed design

To supervise the field investigation and test works of the above items (3) (a) through (g) to be executed by the local consultants and to provide technical guidance for their staff.

(5) Basic design and cost estimate

To do basic design and prepare estimates of construction cost as follows:

(a) To prepare design criteria for detailed design of all the major components with respect to methodology, analysis and computation criteria, etc.,
(b) To make a final review and revision of layouts and optimum scale of the plant based on the investigation results of item (4),
(c) To do revision of design of main structures including the intake weir, intake, waterway, surge tank, powerhouse, generating equipment with switchyard facilities, metal works of gates and penstocks, and transmission lines,
(d) To study construction schedules at basic design level,
(e) To estimate construction costs st basic design level,
(f) To confirm economic feasibility of the project, and
(g) To conduct hydraulic model tests for the surge tank.

(6) Detailed design

To do detailed design, construction schedule and cost estimate as follows.

(a) To plan preparatory works including layout of camp, workshops, warehouses, etc., and supply of electric power and water.
(b) To design access and permanent roads including bridges.
(c) To design in detail the civil work of structures including the diversion channel, intake weir, intake, headrace tunnel, surge tank, penstock line, powerhouse with tailrace, switchyard, etc.
(d) To design in detail generating equipment and auxiliary facilities.
(e) To design in detail the metal work such as gates, penstocks and valves.
(f) To design in detail the transmission line including towers and a substation including electrical equipment.
(g) To make detailed construction schedules/networks.
(h) To do construction cost estimate in detail.
(i) To study on environmental and other aspects, if necessary.

(7) Preparation of tender documents

To prepare tender documents for the following work items.

(a) Documents of pre-qualification questionnaire.
(b) Tender documents for civil works.
(c) Tender documents for generating equipment.
(d) Tender documents for metal works.
(e) Tender documents for a transmission line and a substation.
(f) Tender documents for preparatory works, access roads and bridges.

(8) Documents to be prepared

To prepare the following reports and documents.

(a) Inception report.
(b) Tender documents for field investigation of the above item (3).

- (c) Reports with data books on field investigation.
- (d) Report on design criteria.
- (e) Design report with drawings.
- (f) Cost estimate.
- (g) Implementation programme.
- (h) Tender documents for the works of the above item (7).
- (i) Quarterly progress reports.

(9) Transfer of knowledge

To effect transfer of technical knowledge to LBDA's staff and local consultants during the service period.

(10) Assistance in pre-qualification

To assist LBDA in the pre-qualification of contractors.

10.3 Feasibility Study and Stage Implementation for the Second Stage Projects

10.3.1 Feasibility Study for the Second Stage Projects

The Sondu River Multipurpose Development Project will ultimately comprise the following three independent components as described in the preceding chapters. Those are;

(1) Sondu/Miriu run-of-river hydropower project,
(2) Kano Plain irrigation project utilizing the Sondu River water, and
(3) Magwagwa dam and hydropower project.

The present status of undertaking for those projects is, however, different one another as follows.

	Undertaking completed	Undertaking followed by
Sondu/Miriu Hydropower	Feasibility	Detailed Engineering and Implementation
Kano Plain Irrigation		
(i) for 8,540 ha	Pre-feasibility	Feasibility
(ii) for 7,560 ha*	Master plan	(Feasibility)
(iii) for 10,000 ha*	Master plan	(Feasibility)
Magwagwa Dam and Hydropower	Master plan	Feasibility

* Tentative figures derived from the areas demarcated by UNDP/LOTTI study

As dealt with this study, the first stage development of the Sondu River Multipurpose Project comprised the Sondu/Miriu run-of-river hydropower project and the irrigation of 8,540 ha in Nyakach Plain.

Since the irrigation project was proven to be feasible although the study level was in pre-feasibility, the study level of the irrigation project should be graded up to feasibility study in the earliest opportunity. Moreover, the water after hydropower generation is ample for irrigating nearly 16,000 ha. In this respect, recommended for the feasibility study of the irrigation project is to incorporate the possibly extensible area of 7,560 ha with 8,540 ha dealt with this study.

The development following the first stage will be the construction of Magwagwa dam and hydropower project as the second stage. Additional firm water is to be available with this project for the further extension of irrigation area of 10,000 ha or more in Kano Plain. With this view, the feasibility study of those two Magwagwa dam and 10,000 ha irrigation projects is desired to be undertaken in a single package as a multipurpose project in appropriate time.

10.3.2 Stage Implementation

Taking into account the results of the study and probable times to be required for accomplishing the undertakings in several phases until the commission of each project, a tentative implementation schedule of those two Magwagwa and 10,000 ha irrigation projects including the first stage will be set out as follows.

	F/S*	D/D**	Construction	Commissioning
Sondu/Miriu Hydropower	1985	1987	1989-1992	1993
Kano Plain Irrigation				
(i) for 8,540	1986/87	1988/89	1991-1996	1993-1997
(ii) for 7,560	(1986/87)	(1991/92)	(1992-1997)	(1994-1998)
(iii) for 10,000	(1988/89)	(1991/92)	(1994-2000)	(1996-2000)
Magwagwa Dam and Hydropower	1988/89	1990/91	1992-1995	1996

* : Feasibility Study

**: Detailed Engineering

In this schedule, the following consideration is taken into account. The implementation of irrigation project is usually affected by the progress of construction of the tertiary and on-farm units. Especially the on-farm development should require participation of the farmers, who have the land, and land levelling and reformation sometimes. Moreover, most of the farmers are not so familiar with irrigation farming and probably need a considerable time for water management. It is, therefore, deemed practical to develop the tertiary units by 2,000 ha or so successively every year.