Substations to be extended are the Chemosit, Muhoroni and Lessos substations.

7.1.2 Construction plan

(1) Basic conditions

The construction method and sequence are planned on the basis of the mode of construction and the target schedule of construction. Availability of construction forces, weather condition, geological and topographic conditions at the site and the mechanized construction method are as well taken into consideration besides the matters mentioned above. Major plant and equipment used for construction are listed in Table 7.1.

The commencement of the construction works is scheduled in July, 1997 after the contract award. The project is planned to be completed by the end of December, 2002 using information and data available at this moment, giving a time period of 5.5 years (66 months). Preparation of a more realistic construction schedule, i.e. shortening of the construction time period, will rely on the structural drawings prepared in the Detailed Design Stage.

With regard to the workable days, 260 days are assumed in a year for concrete facing works and earthworks. While, workable days for concrete, grouting and tunnel works are planned to be 290 days per year.

(2) Preparatory works and construction facilities

(a) Access road

Since there are no available roads to the main dam site, the power station site, the portal of the drain tunnel and the surge tank in terms of construction works, the permanent access roads are planned to be connected from the existing road, C-22 Route. A total length of the access roads to be constructed is 4,000 m. Temporary access roads required for the construction services will be branched off the permanent access road, C-22 Route.

(b) Temporary buildings

The temporary buildings required for the construction works are planned to be provided mainly at the main dam site and the power station site. The

temporary buildings consist of a contractor's office, quarters, a repair shop, a steel workshop, a warehouse, labour quarters and so forth, requiring about 15,000 m^2 in a total floor area.

(c) Water supply

Water required for the construction and the base camp is planned to be taken from the Sondu River and other nearby tributaries. Water supply facilities will be required separately at the main damsite and the power station site, requirements of which are to be 5.0 m^3/min and 4.5 m^3/min, respectively.

(d) Power supply

Electric power for the construction is at this moment planned to be supplied with a diesel generator of 1,600 kW for the main damsite and 3,300 kW for the powerhouse site to carry out civil works, metal works and generating equipment installation works, taking into account high power demands without break for construction. Meanwhile, electric power to the base camp is planned to be supplied from the existing 33 kV distribution line by extension. It is however noted that the studies to seek power supply sources for construction should be re-examined in the detailed design taking into account the availability of electric power in the grid at that time.

(e) Telecommunication

Wired telephone facilities will be provided for the construction use, and an automatic telephone exchange of 50 circuits will be installed at the contractor's office.

(3) River diversion and cofferdam

River diversion for the construction of main dam is planned to be carried out by the diversion tunnel method. Construction works for the diversion tunnels and the cofferdam `are on the critical path of the construction schedule. Two concrete-lined diversion tunnels with the dimensions of 6.2 m in a diameter and 1,291 m in a total length will be driven in 8 months of 1998. A full-face attack method is applied for the tunnel excavation and a driving rate is to be 80 m per month. Rocks will be drilled by 9-boom drill jumboes and the broken rocks will be loaded by 0.6 m^3 side-muck loaders into 8 ton dump trucks.

An arch and then invert method is planned to be applied for concrete lining and its progress rate is to be 126 m per month with 10.5 m sliding forms. Concrete will be transported by 3.2 m^3 agitator trucks from the 0.75 m^3 x 2 concrete plant and will be placed behind the 10.5 m sliding forms by means of a 60 m^3/hr concrete pump car.

Succeeding the completion of two diversion tunnels, the upstream primary cofferdam will be constructed, and river water will be diverted into the No. 1 and No. 2 diversion tunnels in February, 1999.

Second river diversion is planned to be made by closing the No. 2 diversion gate in August, 2001 of the dry season before starting the river outlet works. Plug concrete placed in the No. 2 diversion tunnel burying the steel pipe and valve will be carried out by May, 2002. Plug concrete of the No. 1 diversion tunnel will be placed after the closure of the No. 1 diversion gate and the construction of the access tunnel driven from the No. 2 diversion tunnel.

The zoned rockfill type cofferdam of 224,600 m^3 in embankment volume is planned to be built between the upstream primary cofferdam and the main dam after a dry space is secured for constructing the cofferdam by releasing river water through the diversion tunnels. The cofferdam will be constructed prior to the embankment of main dam and the construction of toe slab concrete. Impervious earthfill materials will be hauled by 11 ton dump trucks from the borrow area and compacted by 13.5 ton tamping rollers. Rockfill and riprap materials will be obtained from the quarry and hauled by 32 ton dump trucks.

(4) Main dam

All works of the main dam, which is the concrete facing rockfill type, are scheduled to be performed for a period of 4 years from 1999 to 2002. The following are the main works for the dam construction:

(a) Foundation excavation

Excavation works are scheduled to be performed for 1 year of 1999 in parallel with the rockfill embankment and toe slab concrete works. The excavation of common and weathered rock will be carried out using 32 ton bulldozers with the ripper, 5.0 m^3 wheel loaders and 32 ton dump trucks. Trench excavation of rock for toe slab concrete will be made using 10 m^3/min

crawler drills and 30 kg jack hammers for drilling and blasting, 0.6 m^3 backhoes and 11 ton dump trucks. The foundation will be cleaned using hand tools and skips as the final treatment.

(b) Embankment

The embankment of rockfill is scheduled to be carried out for a period of 18 months from July, 1999 to December, 2000. The embankment volume of 3,911,000 m^3 is planned to be obtained from quarried rock of 3,611,000 m^3 and stockpiled rock of 300,000 m^3. The quarried rock excavation is planned to be done by the 7.5 m to 10 m high bench-cut method. Rock will be drilled by 15 m^3/min crawler drills and loaded by 5.0 m^3 wheel loaders into 32 ton dump trucks. At the embankment site, materials will be spread by 21 ton bulldozers and compacted by 15 ton vibrating rollers.

The transition embankment zone is planned to be placed between the rockfill zone and the concrete face slab. Transition zone materials, the volume of which is 143,600 m^3 with a size smaller than 150 mm in diameter, will be transported from the quarry site and be produced by 100 ton crushing plants. The materials will be spread by 11 ton bulldozers and compacted by 10 ton vibrating rollers. The upstream slope of the transition zone will be shaped by 0.6 m^3 backhoes, and compacted by the 10 ton vibrating roller pulled by 30 ton crawler cranes. And then, the slope will be protected with asphalt prime coat using the 1,000 litre distributor pulled by the 2 ton winch.

Riprap materials, supplied from the quarry site, will be handled by 0.6 m^3 backhoes on the slope of rockfill and all voids will be filled with smaller rock fragments.

The impervious earthfill zone of 68,600 m^3 is planned to be provided on the toe concrete slab and the main concrete face slab. Earthfill materials will be placed for 6 months from December, 2001 to May, 2002, in parallel with backfill works of 232,000 m^3. Impervious materials will be transported from the borrow area and backfill materials will be obtained from the spoil bank.

Embankment works of rock above El. 1,665 m will be carried out from May to August 2002 after the completion of the parapet wall. Following the last stage of rock embankment, the road pavement works will be performed.

(c) Foundation treatment

Consolidation grouting of 2,800 m and curtain grouting of 41,200 m will be carried out for 18 months in parallel with toe concrete slab works. Holes for the injection of consolidation grout will be drilled with 7 m^3/min crawler drills and 5.5 kW rotary boring machines. Curtain grout holes will be drilled by 5.5 kW and 11 kW rotary boring machines. Cement grout will be mixed at the central plant, delivered to 200 litre x 2 grout mixer installed at work site and injected by 7.5 kW and 11 kW grout pumps.

(d) Concrete face slab

Toe slab concrete will be placed in the rock trench portion in advance of rockfill embankment. Concrete will be transported from the 0.75 m^3 x 2 concrete plant and placed by 60 m^3/hr concrete pump cars.

Filler slab concrete works are scheduled to be performed for 4 months from November, 2000 to February, 2001 before the commencement of main slab concrete works. A temporary access road will be constructed on the dam abutment for transporting concrete and placing reinforcement mat and concrete. The reinforcement mat of 7.5 m x 6 m will be handled by 30 ton crawler cranes, and concrete will be placed by 60 m^3/h concrete pump cars. Concrete on the slope will be placed by means of the 7.5 m wide slipforms pulled by the winch-truck stationed at the dam crest.

Following filler slab concrete works, the main slab of 15 m wide is scheduled to be placed for a period of 12 months between March, 2001 and February, 2002 from the bottom elevation of toe slab to the parapet wall elevation of El. 1,665.50. Mortar pads of 600 mm wide will be provided at the slab joints to install steel waterstop.

The reinforcement mat with the dimensions of 15 m x 6 m will be transported by reinforcement trolleys and installed upwards from the bottom. Slab concrete will be placed by means of 15 m wide slipforms with a curing trolley.

One concrete plant is planned to be provided only for the main slab concrete works, since the concrete operation is continuous for several days. Concrete will be produced by the 0.75 m^3 x 2 concrete plant located at the dam

abutment and transported by 4.5 m^3 agitator trucks to the top of embankment. And then, concrete will be carried through delivery chutes to the slipform equipment. The reinforcement trolley and slipform will be shifted to another block using transfer trolley provided on the top of embankment.

After the completion of the main slab, parapet wall concrete will be placed for 6 months from January to June, 2002. The concrete will be placed by 60 m^3/hr concrete pump cars.

Concrete aggregates including sands will be produced by the 100 ton/hr crushing plant built on the main dam access road, raw materials for which will be obtained from the tunnel fragment stockpiles.

(5) Saddle dam

The saddle dam is planned to be a homogeneous earthfill type, the embankment volume of which is estimated at 409,900 m^3. The construction time period including foundation excavation is scheduled to be 14 months from March, 2000 to April, 2001. Impervious earthfill materials will be hauled from the borrow area using 21 ton bulldozers, 2.3 m^3 tractor shovels and 11 ton dump trucks. The materials will be spread by 11 ton bulldozers and compacted by 13.5 ton tamping rollers with a 15 ton tractor.

(6) Spillway

Excavation works of 982,700 m^3 will be performed in parallel with the foundation excavation of the main dam in 1999. Excavated rock materials will be hauled to the stockpile and will be used for rock embankment materials. The excavation works will be carried out using 10 m^3/min crawler drills, 32 ton bulldozers with a ripper, 5.0 m^3 wheel loaders and 32 ton dump trucks.

Concrete works of 46,300 m^3 are scheduled to be carried out for 2 years from September, 1999 to August, 2001. The concrete will be produced by the other 0.75 m^3 x 2 concrete plant built at the dam abutment, which will be used for the concrete works of intake tunnel, headrace tunnel, intake gate shaft and so on as well. Concrete placement will be carried out using 3.2 m^3 agitator trucks, 60 m^3/hr concrete pump cars and 1.0 m^3 concrete buckets with a 30 ton truck crane.

(7) River outlet

Such river outlet facilities as the hollow jet valve and the steel pipe are planned to be installed in the middle portion of the No. 2 diversion tunnel. Succeeding the closure of the No. 2 diversion gate, intake concrete plug and intake tower structure will be constructed in 2001. Also, chamber excavation, steel pipe installation, plug concrete placement, installation of the hollow jet valve and so forth are scheduled to be completed by May, 2002.

The No. 1 diversion gate is scheduled to be closed in June, 2002 and the access tunnel will be connected to the chamber from the No. 1 diversion tunnel before the commencement of concrete plug works.

The installation of gate leaves, guide frames, hollow jet valve, steel conduit and trashracks for the river outlet facilities is scheduled to be carried out for 10 months from August, 2001 to May, 2002 taking into consideration the progress of civil works.

(8) Intake and intake tunnel

The intake tunnel of 500 m long is designed upstream of the headrace tunnel, of which tunnel excavation and concrete lining works will be carried out as part of the headrace tunnel works. Open excavation works of 19,400 m^3 are scheduled to be performed for 2 months.

(9) Headrace tunnel

A circular type tunnel with reinforced concrete lining has the dimensions of 5.4 m in diameter and 6,690 m long. Two work adits of 4.5 m wide and 490 m long will be constructed by mid 1998 prior to the construction commencement of the headrace tunnel. The work adit No. 1 is planned to be an inclined type and to be driven 4,000 m downstream of the portal of the intake tunnel. The other work adit No. 2 will be driven 40 m upstream of the downstream end of the headrace tunnel and will work as a drain tunnel after the completion of construction.

The tunnel excavation works including the intake tunnel are scheduled to be 2 years from July, 1998 to June, 2000. A full-face attack method is recommended to apply for driving the tunnel, while hauling of broken rocks is by the rail method. Three tunnel faces are planned to be attacked simultaneously using three sets of

tunnel equipment crew. A driving rate is planned to be 110 m per month for each face. Drilling works will be carried out using 7-boom drill jumboes. Broken rocks will be loaded by 0.4 m^3 muck loaders into 6 m^3 muck cars with a 10 ton battery locomotive for hauling. The broken rocks carried to the open yard by those equipment will be loaded by 1.2 m^3 tractor shovels into 8 ton dump trucks and will be carried to the spoil bank.

Concrete lining works are scheduled to be performed for 23 months from April, 2000 to February, 2002. A full circular method is recommended to apply for concrete lining, and three sets of sliding steel forms with a travelling needle beam will be provided. Concrete lining is planned to progress at a rate of 126 m per month with a 10.5 m long sliding form. Concrete will be transported from two concrete plants. One is 0.75 m^3 x 2 concrete plant built at the main dam site and the other is 1.0 m^3 x 2 concrete plant at the power station site. The concrete will be transported by 3.2 m^3 agitator trucks from the concrete plants to the tunnel portals, discharged into 6 m^3 pneumatic placers with an 8 ton battery locomotive, and placed behind the 10.5 m long sliding form by the pneumatic placers.

Following the completion of concrete lining works at each section, backfill grout, consolidation grout and curtain grout will commence in April, 2001 and continue by March, 2002. Mortar of backfill grout will be injected into voids and spaces using 11 kW low pressure grout pumps. Consolidation grout holes will be drilled using 2.7 m^3/min leg drills and 5.5 kW rotary boring machines. Cement grout will be mixed at the portable grout plant in the tunnel, delivered to 200 litre x 2 grout mixers and injected by 7.5 kW grout pumps.

(10) Intake gate shaft

The intake gate shaft is planned to be 8.4 m in diameter and 65.8 m high, and located 500 m downstream of the intake tunnel portal. Shaft excavation will be carried out for 5 months from April to August, 2000 after the completion of headrace tunnel excavation.

A pilot shaft of 2 m x 2 m will be driven by the raise climber machine upward from the bottom and then the shaft will be enlarged downward. Drilling of rock will be carried out using 2.7 m^3/min stoper drills for the pilot shaft, and 7 m^3/min crawler drills and 2.4 m^3/min jackhammers for enlargement. Broken rocks will be gathered into the pilot shaft using 0.4 m^3 tractor shovels. Mucking will be made using 0.4 m^3 muck loaders and 6 m^3 muck cars through the intake tunnel.

Concrete works including initial lining and shaft structures are scheduled to be performed for 8 months from September, 2000 to April, 2001.

Concrete lining works will be carried out from the shaft bottom. Concrete will be discharged into 1 m^3 buckets from 3.2 m^3 agitator trucks, handed to the concrete hopper by 30 ton truck crane and distributed into the placing spots through the chute. The concrete works will be completed prior to the metal works.

The gate leaves, the guide frames, the trashracks, the hoists and the necessary accessories for the intake gate will be fabricated to sub-assembly units at the contractor's factory. The sub-assemblies delivered to the project site will further be carried to the installation site by 20 ton trailers and handled by 30 ton truck cranes.

(11) Surge tank

The surge tank shaft is planned to be 18 m in diameter and 95.6 m high, and is located at the end of the headrace tunnel. Shaft excavation works including drilling of the pilot shaft and enlargement of the shaft and the bottom of tunnel are scheduled to be carried out for 11 months from July, 2000 to May, 2001. Concrete lining including lining at the bottom of tunnel will subsequently be carried out for 7 months in 2001.

Open excavation will be carried out using 10 m^3/min crawler drills, 21 ton bulldozers with a ripper, 2.3 m^3 tractor shovels and 11 ton dump trucks. The pilot shaft of 2 m x 2 m will be excavated upward from the bottom at the centre of shaft using 2.7 m^3/min stoper drills mounting the raise climber. After drilling the pilot shaft up, enlargement to the full shaft diameter will be made by drilling and shooting with 7 m^3/min crawler drills and 2.4 m^3/min jackhammers. Broken rocks will be dropped into the pilot shaft using 0.3 m^3 backhoes and loaded out using 0.4 m^3 muck loaders, 6 m^3 muck cars, 1.2 m^3 tractor shovels and 8 ton dump trucks.

Concrete lining works will be made upward from the shaft bottom after the completion of shaft enlargement. Concrete placed with 1.2 m lift will be discharged into 1 m^3 buckets from 3.2 m^3 agitator trucks, handed to concrete hoppers by 1 m^3 buckets with a 30 ton truck crane and distributed into the placing spot through the chute.

(12) Penstock

The steel penstock of 198 m long with a diameter varying 4.4 m to 2.1 m after bifurcation consists of the upper horizontal tunnel portion of 24 m long, the vertical shaft portion of 134 m long and the lower horizontal tunnel portion of 40 m long. Tunnel and shaft excavation works will be performed for 8 months from April, 1991. Concrete works including tunnel lining and backfill concrete around the steel penstock are scheduled in 2001.

Upper tunnel excavation and concrete works will be executed in a similar way to the headrace tunnel. The vertical shaft works will be divided into the pilot shaft of 2 m x 2 m and the enlargement portion. The pilot shaft will be excavated upward from the lower horizontal tunnel bottom using 2.7 m^3/min stoper drills with a raise climber. Enlargement to the full shaft diameter will be made by drilling and shooting with 2.4 m^3/min jackhammers. Broken rocks will be loaded by 0.6 m^3 dump loaders into 4 ton dump trucks and hauled through the bifurcation access tunnel and the powerhouse access tunnel.

Backfill concrete around the steel penstock will be placed upward from the shaft bottom in parallel with the steel penstock installation. Concrete will be transported from the headrace tunnel by 3 m^3 agitators and discharged into 1 m^3 buckets with a 200 kW winch. As for the lower horizontal tunnel, the bifurcation chamber and the branch penstock tunnel, concrete will be transported by 3.2 m^3 agitator trucks from the access tunnel and placed by 45 m^3/hr concrete pumps.

Penstock metal works are scheduled to be performed in a period of 9 months from May, 2001 to January, 2002. Before starting instillation works, preparatory works of 3 months will be required for all the metal works.

The steel plates transported from the Mombasa port to the stock yard of the project will be welded by automatic welding machines into 6 m long penstock segments at the site workshop. Each pipe segment will be transported to the installation site by 20 ton trailers. The penstock installation in the tunnel will be carried out by transporting penstock-unit by rail-mounted carriers, while a 200 kW winch with the platform will be used for the vertical penstock portion.

(13) Power station

The powerhouse of underground-type reinforced concrete structure with the cavern dimensions of 60 m long, 22 m wide and 38 m high is constructed to accommodate two 60 MW Francis type turbines and two 66.8 MVA generators. The power station works consist of an access tunnel, a cable tunnel, an underground powerhouse, a gate chamber, a tailrace surge tank and an outdoor switchyard. The following are the main works for the power station construction:

(a) Access tunnel

A main access tunnel of 7 m wide and 6 m high is planned to be drilled for reaching the generator floor level of the powerhouse, being 900 m long and 10% in gradient. Access tunnels to respective structures will be branched off the main access tunnel for the construction use of the underground powerhouse, i.e. the access to gate chamber of 130 m long, the access to cavern roof of 80 m long, the access to the roof of tailrace surge tank of 80 m long and the access to penstock bifurcation chamber of 250 m long. All of the construction access tunnels are to be 4 m wide and the gradient is within 10%.

The access tunnel will be constructed in 1998 and 1999, considering the construction schedule of the permanent underground structures. All of excavation for the access tunnels will be made by means of the dump-truck method and the full-face attack method. A driving rate is planned to be 80 m per month for each access tunnel. Drilling works will be carried out using 7-boom truck-mounted drill jumboes. Broken rocks will be loaded by 0.6 m^3 side-muck loaders into 8 ton dump trucks for hauling to the spoil bank.

(b) Cable tunnel

An inclined cable tunnel of 120 m long and 30% in gradient is planned to be located 350 m inside from the access tunnel entrance. The cable tunnel is to be a vertical wall and arch roof type concrete lined tunnel of 2.5 m wide and 2.5 m high.

The tunnel excavation works and the concrete lining works will be carried out for 4 months from June 1999. A full-face attack method is applied for driving the inclined tunnel and the hauling of broken rocks is by the rail

method with an inclined winch. The driving will be made by 2.7 m^3 leg drills with a portable deck. Broken rocks will be loaded by 0.2 m^3 inclined muck loaders into 3 m^3 muck cars with a 100 kW winch. The concrete lining works will be made by 45 m^3/hr concrete pump cars provided at the both sides of the tunnel entrance and in the main access tunnel.

(c) Underground powerhouse

The powerhouse structure is scheduled to be completed by December 2000 before the commencement of the installation of overhead travelling crane. The first stage of construction consists of cavern excavation, placement of substructure concrete, installation of the draft tubes and placement of the second concrete for them. The second stage consists of construction of the superstructure, installation of the overhead travelling crane and casing, placement of the second concrete and installation of the turbines and generators.

Excavation of the powerhouse cavern will be performed for 11 months from December, 1997 and completed by November, 1991 before the concrete works of substructure. The cavern will be excavated conventionally downward from the roof of the initial access tunnel driven off the main access tunnel.

Roof heading of 56 m long, 6 m wide and 7 m high will be driven along the powerhouse centre. Both of the slides will be slashed out in 3 m heading width to expose the roof of powerhouse. Drilling will be made using 2 boom crawler jumboes and broken rocks will be loaded by 1.4 m^3 side dump tractor shovels into 8 ton dump trucks. Immediately after exposing the surface of the roof rock, rock bolting, shotcreting and PC anchoring are planned for protecting it.

After the completion of roof cavern excavation, the walls will be then presplitted, and then the remaining cavern portion will be benched down. The bench-cut excavation will be carried out with 1.5 m bench height using 10 m^3/min crawler drills, 21 ton bulldozers with rippers, 0.6 m^3 backhoes, 1.4 m^3 side-dump tractor shovels and 8 ton dump trucks. Rock bolting, shotcreting and PC anchoring will be carried out for each benching-down.

Excavation works between El. 1,472.00 m and El. 1,457.00 m will be made with the similar bench-cut method and broken rocks will be hauled through the main access tunnel. The shaft enlargement method is planned to be applied below El. 1,457.00 m. Two pilot shafts will be provided for the mucking. Broken rocks will be hauled through the tailrace tunnel. Shaft excavation and enlargement will be carried out in a similar way to the surge tank.

Concrete works of the substructure will be carried out using 3.2 m^3 agitator trucks, 60 m^3 concrete pump cars and 1 m^3 buckets with a temporary 10 ton overhead crane. Concrete will be transported to the powerhouse through the main access tunnel. One concrete plant with a 1.0 m^3 x 2 mixer will be installed for the construction of power station, headrace tunnel, penstock, surge tank and tailrace tunnel.

Following the concrete placement to the substructures, draft tube installation, concrete placement to other structures and the second concrete placement to the draft tubes, an overhead travelling crane is scheduled to be provided in January, 2001 to install the casings, turbines and generators. The powerhouse building works will be performed in parallel with the instillation of turbines and generators.

(d) Gate chamber

The concrete lined gate chamber of 3 m wide, 3.5 m high and 25 m long is planned to be located between the powerhouse and the tailrace surge tank. Two shafts of 4 m x 1 m and 20 m high will be provided at the gate chamber. Excavation works will be performed for 2 months from mid-August, 1999. While, the concrete lining works are scheduled to be carried out for 3 months from December, 1999. Drilling works for the gate chamber will be carried out using 2.7 m^3/min leg drills with a portable deck. Shaft excavation will be made upward from the bottom using 2.4 m^3/min stoper drills. Broken rocks will be loaded and carried by 1.4 m^3 side-dump tractor shovels to the access tunnel, and then loaded into 8 m^3 agitator trucks through the access tunnel and placed by 45 m^3/hr concrete dumps.

(e) Tailrace surge tank

The underground tailrace surge tank of 23 m in diameter and 26 m high is planned to be located 50 m downstream from the gate chamber. Excavation works including the cavern roof, the pilot shaft and the enlargement of shaft are scheduled to be carried out for 2 months from mid-May, 1999. Concrete lining including lining at the bottom of tunnel will be carried out for 3 months from December 1999.

Access to the surge tank roof will be provided to connect to the main access tunnel. The roof cavern will be excavated and protected in a similar way to the excavation works carried out for the roof cavern of powerhouse. Enlargement of the pilot shaft will be made in a similar way to that of the surge tank, and broken rocks will be hauled through the tailrace tunnel.

(14) Tailrace tunnel

A circular type tunnel with reinforced concrete lining has the dimensions of 5.4 m in diameter and 1,850 m long. Tunnel excavation works are scheduled to be carried out in about 1.5 years from January, 1998 to May, 1999. A full-face attack method is recommended to apply for driving the tunnel, while hauling of broken rocks is by the rail method. The driving will be carried out by one heading from the downstream portal. Drilling and mucking are performed in a similar way to those of the headrace tunnel.

Concrete lining works are scheduled to be performed for 15 months from June, 2000 to August, 2001 after the completion of gate chamber concrete works. A full circular method is recommended to apply for concrete lining, and one set of sliding steel form with the travelling needle beam will be provided. Concrete lining works and grouting works are carried out with the same method applied for the headrace tunnel concrete works.

7.1.3 Construction schedule

(1) Project schedule

The target date for the commissioning of generating equipment is planned to be January, 2003. Main construction works of the Project are planned to be 5.5 years from July, 1997 to December, 2002, while 11 years will be required for the Project after the completion of the feasibility study as shown in Figure 7.1. The financial

arrangement required for the detailed design stage and the construction work stage shall be made by the Kenya Power Co., Ltd.

The following basic schedule shall be kept in order to secure the commissioning target of the Project:

(a)	Financial arrangement for the detailed design	:	10 months from November 1991 to August 1992
(b)	Selection of a consultant for the detailed design	:	3 months from September 1992 to November 1992
(c)	Detailed design and preparation of tender documents	:	24 months (2 years) from December 1992 to November 1994
(d)	Financial arrangement for construction works	:	12 months (1 year) from December 1994 to November 1995
(e)	Selection of a consultant for construction works	:	6 months from December 1995 to May 1996
(f)	Tender and contract including prequalification	:	13 months from June 1996 to June 1997
(g)	Main construction works	:	66 months (5.5 years) from the commencement of July 1997 to the completion of December 2002
(h)	Commissioning of the commercial operation	:	Beginning of January 2003.

(2) Construction schedule

Figure 7.1 shows the construction schedule of the Project. The land acquisition and compensation for the Project will be settled by the Kenya Power Co., Ltd. prior to the commencement of the construction. The work schedule for the major items are summarized by year as follows:

1997

(a) Award of contracts for civil works including preparatory works
(b) Mobilization and construction of site facilities
(c) Construction of the base camp and the access roads
(d) Excavation of the diversion tunnels and work adits
(e) Excavation of the tailrace tunnel and the access tunnel

1998

(a) Excavation and concrete works of the diversion tunnels
(b) Excavation of the intake tunnel and the headrace tunnel
(c) Excavation and concrete works of the work adits
(d) Excavation of the tailrace tunnel
(e) Excavation of the access tunnel
(f) Excavation of the cable tunnel
(g) Excavation of the underground powerhouse
(h) Construction of the base camp and the access roads

1999

(a) Award of contracts for the metal works, the generating equipment, the transmission lines and the substation equipment
(b) River diversion
(c) Excavation and embankment of the cofferdam
(d) Excavation, embankment, grouting and toe concrete works of the main dam
(e) Excavation and concrete works of the spillway
(f) Excavation of the headrace tunnel
(g) Excavation of the tunnel and the shaft
(h) Excavation of the tailrace tunnel
(i) Excavation of the access tunnel
(j) Excavation and concrete works of the cable tunnel
(k) Excavation and concrete works of the underground powerhouse
(l) Excavation of the gate chamber
(m) Excavation and concrete works of the tailrace surge tank

2000

(a) Embankment and grouting works of the main dam
(b) Concrete works of the toe slab and the filler slab for the main dam
(c) Excavation and embankment works of the saddle dam
(d) Excavation and concrete works of the spillway
(e) Excavation and concrete works of the headrace tunnel
(f) Excavation and concrete works of the intake gate shaft
(g) Excavation of the surge tank
(h) Concrete works of the tailrace tunnel
(i) Concrete works of the powerhouse including its second concrete around the draft tube
(j) Concrete works of the gate chamber

(k) Concrete works of the tailrace surge tank
(l) Excavation of the switchyard
(m) Architectural building works
(n) Installation of the draft tube
(o) Civil works for the transmission lines

2001

(a) Gate closure of the No. 2 diversion tunnel
(b) Concrete facing works of the main slab for the main dam
(c) Embankment of the saddle dam
(d) Concrete works of the spillway
(e) Construction of the river outlet
(f) Concrete and grouting works of the headrace tunnel
(g) Concrete works of the intake gate shaft
(h) Excavation and concrete works of the surge tank
(i) Installation of the steel penstock pipe in parallel with plug concrete
(j) Concrete and grouting works of the tailrace tunnel
(k) Works of second concrete for the powerhouse
(l) Concrete works of the outdoor switchyard
(m) Excavation and concrete works of the outlet channel
(n) Building works
(o) Implementation of metal works including the intake and the river outlet facilities
(p) Installation of the overhead crane and the casings
(q) Installation of the generating equipment and the switchgears
(r) Erection of the transmission lines
(s) Installation of the substation equipment

2002

(a) Gate closure and plug concrete of the No. 1 diversion tunnel and dam impounding
(b) Earthfill and embankment works of the main dam
(c) Concrete facing works of the main slab for the main dam
(d) Concrete works of the parapet wall
(e) Construction of the river outlet
(f) Concrete and grouting works of the headrace tunnel
(g) Plug concrete of the work adits
(h) Installation of the generating equipment and the switchgears

(i) Building works
(j) Installation of the river outlet facilities
(k) Installation of the steel penstock pipe
(l) Erection of the transmission lines
(m) Installation of substation equipment
(n) Commissioning tests
(o) Demobilization.

7.2 Cost Estimates

7.2.1 Introduction

Construction costs for the Project are estimated on the basis of the preliminary design. Unit prices for each work item are established considering local conditions, available construction equipment and materials and suitability of the construction method and referring to similar international projects.

The foreign and local currency portions of the project costs are estimated on basis of US Dollar and Kenya Shilling respectively, and the foreign currency portion expressed in US Dollar is converted to Kenya Shilling for assessing the total cost.

Assumptions and conditions applied for the cost estimate are as follows:

(a) Price level : Price as of November, 1990

(b) Exchange rate : US Dollar 1.00 = Kenya Shilling 23 = Japanese Yen 140 (or KShs. 1.00 = Yen 6.09)

(c) Work quantity : Quantities estimated from the preliminary design for the work items given in Table 7.9.

(d) Construction works will be carried out by the contractor selected through an international competitive bidding.

(e) Construction costs are divided into direct construction cost and indirect construction cost. The direct construction costs (contract cost) are the cost for preparatory works, civil works, metal works, generating equipment, transmission lines and substation equipment. While, the indirect construction

costs are the ones required for land acquisition and compensation, administration expenses, engineering services and contingencies.

7.2.2 Preparatory works

Costs for the preparatory works comprise of the costs for insurance of works, temporary buildings, water supply system, electric power supply system, telecommunication system, provision of medical facilities, operation of medical services, inland transportation, testing laboratory and temporary access roads. The cost for preparatory works is estimated at 10 percent of the sum of civil works.

7.2.3 Civil works

The costs of civil works are estimated by adopting unit rates including labour cost, material cost, equipment cost and contractor's overhead expenses and profits.

(1) Labour cost

Wages obtained in Kisumu and Nairobi (refer to Table 7.2) are based on the direct daily wages in an 8-hour shift of labour.

(2) Material cost

Most of construction materials are supplied from local markets, and therefore the local material prices were canvassed in Kisumu and Nairobi as shown in Table 7.3. These local material prices include local net price, inland transportation, duties and value added tax, i.e. the purchase price at the project site. The imported materials which are not available in local markets are estimated on the exemption of import duties and taxes.

(3) Equipment cost

Equipment and plant for the construction will be provided by the contractor. Referring to prevailing prices in Japan as of November, 1990, the prices of equipment itself are estimated based on the CIF price in Mombasa. The duties and taxes charged for the import of equipment are excluded in this cost estimate.

The equipment cost is divided into foreign and local portions. The foreign currency portion mainly includes the costs of depreciation, spare parts and consumable, while the local currency portion includes the cost of mechanic labour, the cost for

the repair and maintenance and administration expenses. The costs of equipment required for the project are listed in Table 7.4.

(4) Contractor's indirect cost

Overhead expenses and profits are contributed to the unit rates of each work item. These expenses are estimated at 25 percent of the direct cost including labour cost, material cost and equipment cost.

(5) Unit price

The unit prices for each work item are estimated in accordance with the above conditions as shown in Table 7.9.

(6) Bill of quantities

Cost estimates of civil works are based on the work quantity obtained from the preliminary design of the following structural components:

- Diversion tunnel
- Cofferdam
- Main dam
- Saddle dam
- Spillway
- River outlet
- Waterway (Intake & intake tunnel, Headrace tunnel, Intake gate shaft, Surge tank, Work adits, Penstock and Tailrace tunnel)
- Power station (Access tunnel, Cable tunnel, Underground powerhouse, Gate chamber, Tailrace surge tank and Outdoor switchyard)
- Outlet channel
- Architectural building
- Access road
- Base camp.

7.2.4 Metal works

The prices for metal works are based on the recent international contract prices of similar works. The cost of imported equipment and materials is estimated at the CIF price in Mombasa excluding import duties and taxes. Costs for supply and delivery of imported items, ocean freight and insurance are included in the foreign currency portion. Costs for

unloading and other charges at the port and for inland transportation are estimated in the local currency portion. Installation costs are portionally shared by the foreign and local portions. Structural components to estimate the cost of metal works are as follows:

- Diversion gate
- River outlet valve
- River outlet trashracks
- Intake trashracks
- Intake gate
- Drain valve
- Steel penstock
- Draft tube gate
- Tailrace gate.

7.2.5 Generating equipment

Price estimates of generating equipment are the same as those of metal works. Cost components of generating equipment are as follows:

- Turbines
- Generators
- Transformers
- Switchgear and control equipment
- Supervisory equipment
- Ancillary equipment
- Miscellaneous equipment
- Transmission line protective relays
- PLC communication.

7.2.6 Transmission line and substation equipment

The prices for tower materials, conductors and substation equipment are estimated at the CIF price in Mombasa excluding import duties and taxes. Civil works such as site clearance, earthwork and foundation treatment are included in the transmission line cost. Other conditions to estimate the foreign and local portions are the same as those of metal works. Following are the transmission line routes and substations to estimate the construction cost:

- Transmission line	Magwagwa	- Sondu/Miriu
	Magwagwa	- Chemosit
	Magwagwa	- Muhoroni
	Muhoroni	- Lessos
- Substation equipment	Chemosit substation	
	Muhoroni substation	
	Lessos substation.	

7.2.7 Land acquisition and compensation

All required land acquisition and compensation shall be carried out by Kenya Power Co., Ltd. along with the project implementation schedule. Those costs include the costs required for the acquisition of the reservoir and construction areas, transmission line routes, and road alignment as shown in Table 7.5.

7.2.8 Administration expenses

An allowance of 0.5 percent of the direct construction cost is provided for the executing agency of Kenya Power Co., Ltd., which is a part of the local currency portion.

7.2.9 Engineering services

The cost of engineering services for the detailed design including the preparation of tender documents is estimated based on the assumed man-months (Expatriate 238 M/M, Local 116 M/M). As for construction supervision, the engineering services cost is estimated at 7 percent of the sum of direct construction cost, sharing the foreign currency portion of 85 percent and the local currency portion of 15 percent.

7.2.10 Contingencies

Contingencies are provided to cope with unforeseen physical conditions (physical contingency) and inflation (price escalation). The rate of physical contingency is assumed at 10 percent of an amount required for preparatory works, civil works, administration expenses and engineering services, while 5 percent for metal works, generating equipment, transmission lines and substation equipment.

The cost of price escalation is estimated over a period of 11 years from 1992 to 2002 applying the inflation rates of 2 percent per annum for the foreign currency portion and 10 percent per annum for the local currency portion.

7.2.11 Construction cost

The construction cost of the project excluding price escalation is estimated at KShs. 7,555 million (US$328.48 million) equivalent in total, consisting of KShs. 4,963 million in the foreign currency portion (US$215.78 million, 65.7%) and KShs. 2,592 million in the local currency portion (34.3%).

The total construction cost of the project including price escalation is estimated at KShs. 11,478 million (US$499.03 million) equivalent in total, consisting of KShs. 5,921 million equivalent in foreign currency portion (US$257.45 million, 51.6%) and KShs. 5,556 million in local currency portion (48.4%). The following show the summary of the total construction cost, and further details are referred to in Tables 7.6, 7.7 and 7.9:

	Foreign Currency (1,000 US$)	Local Currency (1,000 KShs.)	Total Equivalent (1,000 KShs.)
Direct cost	176,999.24	1,542,713	5,613,696
Land acquisition	0	804,000	804,000
Administration expenses	0	28,068	28,068
Engineering services	21,477.00	63,048	557,019
Physical contingency	17,307.98	154,135	552,219
Subtotal	215,784.22	2,591,964	7,555,001
			(US$328.48 million)
Price escalation	41,662.07	2,964,499	3,922,727
Total	257,446.29	5,556,463	11,477,728
			(US$499.03 million)

7.2.12 Annual disbursement schedule

Annual disbursement of the construction cost for the foreign and local currencies is estimated on the basis of the construction schedule and is summarised below, and a further detailed disbursement schedule is tabulated in Table 7.8:

Year	Foreign Currency (1,000 US$)	Local Currency (1,000 KShs.)	Total Equivalent (1,000 KShs.)
1992	788.72	522	18,663
1993	4,018.99	2,868	95,305
1994	3,279.92	2,524	77,962
1995	0	494,396	494,396
1996	0	815,738	815,738
1997	27,837.86	478,604	1,118,875
1998	24,497.32	485,876	1,049,314
1999	56,095.76	758,533	2,048,736
2000	56,897.22	1,060,239	2,368,875
2001	68,412.71	1,109,614	2,683,106
2002	15,617.79	347,549	706,758
Total	257,446.29	5,556,463	11,477,728

VIII. PROJECT EVALUATION

8.1 Introduction

This Chapter deals with not only the economic evaluation of the Magwagwa project itself as a hydropower project, but also that of combined development of projects, i.e. combination of three projects of the Magwagwa, the Sondu/Miriu and the Kano for hydropower and agriculture development and combination of two projects of the Magwagwa and the Sondu/Miriu for the full development of hydropower potential in the Sondu River, in Section 8.2. Furthermore, financial viability of the Magwagwa project is discussed in Section 8.3, and a brief description of the overall evaluation of the project is finally given in Section 8.4.

8.2 Economic Evaluation

8.2.1 Integrated development of the Sondu River and the Kano plain

Economic evaluation of the integrated development in the Sondu River and the Kano plain by Magwagwa and Sondu/Miriu power schemes and the Kano irrigation scheme was carried out as part of the studies to seek the optimal development scale of the Magwagwa reservoir (refer to Section 5.3), showing the high viability of the project.

Following the plan optimization, preliminary design and cost estimate of the project were made on a feasibility study level. The cost estimates furthermore include the preparation of disbursement schedule based on the proposed construction plan, in which commissioning of the project with an installed capacity of 120 MW is set at the beginning of year 2003 as revealed in the planting-up study. It is noted that energy outputs from the Magwagwa power plant used for the planting-up study are based on the multi-reservoir operation.

Economic viability of the project, in which three components of Magwagwa, Sondu/Miriu and Kano projects are included, was re-assessed by taking into account the studies carried out after the plan optimization (Section 5.3) as mentioned above, showing high viability of the integrated development project by a net benefit of US$135.00 million (a discount rate of 10%) and EIRR of 13.54%. A cash flow for the evaluation is given in Table 8.1, and the conditions and assumptions applied for the above economic assessment are referred to Section 5.2.

Sensitivity tests were carried out for the following cases taking into consideration uncertainties involved in the future costs, fuel prices and so on:

(1) 10% and 20% up for the capital costs of three schemes,
(2) 10% and 20% down for the benefits of three schemes, and
(3) Combinations of 10% cost up and 10% benefit down, and 20% cost up and 20% benefit down.

The results of sensitivity tests are summarized as follows:

	Cases	Net present value, million US$	Economic internal rate of return, %
(1)	10% cost up	100.85	12.46
(2)	20% cost up	66.71	11.53
(3)	10% benefit down	87.35	12.35
(4)	20% benefit down	39.71	11.10
(5)	10% cost up plus 10% benefit down	53.21	11.34
(6)	20% cost up plus 20% benefit down	-28.59	9.31

Even on the most unfavourable condition of 20% construction cost up plus 20% benefit down, the project still keeps EIRR of 9.31%, so that sensitivity tests verify the project viable in terms of economic evaluation.

8.2.2 Single development of the Magwagwa

Although the Magwagwa project is a component of the integrated development in the Sondu River and the Kano plain, the project is considered to be independently developed as a single purpose project of hydropower generation. In this context, the Magwagwa project was assessed on the condition that energy generated from the Magwagwa power plant excluding incremental benefits from the Sondu/Miriu by installing the Magwagwa is only counted as benefits and that all the construction costs of the Magwagwa dam are borne by the Magwagwa power plant, revealing a net benefit of US$23.56 million for a discount rate of 10% and EIRR of 11.29%. It can be concluded that the Magwagwa project is viable even in developing independently as a single purpose project of hydropower generation.

Sensitivity tests were carried out for the following two cases to assess the soundness in developing independently as a single purpose project of hydropower generation:

(1) 10% cost up, and
(2) 10% benefit down.

The results of sensitivity tests are summarized as follows:

Cases		Net present value, million US$	Economic internal rate of return, %
(1)	10% cost up	8.09	10.42
(2)	10% benefit down	5.74	10.32

Judging from the above results of sensitivity tests, the Magwagwa project shows the viability to develop independently as a single purpose project of power generation.

8.2.3 Serial development of the Sondu/Miriu and the Magwagwa

The Magwagwa project was assessed viable in the preceding Section 8.2.2 even as an independent hydropower project. There would be another interest to evaluate viability of serial development of the Sondu/Miriu and the Magwagwa, since the earlier development of the Sondu/Miriu, which is now in the stage of detailed design, is more realistic.

Serial development of the Sondu/Miriu and the Magwagwa was assessed viable with a net benefit of US$91.64 million for a discount rate of 10% and EIRR of 13.52%. On this computation, given is the condition that incremental benefits from the Sondu/Miriu are counted after the installation of the Magwagwa and that all the construction costs of the Magwagwa dam are borne by the Magwagwa power plant.

Sensitivity tests were carried out for the following cases:

(1) 10% and 20% up for the capital costs of two schemes,
(2) 10% and 20% down for the benefits of two schemes, and
(3) Combinations of 10% cost up and 10% benefit down, and 20% cost up and 20% benefit down.

The results of sensitivity tests are summarized as follows:

	Case	Net present value, million US$	Economic internal rate of return, %
(1)	10% cost up	79.10	12.52
(2)	20% cost up	55.22	11.65
(3)	10% benefit down	68.80	12.42
(4)	20% benefit down	34.62	11.26
(5)	10% cost up plus 10% benefit down	44.92	11.47
(6)	20% cost up plus 20% benefit down	-13.14	9.58

The above results show the high viability in developing hydropower potential in the Sondu River basin by installing the Sondu/Miriu and the Magwagwa in a series, furthermore implying that the Kano irrigation project would retain viability of more or less 13.5% in terms of EIRR judging from the comparison of prime test results between Section 8.2.1 and this Section.

8.3 Financial Evaluation

Financial evaluation puts its primal purpose on financial viability of the Magwagwa hydropower project itself and manageability of the implementing agency (KPC) to repay foreign and local portions of investment costs. As far as the aspect of financial viability is concerned, analytical viewpoint focuses on financial rate of return to all resources engaged when the project is implemented. Its analysis usually puts an emphasis on FIRR which is the discount rate to equalize the present worth of investment costs and projected revenue amounts. Concerning to financial manageability of the implementing agency, analyses are placed on financial impact of the project to the implementing agency.

8.3.1 FIRR

Financial costs of the Magwagwa project are estimated at the price level of November, 1990 as dealt with in the preceding Chapter 7. Price contingency is added to the financial cost of the project applying the annual inflation rates of foreign currency portion (2%) and local currency portion (10%) to the respective investment costs annually disbursed. Meanwhile, operation and maintenance costs of the project are simply assumed at 1% of direct construction cost.

Power revenue is earned by selling generated energy. Electricity tariff, which is a crucial element for the assessment of financial viability as well as the amount of energy generation, is estimated at US$0.060/kWh (KShs 1.38/kWh) on an average at the level of November, 1990. Incremental energy generated from the Sondu/Miriu after the completion of the Magwagwa(158.4 GWh/yr) is counted as benefits besides the energy generated from the Magwagwa itself.

FIRR, as seen in Table 8.2, was estimated at 11.14% on the condition of excluding price escalation from both of costs and benefits. Thus, the project is judged viable in terms of FIRR.

Sensitivity tests for FIRR were carried out taking into account future costs and electricity tariff as follows:

Case 1 : Price escalation (refer to Sub-section 7.2.12) is counted for costs, but not for revenue.

Case 2 : Price escalation is counted not only for costs, but also for revenue; that is, electricity tariff is increased by 5% per annum, although past performance is 12% per annum, by the commissioning year of the project.

The results of the sensitivity tests are summarized as follows:

	FIRR, %
Case 1	7.61
Case 2	13.95

Even on the most unfavourable condition for the project, i.e. Case 1, the project will expect the return of 7.6% in FIRR, so that the project can be assessed viable in terms of financial analysis.

8.3.2 Loan repayability

(1) Terms of loan

Following are assumed as the terms of loan so as to examine the loan repayability of the Project:

1) Foreign loan:

- Amount of loan : 85% of total cost
- Interest rate : 2.5%
- Repayment period : 30 years
- Grace period : 10 years

Land acquisition cost, tax and duties etc. are non-eligible for the loan. All the repayments will be made in form of annual equal installments with the interest during construction capitalized.

2) Loan repayability

Table 8.3 presents an examination of loan repayability based on the above assumptions. It is noted that average electricity tariff is fixed at US$0.060/kWh which prevails at the level of November, 1990 and that incremental energy generated from the Sondu/Miriu after the completion of the Magwagwa is included as the benefit of the Magwagwa. As shown in the said table, annual balance of the revenue and expenditures of the Project would become surplus from Year 12, when the revenue of the Project is expected to be obtained for the first time. From that year, the revenue would counterbalance the cumulative deficit and get it surplus in Year 29.

The Government of Kenya should secure the funds that meet the anticipated expenditure during the period without revenue (from Year 1 to Year 11). The total fund requirement would amount to some US$146 million for the eleven years. On a yearly basis, the maximum fund requirement a year would become US$35 million.

8.4 Overall Evaluation of the Project

As discussed in the preceding Sections, the Project was assessed viable in economic and financial terms. On the other hand, the project will inundate an area of 26 km^2, resulting in causing an issue to displace some 700 households,or 4,300 people, which would be the most severe impact for the Project. To obtain the soundness and acceptability of the project from the social and natural environmental viewpoints besides the technical, economic and financial viability of the project, reasonable and acceptable measures should be taken for the 4,300 people who would involuntarily be displaced from the submerged area of the Magwagwa reservoir.

A "land for land" compensation principle is recommended to be applied for the acquisition of land to be submerged in the reservoir area considering the kinship and other socio-cultural factors of the local people, the Kipsigis and the Kisii. A preliminary survey in this study identified six possible resettlement sites, which still require in-depth studies including hearings to local people to assess suitability as the resettlement sites.

Finally, institutional set-up is desired to be formulated to handle the resettlement issue as early as possible. KPC is expected to play a role as a pivot agency, and its main tasks will include public relations with the affected people to smoothly carry out the studies and coordination with the required line agencies and ministries.

Tables

Table 2.1 Gross Domestic Product, 1982-1988

(Unit: K£ million)

	1982	1983	1984	1985	1986	1987	1988	Annual Ave. Growth Rate
Non-monetary Economy	164.58	170.35	178.40	192.90	191.15	197.34	204.27	3.70%
Monetary Economy	2780.04	2864.60	2969.58	3109.84	3293.01	3452.18	3634.18	4.57%
Agriculture	907.17	945.65	941.05	975.59	1023.39	1062.50	1109.26	3.42%
Manufacturing	372.32	389.07	405.84	424.07	448.67	474.34	502.80	5.54%
Services & Others	1500.55	1529.88	1622.69	1710.18	1820.95	1915.51	2022.12	5.11%
Total GDP	2944.62	3034.95	3147.98	3302.70	3484.16	3649.76	3838.45	4.52%

Sources: Economic Survey 1986, 1988 and 1989

Table 2.2 Target Growth Rates by Sector

(% per year at factor cost)

	1989-93	1988-2000
Non-monetary GDP	3.6	3.5
Agriculture	4.5	5.3
Manufacturing	6.4	7.5
Trade, restaurant & hotels	7	5.5
Government services	5	5.4
Other sectors	5.2	6.7
GDP at market prices	5.4	5.9
Population	3.7	3.7
GDP per capita	1.6	2.1

Sources: (1) Session Paper No.1 of 1986
(2) Development Plan, 1989-93

Table 3.1 Annual Rainfall in the Sondu River Basin (1/3)

ID.No.	9034024	9035001	9035003	9035013	9035067	9035075	9035079	9035129	9035233	9035253	9035260	9035261	9035292	
ST.	Craigmore	Jamji	Kericho	Sotik	Reginget	Kaisuge	Kenwik	Marindas	Teret	Cheplelwa	Koiwa	Ngoina	Ndoinet	Basin
Name	Sotik	Estate	DC.	Monieri	Estate	House	Mission	Farm	Forest St.	S. Scheme	Estate	Estate	Forest St.	Rainfall
LAT.	0°49'S	0°28'S	0°23'S	0°40'S	0°25'S	0°20'S	0°45'S	0°21'S	0°27'S	0°49'S	0°37'S	0°33'S	0°25'S	
LONG.	34°59'E	35°12'E	35°17'E	35°04'E	35°41'E	35°23'E	35°20'E	35°42'E	35°37'E	35°06'E	35°19'E	35°03'E	35°33'E	
ALT.	El.1951m	El.1829m	El.1981m	El.1813m	El.2697m	El.2195m	El.2012m	El.2804m	El.2438m	El. 1829m	El.2256m	El.2012m	El.2439m	
1905			2237											
1906			1804											
1907			1515											
1908			2058											
1909			1379											
1910			1849											
1911			1633											
1912			1813											
1913			1647											
1914			1928											
1915			2032											
1916			2079											
1917			2152	1625										
1918			1167	911										
1919			1940	1630										
1920			1678	1414										
1921			1364	1303										
1922			1950	1645										
1923			2178	1305										
1924		1405	1672	1287										
1925		1540	1727	1358										
1926		1961	2267	1443										
1927		1220	1668	1133										
1928	1478	1645	1739	1251										
1929	1156	1338	1471	1281										
1930	1650	1829	2044	1659										
1931	1488	1828	1937	1404										
1932	1390	1608	1766	1279										
1933	1256	1327	1637	1189										

Table 3.1 Annual Rainfall in the Sondu River Basin (2/3)

ID.No.	'9034024	'9035001	'9035003	'9035013	'9035067	'9035075	'9035079	'9035129	'9035233	'9035253	'9035260	'9035261	'9035292	
ST.	Craigmore	Jamji	Kericho	Sotik	Reginget	Kaisuge	Kenwik	Marindas	Teret	Chepielwa	Koiwa	Ngoina	Ndoinet	Basin
Name	Sotik	Estate	DC.	Monieri	Estate	House	Mission	Farm	Forest St.	S. Scheme	Estate	Estate	Forest St.	Rainfall
1934	1086	1343	1505	1308										
1935	1283	1832	1875	-										
1936	1380	1783	1917	1458										
1937	1844	2082	2294	1398										
1938	1209	1715	1856	1209	1096									
1939	1234	1272	1456	910	861	1211								
1940	1393	1630	1843	1373	1156	1851	1201							1492
1941	1655	1907	2223	1459	1479	2183	1522							1775
1942	1566	1586	1814	1312	1429	1606	1376							1527
1943	1267	1290	1386	1240	-	1242	1069							1249
1944	1588	1752	1455	1343	1049	1622	1571							1483
1945	1249	1285	1713	1362	985	1808	1021							1346
1946	1448	1451	1672	1254	1218	1608	1356							1430
1947	1735	1852	2342	1621	1165	2182	-							1816
1948	1312	1610	1914	1366	1056	1478	1151							1412
1949	1248	1044	1906	1082	1016	1397	1128							1260
1950	1402	1557	1941	1304	885	1518	1148							1394
1951	1756	2048	2456	1789	1469	2121	1752	1510						1863
1952	1421	1779	1858	1376	934	1423	1392	-						1455
1953	1085	1292	1562	1057	764	1292	1415	-						1210
1954	1192	1485	1764	1214	1187	1863	1399	1435						1442
1955	1719	1565	1781	1366	1248	1693	1051	1556						1497
1956	1283	1675	1764	1270	1369	2238	1186	1779						1571
1957	-	1657	1682	1518	1164	1772	1452	1071						1474
1958	1369	1624	1803	1552	1234	1633	1271	1084						1446
1959	1355	1593	1850	1265	987	1883	1179	1073						1398
1960	1557	1559	2125	1247	-	1929	1270	1192						1554
1961	1710	2060	2632	1646	1487	2126	-	1434	1564					1832
1962	1767	1833	2273	1517	1227	2010	1712	-	1075					1677
1963	1838	1935	2097	1581	1324	2170	1635	1208	1379					1685
1964	1419	1833	2002	1322	1229	1826	1161	1339	1243					1486
1965		1571	1665	1232	834	1526	1531	714	584	1195				1206
1966		1810	1753	1410	1141	1611	1568	1127	859	1394				1408

Table 3.1 Annual Rainfall in the Sondu River Basin (3/3)

ID.No.	'9034024	'9035001	'9035003	'9035013	'9035067	'9035075	'9035079	'9035129	'9035233	'9035253	'9035260	'9035261	'9035292	
ST.	Craigmore	Jamji	Kericho	Sotik	Reginget	Kaisuge	Kenwik	Marindas	Teret	Cheplelwa	Koiwa	Ngoina	Ndoinet	Basin
Name	Sotik	Estate	DC.	Monieri	Estate	House	Mission	Farm	Forest St.	S. Scheme	Estate	Estate	Forest St.	Rainfall
1967		1829	1986	1536	1453	2119	1267	1180	1105	1156		1537		1517
1968		1997	2388	2021	1504	1753	1545	1270	-	1693		1847		1780
1969		1413	1380	1227	930	1405	1278	766	1062	1164		1396		1202
1970		2033	2373	1644	1691	2146	1760	1335	1557	-		1708		1805
1971		1447	1773	1220	1399	1855	1277	1244	1194	-	1599	1330		1434
1972		1539	1957	1232	924	1695	1366	814	903	1267	1973	1435		1373
1973		1666	1903	1346	1184	1576	-	822	675	1466	1769	1705		1411
1974		1519	1785	1496	1208	1840	-	-	1017	-	-	-		1478
1975		1692	1643	1391	1255	1878	1505	-	1158	-	1647	-		1521
1976		1545	1691	1446	857	1358	1138	-	767	-	-	-	1180	1248
1977		1745	2120	1702		2041	1429	1485	1473	-	2252	-	2028	1808
1978		2345	2433	1591		2171	1625	1576	1281	-	2098	-	1905	1892
1979		1736	1638	1321		1581	1384	-	1407	-	1628	-	1456	1519
1980		1482	1369	1244		1436	-	982	805	-	1683	-	1368	1296
1981		1865	1887	1555		1819	1500	1302	943	-	-	-	1785	1582
1982		1812	2435	1573		1855	1563	1344	1140	-	2042	-	1938	1745
1983		1440	2017	1421		2094	1332	1505	1095	-	1852	-	1479	1582
1984		1434	1699	1228		1468	1205	605	530	-	-	-	1043	1152
1985		1462	1960	1652		1692	1488	1272	1120	-	-	-	-	1521
1986		1256	1407	1174		1433	1174	1125	1002	-	1721	-	1291	1287
1987		1306		1171		1943	1485		884	-	1809	-	1341	1420
1988		1978		1421		2113			1186	-	2317	-	-	1803
Sample	36	65	82	71	37	50	43	29	27	7	13	7	11	49
Mean	1439	1639	1858	1382	1173	1762	1368	1212	1074	1334	1876	1565	1529	1505
Min.	1085	1044	1167	910	764	1211	1021	605	530	1156	1599	1330	1043	1152
Max.	1844	2345	2632	2021	1691	2238	1760	1779	1564	1693	2317	1847	2028	1892

Table 3.2 Probable Daily Rainfall in the Sondu River Basin

Unit: mm/day

ID.No.	9035001	9035003	9035013	9035067	9035075	9035079	9035129	9035233
ST.	Jamji	Kericho	Sotik	Reginget	Kaisuge	Kenwik	Marindas	Teret
Name	Estate	DC.	Monieri	Estate	House	Mission	Farm	Forest St.
LAT.	0°28'S	0°23'S	0°40'S	0°25'S	0°20'S	0°45'S	0°21'S	0°27'S
LONG.	35°12'E	35°17'E	35°04'E	35°41'E	35°23'E	35°20'E	35°42'E	35°37'E
ALT.	El.1829m	El.1981m	El.1813m	El.2697m	El.2195m	El.2012m	El.2804m	El.2438m
Sample No.	64	74	65	36	43	64	28	26
Return Period (yr.)								
1.01	34	34	27	20	26	34	29	26
1.05	39	39	33	25	32	39	33	31
1.11	42	43	37	27	36	42	35	34
1.25	46	48	42	21	41	46	38	37
1.5	51	52	47	36	47	51	41	41
2	56	58	54	41	53	56	45	46
5	69	73	70	53	70	69	55	58
10	78	83	81	62	81	78	62	66
20	86	92	92	70	92	86	68	73
30	91	98	98	74	98	91	71	78
40	95	102	102	77	102	95	74	81
50	97	105	105	80	105	97	76	83
80	103	111	112	85	112	103	80	88
100	105	114	115	88	115	105	82	91
200	113	123	125	95	126	113	88	98
500	124	135	139	105	139	124	96	107
1000	132	144	149	113	149	132	102	115

Table 3.3 Monthly Discharge at 1JG1 Station

River Name : Sondu/Miriu
ID.Number : 1JG1
Catchment Area : 3260 km2
Latitude : 0°23'35"S
Londitude : 35°00'30"E

Unit : m3/s

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
1946					14.1	48.3	37.5	83.1	82.5	33.2	16.9	9.9	40.7
1947	13.2	11.8	15.6	99.6	265.0	79.8	52.1	56.3	59.9	53.4	13.4	8.5	60.7
1948	5.3	3.5	2.8	5.2	9.6	25.4	26.6	57.3	64.4	19.0	10.3	5.9	19.6
1949	3.5	2.8	1.7	4.2	5.5	13.5	15.8	36.1	57.6	23.5	10.8	9.3	15.4
1950	6.6	3.9	5.7	14.1	20.9	22.6	35.4	44.8	57.9	24.2	10.5	7.0	21.1
1951	4.5	4.7	4.2	110.5	92.0	87.6	35.2	45.1	28.5	31.4	45.8	123.5	51.1
1952	60.4	14.7	8.7	44.8	201.5	66.5	29.0	52.9	46.6	25.7	15.7	10.6	48.1
1953	5.6	3.2	2.3	6.2	9.9	10.7	9.9	12.0	9.7	7.0	6.7	6.4	7.5
1954	3.3	1.7	1.6	5.9	45.8	75.3	39.0	34.1	56.1	25.9	13.3	11.0	26.1
1955	5.9	5.5	3.1	6.8	16.3	10.2	16.5	45.2	86.0	63.4	25.0	19.2	25.3
1956	41.6	31.6	14.5	36.8	104.1	75.3	48.2	54.0	86.6	40.6	27.7	16.7	48.1
1957	8.6	7.0	6.5	47.7	114.0	149.8	63.3	53.4	45.5	15.3	10.6	9.4	44.2
1958	6.5	9.7	9.7	9.8	67.0	33.8	34.7	32.8	45.3	27.8	13.9	11.5	25.2
1959	8.6	6.6	11.7	37.0	69.8	35.2	16.1	18.2	28.6	22.8	23.3	14.5	24.4
1960	9.7	6.2	17.9	70.1	62.6	55.4	36.6	40.1	78.8	43.5	23.2	13.1	38.1
1961	6.8	4.5	4.3	9.7	24.1	15.5	12.9	33.0	46.3	56.6	258.9	227.2	58.3
1962	85.6	26.7	12.7	32.7	182.6	111.7	88.5	45.8	86.2	73.2	31.1	18.0	66.2
1963	32.0	25.0	21.5	74.1	265.0	118.4	35.0	51.3	37.6	11.0	12.7	88.1	64.3
1964	33.8	13.4	25.4	186.9	108.5	49.0	69.1	71.9	60.7	75.3	22.1	11.4	60.6
1965	10.0	6.4	4.0	32.5	72.7	23.6	15.4	16.4	17.0	11.8	31.6	22.1	22.0
1966	11.0	11.3	32.4	89.5	80.9	33.3	26.4	24.6	71.0	24.1	22.9	11.9	36.6
1967	6.6	4.3	3.6	19.9	99.1	64.2	75.5	40.1	30.8	17.0	21.2	57.1	36.6
1968	15.3	17.2	51.3	119.6	161.0	92.6	57.3	93.6	46.8	17.7	29.3	93.3	66.3
1969	22.8	48.9	39.5	29.8	37.5	23.7	14.2	16.9	34.9	14.1	9.6	6.9	24.9
1970	14.3	22.6	66.7	126.2	115.6	82.6	42.5	79.9	79.6	59.1	27.1	11.9	60.7
1971	10.5	6.8	4.6	11.2	41.8	66.5	64.1	100.4	93.9	46.2	16.8	10.4	39.4
1972	10.2	9.2	7.4	7.7	32.4	41.4	45.9	44.4	26.7	19.8	74.6	47.2	30.6
1973	43.6	32.6	20.1	12.5	33.2	80.7	31.4	48.7	62.9	36.6	30.0	13.4	37.1
1974	7.1	4.5	5.7	72.2	51.2	56.6	130.9	67.0	55.0	42.8	24.2	11.0	44.0
1975	6.2	4.4	5.5	28.8	33.3	50.5	42.4	94.4	136.6	81.9	36.8	14.4	44.6
1976	8.9	6.2	5.4	8.4	22.8	41.6	58.0	50.9	73.2	21.7	11.3	9.1	26.5
1977	11.6	24.0	13.9	89.5	164.0	81.0	109.9	78.3	55.4	26.1	109.9	78.6	70.2
1978	31.3	28.2	168.1	198.2	153.5	46.5	58.5	55.9	70.5	73.8	40.7	28.6	79.5
1979	21.2	69.6	48.1	69.5	92.7	75.2	56.3	63.4	35.4	15.3	10.1	7.6	47.0
1980	5.9	5.2	7.7	14.8	39.4	55.9	64.6	33.4	32.3	14.0	13.2	10.4	24.7
1981	5.7	6.3	12.5	142.1	93.5	33.4	40.3	79.3	62.3	56.7	22.0	13.1	47.3
1982	7.6	4.5	2.7	4.8	44.0	72.2	36.9	65.1	50.2	35.8	122.3	163.9	50.8
1983	26.8	11.7	7.5	17.0	48.9	50.5	42.8	55.1	107.7	80.2	51.8	24.5	43.7
1984	15.8	8.7	6.2	11.7	14.2	10.2	10.7	29.1	32.3	19.6	15.4	30.5	17.6
1985	9.2	9.4	10.1	104.3	107.7	77.9	46.8	77.7	62.6	22.0	23.0	15.4	47.2
1986	8.4	7.3	7.3	14.2	38.4	36.5	26.0	33.5	32.5	19.2	12.8	15.9	21.0
1987	9.9	7.2	20.9	26.5	68.4	131.5	49.2	24.5	21.0	16.7	35.7	25.6	36.4
1988	15.1	14.4	17.3	82.3	170.9	60.7	52.7	99.3	90.8	82.9	38.8	21.1	62.2
1989	12.2	13.6	14.2	66.7	119.4	54.8	32.1	49.7	80.5	73.4	45.1	47.2	50.7
1990	72.2	26.3	123.6	289.9	114.6	67.5	31.1	38.6			18.7	13.6	79.6
MEAN	17.3	13.5	19.9	56.6	82.9	57.7	43.6	51.7	57.4	36.4	33.0	31.7	42.0
MAX.	85.6	69.6	168.1	289.9	265.0	149.8	130.9	100.4	136.6	82.9	258.9	227.2	79.6
MIN.	3.3	1.7	1.6	4.2	5.5	10.2	9.9	12.0	9.7	7.0	6.7	5.9	7.5

Table 3.4 Runoff Coefficient in the Sondu River Basin

Basin	Sondu River				Yurith River				Kipsonoi River			
ST. No.	1JG1				1JD3				1JF8 (1JF1)			
CA.	3260 km2				1570 km2				1540 (1523) km2			
	Runoff (m3/s)	Runoff (mm)	Rainfall (mm)	Coeff. (%)	Runoff (m3/s)	Runoff (mm)	Rainfall (mm)	Coeff. (%)	Runoff (m3/s)	Runoff (mm)	Rainfall (mm)	Coeff. (%)
Year												
1947	60.7	587	1816	32%			2125				1507	
1948	19.6	190	1412	13%			1667				1221	
1949	15.4	149	1260	12%			1449				1119	
1950	21.1	204	1394	15%			1672				1185	
1951	51.1	494	1863	27%			2034				1655	
1952	48.1	465	1455	32%			1687				1281	
1953	7.5	73	1210	6%			1382		3.0	62	1080	6%
1954	26.1	252	1442	18%			1637		8.8	182	1285	14%
1955	25.3	245	1497	16%			1649				1388	
1956	48.1	465	1571	30%			1864				1377	
1957	44.2	428	1474	29%			1546		19.5	404	1301	31%
1958	25.2	244	1446	17%			1536		7.1	147	1302	11%
1959	24.4	236	1398	17%			1600		6.1	126	1172	11%
1960	38.1	369	1554	24%			1701		9.1	188	1317	14%
1961	58.3	564	1832	31%			2063		14.8	306	1568	20%
1962	66.2	640	1677	38%			2039				1460	
1963	64.3	622	1685	37%			1853				1494	
1964	60.6	586	1486	39%			1750				1286	
1965	22.0	213	1206	18%			1369				1015	
1966	36.6	354	1408	25%			1575				1250	
1967	36.6	354	1517	23%			1779				1319	
1968	66.3	641	1780	36%			1852				1647	
1969	24.9	241	1202	20%			1241				1118	
1970	60.7	587	1805	33%	39.4	788	1972	40%			1616	
1971	39.4	381	1434	27%	30.5	610	1584	39%			1323	
1972	30.6	296	1373	22%			1596				1239	
1973	37.1	359	1411	25%	27.4	548	1547	35%			1281	
1974	44.0	426	1478	29%			1715				1240	
1975	44.6	431	1521	28%	34.4	688	1715	40%			1391	
1976	26.5	256	1248	21%	21.2	424	1444	29%			1052	
1977	70.2	679	1808	38%	44.5	890	1945	46%			1668	
1978	79.5	769	1892	41%	53.0	1061	2088	51%			1634	
1979	47.0	455	1519	30%			1608				1435	
1980	24.7	239	1296	18%			1387				1179	
1981	47.3	458	1582	29%			1732				1325	
1982	50.8	491	1745	28%			1904				1532	
1983	43.7	423	1582	27%			1731				1441	
1984	17.0	164	1152	14%	11.7	234	1250	19%			892	
1985	47.2	457	1521	30%	25.0	500	1597	31%			1383	
1986	21.0	203	1287	16%	14.1	282	1372	21%	5.6	115	1239	9%
1987	36.4	352	1420	25%			1600		11.8	242	1337	18%
1988	62.2	602	1803	33%	34.0	680	2136	32%	16.5	338	1641	21%
Sample	42	42	42	42	11	11	42	11	10	10	42	10
Mean	41.0	396	1511	26%	30.5	610	1690	36%	10.2	211	1338	16%
Min.	7.5	73	1152	6%	11.7	234	1241	19%	3.0	62	892	7%
Max.	79.5	769	1892	41%	53.0	1061	2136	50%	19.5	404	1668	24%

Table 3.5 Sediment Inflow in the Magwagwa Reservoir

Year	At the 1JG1 Station			Sediment Inflow into Magwagwa Reservoir (1000m3)	Annual Denundate Rate (mm/year)
	Average Discharge (m3/s)	Accum. Sediment Volume (1000m3)	Daily Max Sediment Inflow (1000m3)		
1946	40.69	312.66	-	298.50	0.094
1947	60.71	1082.20	46.58	1033.20	0.327
1948	19.60	181.52	3.31	173.30	0.055
1949	15.36	126.45	2.52	120.72	0.038
1950	21.13	183.41	2.52	175.10	0.055
1951	51.08	725.05	17.67	692.23	0.219
1952	48.10	702.69	18.63	670.88	0.212
1953	7.46	34.28	0.35	32.73	0.010
1954	26.08	268.16	4.54	256.02	0.081
1955	25.27	262.21	4.37	250.34	0.079
1956	48.15	573.30	6.63	547.34	0.173
1957	44.24	615.85	14.18	587.97	0.186
1958	25.19	236.42	7.07	225.72	0.071
1959	24.37	220.14	3.63	210.17	0.067
1960	38.09	413.64	4.68	394.92	0.125
1961	58.33	1148.09	32.24	1096.11	0.347
1962	66.25	985.65	23.61	941.03	0.298
1963	64.29	1138.78	24.59	1087.22	0.344
1964	60.63	972.19	47.80	928.18	0.294
1965	21.96	203.83	6.18	194.60	0.062
1966	36.60	425.29	10.74	406.04	0.128
1967	36.63	425.02	5.78	405.78	0.128
1968	66.25	1007.22	25.89	961.63	0.304
1969	24.90	214.54	7.65	204.82	0.065
1970	60.70	834.07	10.24	796.31	0.252
1971	39.44	483.35	7.57	461.47	0.146
1972	30.58	306.92	4.25	293.03	0.093
1973	37.14	386.72	6.59	369.21	0.117
1974	44.03	559.65	12.55	534.31	0.169
1975	44.61	585.33	9.02	558.83	0.177
1976	26.45	267.00	5.01	254.91	0.081
1977	70.20	1073.45	16.28	1024.85	0.324
1978	79.47	1298.23	33.67	1239.46	0.392
1979	47.04	557.50	6.35	532.26	0.168
1980	24.73	234.08	3.42	223.48	0.071
1981	47.27	638.85	18.02	609.93	0.193
1982	50.83	761.51	24.42	727.04	0.230
1983	43.72	512.79	8.46	489.58	0.155
1984	17.05	122.66	4.00	117.11	0.037
1985	47.18	610.40	8.74	582.77	0.184
1986	21.01	164.67	1.46	157.21	0.050
1987	36.41	431.61	11.37	412.07	0.130
1988	62.18	905.65	14.45	864.65	0.274
1989	50.73	631.52	-	602.93	0.191
1990	79.61	1232.01	-	1166.69	0.369
Average	42.04	556.81	-	531.39	0.168

Note : Estimated sediment volume includes the bedload which is assumed to be 20% of the suspended load.

Table 3.6 Geological Sequence in the Study Area

AGE	SYMBOL	DESCRIPTION
RECENT	Al	Superficial alluvium Sand, Graves, Silt, Clay
PLEINSTOCENE	Pl	Pl Undifferentiated includes Lake deposits Plt Mau and Londiani Ashes and Tuffs Plb Londiani Matic Basalts and Basanites
TERTIARY	Tv	Tv Tertiary volcanics Kericho phonolite and Nyabondo phonolite
PRE CAMBRIAN	B	(BUKOBAN SYSTEM) Ba Rhyolites and tuffs, porphyritic felsites and Andesites Bq Quartzites with some cherts Bb Basalts and porphyritic basalts
PRE CAMBRIAN	Gn	Nyanzian roof pendant (Hornblende gneiss)
PRE CAMBRIAN	N	(NYANZIAN SYSTEM) NR Rhyolite with intercalated tuffs (NRt and Agglomerates, Basalt, Na Andesites, Dasites and Tuffs
ARCHEAN	M	(BASEMENT SYSTEM) Undifferentiated gneiss, schists and quartzites, includes MN-Nyanzian schists and MK-Kavirondian schists
	GD	INTRUSIVES Granites (G3-Post Kavirondian (G2-Post Nyanzian Miriu Granodiorite (G -Undated

Table 3.7 Results of IEE

Environmental Item	Ecological Region			
	I Catchment	II Inundation	III Reduction	IV Fluctuation
A) Problems due to the Location				
1. Inundation of mineral resources	*	0	*	*
2. Repreciation of forestry	*	0	*	*
3. Historical remains/Assets	*	0	0	0
4. Watershed erosion	*	=	*	*
5. Navigation	*	0	0	0
6. Migrating valuable fish	*	0	0	0
7. Precious ecology	0	0	0	0
8. National park/game reserve	0	0	0	0
9. Disturbance of health facility use	-/B	*	0	0
B) Problems in Construction Stage				
1. Soil erosion	*	-/C	*	*
2. Water quality deterioration	*	*	-/C	=
3. Disturbance of transportation	-/C	-/C	*	*
4. Communicable diseases	0	-/C	0	0
C) Problems in Operation Stage				
1. Micro-climate change	*	=	*	*
2. Change of water temperature	*	*	-/C	-/C
3. Deterioration of water quality	*	0	-/C	-/C
4. Eutrophication	*	-/B	0	0
5. Precious ecology	0	=	=	=
6. Fishery	*	+/B	0	0
7. Downstream erosion	*	*	=	=
8. Aggradation of in riverbed	*	=	*	*
9. Water use conflict	*	*	=	0
10. Vector borne diseases	*	-/A	-/B	0
11. Recreation	*	+/C	=	=

Note:

(1) 1 : Upper side is the expected effect, and lower side is its magnitude.

(2) * : No relation considered.
0 : No effect expected.
+ : Positive effect expected.
- : Negative effect expected.
= : Neutral effect expected, i.e. there may be a change but such change will be neither benefitial nor harmful.

(3) A : Effect which has relatively high level of magnitude,
B : Effect which has relatively medium level of magnitude,
C : Effect which has relatively low level of magnitude.

(4) The following items are to be examined in the Social Environmental Study of the Project.
- Resettlement, Cultural tribes, Loss of community, Compensation, Land use, and Land value.

Table 3.8 Summary of Socio-economic Characteristics in the Reservoir Area

Socio-cultural aspects

- Almost all of them belong to two ethnic groups: the Gusii and the Kipsigis,
- Population density is high, especially in the Nyamira side,
- The young and children occupy the largest share in the population,
- The literacy and education level among the household heads is not high,
- Majority of families appears to be nuclear, but polygamous ones still prevail,
- Kinship systems still play an important role in the ordinary life,
- The women's group is the largest socio-economic organization,
- They have little experience in out-migration and living with in-migrants, and
- Almost all of them prefer " land for land " approach in compensation.

Economic aspect

- Majority of them depends on land as either farmers, especially mixed farmers, or agricultural labourers ,
- Earnings from non-agricultural sectors are important as first or secondary income sources,
- The imbalance in income distribution appears larger in the Kericho than in the Nyamira,
- Most of them do not seem to afford to spend for those other than requirements for their daily lives,
- Majority of them does not have debt and has not accustomed to borrow money from formal institutions,
- They have elaborated a sophisticated production system of high productivity and diversity with traditional skills well suited to the specific environment and agro-ecological conditions,
- Land is getting diminished and fragmented,
- Most of all the households sustain self-sufficiency of food,
- Livestock rearing brings a variety of benefits to the farmers, and
- Commercial activities centred around the trading centres are in a small-scale, but provide essential requirements including employment opportunities for their ordinary lives.

Table 3.9 Employment Structure in the Areas

(Unit: %)

Main Activity	Kericho		Nyamira		All	
	Total Pop	Work Group	Total Pop	Work Group	Total Pop	Work Group
Mixed farmers	25.1	(63.7)	20.4	(57.3)	23.7	(61.9)
Crop farmers	3.5	(8.9)	2.3)	(6.5)	3.1	(8.1)
Livestock farmers	0	(0)	0	(0)	0	(0)
Self employed in household business	2.4	(6.1)	2.0	(5.6)	2.3	(6.0)
Employed in household business	0.7	(1.8)	0.9	(2.5)	0.8	(2.1)
Wage employment	6.5	(16.5)	8.4	(23.6)	7.1	(18.5)
Unemployed	0.8	(2.0)	1.2	(3.4)	0.9	(2.4)
Sick/disabled	0.4	(1.0)	0.4	(1.1)	0.4	(1.0)
(Total)		(100.0)		(100.0)		(100.0)
Schooling	38.6		44.1		40.3	
Young Children	21.9		20.3		21.4	
Not Stated	0.1		0		0.1	
Total	100.0		100.0		100.0	
(N=	3,324		1,448		4,772)	

Table 3.10 Summary of a Result of Initial Screening for Socio-economic Impacts

Major Causes	Major Impacts	Number of People Affected	Intensity of Impacts	Difficulty of Prevention/ Alleviation
I. Pre-construction Stage				
1. Land Acquisition	• Displacement of people	+	++	++
	• Loss of land	?	++	++
II. Construction Stage				
1. Influx of Labours	• Social frictions	? (++)	++	+
	• Occurrence of diseases	(To be assessed in Natural Environmental Study)		
2. Generation of Job Opportunities	• Improving living standards	? (++)	+	-
	• Influence on farming	?	+	++
3. Increase in Traffic Volume	• Disturbance of transportation	? (++)	+	+
4. Reduction of Flow Downstream	• Influence on water use	(To be assessed in Natural Environmental Study)		
III. Impounding of the Reservoir				
1. Displacement of the People	• Decrease in living standards	++	++	++
	• Damages on social aspects	++	++	++
2. Inundation of Land & Structures				
2.1 Roads	• Disturbance to socio-economic activities	? (++)	++	+
2.2 Trading Centres	• - do -	? (++)	++	++
2.3 Public Facilities	• - do -	? (++)	++	+
2.4 Cultural/Historical Sites	• Spiritual damages on people	?	++	? (++)
2.5 Lands	• Rise in land value	?	++	++
	• Shortage of agricultural products	? (+)	+	+
IV. Operation Stage				
1. Provision of Water Supply	• Improving living standards	? (++)	++	-
2. Provision of Electricity	• - do -	? (++)	?	-
3. Generation of Job Opportunities	• - do -	? (+)	++	-
4. Possibility of Fishery	• - do -	? (+)	?	-

Note: ++ = Significant, + = Not significant, - = No need to consider, ? = Unknown
Signs in parentheses stand for inference.

Table 3.11 Rough Estimate of Land Acquisition Cost (Portion of Total Compensation Cost)

1. Estimate of Land Use in Reservoir Area

Land Use Type		Area (km2)
Total*		26
River*		1.18
Swamp*		0.66
Scrub*		2.44
Forest*		1.72
Sub-total		6.00
Transport network/ Homestead land/ Hedges	3%**	0.8
Arable/pasture land	100%	19.2
Arable land	56%***	10.8
Cash crops	[36%]**	3.9
Staple crops	[54%]**	5.8
Vegetables	[4%]**	0.4
Others	[6%]**	0.6
Pasture land	42%***	8.1
Other (waste land)	2%***	0.4

Notes:
* Obtained from Map (1:5000)
** Based on Integrated Land Use Survey, 1983
*** Based on Household Survey for the Project

2. Land within Reservoir Area

	Nyamira Side	Kericho Side	Total
1) Land Area (km2)	7.8	18.2	26
2) River Area (km2)	0.2	1	1.2
3) 1) - 2) (km2)	7.6	17.2	24.8
Average Land Value (Kshs. /acre)	30000	35000	-
Average Land Value (Kshs. /ha)	74130	86485	-
Land Value (Kshs.1000)	56339	148754	205093

3. Land outside Reservoir Area*

	Nyamira Side	Kericho Side	Total
Land Area (km2)	3.1	7.1	10.2
Average Land Value (Kshs. /acre)	30000	35000	-
Average Land Value (Kshs. /ha)	74130	86485	-
Land Value (Kshs.1000)	22980	61404	84385

* Excluding severely or injurly affected land
As average size of each household's land is 5 ha, total land of affected households amounts to some 3,500 ha. The balance between that and reservoir area excluding river is 10.2 km2.

4. Houses*

	Nyamira Side	Kericho Side	Total
Average Value (Kshs./household)	8130	6940	-
Number of Households Affected (Reservoir + Other Structures)	430	320	-
Total value (Kshs.1000)	3496	2221	5717

* Excluding those which live outside the reservoir, but are forced to move

5. Perennial Trees

	Area (km2)*	Value (Shs./acre)	Total Value (Kshs.1000)
Tea	7.5	125000	233100

* Assuming tea planted in all land for cash crops

6. Standing crops

Total Value* (Kshs.1000)	23773

* Estimate from Field Survey

7. Total

a. Total of 2 through 6 (Kshs.1000)	552068
b. Compensation for disturbance (15% of 7) (Kshs. 1000)	82810
9. Total (a + b) (Kshs. 1000)	634878

Table 3.12 Negative Impacts Resulting from Compensation in Cash

Negative impacts on the displaced people

The most serious case for the displaced people is that they fail to regain their bases for livelihood even if provided with large amount of money. This failure may partly be attributable to their use of cash not for investment, but for consumption. More often than not, however, most of them cannot obtain their alternative socio-economic bases such as land, employment, communities etc., due to the hardship of living conditions surrounding them.

They often find it difficult to obtain, on an individual basis, the land in the same size and productivity as that of previous one, especially in the vicinity of the reservoir because of rise in land value induced by the projects, and more essentially less availability of such land resulting from high population pressure on land. Those who look for employment in non-agricultural sectors most likely fail to get prospective one since they usually have no requirement of skills and knowledges and often a few employment opportunities.

For social aspects, the evacuees would lose chances to resettle themselves in group without finding land enough to absorb them. The resettlement on an individual basis would negatively affect their efforts to reconstruct their livelihoods, in particular if they have relied on social networks and on their own culture. "Cash for land" approach cannot take into account evacuees' invisible property including the above aspects.

Negative impacts on the Project

The affected people know better than not to anticipate the hardship after the evacuation when provided with cash only. Therefore, "cash for land" approach sometimes brings about their resistance to move, resulting in delay in the schedule of projects and therefore cost over-run.

In the longer term, displaced people's failure to regain the bases for livelihood often results in their influx into urban centres in search for employment or their return to the vicinity of homeland inundated, where there are their relatives and social networks who can take care of them, to some extent. Increase in population density around the reservoir area cause environmental deterioration by accelerating reclamation, encroachment of forest areas, overgrazing etc. As a result, soil erosion, and hence sedimentation is accelerated, so that the economic life of dam is shortened as compared to the designed one.

Table 3.13 Possible Problems with Regard to Involuntary Resettlement

Preparation for Resettlement	Transfer (Uprooting) Period	Transitional Period	Self-sustenance (Rerooting) Period
DISPLACED PEOPLE			
ECONOMIC ASPECTS			
(1) Fear of losing property, jobs etc. (2) Uncertainty of establishing economic base (3) Suspicion whether the government accepts their claims (4) Existence of those who would be displaced, but without compensation	(1) Negative impacts on economic activities at home, in the case that they have to prepare living environment at resettlement sites by themselves: high "opportunity cost" (2) Existence of problems involved with the move: such as timing of move, underestimate of properties to be taken with the displaced people etc.	(1) No revenue due to preparation for establishing economic base (inmaturity of crops, changes in occupations, etc.) (2) Burden of debts for housing, electricity, etc. (3) Insufficiency of land both quantitatively and qualitatively. (4) Existence of those who were displaced, but without compensation (landless, etc.) (5) Mismanagement/misuses of compensation grant (6) Constraints to economic activities due to insufficient economic structure (7) Government's failure to keep its promises (8) Delay of preparation in new sites (9) More hardship to low income households (10) Existence of those who had to leave from resettlement sites	(1) Insufficiency of land for "Second Generation" (2) Difficulty to live their lives on a self-help basis
SOCIO-CULTURAL ASPECTS			
(1) Sadness of their home land and holy places taking over from ancestors being submerged (2) Fear of destruction of communities (3) Uneasiness of beginning a new life (4) Existence of those who could not move to remote areas due to old age's preference, attachment to family, etc.	(1) Destruction of communities	(1) Difficulty of reconstructing viable communities (leadership, functions, necessity of non-farmers, etc.) (2) Frictions with host populations (3) Government's failure to keep its promises (4) Insufficiency of social infrastructure, including water supply, housing, etc. (5) Increase in stress for various reasons (6) Delay of preparation in new sites (7) Lack of experiences for adapting new environments	
OTHERS RELATED TO DISPLACED PEOPLE			
(1) More difficult situation to obtain land and increase in rent etc., due to rise in land value	(1) Difficulty of finding another job for those who lost their job due to inundation (2) Decrease in labours (3) Destruction of communities (4) Delay of reconstructing lost facilities	(1) Host population's frictions with settlers (2) Host populations' tendency to treat resettlers as unfairly privileged	

Table 3.14 Summary of Preliminary Investigation on Possible Resettlement Sites

Areas investigated \ Criteria	(1) Displaced people's preference	(2) Vicinity of the reservoir areas	(3) Land conditions	(4) Similarity of agro-ecological zone	(5) Availability of non-farm employment opportunities	(6) Social affinity	(7) Availability of water sources and accessibility	(8) Land ownership	(9) Value of lands	(10) Side-effects of the resettlement	(11) Remarks
1. Settlement schemes in Kericho and Nyamira/Kisii districts	–	–	–	–	–	–	–	Government	–	–	No plans both in Kericho and Nyamira/Kisii districts.
2. Swamp/Marsh areas in Kericho and Nyamira/Kisii districts	?	△	X	○	?	○	○	County councils	?	Negative effects on those living around the areas	Soil and topographic conditions are not good.
3. Ngoina and other adjacent tea estates in Kericho and Nyamira districts	◎	◎	?	◎	?	◎	○	Private company (Partly Government land)	?	Negative effects on some workers at estate	1,350 ha (Ngoina estate)
4. Simbauti farm in Nyamira district	○	△	?	○	?	○	?	A Co-operative union	?	?	The land appears earmarked for other use. 300 ha
5. Government land in Kericho district	?	△	?	○	?	○	?	Government	?	?	No investigation was carried out.
6. ADC farms in Trans Nzoia district	△	X	?	○	?	△	?	Government	?	Possible negative effects on some workers at farms	Some 35,000 ha

Notes : ◎ = Excellent
○ = Good
△ = Fair
X = Bad
? = Unknown
– = No need to assess

Table 4.1 Existing and Committed Power Plants (1/2)

(A) EXISTING

(A-1) HYDROPOWER STATION

Name of STN.	River	No. of Unit	Year Installed	Type of Turbine	Station Capa. (MW)	Effect. Capa. (MW)	Ann. Prod. (GWh) in 1989/90
Tana (KPC)	Maragua &	3	1932/52	Francis	14.4	12.4	94.0
	Tana	2	1954/55	Francis			
Wanjii (KPC)	Maragua	4	1952	Francis	7.4	7.4	55.0
Sagana Falls (KPLC)	Tana	3	1954/55/60	Francis	1.5	1.5	
Mesco (KPLC)	Maragua	1	1933	Francis	0.3	0.3	
Ndula (KPLC)	Thika	2	1925	Francis	2.0	2.0	21.0
Selby Falls (KPLC)	Sosiani	2	1952	Francis	0.4	0.4	
Gogo Falls (KPLC)	Kuja	2	1958	Francis	2.0	2.0	
Masinga (TARDA)	Tana	2	1981	Francis	40.0	40.0	124.0
Kamburu (TRDC)	Tana	3	1974/76	Francis	91.5	84.0	382.0
Gitaru (TRDC)	Tana	2	1978	Francis	145.0	145.0	762.0
Kindaruma (TRDC)	Tana	2	1968	Francis	44.0	44.0	216.0
Kiambere (TRDA)	Tana	2	1988	Francis	144.0	140.0	863.0
Imported from UGANDA						(30.0)	(174.0)
Total Existing Power Station (including Imports)					492.50	479.00 (509.00)	2,517.0 (2,691.0)

(A-2) THERMAL POWER STATION

Name of STN.	River	No. of Unit	Year Installed	Type of Turbine	Station Capa. (MW)	Effect. Capa. (MW)	Ann. Prod. (GWh) in 1989/90
Kipevu (Steam)	Coast	6	1956-1974	Steam	98.00	26.0	97.0
Kipevu	Coast	1	1972/87	Gas	30.00	30.0	10.0
Nairobi South	Nairobi	1	1973	Gas	17.90	13.8	0.0
Total Existing Thermal					145.90	69.8	107.0

(A-3) INTERCONNECTED DIESELS

Name of STN.	River	No. of Unit	Year Installed	Type of Turbine	Station Capa. (MW)	Effect. Capa. (MW)	Ann. Prod. (GWh) in 1989/90
Ruiri		2	1948/49	Diesel	3.00		
Mbaraki		2	1947/49	Diesel	1.70	8.0	2.0
Nairobi South	Nairobi	8	1954-57	Diesel	13.58		
Total Existing Diesel Power Station					18.28	8.0	2.0

(A-4) GEOTHERMAL POWER STATION

Name of STN.	River	No. of Unit	Year Installed	Type of Turbine	Station Capa. (MW)	Effect. Capa. (MW)	Ann. Prod. (GWh) in 1989/90
Olkaria Nairobi		3	1981-85		45.00	43.00	336.00
Total Existing Geothermal Power Station					45.00	43.00	336.00

Table 4.1 Existing and Committed Power Plants (2/2)

(A-5) ISOLATED POWER STATION

Name of STN.	River	No. of Unit	Year Installed	Type of Turbine	Station Capa. (MW)	Effect. Capa. (MW)	Ann. Prod. (GWh) in 1989/90
Wajii	Central	3	1982	Diesel	0.640	0.280	
Mandera	N. East	3	1979-84	Diesel	0.340	0.3335	
Garissa	N. East	4	1972-82	Diesel	0.904	0.775	
Lodwar	N. Rift	3	1976-81	Diesel	0.380	0.245	12.0
Moyale	East	2	1986	Diesel	0.400	0.198	
Marsabit	East	3	1978-84	Diesel	0.340	0.330	
Lamu	Coast	4	1977-84	Diesel	0.934	0.720	
Total Existing Isolated Power Station					3.938	2.882	12.0

(B) PLANTS UNDER CONSTRUCTION OR HAVING BEEN STUDIED (PREFEASIBILITY)

Name of STN.	River	No. of Unit	Year Installed	Type of Turbine	Station Capa. (MW)	Effect. Capa. (MW)	Ann. Prod. (GWh) in 1989/90
Turkwel (const.)	Western	2	1991	Hydro	107.00	107.00	309.0 *1
Sondu/Miriu (F/S)	Western			Hydro	49.00	49.00	261.0 *2
Magwagwa (F/S)	Western			Hydro	95.00	73.00	438.0 *2
Mutonga	Tana			Hydro	60.00	60.00	234.0 *2
Low Grand Falls	Tana			Hydro	120.00	88.00	482.0 *2
High Grand Falls	Tana			Hydro	180.00	141.00	802.00
N.E. Olkaria	Rift Valley			Geo	60.00	60.00	
Total					671.00		

Sources : KPLC Annual Report of the year ended 30th June, 1990, Kenya National Power Development Plan 1986-2006 of ACRES and Table 4.6 of this report.

Note : (1) Annual Production of the period of July 1878 to June 1990 from KPLC Annual Report
(2) *1 : Page 3-90 of Acres Report
*2 : Table 5.1 of Acres Report

Table 4.2 : Transformers in Service and Total Installed Capacity

(A) EXISTING

Station & Voltage	AS AT 31ST DECEMBER (MVA) 1979	1980	1981	1982	1983	1984	1985	1986	AS AT 30th JUNE (MVA) 1987	1988	1989
(A-1) Generation Step-up Station											
11/220kV	-	-	-	-	-	-	-	-	-	170.0	170.0
11/132kV	331.0	331.0	397.0	397.0	397.0	397.0	417.0	417.0	417.0	417.0	417.0
11/66kV	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
11/33kV	137.0	137.0	137.0	137.0	137.0	137.0	137.0	137.0	178.0	217.0	217.0
11/40kV	5.0		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
3.3/11/40kV	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
3.3/33kV	2.3	2.3	2.3	2.3	3.0	3.0	4.0	4.0	4.0	4.0	4.0
3.3/40kV	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
132/220kV	-	-	-	-	270.0	540.0	540.0	540.0	540.0	540.0	540.0
Total	521.3	517.3	583.3	583.3	854.0	1124.0	1145.0	1145.0	1186.0	1395.0	1395.0
								(Average Annual Growth Rate: 11.01%			
(A-2) Distribution Substation											
220/132kV	-	-	-	-	180.0	580.0	580.0	580.0	580.0	580.0	580.0
132/66kV	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	210.0	210.0	270.0
132/33kV	180.0	180.0	180.0	180.0	239.0	239.0	285.0	285.0	285.0	285.0	308.0
66/11kV	323.0	323.0	323.0	323.0	323.0	346.0	369.0	369.0	369.0	395.0	441.0
66/40kV	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
40/11kV	15.5	15.5	15.5	15.5	15.5	16.0	16.0	16.0	16.0	19.0	19.0
33/11kV	223.0	237.0	262.0	270.0	286.0	294.0	302.0	325.0	333.0	358.0	356.0
Total	951.5	965.5	990.5	998.5	1253.5	1684.5	1761.5	1784.5	1807.0	1861.5	1989.0
									(Average Annual Growth Rate: 8.07%		
(A-3) Distribution Transformer											
11kV/415V & 33kV/415V	649.0	726.0	789.0	871.0	931.0	1005.0	1056.0	1092.0	1173.0	1300.0	1376.0
									(Average Annual Growth Rate: 8.23%		

(B) UNDER CONSTRUCTION

Turkwel Project:	Generation Step-up Station at Turkwel	11/231kV, 2 units of 59MVA
	Step-down at Lessos Substations	220/132kV, 2 units of 75MVA

Source : Information from KPLC

Table 4.3 Existing Transmission Systems

(A) Transmission lines

(EXISTING)

Region	As of:	220kV.1cct (km)	132kV.1cct (km)	132kV. 2cct (km)	66kV.1cct (km)	40kV.1cct (km)	33kV (km) 1 cct	33kV (km) 2-wire	33kV (km) SWER	33kV (km) U.G
Nairobi	Dec.1976	-	-	582.96	215.80	107.78	17.99		72.92	-
	Dec. 1983	300.00	-	584.65	250.58	113.28	151.12	-	75.22	-
	Jun. 1988	302.00	-	589.85	254.18	113.28	229.05	0.82	75.22	-
Rift Valley	Dec.1976	-	-	-	-	-	302.49	0.47	-	-
	Dec. 1983	-	-	-	-	-	566.24	1.74	-	-
	Jun. 1988	-	-	-	-	-	624.35	11.54	-	-
Western	Dec. 1976	-	-	-	-	-	533.96	-	-	-
	Dec. 1983	-	-	157.26	-	-	888.25	1.16	-	-
	Jun. 1988	-	-	157.26	-	8.00	1147.65	9.31	-	-
Coast	Dec. 1976	-	-	-	-	-	226.15	8.58	-	0.57
	Dec. 1983	128.00	-	78.04	-	-	379.29	9.67	-	1.26
	Jun. 1988	128.00	-	78.40	-	-	486.06	9.67	-	1.40
Mt. Kenya	Dec.1976	-	-	-	-	-	235.83	-	-	-
	Dec. 1983	-	-	137.60	-	-	281.25	-	-	-
	Jun. 1988	-	-	137.60	-	-	358.07	2.95	-	-
K.P.C.	Dec. 1976	-	405.23	-	134.89	-	-	-	-	-
	Dec. 1983	-	405.23	23.11	134.89	-	-	-	-	-
	Jun. 1988	-	405.23	23.11	134.89	-	-	-	-	-
TRDC	Dec.1976	101.88	-	16.84	-	-	-	-	-	-
	Dec. 1983	216.96	7.70	18.38	-	-	-	-	-	-
	Jun. 1988	216.96	7.70	18.38	-	-	-	-	-	-
Whole System	Dec. 1976	101.88	405.23	599.80	350.69	107.78	1316.42	10.15	72.92	0.57
	Dec. 1977	101.88	405.23	600.93	365.79	107.78	1354.52	10.80	72.92	0.76
	Dec. 1978	209.65	412.93	603.03	365.79	107.78	1417.62	10.95	72.92	0.76
	Dec. 1979	209.66	412.93	603.03	365.79	107.78	1444.08	22.09	72.92	0.76
	Dec. 1980	216.96	412.93	608.83	367.27	113.28	1723.25	11.20	72.92	1.26
	Dec. 1981	216.96	412.93	608.83	367.27	113.28	1954.57	11.20	75.22	1.26
	Dec. 1982	216.96	412.93	661.03	367.27	113.28	2128.27	11.20	75.22	1.26
	Dec. 1983	644.96	412.93	681.43	385.47	113.28	2366.15	12.57	75.22	1.26
	Dec. 1984	644.96	412.93	681.43	385.47	113.28	2284.17	12.57	75.22	1.26
	Dec. 1985	-	n.a	n.a	n.a	n.a	n.a	n.a	n.a	n.a
	Jun. 1986	644.96	412.93	681.43	386.90	113.28	2526.47	12.57	75.22	1.26
	Jun 1987	646.96	412.93	683.43	387.07	113.28	2606.20	32.87	75.22	1.26
	Jun.1988	646.96	412.93	686.63	389.07	121.28	2845.18	34.29	75.22	1.40
	Average Annual Growth Rate over 11.5 years(%)	0.16	1.18	0.91	0.10		6.93	11.17	0.27	8.13

Table 4.4 Existing Distribution Systems

(B) Distribution lines
EXISTING

Region	As of:	11kV (km)							L.V. (km)		
		6-Wires	3-Wires	2-Wires	SWER	U.G. Cable	Arial Cable	Total	O.H.	U.G. Cable	Total
Nairobi	Dec. 1976	3.54	1901.16	133.25	66.70	114.92	0.16	2219.73	941.37	61.82	1003.19
	Dec. 1983	3.54	2424.52	165.29	49.40	138.73	1.89	2783.37	1213.29	156.80	1370.09
	Jun. 1988	3.54	2713.16	220.10	49.60	169.14	2.53	3158.12	1455.99	183.06	1639.05
Ann. Grow.(%)		0	3.14	4.46	-2.61	3.42	27.13	3.11	3.87	9.90	4.36
Rift Valley	Dec. 1976	0.15	484.42	29.95	-	4.48	-	519.00	149.70	2.80	152.50
	Dec. 1983	0.15	625.59	50.24	-	6.61	-	682.59	220.26	5.73	225.99
	Jun. 1988	0.15	733.39	68.88	-	7.91	-	810.33	369.34	6.40	375.74
Ann Grow.(%)		0	3.67	7.51	-	5.07	-	3.95	8.17	7.45	8.16
Western	Dec. 1976	-	859.27	51.79	-	2.76	-	913.82	287.09	7.49	294.58
	Dec. 1983	-	1091.64	66.29	-	6.09	-	1164.02	399.91	26.71	426.62
	Jun. 1988	-	1187.79	134.15	-	7.30	-	1329.24	683.19	39.54	722.73
Ann. Grow.(%)		0	2.86	8.63	-	8.83	-	3.31	7.83	15.57	8.12
Coast	Dec. 1976	4.04	382.66	53.81	-	30.83	0.43	471.77	329.06	6.38	335.44
	Dec. 1983	4.04	496.78	48.98	-	42.75	0.43	592.98	400.45	12.05	412.50
	Jun. 1988	4.04	535.88	65.54	-	49.06	0.70	655.22	466.59	15.54	482.13
Ann. Grow. (%)		0	2.97	1.73	-	4.12	4.33	2.90	3.08	8.05	3.20
Mt. Kenya & KPC	Dec. 1976	-	594.79	29.59	-	2.86	-	627.24	194.63	1.79	196.42
	Dec. 1983	-	1000.98	70.39	-	3.89	-	1075.26	357.01	15.76	372.77
	Jun. 1988	-	1110.99	112.30	-	4.86	-	1228.15	580.23	18.94	599.17
Ann. Grow. (%)		0	5.56	12.30	-	4.72	-	6.02	9.96	22.77	10.18
Whole Kenya	Dec. 1976	7.73	4222.30	298.39	66.70	155.85	0.59	4759.29	1901.85	80.28	1982.13
	Dec. 1977	7.73	4398.32	304.76	67.50	159.47	0.59	4938.68	195897	82.20	2041.17
	Dec.1978	7.73	4531.49	317.12	74.35	164.38	0.59	5095.66	2007.63	85.97	2093.60
	Dec.1979	7.73	4705.25	334.81	74.35	168.97	0.59	5291.17	2091.40	98.73	2190.13
	Dec.1980	7.73	4849.07	358.26	74.35	172.83	1.34	5463.58	2160.09	103.73	2263.82
	Dec.1981	7.73	5096.22	367.76	49.40	183.33	1.59	5706.03	2306.77	124.96	2431.05
	Dec.1982	7.73	5388.18	391.98	49.40	188.06	1.59	6026.94	2451.79	128.40	2580.19
	Dec.1983	7.73	5639.51	401.19	49.40	198.07	2.32	6298.22	2590.92	217.05	2807.97
	Dec.1984	7.73	5794.06	423.45	49.40	217.38	2.73	6494.75	2756.48	229.09	2985.57
	Dec.1985	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	Jun.1986	7.73	6047.01	489.69	49.60	228.91	3.23	6826.17	3268.76	246.31	3515.07
	Jun.1987	7.73	6146.31	546.96	49.60	231.94	3.23	6985.77	3321.81	253.95	3575.76
	Jun.1988	7.73	6281.21	600.97	49.60	238.27	3.23	7181.01	3555.34	263.48	3818.82
Ann. Grow. (%)		0	3.51	6.28	-2.61	3.76	15.84	3.64	5.59	10.89	5.87

Table 4.5 Total Power Supply and KPLC Electricity Sales

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	Average Growth Rate 72-89	72-79	79-89
Source of Supply (GWh)																					
Hydro	376	383	526	634	563	785	1053	1288	1040	1362	1377	1458	1471	1660	1793	1892	2172	2254	11.11	19.23	5.76
Oil Thermal	256	302	229	242	376	317	252	205	333	283	260	114	174	83	144	207	96	14	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	260	114	174	83	144	207	96	14	-	-	-	-
Diesel	27	28	21	10	63	20	5	1	22	1	1	-	1	2	9	24	6	1	-	-	-
Gas Turbine	-	4	14	2	40	11	2	1	25	-	-	-	-	4	n.a	n.a	n.a	n.a	-	-	-
Net Imports	283	302	296	261	240	272	217	160	315	194	212	179	215	269	192	116	163	-	-	-	
(ratio to total supply)	(30.4)	(29.6)	(27.2)	(22.6)	18.7)	(19.4)	(14.2)	(9.7)	(18.2)	(10.3)	(10.9)	(8.9)	(10.3)	(9.3)	(10.8)	(10.1)	(4.3)	(5.9)	-	-	-
Uncounted)	-10	-7	1	7	0	0	0	0	0	0	0	0	0	0	n.a	n.a	n.a	n.a	-	-	-
Total Supply Generated	932	1021	1087	1156	1282	1405	1529	1655	1735	1879	1946	2013	2094	2300	2494	2674	2713	2748	6.60	8.50	5.20
Station Use	33	24	21	20	32	28	25	22	29	29	31	29	28	27	n.a	n.a	n.a	n.a	-	-	-
Net Generation	899	988	1066	1136	1250	1377	1504	1633	1706	1850	1915	1984	2066	2273	2494	2674	2713	2748	6.79	8.90	5.34
Growth in Net generation (%)	-	9.9	7.9	6.6	10.0	10.2	9.2	8.6	4.5	8.4	3.5	3.6	4.1	10.0	9.7	7.2	1.5	1.3	-	-	-
T & D Losses (GWh)	104	128	141	135	168	174	203	220	234	255	280	302	282	317	(122)	347	411	455			
% of Net Generation	11.6	13.0	13.2	11.9	13.4	12.6	13.5	13.5	13.7	13.8	14.6	15.2	13.6	13.9	(5.1)	13.0	151	16.6			
% of Sales	13.1	14.9	15.1	13.5	15.5	14.5	15.6	15.6	15.9	16.0	17.1	17.9	15.9	16.2	(12.2)	15.6	17.3	18.5			
Total KPLC Sales (GWh)	795	860	925	1001	1082	1203	1301	1409	1468	1593	1631	1677	1775	1944	1035	2205	2332	(2412)	6.75	8.50	5.50
Interconnected KPLC System	-	-	-	-	-	-	-	-	-	1590	1629	1673	1771	1940							
Isolated KPLC Load Centres	-	-	-	-	-	-	-	-	-	3	2	4	4	4							
Total Ref Sales (GWh)	-	-	-	-	-	-	-	2	4	6	7	10	15	19	(10)	25	36	49			
REF Sales from Interconnected System										5	6	9	13	16							
REF Sales at Isolated Load Centres										1	1	1	2	3							
Total Sales (GWh)	795	860	925	1001	1082	1203	1301	1411	1472	1599	1638	1687	1790	1963	(1045)	2230	2373	2461	6.87	8.50	5.71
Growth in Sales (%)	11.2	8.2	7.6	8.2	8.1	11.2	8.1	8.5	4.3	8.6	8.6	2.5	2.9	6.1	9.7	8.9	6.0	3.2			
Max. Demand, Generated	146	161	171	184	207	223	256	269	290	313	317	334	349	387	418	430	461	480	7.50	9.10	6.00
Load Factor (%)	72.7	71.8	72.6	71.7	70.5	71.9	68.2	70.2	68.1	68.5	70.1	68.8	69.3	67.8							

Sources: Acres Report, Appendix Vo. 1 Table B2.1 & KPLC Information

Note: (1) Maximum demand (MW) is for integrated system only and includes station power use.
(2) Load factor is based on totalsupplly generated for integrated system divided by maximum demand.

Table 4.6 Energy Generation in Past by Power Station (1/8)

A. Hydro Power Plant

(A-1) WANJII (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	3.5	3.4	3.4	4.2	5.4	5.4	3.4	3.5	3.3	5.4	4.6	3.4
FEB	4.5	2.8	3.4	3.6	3.7	4.8	2.7	3.0	2.6	4.2	3.4	3.2
MAR	5.4	2.6	3.3	3.8	2.9	1.2	2.7	3.2	2.8	3.4	3.6	4.8
APR	4.2	2.5	4.0	2.8	4.5	1.0	2.8	3.3	3.0	4.6	3.5	5.1
MAY	4.9	2.5	4.7	3.5	5.2	0.7	2.7	3.3	3.2	5.3	3.5	5.4
JUN	4.9	2.3	4.6	3.9	5.2	2.7	2.4	2.6	3.3	5.1	5.0	4.7
JUL	2.6	2.7	4.7	3.2	5.5	3.2	2.6	2.7	3.4	5.3	5.3	5.3
AUG	1.5	2.7	4.3	2.8	5.5	3.9	2.5	3.5	4.9	3.5	5.4	4.0
SEP	2.7	2.5	3.7	5.0	5.2	2.6	2.3	3.3	4.1	3.1	5.2	5.2
OCT	3.0	2.7	3.7	4.9	5.4	2.0	3.4	3.4	4.1	3.9	5.5	4.9
NOV	3.1	1.5	4.1	4.4	5.0	1.9	3.3	3.3	4.9	3.2	5.2	3.3
DEC	3.3	3.4	4.2	5.5	5.3	2.3	3.4	3.5	5.0	3.8	4.0	0.0
Total	43.6	31.8	48.1	47.6	58.8	31.7	34.2	38.6	44.6	49.9	54.2	49.3

(A-2) KIAMBERE (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	-	-	-	-	-	-	-	-	-	-	2.96	66.36
FEB	-	-	-	-	-	-	-	-	-	-	15.23	60.89
MAR	-	-	-	-	-	-	-	-	-	-	56.64	68.31
APR	-	-	-	-	-	-	-	-	-	-	37.85	64.58
MAY	-	-	-	-	-	-	-	-	-	-	47.75	68.36
JUN	-	-	-	-	-	-	-	-	-	-	45.58	67.42
JUL	-	-	-	-	-	-	-	-	-	-	71.68	0
AUG	-	-	-	-	-	-	-	-	-	-	0	69.13
SEP	-	-	-	-	-	-	-	-	-	-	63.08	60.93
OCT	-	-	-	-	-	-	-	-	-	-	65.49	56.19
NOV	-	-	-	-	-	-	-	-	-	-	66.92	67.03
DEC	-	-	-	-	-	-	-	-	-	-	0	67.03
Total	-	-	-	-	-	-	-	-	-	-	473.18	716.23

(A-3) KAMBURU (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	44	27	26	29	25	27	29	28	33	37	37	35
FEB	34	23	19	28	24	26	28	27	29	36	36	31
MAR	43	25	13	26	25	29	29	32	30	39	28	30
APR	50	25	13	28	22	25	28	33	28	33	33	33
MAY	52	25	36	28	26	31	28	40	33	34	37	33
JUN	44	30	30	28	28	33	27	42	31	35	37	31
JUL	44	28	28	30	33	33	26	38	35	35	35	34
AUG	28	28	21	27	30	34	25	34	34	38	33	35
SEP	24	26	20	27	29	30	29	32	32	37	34	31
OCT	29	29	19	31	33	29	29	34	34	48	34	36
NOV	32	24	27	29	34	30	31	30	33	39	38	37
DEC	28	26	25	24	27	27	32	27	34	36	38	34
Total	452	316	277	335	386	354	341	397	386	447	420	400

(A-4) NDULA (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	421.2	326.7	199.9	1205.5	229.1	228.3	577.0	686.9	167.6	776.2	148.1	623.8
FEB	676.1	462.1	483.0	750.3	141.2	179.8	99.3	92.4	21.7	177.5	52.9	588.4
MAR	235.0	419.6	480.1	442.3	119.8	261.0	56.9	0	38.8	80.7	171.9	703.5
APR	240.3	413.5	720.2	0	233.7	180.4	114.4	0	368.1	406.6	418.6	606.8
MAY	266.0	449.1	426.9	0	240.5	214.2	66.6	0	517.6	655.8	539.3	370.9
JUN	229.5	302.3	441.5	0	249.8	252.1	22.0	0	273.0	608.8	90.4	648.2
JUL	330.0	498.4	894.6	118.2	246.8	282.1	28.3	234.2	607.8	640.8	540.4	731.0
AUG	305.6	517.0	1124.4	108.0	221.3	416.4	19.4	419.7	606.4	587.8	479.9	750.6
SEP	295.7	477.5	678.2	66.4	261.0	312.0	18.2	421.7	287.0	169.6	556.4	756.4
OCT	257.8	374.9	587.3	248.2	233.0	339.6	310.9	68.7	159.8	64.4	527.4	958.6
NOV	259.0	445.8	1164.4	228.1	257.5	482.0	1211.0	374.2	729.9	580.7	562.2	385.9
DEC	215.3	274.4	12908.0	261.5	437.5	351.1	1253.4	535.8	687.5	550.0	670.4	0
Total	3731.5	4961.3	20108.5	3428.5	2871.2	3499.0	3777.4	2833.6	4465.2	5298.9	4757.9	7124.1

Table 4.6 Energy Generation in Past by Power Station (2/8)

(A-5) SELBY (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	262.1	198.9	45.1	1.4	34.3	61.8	64.1	5.6	5.5	6.6	0	47.6
FEB	233.9	198.9	28.7	5.1	25.5	46.1	36.1	4.8	4.8	0.8	0	60.5
MAR	266.8	148.2	17.0	41.8	24.0	22.3	18.1	3.6	2.4	0	0	41.4
APR	254.6	147.1	121.0	245.1	12.9	0	11.6	65.7	6.1	17.5	0	43.8
MAY	209.2	147.7	238.0	127.9	65.8	50.1	10.3	96.1	65.8	61.0	0	50.7
JUN	166.5	141.2	241.3	59.3	58.4	51.4	0	66.0	55.6	83.6	0	82.2
JUL	257.4	143.3	240.0	56.6	61.7	56.9	0	55.7	98.0	96.1	0	55.9
AUG	249.6	142.7	193.6	35.7	62.5	68.9	0	59.2	90.0	97.6	0	110.7
SEP	239.8	167.2	168.4	104.4	63.1	65.9	0	82.9	86.1	40.1	0	86.7
OCT	240.6	86.3	74.9	114.4	99.0	53.6	0	44.5	38.4	1.7	0	64.7
NOV	225.4	165.7	66.2	111.0	39.4	67.8	14.2	41.9	20.9	30.3	0	0
DEC	228.8	0	0	78.3	40.2	51.8	9.8	6.9	12.7	19.1	0	0
Total	2834.7	1687.2	1434.2	981.0	586.8	596.6	164.2	532.9	486.3	454.4	0	644.4

(A-6) MESCO (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0.12	0.13	0.13	0.23	0.12	0.12	0.11	0.24	0.04	0.24	0.26	0.23
FEB	0.15	0.12	0.23	0.22	0.11	0.09	0.09	0.13	0.19	0.23	0.22	0.21
MAR	0.09	0.13	0.24	0.22	0.12	0.13	0.10	0.22	0.23	0.24	0.24	0.23
APR	0.10	0.11	0.16	0.10	0.11	0.12	0.09	0.20	0.20	0.22	0.22	0.24
MAY	0.10	0.12	0.13	0.11	0.10	0.13	0.10	0.20	0.20	0.24	0.22	0.25
JUN	0.11	0.12	0.13	0.13	0.13	0.13	0.15	0.09	0.08	0.22	0.23	0.23
JUL	0.12	0.02	0.19	0.14	0.12	0.13	0.21	0.10	0.17	0.24	0.25	0.25
AUG	0.12	0.00	0.23	0.11	0.03	0.15	0.20	0.08	0.22	0.24	0.23	0.25
SEP	0.04	0.00	0.22	0.13	0.13	0.13	0.19	0.22	0.22	0.25	0.21	0.18
OCT	0.12	0.00	0.22	0.13	0.12	0.12	0.22	0.01	0.24	0.25	0.11	0.22
NOV	0.13	0.13	0.23	0.13	0.13	0.13	0.22	0.00	0.23	0.25	0.23	0.22
DEC	0.11	0.12	0.23	0.10	0.12	0.12	0.24	0.00	0.24	0.27	0.25	0.22
Total	1.31	1.00	2.34	1.75	1.34	1.50	1.92	1.49	2.25	2.89	2.67	2.73

(A-7) MASINGA (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	-	-	-	0.00	11.83	0.11	18.16	14.43	22.42	21.07	19.06	10.48
FEB	-	-	-	0.00	8.57	0.54	16.62	13.15	17.80	22.43	16.04	11.44
MAR	-	-	-	0.00	11.88	7.41	15.60	13.43	12.65	21.72	8.73	15.23
APR	-	-	-	0.00	5.65	10.17	9.74	6.15	13.68	15.65	8.33	7.00
MAY	-	-	-	0.00	2.92	0.34	17.38	13.21	9.48	7.54	6.73	4.67
JUN	-	-	-	0.00	0.17	0.98	16.63	9.12	9.28	11.92	7.73	3.52
JUL	-	-	-	5.74	0.48	0.74	14.27	11.66	11.54	24.16	4.80	6.12
AUG	-	-	-	9.36	0.04	2.11	13.07	17.36	20.34	18.80	11.48	11.47
SEP	-	-	-	12.72	3.84	10.28	12.70	17.20	19.43	19.29	5.76	14.51
OCT	-	-	-	8.24	3.35	14.30	7.74	14.09	18.20	20.48	7.63	13.36
NOV	-	-	-	7.86	1.10	8.94	11.48	12.13	13.16	14.40	11.32	10.04
DEC	-	-	-	14.60	0.15	14.28	12.15	19.46	16.34	17.93	9.98	
Total	-	-	-	58.52	49.98	70.20	165.74	161.39	184.32	215.39	117.59	107.84

(A-8) KINDARUMA (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	22.1	16.3	13.6	14.0	12.4	17.3	14.2	14.8	16.1	15.7	19.2	20.0
FEB	16.1	17.3	9.4	12.4	11.8	13.3	13.9	13.1	14.5	12.0	17.9	14.8
MAR	22.6	17.6	5.3	13.4	13.0	15.4	16.0	16.2	16.8	14.3	15.4	15.9
APR	15.4	18.4	5.6	13.6	11.3	13.6	14.1	17.5	15.8	17.5	16.3	16.0
MAY	14.8	17.4	12.7	17.0	14.6	18.1	14.9	16.5	19.1	17.6	18.3	15.3
JUN	20.5	13.0	15.5	17.6	13.8	20.9	11.8	19.6	19.8	17.9	19.7	19.4
JUL	21.5	16.0	13.7	15.3	17.1	19.4	13.1	19.9	20.3	18.1	18.1	18.7
AUG	13.0	17.8	9.9	14.2	14.7	15.8	12.8	17.8	17.5	19.5	18.2	17.2
SEP	11.5	13.4	9.8	13.9	15.0	9.3	12.8	17.3	17.1	19.4	16.9	15.8
OCT	12.7	12.3	9.6	15.3	15.7	13.1	14.5	16.7	0.0	20.0	17.9	18.9
NOV	11.9	15.1	12.7	14.8	18.1	16.7	17.4	17.1	13.2	20.0	21.1	19.8
DEC	10.8	13.8	11.1	12.1	16.4	14.2	17.2	15.7	14.8	19.5	20.4	19.9
Total	192.9	188.4	128.9	173.6	173.9	187.1	172.7	202.2	185.0	211.5	219.4	211.7

Table 4.6 Energy Generation in Past by Power Station (3/8)

(A-9) TANA (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	8.8	8.5	0.0	8.9	7.1	6.3	5.5	7.2	6.3	6.5	7.4	4.3
FEB	8.3	4.5	0.0	6.3	6.3	4.9	3.2	6.2	4.1	5.5	4.8	4.0
MAR	10.6	8.6	0.0	7.2	5.0	3.9	2.6	6.4	4.6	5.7	6.1	6.4
APR	8.2	7.7	0.0	8.6	8.7	5.2	4.6	5.6	5.7	7.3	6.3	8.3
MAY	8.4	6.9	0.0	6.2	7.3	6.4	4.8	4.3	6.4	8.9	4.8	7.3
JUN	10.1	5.6	0.0	6.4	6.7	5.9	3.9	3.9	6.0	8.3	5.6	7.4
JUL	9.6	5.9	6.9	7.7	6.6	5.7	4.2	4.5	6.3	9.2	6.6	7.3
AUG	7.9	6.0	8.7	6.9	6.5	4.8	3.8	4.6	3.4	8.5	6.2	7.2
SEP	6.9	6.6	6.4	5.3	5.8	5.5	3.7	5.2	5.0	6.3	7.6	6.8
OCT	7.2	8.7	6.9	6.9	5.8	5.6	7.2	6.4	6.0	5.8	7.7	7.6
NOV	7.7	5.6	9.4	6.9	6.0	5.4	7.6	6.4	7.5	8.3	5.9	8.1
DEC	8.1	2.9	9.7	5.7	4.1	5.3	7.6	6.8	6.9	8.7	5.4	8.5
Total	101.8	77.5	48.0	82.9	75.6	64.9	58.7	67.5	68.1	89.0	74.3	83.2

(A-10) GITARU (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0	52	53	56	51	54	57	59	65	72	74	67
FEB	0	51	38	52	47	55	57	52	58	70	67	59
MAR	0	56	23	52	52	61	64	66	66	75	57	58
APR	0	54	25	50	45	55	55	69	61	64	64	63
MAY	0	57	53	55	50	59	59	57	74	68	68	68
JUN	0	53	57	55	53	61	47	60	75	68	68	65
JUL	7	58	54	55	63	65	52	75	80	70	59	67
AUG	39	61	40	52	61	67	52	71	70	75	66	64
SEP	46	54	38	52	62	61	51	68	69	73	65	59
OCT	49	52	38	58	65	62	57	67	66	76	69	70
NOV	51	55	50	60	61	68	69	67	65	77	71	63
DEC	49	55	46	48	0	56	65	63	67	74	68	
Total	241	658	515	645	610	724	685	774	817	862	796	703

(A-11) SAGANA (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	1.05	0.73	0.58	0.54	0.97	1.00	0.85	0.61	0.38	0.77	0.70	1.07
FEB	0.76	0.67	0.45	0.13	0.54	0.80	0.47	0.48	0.24	0.47	0.36	0.87
MAR	0.72	1.00	0.51	0.47	0.40	0.49	0.39	0.57	0.37	0.60	0.78	0.64
APR	0.71	1.03	0.90	1.01	0.98	0.65	0.56	0.84	0.75	0.93	0.98	1.01
MAY	1.01	1.07	1.03	1.06	1.05	0.93	0.46	0.96	1.04	1.08	1.11	1.11
JUN	1.06	1.02	1.02	1.00	1.04	0.96	0.26	0.99	1.05	1.06	1.08	0.98
JUL	1.02	1.11	0.82	1.06	1.06	0.99	0.31	0.97	1.09	0.86	1.04	0.88
AUG	0.85	1.08	0.59	1.08	1.04	0.96	0.21	0.68	1.01	0.75	1.06	0.79
SEP	0.71	0.87	0.40	0.99	0.83	0.97	0.37	0.66	0.91	0.41	1.04	0.94
OCT	0.76	1.00	0.51	0.99	0.85	0.99	0.79	0.86	0.99	0.42	0.80	1.09
NOV	0.71	0.94	1.02	0.99	0.98	0.93	0.84	0.89	1.06	0.95	0.93	1.05
DEC	0.73	1.02	0.90	1.04	1.03	0.92	0.94	0.86	1.10	0.89	1.07	1.11
Total	10.09	11.54	8.73	10.36	10.77	10.59	6.45	9.37	10.39	9.19	10.95	11.54

(A-12) GOGO FALLS (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0.00	0.00	0.00	0.36	0.56	0.59	0.50	0.00	0.00	0.00	0.00	N.A
FEB	0.00	0.00	0.00	0.20	0.44	0.55	0.26	0.00	0.00	0.00	0.00	N.A
MAR	0.00	0.00	0.00	0.22	0.27	0.00	0.25	0.00	0.00	0.00	0.00	N.A
APR	0.00	0.00	0.00	0.34	0.00	0.54	0.26	0.23	0.00	0.00	0.00	N.A
MAY	0.00	0.00	0.00	0.41	1.08	1.00	0.28	0.31	0.00	0.00	0.00	N.A
JUN	0.00	0.00	0.00	0.44	0.77	1.02	0.27	0.30	0.00	0.00	0.00	N.A
JUL	0.00	0.00	0.00	0.52	1.01	0.88	0.27	0.36	0.00	0.02	0.00	N.A
AUG	0.00	0.00	0.07	0.00	0.77	0.72	0.27	0.34	0.00	0.83	0.00	N.A
SEP	0.00	0.00	0.45	0.51	0.94	0.62	0.25	0.00	0.00	0.00	0.00	N.A
OCT	0.00	0.00	0.84	0.00	0.88	0.57	0.29	0.00	0.00	0.00	0.00	N.A
NOV	0.00	0.00	0.77	0.00	0.79	0.56	0.29	0.00	0.00	0.00	0.00	N.A
DEC	0.00	0.00	0.67	0.00	0.00	0.60	0.27	0.00	0.00	0.00	0.00	N.A
Total	0.00	0.00	2.80	3.00	7.51	7.64	3.46	1.54	0.00	0.85	0.00	N.A

Table 4.6 Energy Generation in Past by Power Station (4/8)

B. Thermal Power Plant

(B-1) KIPEVU(Steam) (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	23.21	14.78	22.71	25.18	24.34	17.28	5.01	12.24	9.91	11.09	25.31	2.74
FEB	26.63	14.52	24.26	24.64	24.16	16.66	4.97	13.62	11.44	15.49	24.25	2.55
MAR	20.92	15.77	32.21	29.51	26.86	17.91	6.10	16.63	9.62	16.57	22.18	2.04
APR	22.06	14.89	36.66	25.18	24.46	17.00	6.45	2.41	15.06	7.85	3.83	1.52
MAY	22.55	16.53	17.37	25.29	25.07	10.57	9.60	2.91	7.86	17.75	4.76	0.86
JUN	22.32	19.15	17.63	22.99	24.53	2.64	24.98	1.12	6.15	15.01	4.60	4.35
JUL	25.35	18.54	22.14	20.98	21.28	3.49	29.28	0.66	6.59	16.87	5.16	4.11
AUG	18.91	17.30	33.53	22.19	19.87	3.23	28.05	0.58	8.11	18.73	1.47	
SEP	16.46	19.08	34.13	22.52	15.82	10.57	26.86	0.71	10.33	19.69	1.13	13.80
OCT	18.43	19.20	32.26	21.49	17.40	6.69	18.47	10.34	22.61	20.66	0.80	
NOV	17.03	16.65	28.71	22.67	13.64	4.46	9.24	13.45	25.23	24.51	1.38	
DEC	18.22	18.46	31.22	22.59	17.38	3.60	4.44	8.39	11.49	22.55	1.34	
Total	252.09	204.87	332.83	285.23	254.81	114.10	173.67	83.06	144.40	206.77	96.21	31.97

(B-2) KIPEVU(Gas) (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN												
FEB												
MAR												
APR												
MAY												
JUN												
JUL												
AUG												
SEP												
OCT												
NOV												
DEC												
Total												

(B-3) NAIROBI SOUTH(Gas) (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN												
FEB												
MAR												
APR												
MAY												
JUN												
JUL												
AUG												
SEP												
OCT												
NOV												
DEC												
Total												

Table 4.6 Energy Generation in Past by Power Station (5/8)

C. Diesel Power Plant

(C-1) RUIRU : (Interconnected) (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	8.4	4.6	486.8	2.0	18.8	0.5	1.5	68.7	90.1	10.2	46.0	22.5
FEB	322.4	4.6	1430.7	9.1	2.0	0.5	0.6	2.0	76.4	101.9	45.1	16.1
MAR	42.4	2.3	1049.2	2.0	7.5	0	1.5	19.0	46.5	165.4	2.3	4.5
APR	85.6	4.6	376.1	2.0	2.0	0	4.7	18.1	13.0	514.4	23.4	1.0
MAY	149.5	4.6	0	2.0	2.0	0.5	1.1	116.8	52.2	352.9	0.3	2.0
JUN	27.3	4.6	0	2.0	2.0	0.5	1.3	37.9	79.2	26.9	0.5	10.6
JUL	40.9	4.6	1.9	2.0	2.0	0.5	0.9	25.0	45.9	29.1	7.8	14.0
AUG	15.0	4.6	2.0	2.0	2.0	0.5	1.0	11.0	21.5	24.8	1.9	26.7
SEP	4.6	4.6	192.1	0	2.0	9.8	0	4.9	41.3	69.5	0.6	15.4
OCT	2.6	4.6	475.4	2.0	2.0	0.5	0	12.2	55.3	39.1	36.8	41.6
NOV	4.6	4.6	6.3	2.0	2.0	0.5	18.8	23.0	1.0	57.4	74.5	10.6
DEC	4.6	4.6	2.0	2.0	2.0	0.5	0	5.5	309.7	66.5	57.5	20.9
Total	707.9	52.9	4022.5	29.1	46.3	14.3	31.4	344.1	832.1	1458.1	296.7	187.9

(C-2) MBARAKI (Interconnected) (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	26.9	34.1	15.5	0	52.4		0	68.5	22.2	62.7	30.9	61.7
FEB	52.5	0	18.2	3.5	0	1.8	0	3.7	28.9	0	24.6	13.2
MAR	24.3	21.4	0	1.6	4.5	2.6	0	23.0	26.1	45.8	1.3	12.7
APR	26.9	1.1	2.3	1.8	0	10.1	0	12.7	7.5	2.9	40.9	0
MAY	33.7	16.6	8.4	0.1	0	1.5	0	162.7	20.3	3.5	6.9	0
JUN	9.0	7.4	0	0	0	0	0.8	22.9	22.7	15.4	0.7	0
JUL	13.4	0	1.0	0	0	1.2	0.7	11.3	11.8	77.3	0	3.9
AUG	6.0	44.9	1.1	0	0.5	0	1.1	5.7	4.7	47.0	13.6	-
SEP	2.9	1.2	0	0.6	0	3.6	0	9.9	4.6	51.0	31.9	10.0
OCT	2.0	13.5	0	2.7	8.8	0	33.6	10.6	29.6	57.3	91.3	15.5
NOV	12.5	0	5.4	0.7	11.8	0	8.7	35.2	10.9	79.4	83.2	
DEC	1.1	39.2	5.9	28.0	0	0	4.8	2.7	20.5	62.1	87.7	10.4
Total	211.2	179.4	57.8	39.0	78.0	20.8	49.7	368.9	209.8	504.4	413.0	127.4

(C-3) NAIROBI SOUTH (Interconnected) (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0.20	0.15	1.28	0.00	0.16	0.00	0.00	0.80	0.86	0.91	1.67	0.26
FEB	0.71	0.02	7.92	0.06	0.01	0.00	0.00	0.04	1.40	1.41	1.32	0.04
MAR	0.48	0.01	11.92	0.01	0.02	0.00	0.00	0.10	0.52	1.53	0.84	0.01
APR	1.03	0.08	7.21	0.00	0.00	0.00	0.02	0.23	0.03		0.79	0.00
MAY	1.35	0.12	0.04	0.00	0.00	0.00	0.00	1.82	0.51	6.19	0.13	0.31
JUN	0.28	0.04	0.00	0.02	0.00	0.00	0.00	0.47	1.10	1.88	0.04	0.13
JUL	0.37	0.01	0.00	0.01	0.03	0.00	0.00	0.49	0.49	2.21	0.11	
AUG	0.11	0.03	0.00	0.00	0.00	0.00	0.00	0.22	0.11	1.31	0.04	0.35
SEP	0.02	0.84	2.90	0.00	0.01	0.05	0.00	0.07	0.24	1.45	0.11	0.08
OCT	0.02	0.05	7.14	0.01	0.01	0.00	1.05	0.16	1.00	0.88	0.13	
NOV	0.01	0.00	0.07	0.00	0.02	0.00	0.06	0.53	0.68	1.73	0.30	
DEC	0.01	0.09	0.08	0.00	0.00	0.00	0.10	0.29	0.73	2.23	0.10	
Total	4.59	1.44	38.56	0.11	0.26	0.05	1.23	5.22	7.67	21.73	5.58	1.18

Table 4.6 Energy Generation in Past by Power Station (6/8)

D. Geothermal Power Plant

(D-1) OLKARIA (GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	-	-	-	0.0	11.3	23.3	22.4	22.3	31.8	32.3	31.2	30.3
FEB	-	-	-	0.0	10.5	21.0	20.0	20.8	28.8	29.0	25.1	27.9
MAR	-	-	-	0.0	11.7	22.5	22.9	14.7	30.8	31.8	30.6	30.2
APR	-	-	-	0.0	11.3	22.1	22.3	17.3	30.2	30.3	29.4	27.0
MAY	-	-	-	0.0	11.6	22.4	23.2	33.4	27.7	31.4	29.0	29.9
JUN	-	-	-	0.0	10.4	22.6	22.2	33.0	31.4	30.4	29.3	28.5
JUL	-	-	-	7.0	1.3	18.4	22.5	33.2	32.3	25.9	27.1	30.0
AUG	-	-	-	0.0	0.0	20.3	19.7	33.0	31.1	27.4	23.0	0.0
SEP	-	-	-	5.1	4.1	22.4	22.0	32.1	30.2	26.6	25.5	27.3
OCT	-	-	-	0.0	0.0	22.7	22.8	33.1	31.3	31.4	21.6	27.6
NOV	-	-	-	4.8	2.8	21.4	5.2	30.9	31.6	30.5	22.2	28.0
DEC	-	-	-	11.1	21.3	23.2	7.2	32.1	32.1	31.7	29.1	29.2
Total	-	-	-	28.0	96.3	262.3	232.4	335.9	369.3	358.7	323.1	315.9

E. Imports from UEB

(GWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	19.96	14.83	29.09	19.57	17.13	16.40	14.10	23.83	25.75	22.60	12.97	4.59
FEB	22.50	10.97	33.28	19.57	15.74	13.50	16.24	21.10	23.76	11.58	14.54	9.80
MAR	20.60	13.62	47.16	18.75	19.42	16.90	20.98	25.10	30.68	15.85	14.49	16.92
APR	21.20	6.28	43.37	20.31	19.04	12.60	18.20	22.60	24.60	14.05	13.09	14.09
MAY	23.60	9.91	19.19	15.09	17.84	15.00	20.85	14.17	13.07	15.24	9.13	12.94
JUN	19.43	10.52	16.59	15.15	16.63	14.20	21.07	11.91	11.19	16.75	8.28	13.24
JUL	23.72	10.88	0.00	15.68	18.04	17.20	12.90	16.48	21.70	17.07	8.76	14.01
AUG	21.62	9.94	47.62	16.56	17.86	18.20	25.96	18.60	21.90	16.13	9.64	11.91
SEP	17.44	15.35	44.50	15.36	17.87	15.77	16.84	19.00	27.68	19.39	10.04	14.10
OCT	13.66	20.47	43.82	17.55	19.13	12.94	22.20	20.30	25.80	21.22	8.23	13.19
NOV	11.31	19.23	28.29	9.72	17.16	12.10	24.77	19.30	19.58	13.46	3.64	18.62
DEC	11.20	18.54	18.38	14.51	16.42	13.70	26.30	18.80	22.94	8.49	3.33	19.74
Total	226.24	160.54	371.29	197.82	212.28	178.51	240.41	231.19	268.65	191.83	116.14	163.15

Table 4.6 Energy Generation in Past by Power Station (7/8)

F. Isolated Diesel Power Plant

(F-1) WANJII (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0	0	0	0	0	9.3	29.3	65.5	85.6	95.6	117.1	113.7
FEB	0	0	0	0	0	12.5	28.2	65.1	76.0	89.1	110.4	106.9
MAR	0	0	0	0	0	20.0	31.1	78.6	83.9	105.2	116.9	120.4
APR	0	0	0	0	0	19.7	29.4	74.9	75.9	104.2	106.3	110.5
MAY	0	0	0	0	0	0	32.2	72.9	81.2	0	107.9	104.6
JUN	0	0	0	0	0	25.0	54.4	74.1	83.2	103.0	102.9	109.5
JUL	0	0	0	0	0	25.8	57.4	74.3	83.4	110.8		117.9
AUG	0	0	0	0	0	24.0	61.2	74.1	83.6	109.9	117.0	120.1
SEP	0	0	0	0	0.9	25.7	63.8	73.8	90.4	110.5	117.8	121.8
OCT	0	0	0	0	0.9	26.3	67.2	78.3	96.0	115.6	118.8	121.3
NOV	0	0	0	0	2.7	25.6	61.6	74.9	88.0	111.1	113.9	112.8
DEC	0	0	0	0	5.9	26.0	63.4	84.7	90.7	113.3	112.4	89.4
Total	0	0	0	0	10.4	239.9	579.2	891.2	1018.1	1168.3	1241.4	1348.9

(F-2) MANDERA (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0	0	11.7	13.4	17.1	19.4	26.0	30.0	74.4	86.1	111.0	113.7
FEB	0	0	11.4	12.8	15.7	19.5	24.8	25.7	69.2	72.4	102.2	109.8
MAR	0	0	12.9	13.4	16.5	22.7	25.8	29.7	73.1	0	103.9	110.7
APR	0	0	12.0	11.6	16.0	21.6	23.8	28.3	78.0	90.9	100.2	110.5
MAY	0	0	12.3	12.3	16.4	23.7	24.7	30.1	85.5	88.5	104.3	103.4
JUN	0	1.1	13.1	13.0	17.5	23.7	25.8	28.8	86.3	83.0	89.5	96.0
JUL	0	6.2	14.4	15.6	19.0	25.3	27.4	31.8	88.7	91.9	117.2	107.5
AUG	0	8.8	14.5	15.7	18.8	24.9	27.2	34.2	85.8	96.0	118.8	
SEP	0	10.6	12.3	14.9	18.5	23.8	29.5	33.6	93.0	99.9	118.9	118.5
OCT	0	10.8	13.2	16.3	16.2	24.6	32.3	33.7	92.8	104.8	121.9	121.8
NOV	0	10.9	12.5	15.7	17.1	24.2	29.0	62.7	88.9	106.4	116.1	114.8
DEC	0	10.6	12.5	16.5	17.7	24.3	30.4	71.6	91.7	109.8	114.7	
Total	0	59.0	152.8	171.2	206.5	277.7	326.7	440.2	1007.4	1029.7	1318.8	1106.7

(F-3) GARISSA (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	67.5	66.5	89.4	96.5	114.5	107.0	145.0	151.2	186.3	188.4	265.6	270.0
FEB	64.0	63.0	82.5	85.2	104.7	109.7	148.4	146.9	180.1	186.6	293.8	259.2
MAR	66.9	76.8	87.7	95.8	115.5	127.5	159.9	163.6	208.3	220.5	282.5	283.1
APR	63.2	71.5	83.2	79.7	99.6	124.6	146.6	144.8	178.5	208.5	251.6	272.2
MAY	67.5	74.2	93.9	90.2	101.8	136.8	144.6	155.4	180.9	229.7	263.9	303.2
JUN	72.4	73.2	84.4	87.0	103.3	132.8	140.8	162.6	173.3	227.4	262.7	296.0
JUL	71.5	78.1	94.8	79.3	106.1	136.2	145.8	170.5	178.1	235.5	280.5	286.8
AUG	76.2	84.4	98.1	87.4	105.1	133.2	133.8	173.3	181.7	238.7	265.1	291.2
SEP	76.1	84.4	100.4	92.7	105.1	142.8	147.3	169.1	202.5	245.5	270.5	290.7
OCT	77.9	93.3	103.6	93.6	98.7	151.7	161.9	179.8	204.6	264.5	284.5	295.7
NOV	70.0	82.0	84.9	99.4	101.6	143.5	143.5	171.5	201.1	263.6	262.5	
DEC	70.1	81.6	89.9	100.7	104.6	139.7	139.3	170.7	179.6	261.7	258.8	
Total	843.3	929.0	1092.8	1087.5	1260.6	1585.5	1756.9	1959.4	2255.0	2770.6	3242.0	2848.1

(F-4) LODWAR (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	12.6	11.9	17.3	17.0	26.2	36.3	37.8	54.9	79.6	81.7	87.9	95.3
FEB	11.4	11.4	16.8	17.1	25.0	35.3	39.5	48.9	71.2	77.7	86.5	90.6
MAR	11.6	13.1	18.5	22.2	29.2	37.8	41.6	58.8	74.4	96.3	95.7	104.3
APR	12.4	12.2	16.8	24.1	27.4	34.2	37.2	53.8	78.4	83.4	84.4	90.9
MAY	13.2	11.9	17.9	26.0	30.6	36.7	38.6	65.3	79.4	88.7	90.4	98.1
JUN	12.6	12.3	21.0	24.9	32.4	37.5	38.4	68.1	72.8	83.8		99.6
JUL	13.0	15.0	22.2	26.7	31.9	37.5	44.9	69.9	80.4	92.0	90.6	105.3
AUG	13.8	17.5	21.0	26.8	31.3	38.8	44.0	69.3	80.5	93.8	93.1	109.6
SEP	12.5	17.6	22.4	26.5	32.2	36.9	47.1	71.2	79.8	92.5	91.3	
OCT	14.1	18.5	22.5	28.9	34.6	34.6	51.9	77.4	88.0	95.7	96.5	
NOV	13.8	16.9	19.5	27.2	33.4	37.9	52.7	77.0	85.7	91.1	96.4	
DEC	12.1	16.8	17.3	25.5	0	38.0	51.5	75.0	71.8	86.1	91.4	
Total	153.1	175.1	233.2	292.9	334.2	441.5	525.2	789.6	942.0	1062.8	1004.2	793.7

Table 4.6 Energy Generation in Past by Power Station (8/8)

(F-5) MOYALE (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0	0	0	0	0	0	0	0	0	19.0		46.8
FEB	0	0	0	0	0	0	0	0	0	24.7		42.4
MAR	0	0	0	0	0	0	0	0	0	25.8		48.2
APR	0	0	0	0	0	0	0	0	0	25.6		46.3
MAY	0	0	0	0	0	0	0	0	0	26.5		46.9
JUN	0	0	0	0	0	0	0	0	14.5	28.1		51.1
JUL	0	0	0	0	0	0	0	0	8.6	31.0	43.3	59.8
AUG	0	0	0	0	0	0	0	0	10.9	32.5	48.3	61.6
SEP	0	0	0	0	0	0	0	0	12.4	34.0	51.3	57.0
OCT	0	0	0	0	0	0	0	0	13.8	38.4	49.6	64.5
NOV	0	0	0	0	0	0	0	0	17.7	38.1	48.7	
DEC	0	0	0	0	0	0	0	0	24.5	38.9	38.4	
Total	0	0	0	0	0	0	0	0	102.4	364.6	279.6	524.6

(F-6) MARSABIT (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	0	23.8	25.7	31.0	35.9	42.3	47.5	65.7	70.7	74.1	83.3	87.2
FEB	0	21.1	25.8	28.9	32.8	41.4	51.1	60.1	65.5	68.2	81.0	85.3
MAR	0	23.5	26.4	34.8	37.5	45.3	57.9	66.1	73.7	74.6	86.0	92.8
APR	0	22.9	25.8	32.9	38.0	41.8	56.3	68.3	72.6	73.3	85.2	90.9
MAY	0	24.0	26.1	34.3	38.9	42.7	0	72.7	78.6	78.3	84.9	102.2
JUN	0	23.0	27.5	32.8	37.5	44.0	57.3	72.2	78.0	79.1	87.2	90.5
JUL	0	24.5	29.9	32.6	41.4	49.3	60.3	77.4	78.2	79.3	89.9	96.1
AUG	0	25.5	28.3	31.9	39.0	48.3	63.5	69.8	77.8	82.6	81.1	107.2
SEP	0	24.6	29.6	33.6	39.0	45.5	62.1	67.3	77.1	79.5		89.0
OCT	0	27.3	31.5	37.3	43.8	48.1	67.3	71.9	83.3	83.3	82.9	113.3
NOV	0	26.7	33.5	35.9	42.9	47.6	69.2	73.7	84.3	80.5	91.2	103.3
DEC	0	25.8	30.9	37.2	43.8	48.2	63.7	74.2	79.9	76.8	100.2	101.5
Total	0	292.7	341.0	403.2	470.5	544.5	656.2	839.4	919.7	929.6	952.9	1159.3

(F-7) LAMU (MWh)

Month	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JAN	76.8	81.2	94.8	110.6	120.7	0	138.4	142.8	161.8	179.2	182.3	205.6
FEB	74.2	69.9	91.8	109.3	105.5	117.3	128.2	131.0	147.4	167.0	176.9	196.1
MAR	82.5	77.5	96.4	114.5	119.9	132.1	139.3	129.9	164.3	188.5	196.1	223.7
APR	75.1	80.1	96.2	111.6	55.9	125.4	138.1	143.5	151.6	179.8	179.5	213.3
MAY	70.5	75.9	86.3	95.6	107.6	111.4	121.0	140.9	158.0	180.1	185.2	211.6
JUN	61.0	73.4	89.0	97.5	99.4	119.3	129.9	138.2	145.7	162.2	174.1	197.9
JUL	71.5	0	99.8	111.9	117.5	119.4	134.1	135.1	157.0	177.4	188.4	220.9
AUG	81.9	90.9	105.0	110.3	113.4	125.9	132.7	147.7	168.1	182.2	191.9	231.0
SEP	77.2	83.8	95.2	104.1	110.9	115.4	124.0	142.0	15.2	175.6	191.4	224.2
OCT	81.3	88.0	100.2	109.6	113.8	124.7	132.6	153.1	171.8	186.9	200.5	245.0
NOV	77.5	83.6	105.5	105.4	114.7	124.6	135.6	151.6	171.7	186.1	206.1	238.4
DEC	80.2	92.5	113.4	118.3	122.4	134.2	152.2	164.1	175.1	188.2	204.6	
Total	909.7	896.8	1173.6	1298.7	1301.7	1349.7	1606.1	1719.9	1788.7	2153.2	2276.9	2407.7

Table 4.7 Total Power Supply and KPLC Electricity Sales by Consumer's Group

(MWh)

Region and Tariff Category	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	(Jan-Jun) 1986	86/87	87/88	88/89
Nairobi Region																		
Group -1	168892	180504	192345	208052	217373	244314	252352	252533	261766	283498	292195	312274	331036	339585	184610	405029	488987	n.a
Group -2	230350	263694	287498	299620	333105	376693	406704	428309	466581	510796	514802	521546	550393	613912	322474	681828	719525	n.a
Group -3	106065	108162	107607	119388	115673	101627	106768	110007	99163	105650	101767	96562	103959	95536	47050	100754	94616	n.a
Subtotal	505307	552360	587450	627060	666151	722634	765824	790849	827510	899944	908764	930382	985388	1049033	554134	1187611	1303128	n.a
Coast Region																		
Group -1	41375	45290	50482	53428	52866	58465	64566	69312	72904	81557	80356	85726	88661	98541	n.a	112950	135251	n.a
Group -2	144352	148861	168649	179650	209879	238451	261680	270020	279373	304322	307778	309967	317821	337312	n.a	382643	405392	n.a
Group -3	4765	5063	4778	5051	4879	4444	4463	4537	4742	4504	4301	4378	4298	3848	n.a	3566	3135	n.a
Subtotal	190492	199214	223909	238192	267624	301360	331609	343869	357019	390383	392435	400071	410780	439710	n.a	499159	543778	n.a
Rift Valley Region																		
Group -1	14154	15042	15913	17700	18655	18700	21706	23515	25118	28337	33639	32338	33113	36423	n.a	37683	47841	n.a
Group -2	20561	22237	23853	27382	34905	43195	46242	44835	44929	48298	50730	50865	56094	62042	n.a	77699	87094	n.a
Group -3	3605	4595	4522	5827	5935	1387	1626	2475	1908	1912	2177	1866	2595	907	n.a	1931	1716	n.a
Subtotal	38320	41874	44288	50909	59495	63282	69574	70825	71955	78547	86546	85069	91802	99372	n.a	117313	136651	n.a
Western Region																		
Group -1	18399	19644	21772	25121	23924	28531	30772	36394	34427	36707	39577	40947	45196	50457	n.a	55656	75290	n.a
Group -2	38821	43165	43849	55925	61427	84244	99109	127399	133839	139304	151927	161277	171931	214926	n.a	247314	267394	n.a
Group -3	3508	3462	3763	4284	3855	3580	3679	3888	3680	3839	3742	3923	3267	3448	n.a	2977	2831	n.a
Subtotal	60728	66271	69384	85330	89206	116355	133560	167681	171946	179850	195246	206147	220394	268831	n.a	305947	345515	n.a
Mt.Kenya Region																		
Group -1	included in sales of Nairobi Region							16941	18945	19170	20446	22541	24692	29139	n.a	31684	40735	n.a
Group -2								17507	19256	22822	25758	30407	39556	56033	n.a	61568	61647	n.a
Group -3								1712	1860	1886	2115	1873	2067	1885	n.a	1650	1880	n.a
Subtotal								36160	40061	43878	48319	54821	66315	87057	n.a	94902	104262	n.a
Total of whole Kenya in KPLC Power Grid																		
Group -1	242820	260480	280512	304301	312818	350010	370296	398695	413160	449269	466213	493826	522698	544145	(184610)	643002	788104	734000
Group -2	434084	477957	523849	562577	639316	472583	813735	888070	943978	1025542	1050995	1074062	1135795	1284234	(322474)	1451052	1541052	1552000
Group -3	117943	121282	120670	134550	130342	111038	116536	122619	111353	117791	114102	108602	116186	105624	(47050)	110878	104178	114000
Grand Total	794847	859719	925031	1001428	1082476	1203631	1300567	1409384	1468491	1592601	1631310	1676490	1774679	1944003	(554134)	2204932	2433334	2401000

Table 4.8 Number of Consumers in the Past (1/2)

	A0	A1	B0	B1	B2	B3	C1	C2	C3	D0	E0	F1-F9	TOTAL
NAIROBI AREA													
As in Dec. 1980	60,273	-	-	601	19	1	40	22	4	717	18	857	62,552
1981	64,226	-	-	660	17	0	43	25	5	778	16	864	66,634
1982	68,183	-	-	715	19	0	44	28	5	899	16	897	70,806
1983	72,478	-	115	641	16	0	42	31	5	991	17	935	75,296
1984													
1985	68,174	13,488	137	672	17	0	52	39	5	797	19	860	84,260
As in Jun. 1986	69,995	13,872	143	704	17	0	54	39	5	851	18	897	86,595
1987	73,351	14,789	154	730	17	0	60	42	5	826	30	971	90,975
1988	76,605	15,639	171	781	14	0	64	47	5	845	31	1,076	95,278
1989	109,236	19,092	174	844	12	0	72	49	5	1,023	38	1,141	131,686
COAST AREA													
As in Dec. 1980	31,650	-	-	215	5	3	13	8	0	91	8	277	32,270
1981	33,431	-	-	234	3	0	12	10	1	134	5	294	34,124
1982	35,123	-	-	251	2	0	14	12	2	123	6	311	35,844
1983	35,460	-	4	226	1	0	21	12	3	82	5	322	36,136
1984													
1985	32,100	5,944	3	239	1	0	29	13	3	53	4	357	38,746
As in Jun. 1986	32,372	6,203	4	271	1	0	28	13	3	54	3	358	39,310
1987	33,280	6,581	3	277	1	0	30	13	3	46	3	399	40,636
1988	34,701	6,977	2	270	4	0	42	15	3	51	4	407	42,476
1989	36,563	7,571	4	278	3	0	42	15	3	54	4	421	44,958
RIFT VALLEY AREA													
As in Dec. 1980	9,318	-	-	109	0	0	6	1	0	50	24	56	9,564
1981	9,903	-	-	108	0	0	7	1	0	52	24	80	10,175
1982	10,550	-	-	120	0	0	8	1	0	53	24	92	10,848
1983	11,040	-	22	106	0	0	8	1	0	54	23	88	11,342
1984													
1985	9,116	2,894	39	118	0	0	8	4	0	48	20	120	12,367
As in Jun. 1986	9,602	3,002	48	128	0	0	9	4	0	48	21	128	12,990
1987	9,839	3,099	53	140	0	0	9	5	0	46	23	157	13,371
1988	10,652	3,298	68	150	1	0	10	5	0	46	24	234	14,488
1989	36,563	7,571	4	278	3	0	42	15	3	54	4	421	44,958
WESTERN AREA													
As in Dec. 1980	15,751	-	-	129	5	0	8	7	0	21	19	187	16,127
1981	16,764	-	-	145	3	0	8	9	0	27	14	185	17,155
1982	17,791	-	-	155	3	0	9	11	0	30	14	189	18,202
1983	18,878	-	10	145	4	0	9	11	0	30	14	192	19,293
1984													
1985	15,319	5,233	9	176	5	0	8	10	1	25	12	217	21,015
As in Jun. 1986	15,637	5,402	9	178	4	0	10	12	1	20	10	232	21,515
1987	16,490	5,786	9	190	4	0	11	13	1	26	10	267	22,807
1988	17,180	6,092	11	177	3	0	24	16	1	18	11	287	23,820
1989	18,494	6,592	11	182	7	0	30	15	1	19	11	300	25,662

Table 4.8 Number of Consumers in the Past (2/2)

		A0	A1	B0	B1	B2	B3	C1	C2	C3	D0	E0	F1-F9	TOTAL
MT.KENYA AREA														
As in Dec.	1980	3,104	-	-	58	1	0	2	1	0	28	7	83	3,284
	1981	8,800	-	-	62	1	0	2	1	0	24	7	84	8,981
	1982	9,449	-	-	71	1	0	2	1	0	32	7	99	9,662
	1983	10,188	-	3	74	1	0	2	1	0	37	7	117	10,430
	1984													
	1985	7,791	3,945	4	84	1	0	3	3	0	27	6	183	12,047
As in Jun.	1986	8,085	4,051	6	78	1	0	3	3	0	30	6	199	12,462
	1987	8,775	4,350	8	84	0	0	2	4	0	25	7	213	13,468
	1988	9,578	4,705	8	87	0	0	8	3	0	27	8	267	14,691
	1989	10,617	5,414	12	97	0	0	12	3	0	29	9	295	16,488
TOTAL KPLC NUMBER OF CONSUMERS														
As in Dec.	1980	120,096	-	-	1,112	30	4	69	39	4	907	76	1,460	123,797
	1981	133,124	-	-	1,209	24	0	72	46	6	1,015	66	1,507	137,069
	1982	141,096	-	-	1,312	25	0	77	53	7	1,137	67	1,588	145,362
	1983	148,042	-	154	1,192	22	0	82	56	8	1,194	66	1,654	152,470
	1984													
	1985	132,500	31,504	192	1,289	24	0	100	69	9	950	61	1,737	168,435
As in Jun.	1986	135,691	32,530	210	1,359	23	0	104	71	9	1,003	58	1,814	172,872
	1987	141,735	34,605	227	1,421	22	0	112	77	9	969	73	2,007	181,257
	1988	148,716	36,711	260	1,465	22	0	148	86	9	987	78	2,271	190,753
	1989	186,346	42,378	275	1,562	24	0	166	86	9	1,166	82	2,403	234,497
R.E.F. NUMBER OF CONSUMERS														
As in Dec.	1980	1,426	-	-	7	0	0	0	0	0	0	0	1	1,434
	1981	2,364	-	-	7	0	0	0	0	0	1	0	6	2,378
	1982	3,122	-	-	8	0	0	0	0	0	0	0	9	3,139
	1983	4,410	-	-	10	0	0	0	0	0	0	6	10	4,436
	1984													
	1985	3,730	2,288	0	23	0	0	0	0	0	1	6	21	6,072
As in Jun.	1986	4,018	2,559	0	22	0	0	0	0	0	2	6	24	6,631
	1987	5,100	3,531	2	0	0	0	0	0	0	0	6	32	8,673
	1988	6,518	4,850	3	38	0	0	0	1	0	0	6	43	11,459
	1989	8,799	6,195	4	58	0	0	2	1	0	3	6	64	15,132
COUNTRY-WIDE (KPLC PLUS R.E.F.) NUMBER OF CONSUMERS														
As in Dec.	1980	121,522	-	-	1,119	30	4	69	39	4	907	76	1,461	125,231
	1981	135,488	-	-	1,216	24	0	72	46	6	1,016	66	1,513	139,447
	1982	144,218	-	-	1,320	25	0	77	53	7	1,137	67	1,597	148,501
	1983	152,452	-	154	1,202	22	0	82	56	8	1,194	72	1,664	156,906
	1984													
	1985	136,230	33,792	192	1,312	24	0	100	69	9	951	67	1,758	174,504
As in Jun.	1986	139,709	35,089	210	1,381	23	0	104	71	9	1,005	64	1,838	179,503
	1987	146,835	38,136	229	1,421	22	0	112	77	9	969	79	2,039	189,928
	1988	155,234	41,561	263	1,503	22	0	148	87	9	987	84	2,314	202,212
	1989	195,145	48,573	279	1,620	24	0	168	87	9	1,169	88	2,467	249,629

Table 4.9 Regional and National Electric Load Forecast (Median Growth)

REGIONAL LOAD FORECAST (MEDIAN)	1987/88 (actual)	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
NAIROBI REGION																												
Domestic Sales, (GWh)	489.0	511.1	532.9	554.9	577.2	600.9	625.8	651.9	679.6	708.6	739.2	770.7	804.9	841.1	878.7	917.8	958.0	998.9	1041.4	1085.7	1131.8	1179.9	1230.1	1282.4	1336.9	1393.7	1453.0	1514.8
Commerc. & Indust. Sales, (GWh)	719.5	760.0	799.2	841.5	880.9	922.2	968.0	1015.5	1065.4	1117.8	1172.9	1229.8	1291.2	1355.6	1422.7	1492.1	1563.2	1633.4	1710.6	1791.4	1876.1	1964.8	2057.7	2154.9	2256.8	2363.5	2475.2	2592.2
Off-Peak Sales, (GWh)	94.6	92.1	91.4	91.4	92.8	94.8	96.6	98.8	101.0	103.3	106.0	107.6	112.1	113.6	118.7	121.5	123.7	125.0	127.9	130.2	133.9	136.9	140.1	143.2	146.6	150.0	153.4	156.9
Total Energy Sales of KPLC, (GWh)	1303.1	1363.2	1423.5	1487.8	1550.9	1617.9	1690.4	1766.2	1845.9	1929.7	2018.1	2108.1	2208.1	2312.2	2420.1	2531.4	2645.0	2757.3	2879.9	3008.0	3141.8	3281.7	3427.9	3580.6	3740.3	3907.2	4081.6	4263.9
Growth Rate of Energy Sales, (%)	-	4.6	4.4	4.5	4.2	4.3	4.5	4.5	4.5	4.5	4.6	4.5	4.7	4.7	4.7	4.6	4.5	4.2	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Regional Load Factor, (%)	-	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Peak Load, (MW)	231.0	259.4	270.8	283.1	295.1	307.8	321.6	336.0	351.2	367.1	384.0	401.1	420.1	439.9	460.4	481.6	503.2	524.6	547.9	572.3	597.8	624.4	652.2	681.2	711.6	743.4	776.6	811.2
Growth Rate of Peak Load, (%)	-	12.3	4.4	4.5	4.2	4.3	4.5	4.5	4.5	4.5	4.6	4.5	4.7	4.7	4.7	4.6	4.5	4.2	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5
COAST REGION																												
Domestic Sales, (GWh)	135.3	142.4	149.6	156.8	164.3	172.3	180.7	189.8	199.3	209.3	220.0	231.1	243.3	256.2	269.9	284.2	299.0	314.2	330.0	346.7	364.2	382.5	401.8	422.1	443.4	465.8	489.3	514.0
Commerc. & Indust. Sales, (GWh)	405.4	433.3	457.2	483.7	501.4	520.3	540.1	560.8	582.4	604.8	628.1	651.8	677.2	703.4	730.4	758.1	786.1	814.1	843.0	872.9	903.9	936.0	969.3	1003.7	1039.3	1076.2	1114.5	1154.0
Off-Peak Sales, (GWh)	3.1	3.7	3.7	3.7	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.3	4.5	4.7	4.8	4.9	5.0	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Total Energy Sales of KPLC, (GWh)	543.8	579.4	610.5	644.2	669.4	696.4	724.7	754.6	785.8	818.3	852.4	887.2	925.0	964.4	1005.1	1047.2	1090.1	1133.3	1178.2	1224.8	1273.3	1323.8	1376.3	1431.0	1488.0	1547.3	1609.0	1673.3
Growth Rate of Energy Sales, (%)	-	6.6	5.4	5.5	3.9	4.0	4.1	4.1	4.1	4.1	4.2	4.1	4.3	4.3	4.2	4.2	4.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Regional Load Factor, (%)	-	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
Peak Load, (MW)	107.0	103.4	108.9	114.9	119.4	124.2	129.3	134.6	140.2	146.0	152.0	158.3	165.0	172.0	179.3	186.8	194.4	202.1	210.2	218.5	227.1	236.1	245.5	255.2	265.4	276.0	287.0	298.5
Growth Rate of Peak Load, (%)	-	-3.36	5.4	5.5	3.9	4.0	4.1	4.1	4.1	4.1	4.2	4.1	4.3	4.3	4.2	4.2	4.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
RIFT VALLEY REGION																												
Domestic Sales, (GWh)	47.8	51.0	54.3	57.7	61.2	64.9	69.0	73.4	78.0	83.1	88.6	94.2	100.7	107.4	114.8	122.6	130.7	139.2	148.4	158.2	168.6	179.6	191.5	204.1	217.5	231.8	247.1	263.3
Commerc. & Indust. Sales, (GWh)	87.1	96.0	104.3	109.1	113.6	118.4	123.5	129.0	134.6	140.5	146.7	153.0	159.9	166.9	174.3	181.8	189.5	197.3	205.3	213.6	222.3	231.3	240.7	250.5	260.7	271.3	282.3	293.8
Off-Peak Sales, (GWh)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Energy Sales of KPLC, (GWh)	136.7	148.7	160.3	168.5	176.5	185.1	194.2	204.1	214.3	225.4	237.0	249.0	262.2	276.1	290.8	306.2	321.9	338.2	355.4	373.5	392.6	412.7	433.9	456.3	479.9	504.8	531.1	558.8
Growth Rate of Energy Sales, (%)	-	8.8	7.8	5.1	4.7	4.9	5.0	5.1	5.0	5.2	5.2	5.1	5.3	5.3	5.3	5.2	5.1	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.2
Regional Load Factor, (%)	-	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Peak Load, (MW)	30.0	33.9	36.6	38.5	40.3	42.3	44.3	46.6	48.9	51.5	54.1	56.8	59.9	63.0	66.4	69.9	73.5	77.2	81.1	85.3	89.6	94.2	99.1	104.2	109.6	115.3	121.3	127.6
Growth Rate of Peak Load, (%)	-	13.2	7.8	5.1	4.7	4.9	5.0	5.1	5.0	5.2	5.2	5.1	5.3	5.3	5.3	5.3	5.2	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.2
WESTERN REGION																												
Domestic Sales, (GWh)	75.3	80.5	85.8	91.1	96.8	102.8	109.4	116.4	123.9	132.0	140.7	150.0	160.3	171.3	183.1	195.7	209.0	222.7	237.5	253.2	270.1	288.0	307.1	327.5	349.2	372.4	397.1	423.4
Commerc. & Indust. Sales, (GWh)	267.4	286.4	305.0	326.9	350.2	375.8	403.6	433.6	466.1	501.1	539.0	579.0	623.3	671.1	722.3	776.7	834.0	893.7	957.3	1025.4	1098.4	1176.6	1260.4	1350.1	1446.3	1549.2	1659.5	1777.6
Off-Peak Sales, (GWh)	2.8	3.3	3.3	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.2	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Energy Sales of KPLC, (GWh)	345.5	370.2	394.1	421.3	450.4	482.1	516.5	553.7	593.7	636.9	683.6	733.0	787.8	846.7	909.8	976.9	1047.5	1121.0	1199.4	1283.3	1373.1	1469.2	1572.1	1682.2	1800.0	1926.2	2061.2	2205.7
Growth Rate of Energy Sales, (%)	-	7.2	6.5	6.9	6.9	7.0	7.1	7.2	7.2	7.3	7.3	7.2	7.5	7.5	7.4	7.4	7.2	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Regional Load Factor, (%)	-	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Peak Load, (MW)	79.0	81.3	86.5	92.5	98.9	105.8	113.4	121.5	130.3	139.8	150.1	160.9	172.9	185.9	199.7	214.5	230.0	246.1	263.3	281.7	301.4	322.5	345.1	369.3	395.2	422.9	452.5	484.2
Growth Rate of Peak Load, (%)	-	2.9	6.5	6.9	6.9	7.0	7.1	7.2	7.2	7.3	7.3	7.2	7.5	7.5	7.4	7.4	7.2	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
MT. KENYA REGION																												
Domestic Sales, (GWh)	40.7	44.2	47.8	51.6	55.4	59.7	64.5	69.6	75.2	81.2	88.0	95.1	103.1	112.1	121.6	132.1	143.2	154.9	167.7	181.6	196.6	212.8	230.4	249.4	270.1	292.4	316.5	342.7
Commerc. & Indust. Sales, (GWh)	61.6	57.8	62.1	68.1	74.9	82.6	91.1	100.7	111.3	123.0	136.1	150.3	166.5	184.5	204.3	226.0	249.7	274.9	302.7	333.3	367.1	404.2	445.1	490.2	539.8	594.5	654.7	720.9
Off-Peak Sales, (GWh)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total Energy Sales of KPLC, (GWh)	104.3	103.9	111.8	121.6	132.2	144.2	157.5	172.1	188.5	206.3	226.1	247.5	271.8	298.9	328.2	360.5	395.2	432.3	472.9	517.4	566.1	619.5	678.0	742.2	812.4	889.4	973.7	1066.1
Growth Rate of Energy Sales, (%)	-	-0.3	7.6	8.7	8.7	9.1	9.2	9.3	9.5	9.4	9.6	9.4	9.8	9.9	9.8	9.8	9.6	9.4	9.4	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.5
Regional Load Factor, (%)	-	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Peak Load, (MW)	22.0	26.4	28.4	30.8	33.5	36.6	40.0	43.7	47.8	52.3	57.4	62.8	69.0	75.8	83.3	91.4	100.3	109.7	120.0	131.2	143.6	157.2	172.0	188.3	206.1	225.6	247.0	270.5
Growth Rate of Peak Load, (%)	-	19.9	7.6	8.7	8.7	9.1	9.2	9.3	9.5	9.4	9.6	9.4	9.8	9.9	9.8	9.8	9.6	9.4	9.4	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.5
NATIONAL TOTAL																												
Domestic Sales, (GWh)	788.1	829.4	870.5	912.1	954.8	1000.6	1049.3	1101.1	1155.9	1214.2	1276.5	1341.1	1412.2	1488.1	1568.1	1652.4	1739.9	1829.9	1925.0	2025.3	2131.2	2242.9	2360.9	2485.5	2617.1	2756.1	2903.0	3058.2
Commerc. & Indust. Sales, (GWh)	1541.0	1633.4	1727.9	1829.4	1921.0	2019.3	2126.3	2239.6	2359.8	2487.3	2622.8	2764.0	2918.1	3081.5	3254.0	3434.7	3622.5	3813.3	4018.8	4236.8	4467.9	4713.1	4973.3	5249.5	5542.9	5854.7	6186.2	6538.6
Off-Peak Sales, (GWh)	104.1	102.7	103.0	102.0	103.5	105.7	107.7	110.0	112.5	115.0	118.0	119.7	124.7	128.6	131.9	135.0	137.3	138.8	141.9	144.9	147.9	150.9	154.1	157.3	160.6	164.0	167.4	171.0
Total Energy Sales of KPLC, (GWh)	2433.4	2565.5	2700.4	2843.4	2979.3	3125.6	3283.4	3450.7	3628.2	3816.5	4017.3	4224.8	4455.0	4698.3	4954.1	5222.1	5499.8	5782.0	6085.7	6406.9	6745.9	7106.9	7488.2	7892.3	8320.6	8774.8	9256.6	9767.8
Growth Rate of Energy Sales, (%)	-	5.4	5.3	5.3	4.8	4.9	5.0	5.1	5.1	5.2	5.3	5.2	5.4	5.5	5.4	5.4	5.3	5.1	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.5	5.5	5.5
Regional Load Factor, (%)	-	58.1	58.0	58.0	57.9	57.9	57.8	57.7	57.6	57.6	57.5	57.4	57.3	57.3	57.2	57.1	57.0	56.9	56.8	56.7	56.7	56.6	56.5	56.4	56.3	56.2	56.1	56.0
Peak Load, (MW)	469.0	504.3	531.2	559.8	587.2	616.7	648.6	682.4	718.4	756.7	797.6	839.9	886.9	936.7	989.1	1044.2	1101.4	1159.7	1222.5	1289.0	1359.6	1434.4	1513.9	1598.2	1687.9	1783.1	1884.3	1992.0
Growth Rate of Peak Load, (%)	-	7.5	5.3	5.4	4.9	5.0	5.2	5.2	5.3	5.3	5.4	5.3	5.6	5.6	5.6	5.6	5.5	5.3	5.4	5.4	5.5	5.5	5.5	5.6	5.6	5.6	5.7	5.7
Network Losses, (GWh) : 16.2%		415.6	437.5	460.6	482.6	506.4	531.9	559.0	587.8	618.3	650.8	684.4	721.7	761.1	802.6	846.0	891.0	936.7	985.9	1037.9	1093.0	1151.3	1213.1	1278.6	1347.9	1421.5	1499.6	1582.4
Station-Use Energy, (GWh) : 1.4%		41.7	43.9	46.3	48.5	50.8	53.4	56.1	59.0	62.1	65.4	68.7	72.5	76.4	80.6	85.0	89.5	94.1	99.0	104.2	109.8	115.6	121.8	128.4	135.4	142.7	150.5	158.9
Gross Generation Requirement, (GWh)		3022.8	3181.8	3350.5	3510.4	3682.8	3868.7	4065.9	4275.0	4496.9	4733.4	4978.0	5249.1	5535.8	5837.2	6153.0	6480.2	6812.8	7170.6	7549.1	7949.7	8373.8	8823.2	9299.3	9803.9	10339.1	10906.7	11509.5

Table 4.10 Regional and National Electire Load Forecast (Low Growth)

REGIONAL LOAD FORECAST (LOW)	1987/88 (actual)	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
NAIROBI REGION																												
Domestic Sales, (GWh)	489.0	509.4	530.3	551.6	572.4	594.6	617.8	642.2	668.0	694.8	723.3	752.4	784.1	817.5	852.3	888.3	925.3	962.7	1,001.5	1,041.9	1,084.0	1,127.7	1,173.2	1,220.5	1,269.8	1,321.0	1,374.3	1,429.8
Commerc. & Indust. Sales, (GWh)	719.5	757.1	792.2	829.8	860.9	894.2	929.5	966.7	1,005.8	1,046.6	1,089.5	1,133.4	1,180.6	1,230.2	1,281.5	1,334.1	1,387.8	1,441.7	1,497.4	1,555.3	1,615.5	1,678.0	1,742.9	1,810.3	1,880.3	1,953.1	2,028.6	2,107.1
Off-Peak Sales, (GWh)	94.6	92.1	91.4	91.4	92.8	94.8	96.6	98.8	101.0	103.3	106.0	107.6	112.1	115.6	118.7	121.5	125.7	125.0	127.9	130.8	133.9	136.9	140.1	143.3	146.6	150.0	153.4	156.9
Total Energy Sales of KPLC, (GWh)	1,303.1	1,358.5	1,414.0	1,472.8	1,526.1	1,583.6	1,643.9	1,707.7	1,774.8	1,844.8	1,918.8	1,993.4	2,076.9	2,163.3	2,252.5	2,343.9	2,436.8	2,529.3	2,626.8	2,728.1	2,833.5	2,942.6	3,056.2	3,174.1	3,296.7	3,424.0	3,556.3	3,693.8
Growth Rate of Energy Sales, (%)	-	4.3	4.1	4.2	3.6	3.8	3.8	3.9	3.9	3.9	4.0	3.9	4.2	4.2	4.1	4.1	4.0	3.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Regional Load Factor, (%)	-	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Peak Load, (MW)	231.0	258.5	269.0	280.2	290.4	301.3	312.8	324.9	337.7	351.0	365.1	379.3	395.1	411.6	428.6	445.9	463.6	481.2	499.8	519.0	539.1	559.9	581.5	603.9	627.2	651.5	676.6	702.8
Growth Rate of Peak Load, (%)	-	11.9	4.1	4.2	3.6	3.8	3.8	3.9	3.9	3.9	4.0	3.9	4.2	4.2	4.1	4.1	4.0	3.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
COAST REGION																												
Domestic Sales, (GWh)	135.5	142.2	149.2	156.2	163.2	170.6	178.6	186.9	195.8	205.1	215.1	225.3	236.6	248.6	261.1	274.2	287.8	301.6	316.0	331.2	347.0	363.6	381.1	399.3	418.4	438.5	459.5	481.5
Commerc. & Indust. Sales, (GWh)	405.4	431.9	454.0	470.1	483.8	498.5	513.6	529.8	546.4	563.8	581.8	600.0	619.5	639.7	660.5	681.4	702.7	723.8	745.5	767.9	790.9	814.7	839.1	864.3	890.2	916.9	944.4	972.7
Off-Peak Sales, (GWh)	3.1	3.7	3.7	3.7	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.3	4.5	4.7	4.8	4.9	5.0	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Total Energy Sales of KPLC, (GWh)	543.8	577.8	606.9	629.9	650.7	672.9	696.1	720.7	746.4	773.1	801.1	829.7	860.6	893.0	926.3	960.5	995.5	1,030.4	1,066.8	1,104.3	1,143.1	1,183.5	1,225.3	1,268.8	1,313.8	1,360.6	1,409.1	1,459.4
Growth Rate of Energy Sales, (%)	-	6.3	5.0	3.8	3.3	3.4	3.4	3.5	3.6	3.6	3.6	3.6	3.7	3.8	3.7	3.7	3.6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6
Regional Load Factor, (%)	-	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
Peak Load, (MW)	107.0	103.1	108.3	112.4	116.1	120.0	124.2	128.5	133.1	137.9	142.9	148.0	153.5	159.3	165.2	171.3	177.6	183.8	190.3	197.0	203.9	211.1	218.6	226.3	234.3	242.7	251.3	260.3
Growth Rate of Peak Load, (%)	-	-3.7	5.0	3.8	3.3	3.4	3.4	3.5	3.6	3.6	3.6	3.6	3.7	3.8	3.7	3.7	3.6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6
RIFT VALLEY REGION																												
Domestic Sales, (GWh)	47.8	51.0	54.1	57.4	60.7	64.2	68.0	72.0	76.4	81.0	86.0	91.4	97.2	103.4	110.1	117.2	124.7	132.3	140.5	149.1	158.4	168.2	178.6	189.6	201.3	213.8	227.0	241.1
Commerc. & Indust. Sales, (GWh)	87.1	95.6	103.5	107.8	111.3	115.2	119.2	123.5	128.0	132.6	137.3	142.3	147.5	153.0	158.7	164.6	170.4	176.3	182.3	188.6	195.1	201.9	208.8	216.0	223.5	231.2	239.2	247.4
Off-Peak Sales, (GWh)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Energy Sales of KPLC, (GWh)	136.7	148.3	159.3	166.9	173.7	181.1	188.9	197.2	206.0	215.3	225.1	235.4	246.4	258.1	270.6	283.4	296.8	310.2	324.5	339.5	355.2	371.7	389.1	407.4	426.6	446.7	467.9	490.2
Growth Rate of Energy Sales, (%)	-	8.6	7.4	4.7	4.1	4.3	4.3	4.4	4.5	4.5	4.5	4.6	4.7	4.8	4.8	4.8	4.7	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.8
Regional Load Factor, (%)	-	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Peak Load, (MW)	30.0	33.9	36.4	38.1	39.7	41.3	43.1	45.0	47.0	49.2	51.4	53.7	56.3	58.9	61.8	64.7	67.8	70.8	74.1	77.5	81.1	84.9	88.8	93.0	97.4	102.0	106.8	111.9
Growth Rate of Peak Load, (%)	-	12.9	7.4	4.7	4.1	4.3	4.3	4.4	4.5	4.5	4.5	4.6	4.7	4.8	4.8	4.8	4.7	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.8
WESTERN REGION																												
Domestic Sales, (GWh)	75.3	80.3	85.3	90.6	95.8	101.5	107.5	114.0	121.1	128.5	136.5	145.0	154.4	164.5	175.3	186.7	198.7	211.0	224.3	238.4	253.4	269.4	286.3	304.4	323.5	343.9	365.5	388.5
Commerc. & Indust. Sales, (GWh)	267.4	284.8	301.2	320.3	338.6	358.6	380.2	403.5	428.4	455.0	483.6	513.4	546.4	581.6	618.9	658.1	698.9	741.0	785.3	832.3	882.1	934.9	990.9	1,050.2	1,113.0	1,179.7	1,250.3	1,325.1
Off-Peak Sales, (GWh)	2.8	3.3	3.3	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.2	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Energy Sales of KPLC, (GWh)	345.5	368.4	389.8	414.2	437.8	463.6	491.3	521.1	553.2	587.4	624.1	662.5	705.0	750.4	798.6	849.3	902.1	956.6	1,014.2	1,075.4	1,140.2	1,208.9	1,281.8	1,359.1	1,441.2	1,528.1	1,620.4	1,718.2
Growth Rate of Energy Sales, (%)	-	6.6	5.8	6.3	5.7	5.9	6.0	6.1	6.2	6.2	6.3	6.2	6.4	6.4	6.4	6.3	6.2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Regional Load Factor, (%)	-	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Peak Load, (MW)	79.0	80.9	85.6	90.9	96.1	101.8	107.8	114.4	121.4	128.9	137.0	145.4	154.8	164.7	175.3	186.4	198.0	210.0	222.7	236.1	250.3	265.4	281.4	298.4	316.4	335.5	355.7	377.2
Growth Rate of Peak Load, (%)	-	2.4	5.8	6.3	5.7	5.9	6.0	6.1	6.2	6.2	6.3	6.2	6.4	6.4	6.4	6.3	6.2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
MT. KENYA REGION																												
Domestic Sales, (GWh)	40.7	44.1	47.5	51.1	54.7	58.7	63.0	67.8	72.9	78.6	84.6	91.2	98.5	106.4	115.2	124.5	134.5	145.0	156.2	168.2	181.2	195.3	210.3	226.6	244.1	263.0	283.3	305.2
Commerc. & Indust. Sales, (GWh)	61.6	57.4	60.9	66.2	71.5	77.5	84.0	91.2	99.2	107.8	117.3	127.5	139.0	151.6	165.3	180.2	196.8	212.6	230.6	250.2	271.4	294.8	319.4	346.5	375.9	407.8	442.4	480.0
Off-Peak Sales, (GWh)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total Energy Sales of KPLC, (GWh)	104.3	103.4	110.3	119.2	128.1	138.1	148.9	160.9	174.1	188.4	204.0	220.8	239.7	260.4	282.9	307.1	332.9	360.0	389.3	420.9	455.1	492.2	532.3	575.6	622.5	673.3	728.2	787.7
Growth Rate of Energy Sales, (%)	-	(0.8)	6.6	8.1	7.5	7.8	7.9	8.0	8.2	8.2	8.3	8.2	8.5	8.6	8.6	8.6	8.4	8.2	8.1	8.1	8.1	8.1	8.1	8.1	8.2	8.2	8.2	8.2
Regional Load Factor, (%)	-	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Peak Load, (MW)	22.0	26.2	28.0	30.2	32.5	35.0	37.8	40.8	44.2	47.8	51.8	56.0	60.8	66.1	71.8	77.9	84.4	91.3	98.8	106.8	115.5	124.9	135.0	146.0	157.9	170.8	184.7	199.8
Growth Rate of Peak Load, (%)	-	19.3	6.6	8.1	7.5	7.8	7.9	8.0	8.2	8.2	8.3	8.2	8.6	8.6	8.6	8.6	8.4	8.2	8.1	8.1	8.1	8.1	8.1	8.1	8.2	8.2	8.2	8.2
NATIONAL TOTAL																												
Domestic Sales, (GWh)	788.1	827.0	866.5	906.9	946.8	989.6	1,034.9	1,082.9	1,134.2	1,188.1	1,245.5	1,305.3	1,370.8	1,440.4	1,514.0	1,590.8	1,670.8	1,752.6	1,838.5	1,928.9	2,024.0	2,124.2	2,229.5	2,340.4	2,457.2	2,580.1	2,709.6	2,846.0
Commerc. & Indust. Sales, (GWh)	1,541.3	1,626.8	1,711.8	1,794.1	1,866.0	1,944.0	2,026.5	2,114.7	2,207.8	2,305.9	2,409.6	2,516.6	2,633.1	2,756.2	2,885.0	3,018.4	3,155.9	3,295.3	3,441.2	3,594.3	3,755.1	3,923.9	4,101.1	4,287.3	4,483.0	4,688.6	4,904.9	5,132.3
Off-Peak Sales, (GWh)	104.1	102.7	102.0	102.0	103.5	105.7	107.7	110.0	112.5	115.0	118.0	119.7	124.7	128.6	131.9	135.0	137.3	138.8	141.9	144.9	147.9	150.9	154.1	157.3	160.6	164.0	167.4	171.0
Total Energy Sales of KPLC, (GWh)	2,433.4	2,556.5	2,680.3	2,803.0	2,916.4	3,039.3	3,169.0	3,307.6	3,454.5	3,609.0	3,773.1	3,941.7	4,128.6	4,325.3	4,530.9	4,744.2	4,964.0	5,186.6	5,421.6	5,668.1	5,927.0	6,199.0	6,484.7	6,785.1	7,100.8	7,432.8	7,781.9	8,149.3
Growth Rate of Energy Sales, (%)	-	5.1	4.8	4.6	4.0	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.7	4.8	4.8	4.7	4.6	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7
National Load Factor, (%)	-	58.1	58.0	58.0	57.9	57.9	57.8	57.8	57.7	57.6	57.6	57.5	57.4	57.4	57.3	57.2	57.2	57.1	57.0	56.9	56.9	56.8	56.7	56.6	56.6	56.5	56.4	56.3
Peak Load, (MW)	469.0	502.5	527.2	551.8	574.7	599.5	625.7	653.7	683.5	714.8	748.1	782.4	820.5	860.6	902.6	946.3	991.4	1,037.2	1,085.5	1,136.4	1,189.8	1,246.1	1,305.3	1,367.6	1,433.3	1,502.4	1,575.2	1,652.0
Growth Rate of Peak Load, (%)	-	7.1	4.9	4.7	4.1	4.3	4.4	4.5	4.6	4.6	4.7	4.6	4.9	4.9	4.9	4.8	4.8	4.6	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.9
Network Losses, (GWh) : 16.2%		414.2	434.2	454.1	472.4	492.4	513.4	535.8	559.6	584.7	611.2	638.6	668.8	700.7	734.0	768.6	804.2	840.2	878.3	918.2	960.2	1,004.2	1,050.5	1,099.2	1,150.5	1,204.1	1,260.7	1,320.2
Station-Use Energy, (GWh) : 1.4%		41.6	43.6	45.6	47.4	49.4	51.6	53.8	56.2	58.7	61.4	64.1	67.2	70.4	73.7	77.2	80.8	84.4	88.2	92.2	96.4	100.8	105.5	110.4	115.5	120.9	126.6	132.6
Gross Generation Requirement, (GWh)		3,012.3	3,158.1	3,302.7	3,436.2	3,581.1	3,734.0	3,897.2	4,070.4	4,252.3	4,445.7	4,644.4	4,864.6	5,096.3	5,338.6	5,590.0	5,848.9	6,111.2	6,388.1	6,678.6	6,983.6	7,304.0	7,640.7	7,994.6	8,366.8	8,757.8	9,169.2	9,602.0

Table 4.11 Reginal and National Electric Load Forecast (High Growth)

REGIONAL LOAD FORECAST (HIGH)	1987/88 (actual)	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
NAIROBI REGION																												
Domestic Sales, (GWh)	489.0	506.7	531.4	553.0	575.3	599.2	624.1	650.4	678.1	707.2	737.7	769.2	803.3	839.1	876.6	915.4	955.5	996.1	1,039.6	1,085.0	1,132.4	1,181.8	1,233.4	1,287.2	1,343.4	1,402.0	1,463.2	1,527.1
Commerc. & Indust. Sales, (GWh)	719.5	761.1	804.1	851.4	900.9	954.0	1,010.5	1,070.5	1,133.9	1,201.0	1,271.9	1,345.5	1,425.0	1,508.8	1,596.6	1,688.0	1,782.7	1,879.0	1,980.5	2,087.4	2,200.1	2,318.9	2,444.2	2,576.1	2,715.2	2,861.9	3,016.4	3,179.3
Off-Peak Sales, (GWh)	94.6	92.1	91.4	91.4	92.8	94.8	96.6	98.8	101.0	103.3	106.0	107.6	112.1	115.6	118.7	121.5	123.7	125.0	127.9	130.8	133.9	136.9	140.1	143.3	146.6	150.0	153.4	156.9
Total Energy Sales of KPLC, (GWh)	1,303.1	1,359.9	1,426.9	1,495.8	1,569.0	1,648.1	1,731.2	1,819.7	1,913.0	2,011.5	2,115.6	2,222.4	2,340.3	2,463.5	2,591.9	2,724.9	2,861.9	3,009.1	3,148.0	3,303.2	3,466.3	3,637.6	3,817.6	4,006.6	4,205.2	4,413.9	4,633.1	4,863.3
Growth Rate of Energy Sales, (%)	-	4.4	4.9	4.8	4.9	5.0	5.0	5.1	5.1	5.1	5.2	5.0	5.3	5.3	5.2	5.1	5.0	5.2	4.6	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.0
Regional Load Factor, (%)	-	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Peak Load, (MW)	231.0	258.7	271.5	284.6	298.5	313.6	329.4	346.2	364.0	382.7	402.5	422.8	445.3	468.7	493.1	518.4	544.5	570.8	598.9	628.5	659.5	692.1	726.3	762.3	800.1	839.8	881.5	925.3
Growth Rate of Peak Load, (%)	-	12.0	4.9	4.8	4.9	5.0	5.0	5.1	5.1	5.1	5.2	5.0	5.3	5.3	5.2	5.1	5.0	4.8	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.0
COAST REGION																												
Domestic Sales, (GWh)	135.3	142.9	150.7	158.7	167.2	176.3	185.9	196.3	207.2	218.9	231.4	244.4	258.6	273.9	290.1	307.0	324.7	343.1	362.4	382.8	404.4	427.1	451.2	476.6	503.4	531.8	561.7	593.4
Commerc. & Indust. Sales, (GWh)	405.4	435.9	464.0	495.3	529.6	547.4	575.7	605.6	636.8	669.5	703.8	739.1	776.8	816.3	857.1	897.2	942.4	986.3	1,031.6	1,079.0	1,128.6	1,180.5	1,234.7	1,291.4	1,350.8	1,412.9	1,477.8	1,545.7
Off-Peak Sales, (GWh)	3.1	3.7	3.7	3.7	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.3	4.5	4.7	4.8	4.9	5.0	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Total Energy Sales of KPLC, (GWh)	543.8	582.5	618.4	657.7	699.5	727.6	765.6	805.8	848.1	892.6	939.5	987.8	1,039.9	1,094.9	1,152.0	1,209.0	1,272.1	1,334.4	1,399.2	1,467.0	1,538.2	1,612.8	1,691.1	1,773.2	1,859.4	1,949.9	2,044.7	2,144.3
Growth Rate of Energy Sales, (%)	-	7.1	6.2	6.4	6.4	5.2	5.2	5.3	5.2	5.2	5.3	5.1	5.3	5.3	5.2	5.0	5.2	4.9	4.9	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Regional Load Factor, (%)	-	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
Peak Load, (MW)	107.0	103.9	110.5	117.3	123.3	129.8	136.6	143.7	151.3	159.2	167.6	176.2	185.5	195.3	205.5	215.7	226.9	238.0	249.6	261.7	274.4	287.7	301.6	316.3	331.7	347.8	364.7	382.5
Growth Rate of Peak Load, (%)	-	-2.9	6.2	6.4	5.1	5.2	5.2	5.3	5.2	5.2	5.3	5.1	5.3	5.3	5.2	5.0	5.2	4.9	4.9	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9
RIFT VALLEY REGION																												
Domestic Sales, (GWh)	47.8	51.2	54.8	58.5	62.2	66.6	71.2	76.3	81.8	87.6	94.0	100.7	108.2	116.4	125.3	134.6	144.6	155.1	166.3	178.4	191.3	205.1	219.9	235.8	252.9	271.2	290.8	311.8
Commerc. & Indust. Sales, (GWh)	87.1	96.4	105.7	111.7	118.2	125.1	132.4	140.3	148.5	157.2	166.3	175.9	186.2	197.0	208.3	220.0	232.2	244.8	257.6	271.3	285.6	300.8	316.7	333.5	351.2	369.8	389.4	410.0
Off-Peak Sales, (GWh)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Energy Sales of KPLC, (GWh)	136.7	149.4	162.3	171.9	182.2	193.5	205.3	218.3	232.0	246.5	262.0	278.4	296.2	315.2	335.3	356.3	378.4	401.5	425.7	451.3	478.6	507.6	538.3	571.0	605.8	642.7	681.9	723.5
Growth Rate of Energy Sales, (%)	-	9.3	8.7	5.9	6.0	6.2	6.1	6.3	6.3	6.3	6.3	6.2	6.4	6.4	6.4	6.3	6.2	6.1	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Regional Load Factor, (%)	-	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Peak Load, (MW)	30.0	34.1	37.1	39.3	41.6	44.2	46.9	49.8	53.0	56.3	59.8	63.6	67.6	72.0	76.5	81.4	86.4	91.7	97.2	103.0	109.3	115.9	122.9	130.4	138.3	146.7	155.7	165.2
Growth Rate of Peak Load, (%)	-	13.7	8.7	5.9	6.0	6.2	6.1	6.3	6.3	6.3	6.3	6.2	6.4	6.4	6.4	6.3	6.2	6.1	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1
WESTERN REGION																												
Domestic Sales, (GWh)	75.3	80.9	86.5	92.4	98.8	105.8	113.3	121.4	130.1	139.7	149.9	160.9	173.1	186.4	200.7	215.9	232.2	249.1	267.4	287.0	308.1	330.7	355.0	381.0	409.0	439.0	471.2	505.8
Commerc. & Indust. Sales, (GWh)	267.6	289.6	313.3	341.6	374.9	412.1	453.2	498.7	548.6	603.6	664.2	729.7	803.3	882.0	972.4	1,068.4	1,171.9	1,282.5	1,402.8	1,534.5	1,678.5	1,836.1	2,008.4	2,196.9	2,403.1	2,628.7	2,875.4	3,145.5
Off-Peak Sales, (GWh)	2.8	3.3	3.3	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.2	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Energy Sales of KPLC, (GWh)	345.5	373.8	403.1	437.3	477.1	521.5	570.1	623.7	682.4	747.1	818.0	894.7	980.6	1,072.7	1,177.5	1,288.8	1,408.5	1,536.2	1,674.9	1,826.2	1,991.2	2,171.4	2,368.0	2,582.6	2,816.7	3,072.3	3,351.2	3,655.7
Growth Rate of Energy Sales, (%)	-	8.2	7.9	8.5	9.1	9.3	9.3	9.4	9.4	9.5	9.5	9.4	9.6	9.4	9.8	9.4	9.3	9.1	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1
Regional Load Factor, (%)	-	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Peak Load, (MW)	79.0	82.1	88.5	96.0	104.7	114.5	125.1	136.9	149.8	164.0	179.6	196.4	215.3	235.5	258.5	282.9	309.2	337.2	367.7	400.9	437.1	476.7	519.8	566.9	618.4	674.5	735.7	802.5
Growth Rate of Peak Load, (%)	-	3.9	7.9	8.5	9.1	9.3	9.3	9.4	9.4	9.5	9.5	9.4	9.6	9.4	9.8	9.4	9.3	9.1	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1
MT. KENYA REGION																												
Domestic Sales, (GWh)	40.7	44.6	48.4	52.4	56.9	61.9	67.4	73.4	80.0	87.1	95.1	103.7	113.5	124.3	136.1	149.1	162.9	177.9	194.2	212.0	231.5	252.7	275.9	301.2	328.8	359.0	391.9	427.9
Commerc. & Indust. Sales, (GWh)	61.6	58.8	64.4	72.3	82.2	93.6	106.7	121.7	138.8	158.3	179.6	205.7	235.0	268.4	306.3	349.0	397.0	450.3	510.3	578.4	655.6	743.1	842.3	954.6	1,082.0	1,226.4	1,390.0	1,575.5
Off-Peak Sales, (GWh)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total Energy Sales of KPLC, (GWh)	104.3	105.2	114.7	126.6	141.9	157.4	175.9	196.9	220.8	247.5	276.8	311.5	350.7	395.0	444.7	500.4	562.4	630.6	707.0	792.9	889.6	998.3	1,120.6	1,258.3	1,413.3	1,587.9	1,784.4	2,005.9
Growth Rate of Energy Sales, (%)	-	0.9	9.0	10.4	11.4	11.0	11.8	11.9	12.1	12.1	11.9	12.5	12.6	12.6	12.6	12.5	12.4	12.1	12.1	12.2	12.2	12.2	12.3	12.3	12.3	12.3	12.4	12.4
Regional Load Factor, (%)	-	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Peak Load, (MW)	22.0	26.7	29.1	32.1	35.8	39.9	44.6	50.0	56.0	62.8	70.2	79.0	89.0	100.2	113.8	126.9	142.7	160.0	179.4	201.2	225.7	253.2	284.3	319.2	358.5	402.8	452.7	508.8
Growth Rate of Peak Load, (%)	-	21.3	9.0	10.4	11.4	11.6	11.8	11.9	12.1	12.1	11.9	12.5	12.6	12.6	12.6	12.5	12.4	12.1	12.1	12.2	12.2	12.2	12.3	12.3	12.3	12.3	12.4	12.4
NATIONAL TOTAL																												
Domestic Sales, (GWh)	788.1	826.3	871.8	915.1	960.6	1,009.9	1,061.9	1,117.8	1,177.1	1,240.5	1,308.2	1,379.0	1,456.7	1,540.2	1,628.8	1,722.0	1,819.9	1,921.3	2,030.0	2,145.2	2,267.5	2,397.4	2,535.3	2,681.8	2,837.5	3,003.0	3,178.9	3,365.9
Commerc. & Indust. Sales, (GWh)	1,541.1	1,641.7	1,751.5	1,872.3	1,996.8	2,132.3	2,278.5	2,436.7	2,606.7	2,789.7	2,985.7	3,196.0	3,426.3	3,672.5	3,940.7	4,222.5	4,526.2	4,842.7	5,182.9	5,550.6	5,948.5	6,379.4	6,846.2	7,352.6	7,902.4	8,499.6	9,149.0	9,855.8
Off-Peak Sales, (GWh)	104.2	102.7	102.0	102.0	103.5	105.7	107.7	110.0	112.5	115.0	118.0	119.7	124.7	128.6	131.9	135.0	137.3	138.8	141.9	144.9	147.9	150.9	154.1	157.3	160.6	164.0	167.4	171.0
Total Energy Sales of KPLC, (GWh)	2,433.3	2,570.8	2,725.3	2,889.4	3,060.8	3,248.0	3,448.1	3,664.5	3,896.3	4,145.2	4,411.9	4,694.7	5,007.8	5,341.3	5,701.3	6,079.5	6,483.4	6,902.8	7,354.7	7,840.7	8,363.9	8,927.7	9,535.7	10,192.	10,900.	11,667.	12,495.	13,393.
Growth Rate of Energy Sales, (%)	-	5.6	6.0	6.0	5.9	6.1	6.2	6.3	6.3	6.4	6.4	6.4	6.7	6.7	6.7	6.6	6.6	6.5	6.5	6.6	6.7	6.7	6.8	6.9	7.0	7.0	7.1	7.2
Regional Load Factor, (%)	-	58.1	58.0	57.9	57.9	57.8	57.7	57.6	57.5	57.4	57.3	57.1	57.0	56.9	56.8	56.6	56.5	56.4	56.2	56.1	56.0	55.8	55.7	55.5	55.4	55.2	55.1	54.9
Peak Load, (MW)	469.0	505.5	536.4	569.3	604.0	641.9	682.6	726.7	774.0	825.0	879.7	938.0	1,002.6	1,071.6	1,146.5	1,225.3	1,309.7	1,397.7	1,492.7	1,595.2	1,705.9	1,825.6	1,955.0	2,095.1	2,246.9	2,411.6	2,590.2	2,784.3
Growth Rate of Peak Load, (%)	-	7.8	6.1	6.1	6.1	6.3	6.3	6.5	6.5	6.6	6.6	6.6	6.9	6.9	7.0	6.9	6.9	6.7	6.8	6.9	6.9	7.0	7.1	7.2	7.2	7.3	7.4	7.5
Network Losses, (GWh) : 16.2%	-	416.5	441.5	468.1	495.9	526.2	558.6	593.6	631.2	671.5	714.7	760.5	811.3	865.3	923.6	984.9	1,050.3	1,118.3	1,191.5	1,270.2	1,355.0	1,446.3	1,544.8	1,651.1	1,765.9	1,890.0	2,024.2	2,169.6
Station-Use Energy, (GWh) : 1.4%	-	41.8	44.3	47.0	49.8	52.8	56.1	59.6	63.4	67.4	71.8	76.4	81.5	86.9	92.7	98.9	105.5	112.3	119.6	127.6	136.1	145.2	155.1	165.8	177.3	189.8	203.3	217.9
Gross Generation Requirement, (GWh)	-	3,029.1	3,211.2	3,404.5	3,606.5	3,827.0	4,062.3	4,317.7	4,590.9	4,884.2	5,198.4	5,531.6	5,900.5	6,293.4	6,717.7	7,163.3	7,639.1	8,133.4	8,665.9	9,238.5	9,855.0	10,519.	11,236.	12,009.	12,844.	13,746.	14,723.	15,780.

Table 5.1 Principal Features of Development Alternatives

No.	Item	Unit	Alt-1	Alt-2	Alt-3	Alt-4.1	Alt-4.2	Alt-5	Alt-6	Alt-7
1	Annual Mean Discharge	m3/s	41.6	41.6	41.6	41.6	41.6	41.6	41.6	41.6
2	Firm Discharge	m3/s	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1
3	Full Suply Level	El.m	1662.9	1662.9	1662.9	1662.9	1662.9	1662.9	1662.9	1662.9
4	Minimum Operation Level	El.m	1606.3	1606.3	1606.3	1606.3	1606.3	1606.3	1606.3	1606.3
5	Rated Water Level	El.m	1644.0	1644.0	1644.0	1644.0	1644.0	1644.0	1644.0	1644.0
6	Tailrace Water Level	El.m	1546.0	1518.0	1458.0	1443.0	1435.0	1435.0	1399.0	1374.0
7	Length of Headrace Tunnel	m	2400	4550	7200	6900	7000	4750	4600	4450
8	Length of Penstock Tunnel	m	1160	135	1610	235	245	245	290	325
9	Length of Tailrace Tunnel	m	0	1950	0	4470	6030	5930	13450	16350
10	Headrace Tunnel Diameter	m	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
11	Tailrace Tunnel Diameter	m	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
12	Penstock Tunnel Diameter	m	4.5	4.4	4.2	4.1	4.1	4.1	4.0	4.0
13	Gross Head	m	98.0	126.0	186.0	201.0	209.0	209.0	245.0	270.0
14	Loss Head of Headrace Tunnel	m	4.1	7.9	12.4	11.9	12.1	8.2	7.9	7.7
15	Loss Head of Tailrace Tunnel	m	0.0	3.4	0.0	7.7	10.4	10.2	23.2	28.2
16	The Other Loss Head	m	2.0	2.5	3.7	4.0	4.2	4.2	4.9	5.4
17	Total Loss Head	m	6.1	13.7	16.2	23.7	26.7	22.6	36.0	41.3
18	Effective Head	m	91.9	112.3	169.9	177.4	182.4	186.5	209.0	228.7
19	Peak Power Output	MW	54.7	66.8	101.1	105.6	108.5	111.0	124.4	136.1
20	Firm Energy Output	GWh/Year	159.8	195.1	295.2	308.3	316.9	324.0	363.2	397.5
21	Secondary Energy Output	GWh/Year	33.6	41.0	62.0	64.7	66.6	68.0	76.3	83.5
22	Total Energy Output	GWh/Year	193.3	236.1	357.2	373.0	383.5	392.0	439.4	481.0

Notes : Annual mean discharge and firm discharge are referred to the Sondu River Multipurpose Development Project.

Table 5.2 Comparison of Development Alternatives

Unit : 1,000 US$

	Alt-1	Alt-2	Alt-3	Alt-4.1	Alt-4.2	Alt-5	Alt-6	Alt-7
1. PREPARATORY WORKS	5645	8579	8001	10501	11210	10987	13925	15087
2. CIVIL WORKS	88512	147679	131387	183496	197387	192802	250531	272867
2.1 River Diversion Works	2368	2368	2368	2368	2368	2368	2368	2368
2.2 Dam and Spillway	57374	57374	57374	57374	57374	57374	57374	57374
2.3 Waterway	26252	61023	71645	92192	104877	94086	145780	165300
2.4 Power House	2518	26915	6825	31562	32769	38974	45010	47825
3. METAL WORKS	4441	3236	6227	3537	3569	3560	3713	3848
4. GENERATING AND SUBSTATION EQUIPMENT	13570	14460	16460	16880	17050	17180	17890	18490
5. TRANSMISSION LINE	6370	6200	5940	6110	6200	6200	6370	6540
6. TOTAL OF DIRECT COST	118537	180153	175181	220525	235416	230728	292429	316832
7. ENGINEERING SERVICE & ADMINISTRATION	11854	18015	17518	22052	23542	23073	29243	31683
8. RELOCATION COST	37560	37560	37560	37560	37560	37560	37560	37560
8.1 Farm Land	30000	30000	30000	30000	30000	30000	30000	30000
8.2 Road	7560	7560	7560	7560	7560	7560	7560	7560
9. PHYSICAL CONTINGENCY	25193	35359	34539	42020	44478	43704	53885	57911
10. TOTAL OF CONSTRUCTION COST	155584	233528	227238	284598	303435	297505	375556	406426
ECONOMIC EVALUATION (without Sondu/Miriu Incremental Energy Output)								
ANNUAL ENERGY OUTPUT (GWh/year)	193.3	236.1	357.2	373.0	383.5	392.0	439.4	481.0
ANNUAL ECONOMIC COST (Mil.US$)	12.91	19.39	18.86	23.61	25.19	24.70	31.17	33.73
UNIT PRICE (US cent/KWh)	6.68	8.21	5.28	6.33	6.57	6.30	7.09	70.09
EIRR (%)	10.33	8.44	12.77	10.85	10.49	10.91	9.75	9.86
B-C (Mil.US$)	2.26	-15.55	29.55	10.93	6.69	12.17	-4.07	-2.49

Note : The base year to estimate present worth of benefits and costs is set at the first year of construction.

Table 5.3 Optimized Scale of the Magwagwa Scheme

	Items	Unit	Development priority	
			Irrigation	Power
1	Magwagwa Hydropower Project			
1.1	Dam Crest Elevation	El.m	1,670.0	1,670.0
1.2	Full Supply Level	El.m	1,665.0	1,665.0
1.3	Economic Cost	mil.$	246.1	246.1
1.4	Installed Capacity	MW	100.0	100.0
1.5	Max. Plant Discharge *1	m3/s	64.0	64.0
1.6	Dependable Capacity	MW	87.4	88.2
1.7	Firm Energy	GWh/year	255.1	257.5
1.8	Average Energy *2	GWh/year	452.6	447.3
2	Sondu/Miriu Hydropower Project			
2.1	Economic Cost	mil.$		
2.2	Installed Capacity	MW	60.0	60.0
2.3	Dependable Capacity	MW	51.2	51.4
2.4	Firm Energy	GWh/year	269.0	270.3
2.5	Average Energy	GWh/year	368.4	360.2
3	Kano Plain Irrigation Project			
3.1	Max. Irrigable Area	ha	25,640	21,940
3.2	Irrigation Economic Cost	mil.$	191.7	165.0
3.3	Annual Net Benefit	mil.$	33.7	29.0
4	Economic Comparison			
4.1	Magwagwa Hydropower Scheme			
	B-C	mil.$	26.34	25.16
	EIRR	%	11.9%	11.8%
4.2	Sondu River Basin Multipurpose Scheme (Magwaagwa + Sondu/Miriu +Kano)			
	B-C	mil.$	82.48	79.43
	EIRR	%	12.6%	12.6%

Note: *1 Maximum plant discharge is based on 8-hour peak operation.

*2 Incremental energy generation accrued from the multi-reservoir operation, which is discussed in subsequent Section 5.4, is not included.

Table 5.4 Example of Cash Flows

Unit : million US$

No.	Year	Capital Cost			OM cost			Total	Benefit			Total	SONDU B-C	MAGWA B-C	KANO B-C	S+M B-C	M+K B-C	S+M+K B-C
		SONDU	MAGWA	KANO	SONDU	MAGWA	KANO		SONDU	MAGWA	KANO							
0	1993	14.70	0	0	0	0	0	14.70	0	0	0	0.00	-14.70	0.00	0.00	-14.70	0.00	-14.70
1	1994	34.30	0	0	0	0	0	34.30	0	0	0	0.00	-34.30	0.00	0.00	-34.30	0.00	-34.30
2	1995	39.20	0.00	0.00	0	0	0	39.20	0	0	0	0.00	-39.20	0.00	0.00	-39.20	0.00	-39.20
3	1996	9.80	0.00	0.00	0	0	0	9.80	0	0	0	0.00	-9.80	0.00	0.00	-9.80	0.00	-9.80
4	1997		0.00	5.75	0.98	0	0.00	6.73	16.01	0.00	0.00	16.01	15.03	0.00	-5.75	15.03	-5.75	9.28
5	1998		36.92	13.42	0.98	0	0.00	51.31	16.01	0.00	0.00	16.01	15.03	-36.92	-13.42	-21.88	-50.33	-35.30
6	1999		61.53	28.76	0.98	0	0.00	91.26	16.01	0.00	0.00	16.01	15.03	-61.53	-28.76	-46.49	-90.28	-75.25
7	2000		73.83	38.34	0.98	0.00	0.00	113.15	16.01	0.00	0.00	16.01	15.03	-73.83	-38.34	-58.80	-112.17	-97.14
8	2001		49.22	38.34	0.98	0.00	0.00	88.54	16.01	0.00	8.43	24.44	15.03	-49.22	-29.91	-34.19	-79.14	-64.10
9	2002		24.61	38.34	0.98	0.00	1.20	65.13	16.01	0.00	16.85	32.86	15.03	-24.61	-22.69	-9.58	-47.30	-32.27
10	2003			28.76	0.98	2.46	2.40	34.59	16.01	43.91	25.28	85.20	15.03	41.45	-5.88	56.48	35.58	50.61
11	2004				0.98	2.46	3.59	7.04	16.01	43.91	33.70	93.62	15.03	41.45	30.11	56.48	71.56	86.59
12	2005				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
13	2006				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
14	2007				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
15	2008				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
16	2009				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
17	2010				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
18	2011				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
19	2012				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
20	2013				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
21	2014				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
22	2015				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
23	2016				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
24	2017				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
25	2018				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
26	2019				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
27	2020				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
28	2021				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
29	2022				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
30	2023				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
31	2024				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
32	2025				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
33	2026				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
34	2027				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
35	2028				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
36	2029				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
37	2030				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
38	2031				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
39	2032				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
40	2033				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
41	2034				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
42	2035				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
43	2036				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
44	2037				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
45	2038				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
46	2039				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
47	2040				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
48	2041				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
49	2042				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
50	2043				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39
51	2044				0.98	2.46	4.79	8.23	16.01	43.91	33.70	93.62	15.03	41.45	28.91	56.48	70.36	85.39

Table 5.5 Construction Cost of the Magwagwa Hydropower Project

		ALT-1	ALT-2	ALT-3	ALT-4	ALT-5	ALT-6	ALT-7	ALT-8
	Dam Crest Elevation (El.m)	1675.0	1672.5	1670.0	1667.5	1665.0	1660.0	1655.0	1650.0
I.	PREPARATORY WORKS	19.62	18.30	16.76	15.80	14.77	13.39	12.10	11.05
II.	CIVIL WORKS	196.22	182.96	167.59	157.95	147.71	133.93	120.99	110.46
	2.1 Diversion Tunnel	10.17	10.08	9.99	9.88	9.79	9.61	9.41	9.20
	2.2 Coffer Dam	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64
	2.3 Main Dam	103.66	95.43	85.21	80.42	75.30	66.39	59.10	52.87
	2.4 Spillway	15.49	13.78	12.07	10.36	9.91	9.47	9.12	8.79
	2.5 Waterway	38.03	36.62	35.20	33.89	30.99	28.58	25.12	22.69
	2.6 Surge Tank	7.16	6.73	6.31	5.88	5.25	4.53	3.72	3.14
	2.7 Open Penstock Line	4.81	4.63	4.45	4.20	4.08	3.92	3.77	3.62
	2.8 Powerhouse	5.62	5.31	4.95	4.63	4.35	4.07	3.80	3.53
	2.9 Tailrace	6.33	6.03	5.67	5.33	4.99	4.65	4.31	3.98
	2.10 Saddle dam	2.31	1.71	1.10	0.72	0.41	0.07	0.00	0.00
III	METAL WORKS	5.04	4.81	4.52	4.30	4.09	3.76	3.40	3.14
IV	GENERATION AND SUBSTATION EQUIPMENT	27.70	26.20	24.43	23.47	22.50	20.96	19.15	17.83
V	TRANSMISSION LINE	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94
VI	TOTAL OF DIRECT COST	254.52	238.21	219.24	207.46	195.01	177.98	161.58	148.42
VII	ENGINEERING SERVICE &ADMINISTRATION	25.45	23.82	21.92	20.75	19.50	17.80	16.16	14.84
VIII	RELOCATION COAT	46.31	43.81	40.06	37.56	36.56	33.44	27.56	25.06
	8.1 Farm Land	38.75	36.25	32.50	30.00	29.00	25.88	20.00	17.50
	8.2 Road	7.56	7.56	7.56	7.56	7.56	7.56	7.56	7.56
IX	PHYSICAL CONTINGENCY	43.13	40.44	37.31	35.36	33.31	30.50	27.79	25.62
X	TOTAL OF CONSTRUCTION COST	369.41	346.27	318.53	301.12	284.38	259.72	233.09	213.94
XI	TOTAL OF ECONOMIC COST	284.78	266.98	246.06	233.01	219.69	200.97	182.15	167.66