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Energy Sector Management Assistance Programme

Tanzania

Power Loss Reduction Study

Volume I: Transmission and Distribution System Technical Loss Reduction and Network Development

Report No. 204A/98

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ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and 15 bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions around three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, other donors, and development experts from regions benefiting from ESMAP's assistance. The ESMAP CG is chaired by a World Bank's Vice President, and advised by a Technical Advisory Group (TAG) of four independent energy experts that reviews the Programme's strategic agenda, its work plan, and its achievements. ESMAP relies on a cadre of engineers, energy planners, and economists from the World Bank to conduct its activities under the guidance of the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported over the years by the World Bank, the UNDP and other United Nations agencies, the European Union, the Organization of American States (OAS), the Latin American Energy Organization (OLADE), and public and private donors from countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information, a copy of ESMAP Annual Report or copies of completed projects, contact:

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TANZANIA

POWER LOSS REDUCTION STUDY

VOLUME 1:
TRANSMISSION AND DISTRIBUTION SYSTEM TECHNICAL LOSS REDUCTION AND NETWORK DEVELOPMENT

November 1992

ABBREVIATIONS

km	Kilometer
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere, reactive
kW	Kilowatt
kWh	Kilowatt hour
MVA	Megavolt ampere
MVAr	Megavolt ampere, reactive
MW	Megawatt
MWh	Megawatt hour
var	reactive volt ampere
US$	United States Dollar

ACRONYMS

ESMAP	Joint UNDP/World Bank Energy Sector Management Assistance Programme
IDA	International Development Association
JICA	Japan International Corporation Agency
SIDA	Swedish International Development Agency
SVS	Static var compensation System
TANESCO	Tanzania Electric Supply Company Ltd.
TIRDO	Tanzania Industrial Research and Development Organization

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List of Annexes

The following Annexes provides details of the computations used in the analysis:

This report was prepared in 1992 consequent to a study conducted during 1990 to 1992 in association with a distribution planning unit established in the Tanzania Electric Supply Company (TANESCO).

The report is in two volumes; volume 1 dealing with the technical studies conducted on transmission and distribution systems and volume 2 dealing with non-technical loss issues. The Bank team carrying out the study consisted of Messrs. Winston Hay, Chrisantha Ratnayake, and Ms. Paivi Koljonen. Volume 1 was prepared by Mr. Ratnayake and volume 2 by Mr. Hay. The assistance and participation of the distribution planning unit in TANESCO in carrying out the detailed studies on which this report is based is readily acknowledged.

EXECUTIVE SUMMARY

1. The Tanzania Electric Supply Company (TANESCO), a state-owned utility, is responsible for the generation, transmission, and distribution of electricity in mainland Tanzania. Over the past several years, TANESCO's operations have suffered from poor system performance in the East and Northeast regions at times of peak demand. Despite use of all available thermal generation and curtailment of supply to certain major consumers, network voltages remain excessively low, and the system suffers from frequent outages that may affect the entire network. Concomitantly, equipment damage and burnouts occur in the installations of the supply authority and its consumers. In many areas, requests for new consumers cannot be met because of the poor system voltages. Symptomatic of the problem are energy losses of some 21 percent of net generation, a level considerably higher than the economic limits for the TANESCO system (after allowing for nontechnical losses). The shortcomings of the system have resulted in substantial economic losses to the country and financial constraints on the company. Moreover, high load growth rates are expected over the next few years, and the situation will worsen considerably without timely corrective action.

2. The major cause of the low system voltages has been identified as deficiencies in the transmission system. The network supplying the eastern and northeastern parts of the system is heavily overburdened and has clearly exceeded technical and economic loading levels, causing the distribution system to receive power at voltages far below the required level. In contrast, the western sections of the network experience high system voltages because of the long and comparatively lightly loaded 220 kV lines, thus further complicating the control of the transmission system voltages.

3. Two major development projects have been implemented for the distribution systems within the last five years, alleviating supply conditions to a large extent. But the rapid increase of load during this period and the absence of systematic network planning have caused many parts of the system to revert once again to poor operating conditions. A major contributory factor has also been the difficulty faced by TANESCO in undertaking sufficient network improvements outside of externally funded projects because of the lack of foreign exchange. Thus, considerable inputs are still required in the distribution systems to bring the networks to a satisfactory operating condition.

4. In 1989, TANESCO requested the joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) to assist in the development of a program of activities that would improve network voltage levels, reduce overall energy losses and generally improve the quality of supply to consumers. A study was commenced in late 1989 with funds provided by the Swedish International Development Authority (SIDA). A team of consultants comprising of a specialist each in the fields of transmission, distribution, commercial operations, load forecasting, and nontechnical losses was engaged for short term visits to assist in the study. In addition, a local consultancy firm was engaged to undertake the study of the economic costs of outages with respect to industrial consumers. Counterpart staff provided by TANESCO also worked

in close coordination with the ESMAP staff and consultants and provided valuable inputs.

Project Objectives

5. The project seeks to find solutions to redress the poor supply conditions in TANESCO's power network and to reduce the existing high level of system losses. In particular possibilities of any short term actions to improve network voltages and enable new consumers to be added to the system at locations where such difficulties exist are to be explored. A major goal is also the development of TANESCO's competence in the field of distribution system planning so that timely action would continue to be taken to keep the networks at acceptable technoeconomic standards. Specific objectives are as follows:

- Identification of the main reasons for the poor system performance in the east and northeast regions of the network and development of solutions for rectification

- Identification of the sources of technical and nontechnical losses and development of reliable estimates of the contribution of each to overall losses

- Development of projects to reduce technical losses to economic levels

- Introduction to TANESCO of state-of-the-art techniques of data collection and distribution system planning and training counterpart staff to ensure the continuity of the applications.

6. The study report is issued in two volumes, undertaking the technical and nontechnical problems, respectively. The present report, volume (i), *Transmission and Distribution System Technical Loss Reduction and Network Development* deals with the diagnoses of problems and provides proposals to improve the technical condition of the transmission and distribution systems.

Achievements and Conclusions

7. The principal cause of the low system voltages experienced in many areas of the east and northeast was identified as the insufficiencies of the 220 kV transmission lines from Kidatu to Dar es Salaam as well as the 132 kV lines supplying the northeast loads. The study has identified solutions that can be applied in the short term to enable the system performance to be strengthened considerably. These consist of introducing reactive compensation equipment both in the transmission and distribution systems. The report recommends 45 MVAr of switched capacitors at Dar es Salaam and 30 MVAr of variable compensation using a Static var Compensation unit (SVS) at Arusha for the transmission system; it recommends 22 MVAr of capacitors for installation in the distribution system. Some subsidiary improvements to the transmission system, consisting of a 10 MVAr reactor at Mbeya (to contain the voltage rise in the western sections of the grid system) and shifting of an existing reactor from Ubungo to Ras Kiromany (for voltage control and loss reduction), are also identified.

8. In addition to the above recommendations some improvements of an operational nature was carried out while the studies were in progress. These consisted of the rearrangement of generator tap settings at the power stations and the introduction of a circuit breaker to control a reactor in service at Ubungo.

9. System studies were conducted on the distribution networks in the four major load centers: Dar es Salaam, Tanga, Moshi, and Arusha. Although the reactive compensation measures recommended (para 7) will provide some immediate relief, more substantial developments involving major changes to the network configurations are required in the longer term. Such requirements are presented as a package of proposals for which international funding will require to be secured. These development proposals will improve system performance considerably and reduce network losses to economic levels.

10. The study was conducted in close cooperation with TANESCO staff and emphasized training of the counterpart staff in the techniques and methodologies of distribution system planning. A study unit was established to undertake collection and analysis of network data on the distribution system. Microprocessor based instrumentation was provided to record and store network load data for subsequent downloading to a computer. The unit was provided with computers and state-of-the-art software packages to establish a mapping data base and undertake the required system analysis of the transmission and distribution networks. The hard work and dedication of the counterpart staff was recognised by TANESCO's management and the unit was soon institutionalized in the organization structure within the operations directorate responsible to oversee the functions of the zonal distribution organizations.

System Loss Analysis

11. Important load characteristics on the networks were collected by conducting extensive field measurements using electronic recording loggers, and these data were used to compute the losses of medium voltage (MV) and low voltage (LV) feeders. Using the data together with the monthly billing information from the sales summaries enabled development of a power and energy flow table. The table provides information on the losses (as well as supplies) at each voltage level as a percentage of the net power generated and indicates that the overall technical losses of the system amount to 19.3 percent for peak power and 11.5 percent for energy, based on net generation. Because the overall energy losses are approximately 21 percent, it can be inferred that the nontechnical losses account for 9.5 percent of the energy produced.

12. The transmission system presently exhibits peak losses of about 8.0 percent and energy losses of about 4.4 percent. These loss levels will drop with the commissioning of a second circuit to Dar es Salaam (1995) and the Singida-Arusha connection (possibly by 1996). A further reduction will occur with the commissioning of the new Pangani power station, expected in 1995. The peak losses will fall to about 5 percent with all these developments in place. However, loss levels will again increase when the Kihansi power station is commissioned because of the increased

load transmitted to the main load center at Dar es Salaam.

13. The overall loss levels of the MV system are not excessive. This is attributable to the development work carried out by two recent distribution system improvement projects--the Dar es Salaam rehabilitation project, funded by the Japan International Corporation Agency (JICA) and the Power Project IV, funded by IDA. However, a number of feeders still have excessive loss levels, and the situation will worsen considerably with the expected load growth. Proposals to reduce the losses of these feeders to economically acceptable levels are contained in sections 8 to 11 of this report.

14. In comparison with the losses of the MV system, the losses of the LV networks are extremely high, with average values of the samples studied in the four regions ranging from 6.5 to 10.5 percent for peak losses. These high levels, combined with the fact that a substantial portion of the system load flows through the LV system, mean that LV line losses account for 45.7 and 35.1 percent of the overall peak and energy losses, respectively. Two major factors contribute to the high loss levels in the LV networks: the high imbalance between phase currents in the three phases and the long lengths of LV feeders used in the network design. The former can be corrected without any capital investment, and savings of perhaps up to 25 percent of the existing losses on the LV lines could be made if such an exercise is carried out. To reduce the remaining LV line losses, the number of transformers in the network should be increased substantially, so that the lengths of LV lines can be reduced. The shortening of these lines will also reduce the area of supply of the individual transformers and increase the overall reliability of the system. An estimate for such requirements is included under LV rationalization in section 12. Loss improvement in the LV system should also include a program to purchase lower loss transformers by evaluating the annualized cost of losses together with the purchase price (a common practice among utilities but not presently followed by TANESCO). Further, the existing high core losses in a number of underloaded transformers can be reduced by implementing a transformer load management program to reallocate transformers to better suit the loads supplied.

Reactive Compensation Requirements for the Transmission System

15. Preliminary studies have indicated that the poor system voltages in many parts of the system are caused by the deficiencies in the transmission network. TANESCO has plans to rectify these deficiencies by constructing new transmission lines (a second circuit to Dar es Salaam from Kidatu and the Singida-Arusha connection). However, at the commissioning dates presently feasible for these lines, a number of years of continued poor system conditions will have to be endured, and load additions at important locations will have to be suppressed unless other developments are introduced. Load flow studies were therefore conducted on the transmission system to ascertain possible solutions of meeting the expected load additions in the immediate future. The results of these studies (described in section 4) indicate that reactive compensation equipment can be used to improve system performance substantially, particularly in the period before the new lines are commissioned. These reactive compensation measures are recommended

for Dar es Salaam and Arusha, the two extremities of the eastern and northeastern sections of the transmission network. With these measures in place, the voltage regulation problems in the transmission system will be resolved, and supply can be provided to the distribution networks at acceptable voltage levels for all normal operating conditions.

16. Several benefits will accrue from these proposals, but only a few can be quantified accurately. The compensation recommended for installation at Dar es Salaam will ensure that the expected additional loads in the city and its environs can be met at acceptable voltage levels without resorting to additional thermal generation (which would otherwise be necessary) during the period up to the commissioning of the second circuit from Kidatu. Similarly, the compensation to be provided at Arusha will ensure that the network can bear the expected load additions in the northeast until the Singida-Arusha connection is introduced. The compensation to be provided at Dar es Salaam will also provide a substantial reduction of losses and improve system reliability.

17. After the commissioning of the new transmission lines, both installations will continue to play a useful function. The installation at Dar es Salaam will provide significant savings during times of line outages. Further, after the Kihansi power project is commissioned (by 1998), the capacitive compensation required at Dar es Salaam will increase substantially (up to about 75 MVAr) because of the increased power transfer over the Kidatu-Morogoro-Dar es Salaam lines, and the proposed installation will form a part of this requirement. After the Singida-Arusha line is commissioned, the installation at Arusha will serve a voltage control function by operation in reactive mode (particularly at times of low load).

18. The benefits of connecting additional load (as will be possible with the Arusha SVS) and the reduction of thermal generation requirements (with capacitors at Dar es Salaam) have been valued at US $0.10/kWh, equal to the average incremental cost (AIC) of supply at distribution level in the TANESCO system. Arusha, too, will experience a reduction of thermal generation that will otherwise be required (to support a limited load possible), but the value of such avoided generation has not been costed in view of the close correspondence between thermal generation costs and the value of new sales. The alternative cost of supporting the additional load is in fact considerably higher in Tanzania (see Table C1.1 for the cost of supply using small diesel generators). The value of the savings on outage energy units (used for capacitor installation at Dar es Salaam) has been estimated at US$1.00/kWh, ten times the AIC of supply, a figure that compares favorably with studies done elsewhere. A research study conducted as part of the project by the Tanzania Industrial Research and Development Organization (TIRDO) indicated a value of US$2.29/kWh to industrial consumers for unannounced outages. Cost-benefit analyses conducted with the values indicated above ($0.10/kWh for additional load supplied and $1.00/kWh of outages saved) provided benefit/cost ratios of 28.8:1 and 5:1 for the proposals at Dar es Salaam and Arusha, respectively. Even if the rates used for the benefits are reduced by 50 percent, the high economic viability of the proposals is obvious. In addition, a number of benefits of the proposals have not been quantified: the reduced incidence of damage to equipment owned by TANESCO and its consumers, improved quality of service and increased consumer satisfaction, reduced operation and maintenance expenses, and reduced adverse effects of delays to planned investment in generation and

transmission.

19. The reduction of adverse effects of delays to planned investment in generation and transmission is worthy of particular consideration in the context of TANESCO's previous experiences. The present plans are for the transmission line from Kidatu to Dar es Salaam to be commissioned in two sections by 1993 and 1995, respectively, and for the Singida-Arusha line to be commissioned in 1996. In the past difficulties faced by TANESCO in obtaining the necessary foreign exchange, and other shortcomings in project management have forced considerable slippage of planned investment. The benefits of the present proposals will increase substantially in the event of such delays; in the absence of reactive compensation at the scale proposed, TANESCO will be forced to resort to extensive load shedding and increased thermal generation over the period of such delays. In any event heavy demands will be placed on thermal generation to meet the hydro generation shortfall until 1998, when the Kihansi project is expected to be commissioned and the present plans for meeting the extent of the shortfall are far from satisfactory. Thus, any marginal relief of the need for thermal generation will be of enhanced value, as it is highly probable that TANESCO will not be able to meet the future demand. Therefore, the reactive compensation measures proposed could be justified even solely on the basis of providing sufficient security for the possible slippage of the planned investment in major generation and transmission projects.

20. The proposed installation at Arusha is a Static var System (SVS), employing Thyristor-controlled reactors. It will provide the best technical solution to the complex problems at this location. If TANESCO is unable to procure the necessary funds for this installation in a timely manner, switched capacitors up to the same rating should be purchased instead. This solution will provide a lesser technical performance but will still provide high economic benefits, at a benefit/cost ratio of 6.4, assuming only half the value of benefits attributed to the prefered solution. This alternative proposal is made because of the urgency of the requirements. In fact, compensation requirements at both locations are already overdue; early implementation will enable TANESCO to recoup higher savings, and delays in implementation will cause substantial losses. On the average for both installations, four months of delay are equivalent to the loss of half the value of the installation costs. This indicates the need for immediate action to capture the full benefits of the proposals.

21. Three other recommendations are made to improve the performance of the transmission system. The first is shifting the existing 20 MVAr reactor at Ubungo to Ras Kiromany, the mainland terminal of the submarine cable supplying power to Zanzibar. This proposal will provide substantial loss reduction and voltage control benefits. Considering only the former, a benefit/cost ratio of 20:1 and a pay back period of 4.5 months have been demonstrated. The second is installing a 10 MVAr switchable reactor at Mbeya to enable better control of the transmission voltages in the southwestern section of the network. The third is providing 10 MVAr of switched capacitors in the distribution network at Tanga; the compensation will provide substantial relief to the northeastern sections of the system. This proposal is justified by the loss reductions that will be achieved along the 132 kV line to Tanga at a benefit/cost ratio of 21:1.

Reactive Compensation Requirements for the Distribution System

22. Long-term improvement of the conditions in the distribution system is dealt with in sections 8 to 11. However the developments identified will require at least three to five years for implementation because of the necessity to arrange for external financing as well as other logistical difficulties in procurement and project management. However, it is possible to provide early relief for the high losses and excessive voltage drops by installing capacitor banks in the distribution system. Providing compensation in the distribution system will also reduce the compensation requirements in the transmission system. In fact, progressive improvements of the existing power factors at the grid substations have been taken into account in the studies that determined the requirements of the transmission system.

23. The lead time for the purchase of these capacitors (particularly those to be fixed on distribution lines) is extremely short (about six months), and installation can be undertaken by TANESCO's own staff as the items are received. The selection of appropriate locations for the capacitors and the resulting loss reduction benefits at various voltage levels in the distribution system are discussed in section 7, and a summary of the recommended installations with related benefit/cost ratios is provided in Table 7.1. Total savings of 3,180 MWh per annum can be expected from the application of the capacitors recommended for the distribution system, giving an overall benefit/cost ratio of 10.6:1. The loss reduction represents a 3 percent reduction of the existing overall distribution system technical losses (estimated at 100 GWh), equivalent to 0.2 percent of the annual energy produced.

Distribution System Development and Training of TANESCO staff in Distribution Planning

24. Distribution systems in the four major load centers of the country–the regions encompassing Dar es Salaam, Tanga, Moshi, and Arusha–were selected for detailed study. These four regions collectively account for 75 percent of the energy consumed in the grid-supplied system. The study was conducted by a team of TANESCO engineers established in a newly formed distribution planning department. A program was carried out to collect all relevant distribution system data, such as the conductor sizes and connected loads, and network maps were compiled for the study areas. The loading patterns at selected locations were measured using a number of instruments–in particular, electronic loggers capable of storing the required characteristics for subsequent downloading to a computer. A package of computerized mapping and distribution planning software was provided to set up the data base and undertake the analysis. TANESCO staff has mastered the operation of the software and completed the establishment of the digital mapping data base in all four of the regions included in the study. They are also proficient in operating the load flow programs that interlink with the data base and have conducted a number of studies using the software. In addition to these studies, simpler techniques using calculations performed on computer spreadsheets (see Annexes A and D1) have been used to compute the required characteristics of all the MV feeders as well as a sufficiently representative sample of LV feeders in the study regions.

25. The network planning procedure consists of modeling the system to be studied either using the specialized software package or the spreadsheet methodology and determining operating characteristics such as technical losses, loading levels, and line voltage drops. Studies were also made to determine the ability to extend normal supply configurations (to provide alternative supply sources that can be utilized during network outages). The present situation as well as the network conditions in future years were studied, and the effects of various development possibilities examined. The studies were also used to prepare guidelines corresponding to optimum economic performance levels to facilitate the planning procedures. These guidelines include tables and graphs (see Annex D2) that can be applied conveniently to determine the operating characteristics (losses and voltage drops) at various loading levels.

26. The study has addressed two major long-term goals related to institutional development. First, the distribution networks that constitute a vast number of segments of lines and equipment have been collated in a computerized data base that can be updated continuously as network improvements proceed. Second, TANESCO engineers have been trained in conducting the required technical and economic analyses. Software and other study aids have been supplied to predict network performance, such as losses and line-end voltages. In addition, methodologies of computing economic benefits of proposed development options have been established. The unit established is expected to continue the task of monitoring the distribution systems in the future and planning the required developments in a timely manner to maintain the networks at optimal performance levels. The unit is also expected to play an important role in refining the proposals, monitoring the work, and updating the computerized data base as the work is implemented.

27. Sections 8 to 11 of this report deal with the major distribution system development requirements for the four regions. The proposals presented consist of the introduction of new grid substations (132/33 kV) and primary substations (33/11 kV) and uprating the voltage of certain feeders. These efforts are designed to enhance the "bulk supply" function of the distribution systems and to provide economically acceptable loss levels and reliability standards. The individual proposals have been subjected to economic analyses, and the related cost/benefit tables are presented in Annex E. The benefits accounted for are the reduction of losses, the ability to supply new consumers (where supply restriction existed formerly), and the reduction of outages. When all three components are evaluated, the benefit/cost ratios generally exceed 5:1. When the latter benefits mentioned above are not readily quantifiable, the proposals are justified on the basis of the loss reduction benefits alone.

28. Section 12 deals with improvements required to the distribution system supplementary to the major developments dealt with in sections 8 to 11. These requirements consist of three categories of work:

- reinforcement of MV systems combined with network rehabilitation,
- rationalization of LV systems, and
- system expansion.

29. The reinforcements required in the first category consist mainly in reconductoring MV line sections presently conductored with gauges too small for the economic dispatch of the load carried. In addition, some new lines are also deemed advantagous in order to reduce the feeder routes in the network. Many of the lines to be reconductored are also antiquated and need extensive rehabilitation. It is for this reason that reinforcement and rehabilitation are conjoined under the same category of work. The rehabilitation will cover requirements of both the MV and LV lines (including those which are not being reconductored) as well as requirements at substations and transformer stations. Rehabilitation–in effect, delayed maintenance efforts–constitutes the major portion of the costs.

30. Specific economic analyses to justify rehabilitation efforts is in reality quite superfluous; if the utility is to remain in business it must keep the existing networks serviceable enough to supply existing consumers. Also if major maintenance is further postponed, the networks will deteriorate rapidly, resulting in burnouts and damage to healthy equipment, with potentially high costs. Finally, no convenient procedures are available to measure the varied benefits of rectifying delayed or neglected maintenance, and engineering judgment often determines the nature and extent of rehabilitation requirements. Nonetheless, an analysis of the possible savings of outage costs that can be achieved by conducting rehabilitation can be gauged from Tables E6.1 to E6.4 of Annex E for the four regions, respectively. At an estimated outage saving of 1 percent of the power supplied and a cost of US$1.00/kWh, the benefit to cost ratios are in the range of 7.5:1 to 17.7:1 for the four regions. The net benefits remain positive even if the outage savings are reduced to 0.3 percent of power supplied and valued at US $ 0.75/kWh along with a reduction of the sales growth rate to 0.04 percent (from 0.08 percent).

31. The second category of suplementary work (see para 28) is LV rationalization, required in view of the high losses existing in the LV systems. The loss analysis detailed in section 3 indicates that 45.7 percent of the total power losses and 35.1 percent of the total energy losses occur in the LV lines. A substantial portion of these losses can be removed by balancing the load of the three phases. At Dar es Salaam in particular, more than 30 percent of the total LV line losses can be attributed to unbalanced conditions. The remaining losses can be reduced to economic levels by introducing a greater number of transformers to reduce the line lengths of the LV network. Estimated requirements for carrying out this work are included under the LV rationalization category. An economic analysis using estimated loss savings is provided in Table E7 in Annex E.

32. System expansion work (identified as the third category of suplementary work in para 28) is designed to extend the networks to cover new areas that have very promising load growth potential. These areas are in close proximity to the existing supply systems, and in many instances unorthodox extensions from the existing networks are already being erected to meet the pressing demand for power. Each of the new areas to be electrified is being subjected to an economic analysis (see Table E8 in Annex E) by computing the benefits from expected sales (less the upstream costs incurred in supplying power to the distribution network). The results of such analyses for the developments studied in detail so far are presented in the report and indicate very

high returns. The total cost of the areas that require electrification have been compiled based on presently available data. TANESCO's planning staff will continue the task of designing and analyzing each individual network expansion proposal and ensure that only the economically acceptable projects are included.

Total Project Costs

33. The total costs of the proposed development work in the transmission and distribution systems are presented below.

Costs of Development Work in Tanzania's Transmission and Development Systems

Costs of Reactive Compensation Requirements	*US$'000*
Switched capacitor banks at Ubungo/Ilala	825
SVS unit at Arusha	5,000
10 MVAr reactor at Mbeya	200
Shifting of existing reactor from Ubungo to Ras Kiromany	10
Reactive compensation requirements in the distribution system (inclusive of 10 MVAr at Tanga)	175
Contingencies	790
TOTAL	***7,000***

Cost of Distribution System Development

Activity	*Dar es Salaam*	*Moshi*	*Arusha*	*Tanga*	*US$'000*
MV network development	7,002	1,543	1,332	4,344	14,221
Transmission stns., LV reinf.	3,014	1,279	996	1,544	6,833
Network expansion	5,703	1,088	1,002	2,038	9,831
MV and LV rehabilitation	5,233	1,689	1,568	1,892	10,363
Contingencies					1,753
TOTALS	***20,951***	***5,599***	***4,879***	***9,819***	***43,000***
TOTAL COST FOR DEVELOPMENTS IN TRANSMISSION AND DISTRIBUTION SYSTEMS:					***$50,000***

1. INTRODUCTION

Background

1.1 The United Republic of Tanzania is situated on the east coast of Africa, its eastern coast lying between 2° and 11° south of the equator. The country comprises a large mainland area and a number of islands, the largest of which is Zanzibar. Mainland Tanzania, with an area of about 940,000 square kilometers, is bordered on the east by the Indian Ocean; on the north by Kenya, Lake Victoria, and Uganda; on the northwest by Rwanda and Burundi; on the west by Lake Tanganyika, Zambia, Malawi, and Lake Malawi; and on the south by Mozambique. The most recent census (1988) assessed the population of Tanzania as 23 million, 1.5 million of whom lived in Dar es Salaam, the nation's largest city and commercial capital. The overall annual rate of population growth in recent years has been 3.4 percent, but the rate of urbanization is appreciably higher. It is estimated that the current (1991) population of Dar es Salaam is about 2 million persons.

1.2 The economy of Tanzania depends heavily on agricultural products, but there is some mining activity, primarily in diamonds and other gems, gold, and coal. Significant increases in industrial output have occurred over the last few years, and tourism is also an important and growing foreign exchange earner. The per capita gross national product was estimated at approximately $110 in 1990.

1.3 The Tanzania Electric Supply Company Limited (TANESCO) is responsible for the generation, transmission, and distribution of electricity throughout mainland Tanzania. Although TANESCO sends electricity to Zanzibar through an interconnecting submarine cable, power supplies within Zanzibar are administered by a separate authority, the State Fuel and Power Corporation.

1.4 Over the past several years TANESCO's operations have suffered from low system voltages in the eastern and northeastern regions at times of peak demand. This has necessitated operation of diesel generating plant solely for voltage regulation. Despite the use of thermal generation. TANESCO has had to curtail supply to certain major consumers and reduce the rate at which new consumers are added to the system in areas where the distribution lines are overloaded. System disturbances often result in extensive outages sometimes affecting the entire network. Consumers who require a stable supply of power are therefore compelled to procure standby generating equipment. In addition energy losses on the system have increased steadily, currently exceeding 20 percent of net generation. The effects of these undesirable conditions have contributed to substantial economic losses to the country as well as to financial constraints on the company's operations.

ESMAP Assistance

1.5 In 1989, TANESCO requested the joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) to assist in the development of a program of activities that would improve system voltage levels, reduce overall energy losses and generally improve the quality of supply to its consumers. Funds provided by the Swedish International Development Authority enabled ESMAP to respond positively to TANESCO's request and the study was initiated in October 1989. ESMAP staff and consultants have worked closely with TANESCO counterpart staff in analyzing the problems and in identifying economic solutions. In the course of the study extensive use has been made of computerized techniques for power system mapping and analysis and as a result TANESCO's staff has developed significant skills in these areas.

1.6 This report describes the results of the studies on the transmission and distribution systems. Network losses are analyzed and solutions identified for the low voltages in the transmission system and poor supply conditions in the distribution systems at Dar es Salaam, Tanga, Moshi, and Arusha, which collectively constitute 75 percent of the total grid supplied load in the country. The recommendation for the voltage improvement in the transmission system consist of the provision of reactive compensation to enable the network to be operated at satisfactory voltage levels until planned transmission system developments can be introduced. The recommendations for the improvement of the distribution systems contain proposals for the major developments required to provide supply at economic loss levels and improve the system reliability. They also cover improvements necessary for the rehabilitation and rationalization of the existing networks in the study areas as well as system extensions required to provide supply to adjacent areas where significant urban development is already in progress. A separate report deals with the high nontechnical losses observed in the system. It describes the efforts made to reduce these losses by conducting systematic field operations and provides solutions to manage nontechnical losses in the longer term.

2. THE TANESCO POWER SYSTEM

2.1 The majority of mainland Tanzania is supplied from an interconnected power grid. There are a number of isolated systems supplied by diesel generators but these are very small in comparison to the interconnected grid and account for less than five percent of the electric energy consumed annually. This report will be concerned only with the interconnected grid system and especially with the problems of low voltages experienced in the northern and northeast regions. Map IBRD 22162 shows the geographic distribution of TANESCO's generation and transmission system.

Generation

2.2 More than 98 percent of annual generation is from six hydroelectric stations with aggregate rated capacity of 327 MW, as shown in Table 2.1 below.

Table 2.1

Station	River	Rated Capacity (MW)
Kidatu	Great Ruaha	200
Mtera	Great Ruaha	80
Hale	Pangani	21
Pangani Falls	Pangani	17
Nyumba ya Mungu	Pangani	8
Kikuletwa	Pangani	1

2.3 There are a number of diesel stations and a single gas-turbine generator (not in operation at present) connected to the grid but these are normally used only for emergency generation or voltage support. The aggregate rated capacity of thermal generating units on the grid system is about 100 MW. The capacity available at the end of 1990 was only about 30 MW. Since then a program of rehabilitation of the thermal station at Ubungo, adjacent to the major 220/132/33/11 kV substation supplying Dar es Salaam has increased the available capacity by a further 31 MW (with all six diesel units rehabilitated).

Transmission

2.4 Figure B4 of Annex B is a one-line schematic of the transmission system, which consists of lines operating at 220, 132 and 66 kV. Over three quarters of the power generated is transmitted by the single circuit 220 kV line (of 132 km) running east from Kidatu to Morogoro. Bulk of the load continues eastward thereafter on a single circuit line (of 178 km) to the principle load center, Dar es Salaam. The remaining power is transformed to 132 kV at Morogoro and a line operating at this lower voltage runs parallel to the 220 kV line between Morogoro and Dar es Salaam. This line has a switching station approximately mid way at Chalinze from which the north eastern network is supplied. Areas in Western Tanzania are supplied from a separate 220 kV system by lines running from Kidatu and Mtera to Mbeya on the southwest and Mwanza on the northwest. The north western network also has two 132 kV spurs supplying Tabora and Musoma.

2.5 The 132 kV system is the backbone of the transmission grid north of Dar es Salaam, with a line extending from Chalinze through Hale to Moshi and Arusha, with a spur from Hale to Tanga, the second largest city of Tanzania. All generating stations on the Pangani River system feed into this 132 kV network. The TANESCO grid is interconnected with that of Zanzibar at 132 kV through overhead lines on land and a submarine cable from Ras Kiromany on the mainland to Ras Fumba in Zanzibar.

2.6 The only 66 kV line currently in regular operation is that between the Nyumba Ya Mungu generating station and the 132/66 kV substation at Kiyungi near Moshi. The 66 kV interconnection between Kiyungi and Arusha is still operable but since the completion of the Kiyungi/Arusha 132 kV line the 66 kV circuit is not normally energized. Subtransmission lines operating at 33 kV emanate from the grid substations shown in Figure B4 (Annax B) and are used to energize distribution substations as well as to supply certain consumers directly.

2.7 All transmission lines are of single-circuit construction with limited or no supply alternatives in the event of unavailability of any one line.

Distribution

2.8 In city areas the majority of primary distribution lines operate at 11 kV with the secondary voltage being 400 V three-phase or 230 V single-phase. 33 kV is used as a subtransmission voltage for bulk supply to distribution substations, but some distribution transformers and major consumers are also directly energized from this voltage. In rural areas 33 kV forms the bulk of the primary distribution voltage.

Consumers and Demand

2.9 At the end of 1990 TANESCO had approximately 155,300 consumers with annual average energy consumption of about 10,000 kWh. The peak system demand was 264 MW. As is shown in Table 2.2 below, peak demand and annual energy consumption over the past five years have been increasing at an average annual rate of 11 percent. The number of consumers in Dar es Salaam and its immediate environs at the end of 1990 was about 70,000 with a peak demand of approximately 100 MW and annual consumption of 590 GWh.

Table 2.2. Power and Energy Demand TANESCO Grid System, 1984 to 1990

	1985	1986	1987	1988	1989	1990
Peak demand MW	176	183	200	219	253	264
Generation GWH	915	1041	1169	1303	1436	1565
Sales GWH	696	822	871	1005	1110	1254
Consumers 000s	126	133	111	129	144	155
Losses GWH	219	219	298	298	326	311
Losses (% gen)	24.0	21.0	25.4	22.9	22.7	19.9
% inc. Peak		3.9	9.4	9.5	15.5	4.4
% inc Gener/n		13.8	12.1	11.5	10.2	9.0
% inc Sales		18.2	6.0	15.3	10.5	13.0
% inc. Consu/m				16.0	12.0	7.6

Note: There are number of inaccuracies in the data compiled at TANESCO and the figures should be taken to represent approximate values. The consumer records were adjusted in 1987 resulting in the removal of a number of 'dead' accounts.

System Operations

2.10 Since the mid-1980s, TANESCO's operations have been handicapped by low system voltages in Dar es Salaam and areas in the northeast. At times of peak system demand that normally occurs between 9 a.m and 3 p.m. in the daylight hours and 6 and 9 p.m. in the evening (see Figure 3) the voltage on the 220 kV busbars at Ubungo, the 220/132 kV substation supplying Dar es Salaam, falls to 175 kV or less. At Arusha in the northeast it is necessary to run the diesel generating units and in addition shed certain loads at times of peak demand in order to maintain system voltages. Even then the voltage conditions are below acceptable levels. The long and relatively lightly loaded transmission lines in the west limit the level to which the voltage on the generator busbars at Kidatu and Mtera can be raised without resulting in unacceptably high voltages at the peripheral grid substations.

2.11 The low-voltage conditions on the transmission system in Dar es Salaam and other areas in the east are compounded by overloaded distribution circuits. Many consumers frequently experience single-phase supply voltages of less than 180 volts instead of the nominal 230 volts. The overloaded distribution circuits are, in part, the result of inadequate distribution planning and the fact that investment in distribution over the past decade has not been commensurate with the increase in consumer demand. TANESCO has had to restrict the rate at which it adds new consumers to the system in certain areas of Dar es Salaam because of the overloaded condition of existing distribution circuits. The overloaded distribution lines and poor power factor control by some consumers have contributed to a steady increase in system energy losses. As can be seen from Table 2.3 above, system losses have remained at a high level (around 20 to 25%) in spite of two major distribution development projects undertaken during the last five years. However not all of these losses are due to overloaded lines or other technical considerations. A significant proportion is due to the failure of the metering and billing system to capture all of the units consumed.

2.12 The low voltages experienced in the high load-density areas of eastern and northeastern Tanzania often result in lost production and equipment damage. The high voltages in the western areas place undue stress on consumers equipment and are believed to have resulted in failure of a number of grid substation transformers. Inadequate investment in the distribution system not only increases losses and restricts the rate at which consumers are added to the system as previously mentioned but also contributes to poor physical condition of much of the distribution plant. In consequence certain areas experience frequent supply outages many of which are of long duration. The various undesirable characteristics of current operations on TANESCO's transmission and distribution systems cause substantial economic loss to the country as well as financial penalties to TANESCO itself.

System Expansion

2.13 TANESCO's system expansion plans are based on a study undertaken by the Canadian consultants Acres International and completed in 1985. The demand forecasts have since been revised regularly by TANESCO and Acres, most recently in 1990. The projected demand for the period 1991 to 2005 is as shown in Table 2.3.

Table 2.3. Forecast of Power and Energy demand upto 2005

¦Actual¦<----------------------Projected---------------------->¦

	1990	1991	1992	1993	1994	1995	1996	1997	2002
Peak Demand (MW)	264	297	325	352	373	395	416	438	569
Annual Energy (GWh)	1254	1395	1507	1614	1722	1842	1977	2118	2853
Annual Growth (%)	13.1	11.2	8.0	7.1	6.6	7.0	7.3	7.1	-
Load Factor (%)	67.6	66.6	66.0	65.0	65.0	65.0	65.0	65.0	65.0

Note: The 1990 values represent actual system performance. The values for other years are projected. The figures for 1991 have still not been finalized by TANESCO.

2.14 It is seen that the high load growth over the last few years are expected to continue though at a slightly reduced rate. There is also a good possibility that TANESCO will experience a more rapid increase in demand than is currently projected.

Generation Expansion

2.15 TANESCO's plans to increase generating capacity in the period 1991 to 2000 are as follows:

- To undertake further rehabilitation of the diesel plant in the western parts of the grid system to provide an additional 20 MW by 1994.
- Redevelopment of the Pangani Falls site to provide an increase of 49 MW in 1995
- Construction of a new generating station on the Kihansi River (the Lower Kihansi plant, near Iringa) to provide 150 MW in 1998.

2.16 Comparison of planned investment in generation with projected demand indicates a severe capacity shortage if any large generating unit should be out of service over the period beyond 1992. This situation would be compounded in the event of unfavorable hydrologic conditions, especially in the Great Ruaha/Kihansi watersheds. Adverse rainfall conditions in the catchment areas combined with the non availability of hydro generation units have in fact caused large scale load shedding during many periods in 1992.

Investments in Transmission

2.17 From now until 2000 TANESCO plans to invest in two major transmission projects. The first is a second 220 kV line (300 km) from Kidatu to Dar es Salaam (probably to a new substation site and not Ubungo) via Morogoro. Construction has already begun for the section Kidatu to Morogoro. Funds are still being sought for the section from Morogoro to Dar es Salaam, which is planned to be in service by the end of 1994. The second major investment in transmission will be the Singida to Arusha 220 kV line (about 280 km) expected to be completed by the end of 1995.

Improvements in Distribution

2.18 TANESCO is currently developing plans to rectify the effects of past inadequacies in investment in the distribution systems and to be well positioned to meet the consumer demands of the future. The current ESMAP study will provide the required assistance in determining the investments at the major load centers of Dar es Salaam, Tanga, Moshi and Arusha. TANESCO is independently developing distribution plans for the other service areas. Investment financing is expected from a new World Bank (International Development Agency) power credit as well as from bilateral financial agencies.

3. ANALYSIS OF SYSTEM LOSSES

3.1 A power system can be divided conveniently into a number of sections in accordance with the voltage of operation. All major generation stations feed into the transmission system, which in the case of TANESCO consists of a radial network of 220 kV and 132 kV lines. At present, only one load (the power supply to Zanzibar) is supplied directly at the transmission voltage. Grid substations on the transmission system located at major load centers transform power to 33 kV, and feeders at this voltage are used as the first stage of the distribution system. Some of the larger loads are supplied from the 33 kV lines, while others are fed directly off transformers connected to these lines. 33 kV lines are also used to provide supply to rural areas with 33 kV/LV transformers supplying the low voltage networks. The remaining load undergoes a further transformation at primary substations (33 kV/11 kV) resulting in an additional system voltage of 11 kV. Part of the load supplied is fed at the same voltage (11 kV) to larger consumers; a second part is supplied to consumers directly from step down transformers at low voltage; and a third part is carried along LV lines and supplies the rest of the consumers. Consumers supplied at 33 and 11 kV are classified as medium voltage loads. Those supplied at LV are considered as bulk LV loads if fed directly off transformer stations and as retail LV load if fed from the LV lines. The system consists of a hierarchial structure as shown in Fig. 3.1. A substantial portion of the total network load flows along the 11 kV and LV systems.

3.2 Technical losses on the system occur in all sections of the network. Almost the entirety of these losses are caused by the heating effect of an electric current when flowing along a conductor. The exception is the losses caused in magnetizing transformer cores. In addition to the network losses described above, losses also occur at power stations due to the consumption of auxiliary equipment as well as losses on generator transformers. The overall losses (inclusive of the losses in generation stations) are termed gross losses, while the portion of the losses that occur in the transmission and distribution networks are considered as net losses. In the present exercise we will concern ourself with the analysis of net losses, that is, those occurring in the transmission and distribution systems.

3.3 Power supply systems also contain nontechnical losses. These losses are caused by deficiencies in billing and meter reading as well as by consumption not captured by meters. The difference between units sent out of the power stations and units sold (as appearing in the billing statement) are the net system losses consisting of the sum of the two components, technical and nontechnical losses described above. The present report deals with the technical component; a complementary report is being issued regarding nontechnical losses.1/

1/ This Report is entitled *Tanzania: Reduction of Nontechnical Losses.*

3.4 The load at various sections of a power network can be expressed in power demand (MW) as well as in energy (MWh) terms. Similarly, system losses are also expressed in power (MW) and energy (MWh) terms; the energy loss being the integration of the power losses over the relevant time period. The ratios of the average to peak values for the power demand and power loss are termed the load factor and the loss factor respectively; the relationships between the various parameters are provided in Annex D. During the study an extensive measurement program was conducted using electronic instruments capable of recording and storing the required power flow characteristics and subsequently downloading these measurements to a computer. One of the instruments used, the DIP 6000, uses three clip-on current transformers and three voltage transducers to record the current, voltage, power factor and power values of three phase networks. Two others, the load logger (which can be placed on overhead lines) and the load profiler records the current of individual phase conductors. All the instruments can be programmed to perform measurements at pre determined intervals and are also supplied with software to facilitate down loading the data and performing analyses of the results.

3.5 The program of power flow measurements carried out included all the 33 and 11 kV feeders in the study area as well as a representative sample of low voltage (LV) feeders and distributors. Some typical results of daily loading profiles and other characteristics are given in Annex A. These results provided values for the load factor and loss factor of individual feeders as well as for network components at various operational levels. These values have been used when necessary to convert the power and power loss figures to energy and energy loss terms in the various computations appearing hereafter.

Network Losses in the Distribution System

3.6 In contrast to the transmission system, distribution networks contain an extremely large number of line sections and the building up of the necessary data base as well as its modeling for analysis is far more complex. An important initial step has been made by introducing computer programs to build up a data base and conduct the required system studies for the distribution networks (see Section 7 for a description of the software provided). During the course of the project significant progress has been made in establishing the data bases and performing studies in limited areas of the network. This work is continuing and the study team established is expected to complete modeling the medium voltage distribution systems in the entirety of the Coastal and North Eastern Zones (consisting of the cities Dar es Salaam, Tanga, Moshi, Arusha as well as the associated peripheral areas) by end 1992. However, in order to obtain an early assessment of the existing technical losses in the system an approximate methodology (as explained in Annex D1) has been developed and applied in parallel with the more exhaustive computer applications. This procedure has been used to compute the line losses and terminal voltage drops of all medium voltage networks in the study areas for three typical loading conditions consisting of peak, mid and base load. A similar study has been made on a sample of LV systems in the four regions. The sample consisted of a total of 105 transformer stations having 367 distributors and is therefore considered to be sufficiently representative of the total LV network. Sample results of these studies are presented in Annex A. The losses and voltage drops have been worked out for the 1991 year loads as well as the expected load in 1995 with no developments made to the existing system. The calculations have been repeated with the proposed system developments described in sections 8 to 11.

3.7 The results of the power loss studies for both MV and LV systems indicate a wide diversity of performance among the various feeders. Summaries of the total losses obtained for each region are presented in Tables 3.1 and 3.2 below:

Table 3.1. Total Power and Energy Losses in Percent of Input at Each Voltage Level, 1991 Loads

	Dar-es-Salaam	Tanga Town	Tanga District	Tanga whole Region	Moshi	Arusha
1) 33 KV lines Power losses	2.0	2.20	1.30	1.91	3.80	3.7
2) 33 KV lines Energy losses	1.50	1.65	2.38	1.43	2.90	2.8
3. 11 KV lines Power losses	2.80	1.80	2.61	2.04	3.00	5.7
4. 11 KV lines Energy losses	2.10	1.35	1.96	1.50	2.30	4.3
5. LV lines Power losses	8.90	-	-	7.80	1.04	6.5
6. LV lines Energy losses	6.20	-	-	5.50	0.72	4.6

Table 3.2. Total Power and Energy Losses in Percent of Input at Each Voltage Level: 1995 Loads with existing system configuration

	Dar-es-Salaam	Tanga Town	Tanga District	Tanga whole Region	Moshi	Arusha
1) 33 KV lines Power losses	2.36	2.6	1.6	2.1	4.46	4.35
2) 33 KV lines Energy losses	1.77	1.95	1.2	1.58	3.34	3.26
3. 11 KV lines Power losses	3.83	2.20	3.08	2.44	3.55	6.37
4. 11 KV lines Energy losses	2.86	1.65	2.31	1.83	2.66	4.77
5. LV lines Power losses	10.35	-	-	9.07	1.21	7.56
6. LV lines Energy losses	7.21	-	-	6.32	0.84	5.27

3.8 The percentage losses provided in Tables 3.1 and 3.2 are based on the input power at the respective voltages. These percentages can be converted to the base of the input power and energy of the total system by consecutively accounting for the loads and calculating the losses along each section of the network hierarchy (described in para 3.1 and shown in Figure 3.1). Such an analysis has been conducted for the distribution system using the monthly billing data for the year 1990 for the four regions and is presented in Table A4 in Annex A. In this analysis the maximum demands (kVA) recorded in the various tariff categories have been converted to peak loads by use of estimated coincidence factors and the consumption of retail units (where the kVA demand is not recorded) has been converted using an estimated overall load factor. The estimated figures have been derieved from the data collected from field measurements and the total demand figures have been reconciled with recorded values thus indicating a good degree of reliability for the results obtained. Thereafter the average values for power and energy losses at various voltage levels (presented in Table 3.1) have been used to develop a hierarchial power and energy flow table consisting of the loads and losses occurring at each level in the network. Finally the losses and loads at each voltage level are expressed as percentages of the input to the distribution system. A summary of the results of these tables is presented in Table 3.3 below. Charts indicating the comparative losses of the four regions, the total sales and loss breakdown and the breakdown of overall distribution losses are presented in Figures 3.2 to 3.4.

Table 3.3. Distribution Network Losses in Percent of Input to Distribution System

	FOR ALL 4 REGIONS	DAR ES SALAAM	TANGA	MOSHI	ARUSHA
POWER LOSSES					
33 kV line loss	2.26	2.00	1.20	3.79	3.70
SS T/f loss	1.22	1.26	1.02	1.18	1.21
11 kV line loss	2.44	2.32	1.34	2.32	4.53
LV t/f loss	1.16	1.19	0.88	1.31	1.19
LV line loss	5.97	6.22	4.42	7.61	4.74
Sum of losses	13.05	12.98	8.86	16.22	15.36
ENERGY LOSSES					
33 kV line loss	1.69	1.50	0.90	2.85	2.77
SS T/f loss	1.14	1.18	0.75	1.34	1.22
11 kV line loss	1.74	1.63	0.74	1.98	3.42
LV t/f loss	1.00	1.01	0.86	1.17	0.97
LV line loss	3.02	3.26	1.96	3.67	2.41
Sum of losses	8.59	8.58	5.21	11.00	10.80

3.9 An examination of the distribution system losses developed above indicate that the overall network loss levels for the medium voltage feeders are not excessive (particularly in comparison to those in many developing countries). The low loss values in many parts of the network is the result of two major distribution development projects carried out recently. However, there still remains a number of feeders where the loss levels are considerably high. Further with the expected load growth between now and 1995 the situation will worsen considerably unless corrective action is undertaken. A number of system improvements to reduce losses in areas where they are exceptionally high have been formulated in sections 8 to 11. A particular difficulty that TANESCO faces is that it can not often mobilize the funds (particularly foreign exchange) necessary to undertake development requirements in a timely manner. It is therefore very necessary to ensure that all necessary steps are taken to limit the time delays associated securing the necessary financing facilities.

3.10 The sample studies conducted for the low voltage systems indicate that the network losses in this section of the network is exceptionally high. The average peak losses for LV networks in the four regions yielded results between 6.5 and 10.5% of the input power. The LV line losses together with the transformer losses exceeded half the overall distribution system peak losses. In energy losses too this figure came close to the half mark (46.7%, see Fig. 3.4.). Clearly this is an area where considerable loss reduction inputs are required. One major factor is the high unbalance existing in many of the schemes studied. The losses due to line unbalance is exceptionally high in Dar es Salaam and Tanga where savings as high as 30 and 20% of the existing losses can be realized by undertaking a program of load balancing, without incurring any capital investment. The other major loss reduction improvement required in the LV networks is the introduction of a substantial number of additional distribution transformers to reduce the LV line lengths. A program of transformer replacements and interchanges need also to be carried out to enable more efficient loading levels to be achieved (to optimize transformer losses). TANESCO should also change its present practice regarding transformer purchases by including the evaluation of lifetime cost of losses thereby ensuring that low loss transformers are secured in the future. These developments are discussed in section 12.

Transmission System Losses

3.11 Losses in the transmission system can readily be obtained by the results of the load flow studies conducted. Section 4 discusses these studies and Annex B presents the results of the computations made. Typical peak, mid and base load flows for each year from 1991 to 1998 have been performed. In order to calculate the energy losses a simplified load duration curve consisting of 25% of average peak load, 42% of average mid load (taken at 80% of peak) and 33% of base load has been assumed. While the peak and base load values have been taken direct from the results of the studies, the mid load values have been estimated by reference to load flows conducted with similar operating conditions. These results are presented in Table 3.4 below:

Table 3.4. Transmission System Losses in Percent

Year	Proposed Developments	Peak	Mid-Load	Base-Load
1991		8.0	3.0	5.5
1992		9.0	3.0	4.7
1993	Kidatu-Morogoro 2nd cct.	5.8	3.5	4.4
1994		6.0	3.8	4.8
1995	Morogoro-Ubungo 2nd cct. New Pangani P.S.	5.5	4.0	4.3
1996	Singida-Arusha Line	5.0	4.0	4.2
1997		5.4	4.2	4.4
1998	Kihansi P.S.	6.2	4.3	4.6

3.12 The results indicate a number of step changes to the loss levels that occur with various network developments introduced. System losses decrease with the transmission developments of the second circuit to Dar es Salaam and the Singida-Arusha connection as well as the New Pangani Falls power station. Peak losses decrease in certain years due to thermal generation inputs (supplied at Ubungo, the main load center) to meet the hydro power deficit. With the commissioning of the Kihansi project the necessity of thermal generation is removed and the power flow along the Kidatu-Morogoro-Ubungo lines is increased resulting in higher transmission system losses. The introduction of reactive compensation (proposed in this report) at Ubungo will also contribute to substantial loss reduction both before 1995 and after 1998.

Loss Analysis for Total System

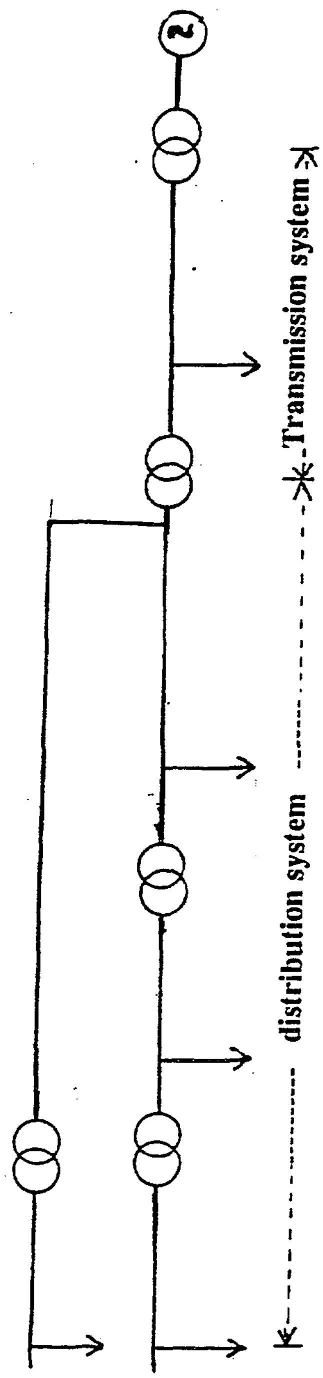
3.13 The present level of network losses derived for the transmission system and the load supplied at this level (to Zanzibar) has been combined with results of the distribution system power flow developed (in Table A4 of Annex A) to obtain the overall network power flow and system losses based on net generation (ie. input to the transmission system). For this purpose the percentage figures obtained for supplies and losses for the four regions studied are assumed to represent the entire grid supplied distribution system. Summary information from this table is provided at Table 3.5. It is seen that line losses of transmission and distribution systems are approximately of equal significance. The results of the above loss analysis for the total system (based on net generation) is also presented in Fig. 3.5.

Table 3.5. Breakdown of System Losses and Supplies by Voltage Level

	POWER		ENERGY	
	Values Expressed as % of:-		Values Expressed as % of:-	
	Net Gen	Total losses	Net Gen	Total losses
BREAKDOWN OF LOSSES				
132 kV loses	8.00	41.52	4.00	34.85
33 kV line loss	1.98	10.27	1.50	13.03
SS t/f loss	1.03	5.36	0.97	8.43
11 kV line loss	2.06	10.71	1.50	13.03
LV t/f loss	1.03	5.36	0.88	7.66
LV line loss	5.16	26.78	2.64	22.99
SUM of Losses	19.27	100.00	11.48	100.00
Total transmission	8.00	41.50	4.00	34.85
Total Distribution	11.30	58.50	7.50	65.15
BREAKDOWN OF SUPPLIES				
132 kV Supplies	5.91	7.32	8.11	9.16
33 kV Supplies	8.86	10.97	12.49	14.11
11 kV Supplies	5.50	6.82	12.58	14.21
LV Supplies	60.46	74.89	55.34	62.51
SUM of Supplies	80.73	100.00	88.52	100.00
Total losses + supplies	100.00		100.00	

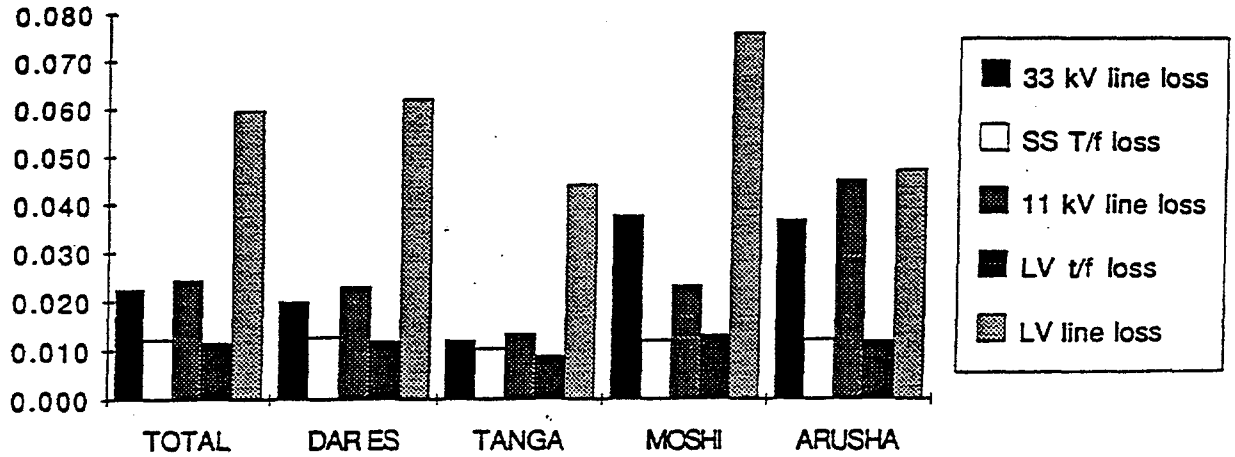
Figure 3.1

POWER SYSTEM SUPPLY HIERARCHY

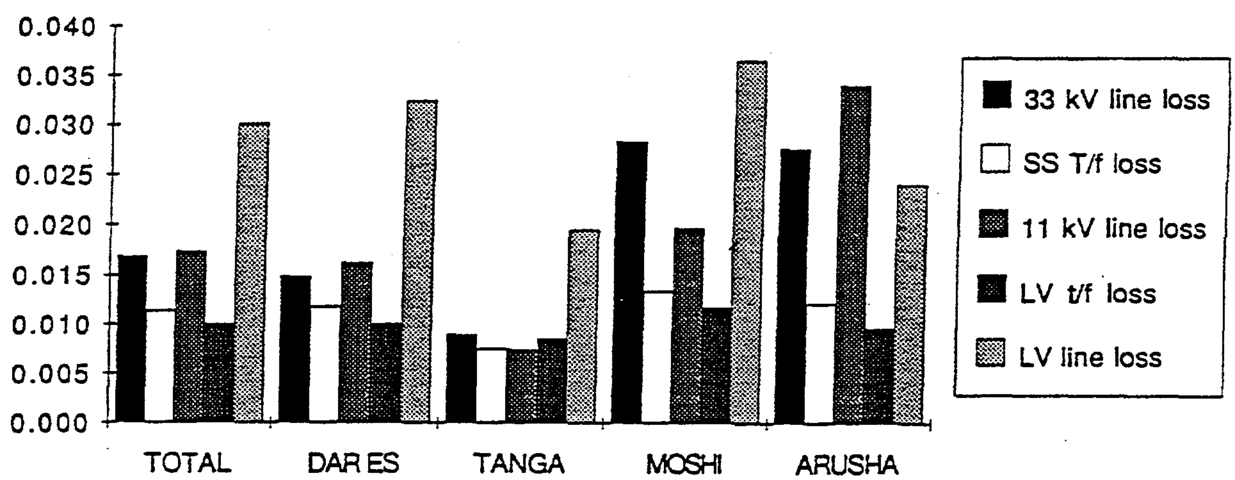


Network components	Sources of losses	Supplies
Power station generators	generator axillaries	
Generator transformers	transformer losses	
	transmission system losses	
		HV consumers (Zanzibar)
Grid Substation transformers 220 or 132/33 kV	transformer losses	
	33 kV line losses	
		33 kV consumers
Primary Substations 33/11 kV	transformer losses	
	11 kV line losses	
		11 kV consumers
Supply transformers 33 or 11 kV/400V	transformer losses	
	LV line losses	
		LV consumers

Figure 3.2

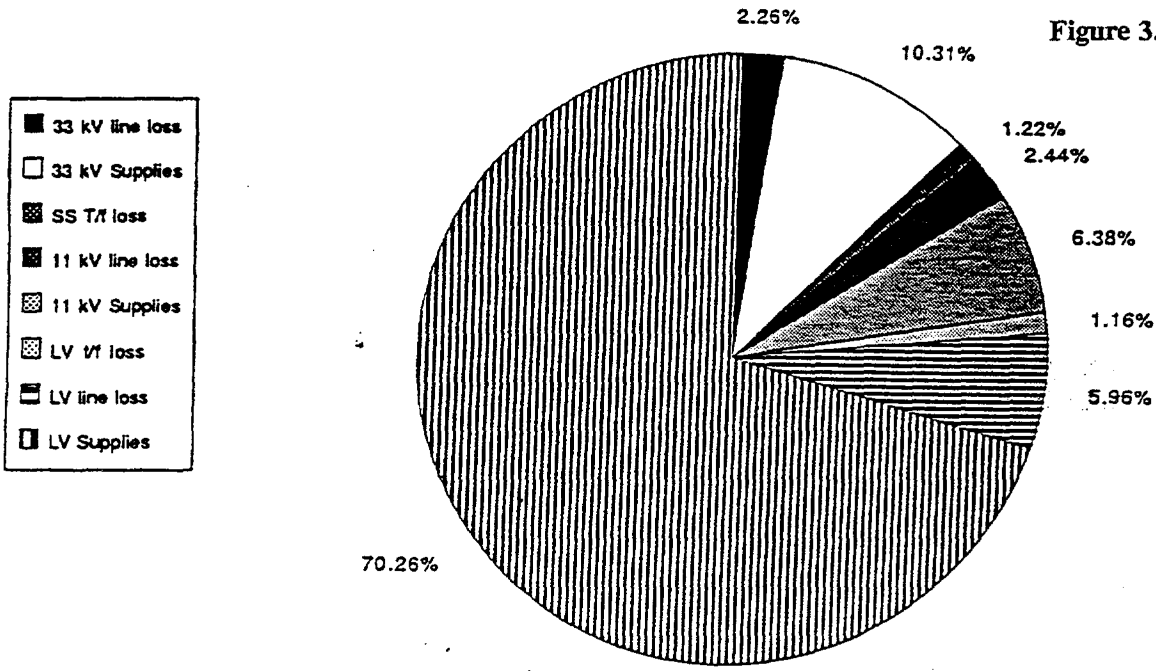


Distribution System Peak Power Losses (expressed as % power input at 33kv).

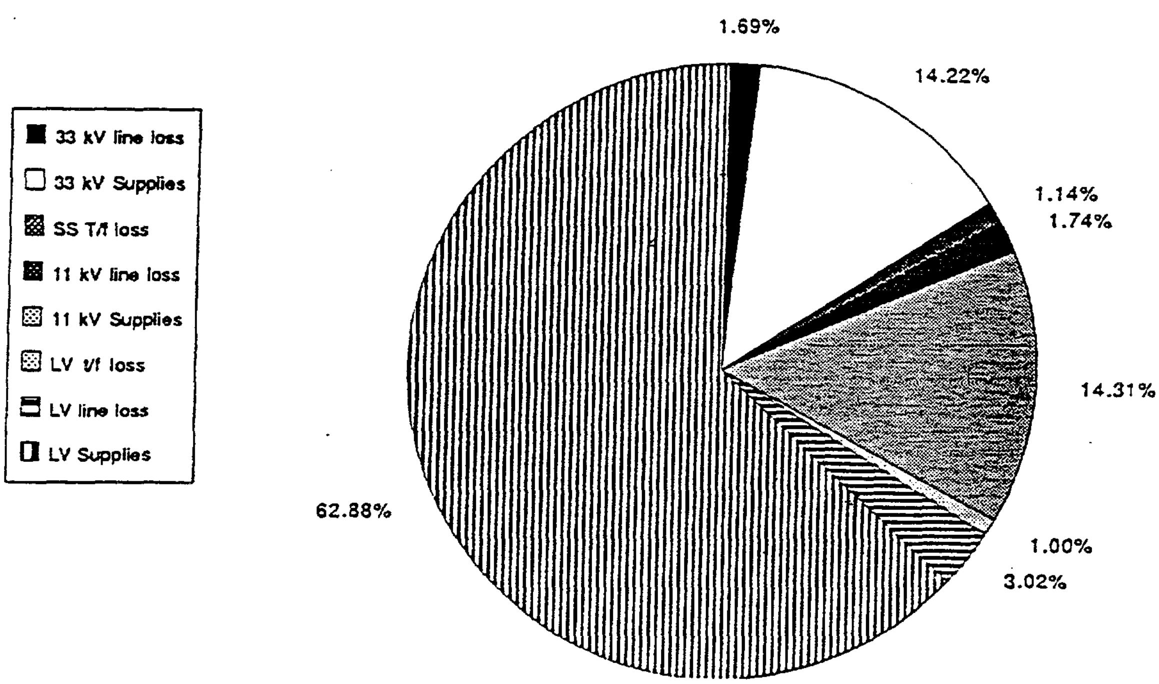


Distribution System Energy Losses (expressed as % energy supplied at 33 kv).

Figure 3.3

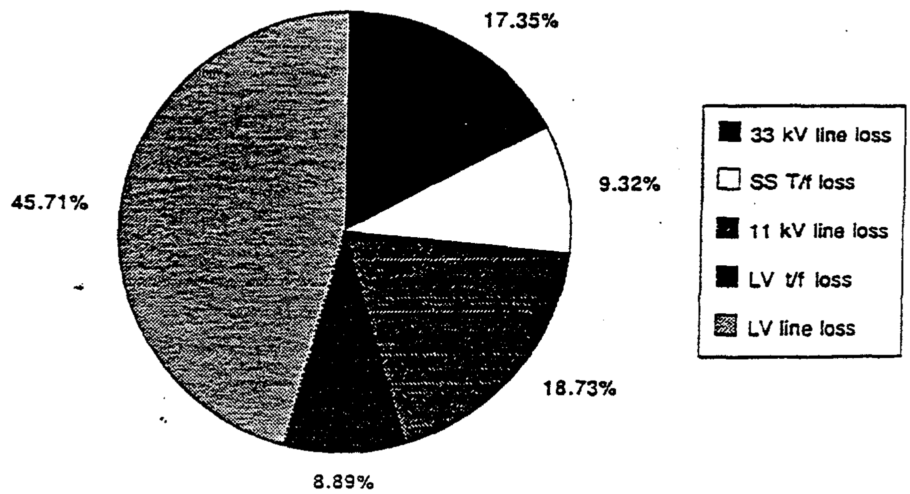


Distribution System Peak Power Supplies and Loss Composition
(expressed as % power input at 33kv)

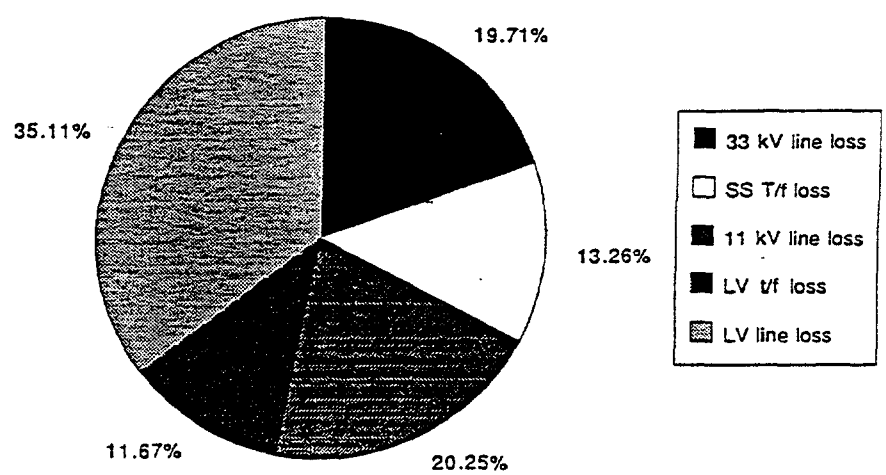


Distribution System Energy Supplies and Loss Composition
(expressed as % energy supplied at 33 kV)

Figure 3.4

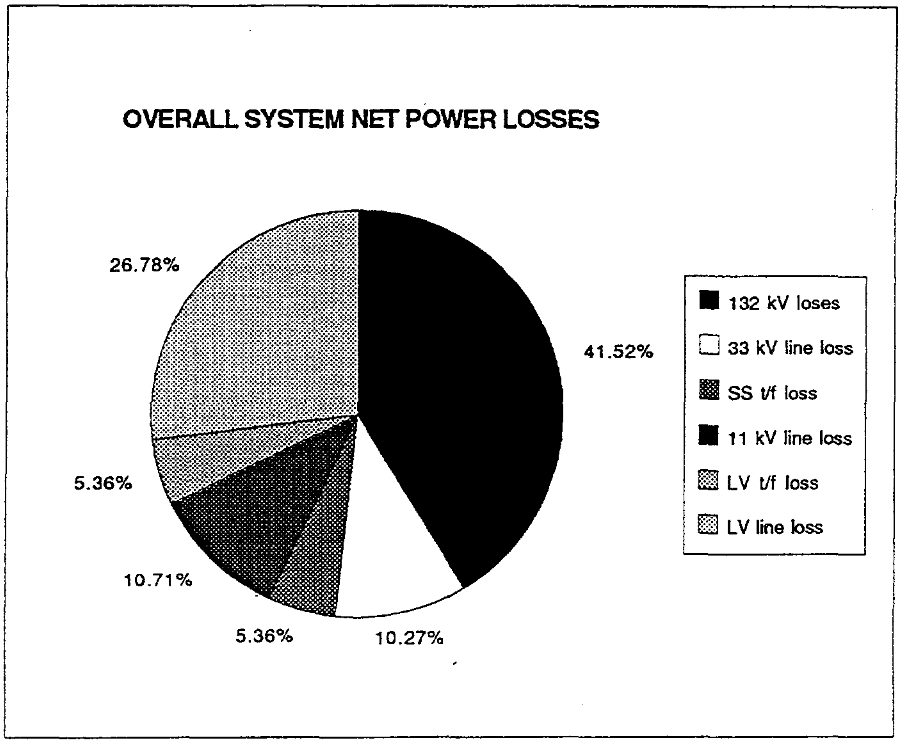


Composition of Peak Distribution Losses by Category
(expressed as % of total Distribution System Power Loss).

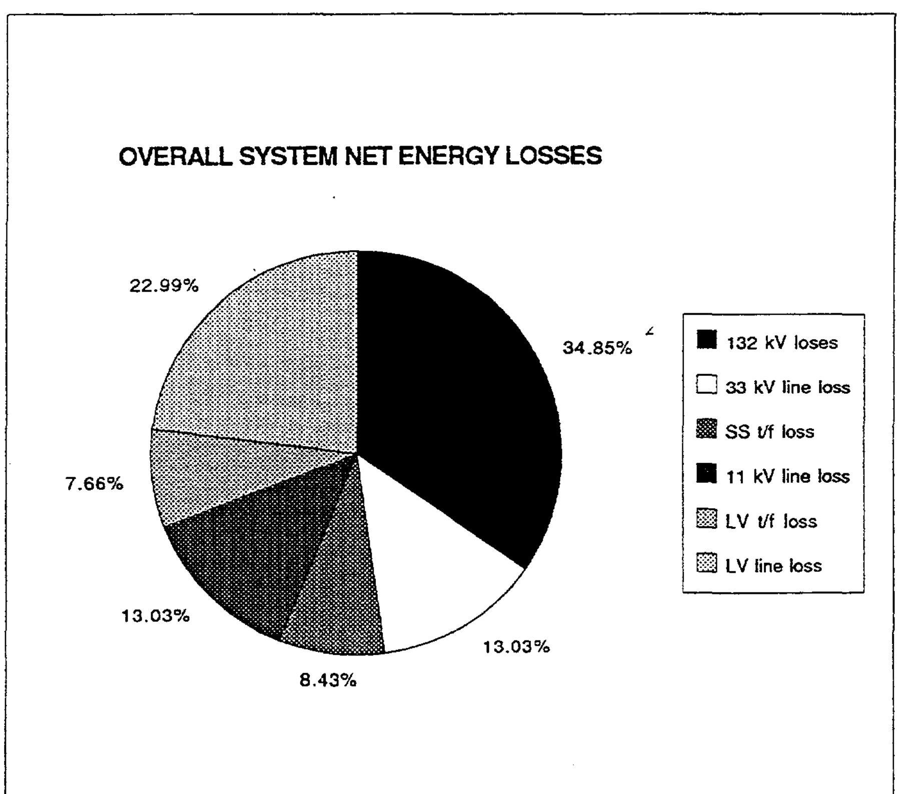


Composition of Energy Losses by category
(expressed as % of total Distribution System Energy Loss).

Figure 3.5



NOTE: Total power losses amount to 19.3 % of net generation



NOTE: Total energy losses amount to 11.5 % of net generation

4. REACTIVE COMPENSATION FOR THE TRANSMISSION SYSTEM

Background

4.1 At present the transmission system is severely overloaded in the east and northeast sections leading to very poor voltages at the main 220/132 kV receiving station at Ubungo (Dar es Salaam) as well as at the peripheral substations of Tanga and Arusha. The extent of the voltage depression experienced at day and night peak loads can be seen from Figures 4.1 and 4.2, which indicate the voltage readings obtained on a typical week day at the substations at Ubungo and Arusha. This depression of voltage at the substations is a principal cause of the low system voltage existing in the distribution system. In contrast to the east and northeast sections the network in the west is comparatively lightly loaded and care must be exercised to prevent the voltage at the extremities exceeding safe limits. For this purpose a number of reactors (both switchable and directly connected) are installed at seven of the nine substations in the west. The dangers of possible high voltage in the west further complicate the control of the voltage conditions in the east and northeast.

4.2 TANESCO's current plans to redress the transmission system deficiencies of the east and north east are as follows:

- Construct a second circuit 220 kV line from Kidatu to Dar es Salaam via Morogoro (the contract for the first section, Kidatu to Morogoro has already been awarded and the line is expected to be commissioned by early 1993; funds for the second section Morogoro to Dar es Salaam are presently being sought and the line is expected to be in service by January 1995).

- Construct a 220 kV connection between Singida in the north west and Arusha in the north east (expected to be in service by 1996).

The above developments have been selected after studies carried out by TANESCO's consultants ACRES International and represent the long term least cost solutions among the limited options available. However, these proposals by themselves and at the commissioning dates presently feasible are insufficient to resolve the poor voltage conditions that would continue to be experienced for some time.

4.3 Load flow studies on the transmission network were therefore conducted in order to examine possible short and medium term solutions for the rectification of the voltage control problems. Normally the maximum load on transmission lines occur at times of system peak load. However in some situations the most severe loading conditions are experienced at other operating periods. Such situations occur in the TANESCO network when the thermal generation requirements to meet the hydro shortfall results in a lower transfer of power along the main transmission lines at peak times than at other operational periods. The studies have therefore covered a number of such operational periods. Consideration has also been given to exigencies such as the outage of transmission lines supplying important load centers. It is seen from these studies that network voltages can be considerably improved by introducing reactive compensation at certain line extremities. A further benefit of reactive compensation is the reduction of losses in the network. The studies presented in this section therefore seek to determine the best possible application of reactive compensation measures to improve the transmission system voltage levels and obtain loss reduction benefits.

Methodology for Load Flow Studies

4.4 The performance of the transmission network during various future periods will vary considerably according to the addition of various generation and transmission developments as well as with the expected load growth. For this reason and in order to establish the usefulness of the reactive compensation measures to be employed over a reasonable period load flow studies have been performed yearly from 1991 to 1998. Some studies beyond these years have also been done particularly to assess the impact of possible export of power to Kenya. As discussed in para 4.2 above, studies have been performed to represent system performance at maximum system peak for the various years as well as at lower loading conditions. Table B1 of Annex B report provides the expected yearly maximum loads for the total system as well as the distribution of the loads at each grid substation. The import/export requirements indicating the power transfer conditions between the various load and generation centers in the system are also presented in this table. The overall load forecast tallies with the present forecast in use by TANESCO (prepared by ACRES) and represents an average annual load growth of around 6.75%. Transmission line data including impedances used in the study are provided in Table B2 of Annex B. In performing the load flow studies the range of bus voltages considered acceptable for technically satisfactory operation was chosen to be between +5% and -5% of nominal voltage. An exception was made for the Ubungo 220 kV bus voltage, which was allowed to drop to as low as -10% in view of the possibility of keeping the 132kV bus voltage at about -5% by use of the tap-changing facilities of the 220/132 kV transformers. Three other 220/132 kV transformations are used in the system; these being at Morogoro, Shinyanga and Mwanza. The latter two locations do not present any particular problem as any fluctuations on the 220 kV system can be accommodated by small variations of the tapchanger from the standard position. In Morogoro the 220 kV voltage will be higher than at Ubungo. Further the chief concern here will be the necessity to maintain the 132 kV side voltage as high as possible due to the need to maintain voltages along the Chalinze-Hale-Arusha line. Thus no special voltage conditions need to be applied for the 230/132 kV transformers other than the one at Ubungo. For all 220/132 kV transformers the tap changer operating range allowed was +/- 6% of nominal and a suitable selection within this range was used to obtain the best possible operating conditions.

4.5 The best candidate locations for applying reactive compensation are the heavily loaded line extremities. In the TANESCO transmission system these locations are found at Dar se Salaam (the extremity of the eastern radial) and at Arusha and Tanga (the extremities of the north eastern radial). Once the overall requirements at or close to these two locations are determined consideration should be given to their distribution among adjacent substations. The extent of the such distribution will depend on the total capacity required as well as the operational demands on the compensators. Thus in the discussion hereafter the reactive compensation requirements are indicated by their principal locations, Ubungo and Arusha. After finalizing the overall quantities required, consideration will be given to operational aspects as well as secondary advantages and recommendations will be made as to the distribution of the compensation to be applied among adjacent locations. Thus the requirements indicated in the following discussion at Arusha may in fact be distributed between Arusha and Moshi and the requirements indicated at Ubungo may in fact be distributed between Ubungo and Ilala (the second step down station, 132/33 kV, in Dar es Salaam). Further it should be noted that the existing capacitors in the system (5 MVAr at Moshi and 2.5 MVAr at Arusha) are included within the quantities provided in the various load flow results.

Preliminary System Improvements

4.6 At the commencement of the study two operational measures were identified to improve the poor voltage conditions experienced at peak load. The first consist of the installation of a circuit breaker to control the operation of the 20 MVAr reactor installed at Ubungo to enable this reactor to be switched off during normal operation and introduced only when required at very low load (see also para 4.11). The second measure consist of adjustments to the generator transformer tap possitions at Kidatu in order to raise the 220 kV voltage at this station to a higher value. Both these measures were put in practice during the study resulting in incremental improvements to the voltage profile.

4.7 Certain other improvements requiring minimal capital investment can also be effected to rationalize and improve the performance of the existing system. It is necessary to address such possibilities prior to undertaking an analysis to determine the extent of major reactive compensation requirements (at the east and northeast system extremities). Consideration could then be focussed on the direct benefits of the main reactive compensation proposals after allowing for improvements that are possible to be achieved by other means. The various measures that could be employed in this respect are discussed below:

Reducing the Voltage Rise in the Western Section of the Network

4.8 As discussed earlier, the line voltage in the northwest (extending up to Musoma) and the southwest (extending up to Mbeya) will rise to unacceptable levels unless the reactors installed are switched on and the Kidatu and Mtera bus voltages are restrained. It is thus appropriate to examine if this restriction on the increase of the generation station voltages could be relaxed. This is particularly so since a higher voltage at Kidatu will reduce the reactive compensation requirements at Ubungo by allowing for a greater voltage drop. With respect to the compensation requirements at Arusha the Ubungo voltage is not so critical as the tap changer at Morogoro as well as the generation at Hale will allow the voltage to be raised at these intermediate points. However during the initial years (until the new Pagani power station is introduced) when the generation at Hale is sometimes insufficient to allow for the maintenance of the maximum desired voltage and the drop in the Kidatu-Morogoro section is excessive the rise in the Kidatu voltage does have a positive effect on the compensation requirements at Arusha too.

4.9 Under normal peak load conditions, the Kidatu voltage can be raised to about 1.03 p.u. without causing the peripheral station voltages in the north and south western sections to exceed the upper limit of 1.05 p.u. However there are some particular circumstances that cause concern in keeping to such a voltage level. These aspects are discussed below:

- Three diesel generation stations Nayakato (13.5 MW, connected to Mwanza), Mwanza South (4.5 MW), and Mbeya (10 MW) are connected to the grid in the southwest section. When thermal generation is required to meet peak shortages these stations will need to be operated. In fact during the early period of 1991 much of the peak period diesel generation (required due to the unavailability of a machine at Kidatu) came from the station at Nayakato. Such local generation will reduce the loading on the 220 kV lines and result in considerably high voltages at the grid substations of Mbeya and Mwanza if the Kidatu voltage is also maintained at a high level.

- The loads in the southwest are mainly dependent on two large industrial loads, a paper mill and a cement factory. Quite often either or both the factories are not in operation. At such times the loading on this section is very light when the rest of the system experiences peak load conditions. A saturated reactor providing variable output up to 30 MVAr is available at Mwanza. However the reactor is designed to maintain a constant voltage at 11 kV to the paper factory and the output cannot be varied as required by the grid operating conditions.

- A situation similar to the abnormally low loads discussed above is that caused by the tripping of large loads. Since the loads at both the northwest and the southwest consist basically of a few large load concentrations, tripping of 33 kV feeders or grid substation loads will cause sharp voltage rises that can be detrimental to equipment connected to the system. In fact, there has already been instances of damage to grid substation transformers due to core saturation caused by exposure to high voltages. A particular problem has also arisen at Mbeya where the transformers were found to be inadequately designed to withstand high voltages.

4.10 The reactors presently installed in the system as well as the dispersed nature of the loads do not cause such serious concerns in the north west. In the south west however the only reactor connected at Mwanza (whose output is controlled by the paper mill load) is insufficient to effect the necessary control. It is therefore proposed that a 10 MVAr switchable reactor be installed at Mbeya. Load flow runs conducted with such a reactor at Mbeya indicates that the voltage rise can be effectively controlled. For example, the 1991 peak load flow with 1.03 p.u. voltage at Kidatu caused a voltage of 1.043 p.u. at Mbeya without a reactor and the voltage was reduced to 1.004 p.u. with the use of a 10 MVAr reactor. In order to give sufficient leverage for the variation of the Kidatu voltage therefore the analysis is conducted with a 10 MVAr reactor at Mbeya being included in the proposals.

Installation of a Reactor at Ras Kiromany

4.11 The 38 km submarine cable that provides power from the TANESCO system to Zanzibar generates about 33 MVAr of reactive power. The MW and MVAr load in Zanzibar is relatively small compared to this var generation and consequently the line load is dominated by the var flow to Ubungo. In addition the line losses remain practically unchanged during varying load conditions, even increasing slightly during base load periods due to the higher cable var generation resulting from the higher base load system voltages. Line losses from Ubungo to Ras Kiromany (the mainland end of the cable) can be substantially reduced by installation of compensating reactors at either or both ends of the cable. At present a compensating reactor is installed at Ubungo to help reduce the voltage rise due to the cable during light load periods. This reactor was originally directly connected to the line with no possibility of switching it in or out. However at peak periods there is a need for capacitive injection on the system and not for an inductive load. After recommendations made during the ESMAP studies TANESCO installed a circuit breaker in order to allow the reactor to be connected to the bus only when required to limit the voltage rise at periods of low loads. Although this arrangement helps to resolve the present critical voltage problems it is unsatisfactory in many respects. As a result of the reactor being installed at Ubungo rather than at the cable that is the source of the var generation, the voltages at Ras Kiromany, Ras Fumba and Mtoni (the latter two locations being in Zanzibar) are higher than at Ubungo and thereby limit the value to which the Ubungo voltage can be raised. The load flow results indicate that the voltage rise from Ubungo to Ras Fumba varies from 2.7 to 3.5 percent, depending on the extent of the cable var generation with changing voltage levels as well as on the load in Zanzibar. The resultant limitation on the Ubungo voltage will affect the ability to control voltage levels in the northeast, which would normally require maintaining as high a voltage as possible at Ubungo and Morogoro. Another disadvantage is the higher losses in the Ubungo Ras Kirosmany section discussed earlier. Yet another drawback of the present reactor arrangement is that the switching on and off of the reactive load of 20 MVAr will cause considerable step changes in voltage at all busses in the east and northeast. In fact the present switching operation of the reactor should be viewed as an emergency procedure to help achieve some voltage improvement until a more technically acceptable arrangement is made.

4.12 The technically optimal solution is to have two reactors of equal size, one at each end of the cable. This will limit the var flow in the Ubungo-Ras Kiromany line and in the cable itself. However since a 20 MVAR reactor is already available at Ubungo, the most feasible practical solution is to transfer this reactor to Ras Kiromany. (The loss reduction would be about the same if the reactor were transferred to either of the two cable ends but the cost of transport by sea to

Ras Fumbo would make overall costs much higher for this location). The load flow results indicate that the installation of 10 or 20 MVAR reactors at Ras Kiromany will restrain the voltage rise between Ubungo and Ras Fumbo to about 2.0 and 1.0 percent respectively (in comparison to an average of about 3.0 percent with the reactor at Ubungo). The loss reduction benefits are evaluated in Table C2 of Annex C and indicate benefit to cost ratios as high as 20 to 1 and pay back periods as low as 4.5 months. Having the reactor in fixed service at Ras Kiromany will require an increase in the capacitance of the reactive compensation equipment to be installed at Ubungo by an amount equivalent to the rating of the reactor when compared with the alternative of being able to disconnect the existing reactor from the system. For this reason the cost/benefit analysis shown in Table C2 includes the cost of the additional capacitance required in the overall cost of transferring the reactor. Use of a single 20 MVAR reactor is the primary suggestion because the existing 20 MVAR reactor at Ubungo can be conveniently transferred whereas the 10 MVAR reactors currently installed on the system are all rated for 33 kV, which voltage is not available at Ras Kiromany or Ras Fumba. Transfer of the existing 20 MVAR reactor to Ras Kiromany is therefore recommended in view of the high economic rates of return and substantial technical advantages. Once transferred, switching the reactor on and off in accordance with low and high system demands will not be feasible. Therefore the transfer can only take place after adequate variable/switchable compensation is provided at Ubungo.

Employing Part of the Reactive Compensation Requirements at Tanga

4.13 The ability to maintain the voltage at Hale (where generation capacity is available) at the upper limit is a critical factor in obtaining the best possible voltage profile in the northeast. However such ability is dependent on sufficient MW and MVAr generation at Hale together with the supply of the required reactive compensation at Ubungo (to enable the Morogoro voltage to be raised as high as possible). Until the commissioning of the new Pangani Falls power station generation support at Hale is not always able to maintain this desired voltage level. Further with increasing load over the years the voltage drop between Hale and Tanga will increase to excessive values. Thus for the 1992 load the voltage drop between Hale and Tanga, with the Hale voltage maintained at 1.04 p.u. is 0.033 p.u. while for the 1998 load the drop increases to 0.09 p.u. Voltage improvement at Tanga as well as support in maintaining the required voltage level at Hale can be accomplished by providing reactive compensation at Tanga. In consideration of the load at Tanga a 10 MVAr of compensation is expected to provide the required support. The compensation may be effected by power factor correction within the power installation of the cement factory itself (which is the major load fed from this substation) combined if necessary by additional compensation at the other major loads and 33/11 kV substation at Majani Mpana. If adequate compensation is not provided directly within the cement factory installation capacitors may be installed at the step-down (33/6.6 kV) substation feeding the factory. In addition to the benefits of improved voltage the capacitors can be justified by the energy loss reduction in 132 kV Hale-Tanga line as well as in the 11 km 33 kV line to the cement factory. The double benefits of improved voltage and reduced losses as well as relaxation of the necessity for high var generation at Hale make it important to introduce reactive compensation at Tanga at the earliest possible opportunity. As this compensation will be provided at the distribution level the matter is further dealt with in Section 6 (see paragraph

6.19). The loss reduction benefits are computed at Table C3 in Annex C. For the purpose of evaluating the reactive compensation requirements in the transmission system the load at Tanga is assumed to be compensated by a capacitor of 10 MVAr.

Improving Low Power Factor Levels in the Distribution System

4.14 The existing power factors at the major grid substations are presently at very low values, with some stations as low as 0.8 p.u. (which represents a var load of half the active power load). With various system development and loss reduction measures (including capacitor applications) under consideration for the distribution system the future power factors at the grid substations are expected to improve from the existing low values. The reactive loads used for the study at the various substations are thus computed on the assumption of the improvement of the power factors to 0.82 by 1995 and 0.85 by 2001. To effect this improvement 37 MVAr of capacitors are required to be introduced between now and 1995. This enables the benefits of the reactive compensation proposals in the transmission system to be computed after giving due allowance to the developments expected in the distribution systems.

4.15 In accordance with the above discussion, the reactive compensation requirements for the transmission system are examined on the assumption that the following preliminary developments are also introduced:

- The installation of a 10 MVAr (switchable) reactor at Mbeya. With this reactor in place the Kidatu voltage is allowed to be raised to 1.03 p.u. under normal peak operating conditions.

- The shifting of the 20 MVAr reactor presently at Ubungo to Ras Kiromani.

- The improvement of the power factor at Tanga by the installation of 10 MVAr of capacitors in the distribution system.

- The improvement of the power factor of the distribution system load from the present low values to 0.90 by 1995.

The Study of Network Operation at Different Load Levels

4.16 The yearly peak loads provided in Table B1 in Annex B represent the highest system load expected for that particular year. This situation would occur only for a few hours during relatively few days in each year and represents the maximum load demand to which the system would be subjected. Hence, it indicates the generation and transmission capacity required. The system need also to be evaluated at other operating loads, particularly those that are sustained over a long period. Such studies will provide a better measure of the benefits of loss reduction and saved thermal generation.

4.17 The load duration curve for the system indicates the period over which a particular load is exceeded. Typical load duration curves for a normal working day, for weekends, and a consolidated curve for the whole year are presented in Figures B1 to B3, in Annex B. The yearly load duration curve can also be approximated using a step function in which the value of each step represents the average load over a certain loading period. In the first instance, load-flow studies need to be conducted for the maximum expected load of a particular year. To relate the results of these studies to other loading periods of later years, the steps of the approximated load duration curve have been selected to coincide with the maximum loads of previous years. Using this methodology, it is possible to use each load flow study to predict the system behavior at different loading periods over a number of years. The steps selected and their correspondence with the loads of previous years are shown in Table 4.1.

Table 4.1

	% of Max. Yearly Peak	No. years back corresponding max. system peak	% time load exceeded
Maximum yearly system peak	100	0	0.1
Load step 1	93	1	8
Load step 2	87	2	30
Load step 3	81	3	40
Load step 4	76	4	50
Load step 5	67	6	67
Load step 6	62	8	83
System base load	50	10	100

4.18 Column 2 of Table 4.1 indicates the loading level of each step as a percentage of the maximum system peak for the year, and column 3 indicates the number of years backward necessary for the maximum system peak of such previous year to be equivalent to the load step of the current year under consideration. Thus, the maximum yearly system peak load for a particular year represents the highest loading conditions for that year as well as a number of subsequent loading steps for the succeeding years. For example, the 1992 maximum yearly system peak load would represent load step 1 of 1993, load step 2 of 1994, and so on. Load steps 1 and 2 could be considered as within the peak loading periods, and load steps 3, 4, and 5 could be considered as within the mid-loading period of the load duration curve. By selecting the generation availability and other system conditions, such as transmission developments, to suit the particular year under consideration, the procedure provides means of evaluating the network performance not only at the system peak of a particular year but at the various loading conditions of future years. In the system studies conducted, load flow computations have been performed for the maximum yearly system peak, the four subsequent loading steps, and the minimum load represented by the system base load. It can also be seen that some of the system studies representing normal operating conditions in a particular year will represent periods of system outages (at different loading steps) in future years. This will be applicable when there are expected developments in generation or transmission facilities between the two years in question.

Results of Load Flow Studies

4.19 A large number of computations representing different generation and transmission line availability conditions have been performed for the various loading conditions described earlier. The studies have been conducted taking into account the operating principles and system conditions detailed in paras 4.4 and 4.15. In particular, the Kidatu bus voltage is not raised above 1.03 p.u. in order to contain the voltages of other 220 kV buses in the west (particularly in the event of any local load rejection at the substations combined with thermal generation in the west). The var generation at Hale is adjusted to maintain a target voltage of 1.04 p.u at this bus. In interpreting the results of the load flow studies, it must be borne in mind that the compensation applied at the buses at Ubungo and Arusha are dependent on each other if the Hale voltage is below the target level. The chief concern in the northeast is to maintain voltage levels. This often requires a var flow in the reverse direction to the active power flow and hence there are no loss reduction benefits by increasing the extent of the compensation. At Ubungo, however, loss reduction benefits can be realized by increasing the compensation over the minimum requirements for voltage control. Studies have been performed to indicate the extent of such benefits. For the period before the commissioning of the new Pangani Falls power station the generation availability at Hale is critical to satisfactory system performance. At periods of low rainfall the firm power availability at Hale and Moshi reduces to 24 MW and 4 MW respectively. The studies up to the year 1995 therefore include both the maximum (34 MW at Hale and 8 MW at Moshi) as well as firm generation availability conditions in the north east.

4.20 Bus voltages and other important characteristics of each load flow study have been extracted and presented in a number of tables in Annex B. The tables are numbered according to the year and the loading step. The studies with line outages are prefixed by the letter O. In addition two summary tables are presented in Annex B. Table B3 indicates the loss reduction and voltage improvement in various years by incremental changes to the capacitive injection provided at Ubungo while Table B4 indicates the network voltage changes that occur with incremental changes to the injection provided at Arusha. A discussion, on the results of the load flow studies for each year is given in the succeeding paragraphs. The situation at the maximum system load as well as at lower loading levels (see paras 4.17 and 4.18 are discussed and compensation requirements to maintain minimum satisfactory network voltage levels are indicated. In the discussion, it is assumed that the preliminary system improvements detailed in para 4.15 are already effected. Further the locations for reactive compensation is mentioned as Ubungo and Arusha with the understanding that the actual application may be distributed among the adjacent grid substations (see para 4.5). With respect to the compensation in the northeast since 5 MVAr is already available at Moshi, this compensation is applied at the Moshi bus and the additional requirements placed at Arusha. The Arusha compensation indicated in the discussion includes the 2.5 MVAr presently available at this location.

System Performance for 1991

4.21 Thermal generation is not required to meet the maximum load in 1991 if the maximum output of all hydro stations are available. However, in the absence of var compensation at Ubungo network voltages are depressed to unacceptable levels at that location as well as in the northeast. With full hydro generation availability in the northeast (34 MW at Hale and 8 MW at Moshi), the minimum var compensation requirements for satisfactory voltage levels can be considered as 30 MVAr at Ubungo, 10 MVAr at Tanga, 5 MVAr at Moshi and 13.6 MVAr at Arusha. This level of compensation will result in the Ubungo HV (nominal 220 kV) voltage dropping down to 0.92 p.u. at peak with Kidatu voltage maintained at 1.03 p.u. (a drop of 11 percent). Additional compensation provided at Ubungo will increase the system voltages and provide substantial loss reduction benefits as evidenced from Table B3, Annex B. It is also seen that with a compensation level of 35 MVAr or more at Ubungo the Hale voltage can be maintained at the desired level of 1.04 p.u. thus enabling better system performance particularly in the northeast.

4.22 With firm generation conditions in the northeast (24 MW at Hale and 4 MW at Moshi), there is a supply shortfall of about 10 MW to meet peak load requirements with hydro resources alone. With this power together with 30 MVAr of reactive power supplied at Ubungo, the compensation required at Arusha increases from 13.6 MVAr to 33.5 MVAr. A particular problem encountered with the restricted generation in the northeast is the inability to keep the Hale voltage at a high level, thus requiring increased compensation at the northeast line extremities. The Hale voltage can be increased however with increased var injection at Ubungo resulting in reduced compensation requirements in the northeast. Thus, the compensation requirements at Arusha drop to 28.9, 21.6 and 15.9 MVAr corresponding to increases of var supply at Ubungo to 35, 45 and 55 MVAr respectively. The increase of var compensation (at Ubungo) is also accompanied by substantial loss reduction benefits (see Table B3 of Annex B). Desirable compensation levels for the 1991 maximum load situation would thus be either 50 var at Ubungo with 16 MVAr at Arusha or 40 MVAr at Ubungo with 21.5 MVAr at Arusha (keeping in mind that when generation is provided at Ubungo some var supply is also possible from the generators).

System Performance for 1992

<u>Maximum Load Condition for 1992</u>

4.23 To meet the expected maximum load in 1992, thermal support of about 12 MW is required in addition to the full availability of all hydro stations. In addition substantial reactive compensation is also required at Ubungo and in the northeast. With 12 MW and 30 MVAr supplied at Ubungo (6 MVAr of which could be supplied by the generators) and 5, 10 and 21.4 MVAr at Moshi, Tanga and Arusha respectively, the Ubungo HV drops to 0.89 p.u. (Arusha being at 0.95 p.u.). The voltage improvement and loss reduction benefits by successive additions of var compensation is seen from Table B4 in Annex B.

4.24 For firm hydrogeneration conditions in the northeast, 27 MW of thermal power will be required to meet the shortfall in generation capacity. With all of this active power supplied at Ubungo, a reactive supply of about 50 MVAr is also required, primarily for the purpose of keeping the Hale voltage sufficiently high. For these conditions, the compensation required at Arusha is 30 MVAr (compared to the 21.4 MVAr required for the full hydro availability condition). If the var injection at Ubungo is now raised to 60 MVAr, the requirement at Arusha drops to 25 MVAr.

4.25 The required compensation at Ubungo and Arusha for the year 1992 could thus be considered as 45 MVAr and 25 MVAr respectively (to meet the firm generation conditions in the northeast along with a generation of 27 MW and 15 MVAr at Ubungo).

4.26 Load Step 1 for 1992. The system conditions at the load step 1 for 1992 will be the same as the maximum load condition for 1991 and the discussion in paras 4.18 and 4.19 will also apply to this situation.

System Performance for the Year 1993

1993 Maximum Load Condition

4.27 The second circuit from Kidatu to Morogoro is expected to be available for operation by this time. In order to meet the maximum expected load for the year about 30 MW of thermal generation need to be provided in addition to maximum output from all hydro plant. Even with such generation injection and the var compensation required to maintain voltages in the northeast, the Ubungo voltage will be substantially depressed, unless sufficient var compensation is also provided at this busbar. With 10, 5 and 25 MVAr at Tanga, Moshi and Arusha, respectively, a 30 MW, 10 MVAr supply at Ubungo results in the HV bus at Ubungo being depressed to 0.90 p.u. Furthermore, the Hale voltage can only be maintained at about 0.994 p.u. under these conditions. Successive addition of var compensation at Ubungo will increase the system voltage and reduce network losses as seen from Table B3 of Annex B.

4.28 It is observed that 50 MVAr of injection will be required at Ubungo (15 MVAr from the generators and 35 MVAr from capacitors) in order to maintain the target voltage of 1.04 p.u. at Hale. Due to the increase of voltage at Hale, successive increase of var injection at Ubungo results in the reduction of the var requirements at Arusha. Thus, an increase from zero to 50 var at Ubungo causes a reduction of the requirement at Arusha from 29.4 VAr to 18.3 VAr.

1993 Load Step 1

4.29 For the load step 1 loading condition about 10 MW thermal generation is required to be supplied at Ubungo when all hydro plant is in operation. The improvement of the voltage levels and reduction of system losses with additional var injection is depicted in Table B3 of Annex B. As in the yearly maximum load condition, successive additional var injection at Ubungo results in an improvement of the Hale voltage and the reduction of the var requirements at Arusha. The desired var requirement for the selected conditions are 25 MVAr at Ubungo and 20 MVAr at Arusha.

1993 Load Step 2

4.30 The loading conditions during load step 2 for 1993 enables the System to be operated without thermal support if the full output of all hydro plant is available. In the absence of reactive compensation at Ubungo, however, the system voltage remains low. With 10, 5 and 12.9 MVAr at Tanga, Moshi and Arusha, respectively (necessary to keep the northeast voltages above 0.95 p.u.) the Ubungo HV level is at 0.90 p.u. if no compensation is applied at this bus. The Hale voltage (1.032 p.u.) is also below the target level (1.04 p.u.). The reduction of system losses and improvement of voltage with the addition of var compensation at Ubungo is seen from Table B3 in Annex B.

4.31 If only the firm generation outputs of 24 MW at Hale and 4 MW at Moshi are available, a minimum of 6 MW of thermal generation support is required. In such circumstances, maintaining the Hale voltage becomes increasingly difficult. The required compensation at Arusha increases from approximately 12 MVAr (in the full generation availability condition) to a value ranging from 21.5 to 30.0 MVAr for var injections at Ubungo ranging from 27 MVAr to zero (inclusive of the vars produced by the generators).

System Performance for the Year 1994

4.32 For the year 1994 the network will remain unchanged from that of 1993. Thus, operating performance for a number of loading conditions for this year may be determined from the studies for the year 1993. The 1993 year studies, corresponding to the loading periods in 1994, are as follows:

1994 load step 1 = 1993 maximum system load, see paras 4.27 to 4.28
1994 load step 2 = 1993 load step 1, see para 4.29
1994 load step 3 = 1993 load step 2, see para 4.30

System Performance for the Year 1995

4.33 New developments expected to be available for the year 1995 are the second circuit line from Kidatu to Morogoro and the new Pangani Falls power station. The former will bring added reliability benefits, particularly to the load at Ubungo and reduce losses (in that section of the network) considerably. The line capacitive generation produced will also eliminate the need for reactive compensation at Ubungo. The new generation will help reduce the hydro generation shortfall and assist in reducing the system losses particularly in the northeastern sections. The additional generation injection in this region will also help maintain network voltages and reduce the need for reactive compensation at Arusha. There is, however, a reasonable probability of the new Pangani Falls power plant being delayed until late 1995 or early 1996. Hence, the system performance for 1995 has been studied both with and without the availability of the new Pangani Falls power station.

1995 Maximum Load Condition (with new Pangani Falls available)

4.34 Despite the added hydro generation facility, thermal generation of about 30 MW is required to meet the maximum system load of 1995. If this generation is provided at Ubungo, additional var contribution from the generators can also be used. Under these circumstances, reactive compensation is not required at Ubungo to maintain voltage control. The addition of capacitors will contribute to loss reduction benefits but to a lesser extent than in previous years.

4.35 The increased generation availability at Hale (from new Pangani Falls) now enables the bus voltage to be raised as high as desired at this bus bar. Thus with Hale maintained at a voltage of 1.04 p.u. and with the existing 5 MVAr capacitor at Moshi, the compensation requirements at Arusha are 31, 25, 21 MVAr, respectively for generation of 0, 4 and 8 MW at Moshi.

1995 Load Steps 1 to 3 (with new Pangani Falls available)

4.36 As the load decreases from the maximum load condition for the year the requirement for thermal generation at Ubungo will decrease. Accordingly the power flow along the Kidatu-Morogoro-Ubungo lines will increase slightly up to the step 2 condition at which point thermal generation at Ubungo will become redundant (for the full hydro availability condition). Capacitive injection is not required at Ubungo and system voltages can be maintained without difficulty except at Arusha-Moshi. The compensation requirement at Arusha will also reduce as the load is reduced from the peak condition and will be 18 and 20 MVAr respectively for the load step 2 condition for a generation availability of 8 and 4 MW respectively at Moshi. For the load step 3 condition the Arusha compensation will reduce further to 6 and 10 MVAr respectively.

1995 Maximum Load Condition (new Pangani Falls not available)

4.37 If the new Pangani Falls station is delayed and is unavailable for operation the thermal generation requirements will be increased considerably by the year 1995. For the maximum expected load in 1995 the shortfall will be 75 MW. Existing thermal facilities and presently proposed developments will not cover this shortfall and substantial new thermal generation facilities will be necessary to cater for this contingency. If such generation facilities are provided at Ubungo the loading on the Kidatu-Morogoro-Ubungo lines will be further reduced and there will be no necessity for reactive compensation at Ubungo. The compensation requirements at Arusha will however increase substantially due to the difficulty of maintaining a satisfactory voltage at Hale in the absence of the added generation capacity. In order to maintain a minimum bus voltage of 0.95 p.u. at Arusha with the availability of the existing north eastern hydro plant at full capacity and the generation shortfall supplied at Ubungo, capacitive injection totalling xx will be required at Arusha - Moshi.

1995 Load Steps 1 to 3 (new Pangani Falls not available)

4.38 The thermal requirements will keep reducing as the load falls and by the load step 3 condition of 1995 it will almost be eliminated. The compensation required at Arusha will reduce likewise along with the improvement of the voltage at Hale and the reduced loads on the lines and by the step 1 condition only 6 MVAr will be required at Arusha (with the existing 5 MVAr at Moshi). However, if only the existing firm generation availability of 24 MW at Hale and 4 MW at Moshi can be relied upon the hydro generation shortfall will be about 25 MW for the load step 3 condition. Under these conditions the difficulty of maintaining the Hale voltage will require the compensation at Arusha to be raised to 29 MVAr.

System Performance Beyond 1995

4.39 The thermal requirements to bridge the hydro generation shortfall increases each year until the next expected hydro addition, Kihansi is introduced (1998). Thus, with the required thermal generation provided at Ubungo the active and reactive power carried over the Kidatu-Morogoro-Ubungo lines will in fact decrease (although by a small margin) over this period in relation to the corresponding load step of the preceding year (with a corresponding increase of the Kidatu and Mtera generation feeding the western loads). The system will therefore not require any capacitive injection at the Ubungo bus bars. In the northeast, however, the network loads will continue to increase with no additional assistance available from generation or transmission development (after the new Pangani Falls station is introduced). Thus, the period 1995 onwards will see a continued increase of var compensation requirements at Arusha -Moshi until the proposed Singida-Arusha line is commissioned. Current expectations are for this line to be commissioned in 1996. However, it would be useful to examine the implications of the delay as well as the effect of expediting this line. Accordingly load flow studies have been performed with the line introduced as early as 1995 as well as the without the line in service up till 1998. The results of these studies (presented in Annex B) can be used to evaluate system performance with and without the line in operation during this period.

Effect of the Singida-Arusha Connection

4.40 When the Singida-Arusha connection is introduced the power flows on the Kidatu - Morogoro-Ubungo line as well as the lines in the north eastern network will be substantially reduced improving the performance of the system considerably. There will be a direct power transfer from the western section to the northeastern section resulting in a substantial reduction of system losses. Capacitive compensation will now not be required in the northeast in view of the power injection provided at Arusha as well as the vars introduced by the line charging current. If the line is introduced in 1995 the maximum load conditions for that year will show a loss saving of about 3.0 MW and the thermal generation will correspondingly be reduced. The loss reduction for the maximum load of 1996 will be about 5 MW. The importance of this line increases greatly with the introduction of the Kihansi station, which will result in the flow of a considerably larger amount of power from the central highlands to the east and north eastern areas of the network (with a corresponding reduction of thermal power injection otherwise required at Ubungo). The network performance after the introduction of the Kihansi project is dealt with in the succeeding paragraphs.

System Performance for the Year 1998

4.41 The Kihansi hydro plant is expected to be commissioned for operation during late 1997 and will be available during the year 1998. With this development, thermal support will no longer be required for a number of years. The loading on the Kidatu-Ubungo lines will be substantially increased and once again the need for reactive compensation at Ubungo will arise. The Kihansi power will be connected to the grid at Iringa from whence it will flow to Ubungo via Kidatu. Hence, the bus voltage at Iringa will need to be higher than that maintained at Kidatu. The Mtera voltage too will be at the level of the Iringa bus voltage as no substantial power flow is expected to occur from Iranga to Mtera. In order to contain the voltage at these busbars it is found that var absorption has to be resorted to at the Kihansi and Mtera generation stations. The extent of var absorption required will depend on the reactors employed in the western section and the voltage maintained at Kidatu. It is also seen from the load flow studies that the system voltages in the northwest are very sensitive to incremental changes in the reactive compensation employed. The studies conducted indicate that it is not advisable to maintain Kidatu at voltages higher that 1.03 p.u. under normal operating conditions. The corresponding Iringa voltage will be around 1.04 p.u.

4.42 As discussed earlier the role of the Singida-Arusha 220 kV connection will be substantially enhanced with the addition of the Kihansi station. In order to assess the impact of this line as well as to understand the implications of its delay, the system behavior for the year 1998 is studied both with and without the operation of the Singida-Arusha line.

<u>1998 Maximum Load Condition (with the Singida-Arusha line)</u>

4.43 The power flow to Arusha from the northwest considerably reduces the loading of the northeastern 132 kV line sections. The total system losses reduce to approximately half the value in the absence of the new line. The available hydro generation exceeds the requirements for the maximum expected load of 1998 and the maximum stress on the transmission network occurs when generation in the northeast is reduced allowing for full power output from the major hydro stations in the center. Accordingly, generating 50 MW at Hale/Pangani with no generation at Moshi provides the most onerous conditions for the system. For these conditions a minimum of 25 MVAr of var injection is required at Ubungo to maintain a satisfactory voltage profile (Kidatu at 1.03 p.u. and Ubungo HV bus at 0.92 p.u.). The increase of var compensation from this minimum value will provide substantial loss reduction benefits as shown in Table B3 in Annex B.

4.44 With the Hale and Moshi generation increased to the maximum values the power transmission throughout the network is reduced. The minimum compensation required at Ubungo for a satisfactory voltage profile is now about 18 MVAr.

1998 Maximum Load Condition (Without the Singida-Arusha Line)

4.45 Without the Singida-Arusha connection the system is considerably overburdened in carrying the maximum load of 1998. The total system losses (with sufficient var compensation applied) rises to 9 percent and the northeast section losses rise to 15 percent (of input power). Due to this high level of losses, there is very little slack in generation capacity. With the 8 MW at Moshi being unavailable and Kihansi supplying 140 MW all other hydro plant has to operate at maximum capacity to meet the system load. With the Hale voltage maintained at 1.04 p.u. var compensation of 25 and 30 respectively is required at Moshi and Arusha when there is no generation at Moshi. If full generation (8 MW, 4 MVAr) is available at Moshi, the additional (static) compensation at Moshi may be reduced to 10 MVAr (while maintaining Arusha at 30 MVAr). (In this instance var compensation requirements are stated at both Arusha and Moshi deviating from the previous practice of stating the new requirements lumped at Arusha. This is because the application of the total requirements at Arusha will depress the Moshi voltage to unacceptably low values).

4.46 With the above compensation levels provided in the northeast at least 25 MVAr is required at Ubungo to maintain a satisfactory voltage. Increase of var compensation will improve the voltage profile and reduce the system losses as shown in Table B3 of Annex B.

Power Export Possibilities to Kenya

4.47 Possibilities of exporting power to Kenya are being considered to supply the shortages in the Kenyan power system either at Nairobi or at Mombasa. The use of the Singida-Arusha line extension by making a connection from Arusha to Nairobi is being considered for the Nairobi supply. 1998 peak power flows with this connection (using Bison conductor, which is used for all the 220 kV lines in the western section, for both Singida-Arusha and Arusha-Nairobi lines) indicate the necessity of 35 MVAr of compensation at Arusha for a 50 MW, 25 MVAr supply to Nairobi (with full available hydro generation plus 30 MW of thermal supply at Ubungo). With this transfer the loading on the initial sections of the lines in the west (Iranga-Dodoma-Singida) rises to over 50 percent of thermal rating. The losses in the western section also rises to 6 percent of the power flow. At any rate if power supply to Nairobi via Arusha is to be provided at a future date, the compensation at Arusha will be a necessity.

4.48 A connection from the east up to Mombasa with a 220 kV line from Chalinze to Mombasa via Hale and Tanga seems to be more appropriate on considerations of the network power flows. In addition the gas development from Songo Songo enables exportable power to be available in the eastern section of the network. A 2001 year peak power flow with full hydro generation (inclusive of the second stage Kihansi) and 120 MW (gas fired thermal plant) at Ubungo gives a satisfactory power flow and voltage profile for a 100 MW transfer to Mombasa. No reactive compensation is required along the new transmission line or elsewhere in the system.

4.49 The above discussion is not intended to arrive at specific conclusions for the possibilities of power export to Kenya but in order to form an idea of the capacity of the network for meeting possible new demands in the future.

System Operation at Base Load

4.50 A number of studies for base load operation has been conducted in order to examine the behavior at low load times. Some of the studies include the rejection of half the load at Ilala (the second step down station in Dar es Salaam) in order to provide a situation which could arise with a lower than normal base load. Another method of considering loads lower than the given base load for the year is to consider base load runs of previous years (while allowing for network changes relevant to the future year).

4.51 For the initial years after the commissioning of the second circuit to Dar es Salaam the generators will have to operate at substantial leading power factors if both circuits are placed in service. If for example the 1992 average base load is taken as a minimum load in 1995, it is seen that the machines at Kidatu and Mtera will have to operate at leading power factors of around 0.85. Since the power output is low at these times, the operation is within the generator capabilities. However, a number of other factors may need to be considered in such situations. Firstly it is normal for a number of machines to be taken off the system at base load times. Secondly, machine stability aspects need to be examined as generation operating regimes are more restrictive for leading than lagging operation. Thirdly, it is possible that both machines at Mtera may not be available during certain base periods, thus requiring further var absorption at Kidatu and causing problems for the voltage control of the north western lines. A full examination of these aspects inclusive of stability studies in the network at base load is beyond the scope of this study. It could, however, be concluded that greater flexibility of operation would be possible if var absorption facilities were available at Ubungo.

4.52 . The difficulties of high leading vars produced by the machines can also be avoided by disconnecting the second circuit (or one of its sections) during low load times. The studies show that with any one section of the second circuit out of service the situation is considerably improved. Hence this mode of operation could be resorted to if difficulties are anticipated for the stable operation of the system at base load. However, considerable step changes in voltages will be experienced with the switching on and off of the line sections.

System Operation During Outages

4.53 A basic reliability standard usually applied to transmission system planning is the "n-1" criteria, which requires the system loads (or as a minimum, the important load centers) to be maintained in the event of the outage of any one of the major transmission lines. The present TANESCO transmission system does not allow for such a contingency for any of its major loads. With the increase of system load over the coming years it would be necessary to place greater emphasis on reliability standards and allow some possibility of maintaining supply to important load centers in such circumstances. In particular with the introduction of the second circuit Kidatu-Morogoro-Dar es Salaam the network should be able to meet at least most of the load at Dar es Salaam with one of the line sections out of service. The incidence of line outages vary from short duration line trippings caused by atmospheric disturbances to longer duration outages caused by failure or damage to line hardware. With the increase of the service life of the existing transmission line it would also be reasonable to expect a greater incidence of the latter category and thus an added concern on maintaining adequate reliability standards are further justified.

4.54 Load flow studies have been conducted to determine the ability of the system to meet various outages. Some of the load flow studies specifically relate to certain outage conditions with a line section taken out of service. Other outage conditions can be deduced from the normal load flow results of previous years during which time the line to be disconnected was not in service (with the loading levels selected to provide the required bus loads for the condition studied). Outages which are meaningful in the context of system operation are (i) one of the line sections in the Kidatu-Morogoro-Ubungo lines, (ii) the Singida-Arusha connection and (iii) a line section in the north eastern network from Hale to Arusha. The latter two outages will be of relevance after the Singida-Arusha line is commissioned by about 1996. With respect to the Kidatu-Morogoro-Ubungo lines the outage of the Morogoro-Ubungo section is more demanding on the system than the Kidatu-Morogoro section and hence the study will be limited to the analysis of the former. With respect to item iii, the Hale-Same line outage will be considered. This condition will enable the Arusha and Moshi loads to be supplied by the north west leaving Hale to supply the load at Hale and Tanga and export any remaining power to the eastern load center of Ubungo-Ilala. The most severe outage in the northeast in the later years is clearly the outage of the Singida-Arusha line, which will require the entire load of the north east to be supplied by the power stations at Hale/Pangani and the Kidatu-Morogoro-Ubungo line. The following paragraphs describe the system capabilities of meeting the above outages during various future years.

4.55 The ability to maintain service during line outages will commence from 1993 when the Kidatu-Morogoro section of the second circuit is expected to be completed. Outage studies for the 1993 maximum load condition indicates that along with a 30 MW (and 20 MVAr) thermal generation at Ubungo a further 20 MVAr of compensation is required to support the system load if one of the Kidatu-Morogoro sections is outaged. At lower loading levels the 1993 system outage conditions can be deduced from the normal system operation of 1992 (since an outage of one of the Kidatu-Morogoro lines will correspond to the network conditions prevailing in 1992). Thus the results of the maximum system load of 1992 indicates that the load step 1 condition of 1993 will require 12 MW (and 7 MVAr) of thermal generation and 18 MVAr of reactive compensation. At a lower load level corresponding to load step 2 (maximum system load of 1991) 30 MVAr of compensation will provide the ability to supply the full load without resorting to thermal generation. The requirements indicated above (from maximum load to load step 2 of 1993) will also correspond exactly to the 1994 load conditions reduced by one load step (load step 1 to average mid load step 3).

4.56 The additional reliability to be gained by reactive compensation will acquire greater significance after 1995 when the second circuit is fully commissioned and when additional hydro generation (Hale/Pangani increased to 80 MW) is available in the north east. At the maximum load of 1995 a thermal generation of 25 MW will be required to meet the hydro generation shortfall. To meet the Morogoro-Ubungo outage condition 15 MVAr from the thermal generation together with a further 10 MVAr of var compensation will be required. When the load drops to load step 1 the system can operate without thermal injection if all hydro plant is fully operational. To support an outage of one of the Morogoro-Ubungo circuits during load steps 1 or 2 var compensation of around 15 MVAr is required for the various hydro generation combinations possible. The above operational conditions for 1995 could be related to the equivalent loading conditions during the years 1996 and 1997 with the system remaining unchanged (i.e., with the Singida-Arusha line unavailable).

4.57 From 1998 onwards, both the Singida-Arusha connection and the Kihansi power are expected to be available. An outage of the Singida-Arusha connection can be withstood without supply interruption during the 1998 maximum load condition by having a minimum of 20 MVAr of compensation at Ubungo together with 50 MVAr of compensation at Arusha and Moshi. Outages of both the Singida-Arusha connection and one circuit of the Morogoro-Ubungo line can be met satisfactorily if the compensation at Ubungo is raised to 30 MVAr. An outage of the connection between Hale and Same will separate the network once again with the loads at Arusha and Moshi transferred to the north western side. The compensation required at Ubungo to support this outage at the maximum load of 1998 exceeds the compensation required for the Singida-Arusha outage in view of the lack of mvar flow from Arusha-Moshi to Ubungo. For the above outage a minimum of 50 MVAr is required at Ubungo (HV voltage at Ubungo being 0.885 p.u.).

4.58 The outage studies described above indicate that about 30 MVAr at Ubungo and 30 MVAr at Arusha will provide the ability to cover most contingencies from 1995 to 1997 with minimal thermal support. If a further 20 MVAr is provided at Moshi, the full load of the system can be met for an outage of the Singida-Arusha line during 1988.

Slippage of Planned Investment

4.59 The results of the outage studies can also be used to ascertain the performance of the system in the event of the delay of introducing any of the planned developments. Delays in procurement of funds as well as in the award and management of construction projects are fairly common experiences with TANESCO. It would thus be prudent to have sufficient system capacity to be able to meet (say) the expected maximum load condition for at least one year of slippage for projects under construction and two years slippage for projects in the planning stage.

4.60 A special case of the ability to meet a slippage of planned investment is the flexibility provided to change the investment portfolio when new opportunities arise or there is a change of the conditions assumed for system planning. A matter of some concern in the present instance is the possibility of an extended delay of the Kihansi project (unexpected delays of hydro projects of this nature are fairly common occurrences). This fact coupled with the possibility of advancing the exploitation of the Songo Songo gas supply for power generation is of particular significance in TANESCO's strategic planning decisions. If such a situation arises the availability of sufficient capacitors at Ubungo will enable the Morogoro-Ubungo section of the second circuit to be delayed. The importance of this line will be greatly diminished if there is sufficient injection of thermal power at Ubungo. Hence TANESCO's ability to shift its priorities and options will be a substantial advantage to be considered for the introduction of reactive compensation measures.

4.61 Another possibility is a 220 kV development from Ubungo to Mombasa. This possibility is also connected with the gas generated power option at Ubungo. Studies have shown that if any power export to Kenya is to be considered the possibility of extending the proposed Singida-Arusha connection to Nairobi has only limited power transfer capability. The connection to Mombasa with substations at Hale and Tanga can be a viable option depending on the amount of power to be transported. If this possibility becomes promising it is possible that the extension of the proposed 220 kV system in the north east from Hale to Arusha could become more beneficial than the presently planned Singida-Arusha connection. The economic choice will depend on the expected load growth in the north eastern and north western sections, the power available for export and its value at the possible receiving points of Mombasa and Nairobi. The advantage of having reactive compensation installed at Arusha, however, is that if required by any change of circumstances TANESCO will have more flexibility in its ability to revise future investment options.

Loss Reduction Benefits

4.62 The preceding discussions related to the provision of the minimum reactive compensation requirements in order to maintain the system voltage during normal and exigency situations. The compensation provided at Arusha results in a flow of reactive power in a direction opposite to the active power due to the low capacity of the network and no loss reduction benefits will accrue with any increase of compensation. At Ubungo however, the compensation in excess of the amount required to maintain minimum voltages at any given loading condition will provide considerable loss reduction benefits. In addition the voltage profile could be considerably improved with additional capacitors and there will be a general improvement of reliability standards. These benefits will vary according to the loading and generation conditions prevailing at a given time. Some examples of the additional loss reduction benefits achievable by using compensation levels in excess of the minimum requirements are given in Table B.3 of Annex B. These benefits should clearly be taken into account in determining the extent of compensation to be employed.

Selection of var Compensating Systems

4.63 The foregoing paragraphs discussed the var compensation requirements necessary at Ubungo and Arusha in order to maintain a satisfactory system voltage profile. Additional loss reduction benefits derived from increasing the level of compensation over the minimum requirements have also been discussed. The studies conducted to cover a 10 year period from 1991 indicate the changing requirements of var compensation with time. The requirements also change with loading conditions which vary with the time of day. As discussed in para 4.5 the locations Ubungo and Arusha were selected as reasonable representations of the eastern and north eastern line extremities. It is now necessary to identify the types of compensation and the extent to which the compensation to be applied should be distributed (if so required) among adjacent locations.

Compensation Requirements at Ubungo

4.64 Of the two main locations requiring compensation the most pressing need is at Ubungo. Further the compensation would have its maximum benefits in the immediate short term by enabling the system to meet the load growth expected in the years before the commissioning of the second circuit, Kidatu-Morogoro-Dar es Salaam. If the TANESCO system was equipped with suitable var compensation at the present time the benefits realized due to the ability to meet the load growth at satisfactory voltage levels and in avoiding thermal generation would be exceptionally high. In these early years the compensation requirements will vary widely with the loading conditions and the ideal solution would have been a variable var compensation system. If the system could handle variable var supply it would in addition provide benefits during network outages, tripping and energization of transmission lines, as well as during sudden load variations. Stable operation would even be possible in the event of a disturbance as heavy as the tripping or energization of the Zanzibar cable or either of the 220 kV circuits to Dar es Salaam (after the second line is introduced). However if action is now taken to obtain a variable var compensating system it could only be commissioned by about late 1993 or early 1994. This would leave a period of only just over one year to reap the high benefits from the period before the commissioning of the second circuit up to Ubungo. On the other hand switched capacitors could be introduced much faster and if acted upon immediately at least two years of benefits could be realized before the second circuit is completed up to Ubungo. The benefits will continue even after the second circuit has been commissioned as previous discussions of the various operating scenarios show.

4.65 In view of the urgency of the requirements therefore it is recommended that the quickest method of obtaining the required compensation be pursued. Tables C.5 of Annex C discussed in Section 5 indicate the benefits achievable from reactive compensation of 30 MVAr in two switchable banks followed by a third switchable bank of a further 15 MVAr. While the inclusion of the first two banks provide a benefit to cost ratio of 39 to 1 the addition of a third bank is also beneficial at a ratio of over 8 to 1. For this reason it is recommended that three banks of capacitors of 15 MVAr each be purchased on an immediate basis. If action is taken immediately (early 1992) it is possible for the capacitors to be in service by the beginning of 1993. The banks need to be switchable and control circuit breakers and associated equipment should be provided. Two of these banks may be placed at Ubungo at the 33 kV supply point earlier used by reactors. The third bank is recommended to be installed at Ilala in order to capture in addition, the loss reduction benefits on the Ubungo-Ilala line. This separation will also assist in reducing the excess capacitance on the system in the event of tripping of the Ilala line.

4.66 The installation will have a high benefit period up to the commissioning of the second circuit to Ubungo. Thereafter the benefits will be mainly in the reduction of system outages until additional power is transported along the Kidatu-Morogoro-Ubungo lines consequent to the commissioning of the Kihansi power plant. At this time the compensation required at Ubungo/Ilala will rise to about 70 MVAr. Thus the present application should be considered both as an immediate necessity and as an advancement of future requirements.

Compensation Requirements at Arusha

4.67 With respect to the reactive compensation requirements for the northeast the initial period of high benefits is considerably longer than for the application at Ubungo/Ilala. The ability to supply additional load consequent to the improvement of network voltages will also keep increasing with time until the Singida-Arusha line is introduced (presently expected in 1996). Further the recommendation in para 4.13 to install capacitors in the distribution system at Tanga could be acted upon immediately to provide some relief until the compensation at Arusha can be installed. After the Singida-Arusha connection is introduced the requirement for compensation will shift from capacitive to inductive for normal system operation while requirements to meet an outage of the new Singida-Arusha connection will remain capacitive. The above considerations need to be taken account of in determining the most suitable mode of application of the reactive compensation measures to be installed.

4.68 A major consideration in instances where var compensation is relatively high compared to the power flow on the lines is the variation of network voltages when changes are affected either to the compensation level or to other network operating parameters. Table B.4 in Annex B indicates the variations of (the steady state) system voltages to be expected for incremental changes of var compensation at various operating conditions. When network voltages are highly sensitive to the compensation provided, var injection is best accomplished by static var compensation systems (SVS) using thyristor controlled reactors (TCR). These SVS installations are capable of reacting within about one cycle to any alteration of system conditions and producing the exact level of compensation required to maintain the reference voltage at the preset value. If the compensation were to be provided by a mixture of switched capacitors a number of operational problems may arise. Fairly high voltage variations could be experienced in the network and sections of the system could also be subjected to unacceptable voltage levels both high and low for short periods of time. If switched capacitors are to be provided the size of each unit needs to be small (about 5 MVAr) and switching facilities will need to be provided for each unit. The operation will need to be coordinated by a voltage supervisory system to allow the units to be introduced or disconnected in sequence in accordance with the compensation requirements. It is possible that the precise coordination of the large number of switched units required to obtain satisfactory operation of the system for all normal system variations may not be technically feasible. Without the rapid response characteristics (which can be provided by the TCR unit of an SVS) additional problems such as hunting of switching operations is also to be expected in view of the high sensitivity of network voltages to var injection changes.

4.69 In addition to maintaining network voltages during normal operational changes of the system load and the generation pattern an SVS installation would be of invaluable benefit during network outages. The fast response characteristic of the SVS will enable network stability to be maintained following major system disturbances (such as line outages or generator trippings). Although difficult to quantify in precise terms considerable advantages are expected from the improved system stability provided by an SVS unit installed at Arusha.

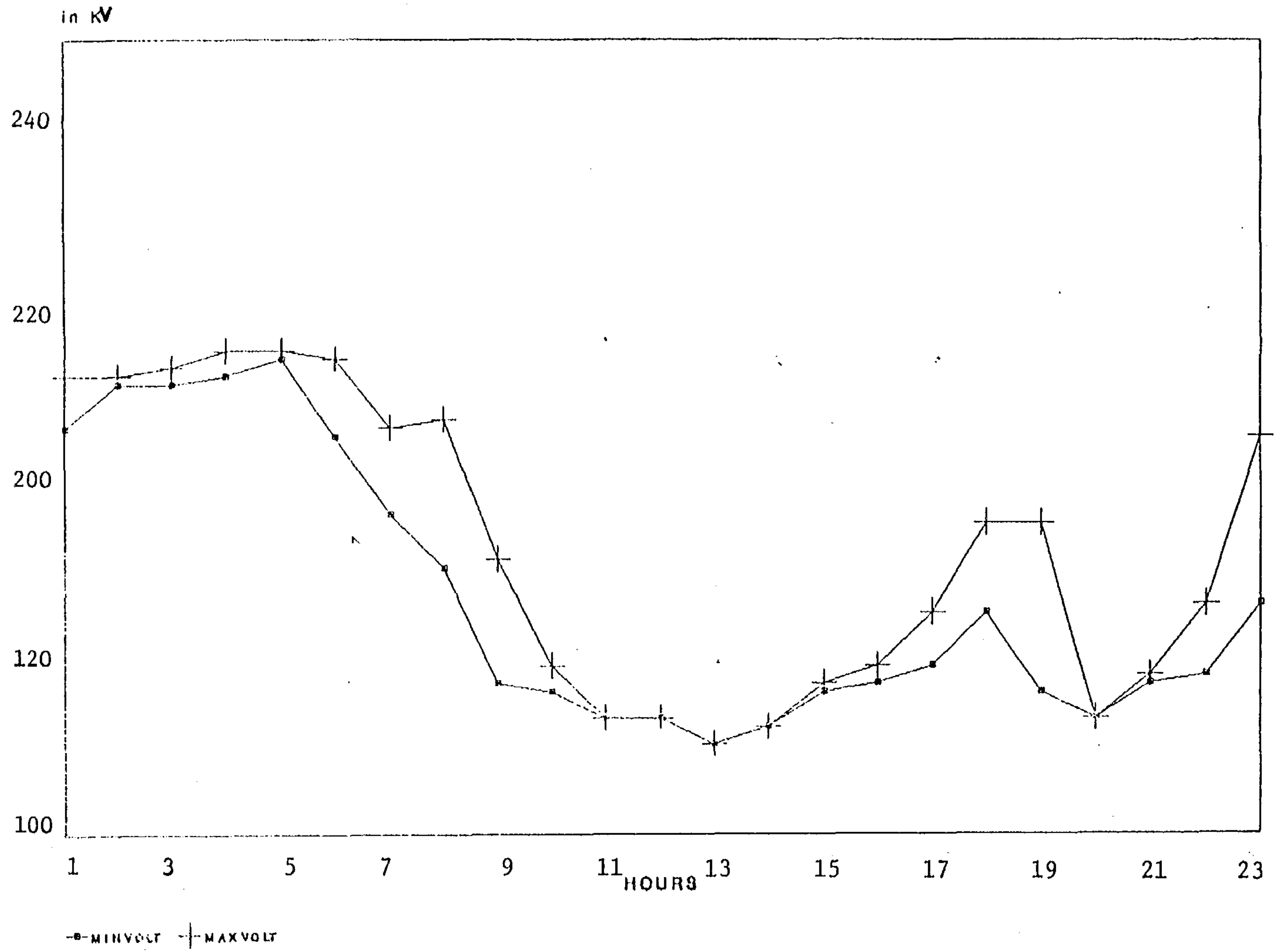
4.70 In view of these operational benefits as well as the fact that the higher costs of SVS units are more than justified by economic evaluation (see Section 5) it is recommended that the compensation at Arusha be provided by an SVS unit. The unit would consist of a TCR and the required capacitor banks (including filters) providing a var variation from 0 to +30 2/ MVAr. Arusha has been selected for the northeast location, in consideration of the current installation of 5 MVAR of capacitors in the substation at Moshi (Kiyungi), and the requirement for reactive compensation at Arusha or Singida when the planned Singida to Arusha line is placed in operation (see para below).

4.71 When the Singida-Arusha line is in service the SVS unit would not be called upon to provide any substantial capacitive var injection duty under normal operation conditions. However the capacitive mode could be used to maintain continuity of supply during outages of the Singida-Arusha line. Alternatively the capacitor banks could be shifted to other locations at which var compensation would then be required. With the Singida-Arusha line in operation the compensation needs will change from capacitive to inductive. Hence the best technical solution would be to add circuit breaker control to the capacitor units to enable the SVS operating range to be increased to (say) -25 to +30 thus providing for the inductive requirements during normal operation and capacitive requirements during line outages.

4.72 Although thyristor-controlled reactors can be purchased to operate at up to 33 kV, cost considerations make voltages of about 11 kV the optimum level if units operating at higher voltages cannot be connected directly to the system. The grid substation transformer capacity at Arusha energizing the 33 kV bus is inadequate to carry both the combined loads of the system and that of the SVS. Therefore since a new step down transformer would be required for the SVS unit to function at 33kV, operation of the SVS at 11 kV would be more economical. The capacitive units could be installed in three groups—one supplying the necessary filters for the suppression of harmonics and the other two providing the banks that will be subsequently converted to switched units when the inductive mode of operation is required.

2/ (+) indicates capacitive compensation and (-) indicates inductive compensation.

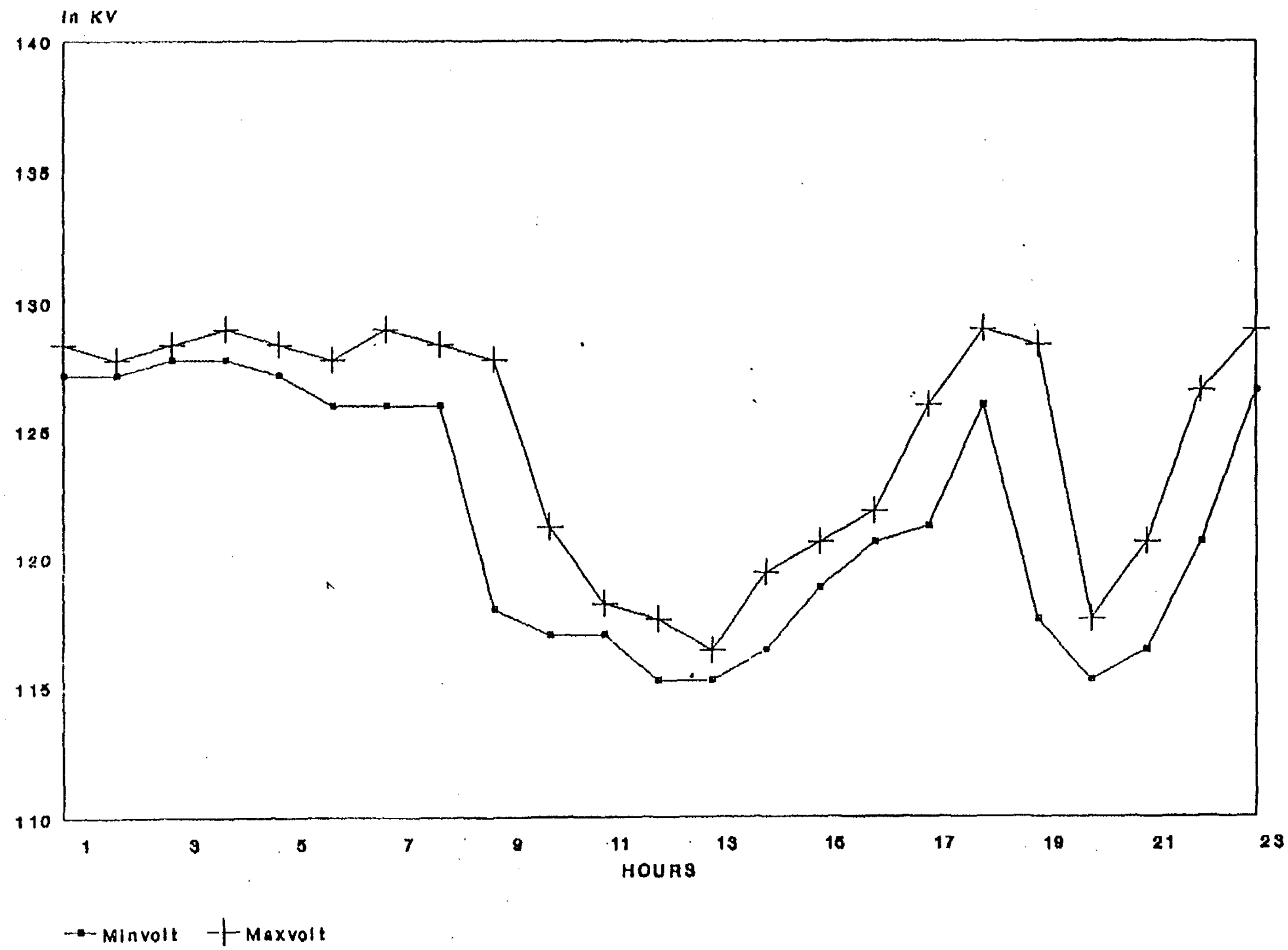
UBUNGO 220 KV BUS DAILY VOLTAGE PROFILE



Note: Data collected on March 21, 1990

Figure 4.1 A

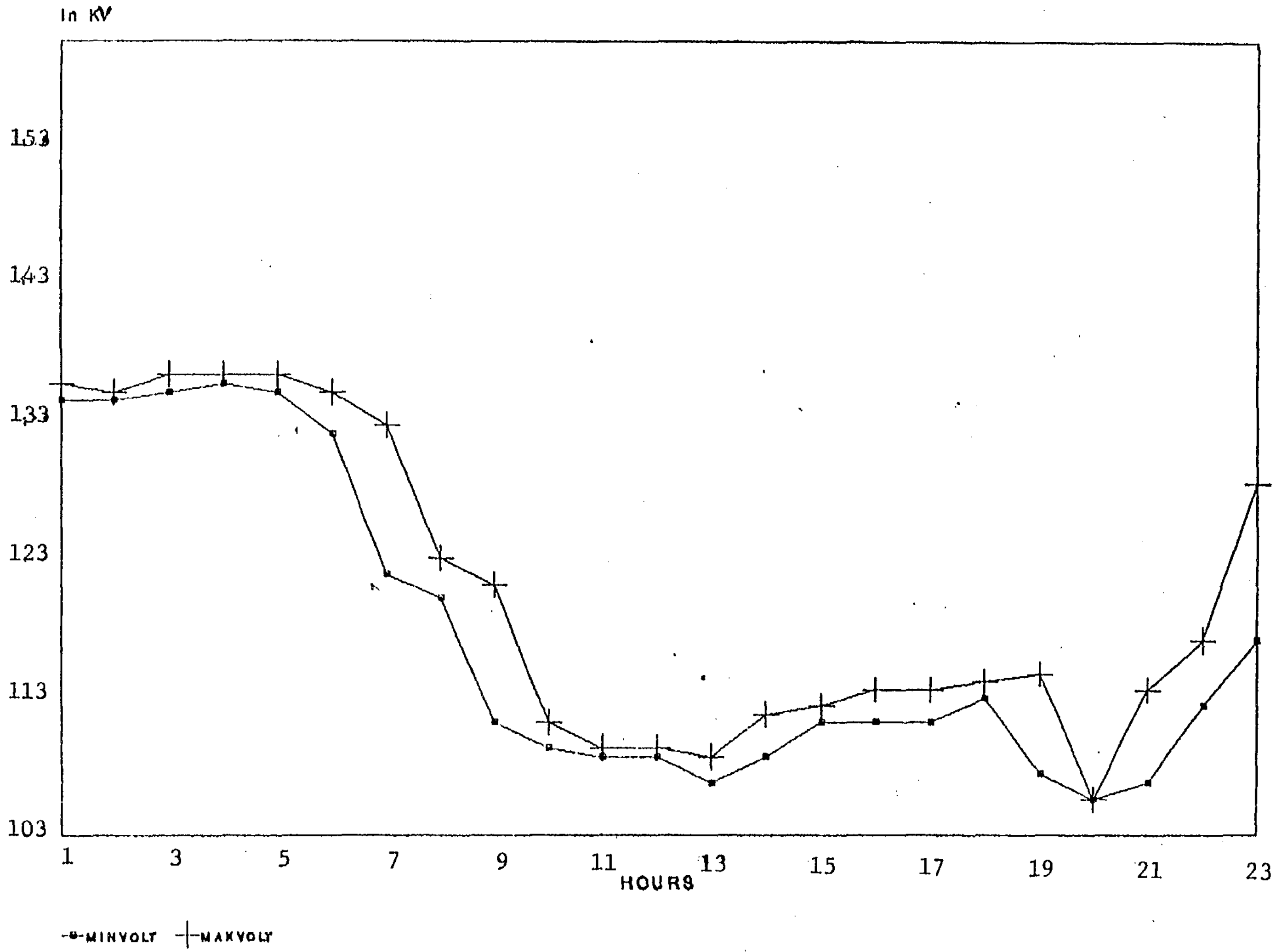
UBUNGO 132 KV BUS DAILY VOLTAGE PROFILE



Note:Data collected on March 21, 1990

Figure 4.1 B

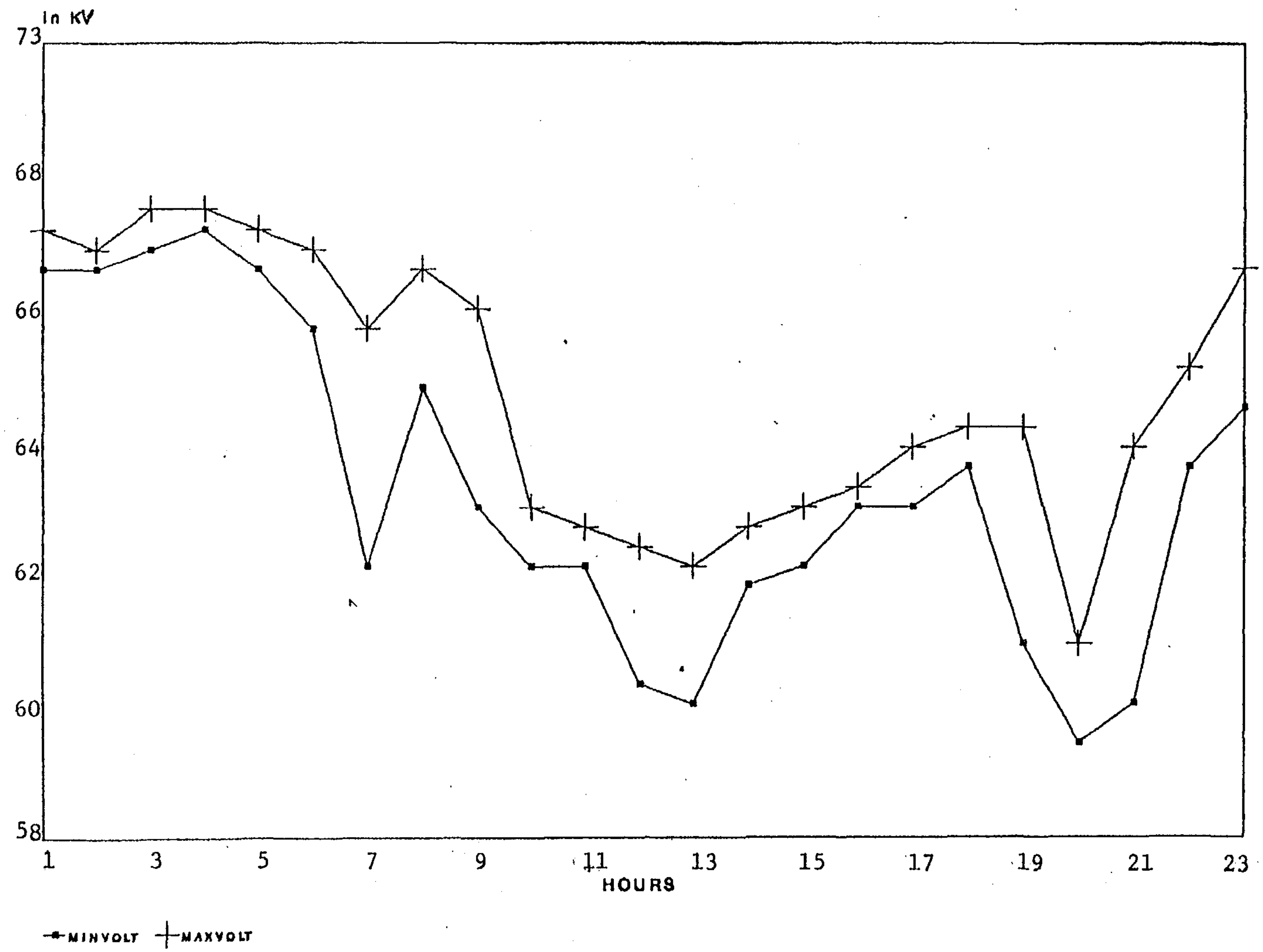
KIYUNGI 132 KV BUS DAILY VOLTAGE PROFILE



Note: Data collected on March 21, 1990

Figure 42 A

KIYUNGI 66 KV BUS DAILY VOLTAGE PROFILE



Note: Data collected on March 21, 1990

Figure 4.2 B

5. ECONOMIC ANALYSIS OF PROPOSALS FOR POWER FACTOR COMPENSATION AT THE TRANSMISSION LEVEL

5.1 At present the loads (active and reactive) on the east and northeast sections of the TANESCO grid are considerably in excess of the capacity of the network if voltages are to be maintained within the limits required by statutory regulations and the range generally considered as being technically acceptable. The high reactive currents flowing through certain sections of the system result in high power and energy losses. Furthermore although the system is not currently generation constrained (if all commissioned plants are operational at rated power) the addition of new loads is restricted in a number of locations in the east and northeast due to the difficulty in maintaining satisfactory consumer supply voltages in those locations.

Benefits of Investment in Reactive Compensation

5.2 The power transfer capabilities of the network can be increased by application of reactive compensation measures. In addition a number of other subsidiary benefits can be achieved. For the reactive compensation applications under consideration the following economic benefits can be realized:

(a) Increases in energy supply, above that which the network can currently sustain while maintaining satisfactory voltages

(b) Reduction or elimination of thermal generation otherwise required for voltage support

(c) Lower power and energy losses in certain sections of the network which currently experience high reactive power flows

(d) Reduced operating and maintenance expenses

(e) Reduced incidence of damage to equipment owned by TANESCO and by its consumers

(f) Improved quality of supply to consumers and therefore greater consumer satisfaction

(g) Reduced impact of any slippage or postponement of planned investment in transmission and generation as a result of the ability to transmit increased loads over existing circuits

(h) Possible postponement of transmission and generation investment.

5.3 Not all of these benefits can be accurately quantified. The data available is insufficient to allow development of realistic estimates of the economic value of reduced operating and maintenance expenses, of reduced incidence of equipment damage or of improved consumer satisfaction. In addition TANESCO is presently firmly committed to a generation and transmission expansion program over the period covered by this study and the recommendations presented in this report will have little or no effect on these investment plans. However the application of reactive compensation will enable the system to increase its load carrying capabilities and will therefore provide a crucial role in alleviating difficulties of meeting the network loads. This increased capability is of particular significance in view of the shortage of transmission capacity to meet the expected load with the developments currently planned. It will also assume added significance in the event of any unanticipated slippage of planned investment in transmission and generation projects. Another significant advantage is with respect to the possible change of investment plans, particularly in connection with the proposed use of natural gas from the Songo Songo gas field for power generation. The Government of Tanzania is now actively considering the early usage of this energy source in power generation. Once again the presence of reactive compensation measures will provide additional flexibility in changing investment planning decisions by increasing the critical time periods for new developments to be commissioned. In particular it may also be possible for the second line from Morogoro to Dar es Salaam to be substantially delayed if firm thermal generation is available at Dar es Salaam. However, it is not possible to quantify the extent of benefits provided in the event of unanticipated slippage of investment projects or in providing added flexibility of planning options. Therefore although these benefits are very real and pertinent in the context of TANESCO's system planning strategy, no credit is assigned to possible postponement of investment in generation and transmission in the present analysis. For these reasons the economic evaluation undertaken in this report will consider only a part of the benefits that will actually accrue from the proposals.

5.4 In the case of compensation to be provided at Ubungo the major portion of the benefits arise from the reduction of thermal generation that would otherwise be required at Ubungo up to the year of commissioning the second transmission circuit to Dar es Salaam to maintain minimum acceptable voltage levels. The ability to maintain system operations with the full network load during outages of any of the transmission circuits (when both circuits are installed) to Dar es Salaam has also been computed as benefits by estimating the increase in energy sales as a result of reduced outages. In addition the resulting loss reduction benefits have been evaluated.

5.5 In the case of compensation to be provided at Arusha the benefits evaluated are the value of the additional loads that can be connected to the system over and above the maximum load that can otherwise be supplied at an acceptable voltage. The maximum demands which can be supplied by the existing network (at the various bus bars), while maintaining satisfactory voltage conditions are in fact less than the loads supplied at present. Therefore the methodology employed for economic evaluation of increased consumption recognizes as benefits not only the new consumer demands which can be accommodated but also that increment of the existing demand which is the cause of the unsatisfactory voltage conditions.

The Value of Unsupplied or Poorly Supplied Energy

5.6 The economic losses which occur due to deficiencies of the power system cannot be accurately quantified because of their varied and diverse nature. In general, such losses greatly exceed the cost of the measures which would be required to correct those deficiencies. However, an estimate of the value of the possible new sales which TANESCO is unable to supply (including that portion of additional sales which cause poor supply conditions in the network) may be obtained by determining the cost to TANESCO's consumers of providing such energy from alternative sources. The most practical alternative, and by far the most commonly applied in Tanzania, is the use of small diesel generators installed on the consumers' premises. Table C.1.1 in Annex C shows the cost (at border prices) of power supply from a 2 MW diesel generator. The table indicates that these costs vary approximately between $0.12/kWh (all costs are stated in U.S. dollars) and $0.33/kWh, depending on the degree of utilization of the plant. In a country such as Tanzania the actual costs may be much higher as is illustrated by the fact that the table indicates the investment cost of the plant to be $800 /KW whereas the cost of a similar diesel plant being supplied to the Harbors Authority in Dar es Salaam has been reported to be as high as $2000 /KW. Operation and maintenance costs of isolated diesel plant on the TANESCO system are also reported to be considerably higher than the comparable costs given in the table. The generator used as the basis of the calculations is rated at 2 MW which is a higher rating than that of the average autogenerating unit installed in Tanzania. Costs from smaller units would tend to be higher because of economies of scale. It may therefore be safely assumed that in Tanzania the overall costs of energy from diesel generating units installed as an alternative to grid supplied energy will be higher than the equivalent costs indicated in Table C.1.1.

5.7 An alternative method of quantifying the value of electric energy is to use the Long Range Marginal Cost (LRMC) or the Average Incremental Cost (AIC) of power supply as the economic value of the energy supplied. The AIC for the Tanzanian power supply has been calculated and is summarized in Table C.1.2. This table indicates that the AIC works out to US$0.104 and $0.094 per KWh at discount rates of 12 and 10 percent respectively for energy supplied at the distribution level.

5.8 Of the two methods of determining the value of energy not (or unsatisfactorily) supplied, the former, based on the installation of small diesel generators at individual load centers, may be considered as the medium term supply cost (requiring a lead time of about two to three years in the situation prevailing in Tanzania). The latter method is based on the optimal cost of long term supply options (with a lead time of roughly four to seven years). The poor voltages and the inability to supply consumer demand are current realities and the benefits attributed to the proposed investments are specifically those which would be realized in the immediate to medium term. Therefore the true energy cost to be used in evaluating any measures which would bring rapid relief to the network should be the short term costs, which would be higher than both alternative costs discussed above. However in order to ensure that the recommended solutions are truly economical a conservative figure of $0.10/KWh has been used in the evaluation of economic benefits. This figure is also conservative with respect to studies done elsewhere in Africa3/ where higher values have been obtained as the willingness to pay for the provision of electrical power.

The value of loss reduction benefits

5.9 Loss reduction achieved by reactive compensation occurs mainly during the day and night peak hours. Hence the value of these benefits will be closer to the peak power costs than to the average energy costs (discussed in the preceding paragraphs). However, once again US$0.10/KWh has been selected to represent a conservative estimate of the benefits.

Cost of outage savings

5.10 The cost of announced as well as unannounced supply outages for connected consumers will be many times higher than the value of energy designed to prospective consumers. These costs are associated with a wide variation of circumstances ranging from high value items such as lost production to inconveniences of lower value such as leisure or enjoyment foregone. A study conducted as a part of the project using a Tanzanian research organization (Tanzanian Industrial Research and Development Organization) yielded the average value of US$2.25 per kWh for unannounced outages for a selected sample of industrial organizations in Tanzania. With respect to classes of consumers not covered under the study (such as residential and commercial consumers) the value would be somewhat lower. Studies conducted by Acres International and USAID in 1992 yielded values ranging from US$0.30 to US$1.00 per kWh depending on the duration of outage as well as the type of economic activity interrupted as a result of the outage. Since the outages saved as a result of the reactive compensation measures proposed are at peak hours and at the major load centers a value at the higher limit is more appropriate. For the purpose of evaluating such benefits an estimated value of US$1.00 per kWh has been taken to represent the value of such outage savings. This figure agrees with the studies conducted elsewhere where the cost of outages approximates to about five to ten times the LRMC of supply.

Cost of Compensation Equipment

5.11 Budgetary costs for various sizes of capacitors to be used in distribution lines along with the associated equipment required for their installation (at medium voltages of 11 and 33 kV) and at various capacities under switched and unswitched conditions are provided in Tables C.7.1 to C.7.3 in Annex C. The unit cost of the capacitors themselves (without support structures, switching and protection equipment, in $/kVAr) do not vary with the voltage of application. The cost of switchgear however will vary substantially according to the operating voltage. For capacitors to be used at substations the additional cost will consist of the support structure, control equipment

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3/ 1991 studies conducted for residential consumers produced values of US$ 0.11 in Burundi and Rwanda and US$ 0.18 to 0.20 in West Africa.

and switchgear. These costs are developed in the benefit to cost table for the Ubungo application (Table C.5 in Annex C).

5.12 Proposals including budgetary costs for static var compensation systems (SVS) with capacities of between 20 and 55 Mar employing combinations of a thyristor controlled reactor and fixed capacitor banks were obtained from four internationally recognized suppliers of such equipment. From these proposals estimates of the cost of installing SVS units were developed. These estimates are shown in Table C.4 in Annex C. The cost of installing the recommended SVS units is expected to vary from approximately \$90/kVAr to \$200/kVAr depending on the rating, the necessity for a step-down transformer and the number of switched capacitor banks required. The proposal for the SVS unit at Arusha is for an output variation from 0 to 30 Mar without the provision of circuit breakers at the initial stage. The expected cost for such a system based on international competitive bidding procedures is expected to be around US\$4.25 million. However there are only a limited number of suppliers of this equipment and the value of US\$5 million is taken for the economic analysis.

Calculation of benefits and benefit to cost ratios

Compensation to be provided at Ubungo/Ilala

5.13 In the immediate term the reactive compensation to be provided at Ubungo will result in a saving of thermal generation otherwise required to support the voltage up to the commissioning of the second 220 kV circuit to Ubungo. The load flow studies indicate that up to 10MW of thermal generation can be avoided during the load steps 1 and 2 of 1993 and load steps 2 and 3 of 1994. From 1995 onwards savings will accrue through load sheddings avoided during line outages. These benefits have been computed in Tables C5.2 in Annex C. In addition to the above benefits the installation of the recommended amount of capacitors will provide loss reduction benefits at various loading conditions (see para 5.14 below). After 1998 when generation from Kihansi should be available the loading on the Kidatu-Morogoro-Ubungo lines will increase considerably and the compensation required will greatly exceed the present recommendations. Thus, in the period after 1998, high benefits will again be reaped from the reactive compensation measures. However, in order to focus on the benefits that will accrue in the short term the benefits after 1998 are not evaluated. Instead, the discounted value of the capacitors in 1998 is subtracted from the economic cost in the benefit/cost analysis.

5.14 The loss reduction component of the benefits have been computed from the results of the load flow studies conducted at a number of operating periods in different years with the application of varying amounts of compensation (see Section 4 para 4.62). The results of these studies are summarized in Table B.3 of Annex B. Loss reduction benefits will be high when there is a necessity to transport a large amount of reactive power along the Kidatu-Morogoro-Ubungo lines in the absence of reactive compensation. Conversely the benefits will be low when either the power transfer along this line is low or when there is sufficient thermal generation at Ubungo to supply most of the required reactive power. Due to the complexity of accommodating all operating conditions only the periods during which the benefits are substantial have been computed. Table C 5.1 in Annex C provides the loss savings evaluated for the recommended compensation at different operating periods. The benefits indicated are the power and energy savings resulting from the application of the recommended amount of compensation in comparison with the condition when no compensation is applied. In some of the operating periods considered however the system voltages are lower than acceptable levels in the absence of reactive compensation. If the network load is to be supported without reactive compensation, thermal generation is required to be provided during these periods as indicated in para 5.13 above. Thus it is more appropriate to compute the value of saved generation during these periods rather than that of loss reduction. (Since the capacitors will not produce substantial loss reduction benefits with the thermal generation operational in these periods both benefits cannot be counted).

5.15 The benefit to cost ratios computed in Tables C5.1 and C5.2 in Annex C have been summarized for various combinations of benefits and are presented in Table 5.1 below.

Table 5.1. Benefit-to-Cost Ratios for Capacitor Application at Ubungo/Ilala

Benefits considered	30 Mar Application	Additional 15 Mar	Total 45 Mar application
Loss reduction benefits only (with no generation supplied for voltage improvement)	8.8	2.5	6.7
Loss reduction benefits only (with generation supplied for voltage improvement)	5.0	0.9	3.6
Avoided generation and outages	30.1	6.0	22.1
Avoided generation and outages plus loss reduction	39.0	8.6	28.8

Payback period considering all benefits = 3.0 months

5.16 It is clear that the proposal is extremely beneficial with high benefit to cost ratios as well as quick pay back. In addition the benefits remain high even with substantial changes to the capital costs as well as the rates used to value the benefits. It is important to realize that the benefits will decline with delay of implementation of the proposal. Thus early implementation of the proposals is a key element to their success.

Compensation to be Provided at Arusha

5.17 Without reactive compensation at Arusha no new loads could be added to the system at Moshi or Arusha as network voltages are already depressed below acceptable levels. Even at present loading levels there is considerable load shedding during peak hours and new connections are withheld in certain areas which experience severe voltage problems. When the generation at Hale is weak the problems are further compounded as reactive injection at this point will also be low. In the years before the commissioning of new Pangani Falls there will be difficulties in maintaining the Hale voltage at a high value (required to keep the line end voltages acceptable) when operating Hale and Moshi at their firm capacities. In such circumstances the compensation provided at Arusha will also benefit Tanga by increasing the var flow from Hale to Chalinze. Correspondingly the compensation provided at Tanga will also benefit Arusha.

5.18 The benefits of the compensation provided at Arusha are evaluated by the increased load which can be supplied at Arusha and Moshi. The secondary benefits at Tanga have not been taken account of. (These benefits will only be present when the generation at Hale is low and it would be difficult to quantify such benefits sufficiently accurately). The benefits are evaluated only up to commissioning of the Singida-Arusha line. There will however be continuing benefits due to the ability to meet system outages (of the Singida-Arusha line or any of the line sections between Hale and Arusha) as well as the possibility of supplying any inductive compensation necessary to stabilize network voltages when the Singida-Arusha line is introduced. (By installing circuit breakers on the capacitor units of the SVS, it could be made to operate in the reactive mode as well). Due to the very long length of the Singida-Arusha line (approx. 300 km) the provision of variable inductive supply will be a necessity when this line is introduced. The required inductive compensation could be provided (though less effectively) by other means such as switched or saturated reactors. Thus in order to allow for the continuing benefits after the commissioning of this line the net economic cost of the proposal is computed by crediting 30 percent of the total cost of the SVS unit (considered to represent the alternative cost of inductive compensation) to be effective 1 year before the line is commissioned. The cost benefit analysis of the proposal is provided in Table C6 in Annex C and indicates a benefit/cost ratios of 5.0 and 3.1 respectively for the cost of the proposal being computed with and without the credit for continuing benefits mentioned above (the SVS installation commissioned by end 1993 and Singida-Arusha line to be commissioned by end 1995). It is seen that with delays in the commissioning of this line the benefit/cost ratio of the reactive compensation will increase substantially.

5.19 An alternative solution to enable TANESCO to meet the expected load increases in Moshi and Arusha is to install switched capacitors (preferably 3 x 5 MVAr each at Moshi and Arusha). This solution will give a lower level of technical performance and much care will have to be exercised in the design of the control systems to ensure that satisfactory voltage levels are maintained and other technical problems (such as possible hunting of circuit breaker operations) are avoided. However if TANESCO is unable to procure the necessary funds for the recommended solution with the SVS installation the next best alternative is to proceed with the installation of switched capacitors thus being able to meet the expected load increases of the two cities although at a lower level of technical performance. Accordingly Table C6 in Annex C also provides a cost benefit analysis for this option. An economic comparison of the two options is not feasible as the technical advantages of the superior solution are not readily quantifiable. Table 5.2 provides a summary of the benefit to cost ratios and pay back periods achievable for the two options including their sensitivity to the capital costs used as well as to the valuation of benefits.

5.20 The benefit-to-cost ratios and pay back periods obtained for the compensation proposals for both Ubungo and Arusha clearly indicate that it would very advantageous for TANESCO to install the recommended reactive compensation devices as quickly as possible. The network is already unable to support the current load and delays in providing the necessary solutions will result in considerable losses to TANESCO as well as to the national economy. Thus the urgency of the requirements cannot be over stressed.

Table 5.2. Benefit-to-lost Ratios for Reactive Compensation at Arusha

Years of benefits counted	SVS Installation B/C ratio 1	SVS Installation B/C ratio 2	Switched Capacities
With Commissioning in 1993 beginning:			
1993 and 1994	3.3	5.5	6.6
1993 to 1995	4.7	7.5	9.6
1993 to 1996	6.3	9.5	12.8
1993 to 1997	7.9	11.5	16.2
With Commissioning in 1994 beginning:			
1994 only	1.7	2.9	3.4
1994 to 1995	3.1	5.0	6.4
1994 to 1996	4.7	7.1	9.6
1994 to 1997	6.4	9.2	13.0

Note: B/C ratio 1 is made without giving consideration to the value of the SVS equipment after commissioning the Singida-Arusha line.

B/C ratio 2 is made with a rebate of half the value of the SVS given at time of construction of the new line.

6. DISTRIBUTION SYSTEM DEVELOPMENT AND PLANNING GUIDELINES

Background

6.1 More than 75 percent of the existing load on the TANESCO system is concentrated in the cities (and environs) of Dar es Salaam, Tanga, Moshi, and Arusha. Furthermore, the highest load growth rates are in these same areas. Because of the importance of these areas, and also because of time limitations, the present study is limited to their distribution systems (the 33 kV and lower voltage networks). Overall distribution network losses are 13 percent for power and 8.6 percent for energy (see section 3). For the 33 kV lines, power and energy losses are 2.26 percent and 1.69 percent, respectively. For the 11 kV lines, the losses are 2.44 percent and 1.74 percent, respectively. Aggregate values, however, do not sufficiently indicate the complexity of the problem of poor performance or overloading of particular areas of the network. This is because distribution systems are typically nonhomogeneous, and the poor performance and high loss levels of a number of feeders are masked by a relatively large number of others with satisfactory performance characteristics. In addition, the network sections that are already stressed are most often the ones subjected to further high increases in load demand, so the situation becomes more serious as time passes.

6.2 The network studies conducted on individual feeders indicate that a number of supply areas are presently in need of considerable reinforcement and rehabilitation because of high load growth during the last few years (averaging to as much as 9 percent per annum) in combination with a lack of adequate investment and planning. The voltage levels at some of the locations are so poor that existing loads are restricted, and a moratorium is imposed on new connections. In part, these low voltages stem from poor voltage conditions in the transmission system (discussed in sections 4 and 5). But rectifying the input voltage levels to the distribution networks alone will not be enough to alleviate the poor supply standards experienced by the ultimate consumers. The distribution systems themselves need considerable inputs and carefully planned development to reduce the high losses and improve the reliability of supply in a number of specific areas. Further, networks that have deteriorated because of poor maintenance and overloading of equipment over a number of years also need considerable investment for rehabilitation.

6.3 Over the last six years two major distribution development projects were undertaken: the Dar es Salaam Rehabilitation Project, funded by the Japan International Corporation Association (JICA), and the National Rehabilitation Project funded by the International Development Association (IDA). The Dar es Salaam project carried out certain major improvements to the primary supply system of that city. The work included augmenting the capacity of the Ilala Grid Substation, introducing two new primary (33/11 kV) substations, and increasing the capacity of the 33 kV subtransmission network by increasing the conductor sizes of a number of major 33 kV feeders. Improvements to the secondary distribution facilities however, were limited to certain parts of the city. In the areas covered, approximately one hundred new distribution transformers were introduced, low voltage (LV) systems were strengthened, and network rehabilitation was carried out. The IDA-sponsored National Rehabilitation Project addressed all three sectors of the power system: generation, transmission, and distribution. Only about 30 percent of project funds were allocated for distribution system development, spread among 11 towns. The project was limited mainly to rehabilitation and reconductoring of some lines, addition of transformer stations, and other augmentation work (such as replacement of overloaded transformers). Planned network development was not addressed in a comprehensive manner. As a result, no new primary injection points or major system developments were introduced.

6.4 Despite certain limitations of the two projects, TANESCO's distribution systems benefitted greatly from them, and without them much of the load addition from 1986 to date would not have been possible. However, realization of suppressed demand and the addition of new loads have again reduced many parts of the network to poor operating condition, high system losses, and poor reliability. The situation is compounded by the fact that TANESCO was unable to supplement the work carried out by these two projects with regular and sufficient network improvement, mainly because it lacked sufficient foreign exchange.

6.5 Another matter of concern with respect to the distribution system is that a further release of suppressed demand will occur when the developments contemplated to improve the transmission network voltages are commissioned (TANESCO is already actively pursuing the recommendations contained in Section 5 of this report, and these developments are expected to be in place within the next two years). Thus, substantial improvements in the distribution networks are urgent. The improvements must be designed to cater to the expected load growth in the medium term (the next 5 to 10 years) and blend with the long-term planning possibilities. The network also needs to be expanded to cover a number of urban developments presently in progress, and the resulting load development should be anticipated in the system development plans.

Establishment of a Distribution Planning Department

6.6 Distribution networks comprise a vast number of line segments spread over large geographic areas. Any effective development planning of these networks requires the systematic collection of a large amount of network data. Such data consists of the physical characteristics of the existing systems (particularly conductor and transformer sizes), network loads (preferably at different times of the day), and expected growth rates. The data to be collected are voluminous and need also to be suitably organized to model the systems so that their performance can be subjected to the required technical studies. These technical studies will yield information on a number of important aspects, particularly with respect to system losses, voltage levels, and conductor loadings. The ability to perform these studies for different network connections as well as alternative network development proposals for the loading conditions of selected future years make them particularly important in selecting between various possible alternative development proposals. As in most power utilities in developing countries, the distribution planning function in TANESCO had not been adequately institutionalized. The documented data on the distribution systems were inadequate to undertake any comprehensive distribution planning. Network layouts on geographical maps, which constitute the first step in any distribution planning exercise, were unavailable in many locations, and line diagrams that were available were often outdated. Load readings on important feeders had not been taken, and whatever information that was available was poorly documented and not utilized by the planning staff. Because of the shortage of funds to undertake any major system improvements no serious attempts were made to prepare comprehensive development proposals. A notable exception is the planning study for Dar es Salaam carried out in 1987; but such efforts were not followed up to develop the data base or the planning capabilities of the relevant staff. Further, the improvements that were planned or considered were only short-term measures to resolve specific local issues, and system-wide network studies were not carried out.

6.7 A major objective of the current project was therefore to transfer the technology required and establish within TANESCO a distribution planning department capable of applying state-of-the-art techniques. This is one function that can not be adequately substituted for by external consultancy services obtained from time to time. The long-term data gathering and documentation required can be carried out effectively only by TANESCO personnel who are well acquainted with the networks and other relevant local conditions. Further militating against the use of consultants is the fact that the data collection phase is time consuming and requires only limited technical knowledge. Moreover, much of the required data--particularly data related to the past such as load readings--are already available in various departments within TANESCO. The network planning studies to be conducted are also fairly repetitive and can be grasped easily by the technical staff of the utilities in developing countries. Hence, the project work was carried out by establishing a separate unit within TANESCO to undertake the systematic collection, documentation, and analysis of the data.

6.8 The new unit established functioned as a centralized distribution planning department collecting data from the field, coordinating with the various zonal and regional offices (distribution centers), establishing a centralized data base, and performing the necessary studies. The staff of the unit was trained in the various techniques of distribution system planning. They were introduced to state-of-the-art technology in the instrumentation to be used for gathering system data and in conducting the studies using distribution planning software.

6.9 All aspects of training necessary to enable the TANESCO planning unit to perform unaided after the ESMAP study is completed were provided. The instrumentation used for the data collection exercise contained electronic logging equipment that can store the load characteristics of power lines or consumer installations at predetermined intervals for subsequent downloading to a computer in spreadsheet format. A set of Lotus "macros" was established to retrieve important characteristics such as load factors, loss factors, and power factor at selected time periods from the information downloaded to the spreadsheets. A computer workstation was provided, consisting of an IBM PS2 unit, a digitizer, and a plotter. The distribution planning software supplied consisted of a package of programs from Messrs. Scott & Scott of Seattle, USA. The programs in CMED (Computerized Mapping and Engineering Data) enabled the assimilation of the physical data and electrical characteristics of networks directly off system maps using the digitizer. The programs in DPA (for distribution primary analysis) enabled this data to be used for system modelling and analysis. The networks are modeled by representing the distribution lines by a number of sections (with the connected load within the section treated as a point load acting at the center of the section). The analysis programs enable load-flow studies to be conducted, providing information on the power carried along various sections, the voltage level at any system location (including the terminal voltage drop), and line losses. The programs also include the capability of providing load growth rates in individual sections to enable analysis of system performance for a given future year. It also enables the location of a given number of capacitors to be optimized for minimizing system losses on a particular feeder.

6.10 In addition to the network analysis programs described above, an alternative procedure involving a less rigorous methodology has also been developed to order cover the analysis of all the networks to be studied within the available time frame. The latter procedure enables the (approximate) determination of the principal characteristics required (total line losses and tail-end voltage drop) using certain simplifications and requiring only basic network information. A description of the methodology used for these simplified calculations is provided in Annex D. The results of these studies have been checked with the results of the more rigorous analysis where the computerized data base has been sufficiently developed, and they have been found acceptable. The use of this procedure has made it possible to undertake the study of all the medium voltage (11 and 33 kV) lines in the study area consisting of the load centers at Dar es Salaam, Arusha, Moshi, and Tanga.

6.11 The calculations described above have provided the losses and tail-end voltages of existing networks at the present loading levels as well as at those expected in future years. In particular, the year 1995 has been selected as representative of the period in which the proposed developments could be commissioned. Using the results of these studies, it was possible to identify the specific areas of the networks that need to be developed. The next step is to make a number of proposals to improve system performance and to subject these proposals to the network computations discussed above, in order to determine the operating characteristics to be expected from the proposed systems. The proposals that are technically acceptable are then subjected to an economic analysis using as benefits the network loss reduction and reliability improvements that are to be achieved. The latter benefits are computed by determining the additional load that can be supplied by extending the feeders beyond their normal operating positions. A fuller discussion of the methodology used for the economic analysis is given in paras 6.13 to 6.18 below. Such analyses, conducted for a number of alternative development proposals, also enable comparisons of their relative merits.

6.12 The distribution system studies conducted have yielded a wealth of information on the physical networks as well as on the load characteristics of system components and individual consumers. The value of this data base transcends the ability to formulate a set of proposals for the improvement of the present system. The information collected and the techniques introduced would be invaluable in improving many aspects of TANESCO's long-term planning capabilities. Distribution system planning can henceforth be done with a full knowledge of the capabilities of the future systems proposed. The information collected, as well as other data generated during the studies, can also be invaluable in load forecasting, load management, and tariff formulations exercises. Some items of particular importance are loading densities by geographical localities or feeder coverage, consumer characteristics revealed by their load duration curves, diversity factors for feeders and consumer groups, load factors, loss factors, and power factors of various system components. The establishment of computerized system maps and the association of the electrical data to such a system greatly enhances the value of the data base. One aspect that needs to be emphasized is the necessity of maintaining the data base keeping it current at all times, with regular updates of changes in the system. A concerted effort also needs to be made to increase the application areas and usage of the data gathered. This is the only way to increase the companywide awareness of the importance of the technology enhancement that has been introduced. The establishment of the study unit as a permanent branch within the organization of the Deputy Managing Director (Operations) augurs well for the continuation of the unit to produce useful work after the conclusion of the ESMAP studies.

Economic Analysis of Development Proposals

6.13 The improvements to the distribution systems proposed in the present study can be classified as follows:

(a) System development works for the purpose of loss reduction and improvement of reliability levels;

(b) Expansion of the network to new areas to meet urban development needs; and

(c) Physical rehabilitation of existing networks.

6.14 An economic evaluation of the proposals under the first category can be made by determining the extent of loss reduction and reliability improvements that will be achieved over an identified time period. Load flow studies carried out on the existing and proposed systems directly provide the value of loss reduction benefits. The losses derived from these studies are in kilo Watts (kW) and are related to the time and date for which the load flow is valid (usually peak time and applicable for a particular year). The peak time losses can be converted to energy losses (for a whole year) by using the loss load factor. The losses in subsequent years increase in proportion to the square of the load growth rate as the line losses are proportional to the square of the current carried. Thus system losses and correspondingly the loss reduction benefits of development proposals increase substantially each year, particularly if the load growth of the area is high.

6.15 Reliability benefits arise from saved outages as a result of the ability to feed sections of the network from more than one feeder (thus allowing for alternative feeding possibilities in the event of outages). Such 'saved outages' have been estimated by the total expected annual units consumed multiplied by the estimated per unit increase of reliability. The reliability benefits are thus proportional to the system load and the increases in future years are directly proportional to the growth rate (until the load increases to a level that does not allow for alternative feeding possibilities).

6.16 The methodology used to compute the loss reduction and reliability benefits over a period of future years is detailed in Annex D. The multiplying factors (for varying rates of load growth) to obtain aggregate values for loss reduction and reliability benefits over a given period of years are also provided in two tables. The Average Incremental Costs (AIC) of power supply in the TANESCO system at various voltage levels have been computed and the results are presented in Table C 1.2 of Annex C (see also paras 5.6 to 5.9). The value at the distribution level at 10 percent interest rate, $0.094 per kWh, has been used as the cost of loss savings from the proposed developments. With respect to the reliability improvements the value of outages saved is generally many times the cost of the normal power supply. A discussion on the value of reliability benefits are presented at para. 5.10 in Section 5. For the distribution system developments the value of the energy saved by reduced outages have been estimated at five times the AIC of power. However in order to test the sensitivity of the results to lover values the reliability benefit computations have been repeated at values as low as twice the cost of energy.

6.17 The second category of work covered in the study (see para 6.13) is the expansion of the existing distribution systems to supply new areas where substantial urban development is already in progress. Providing electricity to these areas is expected to enhance the development process and correspondingly increase the rate of consumption growth within a short period. The economic benefits realized from this work is clearly the value of the expected additional sales. The best representative figure for such new sales is the cost of alternative production given by the cost incurred if small diesel plants are employed (see Table C1.2 of Annex C and discussion in previous para). In evaluating the cost of supply the energy costs attributable to the upstream sections (generation and transmission developments) necessary to bring supply to the point of commencement of the distribution investment need to be added to the investment costs. Alternatively the net benefits of the additional sales are computed based on the difference in value between the alternative supply costs (of independent diesel generation, which is at distribution level) and the AIC of supply at the transmission level and these benefits are compared with the cost of the investment. The latter method has been used in the computations.

6.18 The third category of work envisaged in the proposed development is the rehabilitation of existing networks which have deteriorated due to poor maintenance as well as by natural ageing. The upgrading of these networks are more or less mandatory for TANESCO which has an obligation and even a contractual commitment to continue to supply the existing consumers. In fact, due to the above reason this work should be given priority over the other two components. The economic value of the work is in maintaining the assets of the company and its ability to continue profitable operations. Considering the state of the network components marked for rehabilitation it is quite evident that the alternative cost (at present value) of postponement of the rehabilitation works (which inevitably will result in more extensive network replacement at a latter date) together with the cost of outages in the intervening period will be much higher. It is thus considered that the specific economic justification of rehabilitation works identified are superfluous.

Nevertheless, an approximate cost benefit computation is presented based on the outage savings estimated to be achieved by rehabilitating the networks. What is more important is to ensure that an effort is made to ensure that the nature and extent of the rehabilitation works undertaken are consistent with optimum cost effectiveness. This cannot be achieved by any specific cost/benefit computations but needs to be made by good engineering judgement.

Existing Distribution Networks

6.19 As discussed at para 6.6 there were no specific guidelines or standards which TANESCO's distribution planning engineers could have used for measuring the performance of existing networks or for preparing proposals to meet the load increases expected in the future. This situation resulted in the networks being haphazardly extended or loaded without consideration for system performance such as voltage and loss levels, as well as reliability considerations. Unlike generation and transmission projects which are necessarily lumpy and staggered, distribution system development should be a continuous process of meeting the gradually increasing load demand in the various locations. In order to proceed methodically with the development of the distribution systems to cope with this continuously increasing load demand, TANESCO needs to adopt a set of procedures, guidelines and performance criteria. These rules need, of course, to be reviewed and modified from time to time; however it is important that system planners have at any given time a set of rules and procedures by which to measure network performance and to plan development works. They should not have to wait until network performance is so intolerable for the consumer that crisis solutions become necessary.

6.20 As previously discussed, major distribution system reinforcement and expansion works have been undertaken by a number of externally funded projects. These projects were often confined to certain areas of supply or had other limitations defining their scope of work to specific activities (such as rehabilitation or the development of a specific area). Thus these activities have not produced any company-wide guidelines which can be applied for the development of distribution systems. On the other hand these projects as well as TANESCO's own practices built up over a number of years have introduced certain system configurations such as voltage levels, equipment and conductor sizes etc. Further these characteristics are so widespread within the system that any new arrangement or alteration needs to take account of the cost of alterations to the existing networks where this is required. An appropriate strategy would therefore be to examine the existing network characteristics, evaluate their appropriateness and then examine opportunities for improvements, rationalizations and developments of new concepts in the context of the resulting economic benefits.

6.21 The existing primary distribution networks are based on network voltage levels of 33 and 11 kV. The 11 kV systems are generally restricted to developed urban areas while the 33 kV networks provide supply to the 33/11 kV substations and the larger bulk consumers. In low density (rural) areas the 33 kV networks run for long distances and supply consumers either directly off step down transformers or from LV lines connected to such transformers. In some instances the 11 kV lines are also extended for long distances, often commencing from a town and extended to over 20 or 30 km to supply rural loads. Many of the high load carrying conductors have been uprated from a number of lower gauges to 100 or 150 mm. sq. during the course of previous distribution development projects. Other conductor sizes in use for primary distribution are 50 and 35 mm. sq. The step down transformers providing supply to the LV network range from 50 to as high as 630 kVA. Many of these are of the higher ratings (200 kVA and over) and are combined with the use of long secondaries. In most heavily loaded areas 100 mm. sq. conductors have been introduced for LV feeders. The studies conducted by modeling the feeders and direct measurements performed indicate that a number of poorly performing MV feeders have peak line end voltages which drop to as low as 80 percent of nominal and peak loss levels as high as 15 percent of the power supplied.

Planning Concepts

6.22 The major load centers in the country already have extensive 33 and 11 kV networks and hence it is not considered economical to introduce any other voltage level (such as 22 kV) at this time. Further, a review of the feeder losses and tail end voltages of the MV systems indicate that 150 and 100 mm. sq. ACSR conductor could continue to perform as the standard conductor cross sections of the main feeders for the loading levels that are to be expected in the foreseeable future. However, computations carried out (as well as studies carried out eleswhere) indicate that the economic loading level of conductors is in the region of 25 to 40 percent of thermal limits. Thus the network configurations need to be designed to provide loading conditions not exceeding these values. Such reduction of loading levels is best achieved by increasing the number of MV feeders and 33/11kV substations. This strategy will not only reduce network losses but also allow for alternate supply possibilities to be arranged in the event of outages on the normal mode of supply.

6.23 As discribed in para 6.21 a number of primary distribution lines which commence from major load centers have been extended over excessive distances without regard to the voltage drop that will be experienced at the line extremities. In addition, the reliability of the more importent loads located at the commencement of the feeder is affected as suitable interupting devices are not installed along the line. In many of these instances the 11kV lines which have been so extended can be economically uprated to 33kV operation (line losses reducing by a factor of nine from the former value). The construction work involved will entail the change out of line cross arms, insulators and transformers along the feeder. In instances where the loads closer to the commencement of the feeder requires a higher reliability standard the existing 11 kV line can be retained to feed these loads and a new 33 kV line could pick up the load of the rest of the feeder by connecting to the section which is uprated.

6.24 In addition to the 11 kV lines there are also a number of 33 kV lines where the loads and/or the distances are still too great to be supported at this voltage (distances exceeding 100 km have been encounted). In many of these instances the loads are also too small for the justification of the next higher standard voltage, 132 kV, particularly in view of the high cost of the step down substations, 132/33 kV or 132/11 kV which will then be required. The use of 66 kV networks to supply these loads could often prove to be economical. (This voltage was formally in use extensively in the system but almost all such networks have now been replaced by 132 kV). However the design considerations to be used for these 66 kV system should follow those for rural networks (with minimum use of switchgear) in order to keep the costs reduced in line with the level of importance of the load. Sometimes the existence of decommissioned 66 kV networks available in close proximity allows salvaged equipment to be used in order to reduce investment costs. An example of the use of 66 kV as a network voltage is seen from the proposals for the Marangu - Rombo area dealt with in para 10.6

6.25 Another concept that needs to be developed is the decentralization of the LV systems. During previous distribution development projects a number of additional MV/LV transformers have been introduced. This process needs to be continued further and lower capacity transformers employed to serve smaller areas of coverage. Where feasible it will also be prudent to obtain supply to the LV distribution network from a number of transformers installed to feed bulk consumers. With this practice one could also take advantage of the loading diversity between most bulk supplies (which operate in the day time hours) and the LV networks (which usually have their peak at night).

Planning Guidelines

6.26 The results of detailed system studies for a large number of MV networks are presented in the chapters to follow. These studies also include the economic cost benefit analysis of proposed alternatives. Based on the knowledge gained from these studies it is possible to establish a set of general guidelines which would approach optimum system performance levels with respect to network losses and supply reliability. These guidelines may be used as performance indicators for the continued development of TANESCO's distribution systems. It must however be emphasized that major network developments must be subjected to system studies and economic analyses as performed for the proposals contained in this report. The guidelines are to be used mainly to provide general acceptability criteria. Further in particular instances economic analysis may dictate the need to deviate from the standards of performance that are provided in the guidelines.

(A) <u>MV systems in City areas</u>:

A 1. A primary MV system at 33 kV, fed off the grid substations shall be used to feed 33/11 kV substations and where possible large bulk supplies (preferably consumers over 1 MVA).

A 2. Alternative 33 kV supply routes shall be provided to the 33/11 substations and bulk supplies over 5 MVA.

A 3. Standard ratings of the 33/11 kV substations shall be 2 x 10, 1 x 15, 2 x 5, and 1 x

5 MVA. In general substations of smaller capacities are not expected to be economic as 33 kV could continue to be used for the downstream sections. However where existing 11 kV networks or other special considerations exist substations of 1 x 2.5 MVA may be considered.

A 4. Standard sizes of 150 and 100 mm. sq. ACSR 4/ shall be used for the main 33 and 11 kV feeders. The branch lines (where the currents to be carried are not expected to exceed 50 Amps) will be based on 50 mm. sq. ACSR.

A 5. The normal operating peak currents shall not exceed 200 Amps for 150 mm. sq. conductor and 150 Amps. for 100 mm. sq. conductor. Where these values would be exceeded double circuit construction or additional feeders shall be provided.

A 6. Insulated conductors and underground cables will not normally be used. Such construction will only be resorted to when special construction difficulties such as maintaining clearances are encountered.

A 7. The 11 kV feeders shall be erected and operated as 'open rings' from the same substation or be fed from adjacent substations at either end with a normally open position along the way. The entire feeder shall be capable of being fed from one source.

(B) MV systems in rural areas

B 1. The normal MV distribution voltage shall be 33 kV for rural areas. Substations of 33/11 kV and 11 kV distributors shall only be used if it can be demonstrated that the total costs (inclusive of the 33/11 kV substation and additional network losses) will be less than for a 33 kV network development.

B 2. When long transmission distances are involved to lightly loaded areas 33 kV lines may not be able to satisfy the performance criteria detailed in section D below. In such instances the use of sub transmission lines at 66 kV shall be considered. When the use of such an intermediary voltage appears to be advantageous the feasibility of constructing the line at 132 kV and operating it at 66 kV for an initial period should also be investigated.

B 3. The uprating of existing 11 kV distributors to 33 kV shall be evaluated when the loading density is low and line lengths are long.

4/ ACSR - Aluminum conductor steel reinforced.

(C) LV networks

C 1. The use of a larger number of transformers and smaller supply areas from each transformer shall be the main strategy of development. This should lead to over 80 percent of the transformers being of the ratings between 50 and 200 kVA. It is found that many consumer transformers exhibit peak loads during the day time periods. These can be effectively used to feed the LV distribution system during the night time, thus utilizing the load diversity between the consumer groups and enabling the total load to be supplied by a lower installed capacity. The peak loading of transformers shall be between 75 percent and 100 percent of nameplate rating.

C 2. 100 and 50 mm. sq. conductors shall continue to be used for the main feeders of LV systems.

C 3. In city areas all outgoing feeders shall be three phase. Special efforts shall be made to achieve a good load balance right along the feeders and distributors by systematic assignment of successive loads to each of the three phases. Regular (possibly annual) cheks of phase balances are to be made and adjustments made as necessary. Any single phase branches shall be restricted to the supply of less than eight consumers.

C 4. In rural areas the use of single phase transformers shall be considered for the supply to small localities below 50 kVA that are situated close to the MV lines.

(D) Target performance criteria for network planning

D 1. Systematic load forecasting shall be undertaken to provide the basic inputs to network planning. The forecasts shall be prepared in a sufficiently decentralized manner to determine the requirements of each small area of local distribution. The loading densities of existing systems, both on the LV retail network and the MV feeders shall be calculated regularly to provide information on the load growth in these particular areas as well as information on typical loading patterns to be expected in other developing areas.

D 2. The following maximum limits for peak power loss and voltage drop levels shall be used for network planning:

	Peak Power Loss	Peak Voltage Drop
MV feeders, City areas	4.0%	6%
MV feeders, Rural areas	5.5%	9%
LV feeders, City areas	3.0%	5%
LV feeders, Rural areas	5.0%	9%

D 3. In order to assist network planners to predict the operating characteristics of the conductors used in the system a set of graphs indicating the maximum line distance that can be allowed for varying loading levels in order to maintain the line end voltage drop below indicated values have been prepared during the study for (a) lines loaded at their extremities and (b) those with typical load distribution characteristics. Those that pertain to the maximum voltage drops indicated in the table above are given in a set of charts (D2) in Annex D.

7. REACTIVE COMPENSATION ON THE DISTRIBUTION SYSTEM

General Considerations and Methodology

7.1 The previous section detailed the methodology of the studies that need to be performed to reduce losses and improve the reliability of TANESCO's distribution systems. These studies have been performed for the networks in Dar es Salaam, Tanga, Moshi, and Arusha and proposals to bring the systems up to economically acceptable standards are presented in Sections 8 to 12. However, because of difficulties in financing and other logistical problems, TANESCO will likely require at least four to seven years to complete the work planned. In the meantime, substantial relief to the poorly performing sections of the distribution system can be achieved through reactive compensation. The present section deals exclusively with reactive compensation measures that could be economically applied in the short term on the existing distribution feeders.

7.2 Ideally, reactive compensation should be located as close to the reactive loads as possible to obtain the greatest benefits in loss reduction. This is so because, with compensation installed at the source of the reactive demand, the current–and therefore the losses–are reduced in all components upstream of that source. In contrast, if the compensation is placed between the source of reactive demand and the source of input power, the current is reduced only upstream of the compensation.

7.3 A number of considerations complicate the application of the general principle of installing compensation at the source of reactive demand, however. These are:

- The fact that compensation may be uneconomical at downstream locations individually, but the summation of the loads further upstream may provide economic opportunities.

- The need to vary the compensation by switching off excess capacitance as the reactive load reduces (usually with reduction in active power) could be eliminated by placing the capacities sufficiently upstream.

- Since costs of switching and isolation greatly exceed that of the capacitor banks, considerable economies of scale are realized for larger capacitor installations (which require that capacities are placed further upstream), particularly when switched operation is required (see para. 7.9).

7.4 In view of these factors, the most economical program of reactive compensation for a given distribution system must be determined by a study of the loss reduction benefits obtained by the application of various sizes of switched and unswitched capacitors at various locations and a comparison of the benefits with the costs of the respective applications. Several points should be noted about loss reductions provided by the use of capacitors for reactive compensation. First, as the load decreases, the benefits for a particular application decrease substantially; therefore, most of the benefits are realized during the day and night peak load periods. In fact, overcompensation can occur during base load, resulting in a small increase of losses. Second, the benefits of each successive kVAr of capacitance installed on any given feeder decrease incrementally with increases in power factor caused by the previous applications, creating an optimal point beyond which the benefits obtained from additional capacitance on the feeder will not be commensurate with the additional investment required. The initial capacitor installations in a system will thus provide the highest benefits, and in each successive installation thereafter the incremental benefits will decline proportionally. Finally, benefits will continue to be realized upstream of a particular feeder of the distribution system considered, even after they are fully realized in that feeder itself. This is because improvement of the power factors downstream will also improve the power factor in all upstream sections (as noted in para 7.2 above). This also implies that the benefits to be computed should also include the relevant upstream sections of the network.

7.5 The results of a large number of studies on capacitor applications in distribution systems indicate that the compensation requirements close to optimal application can be determined by using the following procedure. Firstly, the requirements in the peripheral sections of the networks which would operate without overcompensation at system base load are identified. Thereafter further applications at suitable upstream locations are examined in a successive manner always maintaining approximately full compensation at base load. At each stage the loss reduction benefits (of both power and energy) should be computed and analyzed for economic acceptability. Clearly those feeders exhibiting excessive voltage drops and power losses will yield the highest benefits and particular attention needs to be given to such feeders. The benefits over the initial years when the existing distribution system is expected to remain unchanged will be high and would in fact increase as the load grows. However, major network developments to reduce network losses and improve reliability of supply have been identified in Sections 8 to 11. These developments will introduce new feeders and substations and would cause substantial alterations to the existing network arrangements particularly in lines exhibiting high losses at present. With the introduction of such developments (expected to be effective over the next four to seven years) a substantial reduction of benefits of the capacitor applications are to be expected. At this stage the suitability of retaining the capacitors in the existing locations should be examined by conducting new power flow studies. Sometimes this is possible due to the increased load at that time. If their retention is not justified or better locations are identified they can be transferred (as an entirety or only the excess quantity) to other locations requiring reactive compensation for optimum system performance.

7.6 The feeders that would benefit from var compensation measures were identified from the network studies carried out (as detailed in Section 6) and additional information on their physical characteristics and loading conditions were obtained, in particular the power factor at various times of the day. The losses currently being experienced on these feeders were calculated using both the approximate analysis methodology and the computer software for network analysis. Thereafter, the improvement of system losses by the application of capacitors of various sizes was determined. The software enabled the selection of the locations along the relevant feeders at which capacitor installations would provide the maximum benefits in loss reduction. A discussion of the loss reduction computations made at various voltage levels is provided in paras 7.12 to 7.14 below, and a summary of the results and corresponding benefit/cost ratios is presented in Tables C.8, C.9, and C.10 in Annex C.

Economics of Capacitor Installation for Power Factor Control

7.7 Capacitors are installed on distributions systems to control the system power factor and thereby reduce losses and improve voltage regulation. The benefits listed in para. 5.2 in section 5 for the transmission system are applicable to reactive compensation on the distribution system as well. However, although the primary objectives of the reactive power control measures proposed for the transmission system are voltage improvement and the consequent ability to supply additional loads, the predominant benefits resulting from capacitor installation on the distribution system are loss reduction (and to a lesser extent voltage improvement). In the TANESCO system the correction of distribution system voltages to conform to acceptable limits is achieved primarily by (a) adjustment of the transmission system voltage (discussed in Sections 4 and 5), and (b) changes to the physical configuration of the distribution system by increasing the number of feeders and/or new transformer stations (discussed in Sections 8 to 11). Further, although the introduction of capacitors will enable some new consumers to be supplied in certain networks presently exhibiting poor voltages, it is not feasible to identify and quantify such benefits. The economic benefits obtained are therefore evaluated only on the basis of the reduction in energy losses experienced on the feeder as a result of the improved power factor. The value placed on each unit of energy by which losses have been reduced was taken as the same as that used for increases in consumer sales and reduction of losses in the evaluation of transmission voltage improvement measures, namely US$0.092/kWh (see para. 5.8, Section 5).

7.8 In general, the loading of the lines (on which loss reduction benefits are achieved) will increase with time. Further, the yearly benefits of a particular capacitor application will increase at a higher rate than the rate of load growth because an uncompensated line will experience a rate of increase of line losses equal to the square of the load growth rate. Detailed studies have revealed that the rate of increase of loss reduction benefits from capacitor applications has been closer to the rate of increase of uncompensated feeder losses than the rate of increase of the feeder load growth. If the lower value of the feeder load growth rate is assumed as being the rate of increase of benefits from capacitor applications, the present worth factor for loss reduction benefits over a period of 10 years (at an interest rate of 10 percent) would work out to 11.5, 10.5, and 9.6 for load growth rates of 11, 9, and 7 percent, respectively. The present worth factors over a period of 6 years would be 7.2, 6.8, and 6.5, respectively, at the same load growth rates given above. In computing the benefits of capacitor applications in the distribution system, a conservative estimate of 6.0 has been used for the present worth factor.

Cost of Capacitor Installations

7.9 The cost of capacitor installations on the distribution system was estimated by determining the market costs of the individual components and the installation costs applicable to Tanzania. Equipment costs for capacitors, switches and other ancillaries are shown in Table C 7.1. in Annex C. The installed costs of unswitched capacitors are presented in Table C 7.2 and for switched capacitors in Table C 7.3. For unswitched capacitor banks rated between 50 and 600 kVAr the estimates of installed costs range from $ 46/kVAr to $ 5.2/kVAr respectively (all costs are stated in United States dollars at mid 1991 prices) for installation on the 11 kV system and from $ 65/kVAr to $ 6.7/kVAr for operation at 33 kV. Specific costs for switched banks of similar ratings range between $ 72.3 and $ 7.4/kVAr installed on the 11 kV system and between $ 166.7 and $ 15.3/kVAr if installed on the 33 kV system. Installation of the capacitors on the 11 kV system (instead of 33 kV) will provide the dual benefits of greater reduction in losses as well as lower investment costs. It will be seen from the tables that the specific costs of capacitor banks rated less than about 200 kVAr are too high for their application on the TANESCO system to be economical.

7.10 For efficient inventory management, the ratings of capacitor banks applied on the distribution lines should be restricted to a small number of standard sizes. The calculations made during the course of the study showed that for the loading conditions experienced in the TANESCO system, banks with standard ratings of 600 kVAr would be best suited for the first stage of application for the most heavily loaded feeders. When placed at the substation busbars (i.e., at 11 kV), the ratings could be as large as required in each case, generally providing up to full compensation at base load. Capacitors varying from 1,000 to 3,000 MVA could be used at the various substations.

Computation of Loss Reduction Benefits

7.11 Loss reduction benefits (in terms of kilowatts saved for a given loading condition) for the various feeders and networks studied have been obtained using both the approximate spreadsheet methodology (see Annex D) and the software package mentioned earlier. The software program used also selects the location at which a given capacitance should be installed to maximize the loss reduction benefits. However, as the analysis using the software package has not been completed for the entirety of the systems in the four study areas, the results of the spreadsheet computations have been selected for the analysis. The loss reduction benefits are usually highest when the feeder is carrying its maximum load. At lower loads (off peak, usually represented by shoulder and base-load steps), the loss reduction achieved will be lower than at peak. The situation is complicated, however, by the fact that the power factor of the feeders vary considerably between the different periods of the day. In many instances, the daytime power factor is substantially worse than at night, even if the loading of the feeder is higher during the latter period. Further, a simple relationship is not available between the loss reduction (of capacitor applications) at the different times of day as in the case of loss reduction achieved by reduction of feeder currents or conductor resistances. In view of these complications, the reduction of energy losses (in kWh) achieved by capacitor applications are computed for most applications by determining the loss reduction achievable at the three selected steps of the load duration curve; peak, shoulder (mid load) and base load. Multiplying the loss reduction at each level by the duration for that level and adding the resulting energy losses for all three tiers will yield the total loss reduction over the period considered (usually one year). Alternatively, the energy savings can be calculated from the peak load power loss reduction by use of the *loss reduction load factor*–a factor that will convert the reduction in power losses at times of peak demand achieved by specific corrective measures to the corresponding energy loss reduction over the (yearly) load cycle. The peak loss reduction (in kW) multiplied by the loss reduction load factor and 8,760 (hours per year) will provide the annual reduction in energy losses (in kWH). As with the loss reduction benefits (noted in para 7.4 above), the loss reduction load factor will also be higher for the application of the first capacitor bank and will decrease thereafter for successive applications. This is because with a fixed capacitor in the system the power factor will keep increasing as the load decreases from peak load to base load. Using the three-tiered load duration curve as before the loss reduction load factor can be computed from the loss reduction at each load condition using the following formula:

loss reduction load factor

$$= \frac{(\Delta P_p \times T_p) + (\Delta P_m \times T_m) + (\Delta P_b \times T_b)}{\Delta P_p \times (T_p + T_m + T_b)}$$

where $\Delta P_p, T_p$ refer to the peak loss reduction and time in hours (per year), respectively. The corresponding values for shoulder (mid) load and base load are given by the subscripts m and b, respectively. When the loss reduction load factor method is employed, only the peak loss reduction is determined, and a suitable loss reduction load factor is selected using the factors determined for feeders having similar loading characteristics. The studies carried out indicate that for the heavily loaded feeders, the first application of banks of 600 kVA rating gives loss reduction load factors of about 70 percent or higher, whereas subsequent applications produce loss reduction load factors of between 60 to 40 percent.

Loss Reduction Benefits at Various Voltage Levels

7.12 Drawing F1-1 in Annex F shows the 33 kV network in Dar es Salaam, which is supplied by the grid substations at Ubungo (220/132/33 kV) and Ilala (132/33 kV). The drawing shows the geographical layout of the 33 kV feeders from these grid substations to the 33/11 kV distribution substations and the major consumers fed at this voltage. Drawing F.2 in Annex F shows the 11 kV network, which obtains supply from the above substations and performs the distribution function to the various areas of the city. The benefits of capacitor applications have been computed in three stages. First, the loss reduction benefits on the 11 kV lines themselves by the application of capacitors on these lines have been computed. Next, benefits on the 33 kV lines because of the capacitors considered earlier (installed on the 11 kV lines downstream), followed by new applications at the 33/11 kV substations (usually at the 11 kV bus bars), were computed. Finally, the transmission load flow program was used to compute the loss reduction that will be achieved on the transmission system (in particular in the 132 kV line from Ubungo to Ilala) for the applications already selected at a lower voltage level.

7.13 Table C8 A and B in Annex C provides the results of the capacitor application studies on 11 kV feeders at Dar es Salaam. In section A, the feeders are modeled according to the present network arrangement. In section B, the arrangement is altered to represent the changes that will be introduced by the system development proposals recommended in section 8 of this report. Applications of 300 and 600 kVA have been studied on a large number of feeders, and the tables provide details of power factor improvement and loss reduction achieved at the three load steps. The energy savings achievable for the network loads of 1991 and 1995, together with the loss reduction load factor and the rate of increase of benefits (over the period 1991 to 1992), are also computed. The latter two figures provide valuable information on the characteristics of loss reduction benefits of capacitor applications and may be used for feeders exhibiting similar loading characteristics. Section B of Table C8 provides information on the reduction of the benefits realizable from feeders that undergo changes consequent to the introduction of the recommended network improvements.

7.14 The benefits realizable in the 33 kV networks are presented in Table C9 of Annex 9. The network alterations described above cause only minor changes in this case (restricted mainly to the Wazo hill feeders I and II) and are indicated in the table. A summary of the benefits achievable in the transmission system is presented in Table C10 of Annex C. Loss reduction benefits in the transmission system are presented with the system conditions as at present for the network loads of 1992, with the introduction of the second circuit Kidatu to Morogoro for the loads in year 1993 and with the completion of the second circuit up to Dar es Salaam for the loads of year 1995. It is seen that substantial benefits are realized for the initial years but reduce considerably when the proposed transmission line developments are commissioned. Thus, a peak time loss reduction of 320 kW and 195 kW per 1000 kVAr of capacitor application are obtained for the whole system for the initial installation and when the total capacitor installation increases from 7,000 to 8,000, respectively. For the subsequent years studied, namely 1993 and 1995, the corresponding benefits reduce to 25 and 89 kW in 1993 and 16 and 59 kW in 1995, respectively. These reductions are caused by the increased reactive generation of the transmission lines as well as the improved system voltages in the later two years. Even the loss reduction of the Ubungo-Ilala line shows a corresponding reduction, varying from 20 to 10 kW per 1,000 kVAr of compensation. In computing the economic benefits of the capacitor applications only, the benefits along the Ubungo-Ilala line (for capacitors placed on lines downstream of Ilala) is considered, at a conservative figure of 10 kW per 1000 kVAr. The benefits for the overall system have been omitted, particularly in view of the recommendations to install other reactive compensation equipment for the transmission system–whose introduction will greatly reduce the benefits that can be achieved by the capacitors in the distribution network. The larger quantities and switching facilities required by the compensation for the transmission system also do not allow its function to be provided solely by the compensation in the distribution networks.

Recommendations for Reactive Compensation on the Distribution System

7.15 Based on the results of the benefits at various voltage levels, ten 11 kV feeders have been selected in Dar es Salaam for capacitor applications by units of 600 kVAr each. The benefits computed at each level are assembled in Table C11 (section A) of Annex C to present the total benefits that can be attributed to a particular application. In considering upstream benefits on the 33 kV lines for applications at 11 kV, each application associated with a particular 33 kV line is taken in turn, and only incremental benefits are credited. The installations are expected to be commissioned in 1993, and the benefits based on the existing system is assumed to occur up to 1996. Thereafter the 11 and 33 kV networks are assumed to be altered by the proposed system developments (given in section 8). An examination of the results of capacitor applications after the new developments are introduced (see Table C8B) indicates that most of the high-benefit applications in the earlier system now show a substantially low level of benefits. This is particularly because it is the poorly performing feeders that are substantially altered in the new developments. It is therefore proposed that the capacitors be removed from their former application and reassigned to feeders that produce better loss reduction benefits. The best locations for their reallocation are presented in section B of Table C11, and the benefits are computed for the years 1997 to 2008, providing for a 15-year lifetime. These benefits are added on to the benefits computed for 1993 to 1996, and the total discounted benefits and the resulting benefit to cost ratios are given in section A of Table C11.

7.16 It is seen that the selected applications have very high benefit-to-cost ratios (ranging from 12.5:1 to 43:1) and low payback periods (ranging from 9 to 1.5 months), indicating the highly profitable nature of the use of reactive compensation measures in the distribution system, particularly as short-term measures. The overall benefit-to-cost ratio for the 10 applications in the 11 kV lines works out to 23:1, and a total of 1.4 MWh per year of energy can be saved at 1991 load levels.

7.17 In addition to the capacitors placed on the 11 kV network, additional compensation can be effectively employed at a number of 33/11 kV substations. The loss-reduction benefits that can be achieved on the 33 kV lines is seen from Table C9 in Annex C. Benefits that can be assigned to the application at the substations are only those that are incremental to the applications already considered at 11 kV. A computation of the benefit-to-cost ratios and payback periods of selected applications at the substations are presented at Table C12 of Annex C. It is seen that about 5,300 MVAr of additional capacitors can be economically employed at the substations selected. Even after allowing for only the incremental benefits, the benefit-to-cost ratios for these applications still remain substantially high (varying from 8.7:1 to 17:1).

7.18 As discussed earlier, the installation of capacitors in the distribution system improves the power factor and reduce losses in the transmission system. The capacitors will thus assist the transmission system operation during system peak and at other heavy load times (when a reduction of the power factor is desired). The proposals in this section recommend the installation of 15.3 MVAr of capacitors in unswitched mode. In para. 4.10 of Section 4, a recommendation was also made for an unswitched 20 MVAr reactor to be installed at Ras Kiromany. The capacitors recommended in the distribution system may be considered to offest most of the reactive vars introduced by the reactor at Ras Kiromany. This further means that the cost of the additional 20 MVAr of compensation included in the economic evaluation of the proposal to shift the reactor to Ras Kiromany could be reduced substantially from the analysis when all the proposals are considered together.

7.19 In para. 4.11 of Section 4, the necessity for compensation of the reactive load at the Tanga grid substation was discussed. The benefits of this investment (loss reduction on the 132 and 33 kV lines) are evaluated in Table C 3. Clearly, compensation would be best provided at or as close as possible to the cement factory, which is the major consumer supplied from this station and is fed by an 11-km-long 33 kV feeder. Since this compensation is to be applied at distribution level, details of the recommendation are included in this section.

7.20 The compensation at Tanga and at two other installations selected at Dar es Salaam--Wazo Hill and ALAF--are primarily dependent on the power factors of the large factories supplied at these locations. The studies conducted on the basis of power factors determined by measurements at these locations take into account any compensation presently employed. Installation of compensation at these locations must be carefully coordinated with the major consumers, who may have plans of their own for improving the power factor of their operations.

Summary of Recommendations

7.21 In consideration of the loss reduction benefits presented in Tables C.8 to C.12 of Annex C and the discussion above, it is concluded that very high economic benefits will be achieved by proceeding with the early application of reactive compensation measures in the distribution system. A summary of the applications selected on the lines as well as the substations is provided at Table 7.1, along with the benefit-to-cost ratios and payback periods. With respect to the installation of capacitors at consumer substations, careful coordination is required with the consumers' own programs.

7.22 Total distribution system energy losses are estimated at about 7.3 percent of gross generation (see Section 3). This percentage corresponds to approximately 100 GWh per annum. The loss reduction that would be achieved by implementation of the recommendations made above for installation of capacitors would result in reduction of distribution losses by about 2.5 percent (which represents 0.2 percent of the total energy produced). The major reduction in technical losses to be achieved on the distribution system will be accomplished by various network improvement measures dealt with in Sections 8 to 11. The reactive compensation measures proposed for the distribution system in this section provide loss savings (at present loading levels) of 2.8 GWh/year, an overall benefit/cost ratio exceeding 10/1 and a payback period less than 7 months.

Table 7.1. Capacitors Recommended for Installation in the Distribution System

Feeder Installed	Change location (after 1996)	capac/ size kVAr	Total units saved MWh/year 1991	1995	Pay Back in months	B/C ratio
On 11 kV lines						
K4, Industrial	Kigam F1	600	295	339	1.4	39.7
K3, Kilwa road	Kigam F2	600	130	133	3.1	18.5
Port	Port	600	129	181	3.1	20.7
O3, Packers	O4, Kinondoni	600	170	174	2.4	22.0
D10, Magomeni	D2,Town1	600	105	94	3.9	13.3
MK1, Msasani	MK4,north east	600	61	87	6.6	12.5
MK2, Tandale	F31,Industrial	600	131	211	3.1	31.2
Kunduchi	F2, RTD	600	274	492	1.5	43.1
U1, Kisiwani	U1, Kisiwani	600	57	99	7.1	15.1
U2, Menzeese	Lugalo	600	50	67	8.1	13.9
TOTAL APPLICATIONS ON 11 KV LINES			1402	1877		23.0
AT 33/11 kV Substations and consumer installations						
ALAF		500	53	59	8.6	15.8
WAZO HILL CEMENT FACTORY		3000	450	566	6.1	8.7
KURASINI		600	49	72	11.2	20.9
OYSTER BAY		600	59	69	9.3	16.0
MBEZI		600	33	53	16.6	17.1
TOTAL APPLICATIONS AT SS. DAR ES SALAAM		5300	644	819	7.5	12.5
TANGA CEMENT FACTORY		2 x 4000	815	1349	5.3	21.0
Total for applications on lines and substations			2861	4045	2.9	

8. DEVELOPMENT PROPOSALS FOR DAR ES SALAAM

The present distribution system

8.1 The present peak load on the Dar es Salaam network is approximately 110 MVA and is supplied from the transmission network by two grid substations, one at Ubungo (2 x 50 MVA) and the other at Ilala (2 x 45 MVA). Four bulk consumers (Wazo hill cement factory, ALAF, Tazara and Friendship Textiles) supplied at 33 kV contribute 20 MW and the rest of the load (90 MW) is distributed along the 11 kV network supplied by eleven 33/11 kV (primary) step down transformers. The present feeder loads on the 33 and 11 kV network as well as calculated peak losses and end voltages are presented in Table A.2.1 of Annex A.

8.2 The present overall loss level (2.2 percent at peak) on the 33 kV system is generally acceptable. Currently the only feeder exhibiting an excessive loss level is the Wazo Hill II feeder (supplying the Wazo Hill cement factory) with present peak losses of 4.9 percent (and a terminal voltage drop of 5.7 percent). The load on Wazo Hill I feeder will also increase substantially over the next few years and the network covering the area supplied by the two feeders will need suitable augmentation. In addition the Factory Zone III feeder also shows a moderately high peak power loss of 4.1 percent. Proposals to reduce the losses on the Wazo Hill II feeder and to optimize feeding arrangements for the area supplied by the Wazo Hill I feeder (while catering for the expected load increases) are provided in this report. The losses on the Factory Zone III feeder are best reduced with the altered feeding arrangements to be made consequent to the second 220/132 grid substation expected to be introduced in Dar es Salaam (see para 8.11) along with the introduction of the second Kidatu-Morogoro-Dar es Salaam 220 kV line. Thus possible improvements to this feeder are not considered to be economical at this stage.

8.3 The overall losses in the 11 kV system (averaging about 3 percent at the 1991 peak) are also not excessive. However there are a few feeders that individually exhibit excessive losses and line end voltage drops. Five of the worst performing feeders are the Kunduchi feeder from Mbezi, Industrial feeder from Kurasini, O4 and O6 feeders from Oyster Bay and the MK2 feeder from Mickocheni. The first of the above feeders already has a peak losses exceeding 10 percent while that of the others range from 5 to 8 percent. The loss levels of all feeders would however increase with load growth if system improvements are not carried out. Thus in order to ascertain the state of the system in the future a calculation of the losses and voltage drops to be expected in 1995 in the absence of any system development works is also provided in Table A.2.1. The loading densities of the areas as supplied by the existing feeding arrangements provide important information particularly in estimation of load growth both for the existing networks as well as for future expansions and are presented in Table A.5 of Annex A. In the following paragraphs various areas of the network that require improvements are examined and solutions proposed to overcome excessive loss levels and poor reliability conditions. The proposals are intended to provide economically acceptable network configurations over the next five to ten years allowing for some additional investment that may be required due to various local load development not currently identifiable. Loss reduction and reliability benefits for the development proposals are computed as discussed at Section 6 and cost benefit analyses of the proposals are also presented. While these proposals primarily cater to the development of the existing systems the capacities of the substations and main feeders are also configured to accommodate the expansion of the networks to new areas that would be electrified shortly.

Network Development proposals

Wazo Hill and Kunduchi areas

8.4 The area north west of the Msasani Bay has a load of about 7 MW at a cement factory at Wazo Hill with a large number of tourist hotels along the Kunduchi and Mbezi beach fronts. The 33 kV Wazo Hill feeders from Ubungo feed the loads; with feeder No II supplying the Cement factory and feeder No I supplying the Mbezi Substation. Mbezi and Kunduchi areas are supplied from 11 kV feeders from the latter. A new housing development has commenced stretching from Mbezi and extending north along Tegeta and Boku up to Ras Kiromany. An urban development plan has also been prepared for the area and water supply, schools and community facilities are in the process of being developed. In addition tourist hotels are also expanding and new ventures are being introduced. The 11 kV feeder supplying the area presently has the highest percentage losses (11.5 percent) and clearly will not be in a position to pick up any additional load. Thus a network rearrangement with additional injection from the subtransmission system is very desirable. The 132 kV line to Zanzibar via Ras Kiromany passes through the area in close proximity to the cement factory. This line is very lightly loaded and increasing the load on the line would also help in controlling the transmission system voltages at the line extremity. A suitable location has been identified for a proposed grid substation close to the Bagamoyo road. The identified location lies approximately mid way between the two load centers, 2.5 km from the cement factory and 2.0 km from the Kunduchi area. Two short double circuit 33 kV feeders from the grid substation could be constructed, one to the Cement Factory and the other to a new 33/11 kV substation at Kunduchi. An economic analysis of this proposal is presented in Table E.1.1 and is found to be very economical with a benefit to cost ratio of 8.0. The benefits from the proposed system consist of a substantial loss reduction by transferring load from the 33 kV system to the 132 kV system, introduction of new capacity to cater to the growing load demand in the Kunduchi area and the improvement of reliability to the cement factory as well as the Kunduchi-Mbezi areas. The substation at Kunduchi will be of initial capacity of 5 MVA (with provision for expansion to 2 x 5 MVA when the load grows sufficiently). The new substation will have 5 feeders: north along Bagamoyo Road, north along the Kunduchi beach, west to feed some local distribution, and two circuits south along Bagamoyo Road.

The Msasani Peninsular

8.5 The Msasani peninsula is presently fed by Feeders O 3 and O 6 from the Oyster Bay primary substation together with feeder MK 1 from the Mikochnai primary substation. Feeder O3 in particular is heavily loaded and exhibits high losses. The two primary substations are situated at a considerable distance from the main load center and the arrangement of the feeders does not provide sufficient reliability. This is a significant disadvantage since the area covers the best residential district in the city. The load growth over the last few years has been quite substantial and is expected to be maintained at a high rate for a few more years before reaching saturation levels. The high growth rate will cause the network performance to worsen in the coming years. In addition to the poor performance of the feeders the two substations supplying the feeders are also heavily loaded. Oyster Bay substation is already loaded up to its capacity and it is expected that the Mikochani substation will reach its design rating by 1995. Thus an additional supply point within the peninsula is clearly required at a very early date. Obtaining suitable land at the center of the peninsula (approximating to the load center) is difficult due to the prime value of land in the area. TANESCO has however been able to secure a site a short distance away. The feeders from the proposed substation have therefore been designed from this location and the loss reduction benefits and capital costs computed accordingly. The cost benefit analysis of the proposal is presented in Table E 1.2 of Annex E. It is however recommended that efforts be made to obtain a more central location, which will further increase both the loss reduction and reliability benefits.

The City Center area

8.6 The existing city center substation has the highest load among the primary substations in Dar es Salaam. Many large buildings presently under construction will cause a substantial increase of load in the near future. In planning the developments required a growth rate of 7 percent has been used for the period up to 1993. Thereafter, the growth rate is assumed to level off gradually down to 2 percent to account for the saturation that would occur as the available land is built up. Although the network losses are quite low in the existing feeders off the City Center substation due to the short distances, the feeders are highly loaded, two of them being in the range of 250 to 300 Amps and two others being in the range of 150 to 200 Amps. The high loading of the feeders prevents their extension for exigency situations. Being the administrative and commercial center of the country the area should have a high reliability of supply. A suitable site for an additional primary substation has been located at Sokoine Drive, which is situated in the area experiencing the highest load growth. The cost/benefit analysis of the introduction of an additional primary substation (33/11 kV, 15 MVA) at this location is given in Table E 1.3 of Annex E. In the absence of this development the capacity of existing primary substation at City Center would need to be augmented in the near future. This alternative investment required and the high value to be assigned to reliability benefits are specific advantages of the proposal and a benefit to cost ratio of 18.6 is attainable.

Kidongo-Chekundu and Chang'ombe areas

8.7 The area along Pugu road south of Ilala is another location that can benefit by injection from the 33 kV system. The southern section is fed by two feeders one from Kurasini and the other from Ilala. Both these feeders are loaded at the line extremities. The feeder from Kurasini in particular has a very high loss level (7.3 percent at peak). The western side, closer to the city is fed by feeders D 2 and D 9 from Ilala and feeder C 5 from City Center. These feeders do not have high losses due to the short distances. However the loading levels are high (close to 200 Amps) and the loads supplied do not have sufficient alternate feeding possibilities. TANESCO is presently considering the possibility of two substations one at Kidongo-Chekundu (for the western section) and the other at Chang'ombe (for the southern section) and sites for the two substations have already been identified. Possible 11 kV connections investigated if both substations are to be constructed give quite low loading levels for the substations as well as the feeders. The introduction of a single substation would suffice for the next ten years or so and the Chang'ombe site is considered to be the more economic to be introduced at the first stage. A substation at this site is capable of reducing the high losses of the Industrial and the D 1 feeders as well as in providing the reliability back up for the Kidongo-Chekundu areas. The new substation will feed a double circuit line along Pugu road. These circuits would take over the existing D 1 feeder load (Keko Mwanga area) and the end portion of the port access feeder (north Kurasini). The latter area will now obtain supply from a rearrangement of the feeders D 1, D 2 and D 9 from Ilala. Part of the load of the D 3 feeder from Ilala will also be transferred to a new feeder from the proposed Chang'ombe substation. The cost benefit analysis of this proposal is presented in Table E 1.4 and is justifiable with a benefit to cost ratio of 12.6.

Magomeni, Manzese and Tandale areas

8.8 The area between Ilala and Ubungo on either side of the Morogoro road is of medium load density with a mixture of residential and industrial load. The area is fed from the line extremities of four feeders one each from the primary substations Ilala (D 10), Oyster Bay (O 4), Mikocheni (MK 2) and Ubungo (U 2). The loading levels and feeder lengths can be approximately halved by a suitably located primary substation. It may be noted that such an arrangement will reduce the network losses to one eighth of the former value resulting in a loss reduction of approximately 88 percent! At present TANESCO is considering a site for a future substation at Magomeni. However the location selected is not so centrally situated as to enable the reduction of the load on most heavily loaded feeder, MK 2. This feeder is one of the five most poorly performing feeders in Dar es Salaam with peak losses of 4.7 percent and a voltage drop of 8.0 percent. Thus any development proposals for this area should address the poor performance of feeder MK 2. It is thus recommended that the proposed substation be shifted towards Mwembe-Chai so that the ends of the four feeders mentioned above can be connected to the new substation. A cost / benefit analysis of this proposal is given in Table E 1.5 of Annex E and yields a very economic ratio of 31.2.

Load development in the southern and south western suburbs

8.9 A number of new developments are taking place in the southern and south western suburbs of the city. The areas with the highest load growths consist of Tabata (in the western side, a short distance north of the airport), Temeke-Yombo (south of Pugu road and east of Kurasini) and Mbagala (south of Kurasini). Studies were made to ascertain the system improvements that are required to ensure that the load growth can be met at technically satisfactory and economically optimum levels. The Tabata area is only about 3 km away from the primary substation at Factory Zone II and a separate primary substation would not be required at the loading levels to be expected in the medium term. The new load should therefore be met by additional 11 kV feeders as required by the load concentrations. The specific development of the networks in this area may also be postponed until a firm decision is taken on the location of the proposed receiving substation for the additional 220 kV circuit from Kidatu.

8.10 In the Mbagala area a 33 kV line has already been constructed from Kurasini to feed a glass factory, which, however, failed to go into production. This line, currently unused, could be used to connect a new primary substation that could then reduce the supply length of the existing Kilwa road feeder from Kurasini. The new substation could in fact separate the Kilwa Road feeder to 3 portions, two being fed from the new Mbagala substation (on either side) and the remaining section being fed from Kurasini. The Temeke-Yombo areas can also be supplied from the new Mbagala and existing Kurasini substations by constructing the required 11 kV lines. The cost benefit analysis of the proposal is given in Table E 1.6 of Annex E and indicates a very economic ratio of 14.0

Future transmission developments and overall feeding arrangements for Dar es Salaam

8.11 A second 220 kV transmission line is planned for construction from Kidatu to Dar es Salaam (the first stage up to Morogoro being already under construction) to rectify network voltages, improve reliability and reduce system losses. This additional circuit will also be particularly useful with the commissioning of the Kihansi project by about 1989. TANESCO is presently considering a new step down station in the Temeke area (south of Ubungo) to receive power from the new line. This option is clearly advantageous for a number of reasons. Firstly it enables an additional injection point to the distribution network to be provided instead of increasing the capacity of the existing step down station thus improving the reliability of the network. To maximize the system reliability transmission connections should be provided from the new station to Ubungo (preferably at 220 kV) and Ilala (at 132 kV). The network will then form a solid interconnection between the three feeding points of the Dar es Salaam area providing optimum security of supply to each point. Secondly, feeders from the new station can rationalize the 33 kV network reducing a number of feeder lengths considerably. In particular the Temeke area is situated close to the load concentrations at Pugu Road (consisting of the Factory Zones I & II, and the directly supplied industries TAZARA and ALAF) and it will be logical to transfer these loads to the new station. Further supply can also be conveniently provided to Kurasini and the proposed Mbagala substations. Due to the expected development of the new receiving substation in the

Temeke area the development proposals for Temeke and Tabata areas are best postponed until the location and arrangements for the new receiving station is finalized.

8.12 In contrast, the area north of Ubungo is unlikely to receive any additional transmission connections for the foreseeable future. Thus it would be prudent to proceed with the early introduction of a 132 step down station at Wazo hill utilizing the existing line to Zanzibar (see para 8.4). An examination of the existing grid substations and the two proposals indicate that the network would be geographically well positioned to provide the city and suburbs of Dar es Salaam with an efficient power supply system. Ubungo and Ilala already provide two main supply points with Ilala conveniently located to feed the city center area. Future load growth is expected towards the north and south of the presently developed areas and convenient locations for grid substations are proposed for both. Adequate 33 kV network routing possibilities are also available to provide the required supply lines and interconnections. The proposed primary substation development envisaged in this report is also observed to blend well with the anticipated transmission development. TANESCO should therefore pursue the identified options as early as time permits.

Summary of MV development proposals for Dar es Salaam

8.13 The system development proposals described above for the city of Dar es Salaam are summarized below. These proposals aim to reduce network losses to economic levels, improve reliability of operation and provide the necessary capacity for the expected future load.

Item	Ref. to C/B table	Cost in US$ 000	B/C Ratio
Grid SS5/ at Wazo & Pr. SS	E.1.1	2278	7.9
Pr. SS at Msasani	E.1.2	983	11.7
Pr. SS at City Center	E.1.3	898	18.6
Pr. SS at Chang'ombe	E.1.4	555	12.6
Pr. SS at Mwembe-Chai	E.1.5	651	31.2
Pr. SS at Mbagala	E.1.5	493	14.0

5/ SS denotes substation and Pr. SS denotes primary subatation (33/11 kV)

9. SYSTEM DEVELOPMENT PROPOSALS FOR TANGA REGION

The Present Distribution System

9.1 The area studied under the Tanga region extends much beyond the Tanga town and its environs. It covers nearly 100 kilometers westward from the coast and about 80 kilometers along the North-South direction. Supply to the distribution network is provided from two main sources. The Tanga town, adjoining areas westward, and the coastal belt are supplied from the 132/33 kV grid substation at Majani Mapana (2 X 20 MVA). The inland area is supplied from the Hale complex (power plant and 132/33 kV grid substation) and the Pangani power station feeding directly on to the 33 kV lines. The largest load in the region is the Tanga Cement Factory, which is supplied by an 11 km double circuit 33 kV line from the Majani Mapana grid substation. The Tanga town has an 11 kV distribution system fed from a 33/11 kV substation situated adjacent to the grid substation. More than 20 other small capacity (300 to 2000 KVA) 33/11 kV substations are dispersed over the region to feed small 11 kV townships networks. Supplies are also provided to some localities and bulk consumers, notably sisal and tea estates, by the 33 kV network. The feeder losses and voltage drops on the 11 and 33 kV lines in the region are given in Table A 2.2 of Annex A for the present loads and those expected in 1995.

9.2 Because of the poor voltages received from the transmission system, the Tanga Cement Factory is restrained from operating at its full capacity. However, the deficiencies of the transmission system are anticipated to be resolved within the next two years, and the distribution system should then be capable of providing the full load expected from this consumer in the most economic manner.6/ In addition to the restriction on the load of the Tanga Cement Factory, a load of about 2.0 to 2.5 MW is shed at system peak due to the capacity shortage at the Majani Mapana 33/11 kV substation. The network feeding Tanga town also needs to be rationalized and its reliability improved in keeping with the importance of this load center. The geographical lay out of the medium voltage network in Tanga town and its vicinity is shown in Drawing F 2.1 in Annex F.

9.3 The interior areas of the Tanga region are of very low loading density and are supplied by very long subtransmission lines at 33 kV. The network arrangement is shown in Drawing F.2.2 of Annex F. Two 33 kV developments from the switching station at Neusegan, one stretching westward via Korogwe to Toronto and Handeni and the other stretching eastward up to the switching station at Kange (close to Tanga) form the backbone of the supply system. From the Kange switching station two 33 kV feeders supply the northern (Moa) and southern (up to Kigombe and Bushuri) coastal areas. There is also a feeder proceeding south from the Hale 33 kV switching station towards Mgambo. The western feeders towards Toronto and Handeni are both

6/ By recommendations discussed in Sections 4 and 5 as well as the New Pangani power station expected in 1995.

approximately 110 km long and exhibit losses of 5 and 4 percent respectively at present loading conditions. The voltage drop at Toronto is of the order of 7.5 percent The loads are however too small and dispersed to justify injection from the transmission system (at 132 kV) or a development at an intermediate voltage of 66 kV. Satisfactory voltage to the consumer can be maintained at present by regulating the 33/11 kV transformer tapchangers. If required a regulating transformer could also be installed mid way along the line at a later date.

9.4 In addition to the long 33 kV lines there are a number of 11 kV lines that are excessively long and exhibit high losses. These include the Mazinde-Lushoto feeder with the longest branch extending up to 50 km, Bushiri II feeder (32 km), Korogwe II feeder (25 km) and the Magunga-Amani feeder (20 km). The rest of the 11 kV feeders have acceptable loss levels and voltage profiles due to their low loading levels.

Network Development proposals

Supply to the Tanga Cement Factory

9.5 This is the largest single load in the region and is presently served by a 11 km 100 mm. sq. double circuit. line from the grid substation at Majani Mapana. Proposals have been formulated to develop this factory and increase its output; but these proposals are hampered by the inadequate and unreliable power supply presently provided. The 132 kV line to Tanga in fact passes very close to the factory but the supply is provided after stepping down at the Majani Mapana grid substation (132/33 kV) and transmission back to the factory over lower voltage (33 kV) lines. A step down facility close to the factory would improve system performance in a number of ways. The primary benefit will be the elimination of the losses in the 33 kV transmission lines and the high security and supply reliability that can be provided to the Cement Factory. In addition the 33 kV lines from Neusagan to Kange could be reconnected to the new grid substation reducing losses and improving the reliability of these lines and relieving further capacity from the Majani Mapana grid substation. This 132/33 kV substation has been recently augmented during the National Rehabilitation Project and the additional capacity which will be made available with the transfer of the Cement Factory load to the new substation is not a necessity immediately. However apart from the load increase expected at the Cement Factory, a number of other loads are expected to go up steeply with the correction of the network voltages and the provision of sufficient capacity at the 33/11 kV substation feeding the Tanga town. Load increases are also expected at the two other major consumers, the Tanzania Fertilizer Corporation and the Steel Rolling Mill. Thus the existing capacity of the Majani Mapana grid substation is expected to be reached by about 1997-98 in the absence of the proposed grid substation. The two grid substations will also act as back up for each other and increase the system reliability for the loads supplied from both. The arrangement will also provide TANESCO with a spare 20 MVA 132/33 kV transformer that could be very useful to cater for any unexpected grid substation transformer failures particularly as sufficient spare transformers are not readily available. The economic analysis for this proposal is provided at Table C 2.1. It is seen that the investment is justifiable by considering only the loss reduction benefits (benefit/cost ratio of 1.7). With the inclusion of reliability benefits at even an outage saving of 1 percent of the energy supplied and a value for saved outages of five times the energy cost the benefit/cost ratio rises to 6. Thus the investment could be considered to be fully justifiable even without considering the additional grid substation capacity provided.

Additional 33/11 kV Substation for Tanga Town

9.6 The geographical layout of the 33 and 11 kV lines in the Tanga town and its vicinities is shown at Drawing F 2.1 of Annex F. The existing 2 x 5 MVA substation adjacent to the grid substation at Majani Mapana situated on the western side of the town presently feeds the entire 11 kV system. This substation is presently incapable of meeting the system peak and 2 to 2.5 MVA of load are already being shed. Thus the load growth in the Tanga town is already constrained. Increase of capacity at the substation will not be sufficient due to two major considerations. Firstly, the 11 kV feeder losses will increase to uneconomical values with the expected load growth. Secondly, the supply reliability to this important town is inadequate as the entire network is fed from a single 33 kV source situated at one extremity. The provision of an additional substation from the eastern side will address both these issues. The new feeders from the substation will approximately halve the length of almost all the existing feeders and will thus considerably reduce the losses on the 11 kV lines. The supply possibilities from either source of supply can be provided to almost 90 percent of the loads and this will increase the reliability of supply considerably. A suitable site has been identified at Sahare for the new substation and the 33 kV line to the Fertilizer Factory could be utilized to provide supply to it. The substation could initially be equipped with a 5 MVA transformer but the layout would provide accommodation for a second 5 MVA transformer (which may be required by about 1999). Three 11 kV feeders extending towards Raskazone, Usagara, and Kwakaheza respectively could be provided immediately from the new substation as shown in Drawing F 2.1. Both the Usagara and Kwakaheza areas are earmarked for high load growth and the sitting of the new substation is optimally placed with respect to this development. A cost ratio of 11.8 is achievable and the benefit analysis is presented at Table E 2.2 of Annex E.

Lushoto town and outlying areas

9.7 The Lushoto town together with a large area extending to the east as far as Herculo and Balangai is supplied by a single circuit 11 kV line from the Mazinde substation. The furthest point in the 11 kV feeder is 50 km along the line route from Mazinde. Due to the low loading densities in the outlying areas the voltage profile and loss levels, though poor, are not as bad as could be expected from such long line lengths. However the Lushoto area is presently experiencing a high load growth and in a few years time it will not be possible to sustain such long line lengths. One solution considered is the establishment of a 33/11 kV substation at Lushoto that will enable the 11 kV lines to be divided to three feeders (Lushoto town area, Soni/Bumbuli and Mkuzi). A 33 kV line of about 10 km will have to be constructed tapping the existing Mazinde line at Kasiga. The 33 kV supply at Lushoto will enable the subsequent extension of the system to areas such as Lukozi and Mlalo , which are potential areas for electrification in the future. The network layout is shown in Drawing F.2.31 of Annex F. The economic analysis shown in Table E.2.31 of Annex E indicates that at the discount rate and load growth considered the proposal is marginally inadmissable (benefit/cost ratio 0.9).

9.8 Another alternative is to convert the eastern part of the 11 kV network to 33 kV and to feed it from a 33 kV line extension from Mlemua. This supply arrangement could be accomplished by the conversion of the existing 11 kV line from Mlemua towards Kulasi and then constructing a 33 kV line up to Bumbuli. The load removed from the 11 kV network will also be removed from the 33 kV line from Magunga to Mazinde, a distance of about 50 km. Due to the reduction of the load along the 33 kV line considerable additional loss reduction benefits are obtained in this alternative. The network layout is shown in Drawing D 2.32. The economic analysis shown in Table E 2.32 of Annex E indicates a benefit/cost ratio of 1.2. Hence this alternative is recommended instead of the installation of a 33/11 kV substation at Lushoto.

Korogwe North feeder

9.9 The northern feeder from Korogwe substation extends 30 km to feed the Kwamndolwa area and a number of tea factories. The peak losses are of the order of 6.5 percent and the line end voltage drops by 8.8 percent. Alternative proposals considered to develop the network consists of:

(a) installation of a 33/11 kV substation at Kwamndolwa by a 6 km line extension,

(b) conversion of the existing line to 33 kV, retaining the existing copper 25 mm.sq. conductor.

(c) conversion of the line to 33 kV together with the replacement of existing conductors with 100 mm. sq. ACSR conductor.

9.10 The network is shown in Drawing F 2.4 of Annex F and the cost/benefit analysis is shown in Tables E 2.41, E 4.42 and E 4.43 respectively of Annex E. Proposals (a) and (c) indicate a higher cost than the present value of benefits. Proposal (b), the conversion of the line with the existing conductors show a benefit/cost ratio of 1.7. This solution is therefore recommended for selection. There are two significant additional benefits in this alternative. Firstly, the copper installed is capable of lasting a considerable period and the replacement of insulators and cross arms can be done with minimum damage to the conductor. It is expected that the uprated and rehabilitated line will last for another 10 to 15 years, which would also be close to the expected technical life of the system configuration. Secondly the voltage conversion will afford an opportunity to change the high loss transformers carrying low loads and optimize transformer losses. There is a good possibility of obtaining significant benefits by the use of low loss single phase transformers. Thus there are a number of additional benefits not quantified in the benefit to cost analysis.

Korogwe West feeder

9.11 The western feeder from Korogwe is 25 km long with peak losses of 8 percent and line end voltage drop of 9.3 percent at present loading conditions. The conversion of this line to 33 kV with the two alternatives of (a) retaining the existing conductor (25 mm.sq. copper) and (b) with a conductor change out to 100 mm.sq. ACSR has been evaluated in Tables E.2.51 and E.2.52. The uprating of the line while retaining the existing conductor is shown to be advantageous with a benefit/cost ratio of 1.5. The change over to 100 mm.sq. conductor while uprating the voltage indicated a higher cost than the present value of loss reduction benefits. The additional advantages of retaining the existing conductor discussed in the para 9.10 (Korogwe North feeder) apply to this case too. Hence the conversion of this feeder to 33 kV while retaining the existing copper conductor is recommended.

Establishing a 33/11 kV substation at Kibaranga

9.12 The southern feeder at 11 kV from Lanzoni substation meets the northern feeder (also at 11 kV) from Muheza substation at Kibaranga. In addition there is a spur line to the west (to Mjesani) from this location. A 33/11 kV substation can conveniently be located at this intersection as the 33kV line to the substation at Lanzoni passes close by. The economic analysis of establishing a substation Kibaranga is presented in Table E 2.6 of Annex E indicates a high benefit/cost ratio of 6.5 and the proposal is recommended for acceptance.

Summary of MV development proposals for Tanga

9.13 The system development proposals recommended at MV for the Tanga region are summarized hereunder. These proposals aim to reduce network losses to economic levels, improve reliability of operation and provide the necessary capacity to meet future load expectations.

Item	Ref. to C/B table	Cost in US$	B/C ratio
20 MVA grid SS at cement mill	E.2.1	1490	24.0
15 MVA SS at Sahare	E.2.2	533	11.8
Conversion of Lushoto-Bambuli to 33 kV	E.2.3.2	945	1.1
Conversion of Korogwe North to 33 kV	E.2.4.2	563	1.5
Conversion of Korogwe West to 33 kV	E.2.5	408	1.4
5 MVA substation at Kibaranga	E.2.6	195	5.4

10. DEVELOPMENT PROPOSALS FOR THE MOSHI REGION

The Present Distribution System

10.1 Supply to the Moshi town and surrounding rural areas is provided from the 2 x 20 MVA grid substation at Kiyungi. The load at Moshi town is distributed entirely from a 11 kV system , which in turn is supplied by two primary substations at Boma la Mbuzi and Trade School. The rural areas north of the town (Uru, Madukani, Kifumbu, Mkombone etc.) are also supplied by extensions off the 11 kV feeders supplying the town. The connection of the rural load has adversely affected the performance of the feeders supplying the important loads at the town center by increasing the feeder load and adding to the line lengths (thus reducing the feeder reliability). The three main feeders supplying important loads in the town area, M 2 and M 3 feeders from the Trade School substation and the Town feeder from Boma la Mbuzi substation are those mainly affected by the connection of the rural loads. The remaining 11 kV feeders from the two substations show satisfactory performance. The rural area immediately west of the town (Weri Weru) is also supplied by a 11 kV feeder from the Trade School substation but the loss levels are satisfactory due to the low loading density.

10.2 The rural areas in the region other than those mentioned above are supplied from four 33 kV feeders; the TPC feeder supplying the area immediately to the south of the grid substation, Machame and KIA feeders supplying the north eastern rural districts and the Rombo feeder supplying the north western districts. The KIA feeder extends west and connects up the Kikuletwa power station (1.16 MW) before proceeding north up to the 33/11 kV substation at Lawati. The Machame feeder extends from the Trade School substation up to the 33/11 kV substation at Machame. The Rombo feeder extends some 122 km from Boma la Mbuzi to supply the areas west of the Moshi town. Although the feeder is lightly loaded the voltage profile is poor with a voltage drop of 6.4 percent at the line extremity due to the extremely long length. Further loading of this feeder will worsen the situation. The KIA and Machame feeders although excessively long are still acceptable with respect to losses and voltage levels due to the very low loading density of the supply areas.

10.3 The geographical layout of the distribution system is shown in drawings F3.1 and F3.2 at Annex F. The peak losses and voltage conditions for the present network for the loads in 1990 and 1995 are computed in Table A.2.3.

Network Development proposals

33/11 kV substation at Majengo area

10.4 The primary distribution capacity of the Moshi town area needs to be increased to meet the expected load growth in the next five to eight years. The most economical method of providing the required capacity is to provide an additional 33/11 kV substation at a location capable of reducing the lengths of those feeders that presently operate at poor performance levels. The supply arrangement should also provide increased reliability benefits to the overall supply area. The town is presently fed from the western (Trade School substation) and the southern (Boma la Mbuzi substation) directions. A suitable site for a new substation is available in the north eastern area of the town at Majengo. Four 11 kV feeders could be arranged from the new substation; southward up to the town area at Unga, eastward up to the town center presently fed by the M 3 feeder (with the feeder also taking the KCMC area load), eastward up to Kibororoni and northwards taking over the rural area of Uru (thus separating this load from the others). The proposed feeding arrangements from the new substation are shown in drawing F.3.1 of Annex F and an economic analysis of the proposal is presented in Table E.3.1 of Annex E. The analysis indicates that the proposal can be justified considering only the loss reduction benefits achievable (benefit/cost ratio of 1.1). However, The location of the new substation is such that supply to most of the town load is firmed up. Loads presently fed off the M 3 feeder from Trade School substation and the Town feeder from the Boma la Mbuzi substation will now have supply possibilities from more than one primary source. At an outage saving of only 1 percent of the energy supplied the benefit/cost ratio is 4.0.

Conversion of the rural section of the Makombone feeder (M 2 from Trade School) to 33 kV

10.5 The M 2 feeder from the Trade School substation feeds a high load density area around the western section of the town and then extends about 18 km northwards to feed a very low load density area at Kifumbu, Chome and Makombone. The present power losses of this feeder (12 percent) and the tail end voltage drop (15.7 percent) are far too excessive. By 1995 these values will rise to 14 percent and 18.4 percent respectively if system improvements are not carried out. A further disadvantage is the low reliability caused by the long rural line sections on the important town loads. A conversion of the rural sections of this feeder to 33 kV operation would thus be very advantageous. This can be conveniently accomplished by constructing a short line section from the substation to Sambarai and converting the rest of the line to Makombone to 33 kV. The M 2 feeder would then be restricted to the town area. The proposed feeding arrangements from the new substation are shown in drawing F 3.2 of Annex F and an economic analysis of the proposal is presented in Table E 3.2 of Annex E. The analysis indicates that the proposal can be justified considering only the loss reduction benefits achievable (benefit/cost ratio of 1.3). The improved reliability to section feeding the town area will enhance the benefit/cost ratio substantially; at an outage saving of only 1 percent of the energy supplied the benefit/cost ratio increases to 7.0.

Proposed 66 kV development from Kiyungi to Marangu

10.6 The 33 kV feeder Boma la Mbuzi-Himo-Marangu-Rombo extends for 122 km resulting in a peak power loss of 8.2 percent and a tail end voltage drop of 17 percent at present loading levels. The area supplied by this feeder is widely dispersed and of a low loading density. The total power to be transmitted is also too low at present to justify an additional grid substation at the standard transmission voltage level of 132 kV. However the 66 kV system between Kiyungi and Njiro is now not operational due to its replacement with a 132 kV system and the existing 66 kV feeder bay as well as the possibility of using some of the line hardware provides an alternative to supply bulk power to Marangu at 66 kV. Further there is also an unused 66/33 kV 10 MVA transformer available at Arusha and this can be utilized for the stepdown station. The optimum location for the substation is at Marangu from which location three feeders can be arranged; the first feeder to supply Holili and the local area of Marangu, the second to feed Rombo and Rongai areas and the third to feed the Himo township and Taveta areas. The introduction of a 132 kV subtransmission to this area is not foreseen for the next 15 to 20 years. Thus it will not be necessary to consider any alternative construction strategies such as the construction to 132 kV standards but with initial operation at 66 kV. The proposed feeding arrangements from the new substation is shown in drawing D 3.3 and an economic analysis of the proposal is presented in Table E 3.3 of Annex E. The cost/benefit ratio considering only the loss reduction benefits is 3.0. With the reliability benefits introduced by the separation of the Rombo feeder from the Boma la Mbuzi load as well as the separation of the Rombo feeder to three sections the benefit/cost ratio will increase to 5.0.

Summary of MV development proposals for Moshi

10.7 The system development proposals for the Moshi region to provide ecomical loss and reliability levels are summarized hereunder together with their benefit to cost ratios.

Item	Ref. to C/B table	Cost in US$ '000	B/C ratio
5 MVA primary substation at Majengo	E.3.1	745	4.0
Conversion of 11 kV lines at Makombone to 33 kV	E.3.2	361	7.0
Construction of 66 kV line to Marangu	E.3.3	482	5.0

11. DEVELOPMENT PROPOSALS FOR THE ARUSHA REGION

The present distribution system

11.1 At present power supply to Arusha is severely hampered by the low transmission system voltages experienced during both the night and day peaks and daily power cuts are required to maintain system voltages. However measures to resolve this problem both immediately (see Sections 4 and 5) and in the long term (construction of the Singida-Arusha line) have been identified and thus the existing difficulties in the transmission system are expected to be resolved shortly. When this is accomplished the release of suppressed demand will bring an added burden to the distribution system. Thus network planning of the distribution system should anticipate this increase of demand and ensure that the expected load can be met at satisfactory technical and economic performance levels.

11.2 The Arusha region is supplied from the 40 MVA 132/33 kV grid substation at Kiyungi. Four primary substations of combined capacity of 20 MVA steps down the supply to the 11 kV system that distributes power to the town area. Two of the 11 kV lines however extend well beyond the town limits and supplies rural areas up to Monduli and Ngaramtoni (west of Arusha). These lines have feeder lengths of 46 and 37 km respectively and exhibit high losses and poor voltage profiles. Clearly additional loads cannot be connected to these lines unless substantial system improvement is carried out. In addition to the loads supplied at 11 kV two large industrial consumers in the city, General Tyre factory (capacity 6 MVA) and Sunflag factory (capacity 6 MVA) are supplied directly off the 33 kV network. The rural area east of Arusha is fed by the 33 kV Arusha-Moshi feeder. Due to the low load density of this feeder the network losses and voltage conditions are not of immediate concern and major network development to this section would not be required for at least the next 7 years. The geographical layout of the distribution system is seen in drawings F 4.1 and F 4.2 in Annex F. The network losses and voltage conditions for the present system are computed in Table A 2.4 with the existing loads and the loads expected in 1995 respectively.

11.3 The main issues to be resolved in the distribution system are the shortage of existing primary distribution capacity and the improvement of supply conditions to the areas presently fed by the long 11 kV feeders, Monduli and Ngaramtoni (Feeder No: 2). The solutions need to ensure reduction of the present high network losses to economic levels.

Network Development proposals

Uprating of the Monduli Feeder to 33 kV

11.4 In order to reduce the line losses and to achieve a satisfactory voltage profile on the existing 11 kV feeder to Monduli, it is proposed to convert this feeder to 33 kV operation. Such a conversion has in fact been envisaged during the original line construction and 33 kV insulation has already been provided. Hence the investment required is only in replacing the transformers, isolators and associated fusing equipment etc. connected to the line sections to be uprated. In addition a section of the line (approximately 8 km) that traverses an area subjected to flooding needs to be diverted. The new line could conveniently be routed by the side of a new highway that has been constructed recently. The construction work should also include the replacement of supports that have deteriorated (expected to be about one third of the total). The costs of diversion and rehabilitation need not be taken account of in conducting an economic evaluation as these are necessitated by the normal maintenance requirements of the existing system. However, it is seen that the loss reduction benefits are sufficiently high as to make the proposal very attractive even with the inclusion of such costs.

11.5 The loading profile of the line consists of a high load concentration at the Monduli town and very lightly loaded areas up to and beyond the town limits. Thus if the line conversion is done only up to the Monduli town and a 33/11 kV substation installed at this location the existing 11/LV transformers at the Monduli town and the 11 kV operated lines proceeding north and south can be retained. It is also proposed that the new 33 kV line be fed from a separate feeder direct from the Njiro grid substation instead of the present feeding position (from the Power House substation busbar). This arrangement will reduce the losses on the 33 kV interconnector and also provide better security of supply. The loads close to the town could be maintained on the existing 11 kV line thus separating the town supply from that of the rural areas. The economic analysis of the proposal is given in Table E 4.1 of Annex E and indicates a benefit to cost ratio of 8.1. It is seen that the cost of the additional new line section to connect to the grid substation can be justified by the loss reduction on the interconnector alone. In addition to loss reduction benefits, substantial reliability benefits are also achieved. The important loads close to the town are presently adversely affected by the long rural line and the separation of this section will bring substantial reliability benefits to these consumers.

33/11 kV substation at Magereza

11.6 The other excessively long 11 kV feeder at Arusha is Feeder No. 2, also supplied from the Power House substation. This feeder extends 40.5 km up to and beyond Ngaramtoni. The calculated figures for feeder peak power losses is 17.5 percent, and, for the tail-end, the voltage drop is 28.9 percent; these figures indicate a severely overstressed loading condition. Clearly no new loads should be connected until system improvements are effected. The poor reliability due to the long feeder length also affects the important loads in the Arusha town supplied at the beginning of this feeder. The most suitable development for this feeder is to construct a new

33/11 kV substation at Magereza. The present long line length outside the town area can then be split to two feeders supplied from this substation. The short section within the town limits would continue to be fed from the Power House substation. The new 33/11 kV substation is best fed from the 33 kV operated line proposed for the Monduli feeder. The change of the feeding arrangement on the 33 kV system will also provide loss reduction benefits as the Power House interconnector is more heavily loaded than the Monduli feeder. An economic analysis of the proposal is presented in Table E 4.2 and indicates a benefit to cost ratio of 12.3.

33/11 kV substation at Mt. Meru hotel

11.7 Feeder no. 3 from the Power House substation (feeding the important load complex in the Mt. Meru area) is presently carrying a load of over 200 Amps. The capacity of the Power House substation that feeds the central town area is also fully utilized. Although the proposed conversion of the Monduli and Ngaramtoni feeders will release about 3 MVA of primary capacity the expected future loads in the Arusha town would still need about 1.6 to 2.0 MVA of additional capacity to provide reliable operation conditions up to about 1998. Further the Power House substation is located at the southern periphery of the town and it would be advisable to have a feeding point from the northern side in order to provide alternate feeding possibilities for the 11 kV feeders. An ideal site to meet the above requirements has been identified by TANESCO close to the Mt. Meru Hotel. This new substation will ensure that the central area of the Arusha town is supplied from two 11 kV sources. It will provide substantial loss reduction benefits as well as a high level of reliability for the loads presently supplied by Feeder Nos. 1 (Mt. Meru) and 3 (Ilboru) from the Power House substation. The 11 kV outlets will be arranged by 3 feeders as shown in Drawing F 4.3 of Annex F. Two 33 kV supply sources are proposed for the new substation. The main source proposed consist of the construction of a second circuit from the grid substation at Njiro to the Power House and then extending this circuit along the existing 11 kV line up to the proposed site. An alternative supply source is also recommended from the existing Arusha-Moshi 33 kV feeder. This short connection will not only enhance the reliability of the entire town area but also that of the loads supplied along the Arusha-Moshi feeder. The additional reliability can be achieved by installation of line switches or isolators positioned at suitable locations to enable all network sections to be supplied from either of the two 33 kV feeders. The economic analysis of the proposal is given in Table E 4.3 and indicates a benefit to cost ratio of 7.0.

33/11 kV substation at Usa/Arumeru

11.8 The village of Arumeru has been established as the local government district headquarters for the Usa area situated towards the west of Kilimanjaro. There is a rapid load growth in the area and the existing supply system with long secondaries from a few 33kV/LV transformers is inadequate to meet the expected loading conditions. It is therefore necessary to increase the number of distribution transformers substantially and rationalize the LV networks in order to provide supply at acceptable technical and economic levels. The most suitable method of increasing the distribution transformers in the area is by converting the primary distribution system to 11 kV. Accordingly a 33/11 kV substation of capacity 2.5 MVA is proposed to be established at Usa. Details of the expected system loads and the appropriate network configuration is being designed by the TANESCO/ESMAP study unit. An economic evaluation will be conducted when the design is completed. The present indications are that a high economic return is to be expected.

33/11 kV substation at Makumira

11.9 The existing 11 kV network at Makumira is supplied by three transformers in series; 33kV/400V, 400V/11kV and an 11kV/400V/11kV earthing transformer. This arrangement has clearly been a result of ad-hoc arrangements made due to funding or equipment limitations. It is necessary to rationalize the arrangement by replacing these three transformers with a single 33/11 kV stepdown transformer. The new transformer will be of 2.5 MVA rating , which will also accommodate the expected future load additions in the area.

Summary of the MV developments for Arusha

11.10 The system development proposals for the Arusha region to provide economical loss and reliability levels are summarized hereunder together with their benefit to cost ratios.

Item	Ref. to C/B table	Cost in US$	B/C ratio
33 kV line conversion Monduli feeder	E.4.1	471	8.1
5 MVA substation at Magereza	E.4.2	356	12.3
5 MVA substation at Mt. Meru Hotel	E.4.3	771	7.0
2.5 MVA substation at Usa/Arumeru	E.4.4	328	-
2.5 MVA substation at Makumira	E.4.5	330	-

12. REHABILITATION, RATIONALIZATION, AND NETWORK EXPANSION

12.1 Power supply in distribution networks is typically achieved in a number of successive stages. These stages generally consist of (a) the transport of bulk power (say at 33 kV) from the terminal points of the transmission system (grid substations) to distribution substations or switching stations at the same voltage level, (b) voltage transformation to a lower, medium voltage (say 11 kV), (c) medium voltage (MV) feeders and distributors7/ (d) voltage transformation to low voltage (LV) and (e) low voltage distributors to retail consumers. The larger loads are usually tapped off upstream at various voltage levels of the system. Sometimes some of the intermediate levels are not utilized, for instance when 33 kV distributors are provided direct off grid substations. The power flow structure however always retains its hierarchial nature and deficiencies upstream will affect conditions at the lower levels of the supply system. Sections 8 to 11 dealt with the major improvements to the MV distribution system in the four regions under study. These developments would ensure that the main characteristics of the power system (up to the MV distributors) would be at adequate technical and economic levels to meet the expected developments in the medium term (from 5 to 10 years). In addition to these works a number of other improvements and developments at the lower levels of the network hierarchy as well as rehabilitation aspects of the entire network are required to bring the system to satisfactory operational standards. These additional items consist of:

(a) rehabilitation of lines (both MV and LV) and substations together with secondary level reinforcements to MV distributors,

(b) rationalization of the LV systems, and

(c) expansion of the existing system to cover new areas requiring electrification.

12.2 Items a and b deal with improvements required for the existing systems. Item a covers rehabilitation works (resulting from a number of years of inappropriate maintenance) as well as secondary level reinforcements for the existing system. The latter aspect deals with improvements required to the MV system at network levels lower than the main developments addressed in Sections 8 to 11. The rationalization of the LV networks covered in item b addresses requirements necessary to improve these networks to acceptable condition by loss reduction and reliability improvement measures. Item c addresses system expansion needs to meet the geographical expansion of the supply area.

7/ In general a feeder will transport bulk power without tapping off loads at intermediate points while a distributor will supply a large number of loads along its length. Often the definition is blurred in common usage, particularly as outgoing supply lines off a substation are commonly termed 'feeders' whether they are tapped along the way or not.

Network rehabilitation and reinforcement

12.3 Field inspections carried out during the study in the four regions indicate that the distribution networks are in need of considerable rehabilitation. The extent of work required to bring the networks to a satisfactory condition varies among different locations. The main shortcomings and deficiencies requiring remedial action are as follows:

(a) conductor connections being made by inappropriate methods resulting in loose connections,

(b) various temporary and unorthodox methods used for connections from the transformers to the overhead lines. In many locations these connections are made without the necessary protective fuses or switchgear. They are also often extremely shabby and constitute a danger to repair workmen,

(c) defective equipment on overhead lines and transformer stations such as isolators and circuit breakers,

(d) defective or malfunctioning equipment and meters in substations,

(e) poor pole top dressings and decayed or corroded cross arms,

(f) decayed poles on distribution lines, and

(g) decayed or partially burnt out service connections.

12.4 The poor condition of the networks has been caused by the shortage of funds to procure necessary material for the required work to be performed in time (particularly as a large number of items are imported), the absence of systematic planning of development works and the lack of suitable maintenance scheduling procedures. The only major network overhauls that were carried out were those organized by foreign funded projects. The JICA funded Dar es Salaam project and the IDA funded National rehabilitation project during the last five years carried out extensive rehabilitation in many sections of the network. However the immediate increase of load in the rehabilitated areas resulted in some of these networks becoming overloaded once again within a short time. This has resulted in burn out of equipment, damage to connectors etc. thus reducing the beneficial effects of the rehabilitation carried out. Hence there still remains a significant extent of work to be done both in areas that have not been rehabilitated in previous projects as well as in some of the areas that were rehabilitated recently.

12.5 As explained in para 12.2 secondary level improvements (not covered in the proposals for the development of the distribution systems in Sections 8 to 11) required to the MV system are also included in this category. These improvements consist mainly of the reconductoring of some line sections presently constructed with conductor gauges too low for the economic dispatch of the load carried. Most of these lines have been constructed many years ago and the lines almost always require extensive rehabilitation in addition to reconductoring. Hence the cost of reconductoring cannot be conveniently separated from that of rehabilitation and the need to group these two items under the same category. In addition a small number of network improvement works such as short interconnections to rationalize the network arrangements are also included under this item.

12.6 The specific rehabilitation and reinforcement requirements such as the extent of pole changing and reconductoring of lines to be included in the project are being assessed by carrying out field inspections of the networks. These inspections are conducted by regional engineers with the support of the ESMAP unit and lists of the works to be carried out are in preparation. Total requirements for this item have been estimated from the information collected so far and a summary of the work to be performed in each area is provided in Table E5 of Annex E. In addition to specific items of work identified by the inspections, bulk provision is made for the materials required for the rehabilitation of substations, transformer stations, line connectors and service connections as well as the tool and equipment required to undertake the work.

12.7 A comprehensive and systematic procedure needs to be followed in organizing the rehabilitation program. The following are some of the important aspects to be addressed:

(a) The work should be programmed area by area, covering each in a comprehensive manner. Arrangements should be made to organize systematic maintenance procedures to the rehabilitated areas so that they will continue to be maintained at the required standards. The areas rehabilitated should be indicated in progress maps and the performance adequately supervised.

(b) The rehabilitation work in the field need to be combined with the training of TANESCO personnel in construction and maintenance methods and procedures.

(c) Appropriate tools and equipment should be supplied and the maintenance staff trained in the correct use of these items.

12.8 The work involved in rehabilitation of existing networks is in fact delayed maintenance and specific justification may well be considered to be superfluous. If the utility is to continue in the business of providing power supply to its existing consumers (which it is legally obliged to do) it is virtually mandatory to have the existing networks maintained in a state of acceptable operation. Further if major maintenance requirements are postponed the networks deteriorate rapidly resulting in burnouts and damages to healthy components. This results in further increase of costs to bring the networks to the required operating condition. In addition deteriorated networks result in a large loss of power supply due to network outages. Networks in poor operating conditions also result in an increase of standby plant installed by consumers. Thus rehabilitating networks that are in a poor state of maintenance result in the following benefits: saving network components from further damage; increased sales due to the reduction of outages;

higher consumer satisfaction and reduced necessity for consumers to procure stand by plant.

12.9 Preventing the networks from further damage may well bring about the greatest benefits. These benefits, however, cannot be readily quantified. Regarding increased sales, an attempt has been made to assess the resulting savings by estimating the extent of outages that can be saved by bringing the networks to acceptable operating condition. An economic analysis considering the benefits of such outage savings is presented in Tables E 6.1 to E 6.4 of Annex E in respect of the four regions under study. At an outage saving of 1 percent of the units sold and an economic cost of outages at $1.00/KWh benefit to cost ratios between 7 and 17 are obtained for the four regions. The results are tested by examining the sensitivity to the estimated figures used for the amount of outages saved; the value of such savings and the load growth rate. A summary of the results of the computations is provided in Table 12.1 below. It is seen that even under the most conservative assumptions the rehabilitation work on the existing systems will produce substantial economic benefits. Thus rehabilitation works while being of the highest priority due to operational necessities are also economically justifiable.

Table 12.1. Cost/Benefit ratios obtained for proposed rehabilitation works

	Sensitivity parameters			
Saved outages (as % of units sold)	1.0	0.75	0.50	0.30
Value of saved outages $/kWh	1.0	0.75	0.75	0.75
Load growth rate % (to 1994)	8.0	4.0	4.0	4.0
Load growth rate % (beyond 1994)	9.0	4.5	4.5	4.5
	BENEFIT/COST RATIOS:			
Dar es Salaam	17.7	6.0	4.0	2.4
Tanga	9.5	3.2	2.1	1.3
Moshi	7.9	2.7	1.8	1.1
Arusha	7.8	2.6	1.8	1.1

Rationalization of L.V. Systems

12.10 There are two aspects that need to be addressed in the development of the low voltage system. The first consists of the rationalization of existing network configurations so that the system complies with technical and economic guidelines developed in Section 6. The second component consists of rehabilitation requirements; replacement of defective or damaged hardware and bringing the installation up to acceptable maintenance standards.

12.11 A sample of LV networks were studied in the four cities and the results of the line loss and voltage drop computations are provided in Section 3 and Annex A. As discussed in Section 3, a significant number of networks showed loss levels higher than economically acceptable levels. One of the simplest means of reducing existing losses is to better balance the phase loads. The sample studies have shown that as much as 15 percent of the existing LV network losses can be reduced by correcting the existing imbalance. It is recommended that an immediate program be instituted to undertake a systematic phase balancing exercise commencing with the transformer stations with the longest line lengths. While the service connections are changed from one phase to the other, an effort should also be made to improve the work standards with the use of suitable materials and working tools. A frequently occurring defect is the use of poorly twisted wire bindings for interconnecting conductors. Either parallel grove clamps or compression crimping methods should be employed for this purpose.

12.12 The next major technical improvement that can be effected is the reduction of the long secondary lengths of LV distributors. Reducing the lengths of LV lines by introducing additional transformers (at locations selected to increase the number of possible feeders from each transformer) will have a substantial impact on the reduction of LV losses. TANESCO counterpart staff are already engaged in the task of selecting the appropriate locations and computing the transformer capacities and other associated investment (new feeder connections etc.) required. As discussed in Section 6 the requirements of additional transformers to inject supply to the LV system would have been much higher and the capacities of the transformers considerably lower if the system was being designed afresh. The presence of the existing network with conductors of 100 and 50 mm. sq. gauge is so widespread that it is not economical to introduce different conductor standards for the addition of the new transformers. It is expected that approximately 50 percent of the existing LV network losses can be reduced by the proposed investment. A benefit to cost analysis of the proposal work is given in Table E7 of Annex E.

<u>LV network rehabilitation</u>

12.13 The rehabilitation requirements of LV networks is similar to those stated in paras 12.3 to 12.4 for MV networks. A particular concern is the transformer station and associated LV connections. It estimated that over 75 percent of these stations require considerable rehabilitation inputs (exceeding work that can be considered under normal maintenance). The benefit to cost computation of Tables E 6.1 to 6.4 includes the work to be undertaken both on MV as well as LV networks and a separate analysis is not attempted in view of the difficulty of obtaining accurate estimates of the benefits.

Network Expansion to New Development Areas

12.14 In all four major cities studied there are a number of areas presently outside the supply system in which new housing and community development has been in progress for some time. These areas adjoin the existing infrastructure of roads and power networks. Further, most of the areas presently covered by the existing distribution systems are already developed close to saturation and the possibility of expansion of the cities mainly rests in the peripheral areas. Tanzania operates an urban development planning system in which the land is surveyed and divided into plots marked out for various types of land usage. These plots are then sold or leased to individuals and corporate bodies. A number of new areas in all four of the cities studied has been subjected to such town planning and survey drawings of the developments envisaged are available. It is reported that in most such areas all the plots demarcated have already been sold. In the areas selected other investment activities have already commenced and are in various stages of development. A number of new buildings as well as many units under construction are observed. It is clear that the lack of infrastructural facilities such as electricity, water and roads is a major constraint to the development of these areas. Once such facilities are introduced there is bound to be a sharp increase of activity and an acceleration of the development process. In particular electricity appears to be the major constraint as water supply can be obtained either by wells in the premises or by community water supply available close by and roads are in any case not well provided even in the areas already developed. Thus in these new developing areas the load growth is expected to be quite high when a reliable power supply is provided.

12.15 Supply to a few of the buildings already constructed in these areas has in fact been already provided. However these connections are being provided in a haphazard manner with long extensions from the peripheries of existing systems and sometimes from the bulk supply transformers available in the area. Such inappropriate construction methods are resorted to mainly because of funding limitations and the desire to limit the cost for each individual customer. This process has resulted in a suboptimal development of the distribution system without giving due consideration to appropriate technical standards. In particular, inappropriate conductor sizes are being used and in many cases it was observed that the lines are being drawn over other plots not yet developed. If such unplanned development is allowed to continue TANESCO will be faced with a number of problems. These include the overloading of existing systems, low voltages at the network peripheries, the inability to supply the increasing load on the extended lines and the excessive costs of repeatedly replacing unplanned construction.

12.16 It is therefore very necessary that comprehensive development proposals be prepared with respect to each such area of network expansion. Thus the present study has undertaken an investigation of these areas consisting of estimation of the expected long term load and the design of appropriate networks to satisfy the planning guidelines detailed in Section 6. Town planning maps are first collected for such areas and the sites examined to ascertain the present state of development as well as the possible supply configurations. The maximum load to be planned for is computed on the basis of the area covered and the expected loading density after comparing the area concerned with similar locations in the existing network for which the load densities have been determined. The development proposals are prepared so that they could be effected in a number of stages. Such a procedure will enable the expected load increases to be met satisfactorily but without over investment at each stage of development. The initial network will be constructed so that the conductor sizing and line routing is such as to be able to accommodate the expected final load. Subsequent stages of the development will include the increase of the number of transformers as well as the augmentation of transformer capacities, additional MV spur lines and further coverage of the LV network.

12.17 A cost benefit analysis is conducted for each development plan (see sample computations in Table series E 8.1 of Annex E). This is accomplished by computing the benefits at the Average Incremental Cost (AIC) of ultimate supply (taken as $ 0.10) less the AIC at transmission level (taken as $ 0.075), thus giving a net benefit of $ 0.025 per unit of sales. From the computations completed by the ESMAP study unit up to date it is seen that the benefit to cost ratios are high (generally over 3.0). This is due to the fact that these new areas selected for electrification are very close to the existing MV network. In some cases the MV feeders actually pass through the areas but the associated MV distributors and supply transformers have not been provided. In addition the major load growth of the cities is expected to occur in these new areas as there are only limited opportunities for new loads to materialize in the already developed areas of these cities particularly in view of the town planning procedures in existence. The details of the work envisaged over the duration of the proposed project in the four regions and a summary of their costs are provided in Table E 8.2 of Annex E.

ANNEX A

DISTRIBUTION SYSTEM CHARACTERISTICS

Annex A

DISTRIBUTION SYSTEM CHARACTERISTICS

List of Figures and Tables

Figures

Tables

Annex A

DISTRIBUTION SYSTEM CHARACTERISTICS

This annex provides a sample of the information obtained on network characteristics from the analysis of the field data collected. The program of feeder measurements using electronic logging instruments provided valuable information on the load variation with time of day (see Figure 1A). This data was transferred to spreadsheet formats enabling the load factor and loss factor of each feeder to be computed (see Table A.1). In addition, loading densities provide important information for planning purposes and such data has been computed by combining the feeder loads with the supply area obtained from the digitized maps. A sample of the results is presented at Table A.5 (for MV feeders) and Table A.6 (for LV feeders).

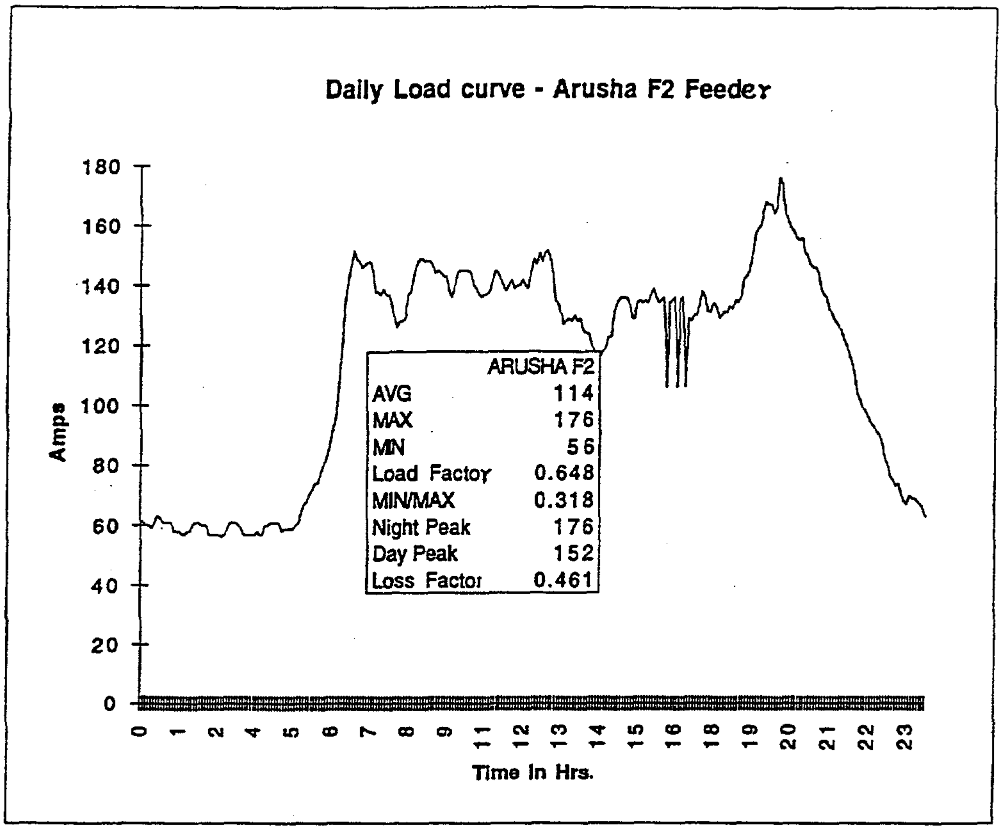
Computations have been performed to obtain the losses and tail end voltage of feeders and distributors using a spreadsheet format based on the methodology developed in Annex D.1. Results of the computation for the 1991 and 1995 peak loading condition at the four regions are presented in Tables A.2.1 to A.2.4. Table A.2.1 for Dar es Salaam contains the full spreadsheet used, while Tables A.2.2 to A.2.3 for the rest of the regions show only summarized information.

The spreadsheet format lends itself well to enable a wide variety of computations to be carried out once the initial data base is established. For example, the mid-load and base load conditions can be simulated by copying out a new set of input current and power factor figures to the relevant columns. The effects of capacitor additions can be modeled by including suitable additional columns to compute the revised input current and power factor. Revised loading data on network rearrangement involving new substations and feeders can be obtained by using ratios for load allocation. By "linking" previously computed data where required, a variety of important information can be obtained. For example, the altered feeders can be combined with those unaffected to provide revised substation loadings; substation loads can be linked to the load on the supply line, etc. These techniques have been used in the computations to produce information on the different load steps (representing peak, mid-load and base load conditions), effects of development proposals and capacitor applications. Due to space limitations, the resulting spreadsheets are not presented.

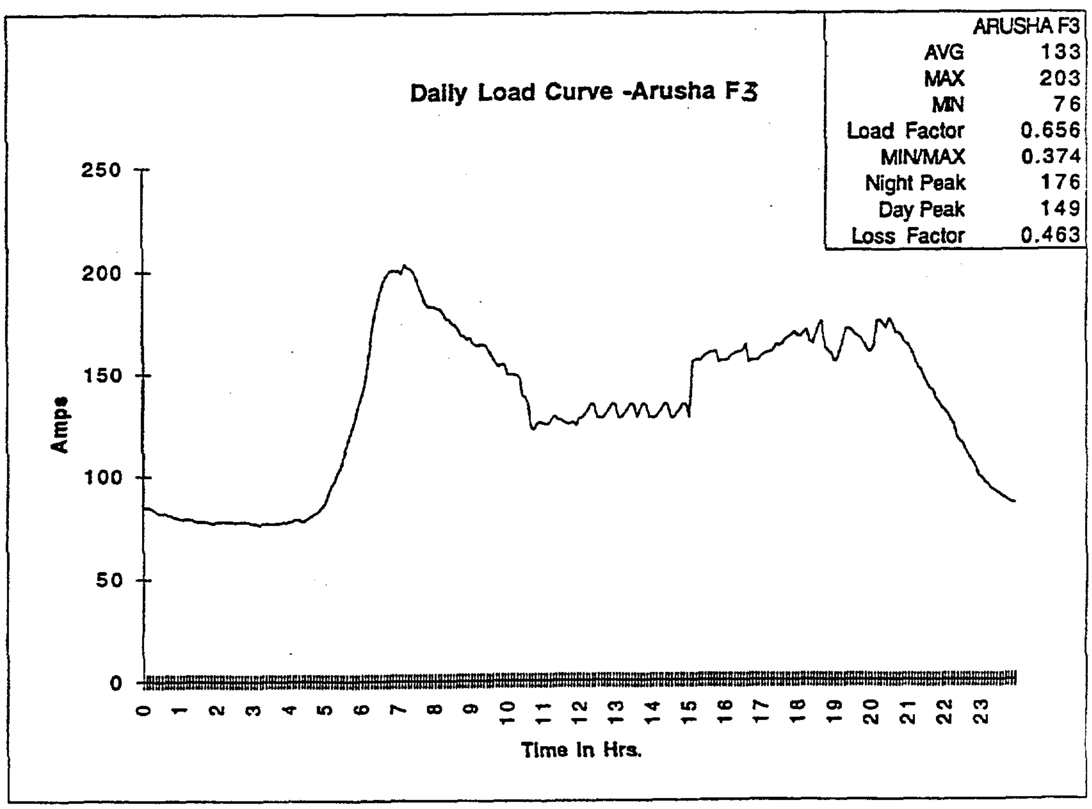
A simplified computation has been performed for LV feeders and a sample is given in Table A.3.1. In this calculation, the total feeder load is divided into the various sections and spurs of the LV system in proportion to the number of houses in each section. The losses for each section is computed (using the methodology in Annex D.1) and the total losses for the feeder is added up. The computations are made assuming a balanced loading situation (for three phase sections) and the percentage increase for the existing imbalance is also provided. Table A.3.2 summarizes the results of studies obtained from 367 feeders off 105 transformer stations.

The above computations resulted in the determination of the loss levels in the medium voltage (33 and 11 kV) and low voltage (0.4 kV) networks. Studies detailed in Section 4 and Annex B provide the results of the loss levels of the transmission system. The information obtained on the losses at each voltage level has, thereafter, been combined with the respective power and energy sales at the respective voltage levels to build a power and energy flow analysis given in Table A.4. This table provides a breakdown of losses as a percentage of the net power supplied to the system.

Figure A1



Daily Load curve - Arusha F2 Feeder
ARUSHA F2
AVG 114
MAX 176
MIN 56
Load Factor 0.648
MIN/MAX 0.318
Night Peak 176
Day Peak 152
Loss Factor 0.461
Amps
Time In Hrs.



Daily Load Curve -Arusha F3
ARUSHA F3
AVG 133
MAX 203
MIN 76
Load Factor 0.656
MIN/MAX 0.374
Night Peak 176
Day Peak 149
Loss Factor 0.463
Amps
Time In Hrs.

Table A 1

Feeder Characteristics Obtained from Load Logger Measurements

Feed/name	Current in Amps. for: AVG	MAX	MIN	MIN/MAX	Night Peak	Day Peak	Load Factor	Loss Factor
	ARUSHA REGION FEEDERS							
NGARENARO	43	68	12	0.176	68	57	0.629	0.423
MONDULI SECTION	27	43	17	0.395	43	27	0.629	0.421
OLURUVANI SPUR	24	30	11	0.367	30	30	0.810	0.678
ARUSHA F1	72	110	41	0.373	110	95	0.656	0.464
ARUSHA F2	114	176	56	0.318	176	152	0.648	0.461
ARUSHA F3	133	203	76	0.374	176	149	0.656	0.463
	MOSHI TOWN FEEDERS							
TOWN-URU SPUR	9	20	4	0.200	20	10	0.449	0.239
MOSHI M1	12	23	7	0.304	23	12	0.501	0.278
MACHAME 33KV	11	25	5	0.200	25	12	0.454	0.240
TOWN FEEDER	101	178	60	0.337	178	131	0.565	0.351
MOSHI M3 11KV	99	167	61	0.365	167	124	0.591	0.377
MOSHI M2 11K V	41	74	28	0.378	74	46	0.559	0.335
BOMA MBUZI-RONGAI	18	38	12	0.316	38	17	0.486	0.263
MOSHI BOMA 11KV	23	40	11	0.275	40	28	0.571	0.375
	TANGA REGION FEEDERS							
	MAZINDE S/S							
MOMBO-KWALUKONGE	1	5	1	0.200	1	5	0.295	0.125
MAZINDE-LUSHOTO	30	48	18	0.375	48	36	0.625	0.413
MAZINDE-MKUMBARA	7	15	1	0.067	8	15	0.488	0.274
	MAJANI MAPANA(TANGA) S/S							
NGUVUMALI	70	104	49	0.471	104	87	0.671	0.471
TANGA1	98	137	67	0.489	131	137	0.718	0.541
TANGA2	87	152	41	0.270	152	102	0.571	0.360
TFC 33KV	14	17	8	0.471	17	16	0.827	0.696
	DAR ES SALAAM REGION FEEDERS							
MK1 feeder	163	219	141	0.644	219	160	0.745	0.566
D9 feeder	221	325	166	0.511	325	236	0.679	0.477
C3 feeder	146	225	95	0.422	120	223	0.649	0.471
D3 feeder	95	152	58	0.382	94	152	0.625	0.432
F2 feeder	118	177	70	0.395	156	176	0.668	0.484
MK3 feeder	184	298	139	0.466	298	215	0.617	0.400
F32 feeder	89	160	40	0.250	83	151	0.558	0.349

Note: The above is a sample of the data obtained off 'Lotus' spreadsheets created using the information downloaded from the electromic data loggers.

MEDIUM VOLTAGE FEEDERS LOSS CALCULATIONS ON PRESENT SYSTEM 1991/1995 -DAR ES SALAAM

LOADS AT SYSTEM PEAK

FEEDER NAME	Growth Rare(%)	Length (km)	Con/d (KVA)	1990 Max. I (Amps)	1995 Max. I (Amps)	Conductor Type, Size	Dist. loss	Factor Volt dr.	Resist. per km	PF Cos ó	Sin ó	Induct. per km	POWER AND LOSS CALCULATIONS 1991 Power (KW)	1995 Power (KW)	1991 Loss (KW)	1995 Loss (KW)	1991 Losses in %	1995 Losses in %	VOLTAGE DROP CALCULATIONS 1991 Voltage Drop in (KV)	1995 Voltage Drop in (KV)	1991 Voltage Drop in (%)	1995 Voltage Drop in (%)
UBUNGO S/S 11 KV FEEDERS 15 = SS Capacity (MVA) 76 = SS loading in % by 1995																						
U1, Kisiwani	8	8.98	10640	175	257	ACSR100	0.4	0.56	0.331	0.94	0.34	0.34	3134	4605	109	236	3.49	5.12	0.65	0.96	5.92	8.70
U2, Manzese	4	8.36	3810	146	178	ACSR 100	0.4	0.56	0.331	0.90	0.44	0.34	2504	3046	71	105	2.83	3.44	0.53	0.64	4.80	5.84
U7, Factory	9	3.91	6345	75	115	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	1329	2045	9	21	0.66	1.01	0.12	0.19	1.12	1.72
U8, University	4	4.35	5300	40	49	ACSR 100	0.9	0.95	0.331	0.94	0.34	0.34	716	872	6	9	0.87	1.06	0.12	0.15	1.11	1.35
										0.93	0.38		7683	10568	195	370	2.54	3.51				
KURASINI S/S 11 KV FEEDERS 15 = SS Capacity (MVA) 86 = SS loading in % by 1995																						
K4, INDUSTRIAL	4	9.52	13245	168	204	ACSR 100	0.8	0.9	0.331	0.91	0.41	0.34	2911	3542	213	316	7.32	8.91	1.10	1.34	10.02	12.19
K3, KILWA RD	4	8.50	10605	231	281	ACSR 100	0.4	0.56	0.166	0.91	0.41	0.17	4005	4873	90	133	2.25	2.74	0.42	0.51	3.83	4.66
PORT	8	4.32	17800	133	195	ACSR 100	0.9	0.95	0.331	0.96	0.28	0.34	2433	3574	68	147	2.81	4.12	0.39	0.57	3.55	5.22
										0.92	0.38		9349	11989	372	596	3.97	4.97				
ILALA S/S 11 KV FEEDERS 45 = SS Capacity (MVA) 58 = SS loading in % by 1995																						
D0, Brewery	4	0.30	4400	90	109	CU 185	1	1	0.118	0.93	0.37	0.08	1595	1940	1	1	0.05	0.07	0.01	0.01	0.06	0.07
D1, Azamia	3	5.45	4720	120	139	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	2130	2469	31	42	1.47	1.70	0.28	0.32	2.50	2.90
D2, Town 1	5	6.05	6700	110	141	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	1955	2495	29	48	1.50	1.91	0.28	0.36	2.55	3.25
D3, Kurasini	3	2.82	5130	180	209	ACSR 100	0.4	0.56	0.331	0.91	0.41	0.34	3121	3618	36	49	1.16	1.35	0.22	0.25	1.98	2.29
D7,	3	2.95	2045	110	128	ACSR 100	0.6	0.7	0.331	0.96	0.28	0.34	2012	2332	21	29	1.06	1.23	0.16	0.19	1.48	1.71
D8, Industrial	2	1.53	300	10	11	ACSR 100	0.9	0.95	0.331	0.96	0.28	0.34	183	202	0	0	0.07	0.08	0.01	0.01	0.09	0.10
D9, Town 2	6	2.53	5515	300	401	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	5316	7114	90	162	1.70	2.28	0.32	0.43	2.90	3.88
D10, Magomeni	4	6.51	5575	199	242	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	3520	4282	102	151	2.90	3.53	0.54	0.66	4.94	6.00
										0.93	0.37		19831	24453	312	481	1.57	1.97			16	
CITY CENTER S/S 11 KV FEEDERS 30 = SS Capacity (MVA) 71 = SS loading in % by 1995																						
C2, Upanga	4	3.26	6230	80	97	ACSR 100	0.4	0.56	0.331	0.98	0.20	0.34	1494	1817	8	12	0.55	0.67	0.10	0.12	0.90	1.10
C3, City Center 1	5	1.20	8715	128	163	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	2268	2895	8	13	0.34	0.44	0.06	0.08	0.59	0.75
C4, City Center 2	5	2.21	10430	141	180	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	2505	3197	18	29	0.70	0.89	0.13	0.17	1.19	1.52
C5, Mnazi Mneja 1	5	1.44	5115	195	249	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	3455	4410	22	35	0.63	0.80	0.12	0.15	1.07	1.37
C6, Mnazi Mneja 2	4	1.76	9605	118	144	ACSR 100	0.4	0.56	0.331	0.96	0.28	0.34	2158	2626	10	14	0.45	0.55	0.08	0.10	0.76	0.92
C8, Tanesco	5	1.44	9260	226	288	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	4005	5111	29	48	0.73	0.93	0.14	0.17	1.24	1.59
										0.94	0.34		15885	20056	94	151	0.59	0.75				
MIKOCHENI S/S 11 KV FEEDERS 15 = SS Capacity (MVA) 100 = SS loading in % by 1995																						
MK1, Msasani	5	8.20	6155	155	198	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	2747	3505	78	127	2.85	3.64	0.53	0.68	4.85	6.19
MK2, Tandale	8	10.84	11710	190	279	ACSR 100	0.4	0.56	0.331	0.91	0.41	0.34	3294	4840	155	336	4.72	6.93	0.88	1.30	8.03	11.80
MK3, Lugalo	3	4.80	3950	80	93	ACSR 100	0.4	0.56	0.331	0.90	0.44	0.34	1372	1590	12	16	0.89	1.03	0.17	0.19	1.51	1.75
MK4, north east	5	4.50	6955	174	222	ACSR 100	0.4	0.56	0.331	0.98	0.20	0.34	3249	4147	54	88	1.67	2.13	0.30	0.38	2.71	3.45
										0.94	0.34		10662	14083	300	568	2.81	4.03				
OYSTERBAY S/S 11 KV FEEDERS 15 = SS Capacity (MVA) 129 = SS loading in % by 1995																						
O2, Mwenge	3	4.22	2715	135	157	ACSR 100	0.4	0.56	0.331	0.98	0.20	0.34	2521	2922	31	41	1.21	1.40	0.22	0.25	1.97	2.28
O3, Packers	4	9.64	9115	296	360	ACSR 100	0.4	0.56	0.331	0.98	0.20	0.34	5527	6725	336	497	6.07	7.39	1.09	1.32	9.87	12.00
O4, Kinondoni	4	2.79	1145	177	216	CU 25	1	1	0.741	0.90	0.44	0.383	3040	3699	195	289	6.42	7.81	0.71	0.87	6.50	7.91
	4	2.79	3790	123	150	ACSR 50	0.6	0.7	0.7	0.90	0.44	0.385	2109	2566	53	79	2.52	3.06	0.33	0.40	3.01	3.67
O4 (TOTAL)	3	5.58	4935	177	206					0.90	0.44		3040	3525	248	367	8.16	10.42	0.00	0.00	0.00	0.00
O5, Seaview	2	3.58	3245	115	127	ACSR 100	0.4	0.56	0.331	0.92	0.39	0.34	2016	2226	19	23	0.93	1.03	0.17	0.19	1.59	1.75
O6, Oyster bay	3	4.28	4320	120	139	ACSR 100	0.4	0.56	0.331	0.93	0.37	0.34	2126	2465	24	33	1.15	1.33	0.22	0.25	1.96	2.27
										0.93	0.36		15231	18037	658	961	4.32	5.33				

Table A.2.1

MEDIUM VOLTAGE FEEDERS LOSS CALCULATIONS ON PRESENT SYSTEM 1991/1995 -DAR ES SALAAM (Continu)

LOADS AT SYSTEM PEAK

FEEDER NAME	Growth Rare(%)	Length (km)	Con/d (KVA)	1990 Max. I (Amps)	1995 Max. I (Amps)	Conductor Type, Size	Dist. loss	Factor Volt dr.	Resist. per km	Old PF Cos φ	Old Sin φ	Induct. per km	POWER AND LOSS CALCULATIONS 1991 Power (KW)	1995 Power (KW)	1991 Loss (KW)	1995 Loss (KW)	1991 Losses in %	1995 Losses in %	VOLTAGE DROP CALCULATIONS 1991 Voltage in (KV)	1995 Drop in (KV)	1991 Voltage in (%)	1995 Drop in (%)
MBEZI S/S 11 KV FEEDERS																						
							15	= SS Capacity (MVA)			67	= SS loading in % by 1995										
KUNDUCHI	10	13.46	10065	180	290	ACSR 50	0.4	0.56	0.7	0.93	0.37	0.385	3189	5137	366	950	11.49	18.50	1.86	3.00	16.93	27.27
PACKERS	3	3.36	2230	60	70	CU 25	0.4	0.56	0.741	0.93	0.37	0.383	1063	1232	11	14	1.01	1.17	0.16	0.19	1.48	1.71
LUGALO	2	6.96	3950	150	166	ACSR 100	0.4	0.56	0.331	0.92	0.39	0.34	2629	2903	62	76	2.37	2.61	0.44	0.49	4.03	4.45
										0.93	0.38		6882	9272	439	1040	6.38	11.22				
FACTORY ZONE 1 S/S 11 KV FEEDERS							10	= SS Capacity (MVA)			57	= SS loading in % by 1995										
F5, BUGURUNI	3	3.2	15420	70	81	ACSR 100	0.4	0.56	0.331	0.71	0.70	0.34	944	1094	6	8	0.66	0.76	0.10	0.12	0.93	1.08
F2, RTD	5	2.5	8610	170	217	ACSR 100	0.4	0.56	0.331	0.71	0.70	0.34	2300	2935	29	47	1.25	1.59	0.20	0.25	1.78	2.27
										0.71	0.70		3244	4030	35	55	1.08	1.37				
FACTORY ZONE II S/S 11 KV FEEDERS							10	= SS Capacity (MVA)			23	= SS loading in % by 1995										
KILTEX	1	0.5	2000	21	22	CU195 U/G	1	1	0.228	0.89	0.46	0.08	356	374	0	0	0.04	0.04	0.00	0.00	0.04	0.04
KISARAWE	1	17.8	7050	28	29	ACSR 50	0.4	0.56	0.7	0.89	0.46	0.385	475	499	12	13	2.47	2.59	0.39	0.41	3.51	3.69
UKONGA	3	5	2265	60	70	ACSR 50	0.4	0.56	0.7	0.89	0.46	0.385	1017	1179	15	20	1.49	1.72	0.23	0.27	2.11	2.45
										0.89	0.46		1848	2053	27	33	1.46	1.63				
FACTORY ZONE III S/S 11 KV FEEDERS							10	= SS Capacity (MVA)			83	= SS loading in % by 1995										
F31, INDUSTRIAL	4	2.6	16545	187	228	ACSR 100	0.4	0.56	0.331	0.71	0.70	0.34	2532	3081	36	54	1.43	1.74	0.22	0.27	2.04	2.48
F32, AIRWING	1	3.38	1775	51	54	ACSR 100	0.4	0.56	0.331	0.88	0.47	0.34	855	899	3	4	0.41	0.43	0.08	0.08	0.69	0.72
F33, AIRWING	1	2.3	3360	68	71	ACSR 100	0.4	0.56	0.331	0.79	0.61	0.34	1016	1068	4	5	0.41	0.43	0.07	0.07	0.64	0.68
F34, KIWALANI	5	5.8	9245	70	89	ACSR 100	0.4	0.56	0.331	0.91	0.41	0.34	1214	1549	11	18	0.93	1.19	0.17	0.22	1.58	2.02
TOTAL										0.79	0.61		5617	6597	55	80	0.98	1.22				
KIGAMBONI S/S 11 KV FEEDERS							5	= SS Capacity (MVA)			81	= SS loading in % by 1995										
Kigam F1	6	10		75	100	ACSR 50	0.4	0.56	0.7	0.89	0.46	0.385	1272	1702	47	85	3.72	4.97	0.58	0.78	5.28	7.07
Kigam F2	6	6		84	112	ACSR 50	0.4	0.56	0.7	0.89	0.46	0.385	1424	1906	36	64	2.50	3.34	0.39	0.52	3.55	4.75
										0.89	0.46		2696	3608	83	148	3.07	4.11				
TOTAL FOR ALL 11 KV (Without diversity)													96347	121251	2602	4452	2.70	3.67				
TOTAL FOR ALL 11 KV (With diversity allowed for)						0.98	= Diversity Factor						94420	118826	2498	4276	2.65	3.60				

Table A.2.1 (cont'd)

Table A.2.1 (cont'd)

MEDIUM VOLTAGE FEEDERS LOSS CALCULATIONS ON PRESENT SYSTEM 1991/1995 -DAR ES SALAAM (Continu)

LOADS AT SYSTEM PEAK

FEEDER NAME	Growth Rare(%)	Length (km)	Con/d (KVA)	1990 Max. I (Amps)	1995 Max. I (Amps)	Conductor Type, Size	Dist. loss	Factor Volt dr.	Resist. per km	OldPF Cos φ	Old Sin φ	Induct. per km	POWER AND LOSS CALCULATIONS 1991 Power (KW)	1995 Power (KW)	1991 Loss (KW)	1995 Loss (KW)	1991 Losses in %	1995 Losses in %	VOLTAGE DROP CALCULATIONS 1991 Voltage Drop in (KV)	1995 Voltage Drop in (KV)	1991 Voltage Drop in (%)	1995 Voltage Drop in (%)
DAR ES SALAAM 33 KV FEEDERS																						
ILALA GRID SUBSTATION																						
ILALA-C.C 1	4.8	2.5	30000	148	187	ACSR 100	1	1	0.331	0.94	0.34	0.36	7943	10028	54	86	0.68	0.86	0.28	0.35	0.84	1.06
ILALA-C.C 11	4.8	2.5	30000	148	187	ACSR 100	1	1	0.331	0.94	0.34	0.36	7943	10028	54	86	0.68	0.86	0.28	0.35	0.84	1.06
ILALA-KURASINI	5.3	5.9	15000	232	301	ACSR 100	1	1	0.331	0.91	0.42	0.36	12045	15597	316	530	2.63	3.40	1.07	1.39	3.25	4.21
KURASINI-KIGAMBON	6.0	4	5000	53	71	ACSR 100	1	1	0.331	0.89	0.46	0.36	2696	3608	11	20	0.41	0.55	0.17	0.23	0.51	0.68
ILALA-OYSTERBAY	3.4	5.6	15000	285	338	ACSR 100	1	1	0.331	0.93	0.36	0.36	15231	18037	453	635	2.97	3.52	1.21	1.43	3.67	4.35
ILALA-FZ I	4.4	4.7	15000	80	99	ACSR 100	1	1	0.331	0.71	0.70	0.36	3244	4030	30	46	0.92	1.14	0.32	0.39	0.96	1.20
ILALA 11 KV	4.3	0	45000	373	460					0.93	0.37		19831	24453	312	481	1.57	1.97				
TOTAL ILALA SS.			110000	946	1259					0.92			66236	82173	1230	1885	1.86	2.29				
TOTAL FOR 33 kV FEEDERS ONLY OFF ILALA S/S													46405	57720	918	1404	1.98	2.43				
UBUNGO GRID SUBSTATION																						
UBUNGO-ALAF *	2.0	9.24	45000	93	103	ACSR 100	1	1	0.331	0.89	0.46	0.36	4731	5223	79	97	1.68	1.85	0.68	0.75	2.07	2.28
UBUNGO-WAZO 1	6.1	8.8	20000	130	175	ACSR 100	1	1	0.331	0.93	0.38	0.36	6882	9272	148	268	2.15	2.89	0.88	1.18	2.66	3.58
UBUNGO-WAZO 1I *	2.5	18.2	15000	123	139	ACSR 100	1	1	0.331	0.80	0.60	0.36	5626	6365	274	350	4.86	5.50	1.86	2.11	5.65	6.39
UBUNGO-TAZARA *	1.5	7.85	10000	55	59	ACSR 100	1	1	0.331	0.85	0.53	0.36	2650	2855	23	27	0.88	0.94	0.35	0.38	1.06	1.14
UBUNGO-MIKOCHENI	5.7	5.15	15000	199	262	ACSR 100	1	1	0.331	0.94	0.34	0.36	10662	14083	202	352	1.89	2.50	0.77	1.02	2.33	3.08
UBUNGO-F111	3.0	11	15000	155	180	ACSR 100	1	1	0.331	0.84	0.54	0.36	7466	8649	263	353	3.52	4.08	1.40	1.62	4.24	4.91
F111-F11	2.1	7	5000	36	40	ACSR 100	1	1	0.331	0.89	0.46	0.36	1848	2053	9	11	0.50	0.55	0.20	0.22	0.61	0.68
UBUNGO-F.TX.2 *	2.0	1.75	4706	40	44	ACSR 100	1	1	0.331	0.80	0.60	0.36	1829	2019	3	3	0.15	0.17	0.06	0.06	0.18	0.20
UBUNGO-NORDIC *	5.0	55	8410	64	82	ACSR 100	0.4	0.56	0.331	0.92	0.39	0.36	3366	4295	89	146	2.66	3.39	1.52	1.94	4.61	5.88
UBUNGO 11 KV	6.6	0	30000	145	200					0.93	0.38	0	7683	10568	195	370	2.54	3.51				
TOTAL UBUNGO SS.			168116	1004	998					0.89			50894	63330	1285	1978	2.53	3.12				
TOTAL FOR 33 kV FEEDERS ONLY OFF UBUNGO S/S													43211	52763	1090	1608	2.52	3.05				

Note: For 33 kV lines items marked with an * have been computed based on feeder currents
All other 33 kV line loads have been computed from data derived from11 kV loads

	1991 Power (KW)	1995 Power (KW)	1991 Loss (KW)	1995 Loss (KW)	1991 Losses in %	1995 Losses in %
TOTAL FOR 33 KV FEEDERS DAR ES SALAAM and based on total load supplied to 33 kV system	117130	145503	2009	3012	1.71	2.07
TOTAL FOR 33 KV FEEDERS DAR ES SALAAM and based on load of 33 kV feeders only	89616	110483	2009	3012	2.24	2.73
TOTAL FOR 33 KV FEEDERS DAR ES SALAAM and based on total load supplied to 33 kV system - diversity allowe(0.98	114787	142593	1929	2892	1.68	2.03
TOTAL FOR 33 KV FEEDERS DAR ES SALAAM and based on load of 33 kV feeders only -with diversity allowed for	87823	108273	1929	2892	2.20	2.67
TOTAL FOR 11 and 33 FEEDERS DAR ES SALAAM and based on total load supplied to 33 kV system	117130	145503	4610	7463.6	3.94	5.13
TOTAL FOR 11 and 33 FEEDERS DAR ES SALAAM and based on load of 11and 33 kV feeders only	89615.7	110483	4610	7463.6	5.14	6.76
TOTAL FOR 11 and 33 FEEDERS DAR ES SALAAM and based on total load supplied to 33 kV system -with diversity allowed for	114787	142593	4428	7168.1	3.86	5.03
TOTAL FOR 11 and 33 FEEDERS DAR ES SALAAM and based on load of 11and 33 kV feeders only -with diversity allowed for	87823.4	108273	4428	7168.1	5.04	6.62

TABLE A 2.2

MEDIUM VOLTAGE SYSTEM LOSS CALCULATIONS 1991/1995 - TANGA REGION.

Feeder Name	Gowth rate used %	Length (km)	1991 Max.I (Amps)	1995 Max.I (Amps)	1991 Power (kW)	1995 Power (kW)	1991 Loss (%)	1995 Loss (%)	1991 Voltage drop (%)	1995 (%)
			MAJANI MAPANA S/S							
NGUVUMALI (i)	4.20	3.5	104.0	122.6	1684	1986	1.12	1.32	1.77	2.08
NGUVUMALI(ii)	4.20	3.0	64.0	75.4	1036	1222	0.62	0.73	1.04	1.23
NGUVUMALI TOTAL	4.20	6.50	104.0	122.6	1684	1986	1.50	1.76	2.81	3.32
C.I.C	4.20	3.6	142.2	167.6	2303	2715	3.14	3.70	3.71	4.38
TANGA I	4.20	11.4	137.0	161.5	2219	2616	3.83	4.52	6.34	7.48
TANGA II	4.20	2.0	152.0	179.2	2462	2902	0.93	1.10	1.48	1.74
SARUJI SPUR (i)	4.20	2.8	32.0	37.7	518	611	0.22	0.26	0.36	0.43
(ii)	4.20	5.0	12.10	14.3	196	231	0.33	0.39	0.44	0.52
MSAMBWENI SPUR	4.20	0.9	9.60	11.3	155	183	0.03	0.03	0.04	0.05
USAGARA SPUR	4.20	4.0	78.00	92.0	1263	1489	0.96	1.13	1.52	1.79
TANGA II TOTAL	4.20		152	179	4595	5416	0.80	0.95	3.84	4.53
TOTAL(Tanga Town 11kv)					10801	14718	2.0	2.1		
			KOROGWE S/S							
KOROGWE I	4.20	7.0	24.0	28.3	389	458	0.92	1.09	1.23	1.45
KOROGWE II	4.20	24.6	43.0	50.7	696	821	5.81	6.85	7.76	9.15
TOTAL					1085	1279	4.06	4.79		
			KWAMGWE S/S							
KWAMGWE	4.20	7.0	11.8	13.9	191	225	0.68	0.80	0.76	0.89
			TONGONI S/S							
MWAKIDILA	4.20	8.0	28.0	33.0	453	535	0.55	0.65	0.96	1.13
			MAZINDE S/S							
LUSHOTO (i)	4.20	12.5	48.0	56.6	777	916	8.24	9.71	7.86	9.27
LUSHOTO (ii)	4.20	21.5	19.2	22.6	311	367	2.27	2.67	3.03	3.57
LUSHOTO (iii)	4.20	38.5	28.8	34.0	466	550	6.09	7.18	8.14	9.60
SUB TOTAL	4.20	72.5	48.0	56.6	777	916	12.80	15.09	19.0	22.4
MKUMBARA	4.20	16.5	15.2	17.9	246	290	3.10	3.65	3.12	3.68
MAZINDE	4.20	5.0	8.0	9.4	130	153	0.55	0.65	0.52	0.62
TOTAL					1153	1359	16.45	19.39		
			BUHURI S/S							
BUHURI I	4.20	5.0	10.0	11.8	162	191	0.34	0.40	0.44	0.52
			MUHEZA TOWN S/S							
TOWN I	4.20	10.0	10.6	12.4	171	202	1.23	1.45	1.26	1.49
MUHEZA II	4.20	5.0	30.7	36.2	497	586	1.26	1.49	1.41	1.66
TOTAL					668	788	1.26	1.48		
			MUHEZA HOSPITAL S/S							
MAGILA	4.20	2.0	1.6	1.9	26	31	0.04	0.05	0.04	0.05
			GOMBA S/S							
GOMBA I	4.20	3.0	14.2	16.7	230	271	0.41	0.48	0.45	0.53
GOMBA II	4.20	5.0	6.6	7.8	107	126	0.36	0.43	0.39	0.46
TOTAL					337	397	0.39	0.47		
			MOMBO S/S							
MOMBO	4.20	17.7	11.9	14.0	193	227	1.73	2.04	1.93	2.27
			LANZONI S/S							
LANZONI I	4.20	5.0	7.0	8.3	113	134	0.29	0.34	0.32	0.38
LANZONI II	4.20	20.0	69.1	81.5	1119	1319	3.39	4.00	5.61	6.62
TOTAL					1232	1453	3.10	3.66		
			MOA S/S							
MOA	4.20	15.6	9.3	11.0	150	177	1.19	1.41	1.33	1.57
			BWEMBWERA S/S							
BWEMBWERA	4.20	4.0	9.9	11.7	160	189	0.44	0.51	0.47	0.55
			NEW SAGEN S/S							
NEW SAGEN	4.20	15.0	26.2	30.9	424	500	2.16	2.54	2.88	3.40
			BUSHIRI S/S							
BUSHIRI I	4.20	14.2	10.0	11.8	162	191	1	1	1.0	1.2
BUSHIRI II	4.20	32.2	30.0	35.4	486	573	5	6	7.1	8.4
TOTAL					648	764	4	5	8.1	9.6

TABLE A 2.2 Cont.

Feeder Name	Gowth rate used %	Length (km)	1991 Max.I (Amps)	1995 Max.I (Amps)	1991 Power (kW)	1995 Power (kW)	1991 Loss (%)	1995 Loss (%)	1991 Voltage drop (%)	1995 (%)
			MAGUNGA S/S							
MAGUNGA	4.20	20.0	63.0	74.3	1020	1203	6.92	8.16	9.24	10.9
			PONGWE S/S							
PONGWE	4.20	4.0	5.5	6.5	89	105	0.27	0.32	0.27	0.32
			MARAMBA S/S							
MARAMBA	4.20	7.0	55.2	65.1	894	1054	2.12	2.50	2.83	3.34
			MNYUZI S/S							
MNYUZI	4.20	12.0	5.0	5.9	81	95	0.33	0.39	0.44	0.52
			MLEMUA S/S							
MLEMUA	4.20	8.0	32.0	37.7	518	611	1.41	1.66	1.88	2.21
			HALE S/S							
HALE	4.20	5.0	40.0	47.2	648	764	1.10	1.30	1.47	1.73
			TORONTO S/S							
TORONTO	4.20	1.5	11.0	13.0	178	210	0.11	0.13	0.14	0.17
			KILULU S/S							
KILULU	4.20	7.0	5.0	5.9	81	95	0.24	0.28	0.31	0.36
			AMBONI S/S							
AMBONI	4.20	1.5	1.6	1.9	25	30	0.02	0.02	0.02	0.02
33 KV LINES										
			FROM HALE/PANGANI POWER STATIONS VIA SONGA SWITCHING STATION.							
KOROGWE I	4.20	33								
sections										
SONGA-KOROGWE	4.20	33	45.0	53.0	2186	2577	2.64	3.11	3.45	4.07
HANDENI SPUR	4.20	80	11.0	13.0	534	630	0.72	0.85	1.22	1.44
MAZINDE SPUR[with sections]										
KOROGWE-MAZINDE	4.20	56	34.0	40.1	1652	1947	1.35	1.59	2.48	2.92
MAZINDE-TORONTO	4.20	23	7.0	8.3	340	401	0.19	0.22	0.29	0.35
TOTAL-KOROGWE I	4.20		45.00	53.0	2186	2577	3.9	4.6		
KOROGWE II	4.20	33								
sections										
SONGA-MAGUNGA	4.20	23	33.0	38.9	1603	1890	0.67	0.79	1.18	1.39
MLEMUA SPUR	4.20	20	10.0	11.8	486	573	0.42	0.50	0.53	0.62
MAGUNGA-KOROGWE	4.20	10	21.20	25.0	1030	1214	0.38	0.44	0.49	0.58
TOTAL-KOROGWE II	4.20		33.0	38.9	1603	1890	1.04	1.23		
KANGE I	4.20	67								
sections										
SONGA-MUHEZA	4.20	10	41.2	48.6	2002	2360	0.66	0.78	0.91	1.07
BUSHIRI SPUR	4.20	70	22.00	25.9	1069	1260	1.09	1.29	2.00	2.36
MUHEZA-CHOTE	4.20	22	19.20	22.6	933	1100	0.75	0.88	0.98	1.16
MOA SPUR [with sections]										
CHOTE-PANDE	4.20	10	15.00	17.7	729	859	0.28	0.33	0.35	0.42
PANDE-MOA	4.20	38	8.10	9.5	394	464	0.22	0.26	0.40	0.47
TOTAL	4.20		41.2	48.6	2002	2360	1.73	2.05		
KANGE II	4.20	67								
sections										
SONGA-MLINGANO	4.20	14	41.2	48.6	2002	2360	1.06	1.25	1.36	1.60
LANZONI SPUR	4.20	16	16.60	19.6	807	951	0.49	0.58	0.63	0.74
NGOMENI SPUR	4.20	15	15.40	18.2	748	882	0.47	0.56	0.57	0.67
MLINGANO-CHOTE	4.20	18	9.20	10.8	447	527	0.30	0.36	0.39	0.46
TOTAL	4.20		41.2	48.6	2002	2360	1.50	1.77		
			FROM MAJANI MAPANA S/S							
T.F.C	4.20	5	20.6	24.3	1001	1180	0.47	0.56	0.47	0.55
S.R.M	4.20	2	24.7	29.1	1200	1415	0.21	0.25	0.21	0.24
CEMENT I-II	2.00	11	309.0	334.5	15013	16250	3.54	3.83	4.29	4.64
TOTAL					17214	18845	3.13	3.35		
PANGANI QUARRY	4.20	4	8.4	9.9	408	481	0.14	0.16	0.13	0.16
KWARANGURU	4.20	1	17.6	20.7	855	1008	0.09	0.11	0.10	0.12
TOTAL					1263	1489	0.11	0.12		

TABLE A 2.3

MEDIUM VOLTAGE SYSTEM LOSS CALCULATIONS 1991/1995 - MOSHI REGION.

Feeder Name	Growth Rate(%)	Length (Km)	1991 Max.I (Amps)	1995 Max.I (Amps)	1991 Power (Kw)	1995 Power (Kw)	1991 Loss (%)	1995 Loss (%)	1991 Voltage Drop (%)	1995 Voltage Drop (%)
11 KV FEEDERS										
			LAWATI S/S							
SANYA JUU	4.0	8.3	10.0	11.7	162	189	0.20	0.24	0.34	0.39
MASAMA	4.0	23	25.0	29.2	405	474	1.41	1.65	2.33	2.73
TOTAL			35.0		567	663	1.07	1.25		
			MACHAME S/S							
HOSPITAL	4.0	11	46.0	53.8	745	872	1.24	1.45	2.05	2.40
KIBO 11	4.0	6	14.0	16.4	227	265	0.21	0.24	0.34	0.40
TOTAL			60.0		972	1137	1.00	1.17		
			BOMA MBUZI S/S							
KIBO	4.0	5	30.2	35.3	489	572	0.82	0.96	1.02	1.19
BOMA	4.0	14	10.7	12.5	173	203	0.54	0.63	0.74	0.87
TOWN FEEDER	4.0	4	219.0	256.2	3547	4149	2.15	2.51	3.56	4.16
URU SECTION										
URU (i)	4.0	4.7	20.0	23.4	324	379	0.75	0.88	0.94	1.09
URU (ii)	4.0	6.8	7.6	8.9	123	144	0.27	0.31	0.37	0.43
KIBOROLONI SPUR	4.0	2.8	74.0	86.6	1198	1402	0.51	0.59	0.84	0.98
UNGA SPUR	4.0	2.2	29.0	33.9	470	549	0.16	0.18	0.26	0.30
TOWN FDR TOTAL			219.0	256.2	3547	4149	2.42	2.83		
TOTAL			259.9		4209	4924	2.16	2.52		
			TRADE SCHOOL S/S							
M1	4.0	15.5	23.0	26.9	372	436	1.96	2.29	2.62	3.06
M2	4.0	29	74.0	86.6	1198	1402	11.79	13.79	15.74	18.42
M3(i)S/S-CCM	4.0	4.4	168.0	196.5	2721	3183	1.85	2.16	3.13	3.66
M3 (ii)CCM-KCMC	4.0	6.9	67.0	78.4	1085	1269	2.54	2.97	3.39	3.97
SUB TOTAL(M3)		11.3	168.0	168.0	2721	3183	2.86	3.34	6.52	7.63
TOTAL			265.0	310.0	4292	5021	5.27	6.17		
			MWANGA S/S							
TOWN FEEDER	4.0	26	23.0	26.9	372	436	1.47	1.72	2.43	2.84
			SAME S/S							
BOMA FEEDER	4.0	12.24	21.9	25.6	354	415	1.74	2.03	2.25	2.64
			GONJA S/S							
NDUNGU	4.0	12.5	14.0	16.4	227	265	0.54	0.63	0.85	1.00
33 KV FEEDERS										
			KIYUNGI S/S							
TPC	1.0	17	72.0	74.9	3498	3640	1.00	1.04	1.69	1.76
KIA	4.0	47.3	27.0	31.6	1312	1535	1.58	1.85	2.36	2.77
KIYUNG-B'MBUZI	4.0	7	150.0	175.5	7288	8526	2.15	2.51	2.60	3.04
B'MBUZI-RONGAI	4.0	121.5	58.6	68.6	2847	3331	5.82	6.81	9.86	11.53
KIYUNGI-T/SCH	4.0	13	131.0	153.3	6365	7446	3.48	4.07	4.21	4.93
T/SCH-MACHAME	4.0	22.2	25.0	29.2	1215	1421	0.45	0.53	0.77	0.90
TOTAL					18462	21146	3.28	3.87		
			NYUMBA YA MUNGU POWER STATION.							
MWANGA	4.0	29	14.5	17.0	704	824	0.52	0.60	0.73	0.85
			SAME S/S							
GONJA	4.0	53	5.8	6.8	282	330	0.31	0.37	0.51	0.60
SAME TOWN	4.0	0.01	7.3	8.5	355	415	0.0001	0.0002	0.0002	0.0002
TOTAL POWER AND POWER LOSS					19803	22715	4.78	5.65		

TABLE A 2.4

MEDIUM VOLTAGE SYSTEM LOSS CALCULATIONS 1991/1995 - ARUSHA REGION

Feeder Name	Growth Rate used %	Length (km)	1991 Max.I (Amps)	1995 Max.I (Amps)	1991 Power (Kw)	1995 Power (Kw)	1991 Loss (%)	1995 Loss (%)	1991 Voltage (%)	1995 Drop (%)
	11KV FEEDERS									
			THEMI S/S							
THEMI	4.00	3.4	100	117	1620	1895	0.82	0.96	1.36	1.59
			KILTEX S/S							
KILTEX	4.00	2.1	35	41	571	668	0.27	0.31	0.37	0.43
KILTEX FACT.	4.00	0.1	12	14	194	227	0.01	0.01	0.004	0.01
TOTAL					765	895	0.20	0.23		
			POWER HOUSE S/S							
MONDULI(i)	4.00	2.0	156	182	2526	2956	1.91	2.24	2.26	2.65
MONDULI(ii)	4.00	29.0	43	50	696	815	7.65	8.94	9.04	10.6
MONDULI(iii)	4.00	14.0	38	44	615	720	2.76	3.23	3.74	4.38
MONDULI TOTAL	4.00	45.0	156	182	2526	2956	4.69	5.49		
FEEDER 1	4.00	3.6	110	129	1781	2084	1.21	1.42	1.92	2.25
FEEDER 2 Town	4.00	2.2	176	206	2850	3334	2.14	2.5	2.67	3.1
FEEDER 2 Rural	4.00	30.0	28	33	455	532	3.62	4.2	4.89	5.7
FEEDER 2 Total					2850	3334	2.71	3.2		
FEEDER 3	4.00	7.2	203	237	3288	3846	3.58	4.19	5.93	6.94
TOTAL					7919	9265	2.74	3.20		
			TENGERU S/S							
TENGERU	4.00	6.0	34	40	548	641	1.32	1.54	1.71	2.00
			MAKUMIRA S/S							
MAKUMIRA	4.00	7.9	16	18	255	298	1.37	1.60	1.47	1.72
	33 KV FEEDERS									
			NJIRO GRID S/S							
INTER-CONNECTOR	4.00	7.0	280	328	13604	15915	4.01	4.69	4.85	5.67
INDUSTRIAL	4.00	9.4	170	199	8260	9662	2.78	3.25	3.75	4.39
			FROM POWER HOUSE S/S							
MOSHI/ARUSHA	4.00	48.6	65	76	3158	3694	2.58	3.02	4.37	5.12
TOTAL FOR ARUSHA REGION					21863	25577	5.02	5.88		

SAMPLE OF LV LINE LOSS CALCULATIONS

TABLE A3

DAR ES SALAAM REGION. 1991 LOADS

MAIN LINE	PHS	DIST. (KM)	NO. H/SES	RES. OH/KM	NO. SECT.	DISTR. FACTOR	LOAD AMP.	POWER KVA	LOSS KW	%LOSS	LOADING OF INDIVIDUAL PHASES IN AMPS R PH	Y PH	B PH	N PH	AVG LOAD	% inc. for unbalance	LOAD DENSITY Amp pe house
MBURAHATI NHC 200KVA																	
MAIN F2	3	0.74	213	0.70	3	0.52	137	94.3	15.09	15.2	180.0	130.0	100.0	55.0	136.7	11.2	1.9
S 1	1	0.41	16	0.32	5	0.44	31	7.1	0.11	1.5							
S 2	1	0.44	39	0.32	8	0.40	75	17.3	0.63	3.5							
S 3	1	0.36	35	0.70	8	0.40	67	15.5	0.92	5.6							
houses in spurs			90		Total for spurs			39.8	1.66	4.0							
houses in main line			123		Total for feeder			94.3	16.75	16.9							
MAIN F1	3	0.62	317	0.32	5	0.44	130	89.7	4.43	4.7	200.0	120.0	70.0	60.0	130.0	24.1	1.2
S1	1	0.38	36	0.70	8	0.40	44	10.2	0.41	3.8							
S2	1	0.40	29	0.70	8	0.40	36	8.2	0.29	3.3							
S3	1	0.30	32	0.70	7	0.41	39	9.1	0.27	2.8							
S4	1	0.25	22	0.70	6	0.42	27	6.2	0.11	1.6							
houses in spurs			119		Total for spurs			33.7	1.07	3.0							
houses in main line			198		Total for feeder			89.7	5.50	5.8							
Total for the Transformer			530				0	184	22.25	11.5							
MWENGE BUS STOP S/S 315 KVA																	
MAIN F1	3	0.54	136	0.32	5	0.44	112	77.1	2.84	3.5	125.0	100.0	110.0	18.0	111.7	1.7	2.5
S1	3	0.14	10	0.70	4	0.47	8	5.7	0.01	0.2							
S2	3	0.13	18	0.70	4	0.47	15	10.2	0.03	0.3							
S3	3	0.11	10	0.70	4	0.47	8	5.7	0.01	0.1							
S4	3	0.14	7	0.70	4	0.47	6	4.0	0.00	0.1							
houses in spurs			45		Total for spurs			25.5	0.05	0.2							
houses in main line			91		Total for feeder			77.1	2.89	3.6							
MAIN F2	3	0.23	41	0.32	3	0.52	33	23.0	0.13	0.5	40.0	40.0	20.0	20.0	33.3	20.0	2.4
S1	3	0.09	13	0.70	2	0.63	11	7.3	0.01	0.2							
S2	3	0.08	6	0.70	2	0.63	5	3.4	0.00	0.1							
houses in spurs			19		Total for spurs			10.7	0.02	0.1							
houses in main line			22		Total for feeder			23.0	0.14	0.6							
MAIN F3	3	0.30	31	0.32	3	0.52	28	19.1	0.115	0.57	45.0	28.0	10.0	30.0	27.7	65.9	2.7
S1	3	0.12	3	0.70	3	0.52	3	1.8	0.001	0.05							
S2	3	0.08	8	0.32	2	0.63	7	4.9	0.002	0.05							
houses in spurs			11		Total for spur			6.8	0.003	0.05							
houses in main line			20		Total for feeder			19.1	0.118	0.59							
Total for the Transformer			208				0	119	3.155	2.52							
ILALA ARUSHA STREET S/S 315KVA																	
MAIN F1	3	0.45	117	0.23	6	0.42	163	112.7	3.48	2.93	200.0	150.0	140.0	80.0	163.3	10.6	4.2
S1	3	0.07	11	0.70	1	1.00	15	10.6	0.03	0.31							
S2	3	0.11	9	0.70	3	0.52	13	8.7	0.02	0.21							
S3	3	0.15	14	0.23	3	0.52	20	13.5	0.02	0.14							
S4	3	0.12	9	0.23	3	0.52	13	8.7	0.01	0.07							
S5	3	0.11	5	0.70	2	0.63	7	4.8	0.01	0.14							
houses in spurs			48		Total for spur			46.2	0.1	0.18							
houses in main line			69		Total for feeder			112.7	3.57	3.01							
MAIN F2	3	0.57	223	0.32	8	0.40	213	147.2	9.96	6.43	160.0	260.0	220.0	20.0	213.3	4.0	2.9
S1	3	0.09	6	0.70	3	0.52	6	4.0	0.00	0.08							
S2	3	0.15	11	0.70	6	0.42	11	7.3	0.01	0.19							
S3	3	0.21	11	0.70	6	0.42	11	7.3	0.02	0.27							
S4	3	0.15	18	0.70	5	0.44	17	11.9	0.04	0.33							
S5	3	0.05	6	0.70	2	0.63	6	4.0	0.00	0.05							
S6	1	0.44	33	0.70	10	0.39	95	21.8	2.13	9.28							
S7	3	0.05	5	0.70	2	0.63	5	3.3	0.00	0.04							
houses in spurs			90		Total for spur			59.4	2.2	3.53							
houses in main line			133		Total for feeder			147.2	12.17	7.86							
MAIN F3	3	0.24	35	0.23	2	0.63	45	31.1	0.21	0.65	30.0	50.0	55.0	20.0	45.0	12.3	3.9
S1	1	0.15	21	0.23	5	0.44	81	18.6	0.20	1.02							
houses in spurs			21		Total for spur			18.6	0.2	1.02							
houses in main line			14		Total for feeder			31.1	0.41	1.26							
Total for the Transformer			375				0	404	16	3.80							

NOTE:

The computations for line losses are made using balanced load conditions
The increase of losses due to existing unbalance is presented separately
The average load in Amps per house is also presented for each feeder

ANALYSIS OF SYSTEM LOSSES AND SALES BY VOLTAGE LEVEL

Table A 4

	Dar es Salaam	Tanga	Arusha	Moshi
TARIFF **Energy sales KWh/month**				
Residential	18,498,636	1,953,995	2,821,276	2,051,777
Light Commercial	4,848,489	879,279	820,261	772,778
Light Industrial	1,433,871	567,801	400,680	431,933
Gen Purpose LV, with KVA charge	7,051,182	537,082	818,093	562,809
High Voltage Supply	6,424,823	1,186,309	2,268,517	1,128,851
Public lighting	226,412	48,592	75,739	75,585
TANESCO staff	094,322	41,988	13,610	27,408
NUWA (Water supply)	3,532,613	271,280		
Agriculture	152,744	1,574,275	49,895	1,385,144
High Voltage Supply -energy intensive	7,904,800	2,662,885	0	0
Zanzibar	5,702,050	0,000	0	0
TOTAL UNITS	55,869,942	9,723,486	7,268,071	6,436,286
Demand in KVA				
Gen Purpose LV, with KVA charge	36,124	2,194	3,635	5,048
High Voltage Supply	27,127	5,155	7,625	3,037
Zanzibar KVA	9,045			
Agriculture	755	6,946	0,363	4,110
High Voltage Supply -energy intensive	18,802	10,748	0	0
NUWA (Water supply)	4,555	589	0	0
TOTAL KVA	87,363	25,633	11,623	12,195

BREAKDOWN OF CONSUMPTION TO VOLTAGE LEVEL

Energy supply:

in KWh per month	Dar es Salaam	Tanga	Arusha	Moshi
132 kV supplies	5,702,050			
33 kV supplies	8,336,800	2,662,885	0	0
11 kV supplies	5,992,823	1,457,590	2,268,517	1,128,851
Supplies at Substations	7,203,926	2,111,357	867,988	1,947,953
LV supplies	25,101,730	3,491,654	4,131,566	3,359,482
Supply from M'dizi	3,532,613			
TOTAL UNITS	55,869,942	9,723,486	7,268,071	6,436,286

in per unit	Dar es Salaam	Tanga	Arusha	Moshi
132 kV supplies	0.11			
33 kV supplies	0.16	0.27	0.00	0.00
11 kV supplies	0.11	0.15	0.31	0.18
Supplies at Substations	0.14	0.22	0.12	0.30
LV supplies	0.48	0.36	0.57	0.52

Power demand

KVA Demand (non-coincident)	Dar es Salaam	Tanga	Arusha	Moshi
132 kV supplies	9,045			
33 kV supplies	19,802	10748.333	0.000	0.000
11 kV supplies	26,127	5211.333	7625.333	3037.182
Supplies at Substations	36,879	9140.583	3998.083	9157.909
LV supplies				

Computation of coincident peak demand

	Co.F	LF	Dar es Salaam	Co.F	LF	Tanga	Co.F	LF	Arusha	Co.F	LF	Moshi
132 kV supplies	1.0		9,045									
33 kV supplies	.500		9,901	.500		5,374	.000		0	.000		0
11 kV supplies	.200		5,225	.300		1,563	.250		1,906	.250		0,759
At Substations	.200		7,376	.200		1,828	.200		0,800	.200		1,832
LV supplies		.550	63,388		.500	9,699		.500	11,477		.500	9,332
Total system peak			94,935			18,465			14,183			11,923

P.U break down of coincident peak demand	Dar es Salaam	Tanga	Arusha	Moshi
132 kV supplies	0.10			
33 kV supplies	0.10	0.29	0.00	0.00
11 kV supplies	0.06	0.08	0.13	0.06
At Substations	0.08	0.10	0.06	0.15
LV supplies	0.67	0.53	0.81	0.78

Note:

Co.F - Coincidence factor
LF - Load factor

Cont. page 2

ANALYSIS OF SYSTEM LOSSES AND SALES BY VOLTAGE LEVEL

Table A 4 Cont.

ANALYSIS OF PEAK POWER (kVA) FLOW:

	loss %		loss %		loss %		loss %	
33 kV input		98,707		18,440		16,756		14,231
33 kV line loss	.020	1,973	.012	221	.037	619	.038	540
33 kV Supplies		9,901		5,374		0		0
Power to SS		82,929		12,537		13,483		11,204
SS t/f loss	.015	1,244	.015	188	.015	202	.015	168
11 kV loss	.028	2,285	.020	247	.057	759	.030	331
11 kV Supplies		5,225		1,563		1,906		759
To LV from 33 kV		3,904		3,254		2,654		2,487
To LV from 11 kV		74,175		7,593		10,616		9,946
Power to LV t/f		78,079		10,847		13,270		12,433
LV t/f loss	.015	1,171	.015	163	.015	199	.015	186
Supplies at SS		7,376		170		800		1,832
LV line loss	.089	6,144	.078	816	.065	794	.105	1,083
LV Supplies		63,388		9,699		11,477		9,332

Analysis of peak contribution in p.u.

33 kV input	1.000	1.000	1.000	1.000
33 kV line loss	0.020	0.012	0.037	0.038
33 kV Supplies	0.100	0.291	0.000	0.000
Power to SS	0.840	0.680	0.805	0.787
SS t/f loss	0.013	0.010	0.012	0.012
11 kV line loss	0.023	0.013	0.045	0.023
11 kV Supplies	0.053	0.085	0.114	0.053
Power to LV t/f	0.791	0.588	0.792	0.874
LV t/f loss	0.012	0.009	0.012	0.013
LV line loss	0.062	0.044	0.047	0.076
LV Supplies	0.717	0.535	0.733	0.784
Sum of losses	0.130	0.089	0.154	0.162

ANALYSIS OF ENERGY (KWh) FLOW:

	losses pu.		losses pu.		losses pu.		losses pu.	
33 kV input		46,374,783		10,258,421		8,147,685		7,232,146
33 kV line loss	.015	695,468	.009	92,318	.028	225,929	.029	205,954
33 kV Supplies		7,578,909		2,662,885		0,000		0
Power to SS		36,532,948		5,146,245		6,602,955		6,460,458
SS t/f loss	.015	547,873	.015	77,177	.015	99,022	.015	96,885
11 kV loss	.021	755,360	.015	76,019	.043	279,012	.023	143,110
11 kV Supplies		5,448,020		1,457,590		2,268,517		1,128,851
To LV from 33 kV		1,567,458		2,356,973		1,318,801		565,735
To LV from 11 kV		29,781,695		3,535,459		3,956,403		5,091,613
Power to LV t/f		31,349,152		5,892,432		5,275,204		5,657,347
LV t/f loss	.015	470,133	.015	88,367	.015	79,111	.015	84,841
Supplies at SS		6,549,024		2,111,357		867,988		1,947,953
LV line loss	.062	1,510,241	.055	201,054	.046	196,540	.074	265,071
LV Supplies		22,819,755		3,491,654		4,131,566		3,359,482

Energy flow (consumption and losses) in p.u.

33 kV input	1.000	1.000	1.000	1.000
33 kV line loss	0.015	0.009	0.028	0.028
33 kV Supplies	0.163	0.260	0.000	0.000
Power to SS	0.788	0.502	0.810	0.893
SS t/f loss	0.012	0.008	0.012	0.013
11 kV line loss	0.016	0.007	0.034	0.020
11 kV Supplies	0.117	0.142	0.278	0.156
Power to LV t/f	0.676	0.574	0.647	0.782
LV t/f loss	0.010	0.009	0.010	0.012
LV line loss	0.033	0.020	0.024	0.037
LV Supplies	0.633	0.546	0.614	0.734
Sum of losses in pu.	0.086	0.052	0.108	0.110
System Load Factor in pu.		76.2	66.6	0.890

Notes to computations:

Allocation of LV supplies (pu) by capacity:								
by voltage level:	33 kV	11 kV	33 kV	11 kV	33 kV	11 kV	33 kV	11 kV
At Substations	.05	.95	.30	.70	.20	.80	.20	.80
Fed from LV lines	.05	.95	.40	.60	.25	.75	.10	.90
Allocation of LV supplies (pu) by energy::								
by voltage level:	33 kV	11 kV	33 kV	11 kV	33 kV	11 kV	33 kV	11 kV
At Substations	.05	.95	.30	.70	.20	.80	.20	.80
Fed from LV lines	.05	.95	.40	.60	.25	.75	.10	.90
LLF/LF for MV		0.75		0.75		0.75		0.75
LLF/LF for LV		0.70		0.70		0.70		0.70

TABLE A 5

LOADING DENCITIES OF MV FEEDERS

FEEDER NAME	SUPPLIED AREA(SQ.KM)	PERIMETER KM	PEAK CURRENT AMP.	PEAK VOLTAGE KV.	PEAK POWER KVA	DENSITY KVA/SQ.KM
MBEZI S/S						
LUGALO	9.30	8.40	180.00	10.50	3274	352
PACKERS	6.00	10.70	60.00	10.80	1122	187
KUNDUCHI	18.20	20.30	180.00	10.00	3118	171
MIKOCHENI S/S						
MK1	3.50	17.50	155.00	10.50	2819	805
MK2	9.40	15.30	285.00	10.00	4936	525
MK3	3.10	8.20	40.00	10.90	755	244
MK4	2.50	10.60	174.00	10.70	3225	1290
OYSTERBAY S/S						
O2	2.20	6.70	135.00	10.70	2502	1137
O3	3.90	15.00	296.00	10.00	5127	1315
O4	4.30	10.00	177.30	10.50	3225	750
O5	1.90	7.30	115.00	10.50	2092	1101
O6	3.10	10.70	120.00	10.50	2182	704
UBUNGO S/S						
U1	13.00	17.40	175.00	10.50	3183	245
U2	5.10	11.50	140.00	10.50	2546	499
U7	3.60	4.50	40.00	10.90	755	210
U8	4.70	9.70	70.00	10.90	1322	281
FACTORY ZONE I S/S						
F2	2.00	5.60	170.00	10.80	3180	1590
F5	2.20	7.30	110.00	10.80	2058	935
ILALA S/S						
D1	2.30	8.70	250.00	10.50	4547	1977
D2	0.80	6.00	190.00	10.50	3456	4319
D3	1.10	5.40	175.00	10.50	3183	2893
D7	2.70	7.20	110.00	10.70	2039	755
D8	3.00	3.00	10.00	10.90	189	63
D9	0.90	5.00	145.00	10.80	2712	3014
D10	5.20	9.90	240.00	10.30	4282	823
CITY CENTER S/S						
C2	1.40	7.30	75.00	10.90	1416	1011
C3	2.60	3.00	240.00	10.90	4531	1743
C4	0.50	3.20	270.00	10.80	5051	10102
C5	0.40	3.80	195.00	10.90	3682	9204
C6	1.90	7.30	118.00	11.00	2248	1183
C8	1.30	1.40	180.00	10.90	3398	2614
KURASINI S/S						
PORT	2.60	8.60	156.30	10.50	2843	1093
INDUSTRIAL	4.90	10.50	185.00	10.50	3365	687
KILWA/ROAD	22.00	27.50	98.00	10.80	1833	83
33 KV FEEDERS TANGA REIGION						
MAZINDE	29.019		34.00	33.00	1943	0.07
TORONTO	12.982		11.20	33.00	640	0.05
HANDENI	22.516		7.00	33.00	400	0.02
MAGUNGA II	6.539		21.00	33.00	1200	0.18
11 KV FEEDERS TANGA REIGION						
LUSHOTO	42.326		34.80	11.00	663	0.02
MUHEZA II	7.844		30.70	11.00	585	0.07
LANZONI II	6.577		69.10	11.00	1317	0.20
MARAMBA	12.230		55.20	11.00	1052	0.09
TANGA TOWN	17.40	36.70	520.00	11.00	9908	569

PARTICULARS OF L.V TRANSFORMER LOADING DATA

TABLE A 6

SAMPLE DATA FROM DAR ES SALAAM

TRANSFORMER LOCATION IDENTITY	TRANSFORMER NAME	CAPACITY KVA	RATED CURR [AMPS]	TRANSFORMER LOADS (AMPS) RPH	YPH	BPH	N	TOTAL LOAD	AVERAGE LOAD	% LOADING OF TRANSF.	POWER KW p.f=0.9	AREA KM2	LOAD DENSITY [W/Msq.]
				OYSTERBAY - MSASANI PENINSULAR									
11 KV FEEDER: O6													
O6.25	TAZAMA FLATS	200	288	77	125	130	51	332	111	38.4	69	0.129	0.5
O6.30E2		315	455	380	420	199	162	999	333	73.2	208	0.084	2.5
O6.30E8		315	455	406	405	410	79	1221	407	89.5	254	0.105	2.4
O6.34	KIMARIO	315	455	330	400	380	46	1110	370	81.3	231	0.113	2.0
O6.34W4	MAHENGE	200	288	260	350	210	58	820	273	94.9	170		
O6.39E4		315	455	280	300	304	125	884	295	64.8	184	0.208	0.9
O6.39E8	OYSTERBAY HOTEL	300	433	310	315	303	42	928	309	71.4	193	0.119	1.6
O6.43W2		200	288	140	130	70	80	340	113	39.4	71		
O6.51		500	722	420	360	300	182	1080	360	49.9	224	0.209	1.1
O6.56E3		200	288	285	275	204	147	764	255	88.4	159	0.119	1.3
11 KV FEEDER: O3													
O3.6E13N1		500	722	75	98	64	59	237	79	10.9	49	0.029	1.7
O3.245E14		300	433	243	143	156	74	542	181	41.7	113	0.067	1.7
O3.61W4		500	722	231	196	290	106	717	239	33.1	149		
O3.59	DERUA	500	722	320	360	200	120	880	293	40.6	183	0.123	1.5
O3.63E4	ITALIAN VILLAGE	315	455	300	340	290	115	930	310	68.1	193	0.108	1.8
O3.64	EUROPA S/MARKET	315	455	208	272	302	113	782	261	57.3	163	0.078	2.1
O3.65E3		300	433	230	180	220	103	630	210	48.5	131	0.075	1.7
O3.68W4	RUSSIAN VILLAGE	315	455	300	400	400	112	1100	367	80.6	229	0.192	1.2
O3.70E4	DARTADINE	500	722	410	410	380	116	1200	400	55.4	249	0.149	1.7
O3.75	CANADIAN VILLAGE	500	722	310	290	170	26	770	257	35.5	160	0.135	1.2
O3.75W4	BAOBAB VILLAGE	300	433	388	412	600	247	1400	467	107.8	291	0.063	4.6
O3.78E4	FINNIDA VILLAGE	315	455	420	180	380	220	980	327	71.8	204	0.067	3.0
O3.81	SALIM A. SALIM	315	455	340	280	400	94	1020	340	74.7	212	0.065	3.3
O3.3N2		300	433	210	192	180	34	582	194	44.8	121	0.087	1.4
O3.4A	DRIVE IN TANESCO	315	455	222	236	236	118	694	231	50.8	144	0.086	1.7
11 KV FEEDER: MK1													
MK1-O3.20E45E1A		315	455	320	340	340	62	1000	333	73.3	208	0.062	3.4
MK1-O3.20E45E4A		500	722	474	418	430	121	1322	441	61.0	275	0.141	1.9
MK1-O3.20E45E9	NIC FLATS	500	722	202	164	202	118	568	189	26.2	118	0.061	1.9
MK1-O3.20E45E45S3		500	722	318	424	340	140	1082	361	50.0	225	0.097	2.3
OVERALL AVERAGE FOR TRANSFORMER STATIONS (FEEDERS O6, O3, & MK1)											4937	2.771	1.8
				MWENGE AREA:									
11 KV FEEDER: MK2													
	MWENGE P/SCH	200	288	170	180	170	158	520	173	60.2	108	0.134	0.8
	MWENGE B/STOP	315	455	210	168	140	68	518	173	37.9	108	0.164	0.7
OVERALL AVERAGE FOR TRANSFORMER STATIONS FEEDER MK2											216	0.298	1.5

NOTE:

The high value of neutral current is observable in almost all transformers

The load density (Watts/meter sq.) provides important data for planning purposes

PREPARED BY ESMAP/TANESCO STUDY UNIT.

Table A.7.

HISTORICAL LOAD DEVELOPMENT IN DAR ES SALAAM ARUSHA, MOSHI AND TANGA

ANNUAL LOADS IN GWH

	Arusha	Moshi	Tanga	Dar es S.	Total/4R
1979	48.8	23.4	68.5	370.7	511.4
1980	49.6	22.4	76.2	379.8	528.0
1981	50.8	23.0	76.7	385.4	535.9
1982	53.4	21.7	74.7	389.7	539.5
1983	57.4	33.6	68.0	361.1	520.1
1984	57.9	36.4	63.2	368.2	525.7
1985	56.1	39.4	74.4	392.4	562.3
1986	64.0	43.8	85.9	415.1	608.8
1987	66.9	49.5	73.9	453.6	643.9
1988	70.4	65.3	95.3	491.9	722.9

% annual load increase

	Arusha	Moshi	Tanga	Dar es S.	Total/4R
1979 – 1980	1.6	−4.3	11.2	2.5	3.2
1980 – 1981	2.4	2.7	0.7	1.5	1.5
1981 – 1982	5.1	−5.7	−2.6	1.1	0.7
1982 – 1983	7.5	54.8	−9.0	−7.3	−3.6
1983 – 1984	0.9	8.3	−7.1	2.0	1.1
1984 – 1985	−3.1	8.2	17.7	6.6	7.0
1985 – 1986	14.1	11.2	15.5	5.8	8.3
1986 – 1987	4.5	13.0	−14.0	9.3	5.8
1987 – 1988	5.2	31.9	29.0	8.4	12.3

% annual increase within selected periods

	Arusha	Moshi	Tanga	Dar es S.	Total/4R
1979 – 1982	3.0	−2.5	2.9	1.7	1.8
1979 – 1983	4.1	14.5	−3.7	−1.7	−0.5
1979 – 1984	3.5	16.5	−6.2	−1.5	−0.6
1982 – 1987	3.8	14.7	−0.2	2.6	3.0
1983 – 1987	3.1	8.1	1.7	4.7	4.4
1984 – 1987	3.7	8.0	4.0	5.4	5.2
1985 – 1987	6.0	7.9	−0.2	4.9	4.6
1982 – 1988	4.7	20.2	4.1	4.0	5.0
1983 – 1988	4.2	14.2	7.0	6.4	6.8
1984 – 1988	5.0	15.7	10.8	7.5	8.3
1985 – 1988	7.9	18.3	8.6	7.8	8.7
1979 – 1988	4.2	12.1	3.7	3.2	3.9

ANNEX B

TRANSMISSION SYSTEM - LOAD FLOW STUDIES

TRANSMISSION SYSTEM - LOAD FLOW STUDIES

List of Figures and Tables

Key results of load flow studies

The key results of load flow studies undertaken are provided in a number of tables in this Annex. Among the data presented are total system losses (including the contribution from the various sections of the network), bus voltages, the generation particulars at the power stations, reactive compensation applied (both inductive and capacitive), tap positions of voltage transformation buses and the power flows along key transmission lines.

Load duration curve for Thursday, Nov. 14, 1991

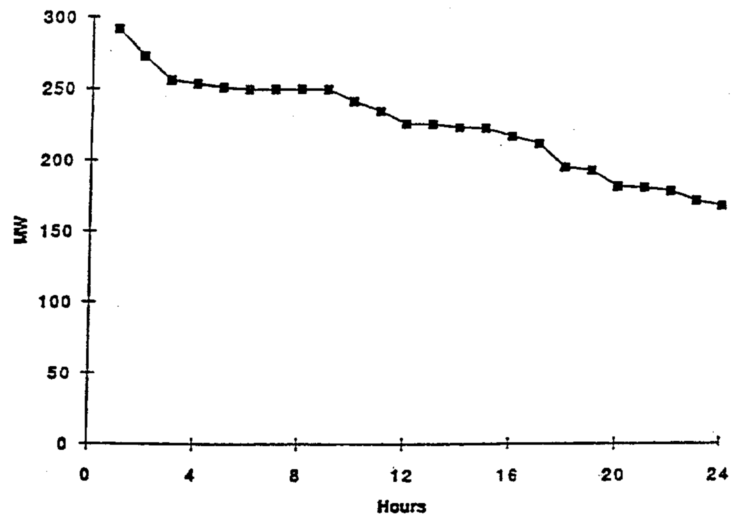


Figure B1

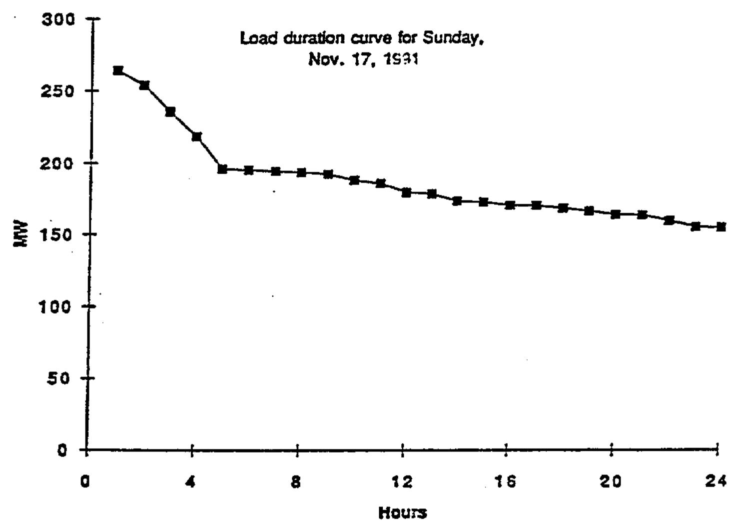


Figure B2

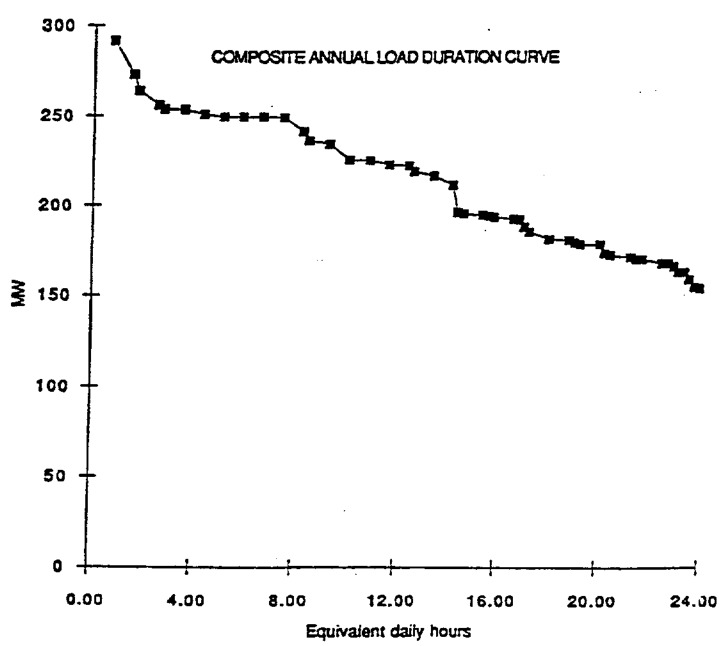
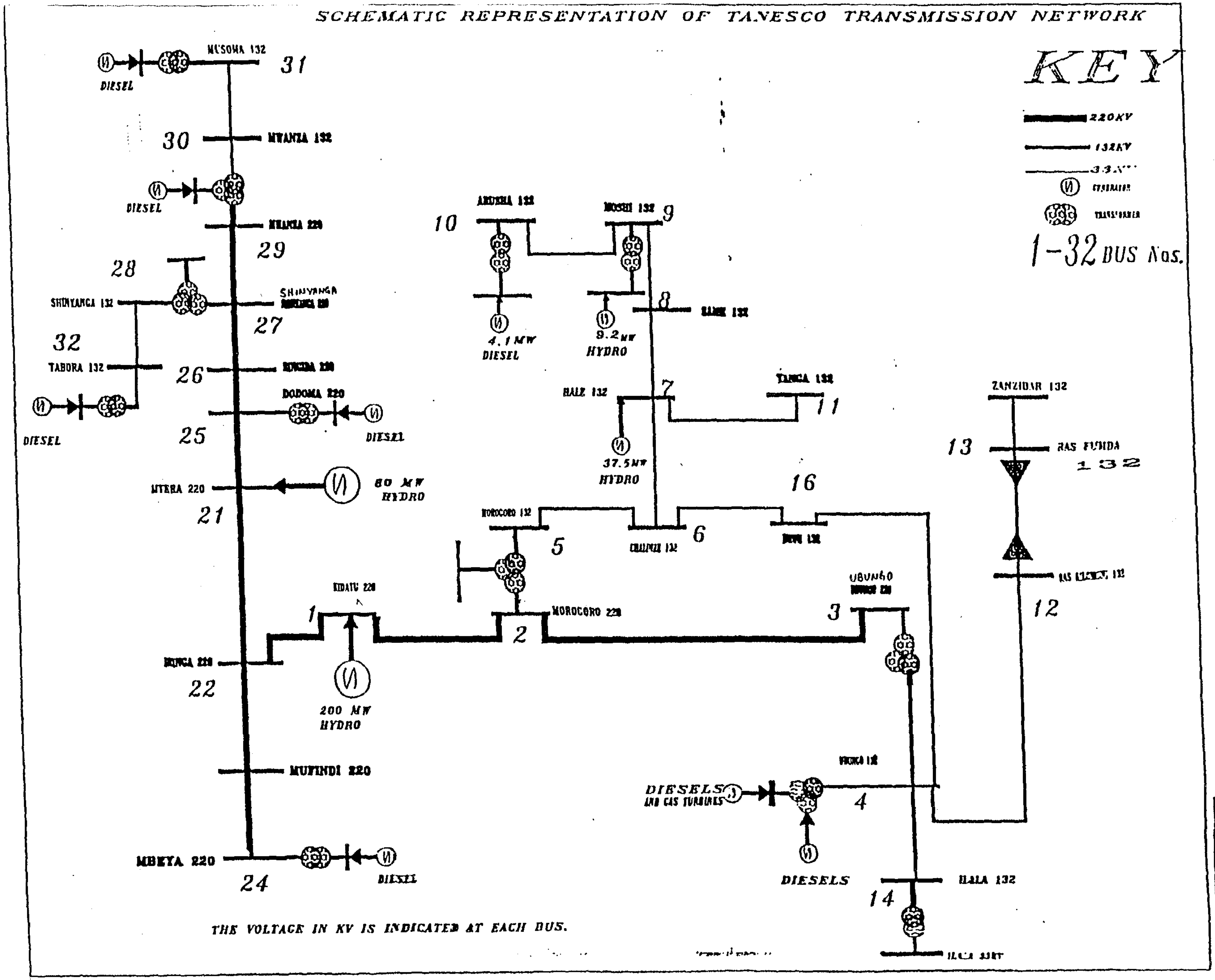


Figure B3



SCHEMATIC REPRESENTATION OF TANESCO TRANSMISSION NETWORK
KEY
220KV
132KV
1-32 BUS Nos.
MUSOMA 132
31
DIESEL
30
MWANZA 132
DIESEL
MWANZA 220
29
28
SHINYANGA 132
SHINYANGA 220
27
32
TABORA 132
26
25
DODOMA 220
DIESEL
DIESEL
MTERA 220
80 MW HYDRO
21
ARUSHA 132
10
MOSHI 132
9
4.1 MW DIESEL
9.2 MW HYDRO
8
HALE 132
7
TANGA 132
11
37.5 MW HYDRO
ZANZIBAR 132
13
RAS FUMBA 132
16
MOROGORO 132
5
6
12
UBUNGO 220
3
1
MOROGORO 220
2
22
200 MW HYDRO
MUFINDI 220
DIESELS AND GAS TURBINES
4
DIESELS
MBEYA 220
24
DIESEL
ILALA 132
14
THE VOLTAGE IN KV IS INDICATED AT EACH BUS.

Figure B4

Table B1

FORECAST YEARLY SYSTEM LOADS AND POWER BALANCE

MAXIMUM EXPECTED NIGHT PEAK LOADS FOR YEAR (BY GRID SUBSTATION)

	Bus number	1991 MW	1991 MVAR	1992 MW	1992 MVAR	1993 MW	1993 MVAR	1994 MW	1994 MVAR	1995 MW	1995 MVAR	1996 MW	1996 MVAR	1997 MW	1997 MVAR	1998 MW	1998 MVAR	1999 MW	1999 MVAR	2000 MW	2000 MVAR	2001 MW	2001 MVAR
KIDATU	1	6.6	2.8	7	3	7.5	3.6	7.9	3.8	8.5	4.1	9.0	4.4	9.8	4.6	10.2	4.9	10.9	3.9	11.6	4.2	12.3	4.9
MOROGORO-HV	2	0.0	0.0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UBUNGO-HV	3	0.0	0.0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UBUNGO-LV	4	50.3	30.2	53.6	32.2	57.4	27.7	61.4	29.7	65.7	31.8	70.3	34.0	75.2	36.4	80.4	38.9	86.1	31.2	92.1	33.4	98.5	35.9
MOROGORO-LV	5	15.7	7.9	16.7	8.4	17.8	8.6	18.9	9.2	20.2	9.8	21.5	10.4	22.9	11.1	24.4	11.8	26.0	9.4	27.6	10.0	29.4	11.6
CHALINZE	6	2.3	1.1	2.4	1.2	2.6	1.2	2.7	1.3	2.9	1.4	3.1	1.5	3.3	1.6	3.5	1.7	3.7	1.4	4.0	1.4	4.2	1.7
HALE	7	3.4	1.7	3.6	1.8	3.8	1.9	4.1	2.0	4.3	2.1	4.6	2.2	4.9	2.4	5.3	2.5	5.6	2.0	6.0	2.2	6.3	2.5
SAME	8	2.3	1.1	2.4	1.2	2.6	1.2	2.7	1.3	2.9	1.4	3.1	1.5	3.3	1.6	3.5	1.7	3.7	1.4	4.0	1.4	4.2	1.7
MOSHI	9	17.9	10.8	19.1	11.5	20.3	9.8	21.7	10.5	23.1	11.2	24.6	11.9	26.2	12.7	27.9	13.5	29.7	10.8	31.6	11.5	33.7	13.3
ARUSHA	10	20.1	12.0	21.4	12.8	22.8	11.0	24.3	11.7	25.9	12.5	27.5	13.3	29.3	14.2	31.2	15.1	33.3	12.1	35.4	12.9	37.7	14.9
TANGA	11	22.3	13.4	23.8	14.3	25.3	12.3	27.0	13.1	28.7	13.9	30.6	14.8	32.6	15.8	34.7	16.8	37.0	13.4	39.4	14.3	41.9	16.6
RAS KIRO	12	0.0	0.0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ZANZIBAR	13	12.3	7.4	13.1	7.9	14.0	6.7	14.9	7.2	15.8	7.7	16.9	8.2	17.9	8.7	19.1	9.2	20.4	7.4	21.7	7.9	23.1	8.1
ILALA	14	56.0	33.6	59.6	35.8	63.6	30.8	68.2	33.0	73.0	35.3	78.1	37.8	83.6	40.4	89.4	43.3	95.7	34.7	102.4	37.2	109.6	43.3
RUVU	16	5.6	3.4	6	3.6	6.4	3.1	6.8	3.3	7.2	3.5	7.7	3.7	8.2	4.0	8.8	4.2	9.3	3.4	9.9	3.6	10.6	4.2
MTERA	21	0.0	0.0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IRINGA	22	5.1	2.5	5.4	2.7	5.8	2.8	6.1	3.0	6.5	3.2	6.9	3.4	7.4	3.6	7.9	3.8	8.4	3.0	8.9	3.2	9.5	3.8
MUFINDI	23	20.1	12.1	21.4	12.9	22.3	10.8	23.1	11.2	24.1	11.6	25.0	12.1	26.0	12.6	27.1	13.1	28.2	10.2	29.3	10.6	30.5	12.0
MBEYA	24	14.6	8.7	15.5	9.3	16.5	8.0	17.6	8.5	18.7	9.1	19.9	9.6	21.2	10.3	22.6	10.9	24.1	8.7	25.7	9.3	27.3	10.8
DODOMA	25	6.2	3.1	6.6	3.3	7.0	3.4	7.5	3.6	8.0	3.9	8.5	4.1	9.0	4.4	9.6	4.7	10.3	3.7	10.9	4.0	11.6	4.6
SINGIDA	26	1.7	0.8	1.8	0.9	1.9	0.9	2.0	1.0	2.2	1.1	2.3	1.1	2.5	1.2	2.6	1.3	2.8	1.0	3.0	1.1	3.2	1.3
SHINYAN-HV	27	0.0	0.0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SHINYAN-LV	28	9.4	5.6	10	6	10.7	5.2	11.3	5.5	12.1	5.8	12.9	6.2	13.7	6.6	14.6	7.1	15.5	5.6	16.5	6.0	17.6	7.0
MWANZA-HV	29	0.0	0.0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MWANZA-LV	30	11.2	6.8	11.9	7.2	13.0	6.3	14.1	6.8	15.4	7.5	16.8	8.1	18.3	8.9	20.0	9.7	21.8	7.9	23.7	8.6	25.8	10.2
MUSOMA	31	5.5	2.8	5.9	3	6.3	3.0	6.7	3.2	7.1	3.4	7.6	3.7	8.1	3.9	8.6	4.2	9.2	3.3	9.8	3.5	10.4	4.1
TABORA	32	3.4	1.7	3.6	1.8	3.8	1.8	4.1	2.0	4.3	2.1	4.6	2.2	4.9	2.4	5.3	2.5	5.6	2.0	6.0	2.2	6.3	2.5
TOTAL LOAD at grid substations		291.8	169.8	310.8	180.8	331.3	160.3	353.2	170.9	376.6	182.2	401.6	194.2	428.2	207.1	456.7	220.9	487.0	176.8	518.4	188.5	554.0	218.8

LOAD COMPOSITION BY REGION IN MW, MVAR

	1991 MW	1991 MVAR	1992 MW	1992 MVAR	1993 MW	1993 MVAR	1994 MW	1994 MVAR	1995 MW	1995 MVAR	1996 MW	1996 MVAR	1997 MW	1997 MVAR	1998 MW	1998 MVAR	1999 MW	1999 MVAR	2000 MW	2000 MVAR	2001 MW	2001 MVAR
North-East Load	68.3	40.2	72.7	42.8	77.4	37.5	82.5	39.9	87.8	42.5	93.5	45.2	99.6	48.2	106.1	51.3	113.0	41.0	120.3	43.7	128.1	50.6
East Load	139.9	82.5	149.0	87.9	159.3	77.0	170.2	82.3	181.9	88.0	194.4	94.0	207.8	100.5	222.1	107.4	237.4	86.2	253.7	92.1	271.2	107.1
North West Load	37.4	20.8	39.8	22.2	42.7	20.6	45.6	22.1	49.1	23.8	52.7	25.5	56.5	27.3	60.7	29.3	65.1	23.6	69.9	25.4	75.0	29.6
South West Load	46.3	26.2	49.3	27.9	52.0	25.1	54.8	26.5	57.8	27.9	60.9	29.6	64.3	31.1	67.9	32.8	71.5	26.0	75.5	27.4	79.6	31.5
Total Load (without losses)	291.8	169.8	310.8	180.8	331.3	160.3	353.2	170.9	376.6	182.2	401.6	194.2	428.2	207.1	456.7	220.9	487.0	176.8	518.4	188.5	554.0	218.8
System peak losses in p.u	0.070		0.080		0.068		0.070		0.050		0.042		0.043		0.048		0.050		0.050		0.050	
Total load plus losses	312.3		335.7		353.9		378.0		395.5		418.4		446.6		478.6		511.4		545.4		581.7	

HYDRO GENERATION BY REGION IN MW

	Existing plant	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Hydro Generation												
North East NYM	2 x 4	8	8	8	8	8	8	8	8	8	8	8
Hale	2 x 10.5	21	21	21	21	21	21	21	21	21	21	21
Pangani		13	13	13	13	60	60	60	60	60	60	60
Total		42	42	42	42	89	89	89	89	89	89	89
North West Mtera	2 x 40	80	80	80	80	80	80	80	80	80	80	80
South West Kidatu	4 x 50	200	200	200	200	200	200	200	200	200	200	200
L. Kihansi									153	153	153	153
U. Kihansi												47
Total		200	200	200	200	200	200	200	353	353	353	400
Total Hydro capability		322	322	322	322	369	369	369	522	522	522	569

HYDRO EXPORT (+) IMPORT (-) BY REGION (IN MW)
(Hydro available in region less load)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
North-East	-26	-31	-35	-40	1	-5	-11	-17	-24	-31	-39
East	-140	-149	-159	-170	-182	-194	-208	-222	-237	-254	-271
North West	43	40	37	34	31	27	23	19	15	10	5
South West	154	151	148	145	142	139	136	285	281	278	320
Total excess hydro capability in MW in system (inclusive of losses)	9.7	-13.7	-31.9	-56.0	-26.5	-49.4	-77.6	43.4	10.6	-23.4	-12.7

TRANSMISSION LINE DATA Table B.1

(used for load flow studies)

LINE (with bus numbers)		Resistance	Inductance	Capacitance	Thermal rating
1 KIDATU	2 MOROGORO-HV	0.007	0.055	34.94	832
1 KIDATU	22 IRINGA	0.025	0.136	20.83	252
2 MOROGORO-HV	1 KIDATU	0.007	0.055	34.94	832
2 MOROGORO-HV	3 UBUNGO-HV	0.018	0.149	23.48	416
4 UBUNGO-LV	16 RUVU	0.049	0.112	2.31	92
4 UBUNGO-LV	12 RAS-KIRO	0.043	0.098	2.02	92
4 UBUNGO-LV	14 ILALA	0.012	0.026	0.50	92
5 MOROGORO-LV	6 CHALINZE	0.086	0.196	4.03	92
6 CHALINZE	16 RUVU	0.053	0.119	2.46	92
6 CHALINZE	7 HALE	0.184	0.418	8.60	92
7 HALE	8 SAME	0.210	0.478	9.83	92
7 HALE	11 TANGA	0.063	0.143	2.95	92
8 SAME	7 HALE	0.210	0.478	9.83	92
8 SAME	9 MOSHI	0.053	0.119	2.46	92
9 MOSHI	10 ARUSHA	0.079	0.177	3.70	92
12 RAS-KIRO	13 ZANZIBAR	0.052	0.030	36.35	92
21 MTERA	22 IRINGA	0.016	0.089	13.67	252
21 MTERA	25 DODOMA	0.022	0.118	17.97	252
22 IRINGA	23 MUFINDI	0.020	0.111	16.93	252
23 MUFINDI	24 MBEYA	0.034	0.187	28.64	252
25 DODOMA	26 SINGIDA	0.033	0.180	27.47	252
26 SINGIDA	27 SHINYAN-HV	0.034	0.187	28.64	252
27 SHINYAN-HV	29 MWANZA-HV	0.022	0.118	18.10	252
28 SHINYAN-LV	32 TABORA	0.213	0.485	9.97	92
29 MWANZA-HV	27 SHINYAN-HV	0.022	0.118	18.10	252
30 MWANZA-LV	31 MUSOMA	0.263	0.597	12.28	92
32 TABORA	28 SHINYAN-LV	0.213	0.485	9.97	92

Note: Resistances and reactances are on a 100 MVA base
Capacitances are in MVAr
The thermal rating is in Amps.

Table B.3 Effects of Capacitor Applications at Dar es Salaam

Year end Load Step	Ubongo Generation MW	Ubongo Generation MVAr	Ubongo Capac. MVAr	Ubongo H.T Vltge	Hale MW	Hale MVAr	Hale Vltge	Moshi MW	Moshi MVAr	Arusha MVAr	Morogoro LV Volt.	System Losses MW	Loss Reductn. MW
With Double circuit lines from Kidatu to Morogoro													
93 Max	30	20	-	.924	34	18.0	1.014	8	9	22.2	1.042	20.43	-
	30	20	30	.980	34	17.3	1.040	8	9	18.3	1.045	18.53	1.90
	30	20	45	1.012	34	15.8	1.040	8	9	18.3	1.046	18.31	.22
93 AP1	5	3	-	.886	34	20.0	1.025	8	9	17.0	1.037	20.60	-
	5	3	30	.951	34	16.6	1.040	8	9	14.8	1.041	18.01	2.59
	5	3	45	.983	34	15.6	1.040	8	9	14.8	1.041	17.56	3.04
93 AP2	0	0	0	.901	34	18.8	1.040	8	9	11.7	1.036	17.55	-
	0	0	30	.960	34	12.6	1.040	8	9	11.7	1.036	15.45	2.10
	0	0	45	.989	34	10.1	1.040	8	9	11.7	1.038	14.99	0.46
94 Max	51	30	0	.970	34	20.0	.991	8	9	24.95	1.041	22.24	-
	51	30	30	1.029	34	20.0	1.004	8	9	22.50	1.036	21.35	0.89
With Double circuit lines from Kidatu-Morogoro-Ubungo													
95 Max	25	15	0	.973	80	-1.8	1.040	8	9	21.1	1.039	15.79	-
	25	15	30	1.013	80	-4.7	1.040	8	9	21.1	1.041	15.38	.41
	25	15	45	1.040	80	-4.2	1.040	8	9	21.1	1.035	15.40	-
95 AP1	10	5	0	.981	80	12.2	1.040	0	5	26.4	1.042	17.79	-
	10	5	30	1.021	80	9.3	1.040	0	5	26.4	1.044	17.37	0.42
	0	0	0	.968	80	7.8	1.04	8	9	17.2	1.034	15.00	-
	0	0	30	1.009	80	4.7	1.04	8	9	17.2	1.036	14.46	0.54
	0	0	45	1.029	80	3.45	1.04	8	9	17.2	1.037	14.39	0.07
95 AP2	0	0	0	.956	80	-1.4	1.04	8	9	18.3	1.037	13.18	
	0	0	30	.999	80	-4.7	1.04	8	9	18.3	1.035	12.44	0.74
	0	0	0	.957	57	9.23	1.04	8	9	18.3	1.038	14.93	
	0	0	30	1.000	57	5.7	1.04	8	9	18.3	1.041	14.03	0.90
95 AM1	0	0	0	.964	80	-7.2	1.062	8	9	15.9	1.034	11.13	
	0	0	30	1.005	80	-10.4	1.04	8	9	14.9	1.037	10.72	0.41
	5	0	0	.963	34	20	1.009	8	9	8.55	1.042	16.36	
	5	0	30	1.005	34	20	1.018	8	9	8.22	1.039	15.72	0.64

Table B3

TABLE B.4

EFFECTS OF INCREMENTAL INCREASE OF CAPACITOR APPLICATIONS AT ARUSHA

Run#	Total losses in MW	BUS VOLTAGES (in pu) With bus numberrs indicated below KIDATU 1	MCROG 5	HALE 7	MOSHI 9	ARUSA 10	UBUNGO MW	UBUNGO MWAR	ARUSH/ MWAR	ARUSHA MVAR CHANGE	ARUSHA VOLTAGE CHANGE in pu
LOAD CONDITIONS CORRESPONDING TO: 1992 MAX, 1993AP1AND 1994AP2											
	Hale 24 MW, 12 MVAr Moshi 4MW, 7MVAr										
92-5L6	22.39	1.030	1.028	0.960	0.931	0.950	15	7	31.8		
92-5L5	22.12	1.030	1.031	0.973	0.951	0.970	15	7	32.1	0.4	0.020
92-5L4	21.93	1.030	1.033	0.986	0.970	0.990	15	7	32.6	0.5	0.020
92-5L3	21.71	1.030	1.041	1.029	1.038	1.062	15	7	35.0	2.4	0.072
LOAD CONDITIONS CORRESPONDING TO: 1995 MAX, 1996AP1AND 1997AP2											
	Hale 80 MW, variable MVAr to maintain1.04 PU Voltage Moshi 0MW, 5MVAr										
B:95MAX-A1	20.62	1.020	1.043	1.040	0.846	0.838	35	17	20.0		
B:95MAX-A2	19.89	1.020	1.043	1.040	0.892	0.894	35	17	25.0	5.0	0.056
B:95MAX-A3	19.81	1.020	1.043	1.040	0.929	0.941	35	17	30.0	5.0	0.047
B:95MAX-3	19.79	1.020	1.043	1.040	0.936	0.950	35	17	31.0	1.0	0.009
B:95MAX-A4	19.94	1.020	1.043	1.040	0.962	0.983	35	17	35.0	4.0	0.033
	Hale 80 MW, variable MVAr to maintain1.04 PU Voltage Moshi 4MW, 7MVAr										
95M-B1	17.51	1.020	1.043	1.040	0.900	0.893	35	17	20.0		
B:95MAX-B2	17.31	1.020	1.043	1.040	0.938	0.941	35	17	25.0	5.0	0.048
B:95MAX-B5	17.3	1.020	1.043	1.040	0.956	0.963	35	17	27.5	2.5	0.022
B:95MAX-B8	17.4	1.020	1.043	1.040	0.959	0.967	35	17	28.0	0.5	0.004
B:95MAX-B9	17.4	1.020	1.043	1.040	0.966	0.976	35	17	29.0	1.0	0.009
	Hale 80 MW, variable MVAr to maintain1.042PU Voltage Moshi 8MW, 9MVAr										
95M-C2	15.57	1.020	1.042	1.040	0.906	0.889	35	17	15.0		
B:95MAX-C3	15.34	1.020	1.042	1.040	0.945	0.939	35	17	20.0	5.0	0.050
B:95MAX-C4	15.42	1.020	1.042	1.040	0.979	0.982	35	17	25.0	5.0	0.043
B:95MAX-C5	15.73	1.020	1.042	1.040	1.009	1.021	35	17	30.0	5.0	0.039

91Max. **POWER FLOW RESULTS - 1991 MAXIMUM AND 1992 MAXIMUM BUS LOADS**

System Details: Single cct. Kidatu-Morogoro-Ubungo

		1991 MAXIMUM BUS LOADS				1992 MAXIMUM BUS LOADS				
Load Flow Run No:		1B1	1B4	B:91MAX-1	B:91MAX-3	B:92MAX-5	B:92MAX-6	B:92MAX-7	B:92MAX-8	B:92MAX-9
TOTAL POWER INPUT		311.5	313.3	308.7	310.2	337.5	335.2	330.5	331.1	333.1
TOTAL LOAD		292.0	292.0	292.0	292.0	310.8	310.8	310.8	310.8	310.8
TOTAL LINE CHARGING		312.9	321.0	330.8	324.3	312.5	319.7	317.9	312.7	305.3
TOTAL LOSS		20.68	21.99	17.61	19.01	26.21	23.94	19.49	20.51	22.56
Bus Voltages:										
	Bus no.									
KIDATU	1	1.030	1.030	1.030	1.030	1.030	1.030	1.030	1.030	1.030
MOROGORO-HV	2	0.974	0.998	0.992	0.971	0.978	0.998	0.991	0.975	0.953
UBUNGO-HV	3	0.927	0.978	0.960	0.918	0.944	0.981	0.960	0.930	0.888
UBUNGO-LV	4	0.969	1.029	1.006	0.959	0.989	1.032	1.007	0.972	0.924
MOROGORO-LV	5	1.025	1.054	1.046	1.022	1.026	1.052	1.045	1.026	0.998
CHALINZE	6	1.003	1.037	1.029	1.000	0.994	1.029	1.027	1.003	0.966
HALE	7	1.030	1.038	1.040	1.037	0.971	1.005	1.040	1.028	0.997
SAME	8	0.969	0.972	0.978	0.976	0.937	0.953	0.977	0.971	0.957
MOSHI	9	0.955	0.957	0.962	0.961	0.934	0.944	0.962	0.958	0.950
ARUSHA	10	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950
TANGA	11	1.014	1.022	1.024	1.020	0.949	0.985	1.022	1.008	0.976
RAS-KIRO	12	0.973	1.034	1.011	0.961	0.992	1.036	1.010	0.974	0.924
ZANZIBAR	13	0.969	1.031	1.008	0.958	0.988	1.033	1.007	0.970	0.920
ILALA	14	0.953	1.014	0.991	0.942	0.972	1.016	0.990	0.955	0.906
RUVU	16	0.983	1.031	1.015	0.976	0.989	1.028	1.014	0.985	0.941
MTERA	21	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036
IRINGA	22	1.029	1.029	1.029	1.029	1.034	1.034	1.034	1.034	1.034
MUFINDI	23	1.017	1.017	1.017	1.017	1.032	1.032	1.032	1.032	1.032
MBEYA	24	1.004	1.004	1.004	1.004	1.038	1.038	1.038	1.038	1.038
DODOMA	25	1.016	1.016	1.033	1.033	1.012	1.012	1.012	1.012	1.012
SINGIDA	26	1.009	1.009	1.053	1.053	1.001	1.001	1.001	1.001	1.001
SHINYAN-HV	27	1.012	1.012	1.082	1.082	0.998	0.998	0.998	0.998	0.998
SHINYAN-LV	28	1.013	1.013	1.085	1.085	0.999	0.999	0.999	0.999	0.999
MWANZA-HV	29	1.010	1.010	1.096	1.096	0.995	0.995	0.995	0.995	0.995
MWANZA-LV	30	1.006	1.006	1.098	1.098	0.990	0.990	0.990	0.990	0.990
MUSOMA	31	1.011	1.011	1.110	1.110	0.992	0.992	0.992	0.992	0.992
TABORA	32	1.022	1.022	1.097	1.097	1.007	1.007	1.007	1.007	1.007
Power Generation and variable var inputs:										
KIDATU	MW	193.488	201.335	186.698	188.151	202.48	200.201	196.519	197.093	199.129
	MWAR	30.93	9.735	13.809	32.819	23.195	4.159	11.047	25.313	46.302
UBUNGO	MW	0	4	0	0	27	27	12	12	12
	MWAR	35	55	45	30	50	60	50	40	30
HALE	MW	34	24	34	34	24	24	34	34	34
	MWAR	17	17	10.154	17	14	14	14.667	17	17
MOSHI	MW	4	4	8	8	4	4	8	8	8
	MWAR	7	7	7	7	7	7	9	9	9
ARUSHA	MW	0	0	0	0	0	0	0	0	0
	MWAR	16.647	15.9	13.216	13.742	29.874	24.458	14.89	16.704	21.409
MTERA	MW	80	80	80	80	80	80	80	80	80
	MWAR	-4.177	-4.178	-18.952	-18.953	-6.431	-6.43	-6.43	-6.43	-6.43
IRANGA	MW	0	0	0	0	0	0	0	0	0
	MWAR	0	0	0	0	0	0	0	0	0
Diesels in	MW	0	0	0	0	0	0	0	0	0
East	MWAR	0	0	0	0	0	0	0	0	0

POWER FLOW RESULTS - 1991 MAXIMUM AND 1992 MAXIMUM BUS LOADS Cont. Page 2

System Details:

Single cct. Kidatu-Morogoro-Ubungo

		1991 MAXIMUM BUS LOADS				1992 MAXIMUM BUS LOADS				
Load Flow Run No:		B:T91-1B1	B:T91-1B4	B:91MAX-1	B:91MAX-3	B:92MAX-5	B:92MAX-6	B:92MAX-7	B:92MAX-8	B:92MAX-9
Section Power flows:										
NORTH-EAST		112.274	106.58	111.45	113.30	109.46	107.45	115.37	116.54	118.37
EAST		109.055	116.376	107.26	106.54	131.90	131.92	119.50	118.79	118.58
KID-MORO LINE		187.918	195.765	180.92	182.38	191.43	189.15	185.47	186.05	188.08
EAST & N/EAST TOTAL		225.918	227.765	222.92	224.38	246.43	244.15	239.47	240.05	242.08
WEST		78.97	78.97	79.18	79.18	84.05	84.05	84.05	84.05	84.05
SYSTEM TOTAL		311.488	313.335	308.70	310.15	337.48	335.20	330.52	331.09	333.13
Section Power Losses in percent:										
NORTH-EAST		0.094	0.112	8.085	8.913	16.140	14.339	9.761	10.415	11.667
EAST		0.032	0.028	3.176	3.478	3.145	2.955	3.212	3.405	3.793
KID-MORO LINE		0.026	0.026	4.377	4.642	4.987	4.707	4.579	4.751	5.155
EAST & N/EAST TOTAL		0.084	0.089	15.638	17.033	24.272	22.001	17.552	18.571	20.615
WEST		0.022	0.022	1.974	1.973	1.945	1.945	1.945	1.945	1.945
SYSTEM TOTAL		0.066	0.070	17.613	19.007	26.217	23.946	19.497	20.515	22.559
Power flows in main lines:										
Kidatu to Moro.	MW	187.918	195.765	180.922	182.376	191.433	189.154	185.471	186.046	188.081
	MVAR	37.964	16.769	20.885	39.894	34.638	15.602	22.49	36.756	57.745
	LOSS (MW)	4.848	5.037	4.376	4.641	4.981	4.7	4.572	4.744	5.148
Moro. to Ubungo	MW	109.055	112.376	107.257	106.542	104.898	104.915	107.499	106.788	106.581
	MVAR	15.247	-2.817	5.165	19.23	6.869	-4.765	4.488	14.379	27.109
	LOSS (MW)	2.428	2.336	2.192	2.379	2.168	2.029	2.203	2.32	2.577
Moro. to Chalinze	MW	58.313	62.655	53.685	55.598	64.623	62.626	56.568	57.736	59.562
	MVAR	-12.168	-16.318	-13.599	-11.184	-9.262	-13.496	-14.246	-11.786	-7.709
	LOSS (MW)	2.868	3.195	2.371	2.614	3.458	3.153	2.64	2.803	3.094
Chalinze to Hale	MW	34.635	46.317	29.197	29.572	54.795	53.336	35.238	35.567	36.438
	MVAR	-22.519	-19.697	-17.717	-23.296	-15.213	-15.199	-19.76	-22.051	-22.813
	LOSS (MW)	2.798	4.054	1.781	2.274	5.811	5.135	2.567	2.886	3.315
Transformer Tap Possitions:										
Morogoro		0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Ubungo		0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Mwanza		1	1	1	1	1	1	1	1	1
Fixed Capacitors / Reactors used:										
	bus no:									
Ubungo	4	0	0	0	0	0	0	0	0	0
Moshi	9	0	0	0	0	0	0	0	0	0
Arusha	10	0	0	0	0	0	0	0	0	0
Tanga	11	10	10	10	10	10	10	10	10	10
RasKiromany	12	-20	-20	-20	-20	-20	-20	-20	-20	-20
Iringa	22	-20	-20	-20	-20	-20	-20	-20	-20	-20
Mufindi	23	-10	-10	-10	-10	-10	-10	-10	-10	-10
Mbeya	24	-10	-10	-10	-10	0	0	0	0	0
Dodoma	25	-30	-30	-30	-30	-30	-30	-30	-30	-30
Singida	26	-30	-30	-30	-30	-30	-30	-30	-30	-30
Shinyanga	27	-20	-20	-20	-20	-20	-20	-20	-20	-20
Shiny/LV	28	0	0	0	0	0	0	0	0	0
Mwanza	29	-10	-10	0	0	0	0	0	0	0

Yr93 **POWER FLOW RESULTS YEAR 1993**

System Details: With Kidatu - Morogoro second circuit

		1993 MAXIMUM BUS LOADS				1993 LOAD STEP 1			1993 LOAD STEP 1	
Load Flow Run No:		1R5	B1R6	m-4	m-6	92-R1	92-R2	92-R3	91-1A2	91-1A5
TOTAL POWER INPUT		351.0	348.9	351.4	349.7	332.4	328.9	329.8	311.7	310.5
TOTAL LOAD		331.2	331.2	331.2	331.2	310.8	310.8	310.8	292.0	292.0
TOTAL LINE CHARGING		331.4	331.4	324.5	331.6	332.6	329.2	335.1	331.4	335.8
TOTAL LOSS		22.19	20.00	20.43	18.8	21.62	18.14	18.74	19.48	17.64
Bus Voltages:										
	Bus no.									
KIDATU	1	1.030	1.030	1.030	1.030	1.030	1.030	1.030	1.030	1.030
MOROGORO-HV	2	1.004	1.004	0.998	1.014	1.004	0.998	1.000	0.994	1.008
UBUNGO-HV	3	0.942	0.942	0.924	0.966	0.965	0.925	0.932	0.908	0.952
UBUNGO-LV	4	0.980	0.980	0.959	1.008	0.997	0.960	0.970	0.940	0.993
MOROGORO-LV	5	1.052	1.052	1.042	1.046	1.049	1.043	1.047	1.039	1.058
CHALINZE	6	1.017	1.019	1.001	1.026	1.012	1.004	1.010	0.999	1.028
HALE	7	1.040	1.040	1.014	1.036	0.985	1.015	1.020	1.040	1.040
SAME	8	0.978	0.979	0.961	0.971	0.950	0.969	0.972	0.973	0.973
MOSHI	9	0.967	0.966	0.951	0.957	0.946	0.960	0.961	0.958	0.958
ARUSHA	10	0.970	0.960	0.950	0.950	0.960	0.960	0.960	0.950	0.950
TANGA	11	1.027	1.025	0.992	1.015	0.964	0.995	1.000	1.027	1.024
RAS-KIRO	12	0.992	0.992	0.960	1.011	1.000	0.962	0.972	0.942	0.997
ZANZIBAR	13	0.987	0.987	0.955	1.007	0.997	0.958	0.968	0.938	0.993
ILALA	14	0.962	0.962	0.941	0.991	0.980	0.943	0.953	0.923	0.977
RUVU	16	0.995	0.996	0.977	1.015	1.002	0.979	0.987	0.967	1.008
MTERA	21	1.036	1.036	1.030	1.030	1.036	1.036	1.036	1.036	1.036
IRINGA	22	1.032	1.032	1.028	1.028	1.035	1.035	1.035	1.035	1.029
MUFINDI	23	1.028	1.028	1.024	1.024	1.036	1.036	1.036	1.036	1.017
MBEYA	24	1.032	1.032	1.028	1.028	1.045	1.045	1.045	1.043	1.004
DODOMA	25	1.008	1.008	1.001	1.001	1.017	1.017	1.017	1.016	1.016
SINGIDA	26	0.990	0.990	0.983	0.983	1.013	1.013	1.013	1.009	1.009
SHINYAN-HV	27	0.983	0.983	0.974	0.974	1.016	1.016	1.016	1.012	1.012
SHINYAN-LV	28	0.983	0.983	0.975	0.975	1.017	1.017	1.017	1.013	1.013
MWANZA-HV	29	0.977	0.977	0.968	0.968	1.015	1.015	1.015	1.010	1.010
MWANZA-LV	30	0.972	0.972	0.963	0.963	1.010	1.010	1.010	1.006	1.006
MUSOMA	31	0.970	0.970	0.960	0.960	1.013	1.013	1.013	1.011	1.011
TABORA	32	0.990	0.990	0.980	0.980	1.026	1.026	1.026	1.022	1.022

Power Generation and variable var inputs:

KIDATU	MW	202.997	204.856	199.372	197.659	199.639	182.165	192.759	193.671	192.468
	MWAR	3.567	3.738	17.556	-11.528	5.2	16.246	12.958	22.176	0.76
UBUNGO	MW	30	22	30	30	10	10	0	0	0
	MWAR	15.901	18.279	20	40	5	18.995	26.997	3.87	25
HALE	MW	34	34	34	34	24	34	34	34	34
	MWAR	17.994	15.119	18	18	12	12	12	19.187	13.681
MOSHI	MW	4	8	8	8	4	8	8	4	4
	MWAR	7	9	9	9	7	7	7	7	7
ARUSHA	MW	0	0	0	0	0	0	0	0	0
	MWAR	24.543	19.06	22.185	18.859	28.933	21.452	20.68	15.685	15.751
MTERA	MW	80	80	80	80	80	80	80	80	80
	MWAR	-1.01	-1.008	-2.908	-2.908	-12.384	-12.384	-12.384	-11.259	-4.179
IRANGA	MW	0	0	0	0	0	0	0	0	0
	MWAR	0	0	0	0	0	0	0	0	0
Diesels in	MW	0	0	0	0	8	8	8	0	0
East	MWAR	0	0	0	0	0	0	0	0	0

Cont. pg.2

Yr93 **POWER FLOW RESULTS YEAR 1993 CONT. PAGE 2**

System Details: With Kidatu - Morogoro second circuit

		1993 MAXIMUM BUS LOADS				1993 LOAD STEP 1			1993 LOAD STEP 1	
Load Flow Run No:		1R5	B1R6	m-4	m-6	92-R1	92-R2	92-R3	91-1A2	91-1A5
Section Power flows:										
NORTH-EAST		118.92	121.158	120.69	116.65	100.266	118.77	121.118	115.578	113.108
EAST		132.906	128.502	131.20	133.67	139.002	117.411	115.414	107.997	109.346
KID-MORO LINE		185.811	187.67	182.16	180.44	204.085	186.611	197.204	188.09	186.899
EAST & N/EAST TOTAL		253.811	251.67	254.16	252.44	242.085	238.611	239.204	226.09	224.899
WEST		89.685	89.686	89.72	89.72	83.554	83.554	83.554	78.981	78.969
SYSTEM TOTAL		350.997	348.856	351.37	349.66	332.639	329.165	329.759	311.671	310.468
Section Power Losses in percent:										
NORTH-EAST		0.120	0.098	0.103	0.097	0.145	0.089	0.088	0.098	0.090
EAST		0.026	0.028	0.027	0.023	0.020	0.031	0.034	0.036	0.031
KID-MORO LINE		0.013	0.013	0.013	0.012	0.014	0.013	0.014	0.013	0.012
EAST & N/EAST TOTAL		0.079	0.071	0.072	0.066	0.083	0.070	0.072	0.078	0.071
WEST		0.024	0.024	0.025	0.025	0.017	0.017	0.017	0.023	0.022
SYSTEM TOTAL		0.063	0.057	0.058	0.054	0.065	0.055	0.057	0.063	0.057
Power flows in main lines:										
Kidatu to Moro.	MW	185.811	187.67	182.156	180.443	204.085	186.611	197.204	188.09	186.899
	MVAR	14.769	14.94	25.906	-3.178	14.655	25.701	22.414	33.861	7.794
	LOSS	2.317	2.363	2.286	2.133	2.781	2.392	2.638	2.479	2.317
Moro. to Ubungo	MW	102.906	106.502	101.199	103.67	129.002	107.411	115.414	107.997	109.346
	MVAR	25.297	25.555	32.851	15.728	19.019	32.957	29.475	41.012	21.305
	LOSS	2.171	2.311	2.245	2.049	1.703	2.484	2.748	2.673	2.352
Moro. to Chalinze	MW	63.075	61.324	60.788	56.764	55.461	59.953	62.297	61.757	59.276
	MVAR	-7.364	-7.69	-3.643	-13.221	-3.477	-4.051	-6.046	-4.44	-8.556
	LOSS	3.117	2.949	2.931	2.632	2.407	2.846	3.062	3.044	2.732
Chalinze to Hale	MW	46.662	40.595	41.913	41.167	54.36	35.77	35.625	35.806	35.346
	MVAR	-24.419	-22.736	-20.821	-20.354	-14.563	-19.066	-18.922	-25.613	-19.553
	LOSS	4.578	3.508	3.719	3.394	5.494	2.729	2.669	3.195	2.564
Transformer Tap Possitions:										
Morogoro		0.95	0.95	0.95	0.97	0.95	0.95	0.95	0.95	0.95
Ubungo		0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Mwanza		1	1	1	1	1	1	1	1	1
Fixed Capacitors / Reactors used:	**bus no:**									
Ubungo	4	0	0	0	0	0	0	0	0	0
Moshi	9	0	0	0	0	0	0	0	0	0
Arusha	10	0	0	0	0	0	0	0	0	0
Tanga	11	14	14	10	10	10	10	10	12	10
RasKirom	12	-10	-10	-20	-20	-20	-20	-20	-20	-20
Iringa	22	-20	-20	-20	-20	-20	-20	-20	-20	-20
Mufindi	23	-10	-10	-10	-10	-10	-10	-10	-10	-10
Mbeya	24	0	0	0	0	0	0	0	0	-10
Dodoma	25	-30	-30	-30	-30	-30	-30	-30	-30	-30
Singida	26	-30	-30	-30	-30	-30	-30	-30	-30	-30
Shinyang.	27	-20	-20	-20	-20	-20	-20	-20	-20	-20
Shiny/LV	28	0	0	0	0	0	0	0	0	0
Mwanza	29	0	0	0	0	0	0	0	0	0

POWER FLOW RESULTS - YEAR 1995 & 1998 MAXIMUM BUS LOADS
WITH NEW PANGANI AVAILABLE BUT WITHOUT SINGIDA-ARUSHA LINE

Yr95/98T

System Details: Double cct. lines Kidatu - Morogoro - Ubungo

		1995 year Maximum loads						1998 Max loads	
Load Flow Run No:		M-C2	M-C5	M-B1	M-B4	M-A1	M-A4	98-D5	98-D9
TOTAL POWER INPUT		392.5	392.7	394.5	393.8	396.9	396.9	499.7	497.0
TOTAL LOAD		376.6	376.6	376.6	376.6	376.6	376.6	456.7	456.7
TOTAL LINE CHARGING		353.2	355.2	353.1	367.8	352.2	354.3	348.4	360.4
TOTAL LOSS		15.57	15.73	17.51	16.9	20.62	19.94	42.83	40.02
Bus Voltages:									
	Bus no.								
KIDATU	1	1.020	1.020	1.020	1.020	1.020	1.020	1.030	1.030
MOROGORO-HV	2	1.005	1.005	1.005	1.018	1.005	1.005	0.973	1.010
UBUNGO-HV	3	0.971	0.971	0.971	0.993	0.971	0.971	0.911	0.985
UBUNGO-LV	4	1.004	1.004	1.004	1.032	1.004	1.004	0.957	1.020
MOROGORO-LV	5	1.042	1.042	1.043	1.067	1.043	1.043	1.038	1.033
CHALINZE	6	1.029	1.029	1.030	1.075	1.029	1.029	1.001	1.024
HALE	7	1.040	1.040	1.040	1.164	1.040	1.040	1.040	1.040
SAME	8	0.928	1.011	0.922	1.160	0.876	0.969	0.949	0.949
MOSHI	9	0.906	1.009	0.900	1.162	0.846	0.962	0.947	0.947
ARUSHA	10	0.889	1.021	0.893	1.181	0.838	0.983	0.949	0.949
TANGA	11	1.019	1.019	1.019	1.149	1.019	1.019	1.010	1.010
RAS-KIRO	12	1.006	1.006	1.007	1.035	1.007	1.007	0.955	1.020
ZANZIBAR	13	1.001	1.001	1.002	1.030	1.002	1.002	0.947	1.013
ILALA	14	0.986	0.986	0.986	1.014	0.986	0.986	0.934	0.998
RUVU	16	1.014	1.014	1.014	1.051	1.014	1.014	0.975	1.019
MTERA	21	1.020	1.020	1.020	1.020	1.020	1.020	1.030	1.030
IRINGA	22	1.021	1.021	1.021	1.021	1.021	1.021	1.037	1.037
MUFINDI	23	1.013	1.013	1.013	1.013	1.013	1.013	1.030	1.030
MBEYA	24	1.017	1.017	1.017	1.017	1.017	1.017	1.029	1.029
DODOMA	25	0.988	0.988	0.988	0.988	0.988	0.988	1.006	1.006
SINGIDA	26	0.985	0.985	0.985	0.985	0.985	0.985	1.003	1.003
SHINYAN-HV	27	0.995	0.995	0.995	0.995	0.995	0.995	0.998	0.998
SHINYAN-LV	28	0.996	0.996	0.996	0.996	0.996	0.996	0.998	0.998
MWANZA-HV	29	1.002	1.002	1.002	1.002	1.002	1.002	0.999	0.999
MWANZA-LV	30	1.002	1.002	1.002	1.002	1.002	1.002	0.997	0.997
MUSOMA	31	0.998	0.998	0.998	0.998	0.998	0.998	0.983	0.983
TABORA	32	1.001	1.001	1.001	1.001	1.001	1.001	0.998	0.998
Power Generation and variable var inputs:									
KIDATU	MW	189.52	189.72	195.47	194.79	201.86	201.89	199.73	197.02
	MWAR	-15.07	-15.07	-15.21	-39.79	-15.01	-15.01	84.861	16.152
UBUNGO	MW	35	35	35	35	35	35	0	0
	MWAR	17	17	17	17	17	17	20	70
HALE	MW	80	80	80	80	80	80	80	80
	MWAR	6.003	-10.63	9.063	0	20.591	1.878	30.953	24.812
MOSHI	MW	8	8	4	4	0	0	0	0
	MWAR	9	9	7	7	5	5	25	25
ARUSHA	MW	0	0	0	0	0	0	0	0
	MWAR	15	30	20	35	20	35	30	30
MTERA	MW	80	80	80	80	80	80	80	80
	MWAR	-3.382	-3.382	-3.382	-3.382	-3.382	-3.383	-16.63	-16.63
IRANGA	MW	0	0	0	0	0	0	140	140
	MWAR	0	0	0	0	0	0	-20	-20
Diesels in	MW	0	0	0	0	0	0	0	0
East	MWAR	0	0	0	0	0	0	0	0

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POWER FLOW RESULTS - YEAR 1995 & 1998 MAXIMUM BUS LOADS WITH NEW PANGANI AVAILABLE BUT WITHOUT SINGIDA-ARUSHA LINE

Yr95/98T

System Details: Double cct. lines Kidatu - Morogoro - Ubungo

		1995 year Maximum loads						1998 Max loads	
Load Flow Run No:		M-C2	M-C5	M-B1	M-B4	M-A1	M-A4	98-D5	98-D9
Section Power flows:									
NORTH-EAST		134.63	134.73	133.88	133.95	133.53	133.42	170.89	163.36
EAST		146.3	146.38	148.86	148.17	151.56	151.62	188.43	193.84
KID-MORO LINE		159.68	159.88	165.63	164.95	172.02	172.05	285.17	282.46
EAST & N/EAST TOTAL		282.68	282.88	284.63	283.95	287.02	287.05	365.17	362.46
WEST		101.34	101.34	101.34	101.34	101.34	101.34	124.36	124.36
SYSTEM TOTAL		392.52	392.72	394.47	393.79	396.86	396.89	499.73	497.02
Section Power Losses in MW:									
NORTH-EAST in MW		8.308	8.469	10.085	9.604	13.000	12.326	24.63	23.29
EAST		2.616	2.617	2.650	2.549	2.700	2.701	6.31	5.45
KID-MORO LINE		1.820	1.824	1.948	1.926	2.091	2.091	8.06	7.46
EAST & N/EAST TOTAL		12.744	12.910	14.683	14.079	17.791	17.118	39.00	36.20
WEST		2.882	2.882	2.882	2.882	2.882	2.881	4.94	4.95
SYSTEM TOTAL		15.625	15.792	17.565	16.961	20.673	19.999	43.94	41.14
Section Power Losses in percent:									
NORTH-EAST		0.062	0.063	0.075	0.072	0.097	0.092	0.144	0.143
EAST		0.018	0.018	0.018	0.017	0.018	0.018	0.033	0.028
KID-MORO LINE		0.011	0.011	0.012	0.012	0.012	0.012	0.028	0.026
EAST & N/EAST TOTAL		0.045	0.046	0.052	0.050	0.062	0.060	0.107	0.100
WEST		0.028	0.028	0.028	0.028	0.028	0.028	0.040	0.040
SYSTEM TOTAL		0.040	0.040	0.045	0.043	0.052	0.050	0.088	0.083
Power flows in main lines:									
Kidatu to Moro.	MW	159.68	159.88	165.63	164.95	172.02	172.05	285.17	282.46
	MVAR	-3.643	-3.647	-3.782	-28.37	-3.578	-3.579	72.546	3.837
	LOSS (M\	1.705	1.709	1.833	1.811	1.976	1.977	5.828	5.221
Moro. to Ubungo	MW	111.3	111.38	113.86	113.17	116.56	116.62	188.43	193.84
	MVAR	13.164	13.15	12.699	0.159	12.376	12.361	49.376	-0.741
	LOSS (M\	1.266	1.268	1.316	1.202	1.372	1.373	3.99	3.472
Moro. to Chalinze	MW	26.374	26.482	29.625	29.697	33.287	33.155	66.327	58.82
	MVAR	-6.364	-6.398	-7.339	-18.77	-8.313	-8.285	-7.652	-19
	LOSS (M\	0.566	0.57	0.716	0.872	0.906	0.9	3.543	3.02
Chalinze to Hale	MW	4.568	4.755	10.227	9.49	16.677	16.348	43.325	42.804
	MVAR	-9.095	-9.169	-11.29	-31.16	-13.7	-13.58	-26.89	-22.25
	LOSS (M\	0.072	0.076	0.26	1.233	0.628	0.605	4.376	3.766
Transformer Tap Possitions:									
Morogoro		0.96	0.96	0.96	0.96	0.96	0.96	0.93	0.98
Ubungo		0.95	0.95	0.95	0.95	0.95	0.95	0.93	0.96
Mwanza		1	1	1	1	1	1	1	1
Fixed Capacitors / Reactors used:									
	bus no:								
Tanga	11	10	10	10	10	10	10	10	10
RasKirom	12	-20	-20	-20	-20	-20	-20	-20	-20
Iringa	22	-10	-10	-10	-10	-10	-10	0	0
Mufindi	23	-15	-15	-15	-15	-15	-15	-10	-10
Dodoma	25	-40	-40	-40	-40	-40	-40	-30	-30
Singida	26	-30	-30	-30	-30	-30	-30	-20	-20
Shinyang.	27	-20	-20	-20	-20	-20	-20	-20	-20

POWER FLOW RESULTS - YEAR 1995, 1998 and 2001 MAXIMUM BUS LOADS WITH SINGIDA-ARUSHA LINE

YrS95-03M

System Details: Double cct. lines Kidatu - Morogoro - Ubungo and 220 kV Singida - Arusha connection

		1995	1998 max Loads				2001 Max Loads		
Load Flow Run No:		5-C1Q	98-2D3	98-2D4	98-2S1	98-2S2	1-A2	1-A3	1-A4
TOTAL POWER INPUT		388.4	481.4	480.2	481.9	482.6	579.7	579.6	578.8
TOTAL LOAD		376.6	456.7	456.7	456.7	456.7	553.7	553.7	553.7
TOTAL LINE CHARGING		400.5	391.9	398.8	371.3	365.8	396.4	396.3	405.0
TOTAL LOSS		11.9	24.36	23.15	28.09	29.19	26.18	26.15	25.21
Bus Voltages:									
	Bus no.								
KIDATU	1	1.020	1.030	1.030	1.020	1.020	1.030	1.030	1.030
MOROGORO-HV	2	1.016	0.981	0.996	0.989	0.978	0.994	0.992	1.015
UBUNGO-HV	3	0.993	0.917	0.948	0.934	0.900	0.940	0.941	0.987
UBUNGO-LV	4	1.022	0.940	0.980	0.980	0.940	0.979	0.980	1.033
MOROGORO-LV	5	1.042	0.997	1.015	1.011	0.997	1.042	1.040	1.036
CHALINZE	6	1.036	0.982	1.006	1.001	0.978	1.018	1.017	1.035
HALE	7	1.040	1.033	1.040	1.040	1.034	1.040	1.040	1.040
SAME	8	0.994	1.003	1.006	1.006	1.004	1.025	1.025	1.024
MOSHI	9	0.982	0.993	0.994	0.995	0.993	1.021	1.021	1.020
ARUSHA	10	0.984	1.010	1.010	1.010	1.010	1.002	1.002	1.001
TANGA	11	1.019	0.988	0.995	0.995	0.988	0.990	0.990	0.990
RAS-KIRO	12	1.025	0.937	0.978	0.978	0.937	0.975	0.977	1.032
ZANZIBAR	13	1.020	0.928	0.970	0.970	0.928	0.965	0.967	1.023
ILALA	14	1.004	0.928	0.969	0.969	0.928	0.966	0.968	1.021
RUVU	16	1.026	0.956	0.989	0.985	0.953	0.993	0.994	1.030
MTERA	21	1.020	1.030	1.030	1.020	1.020	1.020	1.020	1.020
IRINGA	22	1.021	1.040	1.040	1.030	1.030	1.034	1.034	1.034
MUFINDI	23	1.013	1.033	1.033	1.022	1.022	1.025	1.025	1.025
MBEYA	24	1.017	1.033	1.033	1.021	1.021	1.022	1.022	1.022
DODOMA	25	0.994	1.003	1.004	0.994	0.994	0.994	0.994	0.994
SINGIDA	26	1.005	1.019	1.020	1.012	1.011	1.014	1.014	1.014
SHINYAN-HV	27	1.018	1.016	1.017	1.009	1.008	1.022	1.022	1.021
SHINYAN-LV	28	1.019	1.016	1.017	1.009	1.009	1.022	1.022	1.021
MWANZA-HV	29	1.025	1.017	1.018	1.010	1.010	1.021	1.020	1.020
MWANZA-LV	30	1.026	1.016	1.017	1.009	1.009	1.019	1.019	1.018
MUSOMA	31	1.025	1.004	1.005	0.996	0.996	1.002	1.002	1.001
TABORA	32	1.025	1.017	1.018	1.010	1.009	1.021	1.021	1.020
ARUSHA-HV		0.974	1.015	1.015	1.014	1.013	1.009	1.009	1.008

Power Generation and variable var inputs:

		1995	98-2D3	98-2D4	98-2S1	98-2S2	1-A2	1-A3	1-A4
KIDATU	MW	190.4	201.38	200.18	201.88	202.56	204.65	204.63	203.83
	MWAR	-36.21	54.934	27.959	22.287	42.108	34.136	39.014	-3.655
UBUNGO	MW	30	0	0	0	0	47	47	47
	MWAR	30	17.947	37.146	88.305	72.715	20	25	60
HALE	MW	80	50	50	50	50	80	80	80
	MWAR	-12.79	25	21.552	22.152	25	7.405	7.509	3.269
MOSHI	MW	8	0	0	0	0	8	8	8
	MWAR	4	5	5	5	5	30	30	30
ARUSHA	MW	0	0	0	0	0	0	0	0
	MWAR	0	7.602	6.436	8.448	9.444	-10	-10	-10
MTERA	MW	80	80	80	80	80	80	80	80
	MWAR	-7.26	-12.01	-12.67	-11.64	-11.21	-14.79	-14.77	-14.76
IRANGA	MW	0	150	150	150	150	160	160	160
	MWAR	0	-20	-20	-20	-20	-20	-20	-20
Diesels in	MW	0	0	0	0	0	0	0	0
East	MWAR	0	0	0	0	0	0	0	0

POWER FLOW RESULTS - YEAR 1995, 1998 and 2001 MAXIMUM BUS LOADS WITH SINGIDA-ARUSHA LINE

YrS95-03M

System Details: Double cct. lines Kidatu - Morogoro - Ubungo and 220 kV Singida - Arusha connection

		1995	1998 max Loads				2001 Max Loads		
Load Flow Run No:		5-C1Q	98-2D3	98-2D4	98-2S1	98-2S2	1-A2	1-A3	1-A4
Section Power flows:									
NORTH-EAST		123.01	116.53	115.45	133.18	134.23	156.30	156.05	151.54
EAST		137.70	175.38	176.47	159.13	157.95	215.30	215.46	219.82
KID-MORO LINE		144.09	246.23	246.03	246.31	246.29	240.51	240.45	240.09
EAST & N/EAST TOTAL		262.09	296.23	296.03	296.31	296.29	375.51	375.45	375.09
WEST		117.81	174.95	173.95	175.37	176.07	191.85	191.88	191.44
SYSTEM TOTAL		388.40	481.38	480.18	481.88	482.56	579.65	579.63	578.83
Section Power Losses in MW:									
NORTH-EAST in MW		3.87	4.56	4.21	6.38	6.77	5.71	5.69	5.44
EAST		2.50	5.26	4.76	7.03	7.49	4.89	4.85	4.42
KID-MORO LINE		1.73	5.03	4.83	4.86	4.98	4.49	4.52	4.33
EAST & N/EAST TOTAL		8.10	14.85	13.81	18.27	19.24	15.10	15.06	14.19
WEST		3.98	9.87	9.72	10.18	10.30	11.37	11.37	11.30
SYSTEM TOTAL		12.07	24.72	23.53	28.45	29.54	26.47	26.44	25.49
Section Power Losses in percent:									
NORTH-EAST		0.031	0.039	0.036	0.048	0.050	0.037	0.036	0.036
EAST		0.018	0.030	0.027	0.044	0.047	0.023	0.022	0.020
KID-MORO LINE		0.012	0.020	0.020	0.020	0.020	0.019	0.019	0.018
EAST & N/EAST TOTAL		0.031	0.050	0.047	0.062	0.065	0.040	0.040	0.038
WEST		0.034	0.056	0.056	0.058	0.058	0.059	0.059	0.059
SYSTEM TOTAL		0.031	0.051	0.049	0.059	0.061	0.046	0.046	0.044
Power flows in main lines:									
Kidatu to Moro.	MW	144.09	246.23	246.03	246.31	246.29	240.51	240.45	240.09
	MVAR	-22.59	56.753	29.501	23.432	43.446	32.764	37.651	-5.134
	LOSS	1.378	4.312	4.087	4.139	4.275	3.933	3.965	3.761
Moro. to Ubungo	MW	107.7	175.38	176.47	159.13	157.95	168.3	168.46	172.82
	MVAR	-3.196	52.061	30.257	25.639	40.752	37.971	33.433	3.038
	LOSS	1.085	3.509	3.188	4.991	5.285	3.017	2.986	2.764
Moro. to Chalinze	MW	14.786	42.035	40.968	58.682	59.794	38.859	38.606	34.103
	MVAR	-5.147	-10.58	-13.44	-18.38	-14.66	-4.615	-5.531	-15.21
	LOSS	0.181	1.595	1.511	3.124	3.237	1.201	1.195	1.07
Chalinze to Hale	MW	-15.14	8.83	9.533	6.4	5.578	1.657	1.625	2.193
	MVAR	1.555	-19.59	-16.32	-16.21	-19.16	-10.61	-10.7	-6.733
	LOSS	0.459	0.604	0.425	0.336	0.494	0.072	0.074	0.016
Singida to Arusha	MW	67.645	115.76	114.74	116.36	117.06	122.79	122.83	122.37
	MVAR	3.499	-0.014	-0.486	-0.63	-0.332	-0.489	-0.474	-0.391
	LOSS	0.984	2.747	2.698	2.827	2.862	3.147	3.149	3.125
Transformer Tap Possitions:									
Morogoro		0.97	0.98	0.98	0.98	0.98	0.95	0.95	0.98
Ubungo		0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Mwanza		1	1	1	1	1	1	1	1
Arusha		0.98	1	1	1	1	0	0	0
Fixed Capacitors / Reactors used:									
RasKirom	12	-20	-20	-20	-20	-20	-20	-20	-20
Iringa	22	-10	0	0	0	0	0	0	0
Mufindi	23	-15	-10	-10	-10	-10	-10	-10	-10
Mbeya	24	0	0	0	0	0	0	0	0
Dodoma	25	-40	-30	-30	-30	-30	-30	-30	-30
Singida	26	-30	-20	-20	-20	-20	-20	-20	-20
Shinyang	27	-20	-20	-20	-20	-20	-10	-10	-10

ANNEX C

ECONOMIC EVALUATION OF REACTIVE COMPENSATION REQUIREMENTS FOR THE TRANSMISSION AND DISTRIBUTION SYSTEMS

Annex C

ECONOMIC EVALUATION OF REACTIVE COMPENSATION REQUIREMENTS FOR THE TRANSMISSION AND DISTRIBUTION SYSTEMS

List of Tables

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COST OF POWER SUPPLY
FROM SMALL DIESEL PLANTS

	Discount Rate 12%			Discount Rate 10%		
	Plant factor 25%	Plant factor 12 %	Plant factor 6 %	Plant factor 25%	Plant factor 12 %	Plant factor 6 %
Investment Cost US$ Million	1.6	1.6	1.6	1.6	1.6	1.6
Capacity MW	2	2	2	2	2	2
Energy MWh/year	4380	2102	1051	4380	2102	1051
Plant Factor	0.25	0.12	0.06	0.25	0.12	0.06
Plant Capacity Cost US$/kW	800	800	800	800	800	800
PW of Annuity Factor 10 years	5.65	5.65	5.65	6.14	6.14	6.14
Discount Rate	12%	12%	12%	10%	10%	10%
Fuel Cost (diesel oil) US$/kWh	0.05	0.05	0.05	0.05	0.05	0.05
O&M Cost of Dieselplant US$/kWh	0.007	0.007	0.007	0.007	0.007	0.007
Fixed Maintenance Cost US$/kW/year	7.1	7.1	7.1	7.1	7.1	7.1
PW of Energy Benefits MWh	24748	11879	5940	26913	12918	6459
PW Fuel Cost US$ Million	1.24	0.59	0.30	1.35	0.65	0.32
PW O&M Cost US$ Million	0.17	0.08	0.04	0.18	0.09	0.04
PW Fixed Maintenance Cost US$ Million	0.08	0.08	0.08	0.09	0.09	0.09
PW Total Cost US$ Million	3.09	2.35	2.02	3.22	2.42	2.05
Total Cost US$/kWh	0.12	0.20	0.34	0.12	0.19	0.32
Total Cost Adjusted for 4 % station use US$/kWh	0.13	0.21	0.35	0.12	0.20	0.33

**ESTIMATED AVERAGE INCREMENTAL COST BY VOLTAGE LEVEL IN 1989 AND 1991 US$.
PLANNING PERIOD 1990-2015**

		Discount Rate	
		12%	10%
PV Generation investment	US$ Million	453	535
PV Hydro generation O&M	"	8	11
PV Diesel operating+fuel+fixed maintenance	"	13	14
PV Energy benefits without genr losses	GWh	8249	10714
AIC AT GENERATION LEVEL US$/kWh		0.057	0.052
PV Transmission investment + 2 % O&M	US$ Million	112	131
PV Energy benefits without genr and trans losses	GWh	7849	10192
AIC AT TRANSMISSION LEVEL US$/kWh		0.072	0.065
PV Distribution investment + 1,5 % O&M	US$ Million	171	193
PV Energy benefits without total losses	GWh	7420	9643
AIC AT DISTRIBUTION LEVEL in 1989 US$/kWh		0.095	0.085
AIC converted to 1991 US$/kWh			
AIC at Generation Level		0.063	0.058
AIC at Transmission Level		0.079	0.072
AIC at Distribution Level		0.104	0.094

Note: Calculations are based on "Investment Program", TANESCO, March 1990 and the Least Cost Hydroelectric Development Plan prepared by Acres International Ltd. for TANESCO in July 1989 "Review of Power Sector Development Program". Details of the investment portfolio are presented in Annex II.

TANESCO'S INVESTMENT PROGRAM

by year of commissioning of investment

Year	Generation	Transmission	Distribution
1990	Diesel Rehabilitation		
1991			Mbeya/Mufindi
1992	New Diesel	Transmission Rehab.	
1993	Ubungo Gas Turb. Rehabilitation	Reactive Compensation	Rural Electrific.
		Kidatu/Morogoro II cct	
1994		Morogoro/Dar es Salaam II cct.	
1995	Pangani Redevel.	Pangani	
1996		Singida/Arusha	Major Distr. I
1997	Kihansi I	Kihansi	
1998			
1999	Kihansi II/Retire Diesel		
2000			Future Distribution
2001			
2002	Masigira	Masigira	
2003			
2004			
2005	Rumakali/Retire Diesel	Rumakali	
2006			Future Distribution
2007	Retire Diesel	Future Transmission	
2008			
2009	Ruhudj	Ruhudj	
2010			
2011			Future Distribution
2012	Mpanga	Mpanga	
2013			
2014			
2015			

In addition, TANESCO's expenditure on local distribution expansion works incurred annually are counted for.

Investments outside the interconnected grid not included

Source: "Investment Program" Tanesco March 1990 and
"Review of 1985 Power Sector Development Plan" Tanesco and Acres International Ltd. July 1989
The need for investments for "Future Transmission" and "Future Distribution" estimated by ESMAP.

TABLE C.2

LOSS SAVINGS BY INSTALLING A REACTOR AT RASKIROMANY

	Reactor used at Ras Kiromany		
	No React.	10 MVAr	20 MVAr
Peak Line Losses in MW			
Ubungo to Ras Kiromani	0.47	0.23	0.08
Loss Savings MW		0.24	0.39
Loss load factor of savings		1	1
Annual savings GWH		2.102	3.416
Value of savings /yr. $ 000's		210	342
Present worth of loss savings in $ 000's		1598	2596
Cost of reactor installation $ 000's			
Reactor transport and labour		5	2
Isolator, struct. etc.		5	5
Additional cost for equivalent capacitor $000's		60	120
Total cost $ 000's		70	127
BENEFIT/COST ratio		23	20
Pay back period in months		4.0	4.5

Note:

0.1 = energy costs in $/ kWh
7.6 = Present worth factor (calculated at 10% interest and for 15 years of benefits)
6 = cost in $/kVAr for equivalent capacitor

TABLE C3

LOSS SAVINGS BY CAPACITOR INSTALLATION AT TANGA CEMENT FACTORY

	1990 - 1992		1993 onwards
PEAK LOSS SAVINGS (kW)			
132 kV Hale Tanga line	58		100
33 kV line at Tanga	75		120
Total peak loss Savings kW	133		220
Loss Reduction Load Factor	0.7		0.7
Annual loss savings kWH	815556		1349040
Value of savings /yr. $ 000's	81.556		134.904
Present worth of loss savings $ 000's from 1992		750	
COST OF CAPACITOR INSTALLATION (2 X 4 MVAR)			
Capacitor banks in $ 000s		28	
Switchgear cost in $ 000s		8	
Total cost in $ 000s		36	
BENEFIT/COST ratio		21	
PAY BACK PERIOD		5.3	Months

Note:

3.5 = Capacitor cost used in $/kVAR

The loading in 1993 is expected to increase due to the removal of the existing constraints.
The present worth of loss reduction has been worked out with one year (1992) at the existing load and thereafter at the new expected load.
The present worth factor used for the streem of losses after 1993 is 6.

TABLE C 4

COSTS OF VARIABLE STATIC VAR COMPENSATING SYSTEMS AT GRID SUBSTATIONS

		MVAR	MVAR	MVAR
Rating of Installation		20	30	55
ESTIMATED PRICES OF COMPONENTS		COST IN US $ 000s		
Thyristor controlled reactor with control and protection systems		1900	2350	3475
Capacitor banks, at	5 $ per KVAR	100	150	275
Step down transformer		350	350	550
Civil works and miscellaneous costs		150	175	200
Switchgear Cost in US $ 000s				
132 kV breaker and associated equipment	300			
11 kV breaker and associated equipment	75			
Additional cost for insurance, freight and installat as % of base costs	25 %			

COST OF COMBINED UNIT WITH STEP DOWN TRANSFORMER

No. of switched capacitor banks (no. of circuit breakers)	TOTAL COST OF SVS UNIT IN US $ 000s		
0	3594	4250	6094
2	3781	4438	6281
3	3875	4531	6375
4	3969	4625	6469
5	4063	4719	6563

COST OF COMBINED UNIT WITHOUT STEP DOWN TRANSFORMER

No. of switched capacitor banks (no. of circuit breakers)	TOTAL COST OF SVS UNIT IN US $ 000s		
0	2781	3438	5031
2	2969	3625	5219
3	3063	3719	5313
4	3156	3813	5406
5	3250	3906	5500

LOSS SAVINGS BY USE OF CAPACITORS AT UBUNGO / ILALA

	Loss savings by 30 MVAr compensation				Loss savings by add'l. 15 MVAr compensation			
	MW	KWH	PV MWH	PV $ 000	MW	KWH	PV MWH	PV $ 000
1993MAX	1.90	333			0.22	39		
** 1993AP1	2.25	2562			0.45	512		
** 1993AP2	2.06	3609			0.50	876		
1993AM1	0	0			0	0		
1993AM2	0	0			0	0		
TOTAL 1993		6504	5375	538		1427	1179	118
Tot. without **		2895	2393	239		551	455	46
1994MAX	0.89	156			0	0		
1994AP1	1.90	2164			0.22	251		
** 1994AP2	2.25	3942			0.45	788		
** 1994AM1	2.06	1805			0.45	394		
1994AM2	0	0			0	0		
TOTAL 1994		8066	6060	606		1433	1077	108
Tot. without **		2320	1743	174		251	188	19
1995MAX	0.41	72			0	0		
1995AP1	0.54	615			0.07	80		
1995AP2	0.82	1437			0	0		
1995AM1	0.41	359			0	0		
1995AM2	0.32	561			0	0		
TOTAL 1995		3043	2079	208		80	54	5
1996MAX	0	0			0	0		
1996AP1	0.41	467			0	0		
1996AP2	0.54	946			0.07	123		
1996AM1	0.82	718			0	0		
1996AM2	0.41	718			0	0		
TOTAL 1996		2850	1769	177		123	76	8
1997MAX	0	0			0	0		
1997AP1	0	0			0	0		
1997AP2	0.41	718			0	0		
1997AM1	0.54	473			0.07	61		
1997AM2	0.82	1437			0	0		
TOTAL 1997		2628	1483	148		61	35	3
TOTAL LOSS REDUCTION BENEFITS 1993 TO END 1997 ($000's)				1677				242
BENEFIT / COST RATIO (loss reduction only)				8.8				2.5
Overall benefit/cost ratio for 45 MVAr						6.7		
Loss reduction benefits excluding periods 1993 AP1&2 and 1994 AP1&AM1 (see note 5)				947				81
Benefit / Cost ratio (addl. loss reduction)				5.0				0.9
Overall benefit/cost ratio for 45 MVAr						3.6		

Notes to computations:

(1) Details of load duration curve:

p.u. time	period
0.02	MAX
0.13	AP1
0.2	AP2
0.1	AM1
0.2	AM2
0.3	BASE
0.05	LB

(2) Interest rate in % 10.0

(3) Energy costs:
$ / kWH 0.1

(4) Net PV of capacitor installation

	$ 000's
30 KVA	190.0
addl 15 KVA	95.0

(see Table B7)

(5) In the periods 1993 AP1 and AP2 and 1994 AP2 and AM1 the system voltages are too low to be supported without caapacitors. The equivalent generation required at Ubungo is 10 and 5 MW respectively. If the benefits of avoiding this generation is counted (Table C5) the benefits of loss reduction for these periods must not be counted again.

BENEFIT / COST ANALYSIS OF SWITCHED CAPACITORS AT UBUNGO

	Value of generation saved at Ubungo by using 30 MVAr of capacitors					Value of saving of outages by using 30 MVAr of capacitors			
Year	MW avoided	Time p.u.	MWh saved	Value in$000	PV $000	MW saved	MWh saved	Value $000	PV $000
1993	10	0.33	28908	2891	2389	30	360	360	298
1994	10	0.30	26280	2628	1974	30	360	360	270
1995						30	360	360	246
1996						35	420	420	261
1997						40	480	480	271
	Total NPV of savings $ 000's				4364				1346

For 30 MVAr Installation	NPV of benefits: saved generation and avoided outages (in $000):	5709
	Benefit / cost ratio for saved generation and avioded outages	30.1
	Additional benefits from loss reduction benefits (see TableC5-1) in $ 000's	1677
	Total savings: saved generation, avoided outages and loss reduction	7386
	Benefit / cost ratio counting all related benefits	39.0
For additional 15 MVAr installation	Estimated benefits of saved generation and avoided outages in $ 000's at 10% of saving for 30 MVAr installation	571
	Benefit / cost ratio for saved generation and avioded outages	6.0
	Additional benefits from loss reduction benefits (see TableC5-1) in $ 000's	242
	Benefit / cost ratio counting all related benefits	8.6
For total installation of 45 MVAr	Benefit / cost ratio for saved generation and avioded outages	22.1
	Benefit / cost ratio counting all related benefits	28.8

Computation of Pay back period:

Benefits of year 1993 (considering only a 30 MVAr application)	3251
Cost of total installation (45 MVAr) at 1991 prices	825
Pay back period (months)	3.0

COST OF CAPACITOR INSTALLATION

	Unit	Rate $000	Qty.	Cost $000	Addl Qty	Addl cost $000
Cost of capacitors	MVAr	5	30	150	15	75
Circuit breakers	Nos.	150	2	300	1	150
Misc. works	Item			25		25
Contingencies				75		25
Total Cost				550		275
PV of cost (incured in 1992)				500		250
PV for installation in 1998 (cost in 1987)				310		155
PV of net cost of proposal				190		95

Notes:

10 = Interest rate in %
0.1 = Value of generation saved in $/kW
1 = Value of saved outages in $/kW
3 = Hrs. per outage
4 = No. of outages per year

BENEFIT / COST ANALYSIS OF INSTALLING REACTIVE COMPENSATION AT ARUSHA — TABLE C 6

Year	1992	1993	1994	1995	1996	1997	1998
Expected load at Moshi MW	19.1	20.3	21.7	23.1	24.6	26.2	27.9
Expected load at Arusha MW	21.4	22.8	24.3	25.9	27.5	29.3	31.2
Total load in MW	40.5	43.1	45.9	48.9	52.1	55.5	59.1
Expected energy sales in GWh (av. LF of 0.65)	230.6	245.6	261.6	278.6	296.7	316.0	336.5
Sales possible with no additional compensation, GWh	159.4	159.4	159.4	182.2	182.2	182.2	182.2
Additional sales in GWh	71.2	86.2	102.1	96.4	114.5	133.7	154.3
Value of addl. sales, M$	7.1	8.6	10.2	9.6	11.4	13.4	15.4
PV of addl. sales, M$		7.1	7.7	6.6	7.1	7.5	7.9

	SVS INSTALLATION			SWITCHED CAPACITORS		
	NPV of Benefits:	B/C ratio 1	B/C ratio 2 see Note 3	NPV of Benefits:	B/C ratio	Singida - Arusha line commissioning in
With commissioning of proposal in 1993 (begining):						
NPV 1993 - 1994 in M$	14.8	3.3	5.5	7.4	6.6	1994 end
NPV 1993 - 1995 in M$	21.4	4.7	7.5	10.7	9.6	1995 end
NPV 1993 - 1996 in M$	28.5	6.3	9.5	14.2	12.8	1996 end
NPV 1993 - 1997 in M$	36.0	7.9	11.5	18.0	16.2	1997 end
Pay back in months	8.4			1.9		
With commissioning of proposal in 1994 (begining):						
NPV 1994 - 1994 in M$	7.7	1.7	2.9	3.8	3.4	1994 end
NPV 1994 - 1995 in M$	14.3	3.1	5.0	7.1	6.4	1995 end
NPV 1994 - 1996 in M$	21.4	4.7	7.1	10.7	9.6	1996 end
NPV 1994 - 1997 in M$	28.9	6.4	9.2	14.5	13.0	1997 end
Pay back in months	7.8			1.7		

Notes:

1. Load supported with existing capacitors at Moshi & Arusha with Hale voltage at max. and firm generation at Moshi is 28 MW with present generation, and 32 MW with New Pangani (1995)

2. Value of addl. sales for fully acceptable technical solution, ie. SVS $/kWh 0.1; for switched cap. $/kWh 0.05

3. B/C calculation 1 is made without any rebate for the value of the SVS unit at the commissioning of the Singida - Arusha line. B/C calculation 2 is made with a rebate of half the value of the SVS at the time of construction of the new line.

4. Interest rate in % 10

5. COST OF SVS 0 TO 30 MVAR (see Table C5):

Cost of SVS unit (1992) M$	5.0
Cost discounted to 1991	4.5

5. COST OF 6 X 5 MVA SWITCHED CAPACITOR BANKS:

	Unit	Rate $000	Qty.	Cost $000
Cost of capacitors	MVAr	5	30	150
Circuit breakers	Nos.	150	6	900
Control cct. & misc.	Item			100
Contingencies				75
Total Cost				1225
PV of cost (incured in 1992)				1114

TABLE C.7.1

UNIT COST OF MEDIUM VOLTAGE CAPACITORS AND ASSOCIATED EQUIPMENT
TO BE INSTALLED ON DISTRIBUTORS

		COST F.O.B in $ 000 's		Capacitor cost
		11kV	33kV	in $ per KVAR
CAPACITOR BANK				
THREE-PH.	50 kVAR	1.20	1.20	24.0
THREE-PH	100 kVAR	1.20	1.20	12.0
THREE-PH	150 kVAR	1.20	1.20	8.0
THREE-PH	200 kVAR	1.35	1.35	6.8
THREE-PH	250 kVAR	1.40	1.40	5.6
THREE-PH	300 kVAR	1.43	1.43	4.8
THREE-PH	400 kVAR	1.55	1.55	3.9
THREE-PH	500 kVAR	1.70	1.70	3.4
THREE-PH	600 kVAR	1.90	1.90	3.2
FUSED CUTOUT		0.20	0.50	
MV OIL SWITCH		1.35	4.85	
SURGE ARRESTERS		0.16	0.68	
POWER TF./CONT. UNIT		0.80	1.25	
Local Transport & Installation				
Unswitched banks		0.50	0.50	
Switched banks		0.60	0.60	

Note:

The above unit costs have been used for the computation of the cost of capacitor banks to be used on 11 and 33 kV networks. (See Tables C 7.2 and C.7.3)

TABLE C 7.2

COST OF UNSWITCHED CAPACITOR BANKS AT 11kV, POLE MOUNTED

RATING 3 PHASE in KVAR	50	100	150	200	250	300	400	500	600
				Installed Cost in $ 000's					
CAPACITOR	1.2	1.2	1.2	1.35	1.4	1.43	1.55	1.7	1.9
FUSED CUTOUT	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
SURGE ARRESTORS	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
TOTAL FOB	1.56	1.56	1.56	1.71	1.76	1.79	1.91	2.06	2.26
FREIGHT & INS. (at 15% FOB)	0.23	0.23	0.23	0.26	0.26	0.27	0.29	0.31	0.34
L TRANS. & INSTALATION	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
TOTAL COST	2.29	2.29	2.29	2.47	2.52	2.56	2.70	2.87	3.10
				Cost per KVAR in $ per KVAR					
FOB	31.20	15.60	10.40	8.55	7.04	5.97	4.78	4.12	3.77
Installed	45.88	22.94	15.29	12.33	10.10	8.53	6.74	5.74	5.17

COST OF UNSWITCHED CAPACITOR BANKS AT 33kV, POLE MOUNTED.

RATING 3 PHASE in KVAR	50	100	150	200	250	300	400	500	600
				Installed Cost in $ 000's					
CAPACITOR	1.20	1.20	1.20	1.35	1.40	1.43	1.55	1.70	1.90
FUSED CUTOUT	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
SURGE ARRESTORS	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
TOTAL FOB	2.38	2.38	2.38	2.53	2.58	2.61	2.73	2.88	3.08
FREIGHT & INS. (at 15% FOB)	0.36	0.36	0.36	0.38	0.39	0.39	0.41	0.43	0.46
L TRANS. & INSTALATION	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
TOTAL COST	3.24	3.24	3.24	3.41	3.47	3.50	3.64	3.81	4.04
				Cost per KVAR in $ per KVAR					
FOB	47.60	23.80	15.87	12.65	10.32	8.70	6.83	5.76	5.13
Installed	64.74	32.37	21.58	17.05	13.87	11.67	9.10	7.62	6.74

TABLE C7.3

COST OF SWITCHED CAPACITOR BANKS AT 11kV, POLE MOUNTED

RATING 3 PHASE in KVAR	50	100	150	200	250	300	400	500	600
				Installed Cost in $ 000's					
CAPACITOR	1.20	1.20	1.20	1.35	1.40	1.43	1.55	1.70	1.90
OIL SWITCH	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35
SURGE ARRESTORS	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
TOTAL FOB	2.71	2.71	2.71	2.86	2.91	2.94	3.06	3.21	3.41
FREIGHT & INS. (at 15% FOB)	0.41	0.41	0.41	0.43	0.44	0.44	0.46	0.48	0.51
L TRANS. & INSTALATION	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
TOTAL COST	3.62	3.62	3.62	3.79	3.85	3.88	4.02	4.19	4.42
				Cost per KVAR in $ per KVAR					
FOB	54.20	27.10	18.07	14.30	11.64	9.80	7.65	6.42	5.68
Installed	72.33	36.17	24.11	18.95	15.39	12.94	10.05	8.38	7.37

COST OF SWITCHED CAPACITOR BANKS AT 33kV, POLE MOUNTED.

RATING 3 PHASE in KVAR	50	100	150	200	250	300	400	500	600
				Installed Cost in $ 000's					
CAPACITOR	1.2	1.2	1.2	1.35	1.4	1.43	1.55	1.7	1.9
OIL SWITCH	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85
SURGE ARRESTERS	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
TOTAL FOB	6.73	6.73	6.73	6.88	6.93	6.96	7.08	7.23	7.43
FREIGHT & INS. (at 15% FOB)	1.01	1.01	1.01	1.03	1.04	1.04	1.06	1.08	1.11
L TRANS. & INSTALATION	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
TOTAL COST	8.34	8.34	8.34	8.51	8.57	8.60	8.74	8.91	9.14
				Cost per KVAR in $ per KVAR					
FOB	134.60	67.30	44.87	34.40	27.72	23.20	17.70	14.46	12.38
Installed	166.79	83.40	55.60	42.56	34.28	28.68	21.86	17.83	15.24

CAPACITOR APPLICATIONS
LOSS REDUCTION BENEFITS ON EXISTING 11 KV SYSTEMS

FEEDER NAME	Length (km)	Feeder Peak Amps	OldPF Cos ό Peak	OldPF Cos ό Day	OldPF Cos ό Base	Peak NewPF Cos ό	Day NewPF Cos ό	Base NewPF Cos ό	Capacit applied (kVA)	LOSS SAVINGS IN MW 1991 night	1995 night	1991 day	1995 day	1991 base	1995 base	'91 Units Saved MWh	'91 Units Saved MWh	Annual % inc. savings	LRLF 1991	LRLF 1995
U1, Kisiwani	9.0	175	0.94	0.82	0.94	0.99	0.95	1.00	600	9.9	16.2	10.0	16.3	3.2	6.3	57	99	15	0.66	0.70
U2, Menzese	8.4	146	0.90	0.87	0.90	0.97	0.98	1.00	600	10.0	12.9	7.1	9.4	3.4	4.8	50	67	8	0.57	0.60
U7, Factory	3.9	75	0.93	0.90	0.93	1.00	1.00	0.89	600	1.2	2.6	1.4	2.9	-0.2	0.5	5	15	32	0.48	0.64
K4, INDUSTRIAL	9.5	185	0.91	0.83	0.91	0.97	0.91	1.00	600	25.7	32.9	41.7	52.3	9.1	12.7	199	256	7	0.88	0.89
K3, KILWA RD	8.5	231	0.91	0.85	0.91	0.96	0.94	0.99	600	8.5	10.7	6.3	8.0	3.4	4.5	46	59	7	0.61	0.63
PORT	4.3	157	0.96	0.86	0.96	1.00	0.94	0.98	600	5.2	9.5	15.7	24.8	0.7	2.8	56	99	15	1.23	1.19
D1, Azamia	5.5	250	0.93	0.96	0.93	0.99	0.99	0.99	600	3.9	4.8	7.4	8.9	0.9	1.3	31	39	6	0.91	0.92
D2, Town 1	6.1	190	0.93	0.83	0.93	1.00	0.90	0.98	600	3.8	5.5	13.7	18.1	0.7	1.5	48	68	9	1.47	1.41
D3, Kurasini	2.8	180	0.91	0.90	0.91	0.97	0.97	1.00	600	4.2	5.0	3.3	4.0	1.5	1.9	22	28	5	0.62	0.63
D9, Town 2	2.5	300	0.93	0.96	0.93	0.96	0.99	0.99	600	6.0	8.4	2.9	4.2	2.5	3.7	28	41	10	0.53	0.55
D10, Magomeni	6.5	230	0.93	0.96	0.93	0.98	0.99	1.00	600	9.3	11.9	7.9	10.2	3.4	4.7	52	68	7	0.63	0.65
C3, City Center 1	1.2	240	0.93	0.96	0.93	0.99	0.99	0.99	600	0.9	1.3	1.5	2.1	0.2	0.4	7	10	10	0.84	0.86
C4, City Center 2	2.2	270	0.93	0.96	0.93	0.99	0.99	1.00	600	2.0	2.8	3.3	4.5	0.6	1.0	15	21	9	0.86	0.87
C5, Mnazi Mneja 1	1.4	195	0.93	0.96	0.93	0.98	1.00	1.00	600	2.0	2.7	1.0	1.4	0.7	1.1	9	13	9	0.51	0.54
C6, Mnazi Mneja 2	1.8	118	0.96	0.96	0.96	1.00	1.00	0.97	600	0.8	1.1	0.5	0.8	0.0	0.2	3	5	14	0.43	0.51
C8, Tanesco	1.4	226	0.93	0.96	0.93	0.97	0.99	1.00	600	2.4	3.3	1.5	2.1	0.9	1.3	12	17	9	0.56	0.58
MK1, Msasani	8.2	155	0.93	0.90	0.98	0.98	0.98	0.98	600	8.5	11.7	7.2	10.0	-0.1	0.8	33	50	11	0.45	0.49
MK2, Tandale	10.8	190	0.91	0.83	0.91	0.96	0.92	1.00	600	17.1	27.2	20.0	31.5	6.4	11.4	112	182	13	0.74	0.76
MK3, Lugalo	4.8	80	0.90	0.87	0.90	1.00	0.98	0.93	600	2.3	3.0	1.0	1.4	0.2	0.5	7	11	11	0.35	0.42
MK4, north east	4.5	174	0.98	0.90	0.98	1.00	0.98	0.99	600	2.1	3.2	4.6	6.4	0.2	0.7	17	27	11	0.93	0.94
O2, Mwenge	4.2	135	0.98	0.90	0.98	1.00	1.00	0.96	600	1.2	1.6	2.2	2.9	-0.2		7	11	10	0.70	0.74
O3, Packers	9.6	296	0.98	0.90	0.98	1.00	0.95	1.00	600	10.4	13.5	17.6	22.2	3.3	4.9	81	106	7	0.89	0.89
O4, Kinondoni	2.8	177	0.90	0.81	0.90	0.96	0.92	1.00	600	24.1	30.6	24.3	30.9	8.9	12.2	145	189	7	0.69	0.70
O5, Seaview	3.6	115	0.92	0.91	0.92	0.99	1.00	0.99	600	2.6	3.0	1.9	2.3	0.6	0.8	12	15	5	0.53	0.55
O6, Oyster bay	4.3	120	0.93	0.90	0.93	0.99	1.00	0.99	600	3.0	3.8	2.4	3.1	0.7	1.1	14	19	7	0.54	0.57
KUNDUCHI	13.5	180	0.93	0.79	0.93	0.98	0.91	1.00	600	35.9	64.8	44.4	78.4	12.3	26.8	236	441	17	0.75	0.78
LUGALO	7.0	150	0.92	0.90	0.92	0.98	0.99	1.00	600	7.5	8.6	5.1	6.0	2.4	2.9	36	43	4	0.55	0.57
F5, BUGURUNI	3.2	110	0.71	0.85	0.71	0.94	0.96	0.96	600	2.7	3.3	3.4	4.1	0.7	1.0	17	21	6	0.72	0.74
F2, RTD	2.5	170	0.71	0.85	0.71	0.81	0.97	0.91	600	6.5	8.6	2.4	3.3	2.8	3.8	29	39	8	0.50	0.52
UKONGA	5.0	60	0.89	0.90	0.89	1.00	0.96	0.83	600	3.1	4.2	1.0	1.9	-0.5	0.0	5	12	23	0.19	0.32
F31, INDUSTRIAL	2.6	195	0.71	0.85	0.71	0.80	0.92	0.89	600	7.6	9.4	5.7	7.1	3.3	4.2	42	53	6	0.63	0.64
F33, AIRWING	2.3	75	0.79	0.78	0.79	0.98	0.97	0.93	600	1.5	1.6	1.8	1.9	0.3	0.3	9	9	2	0.67	0.68
F34, KIWALANI	5.8	100	0.91	0.85	0.91	1.00	0.97	0.88	600	1.9	3.1	5.4	7.5	-0.2	0.4	18	28	12	1.05	1.04
FEEDER 1	10.0	75	0.89	0.90	0.89	1.00	0.96	0.92	600	9.8	15.9	2.0	5.6	0.7	3.8	23	56	24	0.27	0.40
FEEDER 2	6.0	84	0.89	0.90	0.89	1.00	0.98	0.95	600	7.2	11.3	2.0	4.3	1.1	3.1	21	43	20	0.33	0.43

Table C8.A

Table C8-B

CAPACITOR APPLICATIONS LOSS REDUCTION BENEFITS ON 11 KV LINES
AFTER NETWORK REARRANGEMENT

FEEDER NAME	New Length (km)	Old Length (km)	New Feeder Peak Amps	Old Feeder Peak Amps	NIGHT OldPF Cos ϕ	NIGHT NewPF Cos ϕ	DAY OldPF Cos ϕ	DAY NewPF Cos ϕ	BASE OldPF Cos ϕ	BASE NewPF Cos ϕ	Capacit applied (kVA)	LOSS SAVINGS IN MW 1991 Night	LOSS SAVINGS IN MW 1995 Night	LOSS SAVINGS IN MW 1991 Day	LOSS SAVINGS IN MW 1995 Day	LOSS SAVINGS IN MW 1991 Base	LOSS SAVINGS IN MW 1995 Base	'91 Units Saved MWh	'95 Units Saved MWh	Growth rate of loss red/i p.a.	1991 LRLF	1995 LRLF
U1, Kiswani	8.98	8.98	167	175	0.94	0.99	0.82	0.95	0.94	1.00	600	9.9	16.2	10.0	16.3	3.2	6.3	57	99	14.6	0.66	0.70
U2, Menzese	3.30	8.36	75	146	0.90	1.00	0.87	1.00	0.9	0.94	600	1.7	2.3	1.0	1.5	0.2	0.5	6	10	12.6	0.43	0.50
U7, Factory	3.91	3.91	70	75	0.93	1.00	0.90	1.00	0.93	0.89	600	1.2	2.6	1.4	2.9	-0.2	0.5	5	15	32.1	0.48	0.64
K4, INDUSTRIAL	4.20	9.52	53	185	0.91	0.99	0.83	1.00	0.91	0.62	600	1.7	2.7	4.1	5.7	-1.6	-1.2	7	15	19.7	0.51	0.64
K3, KILWA RD	5.70	8.50	105	231	0.91	0.99	0.85	1.00	0.91	0.99	600	2.2	3.0	1.5	2.1	0.6	0.9	10	14	9.3	0.52	0.56
PORT	2.20	4.32	116	157	0.96	1.00	0.86	0.95	0.96	0.97	600	2.2	4.2	7.1	11.3	0.1	1.1	25	44	15.7	1.25	1.20
D0, Brewery	0.30	0.30	84	90	0.93	1.00	0.96	0.99	0.93	0.94	600	0.1	0.2	0.0	0.1	0.0	0.0	0	1	16.2	0.32	0.42
D1, Azamia	1.70	5.45	103	250	0.93	1.00	0.96	0.99	0.93	0.98	600	1.1	1.3	2.1	2.5	0.2	0.3	8	11	6.2	0.91	0.92
D2, Town 1	2.90	6.05	221	190	0.93	0.97	0.83	0.89	0.93	0.99	600	5.0	6.7	9.3	12.1	1.9	2.8	43	57	7.6	0.98	0.98
D3, Kurasini	1.80	2.82	131	180	0.91	0.98	0.90	0.99	0.91	1.00	600	1.9	2.3	1.5	1.8	0.6	0.8	10	12	6.0	0.58	0.60
D9, Town 2	2.00	2.53	133	300	0.93	0.99	0.96	1.00	0.93	1.00	600	1.8	2.7	0.6	1.1	0.5	0.9	7	11	13.9	0.43	0.48
D10, Magomeni	3.20	6.51	93	230	0.93	1.00	0.96	1.00	0.93	0.96	600	1.7	2.3	1.3	1.9	0.2	0.5	7	11	11.5	0.49	0.55
C2, Upanga	3.30	3.26	80	80	0.98	0.98	0.96	0.98	0.98	0.86	600	-0.1	0.1	0.2	0.5	-0.6	-0.5	-2	-1	-32.1	3.17	-0.39
C3, City Center 1	1.10	1.20	49	240	0.93	0.97	0.96	1.00	0.93	0.73	600	0.1	0.2	0.3	0.5	-0.2	-0.1	0	1	52.4	0.34	0.69
C4, City Center 2	0.90	2.21	43	270	0.93	0.93	0.96	0.99	0.93	0.64	600		0.1	0.2	0.3	-0.2	-0.1		0		11.53	0.53
C5, Mnazi Mneja 1	1.40	1.44	186	195	0.93	0.98	0.96	1.00	0.93	1.00	600	2.9	4.1	1.0	1.4	0.7	1.1	10	15	9.8	0.40	0.41
C6, Mnazi Mneja 2	1.80	1.76	113	118	0.96	1.00	0.96	1.00	0.96	0.97	600	0.6	0.8	0.6	0.8	0.0	0.2	3	4	14.2	0.53	0.65
C8, Tanesco	1.30	1.44	63	226	0.93	0.99	0.96	0.97	0.93	0.86	600	0.3	0.5	0.0	0.2	-0.1	0.0	0	1	94.7	0.04	0.30
MK1, Msasani	4.50	8.20	87	155	0.93	1.00	0.90	0.99	0.98	0.89	600	2.1	3.1	2.9	4.2	-0.8	-0.5	8	15	15.8	0.45	0.54
MK2, Tandale	4.50	10.84	69	190	0.91	1.00	0.83	0.99	0.91	0.93	600	2.0	3.9	2.5	4.5	0.1	1.0	11	23	21.5	0.60	0.67
MK3, Lugalo	4.80	4.80	72	80	0.90	1.00	0.87	0.98	0.9	0.93	600	2.3	3.0	1.0	1.4	0.2	0.5	7	11	11.3	0.35	0.42
MK4, north east	4.50	4.50	171	174	0.98	1.00	0.90	0.98	0.98	0.99	600	2.1	3.2	4.6	6.4	0.2	0.7	17	26	11.1	0.93	0.94
O2, Mwenge	4.20	4.22	132	135	0.98	1.00	0.90	1.00	0.98	0.96	600	1.3	1.8	2.2	2.8	-0.2		7	11	10.3	0.64	0.68
O3, Packers	3.20	9.64	116	296	0.98	1.00	0.90	1.00	0.98	0.95	600	0.8	1.3	1.6	2.2	-0.3	-0.1	4	8	15.5	0.63	0.69
O4, Kinondoni	2.80	2.79	74	177	0.90	1.00	0.81	1.00	0.9	0.94	600	7.9	10.9	6.4	9.1	0.8	2.4	34	53	11.8	0.49	0.55
O5, Seaview	3.60	3.58	107	115	0.92	0.99	0.91	1.00	0.92	0.99	600	2.5	2.9	1.9	2.3	0.6	0.8	12	15	4.9	0.54	0.57
O6, Oyster bay	2.80	4.28	67	120	0.93	1.00	0.90	1.00	0.93	0.88	600	0.6	0.9	1.2	1.5	-0.2		4	6	12.1	0.63	0.71
KUNDUCHI	4.20	13.46	38	180	0.93	0.88	0.79	0.99	0.93	0.56	600	-0.6	1.2	2.3	5.8	-2.0	-1.1	-3	14		0.62	1.27
PACKERS	3.40	3.36	57	60	0.93	0.99	0.85	1.00	0.93	0.81	600	1.1	1.7	3.6	4.6	-0.9	-0.6	8	14	13.7	0.86	0.91
LUGALO	7.00	6.96	141	150	0.92	0.98	0.90	0.97	0.92	1.00	600	7.2	8.2	8.9	10.2	2.4	2.9	47	54	3.7	0.75	0.76
F5, BUGURUNI	1.30	3.20	37	110	0.71	0.99	0.85	0.97	0.71	0.81	600	0.7	0.9	0.2	0.3	0.1	0.2	2	3	11.0	0.34	0.40
F2, RTD	2.50	2.50	150	170	0.71	0.81	0.85	0.97	0.71	0.91	600	6.5	8.6	2.4	3.3	2.8	3.8	28	39	8.0	0.50	0.52
KISARAWE	17.80	17.80	31	28	0.89	0.80	0.90	0.79	0.89	0.44	600	-2.8	-2.2	-3.3	-2.7	-8.8	-8.5	-52	-48	-1.9	2.13	2.53
UKONGA	5.00	5.00	54	60	0.89	1.00	0.90	0.96	0.89	0.83	600	3.1	4.2	1.0	1.9	-0.5	0.0	5	12	23.2	0.19	0.32
F31, INDUSTRIAL	2.60	2.60	167	195	0.71	0.80	0.85	0.92	0.71	0.89	600	7.6	9.4	5.7	7.1	3.3	4.2	42	53	6.0	0.63	0.64
F33, AIRWING	2.30	2.30	54	75	0.79	0.98	0.78	0.97	0.79	0.93	600	1.5	1.6	1.8	1.9	0.3	0.3	9	9	2.4	0.67	0.68
F34, KIWALANI	5.80	5.80	64	100	0.91	1.00	0.85	0.97	0.91	0.88	600	1.9	3.1	5.4	7.5	-0.2	0.4	18	28	12.3	1.05	1.04
Kigam F1	10.00	10.00	67	75	0.89	1.00	0.90	0.96	0.89	0.92	600	9.8	15.9	2.0	5.6	0.7	3.8	23	56	24.4	0.27	0.40
Kigam F2	6.00	6.00	75	84	0.89	1.00	0.90	0.98	0.89	0.95	600	7.2	11.3	2.0	4.3	1.1	3.1	21	43	19.6	0.33	0.43

Table C9

CAPACITOR APPLICATIONS
LOSS REDUCTION BENEFITS ON 33 KV LINES

FEEDER NAME	Length (km)	Feeder Peak Amps	Peak OldPF Cos ó	Day OldPF Cos ó	Base OldPF Cos ó	Peak NewPF Cos ó	Day NewPF Cos ó	Base NewPF Cos ó	Capacit applied (kVA)	<--------- 1991 night	LOSS 1995 night	SAVINGS 1991 day	IN MW 1995 day	'------------ 1991 base	----------> 1995 base	Units Saved MWh	Units Saved MWh	Annual % inc. savings	LRLF 1991	LRLF 1995	Inc. of units saved MWh 1991	Inc. of units saved MWh 1995	Inc. of MWh per kVA of capacit 1991	Inc. of MWh per kVA of capacit 1995
ILALA-C.C 1	2.5	148	0.94	0.96	0.94	0.95	0.97	0.98	300	1.2	1.6	1.2	1.5	0.6	0.8	8	10	6	0.72	0.73				
ILALA-C.C 11	2.5	148	0.94	0.96	0.94	0.96	0.97	0.98	600	2.4	3.0	2.2	2.9	1.0	1.4	15	19	7	0.70	0.71	7	9	0.02	0.03
ILALA-KURASINI	5.9	232	0.91	0.87	0.91	0.92	0.88	0.92	300	5.9	7.6	5.5	7.3	2.8	3.7	37	49	7	0.72	0.73				
ILALA-KURASINI	5.9	232	0.91	0.87	0.91	0.92	0.90	0.94	600	11.4	14.9	10.7	14.2	5.4	7.1	71	94	7	0.72	0.72	34	46	0.11	0.15
ILALA-KURASINI	5.9	232	0.91	0.87	0.91	0.94	0.92	0.97	1200	21.5	28.6	20.1	27.1	9.4	13.0	131	178	8	0.70	0.71	60	83	0.10	0.14
ILALA-KURASINI	5.9	232	0.91	0.87	0.91	0.95	0.94	0.99	1800	30.3	40.9	28.2	38.7	12.2	17.5	180	249	8	0.68	0.70	49	72	0.08	0.12
ILALA-KURASINI	5.9	232	0.91	0.87	0.91	0.98	0.97	1.00	3000	44.0	61.8	40.6	58.1	13.9	22.8	244	360	10	0.63	0.66	64	110	0.05	0.09
KURASINI-KIGAMBONI	4.0	53	0.89	0.90	0.89	0.93	0.98	0.98	300	0.9	1.2	0.5	0.7	0.4	0.6	4	6	9	0.56	0.57				
KURASINI-KIGAMBONI	4.0	53	0.89	0.90	0.89	0.96	0.99	1.00	600	1.6	2.3	0.7	1.1	0.6	0.9	7	11	11	0.50	0.53	2	4	0.01	0.01
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.95	0.95	0.91	0.97	600	11.3	13.5	10.2	12.2	5.3	5.6	70	80	3	0.71	0.68				
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.95	0.96	0.93	0.98	1200	21.4	25.7	19.3	23.2	9.5	9.9	129	149	4	0.69	0.66	59	69	0.10	0.12
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.95	0.97	0.94	0.99	1800	30.2	36.8	27.0	33.0	12.3	13.1	177	207	4	0.67	0.64	48	58	0.08	0.10
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.95	0.98	0.96	1.00	2400	37.8	46.6	33.6	41.5	14.0	15.0	215	255	4	0.65	0.62	38	48	0.06	0.08
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.93	0.98	0.97	1.00	2600	40.1	49.7	56.0	72.8	14.3	19.1	285	369	7	0.81	0.85	70	114	0.35	0.57
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.93	0.98	0.97	1.00	2800	42.2	52.6	57.8	75.2	14.4	19.6	293	382	7	0.79	0.83				
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.93	0.98	0.97	1.00	3000	44.2	55.3	59.4	77.5	14.4	20.0	301	394	7	0.78	0.81				
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.93	0.99	0.98	1.00	3200	46.1	57.9	60.9	79.7	14.3	20.2	308	406	7	0.76	0.80				
ILALA-OYSTERBAY	5.6	285	0.93	0.88	0.93	0.99	0.98	1.00	3400	47.6	60.3	62.3	81.7	14.0	20.3	313	416	7	0.75	0.79				
ILALA-FZ I	4.7	80	0.71	0.85	0.71	0.74	0.88	0.78	300	2.6	3.3	1.7	2.1	1.3	1.6	14	18	6	0.62	0.62				
ILALA-FZ I	4.7	80	0.71	0.85	0.71	0.78	0.91	0.85	600	5.0	6.3	3.1	3.9	2.2	2.9	26	33	6	0.60	0.60	12	16	0.04	0.05
UBUNGO-ALAF *	9.2	105	0.89	0.89	0.89	0.91	0.91	0.91	300	3.8	4.3	3.7	4.2	3.8	4.3	33	37	3	0.99	0.99				
UBUNGO-ALAF *	9.2	105	0.89	0.89	0.89	0.93	0.93	0.93	500	6.1	6.8	6.0	6.7	6.1	6.8	53	59	3	0.99	0.99	20	22	0.10	0.11
UBUNGO-ALAF *	9.2	105	0.89	0.89	0.89	0.96	0.95	0.96	1000	10.9	12.3	12.6	14.2	10.8	12.2	100	113	3	1.05	1.05	47	54	0.09	0.11
UBUNGO-WAZO 1 *	8.8	68	0.93	0.84	0.93	0.95	0.90	0.97	600	8.0	11.1	7.8	10.7	3.5	5.1	50	70	9	0.71	0.72				
UBUNGO-WAZO 1 *	8.8	68	0.93	0.84	0.93	0.97	0.94	1.00	1200	14.1	20.4	13.6	19.5	5.1	8.3	83	123	10	0.67	0.69	33	53	0.05	0.09
UBUNGO-WAZO 1 *	8.8	68	0.93	0.84	0.93	0.99	0.98	0.99	1800	18.3	27.7	17.5	26.4	4.8	9.5	99	159	13	0.62	0.66	16	36	0.03	0.06
UBUNGO-WAZO 1 *	8.8	68	0.93	0.84	0.93	1.00	1.00	0.96	2400	20.6	33.0	19.5	31.3	2.6	8.8	98	178	16	0.55	0.62	-1	19	-0.001	0.03
UBUNGO-WAZ0 1I	18.2	140	0.80	0.92	0.92	0.87	0.96	0.97	1000	41.2	47.3	26.5	30.8	25.0	29.0	247	286	4	0.68	0.69				
UBUNGO-WAZ0 1I	18.2	140	0.80	0.92	0.92	0.93	0.99	0.99	2000	71.2	83.5	42.0	50.4	38.9	46.9	397	474	5	0.64	0.65	150	189	0.15	0.19
UBUNGO-WAZ0 1I	18.2	140	0.80	0.92	0.92	0.96	1.00	1.00	3000	90.3	108.7	46.4	59.1	41.7	53.7	450	566	6	0.57	0.60	53	92	0.05	0.09
UBUNGO-TAZARA *	7.9	100	0.85	0.85	0.85	0.99	0.98	0.99	1200	6.0	6.7	7.0	7.6	6.0	6.7	56	62	3	1.06	1.06				
UBUNGO-TAZARA *	7.9	100	0.85	0.85	0.85	1.00	1.00	1.00	1800	6.4	7.5	7.9	9.2	6.4	7.5	60	70	4	1.08	1.08	5	8	0.01	0.01
UBUNGO-TAZARA *	7.9	100	0.85	0.85	0.85	0.96	0.98	0.96	2400	5.1	6.5	7.2	8.8	5.1	6.5	50	64	6	1.14	1.12	-10	-7	-0.02	-0.01
UBUNGO-MIKOCHENI	5.2	199	0.94	0.87	0.95	0.96	0.90	0.98	600	6.8	9.1	7.3	9.9	2.6	3.7	43	58	8	0.72	0.73				
UBUNGO-MIKOCHENI	5.2	199	0.94	0.87	0.95	0.97	0.93	1.00	1200	12.4	17.2	13.6	18.7	4.2	6.2	76	107	9	0.70	0.71	33	49	0.06	0.08
UBUNGO-MIKOCHENI	5.2	199	0.94	0.87	0.95	0.98	0.95	1.00	1800	17.0	24.0	18.6	26.4	4.5	7.6	99	146	10	0.67	0.69	23	39	0.04	0.06
UBUNGO-F111	11.0	155	0.84	0.87	0.84	0.94	0.95	0.99	2000	50.7	60.9	46.0	58.5	18.7	23.8	296	364	5	0.67	0.68				
UBUNGO-F111	11.0	155	0.84	0.87	0.84	0.97	0.98	0.99	3000	66.1	81.3	62.0	77.7	18.0	25.6	356	458	6	0.62	0.64	60	94	0.06	0.09
UBUNGO-F111	11.0	155	0.84	0.87	0.84	0.99	1.00	0.92	4000	74.7	95.0	69.3	90.3	10.6	20.8	358	493	8	0.55	0.59	2	35	0.00	0.04
F111-F11	7.0	36	0.89	0.90	0.89	0.94	0.96	0.98	300	1.0	1.2	0.7	0.8	0.4	0.5	5	6	3	0.62	0.62				
F111-F11	7.0	36	0.89	0.90	0.89	0.98	1.00	0.99	600	1.7	1.9	1.1	1.3	0.4	0.6	8	9	5	0.53	0.55	2	3	0.01	0.01
UBUNGO-F.TX2 *	1.8	50	0.80	0.80	0.80	0.86	0.85	0.86	300	0.4	0.4	0.5	0.6	0.4	0.4	4	4	3	1.09	1.09				
UBUNGO-F.TX2 *	1.8	50	0.80	0.77	0.80	0.92	0.87	0.92	600	0.7	0.8	1.0	1.1	0.7	0.8	7	8	3	1.14	1.14	3	4	0.01	0.01
UBUNGO-NORDIC *	55.0	64	0.92	0.92	0.92	0.97	0.99	0.97	600	9.1	12.3	5.3	7.4	9.1	12.3	68	93	6	0.86	0.87				
UBUNGO-NORDIC *	55.0	64	0.92	0.92	0.92	1.00	0.99	1.00	1200	13.4	19.7	5.7	9.9	13.4	19.7	95	144	11	0.81	0.83	26	51	0.04	0.09

Note: LRLF = Loss reduction load factor
The loss reduction load factor has been calculated based on the system peak values and not the individual peak values (for maximum savings)

Table C.10

LOSS REDUCTION ON UBUNGO - ILALA 132 KV LINE AND TOTAL SYSTEM BY DOWN STREAM CAPACITOR APPLICATIONS

Year 1992 with existing system

UB- Ilala line loss MW	Tot. sys. Loss MW	Capacit. at Ilala kVAr	UB- Ilala loss red/n kW	Tot. sys. loss red/n kW	Incremental loss red/n UB- Ilala UB-IL	Incremental loss red/n Tot. sys. Tot. sys.	Energy losses p.a. UB-IL MWh	Energy losses p.a. Tot. sys. MWh	Incremental energy savings UB-IL MWh	Incremental energy savings Tot. sys. MWh
0.713	21.48									
0.69	21.16	1000	23	320	23	320	101	1402	101	1402
0.668	20.86	2000	45	620	22	300	197	2716	96	1314
0.648	20.59	3000	65	890	20	270	285	3898	88	1183
0.629	20.37	4000	84	1110	19	220	368	4862	83	964
0.611	20.165	5000	102	1315	18	205	447	5760	79	898
0.594	19.965	6000	119	1515	17	200	521	6636	74	876
0.578	19.765	7000	135	1715	16	200	591	7512	70	876
0.563	19.57	8000	150	1910	15	195	657	8366	66	854

Year 1993 with double circuit Kidatu - Morogoro

0.654	18.79	0								
0.629	18.68	2000	25	110	25	110	109	482	109	482
0.607	18.57	4000	47	220	22	110	206	964	96	482
0.585	18.47	6000	69	320	22	100	302	1402	96	438
0.565	18.38	8000	89	410	20	90	390	1796	88	394

Year 1995 with double circuit Kidatu - Morogoro - Ubungo

0.763	17.59	0								
0.747	17.56	1000	16	30	16	30	70	131	70	131
0.736	17.53	2000	27	60	11	30	118	263	48	131
0.725	17.49	3000	38	100	11	40	166	438	48	175
0.714	17.44	5000	49	150	11	50	215	657	48	219
0.704	17.38	7000	59	210	10	60	258	920	44	263

Loss reduction load factor used for
computation of energy savings = 0.50

ECONOMIC ANALYSIS OF SELECTED CAPACITOR APPLICATIONS ON II kV LINES

TABLE C 11
SECTION A

ANALYSIS OF BENEFITS WITH NETWORK UNCHANGED

FEEDER NAME	Capacitor KVA	Units Saved MWh/feeder 1991	1995	load gr. rate	growth rate of benefits	MF for loss red/n benefits	PW of benefits '93 to '96 in $000		Benefit to Cost ratio '93-'96	Pay Back in months only	total benefits	Benefit to Cost ratio 1993-2008
Fed from Ilala Grrid SS												
		Benefits on 11 kV lines					11 kV lines		11 kV lines only			
K4, Industrial	600	199	256	4	6.5	3.69	67.6		26.4	2.0	75.1	27.5
K3, Kilwa road	600	46	59	4	6.4	3.68	15.6		6.1	8.8	20.1	7.3
Port	600	56	99	8	15.3	4.51	23.2		9.1	7.2	26.9	9.8
O3, Packers	600	81	106	4	7.0	3.73	27.8		10.9	5.0	31.5	11.5
D10, Magomeni	600	52	68	4	6.9	3.73	17.8		7.0	7.8	20.9	7.6
		Benefits on 33 kV lines					33 kV lines	33 & 11 kV lines	11 & 33 kV lines			
K4, Industrial	600	43	57		7.3	3.76	14.9	82	32.2	1.7	93.1	34.0
K3, Kilwa road	600	31	48		11.6	4.14	11.8	27	10.7	5.3	35.2	12.8
Port	600	20	56		29.4	6.10	11.2	34	13.4	5.3	41.2	15.0
O3, Packers	600	36	42		3.9	3.48	11.5	39	15.3	3.5	44.9	16.4
D10, Magomeni	600							18	7.0		20.9	7.6
		Benefits on UB-IL 132 kV line					132kV line	All lines	All lines			
K4, Industrial	600	53	26			3.17	15.5	97.9	38.2	1.4	108.6	39.7
K3, Kilwa road	600	53	26			3.17	15.5	42.9	16.7	3.1	50.6	18.5
Port	600	53	26			3.17	15.5	49.9	19.5	3.1	56.6	20.7
O3, Packers	600	53	26			3.17	15.5	54.8	21.4	2.4	60.3	22.0
D10, Magomeni	600	53	26			3.17	15.5	33.3	13.0	3.9	36.4	13.3
Fed from Ubungo Grid SS												
		Benefits on 11 kV lines					11 kV lines		11 kV lines only			
MK1, Msasani	600	33	50	8	10.9	4.09	12.4		4.8	12.3	17.3	6.3
MK2, Tandale	600	112	182	8	12.9	4.27	44.0		17.2	3.6	54.4	19.9
Kunduchi	600	236	441	10	16.9	4.67	101.4		39.6	1.7	103.7	37.9
U1, Kisiwani	600	57	99	8	14.8	4.46	23.4		9.1	7.1	41.3	15.1
U2, Menzeese	600	50	67	4	7.6	3.79	17.4		6.8	8.1	28.2	10.3
		Benefits on 33 kV lines					33 kV lines	33 & 11 kV lines	11 & 33 kV lines			
MK1, Msasani	600	28	37		7.2	3.75	9.7	22	8.6	6.6	34.1	12.5
MK2, Tandale	600	19	29		11.2	4.11	7.2	51	20.0	3.1	85.3	31.2
Kunduchi	600	38	51		7.6	3.79	13.2	115	44.7	1.5	117.9	43.1
U1, Kisiwani	600							23	9.1	7.1	41.3	15.1
U2, Menzeese	600							17	6.8	8.1	38.1	13.9
TOTAL FOR ALL 10 APPLICATIONS											**629.1**	**23.0**

Note:

0.092 = Value of loss red/n benefits $/ kWh
3100 = Cost of application, 600 kVA, $
2560 = Cost of application, 300 kVA, $
10 = Discount factor in %
1996 = year of termination of benefits of lines to be altered
1993 = year of commencement of benefits
1991 = base year for discounting

See section B (next page) for computation of benefits beyond 1996, after major network develoments are affected

ECONOMIC ANALYSIS OF SELECTED CAPACITOR APPLICATIONS ON II kV LINES (Cont.)

TABLE C 11
SECTION B

WITH NETWORK CHANGES AND RELOCATION EFFECTIVE 1997 (section B)

FEEDER NAME NEW LOCATION	OLD LOCATION	Capacit. KVA	MWh/pa Saving 1991	1995	growth feeder load gr. rate %	gr. rate rate of benefits %	effective gr. rate after discount.	MF for benefits	PW of loss red/n benefits in $000 1997 to 2008		B/C ratio
Fed from Ilala Grrid SS											
		Benefits on 11 kV lines							11 kV lines only		
Kigam F1	K4, Industrial	600	23	56	4	24.9	1.14	3.6	7.5		43.1
Kigam F2	K3, Kilwa road	600	21	43	4	19.6	1.09	2.3	4.5		25.5
Port	Port	600	25	44	8	15.2	1.05	1.6	3.6		20.8
O4, Kinondoni	O3, Packers	600	34	53	4	11.7	1.02	1.2	3.7		20.9
F2, RTD	Kunduchi	600	28	39	10	8.6	0.99	0.9	2.3		13.0
D2,Town1	D10, Magomeni	600	43	57	4	7.3	0.98	0.8	3.1		17.6
		Benefits on 33 kV lines							33 kV only	11 & 33 kV lines	
Kigam F1	K4, Industrial	600	43	57		7.3	0.98	0.8	3.1	10.6	60.8
Kigam F2	K3, Kilwa road	600	31	48		11.6	1.01	1.2	3.3	7.7	44.3
Port	Port	600	43	57		7.3	0.98	0.8	3.1	6.7	38.5
O4, Kinondoni	O3, Packers	600	36	42		3.9	0.94	0.6	1.9	5.5	31.6
F2, RTD			15	19		6.1	0.96	0.7	1.0	3.2	18.5
D2,Town1	D10, Magomeni	600							0.0	3.1	17.6
Fed from Ubungo Grid SS											
		Benefits on 11 kV lines							11 kV lines only		
MK4,north east	MK1, Msasani	600	17	26	8	11.2	1.011	3.1	5		27.7
F31,Industrial	MK2, Tandale	600	42	53	8	6.0	0.9635	2.7	10		59.3
Lugalo	U2, Menzeese	600	47	54		3.5	0.9412	2.5	11		61.9
U1, Kisiwani	U1, Kisiwani	600	57	99	8	14.8	1.0436	3.4	18		102.3
		Benefits on 33 kV lines							33 kV only	11 & 33 kV lines	
MK4,north east	MK1, Msasani	600	28	37		7.2	0.9747	2.8	7	12	68.6
F31,Industrial	MK2, Tandale	600	99	120		4.9	0.9539	2.6	24	34	194.9
Lugalo	U2, Menzeese	600	38	51		7.6	0.9785	2.8	10	21	118.0
U1, Kisiwani	U1, Kisiwani	600								18	102.3

0.092 = Value of loss red/n benefits $/ kWh
310 = Cost of application, 600 kVA
256 = Cost of application, 300 kVA
10 = Discount factor in %
2008 = year of termination of benefits of lines to be altered
1997 = year of commencement of benefits
1991 = base year for discounting

> The benefit to cost ratio has been worked out assuming a new investment year in 1997 and counting the benefits from 1997 to 2008. The present value of these benefits is taken account in page 1when computing for the period 1997 to 2003.

Note: Losses for 1991 and 1995 are calculated as if the new proposed arrangements have been affected

BENEFIT TO COST ANALYSIS FOR CAPACITOR APPLICATIONS AT THE 33/11 kV SUBSTATIONS INCLUDING CONSUMER INSTALLATIONS

FEEDER NAME	Capacit. in kVA at SS	Cost of Installation at SS in $	Savings in year 1991 night peak kW	Savings in year 1991 Units MWh	Savings in year 1995 night peak kW	Savings in year 1995 Units MWh	savings growth rate in %	savings growth rate in % (discounted)	benefit counted up to	MF for Savings	Value of Savings in $000's	Benefit to Cost ratio	Pay back period (months)
ILALA-OYSTERBAY	600	4200	7.6	37.6	9.8	47.6	6.09	0.96	2003	8.9	30.8	7.3	14.6
ILALA-OYSTERBAY	800	5600	9.9	107.4	12.9	161.4	10.72	1.01	2003	11.4	113.1	20.2	6.8
UBUNGO-ALAF *	1000	7000	10.9	100	12.3	113	3.12	0.94	2003	7.6	70.0	10.0	9.1
UBUNGO-WAZO II	1000	7000	41.2	247	47.3	286	3.71	0.94	1997	4.2	95.5	13.6	3.7
UBUNGO-WAZO II	2000	14000	71.2	397	83.5	474	4.56	0.95	1997	4.3	157.2	11.2	4.6
UBUNGO-WAZO II	3000	21000	90.3	450	108.7	566	5.92	0.96	1997	4.5	185.1	8.8	6.1
UBUNGO-F111	2000	14000	50.7	296	60.9	364	5.29	0.96	2003	8.5	232.6	16.6	6.2
UBUNGO-F111	3000	21000	66.1	356	81.3	458	6.48	0.97	2003	9.1	298.1	14.2	7.7
UBUNGO-F111	4000	28000	74.7	358	95.0	493	8.36	0.99	2003	10.1	331.2	11.8	10.2

Note:

0.092 Value of loss reduction benefits in $ per kW
7 Cost of capacitors at Substations in $ per kVAr
10 Discount factor in %
1991 base year for discounting

The OysterBay loss reduction is computed on the incremental benefits after allowing for downstream development

Table C.12

ANNEX D

PLANNING METHODS AND GUIDELINES FOR DISTRIBUTION SYSTEMS

Annex D

PLANNING METHODS AND GUIDELINES FOR DISTRIBUTION SYSTEMS

Contents

ANNEX D

PLANNING METHODS AND GUIDELINES FOR DISTRIBUTION SYSTEMS

Introduction

This annex provides some basic information on the planning methods which were employed in the study of power distribution systems and the associated economic analysis. A description of the commonly used terms together with the relevant formulae is provided in page 2. During the course of the project specialized software to build network geographical data bases and to conduct load flow analysis was provided and TANESCO staff trained in their application. However due to the need to undertake extensive field verification of the existing networks the building up of this data base is quite time consuming. Thus in addition to the more detailed analysis provided by the computer programs an approximate methodology is also provided to determine the main characteristics required for the planning exercise, namely the determination of system losses and the tail end voltage conditions of the feeders. The method employed for this analysis is detailed in section D 1 and relies on the ability of modeling the distributor as a radial line with loads of equal magnitude acting at equally spaced distances along the distributor. The method provides a set of multiplying factors which can be used to convert the losses and tail end voltage drops of a tail end load condition (which is readily ascertainable) to that of a distributor. In instances where the distributor is too complex to be modeled in this manner it has been divided into a number of sections which are then amenable to such representation and the results for the original distributor has been built up from the individual components. In the course of the studies it has been found that the methodology provides results well within the limits of acceptable accuracy. Computer spreadsheets have also been built to use the formulae in a convenient fashion. Due to the simplicity of this method, results for all feeders and distributors can be obtained in a short time with minimum data requirements. Thus this method is recommended to be used when data and time limitations do not warrant a more detail analysis.

Section D 2 presents a sample from a set of charts which show the variation of the feeder or distributor load with line length for stipulated values of tail end voltage drops. These charts have also been developed using spreadsheets based on the computation described in section D 1. The charts can be used to determine the acceptable loading levels for different line lengths and conductor sizes; they are thus a convenient means of determining conductor configurations required for acceptable network performance.

The benefits of loss reduction and reliability improvement over a period of years need to be computed in order to undertake economic analyses of development proposals. Technical studies are usually done with the maximum loading of a particular year. However both loss reduction and reliability improvement benefits increase with network load over time. It is therefore necessary to find convenient methods of evaluating the discounted value of such benefits over a given period of time. Section D 3 contains tables providing factors that can be used to convert the benefits of a particular year to the present worth of a series of future benefits extending over a number of years. These tables are once again derived from simple computer spreadsheets which can be used to provide the required values for varying time periods, growth rates and discount factors. Tables D 3.1 and D 3.2 assume a constant rate of growth over the period of analysis. In Table D 3.3 the study period is broken down to a variety of sub periods and the growth rate could be varied between the sub periods. Thus the technique can be used to obtain the most appropriate conversion factor to suit the particular condition of the situation under study.

A DESCRIPTION OF COMMONLY USED TERMS AND FORMULAE

Each term described is followed by the symbol used, formulae connected with its use (if applicable), units used and a brief description.

Feeders: Lines that transport power over some distance. In general a feeder is higher in the supply hierarchy than a distributor. A line which will transport power between two points in the system without intermediate tappings will always be termed a feeder and a line which is tapped along its way will be termed a distributor.

Distributor: A power supply line which is tapped along its length to feed loads or consumers.

Load factor: LF - $E = P \cdot T \cdot (LF)$ - ratio or %

The ratio of average load (kW) to the peak load (kW) over some time period (usually one month or one year).

Loss load factor: LLF - $\Delta E = \Delta P \cdot T \cdot (LLF)$ - ratio or %

The ratio of average losses (kW) to the peak losses (kW) over some time period (usually one month or one year).

Loss reduction load factor: LRLF - $\Delta\Delta E = \Delta\Delta P \cdot T \cdot (LRLF)$ - ratio or %

When loss reduction is achieved by the use of capacitors, the reduction in power losses has a wide variation over different loading conditions. In some instances a loss reduction at peak time may be accompanied by a loss increase during base load times. The loss reduction load factor is the total energy saved by the application divided by both the peak time loss savings and the applicable time period.

Coincidence factor: C_f - $C_f = P^* \div P$ - ratio or %

The ratio of the load (of the line or network section considered) at system peak time to its own peak load. This term is also called the Peak responsibility factor.

Note:

P (in kW)	= power supplied at peak load for the line, equipment or network considered over the time period, T
E (in kWh)	= energy supplied over time period, T
ΔE (in kWh)	= energy losses in time period, T
ΔP (in kW)	= peak power losses in
$\Delta\Delta E$ (in kWh)	= reduction in energy losses by a specified application (usually capacitors)

Annex D 1

COMPUTATION OF LINE LOSSES AND VOLTAGE DROP OF DISTRIBUTORS

The line losses and voltage drop of a short distribution line with a single load at its extremity can be found from the following simple formulae:

line losses = $3 \, . \, I^2 . \, r \, . \, L$
Line end voltage drop = $I \, . \, L \, . \, (r \, . \cos \theta + x \, \sin \theta)$

where:
I = line current
L = line length
r = resistance in Ohms per unit length
x = inductance in Ohms per unit length
θ = power factor angle

In practice however a distribution line consist of a number of branches or tapping points and is loaded at various points along its length at irregular intervals. In such instances, the power flow characteristics including line losses and tail and voltage drops can only be accurately determined by using suitable computer programs to handle the iterative nature of the solution. However a simplified methodology can be developed to obtain an approximate solution which will yield results within acceptable accuracy limits.

The computation is made with the distributor modeled as a simple radial line with a number of loads of equal magnitude (acting at nodes along the line) separated from each other by equal distances (line sections) as shown in Fig: D 1. Experience has shown that it is fairly convenient to represent typical distributors by such models. The total length will be the radial length of the distributor ignoring the branch lines and the number of sections will be determined according to the magnitude and the dispersion pattern of the loads. In certain cases branch lines can be modeled separately and the total load of a branch taken as acting at the appropriate location along the main distributor (which is also modeled separately).

The power flow along each section of the model is the flow along the previous section less the load acting at the node at the beginning of the section. Neglecting the difference in the phase angle of the currents flowing along the various sections the following relationships can be derived.

Where: no. of sections = n

Load at each node = $\frac{I}{n}$ amps

Current flowing along the sections, commensing with the start of the distributor:

$$I, \quad I\frac{(n-1)}{n}, \quad I\frac{(n-2)}{n}, \ldots\ldots\ldots\ldots, \quad \frac{I}{n}$$

The power loss along the section (r + 1) will be:

$$3\, r \frac{L}{n} \left[I \frac{(n-r)}{n} \right]^2 \quad \text{and}$$

the voltage drop in the section will be:

$$I \frac{(n-r)}{n} \; (r \cos \Theta + jx \sin \Theta)$$

The total line loss and tail end voltage drop could now be obtained by summing up as follows:

Total line loss

$$= \frac{3.r\,L}{n} \left[I^2 \frac{(n)^2}{n^2} + I^2 \frac{(n-1)^2}{n^2} + I^2 \frac{(n-2)^2}{n^2} + \ldots\ldots + \frac{I^2}{n^2} \right]$$

$$= 3.\,r\,L\,I^2 \left[\frac{n^2\; n^2 + (n-1)^2 + (n-2)^2 + \ldots\ldots\ldots + 1^2}{n^3} \right]$$

$$= 3.\,r\,L\,I^2 \left[\frac{1^2 + 2^2 + 3^2 + \ldots\ldots\ldots + n^2}{n^3} \right]$$

$$= \text{(losses if total load was at line end)} \,.\, \frac{(1^2 + 2^2 + \ldots\ldots\ldots + n^2)}{n^3}$$

and,

Line end voltage drop

$$= (r \cos\Theta + j\,x \sin\Theta) \frac{L}{n} \left[I\,n + I \frac{(n-1)}{n} + I \frac{(n-2)}{n} + \ldots\ldots\ldots\ldots + \frac{I}{n} \right]$$

$$= (r \cos\Theta + j\,x \sin\Theta) \frac{L}{n^2} \left[1 + 2 + 3 + \ldots\ldots\ldots + n \right]$$

$$= (r \operatorname{Cos}\Theta + j \sin\Theta)\; L \; \frac{(1+n)}{2n}$$

$$= \text{(voltage drop if total load was at line end)} \,.\, \left(\frac{1+n}{2n} \right)$$

Using the above relationship a set of multiplying factors could be derived to convert the tail end load situation to that of a distributor with the same length and sending end load. Table D1.1 provides a summary of such multiplying factors.

Annex D 1

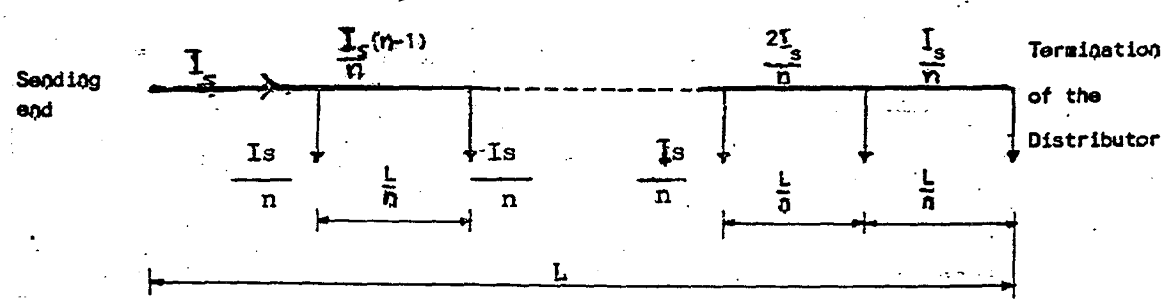
Table D 1.1

CONVERSION FACTORS FOR DISTRIBUTORS

No. of Sections (with Identical loads)	Multiplying factor for	
	Line end voltage	Line losses
(Tail end load)	1.0	1.0
2	0.750	0.625
3	0.667	0.519
4	0.625	0.469
5	0.600	0.440
6	0.583	0.421
7	0.571	0.408
8	0.563	0.398
9	0.556	0.391
10	0.550	0.385
11	0.545	0.380
Uniformly distributed load	0.500	0.333

Note: The above factors convert the line end voltage and line losses of a terminally loaded line to that of a symetrical linear distributor of equal load consisting of a number of equally loaded sections.

Fig. D.1 Representation of a distributor.



LENGTH vs LOAD 33 kV, 5% VOLT DROP

Dist. Load (0.6), PF=0.85

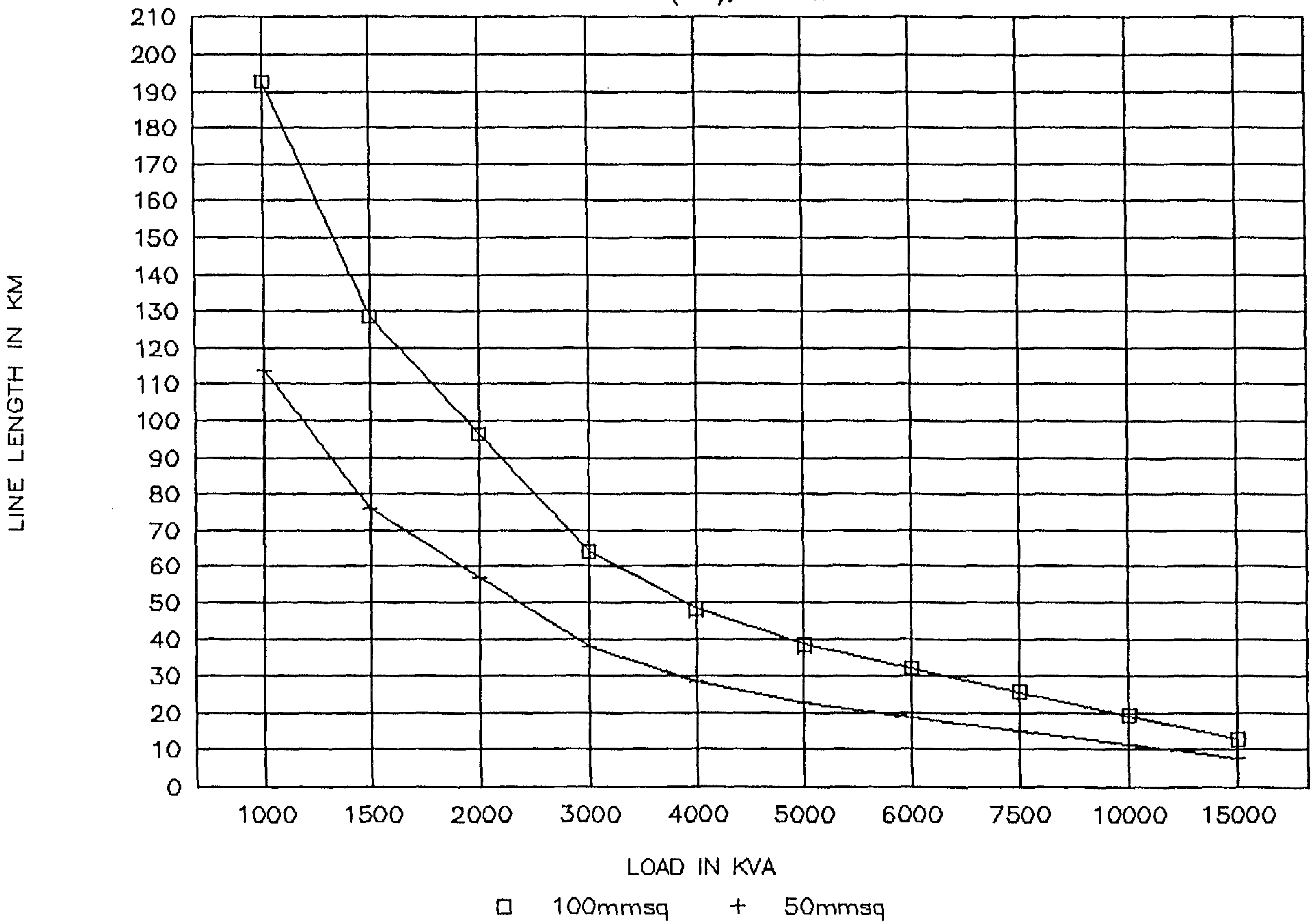


Table D.2.2.1.

Table D.2.2.2

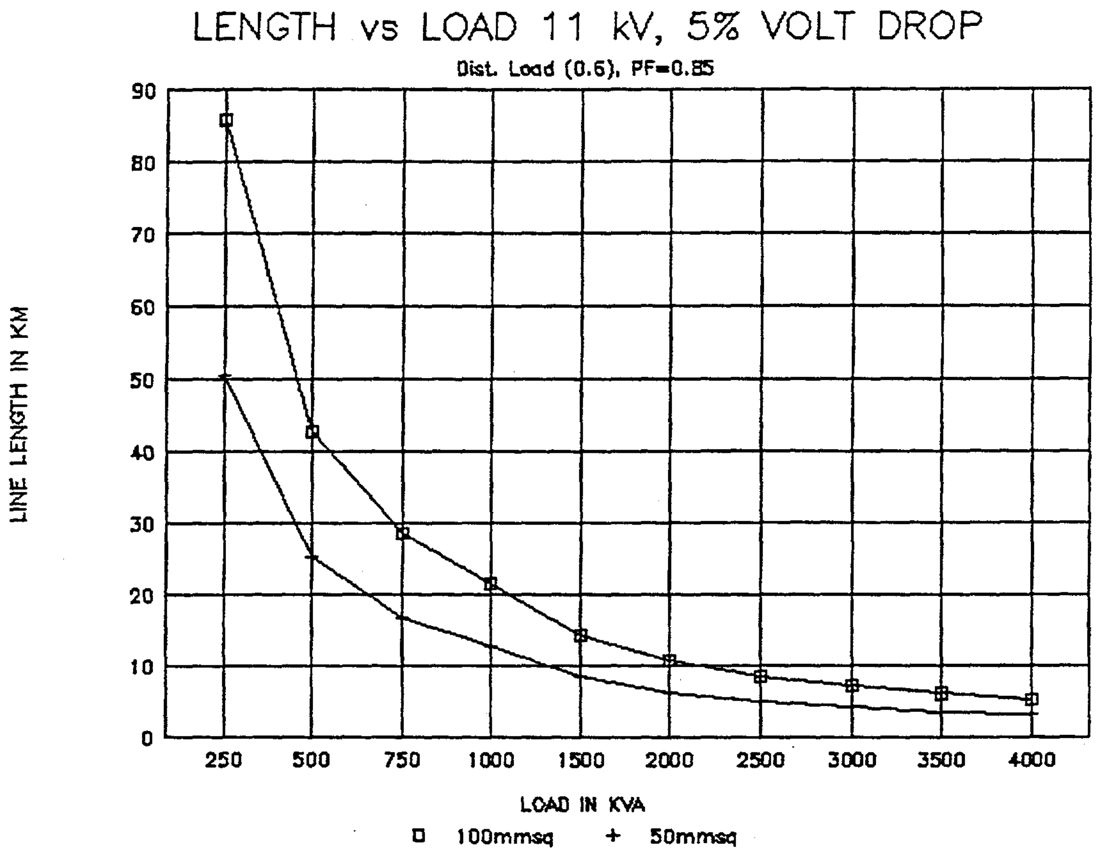


Table D.2.1.2

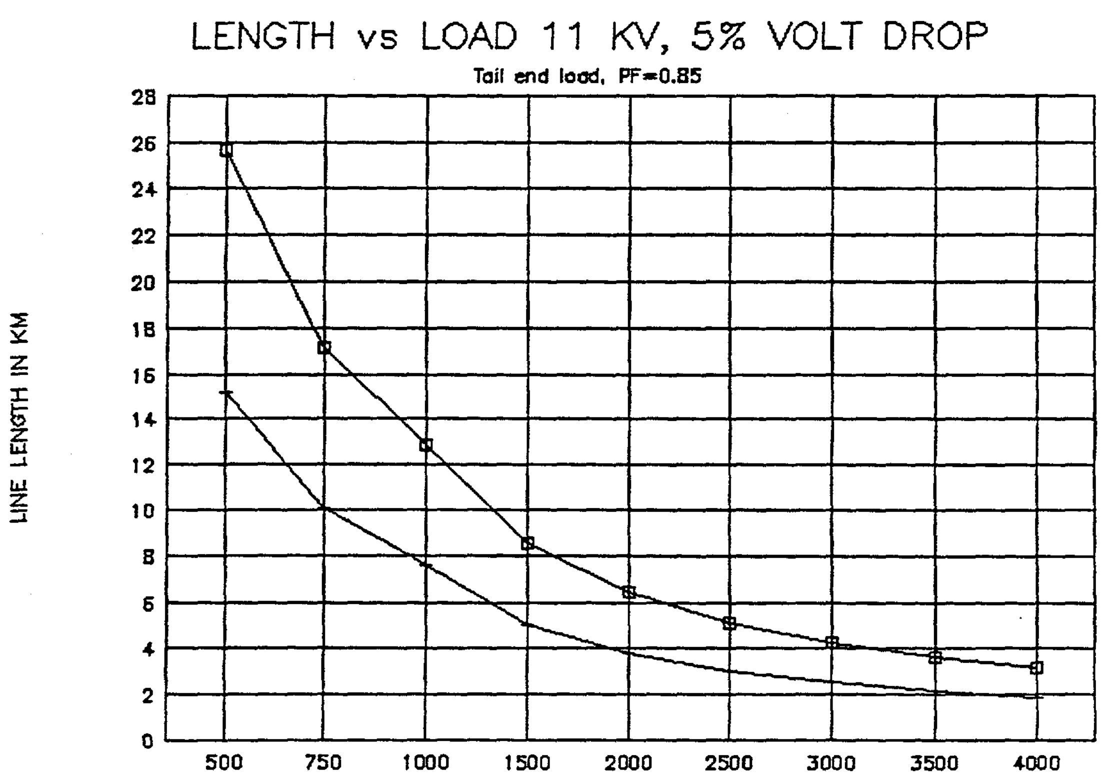


Table D.2.2.3

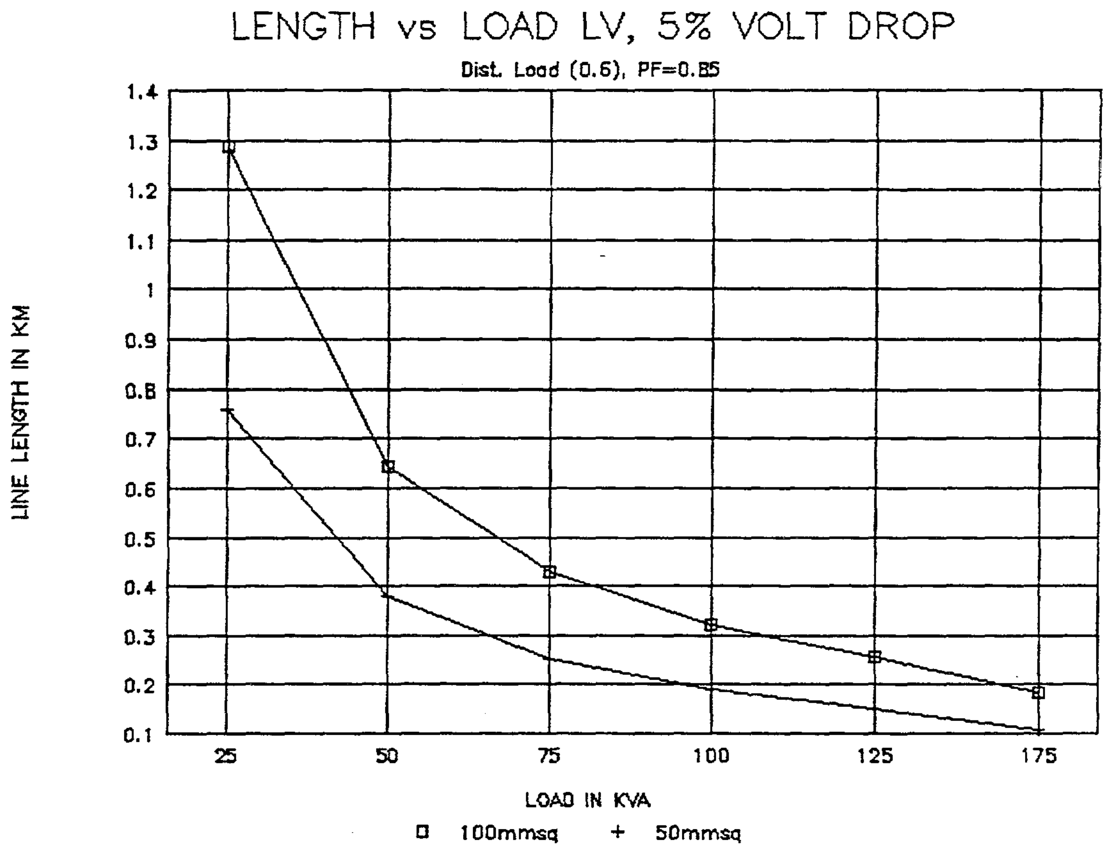


Table D.2.1.3

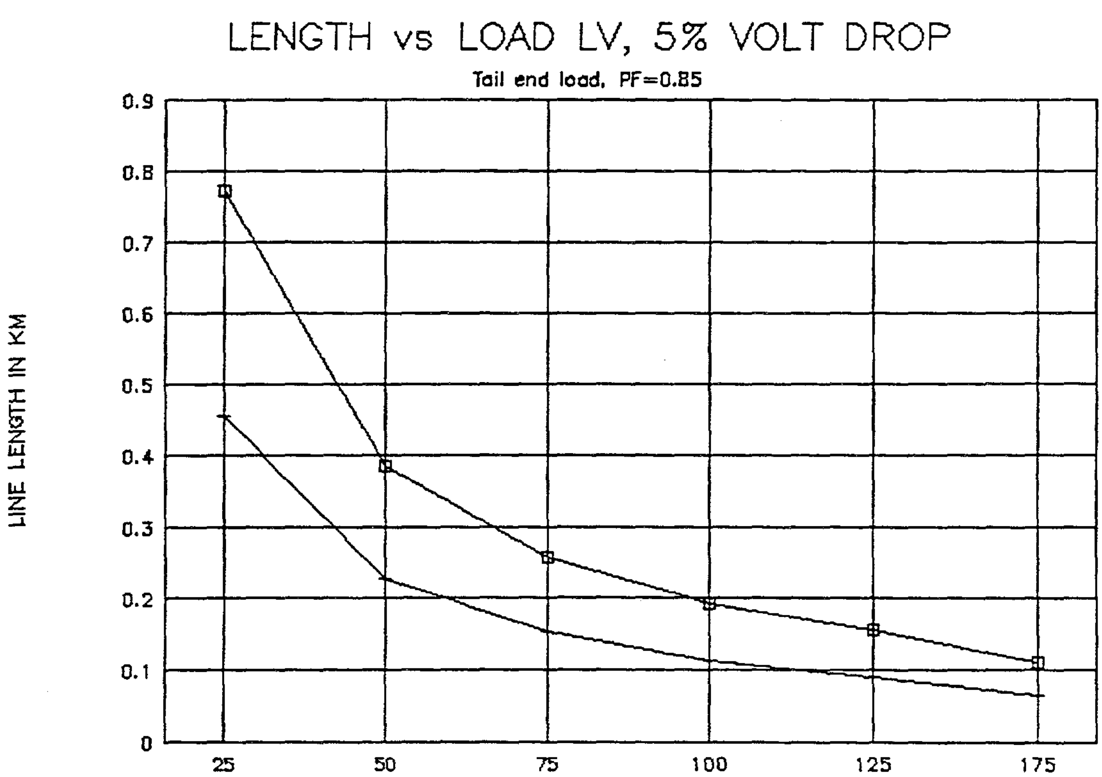


Table D3.1

PRESENT WORTH FACTORS FOR LOSS REDUCTION BENEFITS OF FUTURE YEARS

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1.05 = GROWTH RATE	1.1 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.10	1.22	1.34	1.48	1.63	1.80	1.98	2.18	2.41	2.65	2.93	3.23	3.56	3.92	4.32	4.76
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. loss reduction benefits	1.00	1.00	1.00	1.01	1.01	1.01	1.01	1.02	1.02	1.02	1.02	1.03	1.03	1.03	1.03	1.03	1.04
Cumilative PW of benefits	1.00	2.00	3.01	4.01	5.02	6.03	7.05	8.06	9.08	10.10	11.13	12.15	13.18	14.21	15.24	16.28	17.31
1.07 = GROWTH RATE	1.1 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.14	1.31	1.50	1.72	1.97	2.25	2.58	2.95	3.38	3.87	4.43	5.07	5.81	6.65	7.61	8.72
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. loss reduction benefits	1.00	1.04	1.08	1.13	1.17	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.90
Cumilative PW of benefits	1.00	2.04	3.12	4.25	5.43	6.65	7.92	9.24	10.62	12.05	13.54	15.10	16.71	18.39	20.15	21.97	23.86
1.09 = GROWTH RATE	1.1 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.19	1.41	1.68	1.99	2.37	2.81	3.34	3.97	4.72	5.60	6.66	7.91	9.40	11.17	13.27	15.76
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. loss reduction benefits	1.00	1.08	1.17	1.26	1.36	1.47	1.59	1.71	1.85	2.00	2.16	2.33	2.52	2.72	2.94	3.18	3.43
Cumilative PW of benefits	1.00	2.08	3.25	4.51	5.87	7.34	8.93	10.64	12.49	14.49	16.65	18.99	21.51	24.23	27.17	30.35	33.78
1.11 = GROWTH RATE	1.1 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.23	1.52	1.87	2.30	2.84	3.50	4.31	5.31	6.54	8.06	9.93	12.24	15.08	18.58	22.89	28.21
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. loss reduction benefits	1.00	1.12	1.25	1.41	1.57	1.76	1.97	2.21	2.48	2.78	3.11	3.48	3.90	4.37	4.89	5.48	6.14
Cumilative PW of benefits	1.00	2.12	3.37	4.78	6.35	8.12	10.09	12.30	14.78	17.56	20.66	24.15	28.05	32.41	37.31	42.79	48.93
1.05 = GROWTH RATE	1.08 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.10	1.22	1.34	1.48	1.63	1.80	1.98	2.18	2.41	2.65	2.93	3.23	3.56	3.92	4.32	4.76
Discount factor	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29
P.W. loss reduction benefits	1.00	1.02	1.04	1.06	1.09	1.11	1.13	1.16	1.18	1.20	1.23	1.25	1.28	1.31	1.33	1.36	1.39
Cumilative PW of benefits	1.00	2.02	3.06	4.13	5.21	6.32	7.45	8.61	9.79	10.99	12.22	13.48	14.76	16.06	17.40	18.76	20.15
1.07 = GROWTH RATE	1.08 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.14	1.31	1.50	1.72	1.97	2.25	2.58	2.95	3.38	3.87	4.43	5.07	5.81	6.65	7.61	8.72
Discount factor	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29
P.W. loss reduction benefits	1.00	1.06	1.12	1.19	1.26	1.34	1.42	1.50	1.59	1.69	1.79	1.90	2.01	2.14	2.26	2.40	2.54
Cumilative PW of benefits	1.00	2.06	3.18	4.38	5.64	6.98	8.40	9.90	11.50	13.19	14.98	16.88	18.89	21.03	23.29	25.69	28.24
1.09 = GROWTH RATE	1.08 = INTEREST RATE																
Increased losses p.u.																	
-with load growth	1.00	1.19	1.41	1.68	1.99	2.37	2.81	3.34	3.97	4.72	5.60	6.66	7.91	9.40	11.17	13.27	15.76
Discount factor	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29
P.W. loss reduction benefits	1.00	1.10	1.21	1.33	1.46	1.61	1.77	1.95	2.15	2.36	2.60	2.86	3.14	3.46	3.80	4.18	4.60
Cumilative PW of benefits	1.00	2.10	3.31	4.64	6.11	7.72	9.49	11.44	13.58	15.94	18.54	21.40	24.54	27.99	31.80	35.98	40.58

Note: The above computation assumes that the system load can be met in future years both by the existing and proposed systems.
The growth rate and discount rate has been expressed as per unit factors
The table provides multiplying factors that convert the present year benefits to that of the discounted benefits of a period of future years
If the perriod of benefits starts in a future year a subtraction of the relevant factors in the table will provide the appropriate multiplying factor

PRESENT WORTH FACTORS OF REIABILITY BENEFITS OF FUTURE YEARS

	1991	1992	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1.05 = GROWTH RATE	1.1 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	2.18
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. reliability benefits	1.00	0.95	0.91	0.87	0.83	0.79	0.76	0.72	0.69	0.66	0.63	0.60	0.57	0.55	0.52	0.50	0.48
Cumilative PW of benefits	1.00	1.95	2.87	3.74	4.57	5.36	6.11	6.84	7.53	8.18	8.81	9.41	9.98	10.53	11.05	11.55	12.02
1.07 = GROWTH RATE	1.1 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.07	1.14	1.23	1.31	1.40	1.50	1.61	1.72	1.84	1.97	2.10	2.25	2.41	2.58	2.76	2.95
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. reliability benefits	1.00	0.97	0.95	0.92	0.90	0.87	0.85	0.82	0.80	0.78	0.76	0.74	0.72	0.70	0.68	0.66	0.64
Cumilative PW of benefits	1.00	1.97	2.92	3.84	4.73	5.61	6.45	7.28	8.08	8.86	9.62	10.35	11.07	11.77	12.45	13.11	13.75
1.09 = GROWTH RATE	1.1 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.09	1.19	1.30	1.41	1.54	1.68	1.83	1.99	2.17	2.37	2.58	2.81	3.07	3.34	3.64	3.97
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. reliability benefits	1.00	0.99	0.98	0.97	0.96	0.96	0.95	0.94	0.93	0.92	0.91	0.90	0.90	0.89	0.88	0.87	0.86
Cumilative PW of benefits	1.00	1.99	2.97	3.95	4.91	5.87	6.81	7.75	8.68	9.60	10.51	11.42	12.31	13.20	14.08	14.95	15.82
1.11 = GROWTH RATE	1.1 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.11	1.23	1.37	1.52	1.69	1.87	2.08	2.30	2.56	2.84	3.15	3.50	3.88	4.31	4.78	5.31
Discount factor	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29	0.26	0.24	0.22
P.W. reliability benefits	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.08	1.09	1.10	1.11	1.12	1.14	1.15	1.16
Cumilative PW of benefits	1.00	2.01	3.03	4.05	5.09	6.14	7.19	8.26	9.33	10.42	11.51	12.62	13.73	14.86	15.99	17.14	18.29
1.05 = GROWTH RATE	1.08 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	2.18
Discount factor	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29
P.W. reliability benefits	1.00	0.97	0.95	0.92	0.89	0.87	0.84	0.82	0.80	0.78	0.75	0.73	0.71	0.69	0.67	0.66	0.64
Cumilative PW of benefits	1.00	1.97	2.92	3.84	4.73	5.60	6.44	7.26	8.06	8.84	9.59	10.33	11.04	11.73	12.41	13.06	13.70
1.07 = GROWTH RATE	1.08 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.07	1.14	1.23	1.31	1.40	1.50	1.61	1.72	1.84	1.97	2.10	2.25	2.41	2.58	2.76	2.95
Discount factor	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29
P.W. reliability benefits	1.00	0.99	0.98	0.97	0.96	0.95	0.95	0.94	0.93	0.92	0.91	0.90	0.89	0.89	0.88	0.87	0.86
Cumilative PW of benefits	1.00	1.99	2.97	3.94	4.91	5.86	6.81	7.75	8.67	9.59	10.50	11.41	12.30	13.19	14.07	14.94	15.80
1.09 = GROWTH RATE	1.08 = INTEREST RATE																
Increased reliability p.u.																	
-with load growth	1.00	1.09	1.19	1.30	1.41	1.54	1.68	1.83	1.99	2.17	2.37	2.58	2.81	3.07	3.34	3.64	3.97
Discount factor	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29
P.W. reliability benefits	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09	1.10	1.11	1.12	1.13	1.14	1.15	1.16
Cumilative PW of benefits	1.00	2.01	3.03	4.06	5.09	6.14	7.20	8.26	9.34	10.43	11.52	12.63	13.75	14.87	16.01	17.16	18.32

Note: The above computation assumes that the system load can be met in future years both by the existing and proposed systems.
The growth rate and discount rate has been expressed as per unit factors
The table provides multiplying factors that convert the present year benefits to that of the discounted benefits of a period of future years
If the perriod of benefits starts in a future year a subtraction of the relevant factors in the table will provide the appropriate multiplying factor

Table D.3.2

Table D3.3

PRESENT WORTH OF LOSS REDUCTION AND RELIABILITY BENEFITS OF FUTURE YEARS WITH VARIABLE GROWTH RATES BETWEEN SUB-PERIODS

1.1 = Discount factor	YEAR OF COMMENCEMENT OF SUB PERIOD						
	1990	1993	1998	2001	2005	2007	2010
Load growth rate p.a.	1.08	1.05	1.04	1.03	1.02	1.01	
Load at year as pu. of load in yr. 1	1	1.26	1.61	1.81	2.04	2.12	2.18
Loss red. benefits as pu. of benefits in yr. 1	1	1.59	2.58	3.27	4.14	4.48	4.76
Reliab. benefits as pu. of benefits in yr. 1	1	1.26	1.61	1.81	2.04	2.12	2.18
Benefit growth per yr./discount fac.							
- *loss reduction*	1.060	1.002	0.983	0.964	0.946	0.927	
- reliability	0.982	0.955	0.945	0.936	0.927	0.918	
Years in sub period (from yr. in column to yr. in next colu	3	5	3	4	2	3	
Present Worth (to begining) of sub period							
loss reduction	3.18	7.97	7.63	12.40	8.06	12.50	
reliability	2.95	5.75	4.56	6.57	3.92	5.85	
Present Worth factor for Yr. to yr. 1	1.000	0.751	0.467	0.350	0.239	0.198	

PRESENT WORTH FACTORS	TOTAL '90-'08	TOTAL '93-'08						
loss reduction	21.48	18.296	3.185	5.988	3.557	4.347	1.930	2.473
reliability	13.80	10.850	2.946	4.321	2.130	2.304	0.939	1.157

Note: (1) The above is an example of a Lotus format prepared in order to calculate the present worth of benefits of loss reduction and reliability improvements over a period of analysis where the load growth varies in each sub period.
(2) The second total column allows the benefits from the first period to be omitted.
(3) The variables are: discount rate, length and no. of sub periods, growth rate in each sub period.
(4) The benefits in the first year (1990 in this case) when muntiplied by the present worth factor (in the total column) will provide the present worth of benefits of the total period discounted to the first year (1990)

ANNEX E

ECONOMIC ANALYSIS FOR DISTRIBUTION SYSTEM DEVELOPMENT

Annex E

ECONOMIC ANALYSIS FOR DISTRIBUTION SYSTEM DEVELOPMENT

List of Tables

List of Tables

COST BENEFIT ANNALYSIS FOR
PROPOSED 30 MVA GRID SUBSTATION AT WAZO HILL AND 5 MVA PRIMARY SUBSTATION AT KUNDUCHI TABLE E 1.1 pg 1

(1) LOAD CHARACTERISTICS OF AFFECTED FEEDERS

	Period	'90-'93	'93-'96	'96-'99	'99-'02	'02-'05	'05-'08
(1.1) Load growth characteristics							
Estimated load growth pu. for feeders		0.07	0.07	0.07	0.07	0.07	0.07
Estimated load growth pu. for cement fac.		0.015	0.015	0.015	0.015	0.015	0.015

YEAR	1990	1993	1996	1999	2002	2005	2008
(1.2) Peak Load in MW							
Cement Factory load	7.100	7.424	7.763	8.118	8.489	8.877	9.282
Kunduchi SS load	2.267	2.777	3.402	4.168	5.106	6.255	7.662
Mbezi - Kunduchi feeder	0.800	0.980	1.201	1.471	1.802	2.207	2.704
Total Load affected by loss red/n and reliability improvement	10.167	11.181	12.366	13.757	15.396	17.338	19.648
Overall load growth p.a.		3.19	3.38	3.58	3.79	4.00	4.21
New load at Mbezi SS	4.936	6.047	7.408	9.075	11.117	13.619	16.683
(1.3) Annual energy in GWH							
0.85 = Load factor for Cement Factory							
0.65 = Load factor for all feeders							
Cement Factory load	52.867	55.281	57.807	60.447	63.208	66.096	69.115
Kunduchi SS load	12.908	15.813	19.371	23.731	29.071	35.613	43.628
Mbezi - Kunduchi feeder	4.555	5.580	6.836	8.375	10.259	12.568	15.396
Total Load affected by loss red/n and reliability improvement	70.330	76.675	84.014	92.552	102.539	114.277	128.139
Overall load growth p.a.		2.89	3.06	3.25	3.44	3.64	3.85
New load at Mbezi SS	28.106	34.430	42.179	51.671	63.299	77.544	94.995

(2) CONCLUSIONS FROM ESTIMATED LOAD DISTRIBUTION:

Capacity of Kunduchi SS — 1*5 MVA by (1993) with augmentation to 2*5 MVA by Yr. 2000
Capacity required at existing Mbezi SS — Existing 1* 15 Mva is sufficient up to beyond Yr. 2000

Estimation of benefits - 76.7 GWH of sales by 1993 increasing at 3% pa. will be benefitted by
(1) Loss reduction as calculated below on an analysis by feeder
(2) Additional capacity provided to meet new loads
and (3) Reliability benefits estimated by outages saved (as % of total sales)

(3) CAPITAL WORKS (all costs in $ 000's)

Grid SS	Unit	Qty	Rate	Cost
132/33 kV transformer 30 MVA	nos	1	450	450
132 kV incommer	nos	1	220	220
33 kV feeder CB units	nos	4	120	480
Substation structure & auxiliaries	item	1	100	100
33 kV feeders dc 100 mm sq	km	5	35	175
Primary SS				
33 kV feeder CB units	nos	2	120	240
33/11 kV transformer 5 MVA	nos	1	170	170
11 kV CB units	nos	6	55	330
Substation structure & auxiliaries	item	1	50	50
11 kV feeders	km	3	21	63
TOTAL COST (Work proposed in 1991)				2278
Cost of augmentation of Kunduchi SS in 2000				345
Total Costs discounted to 1990				2204

COST BENEFIT ANNALYSIS FOR
PROPOSED 30 MVA GRID SUBSTATION AT WAZO HILL AND 5 MVA PRIMARY SUBSTATION AT KUNDUCHI

TABLE E 1.1 pg 2

(4) COMPUTATION OF BENEFITS

(4.1) LOSS REDUCTION BENEFITS

0.1 =Energy cost $/kwh (at dist.)
0.35 =Loss load factor, feeders
0.85 =Loss load factor for cement fac.

0.25 =Energy cost at dist less up streem
1.1 = discount factor

Original system losses 1990		Proposed system losses 1990	
Feeder	Losses kW	Feeder	Losses kW
Kunduchi 11 kV F	366	K/SS 11 kV feeders	9
Ub - Mbezi 33 kV	36	Mbezi-K 11kV feed.	4
W/Hill cement fac.	300	Ub - Mbezi 33 kV	21
		Ub - new G/SS	3
Total loss		Total loss	
W/Hill cement fac.	300	W/Hill cement fac.	3
Other feeders	402	Other feeders	37

Loss reduction benefits from 1993

	1990 KW	1990 KWH	Value of benefits in $ 000's Yr. 1990	MF *	Period '93-'08
W/Hill cement fac.	297	2211462	221.146	9.87	2182.712
Other feeders	365	1118814	111.881	20.15	2254.410
TOTAL	662	3330276	333.028		4437.123
Value of benefits discounted to 1990 $ 000's					3333.676
BENEFIT/COST RATIO WITH LOSS REDN. BENEFITS ONLY					1.5

(4.2) BENEFITS FROM ADDITIONAL CAPACITY TO SUPPLY NEW LOADS

YEAR	1993	1996	1999	2002	2005	2008
New Kunduchi SS load	2.777	3.402	4.168	5.106	6.255	7.662
Load which could be supplied by former network	2.000	2.000	2.000	2.000	2.000	2.000
New load possible by additional capacity	0.777	1.402	2.168	3.106	4.255	5.662
p.u growth of additional capacity		0.217	0.156	0.127	0.111	0.100

PW to 1993, new Kunduchi SS load (15 years from 1993) GWH	34.575	12.45 =MF*
PW to 1993 possible supply (15 years from 1993) with existing system GWH	16.740	8.37 =MF*
PW (to 1993) of benefits from new capacity in $ 000's	4459	
Value of benefits discounted to 1990, $ 000's	3350	
BENEFIT/COST RATIO WITH LOSS REDN. PLUS NEW CAPACITY	3.0	

(4.3) RELIABILITY BENEFITS

	Estimated Values	Sensitivity for variations in % units saved and cost value of saved energy				
Est. outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Est. outages saved 1993 GWH	1.150	1.150	0.767	0.767	0.383	0.383
PW fac. (MF) of reliab. benefits (15yrs.at 3% Load.gr.)	9.85	9.85	9.85	9.85	9.85	9.85
PW outages saved 15 yrs from 1993 discounted to 1990. (GWH)	8.511	8.511	5.674	5.674	2.837	2.837
Value of reliability benefits						
Value saved outages - multiple of energy cost	10	5	5	3	3	2
PW reliability benefits $ 000's	8511	4256	2837	1702	851	567
Total benefits (loss redn & reliabi.) $000's	17407	13152	11733	10598	9747	9463
BENEFIT/COST RATIO WITH ALL BENEFITS LISTED ABOVE	7.9	6.0	5.3	4.8	4.4	4.3

* Note: MF - Provides the muntiplying factor for PW of benefits extended over a given period taking into account the load growth (see annex 2)

COST BENEFIT ANALYSIS FOR
PROPOSED PRIMARY SUBSTATION 15 MVA AT MSASANI PENINSULAR

TABLE E 1.2
pg. 1

(1) LOAD CHARACTERISTICS OF AFFECTED FEEDERS

Period	'90-'93	'93-'96	'96-'99	'99-'02	'02-'05	'05-'08	
Estimated load growth pu. for all feeders	0.05	0.05	0.03	0.02	0.02	0.02	
YEAR	1990	1993	1996	1999	2002	2005	2008
New Msasani substation feeders							
Feeder F 1 Amps	101	117	135	148	157	167	177
Feeder F 2 Amps	109	126	146	160	169	180	191
Feeder F 3 Amps	167	193	224	245	260	275	292
Total load Amps	377	436	481	558	616	680	751
Total demand on SS (MVA)	7.183	8.315	9.168	10.628	11.734	12.955	14.303
System peak loads - affected sections							
New substation load MW	6.465	7.484	8.663	9.467	10.046	10.661	11.314
MK1 and O 2 & O 6 load MW	4.218	4.883	5.653	6.177	6.555	6.957	7.382
Total load MW	10.683	12.367	14.316	15.644	16.601	17.618	18.696
Overall load growth p.a.		4.95	4.95	2.97	1.98	1.98	1.98
Av.load factor 0.65							
Total energy MWH	60829	70418	81517	89076	94528	100314	106454
Overall load growth p.a.		4.95	4.95	2.97	1.98	1.98	1.98

(2) CONCLUSIONS FROM ESTIMATED LOAD DISTRIBUTION

Capacity of Msasani Substation: 1 x 15 MVA is sufficient up to and beyond Yr.2000

Estimation of benefits: (1) Loss reduction as calculated below on an analysis by feeder.
(2) *The Oyster Bay substation is already fully loaded (considering also the other feeders not indicated above.*
Thus the cost of augmenting the existing SS to 2*15 may be set off as being avoided costs.
Since the above avoided cost is taken account of no aditional benefits from new consumers are included in the analysis.
(3) Reliability benefits estimated by outages saved (as % of total sales).

(3) CAPITAL WORKS *(all costs in $ 000's)*

	Unit	Qty	Rate	Cost
33 kV S.C.line 100 mm sq ACSR	km	5.3	23	122
33 kV feeder CB units	nos	2	120	240
33/11 kV transformer 15 MVA	nos	1	225	225
11 kV feeder CB units	nos	4	55	220
Substation structure & auxiliaries	item	1	50	50
11 kV line 100 mm sq ACSR	km	6	21	126

TOTAL COSTS	983
Avoded Costs of augumentation of Oyster Bay SS	225
(only the cost of one 15 MVA Tf. is included as the existing 3*5 MVA Tf. will be recovered)	
NET COSTS FOR ECONOMIC ANALYSIS	758
Net Costs discounted to 1990	689

NOTE: Expenditure is assumed in 1991 and benefits are computed from 1993

Cont. pg.2

COST BENEFIT ANALYSIS FOR PROPOSED PRIMARY SUBSTATION 15 MVA AT MSASANI PENINSULAR (CONT)

TABLE E 1.2
pg. 2

(4) COMPUTATION OF BENEFITS

(4.1) LOSS REDUCTION BENEFITS

0.1 = Energy cost $/KWH
0.35 = Feeder load loss factor
1.1 =Discount factor

Original system losses 1990			Proposed system losses 1990		
Feeder	Amps	Losses kW	Feeder	Amps	Losses kW
O 6	120	24	O 6	32	1
O 3	296	335	O 3	119	18
MK 1	155	78	MK 1	95	16
O/BAY33K\	260	376	F 1	101	7
MK 33KV			F 2	109	11
			F 3	68	4
			F 4	99	7
			O/BAY33K\	208	240
			TO MS33KV	126	83
			MK 33KV		
TOTAL		814	TOTAL		388

Loss reduction benefits from 1993:-

	1990 KW	1990 KWH	MF*	VALUE OF BENEFITS 1993 - 2008 discounted to1990
All feeders	426	1306718	12.58	1644

Benefit/Cost ratio considering only loss red. 2.4

(4.2) RELIABILITY BENEFITS

	Estimatec Values	Sensitivity for variations in % units saved and cost of saved energy				
Est. outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Est. outages saved 1990 loads (MWH)	912	912	608	608	304	304
PW fac. reliability benefits '93-08 (MF*)	8.83	8.83	8.83	8.83	8.83	8.83
PW outages saved 1993 to 2008 MWH	8057	8057	5371	5371	2686	2686
Value of reliability benefits						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	6445	4028	2686	1611	806	537
TOTAL BENEFITS (loss redn & reliabi.) $000's	8089	5672	4329	3255	2450	2181
Benefit / Cost ratio	11.7	8.2	6.3	4.7	3.6	3.2

* Note: MF - Provides the muntiplying factor for PW of benefits discounted to 1990 extended over a given period from 1993 (taking into account the load growth effects (see annex D)

COST BENEFIT ANALYSIS FOR
PROPOSED PRIMARY SUBSTATION 15 MVA AT SOKONI DRIVE

TABLE G1.3

(1) ESTIMATED LOAD DISTRIBUTION

Period	'90-'93	'93-'96	'96-'99	'99-'02	'02-'05	'05-'08
Estimated load growth pu.	0.07	0.07	0.06	0.03	0.02	0.02
YEAR	1990	1993	1996	1999	2002	2005
New Sokoini Drive Sub Station						
Total feeder load in Amps	367	450	505	586	647	714
Total substation load MVA	6.992	8.566	9.625	11.158	12.319	13.601
New substation load MW	6.293	7.709	8.662	10.042	11.087	12.241
C 3, C4, C8 Load MW	8.500	9.095	9.732	10.316	10.625	10.838
Total load MW	14.793	16.804	18.394	20.358	21.712	23.079
Overall load growth p.a.		4.30	3.03	3.40	2.15	2.03
Av.load factor 0.65						
Total energy MWH	84233	95685	104736	115916	123630	131410
Overall load growth p.a.		4.30	3.03	3.40	2.15	2.03

(2) CONCLUSIONS FROM ESTIMATED LOAD DISTRIBUTION

Capacity of Sokoini Drive SS. — 1*15 MVA is sufficient up to and beyond Yr.2000

Estimation of benefits —
(1) Loss reduction as calculated below on an analysis by feeder.
(2) The City Center substation would be fully loaded by 1993
Thus the cost of augmenting the existing SS to 2*15 may be set off as being avoided costs
Since the above avoided cost is taken account of no aditional benefits from new co
are included in the analysis.
(3) Reliability benefits estimated by outages saved (as % of total sales).

(2) CAPITAL WORKS (all costs in $ 000's)

	Unit	Qty	Rate	Cost
33 kV S.C.line 100 mm sq ACSR	km	3.8	23	87
33 kV feeder CB units	nos	2	120	240
33/11 kV transformer 15 MVA	nos	1	225	225
11 kV feeder CB units	nos	5	55	275
Substation structure & auxiliaries	item	1	50	50
11 kV line 100 mm sq ACSR	km	1	21	21

TOTAL COST	898
Avoded Costs of augumentation of City Center SS (only the cost of one 15 MVA Tf. is included as the existing 3*5 MVA Tf. will be recovered)	225
NET COSTS FOR ECONOMIC ANALYSIS	673
Net Costs discounted to 1990	612

NOTE: Expenditure is assumed in 1991 and benefits are computed from 1993

Cont. pg.2

COST BENEFIT ANALYSIS FOR
PROPOSED PRIMARY SUBSTATION 15 MVA AT SOKONI DRIVE (Cont.)

TABLE E 1.3
pg. 2

(4) COMPUTATION OF BENEFITS

(4.1) LOSS REDUCTION BENEFITS

0.1 = Energy cost $/KWH
0.35 = Feeder load loss factor

1.1 =Discount factor

Original system losses 1990			Proposed system losses 1990		
Feeder	Amps	Losses kW	Feeder	Amps	Losses kW
C 3	240	27	C 3	32	12
C 4	270	64	C 4	119	11
C 8	180	19	C 8	95	17
IL-City	320	254	SK 1	101	4
Center 33 kV			SK 2	109	5
			SK 3	68	2
			SK 4	99	4
			IL-CC	198	97
			IL-SkD	122	56
TOTAL		364	TOTAL		208

Loss reduction benefits from 1993:-

	1990 KW	1990 KWH	MF*	VALUE OF BENEFITS 1993 - 2008 discounted to1990
All feeders	156	478333	17.70	847
Benefit/Cost ratio considering only loss red.				1.4

(4.2) RELIABILITY BENEFITS

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Est. outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Est. outages saved 1990 loads (MWH)	1263	1263	842	842	421	421
PW fac. reliability benefits '93-08 (MF*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	13140	13140	8760	8760	4380	4380
Value of reliability benefits						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	10512	6570	4380	2628	1314	876
TOTAL BENEFITS (loss redn & reliabi.) $000's	11359	7417	5227	3475	2161	1723
Benefit / Cost ratio	18.6	12.1	8.5	5.7	3.5	2.8

* Note: MF - Provides the muntiplying factor for PW of benefits discounted to 1990
extended over a given period from 1993 (taking into account the load growth effects (see annex 2)

cb-Chang

Table E 1.4

COST BENEFIT ANNALYSIS FOR NEW PRIMARY SUBSTATION AT CHANG'OMBE

6 = %load growth
15 = analysis period
1.124 = loss gr.fac. pa.
0.1 = Energy costs $/KWH
0.35 = loss load factor
1.1 = discount factor pa.
17.48 = P.W. factor for loss redn. over period of analysis

COMPUTATION OF BENEFITS:

(a) LOSS REDUCTION BENEFITS

	1991 KW	1991 KWH/yr.	1993 KWH/yr.
Existing line losses	638	1,956,108	2,469,541
Losses after new dev.	274	840,084	1,060,587
Peak loss savings	364	1,116,024	1,408,955
Value of savings 1993-2008 in $ 000's			2462
Value of savings discounted to 1991			2035

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
33 kV line 100 mmsq.	0.7	22.8	16.0
Substation Costs:			
Transformer 5 MVA 33/11 kV	1	170.1	170.1
33 kV circuit breaker and bay	1	123.0	123.0
11 kV circuit breaker and bay	5	49.2	246.0
Total Cost (assumed in 1992) US $000's			555.1
Cost discounted to 1991			504.6
Benefit/Cost ratio considering loss reduction benefits only			4.0

(b) RELIABILITY BENEFITS

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Est. outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Est. outages saved 1991 loads (MWH)	460	460	307	307	153	153
PW fac. reliability benefits '93-08 (MF*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	4783	4783	3189	3189	1594	1594
Value of reliability benefits						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	3826	2391	1594	957	478	319
TOTAL BENEFITS (loss redn & reliabi.) $000's	4331	2896	2099	1461	983	823
Benefit / Cost ratio (loss reduction & reliability benefits)	12.6	9.8	8.2	6.9	6.0	5.7

* Note: MF - Provides the muntiplying factor for PW of benefits discounted to 1990 extended over a given period from 1993 (taking into account the load growth effects (see annex 2)

30660 = System load in MWh (at 1991 level) benefiting by increased reliability cb-MbCh

Table E 1.5

COST BENEFIT ANNALYSIS FOR NEW PRIMARY SUBSTATION AT MWEMBE-CHAI

Computation factors

1.1	= discount factor p.a.		
9	= % annual load growth	0.10	= Energy costs $/KWH
15	= analysis period	0.60	= load factor
1.188	= loss growth factor p.a	0.35	= loss load factor

27.17 = P.W. factor for loss reduction over period of analysis (MFlr)

COMPUTATION OF BENEFITS:

(a) Loss reduction benefits

	1991 KW	1991 MWH/yr.	1993 MWH/yr.
Existing line losses	866	2,655	3,748
Losses after new dev.	345	1,058	1,493
Peak loss savings	521	1,597	2,255
Value of savings 1993-2008 in $ 000's			6127
Value of savings discounted to 1991 ($000)			5063

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
33 kV line 100 mmsq.	1.1	22.8	25.1
Substation Costs:			
Transformer 15 MVA 33/11 kV	1	225.5	225.5
33 kV circuit brreaker and bay	1	123.0	123.0
11 kV circuit brreaker and bay	5	49.2	246.0
11 KV line additions (100mmsq.)	1.5	20.7	31.1
Total Cost (assumed in 1992) US $000's			650.6
Cost discounted to 1991 ($000)			591.5
Benefit/Cost ratio considering loss reduction benefits only			8.6

(b) Reliability benefits

System load in MW (at 1991 level) benefiting by increased reliability	11.7
Annual load, MWh (1991) of section with reliablity improvement	102493

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Estimated outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Estimated outages saved 1991 loads (MWH)	1537	1537	1025	1025	512	512
PW factor for reliability benefits '93-08 (MFrb*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	15989	15989	10659	10659	5330	5330
Value of reliability benefits:						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	12791	7994	5330	3198	1599	1066
TOTAL BENEFITS (loss redn & reliabi.) $000's	13383	8586	5921	3789	2190	1657
Benefit / Cost ratio (loss reduction & reliability benefits)	31.2	23.1	18.6	15.0	12.3	11.4

* Note: MFrb - Provides the muntiplying factor for PW of benefits discounted to 1991 extended over a given period from 1993 (taking into account the load growth effects (see annex B)

cb-Mb

Table E 1. 6

COST BENEFIT ANNALYSIS FOR NEW PRIMARY SUBSTATION AT MBAGALA

Computation factors

1.1	= discount factor p.a.		
9	= % annual load growth	0.10	= Energy costs $/KWH
15	= analysis period	0.60	= load factor
1.188	= loss growth factor p.a	0.35	= loss load factor

27.17 = P.W. factor for loss reduction over period of analysis (MFlr)

COMPUTATION OF BENEFITS:

(a) Loss reduction benefits

	1991 KW	1991 MWH/yr.	1993 MWH/yr.
Existing line losses	82	251	355
Losses after new dev.	28	86	121
Peak loss savings	54	166	234
Value of savings 1993-2008 in $ 000's			635
Value of savings discounted to 1991 ($000)			525

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
33 kV line 100 mmsq.	1.4	22.8	31.9
Substation Costs:			
Transformer 5 MVA 33/11 kV	1	170.1	170.1
33 kV circuit brreaker and bay	1	123.0	123.0
11 kV circuit brreaker and bay	3	49.2	147.6
11 KV line additions (100mmsq.)	1	20.7	20.7

Total Cost (assumed in 1992) US $000's	493.3
Cost discounted to 1991 ($000)	448.5
Benefit/Cost ratio considering loss reduction benefits only	1.2

(b) Reliability benefits

System load in MW (at 1991 level) benefiting by increased reliability	4.873
Annual load, MWh (1991) of section with reliablity improvement	42688

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Estimated outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Estimated outages saved 1991 loads (MWH)	640	640	427	427	213	213
PW factor for reliability benefits '93-08 (MFrb*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	6659	6659	4440	4440	2220	2220
Value of reliability benefits:						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	5327	3330	2220	1332	666	444
TOTAL BENEFITS (loss redn & reliabi.) $000's	5776	3778	2668	1780	1114	892
Benefit / Cost ratio (loss reduction & reliability benefits)	14.0	9.6	7.1	5.1	3.7	3.2

* Note: MFrb - Provides the muntiplying factor for PW of benefits discounted to 1991 extended over a given period from 1993 (taking into account the load growth effects (see annex B)

PROPOSED GRID SUBSTATION 30 MVA AT TANGA CEMENT FACTORY

TABLE E 2.1

ESTIMATED LOAD DISTRIBUTION

Period		'90-'93	'93-'95	'95-'97	'97-'00	'00-'02	'02-'05
Estimated load growth pu. for feeders		0.07	0.07	0.07	0.07	0.07	0.07
Estimated load growth pu. for cement fac.		0.7	0.015	0.015	0.015	0	0
YEAR	1990	1993	1995	1997	2000	2002	2005
Cement Factory load MW	10.000	17.000	17.514	18.043	18.589	18.589	18.589
Moa feeder MW	1.000	1.145	1.311	1.501	1.838	2.105	2.579
Bushiri feeder MW	1.000	1.225	1.403	1.606	1.967	2.252	2.759
Total load MW	12.000	19.370	20.227	21.150	22.394	22.946	23.926

CAPITAL WORKS (costs in $ 000's)

	Unit	Qty	Rate	Cost
132/33 kV transformer 30 MVA	nos	1	450	450
132 kV incommer	nos	1	220	220
33 kV feeder CB units	nos	6	120	720
Substation structure & auxiliaries	item	1	100	100
TOTAL COST				1490

COMPUTATION OF BENEFITS

(a) LOSS REDUCTION BENEFITS

0.1 =Energy cost $/kwh 0.35

and loss load factors 0.35 For feeders

0.85 For cement fac.

Original system losses 1993			Proposed system losses 1990		
Feeder	Amps	Losses kW	Feeder	Amps	Losses kW
K 1		52	K 1 /1		2
K 2		52	K 2 /1		2
Cement		490	K 1 /2		2
			K 2 /2		2
			Cement		10
Total loss			Total loss		
	Cement	490		Cement	10
	Feeders	104		Feeders	8
			kW	$ 000's	

Table E 2.1 (Contd.)

Loss reduction benefits 1993

	1993 KW	1993 KWH	VALUE in $ 000's 1993	MF	Value'93-'06
Cement	480	1471680	147.168	7.04	1036.063
Feeders	96	714816	71.482	20.74	1482.528
TOTAL	576	2186496	218.650		2518.591

Value of loss redn. benefits 1993 - 2003

(b) RELIABILITY BENEFITS

Sections with enhanced reliability							
Period		'90-'93	'93-'95	'95-'97	'97-'00	'00-'02	'02-'05
Estimated load growth pu. for feeders		0.07	0.07	0.07	0.07	0.07	0.07
Estimated load growth pu. for cement fac.		0.7	0.015	0.015	0.015	0	0
Estimated load growth pu. for Tanga & ass.		0.04	0.04	0.04	0.04	0.04	0.04
YEAR	1990	1993	1995	1997	2000	2002	2005
Cement Factory load MW	10.000	17.000	17.514	18.043	18.589	18.589	18.589
Moa feeder MW	1.000	1.145	1.311	1.501	1.838	2.105	2.579
Bushiri feeder MW	1.000	1.225	1.403	1.606	1.967	2.252	2.759
Tanga city and K 1 K 2 loads	7.000	7.874	8.857	9.963	11.207	12.607	14.181
Total load MW	19.000	27.244	29.084	31.113	33.601	35.552	38.107
Overall load growth p.a.		12.63	2.18	2.25	2.57	1.88	2.32
Energy cement fac. (85%lf) MWH	74460	126582	130408	134350	138410	138410	138410
Energy other loads (65%lf) MWH	51246	58329	65883	74419	85483	96591	111137
Total energy MWH	125706	184911	196291	208768	223893	235001	249547
Overall load growth p.a.		13.58	1.99	2.05	2.34	1.61	2.00
Est. outages saved as % of annual energy		5	5	3	3	1	1
Est. outages saved 1993 MWH		9246	9246	5547	5547	1849	1849
PW fac. reliability benefits '93-06 at 2% gr.		7.15	7.15	7.15	7.15	7.15	7.15
PW outages saved 1993 to 2006 MWH		66106	66106	39663	39663	13221	13221
Value of reliability benefits							
Value saved outages - multiple of energy cost		5	1	5	1	5	1
PW reliability benefits $ 000's		33053	6611	19832	3966	6611	1322
Total benefits (loss redn & reliabi.) $000's		35571	9129	22350	6485	9129	3841
Benefit / Cost ratio		24	6	15	4	6	3

cb-Sah

Table E 2.2

COST BENEFIT ANALYSIS FOR NEW PRIMARY SUBSTATION AT SAHARE

Computation factors

1.1	= discount factor p.a.		
6	= % annual load growth	0.10	= Energy costs $/KWH
15	= analysis period	0.75	= load factor
1.124	= loss growth factor p.a	0.40	= loss load factor

17.48 = P.W. factor (MFlr*) for loss reduction over analysis period indicated above

COMPUTATION OF BENEFITS:

(a) Loss reduction benefits

	1991 KW	1991 MWH/yr.	1993 MWH/yr.
Existing line losses	122	427	540
Losses after new development	92	322	407
Peak loss savings	30	105	133
Value of savings 1993-2008 in $ 000's			232
Value of savings discounted to 1991 ($000)			192

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
33 kV line 100 mmsq.	1	22.8	22.8
Substation Costs:			
Transformer 5 MVA 33/11 kV	1	170.1	170.1
33 kV circuit breaker and bay	1	123.0	123.0
11 kV circuit breaker and bay	4	49.2	196.8
11 KV line additions (100mmsq.)	1	20.7	20.7

Total Cost (assumed in 1992) US $000's	533.4
Cost discounted to 1991 ($000)	484.9
Benefit/Cost ratio considering loss reduction benefits only	0.4

(b) Reliability benefits

System load in MW (at 1991 level) benefiting by increased reliability	4.6
Annual load, MWh (1991) of section with reliability improvement	40297

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Estimated outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Estimated outages saved 1991 loads (MWH)	604	604	403	403	201	201
PW factor for reliability benefits '93-08 (MFrb*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	6286	6286	4191	4191	2095	2095
Value of reliability benefits:						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	5029	3143	2095	1257	629	419
TOTAL BENEFITS (loss redn & reliability) $000's	5514	3628	2580	1742	1114	904
Benefit / Cost ratio (loss reduction & reliability benefits)	11.8	7.9	5.7	4.0	2.7	2.3

* Note: See Annex D for determination of multiplying factors to obtain PW of benefits over a future time period (given a constant annual load growth)
MFlr - represents the factor for loss reduction benefits and
MFrb - represents the factor for reliability benefits

CB-Luso1 Table E 2.32

COST BENEFIT ANALYSIS FOR TRANSFER OF ZELEVA-BUMBUL LOADS TO 33 kV
BY CONVERTING AND REHAB. OF EXISTING CU 25 LINES TO 33 kV

4 = %load growth	0.1 = Energy costs $/KWH
15 = analysis period	0.35 = loss load factor
1.082 = loss gr.fac. pa.	1.1 = discount factor pa.
13.36 = P.W. factor for loss redn. over period of analysis	

COMPUTATION OF BENEFITS:

	1990	1990	1993
33 kV system losses	KW	KWH/yr.	KWH/yr.
Existing line losses	251	769566	973746
Proposed system line losses	184	564144	713822
loss savings	67	205422	259924
Value of savings 1993-2008 in $ 000's			347
Value of savings discounted to 1990			261

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
convertion and rehab of line	45	14	630.0
construction of new line	12	18	216.0
Conversion of distribution stations			
300 KVA trans.	1	10.5	10.5
200 KVA trans.	1	9.2	9.2
150 KVA trans.	3	8.4	25.2
100 KVA trans.	3	7.8	23.4
50 KVA trans.	2	5.8	11.6
25 KVA trans.	1	5	5.0
10 KVA trans	7	2	14.0
Total cost			944.9
Cost saving due to deferment of augumt. of 33/11 kV SS			100.0
Cost saving due to avoiding of rehab. dist stn(20%new)			189.0
Cost saving due to avoiding of rehab. line (@8 k$/km)			360.0
Economic costs (assumed incurred in 1992)			295.9
Economic costs discounted to 1990			244.6
Benefit/Cost ratio			1.1

cb-korn1

Table E.2.4.1

COST BENEFIT ANNALYSIS FOR ERRECTION OF A 2.5 MVA PRIMARRY SS AT KWAMNDOLWA FOR LOSS REDUCTION OF THE KOROGWE NORTH FEEDER

3	= %load growth	0.1	= Energy costs $/KWH
15	= analysis period	0.35	= loss load factor
1.061	= loss gr.fac. pa.	1.1	= discount factor pa.
11.79	= P.W. factor for loss redn. over period of analysis		

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	41	125706	150100
Losses after new dev.	8	24528	29288
loss savings	33	101178	120812
Value of savings 1993-2008 in $ 000's			142
Value of savings discounted to 1990			107

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Conversion of 33 kV line (km)	6.2	23	142.6
Substation Costs:			
Transformer 2.5 MVA 33/11 kV	1	125	125.0
33 kV OCB	1	18	18.0
11 kV OCB	1	10	10.0
Total Cost US $000's			295.6
Cost savings by deferment of aug. of Korogwe SS			150.0
Economic costs (assumed incurred in 1991)			145.6
Economic costs discounted to 1990			132.4
Benefit/Cost ratio			0.8

Note: In addition to the loss reduction benefits there are reliability benefits which are not accounted for.

cb-korn3 Table E2.42

COST BENEFIT ANALYSIS FOR CONVERTION OF KOROGWE NORTH FEEDER TO 33 kV
(B) Converting and rehab. the existing line CU 25 to 33 kV.

3 = %load growth	0.1 = Energy costs $/KWH
15 = analysis period	0.35 = loss load factor
1.061 = loss gr.fac. pa.	1.1 = discount factor pa.
11.79 = P.W. factor for loss redn. over period of analysis	

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	39	119574	142778
Proposed line losses	4	12264	14644
~~Peak~~ loss savings	35	107310	128134
Value of savings 1993-2008 in $ 000's			151
Value of savings discounted to 1990			113

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
conversion and rehab of line	32.5	14	455.0
Convertion of distribution stations			
300 KVA trans.	1	10.5	10.5
200 KVA trans.	1	9.2	9.2
150 KVA trans.	2	8.4	16.8
100 KVA trans.	2	7.8	15.6
50 KVA trans.	7	5.8	40.6
25 KVA trans.	3	5	15.0
Total cost			562.7
Cost saving due to deferment of augumt. of 33/11 kV SS			100.0
Cost saving due to avoiding of rehab. dist stn(20%new)			112.5
Cost saving due to avoiding of rehab. line (@8 k$/km)			260.0
Economic cost (assumed incurred in 1992)			90.2
Economic costs discounted to 1990			74.5
Benefit/Cost ratio			1.5

cb-korn2

Table - E.2.4.3

COST BENEFIT ANNALYSIS FOR CONVERTION OF KOROGWE NORTH FEEDER TO 33 kV
(B) Constructing a new line with 100 mmsq. ACSR

3 = %load growth	0.1 = Energy costs $/KWH
15 = analysis period	0.35 = loss load factor
1.061 = loss gr.fac. pa.	1.1 = discount factor pa.
11.79 = P.W. factor for loss redn. over period of analysis	

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	39	119574	142778
Proposed line losses	2	6132	7322
loss savings	37	113442	135456
Value of savings 1993-2008 in $ 000's			160
Value of savings discounted to 1990			120

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Constructing of line (km)	32.5	23	747.5
Conversion of distribution stations			
300 KVA trans.	1	10.5	10.5
200 KVA trans.	1	9.2	9.2
150 KVA trans.	2	8.4	16.8
100 KVA trans.	2	7.8	15.6
50 KVA trans.	7	5.8	40.6
25 KVA trans.	3	5	15.0
Total cost			855.2
Cost saving due to deferment of augumt. of 33/11 kV SS			100.0
Cost saving due to avoiding rehab ofline 32.5 km @8k$			260.0
Cost saving due to avoiding rehab of dist.t/f (20%new)			171.0
Economic costs (assumed incurred in 1992)			324.2
Economic costs discounted to 1990			267.9
Benefit/Cost ratio			0.4

cb-korw1

Table E 2.5.1.

COST BENEFIT ANNALYSIS FOR CONVERTION OF KOROGWE WEST FEEDER TO 33 kV
(A) Converting and rehab. the existing line CU 25 to 33 kV.

3	= %load growth	0.1	= Energy costs $/KWH
15	= analysis period	0.35	= loss load factor
1.061	= loss gr.fac. pa.	1.1	= discount factor pa.
11.79	= P.W. factor for loss redn. over period of analysis		

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	41	125706	150100
Proposed line losses	3.5	10731	12813
loss savings	37.5	114975	137286
Value of savings 1993-2008 in $ 000's			162
Value of savings discounted to 1990			122

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Constructing of line (km)	25	14	350.0
Conversion of distribution stations			
500 KVA trans.	1	12	12.0
300 KVA trans.	1	10.5	10.5
200 KVA trans.	1	9.2	9.2
100 KVA trans.	2	7.8	15.6
50 KVA trans.	1	5.8	5.8
25 KVA trans.	1	5	5.0
Total cost			408.1
Cost saving due to deferment of augumt. of 33/11 kV SS			100.0
Cost saving due to avoiding rehab of line 25 km @ 8k$			200.0
Economic costs (assumed incurred in 1992)			108.1
Economic costs discounted to 1990			89.3

Benefit/Cost ratio 1.4

cb-korn2

Table E.2.5.2

COST BENEFIT ANNALYSIS FOR CONVERTION OF KOROGWE WEST FEEDER TO 33 kV
(B) Constructing a new line with 100 mmsq. ACSR

3	= %load growth	0.1	= Energy costs $/KWH
15	= analysis period	0.35	= loss load factor
1.061	= loss gr.fac. pa.	1.1	= discount factor pa.
11.79	= P.W. factor for loss redn. over period of analysis		

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	41	125706	150100
Proposed line losses	1	3066	3661
loss savings	40	122640	146439
Value of savings 1993-2008 in $ 000's			173
Value of savings discounted to 1990			130

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Constructing of line (km)	25	23	575.0
Conversion of distribution stations			
500 KVA trans.	1	12	12.0
300 KVA trans.	1	10.5	10.5
200 KVA trans.	1	9.2	9.2
100 KVA trans.	2	7.8	15.6
50 KVA trans.	1	5.8	5.8
25 KVA trans.	1	5	5.0
Total cost			633.1
Cost saving due to deferment of augumt. of 33/11 kV SS			100.0
Cost saving due to avoiding rehab of line 25 km @ 8k$			200.0
Economic costs (assumed incurred in 1992)			333.1
Economic costs discounted to 1990			275.3

cb-kibar

Table E. 2.6

COST BENEFIT ANNALYSIS FOR ERRECTION OF A 2.5 MVA PRIMARRY SS AT KIBARANGA

3 = %load growth
15 = analysis period
1.061 = loss gr.fac. pa.
11.79 = P.W. factor for loss redn. over period of analysis

0.1 = Energy costs $/KWH
0.35 = loss load factor
1.1 = discount factor pa.

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	209	640794	765142
Losses after new dev.	65	199290	237963
loss savings	144	441504	527179
Value of savings 1993-2008 in $ 000's			621
Value of savings discounted to 1990			467

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Substation Costs:			
Transformer 2.5 MVA 33/11 kV	1	125	125.0
33 kV OCB	1	50	50.0
11 kV OCB	1	20	20.0
Total Cost US $000's			195.0
Cost savings by deferment of aug. of Mazinde SS			100.0
Economic costs (assumed incurred in 1991)			95.0
Economic costs discounted to 1990			86.4
Benefit/Cost ratio			5.4

cb-Majen

Table E 3.1

COST BENEFIT ANNALYSIS FOR ESTABLISHING A 33/11 kV SUBATATION AT MAJENGO AT MOSHI TOWN

7 = %load growth	0.1 = Energy costs $/KWH
15 = analysis period	0.35 = loss load factor
1.145 = loss gr.fac. pa.	0.55 = load factor
1.07 = load gr.fac. pa	1.1 = discount factor pa.

Present worth factors over period of analysis:

20.15 = for loss redn.	12.45 = for reliability impt.

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Const. of 33 kV line 100 mmsq. (km)	5	23	115.0
Substation Costs:			
Transformer 5 MVA 33/11 kV	1	170	170.0
33 kV bays	2	120	240.0
11 kV bays	4	55	220.0
	Total Cost US $000's		745.0

PW of postponement of augn. of existing substations	150.0
Economic costs (assumed incurred in 1991)	595.0
Economic costs discounted to 1990	540.9

COMPUTATION OF BENEFITS:

Loss reduction benefits	1990	1990	1993
----------------------	KW	KWH/yr.	KWH/yr.
Existing line losses	124	380184	570554
Losses after new dev.	47	144102	216258
Loss savings	77	236082	354295
Value of savings 1993-2008 in $ 000's			714
Value of savings discounted to 1990			536
Benifit / Cost ratio for loss red/n benefits only			1.0

Reliability benefits	1990	1990	1993
-------------------	KW	MWH/yr.	MWH/yr.
feeder sections with enhanced reliability			
M 3 from T/school	2429	11703	14337
Town F from Boma	1458	7025	8605
Total loads with enhanced reliability			22942

	Estimated Values	Sensitivity for variations of energy cost & est. savings		
Estimated energy saved (%)	1.5	1.5	1	1
Value in (pu. of en.cost)	5	2	5	2
Value of sav. energy $ 000's	2142	857	1428	571
Savings discounted to 1990	1609	644	1073	429
Total savings $ 000's	2146	1180	1609	965
Benefit / Cost ratio	4.0	2.2	3.0	1.8

cb-Makomb. Table E 3.2

COST BENEFIT ANNALYSIS FOR CONVERTION OF MAKOMBONE FEEDER TO 33 kV

3 = %load growth
15 = analysis period
1.061 = loss gr.fac. pa.
11.79 = P.W. factor for loss redn. over period of analysis

0.1 = Energy costs $/KWH
0.35 = loss load factor
1.1 = discount factor pa.

COMPUTATION OF BENEFITS:

	1990 KW	1990 KWH/yr.	1993 KWH/yr.
Existing line losses	41	125706	150100
Proposed line losses	3.5	10731	12813
Peak loss savings	37.5	114975	137286
Value of savings 1993-2008 in $ 000's			162
Value of savings discounted to 1990			122

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Constructing of line (km)	18	14	252.0
Convertion of distribution stations			
200 KVA trans.	1	9.2	9.2
100 KVA trans.	2	7.8	15.6
50 KVA trans.	6	5.8	34.8
25 KVA trans.	10	5	50.0
Total cost			361.6
Cost saving due to deferment of augumt. of 33/11 kV SS			100.0
Cost saving due to avoiding rehab of line @ 8k$/ Km			144.0
Economic costs (assumed incurred in 1992)			117.6
Economic costs discounted to 1990			97.2

Benefit/Cost ratio 1.3

COST BENEFIT ANALYSIS OF CONSTRUCTING A 66 kV LINE AND 66/33 kV SUBSTATION AT MARANGU

3 = %load growth	0.1 = Energy costs $/KWH
15 = analysis period	0.35 = loss load factor
1.061 = loss gr.fac. pa.	0.55 = load factor
1.03 = load gr.fac. pa	1.1 = discount factor pa.

Present worth factors over period of analysis:

11.79 = for loss redn.	9.85 = for reliability impt.

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
Construction of 66 kV line			
with part recovered material	30	15	450.0
Construction of 66/33 substation			
33 kV breakers	1	50	50.0
33 kV load break switches	3	10	30.0
Costs (assumed incurred in 1991)			530.0
Economic costs discounted to 1990			481.8

COMPUTATION OF BENEFITS:

Loss reduction benefits:	1990	1990	1993
-------------------------	KW	KWH/yr.	KWH/yr.
Existing line losses	557	1707762	2039157
Proposed line losses	105	321930	384401
Loss savings	452	1385832	1654756
Value of savings 1993-2008 in $ 000's			1950
Value of savings discounted to 1990			1465
Benifit / Cost ratio for loss red/n benefits only			3.0

Reliability benefits	1990	1990	1993
--------------------	KW	MWH/yr.	MWH/yr.
feeder sections with enhanced reliability			
Loads on Boma and Majengo (new) SS	5186	24986	27303
Loads on new 66 kV line	2721	13110	14325
Total loads with enhanced reliability			41628

	Estimated Values	Sensitivity for variations of energy cost & est. savings		
Estimated energy saved (%)	1.5	1.5	1	1
Value in (pu. of en.cost)	2	1.5	2	1
Value of sav. energy $ 000's	1231	923	820	410
Savings discounted to 1990	925	693	616	308
Total savings $ 000's	2390	2159	2082	1773
Benefit / Cost ratio	5.0	4.5	4.3	3.7

cb-Mon

Table E4.1

COST BENEFIT ANALYSIS FOR CONVERTION OF THE MONDULI LINE TO 33 kV OPERATION AND CONSTRUCTION OF A PRIMARY SUBSTATION AT MONDULI

Computation factors

1.1	= discount factor p.a.		
4	= % annual load growth	0.10	= Energy costs $/KWH
15	= analysis period	0.50	= load factor
1.082	= loss growth factor p.ε	0.30	= loss load factor

13.36 = P.W. factor (MFlr*) for loss reduction over analysis period indicated above

COMPUTATION OF BENEFITS:

(a) Loss reduction benefits

	1991 KW	1991 MWH/yr.	1993 MWH/yr.
Existing line losses	119	313	366
Losses after new development	33	87	101
Peak loss savings	86	226	264
Value of savings 1993-2008 in $ 000's			353
Value of savings discounted to 1991 ($000)			292

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
33 kV line 100 mmsq. (initial section)	6	22.8	136.8
Substation Costs:			
Transformer 2.5 MVA 33/11 kV	1	170.1	170.1
33 kV circuit breaker and bay	1	55.4	55.4
11 kV circuit breaker and bay	4	24.6	98.4
11 KV line additions (100mmsq.)	0.5	20.7	10.4
Total Cost (assumed in 1992) US $000's			471.1
Cost discounted to 1991 ($000)			428.2
Benefit/Cost ratio considering loss reduction benefits only			0.7

(b) Reliability benefits

System load in MW (at 1991 level) benefiting by increased reliability	2.5
Annual load, MWh (1991) of section with reliability improvement	21901

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Estimated outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Estimated outages saved 1991 loads (MWH)	329	329	219	219	110	110
PW factor for reliability benefits '93-08 (MFrb*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	3416	3416	2278	2278	1139	1139
Value of reliability benefits:						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	2733	1708	1139	683	342	228
TOTAL BENEFITS (loss redn & reliability) $000's	3161	2136	1567	1112	770	656
Benefit / Cost ratio (loss reduction & reliability benefits)	8.1	5.7	4.3	3.3	2.5	2.2

* Note: See Annex D for determination of multiplying factors to obtain PW of benefits over a future time period (given a constant annual load growth)
MFlr - represents the factor for loss reduction benefits and MFrb - represents the factor for reliability benefits

cb-Magereza

Table E 4.2

COST BENEFIT ANALYSIS FOR NEW PRIMARY SUBSTATION AT MEGAREZA

Computation factors

1.1	= discount factor p.a.		
3	= % annual load growth	0.10	= Energy costs $/KWH
15	= analysis period	0.75	= load factor
1.061	= loss growth factor p.a	0.40	= loss load factor

11.79 = P.W. factor (MFlr*) for loss reduction over analysis period indicated above

COMPUTATION OF BENEFITS:

(a) Loss reduction benefits

	1991 KW	1991 MWH/yr.	1993 MWH/yr.
Existing line losses	77.4	271	305
Losses after new development	26.5	93	105
Peak loss savings	50.9	178	201
Value of savings 1993-2008 in $ 000's			237
Value of savings discounted to 1991 ($000)			196

COST OF CAPITAL WORKS in $ 000's

	Qty.	rate	Cost
33 kV line 100 mmsq.	1	22.8	22.8
Substation Costs:			
Transformer 2.5 MVA 33/11 kV	1	170.1	170.1
33 kV circuit breaker	1	55.4	55.4
11 kV circuit breaker	2	24.6	49.2
11 KV line additions (100mmsq.)	1	20.7	20.7
Total Cost (assumed in 1992) US $000's			318.2
Cost discounted to 1991 ($000)			289.3
Benefit/Cost ratio considering loss reduction benefits only			0.7

(b) Reliability benefits

System load in MW (at 1991 level) benefiting by increased reliability	2.8
Annual load, MWh (1991) of section with reliability improvement	24529

	Estimated Values	Sensitivity for variations in % units saved and cost of saved energy				
Estimated outages saved as % of annual energy	1.5	1.5	1	1	0.5	0.5
Estimated outages saved 1991 loads (MWH)	368	368	245	245	123	123
PW factor for reliability benefits '93-08 (MFrb*)	10.4	10.4	10.4	10.4	10.4	10.4
PW outages saved 1993 to 2008 MWH	3826	3826	2551	2551	1275	1275
Value of reliability benefits:						
Value saved outages - multiple of energy cost	8	5	5	3	3	2
PW reliability benefits $ 000's	3061	1913	1275	765	383	255
TOTAL BENEFITS (loss redn & reliability) $000's	3350	2203	1565	1055	672	544
Benefit / Cost ratio (loss reduction & reliability benefits)	12.3	8.3	6.1	4.3	3.0	2.6

* Note: See Annex D for determination of multiplying factors to obtain PW of benefits over a future time period (given a constant annual load growth)
MFlr - represents the factor for loss reduction benefits and MFrb - represents the factor for reliability benefits

SUM-RR1

Table E.5.1

SUMMARY OF MV REHABILITATION & TRANSF. FOR LV REINFORCMENT

REGION	M.V. REHABILITATION REQTS. Reconduct. 100 mmsq	50 mmsq	Pole Replace	MV LINE EXTENSIONS AND ASSOCIATED TRANSFORMER STATIONS. 33 kV 100 mmsq	11 kV 100 mmsq	50 mmsq	33KV/LV Trans. 160/200	25to100	11 KV/LV Transformers by KVA 200/250	100/160	25to63
ARUSHA	10	1	606	6.4	11.8	2.1	1		1	8	1
MOSHI	21		171		3.8	2.7			8	4	
TANGA	1		77	5.0	13.1		2	2	4	2	5
DAR ES S	152		1281	5.0	24.0			10	40	20	
TOTAL Identif/d	184	1	2135	16.4	52.7	4.8	3	12	53	34	6
Project	200	10	2500	20	60	20	10	15	60	50	40
FOREIGN COST											
Rate	12	10	0.22	21	18	13	9	5.5	9.3	6.5	4.4
Cost $000	2400	100	550	420	1080	260	90	83	558	325	176
LOCAL COST											
Rate	0.8	0.6	0.03	1	0.9	0.6	0.43	0.25	0.44	0.3	0.2
Cost $000	160	6	75	20	54	12	4.3	3.8	26.4	15.0	8.0
TOT. COST	2560	106	625	440	1134	272	94	86	584	340	184

TOTAL COSTS in $ 000's:	MV REHABILITATION Foreign	Local	Total	TRANSF. AND LV REINFORCEMENT Foreign	Local	Total
Works identified above $000	3050	241	3291	2992	143	3135
S/Ph transf. & LV lines				500	50	550
Rehab. material for MVlines	1000	100	1100			
Rehab. material for Pr. SS	1500	200	1700			
Total cost in $ 000's	5550	541	6091	3492	193	3685

SUM-RR2

SUMMARY FOR REHABILITATION AND REINFORCEMENT OF LV LINES

REGION	NEW LV EXTENSIONS #100	#50	RECOND. & REHAB #100	#50	REPLACE POLES	PHASE ADDITION #100	#50
Presently Identified Works in km:							
ARUSHA	11.4		9.0	9.1	297		1
MOSHI	9.8			3.6	131		4
TANGA	18.3	12.2	25.8	2.7	667	13	18
DAR ES S	81.0		75.0	24.0	1000	10	12
TOTAL							
Identif/d	120.5	12.2	109.8	39.3	2095	23	35
Project	150.0	50.0	150.0	75.0	2500	30	50
FOREIGN COST							
Rate	16	12	10	8	0.2	6	5
Cost $000	2400	600	1500	600	500	180	250
LOCAL COST							
Rate	0.8	0.6	0.7	0.5	0.01	0.3	0.30
Cost $000	120	30	105	37.5	25	9	15.0
TOT. COST	2520	630	1605	638	525	189	265

TOTAL COST FOR LV REHAB & REINFORCEMENT IN $ 000's:

	LV Reinforcement Foreign	Local	Rehabilitation Foreign	Local
Works listed above $ 000's	3000	150	3030	192
Rehab. (only) of LV lines			500	25
Rehab of trans. stns.			500	25
TOTAL	3000	150	4030	242

Table E.5.2

Table E.6.1.

REH-DAR

COST / BENEFIT ANALYSIS OF REHABILITATION OF MV AND LV SYSTEMS AT DAR ES SALLAM
(based on outage savings)

	Estimated value for variables	Sensitivity to changes in the value of the variables involved				
P.U OUTAGES AVOIDED	0.010	0.0075	0.0075	0.0075	0.005	0.003
VALUE OF OUTAGES SAVED $/KWH	1.00	1.00	0.75	0.75	0.75	0.75
PERIOD OF ANALYSIS (years)	15	15	15	15	15	15
GROWTH OF ENERGY SALES (PU)	0.09	0.09	0.045	0.045	0.045	0.045
DISCOUNT FACTOR IN (PU)	0.10	0.10	0.10	0.10	0.10	0.10
PRESENT VALUE FACTOR	14.08	14.08	10.73	10.73	10.73	10.73
UNITS SOLD IN 1989 (GWH)	491.927	491.927	491.927	491.927	491.927	491.927
Growth rate 1989-1994 (pa)	1.08	1.08	1.08	1.04	1.04	1.04
Addl. increase due to syst. dev. (m.f.)	1.1	1.1	1.05	1.05	1.05	1.05
EXPECTED SALES 1994 (GWH)	795.082	795.082	758.942	628.430	628.430	628.430
Benefits and Costs in $ '000 :						
P.V. OF OUTAGE SAVINGS	101785	83973	41659	34495	22997	13798
COST OF REHABILITATION	5756	5756	5756	5756	5756	5756
BENEFIT/COST RATIO	17.7	14.6	7.2	6.0	4.0	2.4

NOTES:

1. The Rehabilitation costs are assumed to be incurred in 1993 and the benefits computed from 1994.
2. The 1994 sales have been computed based on the growth rate indicated and a one time increase to account for the voltage improvement and removal of the capacity restriction (multiplying factor indicated in Table)
3. A number of associated benefits have been unaccounted for. These include:
   (a) damage/burnout of equipment belonging to both the utility and the consumers
   (b) avoided costs of 'breakdown maintenance'
4. All costs are in constant 1991 US $. The PV is worked out for the investment year, 1993

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REH-TAN

COST / BENEFIT ANALYSIS OF REHABILITATION OF MV AND LV SYSTEMS AT TANGA
(based on outage savings)

	Estimated value for variables	Sensitivity to changes in the value of the variables involved				
P.U OUTAGES AVOIDED	0.010	0.0075	0.0075	0.0075	0.005	0.003
VALUE OF OUTAGES SAVED $/KWH	1.00	1.00	0.75	0.75	0.75	0.75
PERIOD OF ANALYSIS (years)	15	15	15	15	15	15
GROWTH OF ENERGY SALES (PU)	0.09	0.09	0.045	0.045	0.045	0.045
DISCOUNT FACTOR IN (PU)	0.10	0.10	0.10	0.10	0.10	0.10
PRESENT VALUE FACTOR	14.08	14.08	10.73	10.73	10.73	10.73
UNITS SOLD IN 1989 (GWH)	95.284	95.284	95.284	95.284	95.284	95.284
Growth rate 1989-1994 (pa)	1.08	1.08	1.08	1.04	1.04	1.04
Addl. increase due to syst. dev.(N2)	1.1	1.1	1.05	1.05	1.05	1.05
EXPECTED SALES 1994 (GWH)	154.004	154.004	147.004	121.724	121.724	121.724
Benefits and Costs in $ '000 :						
P.V. OF OUTAGE SAVINGS	19715	14787	8069	6682	4454	2673
COST OF REHABILITATION	2081	2081	2081	2081	2081	2081
BENEFIT/COST RATIO	9.5	7.1	3.9	3.2	2.1	1.3

NOTES:

1. The Rehabilitation costs are assumed to be incurred in 1993 and the benefits computed from 1994.
2. The 1994 sales have been computed based on the growth rate indicated and a one time increase to account for the voltage improvement and removal of the capacity restriction (multiplying factor indicated in Table)
3. A number of associated benefits have been unaccounted for. These include:
   (a) damage/burnout of equipment belonging to both the utility and the consumers
   (b) avoided costs of 'breakdown maintenance'
4. All costs are in constant 1991 US $. The PV is worked out for the investment year, 1993

CR/2-12-92

REH-MOS

COST / BENEFIT ANALYSIS OF REHABILITATION OF MV AND LV SYSTEMS AT MOSHI
(based on outage savings)

	Estimated value for variables	Sensitivity to changes in the value of the variables involved				
P.U OUTAGES AVOIDED	0.010	0.0075	0.0075	0.0075	0.005	0.003
VALUE OF OUTAGES SAVED $/KWH	1.00	1.00	0.75	0.75	0.75	0.75
PERIOD OF ANALYSIS (years)	15	15	15	15	15	15
GROWTH OF ENERGY SALES (PU)	0.09	0.09	0.045	0.045	0.045	0.045
DISCOUNT FACTOR IN (PU)	0.10	0.10	0.10	0.10	0.10	0.10
PRESENT VALUE FACTOR	14.08	14.08	10.73	10.73	10.73	10.73
UNITS SOLD IN 1989 (GWH)	64.76	64.76	64.76	64.76	64.76	64.76
Growth rate 1989-1994 (pa)	1.08	1.08	1.08	1.04	1.04	1.04
Addl. increase due to syst. dev. (m.f	1.1	1.1	1.05	1.05	1.05	1.05
EXPECTED SALES 1994 (GWH)	104.669	104.669	99.911	82.730	82.730	82.730
Benefits and Costs in $ '000 :						
P.V. OF OUTAGE SAVINGS	13400	10050	5484	4541	3027	1816
COST OF REHABILITATION	1703	1703	1703	1703	1703	1703
BENEFIT/COST RATIO	7.9	5.9	3.2	2.7	1.8	1.1

NOTES:

1. The Rehabilitation costs are assumed to be incurred in 1993 and the benefits computed from 1994.
2. The 1994 sales have been computed based on the growth rate indicated and a one time increase to account for the voltage improvement and removal of the capacity restriction (multiplying factor indicated in Table)
3. A number of associated benefits have been unaccounted for. These include:
   (a) damage/burnout of equipment belonging to both the utility and the consumers
   (b) avoided costs of `breakdown maintenance'
4. All costs are in constant 1991 US $. The PV is worked out for the investment year, 1993

CR/2-12-92

REH-ARU

COST / BENEFIT ANALYSIS OF REHABILITATION WORKS - MV AND LV SYSTEMS AT ARUSHA
(based on outage savings)

	Estimated value for variables	Sensitivity to changes in the value of the variables involved				
P.U OUTAGES AVOIDED	0.010	0.0075	0.0075	0.0075	0.005	0.003
VALUE OF OUTAGES SAVED $/KWH	1.00	1.00	0.75	0.75	0.75	0.75
PERIOD OF ANALYSIS (years)	15	15	15	15	15	15
GROWTH OF ENERGY SALES (PU)	0.09	0.09	0.045	0.045	0.045	0.045
DISCOUNT FACTOR IN (PU)	0.10	0.10	0.10	0.10	0.10	0.10
PRESENT VALUE FACTOR	14.08	14.08	10.73	10.73	10.73	10.73
Computation of Expected Sales in 1994:						
Units sold in 1989 (GWH)	70.114	70.114	70.114	70.114	70.114	70.114
Growth rate 1989-1994 (pa)	1.08	1.08	1.08	1.04	1.04	1.04
Addl. increase due to syst. dev. (N2)	1.1	1.1	1.05	1.05	1.05	1.05
EXPECTED SALES 1994 (GWH)	113.323	113.323	108.171	89.570	89.570	89.570
Benefits and Costs in $ '000 :						
P.V. OF OUTAGE SAVINGS	14507	10881	5938	4917	3278	1967
COST OF REHABILITATION	1858	1858	1858	1858	1858	1858
BENEFIT/COST RATIO	7.8	5.9	3.2	2.6	1.8	1.1

NOTES:

1. The Rehabilitation costs are assumed to be incurred in 1993 and the benefits computed from 1994.
2. The 1994 sales have been computed based on the growth rate indicated and a one time increase to account for the voltage improvement and removal of the capacity restriction (multiplying factor indicated in Table)
3. A number of associated benefits have been unaccounted for. These include:
   (a) damage/burnout of equipment belonging to both the utility and the consumers
   (b) avoided costs of 'breakdown maintenance'
4. All costs are in constant 1991 US $. The PV is worked out for the investment year, 1993

CR/2-12-92

CBE-MAJENGO

ECONOMIC EVALUATION OF NETWORK EXPANSION

NAME OF SCHEME: MAJENGO AREA

INVESTMENT DETAILS FOR FINAL SYSTEM

	11 KV LINES		TRANSFORMERS			L V LINES	
	#100	#50	100	200 KVA	315 KVA	#100	#50
QUANTITY	0	0	0	2	0	0.9	0
RATE $ 000	18.9	13.6	7.0	7.5	8.5	16.8	12.6
COST	0.0	0.0	0.0	15.0	0.0	15.1	0.0

COST OF NETWORK EXPANSION

	TOTAL	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003 TO END
INVESTMENT COST	30	12	0	9	0	9							
PU OF TOTAL		0.4		0.3		0.3							
OP & MAINT. (2%pa)		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	6.6
TOTAL COST		12.7	0.6	9.6	0.6	9.6	0.6	0.6	0.6	0.6	0.6	0.6	6.6
PV OF COST	29	11.5	0.5	7.2	0.4	6.0	0.3	0.3	0.3	0.3	0.2	0.2	2.1

0.5 = AREA OF SUPPLY IN km sq

500 = LOAD DENSITY IN KW/km sq
250 = EXPECTED FINAL LOAD IN KW

VALUE OF BENEFITS

	TOTAL	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003 TO END
LOAD (PU) OF FINAL		0.2	0.4	0.5	0.6	0.65	0.7	0.75	0.8	0.85	0.9	0.925	
LOAD IN KW		50	100	125	150	162.5	175	187.5	200	212.5	225	231.25	2543.7
LOAD FACTOR		0.33	0.33	0.33	0.33	0.35	0.35	0.35	0.4	0.4	0.4	0.4	0.45
LOAD IN MWH		144.5	289.1	361.4	433.6	498.2	536.6	574.9	700.8	744.6	788.4	810.3	10027.5
VALUE OF SALES		14.5	28.9	36.1	43.4	49.8	53.7	57.5	70.1	74.5	78.8	81.0	1002.7
UPSTREAM COSTS		11.6	23.1	28.9	34.7	39.9	42.9	46.0	56.1	59.6	63.1	64.8	802.2
VALUE OF BENEFITS		2.9	5.8	7.2	8.7	10.0	10.7	11.5	14.0	14.9	15.8	16.2	200.5
PV OF BENEFITS	125	2.6	4.8	5.4	5.9	6.2	6.1	5.9	6.5	6.3	6.1	5.7	63.9
B/C RATIO	4.3												

NOTES:

0.1 VALUE OF SALES IN $
0.08 UPSTREAM COSTS IN $

Table E 8.1

TOTAL COSTS FOR NETWORK EXPANSION TO SUPPLY NEW DEVELOPING AREAS IN $ 000's

	MEDIUM VOLTAGE LINES				MV/LV TRANSFORMER STATIONS				LV NETWORK	
	11 kV LINES		33 kV LINES		11 kV/LV TRANSF.		33 kV/LV TRANSF.		CONDUCTOR	
REGION	100MMSQ	50 MMSQ	100MMSQ	50 MMSQ	50/100	100/200	50/100	100/200	100MMSQ	50 MMSQ
ARUSHA	7.8	4.7			4	3	5		15.3	8.4
MOSHI & MWANGA	5.1		0.5	0.6	6	6	2	1	20.6	
TANGA	7.4	1.7	45		4	2	3	1	22.7	
DAR ES S	50.1		1.6		89	60	4		103.7	127.4
TOTAL WORK:										
Identif/d:	70	6	47	1	103	71	14	2	162	136
Project	80	15	60	10	110	80	20	10	200	150
FOREIGN COST										
Rate	18	13	21	16	5	7	5.5	9	16	12
Cost $000	1440	195	1260	160	550	560	110	90	3200	1800
LOCAL COST										
Rate	0.9	0.6	1	1	0.25	0.35	0.25	0.43	0.8	0.6
Cost $000	72.0	9.0	60.0	10.0	27.5	28.0	5.0	4.3	160.0	90.0
TOT. COST	1512	204	1320	170	578	588	115	94	3360	1890

TOTAL COST FOR NETWORK EXPANSION

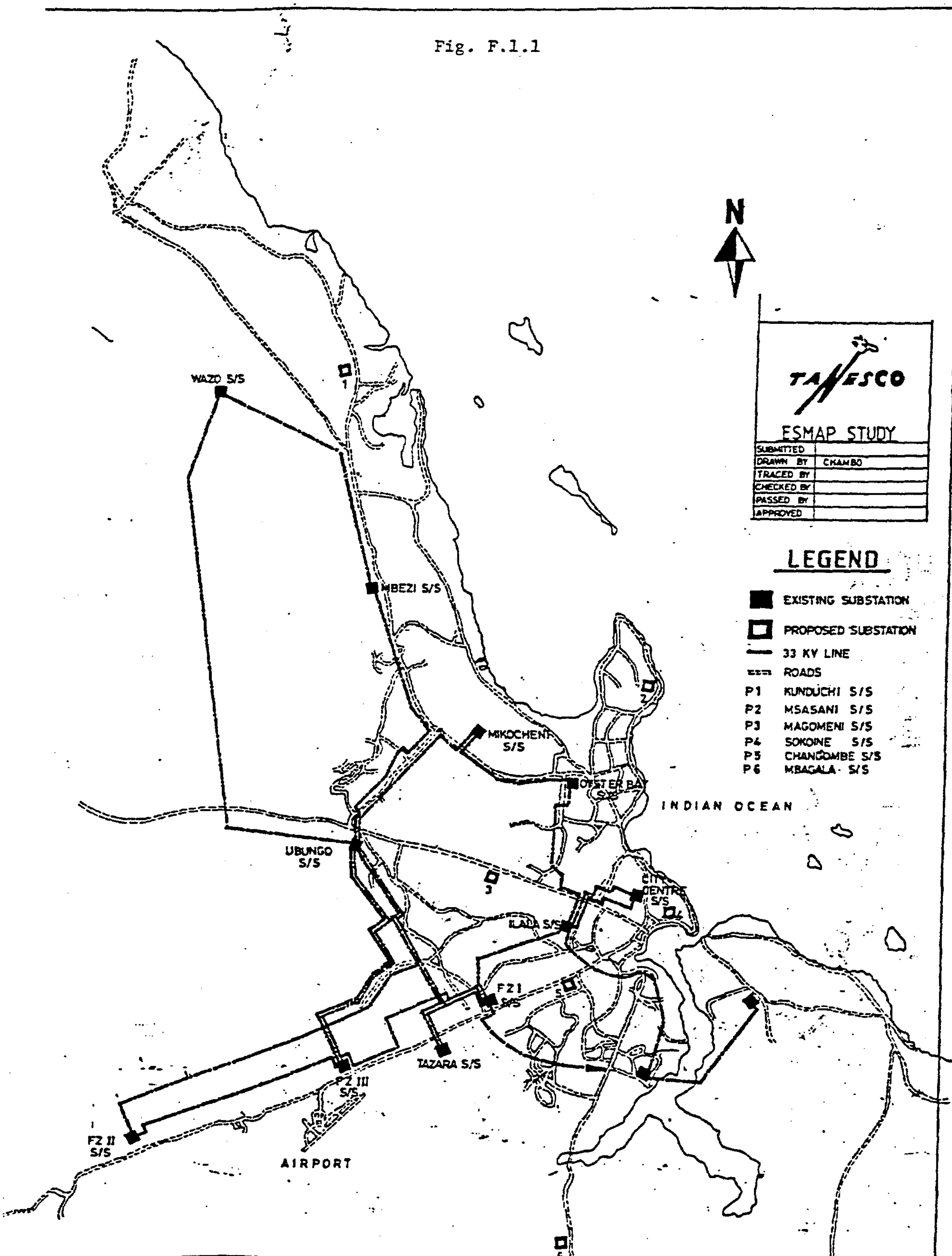
	Foreign	Local	Total
MV LINES	3055	151	3206
TRANSF.	1310	65	1375
LV LINES	5000	250	5250
TOTAL	9365	466	9831

Table E.8.2

Annex F

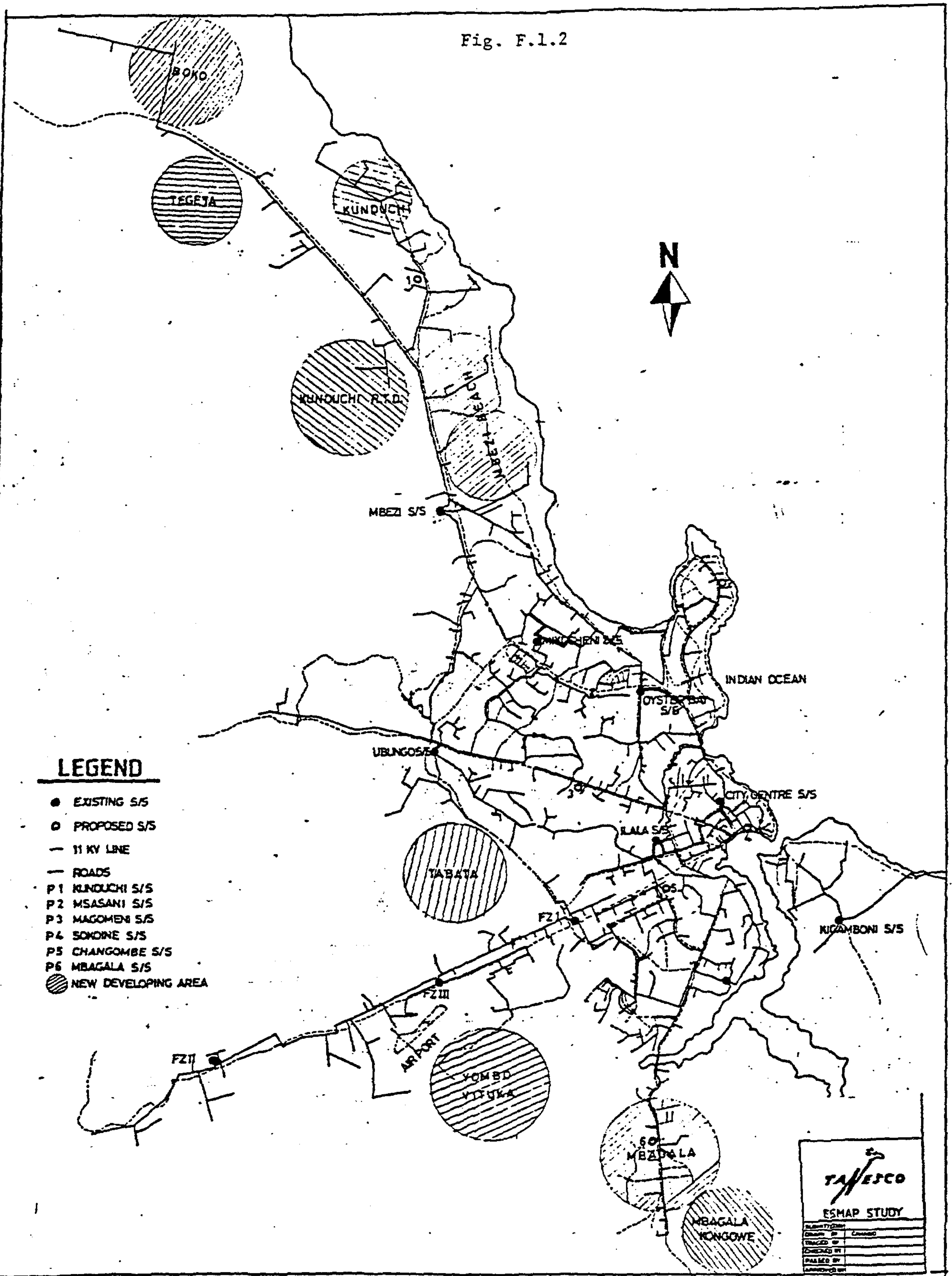
Distribution System network drawings

Fig. F.1.1



33 KV DISTRIBUTION NETWORK IN DAR ES SALAAM

Fig. F.1.2



11 KV DISTRIBUTION NETWORK IN DAR ES SALAAM	DRAWN BY CHAMBO WILLY DATE 7 JUNE 1991 SCALE 1 : 100,000	ESMAP STUDY

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Fig. F.2.1: Tanga District - Medium voltage distribution lines

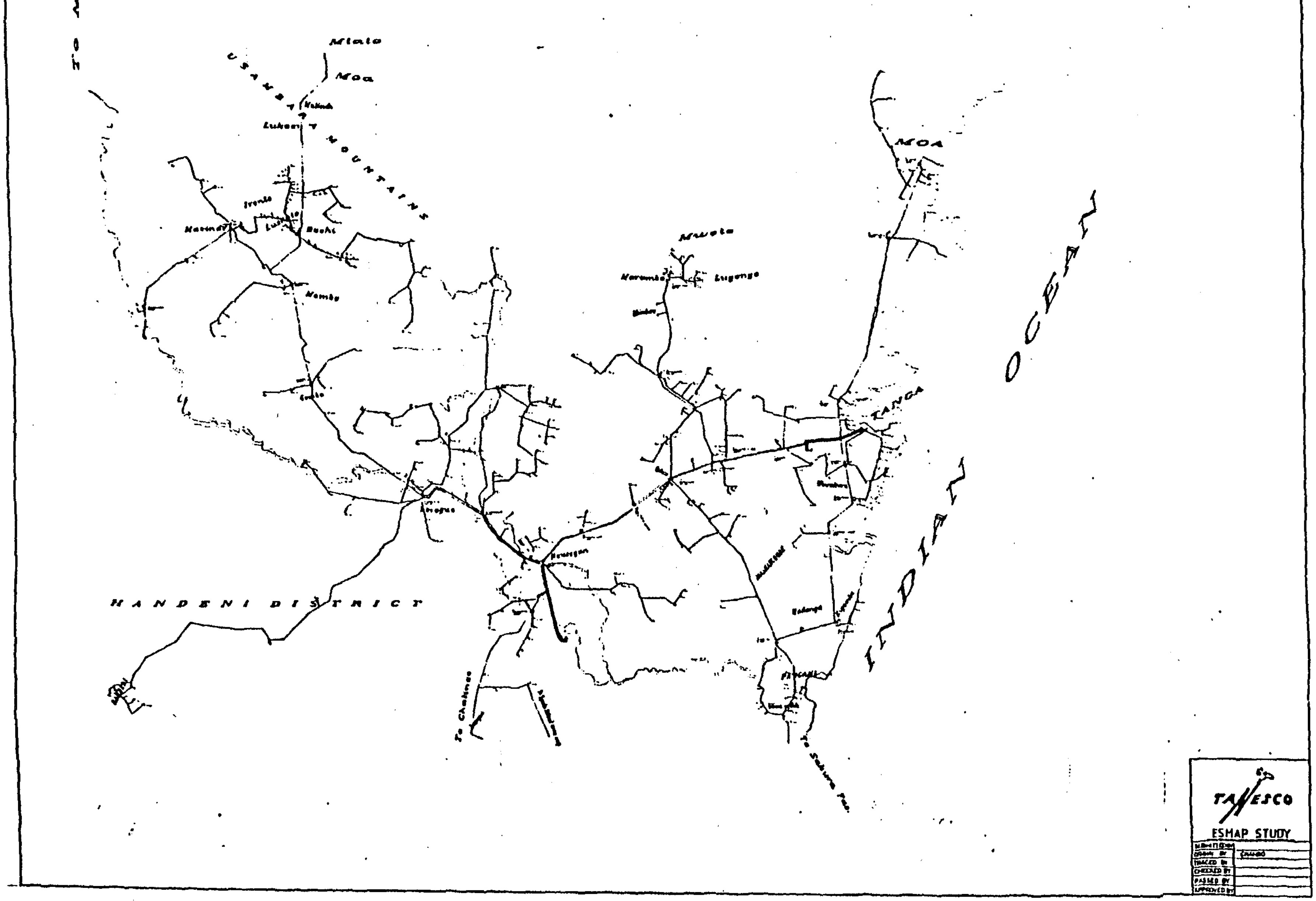
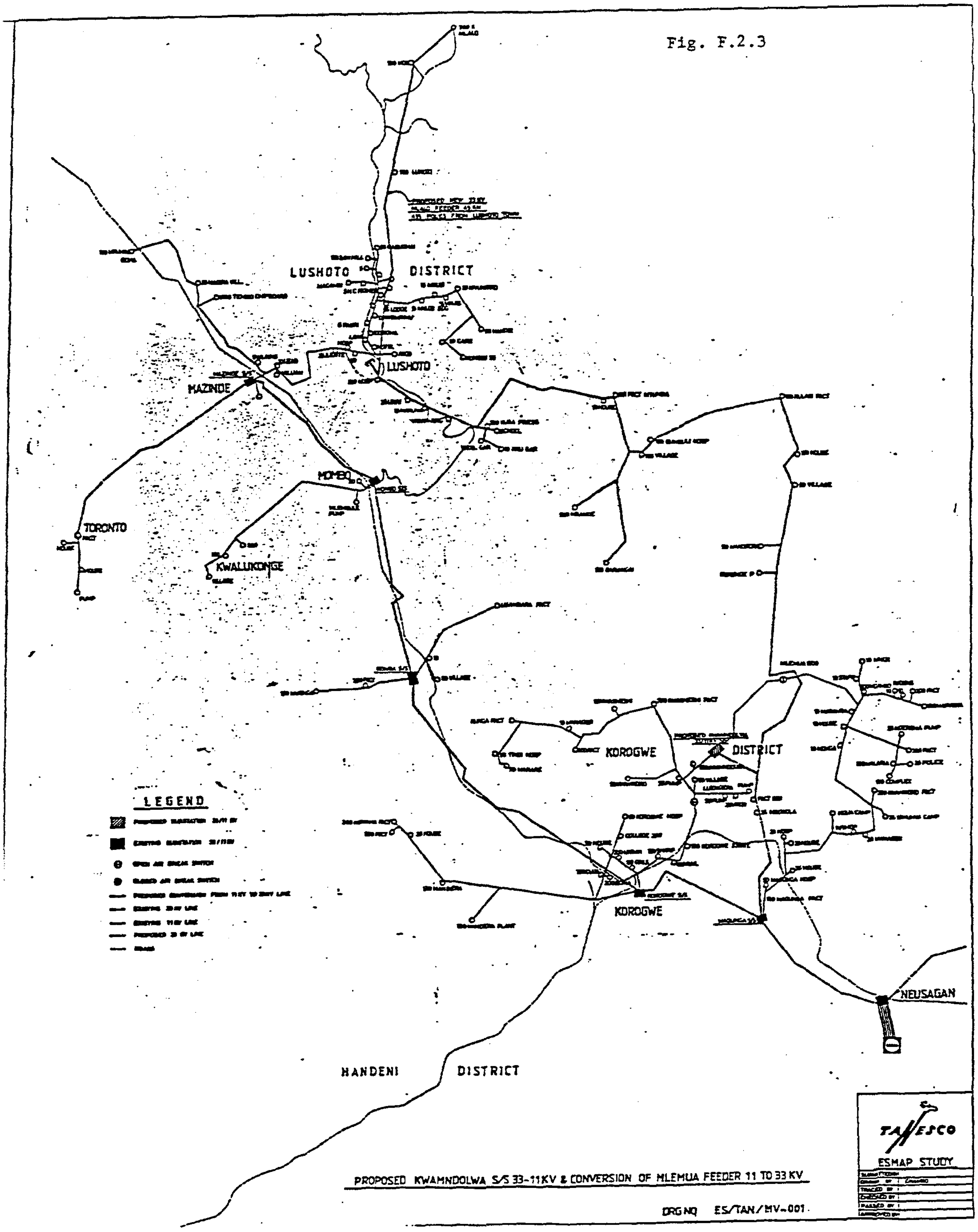


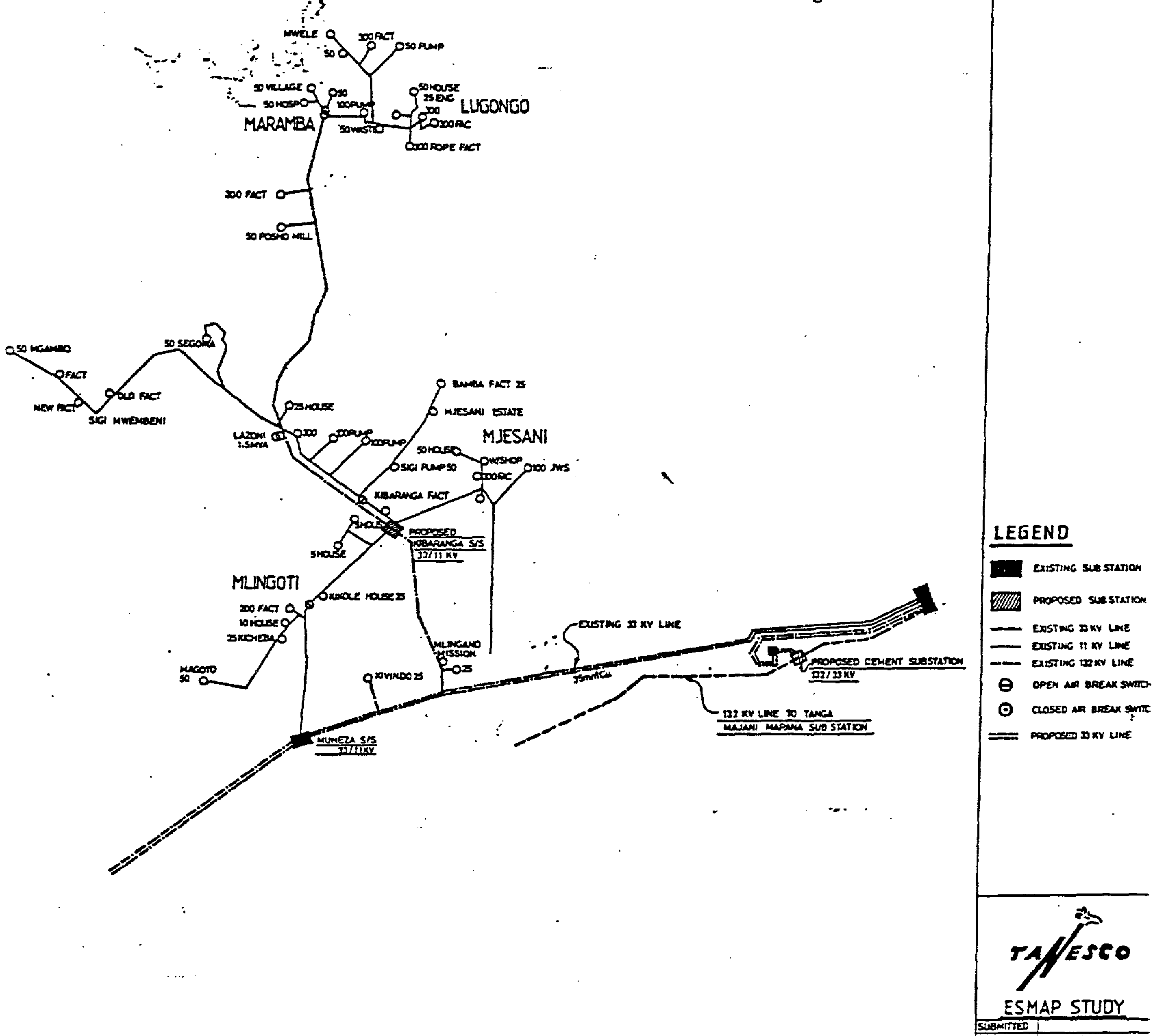
Fig. F.2.3



PROPOSED KWAMNDOLWA S/S 33-11KV & CONVERSION OF MLEMUA FEEDER 11 TO 33 KV

DRG NO ES/TAN/MV-001.

Fig. F.2.6



PROPOSED KIBARANGA SUB STATION 33/11KV & TANGA CEMENT SUB STATION 132/33KV

DRG Nº - ES/TAN/MV-002

Fig.F3.1: MOSHI DISTRICT - Medium voltage distribution lines

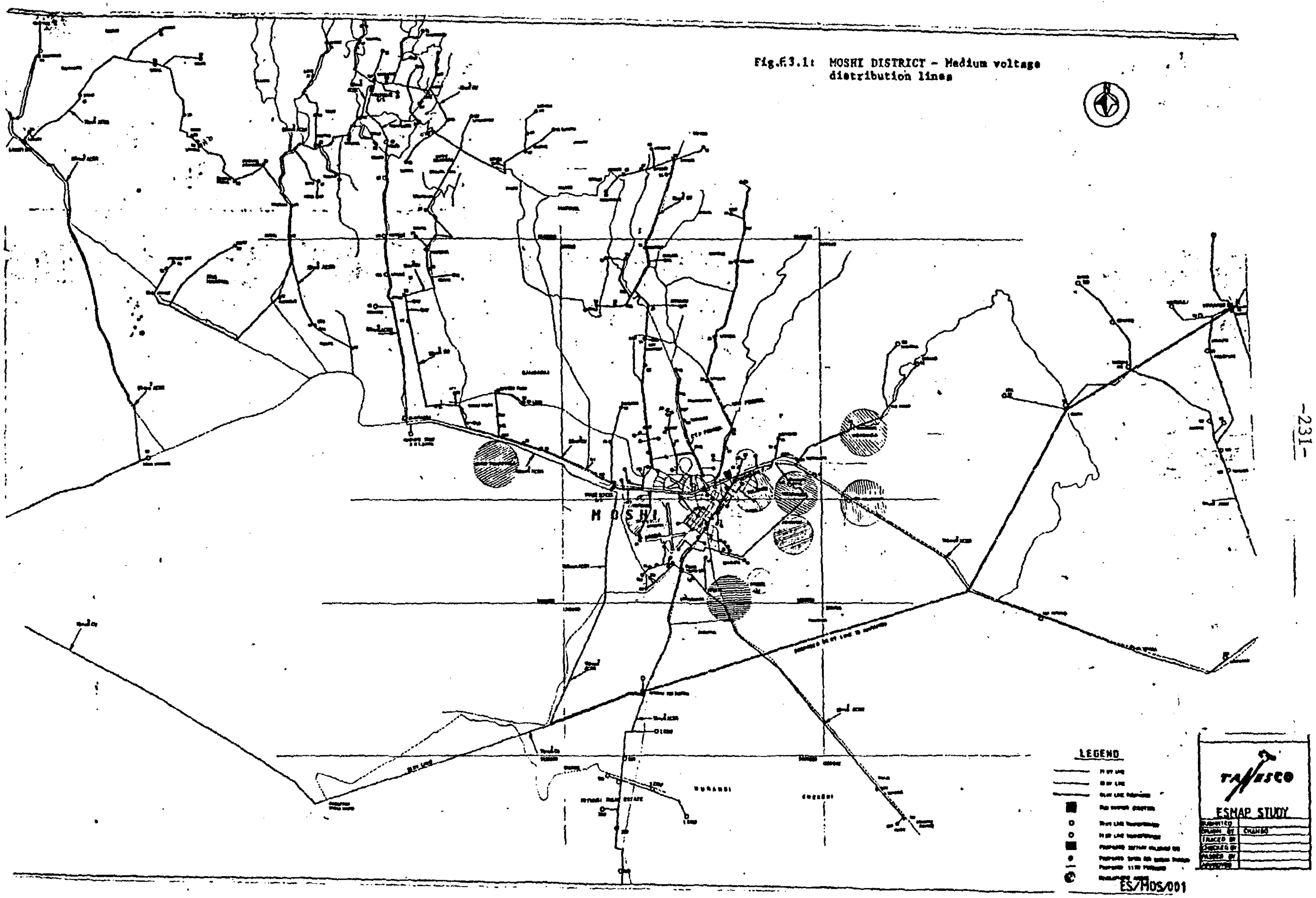


Fig. F.3.2: Moshi District (Drawing No.2)
Main 33 kV Feeding Arrangement and
Proposed 66kV line to Marangu

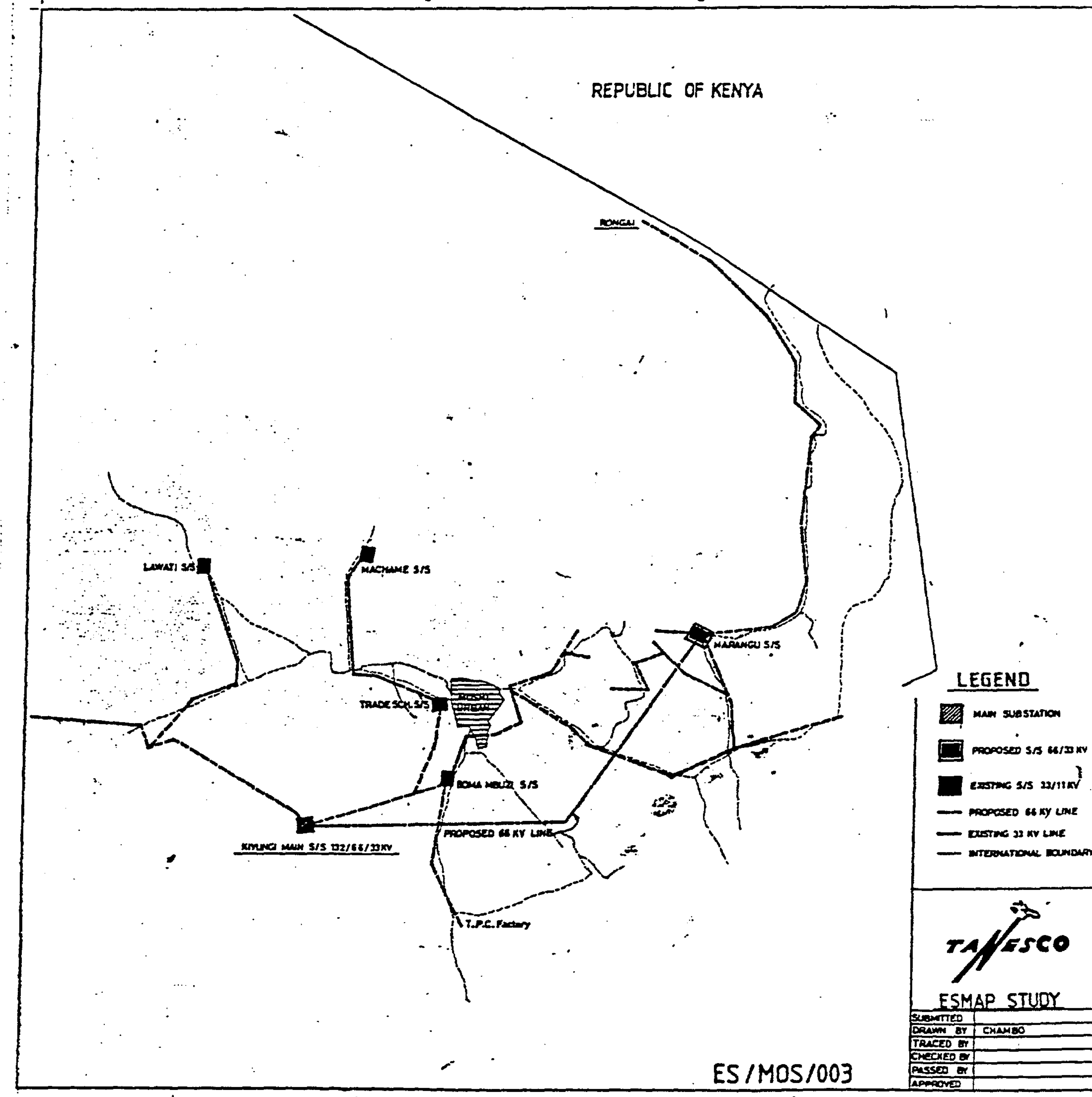
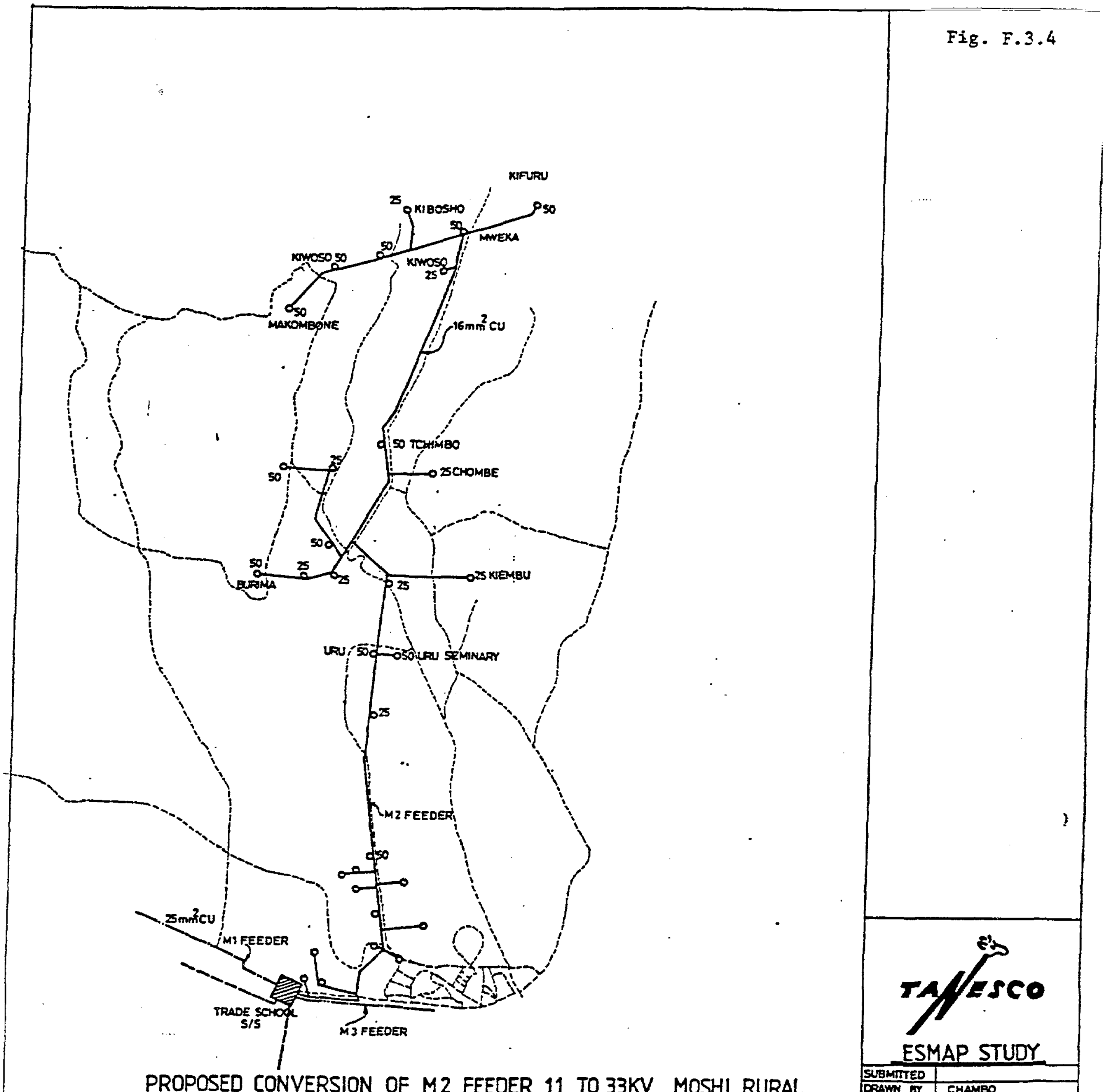


Fig. F.3.4



PROPOSED CONVERSION OF M2 FEEDER 11 TO 33KV MOSHI RURAL

ES/MOS/002

Fig.f.4.1: Arusha District - Medium voltage distribution lines

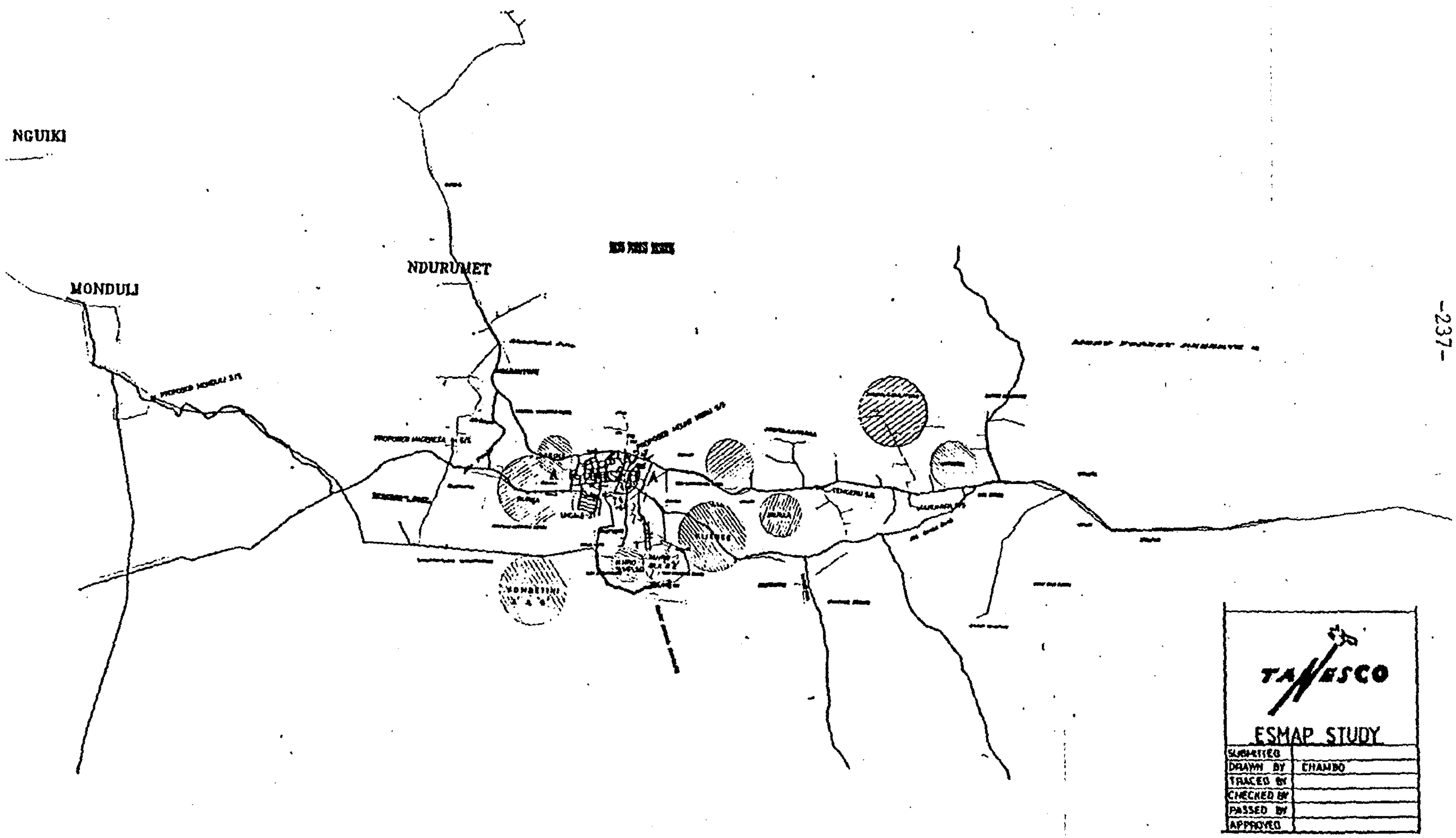
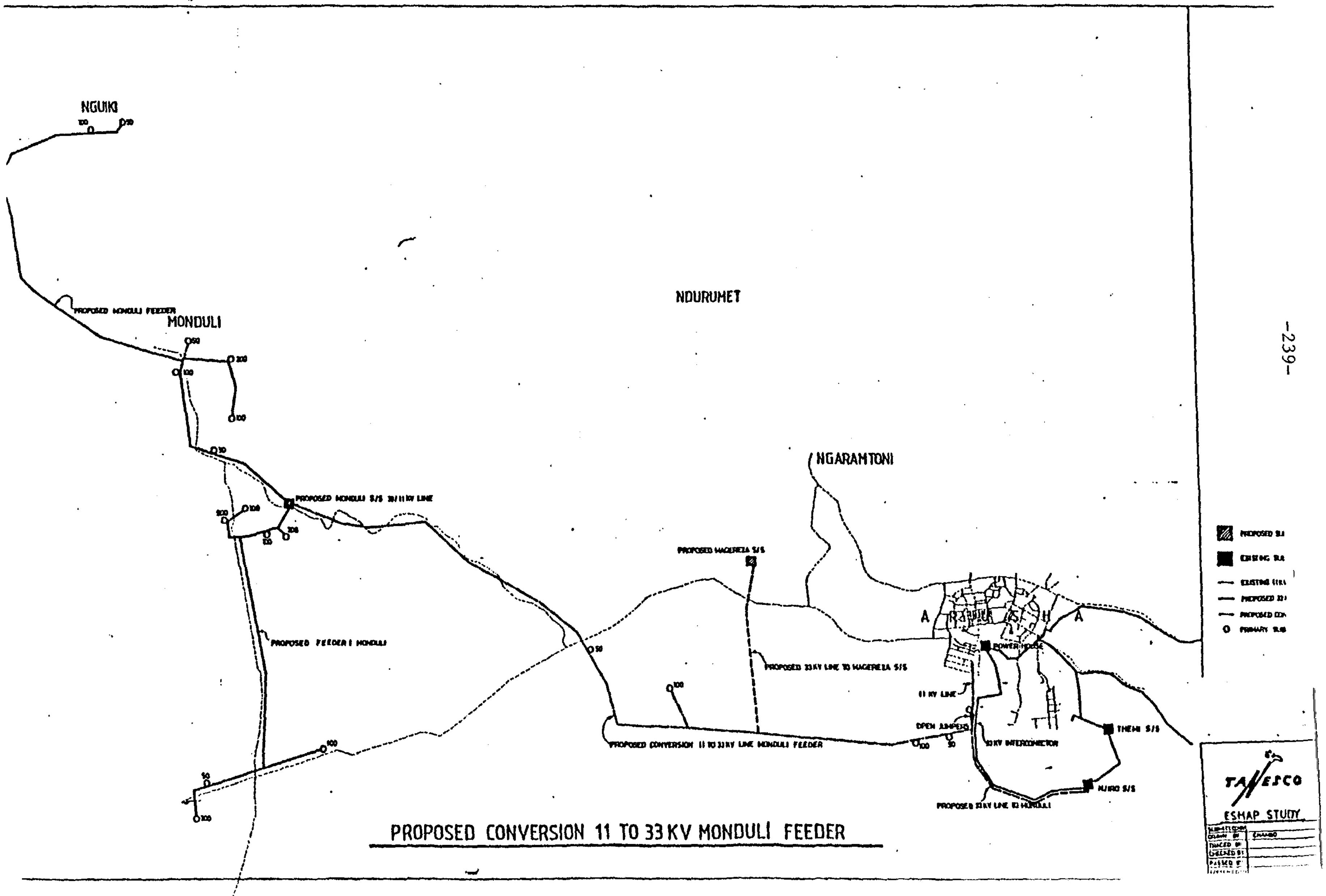
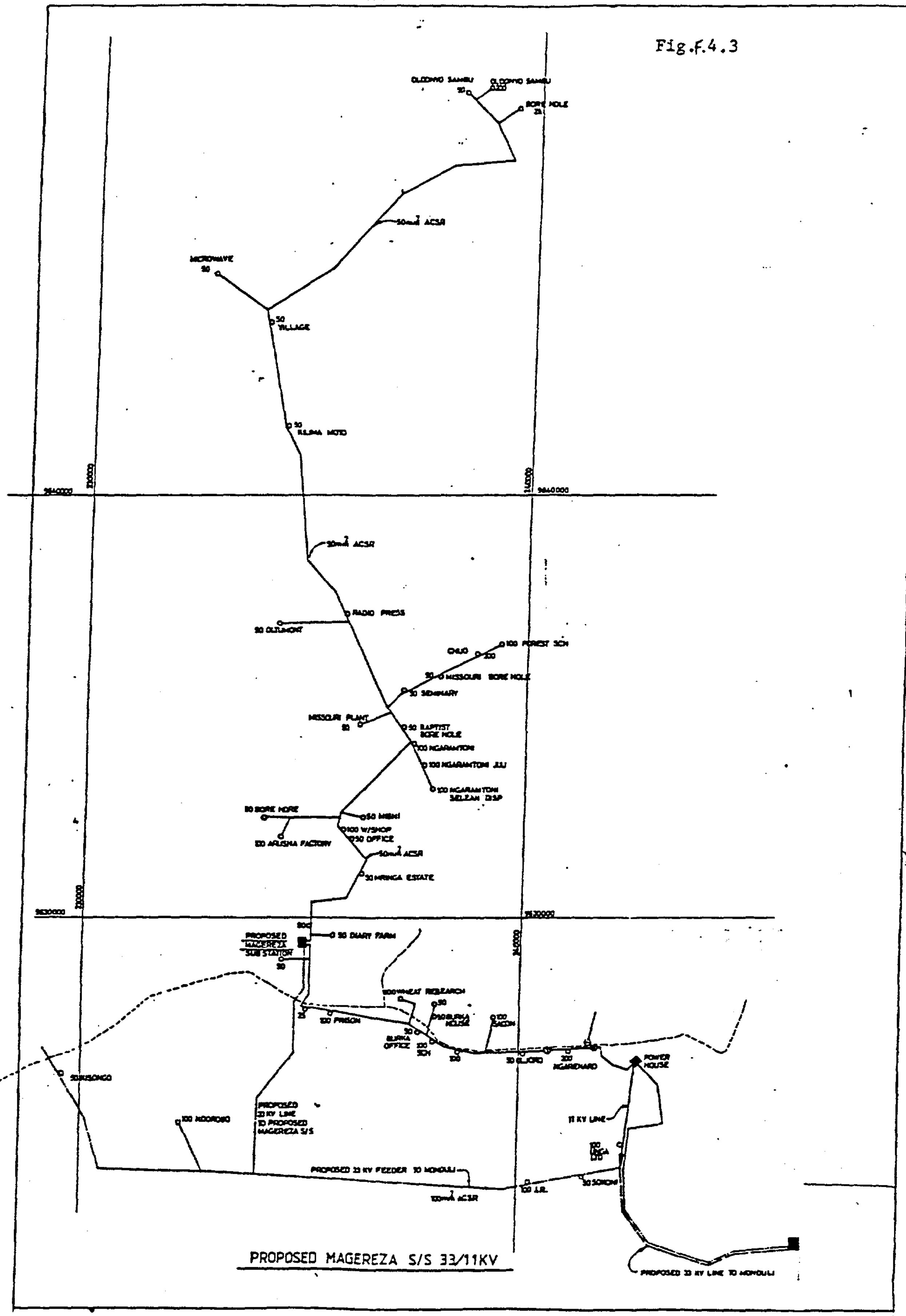


Fig.F.4.2



PROPOSED CONVERSION 11 TO 33 KV MONDULI FEEDER

Fig.F.4.3



PROPOSED MAGEREZA S/S 33/11KV

Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Tanzania	Power Loss Reduction Volume 1: Transmission and Distribution SystemTechnical Loss Reduction and Network Development (English)	06/98	204A/98
	Power Loss Reduction Volume 2: Reduction of Non-Technical Losses (English)	06/98	204B/98
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazahstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazahstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	07/95	173/95
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean Phase II - Status Report (English and Spanish)	12/97	200/97
	Harmonization of Fuels Speficifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ecuador	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

GLOBAL

	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93

Region/Country	Activity/Report Title	Date	Number
	GLOBAL (Continuation)		
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
	Rural Energy and Development Roundtable (English)	05/98	202/98

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