No.

Republic of Ghana
Ministry of Energy
Electricity Company of Ghana
Northern Electricity Department of Volta River Authority

Power Distribution System Master Plan Study for Ghana

Final Report (Main Report)

September 2008

JAPAN INTERNATIONAL COOPERATION AGENCY

Chubu Electric Power Co., Inc.

IL
JR
08-027

Preface

In response to the request from the Government of the Republic of Ghana, the Government of Japan decided to conduct the "Power Distribution System Master Plan Study for Ghana" and entrusted the Study to the Japan International Cooperation Agency (JICA).

JICA sent a Study Team, led by Mr. Keiji SHIRAKI and organized by Chubu Electric Power Co., Inc. to Ghana eight times from February 2007 to July 2008.

The Team held a series of discussions with officials from the Ministry of Energy in Ghana, Electricity Company of Ghana and Northern Electricity Department of Volta River Authority, and conducted related field surveys. After returning to Japan, the Team conducted further studies and compiled the final results in this report.

I hope that the report will contribute to the development of distribution networks, the improvement of power quality in Ghana, and the enhancement of amity between our two countries.

I would also like to express my sincere appreciation to the concerned officials for their close cooperation throughout the Study.

September 2008

Seiichi NAGATSUKA
Vice President
Japan International Cooperation Agency

September 2008

Seiichi NAGATSUKA

Vice President

Japan International Cooperation Agency
Tokyo, Japan

Letter of Transmittal

We are pleased to submit to you the final report for the “Power Distribution System Master Plan Study for Ghana”.

The study was implemented by Chubu Electric Power Co., Inc. from January 2007 to September 2008 based on the contract with the Japan International Cooperation Agency (JICA).

We prepared a countrywide Master Plan regarding the distribution facility development, including distribution network renewal, reinforcement, and extension plans, necessary for stable power supply in Ghana. The works were accomplished with the cooperation of the Electricity Company of Ghana (ECG) and the Northern Electricity Division of the Volta River Authority (VRA-NED), whilst transferring technology to them. In the study, we also prepared an implementation plan of the Master Plan, analyzed distribution losses and examined the distribution business management for developing the business situation of ECG and VRA-NED. Based on the results of the study, we made recommendations regarding all fields of distribution business, from the facility development plan to the business management.

We are convinced that the realization of the recommendations will lead to the acceleration of the distribution network development, which will surely contribute to the economic and social development of Ghana. We devoutly hope that the distribution network renewal, reinforcement and extension will be promoted in accordance with the Master Plan and the Master Plan will be revised properly, reflecting the change in the demand forecast.

Finally, We would like to express our sincere gratitude to JICA, the Ministry of Foreign Affairs and the Ministry of Economy, Trade and Industry for their advice and support. We also would like to express our deep gratitude to the Ministry of Energy, ECG, VRA-NED, the Japanese Embassy in Ghana, the JICA Ghana office and other concerned officials for the close cooperation and assistance through the study.

Keiji SHIRAKI

Team Leader

Power Distribution System
Master Plan Study for Ghana

[Table of Contents]

Figure List

Table List

Appendix

Abbreviation

AAAC	All Aluminum Alloy Conductor
AAC	All Aluminum Conductor
ACGF	African Catalytic Growth Fund
ACSR	Aluminum Cable Steel Reinforced
ACSR-Z	Aluminum Cable Steel Reinforced-Zinc coated
AFD	Agence Française de Dévelopment
AfDB	African Development Bank
B/D	Basic Design
BHN	Basic Human Needs
BSP	Bulk Supply Point
C/C	Coordinating Committee
C/P	Counterpart
CAGR	Compound Average Growth Rate
CBIS	Customer Based Information System
CCA	Chromated Copper Arsenate
cct	circuit
CHPS	Community Based Health Planning and Services
CVT	Cross-linked polyethylene insulated with Vinyl sheathed
D/D	Detailed Design
Df/R	Draft Final Report
EAA	Environmental Audit and Assessment
EC	Energy Commission
ECG	Electricity Company of Ghana
EIA	Environmental Impact Assessment
EIS	Environmental Impact Statement
EMP	Environmental Management Plan
EP	Environment Permit
EPA	Ghana Environmental Protection Agency
EPA	Environment Protection Agency Act
ESA	Environmentally Sensitive Area
F/R	Final Report
F/S	Feasibility Study
FC	Forestry Commission
FGD	Focus Group Discussion
FSD	Forest Services Division
GDP	Gross Domestic Product
GEDAP	Ghana Energy Development and Access Project

GEF	Global Environmental Facility
GH ¢	Ghana Cedi
GIS	Geographic Information System
GOG	Government of Ghana
GPOBA	Global Partnership on Output-Based Aid
GPRS	Ghana Poverty Reduction Strategy
HIPCs	Highly Indebted Poor Country
Ic/R	Inception Report
ICT	Information & Communication Technology
IDA	International Development Association
IEC	International Electrotechnical Commission
IEE	Initial Environmental Evaluation
IFC	International Finance Corporation
IRR	Internal Rate of Return
IT	Information Technology
It/R	Interim Report
KII	Key Informant Interview
KITE	Kumasi Institute of Technology and Environment
LAN	Local Area Network
LBS	Load Break Switch
LME	London Market Exchange
LV	Low Voltage
MCA	The US Millennium Challenge Account
MLFM	Ministry of Lands, Forestry and Mines
MOE	Ministry of Energy
MOFEP	Ministry of Finance and Economic Planning
MP	Master Plan
MSSA	Management Support Services Agreement
MV	Medium Voltage
NCC	the National Commission on Culture
NED	Northern Electricity Department (of VRA)
NEF	National Electrification Fund
NES	National Electrification Scheme
NGC	National Grid Company Ltd
NLCD	National Liberation Council Decrees
NREL	National Renewable Energy Laboratory
PAPs	Project Affected Persons
PCB	Polychlorinated Biphenyls
PEA	Preliminary Environmental Assessment
PILC	Paper Insulated Lead Sheathed Cable

PSS/ADEPT	Power System Simulator/Advanced Engineering
PURC	Public Utilities Regulatory Commission
PURC	Public Utilities Regulatory Commission
PV	Photovoltaic
RE	Rural Electrification
REA	Rural Electrification Agency
REF	Rural Electrification Fund
RMU	Ring Main Unit
S/W	Scope of Work
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEA	Strategy Environmental Assessment
SECO	the Swiss Secretariat for Economic Affaires
SF6	Sulfur Hexafluoride
SHEP	Self-Help Electrification Program
SHS	Solar Home System
SS	Substation
SWERA	Solar and Wind Energy Resource Assessment
TA	Technical Assistance
TICO	Takoradi International Company
TOR	Terms of Reference
UNDP	United Nations Development Programme
UNEP	United Nations Environmental Programme
VALCO	Volta Aluminum Company
VBA	Visual Basic for Applications
VRA	Volta River Authority
W/S	Work Shop
WAGP	West African Gas Pipeline
WAPP	West African Power Pool
WD	Working Day(s)
XLPE	Crosslinked Polyethylene Insulated Vinyl Sheathed Cable

Chapter 1 Introduction

1.1 Particulars leading up to the Study

The Republic of Ghana has posted the target of increasing the rate of household electrification, which is currently about 54 percent, to 70 percent by 2020. It is energetically working to raise the rate. Electrification plans on the national level have already electrified all district capitals, and were followed by the start of the Self-Help Electrification Project (SHEP). The SHEP is concerned with communities with a population of at least 500 that are located no more than 20 kilometers from existing distribution lines. It is aimed at electrification by extension of distribution lines, by having the residents of such communities shoulder the cost of construction of poles for the additional low-voltage distribution lines. Three SHEP installments have already been completed and electrified about 1,400 communities. The fourth installment (SHEP 4) is now under way, and is to electrify another approximately 1,800 communities.

In this way, the government of Ghana is vigorously working to electrify communities by extending the grid. Distribution line extension is decided on the initiative of the local residents in the SHEP, which therefore lacks an overall vision as a distribution plan. Distribution lines are consequently being extended without consideration for economic feasibility. Furthermore, observers have pointed out the problem of a lack of coordination between on- and off-grid electrification projects. For example, distribution lines have been installed in areas that have already been electrified by off-grid systems, such as photovoltaic (PV) systems and other on-premise power generation systems. In addition, the financial position of the Electricity Company of Ghana (ECG) and the Northern Electricity Division of the Volta River Authority (VRA-NED) has deteriorated under the policy of low tariffs continuing from the country's independence and low rates of tariff collection. This has resulted in a lack of full renewal and reinforcement of existing distribution facilities, which are consequently marked by serious deterioration and overload throughout the country. Subquality power is hindering the activities of small and medium enterprises. To improve this situation in Ghana's distribution division, renovate and reinforce distribution facilities, reduce distribution loss, and promote rural electrification (RE) by extension of distribution lines requires formulation of a nationwide master plan for this division from a comprehensive perspective.

In light of these circumstances, the Ghanaian government requested the Japanese government for assistance with the preparation of a nationwide master plan for the distribution division encompassing plans for distribution facility renewal and reinforcement, extension of distribution lines to rural districts, and other tasks.

In response to this request, the Japan International Cooperation Agency (JICA) implemented a preliminary study in July 2006 for consultation about the basic policy for the Master Plan Study and details such as items and schedule, and reached a basic agreement with the concerned institutions in Ghana. In October 2006, the two sides signed and exchanged scope of work (SW) documents.

1.2 Objective

(a) Formulation of a Master Plan for the distribution division extending 10 years into the future and encompassing plans for distribution network renewal, reinforcement, and extension; improvement of distribution business management; and plan execution

(b) Full understanding of the Master Plan contents by the counterpart (CP); preparation of a Master Plan manual for distribution network renewal, reinforcement, and extension; and transfer of technology to enable proper review by the CP even after the completion of the study

1.3 Study plan

1.3.1 Study flow

The Study consists of five stages.

The first stage (kick-off and fundamental study) clarified the Study objectives and framework, and addressed the following tasks.

- Presentation of the Inception Report to the Coordinating Committee
- Collection of basic information
- Assessment of CP planning capabilities

Devoted to technology transfer, the second stage centered around transfer of methodology for Master Plan formulation in a workshop, and included the following work.

- Technology transfer in the first workshop
- Reconsignment
- Microscopic demand forecasting

The third stage was dedicated to Master Plan preparation. A Master Plan draft was prepared through the following steps.

- Preparation of the Master Plan for distribution network renewal, reinforcement, and extension
- Preparation of plans for improvement of distribution business management
- Preparation of a basic data base

The fourth stage focused on checking and revision of the Master Plan draft prepared in the third stage.

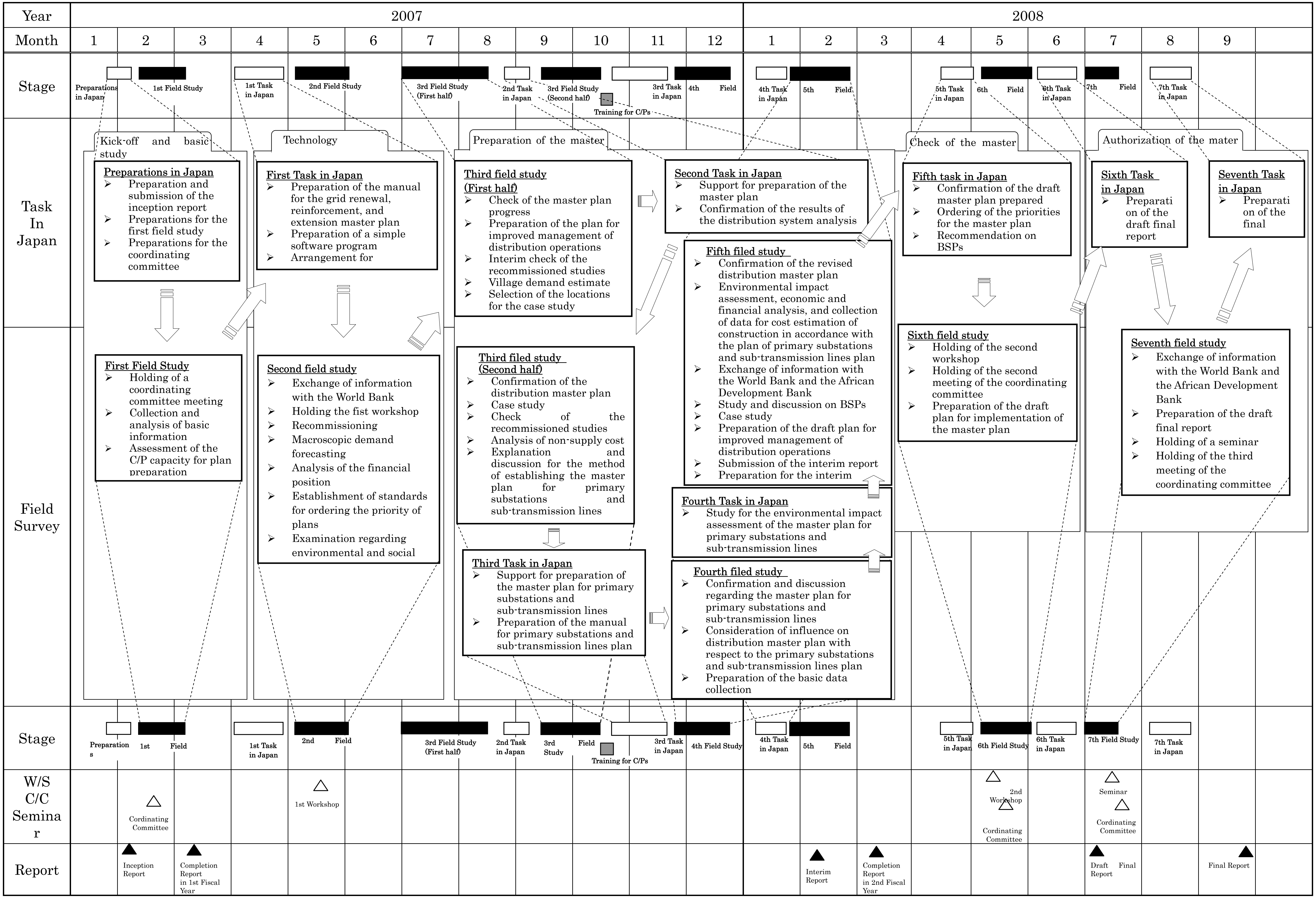
- Confirmation of the Master Plan for distribution network renewal, reinforcement, and extension in a workshop
- Preparation of plans for implementation of the Master Plan and for improvement of distribution business management
- Presentation of the Interim Report to the Coordinating Committee

- Implementation of a case study

The subject of the fifth and final stage was authorization of the Master Plan. It consisted of studies to heighten the workability of the overall Master Plan in aspects such as policy, institutions, economics, and finances. The findings of these studies were compiled into recommendations.

- Publicity among and consultation with concerned institutions in seminars
- Presentation of the draft Final Report to the Coordinating Committee

The following chart shows the overall flow of the Study work.



Year
2007
2008
Month
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9
Stage
Preparations in Japan
1st Field Study
1st Task in Japan
2nd Field Study
3rd Field Study (First half)
2nd Task in Japan
3rd Field Study (Second half)
Training for C/Ps
3rd Task in Japan
4th Field
4th Task in Japan
5th Field
5th Task in Japan
6th Field
6th Task in Japan
7th Field
7th Task in Japan
Task In Japan
Field Survey
Kick-off and basic study
Technology
Preparation of the master
Check of the master
Authorization of the mater
Preparations in Japan
Preparation and submission of the inception report
Preparations for the first field study
Preparations for the coordinating committee
First Task in Japan
Preparation of the manual for the grid renewal, reinforcement, and extension master plan
Preparation of a simple software program
Arrangement for
Third field study (First half)
Check of the master plan progress
Preparation of the plan for improved management of distribution operations
Interim check of the recommissioned studies
Village demand estimate
Selection of the locations for the case study
Second Task in Japan
Support for preparation of the master plan
Confirmation of the results of the distribution system analysis
Fifth filed study
Confirmation of the revised distribution master plan
Environmental impact assessment, economic and financial analysis, and collection of data for cost estimation of construction in accordance with the plan of primary substations and sub-transmission lines plan
Exchange of information with the World Bank and the African Development Bank
Study and discussion on BSPs
Case study
Preparation of the draft plan for improved management of distribution operations
Submission of the interim report
Preparation for the interim
Fifth task in Japan
Confirmation of the draft master plan prepared
Ordering of the priorities for the master plan
Recommendation on BSPs
Sixth Task in Japan
Preparation of the draft final report
Seventh Task in Japan
Preparation of the final
First Field Study
Holding of a coordinating committee meeting
Collection and analysis of basic information
Assessment of the C/P capacity for plan preparation
Second field study
Exchange of information with the World Bank
Holding the fist workshop
Recommissioning
Macroscopic demand forecasting
Analysis of the financial position
Establishment of standards for ordering the priority of plans
Examination regarding environmental and social
Third filed study (Second half)
Confirmation of the distribution master plan
Case study
Check of the recommissioned studies
Analysis of non-supply cost
Explanation and discussion for the method of establishing the master plan for primary substations and sub-transmission lines
Third Task in Japan
Support for preparation of the master plan for primary substations and sub-transmission lines
Preparation of the manual for primary substations and sub-transmission lines plan
Fourth Task in Japan
Study for the environmental impact assessment of the master plan for primary substations and sub-transmission lines
Fourth filed study
Confirmation and discussion regarding the master plan for primary substations and sub-transmission lines
Consideration of influence on distribution master plan with respect to the primary substations and sub-transmission lines plan
Preparation of the basic data collection
Sixth field study
Holding of the second workshop
Holding of the second meeting of the coordinating committee
Preparation of the draft plan for implementation of the master plan
Seventh field study
Exchange of information with the World Bank and the African Development Bank
Preparation of the draft final report
Holding of a seminar
Holding of the third meeting of the coordinating committee
Stage
Preparations
1st Field
1st Task in Japan
2nd Field
3rd Field Study (First half)
2nd Task in Japan
3rd Field Study
Training for C/Ps
3rd Task in Japan
4th Field Study
4th Task in Japan
5th Field
5th Task in Japan
6th Field Study
6th Task in Japan
7th Field Study
7th Task in Japan
W/S C/C Seminar
Cordinating Committee
1st Workshop
2nd Workshop
Cordinating Committee
Seminar
Cordinating Committee
Report
Inception Report
Completion Report in 1st Fiscal Year
Interim Report
Completion Report in 2nd Fiscal Year
Draft Final Report
Final Report

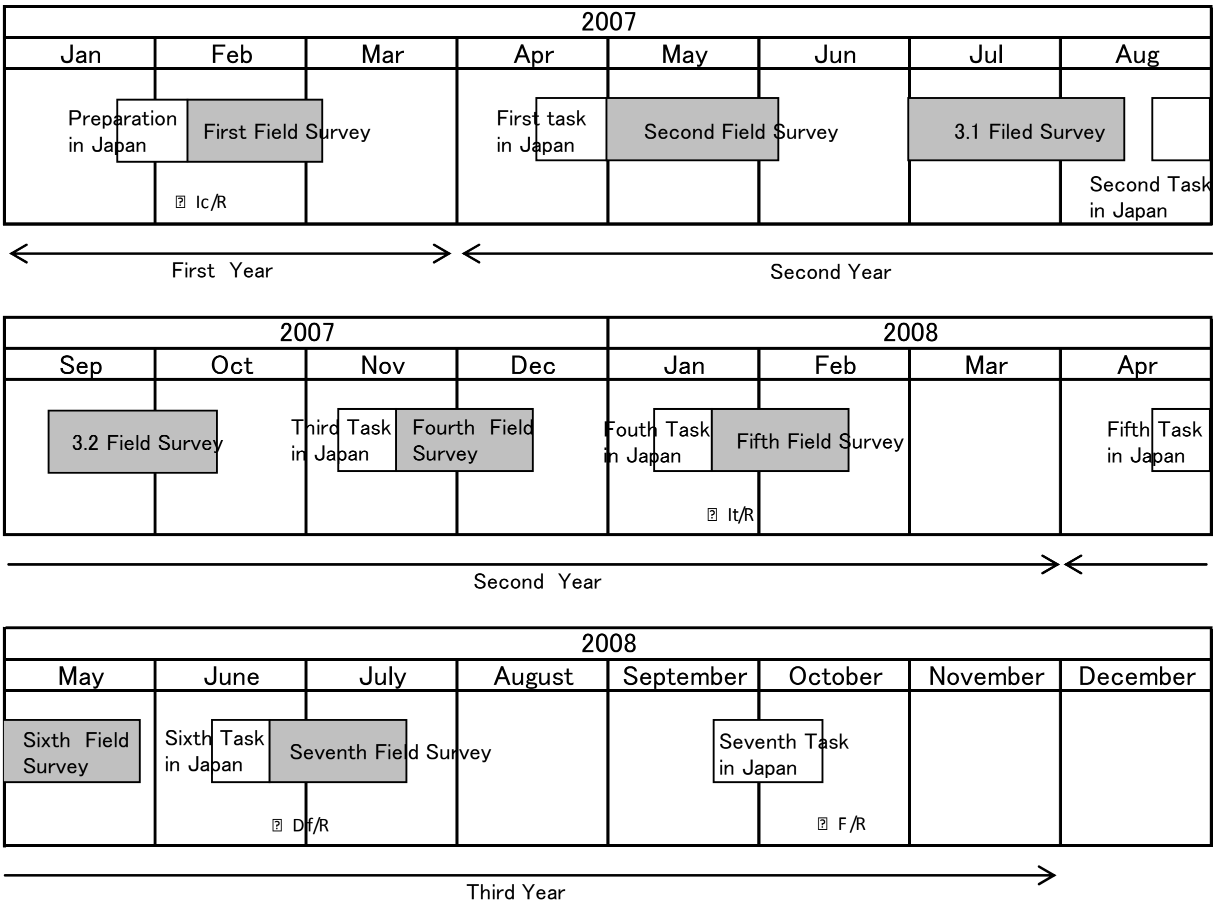
1.3.2 Study schedule

In this master plan study, a total of eight field studies are to be conducted over the period of approximately 18 months from February 2007 to July 2008. The first field study was implemented over a period of about four weeks beginning in mid February 2007.

Fiscal 2007 saw the execution of the second field study over a period of about four weeks beginning in early May, the 3.1 field study over a period of about five weeks beginning in early July, the 3.2 field study over a period of about four weeks beginning in mid September, and the fourth study over a period of about four weeks beginning in mid November. The fifth field study was carried out over a period of about three weeks beginning in late January 2008.

In fiscal 2008, the sixth field study was implemented for about three weeks beginning in late April. The schedule calls for implementation of the seventh field study for about three weeks beginning in late June.

Figure 1-1 shows the overall schedule for the Study.



Source: Prepared by the Study Team

Figure 1-1 Overall schedule

1.4 Membership of the Study Team

The table below shows the membership of the Study Team.

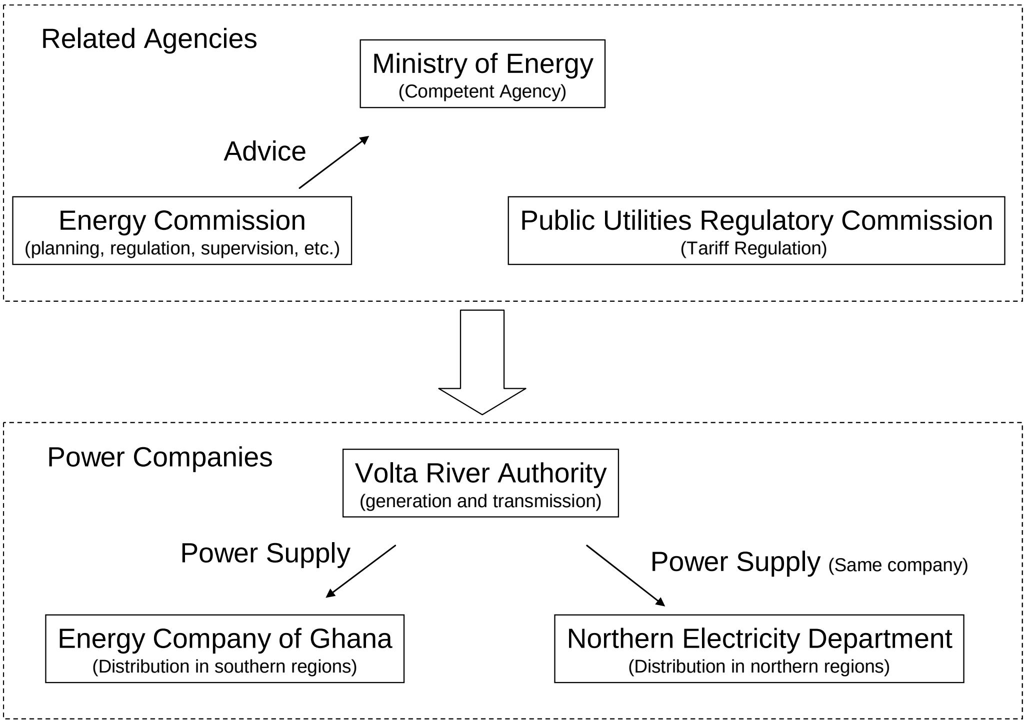
Members	Fields
Keiji Shiraki	Leader /Distribution technology
Kazunori Ohara	Distribution plan 1 /Transmission and substation
Tomohide Kato	Distribution plan 2
Morihiro Iwata	Distribution plan 3
Akira Kamo	Distribution facility design /Cost estimation
Kenzo Ikeda	Power supply-demand study 1 /Environmental and social considerations
Toshiaki Kimura	Power supply-demand study 2 /GIS
Hiroo Yamagata	Economic and financial analysis /Power tariffs
Masayasu Ishiguro	Distribution business management

Chapter 2　Current status of the power sector in Ghana

2.1　Structure of the power sector

The supply of electrical power in the Republic of Ghana relies on hydropower, mainly from the hydropower plant in Akosomobo. In 2007, the installed generation capacity came to a combined 1,903 megawatts, and hydropower accounted for 1,198 megawatts, or 63 percent. In addition, Ghana depends on power imported from neighboring countries for about 5 percent of the final energy consumption.

Aside from the Ministry of Energy (MOE), which is the competent agency with jurisdiction over energy, five institutions are involved in the power sector: 1) the Energy Commission (EC), which engages in advice, planning, regulation, and supervision related to energy policy; 2) the Public Utilities Regulatory Commission (PURC), which regulates tariffs; 3) the Volta River Authority (VRA), which is engaged in power generation and transmission; 4) the Energy Company of Ghana (ECG), which distributes power in the southern regions; and 5) the VRA Northern Electricitiy Department (NED), which distributes power in the northern regions.



Source: Prepared by the Study Team

Figure 2-1　Structure of the power sector

2.1.1　EC

The EC was established in accordance with the Energy Commission Act of 1997 (Act 541). Its role lies in regulation and administration concerning energy resources, and related policy coordination.

The EC makes recommendations concerning the development and use of domestic energy resources, advises the Minister of Energy on policy-making, and builds frameworks for regulation and monitoring in the energy industry. The regulation duties include authorization, inspection, and supervision of projects.

Its role encompasses review of national plans, construction of data bases to assist determination of policy for energy development, and promotion of competition in the energy market.

The Minister of Energy is responsible to (has responsibility over) the EC, which is composed of the chairman and six members, for a total membership of seven.

2.1.2 PURC

The PURC is a regulatory institution established in accordance with the Public Utilities Regulatory Commission Act of 1997 (Act 538). It currently regulates the power and water sectors, and is to regulate the natural gas sector in the future.

The PURC has a membership of nine who are appointed by the President. Its major duties are establishment of guidelines for setting tariffs for services provided by public utilities, examination and approval of power and other tariffs, protection of the interest of consumers and utilities, monitoring of utility services and their observance of standards, promotion of competition among public utilities, inquiry into and arbitration of disputes between customers and utilities, and provision of advice to utilities.

Act 538 gives the PURC the authority to enact regulations. So far, the PURC has implemented two sets of regulations. One is the Public Utilities Termination of Service Regulations 1999 (LI1651), which presents conditions for utility termination of service to customers. The other is the Public Utilities (Complaints Procedure) Regulations 1999 (LI1665), which sets forth procedures for the lodging of complaints by utilities or customers.

2.1.3 VRA

At present, all hydropower generation is conducted on the responsibility of the VRA, which was established in 1961 in accordance with the Volta River Development Act (?) (Act 46) for the purpose of development of the Volta River system as well as generation of power with it, and transmission and wholesaling of this power.

The VRA owns hydropower plants at the two locations of Akosombo (1,038 MW) and Kpong (160 MW), and a thermal power plant at Aboadze (550 MW). To meet the domestic demand, it imports up to 250,000 kilowatts (kW) of power from Cote d'Ivoire to supplement the supply from these generation facilities. In addition to grid power, it installs photovoltaic (PV) power generation systems as off-grid (on-premise) sources.

Transmission facilities are owned and operated through the National Grid Company Ltd. (NGC), a wholly-owned subsidiary of VRA. The transmission system consists of 161- and 69-kilovolt (kV) transmission lines (with an extended length of some 4,000 kilometers) and 36 substations. Ghana's power system is linked by international connection lines to those of Togo (161 kV), Benan (161 kV), and Cote d'Ivoire (220 kV).

2.1.4 ECG

The ECG was established in November 1997 as a joint-stock company based on the Companies Code in accordance with the 1993 _Corporate Act (Act 461). It supplanted the former Electric Corporation of Ghana, which was established as a result of a government ordinance (NLCD 125) in 1967. The government owns all of its stock.

The ECG is a distribution company that purchases almost all of its power from the VRA and sells it to final customers. It is obligated to perform power distribution and supply in eight regions, i.e., Accra East, Accra West, Tema, Eastern, Central, Western, Ashanti, and Volta.

2.1.5 NED

The NED was established as a subsidiary of the VRA in 1987. It took over the responsibility for power distribution and supply to the northern regions of Brong Ahafo, Northern, Upper East, and Upper West from the ECG.

The NED does business in the more expansive and impoverished northern regions, which occupy about 65 percent of the national land area. Many of the customers are physically scattered, and the lifeline tariff is applied for a lot of them. These adverse conditions are increasing investment and operating costs. Because of such problems, the financial position of the NED is seriously deteriorating. In its operation, the NED consequently receives considerable subsidies from the VRA.

2.1.6 Trends in power sector reorganization

In 1997, the Ghanaian government announced a plan for power sector reorganization in order to receive financing for the thermal power plant at Takoradi from the International Development Association (IDA). The plan includes the regional unbundling of the distribution division, creation of a wholesale power market, liberalization of the retail market, and functional unbundling of the VRA. However, it is not making progress.

This sectoral reform is partly supported by GDAP (See the detail in Section 2.1). With regard to the management improvement of the distribution companies, the general framework of unbundling, i.e., the merger of the ECG and the NED, and separation of five franchises[1], has been clarified, but the management system, i.e., the question of whether the five franchises will be operated by one company or five regional independent companies, has not yet determined.

Table 2-1 Power sector reorganization plan and progress

Item	State of progress
1. Regional unbundling of the distribution division (Western, National Capital, Central, Eastern, and Northern regions) and establishment of a management basis	Management system has not yet determined.
2. Functional unbundling and privatization of the VRA	Transformation of the new thermal power plant (TICO) and transmission division (NGC) into subsidiaries
3. Liberalization of the retail market	No progress
4. Establishment of the wholesale power market and conditioning of the regulatory setup	No progress
5. Conclusion of performance-related corporate agreements with the government by the VRA and the ECG	No progress
6. Establishment of a regulatory institution and conditioning of the regulatory setup	Establishment of the EC and the PURC in 1997, and start of work to condition the regulatory setup

Source: Prepared by the Study Team

2.2 Rural electrification plan

2.2.1 National development plan

Ghana was designated as a highly indebted poor country (HIPC) in 2001, and the government has positioned poverty mitigation as a national development plan. (Ghanaian finances fell into deficit in the 1990s, and in 1995, the government prepared Vision 2020, a national development plan aimed at joining the ranks of middle-income countries by 2020.) In 2003, it formulated the Ghana Poverty Reduction Strategy (GPRS) and set about preparing the environment for regional devolution by democratic means from a medium- and long-term perspective. Meanwhile, it has been making plans for activities on six agenda for economic growth and poverty mitigation.

As regards the power sector issues, the GPRS emphasized the necessity of the use of renewable

[1] Western (Western and Central Regions), Capital (Greater Accra Region), Central (Ashanti Region), Eastern (Easter, Volta and Tema Regions), and Northern (Northern, Upper East/West and Brong Ahafo Regions)

energy, especially solar energy, for rural electrification as well as power development. In February 2002, the Minister of Energy, donors, and concerned parties from the power sector in Ghana got together and discussed the Energy Sector Framework, which includes the power sector. In this discussion, rural electrification was referred to as an action plan for access to high-quality energy, which is a requisite basis for economic development

2.2.2 RE plans

(1) National Electrification Strategy (NES)

Ghana's National Electrification Strategy (NES) is aimed at electrification of the country over the period of 30 years from 1990 to 2020. The base resources required for implementation of this plan are being derived from financial assistance (both grant and onerous), tax revenue from the National Electrification Fund (NEF), and the national budget.

In Phase 1 of the NES, the subjects are regional capitals and villages located between substations and regional capitals. Beginning with Phase 2, priority is to be placed on projects with the most economic feasibility.

(2) Self-Help Electrification Program (SHEP)

The Self-Help Electrification Program (SHEP) was prepared to complement the NES. It covers villages located no more than 20 kilometers from medium-voltage (33- or 11-kV) distribution lines. Under the program, the villages must assume the burden of expenses for construction of utility poles for low-voltage distribution lines.

The SHEP is aimed at attainment of the NES electrification targets ahead of schedule. Over the ten-year period from 1990 to 2000, the NES and the SHEP electrified about 1,900 villages.

Electrification projects based on the SHEP are not groundeed in planning from a medium- and long-term perspective, and are strongly colored by political interests. Villages that meet the aforementioned conditions are electrified in an unsystematic manner, one at a time. As a result, even villages on an extension from medium-voltage lines are not electrified if they do not meet the conditions, and the projects may not be feasible as far as revenue is concerned. In addition, the SHEP is sometimes used for political ends. In some cases, even after being installed with low-voltage distribution line facilities, villages have been left unelectrified because of failure to extend medium-voltage distribution lines to them.

In SHEP projects, the subject villages are chosen through direct discussion between the MOE and district assemblies. The MOE likewise contracts directly with businesses for the design and construction work. Because these businesses do not confirm things with the ECG and VRA-NED at the design stage, projects proceed with absolutely no consideration of the influence on the system. It is not unusual for distribution lines to be extended even further from lines whose voltage is already below capacity. The ECG and the VRA-NED are having trouble dealing with the takeover of extended distribution facilities including some not up to standards.

While the ongoing SHEP 4 was suspended for a time due to the shortage of funds, it is being implemented with financial assistance from China and the US Export-Import Bank (described below). The Government of Ghana (GOG) is now planning to implement SHEP 4 in three or four phases. The first phase was completed by the first quarter of 2008 and electrified one hundred and ninety-five villages.

Meanwhile the government is hurrying to establish the Rural Electrification Agency (REA) and expects to make a rational electrification plan in place of SHEP. However, in the plan for distribution-line extension of Component C of GEDAP, the subject villages are quoted from those of SHEP 4. As this indicates, the planning framework of rural electrification has not yet been transferred to a new system.

Table 2-2 Number of villages slated for distribution line extension in the GEDAP

Region	District	No. of Village	Total
Ashanti	Amansie West	34	104
	Kwabre	15	
	Sekyere East	29	
	Atwima	18	
	Asante Akyem North	8	
Central	Abura/Asebu/Kwamakese	32	84
	Cape Coast	7	
	Gomoa	45	
Eastern	Birem South	9	11
	New Juabem	2	
Greater Accra	Ga	51	51
Volta	Ho	21	21
Western	Aowin Suaman	12	138
	Bibiani Anhwiaso Bekwai	12	
	Juabeso Bia	31	
	Jomoro	33	
	Wassa Amenfi	21	
	Nzema East	11	
	Mpohor Wassa	18	
		Total	409

Source: prepared by the Study Team from ECG data

(3) Financial assistance from China

Apart from the GEDAP activities, projects for rural electrification by extension of distribution lines are being promoted with assistance from China.

These projects are implemented as part of SHEP 4, and the government received a US$81 million loan. Using this Chinese loan and additional government funding of US$10 million, i.e., a total of US$91 million, five hundred and eighty villages are to be electrified.

(4) Financial assistance from the US Import-Import Bank

The US ExIm Bank provided a loan for rural electrification, and the National Assembly of Ghana approved a proposal to borrow US$357 million, of which 35.21% are on the grant bases, and the rest, a soft loan. Using these funds, the MOE will implement a special project following Phase 1 of SHEP 4.

(5) Establishment of the Rural Electrification Agency (REA)

The MOE is planning to establish the ERA to correct the unsystematic implementation of rural electrification projects. Nevertheless, its work is still not substantive, as exemplified by the fact that the list of villages for rural electrification in GEDAP was prepared from the SHEP 4 list, and the current scheme has not yet completely shifted to new one.

To support the establishment of the REA, the Government of France provided technical assistance (TA) for study of institutional aspects of the management of the REA and the Rural Electrification Fund. This study was planned as a supplement French project in line with the implementation of GEDAP (However, the French project is outside GEDAP). The duration of the study is about three months, and the final report is expected to be submitted by the end of June 2008.

Although the preparations for the establishment of the REA are gradually progressing, it is necessary for the MOE to contact the district assembly directly in order to collect information on items such as village location and electrification status (electrified/unelectrified) that is essential for developing rural electrification strategies and development plans. The MOE should start to collect the information quickly, in advance of the REA’s establishment.

2.3 Power demand

2.3.1 Outline of the power demand

In Ghana, power is supplied through the system owned by the VRA. In 2004, power sales in the system as a whole came to 6,016 gigawatt-hours (GWh). Although yearly sales exceeded 7,000 GWh until 2002, they dropped substantially in 2003. This decrease was caused by the great limitation on supply to the Volta Aluminum Company (VALCO) due to water shortage, followed by the closure of VALCO plants.

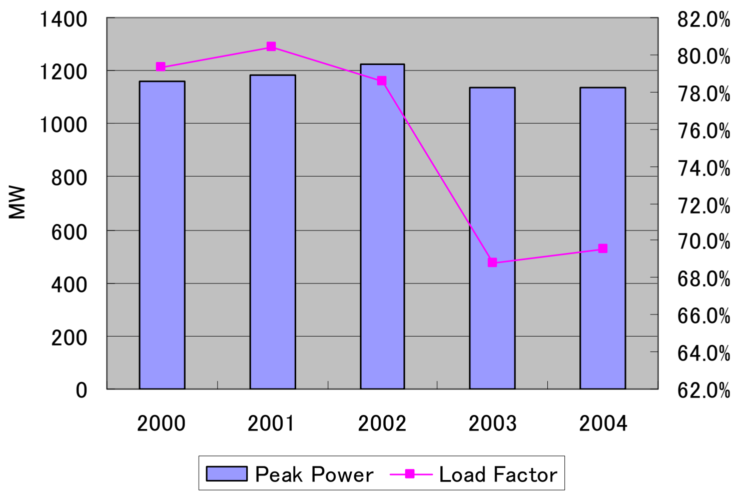
Table 2-3 Power sales in Ghana

Unit:GWh

Year	2000	2001	2002	2003	2004
Generation	7,223	7,859	7,296	5,900	6,039
Hydro	91.5%	84.0%	69.0%	66.0%	72.9%
Thermal	8.5%	16.0%	31.0%	34.0%	27.1%
Net import	472	160	534	339	213
Total import	864	462	1,145	940	878
Total export	392	302	611	601	665
Losses	252	291	413	378	236
Transmission	229	259	368	333	205
Miscellaneous	23	32	45	45	31
Final Supply	7,443	7,728	7,417	5,861	6,016

Source: Strategic National Energy Plan 2006-2020, Energy Commission, July 2006

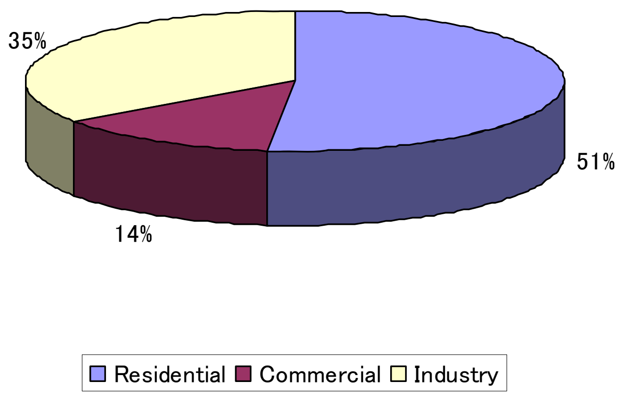
In 2004, the peak power (maximum demand) reached 1,137 MW. It was higher at 1,226 MW in 2002, but decreased, like the power sales, as a result of the closure of VALCO plants. Figure 2-2 shows the trend of peak power and load (capacity) factor.



Source: prepared by the Study Team

Figure 2-2 Peak power and load factor

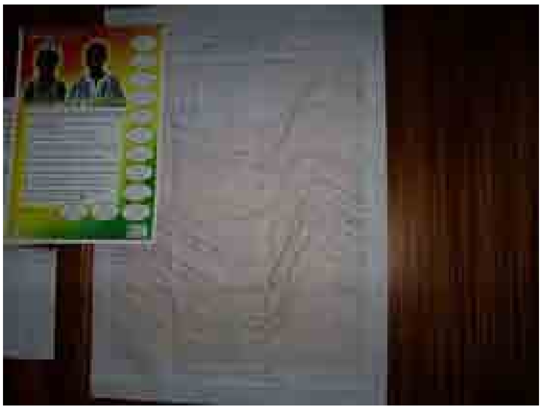
The residential segment has the highest share of the total power sales at 51 percent, and is followed by the industrial segment at 35 percent and commercial segment at 14 percent. Formerly, the industrial segment accounted for the majority, owing to the presence of the VALCO. Recent years have seen rapid growth in the residential segment due to the progress of RE projects.



Source: prepared by the Study Team

Figure 2-3 Makeup of power sales

In fiscal 2007, during the Study term, the Akosombo Dam experienced problems due to a water shortage. The national capital of Accra fell into a situation of having to put up with scheduled outages for 12 hours every 48 hours. The Ghanaian government realizes that this is a serious problem, and is executing plans for development of a dam at Bui and additional thermal power sources.



Source: Taken by the Study Team

Figure 2-4 Water shortage and water level management at Akosombo Dam

2.4 Generation and transmission/transformation facilities

2.4.1 Generation facilities

In 2007, the installed capacity of generation facilities in Ghana consisted of 1,198 MW (63 percent) in hydropower and 705 MW (37 percent) in thermal power, for a total of 1,903 MW (see Table 2-4).

The major hydropower plants are those at Akosombo (1,038 MW) and Kpong (160 MW) on the Volta River system. These were placed into operation in 1965 and 1982, respectively. The Akosombo hydropower plant began operating units 1 - 4 in 1965 and units 5 - 6 in 1972. It increased the capacity to its current level by construction undertaken in 2006.

The main thermal power plants are the Takoradi plant, which is installed with gas-fueled combined-cycle facilities with a capacity of 550 MW (start of operation in 1997); the Tema plant, which has a 30-MW diesel generator (placed into operation in 1961), and a 125-MW barge plant. The Takoradi plant was built in response to power shortages due to repeated droughts in the 1990s. The No. 1 unit (330 MW) commenced operation in 1997. The No. 2 unit was installed in 2000 with joint outlays by the U.S. firm CMS and the VRA (owned by the Takoradi International Company;TICO), but is currently operating only with two 110-MW gas turbines. Plans envision the installation of more steam turbines to increase the capacity to 330 MW. The plan is premised on utilization of gas produced in Nigeria and supplied by the Western African Gas Pipeline (WAGP), and its implementation therefore depends on this supply. The Tema and barge thermal power plants are not in operation.

Table 2-4 Generation facilities in Ghana (2006)

Plant	Year installed	Status	Gross capacity (MW)	Available net Capacity (MW)
Akosombo Hydro	1965/1972	Operating	1,038	1,020
Kpong Hydro	1982	Operating	160	148
Takoradi T1	1997-2000	Operating	330	300
Takoradi T2	2000	Operating	220 (330)	210 (320)
Tema Diesel	1961/1962	Unavailable	30	0
Power Barge	2000	Not commissioned	125	0
Total			1,903 (2,013)	1,678 (1788)

Source: Strategic National Energy Plan 2006-2020, Energy Commission, July 2006


Aksombo Power Plant


Takoradi Power Plant

Source: Taken by the Study Team

Figure 2-5 Photo of power plants in Ghana

2.4.2 Power development plan

There is a serious shortage of power in Ghana due to the low water level of the Volta River, but the fact is that the government has not been able to prepare clear plans for development of power sources.

In response to the power shortage, an MOE spokesman expressed intentions to increase the output of the No. 2 unit at the Takoradi plant by 110 MW by switching to a combined-cycle format by 2009. And Ghana government is developing gas-fueled thermal power on a scale of 400 MW in the Tema industrial zone and unit1 has been already operated. As noted above, these plans are premised on use of gas produced in Nigeria and on supply through the WAGP. However, the gas produced in Nigeria has been supplied yet, and therefore these power plants are generating by oil (see Table 2-5).

Table 2-5 Overview of Tema gas-fueled thermal power

	Capacity	Producer	COD	Remarks
Unit 1	126MW	GE	Operating	Currently, Oil is used.
Unit 2	220MW	Alstom	2009	
Unit 3	50MW	Siemens	2008	

Source: Interview by JICA Study Team

In addition, 200MW(Shen Zen Group),300MW(Cen Power), and 600MW(Capital from Canada) gas-fueled thermal power and 50MW of biomass power are planned.

Ghana also has a lot of remaining hydropower potential, but it has not been developed due to economic and environmental considerations (see Table 2-6).

Table 2-6 Hydropower potential in Ghana

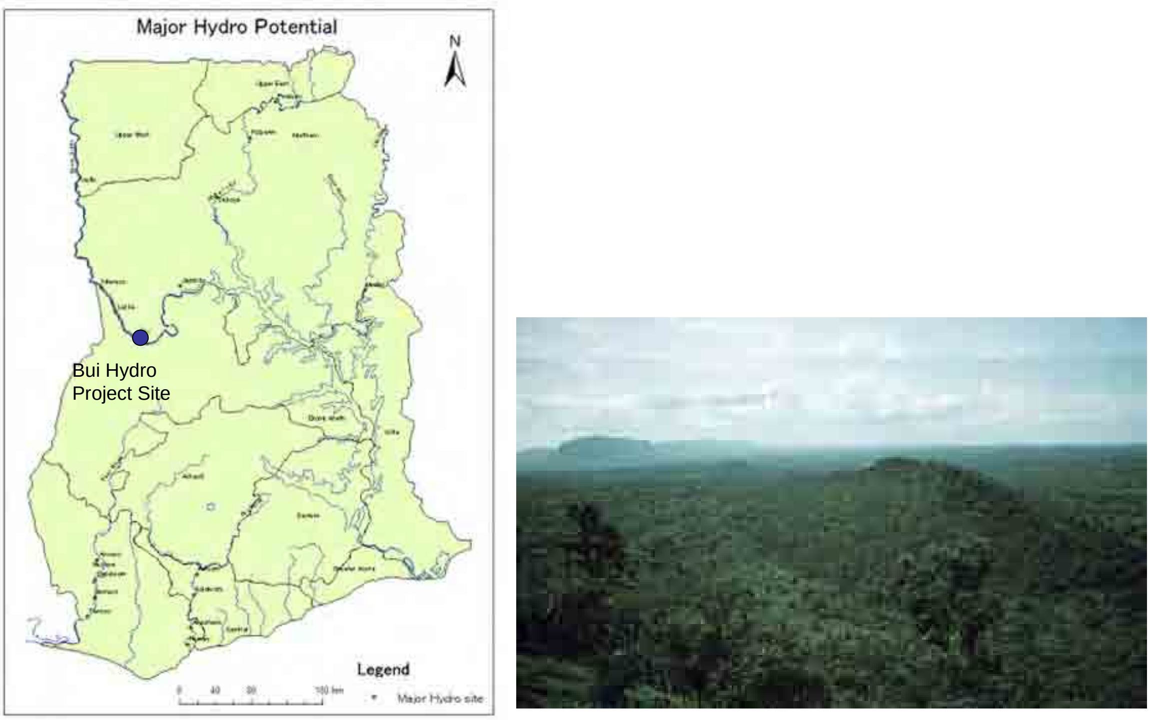
Name	River Basin	Potential (MW)	Generation (GWh)
Jambito	Black Volta	55	180
Bui	Black Volta	400	1,000
Lanka	Black Volta	95	319
Ntereso	Black Volta	64	257
Koulbi	Black Volta	68	392
Daboya	White Volta	43	194
Kulpawn	White Volta	40	166
Pwalugu	White Volta	50	184
Juabo	Oti River	90	405
Tanoso	Tano River	56	259
Jomuro	Tano River	20	85
Sodukrom	Tano River	17	67
Asuaso	Tano River	25	129
Heman	Pra River	90	336
Abaumesu	Pra River	50	233
Kojokrom	Pra River	30	136
Awisam	Pra River	50	205

Source: Study Team interviews

Recently, China decided to provide assistance for a 400-MW hydropower project at Bui on the Black Volta, and the work of detailed design was initiated in June 2007. Environmental impact assessment has already been conducted and the ground-breaking ceremony was hold in August 2007, with president attendance. The total cost of the project is 622 million dollars. Ghana government is preparing 60 million dollars of it and China is loaning 562 million dollars of it (Concession loan and Commercial loan).

Although construction of a dam at Bui will entail submersion of part of the Bui National Park and the relocation of about 2,000 residents, the government is attaching precedence to resolution of the prevailing power shortage over environmental concerns.

In accordance with MOE information, No.1 unit will be completed in 2011. And all units (3 units, total 400MW) will be completed by 2012.



Source: prepared by the Study Team

Figure 2-6　Location of the Bui hydropower project and Bui National Park

<u>Bui dam status</u>

The site for construction of the dam at Bui is about 150 kilometers (or about two and a half hours by car) away from Sunyani. An access road has been built, and matters are at the stage of detailed design. On the site is the office of the concerned Chinese company, and about 20 Chinese staff are staying there. The on-site work is being subcontracted to Ghanaian businesses, and consists of subterranean boring for the purpose of geological survey, surveying of the dam site, and measurement of water level.

Source: Taken by the Study Team

Figure 2-7　Conceptual drawing of the completed Bui Dam and site of the dam

2.4.3 Transmission and transformation facilities (distribution facilities)

Ghana's power system consists of 161- and 69-kV transmission lines (with an extended length of 4,000 km) and 29 trunk substations. The frequency is 50 hertz (Hz). International connection lines link the system to those of Togo (161 kV), Benan (161 kV), and Cote d'Ivoire (225 kV).

The trunk system containing the hydropower plants is comprised of 161-kV lines. The VRA owns and operates facilities up to and including the primary substations in major cities. The ECG and VRA-NED own and operate the 33-kV (or 34.5-kV) subtransmission lines, 33 (or 34.5)/11-kV primary substations, 11-kV distribution lines, and posterior facilities.

About one-third of Ghana's transmission and transformation facilities were built in the 1960s along with the Akosombo hydropower plant. More than 40 years have consequently passed since their construction, and this points to a need for systematic repair over the coming years. Along with the demand expansion in urbanized areas, additional trunk substations are being built in Accra and Kumasi.

2.5 Distribution facilities

2.5.1 Existing distribution facilities

(1) Makeup of the medium-voltage distribution line system

The basic makeup of the medium-voltage distribution line system is as follows.

(a) Cases in which the voltage is reduced from 161-kV (transmission lines) to 33 (34.5) kV in bulk supply points (BSPs), and carried to distrbution substations in 33-kV (34.5-kV) lines

(b) Cases in which the voltage is reduced from 161-kV (transmission lines) to 11 kV in BSPs, and carried to distrbution substations in 11-kV lines

(c) Cases in which the voltage is reduced from 161-kV (transmission lines) to 33 (34.5) kV in BSPs, and carried to remote areas in 33-kV (34.5-kV) subtransmission lines, followed by further reduction to 11 kV for carrying in 11-kV distribution lines to secondary substations.

Cases of the (a) type are most prevalent in the vicinity of Accra, Kumasi, and other big cities as well as BSPs. In more remote areas, cases of the (b) type predominate, and those of the (c) type are also found. In the case of some distribution lines in the (a) category, the voltage drop value is excessive or close to excessive, and an increase to 33 kV is under consideration.

As for configuration, the medium-voltage distribution lines mostly have a radiant pattern, but there are some loop formats in Accra and other urbanized districts.

(2) Makeup of low-voltage distribution lines

The nominal low-voltage value in Ghana is 433/250 V. There are from two to five low-voltage distribution (feeder) lines from a single distribution substation, in a radiant pattern.

2.5.2 Distribution technical standards

Standards for distribution facilities are set down in the electrical power system specifications determined by the ECG. The VRA-NED applies the same standards.

These specifications include general standards for voltage tolerance and distribution facilities (see Table 2-7).

Table 2-7 Examples of norms based on ECG standards

Item		Standard
Frequency		50HZ
Voltage	33-kV system	Nominal voltage：33kV Peak voltage：36kV
	11-kV system	Nominal voltage：11kV Peak voltage：12kV
	Low-voltage system	Nominal voltage：433/250V Peak voltage：438/253V Minimum voltage：358/207V
Supporting structures	33-kV , 11-kV system	Height：11m Span：100m
	11-kV system	Height：11m
	Low-voltage system	Height (cities)：9m Height (districts)：8m
Cable	33-kV system	Aluminum lines（Aluminum Conductor：AAC） Trunk lines：400mm^2、240 mm^2、150 mm^2 Feeders：240 mm^2、120 mm^2、50 mm^2
	11-kV system	Aluminum lines（Aluminum Conductor：AAC） Trunk lines：265mm^2、150 mm^2、120 mm^2 Feeders：120 mm^2、50 mm^2
	Low-voltage system	Aluminum lines（Aluminum Conductor：AAC） Cities：120mm^2、50 mm^2 Districts：25 mm^2 ABC Cable（Aerial Bundled Conductor） 4x50 mm^2、3x50 mm^2、4x25 mm^2、2x25 mm^2
Transformers	33kV/433/250V	500kVA、315kVA、200kVA、100kVA、50kVA
	11kV/433/250V	500kVA、315kVA、200kVA、100kVA、50kVA

(1) Supporting structures

Supporting structures consist mainly of steel towers and concrete poles for medium-voltage distribution lines, and wooden poles and steel pipe poles for low-voltage distribution lines. In the case of medium-voltage distribution line construction, there are two patterns of supporting structure routes: 1) basically along roads, and 2) through open fields or villages. As a result, in many cases, it is only on foot that personnel can access distribution line routes for the purpose of checking, patrols, inspection, and repair.

(2) Cable

The standards stipulate use of aluminum cable, but some copper cable is also in use. Although cable thickness ought to decline in the passage from the substation to the ends, thicker cable is used in some cases to extend the distribution line. Improvements should be made in this respect as far as possible due to problems such as the risk of current flow in excess of the allowable one through the thinner line and the increased complexity of system analysis.

(3) Transformers (distribution substations)

Transformers are generally of the three-phase type, but there is some use of single-phase transformers and single-wire earth return (SWER) transformers in rural districts.

2.5.3 Distribution facility design

The ECG has laid down guidelines for design of subtransmission and distribution lines (hereinafter referred to as the "design guidelines"). The VRA-NED essentially follows the same guidelines. Table 2-8 outlines these design guidelines.

Table 2-8 Outline of design guidelines for subtransmission and distribution lines (excerpt)

Section title	Outline
04. Characteristics of the overhead distribution system	Equipment characteristics and selection standards
05. Characteristics of underground distribution systems	Application of cable systems and cable characteristics
06. Calculation of current in short-circuit failures	Units applied, calculation for short-circuit failures, and calculation for ground failures
07. Protection of distribution facilities	Protective relay formats and methodology for operation of protective relays
08. Voltage drop and distribution loss	Voltage calculation, loss calculation, and loss countermeasures
09. Application of shunt capacitors	Methodology for improvement of power factors and voltage
10. Voltage regulators	Application of voltage regulators
11. Distribution system design standards	Design methodology for overhead and underground distribution facilities
12. Distribution system design procedure	Facility formation in each voltage class, and studies for reinforcement and new construction

Source : Subtransmission and Distribution Design Guidelines

The current status of the major types of distribution facilities may be summarized as follows.

(1) Voltage classes

Figure 2-8 shows the basic makeup of the distribution system in Ghana.

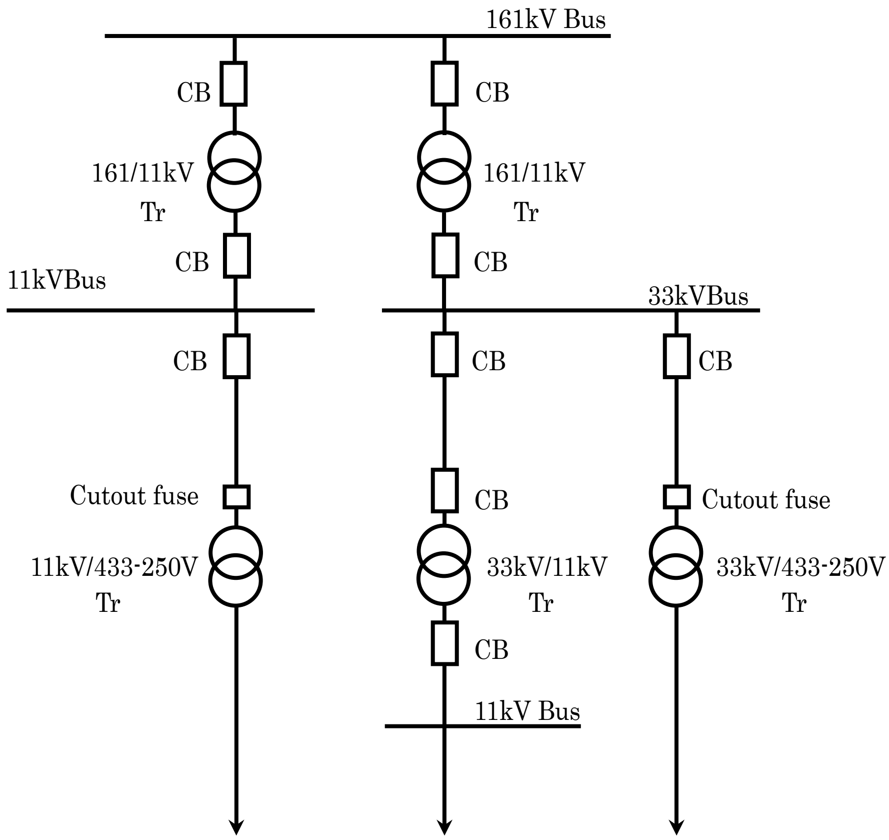


Figure 2-8 Basic makeup of the distribution system

The distribution system consists of three-phase, three-line 33- and 11-kV medium-voltage lines and three-phase, four-line 433- and 250-V low-voltage lines. Much of the area served by the VRA-NED is rural and has a low load density that tends to lengthen the distribution line distance. For this reason, the distribution lines are operated at 34.5 kV, slightly higher than the 33 kV of the ECG lines, to reduce loss.

Table 2-9 shows the voltage classes in standard use in Ghana.

Table 2-9 Voltage classes

Nominal Voltage	Maximum Voltage	Minimum Voltage
33kV (34.5kV)	36kV	29.98kV
11kV	11.69kV	11.58kV

Source: Subtransmission and Distribution Design Guidelines

In the succeeding account, unless noted otherwise, the 33-kV voltage class includes the 34.5-kV lines.

(2) Conductors

Distribution lines in Ghana can be divided into the following two categories:

- Overhead lines
- Underground cables

The main conductors used for overhead lines are all-aluminum alloy conductors (AAAC) and all-aluminum conductors (AAC), both being made of bare aluminum cable. The main sizes are 400, 240, and 150 square millimeters (mm2) in urban areas, and 240 and 150 mm2 in rural areas. Aluminum cable steel-reinforced (ASCR) lines, which are made of bare copper cable, are the main type used for connections from the 33/11-kV transformer secondary side to 11-kV buses. In rural areas, authorities formerly encouraged use of 100-mm2 AAAC and 70-mm2 copper cable, and there remain some dilapidated facilities of this sort. As a more extreme example, there are some places in which very thin cable (e.g., 16- or 35-mm2) was installed. The voltage drop is steep in such areas, and this is presumably a factor creating suppressed demand. For underground cable, the main type in urban areas is cross-linked polyethylene insulated vinyl-sheathed cable (XLPE). Table 2-10 shows the specifications of the cable conductors in standard use for distribution lines in Ghana.

Table 2-10 Standard specifications of overhead and underground cables

Voltage		Type	Size（mm^2）	Ampacity（A）
33kV	Overhead line	AAAC AAC	400 240 150 120 100 70 50	1,066 720 530 455 405 369 260
	Underground cable	Al-XLPE	240	670
11kV	Overhead line	AAAC AAC	400 240 150 120 50	1,066 720 530 455 260
	Underground cable	Al-XLPE	300	729

Source : Subtransmission and Distribution Design Guidelines

(3) Supporting structures

The main type of supporting structure for overhead lines is wooden poles, followed in order by concrete poles, steel towers, and steel poles. In rural areas, there is extensive use of the combination of wooden poles and steel crossarms.

The span distance indicating the interval between supporting structures is relatively short (in the range of 50 - 60 m) in some parts of urban areas, but ranges from 80 to 90 m in rural areas.

(4) Insulators

The standard types of insulator are pin, post, and suspension. Utilities make use of pin insulators for straight-line sections, post insulators to support buses in substations and conductors in sloping sections, and suspension insulators at T-branch points and anchor points.

(5) Switchgears

In addition to opening and closing load current in normal operation for reasons such as a change of the system makeup, switchgears have the role of limiting the impact of system trouble on sound sections to the minimum by isolating the failure section. In Ghana, there are three standard types of switchgears: circuit breakers to intercept current from upper system sections, reclosers, and sectionalizers. Each has its own protective function. Table 2-11 outlines each type.

Table 2-11 Outline of standard switches

Switchgear Type	Outline
Circuit Breaker	➢ Installed at substations that are the origin of distribution lines ➢ Equipped with a protective function
Recloser	➢ Installed at branch points on distribution lines ➢ Smaller breaking capacity than circuit breakers ➢ Can replace breakers in the case of a small short-circuit capacity ➢ Equipped with an engagement lock function
Sectionalizer	➢ Installed on distribution lines to supplement breakers and reclosers ➢ Equipped with an engagement lock function (role as a section switch)

Source: Subtransmission and Distribution Design Guidelines

Circuit breakers are generally of the oil type. Table 2-12 shows their capacities.

Table 2-12 Standard breaker capacity

Voltage	Rated short circuit interrupting current（kA）	Remarks
33kV	31.5	Maximum value on the BSP secondary side
11kV	20.0	

Source: Subtransmission and Distribution Design Guidelines

The figures for breaking capacity in this table are premised on the maximum short-circuit failure on the secondary side of BSPs (bulk supply points; substations forming the boundary between the VRA and the distribution companies ECG and VRA-NED). Therefore, the breaking capacity is determined on the basis of the failure current corresponding with the actual use of distribution facilities (e.g., use of a 13-kA current on an 11-kV bus).

(6) Transformers

Distribution transformers are connected in a T-branch from distribution lines. They consist of a lightning arrester and a cutout fuse. Normally, they are installed on poles, for reasons of economic merit and public safety. Transformers with capacities of 50, 100, 200, or 315 kVA are in widespread use. There is limited installation of on-load tap-changing transformers which can change voltage without power outages. Typically, power outages occur in morning and evening, when there is a big change in demand. Table 2-13 shows the installation formats and capacities of transformers in standard use.

Table 2-13 Specifications of standard transformers

Primary Voltage	Design Type	Size（kVA）
33kV	Pole mounted	25,50（Single phase） 50,100,200,315,500（Three phases）
	Ground mounted	200,315,500（Three phases）
11kV	Pole mounted	25,50（Single phase） 50,100,200,315,500（Three phases）
	Ground mounted	200,315,500（Three phases）

Source: Subtransmission and Distribution Design Guidelines

(7) Neutral grounding system

Regarding the neutral grounding system for transformers, the design guidelines stipulate direct or effective (low-resistance) grounding. Solidly grounding is the standard type among the installed facilities.

(8) System protection

The 33-kV distribution lines are operated as subtransmission lines when used for interconnection between primary substations, and distance relays are consequently used for detection of short circuits for the purpose of protection. In addition, they are operated as distribution lines when used for supply of power to distribution substations. In this case, overcurrent relays are used for protection. For detection of ground faults, ground fault overcurrent relays are installed on both subtransmission and distribution lines.

When 33-kV distribution lines are used as subtransmission lines, the design guidelines stipulate a subtransmission line protection scope of 85 percent for the first section relays and 120 percent for second section relays. The relays have a tolerance for equipment error and a backup protection function. Figure 2-9 presents a conceptual diagram of the scope of protection.

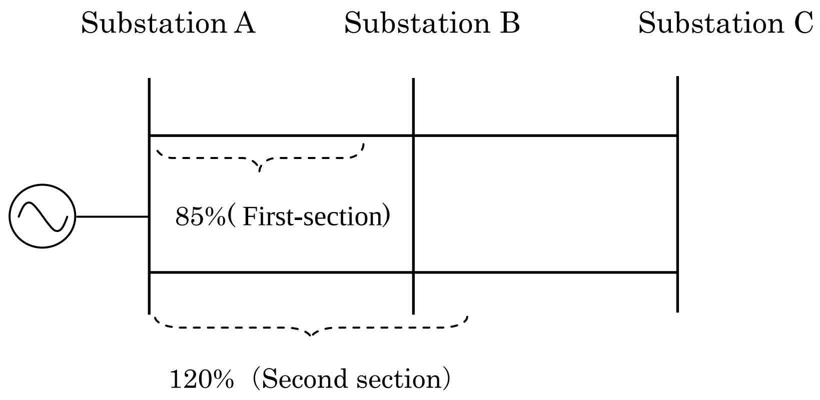


Figure 2-9 Scope of distance relay protection

Distribution lines have a large load fluctuation in each phase, and generally make it more difficult to adjust the setting sensitivity of overcurrent relays than transmission lines. In some cases, upon the occurrence of failure, power is temporarily supplied through sound phases only, i.e., by single-phase operation of transmission lines.

However, this is liable to destabilize the power supply, and it would be preferable to break all three phases.

The breakers installed in substations and cutout fuses installed on the primary side of pole transformers have different operating times, for the purpose of cooperative protection.

On bare lines such as 33-kV overheads, span lengthens as voltage rises, and there is a higher incidence of power outages caused by momentary contact with trees and other conductors. This points to an increasing need for system protection.

(9) Service life

Table 2-14 shows the service life lengths (in terms of number of years) adopted as standards by the ECG for the major types of distribution facilities. In light of the increasing demand and facility age, the ECG and the VRA-NED are making plans for replacement of transformers and dilapidated switches, but a shortage of funds has prevented execution of some parts, and the supply quality is declining as a result of equipment failure. In addition, they have confirmed the existence of suppressed demand by the shortage of transformer capacity as well as conductor capacity.

Generally speaking, distribution facilities in which the secondary side is connected to low-voltage lines are far more numerous than generation and transmission facilities. For this reason, systematic replacement in the interest of preventive maintenance tends to be disadvantageous in the cost aspect and to be given a low priority.

Table 2-14 Standard service life of distribution facilities

Facilities	Service life
33kV Circuit Breakers	25
33kV Gas Circuit Breakers（SF6）	40
11kV Circuit Breakers	25
11kV Gas Circuit Breakers（SF6）	40
33kV Overhead lines（Wood poles）	30
33kV Overhead lines（Steel poles）	40
11kV Overhead Lines	35
33kV Underground Cables	40
11kV Underground Cables	40
LV Overhead lines & Underground Cables	25
Service Lines	25
33/11kV Transformers	40
33/0.4kV Transformers	30
11/0.4kV Transformers	30
11/0.25kV Transformers	30
33kV/LV Substations	30
11kV/LV Substations	30

Source: Subtransmission and Distribution Design Guidelines

2.5.4 Distribution facility cost estimation

The ECG and the VRA-NED each have their own system for calculating the costs required for construction of distribution facilities, inclusive of the material and installation costs. This section presents an outline of each calculation system.

(1) ECG calculation system

To calculate construction costs, the ECG utilizes calculation tools it created itself using Microsoft Excel. Figures 2-10 - 2-12 present examples of these tools. The process of calculation begins with the preparation of a list of unit costs for each type of distribution facility. The operator selects the major facilities on a pull-down menu and enters the quantities.

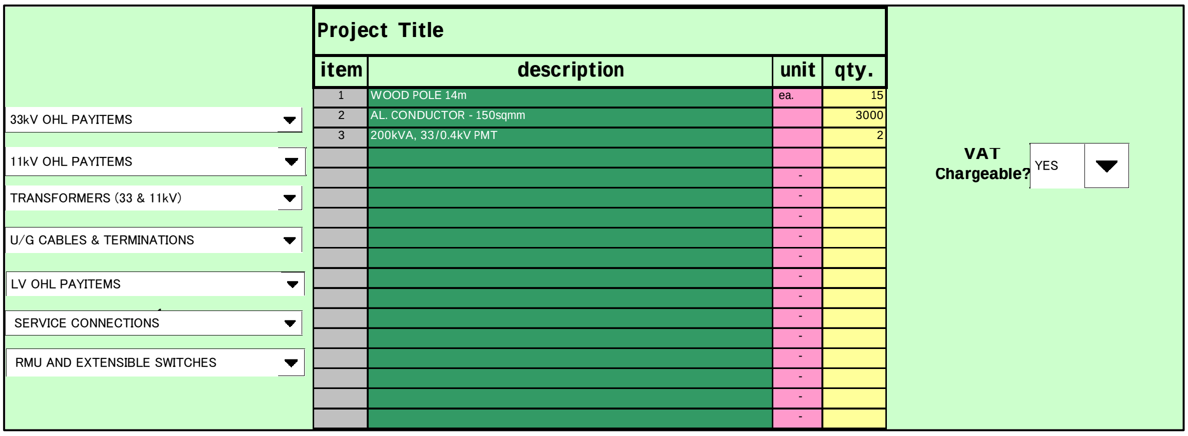


Figure 2-10 Example of calculation of construction costs

Next, an automatic calculation is made of the installation cost in terms of the former cedi (approximately equal to 0.013 yen; since July 2007, the rate has been about 130 yen to the cedi).

Project Title					
WORK SCHEDULE (Work is estimated by PayItems)					
item	**description**	**unit**	**qty.**	**installation (cedis)**	
				unit rate	**amount**
1	WOOD POLE 14m	ea.	15	350,000.00	5,250,000.00
2	AL. CONDUCTOR - 150sqmm	m.	3,000	832.00	2,496,000.00
3	200kVA, 33/0.4kV PMT	ea.	2	3,541,025.00	7,082,050.00
	Sub-Totals (Installation Only)				**14,828,050.00**
	Administration Charge (10%)				**1,482,805.00**
	Transportation (5%)				**741,402.50**
	VAT (Re-chargeable Jobs only)				**2,557,838.63**
	TOTAL - Installation Only				**19,610,096.13**

Figure 2-11 Example of calculation of installation cost

This is followed by automatic input of auxiliary facilities required for construction, such as supporting structures, insulators, fuses, and assembly components. Lastly, an automatic calculation yields the itemization of material and installation costs, and the total construction cost (in former cedi).

item no.	code	description	unit	qnty.	material cost (cedis)		installation cost (cedis)	
					unit rate	amount	unit rate	amount
		Overhead Line Hardware(11kV & 33kV)						
1	1118025	Wood pole 14m	ea	15	3,833,880.00	57,508,200.00	350,000.00	5,250,000.00
		Substation Equipments and Materials						
2	3121055	33 kV expulsion type fuselink6A	ea	6	57,137.00	342,822.00	-	-
3	3111013	33/0.433 kV PMT 200 KVA	ea	2	75,464,201.00	150,928,402.00	2,350,000.00	4,700,000.00
4	3119006	33KV Expulsion type fusegear - single pole	ea	6	2,381,586.00	14,289,516.00	120,000.00	720,000.00
5	1115036	Ancilliary Channel crossarm for 33KV 1.9m Long	ea	10	464,229.00	4,642,290.00	38,000.00	380,000.00
6	1115058	L-Bracket Attachment to Fusegear/Lighting Arrestor	ea	6	10,679.00	64,074.00	-	-
7	1121018	Lightning Arrestor - 33 KV	ea	6	706,016.00	4,236,096.00	89,000.00	534,000.00
8	3121175	LV HRC Fuselink with blade contacts 100A	ea	18	41,491.00	746,838.00	-	-
9	1112058	LV pvc insulated, pvc sheathed Cu. Conductor 70 sq. mm	m	90	51,089.00	4,598,010.00	-	-
10	1111113	PMT Holding Bracket	ea	4	70,000.00	280,000.00	-	-
11	3121291	Wedge type fuse carrier92mm (LV Aerial Fuse Unit)	ea	18	461,431.00	8,305,758.00	-	-
		Overhead Line Conductors & Binding Wire						
12	1113040	Hard drawn Aluminium bare stranded conductor (AAC) 150 sq.mm	m	3000	27,130.00	81,390,000.00	832.00	2,496,000.00
		Earthing Materials						
13	1116140	Copper Earth Rod C/W Clamp	ea	20	36,402.00	728,040.00	35,000.00	700,000.00
14	1114005	Hard drawn bare stranded Cu. conductor 16 sq.mm	m	40	12,399.00	495,960.00	300.00	12,000.00
15	1114015	Hard drawn bare stranded Cu. conductor 35 sq.mm	m	70	25,329.00	1,773,030.00	515.00	36,050.00
16	1112057	LV pvc insulated, pvc sheathed Cu. Conductor 16 sq. mm	m	20	13,037.00	260,740.00	-	-
17	1119023	Plastic staple for cables up to 16sq.mm	ea	40	650.00	26,000.00	-	-
18	1111114	PVC Pipe (Earth Guard)	ea	2	100,000.00	200,000.00	-	-
		Bolts, Nuts, Washers and Connectors						
19	1123149	Al. tap-off clamp (bolted type) 120 / 120	ea	6	13,061.00	78,366.00	-	-
20	1125045	Bolt,Nut & Washers M20 x 280mm	ea	16	15,998.00	255,968.00	-	-
21	1125092	Bolt,Nut & Washers M16 x 40mm	ea	18	4,207.00	75,726.00	-	-
22	1124006	Cu. Compression cable lug 70 sq.mm	ea	60	33,522.00	2,011,320.00	-	-
23	1111111	Flat Square Washer - M16	no.	16	2,000.00	32,000.00	-	-
		Sub-Totals				**333,269,156.00**		**14,828,050.00**
		Sub-Total (Material and Installation)				**348,097,206.00**		
		Administration Charge (10%)				**34,809,720.60**		
		Transportation (5%)				**17,404,860.30**		
		VAT (Re-chargeable Jobs only)				**60,046,768.04**		
		GRAND TOTAL				**460,358,554.94**		

Figure 2-12 Example of calculation of total construction cost

The ECG calculation system described above offers efficiency in the calculation aspect due to the incorporation of macroscopic calculation, and may be termed a suitable tool for calculation of detailed costs in consignment of work to construction companies.

However, it cannot handle calculation of construction costs for certain distribution facilities, subtransmission lines, and primary substations. Improvement of the distribution network in Ghana based on the Master Plan demands cost calculation from a macroscopic perspective, including the listing of unit costs for each pattern of construction anticipated in the work of facility renewal, reinforcement, and extension.

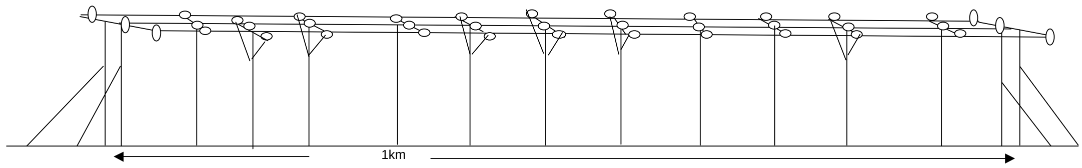
(2) VRA-NED calculation system

In its construction cost calculations, the VRA-NED divides the model costs per facility into material and installation costs, and adds the construction costs up on this basis as necessary. Figures 2-13 present examples of model unit costs.

Material Cost of 1 km, 34.5 kV Line Construction

Date: *May-05*

Sample Drawing



Date: 31st May 2005

Criteria Conditions

The estimating is over 1 km of 34.5 kv line construction
Span length is taken as 90 mtrs
15% of number of poles is taken as the requirement for stays.
Disc and Pin insulators are considered at the same price.
Bush clearing is considered.
This is the first kilometre of construction cost, additional kilometers will not contain two sections.

material List/costing

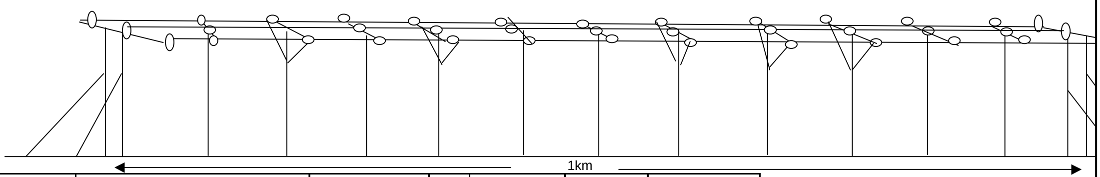
Material Description per km	Unit	Unit price(¢)	Quantity	Material Cost (¢)
HT poles	Sgl	3,519,000	15	52,785,000.00
Terminal crossarms	Sgl	150,000	2	300,000.00
Intermediate Crossarms	Sgl	150,000	11	1,650,000.00
Disc Insulators & hooks	Set	70,000	18	1,260,000.00
Pin & Insulators	Set	60,000	33	1,980,000.00
Crossarm ties	Sgl	15,000	22	330,000.00
Bolts & Nuts, 260mm	Set	15,000	15	225,000.00
Bolts & Nuts, 50mm	Set	10,000	22	220,000.00
100mm conductor	Mtr	15,000	3,000	45,000,000.00
Stays	Set	180,000	2.25	405,000.00
Total Material Cost of Construction of 1 km 34.5 kV Line			¢	*104,155,000.00*

Labour Cost of 34.5 kV Line Construction using VRA Manhour Rates

Date: *May-05*

Sample

Sample Drawing



Labour High Voltage

Item	Broad Description of Work	Sub- description	Unit	Unit rate	Quantity/km	Labour Cost ¢/km
1	HIGH VOLTAGE NETWORK					
1.1	Digging of 1.8m deep hole and	Normal ground	No.	43823.66		
	erection of HT wood Pole in:	Laterite ground	No.	43823.66	15	657,354.90
		Rocky ground	No.	87647.32		
1.2	Mounting of angle iron crossarms	1-phase	set	51886.41		
	complete with straps fixation of	3-phase	set	51886.41	11	570,750.51
	Pin Insulators etc for					
1.3	Mounting of angle iron crossarms	1-phase	set	64670.31		
	complete with straps fixation of	3-phase	set	64670.31	2	129,340.62
	Strain Insulators etc for					
1.4	Erection of Stay equipment	Normal ground	No.	129340.62		
	complete (including staywire) in:	Laterite ground	No.	129340.62	2.25	291,016.40
		Rocky ground	No.	194010.93		
1.5	Installation of Line earthing complete		No.	73798.24	2	147,596.48
1.6	Bush clearing in:	heavy forest	km	175294.64		
		light forest	km	43823.66	1	43,823.66
1.7	Survey & pegging & preparation		km	0.00	1	-
	of survey and as built drawings					
1.8	Stringing of HV Line	120mm sq mm	km	662514.23	1	662,514.23
	HD AL conductor (3-phase) for:	50mm sq mm	km	662514.23		
	Total Labour Cost of Construction of 1km of 34.5 kV Line				¢	2,502,396.80

Figure 2-13 Example of construction model unit cost

The VRA-NED calculation system outlined above reflects consideration for efficiency through automation and other features, and may be regarded as representing an advisable orientation for calculation of macroscopic costs in the Master Plan.

Like the ECG calculation tool, however, it is not adapted to calculation of construction costs for certain distribution facilities, subtransmission lines, and primary substations. For this reason, the VRA-NED must prepare a unit cost list for the anticipated construction patterns.

2.5.5 Supply reliability

In Ghana, the reliability of power supply is extremely low. The main reasons are the neglect to properly replace deteriorated facilities, and trouble caused by voltage drop owing to the failure to adequately reinforce distribution lines.

At the ECG, outages in fiscal 2005 had an average yearly duration per customer of about 28 hours and numbered about 55 per 100 kilometers of lines. While data for fiscal 2006 have been collected only for the number of line outages, this reached about 13,000 at the ECG as a whole. Table 2-15 presents monthly totals for distribution line outages.

Table 2-16 shows the distribution line outage durations and number for the first three quarters of 2006 at the VRA-NED. Over this period, outages had a combined duration of about 1,093 hours and numbered 598.

Recently, the rotating outages accompanying the low water level on the Akosombo dam in the dry season has been carried out.

These figures indicate that the supply reliability is on a insufficient level in the distribution system in Ghana, and point to an urgent need for the preparation and execution of plans to properly renovate and reinforce the distribution network.

Table 2-15 Number of ECG distribution line outages (2006)

Area	Jan	Feb	Mar	April	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
ACCRA EAST	22	43	79	82	52	66	60	69	32	25	109	11	650
ACCRA WEST	77	52	94	60	85	121	109	117	54	72	74	68	983
TEMA	122	172	178	137	187	179	173	128	114	185	190	133	1,898
EASTERN	142	221	261	290	338	220	89	130	120	218	198	125	2,352
VOLTA	122	197	132	134	232	118	142	81	125	152	193	288	1,916
WESTERN	137	114	117	127	150	162	149	144	127	156	138	129	1,650
CENTRAL	133	71	116	99	153	110	120	119	87	120	146	107	1,381
ASHANTI WEST	207	190	187	167	143	87	124	80	245	99	110	85	1,724
ASHANTI EAST	13	18	66	62	29	23	38	27	53	39	64	47	479
ECG TOTAL	975	1,078	1,230	1,158	1,369	1,086	1,004	895	957	1,066	1,222	993	13,033

Source: ECG

Table 2-16 Distribution line outage durations and number at the VRA-NED (up to the third quarter of 2006)

Area	1st Quarter 2006		2nd Quarter 2006		3rd Quarter 2006		Total as at 3rd Quarter	
	Outage Duration in Hrs	No of Outages	Outage Duration in Hrs	No of Outages	Outage Duration in Hrs	No of Outages	Outage Duration in Hrs	No of Outages
Northern	32.72	26	59.60	50	106.01	45	198.34	121
Sunyani	51.90	24	75.04	48	47.07	26	174.01	98
Wa	26.37	21	58.85	82	160.29	46	245.51	149
Bolgaatanga	37.02	13	41.95	27	108.72	28	187.68	68
Techiman	48.95	44	70.34	62	168.05	56	287.33	162
Total	196.95	128	305.78	268	590.14	202	1092.87	598

Source: VRA-NED

Chapter 3 Trends Among International Institutions Assisting the Power Sector

Ghana was formally recognized as having the status of a heavily indebted poor country (HIPC) in 2001, and the majority of assistance provided to it was consequently focused on poverty reduction during the first half of the 2000s. However, due to recognition of the necessity of securing the energy supply needed to develop its economy, international institutions have restarted their assistance in the power sector as well as in other infrastructure fields.

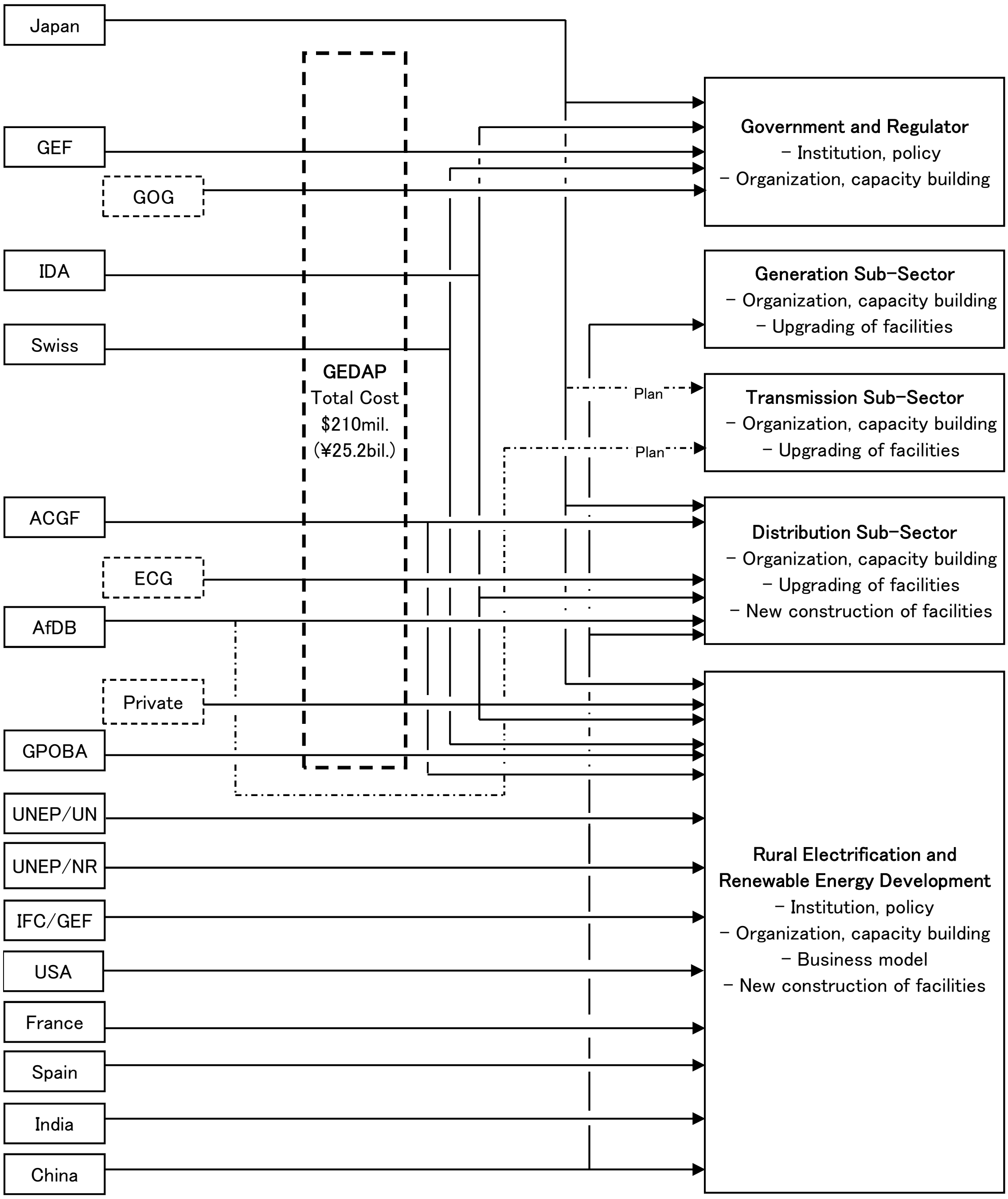
Meanwhile, in June 2007, the Board of the Executive Directors of the World Bank approved the Ghana Energy Development and Access Project (GEDAP), which consolidates funding from a regional development bank, developed countries, the Government of Ghana (GOG) and the Electricity Company of Ghana (ECG) as well as the World Bank and the Global Environmental Facility (GEF).

While GEDAP became the biggest assistance project for the power sector, the African Development Bank (AfDB) also provided funding to the transmission division.

From the United States, the US Export-Import Bank provided funding for rural electrification.

From Europe, Switzerland will provide funding under the GEDAP scheme. Spain and France have also independently made commitments for projects of technical assistance (TA) and funding.

From Asia, in addition to Japan, India and China decided to finance rural electrification programs. Furthermore, China financed the Bui hydropower project, too.



ACGF: African Catalytic Growth Fund; AfDB: African Development Bank; GEF: Global Environmental Facility;
GPOBA: Global Partnership on Output-Based Aide; IDA: International Development Association;
IFC: International Finance Corporation; NREL: National Renewable Energy Laboratory
UNEP: United Nations Environmental Programme; UNF: United Nations F
Source: JICA Study

Figure 3-1 Assistance for the Power Sector

3.1 GEDAP Project

The objectives of the project are to improve the operation efficiency of the distribution system and increase the electrification ratio. The project consists of the following three components:

- Component A: Sector and institutional development (US$13.99 million);
- Component B: Distribution system improvement (US$94.4 million);
- Component C: Electricity access expansion and renewable energy development (US$101.2 million.)

The total cost of the project is US$210.6 million, US$90 million of which are funded by the International Development Association (IDA) of the World Bank group. In addition to foreign assistance, the GOG and the ECG also contribute to the funding in local currency. (See Table 3-2)

The project aims to upgrade the power infrastructure in line with the implementation of power sector reform. One major task is to upgrade the current deteriorated distribution networks and to construct new network systems. Another is to develop power supply systems in unelectrified areas using not only the on-grid system (grid extension) but also off-grid systems such as mini-grid systems and dispersed-type power sources. For the off-grid system development, the project plans to create a new business model, which will involve not only existing electric utilities but also private-sector parties such as local entrepreneurs and solar system dealers, and establish the funding scheme required to run the model. In this connection, a specific aim is to create a loan scheme using local banks in order to facilitate the use of solar home systems (SHSs). (See Table 3-1)

3.1.1 Component A

Component A is aimed at strengthening the capacity of the governmental agencies and two electric utilities.

For the government, this component will enhance the capacity of the Ministry of Energy (MOE), i.e., the policymaker, and the Energy Commission (EC) and the Public Utilities Regulatory Commission (PURC), i.e., regulators. Since review of the current tariff scheme, in which utilities cannot recover their cost, is a major issue, this component will conduct a study of the power tariff and assist the capacity-building of the PURC.

The component will also provide TA to enhance the utilities' corporate management capacity, which is another side of the power tariff issues. The Management Support Services Agreement

(MSSA), which is the main item of the TA, will be funded by Switzerland. In this task, external consultants are expected to be hired to improve the corporate-management capacity, but the Ghanaian and the Swiss sides have not yet agreed on the details of the TA scheme. As a preliminary task, the corporate management of the new distribution company, which will be established by the merger of the ECG with the NED, is being studied. The basic concept of the distribution division structure, that is, the integration of the ECG and the NED into one company and the splitting of franchises into five regions, has been determined. However, the management system, that is, the question of how to operate the distribution business and whether the five franchises will be operated independently or managed as business units under one holding company, has not yet determined.[1]

This component will also strengthen the MOE's capacity as necessary to administrate the corporate management of the Volta River Authority (VRA) and the ECG, and the EC capacity needed for the development of renewable energy resources.

3.1.2 Component B

Component B is aimed at upgrading of the existing distribution facilities of the ECG and installation of new facilities. In accordance with the construction project of the VRA's new bulk supply point (BSP), which will be financed by the AfDB alone, this component will provide funds for installing a new ECG auxiliary facility from the battery limit (funding of the BSP construction is outside the GEDAP scheme).

To improve the capacity of ECG service, the IDA will co-finance the establishment of customer service centers, the replacement of old meters, the installation of necessary equipment. Extension of the prepayment metering system and enhancement of the IT system also will be implemented under this component.

3.1.3 Component C

Component C is aimed at facilitating rural electrification by expanding the use of the existing distribution lines and grid extension.

On the other hand, mini-grid systems using renewable energies will be developed in the areas where such on-grid electrification is difficult. In this project, business operation is expected to be carried out by local entrepreneurs instead of existing distribution companies. To promote the diffusion of SHS in the household sector, this component will create a financing scheme

[1] This study is now being carried out by PricewaterhouseCoopers and expected to be completed

involving local banks. To make the scheme a reality, ARB Apex Bank is already participating in the project.

For the MOE, the component will organize a tentative secretariat with a view to establishing the Rural Electrification Agency (REC) as a preliminary step.

by the end of June 2008.

Table 3-1: Components of the GEDAP Project

Component A: Sector and Institutional Development (US$13.99 million)
Implementing agency: MOE Beneficiaries: MOE, ECG, VRA, EC, PURC, and EPA A1—Regulatory Capacity Strengthening (US$1.76 million) ・ Technical and operational reviews of the VRA and the ECG (IDA-financed). ・ Electricity cost of service and tariff study (IDA-financed). ・ Public education and communication campaign (IDA-financed). ・ Development of renewable energy tariff methodology and schemes, and standardization of power purchase agreement for small renewable energy projects (below 10MW) (IDA-financed). ・ Training and workshops (IDA & SECO-financed). A2—Corporate Strengthening Program for the ECG (US$6.7 million) ・ MSSA for the ECG (SECO-financed): to provide a three-to-five-year technical assistance program to enhance the ECG's management capacity and introduce the company to good commercial management practices. ・ Institutional Development and Capacity-Building (IDA-financed): to provide technical assistance, studies, and capacity-building for the ECG management and senior personnel. A3—Sector Policy and Strategy Development (US$1.96 million) ・ Power Sector Development (IDA-financed): to enhance the government's existing mechanism for monitoring the performance of the VRA and the ECG. ・ Renewable Energy Development (GEF-financed): to enhance the capacity of the EC to promote increased use of renewable energy. A4—Environmental, Social and Project Management (US$3.2 million) ・ Project Coordination. ・ Environmental Monitoring. ・ Monitoring and Evaluation of Project Outcomes. ・ Operation of Interim Access Secretariat.
Component B: Distribution Improvement (US$94.40 million)
Implementing agency: ECG Beneficiary: ECG B1—Distribution System Upgrade (US$68.9 million) ・ Activities financed by the IDA (with co-financing from the ECG) ✧ Upgrading and construction of 33/11kV substations.

- ✧ Addition or replacement of distribution transformation facilities and materials required for network maintenance and expansion.
- ✧ Rehabilitation of low-voltage limes.
- ✧ Reconfiguration of parts of the low-voltage distribution system into a high-voltage distribution system for the peri-urban areas of Accra and Tema.

- Activities financed by the AfDB (with co-financing from the ECG)
  - ✧ Upgrading and construction of 33/11kV substations and 33kV and 11kV overhead lines and switchgear in selected areas.
  - ✧ Rehabilitation of low-voltage lines in selected areas.
  - ✧ Reconfiguration of parts of the low-voltage distribution system in the Takoradi and Kumashi areas.
- Activities financed by the ACGF (with co-financing from the ECG)
  - ✧ Addition and replacement of distribution facilities and other materials required for network maintenance and expansion.
- Activities financed by the GEF
  - ✧ Provision of shunt capacitor compensation in selected parts of the network.

B2—Commercial and Technical Capacity Upgrade (US$25.5 million)

- Activities financed by the IDA (with co-financing from the ECG)
  - ✧ Establishment of new ECG customer service centers and district offices.
  - ✧ Replacement of faulty meters in the entire coverage area of the ECG.
  - ✧ Extension of local area networks/wide area networks to district offices and customer service centers, and development of applications for material management.
  - ✧ Provision of construction and installation equipment, and technical and office tools
  - ✧ Training and capacity-building for the ECG operational personnel
  - ✧ Design and supervision
- Activities financed by the ACGF (with co-financing from the ECG)
  - ✧ Establishment of an ECG-wide call center.
  - ✧ Technical support to supplement network and database management.
  - ✧ Extension of the pre-payment metering system from the Accra region to the Western, Central and Volta regions.
  - ✧ Secondary substation metering and provision of summation current transformers.
  - ✧ Marketing, customer education, and customer perception survey.
  - ✧ Development of secondary automation and supervisory control and data

acquisition (SCADA) systems, for rural networks and for the Takoradi and Kumashi Areas.

Component C: Electricity Access Expansion and Renewable Energy Development (US$101.2 million)

Implementing agencies: MOE, ARB Apex Bank, ECG, and VRA/NED

Beneficiaries: ECG, VRA/NED, rural banks, and rural energy consumers

C1—Intensified Use of Existing Distribution Systems (US$24.6 million)

- ECG (US$19.5 million): to support ECG program to intensify electrification in 412 rural and peri-urban towns of 38 districts in the Eastern, Western, Ashanti, Volta, Central, and Great Accra regions, with connections of about 55,000 new customers.
- VRA/NED (US$5.1 million): to support NED intensification projects in 151 towns/villages in 4 NED-covered regions, with connection of about 20,000 new customers.

C2—Grid Extension (US$50.4 million)

- IDA financing will support grid extension projects in 143 rural towns and villages of 7 districts in the Eastern, Western, Ashanti, and Great Accra regions, with connection of about 24,000 new customers.
- ACFG financing will support grid extension projects in 298 rural towns and villages of 12 districts in the Eastern, Western, Ashanti, Volta, and Great Accra regions, with connection of about 31,000 new customers.
- SECO financing will connect new customers in 89 rural towns and villages in 7 districts in the Central region.

C3—Mini-Grid and Grid-Connected Renewable Energy (US$9.1 million)

- To provide RE grants to eligible developers for development of 5-7 mini-grid systems and 2-3 grid-connected renewable energy systems (1-10MW).
- The developers of mini-grids are local entrepreneurs or community-based organization.

C4—Solar-PV Systems (US$10.9 million)

- System will be 2.5-200Wp.
- To provide financial incentives in order to remove market barriers.
    - ✧ Line-of-Credit facility (IDA US$3 million): part of the credit will be on-lent to participating rural banks, through ARB Apex Bank, to provide the necessary long-term liquidity for financing customer loans for SHS.
    - ✧ Solar-PV Grants (GPOBA US$6 million): the grants provide 50% of the full cost of SHS; the balance is paid by consumer with a down payment for 10% and consumer loans for 40%.

C5—Capacity Building (US$6.2 million)

- Technical assistance to the Access Secretariat and the REA (IDA US$1.2 million).
- Support for the REA and, until its establishment, the MOE to carry out renewable energy feasibility and development studies (GEF US$1.2 million).
- Capacity building for the private sector to assist their development of renewable energy projects (GEF 2.8 million).
- Capacity-building and implementation support for ARB Apex Bank and participating rural banks (ACGF US$0.7 million).

Source: The World Bank, 2007

Table 3-2: GEDAP Project Cost

(Unit: US$ million)

Components		Total Cost	Financing									
			GOG	VRA	ECG	IDA	SECO	GEF	AfDB	ACGF	GPOBA	Private
A	Sector and Institutional Development	13.99	1.19			6.05	6.00	0.75				
A1	Regulatory capacity strengthening	1.76				1.31	0.20	0.25				
A2	ECG corporate strengthening	6.68				0.98	5.70					
A3	Policy and strategy development	1.96	0.11			1.24	0.10	0.50				
A4	Environmental, social and project management	3.16	1.07			2.09						
B	Distribution Improvement	94.43			20.70	40.51			18.21	15.00		
B1	Distribution system upgrade	68.88			12.86	33.14			18.21	4.68		
B2	Commercial & technical capacity upgrade	25.54			7.84	7.37				10.33		
C	Electricity Access and Renewable Energy	101.20				42.45	5.00	4.75		35.00	6.25	7.75
C1	Intensification	24.64				24.64						
C2	Grid expansion	50.35				10.35	5.00			35.00		
C3	Mini grids and grid–connected renewable energy	9.11				3.11						6.00
C4	Solar PV systems	10.86				3.11					6.00	1.75
C5	Capacity building	6.24				1.24		4.75			0.25	
Project Preparation		1.00				1.00						
計		210.61	1.19		20.70	90.00	11.00	5.50	18.21	50.00	6.25	7.75

Source: The World Bank, 2007

3.2 Trends Among Individual Institutions Assisting the Power Sector

3.2.1 AfDB

The AfDB provided US$42 million to upgrade and construct transmission lines. Of this total, US$18 million will be furnished as part of the Component B of the GEDAP project, but another US$14 million will be independently provided for the upgrading of existing and installation of new transmission lines[2].

3.2.2 Agence Française de Dévelopment (AFD)

The AFD financed a study on the institutional arrangement for rural electrification. This study is being executed outside the GEDAP project but is TA synchronized with the rural electrification program of GEDAP. It discusses appropriate institutional structures for establishing the REA and the Rural Electrification Fund. The duration of the study is about three months, and the final report will be submitted by the end of June 2008.

3.2.3 Switzerland

The Swiss Secretariat for Economic Affaire (SECO) will provide a loan of US$11 million for capacity-building for ECG management and implementation of on-grid rural electrification in the GEDAP project.

3.2.4 Spain

The Government of Spain approved assistance of 5 million euros to install solar-photovoltaic (PV) systems in public facilities such as schools, clinics, and police stations in remote areas.

3.2.5 The US Export-Import Bank

The US ExIm Bank is providing a US$357 million loan. This financing has already been approved by the National Assembly of Ghana. Of this total financing, 35.21 percent are on a grant basis, and the remainder is occupied by a soft loan.

3.2.6 The US Millennium Challenge Account (MCA)

The US Millennium Challenge Account (MCA) approved a US$547-million anti-poverty program in Ghana. Under this program, rural electrification is a component of the infrastructure package.

3.2.7 India

The Indian Export-Import Bank provided US$15 million for rural electrification.

---

[2] The AfDB planned to co-finance with the Japan Bank for International Cooperation (JBIC). However, JBIC did not agree, and the AfDB finally decided to finance it alone.

3.2.8 China

The China Export-Import Bank provided US$81 million for rural electrification and US$57 million for pre-payment meters for the ECG. The Government of China also provided a US$562 million loan for the 400MW Bui hydropower project. The construction work started in August 2007. The first unit is expected to be commissioned in 2011, and the second and third units, in 2012,

3.2.9 The United Nations Environmental Programme (UNDP)/UNF Africa Renewable Energy Enterprise Initiative (AREEI)

The UNDP/AREEI offer rural energy entrepreneurs a combination of enterprise development services with modest amounts of start-up financing.

3.2.10 UNEP/NERL/GEF

The UNEP/NERL/GEF are financing the "Solar and Wind Energy Resource Assessment" (SWERA) project.

3.2.11 International Finance Corporation/GEF

The IFC/GEF are financing the "Lighting the Bottom of the Pyramid" project to provide assistance to the Solar-PV development.

Bibliography

The World Bank (2007), *Project Appraisal Report of the Energy Development and Access Project*, June 8, 2007, The World Bank, Washington, DC

PricewaterhouseCoopers (2007), *Revenue management Improvement Study for ECG and NED of VRA (Draft)*, February 2007, Accra

Embassy of Switzerland, Ghana (2007), *Ghana Energy Sector*, January 2007, Accra

Ghana Gazette, 29 September 2006, "Publication of Electricity Tariffs"

Chapter 4 Power demand forecast

4.1 Macroscopic demand forecast

In Ghana, the ECG supplies power to customers in the six southern regions, and the VRA-NED, to those in the four northern regions. Interviews with the two utilities found that each had its own procedure for forecasting demand. Upon adjustments, it was decided to make demand estimates for each ECG and VRA-NED feeder in line with these procedures.

This chapter sets forth the procedures and results of macroscopic demand forecasting for the ECG and VRA-NED.

Area	Region
ECG	Greater Accra Central Eatern Western Ashanti Volta
VRA-NED	Brong-Ahafo Northern Upper-East Upper-West

Land: 239,460km^2

Source: Prepared by JICA Study Team

Figure 4-1 ECG and VRA-NED supply areas

4.1.1 Outline of macroscopic demand forecasting

Macroscopic demand forecasts are made for various objectives. The major ones are as follows.

* Power generation plans

* Plans for transmission and distribution development

* Financial plans and tariff-setting

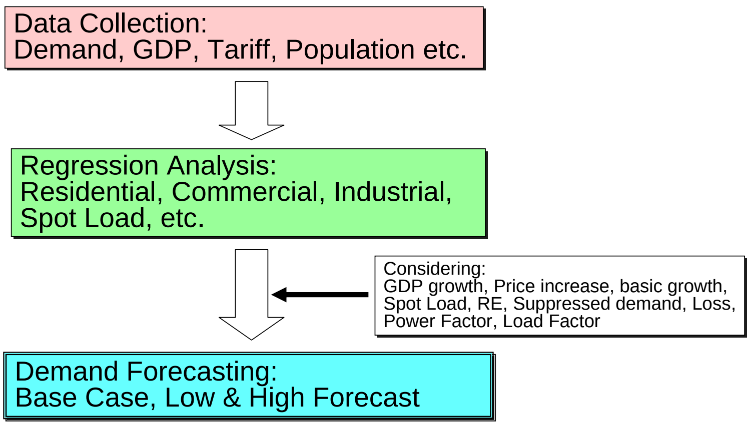
The key point in macroscopic power demand forecasting is to discern which elements affect and determine changes in the demand. The task lies in identifying the proper factors, and preparing relational equations and forecasting scenarios (consisting of base, low-demand, and high-demand cases) based on them.

Generally speaking, there are two major methods for estimating power demand. One is the econometric (macroscopic_ analysis) method, which is grounded in correlations with socioeconomic indicators and the past trend of the demand. The other is microscopic analysis proceeding "from the bottom upward," by making estimates for each component constituting the demand and adding up the results. Each has its strengths and weaknesses. For example, the former can be performed even with comparatively few types of data, but requires time-series data over the forecast period or even longer. In contrast, the latter requires a variety of detailed data for items forming preconditions, but does not need time-series data.

Medium- and long-term plans for distribution facilities basically apply macroscopic analysis because of the huge amount of facilities involved. Therefore, the studies regarding the expansion and reinforcement of existing distribution facilities are implemented through such analyses. Those regarding the installation of additional distribution lines for electrification, on the other hand, require consideration of the situation at each village covered, and consequently necessitate a microscopic analysis of information obtained from the village survey in addition to a macroscopic analysis.

The Study was based on the data and forecasting methods currently utilized by the ECG and the VRA-NED for various reasons, including the ease of obtaining data and constructing a demand forecasting model, ease of updating data and the model, and the fact that both companies already apply the econometric method.

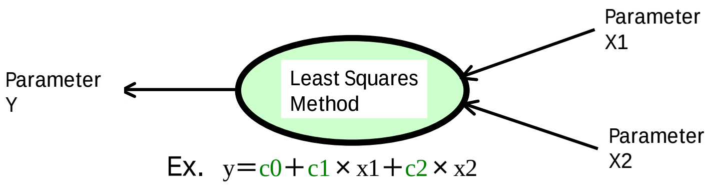
Figure 4-2 shows the basic flow of the macroscopic demand forecast.



Source: Prepared by JICA Study Team

Figure 4-2 Flow of the macroscopic demand forecast

The regression analysis is of the multiple type and confirms the relationship between the power demand and economic indicators (for items such as GDP, population, and power tariffs).



Ex. $y = c_0 + c_1 \cdot x_1 + c_2 \cdot x_2$

Data: $\left((x_1)_j, (x_2)_j, y_j\right) \quad (j = 1, 2, \ldots\ldots, M)$

Prediction: $c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j$ Real value: y_j

$$S = \sum_{j=1}^{M} \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]^2 \rightarrow \text{minimum}$$

$$\downarrow$$

$$\frac{\partial S}{\partial c_0} = 0 \qquad \frac{\partial S}{\partial c_1} = 0 \qquad \frac{\partial S}{\partial c_2} = 0$$

$$\frac{\partial S}{\partial c_0} = \underbrace{\frac{\partial S}{\partial \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]}}_{2\sum_{j=1}^{M} \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]} \cdot \underbrace{\frac{\partial \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]}{c_0}}_{1} = 0$$

$$\frac{\partial S}{\partial c_1} = \underbrace{\frac{\partial S}{\partial \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]}}_{2\sum_{j=1}^{M} \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]} \cdot \underbrace{\frac{\partial \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]}{c_1}}_{(x_1)_j} = 0$$

$$\frac{\partial S}{\partial c_2} = \underbrace{\frac{\partial S}{\partial \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]}}_{2\sum_{j=1}^{M} \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]} \cdot \underbrace{\frac{\partial \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right]}{c_2}}_{(x_2)_j} = 0$$

$$c_0 \cdot M + c_1 \sum_{j=1}^{M} (x_1)_j + c_2 \sum_{j=1}^{M} (x_2)_j = \sum_{j=1}^{M} y_j$$

$$c_0 \sum_{j=1}^{M} (x_1)_j + c_1 \sum_{j=1}^{M} (x_1)_j^2 + c_2 \sum_{j=1}^{M} \left\{ (x_1)_j \cdot (x_2)_j \right\} = \sum_{j=1}^{M} \left\{ (x_1)_j \cdot y_j \right\}$$

$$c_0 \sum_{j=1}^{M} (x_2)_j + c_1 \sum_{j=1}^{M} (x_2)_j \cdot (x_1)_j + c_2 \sum_{j=1}^{M} (x_2)_j^2 = \sum_{j=1}^{M} \left\{ (x_2)_j \cdot y_j \right\}$$

$$\downarrow$$

$$S = \sum_{j=1}^{M} \left[\left\{ c_0 + c_1 \cdot (x_1)_j + c_2 \cdot (x_2)_j \right\} - y_j \right] \rightarrow \text{minimum}$$

$$\downarrow$$

$$y = c_0 + c_1 \cdot x_1 + c_2 \cdot x_2$$

Source: Prepared by JICA Study Team

Figure 4-3 Outline of multiple regression analysis and relational equations

4.1.2 Economic indicators for Ghana

This section presents the trend of economic indicators generally used as parameters for power demand forecasting (i.e., population, gross domestic production, and power tariffs).

(1) Population

Ghana reportedly had a population of 21.03 million in 2005, but the last census was implemented in 2000, and it is hard to ascertain the exact yearly trend. To judge from the available data, the population is increasing at a rate of about 2.4 percent annually.

The statistics indicate that the respective shares of the total population occupied by urban and rural areas came to 43.76 and 56.24 percent in 2000, but the urban share is anticipated to outstrip the rural one beginning around 2010.

Table 4-1 Population

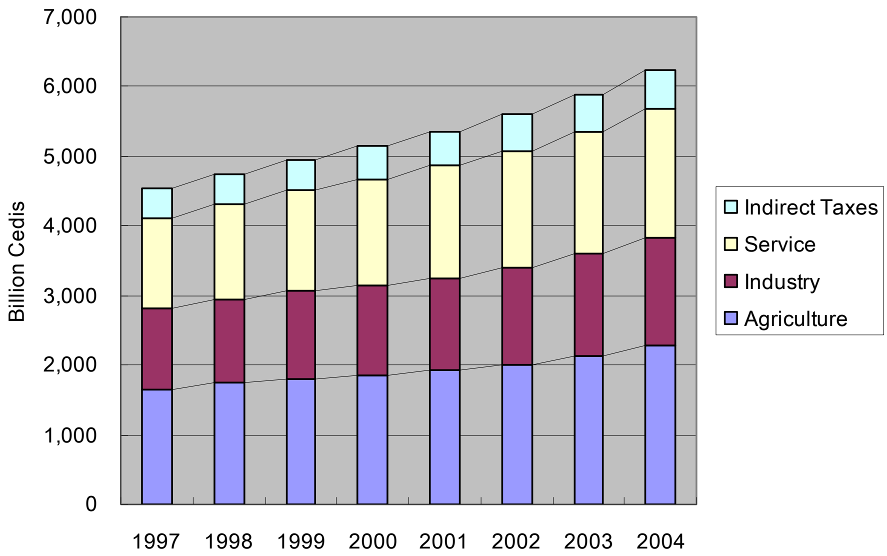
Population (million)

	1970	1984	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total	8.559	12.296		18.100		18.400	18.912		19.900	20.400		21.030
Growth Rate - %		2.60%		2.70%			2.40%					1.25%
Urban % Rural %			36.88% 63.12%				43.75% 56.25%					
Houses Households						4.210	2.182 3.701					

Source: Review of ECG’s Load Forecast Model, ECG

(2) Gross domestic product

In 2004, Ghana's gross domestic product came to about 6,237.8 billion cedi. The shares occupied by the industrial and service sectors are expanding, but the agricultural sector continues to hold the main share. The total product has been increasing at a rate of about 5 percent annually.



Source: Prepared by JICA Study Team

Figure 4-4 Gross domestic product

(3) Power tariffs

For power tariffs, it would not make any sense to compare net values because of the exchange rate influence. When the 2000 level is taken as the standard, however, tariffs increased at rates averaging about 10 percent annually over the ensuing five years. This rate presumably rose due to the recent jump in fuel prices.

Table 4-2 Power tariffs

ECG Average Electricity Price - Total Revenue - Cedi / kWh

	Category	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	'00 -'05 CAGR	'97 -'05
Nominal Price	Residential	37.4	33.0	37.5	98.1	144.9	170.8	284.6	455.4	677.2	733.3	733.3	33.83%	45.03%
	Commercial	51.3	47.8	54.3	179.2	286.6	281.9	498.9	671.7	982.0	1,063.3	1,063.3	30.41%	45.05%
	Industrial	50.3	49.6	52.8	145.0	188.9	215.6	397.4	566.1	711.6	738.3	738.3	27.92%	39.05%
	All	43.9	41.1	45.5	129.1	184.0	203.1	353.6	523.6	728.0	776.0	776.0	30.75%	42.56%
Real Price	Residential	283.0	170.5	144.1	300.6	394.7	371.9	466.2	649.7	762.7	733.3	638.2	11.41%	20.44%
2004 Cedis equiv.	Commercial	388.5	246.8	208.7	549.2	780.8	613.7	817.3	958.3	1,106.0	1,063.3	925.4	8.56%	20.46%
	Industrial	380.8	256.6	203.2	444.3	514.6	469.3	651.0	807.7	801.4	738.3	642.5	6.48%	15.48%
	All	332.3	212.2	175.0	395.6	501.2	442.2	579.2	746.9	819.9	776.0	675.4	8.84%	18.39%
Real Price Growth Rate	Residential	36.1%	-39.7%	-15.5%	108.6%	31.3%	-5.8%	25.4%	39.4%	17.4%	-3.9%	-13.0%		
	Commercial	-13.1%	-36.5%	-15.4%	163.1%	42.2%	-21.4%	33.2%	17.3%	15.4%	-3.9%	-13.0%		
	Industrial	-17.0%	-32.6%	-20.8%	118.6%	15.8%	-8.8%	38.7%	24.1%	-0.8%	-7.9%	-13.0%		
	All	1.1%	-36.1%	-17.5%	126.1%	26.7%	-11.8%	31.0%	29.0%	9.8%	-5.4%	-13.0%		
Residential Sales	MWh	1,126,759	1,222,326	1,287,194	1,182,139	1,318,821	1,403,891	1,551,873	1,613,460	1,660,344	1,752,637	1,867,549		
Total Sales	MWh	2,221,852	2,448,917	2,610,406	2,650,079	2,861,600	2,910,480	3,080,330	3,199,670	3,342,880	3,541,520	3,773,721		
Purchases	MWh	2,693,037	3,087,263	3,386,262	3,431,563	3,848,251	3,918,610	4,174,896	4,326,293	4,495,963	4,818,055	5,052,842		
Adj Purchases	MWh	2,693,037	3,087,263	3,386,262	3,563,711	3,848,251	3,918,610	4,174,896	4,326,293	4,495,963	4,818,055	5,052,842		

Source: Review of ECG's Load Forecast Model, ECG

(4) Preparation of a forecast scenario

Based on the trends described above, the Study Team prepared an explainable scenario for the power demand forecast upon a check of the corresponding scenarios of the ECG and the VRA-NED. As a result, it was decided to execute the demand forecast for each feeder upon adjustment of the scenarios on the two sides in line with the thinking at the ECG and the VRA-NED.

Table 4-3 Scenario for the power demand forecast (ECG)

	Base	Low	High
GDP	**2006-2008 6.0% growth 2009-2015 5.5% growth**	**2006-2008 5.0% growth 2009-2015 5.0% growth**	**2006-2008 6.5% growth 2009-2015 6.0% growth**
Price	**2006-2008 10% increase 2009-2015 5% increase**	**2006-2008 10% increase 2009-2015 5% increase**	**2006-2008 10% increase 2009-2015 0% increase**
Spot Load	**Forecasting each**	**Forecasting each**	**Forecasting each**
RE	**10MVA of new load each year**	**5MVA of new load each year**	**10MVA of new load each year**
Suppressed Demand	**3% of Residential Sales**	**3% of Residential Sales**	**3% of Residential Sales**
Losses	**Technical 10%-9.7% Commercial Same**	**Technical 10%-9.7% Commercial Decrease**	**Technical 10%-9.7% Commercial Increase**

Source: Review of ECG's Load Forecast Model, ECG

4.1.3 Macroscopic demand forecast at the ECG

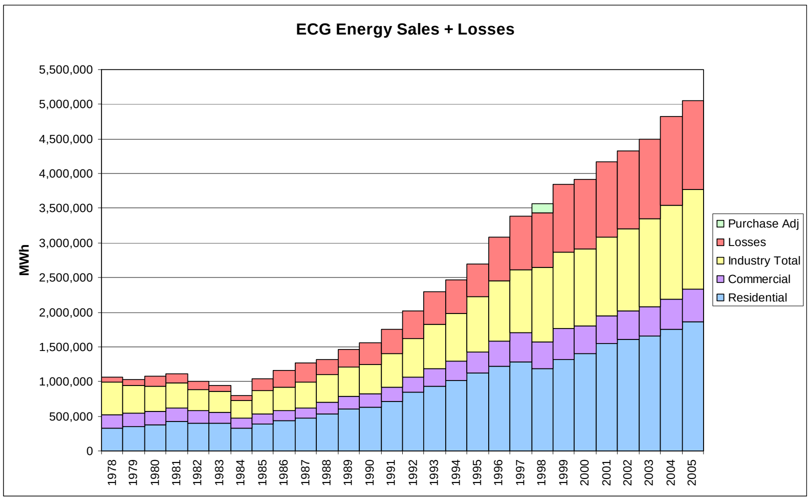
Of Ghana's ten regions, the ECG supplies power to six: Greater Accra, Volta, Central, Eastern, Western, and Ashanti. In 2004, it supplied a total of 4,818 GWh, which accounted for more than 90 percent of the power sales in the entire country.

Table 4-4 ECG and NED number of customers and power sales (2004)

Company	Customers	Purchase GWh
ECG	948,602	4,818
NED	188,344	340
Total	1,136,946	5,158

Source: Review of ECG's Load Forecast Model, ECG

Figure 4-5 shows the trend of ECG power sales from 1978 to the present (2005). Since 1994, the sales have been steadily increasing at rates of 6 or 7 percent annually.



Source: Review of ECG's Load Forecast Model, ECG

Figure 4-5 ECG power sales

The Study Team made a demand forecast based on the review of the ECG's load forecast model implemented in 2006.

Power demand is determined by several factors. The most influential are population growth, economic activities, and power tariffs. The relationship between these factors and the power demand can be checked with reference to historical data. The confirmed relationship (regression formula) is used to forecast the future demand. This is the substance of the econometric method.

In almost all countries, economic growth is the factor most related to increase in the power demand. Expressing the level of economic activity, the GDP is the most reliable and applicable indicator. Power tariffs, too, have a strong correlation with the demand. The basic equation is as follows.

$$D_i = K * GDP_i^{e} * P_i^{p} \qquad (1)$$

D_i: power demand
K: constant items
GDP_i: gross domestic product
P_i: power tariff
e: elasticity relative to the GDP
p: elasticity relative to power tariffs

Population growth is another factor that has a strong connection with the power demand, but it may not directly affect demand if the entire country is not electrified. To increase the forecast accuracy, the Study Team applied coefficients distinct from the GDP and power tariffs in place of population growth.

$$D_i = K * (1+g_b)^{i} * GDP_i^{e} * P_i^{p} \qquad (2)$$

g_b: growth coefficient distinct from GDP and power tariffs

To make a regression analysis, it is necessary to simplify the relational equations (i.e., to make them linear). The constant items can be eliminated (?) by division by the base year (Year 0) level.

$$D_i / D_0 = (1+g_b)^{i} * (GDP_i / GDP_0)^{e} * (P_i / P_0)^{p} \qquad (3)$$

Furthermore, division by the preceding year level produces a relational equation for the items of GDP growth rate and power tariff increase rate.

$$D_i / D_{(i-1)} = (1+g_b) * (GDP_i / GDP_{(i-1)})^{e} * (P_i / P_{(i-1)})^{p} \qquad (4)$$

There is also the following equation.

$$(1+g_{Total}) = (1+g_b) * (1+g_{GDP})^{e} * (1+g_P)^{p} \qquad (5)$$

g_{Total}: rate of demand increase
g_{GDP}: rate of GDP growth

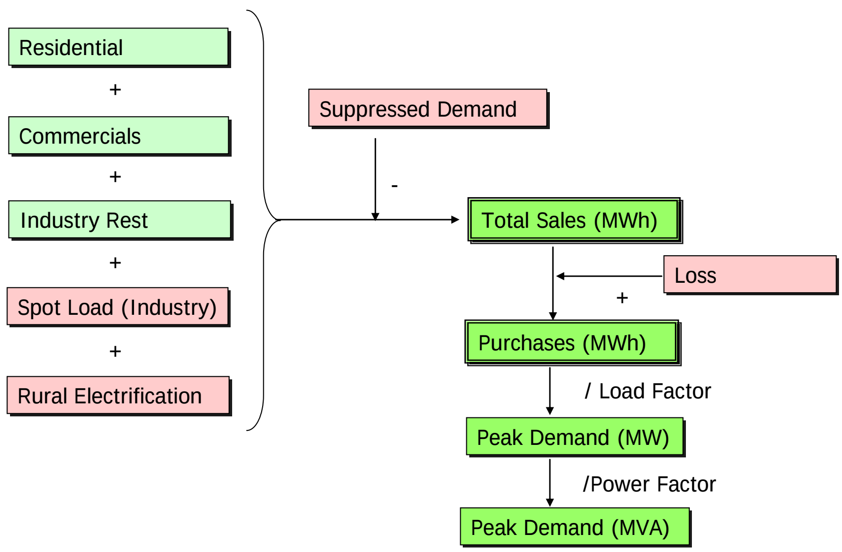
g_P: rate of power tariff increase

Equation 5 can be converted into a multiple equation by using the natural logarithm, as follows.

$$Ln(1+g_{Total})= Ln(1+g_b) + e*Ln(1+g_{GDP}) + p*Ln(1+g_P) \qquad (6)$$

The macroscopic demand forecast is made by performing a regression analysis using this equation.

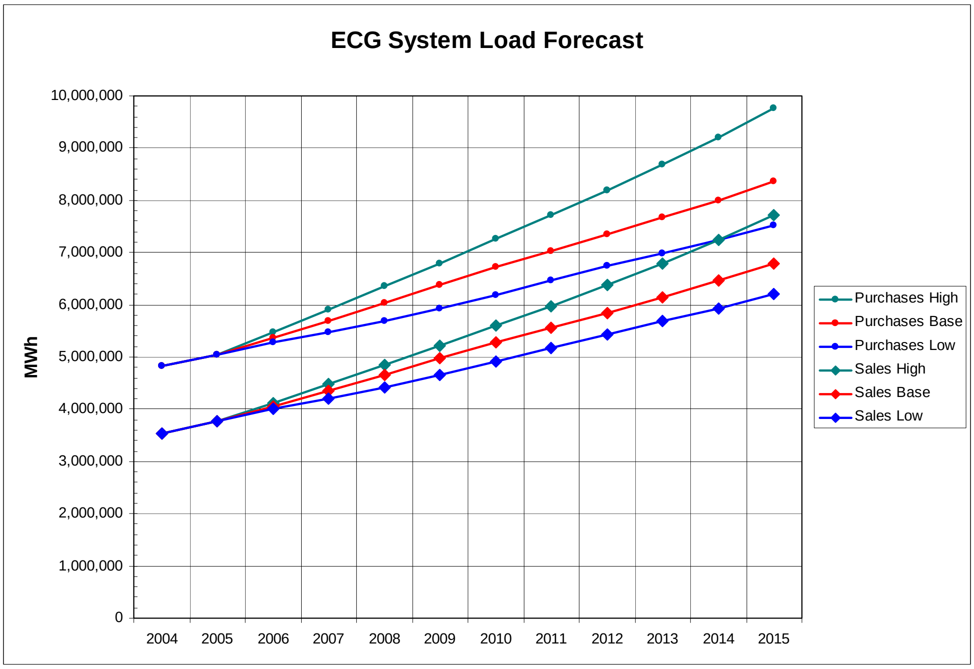
The ECG applies Equation 6 to separately forecast demand for the residential, commercial, and industrial divisions, by multiplying the demand in the preceding year by the growth rate (1 + gTotal). The result is adjusted with consideration of spot load (special industrial demand), RE, and demand suppression due to the impact of factors such as the low water level at the Akosombo dam.



Source: Prepared by JICA Study Team

Figure 4-6 Approach to power demand forecasting at the ECG

As a result, in the base case, the ECG is forecasting a demand increase rate of about 5 percent annually over the years 2005 - 2015.



ECG System Load Forecast : 2006 - 2015

Case		Units	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	'05 -'10 CAGR	'05 -'15
Base	Total Sales	MWh	3,541,520	3,779,003	4,058,112	4,358,830	4,658,177	4,971,559	5,283,936	5,558,530	5,847,195	6,143,993	6,456,432	6,785,365	6.93%	6.03%
	Total Purchases	MWh	4,818,055	5,052,842	5,362,963	5,697,094	6,029,702	6,377,905	6,721,255	7,022,291	7,338,602	7,663,579	8,005,526	8,365,359	5.87%	5.17%
	Peak Load	MW	801	877	914	956	1,012	1,055	1,112	1,145	1,197	1,250	1,306	1,364	4.87%	4.52%
Low	Total Sales	MWh	3,541,520	3,779,003	4,002,249	4,206,203	4,410,061	4,653,346	4,908,106	5,172,159	5,439,132	5,682,064	5,936,849	6,204,098	5.37%	5.08%
	Total Purchases	MWh	4,818,055	5,052,842	5,275,669	5,481,169	5,688,107	5,936,688	6,195,336	6,464,937	6,738,807	6,988,654	7,251,648	7,528,441	4.16%	4.07%
	Peak Load	MW	801	877	899	920	955	982	1,025	1,054	1,099	1,140	1,183	1,228	3.18%	3.43%
High	Total Sales	MWh	3,541,520	3,779,003	4,114,559	4,472,144	4,840,649	5,209,659	5,602,505	5,978,284	6,379,222	6,795,989	7,240,919	7,715,942	8.19%	7.40%
	Total Purchases	MWh	4,818,055	5,052,842	5,463,595	5,899,666	6,347,458	6,794,401	7,264,787	7,712,791	8,189,375	8,683,226	9,208,999	9,768,825	7.53%	6.81%
	Peak Load	MW	801	877	931	990	1,066	1,124	1,202	1,258	1,336	1,416	1,502	1,593	6.52%	6.16%

Source: Review of ECG's Load Forecast Model, ECG

Figure 4-7 Results of the ECG macroscopic demand forecast

4.1.4 Macroscopic demand forecast at the VRA-NED

At the VRA-NED, macroscopic demand forecasting is done not by external consultants but by the VRA-NED engineers themselves. The forecast is made through multiple regression analysis, by means of the following relational equation for the connection of the demand with population, GDP, and power tariffs.

$$P_L=a_0+a_1POP+a2TAR+a_3GDP+a_4LOSS$$

P_L: power demand

POP: population (number of customers)

TAR: power tariffs

GDP: gross domestic product

LOSS: loss rate

a_0: constant items

a_1: coefficient for POP

a_2: coefficient for TAR

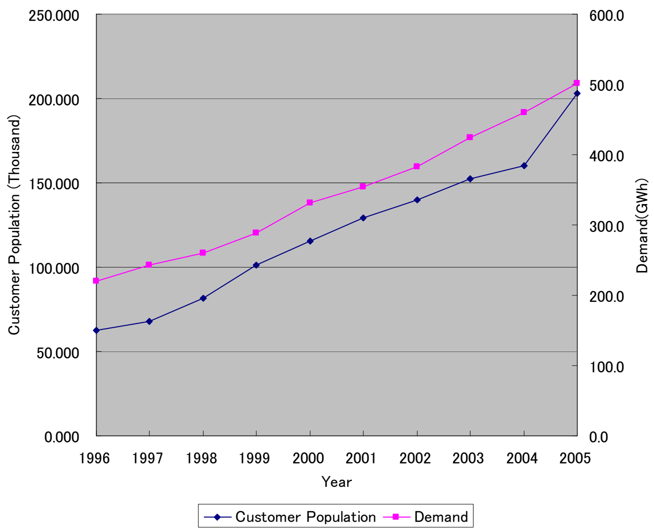
a_3: coefficient for GDP

a_4: coefficient for loss

Because there is no particular industry in the VRA-NED service area, the demand increase over the last ten years has been influenced by the SHEP and other RE projects. For this reason, the residential division has the majority share of power consumption at 63.5 percent, followed by the commercial division at 21.8 percent and the industrial division at 10.4 percent.

Measurements taken at the Techiman substation, which is the gateway to the VRA-NED service area, revealed that the peak power there is 83 megavolt-amperes (MVA) (power factor of 0.98 percent).

In the forecast of the VRA-NED demand, population increase exerts the biggest influence on demand growth. The number of customers in the NED area increased from about 60,000 in 1996 to 202,758 in 2005. The power demand underwent a corresponding increase from 220 to 502 GWh. Graphs show a virtually linear relationship between the two.



Source: Prepared by JICA Study Team

Figure 4-8 Relationship between number of customers and power demand

As in forecasting at the ECG, power tariffs are treated as a negative parameter because rate hikes act to reduce demand. The thinking is that a jump in power tariffs works not only to curtail power use but also to encourage development of energy-conserving technology.

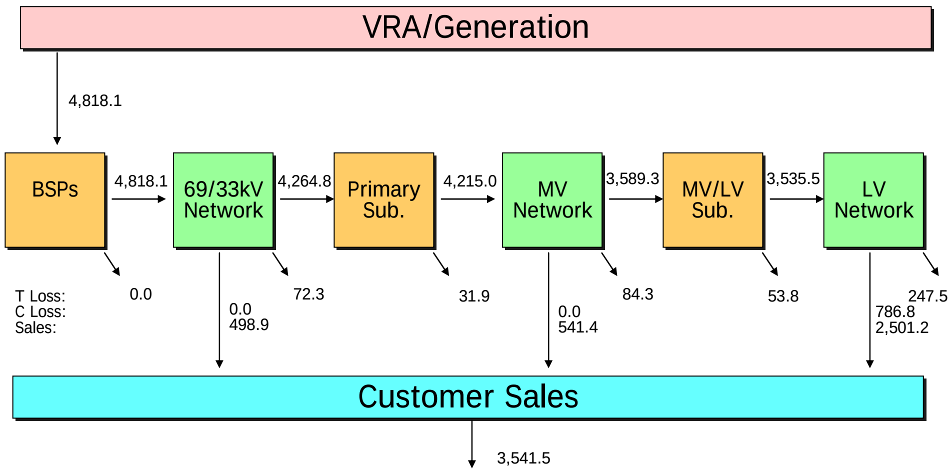
The GDP is treated as a factor supplementing population. The ECG forecast excludes the population parameter on the grounds that it will not have a direct influence on demand because not all areas have been electrified, and includes the GDP parameter in the demand forecast equations. In contrast, the VRA-NED takes account of both the population and GDP parameters on the rationale that inclusion of both in the forecast equations heightens the forecasting accuracy.

Table 4-5 Average error in ECG power forecast equations

Parameter	Average error（GWh）
Excluding GDP	5.974
Excluding population	13.608
Including GDP and population	5.548

Source: Prepared by JICA Study Team

In addition, the loss rate is included as a parameter in the forecast equation. It is considered a negative parameter, on the grounds that the demand would decline if it improved and increase if it didn't. There was discussion about whether to include the loss rate per se in the forecasting equation, and upon consultation with counterparts at the VRA-NED, it was decided to include it only after checking the average gap (error) between the results when included and when excluded.



Source: Prepared by JICA Study Team

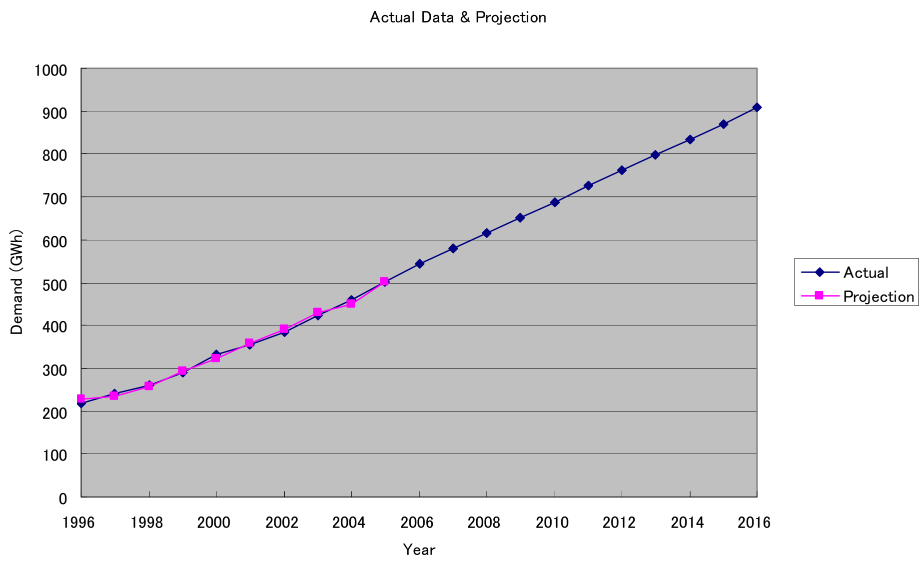
Figure 4-9 Makeup of power loss in Ghana

Table 4-6 Average error in VRA-NED power forecast equations

Parameter	Average error（GWh）
Excluding Loss rate	5.634
Including Loss rate	5.548

Source: Prepared by JICA Study Team

Like the ECG, the VRA-NED includes spot load (special industrial demand) in its equations for forecasting power demand. As a result, it is projecting an increase of 4 - 8 percent annually over the years 2006 - 2016.



Year	C.Pop. (Thousand)	Tariff (Cedi)	GDP ($)	Loss (%)	Energy (GWh)
2006	213	1,031	497	25	543
2007	232	1,155	545	25	580
2008	253	1,265	587	25	617
2009	273	1,367	623	25	652
2010	289	1,504	666	25	687
2011	308	1,646	708	25	727
2012	328	1,750	750	25	762
2013	346	1,873	790	25	798
2014	364	2,000	831	25	834
2015	383	2,128	873	25	871
2016	402	2,247	914	25	907

Source: Prepared by JICA Study Team

Figure 4-10 Results of VRA-NED macroscopic demand forecast

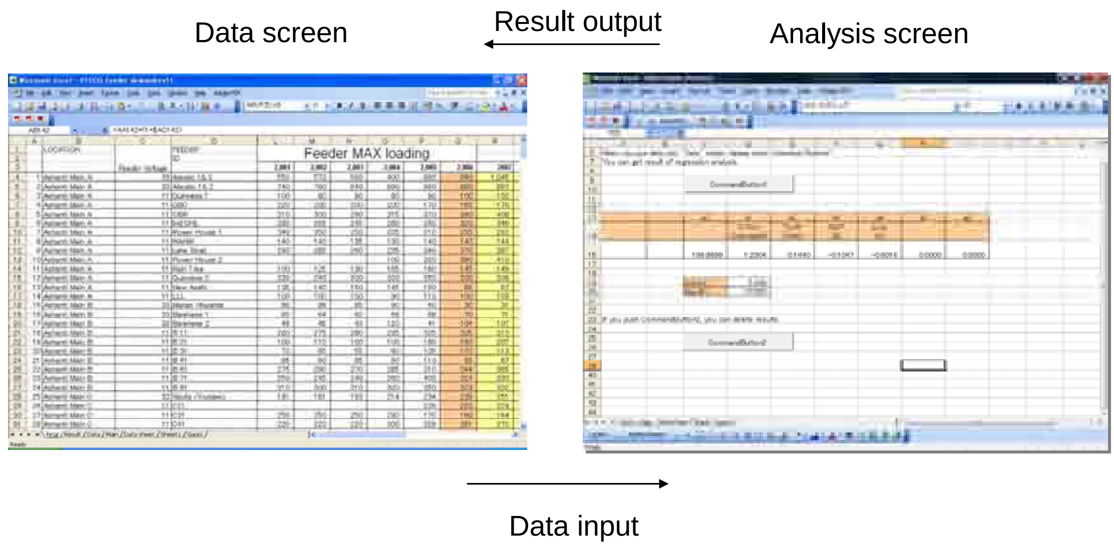
4.1.5 Demand forecast for each feeder

As described in the previous section, macroscopic demand forecasting by the econometric method utilizes the GDP growth rate, tariff increase rate, and other factors as variables, and essentially involves the preparation of separate forecasting equations for the residential, commercial, and industrial divisions.

Macroscopic demand forecasting for distribution plans requires forecasting for each substation to provide the basis for planning. In many cases, nevertheless, substation-specific demand data are not available.

In response to the absence of such data, the Study Team decided to estimate demand for each feeder by the aforementioned method, by regarding the substation current value over the last five years or so as equivalent to demand. Based on the scenarios indicated in Table 4-3, demand forecasts for “Base” case and “High” case were conducted in this study. In accordance with the result of “Base” case, the master plan was prepared. And the result of “High” case was utilized for the evaluation of the influence on the master plan of “Base” case.

As the ECG and the NED have more than 500 feeders taken together, the Study Team took steps to make the work more efficient by preparing simple analytical software using the Visual Basic for Applications (VBA) functions of Microsoft Excel, in cooperation with the counterparts.



Source: Prepared by JICA Study Team

Figure 4-11 Image of analytical software for macroscopic demand forecasting (Excel VBA)

In order to explain the procedure of “simple analysis software”, the demand forecast of ECG’s one feeder (Adoato 1&2) is shown in this report.

At first, the regression analysis is executed in accordance with previous demand data provided by Counter Parts. Parameters of prediction formula are “Year”, “Tariff”, and “GDP”. In the following table, the data for the regression analysis are indicated.

Table 4-7 Data for the regression analysis of "Adoato 1&2" feeder

	Adoato 1& 2 33kV	Price	GDP
Unit	A	Cedi/kWh	Bil. Cedi
2001	550	579	5,357
2002	570	747	5,601
2003	560	820	5,895
2004	400	776	6,238
2005	860	675	6,600
2006	960	743	6,996
2007	984	817	7,415

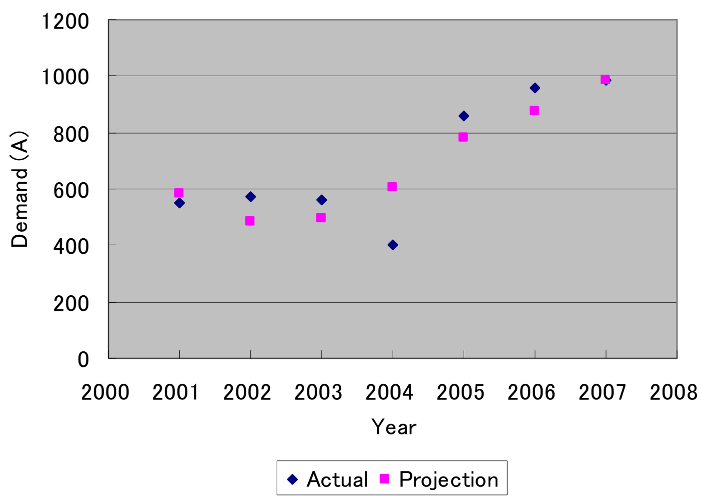
Source: Prepared by JICA Study Team

In case of ECG demand forecast, the following formula is adopted for projection.

$$Ln(Di) = c_0 + c_1 * Year + c_2 * Ln(Pi) + c_3 * Ln(GDPi)$$

Di : Demand (Current)	c_0 : Constant item
Year : Year	c_1 : Coefficient for Year
Pi : Tariff	c_2 : Coefficient for Pi
GDPi : Gross Domestic Product	c_3 : Coefficient for GDPi

As the result of "Adoato 1&2" feeder, C0=1084.42, C1=-0.593, C2=-0.714, and C3=13.325 are provided. Following chart shows the comparison between actual data and projection data. Average error is around 2% of the current.



Source: Prepared by JICA Study Team

Figure 4-12 Comparison between Actual Data and Projection Data

At last, in accordance with the result of the regression analysis, demands from 2008 to 2017 are calculated.　For example, calculation of 2017 case is shown below:

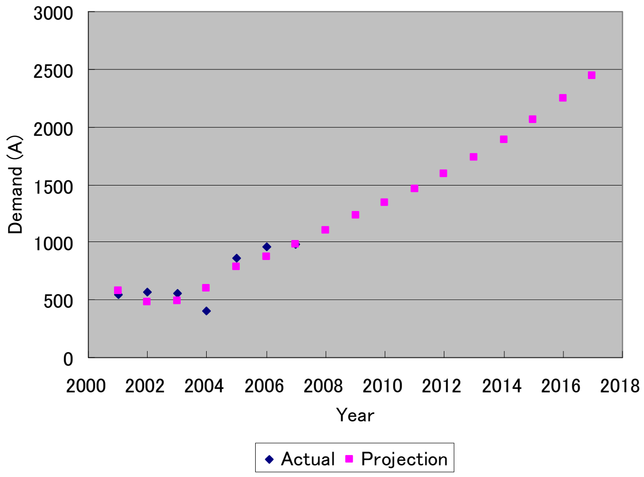
In case of 2017, Pi=1,461, GDPi=12.787.

$$Ln(Di) = c_0 + c_1*Year + c_2*Ln(Pi) + c_3*Ln(GDPi)$$

$$= 1084.42 - 0.593*2017 + 0.714*1{,}461 + 13.325*Ln(12.787)$$

$$= 7.800$$

$$Di = Exp\ (7.800) = 2{,}441$$



Source: Prepared by JICA Study Team

Figure 4-13　Projection by the regression Analysis

Table 4-8 Projection by the regression Analysis

	Actual	Projection	Price	GDP
Unit	A	A	Cedi/kWh	Bil. Cedi
2001	550	582	579	5,357
2002	570	485	747	5,601
2003	560	495	820	5,895
2004	400	605	776	6,238
2005	860	782	675	6,600
2006	960	877	743	6,996
2007	984	984	817	7,415
2008		1,103	899	7,860
2009		1,237	989	8,332
2010		1,347	1,038	8,790
2011		1,466	1,090	9,274
2012		1,596	1,145	9,784
2013		1,738	1,202	10,322
2014		1,892	1,262	10,889
2015		2,060	1,325	11,488
2016		2,242	1,391	12,120
2017		2,441	1,461	12,787

Source: Prepared by JICA Study Team

In case of NED demand forecast, the procedure of projection is same as ECG case.

Table 4-9 presents some of the results of the demand forecast for each feeder. The results for all feeders are contained in the Appendix 4.1.1 and 4.1.2.

Table 4-9 Results of demand forecasting for each feeder (example)

VOLTA RIVER AUTHORITY
Northern Electricity Department

Maximum Demand (2007) and Forecast Maximum Demad (2017) at Bulk Supply Points

Location	Feeder ID	Length (Km)	Conductor Type(sq. mm)	2007 S (MVA)	2008 S (MVA)	2009 S (MVA)	2010 S (MVA)	2011 S (MVA)	2012 S (MVA)	2013 S (MVA)	2014 S (MVA)	2015 S (MVA)	2016 S (MVA)	2017 S (MVA)	Growth rate %
SAWLA															
Damongo	38F4Y	84.00	150AAC	0.71	0.73	0.76	0.79	0.82	0.85	0.88	0.91	0.95	0.98	1.02	3.75%
Sawla Town	38F5Y	4.50	50 AAC	0.23	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.31	0.32	0.33	3.75%
Bole	38F3Y	25.20	150AAC (22Km), 50AAC(3.2km)	0.49	0.51	0.53	0.55	0.57	0.59	0.61	0.63	0.66	0.68	0.71	3.75%
Lawra/Soboo/Erimon	WAF1Y	31.2 from Domwine	150AAC	5.26	5.46	5.66	5.87	6.09	6.32	6.56	6.80	7.06	7.32	7.60	3.75%
Jirapa/Nadowli/Kaleo	WAF1Y	47.9 from Wa	150AAC	0.64	0.66	0.69	0.71	0.74	0.77	0.80	0.83	0.86	0.89	0.92	3.75%
Nandom/Hamile	WAF1Y	77.1 from Nadowli	150AAC	1.13	1.17	1.22	1.26	1.31	1.36	1.41	1.46	1.52	1.57	1.63	3.75%
Wa F1	479BF1	5.90	95XPLE(0.6km), 50AAC(5.3km)	1.42	1.49	1.56	1.63	1.71	1.78	1.87	1.95	2.04	2.14	2.24	4.61%
Wa F2	479BF2	11.60	100AAC(4.4km), 50AAC(3.7km), 120AAC(3.5km)	1.10	1.14	1.18	1.22	1.27	1.31	1.36	1.41	1.46	1.52	1.57	3.66%
Wa F3	479BF3	3.72	95XPLE(0.12km),50AAC(3.6km)	1.61	1.69	1.77	1.85	1.94	2.04	2.14	2.24	2.35	2.46	2.58	4.84%
TOTAL (Sawla S/S)				7.23	7.50	7.78	8.07	8.37	8.68	9.01	9.35	9.70	10.06	10.44	3.75%

Source: Prepared by JICA Study Team

4.2 Village Power Demand Study and Microscopic Demand Forecast

4.2.1 Village Power Demand Study

Power demand forecast is required to pay attention not only to the supply side of power but also to the demand side. It is necessary to ascertain transition of power demand by identifying the circumstances of customers. The Study Team, therefore, carried out a socio-economic survey to collect basic data for power demand forecast. The southern regions[1] were surveyed in this study, while information collected and analyzed in the "Master Plan Study on Rural Electrification Using Renewable Energy Resources in the Northern Part of the Republic of Ghana" (hereinafter referred to as "Renewable Energy Master Plan Study") were utilized for the northern three regions. The survey aims to gather and analyze data of socio-economic situations focusing on electricity and energy issues.

The following points are highlighted in the socio-economic survey.

1) Is electrification really necessary? (Relevance)
   Life pattern in the surveyed areas, the level of electricity needs compared with other livelihood needs, the level of various development and economic activities, etc.

2) What kind of electrification system and scales are appropriate? (Efficacy)
   Electric appliance use in the electrified households, etc.

3) What kind of impact will electrification have? (Impact)
   Social and economic change caused by electrification, customers' perception on the change, etc

4) Are there any problems as regards payment for electricity use? (Sustainability)
   Payable amount based on energy-related expenditures, relationship between electric appliances people want to buy and their disposable income, and capability of operation and maintenance of electrification system, etc.

This socio-economic survey utilized secondary data including available statistical documents and various reports and information obtained by interviews from relevant authorities to understand general socio-economic situations at the regional level because of the constraints of time and budget in the survey. On the other hand, 100 communities were sampled to investigate socio-economic situations at the community level, and questionnaire survey was carried out for households and facilities of each community. This socio-economic survey was recommisioned to the local consultant[2].

(1) Understanding of situations based on secondary data

In addition to the information collected by Renewable Energy Master Plan study, "2000 Population & Housing Census of Ghana: Demographic, Economic and Housing Characteristics" by Ghana

[1] In this study, the southern regions are Brong Ahafo, Greater Accra, Eastern, Volta, Central, Western and Ashanti.
[2] The socio-economic survey was recommissioned to "New Energy" based in Tamale.

Statistical Service 2005 was utilized to understand the general socio-economic conditions of each region.

(2) Outline of Village Power Demand Study

The socio-economic survey was carried out to collect detail information of villages. The outline was described below.

Table 4-10 Outline of Village Power Demand Study

1. Questionnaire survey
(1) Objective Collection of socio-economic data, both quantitative and qualitative, related to electricity and energy demand from households, public facilities, and commercial facilities. (2) Scope The survey will sample about 20 in each community. Out of 20 samples, 14 households, 3 public facilities and 3 commercial facilities are expected, but the number can vary according to the scale of villages and number of households and facilities. Residences in rural areas are usually in the form of compounds bringing together multiple households in a single site. The survey, however, focuses on economically independent groups rather than on compounds. Public facilities are facilities constructed and operated by public finance, including schools, health and medical facilities, water supply facilities, community centers, government facilities, markets, automobile/ bus stations, and street light. Commercial facilities include grocery stores, restaurants, lodging facilities, grain mills and household handicraft facilities. Industrial plants and other large-scale commercial facilities are not surveyed. The sample households in each community were selected at fixed distances from the starting points which are randomly fixed. The distances were calculated according to the total number of households. The public and commercial facilities were selected at random. (3) Survey item 1) General information Family structure, construction materials of houses, occupation of the head, etc. 2) Information related to electricity and energy Knowledge on electrification, lighting fixtures and expenses, use of electric appliances, problems in power use, and payable amount, etc.

2. Focus Group Discussion (FGD)
(1) Objective FGD aimed to collect more detailed qualitative data that would be hard to obtain through the questionnaire survey. Guidelines for FGD were prepared in advance, and FGD were carried out in accordance with the guidelines in principle. However, adjustment were made according to answers and responses of interviewees, namely change of question sequence, and modification, deletions and additions of questions. In particular, the survey aims to identify 1) communities' actual perception on, expectation of, and necessity of electrification, 2) energy consumption and operation and maintenance capability of community. (2) Scope 15 were selected for FGD out of 100 communities. Each group consists of about 10 members in various positions, including community heads, community assembly members, representatives of women's groups, representatives of youth groups, teachers, religious leaders, representatives of water management committees, farmers and merchants. (3) Survey item 1) General information Population, number of compounds, density of compounds and facilities, typical daily activity patterns of residents, presence/absence of public and commercial activities, presence/absence of community organization, presence/absence of community development project, necessary service, etc. 2) Information related to electricity and energy Knowledge on electrification, problems in power use, reason for lack of electricity, effect of electrification, and payable amount, etc.
3. Key Informant Interview (KII)
(1) Objective KII aimed to collect more detailed qualitative data. KII were carried out based on the guidelines in principle, but some adjustments were made as in FGD. (2) Scope Chiefs, community/ district assembly members, etc. (3) Survey item Needs for electrification, effects of electrification, problems of operation and maintenance of electricity facilities, relationship with strategies in the field of education, health and medical facilities.

Questionnaires for households and public/ commercial facilities are attached to Appendix 4.2.1 and 4.2.2. Questionnaires for community profile were Appendix 4.2.3. Some questionnaires are modified between electrified and un-electrified communities.

(3) Procedures of Village Power Demand

Sample villages were selected in accordance with the following procedures.

1) Determination of the number of sample communities

Due to the budget and time constraints, the socio-economic survey aimed to understand general situations of the southern regions of Ghana, and the number of sample were estimated about 100.

The following equation to determine statistically significant number indicated that desirable sample number was 96 taking into account the total number of 82,083 of communities in the southern regions (Population Censes in 2000). 100 samples, therefore, can be considered appropriate to identify general situations.

$$n = \frac{N}{\left(\frac{\varepsilon}{K(\alpha)}\right)^2 \frac{N-1}{P(1-P)} + 1}$$

α : the probability (risk) of miss-estimation of the population characteristics value = ordinary 5 % = $K(\alpha)$ in this case =1.96

ε : margin of plus-or-minus error in the sampling ratio; a figure of plus-or-minus 10% was adopted in this survey because one in excess of 10% makes it difficult to perform a comparative analysis with sufficient certainty.

n : requisite number of samples

N : size of the host population

P : population ratio; share of the communities representing the socio-economic status in the southern regions in host population. To prevent the number of samples from becoming too small, the Study Team applied one of 50% to maximize the P(1-P) value (0.5 x 0.5 = 0.25)

2) Selection of target regions

As a next step, the number of sample communities is allocated according to the relative share of the population of 7 regions.

Region	Number of Communities
Brong Ahafo	12
Greater Accra	20
Eastern	14
Volta	10
Central	10
Western	12
Ashanti	22

2 districts are selected in each region which can represent the cultural, economic and social conditions of the region based on hearings from regional government and other information.

3) Sampling of communities

Sample communities were selected at random from 2 districts in each region. Electrified and un-electrified communities were classified in selecting process to prevent imbalance of samples. Balance of population size and community scale was also taken into account based on the 2000 Population Census.

Sample communities are listed in Appendix 4.2.4. 14 households and 6 commercial and public facilities were selected in each region. The sample accounted for 1,412 households (642 un-electrified, 770 electrified) and 593 commercial and public facilities (un-electrified 256, electrified 337).

(4) Methodology of the Survey

The socio-economic survey was carried out from May to July 2007. The survey consisted of questionnaire survey, FGD, and KII. The respondents to the questionnaire survey are indicated below.

Table 4-11 Number of respondents to the questionnaire survey

District	Un-electrified	Electrified
Atebubu Amantin	44 (6.9 %)	57 (7.4 %)
Ga West	56 (8.7 %)	84 (10.9 %)
Dangme West	61 (9.5 %)	83 (10.8 %)
Afram Plains	42 (6.5 %)	56 (7.3 %)
Keta	28 (4.4 %)	42 (5.5 %)
Krachi	28 (4.4 %)	42 (5.5 %)
Mfantsiman	14 (2.2 %)	42 (5.5 %)
Ajumako	55 (8.6 %)	28 (3.6 %)
Mpohor Wass East	28 (4.4 %)	28 (3.6 %)
Ahanta West	56 (8.7 %)	56 (7.3 %)
Offinso	73 (11.4 %)	84 (10.9 %)
Akuapim North	42 (6.5 %)	56 (7.3 %)
Tano South	42 (6.5 %)	28 (3.6 %)
Kwabre	73 (11.4 %)	84 (10.9 %)
TOTAL	642 (100 %)	770 (100 %)

Source: JICA Study Team

(5) Survey Result Regarding Relevance of Electrification

While it makes life more convenient, electricity, unlike food and water, is not considered essential for the life. Consequently, relevance of electrification cannot be considered high if electric appliances are not so important in the context of the prevailing life patterns, if needs for electricity are lower than those for others, or if development and economic activities requiring electricity are not active. In this section, data on relevance of electrification are analyzed.

1) Current status of residents’ livelihoods and facility activities

a) Livelihoods of local residents

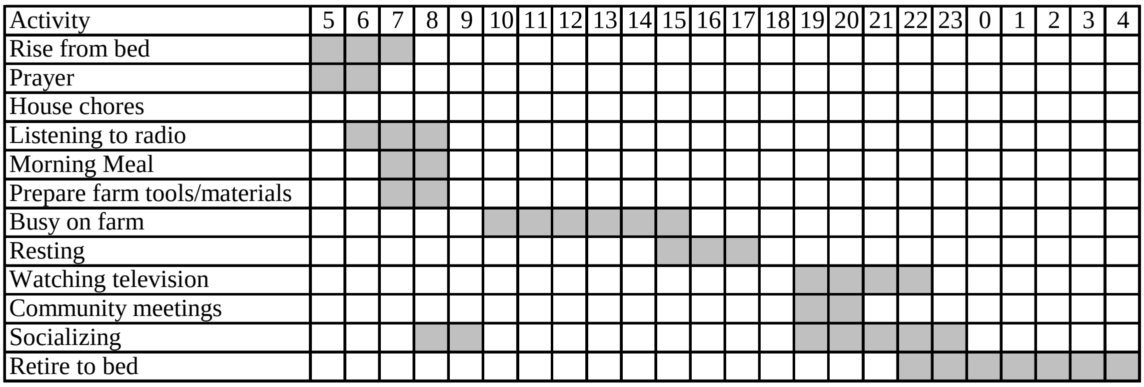
In the questionnaire survey, there is significant difference in residents’ occupations (income generating means) between un-electrified and electrified communities. In particular, farmers in the un-electrified communities accounts for 61.2%, while those in the electrified communities are 30.1%, and namely the difference is more than double. Government official/employee also indicates the similar tendency, 11.9% in the un-electrified communities and 4.4% in the electrified communities. The similar pattern can be observed for residents engaging in commercial activities (businessman/trader) and artisan self employed. Thus, certain correlation can be observed between the electrification status of communities and the occupations of residents. Major occupations found in the surveyed communities are indicated in the next table.

Table 4-12 Occupations in the surveyed communities

Occupation of the household head	Electrified	Un-electrified
Government official/employee	11.9%	4.4%
Artisan self employed	14.2%	6.4%
Businessman/trader	21.4%	10.7%
Farmer	30.1%	61.2%
Fisherman	5.6%	6.1%
Labourer / unskilled worker	1.7%	1.4%
Other	14.8%	9.2%
Unknown	0.3%	0.6%

Source: JICA Study Team

The daily life pattern varies due to the regional tradition and culture, religion, and occupations. The socio-economic survey attempted to ascertain the general life pattern through FGD. The next figures demonstrate the typical activity patterns in ordinary households.



(Source) JICA Study Team

Figure 4-14 Activity pattern of males in ordinary households

Activity	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4
Rise from bed	■	■																						
Prayer	■	■																						
House chores		■	■	■																				
Listening to radio																								
Cooking morning meal		■	■																					
Morning Meal			■	■																				
Prepare farm tools/materials						■																		
Busy on farm						■	■	■																
Resting															■	■	■							
Watching television																								
Community meetings																								
Cooking evening meal														■	■	■								
Socializing/house chores			■	■																				
Retire to bed																			■	■	■	■	■	■

(Source) JICA Study Team

Figure 4-15 Activity pattern of females in ordinary households

Adult males in rural communities tend to engage in activities outside the houses and compounds, while females in general engage in house-keeping and socializing activities inside the houses and compounds. The times when electricity is the most likely to be used are early morning and nighttime. The activities include prayer sessions for a few hours from 5:00 a.m., preparation for cooking at night, and socializing activities before bedtime. TV watching and radio listening also require electricity, but the penetration of TV is not as high as 20 – 40% and radios are usually powered by batteries. During the daytime, people usually work in their farm lands or other outside locations, thus their needs for electricity are low.

Considering the life pattern of ordinary households, the electricity needs are identified for increasing convenience of livelihoods and for entertainment, when using light for 6 hours in the morning and evening, listening to radios for 6 hours, and watching TV for 4 hours per day. The result is similar to that of Renewable Energy Master Plan Study.

Many people in rural areas engaged in farm activities and ratio of those engaging subsistence farming were high. Such situation indicates that cash income of the residents is so limited that their payment capacity for electricity tariff is insufficient. At the same time, there are also some households engaging in economic activities on a regular basis, in particular affluent households in the vicinity of urban areas. For such households, the needs for electric appliances other than light and TV sets can be considered high.

b) Economic activities of commercial facilities

A typical activity pattern of general goods stores whose sample number is significant are indicated as follows.

Activity	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4
Shop opens for business			■	■	■	■	■	■	■	■	■	■	■	■										
Shop closes at sun down														■	■	■	■	■	■	■	■	■	■	■
Busy time			■	■						■	■	■	■	■										

(Source) JICA Study Team

Figure 4-16 Activity pattern of general goods stores

General goods stores are in general open for about 12 hours, operating from 7 a.m. to 6 or 7 p.m. Although some were open till late at night, many were closed associated with the sunset. It is enough to supply for a few hours at night if electricity use was confined to lighting. On the other hand, facilities using refrigerators and freezers, such as bars and cold stores, are expected to consume more electricity.

c) Activities of public facilities

General activity patterns of public facilities, in particular secondary schools and clinics, are indicated in the following figures.

Activity	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4
School opens			■																					
Cleaning			■																					
Classes in progress				■	■	■	■	■	■															
Recreation and rest break									■															
Classes in progress										■	■	■												
Sporting activities											■	■												
Closing												■												
Evening classes/Adult literacy classes															■	■	■							

(Source) JICA Study Team

Figure 4-17 Activity pattern of secondary schools

Activity	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4
Clinic opens				■	■																			
Consultation and treatment				■	■	■	■	■	■	■	■	■	■											
Health education and counseling															■	■								
May open after hours to deal with emergencies														■	■	■	■	■	■	■	■	■	■	■

(Source) JICA Study Team

Figure 4-18 Activity pattern of clinics

Secondary schools are typically open from 8 a.m. to 5 p.m. Sporting activities are conducted for about 2 hours in the afternoon. In the daytime, classes can be held with natural lighting from outside through windows, thus needs for lighting and other electric appliances in the daytime are not very high. In contrast, there are higher needs for electrical lighting for classrooms that are used at night for study by students in higher grades or for adult literacy classes.

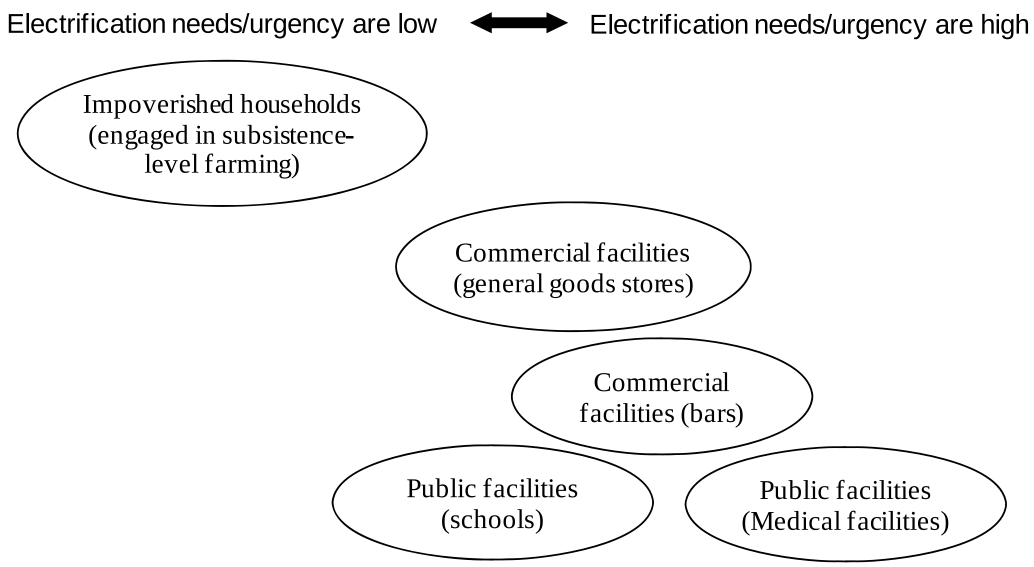
Clinics and other medical facilities are usually operated from 8 a.m. to 6 p.m. For medical facilities, it is not recommended to open the windows even during the daytime because of health reasons. Electrical lighting is essential for ordinary care at night or for coping with emergencies such as childbirth. Furthermore, the needs for electricity are also extremely high for storage of vaccine and blood, storage of bodies, and wireless communications with higher level medical institutions.

Religious facilities have higher needs for electricity during praying time. However, hours of electricity use are fairly short for lighting, cassette players, microphones and speakers. The questionnaire survey revealed that kerosene lamps are widely used for lighting at night (61% of respondents to the questionnaires).

The result of this survey in general can be considered in line with the result of Renewable Energy Master Plan Study.

d) Wrap-up

Electricity needs and urgency by facilities are described in the following figure.



(Source) JICA Study Team

Figure 4-19 Need for electrification by each facility category

In light of the current life and activity circumstances, it is practical to promote electrification from the areas marked by the highest needs and urgency. In particular, households in rural communities do not have enough capacity to pay tariffs on a regular basis because they have limited means of income generation. In contrast, relevance of electrification is considered stronger for affluent households with a regular income and households living in urban areas that are strongly aware of the convenience of electricity and thus presumably have higher motivation for electrification. As for commercial facilities, needs for electrification vary according to facility type. Facilities with refrigerators and freezers have higher needs, while general goods stores do not. The electrification of public facilities should be given high priority because the public facilities are expected to bring broader benefit to many users.

The result observed in the socio-economic survey is similar to that of Renewable Energy Master Plan Study. It can be concluded that there is not significant difference in needs for electricity by facility between the northern 3 regions and the southern regions, though a certain difference was observed due to the cultural, social, and religious difference.

2) Needs of residents

There are a variety of needs for livelihoods other than needs for electricity. The priority of such needs can vary according to the categories of households and facilities. When electricity has lower priority than other items and services, relevance of electrification will also become lower. In such case, it will be extremely difficult to recoup the initial investment in the form of tariffs. It is, therefore, important to make full surveys and investigations of actual needs for electricity in preparation of the master plan.

a) Needs of ordinary households

Needs ranking by the questionnaire survey and FGD are the following.

Table 4-13 Household Needs Ranking by Electrification Status

Needs	Un-electrified	Electrified
House ownership	93 (15 %)	146 (19 %)
Good educational services and facilities	129 (20 %)	150 (20 %)
Public transport	9 (1.4 %)	13 (1.7 %)
System for getting clean water	53 (8.3 %)	71 (9.3 %)
Irrigation	14 (2.2 %)	10 (1.3 %)
Roads, bridges, and other infrastructure	51 (8 %)	24 (3.1 %)
Good electricity	139 (22 %)	64 (8.3 %)
Good health services and facilities	77 (12 %)	87 (11 %)
Latrines	14 (2.2 %)	31 (4 %)
Job opportunities	56 (8.7 %)	158 (21 %)
Other	6 (0.9 %)	13 (1.7 %)
TOTAL	641 (100 %)	767 (100 %)

(Source) JICA Study Team

The top 5 needs as regards goods and services in the un-electrified communities are 1) electricity; 2) good educational services and facilities; 3) house ownership; 4) good health services and facilities; and 5) job opportunities. For the electrified communities, they are 1) job opportunities; 2) good educational services and facilities; 3) house ownership; 4) good health services and facilities; and 5) system for getting clean water.

The needs for “good educational services”, “house ownership” and “good health service” were very strong regardless of the electrification status. Renewable Energy Master Plan Study demonstrates the similar tendency. This is because education, health care and housing are basic human needs (BHN) indispensable for life.

In the un-electrified communities, the first priority was electrification. Compared with the result of Renewable Energy Master Plan Study, communities in the southern regions presumably have stronger expectations for livelihood improvement by electrification.

b) Needs of public facilities

Medical and educational facilities requiring high-level electric appliances have been almost electrified. These facilities are usually located in the electrified areas such as cities since these facilities cannot function without electricity. In addition, the Ministry of Education is now promoting electrification for the diffusion of ICT (Information and Communication Technology) on the district level. Such policy can be a factor for high rate of electrification. The lower-level medical and educational facilities located in rural areas, on the other hand, have not yet been electrified, and thus, electrification can be justified.

Furthermore, the needs for electrification of staff houses attached to medical and educational facilities are high. Electrification is critical for various works within the houses (e.g. research of educational materials by teachers) or for the increase in the motivation of staff from urban areas by providing convenience and comfort. Electrification of these houses can be, therefore, justified.

c) Development and economic activities

If communities have extensive development and economic activities requiring electricity, they presumably have higher electrification needs that would drive the diffusion of electricity.
FGD identified various development and economic activities in the sampled communities. A variety of activities are carried out by various entities including community development committees, committees for infrastructure construction, self-help groups, and associations of agriculture and fishery.

Major development activities are construction of educational facilities and provision of school feeding service, construction of medical facilities, construction and installment of water supply systems (e.g. wells), construction of irrigation facilities, installation of latrines, and construction of roads. Economic activities include agriculture, fishery, grain milling, food processing and restaurant.

In the context of needs for electricity, water pumping of wells and irrigation facilities, and lights and refrigerators of medical facilities require high amount of electricity among development activities. Electrification can be considered to contribute to these development activities. In contrast, economic activities will require less electricity at the moment. However, electric motors are utilized for grain milling, and, thus, there are certain electricity needs in economic activities.

As indicated above, relevance of electrification can be considered high in terms of public facilities. However, the relevance is not so strong for general economic activities at present, though some facilities such as grain mills have higher needs.

(6) Survey Result Regarding Efficacy of Electrification

When electrification is found to be justified, it is necessary to consider the appropriate capacity of electricity facilities. Types and hours of use of electric appliances can be an indicator to forecast present and future power demand. Preference of residents for electricity should also be taken into account. In the southern regions, off-grid photovoltaic (PV) system is rarely introduced, thus the survey focused on the on-grid electrification system.

1) Use of electric appliances at households

Identifying type of electric appliances used in electrified households and hours of use of the appliances implies the appliances that people would or could purchase after electrification, and consequently contributes to power demand forecast. Electric appliances used in the sampled households and hours of the use are indicated in the table below. Some households in the un-electrified communities have small-scale generators for electricity, and own radios and other appliances that can work by batteries.

Table 4-14 Use of Electric Appliances

Appliance	Un-electrified Communities			Electrified Communities		
	Number	Penetration	Use Hours	Number	Penetration	Use Hours
Small colour TV	12	2%	3.8	156	20%	3.9
Big colour TV	13	2%	4.3	175	23%	4.1
Black and white TV	34	5%	3.5	36	5%	3.6
VCR/VCD player	10	2%	2.8	145	19%	3
Radio	437	68%	8.4	392	51%	7.4
Stereo (including Radio)	161	25%	5.8	270	35%	5.5
New small refrigerator	1	0%		87	11%	15
Old small refrigerator	0	0%		42	5%	15.8
New big refrigerator	0	0%		49	6%	12
Old big refrigerator	0	0%		18	2%	15.2
New small deep freezer	0	0%		20	3%	12.6
Old small deep freezer	0	0%		9	1%	13.8
Old big deep freezer	1	0%		11	1%	16.5
New big deep freezer	0	0%		20	3%	12.2
Cell phone	71	11%	2.1	222	29%	3
Incandescent lights	8	1%	8.3	513	67%	9.4
Fluorescent lights	6	1%	7.8	312	41%	9.3
Fan	5	1%	3.3	201	26%	5.2
Flash light	243	38%	2.4	229	30%	2.5
Sewing machine	1	0%		11	1%	5
4 burner cooker electric	0	0%		0	0%	
Air conditioner	0	0%		0	0%	
Electric iron	1	0%		144	19%	1.2
Table top single burner electric cooker	1	0%	2	1	0%	1.5
Coil heater	1	0%		16	2%	0.8
Other	7	1%	4.5	25	3%	4

Source: JICA Study Team

Top 3 appliances were radios, stereos (including radio function) and lights (including flashlights) regardless of the electrification status. Lights are considered as the most basic electric appliances. Needs for flashlights are strong in both the un-electrified and electrified communities without enough street lights. Radios are popular since they are portable and provide a variety of information and entertainment. The other major factors radios are widely used in rural areas are the moderate price compared to TV sets and the convenience to be used by batteries. Stereos are also widely used since they match Ghanaian national traits of music love and they can facilitate social communication by singing and dancing, though they also function as radios.

Once people further pursue the objective of radio and stereo use, they will be interested in purchasing TV sets. TV is highly popular as means of information and entertainment. In the electrified communities, rate of households with small TV is 20%, while big TV is 23%.

In addition, fans and VCR/VCT players are also widely used in the electrified communities. Refrigerators, on the other hand, are not prevalent compared to their necessity.

2) Use of electric appliances at commercial facilities

Almost general goods stores owned radios in both the electrified and un-electrified communities. Major electric appliances used in general goods stores in the electrified communities are lights, radios and stereos, and fans. Approximate hours of use per day are 8 hours for lights, 11 hours for radios and stereos, and 6 hours for fans.

3) Use of electric appliances at public facilities

The major electric appliances used in secondary schools are lights, radios, and TVs. They use lights for 6 hours on average, radios for 4 hours, and TVs for 3 hours.

Lights, refrigerators, fans and TVs are used in medical facilities. Approximate hours of use per day are 12 hours for lights, 6 hours or 24 hours for refrigerators, 11 to 12 hours for fans, and 6 hours for TVs.

As for religious facilities, lights, fans, stereos are used, but many do not use these electric appliances.

(7) Survey Result Regarding Impact of Electrification

Electrification will bring about positive impacts including increasing convenience of livelihoods, but it also brings negative impacts associated with change of lifestyle. The socio-economic survey, therefore, studied such negative impacts and residents' perception. The negative impacts and perception identified are as follows.

Un-electrified communities

- ✓ The prospect of electrification is unclear.

- ✓ Children may stay up late, and may take antisocial action due to watching TV.
- ✓ Information on how to use electricity safely and efficiently is insufficient.
- ✓ Expensive electricity tariffs may increase economic burden.

Electrified communities

- ✓ There is a strong concern that electricity tariffs are inaccurate due to low quality of meters.
- ✓ Electricity cannot be used sufficiently due to the lack of electricity capacity.
- ✓ Low quality of electricity, i.e. high fluctuation of voltage and frequency of blackout, may have negative impacts on electric appliances.

Major concerns of commercial and public facilities also relate to quality, capacity and tariff of electricity, and they are found to have similar concerns as households.

In contrast, many residents expect positive impacts of electrification such as increasing convenience. As a whole, expectation for positive impacts is considered stronger than concerns about negative impacts.

(8) Survey Result Regarding Sustainability

The capacity of customers to pay electricity tariffs is a critical factor to judge sustainability of electrification.

1) Payable amount

a) Ordinary households

Data on economic situations of customers are very important to estimate power demand and payable amount. However, it is difficult to obtain useful economic data in a short period. The major reasons are the following.

- ✓ Residents do not have accurate records for their own income and expenditure
- ✓ Many residents are reluctant to release information on their own economic situations, thus some information acquired may have problems of credibility.
- ✓ Many residents are engaged in subsistence farming and do not have regular income.

The survey, therefore, assumed payable amount of electricity not from data on incomes and expenditures but from energy-related expenditures such as electricity, kerosene, candles and batteries.

Data on energy-related expenditures acquired through the questionnaire survey are the following.

Table 4-15 Energy expenditures of ordinary households (initial cost)

Energy Source	Global	Unelectrified	Electrified
Electricity from National grid	257,803	0	472,751
Electricity from own generator	31,020	51,402	14,026
Kerosene lantern	43,436	43,928	43,026
Candles	118	69	159
Dry cell batteries	31,551	42,377	22,525
Solar Home System	1,137	2,372	108
Battery Charging system	7,691	14,236	2,234
Solar Lantern	708	312	1,039
Other sources	4,326	4,006	4,593
Average Cost/household	377,791	158,701	560,460

Source: JICA Study Team

Table 4-16 Energy expenditures of ordinary households (running cost per month)

Energy Source	Global	Unelectrified	Electrified
Electricity from National grid	28,773	0	52,762
Electricity from own generator	3,530	6,433	1,109
Kerosene lantern	33,911	37,394	31,008
Candles	1,589	1,257	1,866
Dry cell batteries	13,818	17,080	11,099
Solar Home System	104	128	85
Battery Charging system	778	1,680	26
Solar Lantern	0	0	0
Other sources	754	972	573
Average Cost/household	83,258	64,944	98,527

Source: JICA Study Team

The monthly energy-related expenditures of ordinary households are 64,944 cedis in the un-electrified communities, and 98,527 cedis in the electrified communities. Initial cost for on grid electrification was 472,751 cedis on average.

Kerosene and batteries are used even in the electrified households. This is because other energy sources are used in consideration of electricity tariff, and portable appliances such as radios will not fit on grid electrification system.

It is kerosene that is widely used other than electricity. 37,394 cedis in the un-electrified communities and 31,008 cedis in the electrified communities are paid to kerosene. Payment for batteries is also significant. 17,080 cedis are paid in the un-electrified communities, while 11,099 cedis are paid in the electrified communities.

The energy-related expenditures were higher than those estimated in Renewable Energy Master Plan Study. The energy-related expenditures in the southern regions are considered higher than the northern 3 regions.

Payable amount for electricity was estimated based on the energy-related expenditures, in particular those for kerosene and batteries, in the un-electrified communities clarified through the questionnaire survey. Electricity cannot replace the whole use of kerosene and batteries since expenditures for kerosene and electricity are observed even in the electrified households. Taking into account the proportion of current expenditures for electricity to those for non-electricity in the electrified communities, i.e. 53,872 : 44,656, payable amount of residents in the un-electrified communities can be estimated about 35,000 cedis.

The questionnaire survey collected data on willingness of local residents to pay electricity tariff. The result is indicated in the following.

Table 4-17 Amount ordinary households are willing to pay for electricity

	Global		Un-electrified		Electrified	
	No.	Willingness to pay	No.	Willingness to pay	No.	Willingness to pay
Willingness to pay more	74	71,500	55	74,691	19	62,263
Willingness to pay less	576	37,380	474	38,095	102	34,059

Source: JICA Study Team

These amounts should be considered only as a guide because the amounts are not derived from detail investigation on the residents' family accounts but based on the intuitive answers from local residents. It is natural that households want to reduce energy-related expenditures rather than to pay more. The ratio of households willing to pay more to households willing to pay less are 15:85 in the un-electrified communities, while 10:90 in the electrified communities. The ratio of households willing to pay more in the un-electrified communities is higher than that in the electrified communities. This indicates many households need electrification, even paying a certain cost.

b) Commercial facilities

The major expenditures for commercial facilities are indicated in the following table.

Table 4-18 Energy expenditures of commercial facilities (running cost per month)

Type of Enterprise	Un-electrified	Electrified	Total Average
General goods/drug store	45,793	102,259	79,297
Restaurant/chop bar	55,567	112,833	77,042
Drinking bar/pito brewing	99,455	128,746	113,894
Bakery	25,000	211,000	149,000
Furniture making/carpentry shop	12,667	60,800	42,750
Tailor/seamstress	79,143	70,292	73,553
Hair salon or barber shop	41,600	90,176	79,136
Grain milling	378,737	491,156	430,129

Source: JICA Study Team

Energy-related expenditures of general goods stores were 79,297 cedis in total average. 45,793 cedis are paid in the un-electrified communities, while 102,259 cedis are paid in the electrified communities. Kerosene and batteries are used in the electrified communities as well as ordinary households.

Energy-related expenditures of restaurants are 77,042 cedis on the whole. 55,567 cedis are paid in the un-electrified communities, and 112,833 cedis are paid in the electrified communities. For bars, 113,894 cedis in total average, 99,455 cedis in the un-electrified communities, and 128,746 cedis in the electrified communities are paid. In general, commercial facilities of the electrified communities tend to pay more energy-related expenditures than those in the un-electrified communities.

The amount was the same as or above the result of Renewable Energy Master Plan Study, thus the energy-related expenditures in the southern regions are considered higher than those in the northern 3 regions.

c) Public facilities

The major expenditures for public facilities are indicated in the following table.

Table 4-19 Energy expenditures of public facilities (running cost per month)

Type of Public facility	Un-electrified	Electrified	Total Average
Pre/Primary School	15,313	84,308	75,586
Junior Secondary School	35,200	59,600	51,467
CHPS compound	-	186,667	186,667
Clinic	43,000	822,628	666,702
Health center/health post	34,000	163,667	131,250
Governmental office	-	290,000	290,000
Mosque/Church	78,000	88,663	82,161
Vehicle/bus station	76,333	90,250	84,286

Source: JICA Study Team

51,467 cedis are paid in the secondary schools, while 666,702 cedis are paid in the clinics. In the electrified communities, health and medical facilities and governmental offices pay relatively higher energy expenditures. Energy-related expenditures of public facilities in the electrified communities tend to be higher than those in the un-electrified communities.

2) Electric appliances that residents want to purchase

It is critical for power demand forecast to identify electric appliances that people want to purchase. The appliances are indicated in the table below.

Table 4-20 Electric appliances that people want to purchase

	Un-electrified	Electrified
Small colour TV	144 (29.2 %)	103 (19.2 %)
Big colour TV	124 (25.2 %)	121 (22.6 %)
Black and white TV	13 (2.6 %)	4 (0.7 %)
VCR/VCD	11 (2.2 %)	28 (5.2 %)
Radio	8 (1.6 %)	7 (1.3 %)
Stereo (Including radio)	12 (2.4 %)	17 (3.2 %)
Refrigerator-small	49 (9.9 %)	43 (8.0 %)
Refrigerator big	27 (5.5 %)	49 (9.1 %)
Freezer small	5 (1.0 %)	18 (3.4 %)
Freezer big	18 (3.7 %)	61 (11.4 %)
Cell phone	3 (0.6 %)	13 (2.4 %)
Incandescent lights	60 (12.2 %)	14 (2.6 %)
Flourescent lights	6 (1.2 %)	1 (0.2 %)
Fan	5 (1.0 %)	18 (3.4 %)
Flash light	1 (0.2 %)	2 (0.4 %)
Sewing machine	4 (0.8 %)	14 (2.6 %)
Electric iron	2 (0.4 %)	5 (0.9 %)
Table top single burner electric cooker	0 (0.0 %)	3 (0.6 %)
Air conditioner	0 (0.0 %)	7 (1.3 %)
Other	1 (0.2 %)	8 (1.5 %)
Total	493 (100.0 %)	536 (100.0 %)

Source: JICA Study Team

This table demonstrates that 1) needs for TV sets are the highest both in the un-electrified and electrified communities; 2) Needs for lights are high in the un-electrified communities; 3) needs for refrigerators and freezers are high in the electrified communities. This result was largely in line with that of Renewable Energy Master Plan Study.

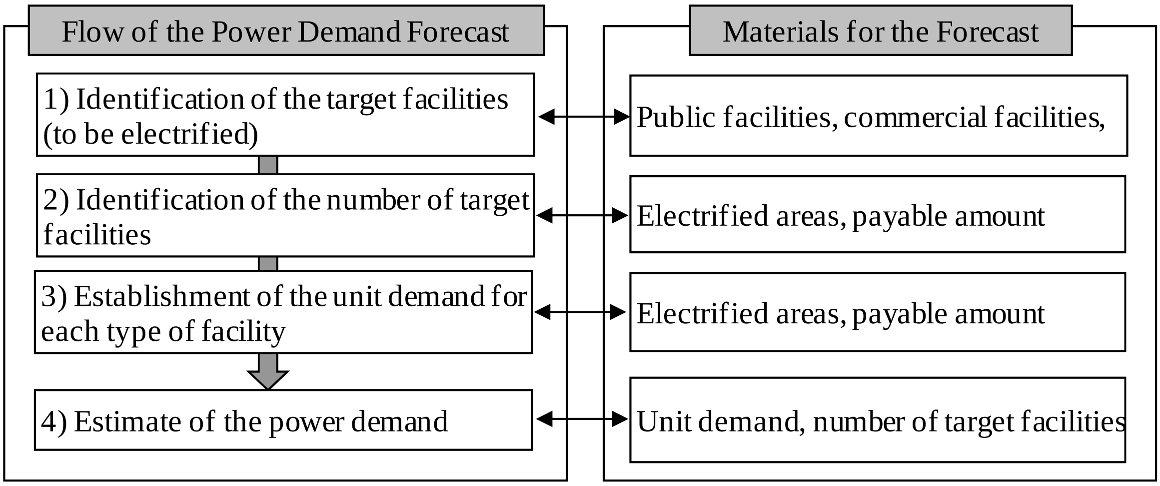
As electrification is promoted, people tend to desire more highly-developed electric appliances. However, the high needs for refrigerators and TV sets demonstrate that only small number of households owns such electric appliances. In other words, ordinary households can purchase only lights and TV sets at most even after electrification, and few households can purchase refrigerators. People will not be able to buy electric appliances if they cannot prepare necessary amount of money. Access to stores dealing with electric appliances and spare parts is also an important factor.

Customers at first typically buy the simple and low-cost lights. However, their needs for other electric appliances will increase as they appreciate their convenience and entertainment value since they will not obtain enough content from the lights. Disposable income, i.e. income beyond the minimum requisite for subsistence, is necessary to purchase electric appliances other than lights. However, households in rural communities in Ghana hardly have significant disposal income since their livelihoods are usually on the subsistence level. Such households cannot purchase electric appliances in addition to the regular payment of electricity tariff. The electrification of household is, therefore, consequently anticipated to proceed at only gradual speed.

The questionnaire survey did not probe type of electric appliances that commercial and public facilities want to obtain. But in secondary schools, the ratio of TV sets and VCRs were higher than other appliances, and thus needs for these appliances are considered high for, for instance, remote education. For health and medical facilities, needs for refrigerators to store medicines should be taken into consideration.

4.2.2 Microscopic Demand Forecast

Microscopic demand forecast is based on the data on the current status of households and commercial and public facilities, and socio-economic situations of electrification target areas. Main customers in rural areas are ordinary households and small-scale commercial and public facilities. Thus, extension, renewal and reinforcement of distribution lines in the rural areas require the forecast of power demand of these facilities. The microscopic demand forecast, therefore, is implemented to complement the macroscopic demand forecast in light of extension, renewal and reinforcement of distribution network in rural areas. The flow of microscopic demand forecast is indicated below.



Source: JICA Study Team

Figure 4-20 Flow of microscopic demand forecast

(1) Identification of Target Facilities

Target facilities for electrification were ordinary households and major commercial and public facilities. Ghanaian government does not have a policy goal regarding household electrification rate. Therefore, the electrification rate of ordinary houses is set in consideration to the current household electrification rate and other situations in the electrified communities. For public facilities, such as schools and medical facilities, the electrification rate is individually determined according to the scale and needs for electricity.

(2) Establishment of the Unit Demand for Each type of Facility

The Study Team adopted the values described in the table below for the capacity of each appliance. The values are based on the mini-survey conducted together with the socio-economic survey.

Table 4-21 Unit demand by electric appliance

Electric Appliances	Capacity (W)
Small colour TV	60
Big colour TV	80
Black and white TV	20
VCR/VCD	20
Stereo (Including radio)	18
Refrigerator	135
Freezer	240
Incandescent lights	60
Flourescent lights	36
Fan	60
Air conditioner	1,200
Electric iron	1,100
Hair Dryer	900
Table top single burner electric cooker	2,200
Sewing machine	100
Computer	360

Source: JICA Study Team

Unit demand of each household (i.e. maximum power demand) was determined based on the type and number of electric appliances in each household, and the household electrification rate in the electrified communities. The same policy was applied to commercial facilities. In terms of public facilities, however, political factors such as government policies to electrify medical facilities and secondary schools are taken into account. Thus, electrification rate electrification rate of these facilities were set as 100 %.

(3) Estimation of Microscopic Power Demand

1) Power demand of ordinary household

The ownership rates and hours of use of electric appliances by electrification status are indicated in the table below.

Table 4-22 Ownership rates and hours of use of electric appliances

Appliance	Un-electrified Communities			Electrified Communities		
	Number	Penetration	Use Hours	Number	Penetration	Use Hours
Small colour TV	12	2%	3.8	156	20%	3.9
Big colour TV	13	2%	4.3	175	23%	4.1
Black and white TV	34	5%	3.5	36	5%	3.6
VCR/VCD player	10	2%	2.8	145	19%	3
Radio	437	68%	8.4	392	51%	7.4
Stereo (including Radio)	161	25%	5.8	270	35%	5.5
New small refrigerator	1	0%		87	11%	15
Old small refrigerator	0	0%		42	5%	15.8
New big refrigerator	0	0%		49	6%	12
Old big refrigerator	0	0%		18	2%	15.2
New small deep freezer	0	0%		20	3%	12.6
Old small deep freezer	0	0%		9	1%	13.8
Old big deep freezer	1	0%		11	1%	16.5
New big deep freezer	0	0%		20	3%	12.2
Cell phone	71	11%	2.1	222	29%	3
Incandescent lights	8	1%	8.3	513	67%	9.4
Fluorescent lights	6	1%	7.8	312	41%	9.3
Fan	5	1%	3.3	201	26%	5.2
Flash light	243	38%	2.4	229	30%	2.5
Sewing machine	1	0%		11	1%	5
4 burner cooker electric	0	0%		0	0%	
Air conditioner	0	0%		0	0%	
Electric iron	1	0%		144	19%	1.2
Table top single burner electric cooker	1	0%	2	1	0%	1.5
Coil heater	1	0%		16	2%	0.8
Other	7	1%	4.5	25	3%	4
Total no. of Respondants	642			770		

Source: JICA Study Team

Ownership rate of lights, radios and stereos are the highest in both the electrified and un-electrified communities. Significant difference is the diffusion rate of TV and fans. Therefore, the diffusion of TV and fans will make clear difference between the electrified and un-electrified communities.

Because information on times of appliance use is not available, the Study Team calculated the average household demand (W) by multiplying the average number of appliances per household, and multiplying the resultant product by a diversity factor (1/2). The result was shown in the table below, and the power demand per household was 121.00W[3].

[3] Electric appliances whose ownership rates were less than 20% were not incorporated into the demand forecast, since they cannot be considered to be purchased by the ordinary households in general. Radios are also not taken into account because they work by batteries. Aging of electric appliances are also not taken into account.

Table 4-23 Power demand per household

	Small color TV	Big color TV	Stereo	Cell phone	Incandescent lights	Flourescent lights	Fan	Flash light	Diversity Factor	Total Capacity (W)
Capacity (W)	60	80	18	1	60	36	60	5		
Number	0.20	0.25	0.39	0.38	2.41	0.94	0.36	0.39		
Subtotal	12	20.2	6.93	0.38	144.72	33.95	21.84	1.95	2	121.00

Note: This table may include rounding errors since the figures are rounded to two decimal places.
Source: JICA Study Team

The power demand of target communities can be calculated by multiplying the power demand per household (121.00W) by the number of households in the communities, and by multiplying the resultant product by household electricity rate. Household electrification of the electrified communities is identified by FGD. However, the participants of FGD could not provide accurate figures, thus the rate may include certain errors. The average household electrification rate in the electrified communities is 71.6%. This figure was more than double of that of Renewable Energy Master Plan Study (32%). In general, household electrification rate in the southern regions is higher than the northern 3 regions. Renewable Energy Master Plan Study concluded that household electrification is being held down due to the incapability of payment and scattered distribution of compounds in the northern regions. However, it should be noted that samples are insufficient and figures from FGD are unavoidably intuitive.

The following equation indicates the power demand of ordinary households in the southern regions of Ghana.

Power Demand of Households = 121.0W ^{*1} x *N* ^{*2} x *71.6%* ^{*3}

*1: Power Demand per Household

*2: Number of Households

*3: Household electrification Rate

2) Power demand of commercial facilities

Grain mills should be separately considered because they require 20 kW per facility. The electrification rate of grain mills was 52.0%, and the power demand can be estimated by the following equation.

Power Demand of Grain Mills = 20,000W ^{*1} x *N* ^{*2} x *52.0%* ^{*3}

*1: Power Demand per Grain Mill

*2: Number of Facilities

*3: Electrification Rate of Grain Mill

For the other commercial facilities, although demand should be estimated by adding up totals of individual facilities, but data on individual facilities were insufficient mainly due to the limited sample number. As a result, the Study Team decided to ascertain the overall trend of commercial facilities, instead of treating commercial facilities separately.

The power demand of each commercial facility is described below. The appliances whose appearance rates are less than 10% were not taken into account, as is Renewable Energy Master Plan Study.

Table 4-24 Power demand by the type of commercial facility

	No. of Facility	Demand of Each Facility	Total
Total Commercial Facilities	**278**	**372.01**	**103,420.00**
General goods/drug store	89	184.56	16,426.00
Restaurant/chop bar	18	294.28	5,297.00
Drinking bar/pito brewing	35	290.14	10,155.00
Tailor/seamstress	24	469.83	11,276.00
Hair salon or barber shop	34	789.94	26,858.00
Mosque/Church	16	162.75	2,604.00
Bakery	2	39.00	78.00
Furniture making/carpentry shop	5	0.00	0.00
Handicraft making	1	0.00	0.00
Repair shop	11	74.91	824.00
Vegetable oil extraction	0	0.00	0.00
Guest house	2	9118.00	18,236.00
Battery charging station	5	82.80	414.00
Communication Center	7	106.00	742.00
Cold store	8	665.38	5,323.00
Private clinic	2	1170.50	2,341.00
Other	19	149.79	2,846.00

Source: JICA Study Team

Electrification rate of commercial facilities except for grain mills were 66.7% based on the FGD and KII. The power demand for commercial facilities except for grain mills can be estimated by the following equation.

Power Demand of Commercial Facilities = 186.0W ^{*1} x *N* ^{*2} x *66.7%* ^{*3}

*1: Power Demand per Commercial Facility

*2: Number of Facilities

*3: Electrification Rate of Commercial Facility

3) Power demand of public facilities

Power demand of public facilities should not be estimated by the current situations of electrification. The government policies of electrification should also be taken into account. The Study Team estimated power demand of educational facilities (secondary schools in particular), medical facilities and others, in line with the category of Renewable Energy Master Plan Study.

1) Educational facilities

As regards secondary schools, 64 schools (47%) were electrified out of 135 schools in the sampled electrified communities. Secondary schools are expected to be politically further electrified, thus, their power demand are independently estimated. The power demand was calculated 211.2W by the result of the socio-economic survey.

2) Health and medical facilities

All health and medical facilities should be the target of electrification since the Ghanaian government has posted electrification of all the facilities as a policy objective. The power demand was calculated as in the following table by the result of socio-economic survey.

Table 4-25 Power demand of health and medical facilities

Health and Medical Facilities	Power Demand
Clinic	932.3 W
Health Center	437.5 W
CHIPS Compounds	336.3 W

Source: JICA Study Team

3) Other public facilities

Governmental offices are set as the electrification target among other public facilities as Renewable Energy Master Plan Study did. The power demand of governmental offices is estimated as 411.5W by the result of the socio-economic survey.

(4) Estimation from population statistics

Power demand can be estimated by the number of target facilities when the data on the number of households, commercial and public facilities in the target area are available. However, such data are, in general, not fully available at the planning stage.

This section, therefore, presents the method to estimate the approximate power demand from population statistics. But the method should be used solely for getting a rough picture of the power demand of un-electrified communities. Thus, it is necessary to determine the type and actual number of the target facilities when planning electrification. In order to ascertain the correlation by the simplest expression, the correlation between population and facilities were described in the form of a linear equation passing through the origin.

Appendix 4.2.5 describes the population, and the number of households and commercial and public facilities. From the data, the correlation between population and the number of households and facilities are derived as indicated the table below. For the correlation in the northern 3 regions, the result of Renewable Energy Master Plan Study was utilized.

Table 4-26 The number of facilities estimated by population statistics

Facilities	Southern Regions	Northern 3 Regions
Ordinary Households	Population x 0.1456	Population x 0.09
Commercial Facilities	Population x 0.0233	Population x 0.025
Grain Mills	Population x 0.001	Population x 0.0021
Secondary Schools	Population x 0.0005	Population x 0.0002
Health and Medical Facilities	Population x 0.0001	Population x 0.001
Governmental Offices	Population x 0.0003	Population x 0.0002

Source: JICA Study Team

(5) Summary of Microscopic Demand Forecast

The result of the microscopic demand forecast was summarized in the table below.

Table 4-27 Equation of microscopic demand forecast (with data on the accurate number of facilities)

Facilities	Southern Regions	Northern 3 Regions
Ordinary Households	121.0W x Number x 71.6%	107.0W x Number x 32%
Commercial Facilities	186.0W x Number x 66.7%	195.7W x Number x 31%
Grain Mills	20,000W x Number x 52.0%	20,000W x Number x 27%
Secondary Schools	211.2W x Number	110.5W x Number
Clinic/ Health Centers	932.3W x Number	278.2W x Number
CHIPS Compounds	437.5W x Number	139.1W x Number
Governmental Offices	411.5W x Number	107.0W x Number

Source: JICA Study Team

Table 4-28 The number of facilities estimated by population statistics

Facilities	Southern Regions	Northern 3 Regions
Ordinary Households	population x 0.1456	population x 0.09
Commercial Facilities	population x 0.0233	population x 0.025
Grain Mills	population x 0.001	population x 0.0021
Secondary Schools	population x 0.0005	population x 0.0002
Clinic/ Health Centers	population x 0.0001	population x 0.001
CHIPS Compounds	population x 0.0003	population x 0.0002
Governmental Offices	population x 0.0003	population x 0.0002

Source: JICA Study Team

The Study Team estimated the microscopic power demand of communities in the northern 3 regions and the southern regions, making use of the above equations. The result was shown in Appendix 4.2.6.

Chapter 5 Procedure for preparation of the master plan for distribution network renewal, reinforcement, and extension

The master plan for distribution network renewal, reinforcement, and extension in this study is composed of the following two plans for power facilities belonging to the Electricity Company of Ghana (ECG) and Volta River Authority - Northern Electricitiy Department (VRA-NED).

- ✓ Plans for primary substations and subtransmission lines
- ✓ Plans for distribution network renewal, reinforcement, and extension

Based on the demand estimates for each medium-voltage distribution line feeder studied in Chapter 4, the plans for primary substations and subtransmission lines are a blueprint for building new and improving existing facilities as components of the superior system.

The plans for distribution network renewal, reinforcement, and extension present the work of these types for medium-voltage distribution lines. Figure 5-1 shows the subjects of the plans in this study, and Table 5-1, the definitions of the subject power facilities.

The Study Team also examined the influence on the bulk supply points (BSP) owned by the VRA.

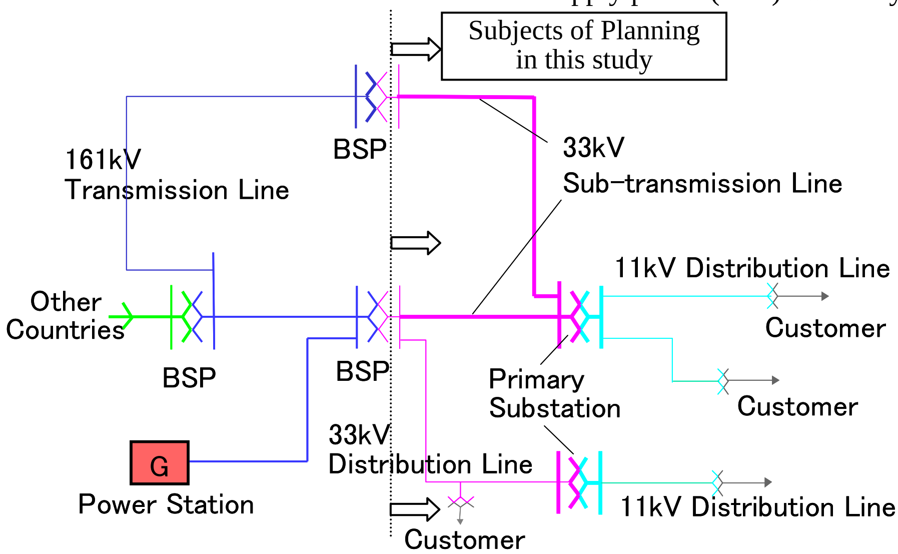


Figure 5-1 Subjects of planning in this study

Table 5-1 Definitions of power facilities that are the subjects of planning in this study

Power facilities	Definitions
Medium-voltage distribution lines	11- and 33-kV distribution lines (ECG) and 11.5- and 34.5-kV distribution lines (VRA-NED)
Primary substation	33/11kV primary substation (ECG)、34.5/11.5kV primary substation (VRA-NED)
Sub-transmission line	Subtransmission lines - 33-kV (or 34.5-kV) power lines between primary substations or between primary substations and BSPs*

*) Lines supplying power directly to low-voltage distribution lines are regarded as medium-voltage lines

5.1 Planning methodology for primary substations and sub-transmission lines

(1) Existing system planning standards

The system planning standards of the ECG and the VRA-NED are contained in Chapter 3 of "Subtransmission and Distribution Design Guidelines" published by the ECG. Table 5-2 outlines them.

Table 5-2 Outline of existing system planning standards (Chapter 3, "Subtransmission and Distribution Design Guidelines")

Section subjects	Outline
3.1 Supply security	- Definition and explanation of supply reliability indicators (e.g., SAIFI and SAIDI) - Targets for outage frequency and duration for each type of distribution facility
3.2 Power quality	- Voltage standards in times of normal operation and emergencies
3.3 Transient voltage profile	- High frequency standards - Voltage imbalance standards
3.4 System composition	- Composition of substation buses - Composition of distribution feeders
3.5 Failure current level	- Failure current standards

The Guidelines contain detailed descriptions of standards for formulating system plans, but not of standards for supply reliability to be applied in each area. In this and other respects, there is a shortage of standards for actual system planning.

(2) System planning standards in the Study

Table 5-3 shows the system planning standards for the Study, determined upon consultation with the counterparts.

Table 5-3 System planning standards and analysis conditions (proposed)

<table>
<tr><th colspan="2"></th><th colspan="2">Description</th></tr>
<tr><td rowspan="2">Heat capacity</td><td>Normal</td><td colspan="2">No more than 100% of the normal power flow</td></tr>
<tr><td>At times of single failure（N-1）</td><td colspan="2">No more than 100% of the power flow at times of single failure (application limited to urban areas, such as Accra, Tema, Kumasi, Takoradi and Sunyani)</td></tr>
<tr><td colspan="2">Voltage</td><td colspan="2">No more than 10% at the distribution line end</td></tr>
<tr><td colspan="2" rowspan="4">System analysis</td><td>System analysis program</td><td>PSS/Adept（ECG)</td></tr>
<tr><td>Study section</td><td>10 years (2008 - 2017), N-1 study has been conducted only in 2017</td></tr>
<tr><td>Power demand</td><td>Power demand forecast described in Chapter 4</td></tr>
<tr><td>System planning</td><td>Examination based on system plans at the GEDAP, Ghanaian government, ECG, and VRA-NED</td></tr>
</table>

As for the system analysis programs, in consideration of the desires at the ECG, it was decided to use PSS/Adept. (An acronym for Power System Simulator/Advanced Engineering, a program for power system analysis made by the U.S. firm Siemens PTI. It is used for analysis of distribution systems).

Siemens PTI, and is used for analysis of distribution systems.

As noted in Section (1) above, the aforementioned Guidelines do not describe the standards applied in each area for supply reliability. In the facility formation for core cities such as Accra and Kumasi, the Study Team bore in mind the N-1 standards in general application. (The N-1 standard is based on the reasoning that, even in the event of failure of one facility in a group of N facilities, there will be no interruption of supply by N-1 facilities. The failed facility is assumed to be one transmission line circuit or one transformer).

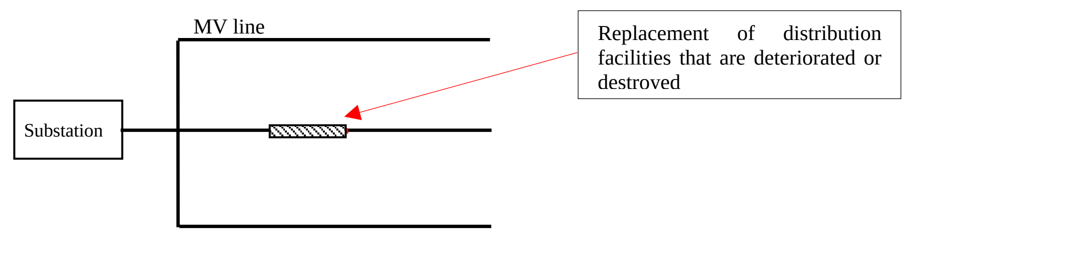
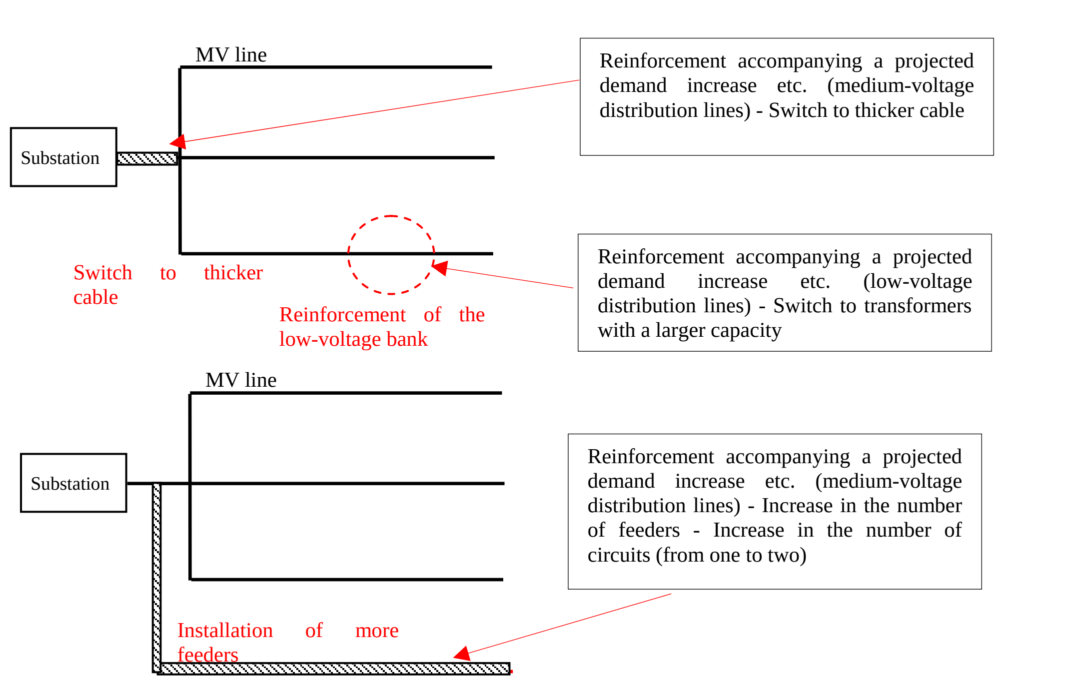
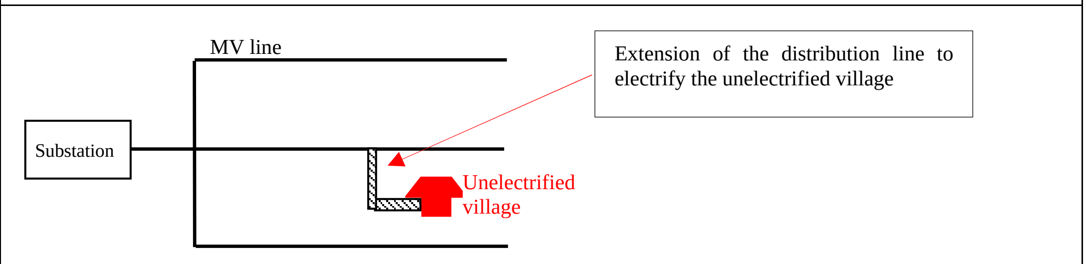
Because demand is dispersed in the VRA-NED area, it would presumably be unnecessary to have a facility formation up to the N-1 standards there in general. In the Sunyani area, nevertheless, the Study Team considered the prospect of facility formation up to the N-1 standards, because it has major industries in the mining and lumber processing fields, and is one of Ghana's key areas.

Appendix 5.1.1 lists the BSPs owned by the VRA. At present, they number 29 and have a combined capacity of 1,622 MVA. Appendix 5.1.2 lists the existing primary substations of the ECG and the VRA. Those of the ECG number 88 and have a combined capacity of 1,761 MVA. The corresponding figures for the NED are five and 19 MVA.

5.2 Planning method for distribution network renewal, reinforcement, and extension

It is the objective of the Study to prepare plans for replacement of deteriorated distribution lines (renewal), expansion of distribution facilities in step with demand growth (reinforcement), and lengthening of distribution lines along with the progress of RE (extension). The subjects are medium-voltage distribution lines.

Table 5-4 Definition of distribution network renewal, reinforcement, and extension

<table>
<tr><td>Distribution line renewal</td><td>
</td></tr>
<tr><td>Distribution line reinforcement</td><td>
</td></tr>
<tr><td>Distribution line extension</td><td>
</td></tr>
</table>

5.2.1 Planning method of distribution network renewal

Plans are drafted for removal of installed facilities that are deteriorated or damaged (due to natural disasters or human acts) and their replacement with new ones. As a general rule, except in the case of facility reinforcement, the newly installed facilities must deliver a performance that is identical or equivalent to those they are replacing.

Both the ECG and the VRA-NED conduct regular patrols and checks of distribution routes in order to detect any defects. The crews identify and ascertain the locations of defects such as supporting structure (especially wooden utility pole) rot, mechanical trouble with switches and breakers, rust on guys (braces) and metal parts, and deterioration of cable covering. For budgetary reasons, however, it is not possible to improve all deteriorated facilities. At present, repairs are promptly made for defects on medium-voltage distribution lines directly linked to supply outages such as cable failure and toppling of supporting structures, but there is almost no other replacement of deteriorated facilities as part of preventive maintenance.

The Master Plan was drafted while taking account of plans for reinforcement of distribution lines based on information about the locations of such defects.

5.2.2 Planning method of distribution network reinforcement

Plans are made to reinforce facilities in response to an increase in load on existing lines along with demand growth, a future current in excess of the facility capacity, and drop in voltage to the extent of deviation from the prescribed value.

For current, based on the discussion with the counterparts in ECG and VRA-NED, the Study considered plans for reinforcement in response to current exceeding the allowable level on the line. For voltage reduction, in light of the standards at each company, it examined plans in the event of a voltage that is at least 7 percent lower than the nominal level at the ECG and 10 percent lower than that at the VRA-NED.

Specifically, examinations were made of the following five measures.

(a) Thicker cable

A switch can be made to thicker cable for 11- and 33-kV (34.5-kV) distribution lines in response to current beyond the allowable level or voltage drop.

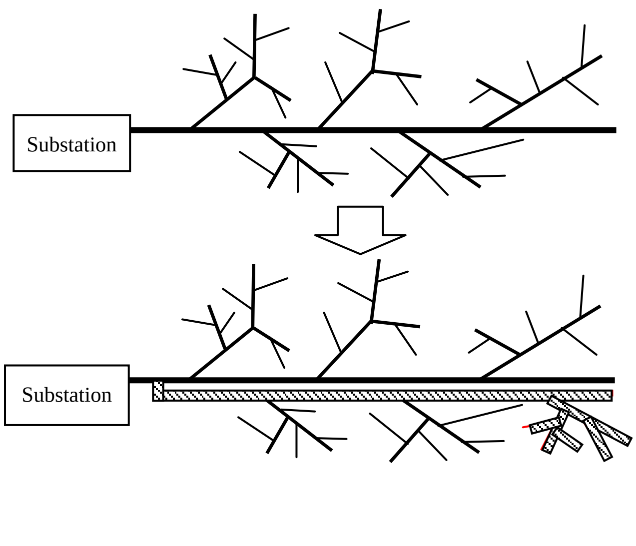


Figure 5-2 Diagram of distribution line split

(b) Splitting of distribution lines

The existing distribution lines can be split into two in order to disperse the load (see Figure 5-2). This approach can be taken when there is capacity margin on the out-going side.

(c) More feeders

If the primary substations already standing have tolerance for installation of more distribution lines (i.e., if there is enough margin as regards the bank capacity of the primary substation and installation space in breakers and cubicles), it may be possible to install additional lines and shift the load on the lines requiring reinforcement to them.

(d) Voltage increase

If the existing distribution lines have a voltage of 11 kV, problems can be met by raising this to 33 (34.5) kV. This approach holds the advantage of fundamentally improving current and voltage, but also has the following drawbacks.

1) It necessitates replacement of breakers on distribution line routes because of the change in breaking capacity. It also requires replacement of all conductors (e.g., lines and cables) and insulation devices (e.g., insulators and breakers) that cannot cope with 33 (34.5) kV.

2) Secondary (distribution) substations must be replaced because the standard cannot cope with 33 (34.5) kV.

3) It would take a lot of time to complete the replacement work. On distribution lines without reverse (?) routes, this would increase the number of outages for work and lengthen the duration.

This step is effective if there are supporting structures and lines that can be diverted for use or if it would be hard to acquire land for installation of new lines.

(e) Installation of boosters

Boosters could possibly be installed in response to voltage drop. Under this approach, boosters would be installed on the power source side of the location where the voltage drop exceeds the standard level, in order to compensate for it. Its chief advantages are the small amount of work entailed and the low expense. Its drawbacks include limitation on the load posterior to the booster by the booster's capacity, which precludes flexible accommodation of future demand growth, and the fact that, unlike other approaches, it is not linked to reduction of distribution loss.

(f) Installation of additional primary substations and BSPs

If the steps outlined above cannot be taken, the option of installing additional primary substations or BSPs must be considered.

When 11-kV lines run for long distances and the aforementioned steps cannot be taken, voltage drop can be countered by installing 33-kV (34.5-kV) subtransmission lines and new primary substations, and connecting the existing 11(11.5)-kV lines to the latter. If the existing distribution lines have a voltage of 33

(34.5) kV, new transmission lines and BSPs would be installed. This approach entails a considerable cost because it is on the level of primary substations and BSPs, but will be taken if necessary.

The analysis concerning medium-voltage distribution lines is based on single-line diagrams and primary substation send-out voltage, and takes up current load factors on such lines and voltage drop at their ends.

The analysis was implemented using the simple calculation sheets prepared by the Study Team. For the VRA-NED, however, it applied the system analysis software NEPLAN, in compliance with counterpart wishes.

Table 5-5 shows the procedure for distribution system analysis

Table 5-5 Procedure for distribution system analysis

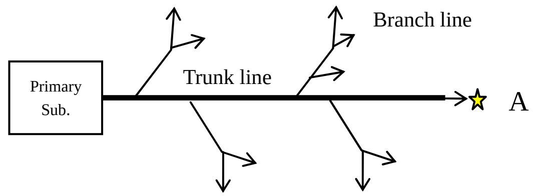
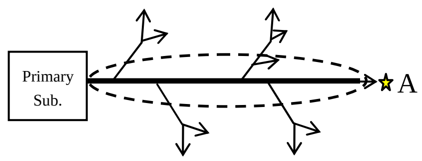
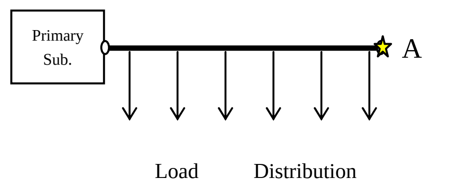
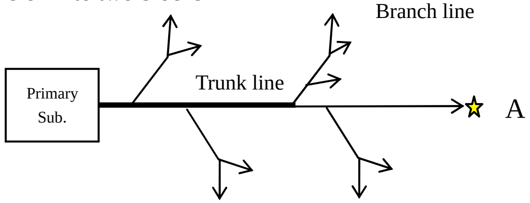
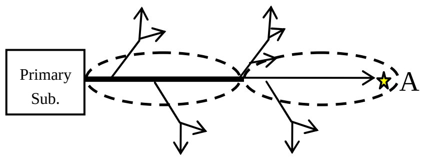
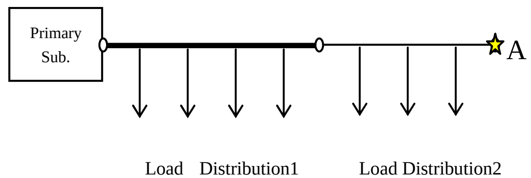
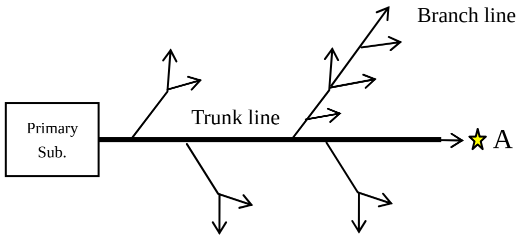
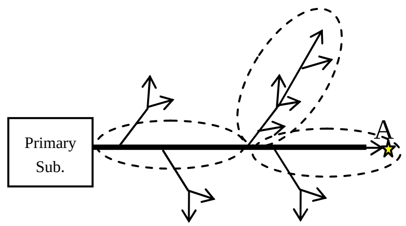
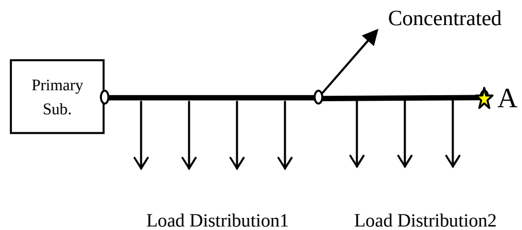
<table>
<tr><th colspan="3">Procedure</th><th>Description</th></tr>
<tr><td rowspan="3">system analysis of existing distribution facilities based on macroscopic demand forecasting</td><td>1</td><td>Preparation of data and materials</td><td>- Single-line diagrams
- Actual peak current at the primary substation out-going point
- Estimated peak current at the primary substation send-out point based on the macroscopic demand forecast</td></tr>
<tr><td>2</td><td>System diagram reduction</td><td>- Preparation of single-line diagrams of feeders to be analyzed
- Condensation of distribution system diagrams at points of analysis</td></tr>
<tr><td>3</td><td>Calculation of voltage drops and current load factors</td><td>- Calculation based on the simple calculation sheet</td></tr>
</table>

Considering even the time constraints, it would not be possible to conduct an analysis based on a precise simulation of the enormous distribution system. It may also be noted that the system is constantly changing as it expands, and it would not be realistic to change the analysis model in response to every change. Futheremore, for an accurate analysis, it is necessary to acquire a lot of demand data for every location. But it is difficult to implement such kind of works for all distribution feeders. For these reasons, the Study Team decided to conduct the analysis with a simple calculation sheet and condensed system diagrams.

Tables 5-6 and 5-7 present the methodology for distribution system condensation. Taken together, they show six condensation models. Because the actual system is more complex, the Study Team considered analysis with combinations of different models in actual application.

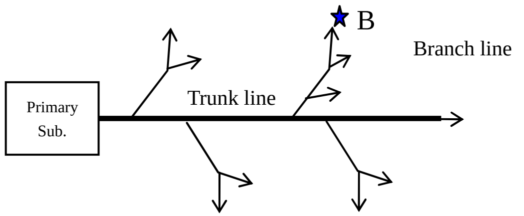
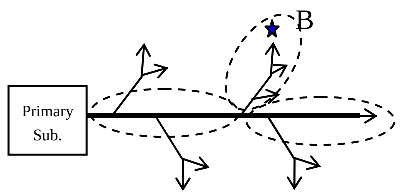
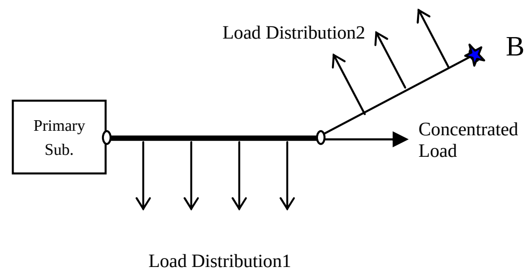
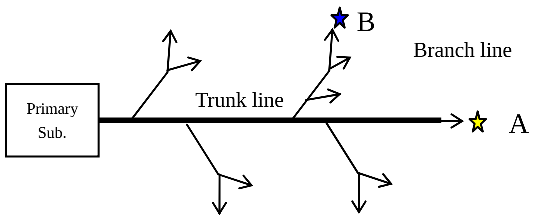
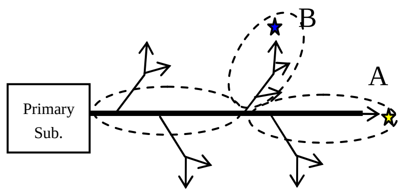
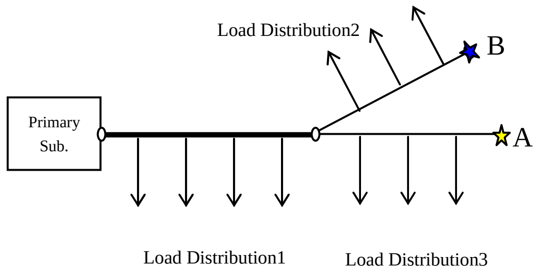
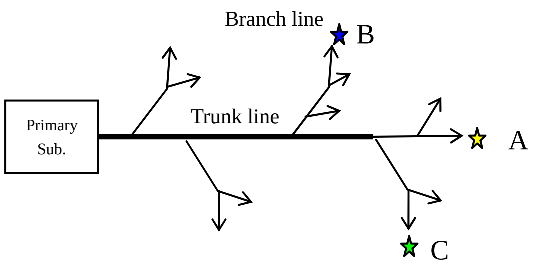
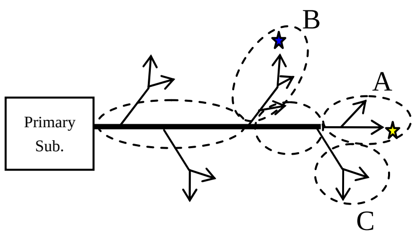
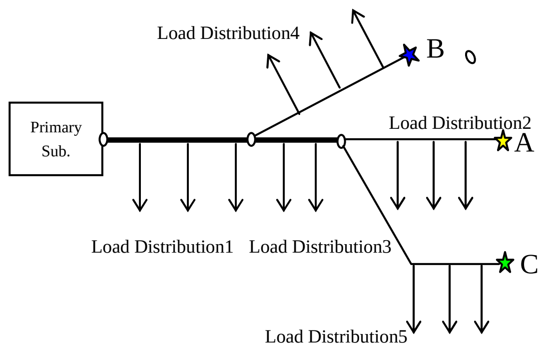
Figure 5-3 shows the simple calculation sheet prepared by the Study Team, and Table 5-8, a list of electrical constants for distribution lines.

Table 5-6 System condensation on simple calculation sheets for the distribution system(case 1)

Actual system diagram		Example of system condensation	
		Blocking	System condensation
1	* One analysis point at the distribution line terminus (end) * Same type of cable from the substation to the analysis point 	One block 	
2	* One analysis point at the distribution line terminus * Change of cable type between the substation and the analysis point * Division into two blocks 	Division into two blocks 	
3	* One analysis point at the distribution line terminus * Higher load in a feeder section 	Division into three blocks 	

** Choice of three types of distributed load: equally distributed, higher closer to the terminus, and higher closer to the sending end

Table 5-7 System condensation on simple calculation sheets for the distribution system(case 2)

	Actual system diagram	Example of system condensation	
		Blocking	System condensation
4	* One analysis point at a feeder terminus * Change of cable type between the main line and the feeder 	* Division into three blocks 	
5	* Two analysis points 	* Division into three blocks 	
6	* Three analysis points 	* Division into five blocks 	

Power System Analysis for Step A *- Power System Analysis for existing system using Macro demand forecast -*

Substation Name	ABC
Feeder Name	No1

: Input data in colored cells

Type-3

Maximum Current I_{max}: 200A

Power factor (cosθ): 0.85

Primary Substation

<Trank Line 1>

Load L_{T1}	48A
Line Type	AAC265mm2
Line Legth Len_{T1}	10km
Type of Distributed Load	Equality
Total Transformer Capacity of secondary substations CAP_{T1}	3000kVA

<Trank Line 2>

Load L_{T2}	48A
Line Type	AAC265mm2
Line Legth Len_{T2}	10km
Type of Distributed Load	Equality
Total Transformer Capacity of secondary substations CAP_{T2}	3000kVA

<Branch Line 2>

Load L_{B2}	24A
Line Type	AAC50mm2
Type of Load	Concentrated
Line Length Len_{B1}	10km
Total Transformer Capacity of secondary substations CAP_{B2}	1500kVA

$\rightarrow I_{max}$

Voltage V_S: 33.0kV

L_{T1} (Distributed Load) R_{T1} =3Ω X_{T1} =4Ω

Trunk Line 1 — Loading 44% — Rated Current =455A

Voltage V_{i1}: 31.7kV (4%Drop)

L_{T2} (Distributed Load) R_{T2} =3Ω X_{T2} =4Ω

Trunk Line 2 — Loading 25% — Rated Current =455A

Voltage V_{i2}: 31.1kV (6%Drop)

L_{B2} (Distributed or Concentrated Load) R_{B2} =6Ω X_{B2} =4Ω

Branch Line 2 — Loading 9% — Rated Current =260A

Voltage V_{r2}: 30.8kV (7%Drop)

L_{B1} (Distributed or Concentrated Load) R_{B1} =6Ω X_{B1} =4Ω

Branch Line 1 — Loading 15% — Rated Current =260A

Voltage V_{r1}: 31.4kV (5%Drop)

L_{B3} (Distributed or Concentrated Load) R_{B3} =6Ω X_{B3} =4Ω

Branch Line 3 — Loading 15% — Rated Current =260A

Voltage V_{r3}: 30.7kV (7%Drop)

<Branch Line 1>

Load L_{B1}	40A
Line Type	AAC50mm2
Type of Load	Received Larger
Line Length Len_{B1}	10km
Total Transformer Capacity of secondary substations CAP_{B1}	2500kVA

<Branch Line 3>

Load L_{B3}	40A
Line Type	AAC50mm2
Type of Load	Received Larger
Line Length Len_{B3}	10km
Total Transformer Capacity of secondary substations CAP_{B3}	2500kVA

=====Equation=====

$V_{i1} = V_s - 1.732 \cdot (R_{T1}\cos\theta + X_{T1}\sin\theta) \cdot (L_{T1} \cdot f_{T1} + L_{T2} + L_{B1} + L_{B2} + L_{B3})$

$V_{i2} = V_{i1} - 1.732 \cdot (R_{T2}\cos\theta + X_{T2}\sin\theta) \cdot (L_{T2} \cdot f_{T2} + L_{B2} + L_{B3})$

$V_{r1} = V_{i1} - 1.732 \cdot L_{B1}(R_{B1}\cos\theta + X_{B1}\sin\theta) \cdot f_{B1}$

$V_{r2} = V_{i2} - 1.732 \cdot L_{B2}(R_{B2}\cos\theta + X_{B2}\sin\theta) \cdot f_{B2}$

$V_{r3} = V_{i2} - 1.732 \cdot L_{B3}(R_{B3}\cos\theta + X_{B3}\sin\theta) \cdot f_{B3}$

$L_{T1} = I_{max} \cdot CAP_{T1} / (CAP_{T1}+CAP_{T2}+CAP_{B1}+CAP_{B2}+CAP_{B3})$

$L_{T2} = I_{max} \cdot CAP_{T2} / (CAP_{T1}+CAP_{T2}+CAP_{B1}+CAP_{B2}+CAP_{B3})$

$L_{B1} = I_{max} \cdot CAP_{B1} / (CAP_{T1}+CAP_{T2}+CAP_{B1}+CAP_{B2}+CAP_{B3})$

$L_{B2} = I_{max} \cdot CAP_{B2} / (CAP_{T1}+CAP_{T2}+CAP_{B1}+CAP_{B2}+CAP_{B3})$

$L_{B3} = I_{max} \cdot CAP_{B3} / (CAP_{T1}+CAP_{T2}+CAP_{B1}+CAP_{B2}+CAP_{B3})$

$I_{max} = L_{T1} + L_{T2} + L_{B1} + L_{B2} + L_{B3}$

V_s : Supply Voltage	I_{max} : Maximum Current	$R_{T1}, R_{T2}, R_{B1}, R_{B2}, R_{B3}$	: Resistance
V_{i1} : Interim Voltage	L_{T1} : Load (Trunk line 1)	$X_{T1}, X_{T2}, X_{B1}, X_{B2}, X_{B3}$	: Reactance
V_{i2} : Interim Voltage	L_{T2} : Load (Trunk line 2)	$f_{T1}, f_{T2}, f_{B1}, f_{B2}, f_{B3}$	: Dispersal Load Factor
V_{r1} : Received Voltage	L_{B1} : Load (Branch Line 1)	$CAP_{T1}, CAP_{T2}, CAP_{B1}$	: Total Transformer Capacity of secondary substations
V_{r2} : Received Voltage	L_{B2} : Load (Branch Line 2)	CAP_{B2}, CAP_{B3}	: Total Transformer Capacity of secondary substations
V_{r3} : Received Voltage	L_{B3} : Load (Branch Line 3)	cosθ	: Power Factor

Figure 5-3 Example of a simple calculation sheet prepared by the Study Team

Table 5-8 List of distribution line constants

No	Type	r（Ω/km）	x（Ω/km）	Rating (A)	Remark
1	AAC400mm2	0.0789	0.3150	1,066	Overhead
2	AAC265mm2	0.1128	0.3254	810	Overhead
3	AAC250mm2	0.1214	0.3286	740	Overhead
4	AAC240mm2	0.1271	0.3314	720	Overhead
5	AAC200mm2	0.1512	0.3371	640	Overhead
6	AAC150mm2	0.2046	0.3485	530	Overhead
7	AAC120mm2	0.2743	0.3568	455	Overhead
8	AAC100mm2	0.3029	0.3625	405	Overhead
9	AAC95mm2	0.3333	0.3645	391	Overhead
10	AAC85mm2	0.3942	0.3684	362	Overhead
11	AAC50mm2	0.6074	0.3843	260	Overhead
12	AAC25mm2	1.528	0.4831	155	Overhead
13	Cu240mm2	0.0849	0.3939	807	Overhead
14	Cu70mm2	0.2897	0.4436	369	Overhead
15	Cu35mm2	0.7056	0.4693	236	Overhead
16	Cu16mm2	1.2952	0.5054	137	Overhead
17	35CuPILC(11kV)	0.668	0.142	155	Underground
18	70CuXLPE(11kV)	0.342	0.132	220	Underground
19	70CuPILC(11kV)	0.342	0.132	220	Underground
20	95CuPILC(11kV)	0.247	0.124	265	Underground
21	95ALXPLE(11kV)	0.2894	0.1512	225	Underground
22	120CuPILC(11kV)	0.196	0.121	295	Underground
23	185CuPILV(11kV)	0.128	0.113	370	Underground
24	185ALXPLE(11kV)	0.1486	0.1265	335	Underground
25	240CuPILC(11kV)(for NED)	0.0983	0.123	415	Underground
26	240CuXLPE(11kV)(for NED)	0.0983	0.141	501	Underground
27	258CuPILC(11kV)	0.0928	0.123	429	Underground
28	240CuXLPE(33kV)	0.0983	0.123	440	Underground
29	240ALXLPE(33kV)	0.1271	0.2166	510	Underground
30	258CuXLPE(33kV)	0.0983	0.141	440	Underground
31	258CuPILC(33kV)	0.0928	0.123	455	Underground
32	2*240ALXLPE(33kV)	0.0636	0.2381	918	Underground
33	35CUBARE	0.5921	0.4693	236	Overhead
34	50ALBARE	0.6074	0.3843	260	Overhead
35	95ALBARE	0.333	0.3645	391	Overhead
36	100ALBARE	0.3029	0.3625	350	Overhead
37	120ALBARE	0.2524	0.3568	390	Overhead
38	150ALBARE	0.2046	0.3485	455	Overhead
39	265ALBARE	0.1143	0.3254	697	Overhead
40	400ALBARE	0.0789	0.315	855	Overhead
41	6*1*120ALBARE	0.126	0.18	780	Overhead
42	6*1*150ALBARE	0.103	0.174	910	Overhead
43	6*1*265ALBARE	0.057	0.165	1394	Overhead
44	95ALPILC	0.2894	0.1512	225	Underground
45	240CUXLPE (for ECG)	0.0928	0.11	480	Underground
46	240CUPILC (for ECG)	0.0983	0.11	397	Underground
47	500CUPILC	0.0473	0.1	800	Underground
48	500ALXLPE	0.061	0.0943	648	Underground
49	3x1x240CUXLPE	0.030933	0.036	1296	Underground
50	3x1x500CUXLPE	0.0236	0.04715	831	Underground
51	3x1x630ALXLPE	0.03712	0.044	755	Underground
52	6*1*240ALXLPE	0.0636	0.0615	790	Underground
53	6*1*240CUXLPE	0.049	0.062	1006	Underground
54	6*1*240CUPILC	0.049	0.0554	837	Underground
55	6x1x500CUXLPE	0.0472	0.0943	1590	Underground
56	6x1x630ALXLPE	0.01856	0.022	1434	Underground

5.2.3 Methods of distribution network extension planning

The national census taken in 2000 found that Ghana had a total of 88,917 localities. Because the locality electrification rate was 54 percent in 2006, it is estimated that more than 50,000 localities remained unelectrified as of 2008.

In this study, a simulation was made of the planning for distribution network (grid) extension to 472 localities whose population and location could be determined.

(1) Estimate of locality demand

The number of customers and size of demand in the subject localities were based on the microscopic demand estimates made from the findings of the survey of locality society in this study (see Chapter 4) and the results of the JICA "Master Plan Study on Rural Electrification Using Renewable Energy Resources in the Northern Part of the Republic of Ghana."

(2) Determination of the RE method

The determination of RE plans requires, first and foremost, examination regarding the RE method, i.e., on-grid or off-grid electrification. In this study, a classification was made of electrification methods on the basis of distance from the nearest primary substation.

Table 5-9 Classification of electrification methods

	Distribution network voltage	
	11kV(11.5kV)	33kV（34.5kV）
On-grid criteria	No more than 20 km	No more than 30 km
Sub-on-grid criteria	No more than 30 km	No more than 50 km
Off-grid criteria	More than 30 km	More than 50 km

Because all of the subject localities met the on-grid or Sub-on-grid criteria, they were taken as the subject of plans for electrification by extension of the grid.

(3) Procedure for preparation of grid extension plans

The procedure began with input of information on distribution lines and localities whose location had been confirmed on maps into the geographic information system (GIS). This was followed by the preparation of plans for extension of existing distribution lines on the GIS to unelectrified localities, beginning with those closest to those existing lines. Calculation of the construction cost was based on the following conditions.

Table 5-10 Unit cost for each type

Items			Unit cost
MV distribution lines (Including such facilities as poles and insulators)	Trunk lines (Adopting 120mm^2 AAC)		25,169 US$/km
	Branck lines (Adopting 50mm^2 AAC)		20,187 US$/km
Distribution transformers	11(11.5)kV/0.4kV	50kVA	7,461 US$/piece
		100kVA	8,694 US$/piece
		200kVA	10,045 US$/piece
	33(34.5)kV/0.4kV	50kVA	10,140 US$/piece
		100kVA	11,458 US$/piece
LV distribution lines			640US$/customer
Service wires			75US$ /customer
Meters			130US$/customer

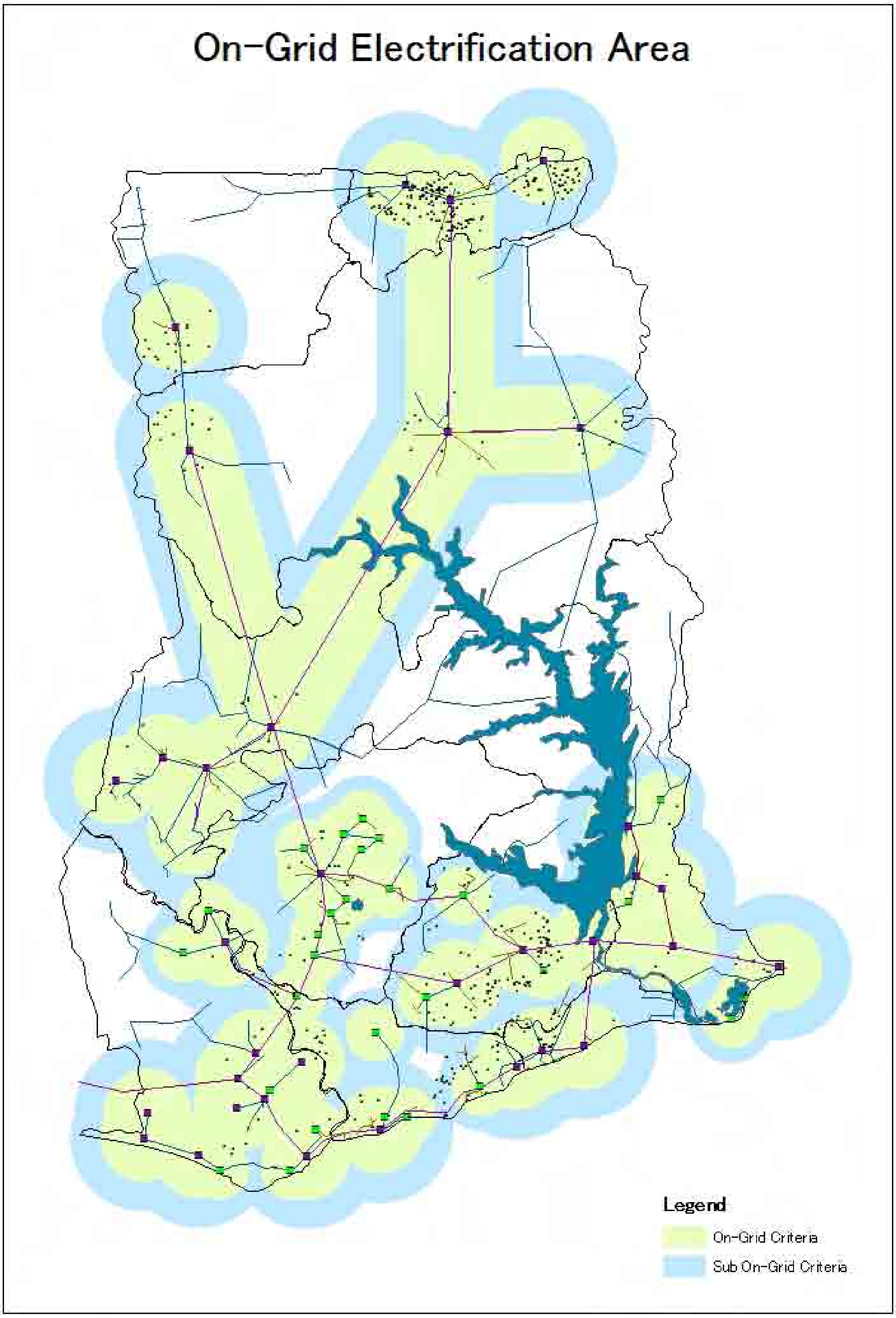


Figure 5-4 Distribution of electrification area

5.3 Distribution facility design

This chapter sets forth a realistic design policy adapted to the Master Plan, which extends about ten years into the future, in light of the partial insufficiency of the current design guidelines established by the ECG and the gap between the ECG and VRA-NED facilities.

(1) Conductors

Conductors applied in distribution facilities must have a satisfactory mechanical strength and resistance to corrosion as well as a capacity sufficient for supply.

Some of the line conductors already installed are not in conformance with the design guidelines, and must be reviewed in the course of planning for future renewal and reinforcement. The following standards have been established for selection of conductors for 33- and 11-kV distribution lines in order to preserve a certain uniformity.

- Trunk lines: 400 or 240mm2 AAAC or AAC
- First branch line: 150-mm2 AAAC or AAC
- Second branch line: 120-mm2 AAAC, AAC, or other cable corresponding with the load
- Underground cable
    - Urban areas: 630mm2 AlXLPE or 500mm2 CuXLPE
    - Other areas: 240mm2 AlXLPE

Use of ASCRs, which have a higher conductivity, is recommended in urban areas with a high load density. Use of a corrosion-resistant type of ACSR-Z is suggested for districts in the southern region where distribution lines run along the coast, to prevent damage from briny air. Although strong winds rarely blow in Ghana, the southern regions face the Gulf of Guinea,and there are apprehensions about occurrence of outage due to such damage in these districts.

Generally speaking, in selection of conductor size, it must be noted that urban areas often present constraints on thermal capacity owing to their high power factor (of about 0.95), and that rural areas are marked by constraints deriving from the voltage drop attending increased resistance because of the longer distribution line lengths.

In the cost aspect, the reduction of the number of conductor types by application of uniform standards can heighten versatility and lower purchasing costs. It should be added that the continuing high level of prices for copper in recent years indicate the need for consideration of the prevailing situation.

(2) Supporting structures

For reasons of economic merit and match with existing facilities,the standard supporting structure is the wooden pole. Steel towers or poles are to be used for overhead distribution lines leading from newly built substations in urban areas.

The safety factor is set at 2.0 for poles and foundations, 2.5 for crossarms and conductors, and 2.0 for insulators and connected parts.

(3) Minimum ground clearance of overhead lines

Table 5-11 shows the minimum ground clearance of aerial distribution lines established with a view to preventing shocks and electromagnetic induction difficulties.

Table 5-11 Overall Ground Clearance Distances

Location	Basic distance (m)		Voltage distance for bare conductor (m)		Total distance (m)	
	Insulated conductor	Bare conductor	33kV	11kV	33kV	11kV
Public places	6.5		0.3	0	6.8	6.5
Railways	6.5		1.2	1.2	7.7	7.7
Roadways	6.5		1.2	1.2	7.7	7.7
Other places	6.0		0.3	0.0	6.3	6.0

(4) Switchgears

The rated capacities of circuit breakers are essentially based on the estimated peak failure current on the secondary side of BSPs, and can bear comparison with those in other countries. Judging from Ghana's present system capacity,it would be preferable to calculate the failure current corresponding with the facility realities in order to avoid cost increases due to purchase of over-spec equipment.

As such, a selection should be made of the breaking capacity that is advantageous overall in the cost aspect instead of reducing costs by standardizing equipment performance.
For long-distance distribution lines, disconnectors are to be installed at proper intervals (basically about 10 km) and at load branch points to assure safety in maintenance and inspection work.

The ring main units (RMUs; devices containing a transformer guard switch and a system interconnection switch in a single unit) adopted in 11-kV open loop systems increase reliability because they make it possible to isolate sound sections from failed ones by opening the load break switch (LBS) on each end of the latter. In spite of this benefit, however, they have a high construction cost.

(5) Transformers

In the installation of transformers, the key issue is the selection of sites and rated capacities. Sites may be selected in accordance with the existing design guidelines. Based on installation on poles, the standards for selection of rated capacities are as follows.

Transformer loss may be divided into two basic categories: non-load loss, which occurs regardless of load, and load loss, which changes with the load current. Non-load loss consists mainly of core loss, which occurs mainly in the iron core serving as the passage of magnetic flux, and is strongly related to rated capacity.Load loss consists mainly of resistance loss in winding due to load current,and is also called "copper loss." The actual resistance of winding rises due to the skin effect of leaked magnetic flux, which expands along with the load current. Copper loss includes the resulting resistance loss and the loss associated with stray load due to eddy current arising in metal structures other than the winding.Load loss is expressed in terms of the value at 75 degrees (centigrade) as the standard winding temperature. Ordinarily, loss other than core and copper loss is on a low level; transformer design requires consideration only of core and copper loss. Transformer efficiency peaks when copper and core loss are equal. As installation of large-capacity transformers right from the start would result in a high core loss and consequently not be advisable, in formulation of the Master Plan, which extends about ten years into the future, capacities will be selected so that the anticipated load is in the range of 80 - 90 percent relative to the rated capacity.

Cutout switches with fuses will be installed in order to prevent transformer overload, protect transformers from short-circuit failures, and assure the outage scope needed for maintenance and inspection.

(6) Number of distribution line circuits

Part of the present ECG facility formation applies the N-1 criteria, but it is not certain whether or not these criteria will be adopted, and the number of circuits will therefore be determined as follows.

The N-1 criteria are based on the rule of preventing outage in the event of a single failure of a distribution facility, e.g., one transmission line circuit or one transformer.

They are applied internationally for improvement of distribution facilities.
A two-circuit design taking account of N-1 criteria will be applied for distribution lines in urban areas and those operated as subtransmission lines. In rural areas, on the other hand, single-circuit design will be allowed from the perspective of cost-effectiveness. For distribution lines applying the N-1 criteria, the operation at about 50 - 60 percent of the rated capacity in normal times is recommended, in consideration of load interchange in times of single-circuit failure and failures at adjacent substations, and of planned outages for inspection and maintenance.

(7) Maintenance of appropriate voltage

The standard approach for maintenance of appropriate voltage for changing load lies in use of both on-load tap-changing transformer and phase-modifying equipment such as shunt capacitors or reactors.

The standard voltage for each feeder is to be divided into three stages (peak, off-peak, and late-night) for overall satisfaction of targets,so that the voltage received by each customer is within the allowable scope.
As for phase-modifying equipment, shunt capacitors are to be brought in for reactive power regulation in times of heavy load, and shunt reactors, in those of light load. These equipment can be operated more

efficiently by ascertaining the load pattern in advance and engaging and disengaging them in accordance with the optimal time schedule determined on this basis.

(8) Neutral grounding system

Transformer neutral points are grounded in order to preserve the safety of line and power equipment, and to reduce insulation. The specific objectives are as follows.

- Prevention of abnormal voltage on line in the event of ground-fault failure
- Curtailment of the voltage rise in sound phases, and reduction of insulation of line and power equipment, in the event of ground-fault failure
- Flow of current to the ground through the neutral point in the event of ground-fault failure, proper detection of the failure by protective relays, and prompt clearing of the failure section

In Ghana, the solidly grounding system is the standard for 33- and 11-kV distribution lines. For the future, it will be necessary to make comparisons with the effective grounding system and select one or the other in coordination with the improvement of the power system. However, the power system has an insulation design anticipating excessive voltage occurring in the event of ground fault failure. It is consequently necessary to make a design that minimizes the aggregate cost through insulation cooperation between the neutral grounding system and the insulation performance of each power facility. Table 5-12 shows the characteristics of the two grounding systems.

Table 5-12 Neutral grounding systems

Grounding system	Characteristics
Solidly grounding	➢ Low possibility of occurrence of abnormal voltage ➢ Almost no rise in the ground voltage of sound phases in the event of ground-fault failures; ability to reduce insulation ➢ Need for measures to counter the large induction problems of telecom lines in the event of failure ➢ Certainty of protective relay operation due to the large ground-fault current ➢ Need for high-speed opening and reclosing to lessen the impact on other transmission systems
Effectively grounding	➢ Determination of the resistance value by the balance between certain operation of the protective relay and the impact on other transmission systems ➢ Rise in the voltage-to-ground of sound phases commensurate with the resistance value in the event of ground-fault failure ➢ Ability to curtail induction problems of telecom lines in the event of failure if the resistance value is large enough

(9) System protection

Circuit breakers, reclosers, and sectionalizers are to be installed for cooperation in protection, with each being endowed with an inverse-time characteristics. More specifically, clear distinctions must be made in the performance aspect to avoid an over-spec status in respect of switchgears as a whole. In the operation aspect, switchgears are to be opened from the load side in the event of system failure to curtail impact from the failure on the upper system as far as possible.

Failures in underground cable systems, unlike those in overhead lines, present a high risk of permanent failure due to causes such as insulation failure. For this reason, these systems should be designed and operated without circuit reclosure.

Generally, the repeated extension of distribution lines increases the system impedance and lowers the failure current on the line end. This makes it more difficult to detect system failures with protective relays. For sure detection of two-phase short-circuit current on the end, it is necessary to consider the conformance with the setting (tap value) of the protective relay each time the distribution line is extended. For flexible accommodation of such extensions and other changes in system constants, it is advisable to heighten the general-purpose properties by, for example, using as many protective relay tap fittings as possible.

5.4 Distribution facility cost estimation

5.4.1 Unit construction cost

This section concerns calculation of the approximate construction cost based on the Master Plans for distribution facility renewal, reinforcement, and extension formulated by the ECG and the VRA-NED. For the unit cost forming the basis of the calculation, it was decided to use those applied by the two utilities for distribution facilities and those applied in past ECG projects for subtransmission lines and primary substations.

Table 5-13 and Table 5-14 show the typical unit construction costs of ECG and VRA-NED respectively. Appendix 5.4.1 shows the unit construction costs used in the study.

Ultimately, the approximate construction cost calculated as shown in this section shall provide footing for economic analysis of projects and ordering of their priority.

Table 5-13 ECG unit construction costs

Description		Unit Cost (Material cost and Labor cost) GH¢	US$
Installation	2×20/26MVA Substation 33/11kV	1,530,000	1,700,000
	33kV Switching Substation	324,000	360,000
	33kV Bay complete with support structures, circuit breakers,current transfers,isolators,	81,000	90,000
	33kV 1cct 265mm^2 AAC,using wool poles	29,700	33,000
	33kV 2cct 265mm^2 AAC,using steel towers	82,800	92,000
	33kV 2cct 400mm^2 AAC,using steel towers	103,500	115,000
	33kV 1cct 630mm^2 Al XLPE	88,200	98,000
	11kV 1cct 150mm^2 AAC, using wool poles	18,900	21,000
	11kV 1cct 240mm^2 Al XLPE	45,000	50,000

(Exchange rate 1USD=0.90GH¢)

Table 5-14 VRA-NED unit construction costs

Description	Unit Cost GH¢	US$
Cost of Construction of 1 km, 3-phase, 34.5 kV Line	11,470.05	12,744.50
Cost of Construction of 1 km, 3-phase, Low Voltage Line	11,507.00	12,785.56
Cost of a 200 KVA, 34.5/0.433 Pole-mounted substation	9,473.50	10,526.11
Cost of a 200 KVA, 11/0.433 Pole-mounted substation	8,472.89	9,414.32
Cost of a 315 KVA, 11/0.433 ground-mounted substation	9,464.77	10,516.41
Cost of a 100 KVA, 11/0.433 Pole-mounted substation	7,519.71	8,355.23
Cost of a 100 KVA, 34.5/0.433 Pole-mounted substation	8,423.19	9,359.10
Cost of a 50 KVA, 34.5/0.433 Pole-mounted substation	7,372.95	8,192.17
Cost of a 50 KVA, 11/0.433 Pole-mounted substation	6,282.44	6,980.48
Cost of a 500 KVA, 34.5/0.433 ground-mounted substation	21,092.49	23,436.09

(Exchange rate 1USD=0.90GH¢)

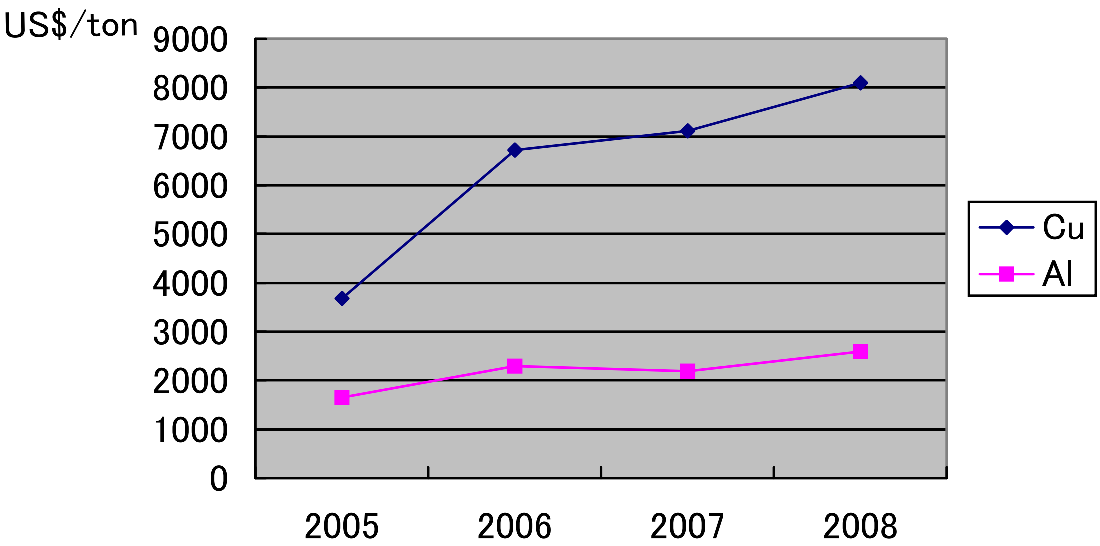
5.4.2 Consideration on the construction unit cost

(1) Overhead conductor

The MV line costs and the LV line costs account high share of the distribution network cost and have a big influence on the cost of the distribution network master, the Study Team made an examination to assess the unit cost level of distribution line construction in Ghana. In connection with product prices, an interview survey was conducted with manufacturers, in light of price variation depending on the purchasing quantity and other conditions as well as the lack of price disclosure by them. The following is an account of the survey findings.

The material costs such as copper cost and aluminum cost are assumed that there was not much difference among manufacturers in respect of material costs, because the material cost is set on the basis of the international market value. The labor cost in the manufacturing cost is not large because most parts of the manufacturing process are mechanized. When a user procures conductors from outside of the country, the shipping cost should be accounted. Consequently, the best approach will to procure conductors from manufacturers that are closest to the country. However, it is necessary to understand that the cost is settled by negotiation. There is one example of estimation about the conductor cost (AAC 100 mm^2, manufactured in Japan and accepted in India), the distance from Japan is close to the distance between Ghana and Europe. According to the estimation, the cost is 115,000 US$/km on condition that the aluminum cost on LME (London Market Exchange) base is 1,750 USD/ton. The cost is almost same level as the unit cost in Ghana considering the LME base cost in 2007 is 2,193 US$/ton.

Since the conductor cost is affected deeply by the material cost, manufacturers will shift the change of the material cost to the conductor cost as fast as possible. The following graph shows the change of the material cost of cupper and aluminum on LME base.



Remark: The cost in 2008 is the average from January to May.

Figure5-5 Change of material cost

From the graph the material cost in 2008 boosted 2.2 times for copper and 1.6 times for aluminum from 2005. The conductor costs must be affected the change of the material costs.

(2) Distribution transformer

The team evaluated the unit cost of the distribution transformer from the fact-finding in other countries examples.

One example is about the transformers, which are manufactured in Japan and are delivered to one African country. The cost will be more than 1.5 times of the unit cost in Ghana. The reason for this is that the manufacturer had to change the specification of the transformer to meet that of the concerned country, because the voltage of the distribution transformer used in Japan is 6600/200(100) V in general, and the volume of procurement is too small to be ignored the cost. The team also found another example that shows the difference in transformer costs in different Asian counties reaches to 2 times. The fact shows that the cost of distribution transformer will depend on the quality control of the product and quantity of procurement. Consequently, the cost of distribution transformer depends on quality control and procurement conditions such as the necessity of specification change and volume of procurement. And the cost will be changed by negotiation between user and manufacturer.

Chapter 6 Master Plan and Implementation Plan for distribution network renewal, reinforcement, and extension

6.1 Results of preparation of plans for primary substations and subtransmission lines

6.1.1 Plans for ECG primary substations and sub-transmission lines

(1) Plans for existing primary substations and subtransmission lines

Attachment 6.1.1.1 presents the plans for existing ECG primary substations and subtransmission lines. The ECG has plans for 28 substation projects at a total cost of about USD58 million and 39 subtransmission line projects at one of about USD32 million by 2012. Funding sources (e.g., the GEDAP and Ghanaian government) have already been determined for most of these projects, but this is not the case for some.

(2) Results for the major cities (Accra, Tema, Kumasi, and Takoradi)

Sections A through D present the results for the four major urban areas in the ECG supply area, i.e., Accra, Tema, Kumasi, and Takoradi, respectively.

A. Planning results for the Accra system

Figure 6-1 shows a diagram for the current 33-kV system in the Accra area. In 2008, the maximum demand was 458 MVA. The Accra system has two BSPs (Achimota and Mallam). About 65 percent of the power demand at peak times is supplied from the Achimota BSP. There is a large power flow in supply from the Achimota BSP to central Accra (on the Achimota-Airport section and between the K and D points, for example; the combined power flow value is 219 MVA). A total of 10 circuits of subtransmission lines (with a combined thermal capacity of 310 MVA) are used in these sections.

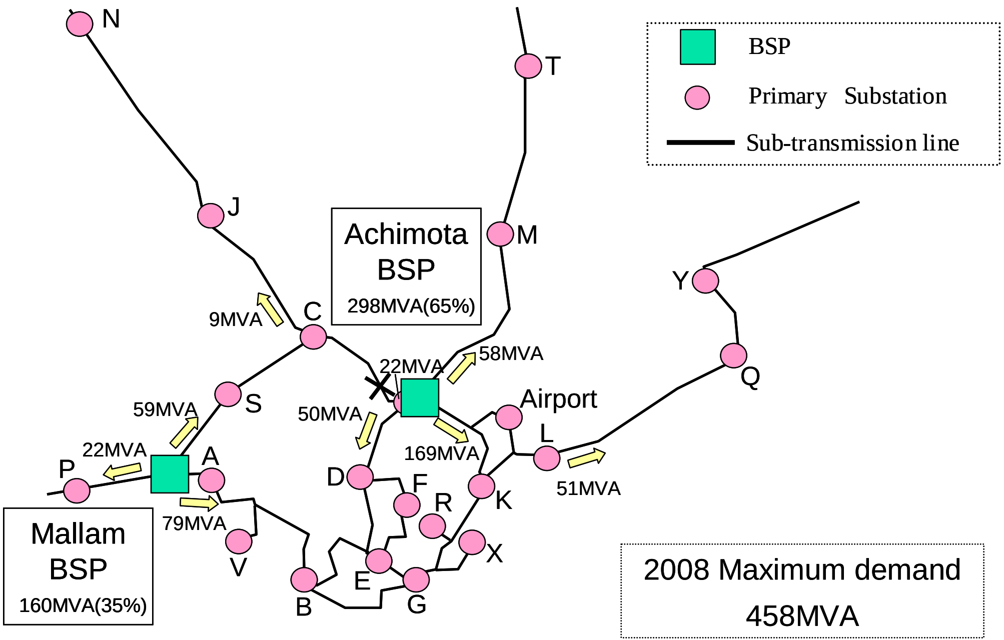


Figure 6-1 Diagram of the current Accra 33-kV system

Figure 6-2 presents a diagram of the system as of 2012 upon implementation of the Ghana Energy Development and Access Project (GEDAP) and other existing projects in their entirety. In that year, the maximum peak demand would reach 516 MVA. Attachment 6.1.1 lists the existing projects in the Accra area. By 2012, GEDAP, the national government project, and other projects are anticipated to add a total of 480 MVA in transformer capacity and 334 km of subtransmission lines (through extensions). Furthermore, under the national government project, a third BSP is to be constructed in the eastern part of the Accra area.

Analysis of the system as of 2012 found that there would not be any overload or voltage problems for the primary substations and subtransmission lines in the Accra area. The existing future plans for primary substations and sub-transmission lines are enough for the maximum demand in 2012.

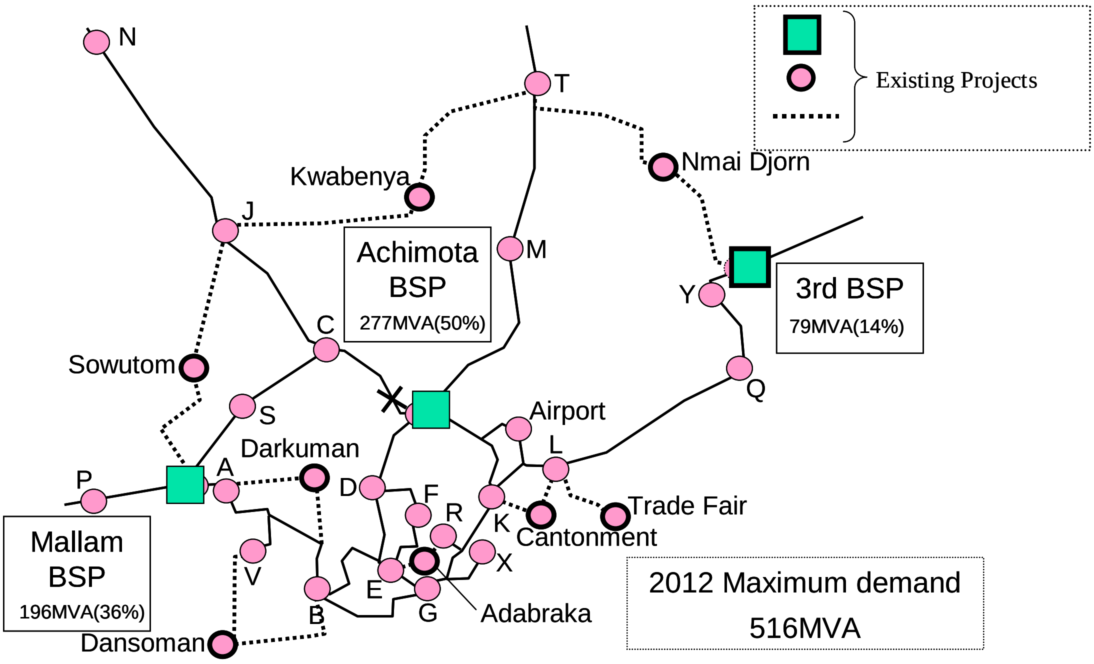


Figure 6-2 Diagram of the Accra 33-kV system in 2012

Although there are no additional plans for the years following 2012, an analysis was made of the system over the years 2013 - 2017 to check for bottlenecks. This analysis found overload on the subtransmission line between the H (Achimota) and E points in the system diagram for 2016 shown in Figure 6-3.

As shown in Table 6-1, the installation of an additional subtransmission line at the overload point was selected as the solution for the aforementioned bottleneck. Besides resolving the bottleneck in 2016, this step would prevent the occurrence of a bottleneck in 2017 (when the maximum peak demand would reach 609 MVA).

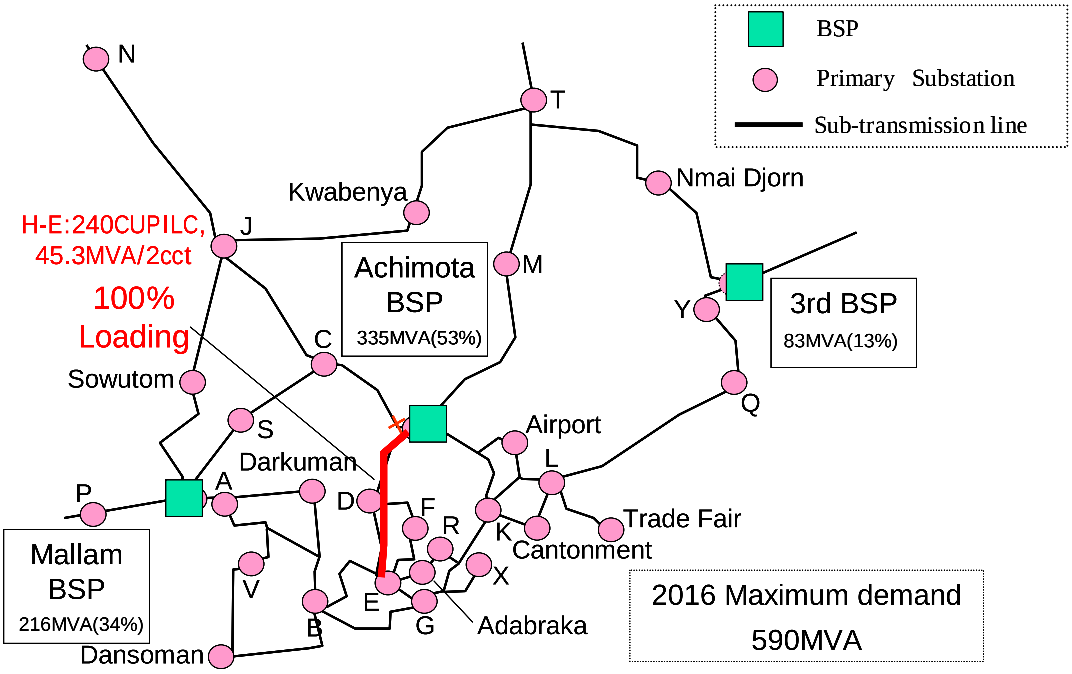


Figure 6-3 Diagram of the Accra 33-kV system in 2016

Table 6-1 Proposed project for the Accra system

Facility name	Bottleneck	Countermeasure	Cost (USD1,000)	Year of implementation
H(Achimota)-E	- Subtransmission line overload	- Installation of two new 630 ALXLPE circuits between H and E (2 circuits x 6.3 km)	1,323	2016

B. Planning results for the Tema system

Figure 6-4 shows a diagram for the current 33-kV system in the Tema area. In 2008, the maximum peak demand was 160 MVA. The Tema 33-kV system is supplied from the Tema BSP.

Figure 6-5 presents a diagram of the system as of 2012 upon implementation of the GEDAP and other existing projects in their entirety. In that year, the maximum peak demand would reach 190 MVA. Attachment 6.1.1.1 lists the existing projects in the Tema area. By 2012, GEDAP, the national government project, and other projects are anticipated to add a total of 200 MVA in transformer capacity and 140 km of subtransmission lines (through extensions). The system will be connected to the BSP built in the Accra area.

Analysis of the system as of 2012 found that there would not be any overload or voltage problems for the primary substations and subtransmission lines in the Tema area. The existing future plans for primary substations and sub-transmission lines are enough for the maximum demand in 2012.

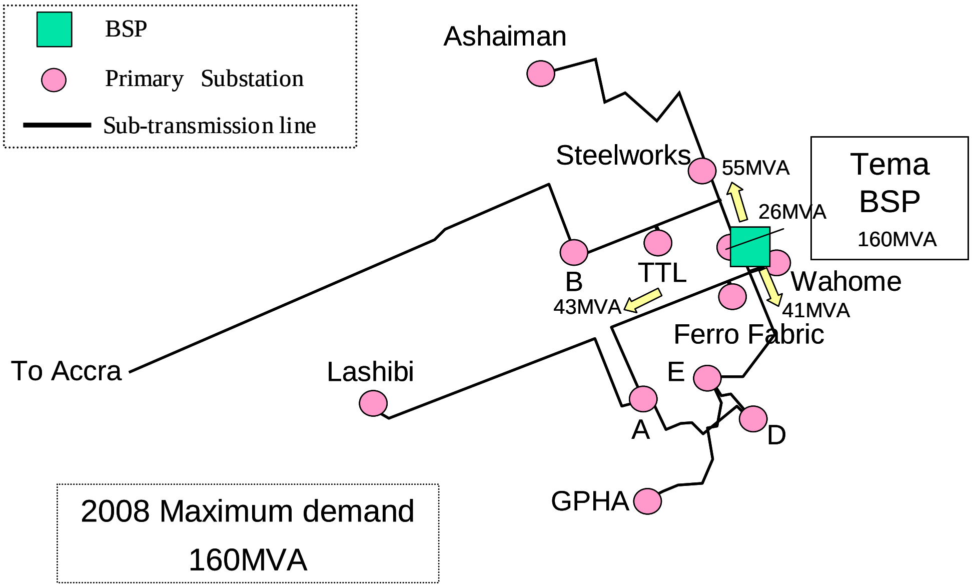


Figure 6-4 Diagram of the current Tema 33-kV system

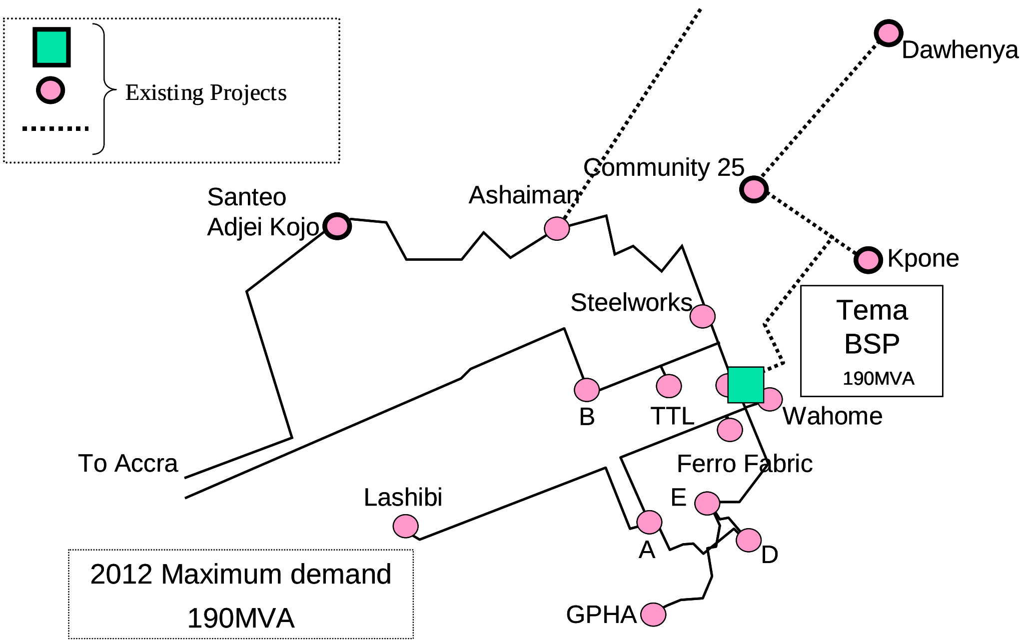


Figure 6-5 Diagram of the Tema 33-kV system in 2012

Although there are no additional plans for the years following 2012 in the Tema area either, an analysis was made of the system over the years 2013 - 2017 to check for bottlenecks. This analysis found overload on the subtransmission line between the H (Tema) and E points in the system diagram for 2016 shown in Figure 6-6.

As shown in Table 6-2, the installation of an additional subtransmission line at the overload point was selected as the solution for the aforementioned bottleneck. Besides resolving the bottleneck in 2016, this step would prevent the occurrence of a bottleneck in 2017 (when the maximum peak demand would reach

240 MVA).

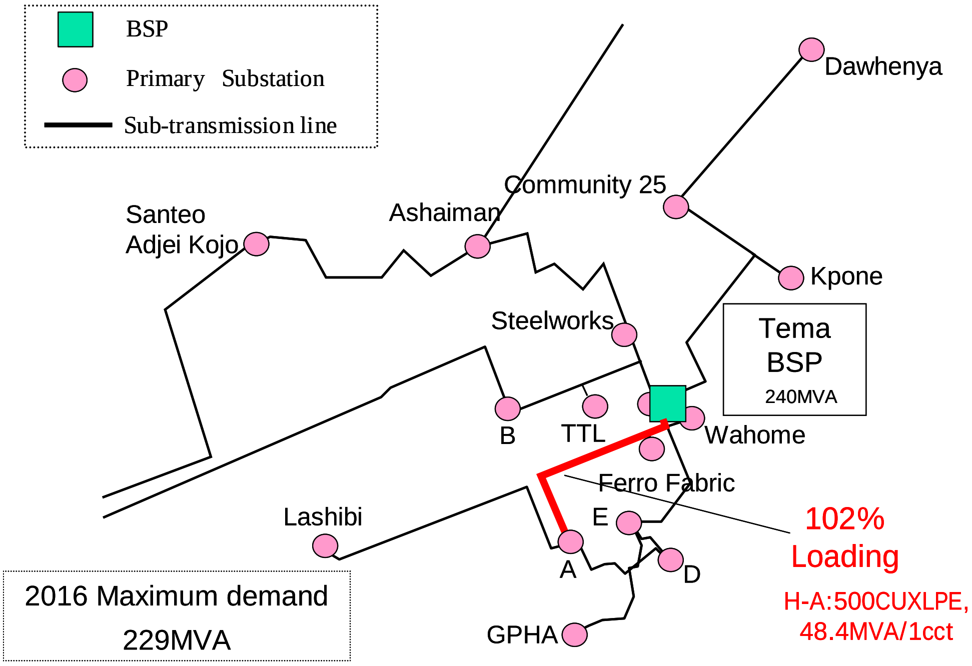


Figure 6-6 Diagram of the Tema 33-kV system in 2016

Table 6-2 Proposed project for the Tema system

Facility name	Bottleneck	Countermeasure	Cost (USD1,000)	Year of implementation
H(Tema)-A	- Subtransmission line overload	- Installation of two new 630 ALXLPE circuits between H and E (1 circuits x 5.6 km)	588	2016

C. Planning results for the Kumasi system

Figure 6-7 shows a diagram for the current 33-kV system in the Kumasi area. In 2008, the maximum peak demand was 174 MVA. The Kumasi 33-kV system is supplied from the Kumasi BSP.

Figure 6-8 presents a diagram of the system as of 2012 upon implementation of the GEDAP in its entirety. In that year, the maximum peak demand would reach 211 MVA. Attachment 6.1.1.1 lists the existing projects in the Kumasi area. By 2012, the GEDAP is anticipated to add a total of 120 MVA in transformer capacity and 52 km of subtransmission lines (through extensions). A second BSP is to be constructed in the eastern part of the Kumasi area.

Analysis of the system as of 2012 found that there would not be any overload or voltage problems for the primary substations and subtransmission lines in the Kumasi area. The existing future plans for primary substations and sub-transmission lines are enough for the maximum demand in 2012.

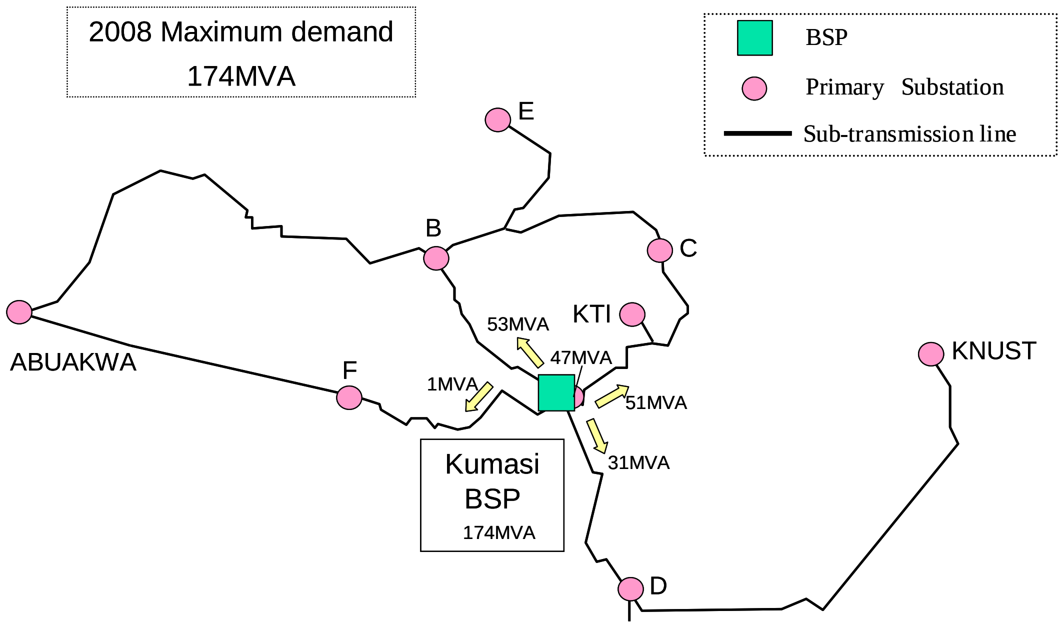


Figure 6-7 Diagram of the current Kumasi 33-kV system

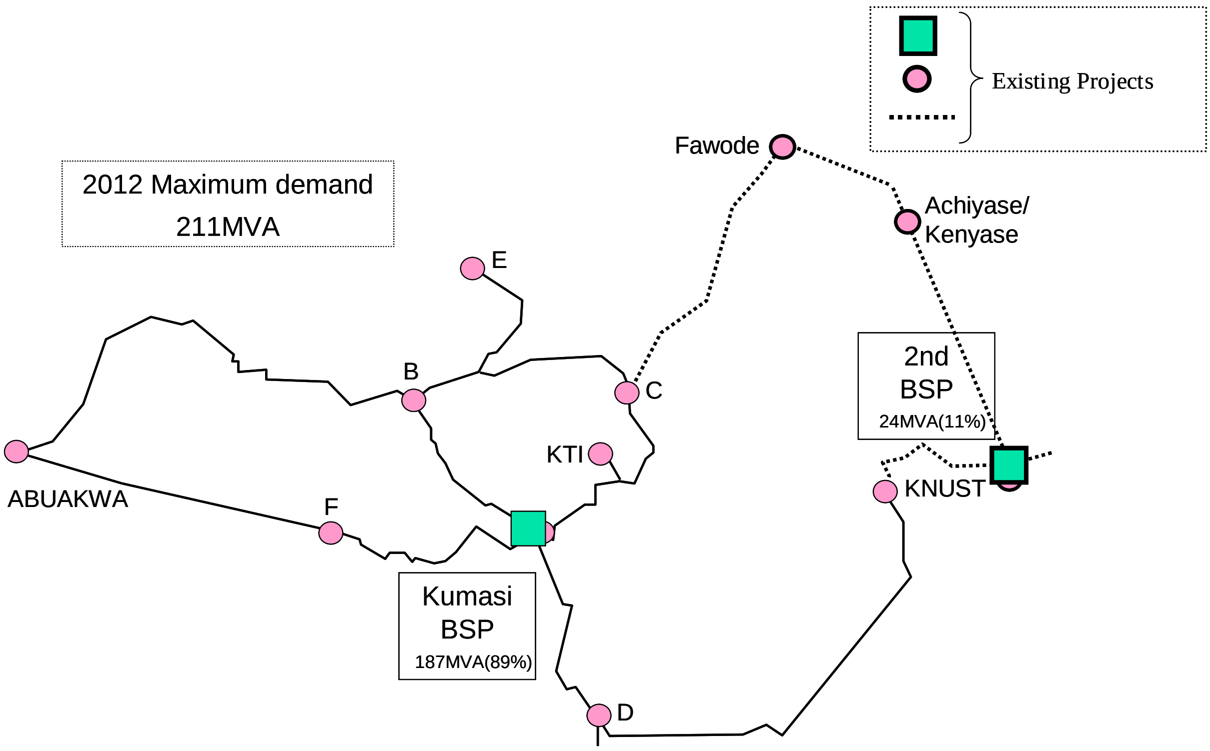


Figure 6-8 Diagram of the Kumasi 33-kV system in 2012

Although there are no additional plans for the years following 2012 in the Kumasi area either, an analysis was made of the system over the years 2013 - 2017 to check for bottlenecks. This analysis found overload on the subtransmission line between the A and KTI points in the system diagram for 2017 shown in Figure 6-9.

As shown in Table 6-3, the installation of an additional subtransmission line at the overload point was selected as the solution for the aforementioned bottleneck. This step would resolve the bottleneck in 2017.

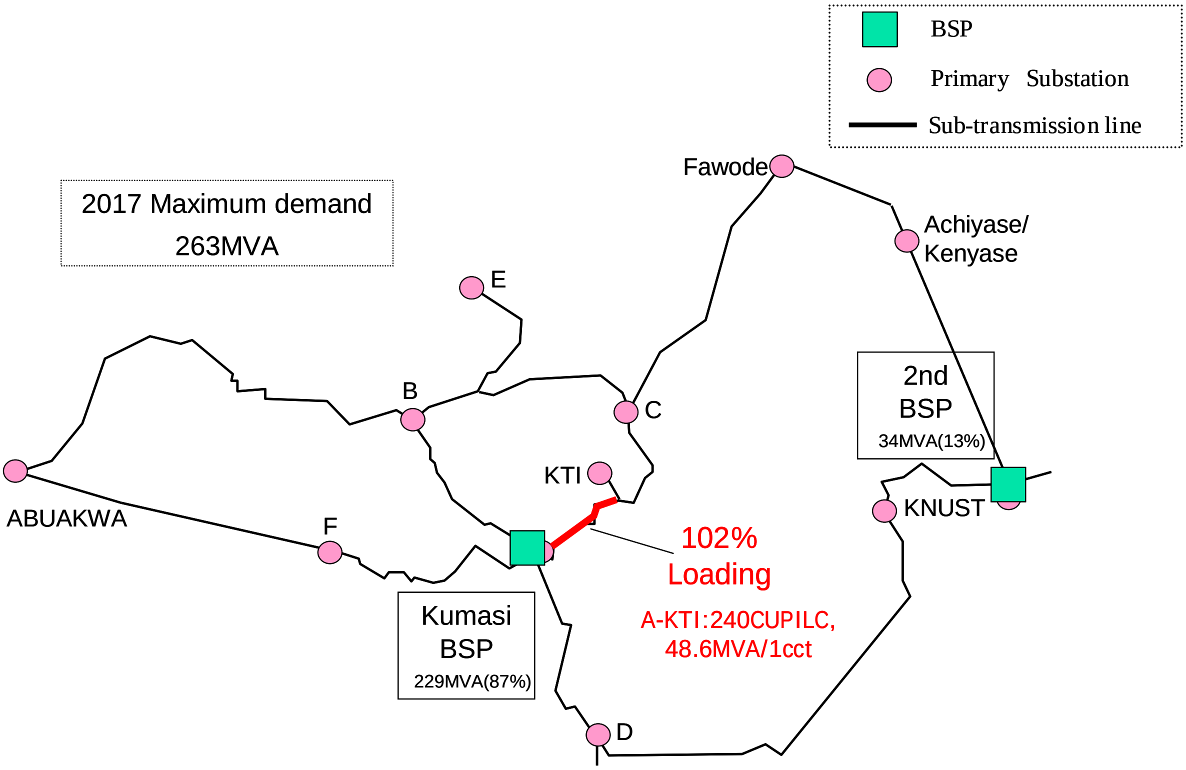


Figure 6-9 Diagram of the Kumasi 33-kV system in 2017

Table 6-3 Proposed project for the Kumasi system

Facility name	Bottleneck	Countermeasure	Cost (USD1,000)	Year of implementation
A-KTI	- Subtransmission line overload	- Installation of two new 630 ALXLPE circuits between H and E (1 circuits x 5.0 km)	525	2017

D. Planning results for the Takoradi system

Figure 6-10 shows a diagram for the current 33-kV system in the Takoradi area. In 2008, the maximum peak demand was 86 MVA. The Takoradi 33-kV system is supplied from the Takoradi BSP.

Figure 6-8 presents a diagram of the system as of 2012 upon implementation of the GEDAP and other existing projects in their entirety. In that year, the maximum peak demand would reach 98 MVA. Attachment 6.1.1.1 lists the existing projects in the Takoradi area. By 2012, the GEDAP and other projects are anticipated to add a total of 90 MVA in transformer capacity and 6 km of subtransmission lines (through extensions).

Analysis of the system as of 2012 found that there would not be any overload or voltage problems for the primary substations and subtransmission lines in the Takoradi area. The existing future plans for primary substations and sub-transmission lines are enough for the maximum demand in 2012.

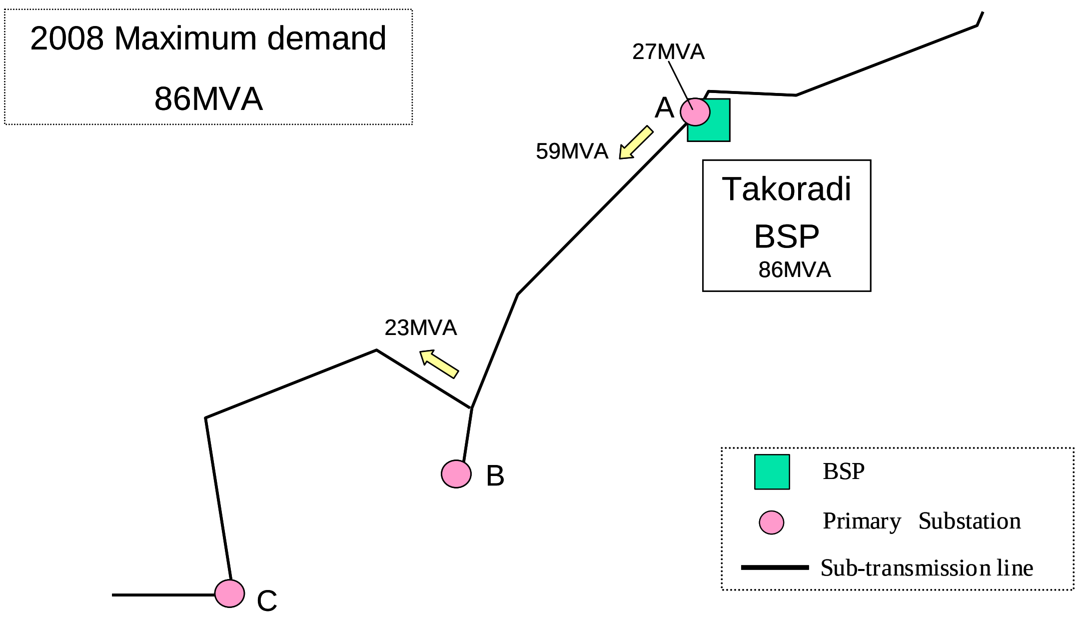


Figure 6-10 Diagram of the current Takoradi 33-kV system

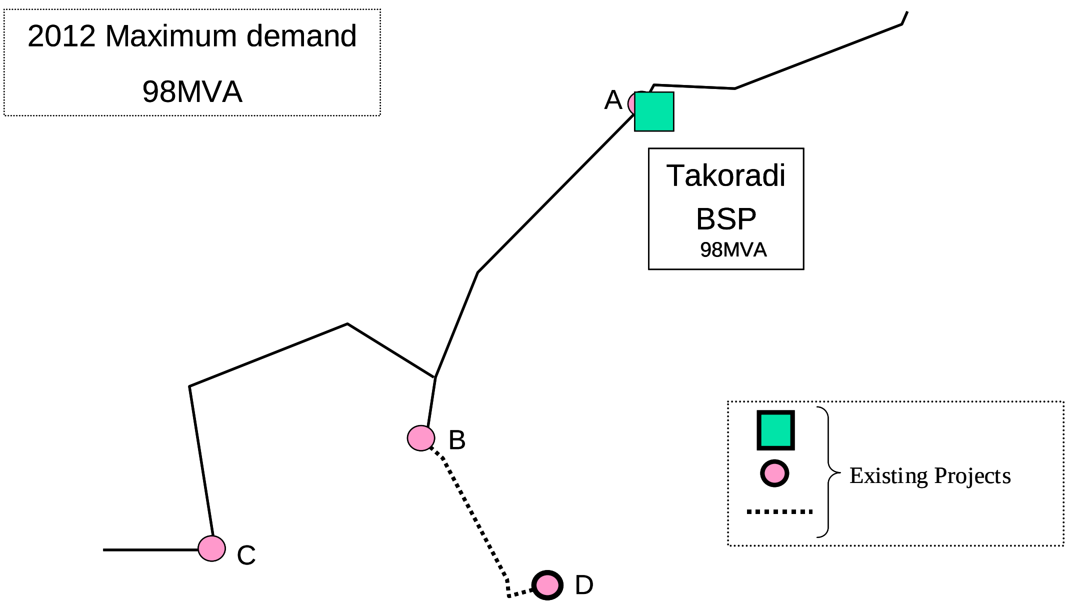


Figure 6-11 Diagram of the Takoradi 33-kV system in 2012

Although there are no additional plans for the years following 2012 in the Takoradi area either, an analysis was made of the system over the years 2013 - 2017 to check for bottlenecks. This analysis found that there would not be any problems in primary substations or on subtransmission lines even in 2017 (when the maximum peak demand would reach 116 MVA), as shown in Figure 6-12. There are consequently no additional projects proposed for the Takoradi system.

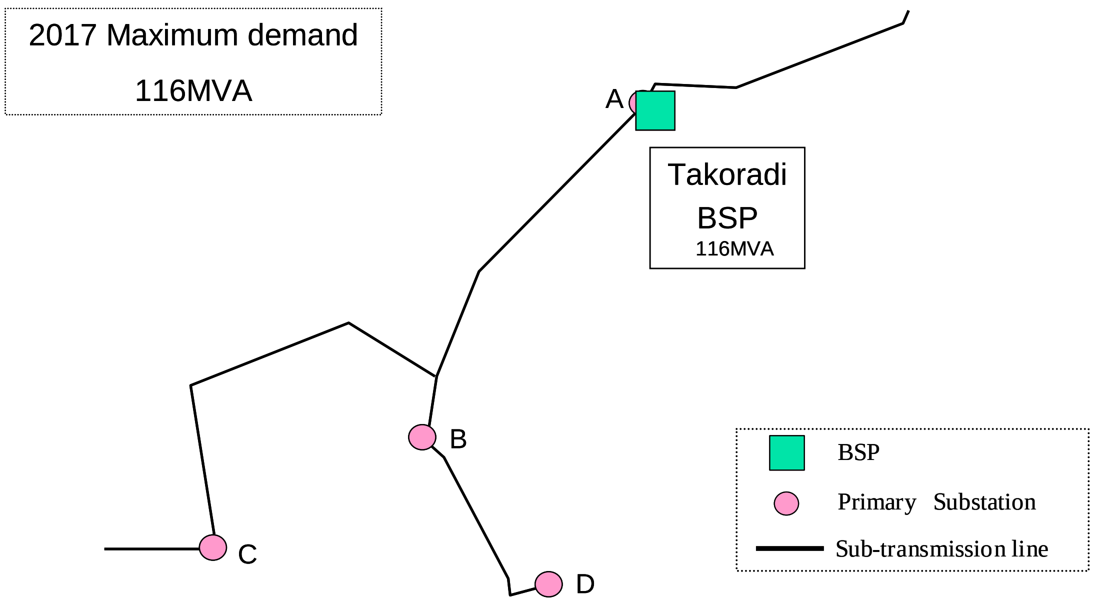


Figure 6-12 Diagram of the Takoradi 33-kV system in 2017

(3) Planning results for other areas

For areas other than the major urbanized ones (Accra, Tema, Kumasi, and Takoradi), the Study Team analyzed the propriety of the primary substation capacity and determined the requisite countermeasures. The results for primary substation capacity are shown in Attachment 6.1.1.2.

The analysis found overload at nine primary substations. The overload at the Cape Coast primary substation in the Central Region is anticipated to be resolved by the construction of a new substation at Elmina in an existing project. The Study Team therefore considered countermeasures for the other eight cases.

As a result, it was decided to propose the installation of additional transformers in order to resolve overload. This was becuse all of the primary substations in question have space for additional transformers. Upon consultation with the C/P, a capacity of 10 MVA was chosen for all of these transformers, because the demand may be expected to grow at a fast pace in all of these areas.

Table 6-4 lists the proposed projects for primary substations in other areas. The proposed projects concern eight primary substations in five regions/areas, and would add a total of 80 MVA in transformer capacity at a total cost of USD1.6 million.

Table 6-4 Proposed projects for primary substations in other areas

Region/area	Facility name	Countermeasure	Capacity	Cost (USD1,000)	Year of implementation
Tema	Kpong	- Installation of an additional transformer	10MVA	200	2016
Western	Atuabo	- Installation of an additional transformer	10MVA	200	2009
	Axim	- Installation of an additional transformer	10MVA	200	2015
Eastern	ODA	- Installation of an additional transformer	10MVA	200	2012
Central	Saltpond	- Installation of an additional transformer	10MVA	200	2009
Volta	Kpeve	- Installation of an additional transformer	10MVA	200	2009
	Tsito	- Installation of an additional transformer	10MVA	200	2015
	Hohoe	- Installation of an additional transformer	10MVA	200	2012

6.1.2 Plans for VRA-NED primary substations and subtransmission lines

Figure 6-13 presents a diagram of the VRA-NED system. It consists of six BSPs, five primary substations, and one switching station.

Table 6-5 presents the results of analysis for VRA-NED subtransmission lines and primary substations. The analysis found that the voltage drop would fail to meet the standard on four of the six subtransmission lines. On any of the six lines, there was judged to be no problem with the current load rate. For primary substations, the analysis found overload at four.

Table 6-6 lists the proposed projects. For subtransmission lines, the proposed countermeasures for improving voltage are installation of capacity banks or thicker line cable. The 34.5-kV Bolgatanga-Bawku line was excluded from the proposed projects because the installation of a new 34.5-kV subtransmission line along with the construction of the Zebilla BSP currently undertaken by the VRA is anticipated to resolve the bottleneck. For primary substations, the Study Team proposed the installation of additional transformers to resolve overload because there is space for them at all substations.

The proposed projects in the VRA-NED service area would entail a total cost of USD629,000 for subtransmission lines and add 16 MVA in transformer capacity at primary substations at a total cost of USD262,000.

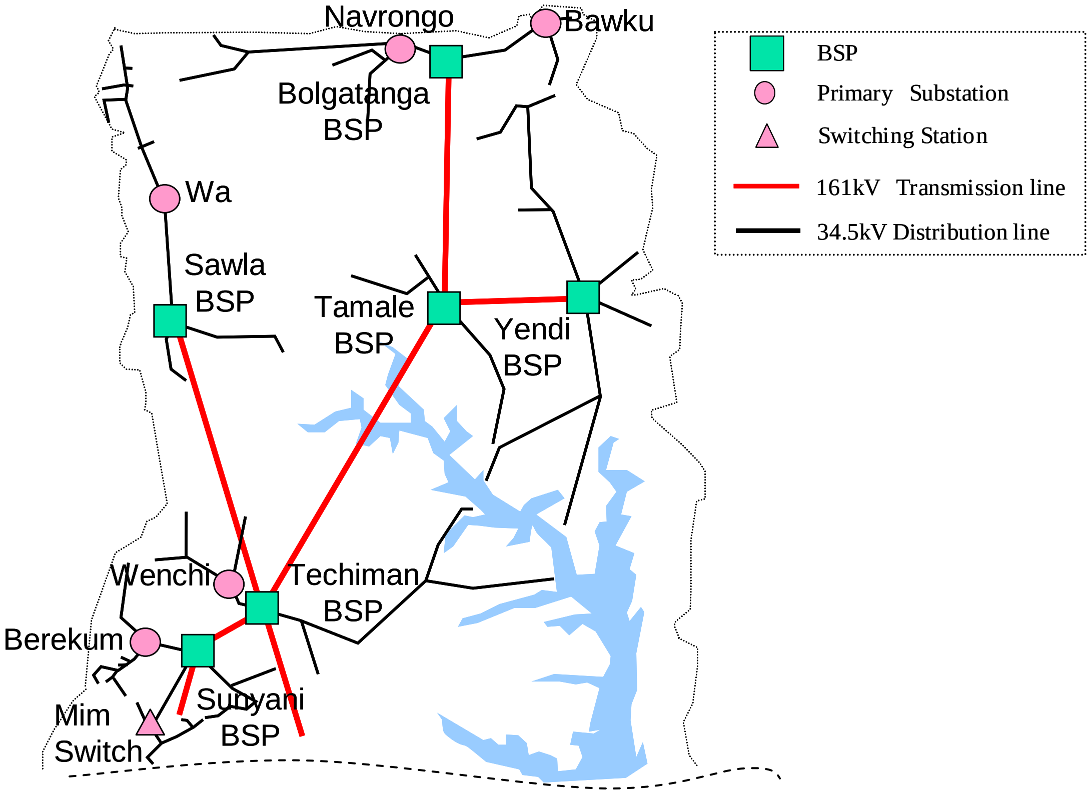


Figure 6-13 Power system diagram of VRA-NED

Table 6-5 Results of analysis for VRA-NED subtransmission lines and primary substations

(a) Analysis result of sub-transmission lines

Region/area	Name of Primary substations and sub-transmission lines	Analysis result	
		Voltage drop (%)	Current loading (%)
Brong Afaho	34.5kV Sunyani-Brekum line	19.3	73.4
Brong Afaho	34.5kV Sunyani-Mim line	29.5	58.5
Brong Afaho	34.5kV Techiman-Wenchi line	3.5	14.0
Upper West	34.5kV Sawla-Wa line	32.5	46.1
Upper East	34.5kV Bolgatanga-Bawku line	16.0	67.0
Upper East	34.5kV Bolgatanga-Navrongo line	1.0	24.8

(b) Analysis result of primary substations

Region	Substation Name	Capacity (MVA)	Maximum Demand (MVA)									
			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
VRA-NED	Berekum	5	4.9	5.0	5.2	5.4	5.6	5.8	6.1	6.3	6.5	6.8
			(97%)	(101%)	(104%)	(108%)	(112%)	(117%)	(121%)	(126%)	(131%)	(136%)
	Wa	5	4.3	4.5	4.7	4.9	5.1	5.4	5.6	5.9	6.1	6.4
			(86%)	(90%)	(94%)	(98%)	(103%)	(107%)	(112%)	(117%)	(122%)	(128%)
	Navrongo	3	1.7	1.8	2.0	2.1	2.3	2.5	2.7	2.9	3.1	3.3
			(56%)	(61%)	(65%)	(71%)	(76%)	(82%)	(89%)	(96%)	(103%)	(111%)
	Bawku	3	2.9	3.2	3.4	3.6	3.9	4.1	4.4	4.7	5.0	5.4
			(98%)	(105%)	(112%)	(120%)	(128%)	(137%)	(147%)	(157%)	(168%)	(179%)
	Wenchi	3	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.5	1.5	1.6
			(37%)	(38%)	(40%)	(41%)	(43%)	(45%)	(47%)	(48%)	(50%)	(52%)

Table 6-6 Proposed projects for the VRA-NED system

Facility	Facility name	Countermeasure	Amount	Cost (1,000US$)	Year of implementation
Sub-transmission line	34.5kV Sunyani-Brekum	- Installation of capacity bank	3000kVar	4	2010
		- Increase in thickness (from 120 to 200 mm2 AAC)	43km	616	
	34.5kV Sunyani-Mim	- Installation of capacity bank	4000kVar	6	2010
	34.5kV Sawla-Wa	- Installation of capacity bank	2000kVar	3	2011
	34.5kV Bolgatanga-Bawku	- Resolution of bottleneck by installation of a new 34.5-kV subtransmission line along with construction of the Zebilla BSP	—	—	—
Primary substation	Berekum	- Installation of an additional transformer	5MVA	83	2009
	Bawku	- Installation of an additional transformer	3MVA	48	2009
	Wa	- Installation of an additional transformer	5MVA	83	2012
	Navrongo	- Installation of an additional transformer	3MVA	48	2016

6.1.3 Examination of supply reliability

The preceding sections considered countermeasures for supply in normal operation, free of failures in the system. This section takes up facility countermeasures to ensure satisfaction of the N-1 standard in order to further heighten supply reliability. The Study Team examined the case of failure of a single subtransmission line circuit, checked for locations at which the thermal capacity on the line would exceed 100 percent in the event of such failure, and examined countermeasures. Sections (1) - (4) below present the findings for the Accra, Tema, Kumasi, and Sunyani systems, respectively.

(1) Results for countermeasures in the Accra system

Figure 6-14 presents the results of analysis for the Accra system as of 2017. The bold lines indicate locations in which the thermal capacity would exceed 100 percent in the event of failure of a single subtransmission line circuit.

Table 6-7 presents countermeasures for resolution of these overload locations. The installation of a total of 17 km of underground cable would give the system an even higher degree of reliability. The cost of the countermeasures would total USD1,785.

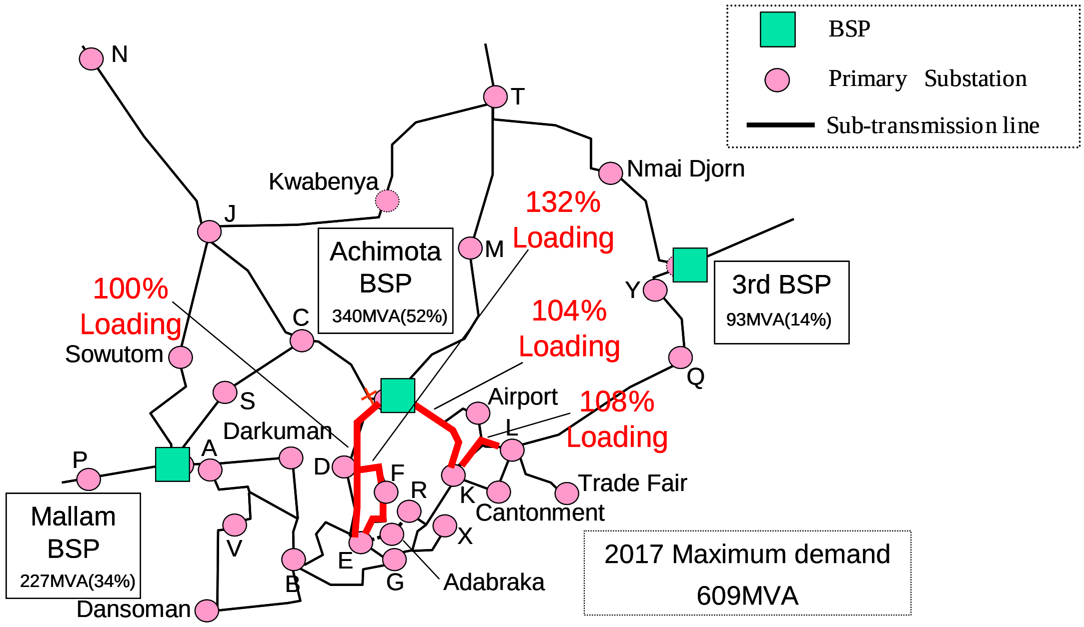


Figure 6-14 Results of analysis for the Accra 33-kV system as of 2017

Table 6-7 List of countermeasures to increase supply reliability in the Accra system

Facility name	Bottleneck	Countermeasure	Cost (USD1,000)	Year of implementation	Facility name
H-K	Overloading of sub-transmission line (one circuit loss of H-K line)	New line H-K 630ALXLPE	4.7km	494	2017
H-E	Overloading of sub-transmission line (one circuit loss of H-E line)	New line H-E 630ALXLPE	6.3km	662	2017
K-L	Overloading of sub-transmission line (one circuit loss of K-L line)	New line K-L 630ALXLPE	3.1km	323	2017
F-E	Overloading of sub-transmission line (one circuit loss of D-F line)	New line F-E 630ALXLPE	2.9km	305	2017
D-F	Overloading of sub-transmission line (one circuit loss of F-E line)				

(2) Results for countermeasures in the Tema system

Figure 6-15 presents the results of analysis for the Tema system as of 2017. The bold lines indicate locations in which the thermal capacity would exceed 100 percent in the event of failure of a single subtransmission line circuit.

Table 6-8 presents countermeasures for resolution of these overload locations. The installation of a total of 8.7 km of underground cable would give the system an even higher degree of reliability. The cost of the countermeasures would total USD1,039.

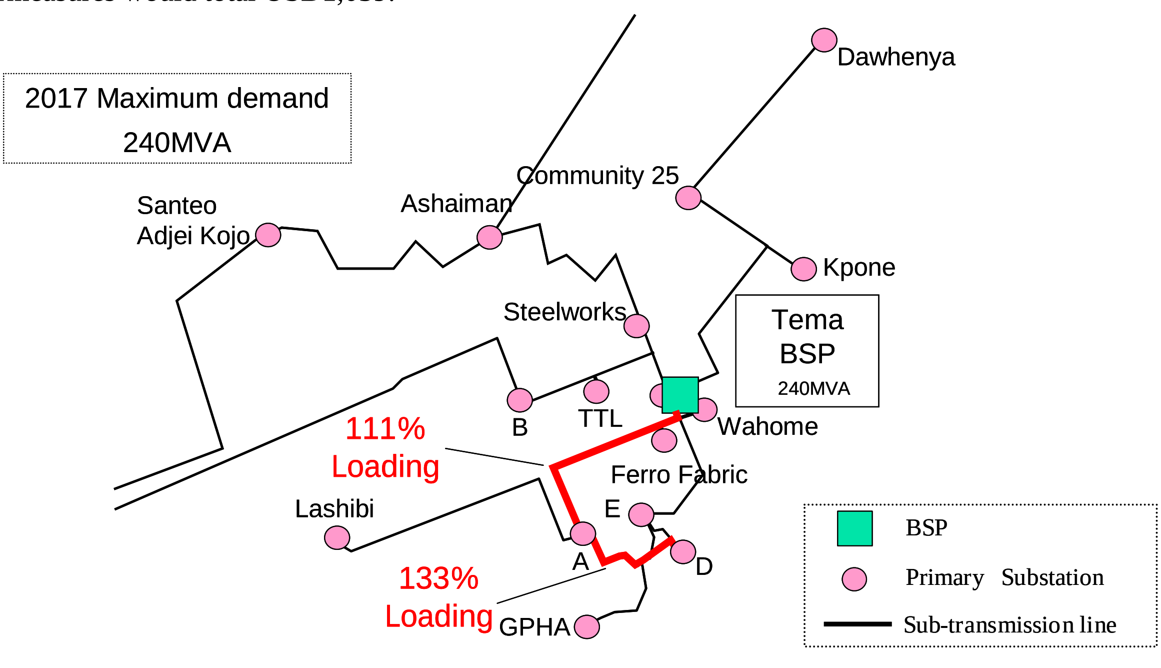


Figure 6-15 Results of analysis for the Tema 33-kV system as of 2017

Table 6-8 List of countermeasures to increase supply reliability in the Tema system

Facility name	Bottleneck	Countermeasure	Cost (USD1,000)	Year of implementation	Facility name
H-A	Overloading of sub-transmission line (one circuit loss of H-K line)	Reinforcement of H-A 240CUPILC to 630ALXLPE	5.6km	669	2017
A-D	Overloading of sub-transmission line (one circuit loss of A-D line)	Reinforcement of A-D 240CUPILC to 630ALXLPE	3.1km	370	2017

(3) Results for countermeasures in the Kumasi system

Figure 6-16 presents the results of analysis for the Kumasi system as of 2017. The bold lines indicate locations in which the thermal capacity would exceed 100 percent in the event of failure of a single subtransmission line circuit.

Table 6-9 presents countermeasures for resolution of these overload locations. The installation of a total of 16.5 km of underground cable and reinforcement of 5 km of overhead distribution lines would give the system an even higher degree of reliability. The cost of the countermeasures would total USD1.244 million.

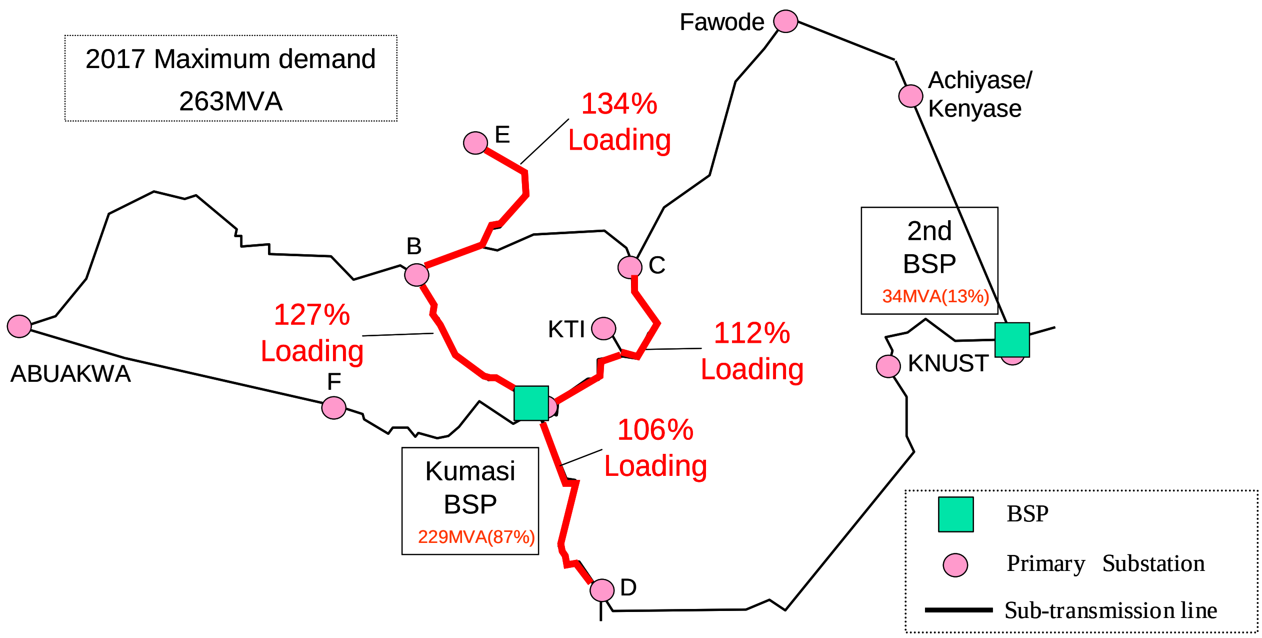


Figure 6-16 Results of analysis for the Kumasi 33-kV system as of 2017

Table 6-9 List of countermeasures to increase supply reliability in the Kumasi system

Facility name	Bottleneck	Countermeasure	Cost (USD1,000)	Year of implementation	Facility name
A-C	Overloading of sub-transmission line (one circuit loss of A-C line)	New line A-C 240ALXLPE	7.0km	348	2017
A-B	Overloading of sub-transmission line (one circuit loss of A-B line)	New line A-B 240ALXLPE	5.0km	248	2017
B-E	Overloading of sub-transmission line (one circuit loss of B-E line)	New line A-C 240ALXLPE	4.5km	223	2017
A-D	Overloading of sub-transmission line (one circuit loss of A-D line)	Reinforcement of A-C 265ALBARE to 400ALBARE	5.0km	424	2017

(4) Results for countermeasures in the Sunyani system

Figure 6-17 presents a system diagram for the Sunyani area. The Sunyani system and the adjacent Techiman system contain two BSPs (Sunyani and Techiman), which supply power through the Berekum and Wenchi substations and the Mim switching station. The area has a lot of woodworking plants and other large-scale plants, and in increase in the supply reliability would also be important for assuring the VRA-NED of stable revenue sources.

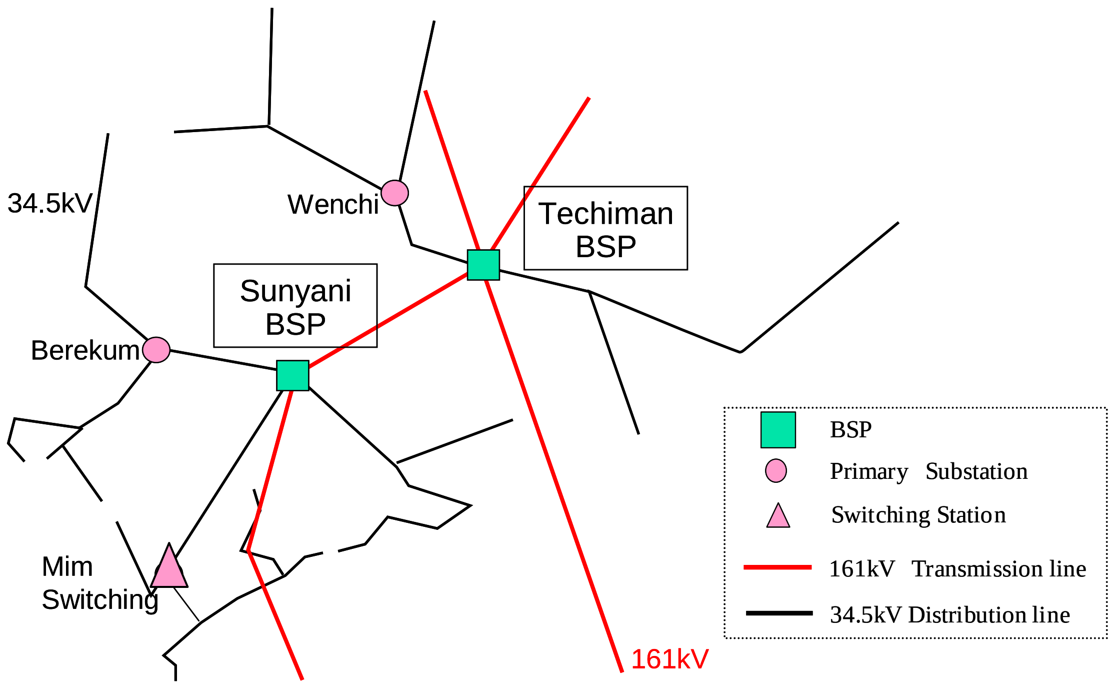


Figure 6-17 Power system diagram of Sunyani area

A. Reliability countermeasures examined

Figure 6-18 and Table 6-10 present the countermeasures examined to improve the reliability of supply. To increase reliability in the 34.5-kV system, the Study Team proposes interconnection of subtransmission lines that are relatively close to each other for operation in a loop enabling satisfaction of the N-1 standard. Steps making loop operation possible would allow uninterrupted supply of power even if one circuit fails. Upon consultation with the C/P, it was decided to interconnect subtransmission lines at three locations, as shown in Table 6-10. The examination is for 2017.

B. Postulated failures

As shown below, in the examination of reliability, the Study Team postulated the failure of one circuit on three subtransmission line sections.

- 34.5-kV Sunyani-Mim subtransmission line
- 34.5-kV Sunyani-Berekum subtransmission line
- 34.5-kV Techiman-Wenchi subtransmission line

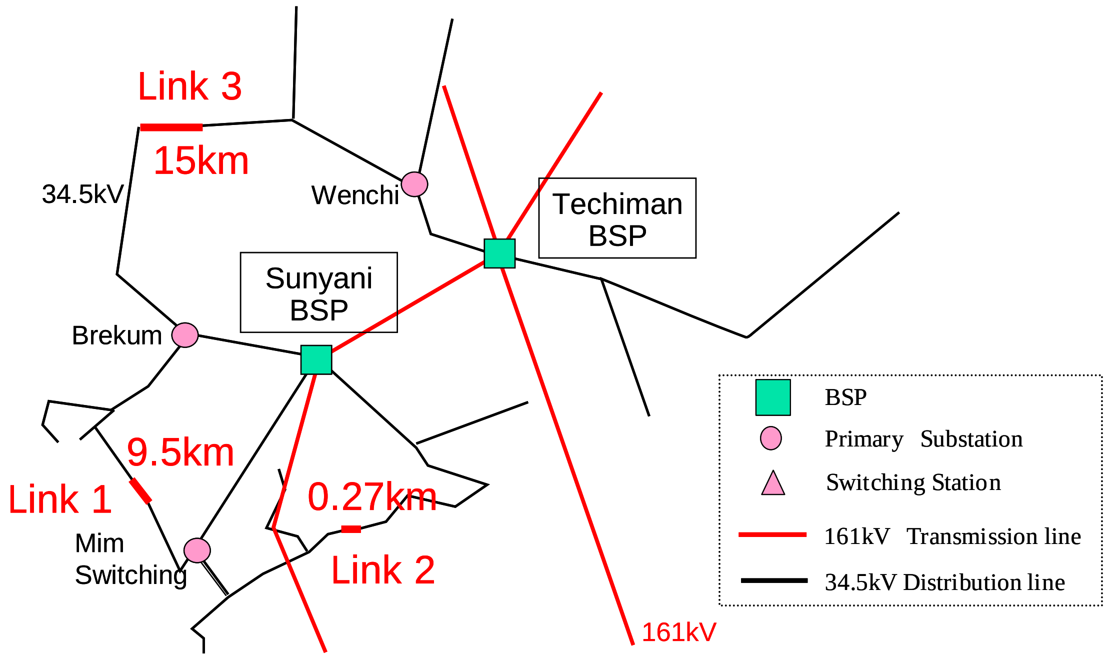


Figure 6-18 Reliability countermeasure to be studied in the Sunani power system

Table 6-10 Reliability countermeasure

Area		Distance (km)	Line type
Link 1	From Bediako to Gambia	9.5	120mm^2 AAC
Link 2	From Tepa to Hwidlum	0.27	120mm^2 AAC
Link 3	From Drobo to New Longoro	15.0	120mm^2 AAC

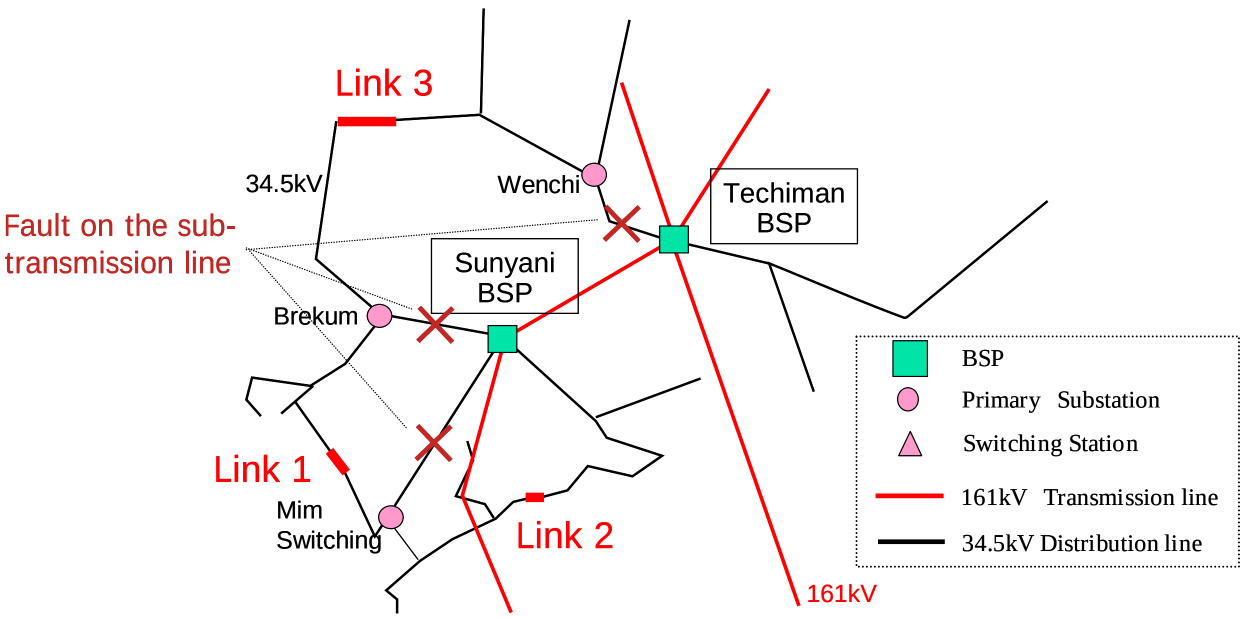


Figure 6-19 Supposed fault of sub-transmission line

C. Examination results

1) Single-circuit failure on the 34.5-kV Sunyani-Mim subtransmission line

Figure 6-20 shows the findings of analysis in this case. As it indicates, in the event of failure of a single circuit on the Sunyani-Mim subtransmission line, there would be a power flow of 5.3 MVA from the Brekum primary substation in Link 1 and of 8.6 MVA from the Sunyani BSP in Link 2. This would make it possible to supply the load from the Mim switching station.

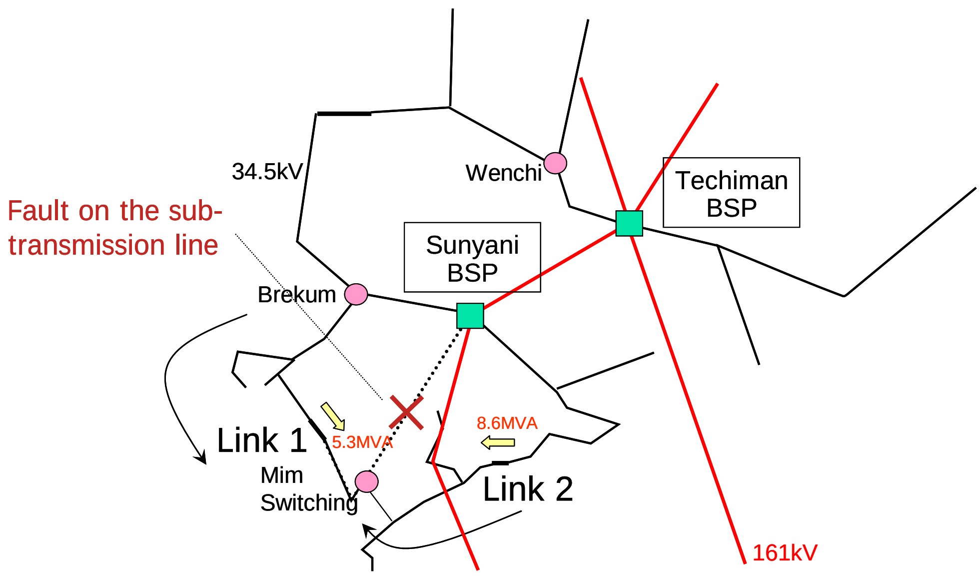


Figure 6-20 Power flow analysis result in case of fault on 34.5kV Sunyani-Mim line

2) Single-circuit failure on the 34.5-kV Sunyani-Berekum subtransmission line

Figure 6-21 shows the findings of analysis in this case. The failure of a single circuit on the Sunyani-Berekum subtransmission line would result in a bigger voltage drop in the vicinity of the Berekum primary substation and make it impossible to supply the load. The supply to the Berekum primary substation is from the Sunyani BSP and Wenchi primary substation, and is made through 34.5-kV distribution lines over a long distance (over 100 km in each case). This is why the voltage drop would be extremely large.

As for prospective countermeasures, this drop could be prevented by giving the 34.5-kV Sunyani-Berekum subtransmission line two circuits instead of the current one. This would enable uninterrupted supply even if one circuit fails on this line.

3) Single-circuit failure on the 34.5-kV Techiman-Wenchi subtransmission line

Figure 6-22 shows the findings of analysis in this case. In the event of failure of a single circuit on the Techiman-Wenchi subtransmission line, the supply to the Wenchi primary substation would be made from the Berekum primary substation about 110 km away. This would magnify the voltage drop; the drop at the Wenchi primary substation would be about 30 percent.

The Study Team proposed a shift to two circuits for the aforementioned Sunyani-Berekum line as described in the preceding section, and consequently took the installation of two circuits as an assumption in its analysis of single-circuit failure on the Techiman-Wenchi subtransmission line. Figure 6-23 shows the findings.

In this case, the rate of voltage drop at the Wenchi primary substation would be about 20 percent, and this would be a considerable improvement. The failure of a single circuit is an emergency situation, and it would not necessarily be required to meet the voltage drop rate standard of no more than 10 percent in this case. For this reason, the Study Team decided that a rate of 20 percent could be tolerated here.

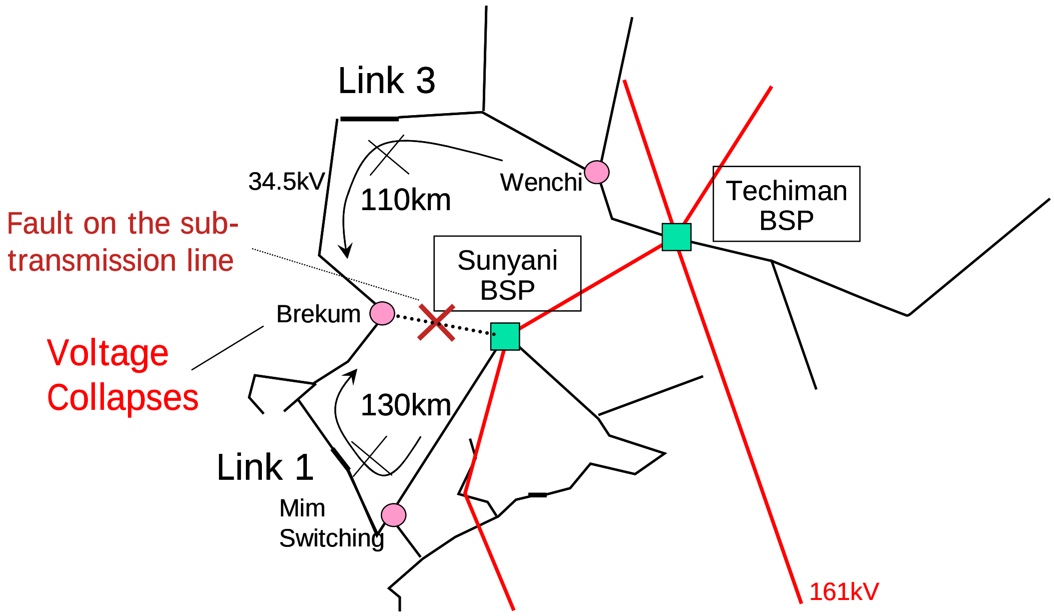


Figure 6-21 Results of power flow analysis in the event of failure on 34.5kV Sunyani-Brekum sub-transmission line

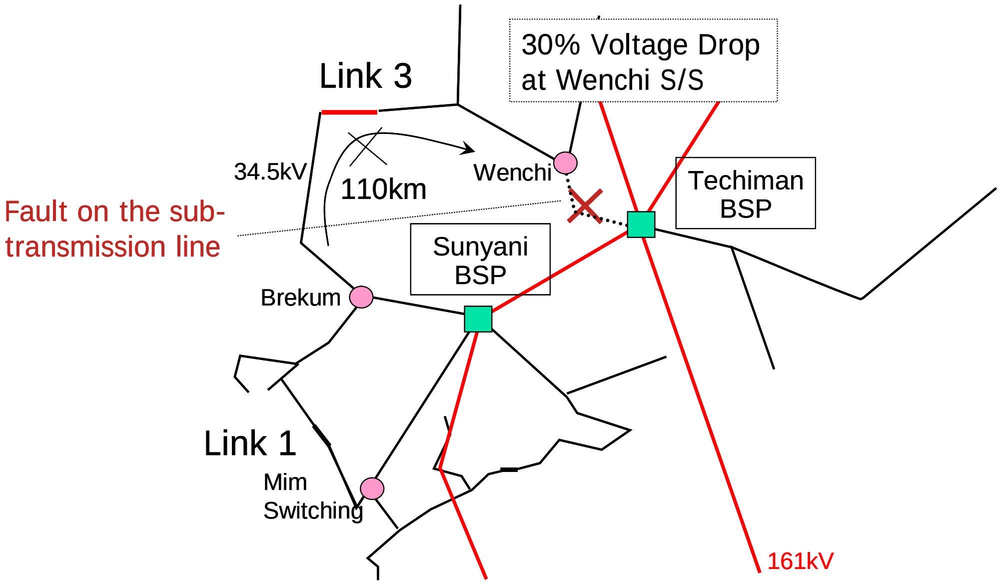


Figure 6-22 Results of power flow analysis in the event of failure on 34.5kV Techiman-Wenchi sub-transmission line

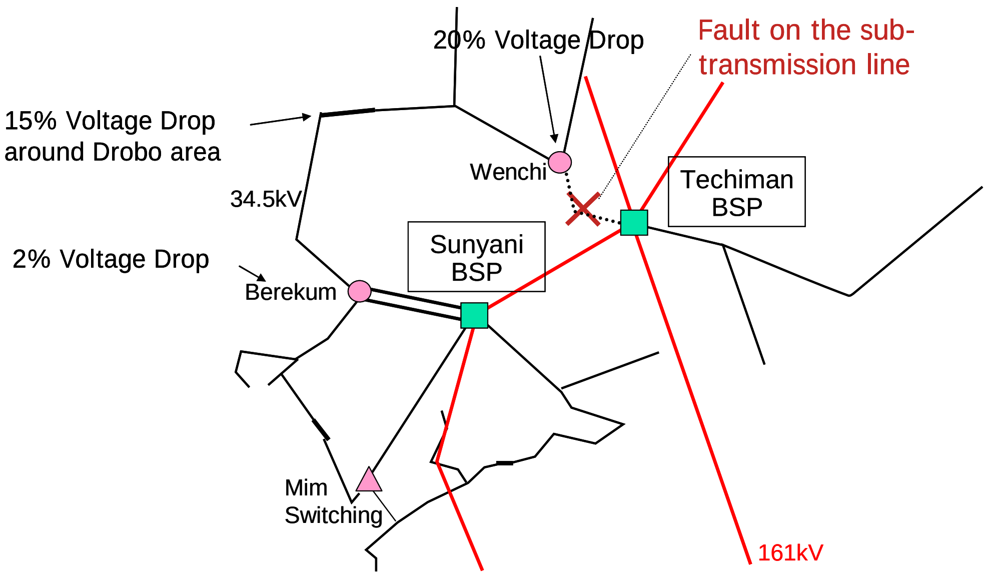


Figure 6-23 Results of power flow analysis in the event of failure on the 34.5-kV Techiman-Wenchi subtransmission line (upon a shift to two circuits on the Sunyani-Berekum line)

Table 6-11 shows the proposed countermeasures for reliability improvement in the Sunyani area and their cost. The total cost would be USD1,901.

Table 6-11 List of countermeasures to increase supply reliability in the Sunyani system

Countermeasures	Cost (1,000US$)	Year of implementaton
Link 1 （From Bediako to Gambia） 120mm^2 AAC, 9.5km, New line	239	2017
Link 2 （From Tepa to Hwidlum） 120mm^2 AAC, 0.27km, New line	7	2017
Link 3 （From Drobo to New Longoro） 120mm^2 AAC, 15km, New line	378	2017
One circuit addition of Sunyani-Berekum line	1,277	2017

6.1.4 Recommendations for BSPs

In this section, the examination about the influence on BSPs by the distribution master plan will be studied. Concretely speaking, the recommendation for BSPs, where some countermeasures are needed, will be conducted after the comparison of the demand assumption from this master plan and the substation capacity of BSP transformer. The updated information of the future development plan of BSPs and the demand record in 2008 have been acquired from VRA and used in the study on this report. The future demand of each BSP is decided with the increasing rate by the existing ECG demand forecast.

Table 6-12 shows the results from the confirmation of BSP capacity. The recommendations presented in sections (1) - (4) below are based on this table.

(1) Ashanti region

For Konongo BSP, the transformer has been overloaded from 2008; however there is no future development plan until 2017. In 2017, the loading of the transformer will be going up to 181%. Therefore, the implementation of reinforcement of transformer is recommended.

For Dunkwa BSP, the implementation of reinforcement of the transformer is also recommended because the loading of transformer will be going up to 111% in 2017.

(2) Western region

For Tarkwa BSP, the transformer has been overloaded from 2008; however there is no future development plan until 2017. In 2017, the loading of the transformer will be going up to 194%. Therefore, the implementation of reinforcement of transformer is recommended.

(3) Eastern region

For Nkawkaw BSP, the transformer has been overloaded by 111% in 2012. The reinforcement is planned in the existing future development plan for this BSP. The implementation of reinforcement of the transformer at Nkawkaw BSP is recommended by 2012.

(4) VRA-NED region

For Sunyani BSP, the loading of the transformer will be 116% in 2012. The reinforcement of the transformer is planned in the future, however, no future plan for the 11.5kV side for the overloaded transformer. Revision of the plan is recommended.

For Tamale BSP, the loading of the transformer will be going up to 106%. The implementation of reinforcement of the transformer is also recommended because the loading of transformer will be going up to 106% in 2017.

Table 6-12 Results of confirmation of BSP capacity (1/3)

BSP name	Demand forecast/Substation Capacity	2008	2012	2017	VRA Exisiting Projects: Committed Projects	VRA Exisiting Projects: Planned Projects	Comments
Achimota	Demand forecast(Distribution)(MVA)	295	261	305		Installation of 1No. 161/34.5kV, 66MVA transformer to replace the 161/34.5kV, 33MVA transformer at Achimota by 2009.	(Accra) 1) 3rd BSP will contribute to relieve the overloading of Achimota BSP. 2) 2 planned projects in Achimota and Mallam is effective to relieve the oveloading of both BSPs.
	Substation Capacity(MVA)	297	330	330			
	Substation Loading(%)	(99%)	(79%)	(92%)			
Mallam	Demand forecast(Distribution)(MVA)	94	106	124		Expansion of Mallam substation with the installation of additional 2No. 161/34.5kV, 66MVA transformers.	
	Substation Capacity(MVA)	132	132	264			
	Substation Loading(%)	(71%)	(80%)	(47%)			
3rd BSP in Accra	Demand forecast(Distribution)(MVA)	-	73	86	Construction of 3rd BSP for Accra/Tema with an initial transformer installed capacity of 2 x. 161/34.5kV, 66MVA transformers by 2009.		
	Substation Capacity(MVA)	-	132	132			
	Substation Loading(%)	-	(55%)	(65%)			
Accra Total	Demand forecast(Distribution)(MVA)	388	440	515			
	Substation Capacity(MVA)	429	594	726			
	Substation Loading(%)	(90%)	(74%)	(71%)			
Tema	Demand forecast(Distribution)(MVA)	138	165	206			
	Substation Capacity(MVA)	231	231	231			
	Substation Loading(%)	(60%)	(71%)	(89%)			
Kumasi (161/34.5kV)	Demand forecast(Distribution)(MVA)	142	188	236	Substations Upgrade Project - Package C which seeks to replace 2No. 161/11.5kV, 13MVA transformers with a 161/34.5kV, 66MVA transformer by 2010.		(Kumasi) 1) 2nd BSP in Kumasi and Substation upgrade project-package C will contribute to relieve the overloading of Kumasi BSP. 2) More load should be transferred to 2nd BSP to relieve the overloading of Kumasi BSP.
	Substation Capacity(MVA)	165	231	231			
	Substation Loading(%)	(86%)	(81%)	(102%)			
Kumasi (161/11.5kV)	Demand forecast(Distribution)(MVA)	34	-	-			
	Substation Capacity(MVA)	26.6	-	-			
	Substation Loading(%)	(128%)	-	-			
2nd BSP in Kumasi	Demand forecast(Distribution)(MVA)	-	24	30	Construction of 2 nd BSP for Kumasi with an initial transformer installed capacity of 2 x. 161/34.5kV, 66MVA transformers by 2009.		
	Substation Capacity(MVA)	-	132	132			
	Substation Loading(%)	-	(18%)	(23%)			
Kumasi Total	Demand forecast(Distribution)(MVA)	176	212	266			
	Substation Capacity(MVA)	191.6	363	363			
	Substation Loading(%)	(92%)	(58%)	(73%)			
Obuasi	Demand forecast(Distribution)(MVA)	12	14	18			
	Substation Capacity(MVA)	21	21	21			
	Substation Loading(%)	(56%)	(68%)	(85%)			
Konongo	Demand forecast(Distribution)(MVA)	6	7	9			Upgrading is needed for Konongo BSP
	Substation Capacity(MVA)	5	5	5			
	Substation Loading(%)	(120%)	(144%)	(181%)			
Nkawkaw	Demand forecast(Distribution)(MVA)	12	15	18		Planned Project to increase installed capacity to 46MVA subject to client interest.	Planned projects to increase installed capacity is needed in 2012.
	Substation Capacity(MVA)	13.3	13.3	46			
	Substation Loading(%)	(93%)	(111%)	(40%)			
Asawinso	Demand forecast(Distribution)(MVA)	42	49	59	Committed Project(Substations Upgrade Project - Package B) to replace 1No. 161/34.5kV, 13MVA transformer with a 161/34.5kV, 33MVA transformer by 2009		Substation upgrade project-package B will contribute to relieve the overloading of Asawinso BSP.
	Substation Capacity(MVA)	46.3	66	66			
	Substation Loading(%)	(92%)	(74%)	(89%)			
Dunkwa	Demand forecast(Distribution)(MVA)	4	5	6			Upgrading is needed for Dunkwa BSP
	Substation Capacity(MVA)	5	5	5			
	Substation Loading(%)	(77%)	(90%)	(111%)			

Table 6-12 Results of confirmation of BSP capacity (2/3)

BSP name	Demand forecast/Substation Capacity	2008	2012	2017	VRA Exisiting Projects		Comments
					Committed Projects	Planned Projects	
Akwatia (161/34.5kV)	Demand forecast(Distribution)(MVA)	11	14	17	Committed Project(Substations Upgrade Project - Package B) to replace 1No. 161/34.5kV, 13MVA transformer with a 161/34.5kV, 33MVA transformer by 2009	Planned Project to install a 161/34.5/11.5kV, 33/33/20MVA transformer in addition to the existing transformers by 2012	
	Substation Capacity(MVA)	13.3	66	66			
	Substation Loading(%)	(85%)	(21%)	(26%)			
Akwatia (161/11.5kV)	Demand forecast(Distribution)(MVA)	3	3	4			
	Substation Capacity(MVA)	5	25	25			
	Substation Loading(%)	(56%)	(13%)	(17%)			
Esiama	Demand forecast(Distribution)(MVA)	7	8	10			
	Substation Capacity(MVA)	33	33	33			
	Substation Loading(%)	(20%)	(24%)	(29%)			
Tafo (161/34.5kV)	Demand forecast(Distribution)(MVA)	13	15	19		Planned Project to replace the 161/11.5kV, 13MVA transformer with a 161/34.5kV, 33MVA transformer by 2012	
	Substation Capacity(MVA)	33	33	33			
	Substation Loading(%)	(38%)	(45%)	(57%)			
Tafo (161/11.5kV)	Demand forecast(Distribution)(MVA)	8	10	12			
	Substation Capacity(MVA)	13.33	46.33	46.33			
	Substation Loading(%)	(63%)	(22%)	(27%)			
Takoradi	Demand forecast(Distribution)(MVA)	61	71	87	Committed Project (Substations Upgrade Project - Package B) to install a 161/34.5kV, 33MVA transformer in addition to the existing transformers by the end of 2008.		Substation upgrade project-package B will contribute to relieve the overloading of Takoradi BSP.
	Substation Capacity(MVA)	66	99	99			
	Substation Loading(%)	(92%)	(72%)	(88%)			
Bogoso	Demand forecast(Distribution)(MVA)	3	4	4			
	Substation Capacity(MVA)	66	66	66			
	Substation Loading(%)	(4%)	(5%)	(7%)			
Tarkwa (161/34.5kV)	Demand forecast(Distribution)(MVA)	27	29	32			
	Substation Capacity(MVA)	33	33	33			
	Substation Loading(%)	(82%)	(88%)	(96%)			
Tarkwa (161/11.5kV)	Demand forecast(Distribution)(MVA)	33	36	39			Upgrading is needed for Tarkwa BSP
	Substation Capacity(MVA)	20	20	20			
	Substation Loading(%)	(166%)	(178%)	(194%)			
Capecoast (161/34.5kV)	Demand forecast(Distribution)(MVA)	21	26	33		Planned Project to replace the 161/11.5/6.6kV, 13/13/4.75MVA transformer with a 161/34.5/11.5kV, 33/33/20MVA transformer by 2012.	Planned project will contribute to relieve the overloading of Capecoast BSP.
	Substation Capacity(MVA)	33	33	33			
	Substation Loading(%)	(64%)	(78%)	(99%)			
Capecoast (161/11.5kV)	Demand forecast(Distribution)(MVA)	11	13	17			
	Substation Capacity(MVA)	13.3	20	20			
	Substation Loading(%)	(82%)	(66%)	(84%)			
Winneba	Demand forecast(Distribution)(MVA)	13	16	21	Committed Project (Substations Upgrade Project - Package C) to replace 1No. 161/11.5kV, 5MVA and 1No. 161/11.5kV, 20MVA transformers with 2No. 161/11.5kV, 13MVA transformers by 2012.		
	Substation Capacity(MVA)	25	26	26			
	Substation Loading(%)	(54%)	(63%)	(80%)			
Ho (161/34.5kV)	Demand forecast(Distribution)(MVA)	-	-	-		Planned Project to replace the 161/11.5kV, 7MVA transformer with 1No. 161/34.5/11.5kV, 13/10/10MVA transformer by 2012.	
	Substation Capacity(MVA)	10	10	10			
	Substation Loading(%)	-	-	-			
Ho (161/11.5kV)	Demand forecast(Distribution)(MVA)	5	6	8			
	Substation Capacity(MVA)	7	10	10			
	Substation Loading(%)	(74%)	(62%)	(78%)			
Kpandu	Demand forecast(Distribution)(MVA)	7	8	11		Planned Project to install a 69/34.5/11.5kV, 20/20/13MVA transformer in addition to the existing transformer by 2012	
	Substation Capacity(MVA)	20	20	20			
	Substation Loading(%)	(34%)	(42%)	(53%)			

Table 6-12 Results of confirmation of BSP capacity (3/3)

BSP name	Demand forecast/Substation Capacity	2008	2012	2017	VRA Exisiting Projects		Comments
					Committed Projects	Planned Projects	
Kpeve	Demand forecast(Distribution)(MVA)	3	4	5			
	Substation Capacity(MVA)	7	7	7			
	Substation Loading(%)	(45%)	(54%)	(67%)			
Asiekpe	Demand forecast(Distribution)(MVA)	0.3	0.4	0.5			
	Substation Capacity(MVA)	16	16	16			
	Substation Loading(%)	(2%)	(2%)	(3%)			
Sogakope	Demand forecast(Distribution)(MVA)	10	11	14			
	Substation Capacity(MVA)	15	15	15			
	Substation Loading(%)	(64%)	(77%)	(95%)			
Aflao	Demand forecast(Distribution)(MVA)	12	14	18			
	Substation Capacity(MVA)	33	33	33			
	Substation Loading(%)	(36%)	(43%)	(54%)			
Kpong	Demand forecast(Distribution)(MVA)	28	34	44			
	Substation Capacity(MVA)	66	66	66			
	Substation Loading(%)	(43%)	(52%)	(67%)			
Sunyani (161/34.5kV)	Demand forecast(Distribution)(MVA)	20	24	29		Planned Project to replace 1No. 161/34.5/11.5kV, 20/12.5/12.5MVA transformer with a 161/34.5/11.5kV, 33/25/12.5MVA transformer by 2012.	Upgrading is needed for Sunyani BSP
	Substation Capacity(MVA)	25	25	25			
	Substation Loading(%)	(81%)	(96%)	(117%)			
Sunyani (161/11.5kV)	Demand forecast(Distribution)(MVA)	12	15	18			
	Substation Capacity(MVA)	12.5	12.5	12.5			
	Substation Loading(%)	(99%)	(116%)	(142%)			
Techiman (161/34.5kV)	Demand forecast(Distribution)(MVA)	9	10	12	Committed Project (Substations Upgrade Project - Package C) to install 1No. 161/34.5/11.5kV, 20/12.5/12.5MVA transformer in addition to the existing transformer by 2012.		
	Substation Capacity(MVA)	12.5	25	25			
	Substation Loading(%)	(74%)	(41%)	(47%)			
Techiman (161/11.5kV)	Demand forecast(Distribution)(MVA)	6	7	8			
	Substation Capacity(MVA)	12.5	25	25			
	Substation Loading(%)	(51%)	(28%)	(32%)			
Tamale (161/34.5kV)	Demand forecast(Distribution)(MVA)	6	7	8		Planned Project to replace 2No. 161/34.5/11.5kV, 20/12.5/12.5MVA transformers with 2No. 161/34.5/11.5kV, 33/25/25MVA transformers by 2012.	Upgrading is needed for Tamale BSP
	Substation Capacity(MVA)	12.5	25	25			
	Substation Loading(%)	(45%)	(26%)	(33%)			
Tamale (161/11.5kV)	Demand forecast(Distribution)(MVA)	18	21	27			
	Substation Capacity(MVA)	12.5	25	25			
	Substation Loading(%)	(144%)	(86%)	(106%)			
Yendi	Demand forecast(Distribution)(MVA)	9	11	13		Planned Project to install 1No. 161/34.5kV, 13MVA transformer in addition to the existing transformer by 2012.	
	Substation Capacity(MVA)	13.3	26.3	26.3			
	Substation Loading(%)	(68%)	(40%)	(49%)			
Bolgatanga (161/34.5kV)	Demand forecast(Distribution)(MVA)	7	9	10		Planned Project to install 1No. 161/34.5/11.5kV, 20/12.5/12.5MVA transformer in addition to the existing transformer by 2012.	
	Substation Capacity(MVA)	12.5	25	25			
	Substation Loading(%)	(60%)	(35%)	(42%)			
Bolgatanga (161/11.5kV)	Demand forecast(Distribution)(MVA)	6	6	8			
	Substation Capacity(MVA)	12.5	25	25			
	Substation Loading(%)	(45%)	(26%)	(31%)			
Sawla	Demand forecast(Distribution)(MVA)	7	8	10			
	Substation Capacity(MVA)	13.3	13.3	13.3			
	Substation Loading(%)	(52%)	(60%)	(72%)			

6.2 Results of preparation of plans for distribution network renewal, reinforcement, and extension

6.2.1 Plans for renewal

As locations requiring renewal, the Study Team selected spots on dilapidated distribution facilities judged to have a substantial adverse impact on public safety or supply reliability. The main items of deterioration requiring repair are medium-voltage distribution lines, distribution transformers, switching equipment, insulators, and supporting structures.

The specific renewal plans are as follows (with indications of the number of facilities and cost).

Table 6-13 Results of preparation of plans for ECG and VRA-NED distribution network renewal (number of facilities)

Enterprise/office		Number of facilities requiring renewal					
		Medium-voltage lines (km)	Transformers (number)	Switching equipment (number)	Insulators (number)	Supprting structures (number)	Guys, crossarms, etc. (number)
ECG	Accra East	58	—	5	243	—	—
	Accra West	28	21	1	—	—	—
	Tema	—	—	15	—	—	—
	Ashanti East	84	—	3	—	55	—
	Ashanti West	86	—	8	—	—	—
	Western	—	—	9	3,726	74	—
	Eastern	30	17	—	—	—	—
	Central	12	—	—	3,330	17	563
	Volta	28	5	62	1,090	160	—
ECG(Total)		326	43	103	8,389	306	563
VRA-NED (Total)		—	38	12	—	—	—

Table 6-14 Results of preparation of plans for ECG and VRA-NED distribution network renewal cost

［Unit: USD1,000］

Enterprise/area		Cost (USD1,000)						Total
		Medium-voltage lines	Transformers	Switching equipment	Insulators	Supporting structures	Guys, crossarms, etc.	
ECG	Accra	540	562	35	17	—	—	1,153
	Tema	—	—	69	—	—	—	69
	Ashanti	3,221	—	990	—	90	—	4,301
	Western	—	—	226	253	79	—	558
	Eastern	335	270	—	—	—	—	606
	Central	75	—	—	226	42	116	459
	Volta	174	55	1,152	74	245	—	1,701
ECG (Total)		4,344	888	2,472	570	456	116	8,847
VRA (Total)		—	449	359	—	—	—	808

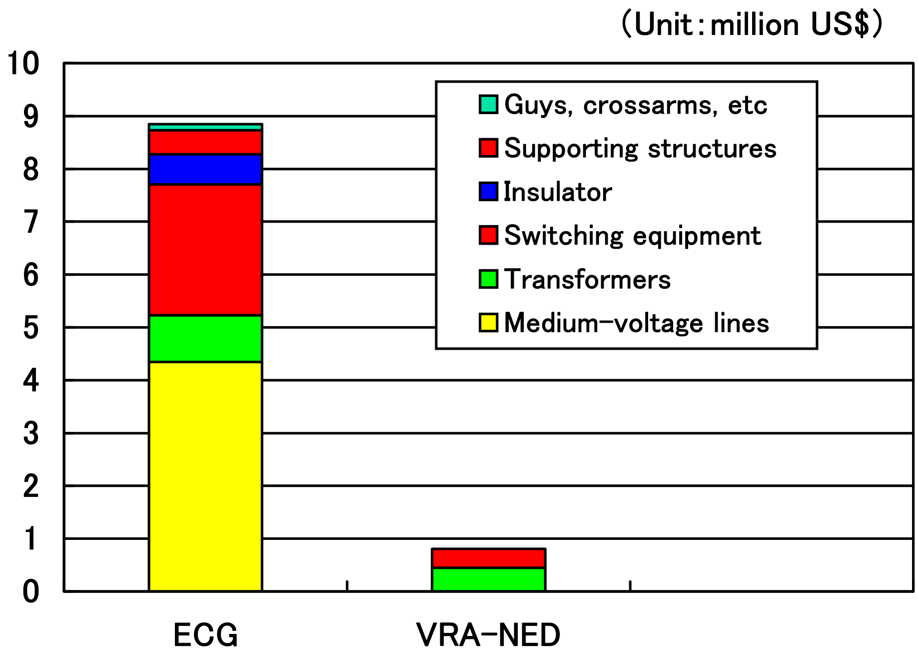


Figure 6-24 Results of preparation of plans for ECG and VRA-NED distribution network renewal

There is a difference between the ECG and VRA-NED, and among ECG offices, in respect of the number of distribution facilities requiring renewal. This is because each office prepared plans based on its own judgmental standards or thinking on deterioration and replacement of distribution facilities; there is no unified standard applied in all ECG offices. However, it is not necessarily advisable for the ECG or the VRA-NED to establish unified companywide standards for application in decisions on deterioration and replacement, considering that a variety of factors are involved, including expenditures that can be directed to renewal, the required supply reliability, and the status of equipment installation in each area.

According to the results, the renewal of distribution network renewal at the ECG and VRA-NED would cost USD8.8 million and 800,000, respectively.

As will be described in Section 9.6 on the maintenance setup, unlike transmission and transformation facilities, distribution facilities generally rely on preventive maintenance. Therefore, if a lot of funds are not available for renewal, the ordinary approach would be one of phased replacement, beginning with the most dilapidated facilities on the list for renewal, i.e., to use facilities until they cannot be used anymore and only then replace them. Even without systematic renewal, however, it would, in effect, be impossible to avoid renewal after failure. As such, a certain amount of funds must be set aside in the budget for renewal.

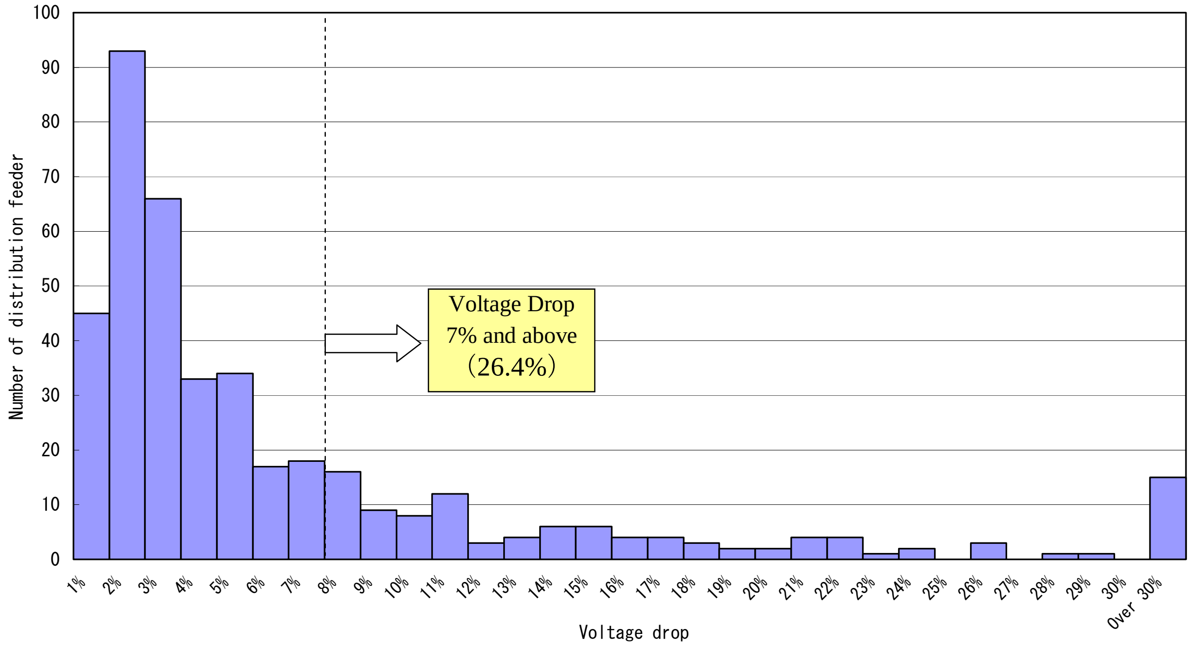
6.2.2 Plans for reinforcement

When the amperage and voltage drop level on individual distribution lines fail to meet the conditions noted below, they must be reinforced to cope with the steadily increasing demand. The planning procedure begins with calculation of the yearly distribution line amperage based on the yearly rate of demand increase extrapolated from the demand forecast. This is followed by application of the yearly amperage to the existing distribution lines. The results provide footing for determination of the types and years of countermeasures to reinforce the lines to cope with the demand increase. (Upon consultation with the counterpart, it was decided to use the rated amperage on the line as the upper limit of allowable current in preparation of the Master Plan. For voltage drop, the study used an upper limit of 7 percent for the ECG and 10 percent for the VRA-NED, based on the standards at these enterprises.)

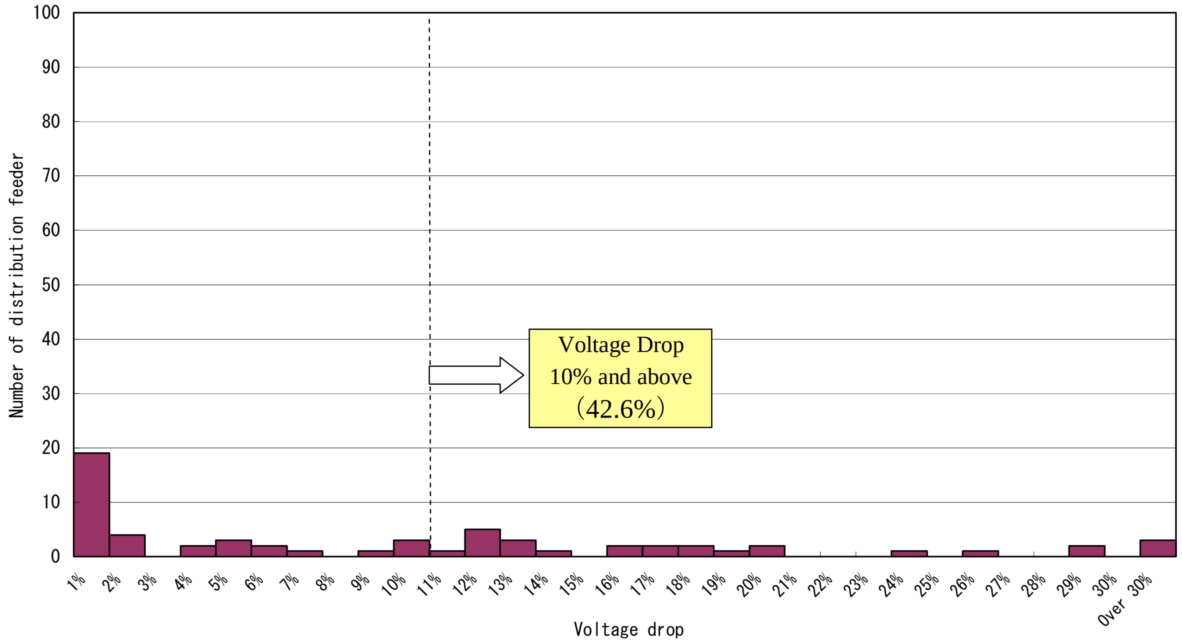
Figure 6-25 and 6-26 shows the results. As is clear from this figure, many medium-voltage distribution lines do not meet the standards for current or voltage even at present. More specifically, the ECG lines are below the current standard, and the VRA-NED lines have excessive voltage drop. These results are thought to reflect the characteristics of the areas served by these companies.

Table 6-15 shows the breakdown of the reinforcement plan and Table 6-16 shows the cost. Appendix 6.2.2 shows details of the reinforcement plans. Total cost for the reinforcement plan is 40,740 thousand US$ for ECG and 6,522 thousand US$ for VRA-NED respectively. The timing of construction is the year in excess of the standard value. Figure 6-27 shows the yealy cost for the reinforcement plan. Over the immediately following years (from 2008 to 2010), the plan would require a lot of budget because such work has not been undertaken extensively thus far.

For ECG, the average value of countermeasures between 2009 and 2017 (nine years), except for the peak value of 2008, is about 2,600 thousand US$ per year. It is thought that the reinforcement countermeasure of this level is necessary annually after the year of 2017.

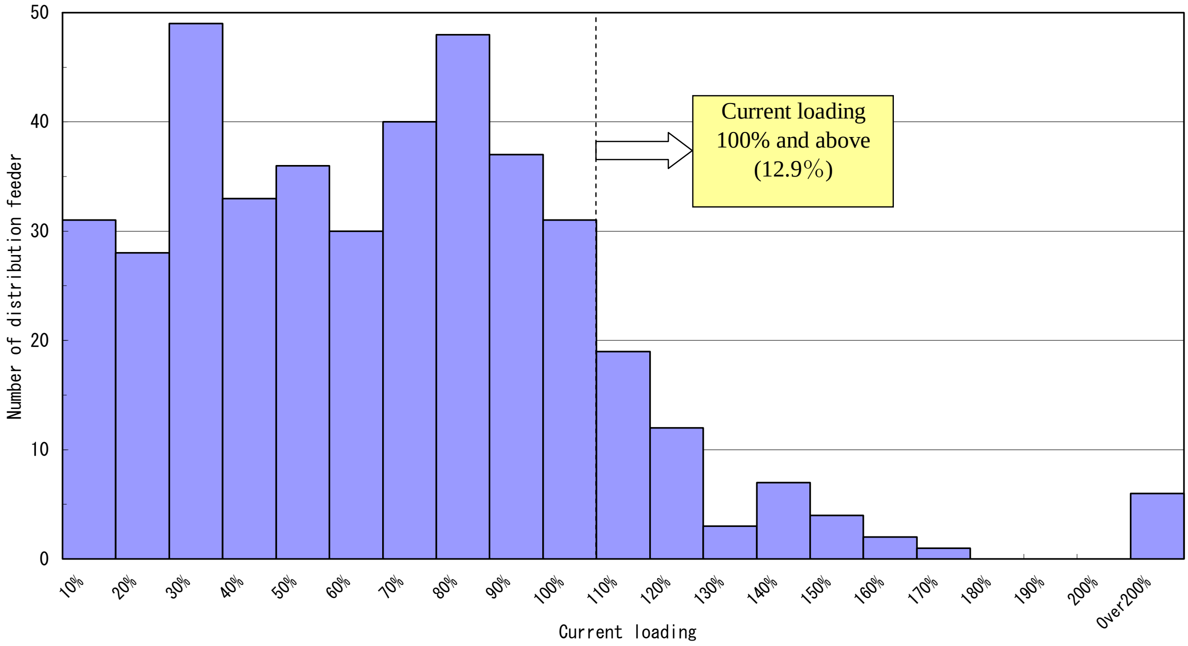


(a) Results for the ECG

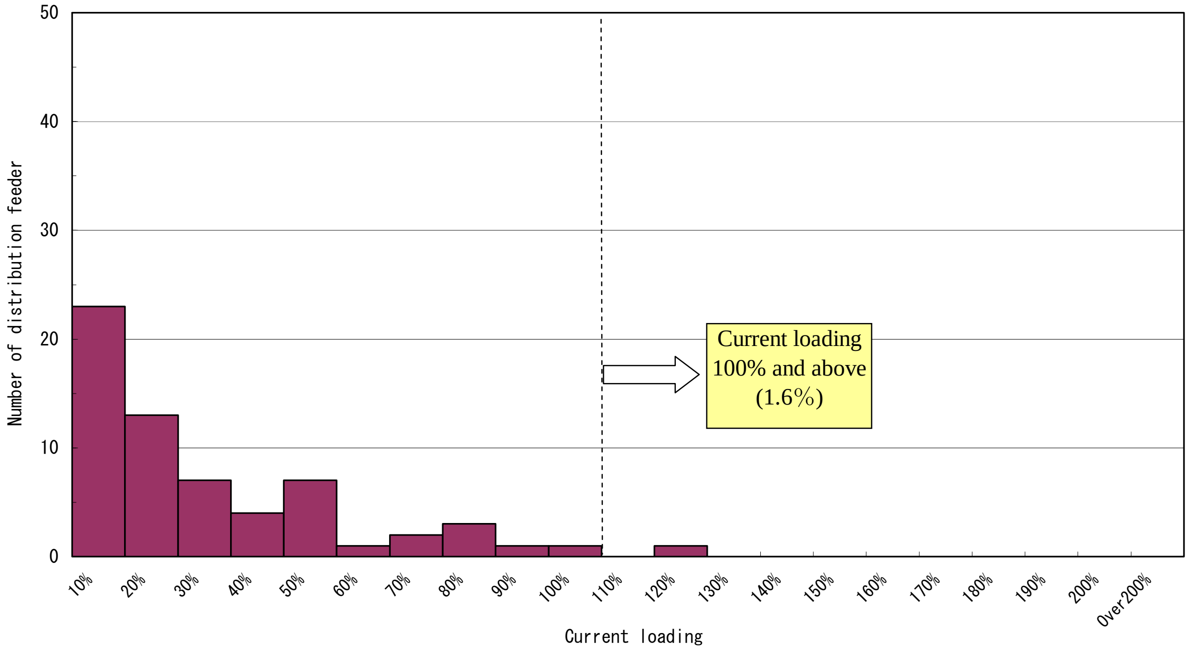


(b) Results for the VRA-NED

Figure 6-25 Results of analysis for distribution line voltage drop (FY2007)



(a) Results for the ECG



(b) Results for the VRA-NED

Figure 6-26 Results of analysis for distribution line current loading (FY2007)

Table 6-15 Reinforcement plan (number of lines for each countermeasure)

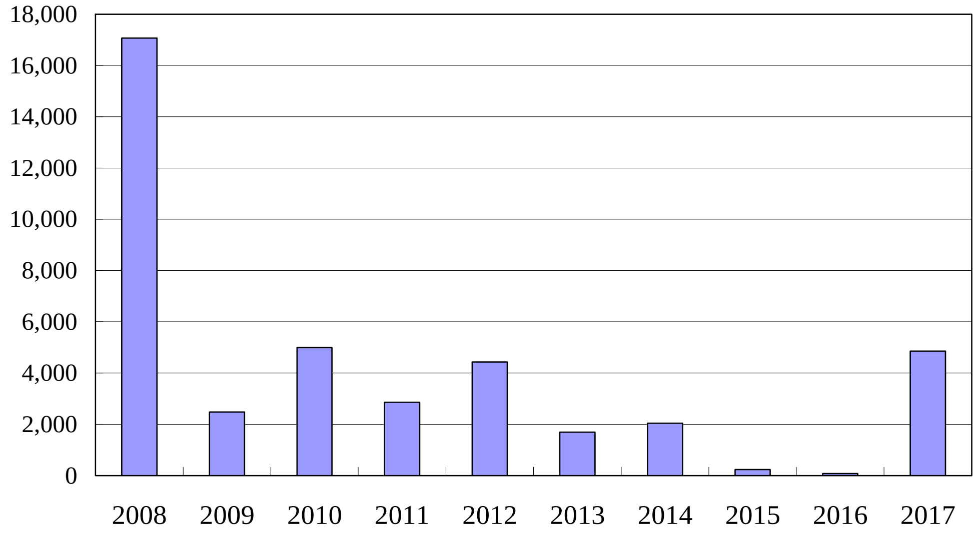
Enterprise/area		Reinforcement plan (number of lines for each countermeasure)							
		New 33kV/11kV substation construction (including ancillary facilities such as 33kV distribution lines)	Installation of new distribution line	Enlargement of lines		Voltage increase	Installation of a capacitor bank, condensor or Booster	Alleviation of load by construction of a switching station	Total
				Overhead line	Cable				
ECG	Accra	54	17	1	20	0	2	0	94
	Tema	3	4	1	5	0	1	0	14
	Ashanti	9	8	3	1	0	4	0	25
	Western	1	0	7	4	1	0	1	14
	Eastern	3	2	1	1	2	0	0	9
	Central	6	1	0	0	0	2	0	9
	Volta	1	4	1	0	0	1	0	7
ECG (Total)		77	36	14	31	3	10	1	172
VRA-NED (Total)		2	4	14	0	3	1	0	24

Table 6-16 Reinforcement plan (cost)

(Unit：1,000 US$)

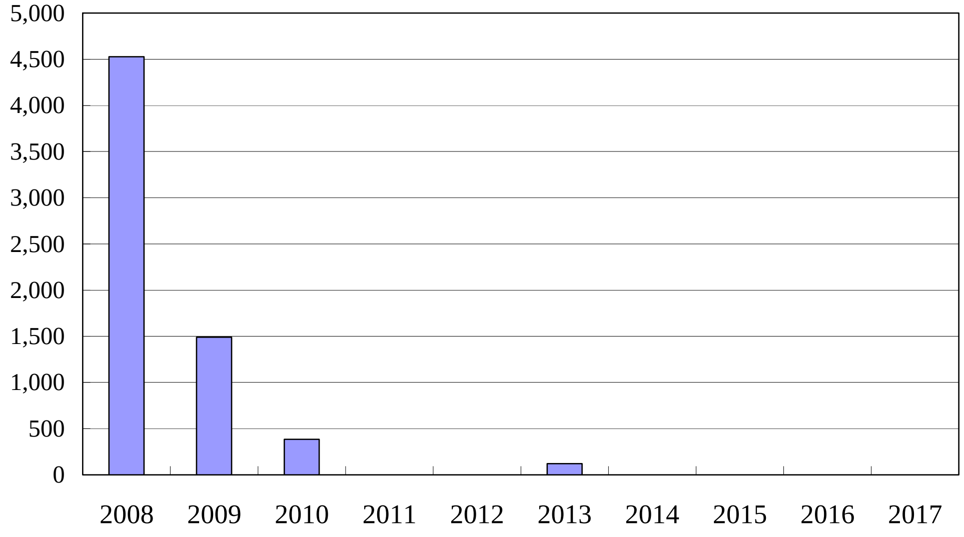
Enterprise/area		Reinforcement plan (cost, but excluding of new primary substation construction cost)							
		New 33kV/11kV substation construction (including ancillary facilities such as 33kV distribution lines)	Installation of new distribution line	Enlargement of lines		Voltage increase	Installation of a capacitor bank, condensor or Booster	Alleviation of load by construction of a switching station	Total
				Overhead line	Overhead line				
ECG	Accra	0	4,903	103	14,407	0	12	0	19,425
	Tema	0	1,387	358	760	0	1	0	2,506
	Ashanti	0	996	240	93	0	24	0	1,353
	Western	745	0	4,590	831	719	0	400	7,285
	Eastern	3,733	1,396	374	189	1,886	0	0	7,578
	Central	0	85	0	0	0	4	0	89
	Volta	243	1,461	700	0	0	100	0	2,504
ECG (Total)		4,721	10,228	6,365	16,280	2,605	141	400	40,740
VRA-NED (Total)		2,337	722	1,490	0	1,873	100	0	6,522

(Unit: thousand US$)



(a) Reinforcement plan for ECG

(Unit: thousand US$)



(b) Reinforcement plan for VRA-NED

Figure 6-27 Reinforcement plan for ECG and VRA-NED

In the case of the ECG, the GEDAP is to construct new primary substations in the Accra, Ashanti, and Central areas. In addition, there is margin in the outlet for out-going lines and in the capacity of switchboards and transformers at the existing substations. For these reasons, the construction of new substations and installation of new lines are often proposed as countermeasures for reinforcement. In contrast, the main countermeasures at the VRA-NED are change of conductor size of distribution lines and change of MV voltage. This is because the substation density is comparatively low and voltage drop is more of a problem than excessive current.

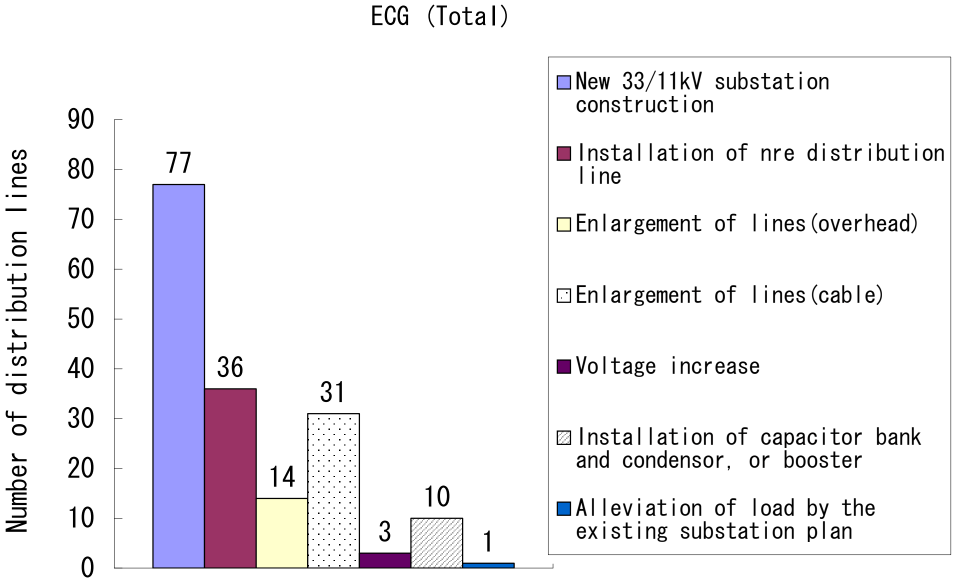


Figure 6-28 Plans for ECG distribution line reinforcement
(Number of lines for each countermeasure)

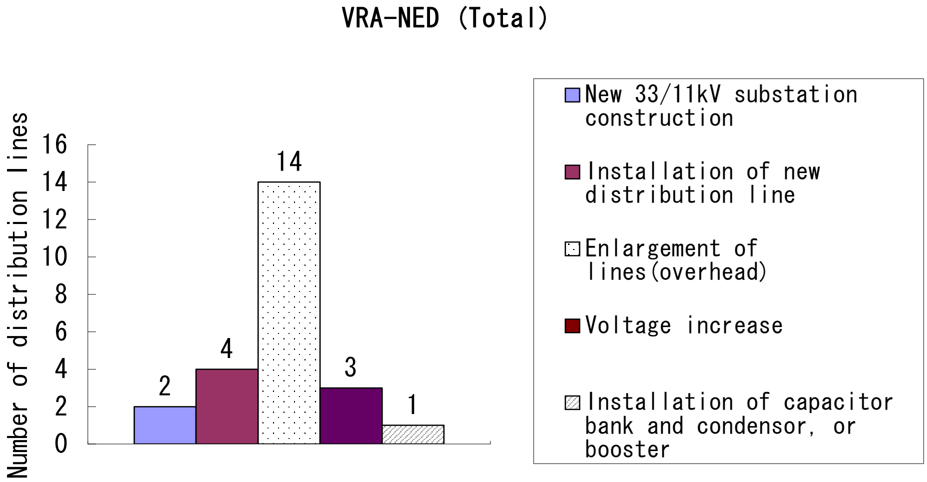


Figure 6-29 Plans for VRA-NED distribution line reinforcement
(Number of lines for each countermeasure)

Figure 6-30 shows the distribution of the countermeasure costs for each line. It can be seen that the cost is generally on a small scale (a few hundreds of thousands of dollars), but there are 11 ECG projects and 2 VRA-NED projects that would cost over USD1 million each. Table 6-17 outlines these large-scale projects.

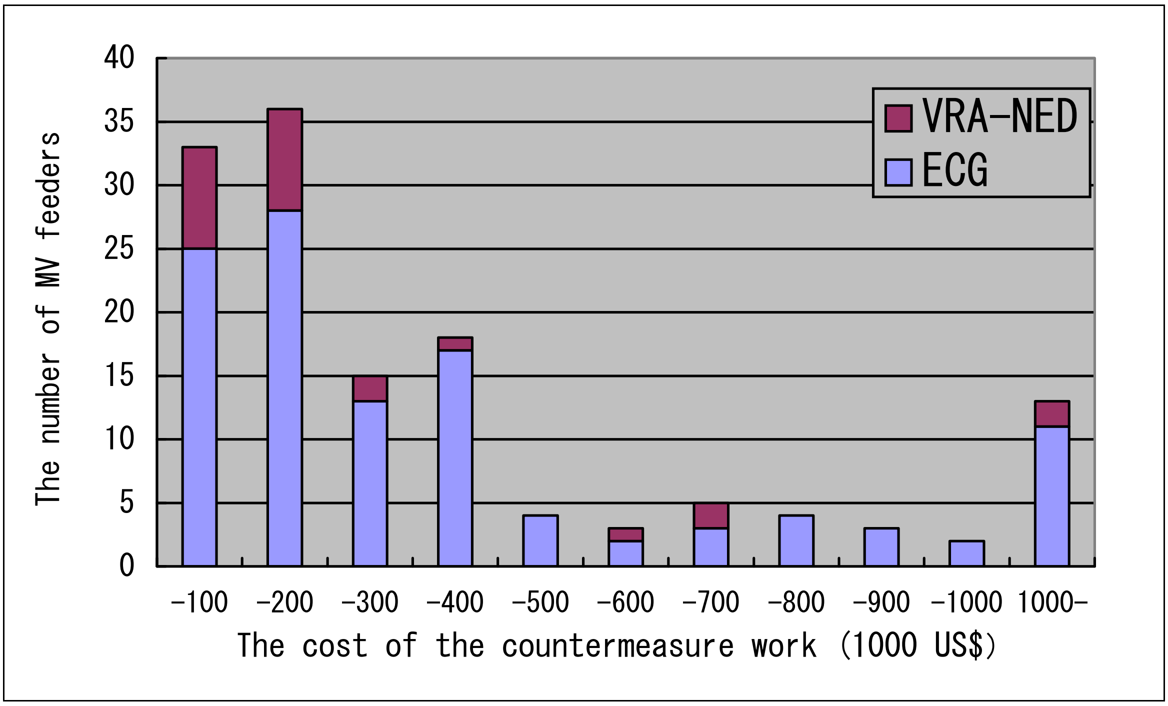


Figure 6-30 Outline of large-scale projects for distribution line reinforcement

Table 6-17 Large-scale projects

Office	Substations	Distribution lines	Project (work)	Requisite year	Cost (USD1,000)
Accra	Main H	H08(H24)	Cable replacement (185mm^2 Al →240mm^2 Cu, 15km)	2013	1,039
Accra	Main K	K05(K150)	Cable replacement (185mm^2 Al →240mm^2 Cu, 18km)	2008	1,246
Accra	Main K	K13(K13)	Cable replacement (185mm^2 Al →240mm^2 Cu, 17km)	2014	1,177
Accra	Main L	L11(L01)	Cable replacement (185mm^2 Al →240mm^2 Cu, 17km)	2017	1,177
Accra	Main M	M01 (Old Legon 1)	Cable replacement (185mm^2 Al →240mm^2 Cu, 16km)	2011	1,108
Accra	Main D	D16	Cable replacement (185mm^2 Al → 6x630mm^2 Cu, 3.2km)	2008	2,032
Western	Dwenase	Juaboso	Aerial line replacement （120mm^2 AAC →240mm^2 AAC, 60km、）	2012	1,942
Eastern	Tafo	Kibi / Suhum	Increase from 11 to 33 kV	2008	1,270
Eastern	Tafo	Tafo	Installation of new 33-kV line (240 mm2 AAC, 25 km) from the Tafo BSP, construction of a 33/11-kVsubstation (10 MVA) ahead of this line, and connection to the existing Tafo distribution line along the way	2008	1,743
Eastern	Akwatia	Asamankese	Installation of new 33-kV line (240 mm2 AAC, 25 km) from the Akwatia BSP, construction of a 33/11-kVsubstation (5 MVA) ahead of this line, and connection to the existing Asamankese distribution line along the way	2008	1,425
Volta	Kpando	"HOHOE-JASIKAN"	Installation of a new 11-kV line (120mm^2 AAC, 48km)	2009	1,024
VRA-NED	Tamale	28F3B	Installation of new 34.5-kV line (185 mm2 ALXLPE, 18 km) from the Tamale BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Tolon), and connection to the existing 28F3B distribution line along the way	2008	1,292
VRA-NED	Sunyani	27F8B	Installation of new 34.5-kV line (120 mm2 AAC, 14 km) from the Sunyani BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Chiraa), and connection to the existing 27F8B distribution line along the way	2008	1,045

Figure 6-31 shows the distribution of the cost of reinforcement countermeasures when viewed as projects in substation units. Seven such projects would be large-scale ones costing over USD2 million, as follows: Accra Main H, Main K, Main H, Main D, Eastern Tafo, and Akwatia.

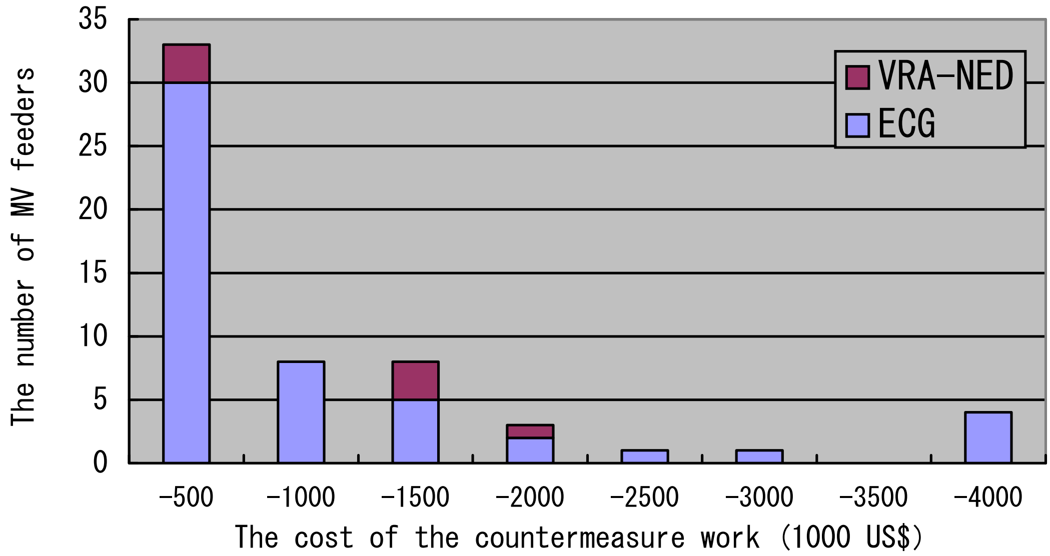


Figure 6-31 Outline of large-scale projects for substations

Table 6-18 Projects costing over USD2 million

Enterprise	Substations	Project cost (USD1,000)
Accra	Main H	3,800
Accra	Main K	3,533
Accra	Main L	2,456
Accra	Main D	3,978
Eastern	Tafo	3,518
Eastern	Akwatia	2,932

6.2.3 Distribution network extension planning

(1) Results of master plan preparation

The results of the preparation of plans for distribution network extension are shown in Table 6-19 and 6-20 and Attachment 6.2.3. Trial calculation of the cost required for execution of this plan yielded a figure of about USD103 million for electrification of all of the 472 subject localities. The electrification cost came to about USD220,000 per locality and USD1,500 per customer.

Table 6-19 Electrification cost

	Number of localities	Number of customers	Electrification cost		
			Total cost (USD, millions)	Electrification cost per locality (USD, thousands)	Electrification cost per customer (USD)
ECG	226	40,265	58.4	258,3	1,450
VRA-NED	246	28,861	44.4	180.5	1,540
Total	472	69,126	102.8	217.8	1,500

Based on these resulta, it is estimated that a 10-percent increase in the electrifiction rate over the next ten years would entail a cost at approximately USD 50 million per year by on-grid electrification.

A breakdown of the construction cost indicates that medium- and low-voltage lines, including supporting structures, account for over 80 percent. This implies that, to reduce the electrification cost, it would be effective to find ways of lowering the cost for medium- and low-voltage lines. For medium-voltage lines, power could conceivably be supplied in a single-phase two-line format in areas where there are not good prospects for a substantial increase in load. Similarly, for low-voltage lines, it is important (also for reducting loss) to shorten the extension distance by installing distribution transformers at the appropriate locations.

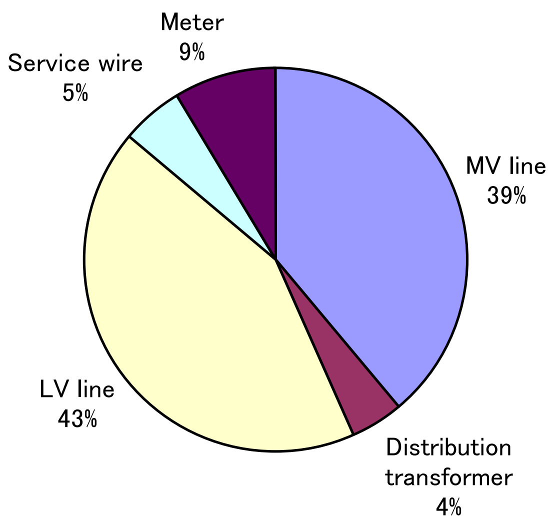


Figure 6-32 Breakdown of electrification cost

Table 6-20 Distribution network extension plans

Regional Name	Substation	No. of u.e. Villages	Total Population	No. of Facilities	Total Demand (kW)	Construction or Installation Cost (US$)					
						MV Line	Secondary S/S	LV line	Service Wire	Meter	**Total**
Great Accra	Mallam	12	9,554	1,632	250.56	973,340	121,681	1,043,143	122,387	212,137	2,472,687
	New Tema	1	634	108	16.63	556,555	10,140	69,223	8,122	14,077	658,116
	Achimota	23	30,375	5,188	796.68	991,951	219,743	3,316,461	389,104	674,447	5,591,705
Ashanti	Obuasi	2	2,395	409	62.81	379,566	20,280	261,495	30,680	53,179	745,200
	New Obuasi	3	3,688	630	96.73	541,628	30,420	402,670	47,243	81,888	1,103,850
	Bekwai	4	6,169	1,054	161.80	392,361	29,846	673,555	79,025	136,976	1,311,763
	Kumasi	6	5,321	909	139.56	283,608	55,483	580,968	68,162	118,147	1,106,369
	Barekese	3	2,999	512	78.66	223,901	22,384	327,443	38,417	66,590	678,735
Western	Daboase	3	2,635	450	69.11	744,206	22,384	287,700	33,754	58,508	1,146,551
	Asawinso	3	4,440	758	116.45	255,887	30,420	484,777	56,876	98,586	926,546
	Takoradi	2	1,684	288	44.17	255,887	20,280	183,866	21,572	37,392	518,997
	Axim	3	2,351	402	61.66	373,169	30,420	256,691	30,116	52,202	742,599
	Tarkwa	3	2,447	418	64.17	270,814	22,384	267,173	31,346	54,333	646,051
	Prestea	2	1,985	339	52.06	511,775	20,280	216,730	25,428	44,075	818,288
	Bogoso	2	1,693	289	44.40	300,668	20,280	184,848	21,687	37,591	565,075
Eastern	Akwatia	7	8,908	1,521	233.63	629,056	56,141	972,610	114,111	197,793	1,969,713
	Oda	6	4,120	704	108.06	838,031	60,841	449,838	52,777	91,480	1,492,967
	Tafo	55	53,916	9,209	1,414.07	4,478,988	444,904	5,886,759	690,664	1,197,151	12,698,466
	Koforidua	6	5,917	1,011	155.19	473,392	60,841	646,041	75,797	131,381	1,387,451
	Nkawkaw	12	8,830	1,508	231.58	1,458,558	95,469	964,094	113,112	196,061	2,827,294
Central	Asebu	1	2,727	466	71.52	38,383	11,458	297,744	34,933	60,550	443,069
	Winneba	28	29,822	5,094	782.17	2,210,322	250,204	3,256,082	382,020	662,168	6,760,796
	Cape Coast	6	4,755	812	124.70	839,192	47,447	519,169	60,912	105,580	1,572,300
	Saltpond	1	600	102	15.74	31,986	7,461	65,510	7,686	13,322	125,966
	Damang	11	10,196	1,741	267.40	1,507,210	111,541	1,113,239	130,611	226,392	3,088,993
	Dunkwa	6	7,223	1,234	189.45	605,987	62,158	788,635	92,527	160,379	1,709,687
Volta	Keta	2	3,508	599	92.00	119,414	21,598	383,017	44,937	77,892	646,858
	Afao	6	5,471	934	143.49	607,732	60,841	597,345	70,084	121,478	1,457,480
	Asiekpe	3	7,046	1,203	184.79	562,952	24,968	769,310	90,259	156,449	1,603,939
	Kpeve	1	825	141	21.64	394,493	7,461	90,077	10,568	18,318	520,918
	Tsito	1	1,705	291	44.72	21,324	10,140	186,159	21,841	37,858	277,321
	Hohoe	2	1,806	308	47.36	481,921	20,280	197,186	23,135	40,100	762,623
Northern	Sawala	14	12,985	1,539	211.14	2,996,014	141,961	983,628	115,404	200,034	4,437,042
	Yendi	6	6,937	822	112.80	518,172	60,841	525,486	61,653	106,864	1,273,015
	Tamale	9	8,161	967	132.70	1,174,949	95,469	618,205	72,531	125,720	2,086,874
Brong Ahafo	Wenchi	4	6,020	1,028	157.88	245,225	31,738	657,287	77,116	133,668	1,145,035
	Brekum	2	3,257	556	85.42	281,476	20,280	355,612	41,722	72,318	771,409
	Techiman	6	6,297	1,076	165.14	910,532	60,841	687,531	80,665	139,819	1,879,387
Upper East	Bawku	53	47,809	5,665	777.40	3,226,698	537,425	3,621,586	424,902	736,498	8,547,108
	Bolgatanga	97	89,637	10,622	1,457.49	4,183,754	860,370	6,790,104	796,649	1,380,858	14,011,735
	Navrongo	38	37,998	4,503	617.86	1,676,447	375,183	2,878,391	337,707	585,359	5,853,088
Upper West	Wa	17	17,574	2,083	285.74	2,476,872	167,024	1,331,250	156,189	270,727	4,402,063
Sub-total (ECG area)		226	235,745	40,265	6,182.96	22,354,257	2,030,182	25,739,559	3,019,893	5,234,482	58,378,373
Sub-total (VRA-NED area)		246	236,675	28,861	4,003.57	17,690,140	2,351,133	18,449,080	2,164,538	3,751,866	44,406,756
Total		**472**	**472,420**	**69,126**	**10,186.53**	**40,044,397**	**4,381,314**	**44,188,638**	**5,184,432**	**8,986,348**	**102,785,129**

(2) Implications regarding grid extension

1) Electrification method

The Study Team drafted plans so that electrification would proceed through extension beginning with the localities nearest to the existing distribution lines (Approach 1). Under the electrification approach taken in Ghana under programs such as SHEP, firstly the localities to be electrified are determined and then plans only for them are drafted (Approach 2). The Study Team examined these two approaches in the aspects of cost and benefit.

The locality of Nayiri Kologu, which is included in the current plan, lies about 20 km from the nearest distribution line in the county of Builsa in the Upper East Region. The plan is to electrify not only Nayiri Kologu but also 14 other localities, one after the other, that lie in front of it (by applying Approach 1).

As compared to the electrification of Nayiri Kologu alone (under Approach 2), this approach will cost 3.5 times as much due to the expenses for the distribution transformers, low-voltage lines, lead-in lines, and other equipment required for electrification of each of these localities. However, there would not be much of a difference in respect of the medium-voltage distribution line cost, and the electrification cost per locality will make up about 7 percent of the total. For the same cost, it would therefore be possible to electrify more than ten times as many localities.

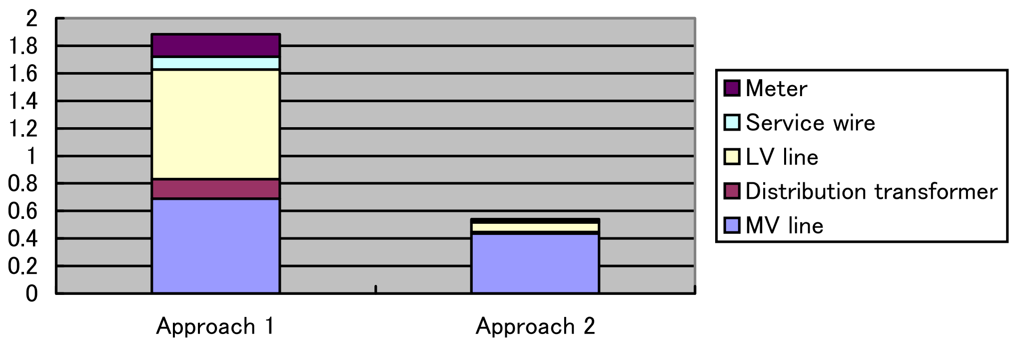


Figure 6-33 Cost comparison of electrification approaches

Table 6-21 Costs and benefits of electrification approaches

		Approach 1 (A)	Approach 2 (B)	A/B
Electrification cost (USD, thousands)		1,883.3	540.5	3.5
Benefit	Number of electrified localities	14	1	14
	Number of customers electrified	1,245	112	11.1

In electrification plans, it is important to decide priorities in the policy aspect by, for example, according precedence to localities on a large scale containing schools, hospitals, and other such facilities. To steadily heighten the electrification rate, it would be advisable to establish priorities on the area level instead of on the locality level, and to electrify all localities in the specific area.

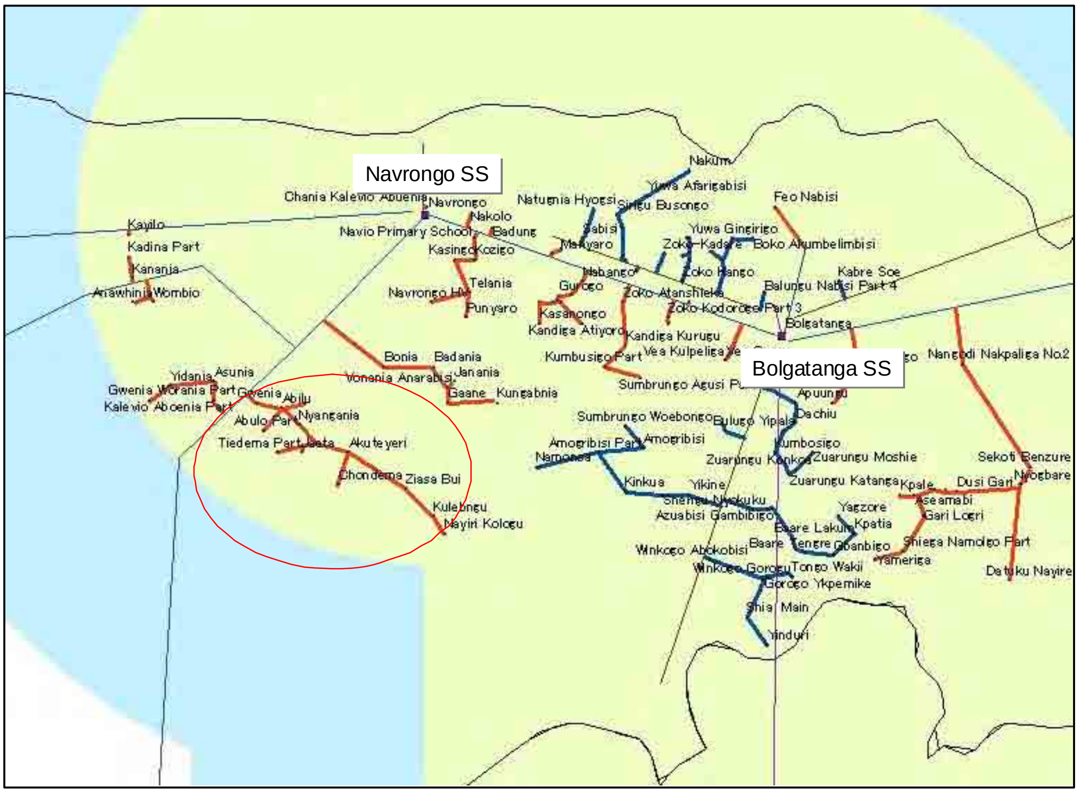


Figure 6-34 Electrification plan for the Upper East Region

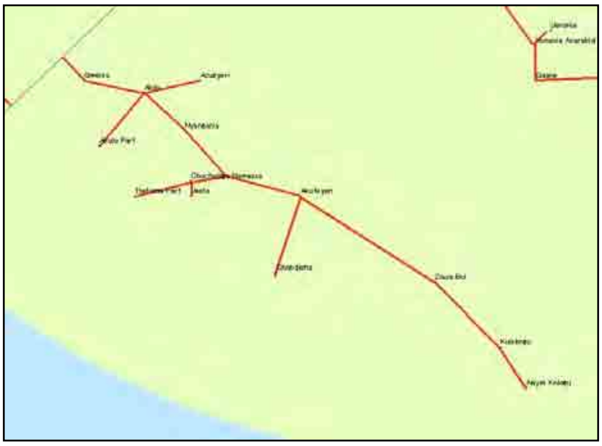


Figure 6-35 Electrification based on Approach1

Figure 6-36 Electrification based on Approach 2

2) Involvement of utilities in the electrification design stage

In RE undertaken in Ghana so far, the plans have been implemented by the MOE or local governments, but the design and construction work has been executed by contractors, without any technical confirmation by the ECG or VRA-NED in the process. In some cases, this has led to the extension of distribution lines from medium-voltage lines already affected by steep voltage drops. The distribution companies to which such facilities are transferred are consequently struggling to maintain them.

From now on, electrification plans are to be implemented by the newly established Rural Electrification Agency (REA). There is thought to be a need for a setup to allow the ECG and VRA-NED to participate in the design stage.

3) Compilation of Data on unelectrified localities

To draft electrification plans, it is indispensable to compile basic information about unelectrified localities on items such as location and population. It is estimated that localities without electricity still number over 50,000, and it would be extremely difficult to collect and compile such information for all of them through visits especially for that purpose. As a result, this work must be performed as efficiently as possible, on opportunities presented by the national census, for example.

6.3 Planning for implementation of the Master Plan

Section 6.2 presented the Master Plan based on the technical perspective. Stable supply requires construction of facilities with enough capacity to meet the demand, and the Master Plan presented in Section 6.2 should ideally be implemented as scheduled. For conformance with financial planning, however, the Study Team considered approaches to deferring some construction for distribution network reinforcement within the allowable scope in the immediately following years.

In the current SHEP scheme, the MOE or the concerned local governments and localities (villages) assume the burden of plans for distribution network extension (rural electrification), which is not undertaken with funds from the ECG and VRA-NED budgets. For this reason, extension was examined separately from the plans for renewal and reinforcment.

(1) Implementation plan for primary substations and subtransmission lines

Because planning delays would affect the entire area, it was assumed that the plan would be implemented as scheduled in the Master Plan. Table 6-22 shows the plans of primary substations and sub-transmission lines. As for the distribution reinforcement plan, there are distribution feeders, which countermeasures are the construction of new primary substations as shown in Table 6.23.

And besides, the scale of construction cost for primary substations and sub-transmission lines is so large that it is necessary to make implementation plans in consideration of securing the fund.

(2) Implementation plan for distribution network renewal and reinforcement

1) Plan for distribution network renewal

In the renewal plan, the Study Team calculated the amount of funds required each year assuming implementation of the improvements for the locations selected as requiring them over a period of five years, and inclusion of this amount in the implementation plan. The selection of specific locations should be studied separately by the ECG and the VRA-NED with consideration of factors such as degree of urgency and synchronization with other construction. As noted above, a calculation was made of the funds that would be required each year of the five-year period of renewal work for the selected locations. The five-year total was estimated at USD8.85 million for the ECG and USD810,000 for the VRA-NED. As a result, the yearly requirement would be USD1.77 million for the ECG and USD160,000 for the VRA-NED. Because there would emerge additional locations requiring renewal even after this five-year period, such funding would have to continue to be budgeted.

2) Plan for distribution line reinforcement

As is clear from the Master Plan findings, there is a fairly large number of distribution lines that already do not meet standards, and this increases the need for reinforcement over the immediately coming years. As a result, the cost from 2008 to 2010 will inevitably be higher. In response, the Study Team considered approaches to deferral of some construction in accordance with the following guidelines.

A. ECG

Toleration of excess current (overcurrent) could lead to distribution line failure. As such, the Study Team decided to ease the standard for voltage drop alone from the present 7 percent to 10 percent over the immediately following years (up to 2011), and to defer construction falling under this level. Similarly, for primary substations, the work of increasing voltage from 11 to 33 kV and replacing cable were judged to be, in effect, difficult to implement in 2008 owing to the large scale. It was consequently decided to defer this work to 2009 and succeeding years.

B. VRA-NED

Based on the same thinking as for the ECG, the Study Team proposed an easing of the voltage drop standard from 10 to 20 percent until 2011 and deferral of improvement in the case of locations under this line. In the same way, construction of primary substation and the work of increasing voltage from 11 to 34.5 kV was rescheduled to 2009 and succeeding years.

Based on these guidelines, the years of implementation for each project are revised as shown in Table 6-24 and Table 6-25. Table 6-26 and 6-27 show the result of reinforcement plan for each regional office.

Figures 6-37 and 6-38 show the implementation plans for primary substation, subtransmission line, and distribution network renewal and reinforcement based on these results.

In addition to the above, with respect to seven new primary substations where the necessity became clear from a distribution network reinforcement plan, the plans are reflected as primary substation plans.

Table 6-22 Primary substation and sub-transmission line plans

Area		Facility name	Countermeasure	Cost (1,000US$)	Year of implementation
ECG	Accra	H(Achimota)-E	- Installation of two new 630 ALXLPE circuits between H and E (2 circuits x 6.3 km)	1,323	2016
	Tema	H(Tema)-A	- Installation of two new 630 ALXLPE circuits between H and E (1 circuits x 5.6 km)	588	2016
		Kpong Primary substation	- Installation of an additional 10MVA transformer	200	2016
	Ashanti	A-KTI	- Installation of two new 630 ALXLPE circuits between H and E (1 circuits x 5.0 km)	525	2017
	Western	Atuabo Primary substation	- Installation of an additional 10MVA transformer	200	2009
		Axim Primary substation	- Installation of an additional 10MVA transformer	200	2015
	Eastern	ODA Primary substation	- Installation of an additional 10MVA transformer	200	2012
	Central	Saltpond Primary substation	- Installation of an additional 10MVA transformer	200	2009
	Volta	Kpeve Primary substation	- Installation of an additional 10MVA transformer	200	2009
		Tsito Primary substation	- Installation of an additional 10MVA transformer	200	2015
		Hohoe Primary substation	- Installation of an additional 10MVA transformer	200	2012
ECG Total				4,036	-
VRA-NED	Sunyani	Sunyani-Brekum	- Installation of capacity bank 3,000kVar	4	2010
			- Increase in thickness (from 120 to 200 mm2 AAC)	616	2010
		Sunyani-Mim	- Installation of capacity bank 4,000kVar	6	2010
		Berekum Primary substation	- Installation of an additional 5MVA transformer	83	2009
	Upper East	Bawku Primary substation	- Installation of an additional 3MVA transformer	48	2009
		Navrongo Primary substation	- Installation of an additional 3MVA transformer	48	2016
	Upper West	Sawla-Wa	- Installation of capacity bank 2,000kVar	3	2011
		Wa Primary substation	- Installation of an additional 5MVA transformer	83	2010
VRA-NED Total				891	-
Ghana Total				4,927	-

Table 6-23 Primary substation plans where necessity was found by distiribution reinforcement plans

Office	Substation (existing)	Distribution line (existing)	Countermeasure	Cost [1,000 US$]
Eastern	Tafo	Tafo	Installation of a new 33-kV distribution line (240 mm2 AAC, 24 km) from the Tafo BSP, construction of a new 33/11-kV substation (10 MVA) ahead of it, and connection to the existing Tafo distribution line along the way	1,743
	Akwatia	Asamankese	Installation of a new 33-kV distribution line (240 mm2 AAC, 25 km) from the Akwatia BSP, construction of a new 33/11-kV substation (5 MVA) ahead of it, and connection to the existing Asamkese distribution line along the way	1,425
	Nkawkaw	Mountains	Aerial line replacement ($16mm^2$ Cu→$120mm^2$ AAC, 32km) Construction of a 33/11-kV substation (5 MVA) along the way, and partial shift of load on the existing Mountains distribution line to the Donkorkrom distribution line	898
Western	Atuabo	Manganese	Voltage increase from 11 to 33 kV and construction of a new 33/11-kV substation (5 MVA)	312
Volta	Tsito	Peki	Construction of new 33/11-kV substations (10 MVA) at the center of the load distribution, installation of a new 33-kV distribution line (120 mm2 AAC, 2 km), and connection for division of the load	343
VRA-NED	Tamale	28F3B	Installation of new 34.5-kV line (185 mm2 ALXLPE, 18 km) from the Tamale BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Tolon), and connection to the existing 28F3B distribution line along the way	1,292
	Sunyani	27F8B	Installation of new 34.5-kV line (120 mm2 AAC, 14 km) from the Sunyani BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Chiraa), and connection to the existing 27F8B distribution line along the way	1,045

Table 6-24 List of measures modified in the implementation planning for ECG

Office	Substation (existing)	Distribution line (existing)	Countermeasure	Year of implementation	
				Before	After
Accra West	Main D (Avenor)	D16	Cable replacement (185mm^2 Al →6x630mm^2 Cu, 3.2km)	2008	2009
Eastern	Tafo	Kibi/Suhum	Voltage increase from 11 to 33 kV	2008	2010
		Tafo	Installation of a new 33-kV distribution line (240 mm2 AAC, 24 km) from the Tafo BSP, construction of a new 33/11-kV substation (10 MVA) ahead of it, and connection to the existing Tafo distribution line along the way	2008	2010
		Koforidua	Installation of a new 33-kV distribution line (240 mm2 AAC, 17 km) from the Tafo BSP, and connection to the existing Tafo Koforidua distribution line	2008	2009
	Akwatia	Akwatia	Voltage increase from 11 to 33 kV	2008	2010
		Asamankese	Installation of a new 33-kV distribution line (240 mm2 AAC, 25 km) from the Akwatia BSP, construction of a new 33/11-kV substation (5 MVA) ahead of it, and connection to the existing Asamkese distribution line along the way	2008	2009
Western	Atuabo	Manganese	Voltage increase from 11 to 33 kV and construction of a new 33/11-kV substation (5 MVA)	2008	2010
Volta	SOGAKOPE	SOGA-AKATSI	Installation of a new 33-kV distribution line and division of the Keta distribution line from Akatsi and Sogakope (120mm^2 AAC, 12.5km)	2008	2009
	Anloga	Keta	Replacement of aerial lines (16mm^2 Cu →120mm^2 AAC, 3.5km) (35mm^2 Cu→120mm^2 AAC, 14.4km) (70mm^2 Cu→120mm^2 AAC, 2.4km)	2008	2009

Table 6-25 List of measures modified in the implementation planning for VRA-NED (1/2)

Substation (existing)	Distribution line (existing)	Countermeasure	Year of implementation	
			Before	After
Tamale	28F3B	Installation of new 34.5-kV line (185 mm2 ALXLPE, 18 km) from the Tamale BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Tolon), and connection to the existing 28F3B distribution line along the way	2008	2011
	28F4B	Installation of a 11.5kV new line (185mm^2 ALXLPE, 4km)	2009	2011
	28F6B	Installation of a 11.5kV new line (185mm^2 ALXLPE, 4km)	2008	2009
	28F8B	Aerial line replacement (100mm^2 AAC → 240mm^2 AAC, 19km)	2009	2010
	28F9B	Installation of a 11.5kV new line (185mm^2 ALXLPE, 4km)	2010	2012
Brekum	Sunyani - Brekum (27F1Y)	Installation of a capacitor bank (3,000 kVar) in the Berekum substation, and aerial line replacement Aerial line replacement (120mm^2 AAC →200mm^2 AAC, 43km)	2010	2012
	"Berekum - Dormaa (BRYF2)"	Aerial line replacement (120mm^2 AAC →150mm^2 AAC, 31km)	2009	2011
	Berekum F1 (BRBF1)	Voltage increase from 11 to 34.5 kV, and aerial line replacement (35mm^2 Cu, 50mm^2 AAC →200mm^2 AAC, 23km)	2008	2009
	Berekum F2 (BRBF2)	Aerial line replacement (50mm^2 AAC →100mm^2 AAC, 6km)	2008	2012
Sunyani	"Sunyani- Mim (27F5Y)"	Installation of a capacitor bank (4,000 kVar) in the Mim switching station to improve voltage	2010	2011
	"Mim/Goaso /Hwidien (MMF1Y)"			
	Scanstyle (MM2FY)			
	Ayum(MMF3Y)			
	Sunyani F3 (27F3B)	Installation of a 11.5kV new line (120mm^2 AAC, 13km)	2008	2009
	Sunyani F7 (27F7B)	Aerial line replacement (35mm^2 AAC →100mm^2 AAC, 7km)	2008	2012
	Sunyani F8 (27F8B)	Installation of new 34.5-kV line (120 mm2 AAC, 14 km) from the Sunyani BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Chiraa), and connection to the existing 27F8B distribution line along the way	2008	2009

Table 6-25 List of measures modified in the implementation planning for VRA-NED (2/2)

Substation (existing)	Distribution line (existing)	Countermeasure	Year of implementation	
			Before	After
Sawla	Sawla-Wa (38YF6)	Installation of a capacitor bank (2,000 kVar) in the Mim switching station to improve voltage	2011	2012
	Wa-Hamile (WAFY1)			
	Wa Township 1 (479BF1)	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement (50mm^2 AAC → 100mm^2 AAC, 6km)	2009	2010
	Wa Township 3 (479BF3)	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement (50mm^2 AAC → 100mm^2 AAC, 5km)	2008	2010
Yendi	Bimbilla (35F5Y)	Installation of a 10-MVA booster station to improve voltage	2008	2011
Bolgatanga	29F1B (BOLGA)	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement (50mm^2 AAC, 120mm^2 AAC → 150mm^2 AAC, 5km)	2010	2011
	29F4B (BOLGA)	Voltage increase from 11 to 34.5 kV, and aerial line replacement (50mm^2 AAC → 100mm^2 AAC, 20km)	2008	2010
	29F6B (BOLGA)	Voltage increase from 11 to 34.5 kV, and aerial line replacement (50mm^2 AAC → 100mm^2 AAC, 8km)	2008	2012

Table 6-26 Results of reinforcement planning (ECG Accra East Office) (1/3)

(Legend)

① : New 33kV/11kV substation construction
(including ancillary facilities such as 33kV distribution lines)
② : Installation of new distribution line
③ : Enlargement of lines（Overhead line）
④ : Enlargement of lines（Cable）
⑤ : Voltage increase
⑥ : Installation of Capacitor Bank and Condensor, or Booster
⑦ : Alleviation of load by construction of a switching station

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation units
Main F	F03(FD38), F15(FK02), F11(FD19), F04(FD48)	①	Partial transfer of load after construction of the Adabraka substation	2009	GEDAP	
Main G	G013(G56), G07(G06), G11(G13), G19(G60), G12(G47), G02(G33), G06(G64), G04(G351), G21(G25)	①	Partial shift of load after construction of the Adabraka substation	2009	GEDAP	
Main H	H02(H351)	④	Cable replacement (120 mm2 Al -> 185 mm2 Al, 15 km) and partial shift of load to the M01 feeder	2008	572	3,800
	H05(H06)	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 13km)	2017	900	
	H10(H10)	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 14km)	2017	969	
	H04(H07)	②	Installation of a new distribution line from the Main H substation, and partial shift of load (120mm^2 AAC, 15km)	2011	320	
	H08(H24)	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 15km)	2013	1,039	

Table 6-26 Results of reinforcement planning (ECG Accra East Office) (2/3)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation units
Main K	K03(K09)	①	Installation of a new distribution line from the Trade Fair substation (to be constructed in 2009), and partial shift of load (120mm^2 AAC, 8km)	2009	171 Only for cost of installing a new line	3,532
	K04(K10)	①	Installation of a new distribution line from the Trade Fair substation, and partial shift of load (120mm^2 AAC, 8km)	2009	171 Only for cost of installing a new line	
	K05(K150)	④	Cable replacement (185mm^2 Al $\rightarrow$ 240mm^2 Cu, 18km)	2008	1,246	
	K13(K13)	④	Cable replacement (185mm^2 Al $\rightarrow$ 240mm^2 Cu, 17km)	2014	1,177	
	K06(K60)	②	Installation of a new distribution line from the Airport substation (already constructed), and partial shift of load (120mm^2 AAC, 9km)	2011	192	
	K10(K61)	②	Same as above (120mm^2 AAC, 7km)	2017	149	
	K11(K06)	②	Same as above (120mm^2 AAC, 9km)	2009	192	
	K12(K07)	②	Same as above (120mm^2 AAC, 11km)	2011	235	
Main L	L11(L01)	④	Cable replacement (185mm^2 Al $\rightarrow$ 240mm^2 Cu, 17km)	2017	1,177	2,456
	L10(L22)	①	Installation of a new distribution line from the Trade Fair substation, and partial shift of load (120mm^2 AAC, 6km)	2017	128	
	L06(L12)	④	Cable replacement (185mm^2 Al $\rightarrow$ 240mm^2 Cu, 12km)	2017	831	
	L04(L03)	①	Installation of a new distribution line from the Trade Fair substation, and partial shift of load (120mm^2 AAC, 6km)	2015	128	
	L03(L02)	①	Same as above (120mm^2 AAC, 9km)	2010	192	
Main M	M05 (Old Legon 2)	①	Partial shift of load after construction of the Nmai Djorn substation	2010	GEDAP	1,172
	M01 (Old Legon 1)	④	Cable replacement (185mm^2 Al $\rightarrow$ 240mm^2 Cu, 16km)	2011	1,108	
	M07 (Madina)	①	Partial shift of load after construction of the Nmai Djorn substation	2010	GEDAP	
	M08 (Kwabenya)	①	Installation of a new distribution line from the Kwabenya substation (to be constructed in 2010 under the GEDAP), and partial shift of load (120mm^2 AAC, 3km)	2010	GEDAP New distribution line installation cost: 64	

Table 6-26 Results of reinforcement planning (ECG Accra East Office) (3/3)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation units
Main Q	Q03 (Teshie 1)	②	Installation of a new distribution line from the Main Q substation, and partial shift of load (120mm^2 AAC, 5km)	2009	107	405
	Q06 (Teshie 3)	②	Same as above (120mm^2 AAC, 5km)	2015	107	
	Q01 (Old Spintex)	②	Same as above (120mm^2 AAC, 4km)	2008	85	
	Q07 (Teshie 2)	②	Same as above (120mm^2 AAC, 5km)	2014	107	
Main T	T03 (Adenta Est.1)	①	Partial shift of load after construction of the Nmai Djorn substation	2010	GEDAP	363
	T09 (Agbogba)	①	Installation of a new distribution line from the Kwabenya substation (to be constructed in 2010 under the GEDAP), and partial shift of load (120mm^2 AAC, 7km)	2010	GEDAP New distribution line installation cost: 149	
	T11 (Pantang)	①	Same as above (120mm^2 AAC, 10km)	2010	213	
Main W	Peduase	⑥	Installation of a capacitor bank (tentatively 4,000 kVar) to improve voltage	2008	6	12
	"W03 (Akropong)"	⑥	Installation of a capacitor bank (tentatively 4,000 kVar) to improve voltage	2008	6	
Main Y	"Y04 (Johnson Wax)"	①	Installation of a new distribution line from the Nami Djorn substation (to be constructed in 2010 under the GEDAP), and partial shift of load (120mm^2 AAC, 5km)	2010	GEDAP New distribution line installation cost: 107	576
	"Y10 (Texpo)", "Y11 (Spintex)"	②	Installation of a new distribution line from the Main Y substation, and partial shift of load (120mm^2 AAC, 12km)	2008	256	
	"Y02 (Old Spintex)"	②	Installation of a new distribution line from the Airport substation (already constructed), and partial shift of load (120mm^2 AAC, 10km)	2013	213	
ECG Accra East Office Total						12,316

Table 6-27 Results of reinforcement planning（ECG Accra West Office） (1/2)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation units
Main A (Odorkor)	A120, A13, A01, A61	①	Partial shift of load after construction of the Darkman substation (2011) and the Sowutuom substation (2010)	2011 2010	GEDAP	
Main B (Korie Bu)	B25, B27, B35, B15, B42, B24, B28, B19, B20	①	Partial shift of load after construction of the New Dansoman substation	2009	GEDAP	
Main C (Achimota Village)	ABC	③	Aerial line replacement ($35mm^2$ Cu →$120mm^2$ AAC, 20km)	2008	103	103
	C20, C60, C14, C13	①	* Partial shift of load after construction of the Sowutuom substation	2010	GEDAP	
Main D (Avenor)	D150	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 2.2km)	2011	152	3,978
	D123	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 4.4km)	2010	305	
	D16	④	Cable replacement ($185mm^2$ Al → $6x630mm^2$ Cu, 3.2km)	2009	2,032	
	D101	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 4.2km)	2008	291	
	D103	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 5.3km)	2008	367	
	D01	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 5.4km)	2011	374	
	D114	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 6.6km)	2008	457	
Main E (Tran-shipment)	E08, E07, EG14, E20, E150	①	Partial shift of load after construction of the Adabraka substation	2009	GEDAP	
Main F (Koko-miemie)	F11, F10	①	Partial shift of load after construction of the Adabraka substation	2009	GEDAP	

Table 6-27 Results of reinforcement planning（ECG Accra West Office） (2/2)

<table>
<tr><th rowspan="2">Substations (existing)</th><th rowspan="2">Distribution lines (existing)</th><th rowspan="2" colspan="2">Type of countermeasure</th><th rowspan="2">Year</th><th colspan="2">Cost (USD1,000)</th></tr>
<tr><th>Distribution line units</th><th>Substation units</th></tr>
<tr><td rowspan="3">Main G (Power House)</td><td>G25</td><td>②</td><td>Installation of a new distribution line from the Main G substation, and partial shift of load
(185mm^2 Al cable, 10km)</td><td>2008</td><td>329</td><td rowspan="3">1,087</td></tr>
<tr><td>G56</td><td>②</td><td>Same as above
(185mm^2 Al cable, 10km)</td><td>2014</td><td>329</td></tr>
<tr><td>GE19</td><td>④</td><td>Cable replacement
(185mm^2 Al → 258mm^2 Cu, 6.2km)</td><td>2014</td><td>429</td></tr>
<tr><td rowspan="2">Main N (Nsawam)</td><td>Nsawam - Accra</td><td>①</td><td>Partial shift of load after construction of the Ofankor substation</td><td>2008</td><td>Posting as new substation construction cost</td><td rowspan="2">320</td></tr>
<tr><td>Adoagyiri -Coaltar</td><td>②</td><td>Partial shift of load to a new feeder from Asamankese feeders</td><td>2008</td><td>320</td></tr>
<tr><td rowspan="3">Main R (Ridge)</td><td>R12</td><td>④</td><td>Cable replacement
(185mm^2 Al → 240mm^2 Cu, 4.9km)</td><td>2011</td><td>339</td><td rowspan="3">983</td></tr>
<tr><td>R11</td><td>④</td><td>Cable replacement
(185mm^2 Al → 240mm^2 Cu, 2.1km)</td><td>2010</td><td>145</td></tr>
<tr><td>R3</td><td>④</td><td>Cable replacement
(185mm^2 Al → 240mm^2 Cu, 7.2km)</td><td>2017</td><td>499</td></tr>
<tr><td>Main S (Kuwa-shieman)</td><td>S10</td><td>①</td><td>Partial shift of load after construction of the Sowutuomr substation</td><td>2010</td><td colspan="2">GEDAP</td></tr>
<tr><td>Main V (Dansoman)</td><td>V02, V10, V11</td><td>①</td><td>Partial shift of load after construction of the New Dansoman substation</td><td>2009</td><td colspan="2">GEDAP</td></tr>
<tr><td rowspan="2">Main Z (Tokuse)</td><td>RADIO</td><td>②</td><td>Installation of a new distribution line from the Main Z substation, and partial shift of load
(120mm^2 AAC, 15km)</td><td>2008</td><td>320</td><td rowspan="2">640</td></tr>
<tr><td>TUBA</td><td>②</td><td>Installation of a new distribution line from the Main Z substation, and partial shift of load
(120mm^2 AAC, 15km)</td><td>2008</td><td>320</td></tr>
<tr><td colspan="6">ECG Accra West Office Total</td><td>7,111</td></tr>
</table>

Table 6-28 Results of reinforcement planning (ECG Tema Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation units
Tema A	A31	④	Cable replacement ($120mm^2$ Cu → $240mm^2$ Cu, 3km)	2009	213	213
Tema B	B111	①	Installation of a new distribution line from the Adjei Kojo substation (to be constructed in 2010 under the GEDAP), and partial shift of load ($120mm^2$ AAC, 3km)	2010	GEDAP Distribution line installation cost: 64	64
Tema C	LUBE OIL	④	Cable replacement ($120mm^2$ Cu → $240mm^2$ Cu, 1.75km)	2012	124	369
	F/H#2	②	Installation of a new distribution line toward PFC Tank and partial shift of load ($240mm^2$ Cu ケーブル, 0.5km)	2010	32	
	AGRONA	④	Cable replacement ($120mm^2$ Cu → $240mm^2$ Cu, 3km)	2010	213	
Tema E	E21	④	Cable replacement ($120mm^2$ Cu → $240mm^2$ Cu, 1km)	2009	71	71
Tema H	Prampram	①	Installation of a new distribution line from the Dawhenya substation (to be constructed in 2010 under the GEDAP), and partial shift of load ($120mm^2$ AAC, 15km)	2010	GEDAP Distribution line installation cost: 320	1,089
	Western Castling	④	Cable replacement ($185mm^2$ Al → $240mm^2$ Cu, 2km)	2011	139	
	H-B1 H-B2	②	Connection of the cable on the trunk portion of the existing H-B2 line to H-B1, for two lines on the trunk portion of H-B1, plus installation of a new cable (630 mm2 Al XLPE, 6 km) for H-B2	2010	630	
Tema L (Lashibi)	Comm.20 (L91)	⑥	Installation of a capacitor bank (tentatively 300 kVar) to improve voltage	2013	1	1
Tema S (Ashiaman)	S31 (AFARIWA)	①	Partial shift of load after construction of the Mobole substation now under planning	2010	Construction of a new substation	
KPONG	Krobo Area	②	Installation of a new distribution line from the substation and partial shift of load ($120mm^2$ AAC, 16km)	2013	341	341
Asutsuare	Asutsuare	③	Aerial line replacement ($35mm^2$ Cu → $120mm^2$ AAC, 16km)	2008	358	358
ECG Tema Offiice Total						2,506

Table 6-29 Results of reinforcement planning (ECG Ashanti East Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation units
Main C	NSUTA -KUWAWU	①	Partial shift of load after construction of the Fawode and Achiase substations (both in 2010)	2010	GEDAP	213
	C21	②	Installation of a new distribution line from the Main F substation and partial shift of load (completed)	2007	Already implemented	
	C41	②	Partial shift of load to the KTI substation ($120mm^2$ AAC, 10km)	2008	213	
	Airport 1	①	Partial shift of load after construction of the Achiase substation (2010)	2010	GEDAP	
	Airport 2	①	Partial shift of load after construction of the Fawode substation (2010), and partial shift of load to the distribution line from Main E	2010	GEDAP	
Main E	E21	①	Partial shift of load after construction of the Fawode substation (2010), and partial shift of load to the distribution line from Main C	2010	GEDAP new distribution line installation cost: 213	
NSUTA	Mampong	③	Aerial line replacement ($16mm^2$ Cu →$120mm^2$ AAC, 10.9km)	2008	67	67
AGONA	NSUTA	①	Partial shift of load after construction of the Achiase substation (2010)	2010	GEDAP	
KONONGO	KONONGO	⑥	Installation of a capacitor bank (tentatively 4000 kVar) to improve voltage	2009	6	18
	AGOGO	⑥	Installation of a capacitor bank (tentatively 4000 kVar) to improve voltage	2010	6	
	ODUMASI	⑥	Installation of a capacitor bank (tentatively 4000 kVar) to improve voltage	2017	6	
EJISU	EJISU	⑥	Installation of a capacitor bank (tentatively 4000 kVar) to improve voltage	2009	6	6
ECG Ashanti East Office Total						517

Table 6-30 Results of reinforcement planning (ECG Ashanti West Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000) Distribution line units	Cost (USD1,000) Substation units
Main A	OBR	②	Partial shift of load to the Guiness 1 feeder completed; installation of four new distribution lines from the Amanform substation (already constructed) and partial shift of load (installation work already started; lengths of 0.1 km (three) and 1 km (one)	*2007* 2008	(Already implemented) distribution line installation cost: 28	129
	IND OHL	④	Cable replacement ($35mm^2$ Cu →$185mm^2$ Al, 2.7km)	2008	92	
	LAKE ROAD POWER HOUSE 2	①	Installation of a new distribution line from the KTI (Japckson Park) substation now under construction and partial shift of load, plus installation of three new distribution lines (each with 185 mm2 Al cable and a length of 0.1 km)	2008	10	
Main B	B11	②	Installation of a new distribution line from the Main E substation and partial shift of load ($120mm^2$ AAC, 5km)	2009	107	533
	B21	②	Installation of a new distribution line from the Main E substation and partial shift of load ($120mm^2$ AAC, 5km)	2009	107	
	B61	②	Installation of a new distribution line from the Abuakawa substation and partial shift of load ($120mm^2$ AAC, 5km)	2008	107	
	B71	②	Installation of a new distribution line from the Abuakawa substation and partial shift of load ($120mm^2$ AAC, 5km)	2009	107	
	B81	②	Installation of a new distribution line from the Abuakawa substation and partial shift of load ($120mm^2$ AAC, 5km)	2009	107	
Main D	D21	①	Plan for a partial shift of load to the Knust substation already constructed	2008	Substation already constructed	
	D31	①	Plan for a partial shift of load to the Knust substation already constructed	2008	Substation already constructed	
BEKWAI	KOKOFU	③	Aerial line replacement ($16mm^2$ Cu → $120mm^2$ AAC, 1.9km)	2008	12	12
Dunkwa	DUNKWA	③	Aerial line and cable replacement ($35mm^2$ Cu → $120mm^2$ AAC, 8.7km) ($16mm^2$ Cu → $120mm^2$ AAC, 1.5km) ($35mm^2$ Cu cable →$185mm^2$ Al XLPE, 2.7km)	2008	162	162
ECG Ashanti West Office Total						836

Table 6-31 Results of reinforcement planning (ECG Western Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation unit
Western A	A10	④	Cable replacement (120mm^2 Cu PILC →185mm^2 Cu PILC, 1.5km)	2017	74	637
	A31	④	Cable replacement (120mm^2 Cu PILC →240mm^2 Cu PILC, 4.3km) Partial shift of load from the existing distribution line A41 to A57	2008	304	
	A55	③	Aerial line replacement (150mm^2 Al → 265mm^2 Al, 7.6km)	2010	259	
Western B	B21	④	Cable replacement (185mm^2 Cu PILC →240mm^2 Cu PILC, 2.9km)	2012	205	453
	B71	④	Cable replacement (120mm^2 Cu PILC →240mm^2 Cu PILC, 3.5km)	2008	248	
Western C	C08	⑤	Voltage increase from 11 to 33 kV	2010	719	719
Bogoso	"Bogoso / Asanko"	⑦	Construction of a switching station and division of the existing distribution lines	2010	400	400
Atuabo	Aboso 1	③	Aerial line replacement (150mm^2 AAC →240mm^2 AAC, 38km)	2012	775	1,976
	Aboso 2	③	Aerial line replacement (150mm^2 AAC →240mm^2 AAC, 38.7km)	2012	789	
	Town 2	③	Aerial line replacement (70mm^2 Cu→240mm^2 AAC, 12km)	2013	100	
	Manganese	①	Voltage increase from 11 to 33 kV and construction of a new 33/11-kV substation (5 MVA)	2008	312	
Asawinso	Awaso /Wiawso	③	Aerial line replacement (150mm^2 AAC →200mm^2 AAC, 15km)	2017	123	725
	Bibiani	③	Aerial line replacement (150mm^2 AAC →400mm^2 AAC, 29.5km)	2012	602	
Dwenase	Juaboso	③	Aerial line replacement （120mm^2 AAC →240mm^2 AAC, about 60km、Need for replacement of supporting structures as well）	2012	1,942	1,942
ECG Western Office Total						6,853

Table 6-32 Results of reinforcement planning (ECG Eastern Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation unit
Tafo	Kibi / Suhum	⑤	Voltage increase from 11 to 33 kV	2010	1,270	3,518
	Tafo	①	Installation of a new 33-kV distribution line (240 mm2 AAC, 24 km) from the Tafo BSP, construction of a new 33/11-kV substation (10 MVA) ahead of it, and connection to the existing Tafo distribution line along the way	2010	1,743	
	Koforidua	②	Installation of a new 33-kV distribution line (240 mm2 AAC, 17 km) from the Tafo BSP, and connection to the existing Tafo Koforidua distribution line	2009	505	
Akwatia	Akwatia	⑤	Voltage increase from 11 to 33 kV	2010	616	2,932
	Asamankese	①	Installation of a new 33-kV distribution line (240 mm2 AAC, 25 km) from the Akwatia BSP, construction of a new 33/11-kV substation (5 MVA) ahead of it, and connection to the existing Asamkese distribution line along the way	2009	1,425	
	Oda	②	Installation of a new 33-kV distribution line (240 mm2 AAC, 30 km) from the Akwatia BSP, and connection to the existing Oda distribution line	2008	891	
Oda	Achiase	③	Aerial line replacement ($35mm^2$ Cu →$120mm^2$ AAC, 56km) ($50mm^2$ AAC→$120mm^2$ AAC, 4km)	2008	374	374
Nkawkaw	Mountains	①	Aerial line replacement ($16mm^2$ Cu→$120mm^2$ AAC, 32km) Construction of a 33/11-kV substation (5 MVA) along the way, and partial shift of load on the existing Mountains distribution line to the Donkorkrom distribution line	2010	898	1,087
	Town	④	Cable replacement ($95mm^2$ Al XLPE, $185mm^2$ Al XLPE →$240mm^2$ Cu XLPE, 3km)	2008	189	
ECG Eastern Office Total						7,911

Table 6-33 Results of reinforcement planning (ECG Central Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000)	
					Distribution line units	Substation unit
WINNEBA	WINNEBA	②	Installation of a new distribution line (120 mm2 AAC, 4 km) and partial shift of load, or partial shift of load to the APAM distribution line	2010	85	86
	SWEDRU 1	①	Partial shift of load after construction of the Swedru substation	2009	GEDAP	
	SWEDRU 2	①	Partial shift of load after construction of the Swedru substation	2009	GEDAP	
	APAM	⑥	Installation of a condensor to increase voltage	2008	1	
SALTPOND	MANKESSIM	⑥	Installation of a condensor to increase voltage	2008	1	1
Cape Coast	SALTPOND	①	Partial shift of load after construction of the Elmina substation, and installation of a condensor to increase voltage	2009	GEDAP 1	2
	FOSU	①	Partial shift of load after construction of the Elmina substation, and installation of a condensor to increase voltage	2009	GEDAP 1	
	ELMINA	①	Partial shift of load after construction of the Elmina substation	2009	GEDAP	
	TOWN 2	①	Partial shift of load after construction of the Elmina substation	2009	GEDAP	
ECG Central Office Total						89

Table 6-34 Results of reinforcement planning (ECG Volta Office)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000) Distribution line units	Cost (USD1,000) Substation unit
KPANDO	HOHOE	⑥	Installation of a 33-kV booster station to increase voltage	2008	100	1,124
	"HOHOE-JASIKAN"	②	Installation of a new 11-kV distribution line ($120mm^2$ AAC, 48km)	2009	1,024	
KPEVE	TOWNSHIP	②	Installation of a tie between the Tsibu Bethel and Agbate distribution lines to take in the existing Township load ($120mm^2$ AAC, 5km)	2009	96	96
HO	TANYIGBE	②	Installation of a new 11-kV distribution line and division of the existing Tanyigbe load ($120mm^2$ AAC, 4km)	2016	75	75
SOGAKOPE	"SOGA-AKATSI"	②	Installation of a new 33-kV distribution line and division of the Keta distribution line from Akatsi and Sogakope ($120mm^2$ AAC, 12.5km)	2009	267	267
TSITO	PEKI	①	Construction of new 33/11-kV substations (10 MVA) at the center of the load distribution, installation of a new 33-kV distribution line (120 mm2 AAC, 2 km), and connection for division of the load	2010	343	343
Anloga	Keta	③	Replacement of aerial lines ($16mm^2$ Cu $\rightarrow$ $120mm^2$ AAC, 3.5km) ($35mm^2$ Cu $\rightarrow$ $120mm^2$ AAC, 14.4km) ($70mm^2$ Cu $\rightarrow$ $120mm^2$ AAC, 2.4km)	2009	700	700
ECG Volta Office Total						2,604

Table 6-35 Results of reinforcement planning (VRA-NED Area) (1/2)

<table>
<tr><th rowspan="2">Substations (existing)</th><th rowspan="2">Distribution lines (existing)</th><th rowspan="2" colspan="2">Type of countermeasure</th><th rowspan="2">Year</th><th colspan="2">Cost (USD1,000)</th></tr>
<tr><th>Distribution line units</th><th>Substation unit</th></tr>
<tr><td rowspan="6">Tamale</td><td>28F3B</td><td>①</td><td>Installation of new 34.5-kV line (185 mm2 ALXLPE, 18 km) from the Tamale BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Tolon), and connection to the existing 28F3B distribution line along the way</td><td>2011</td><td>1,292</td><td rowspan="6">1,907</td></tr>
<tr><td>28F4B</td><td>②</td><td>Installation of a 11.5kV new line ($185mm^2$ ALXLPE, 4km)</td><td>2011</td><td>131</td></tr>
<tr><td>28F6B</td><td>②</td><td>Installation of a 11.5kV new line ($185mm^2$ ALXLPE, 4km)</td><td>2009</td><td>131</td></tr>
<tr><td>28F7B</td><td>③</td><td>Aerial line replacement ($100mm^2$ AAC → $240mm^2$ AAC, 8km)</td><td>2013</td><td>66</td></tr>
<tr><td>28F8B</td><td>③</td><td>Aerial line replacement ($100mm^2$ AAC → $240mm^2$ AAC, 19km)</td><td>2009</td><td>156</td></tr>
<tr><td>28F9B</td><td>②</td><td>Installation of a 11.5kV new line ($185mm^2$ ALXLPE, 4km)</td><td>2012</td><td>131</td></tr>
<tr><td rowspan="5">Brekum</td><td>Sunyani - Drobo (BRYF1)</td><td>③</td><td>Aerial line replacement ($120mm^2$ AAC →$150mm^2$ AAC, 40km)</td><td>2009</td><td>279</td><td rowspan="5">1,141</td></tr>
<tr><td>"Berekum - Dormaa (BRYF2)"</td><td>③</td><td>Aerial line replacement ($120mm^2$ AAC →$150mm^2$ AAC, 31km)</td><td>2011</td><td>216</td></tr>
<tr><td>Berekum F1 (BRBF1)</td><td>⑤</td><td>Voltage increase from 11 to 34.5 kV, and aerial line replacement ($35mm^2$ Cu, $50mm^2$ AAC →$200mm^2$ AAC, 23km)</td><td>2009</td><td>555</td></tr>
<tr><td>Berekum F2 (BRBF2)</td><td>③</td><td>Aerial line replacement ($50mm^2$ AAC →$100mm^2$ AAC, 6km)</td><td>2012</td><td>42</td></tr>
<tr><td>Berekum F3 (BRBF3)</td><td>③</td><td>Aerial line replacement ($16mm^2$ Cu, $50mm^2$ AAC →$100mm^2$ AAC, 8km)</td><td>2008</td><td>49</td></tr>
<tr><td rowspan="3">Sunyani</td><td>Sunyani F3 (27F3B)</td><td>②</td><td>Installation of a 11.5kV new line ($120mm^2$ AAC, 13km)</td><td>2009</td><td>327</td><td rowspan="3">1,421</td></tr>
<tr><td>Sunyani F7 (27F7B)</td><td>③</td><td>Aerial line replacement ($35mm^2$ AAC →$100mm^2$ AAC, 7km)</td><td>2012</td><td>43</td></tr>
<tr><td>Sunyani F8 (27F8B)</td><td>①</td><td>Installation of new 34.5-kV line (120 mm2 AAC, 14 km) from the Sunyani BSP, construction of a 34.5/11.5-kVsubstation (5 MVA) ahead of this line (near Chiraa), and connection to the existing 27F8B distribution line along the way</td><td>2010</td><td>1,045</td></tr>
</table>

Table 6-35 Results of reinforcement planning (VRA-NED Area) (2/2)

Substations (existing)	Distribution lines (existing)	Type of countermeasure		Year	Cost (USD1,000) Distribution line units	Cost (USD1,000) Substation unit
Sawla	Sawla-Wa (38YF6) Wa-Hamile (WAFY1)	⑥	Installation of a capacitor bank (2,000 kVar) in the Mim switching station to improve voltage	2012	3	155
	Wa Township 1 (479BF1)	③	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement ($50mm^2$ AAC → $100mm^2$ AAC, 6km)	2010	37	
	Wa Township 2 (479BF2)	③	Aerial line replacement ($100mm^2$ AAC, $120mm^2$ AAC → $150mm^2$ AAC, 12km)	2010	84	
	Wa Township 3 (479BF3)	③	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement ($50mm^2$ AAC → $100mm^2$ AAC, 5km)	2010	31	
Yendi	Bimbilla (35F5Y)	⑥	Installation of a 10-MVA booster station to improve voltage	2011	100	100
Bolgatanga	29F1B (BOLGA)	③	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement ($50mm^2$ AAC, $120mm^2$ AAC → $150mm^2$ AAC, 5km)	2011	168	1,486
	29F4B (BOLGA)	⑤	Voltage increase from 11 to 34.5 kV, and aerial line replacement ($50mm^2$ AAC → $100mm^2$ AAC, 20km)	2010	649	
	29F6B (BOLGA)	⑤	Voltage increase from 11 to 34.5 kV, and aerial line replacement ($50mm^2$ AAC → $100mm^2$ AAC, 8km)	2012	669	
Techiman	26F1B (TECHIMAN)	③	Replacement of the feeder cable in the starting section with 185 mm2 Al XLPE, and aerial line replacement ($50mm^2$ AAC→ $150mm^2$ AAC, 17km)	2008	125	319
	26F2B (TECHIMAN)	③	Aerial line replacement ($50mm^2$ AAC → $120mm^2$ AAC, 8km)	2009	55	
	WHF2B (WENCHI)	③	Aerial line replacement ($25mm^2$ AAC → $100mm^2$ AAC, 20km)	2008	139	
VRA-NED Total						6,522

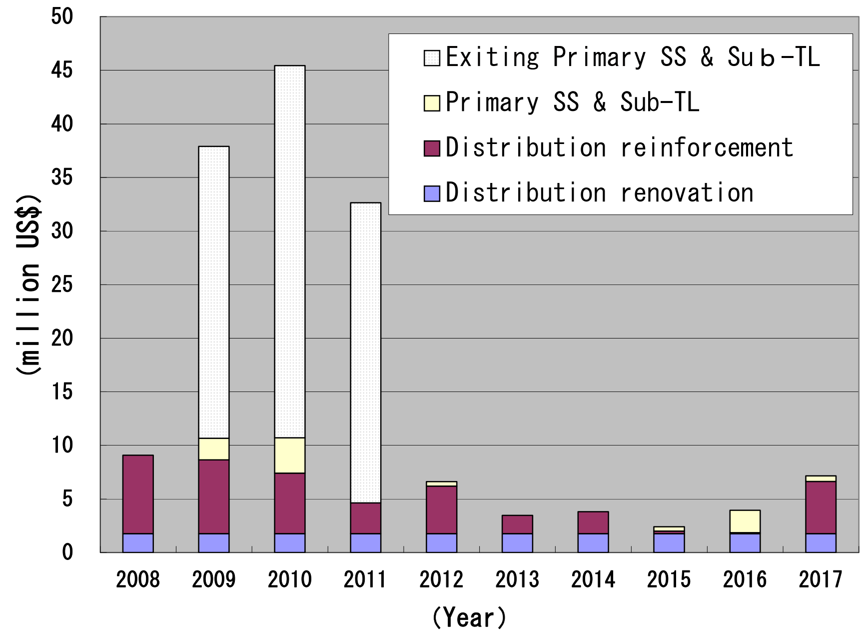


Figure 6-37 Master Plan implementation plan - ECG

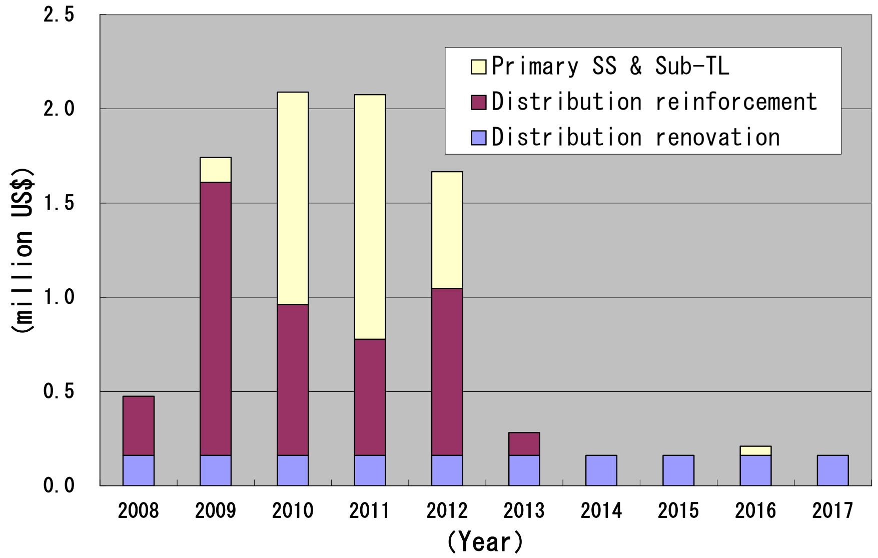


Figure 6-38 Master Plan implementation plan - VRA-NED

(3) Implementation plan for distribution network extension

Plans for distribution network extension cannot be determined merely with reference to financial plans; they require consideration of electrification policy and various other factors. For this reason, the Study Team estimated that attainment of the goal of a 70-percent rate of household electrification by 2020 posted in the NES would require appropriation of about USD50 million per year for construction. (Because the rate in 2006 was 54 percent, this estimate assumed that the electrification work would have to proceed at a pace of about 1 percentage point per year to increase the rate to 70 percent by 2020.)

6.4 Examination of impact in the high case scenario of the power demand forecast

The preparation of requisite plans described in the preceding sections has been premised on the base case scenario of the power demand forecast. This section considers the impact in the high case scenario.

(1) Assessment of impact on the plans for primary stations and subtransmission lines

Table 6-36 shows the differences between the base and high cases of the power demand forecast in the major urban areas served by the ECG. In the high case, the demand would run three or four years ahead of that in the base case in this area.

Table 6-36 Difference between the base and high case scenarios of the power demand forecast

Area	Maximum peak demand in 2017 (MVA)		Demand forecast difference (based on the base case in 2017)
	Base case	High case	
Accra	609.4	747.2	4 years earlier
Tema	239.8	280.0	3 years earlier
Kumasi	262.5	323.6	3 years earlier
Takoradi	116.0	132.3	3 years earlier

The Study Team made a system analysis for the major urban areas in 2017 in the high case scenario, and considered the additional countermeasures that would be required. The results are shown in Table 6-37. It was found that there would be a need for implementation of three subtransmission line projects and seven primary substation projects. It should be noted that modification of the distribution system would result in transfer of some of the distribution line load to other substations, and this could resolve the primary substation overload. For this reason, the primary substation projects require study of this aspect at the stage of detailed design.

Table 6-37 List of additional projects in the high case scenario

Region	Facility name	Bottleneck	Additional projects
Accra	H(Achimota)-K	- Subtransmission line overload（100%）	- Installation of one new 630 ALXLPE circuit (1 circuit x 4.7 km)
	A(Odorkor)	- Primary substation overload（100%）	- Installation of an additional transformer (20MVA)
	Z(Tokuse)	- Primary substation overload（124%）	- Installation of an additional transformer (10MVA)
Tema	D	- Primary substation overload（109%）	- Installation of an additional transformer (20MVA)
Kumasi	A-B	- Subtransmission line overload（102%）	- Installation of one new 240 ALXLPE circuit (1 circuit x 5.0 km)
	B-E	- Subtransmission line overload（100%）	- Installation of one new 240 ALXLPE circuit (1 circuit x 4.5 km)
	A(Kumasi)	- Primary substation overload（102%）	- Installation of an additional transformer (20MVA)
	D(Kaase)	- Primary substation overload（120%）	- Installation of an additional transformer (20MVA)
	P(Bekwai)	- Primary substation overload（190%）	- Installation of an additional transformer (10MVA)
Takoradi	A	- Primary substation overload（112%）	- Installation of an additional transformer (20MVA)

Even in the high case scenario, it was found that there would be no need for additional countermeasures as regards the capacity of ECG primary substations in other areas.

In the VRA-NED service area, in contrast, the analysis discovered the need for addition of capacity in certain primary substations and capacitor banks.

Table 6-38 shows the projects required in the high case scenario of the demand forecast. The total cost is USD7.473 million, or USD3.175 million more than in the base case.

Table 6-38 List of requisite countermeasures in the high case scenario of the demand forecast

Area	Countermeasure	Cost (1,000US$)	Year of implementatin	Remarks
Accra	- Installation of two new 630 ALXLPE circuits between H and E (2 circuits x 6.3 km)	1,323	2012	4 years earlier
	- Installation of one new 630 ALXLPE circuits between H and K (1 circuits x 4.7 km)	494	2017	Additional countermeasure
	A(Odokor) substation, 20MVA transformer addition	340	2017	Additional countermeasure
	Z(Tokuse) substation, 10MVA transformer addition	200	2017	Additional countermeasure
Tema	- Installation of one new 630 ALXLPE circuits between H and A (1 circuits x 5.6 km)	588	2013	3 years earlier
	Kpong substation, 10MVA transformer addition	200	2015	1 year earlier
	D substation, 20MVA transformer addition	340	2017	Additional countermeasure
Kumasi	- Installation of one new 630 ALXLPE circuits between A and KTI (1 circuits x 5.0 km)	525	2014	3 years earlier
	- Installation of one new 240 ALXLPE circuits between A and B (1 circuits x 5.0 km)	248	2017	Additional countermeasure
	- Installation of one new 240 ALXLPE circuits between B and E (1 circuits x 4.5 km)	223	2017	Additional countermeasure
	A(Kumasi) substation, 20MVA transformer addition	340	2017	Additional countermeasure
	D(Kaase) substation, 20MVA transformer addition	340	2017	Additional countermeasure
	P(Bekwai) substation, 10MVA transformer addition	200	2017	Additional countermeasure
Western	Atuabo substation, 10MVA transformer addition	200	2009	—
	Axim substation, 10MVA transformer addition	200	2014	1 year earlier
	A substation, 20MVA transformer addition	340	2017	Additional countermeasure
Eastern	ODA substation, 10MVA transformer addition	200	2011	1 year earlier
Central	Saltpond substation, 10MVA transformer addition	200	2009	—
Volta	Kpeve substation, 10MVA transformer addition	200	2009	—
	Tsito substation, 10MVA transformer addition	200	2013	2 years earlier
	Hohoe substation, 10MVA transformer addition	200	2011	1 year earlier
VRA-NED	Berekum substation, 5MVA transformer addition	83	2009	—
	Navrongo substation, 3MVA transformer addition	48	2015	1 year earlier
	Bawku substation, 3MVA transformer addition	48	2009	—
	Bawku substation, 3MVA transformer addition	48	2014	Additional countermeasure
	Wa substation, 5MVA transformer addition	83	2011	1 year earlier
	Berekum substation, - Installation of capacity bank 13,000kVar	19	2017	Increase of capacity
	Mim switching station、- Installation of capacity bank 18,000kVar	26	2017	Increase of capacity
	Wa substation, - Installation of capacity bank 12,000kVar	17	2017	Increase of capacity
Ghana Total		7,473	—	—

(2) Assessment of impact on the plan for distribution network reinforcement

The Study Team made an assessment of impact on the reinforcement plan for the distribution network in the high case scenario of the demand forecast presented in Chapter 4.

In the high case, the average rate of yearly demand increase would differ from that in the base case as shown in Table 6-39.

Table 6-39 Average rate of yearly demand increase

	- Base case	- High case
ECG	5.10%	6.36%
VRA-NED	4.72%	5.99%

The figure at right graphs the change in maximum current at yearly load increase rates over the ten-year period 2008 - 2017 of 5.10 and 6.36 percent, on a distribution line where the maximum current in 2008 was 280 A.

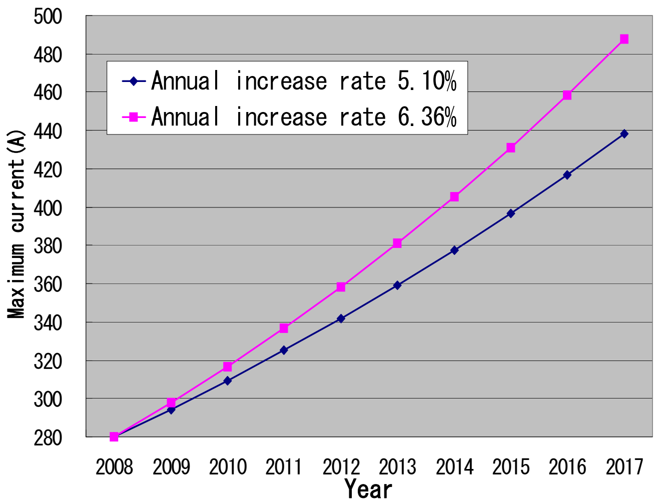


Figure 6-39 Supposed maximum current

If the line consisted of 120-mm2 AAC (with an allowable current of 455 A), the maximum current would not exceed 455 A up to 2017 at an increase rate of 5.10 percent, and there would be no need for reinforcement countermeasures by that year. In contrast, at an increase rate of 6.36 percent, the 455-A ceiling would be exceeded in 2016, and countermeasures would have to be taken by that year.

A study of individual distribution lines revealed that additional countermeasures would have to be taken for 22 ECG feeders if the high case scenario actualized. (There would be no need for additional countermeasures in the VRA-NED area over the years 2008 - 2017.)

Table 6-40 shows the additional countermeasures that would be required at the ECG. Taken together, the additional countermeasures would cost about 6 million US$. This would require expenditures about 1.15 times as high as in the base case over the ten-year period.

At both the ECG and the VRA-NED, demand increase in line with the high case scenario would create the need for implementation of the countermeasures contained in the Master Plan ahead of schedule. Regardless of the demand scenario, the implementation of a countermeasure must be determined after measureing the actual demand and evaluating the neccesity of it.

Table 6-40 Additional countermeasure construction in the event of the high case scenario (ECG) (1/2)

Office	Distribution line (substation)	Impact from actualization of the high case scenario (in 2017)	Proposed countermeasure	
			Type of countermeasure (proposed by the Study Team only)	Approximate cost (USD1,000)
Accra East	Y09 (Coca Cola) [Main Y]	Current load rate **80%→128%**	Installation of a new distribution line from the Main Y substation and partial shift of load (120 mm2 AAC, 15 km; tentative)	320
Accra West	G32 [Main G]	Current load rate **91%→105%**	Cable replacement (185mm^2 Al → 240mm^2 Cu, 3.2km)	222
Tema	A21 [Tema A]	Current load rate **97%→108%**	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 2.0km)	142
	B31 [Tema B]	Voltage drop rate **7%→8%**	Installation of a new distribution line from the Adjei Kogo substation (GEDAP, to be constructed in 2010), and partial shift of load (120 mm2 AAC, 10 km; tentative)	New distribution line installation cost: 213
	New Town [Tema S]	Current load rate **91%→108%** Voltage drop rate **7%→8%**	Partial shift of load after construction of the Mobole substation now in planning	(Construction of a new substation)
Ashanti East	KUMAWU [AGONA]	Voltage drop rate **7%→10%**	Installation of a capacitor bank to improve voltage (4,000 kVar; tentative)	6
Ashanti West	BEKWAI [Main D]	Voltage drop rate **7%→9%**	Aerial line replacement (50mm^2 AAC → 120mm^2 AAC, 61.1km)	378
	D11 [Main D]	Voltage drop rate **6%→8%**	Installation of a new distribution line from the Knust substation already constructed, and partial shift of load (120mm^2 AAC, 10km tentative)	213
	D51 [Main D]	Current load rate **73%→108%**	Installation of a new distribution line from the Knust substation already constructed, and partial shift of load (120mm^2 AAC, 15km tentative)	320
	TUTUKA [OBUASI]	Current load rate **81%→120%**	Cable replacement (185mm^2 Al → 240mm^2 Cu, 1.2km)	83

Table 6-40 Additional countermeasure construction in the event of the high case scenario (ECG) (2/2)

<table>
<tr><th rowspan="2">Office</th><th rowspan="2">Distribution line (substation)</th><th rowspan="2">Impact from actualization of the high case scenario (in 2017)</th><th colspan="2">Proposed countermeasure</th></tr>
<tr><th>Type of countermeasure (proposed by the Study Team only)</th><th>Approximate cost (USD1,000)</th></tr>
<tr><td rowspan="7">Western</td><td>A13 [Station A]</td><td>Current load rate 98%→109%</td><td>Cable replacement (120mm^2 Cu → 240mm^2 Cu, 4.5km)</td><td>319</td></tr>
<tr><td>B32 [Station B]</td><td>Current load rate 100% →150%以上</td><td>Installation of a new distribution line from Station C scheduled for construction (240 mm2 Cu cable, 5 km, and 120 mm2 AAC aerial line, 10 km; tentative)</td><td>534</td></tr>
<tr><td>B41 [Station B]</td><td>Current load rate 100%→107%</td><td>Cable replacement (120mm^2 Cu → 240mm^2 Cu, 3.9km)</td><td>277</td></tr>
<tr><td>B51 [Station B]</td><td>Current load rate 100% →150%以上</td><td>Installation of a new distribution line from Station C scheduled for construction (240 mm2 Cu cable, 5 km, and 120 mm2 AAC aerial line, 10 km; tentative)</td><td>534</td></tr>
<tr><td>B67 [Station B]</td><td>Voltage drop rate 7%→8%</td><td>Installation of a capacitor bank to improve voltage (4,000 kVar; tentative)</td><td>6</td></tr>
<tr><td>B81 [Station B]</td><td>Current load rate 79%→138%</td><td>Cable replacement (185mm^2 Al → 240mm^2 Cu, 1.9km)</td><td>132</td></tr>
<tr><td>C10 [Station C]</td><td>Current load rate 100% →150%以上</td><td>Installation of a new 33-kV distribution line (240 mm2 AAC, 15 km; tentative) from the 33-kV subtransmission line in the Station C vicinity, construction of a new 33/11-kV substation ahead of it, and connection to the existing C10 distribution line along the way</td><td>1,446</td></tr>
<tr><td rowspan="3">Eastern</td><td>St. Joseph [Koforidua]</td><td>Voltage drop rate 6%→11%</td><td>Installation of a second line on the feeder portion (120 mm2 AAC, 16 km; tentative)</td><td>341</td></tr>
<tr><td>Donkorkrom [Nkawkaw]</td><td>Voltage drop rate 7%→8%</td><td>Installation of a booster to raise voltage</td><td>10</td></tr>
<tr><td>Novotex [Nkawkaw]</td><td>Voltage drop rate 7%→8%</td><td>Aerial line replacement (50mm^2 AAC → 120mm^2 AAC, 14.5km)</td><td>90</td></tr>
<tr><td>Central</td><td>Asikuma [Oda]</td><td>Voltage drop rate 7%→8%</td><td>Installation of a booster to raise voltage</td><td>10</td></tr>
<tr><td>Volta</td><td>Ho-Central [Ho]</td><td>Current load rate 84%→132%</td><td>Cable replacement (185mm^2 Al → 240mm^2 Cu, 5.3km)</td><td>367</td></tr>
<tr><td colspan="4">Total for all offices</td><td>5,963</td></tr>
</table>

6.5 Examination of impact in an operating current in the range of 70 - 80 percent

In the study, the Master Plan is preopared on the assumption that the allowable line amperage would be the rated current and that countermeasures would be required for current in excess of this limit. As a result, the Study Team made assessments of the impact if countermeasures were implemented in a status of a certain margin.

More specifically, the Study Team considered the additional countermeasures that would be necessary for the influence of an operating current in the range of 70 - 80 percent, at standard upper limits of both 70 and 80 percent of the allowable current.

The Study Team proposed reinforcement countermeasures for that segment of these distribution lines on which the current in 2017 would exceed 70 percent of the allowable level (excluding those reinforced to correct voltage drop beyond the standard). Table 6-41 presents these countermeasures.

Table 6-41 Amount of increase in distribution lines requiring countermeasures if the allowable current load rate is 70 percent (ECG) (1/3)

Office	Distribution line/substation	Current load rate in 2017	Proposed countermeasures	
			Type of countermeasure (proposed by the Study Team alone)	Estimated cost, USD1,000
Accra East	T10 (DODOWA) [Main T]	75%	Installation of new distribution lines after construction of the Nmai Djorn and Kwabenya substations (2010), and partial shift of load (120 mm2 AAC, 15 km; tentative)	GEDAP, new distribution line installation cost: 320
	Y09 (Coca Cola) [Main Y]	80%	Installation of a new distribution line from the Main Y substation, and partial shift of load (120 mm2 AAC, 15 km; tentative)	320
Accra West	A16 [Main A]	79%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 2.7km)	187
	B24 [Main B]	90%	Partial transfer of load after construction of the New Dansoman substation (2009)	GEDAP
	E26 [Main E]	74%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 3.0km)	208
	G32 [Main G]	91%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 3.2km)	222
	G05 [Main G]	81%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 2.2km)	156
	R13 [Main R]	86%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 4.0km)	284
	R5 [Main R]	86%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 6.5km)	461
	R4 [Main R]	74%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 4.5km)	319
	S02 [Main S]	89%	Installation of a new distribution line after construction of the Sowutuom substation (2010), and partial shift of load (120 mm2 AAC, 15 km; tentative)	GEDAP, new distribution line installation cost: 213
	S11 [Main S]	72%	Installation of a new distribution line after construction of the Sowutuom substation (2010), and partial shift of load (120 mm2 AAC, 15 km; tentative)	GEDAP, new distribution line installation cost: 213

Table 6-41 Amount of increase in distribution lines requiring countermeasures if the allowable current load rate is 70 percent (ECG) (2/3)

Office	Distribution line/substation	Current load rate in 2017	Proposed countermeasures	
			Type of countermeasure (proposed by the Study Team alone)	Estimated cost, USD1,000
Tema	A21 [Tema A]	97%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 2.0km)	142
	A61 [Tema A]	85%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 5.0km)	355
	A71 [Tema A]	78%	Installation of new distribution lines from the Lashibi substation and partial shift of load (120 mm2 AAC, 15 km, and 240 mm2 Cu cable, 5 km; tentative)	641
	A91 [Tema A]	73%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 0.1km)	7
	B31 [Tema B]	86%	Installation of a new distribution line from the Adjei Kojo substation (GEDAP, to be constructed in 2010) and partial shift of load (120 mm2 AAC, 10 km; tentative)	New distribution line installation cost: 213
	B41/71 [Tema B]	79%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 1.0km)	71
	B91 [Tema B]	71%	Installation of a second line for the feeder portion (240mm^2 Cu cable, 6.9km)	443
	ASASUA [Tema D]	76%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 1.1km)	78
	T.O.R [Tema H]	71%	Installation of a second line for the feeder portion (240mm^2 Cu cable, 1.2km)	77
	New Town [Tema S]	91%	Partial shift of load after construction of the Mobole substation now in planning	(Construction of a new substation)
Ashanti West	D51 [Main D]	73%	Installation of a new distribution line from the Knust substation already constructed, and partial shift of load (120 mm2 AAC, 15 km; tentative)	320
	TUTUKA [OBUASI]	81%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 1.2km)	83
Western	A13 [Station A]	98%	Cable replacement (120mm^2 Cu → 240mm^2 Cu, 4.5km)	319
	B81 [Station B]	79%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 1.9km)	132
	C01 [Station C]	94%	Installation of a second line for the feeder portion (185mm^2 Al XLPE, 6.6km)	217
	C10 [Station C]	100%	Installation of a new 33-kV distribution line (240 mm2 AAC, 15 km; tentative) from the 33-kV subtransmission line near Station C, construction of a new 33/11-kV substation (10 MVA) ahead of it, and connection to the existing C10 distribution line along the way	1,446
	New Site /Suhuma [Dwenase]	93%	Aerial line replacement (35mm^2 Cu → 120mm^2 AAC, 0.7km)	16

Table 6-41 Amount of increase in distribution lines requiring countermeasures if the allowable current load rate is 70 percent (ECG) (3/3)

Office	Distribution line/substation	Current load rate in 2017	Proposed countermeasures	
			Type of countermeasure (proposed by the Study Team alone)	Estimated cost, USD1,000
Eastern	Estate Junc. [Koforidua]	78%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 2km)	138
	Accra Rd. [Koforidua]	75%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 3km)	208
	Sawmill [Oda]	71%	Aerial line replacement (35mm^2 Cu → 120mm^2 AAC, 2km)	45
Volta	Ho-Central [Ho]	84%	Cable replacement (185mm^2 Al → 240mm^2 Cu, 5.3km)	367
	DENU [Aflao]	84%	Aerial line replacement (35mm^2 Cu → 120mm^2 AAC, 0.3km)	7
Additional cost required for the reinforcement plan when the upper limit of the current load rate is 80 percent				4,821
Additional cost required for the reinforcement plan when the upper limit of the current load rate is 70 percent				8,228

As shown below, in the event of implementation of countermeasures by the ECG at 70 and 80 percent of the rated current, relative to the cost when the standard is assigned the value of 100 percent, the cost in application of the 70-percent rate would be 1.20 times as high, and that in application of the 80-percent rate, 1.12 times as high.

Table 6-42 Impact at different current load rates (ECG)

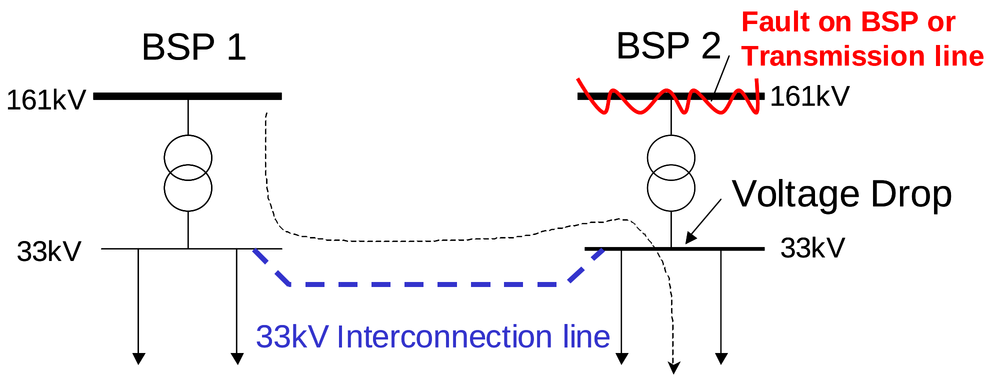
Postulated upper limit of the current load rate	Increase in the number of distribution lines requiring countermeasures	Additional countermeasure cost	Total construction cost, 2008 - 2017
80%	18	Approximately 4,821 thousand US$	45,561 thousand US$
70%	34	Approximately 8,228 thousand US$	48,968 thousand US$

6.6 Reliability improvement measures for the areas outside large-scale cities

The power supply outside large-scale cities of Accra, Kumasi and so on is conducted by the radial distribution system to be spread from stand-alone BSPs. Accordingly, as for the distribution system of the lower system, a total blackout happens when big troubles occur at the BSP of the higher system. As one of the methods to prevent the total blackout, there is a method of linking two places of BSPs with a 33kV interconnection line, which enables to conduct power supply by one BSP when another BSP breaks down. In this section, the technical study is conducted about linking two places of BSPs with a 33kV interconnection line as the reliability improvement measure outside large-scale cities.

(1) Methodology of the study

Figure 6-40 shows the system configuration of BSPs to be studied in this section. Two places of BSPs are linked at the 33kV bus bar of the secondary side of each BSP. When one BSP breaks down, power supply will be conducted from the facilities with no fault using the 33kV interconnection line. The voltage drop occurs at the fault side bus bar by the power flow through the 33kV interconnection line. If the voltage drop at the bus bar of a fault side is large, it brings about obstacles to power supply because the voltage at the end of distribution feeders becomes larger. The technical analysis whether the 33kV interconnection line can supply power or not is conducted using 5% of the targeted value of voltage drop at the fault bus-bar, which is discussed with the counterparts. When one BSP breaks down, the power flow of BSP with no fault will be increased because of the power flow of the fault side. Therefore the capacity of transformer of BSPs is also checked. The year for the study in this section is 2017, which is the last year of the master plan study.



(The similar study is carried out at the time of the BSP1 trouble)

Figure 6-40 Power supply that utilized a 33kV interconnection line at the BSP trouble

(2) Interconnection lines as the study object

Table 6-43 shows the study object of 33kV interconnection lines.

Table 6-43 33kVInterconnection lines as the study object

Region	33kV interconnection lines	Distances (km)
Western／Central	Takoradi BSP～Capecoast BSP	73
Western	Takoradi BSP～Essiama BSP	75
Western	Takoradi BSP～Tarkwa BSP	52
Central	Capecoast BSP～Winneba BSP	74
Volta	Kpeve BSP～Kpandu BSP	40
Volta	Kpeve BSP～Ho BSP	20

(3) Study result

Table 6-44 shows a study result in this section. When the voltage drop of the 33kV interconnection lines is only considered, the power supply for both directions at the fault of BSPs is possible for the 33kV interconnection line between Kpeve BSP and Ho BSP. But there is a limitation when the overloading of the transformer is not permitted at the time of the BSP trouble. For example, the available capacity of the transformer of Kpeve BSP side becomes 2MVA at the time of trouble of Ho BSP. As for the other interconnection lines, some of the load can be supplied when considering the voltage drop and the capacity of BSPs.

This study so far considers the voltage drop by the power flow through the 33kV interconnection line in case of the BSP trouble and the available capacity of BSPs, and technical study is carried out, however, in the concrete implementation of this method, more detailed study is necessary for the capacity confirmation of the substation equipment such as circuit breakers, the reflection of the updated demand, and so on.

Table 6-44 Study result of BSP for reliability improvement in the areas outside large-scale cities

33kV Interconnection lines (Maximum demand in 2017)			Dis-tance	Interconnection, line type	Available capacity (Year 2017)			
					Evaluated value by voltage drop of interconnection lines		BSP available capactiy	
BSP1		BSP2			Capacity	Voltage Drop	BSP1	BSP2
Takoradi BSP (116MVA)	~	Capecoast BSP (49MVA)	73km	400AAC, 2cct	8MVA	5.6%	12MVA	0MVA
〃	~	Essiama BSP (10MVA)	75km	400AAC, 2cct	4MVA	5.7%	12MVA	23MVA
〃	~	Tarkwa BSP (71MVA)	52km	400AAC, 2cct	12MVA	5.5%	12MVA	1MVA
Capecoast BSP (49MVA)	~	Winneba BSP (21MVA)	74km	400AAC, 2cct	4MVA	5.7%	0MVA	5MVA
Kpeve BSP (5MVA)	~	Kpandu BSP (11MVA)	40km	400AAC	7MVA	5.4%	2MVA	9MVA
〃	~	Ho BSP (8MVA)	20km	150AAC	9MVA	5.6%	2MVA	10MVA

Chapter 7 Economic and Financial Analysis of the Master Plan

7.1 Overview of the Master Plan

In the preceding chapters, the existing facilities and plans have been reviewed. Generally, the existing projects have been found to be sound, but based on the future demand, additional projects were identified.

Over the next 10 years, the whole master plan will provide a cumulative power of 25,238 GWh[1], and will require a total investment of about 142 million USD. Of that amount, the newly identified projects will cost about 52 million USD, providing 13,894 GWh over 10 years. The breakdown of the existing projects, and the newly identified projects, are shown in Table 7-1.

Table 7-1 Investment for the Master Plan: Total and the Newly Identified

	Whole Master Plan	Existing Projects (including not-yet financed ones)	Newly Identified Projects
Investment (1,000USD)	142,161	89,976	52,185
		63%	37%
Additional Culmulative Demand for the next 10 years (GWh)	25,238	11,344	13,894
		45%	55%

Source: JICA Study Team

It is important to note that the existing projects are not fully financed yet. As mentioned, the existing projects have been found to be sound, and the newly identified projects are based on the assumptions that the existing projects will come on line as planned. Therefore, while most of the analysis here will focus on the newly identified projects, the importance of providing finance to the existing projects must be emphasized.

[1] The "10 years" here does not necessarily mean 2008-2017. The additional demand is calculated as 10 years after the completion of the individual projects. If there is a project in 2017, the demand will be calculated up to 2026, while demand from projects in 2008 will only be counted up to 2018. There fore, the figure does not correspond exactly with the aggregated power demand.

7.2 Financial Analysis

The financial analysis of the Master Plan is straight forward. The investment has been identified, along with the incremental demand that they provide.

In making the financial analysis, however, a crucial assumption needs to be made. Under the current tariff structure, the utilities do not turn any profit for the additional power sales. Under this structure, the master plan cannot hope to make any financial sense. While this master plan is expected to improve costs in various areas, much of the tariff is taken up by the wholesale cost, which leaves little room for improvement on the utilities' side. In order to make a proper financial assessment, a certain level of profit margin for the power sales needed to be assumed.

Currently, the average tariff for the whole use is about 0.12 GHC/kWh (approximately 12 US cents/kWh). Here, we assume that 5% profit margin is secured on this tariff, which provides a profit of 0.6 US cents/kWh.

Another benefit comes from the decrease in loss. It is assumed that the improvement of the primary substations will bring 0.2 % point improvement in the loss, and the reinforcement of the distribution network will also bring a 3.1% point improvement in the loss of the affected system. This will result in the savings for the power purchase, which would bring huge financial and economic benefits.

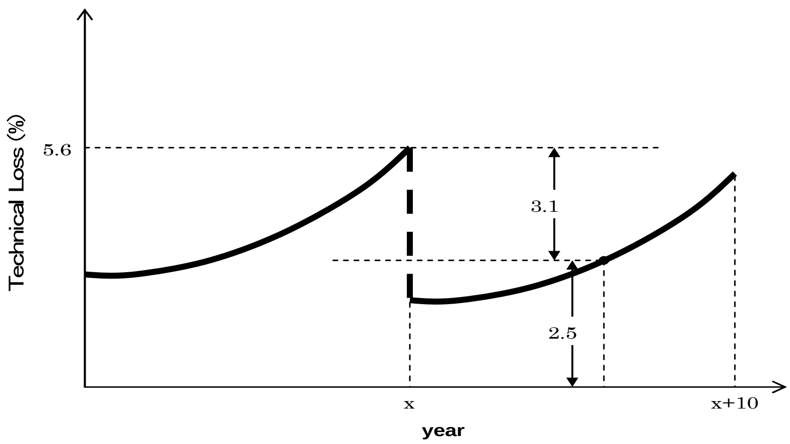


Figure 7-1 Process of technical loss

The regional investment schedule and the demand schedule are shown in the following pages, for the whole master plan and for the newly identified projects within the whole master plan. Since the figures do not assume inflation, this is in real terms. The summary of the results is shown below.

Table 7-2 Investment and Sales for the Whole Master Plan

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Accra	**Investment (1000 USD)**	7,072	18,358	20,208	13,978	0	1,252	2,042	235	1,323	4,653	0	0	0	0	0	0	0	0	0
	Sale (GWh)		128.4	461.8	828.8	1,082.7	1,082.7	1,105.4	1,142.5	1,146.8	1,170.8	1,126.9	793.5	426.5	172.6	172.6	149.9	112.8	108.5	84.5
	Sales (1000 USD)		15,412	55,420	99,459	129,922	129,922	132,650	137,100	137,612	140,496	135,224	95,216	51,177	20,714	20,714	17,986	13,536	13,024	10,140
	Cost (1000 USD)		14,641	52,649	94,486	123,426	123,426	126,018	130,245	130,732	133,471	128,463	90,455	48,618	19,679	19,679	17,087	12,859	12,372	9,633
	Saved Loss	847	3,031	5,433	7,100	7,100	7,251	7,496	7,524	7,683	8,241		0	0	0	0	0	0	0	0
	CF (1000 USD)	-6,225	-14,556	-12,004	-1,905	13,596	12,495	12,086	14,144	13,241	10,613	6,761	4,761	2,559	1,036	1,036	899	677	651	507
	IRR= 19.3%																			
Tema	**Investment (1000 USD)**	358	1,779	3,759	16,902	124	342	0	0	788	0	0	0	0	0	0				
	Sale (GWh)		5.2	31.0	85.4	330.3	332.1	337.1	337.1	337.1	348.5	343.3	317.5	263.1	18.2	16.4	11.4	11.4	11.4	0.0
	Sales (1000 USD)		622	3,716	10,252	39,640	39,855	40,450	40,450	40,450	41,820	41,198	38,104	31,568	2,180	1,965	1,370	1,370	1,370	0
	Cost (1000 USD)		591	3,530	9,739	37,658	37,862	38,427	38,427	38,427	39,729	39,138	36,199	29,990	2,071	1,867	1,302	1,302	1,302	0
	Saved Loss	8	47	130	495	498	505	505	505	523	523		0	0	0	0	0	0	0	0
	CF (1000 USD)	-350	-1,701	-3,443	-15,895	2,356	2,156	2,528	2,528	1,757	2,614	2,060	1,905	1,578	109	98	69	69	69	0
	IRR= -1.6%																			
Ashanti	Investment (1000 USD)	691	438	10,556	0	0	0	0	0	0	531	0	0	0	0	0				
	Sale (GWh)		7.6	12.4	128.0	128.0	128.0	128.0	128.0	128.0	128.0	126.2	121.4	5.8	5.8	5.8	5.8	5.8	5.8	5.8
	Sales (1000 USD)		908	1,484	15,358	15,358	15,358	15,358	15,358	15,358	15,358	15,148	14,572	698	698	698	698	698	698	698
	Cost (1000 USD)		863	1,410	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,390	13,844	663	663	663	663	663	663	663
	Saved Loss	53	86	866	866	866	866	866	866	866	906									
	CF (1000 USD)	-638	-306	-9,616	1,634	1,634	1,634	1,634	1,634	1,634	1,143	757	729	35	35	35	35	35	35	35
	IRR= 3.9%																			
Western	Investment (1000 USD)	985	4,230	1,378	0	4,313	100	0	200	0	197	0	0	0	0	0				
	Sale (GWh)		30	157	198	198	328	331	331	337	337	313	186	144	144	15	12	12	6	6
	Sales (1000 USD)		3,550	18,797	23,763	23,763	39,309	39,669	39,669	40,390	40,390	37,550	22,303	17,337	17,337	1,791	1,431	1,431	710	710
	Cost (1000 USD)		3,373	17,857	22,575	22,575	37,343	37,686	37,686	38,370	38,370	35,672	21,188	16,470	16,470	1,702	1,359	1,359	675	675
	Saved Loss	101	529	669	669	1,105	1,116	1,116	1,136	1,136	1,156									
	CF (1000 USD)	-884	-3,524	231	1,857	-2,020	2,981	3,099	2,920	3,156	2,979	1,877	1,115	867	867	90	72	72	36	36
	IRR= 26.8%																			
East	Investment (1000 USD)	7,013	0	3,398	0	200	0	0	0	0	0	0	0	0	0	0				
	Sale (GWh)		69.4	69.4	103.0	103.0	105.0	105.0	105.0	105.0	105.0	35.6	35.6	2.0	2.0	0.0	0.0	0.0	0.0	0.0
	Sales (1000 USD)		8,328	8,328	12,363	12,363	12,600	12,600	12,600	12,600	12,600	4,272	4,272	237	237	0	0	0	0	0
	Cost (1000 USD)		7,911	7,911	11,744	11,744	11,970	11,970	11,970	11,970	11,970	4,059	4,059	226	226	0	0	0	0	0
	Saved Loss	150	150	223	223	228	228	228	228	228	228									
	CF (1000 USD)	-6,863	566	-2,758	841	646	858	858	858	858	858	214	214	12	12	0	0	0	0	0
	IRR= -6.1%																			
Central	Investment (1000 USD)	2	4,180	85	0	0	0	0	0	0	0	0	0	0	0	0				
	Sale (GWh)		0.1	128.5	131.1	131.1	131.1	131.1	131.1	131.1	131.1	131.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Sales (1000 USD)		7	15,419	15,732	15,732	15,732	15,732	15,732	15,732	15,732	15,725	313	0	0	0	0	0	0	0
	Cost (1000 USD)		7	14,648	14,945	14,945	14,945	14,945	14,945	14,945	14,945	14,938	298	0	0	0	0	0	0	0
	Saved Loss	0	388	396	396	396	396	396	396	396	396									
	CF (1000 USD)	-2	-3,792	1,082	1,183	1,183	1,183	1,183	1,183	1,183	1,183	786	16	0	0	0	0	0	0	0
	IRR= 26.6%																			
Volta	Investment (1000 USD)	1067.0	1320.0	343.0	0.0	200.0	0.0	0.0	200.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0				
	Sale (GWh)		25	55	63	63	67	67	67	72	74	49	19	11	11	6	6	6	2	0
	Sales (1000 USD)		2,940	6,578	7,523	7,523	8,074	8,074	8,074	8,625	8,832	5,892	2,254	1,309	1,309	758	758	758	207	0
	Cost (1000 USD)		2,793	6,249	7,147	7,147	7,670	7,670	7,670	8,194	8,390	5,597	2,141	1,244	1,244	720	720	720	196	0
	Saved Loss	0	0	0	0	0	0	0	0	0	0									
	CF (1000 USD)	-1,067	-1,173	-14	376	176	404	404	204	356	442	295	113	65	65	38	38	38	10	0
	IRR= 4.2%																			
ECG	Investment (1000 USD)	17,188	30,305	39,727	30,880	4,837	1,694	2,042	635	2,186	5,381	0	0	0	0	0	0	0	0	0
	Sale (GWh)	0	265	914	1,537	2,036	2,174	2,204	2,242	2,256	2,294	2,125	1,475	853	354	216	185	148	133	96
	Sales (1000 USD)		31,768	109,740	184,450	244,300	260,850	264,533	268,984	270,768	275,228	255,008	177,036	102,326	42,476	25,926	22,243	17,792	16,008	11,548
	Cost (1000 USD)		30,180	104,253	175,227	232,085	247,807	251,307	255,534	257,229	261,466	242,257	168,184	97,210	40,352	24,630	21,130	16,903	15,208	10,971
	Saved Loss	1,158	4,231	7,717	9,749	10,192	10,361	10,606	10,655	10,831	11,450									
	CF (1000 USD)	-16,030	-24,486	-26,523	-11,908	17,570	21,709	21,791	23,469	22,184	19,831	12,750	8,852	5,116	2,124	1,296	1,112	890	800	577
	IRR= 12.7%																			
VRA-NED	Investment (1000 USD)	4,528	1,627	1,088	3	0	121	0	0	48	0	0	0	0	0	0				
	Sale (GWh)		82	111	131	131	131	133	133	133	134	52	23	3	3	3	1	1	1	0
	Sales (1000 USD)		9,827	13,358	15,719	15,725	15,725	15,988	15,988	15,988	16,092	6,265	2,734	373	367	367	104	104	104	0
	Cost (1000 USD)		9,335	12,690	14,933	14,939	14,939	15,188	15,188	15,188	15,287	5,952	2,598	355	348	348	99	99	99	0
	Saved Loss	0	0	0	0	0	0	0	0	0	0									
	CF (1000 USD)	-4,528	-1,136	-420	783	786	665	799	799	751	805	313	137	19	18	18	5	5	5	0
	IRR= -0.5%																			
Whole Ghana	Investment (1000 USD)	21,716	31,932	40,815	30,883	4,837	1,815	2,042	635	2,234	5,381	0	0	0	0	0	0	0	0	0
	Sale (GWh)	0	347	1,026	1,668	2,167	2,305	2,338	2,375	2,390	2,428	2,177	1,498	856	357	219	186	149	134	96
	Sales (1000 USD)		41,595	123,097	200,168	260,025	276,575	280,521	284,971	286,756	291,320	261,273	179,771	102,700	42,843	26,293	22,347	17,897	16,112	11,548
	Cost (1000 USD)		39,515	116,943	190,160	247,024	262,746	266,495	270,723	272,418	276,754	248,209	170,782	97,565	40,700	24,978	21,229	17,002	15,307	10,971
		1,158	4,231	7,717	9,749	10,192	10,361	10,606	10,655	10,831	11,450									
	CF (1000 USD)	-20,558	-25,621	-26,943	-11,125	18,357	22,375	22,590	24,268	22,935	20,635	13,064	8,989	5,135	2,142	1,315	1,117	895	806	577

Table 7-3 Investment and demand for newly identified projects

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Accra	**Investment (1000 USD)**	7,073	640	813	2,719	0	1,252	2,042	235	1,323	4,653	0	0	0	0	0	0	0	0	0
	Sale (GWh)		204.3	222.8	246.3	324.8	324.8	361.0	420.0	426.8	465.0	395.1	376.6	353.1	274.6	274.6	238.4	179.4	172.6	134.4
	Sales (1000 USD)		24,518	26,736	29,555	38,980	38,980	43,320	50,398	51,213	55,799	47,410	45,192	42,373	32,948	32,948	28,608	21,530	20,715	16,129
	Cost (1000 USD)		23,292	25,400	28,077	37,031	37,031	41,154	47,878	48,652	53,009	45,040	42,932	40,255	31,301	31,301	27,178	20,453	19,680	15,323
	Saved Loss	742	809	895	1,181	1,181	1,313	1,527	1,552	1,691	2,180									
	CF (1000 USD)	−6,331	1,395	1,419	−61	3,130	2,010	1,651	3,837	2,929	317	2,371	2,260	2,119	1,647	1,647	1,430	1,076	1,036	806
	IRR=	25.5%																		
Tema	**Investment (1000 USD)**	358	284	1,259	138	124	342	0	0	788	0	0	0	0	0	0				
	Sale (GWh)		16.2	29.0	86.0	92.3	97.9	113.3	113.3	113.3	149.0	132.8	120.0	63.0	56.7	51.1	35.7	35.7	35.7	0.0
	Sales (1000 USD)		1,944	3,486	10,322	11,071	11,744	13,601	13,601	13,601	17,880	15,936	14,394	7,558	6,809	6,136	4,279	4,279	4,279	0
	Cost (1000 USD)		1,847	3,312	9,806	10,518	11,157	12,921	12,921	12,921	16,986	15,139	13,674	7,180	6,468	5,829	4,065	4,065	4,065	0
	Saved Loss	79	143	421	452	479	555	555	555	730	730									
	CF (1000 USD)	−279	−44	−664	830	909	800	1,235	1,235	622	1,624	797	720	378	340	307	214	214	214	0
	IRR=	61.8%																		
Ashanti	Investment (1000 USD)	691	438	219	0	0	0	0	0	0	531	0	0	0	0	0				
	Sale (GWh)		26.8	43.7	52.2	52.2	52.2	52.2	52.2	52.2	52.2	46.0	29.1	20.6	20.6	20.6	20.6	20.6	20.6	20.6
	Sales (1000 USD)		3,213	5,249	6,267	6,267	6,267	6,267	6,267	6,267	6,267	5,523	3,487	2,469	2,469	2,469	2,469	2,469	2,469	2,469
	Cost (1000 USD)		3,052	4,987	5,954	5,954	5,954	5,954	5,954	5,954	5,954	5,247	3,313	2,345	2,345	2,345	2,345	2,345	2,345	2,345
	Saved Loss	244	398	476	476	476	476	476	476	476	663									
	CF (1000 USD)	−447	121	519	789	789	789	789	789	789	445	276	174	123	123	123	123	123	123	123
	IRR=	90.0%																		
Western	Investment (1000 USD)	865	200	1,378	0	4,313	100	0	200	0	197	0	0	0	0	0				
	Sale (GWh)		23	29	66	66	183	186	186	191	191	173	167	130	130	13	11	11	5	5
	Sales (1000 USD)		2,809	3,459	7,934	7,934	21,942	22,267	22,267	22,916	22,916	20,747	20,097	15,622	15,622	1,614	1,289	1,289	640	640
	Cost (1000 USD)		2,669	3,286	7,538	7,538	20,845	21,153	21,153	21,770	21,770	19,709	19,092	14,841	14,841	1,533	1,225	1,225	608	608
	Saved Loss	128	158	361	361	996	1,011	1,011	1,040	1,040	1,069									
	CF (1000 USD)	−737	98	−844	758	−2,921	2,008	2,124	1,954	2,186	2,018	1,037	1,005	781	781	81	64	64	32	32
	IRR=	31.5%																		
East	Investment (1000 USD)	7,013	0	898	0	200	0	0	0	0	0	0	0	0	0	0				
	Sale (GWh)		90.8	90.8	102.4	102.4	105.0	105.0	105.0	105.0	105.0	14.2	14.2	2.6	2.6	0.0	0.0	0.0	0.0	0.0
	Sales (1000 USD)		10,894	10,894	12,289	12,289	12,600	12,600	12,600	12,600	12,600	1,706	1,706	311	311	0	0	0	0	0
	Cost (1000 USD)		10,350	10,350	11,675	11,675	11,970	11,970	11,970	11,970	11,970	1,620	1,620	295	295	0	0	0	0	0
	Saved Loss	415	415	469	469	481	481	481	481	481	481									
	CF (1000 USD)	−6,598	960	116	1,084	896	1,111	1,111	1,111	1,111	1,111	85	85	16	16	0	0	0	0	0
	IRR=	5.5%																		
Central	Investment (1000 USD)	2	202	85	0	0	0	0	0	0	0	0	0	0	0	0				
	Sale (GWh)		0.4	42.1	59.6	59.6	59.6	59.6	59.6	59.6	59.6	59.2	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Sales (1000 USD)		49	5,048	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,103	2,104	0	0	0	0	0	0	0
	Cost (1000 USD)		47	4,796	6,794	6,794	6,794	6,794	6,794	6,794	6,794	6,747	1,998	0	0	0	0	0	0	0
	Saved Loss	1	130	184	184	184	184	184	184	184	184									
	CF (1000 USD)	−1	−70	352	542	542	542	542	542	542	542	355	105	0	0	0	0	0	0	0
	IRR=	517.0%																		
Volta	Investment (1000 USD)	1067.0	1320.0	343.0	0.0	200.0	0.0	0.0	200.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0				
	Sale (GWh)		25	55	63	63	67	67	67	72	74	49	19	11	11	6	6	6	2	0
	Sales (1000 USD)		2,940	6,578	7,523	7,523	8,074	8,074	8,074	8,625	8,832	5,892	2,254	1,309	1,309	758	758	758	207	0
	Cost (1000 USD)		2,793	6,249	7,147	7,147	7,670	7,670	7,670	8,194	8,390	5,597	2,141	1,244	1,244	720	720	720	196	0
	Saved Loss	111	248	284	284	305	305	305	325	333	333									
	CF (1000 USD)	−956	−925	270	660	481	708	708	529	690	775	295	113	65	65	38	38	38	10	0
	IRR=	21.9%																		
ECG	Investment (1000 USD)	17,069	3,084	4,995	2,857	4,837	1,694	2,042	635	2,186	5,381	0	0	0	0	0	0	0	0	0
	Sale (GWh)	0	386	512	675	760	890	944	1,003	1,020	1,095	869	744	580	496	366	312	253	236	160
	Sales (1000 USD)		46,368	61,451	81,042	91,217	106,759	113,281	120,360	122,375	131,446	104,316	89,233	69,642	59,467	43,925	37,403	30,324	28,309	19,238
	Cost (1000 USD)		44,049	58,378	76,990	86,656	101,422	107,617	114,342	116,256	124,874	99,100	84,772	66,160	56,494	41,728	35,533	28,808	26,894	18,276
	Saved Loss	1,720	2,301	3,090	3,407	4,101	4,324	4,539	4,614	4,936	5,641									
	CF (1000 USD)	−15,349	1,535	1,168	4,602	3,825	7,968	8,161	9,997	8,868	6,832	5,216	4,462	3,482	2,973	2,196	1,870	1,516	1,415	962
	IRR=	26.8%																		
VRA-NED	Investment (1000 USD)	4,528	1,621	1,088	3	0	121	0	0	48	0	0	0	0	0	0				
	Sale (GWh)		82	111	131	131	131	133	133	133	134	52	23	3	3	3	1	1	1	0
	Sales (1000 USD)		9,835	13,355	15,718	15,725	15,725	15,988	15,988	15,988	16,092	6,257	2,737	374	367	367	104	104	104	0
	Cost (1000 USD)		9,343	12,688	14,933	14,939	14,939	15,188	15,188	15,188	15,287	5,945	2,600	355	349	349	99	99	99	0
	Saved Loss	384	522	615	615	615	626	626	626	630	630									
	CF (1000 USD)	−4,144	−607	195	1,398	1,402	1,291	1,425	1,425	1,381	1,434	313	137	19	18	18	5	5	5	0
	IRR=	14.8%																		
Whole Ghana	Investment (1000 USD)	21,597	4,705	6,083	2,860	4,837	1,815	2,042	635	2,234	5,381	0	0	0	0	0	0	0	0	0
	Sale (GWh)	0	468	623	806	891	1,021	1,077	1,136	1,153	1,229	921	766	583	499	369	313	254	237	160
	Sales (1000 USD)		56,202	74,806	96,761	106,942	122,484	129,269	136,347	138,363	147,538	110,574	91,970	70,015	59,834	44,292	37,507	30,429	28,413	19,238
	Cost (1000 USD)		53,392	71,066	91,923	101,595	116,360	122,805	129,530	131,444	140,161	105,045	87,371	66,514	56,843	42,077	35,632	28,907	26,993	18,276
		2,104	2,823	3,705	4,022	4,717	4,950	5,165	5,240	5,566	6,271									
	CF (1000 USD)	−19,493	928	1,362	6,000	5,227	9,259	9,586	11,422	10,250	8,267	5,529	4,598	3,501	2,992	2,215	1,875	1,521	1,421	962

Table 7-4 Summary of the Financial Analysis

Profit margin = 5.0%

	Whole Master Plan			Newly Identified Projects		
	Investment (1000USD)	Total GWh (10 yrs)	FIRR	Investment (1000USD)	Total GWh (10 yrs)	FIRR
Accra	59,298	12,553	19.3%	20,750	5,994	25.5%
Tema	17,063	3,485	−1.6%	3,293	1,490	61.8%
Ashanti	11,986	1,338	3.9%	1,879	728	90.0%
Western	8,809	3,425	26.8%	7,685	1,963	31.5%
East	9,832	1,050	−6.1%	7,779	1,050	5.5%
Central	1,197	1,311	26.6%	289	596	517.0%
Volta	2,417	736	4.2%	3,105	736	21.9%
ECG	110,602	23,898	12.7%	44,780	12,557	26.8%
VRA/NED	9,362	1,341	−0.5%	7,408	1,341	14.8%
Whole Ghana	119,964	25,239	11.9%	52,188	13,898	24.6%
NPV=	7,387 (1000USD, r=10%)			16,496 (1000USD, r=10%)		

The FIRR for the whole Master plan is shown to be about 11.9%, while for the newly identified projects, FIRR is 24.6%.

It is difficult to determine the hurdle rate in this situation. In former reports, 10% has been used as a discount rate for economic performance. Also, the World Bank often asks 8% of ROA in real terms for power sector projects. If we use these figures as benchmarks, both the whole master plan and the newly identified projects are financially justifiable. Using 10% as a discount rate, the whole master plan has an NPV of 7.4 million USD, while the newly identified projects have an NPV of 16 million USD. These figures, however, depend heavily on the profit margin assumptions.

The relationship between the profit margin and the FIRRs are shown in the next table. It can be seen that a level of at least 5% (i.e., a profit of about 0.6 US cents/kWh) is required to make the distribution plan financially viable. Otherwise, the utilities will have a hard time sustaining the facilities.

Table 7-5 Summary of the Financial Analysis

Profit Margin	Whole Master Plan	Newly Identified
3%	4.20%	15.70%
4%	8.30%	20.50%
5%	11.90%	24.60%
6%	15.30%	28.90%
7%	18.60%	32.80%

7.3 Economic Analysis

In the economic analysis, the benefits to the whole economy needs to be considered, as well as the costs.

It is challenging to estimate the total benefits of power to the end user. One way is to use the willingness to pay survey conducted in the socio economic survey. Since the large portion of demand is residential, we will look at the residential willingness to pay. According the survey, the monthly willingness to pay for various energy items in electrified village households were 9.8 USD /month. For the unelectrified villages, the figure was 6.4 USD/month. The difference may reflect the overall wealth of these villages, but it also reflects the familiarity with electricity and the resulting accurate assessment of its value. Initial installment cost should add about 0.5USD/month to both figures. Another survey suggests that the rural energy use of these village households are about 22 kWh/month, based on substitute use[2]. This suggests that the value of power is about 0.47 USD/kWh.

Another way is to base the assumption on previous studies. In the National Electrification Project Feasibility Study (1992), the overall willingness to pay is estimated at 0.25 USD/kWh. This amount will likely increase over the years due to general economic growth, which will likely match pace with the general GDP growth.

The real GDP growth of Ghana since 1992 has been quite steady, as seen in the following table. In the 1990s the growth was generally in the 4% zone, but growth accelerated to above 5% since 2003, and moving higher over 6% in recent years.

[2] National Electrification Project Feasibility Study (1992), Table 6.2.

Table 7-6 Ghana Real GDP Growth

Year	Real GDP Growth (%)
1992	6.173
1993	4.921
1994	3.28
1995	4.023
1996	4.596
1997	4.199
1998	4.691
1999	4.428
2000	3.736
2001	4.184
2002	4.549
2003	5.246
2004	5.585
2005	5.866
2006	6.368
2007	6.388
2008	6.853

Based on this figure, the general wealth of Ghana would have doubled since 1992. Using this GDP growth figure as a deflator, willingness to pay can be assessed at 0.54 USD/kWh, which can be seen as the benefit of a kWh today. As seen, this figure compares nicely with the 0.47 USD/kWh figure derived from the socio-economic survey today.

Based on this figure, the EIRR was calculated, which is summarized as follows

Table 7-7 Summary of the Economic Analysis

Profit margin = 5%

	Whole Master Plan		Newly Identified Projects	
	Total GWh (10 yrs)	EIRR	Total GWh (10 yrs)	EIRR
Accra	12,553	33.1%	5,994	45.8%
Tema	3,485	11.4%	1,490	93.4%
Ashanti	1,338	13.9%	728	121.7%
Western	3,425	50.4%	1,963	53.5%
East	1,050	3.3%	1,050	15.2%
Central	1,311	46.6%	596	815.8%
Volta	736	21.1%	736	37.2%
ECG	23,898	26.6%	12,557	44.6%
VRA/NED	1,341	14.2%	1,341	27.9%
Whole Ghana	25,239	25.6%	13,898	41.5%
NPV=	50,313	(1000USD, r=12%)	43,053	(1000USD, r=12%)

The whole master plan will have an EIRR of 25.6%, while the newly identified projects will have an EIRR o 41.5%. The hurdle rate for an EIRR is difficult to determine. In a previous study, 10% was used, while Asian Development Bank uses a 12% cut-off rate for all projects that applies for a loan. The results are shown that both the whole master plan and the newly identified projects exceed these hurdle rates by a large margin. Therefore, the plan is economically viable.

Using 12% discount rate, the NPV of each project for the whole economy is 50 million USD for the whole master plan, and 43 million for the newly identified projects.

7.4 Study of the Non-Supply Cost of Power

As part of the master plan study, a study was made of the non-supply cost of power to evaluate the magnitude of the effect of unreliable power supply on economic activities at industrial and commercial customers as well as on public facilities such as schools and hospitals in the Accra/Tema and Kumasi areas. The study was intended interalia to confirm items such as production and service loss caused by power supply interruption and direct cost burden for backup power incurred by factories, office buildings, and commercial facilities.

In implementation of the study, the work of conducting questionnaire and interview survey and analyzing data was commissioned to a Ghanaian consulting firm, the Kumasi Institute of Technology and Environment (KITE).

7.4.1 Methodology of the Study

Sampling

Sample customers were chosen in the two areas (i.e., Accra/Tema and Kumasi). Data were collected by questionnaire and interview. To determine the sample framework, an initial sample of 100 industries to which the Special Load Tariffs (SLT) are applied, was purposively made based on the maximum monthly power consumption/demand and industry size. Questionnaires were distributed to all these 100 industrial entities, and the sample size of 54 responded and granted interviews.

The majority of the total sample size (57%) were industrial customers located in the Accra/Tema area, and the remaining (43%), in the Kumasi area. Seventy-eight percent of the sample size fell in the manufacturing sector, and the rest (22%), in the service sector.

The customers which responded to the interview covered 11 industrial categories and included Ghana’s representative industries.

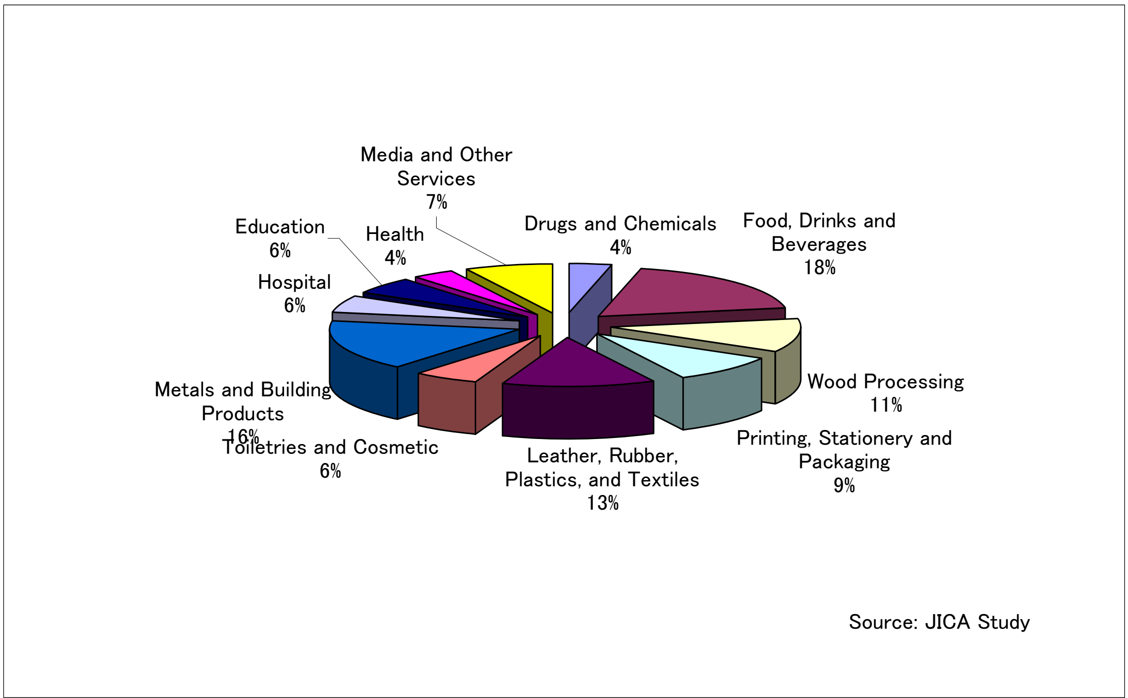


Figure 7-2 Distribution of the Respondents by Industrial Category

<u>Questionnaire</u>

The contents of the questionnaire used to determine the final sample size were as follows:

- General information on the industrial makeup, such as contact information and category of industry;
- Details of business operation, such as major products or services, number of employees, turnover, and monthly consumption of electricity and other energy;
- Occurrence of power supply interruptions;
- Revenue loss due to power interruptions, voltage fluctuation and frequency, and time duration of such interruption during the past year;
- Technical information on any standby generators installed by the customers; and
- General comments by the customer on the electricity supply quality, tariff levels, and related investment trend.

7.4.2 Results of the Questionnaire and Interview Survey

(1) Profiles of Customers

<u>Employment and turnover</u>

The majority (96%) of the respondents were either large-scale (64.8%) or medium-scale firms

(31.5%). Taken together, the respondents employed a total of 14,347 personnel. The umber employed by each company ranged widely between 13 and 1,800, and yielded an average of 276 per entity. The question on average annual turnover was answered by only 31 (57%) of the total respondents. Table 7-8 shows the industrial classification of the 51 respondents providing information on the number of employees and the 31 providing that on turnover.

Table 7-8 Average Turnover and Employment by Industrial Category

Industry	Number of Employees (N=51)	Total Average Annual Turnover (N=31)
Manufacturing	13,575	118,949,127
Drugs and Chemicals	492	1,800,000
Food, Drinks and Beverages	4,044	1,919,142
Wood Processing	3,387	33,195,540
Printing, Stationery and Packaging	690	2,081,187
Leather, Rubber, Plastics, and Textiles	2,395	56,435,097
Toiletries and Cosmetic	832	2,575,933
Metals and Building Products	1,735	20,942,229
Service	772	7,317,665
Hospital	221	322,000
Education	-	0
Health	191	3,200,000
Media and Other Services	360	3,795,665
Total	14,347	126,266,791

Source: JICA Study

The combined 13,575 personnel employed by the respondents belonging to the manufacturing segment accounted for approximately 12% of total number of employees (116,773)[3] known to be working in the manufacturing sector of Ghana's industry.

The combined average annual turnover for the 31 respondents was GH¢126.3 million. The manufacturing sector alone accounted for the bulk (94%) of this amount. The combined average annual turnover (i.e., GH¢118.9 million) of the respondent companies categorized in the manufacturing sector accounted for 12% of the census value added (CVA) of all manufacturing industries in Ghana.

This figure could be much higher, given the fact that the combined average turnover for manufacturing (GH¢118.9 million) in Table 7-8 is the aggregat estimate for only 24 (57%) of the 42 manufacturing concerns covered in the study, as well as the fact that the remaining 43% who did not give estimates are major industries in their respective categories.

This result means that disruptions in power supply to these industries could significantly

[3] 2003 Ghana Industrial Census Report, 2005.

affect the contribution of the manufacturing sector to Ghana's GDP, if such supply interruptions result in production loss.

As shown in Table 7-8, among the industrial entities sampled, those in the three categories of Food, Drinks and Beverages; Wood Processing; and Leather, Rubber, Plastics and Textiles were the major employers, accounting for over 68% of the total number of employees. This observation is basically in conformance with national statistics, which show that Wearing Apparel (23%); Wood Processing (14%) and Food Products and Beverages (13%) categories are the three leading employers in the manufacturing sector.

The table also shows that the Leather, Rubber, Plastics and Textiles, Wood Processing and Metals and Building Products sub-categories were the dominant contributors to the total average annual turnover among the companies sampled, together accounting for over 87% of the annual turnovers provided. National statistics, however, indicate that the Food, Drinks and Beverages sub-category is the second-leading contributor to manufacturing value addition (18%). The reason for what appears to be a discrepancy from national statistics is that only 30% of respondents in this category provided information on annual turnover.

Working pattern

Figure 7-3 summarizes the daily and annual operational pattern of respondents by industrial category. The average daily operating hours for all the entities surveyed ranged between 8 and 24 hours on each working day. Thirty-seven percent of them ran a 24-hour daily work schedule, and another 33%, an average 8-hour work schedule. Averages for all the entities were 16.2 hours per working day and 308 working days per year.

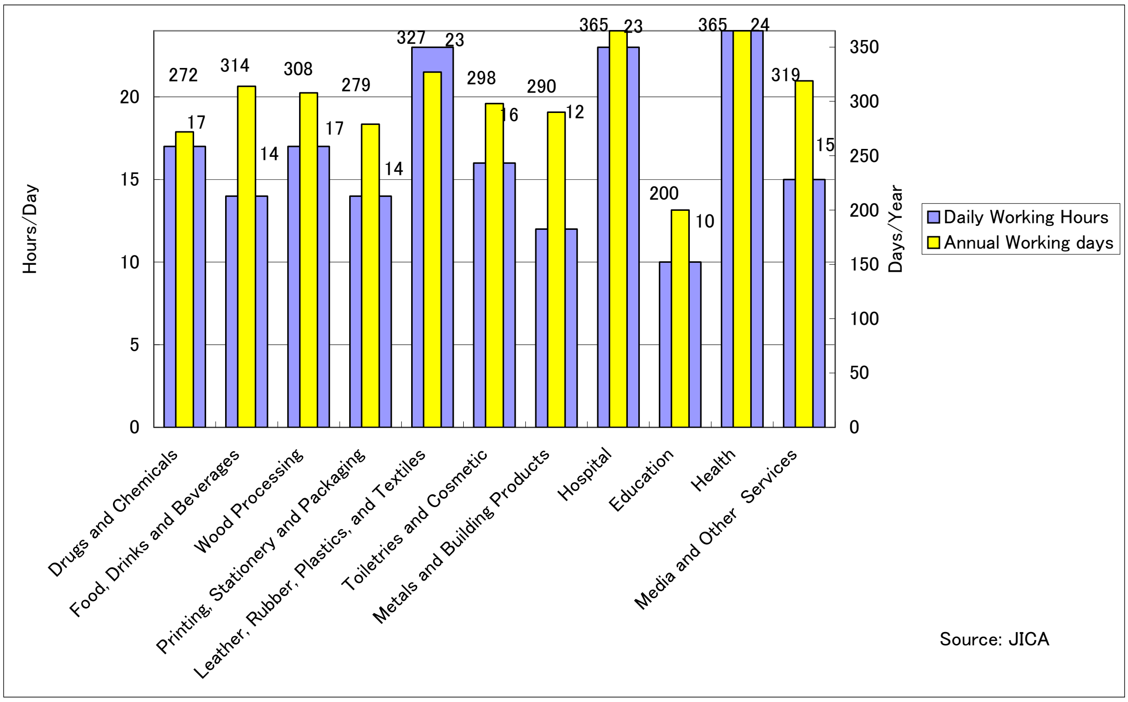


Figure 7-3 Operational Patterns of the Respondents by Industrial Category

(2) Electricity usage and cost

All of the 54 selected entities relied on ECG power supply. Ninety-two percent of them were fully dependent on it, and 8%, partially dependent. Their main usages of power were lighting (100%), powering plant and machinery (91%), refrigeration (69%), process heating (52%), and room conditioning (87%).

The combined average annual electricity consumption by the 51 respondents was estimated at approximately 128 million kWh, which represents 2.3% of the total electricity generated in Ghana in 2006 (5.5 billion kWh). The bulk (89%) was consumed by the respondent entities categorized in the manufacturing sector.

The respondent entities paid GH¢877,747 on average for grid electricity each month. This translates into an average annual grid electricity cost of GH¢10.53 million (US$11.14 million). It should be noted that total annual expenditure on electricity could be much higher since the amount of GH¢10.53 million is the aggregat estimate for only 56% of the installations sampled.

The majority of these entities (72%) spend 10% or less of their total annual expenditure on grid electricity. Except for one company, which spent a corresponding 66% on electricity, the companies spent between 11% and 38%.

Table 7-9 shows the average monthly electricity consumption, power load, and average cost for the entities sampled in each industrial category. The entities in the Food, Drinks and Beverages category were the largest electricity consumers, and were followed by those in the Leather, Rubber, Plastics and Textiles category. This is hardly surprising, since these two categories have the highest and third highest number of firms in the sample size. In the service sector, the Educational category is the biggest electricity consumer

Table 7-9 Monthly Electricity Consumption and Cost of the Respondents by Industrial Category

Industry (N=51)	Total Average Monthly Consumption (kWh)	Total Average Power Load (kW)	Total Average Monthly Cost (GH¢)
Manufacturing	9,438,456	19,075	778,293
Drugs and Chemicals	122,980	240	10,884
Food, Drinks and Beverages	2,703,433	6,613	234,207
Wood Processing	1,409,632	3,130	136,288
Printing, Stationery and Packaging	169,470	299	20,164
Leather, Rubber, Plastics, and Textiles	2,060,380	3,118	215,275
Toiletries and Cosmetic	1,145,345	2,569	81,270
Metals and Building Products	1,827,216	3,106	80,205
Service	1,206,321	2938	99,454
Hospital	101,800	149	13,192
Education	971,396	2,470	68,487
Health	48,825	67	5,576
Media and Other Services	84,300	252	12,200
Total	10,644,777	22,013	877,747

Source: JICA Study

(3) Quality of power supply

The quality of electricity supply to the companies interviewed can be described as erratic and unreliable. The respondents said that power outages and voltage fluctuations were characteristic features.

As shown in Figure 7-4, 63% of respondents experienced outages several times a week, and another 19%, several times a month. Significantly, 6% of the industries indicated that outages were a daily phenomenon. Forty-eight percent of respondents said that outages were unplanned, 33%, planned, and 8%, both planned and unplanned.

Fifty-seven percent indicated that they had experienced voltage fluctuations during the past one-year period. Figure 7-4 also shows that the incidences of brownouts were not as frequent as blackouts. This notwithstanding, 15% said that voltage fluctuation was a daily occurrence at their premises, while another 15% said that it happened several times a week.

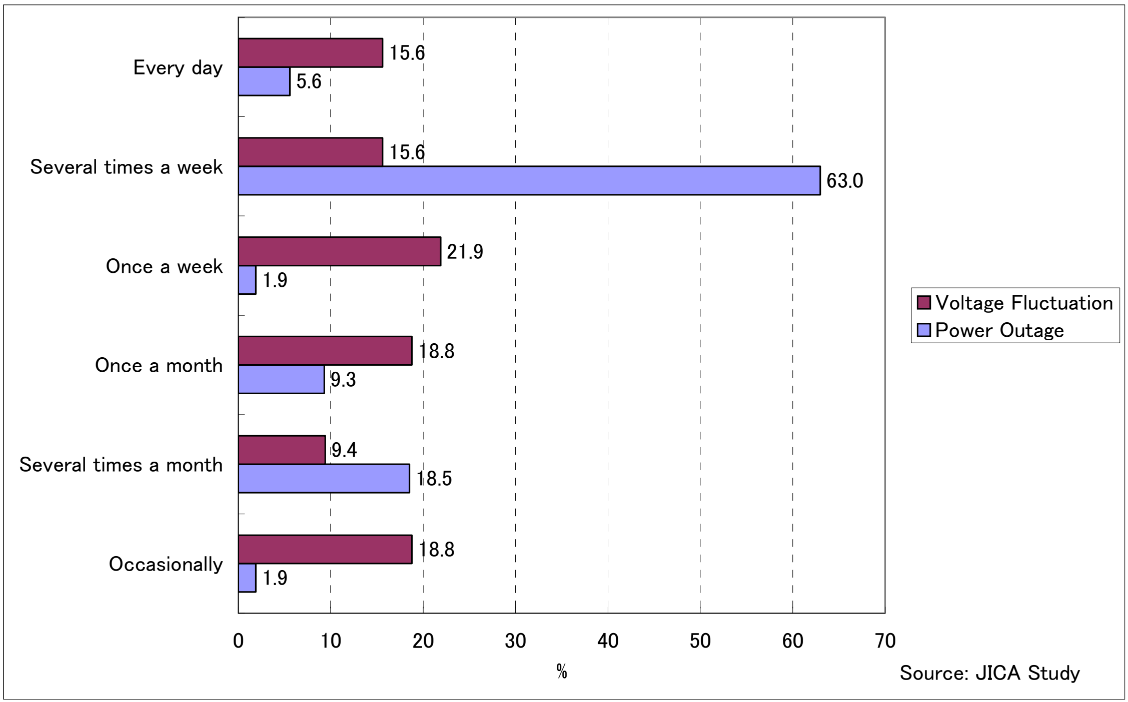


Figure 7-4 Frequency of Power Outage and Voltage Fluctuation at the Respondents

Although the respondents could not provide specific time durations for outages and voltage fluctuations, they did provide general figures. As shown in Table 7-10, while the majority of interruptions in electricity supply lasted for between a few hours to 12 hours, a small number lasted for up to a couple of months.

Table 7-10 Duration of Outage and Voltage Fluctuation at the Respondents

	Few minutes	Few hours	12 hours	1-3 days	4-7 days	1-4 months
Unplanned	-	33	10	9	1	1
Planned	9	35	2	6	1	1
Voltage fluctuation	7	20	-	4	1	-

Source: JICA Study

(4) Measures

As shown in Figure 7-5, the majority (84%) of the respondents said that they had installed stand-by generators (SBGs) to cope with the erratic power supply from the ECG. Another 10% had taken some other measures such as adjusting production schedules, reducing labor and canceling orders as well as installing SBGs. The rest either just rescheduled production (4%) or adjusted production schedule and canceled orders (2%).

Seventy-five percent of respondents who had installed SBGs and could recall how long they have owned their gensets (44 in total) indicated that they had been using their SBGs for 2 or more years (some for as long as 30 years), and the remaining 25% less than 1 year. This suggests that the majority of the SBGs were installed long before the on-going load-shedding program started. All of the SBGs are diesel-engine generators, and the majority (80%) have the capacity to supply power between 60% and 100% of the full load of each entity.

Figure 7-6 shows figures for the capacity and the load factor of the SBGs in the various respondent categories. The respondents in the Food, Drinks and Beverages category have installed approximately 12,100 kVA of captive power, which supplies 82% of their respective full loads on the average. Taken together, the combined installed capacity of the 50 respondents comes to approximately 36,984 kVA.

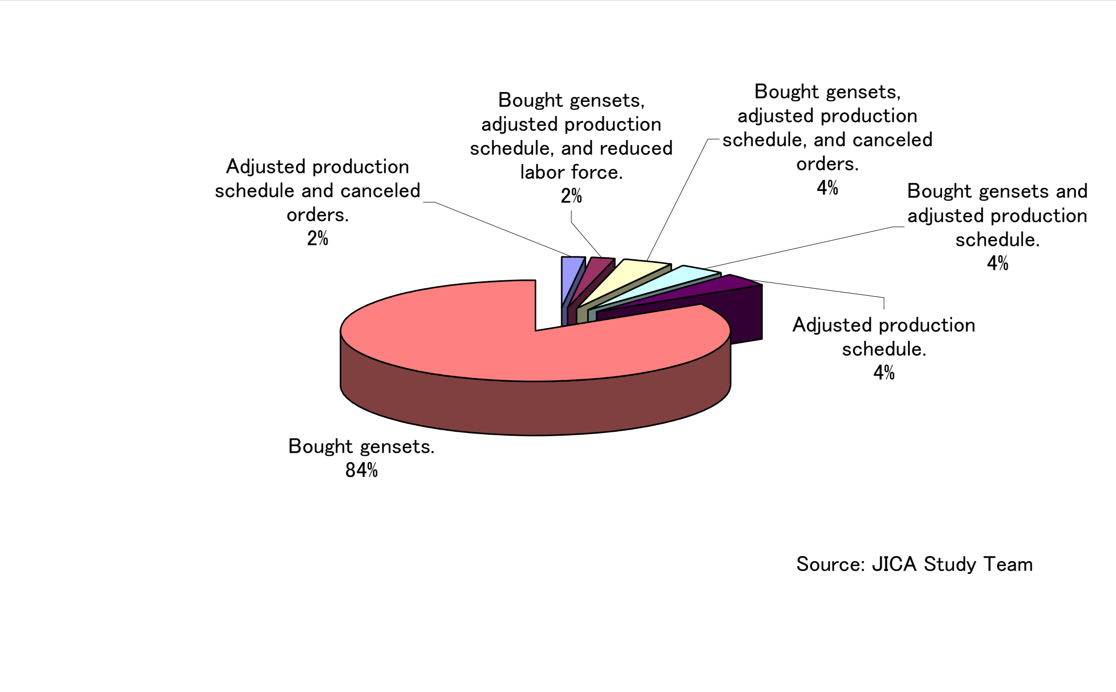


Figure 7-5 Measures in Response to Unreliable Power Supply

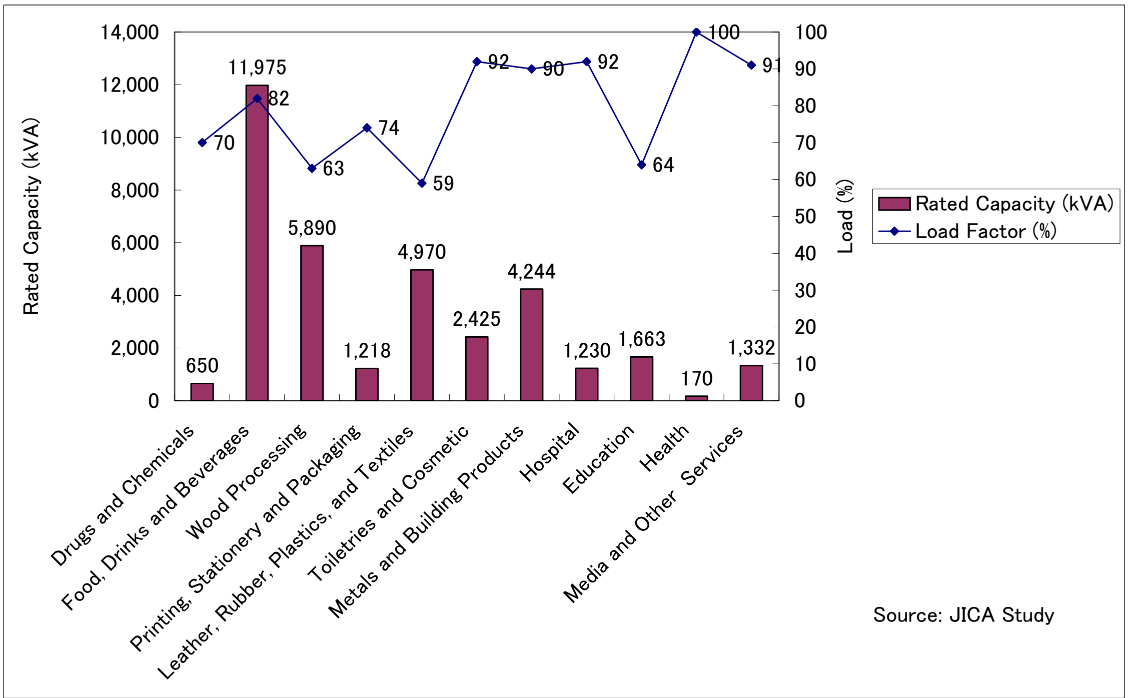


Figure 7-6 Capacity and Load Factor of the SBGs

7.4.3 Estimating the Non-Supply Cost of Power

The study applied three available methodologies to estimate the non-supply cost of power: the production loss method (PLM), captive generation method (CGM), and the willingness-to-pay (WTP) method. Each of these methods has advantages and limitations. Although estimates by the three methods exhibited substantial difference, the results provide information important for grasping the basic status of non-supply cost.

(1) Estimation by the PLM

The PLM is designed to estimate the production or output loss caused by power interruption. The non-supply cost is calculated by dividing the estimated monetary value of production loss by the average volume of interrupted electricity supply. The estimate using the PLM shows the maximum value of loss incurred by the customer in the form of electricity price.

However, the PLM has a shortcoming, in that measures taken by the respondents to avoid the loss are not quantitatively incorporate in the estimate. As a result, the estimate of the production loss is often overstated. A further disadvantage of the method is its reliance on the recall ability of respondents. The value of loss may also often be overstated to the extent that the entire production loss is attributed to the power cut. Moreover, even though the respondents may be able to offer estimates of the loss in revenue, the loss must be estimated in the form of value added. In this context, the estimate also tends to be overvalued.

Supply interruptions can result in direct economic and consequential costs to industrial outfits in forms such as lost production, product/raw material spoilage, damage to equipment, and reduction in profit on sales. Table 7-11 captures the nature of loss incurred or expected to be incurred by the companies surveyed. The three major types of loss were: lost production, damage to equipment, and reduction in profit on sales (which is the consequence of the lost production).

However, only a fraction of those who said that they had incurred loss could provide estimates of the quantum of the loss and had very little record of production downtime and magnitude of loss. In fact, 22 (40%) of respondent companies provided some cost estimates for the loss, but their estimates might be nothing more than “guesstimates” lacking any concrete ground.

Table 7-11 Typical Loss Incurred by the Respondents due to Supply Interruptions

Loss	Percentage of respondents (%) (N=54)	Percentage of Respondents able to Estimate Cost of Loss (%)
Raw materials	33	6
Output/Production	78	19
Profit on sales	59	20
Damage to equipment	78	30
Manpower due to lay-off	11	10
Paid staff unable to work	57	15

Source: JICA Study

<u>Result of estimate</u>

Table 7-12 summarizes the value of hourly loss incurred by the respondents doe to supply interruptions. Value lost or expected to be lost for every hour of power supply interruption is estimated at a total of GH¢ 54,664 (US$57,800).

The distribution of the loss among the various industrial categories indicates that the bulk (54%) of the total hourly loss of GH¢54,664 was incurred by the companies categorized in Wood Processing, whose loss was mainly in the form of equipment damage. However, Table 7-12 should not be used as a basis for comparing loss among the various industrial categories. This is mainly because the number of firms who responded to questions on loss varied from one industrial category to another, and partly because industries which recorded lower loss (e.g., Drugs and Chemicals) could or may have incurred other costs to mitigate the potential loss caused by supply unreliability.

Table 7-12 Loss Attributed to Electricity Supply Interruptions by Industrial Category

	Raw Materials (GH¢/hr)	Lost Output (GH¢/hr)	Staff Inability to Work (GH¢/hr)	Equipment Damage (GH¢/hr)	Total Loss (GH¢/hr)
Manufacturing (N=18)	8,377	15,617	2,111	29,093	52,877
Drugs and Chemicals	-	-	170	-	170
Food, Drinks and Beverages	-	1,153	-	1,085	2238
Wood Processing	2,000	5,804	1,357	20,157	29318
Printing, Stationery and Packaging	-		-	1,000	150
Leather, Rubber, Plastics, and Textiles	6,275	-		2,640	8915
Toiletries and Cosmetic	102	5,190	52	1,895	7239
Metals and Building Products	-	3,470	97	1,316	4847
Service (N=4)	-	100	480	1,207	1,787
Hospital	-	-	470	207	677
Education	-	-	-		0
Health	-	100	-		1100
Media and Other Services	-	-	10	1,000	10
Total	8,377	15,717	2,121	29,300	54,664

Source: JICA Study

Determining the volume of power shortage among the respondents is trickier because respondents could not provide exact durations over which the shortages were experienced. In the absence of such empirical data, we used the duration of SBG operation as a proxy to estimate the aggregated duration of power shortage (See Table 7-13). The aggregat monthly power shortage among the 22 firms is estimated at 1.2 million kWh, and average monthly loss, at approximately GH¢8.7million (US¢9.2 million). This estimate results in a non-supply cost of GH¢39/kWh.

Table 7-13 Non-supply Cost Estimated by the PLM

	Estimated Monthly Shortage in Power supply (kWh)	Total Monthly SBG Usage (Hr)	Hourly Losses Incurred due to Supply Interruptions (GH¢/hr)	Total Monthly Losses due to Supply Interruptions (GH¢)	Non-supply Cost[4] (GH¢/kWh)
Manufacturing	1,171,017	2,033	52,877	8,286,882	49
Service	20,709	762	1,787	374,334	29
Total	1,191,726	2,795	54,664	8,661,216	
Average					39

Source: JICA Study

A different value is obtained for the non-supply cost when the estimate of the monthly usage of the SBGs is reworked using technical information concerning SBG capacity, capacity factor and average monthly fuel consumption as shown in Table 7-14. This calculation results in a much lower monthly power shortage and corresponding lower non-supply cost of GH¢27/kWh.

Table 7-14 Estimation of Total Monthly Production Loss and Non-supply Cost

(N=22)	Estimated Monthly Shortage in Power Supply (kWh)	Total Monthly SBG Usage (Hr)	Hourly Losses Incurred due to Supply Interruptions (GH¢/h)	Total Monthly Losses due to Supply Interruptions (GH¢)	Non-supply Cost (GH¢/kWh)
Manufacturing	361,758	1,315	52,877	1,785,677	25.67
Service	6,909	319	1,787	94,167	28.80
Total	368,667	1,633	54,664	1,879,844	
Average					27

Source: JICA Study

It should be noted, however, that most of the loss (except for damage to equipment) is not or

[4] The non-supply cost by the PLM is calculated by dividing the value of total loss (GH¢) by the duration time of the power supply shortfall (in terms of the hours of using SBGs). The non-supply cost of each industry category is determined by summing that of the individual companies and calculating the average of the total by dividing it by the number of companies (N) within the category.

is probably not actually being incurred. This is because virtually almost all of the companies interviewed (93%) had installed SBGs, which are switched on in a maximum of 30 minutes when power interruption occurs.

(2) Estimation by the CGM

Estimation of the non-supply cost of electricity by the CGM is made from the cost of captive power generation used by the companies. In other words, the average economic costs of backup power using captive units in industries enable an estimate of the non-supply cost of power. The non-supply cost obtained by this method constitutes an indirect estimate of the tariff that a consumer will be willing to pay for grid power. The assumption is that, if a consumer were willing to undertake self-generation, he/she would be willing to pay at least the cost of self-generation as the price for grid power.

This approach also has limitation. The cost of captive power shows the level of the price that a consumer may be willing to pay only for the operation of a generator during the power outage, but not for all of the electricity units required for production. Consequently, it may yield an overestimate. The estimation by the CGM only provides the non-supply cost at the margin.

On the other hand, the cost may be underestimated, as some other cost cannot be monetized. For example, the CGM does not take account of additionally required investment, negative environmental effects such as exhaust gas air and noise, and additional work for the operation of a generator. Furthermore, this cost is generally only applicable to a consumer who has a backup generator. Despite such limitation, the CGM is indicative of the lower bound on the tariff that a consumer is willing to pay at the margin.

Result of estimate

As mentioned earlier on, installation of SBGs was the main measure taken by the customers to cope with supply interruptions. Table 7-15 shows the breakdown of the cost for a customer who has a backup diesel generator. The table shows that approximately GH¢3.1 million (US$3.3 million) had been spent by the 30 respondents who said they had SBGs. This figure would rise to GH¢6.3 million (US$6.7 million), if the cost of the SBGs for the remaining 17 respondents, who indicated that they had installed generators but did not disclosed their cost, were added to the aggregat capital cost, by estimating the necessary installation cost based on the information provided by other respondents and market prices of captive generators.

With regards to operating and maintenance (O&M) cost, the 46 respondent firms spend an average GH¢5.1 million (US$5.4 million) annually on fuel, and another GH¢176,462 (US$187,062) on other O&M cost. Again, this total of O&M cost is thought to be higher given the fact that not all of the respondent companies disclosed information on costs. Significantly, the annual average O&M cost of GH¢5.2 million (US$5.6 million) is about half as high as the average annual expenditure on grid electricity of GH¢10.5 million, while the amount of power obtained from this expenditure on captive generation comes to only about 30% of the total annual energy supplied from the grid.

Extrapolation of the survey results to obtain the nationwide cost of captive generation is hampered due to the limited number of sample data. Meanwhile, a recent study[5] reported that the total annual cost of captive generation by firms in the two sectors is estimated at US$500.4 million.

Table 7-15 Cost of Captive Generation of the Respondents

(Unit: GH¢)

	Capital Cost (N=30)	Average Annual Fuel Cost (N=46)	Average Annual O&M and Other Cost (N=31)
Manufacturing	2,835,408	4,625,946	145,930
Service	239,170	471,599	30,532
Total	3,074,578	5,097,545	176,462

Source: JICA Study

Table 7-16 shows the average unit cost of electricity generation using the SBG, based on estimation of the annualized capital cost and the recurrent O&M costs of 30 respondents. The cost of the SBG is GH¢0.35/kWh on average and therefore about 3 times as high as the current ECG power tariff (i.e., GH¢0.12/kWh).

5 Databank (2007), The Real Cost of the Load-Shedding

Table 7-16 Non-supply Cost Estimated by the CGM

(N=30)	Annualized Capital Cost (GH¢)	Annual O&M Cost (GH¢)	Total Cost (GH¢)	Power Produced by SBG (kWh)	Unit Cost of Captive Power[6] (GH¢/kWh)
Manufacturing	452,989	2,649,562	3,102,551	20,493,097	0.39
Service	38,210	238,635	276,845	3,566,400	0.17
Total	491,199	2,888,197	3,379,396	24,059,497	
Average					0.35

Source: JICA Study

(3) Estimation by the WTP method

Under the WTP method, the non-supply cost is estimated by estimating the consumers' WTP under a hypothetical improved power supply scenario. As compared to the other two methods, this method has an advantage in that it generates a comprehensive interpretation of the total value of electricity supply to consumers. Its success depends on the extent to which respondents are well informed and able to assess the total value of the electricity and the services provided.

This approach also has some limitations. It is highly dependent on questionnaire design and the level of respondent understanding of the hypothetical scenario. The value of the non-supply cost estimated by the WTP method is usually higher than the estimate derived by the CGM and lower than that derived by the PLM. In the case of developing countries, however, the value is also influenced by consumer ability to pay because of the relatively larger number of poor.

Notwithstanding such limitation, the WTP method helps to narrow the range between the upper and lower limits on electricity tariffs and provides insights for a more practical policy on electricity tariffs.

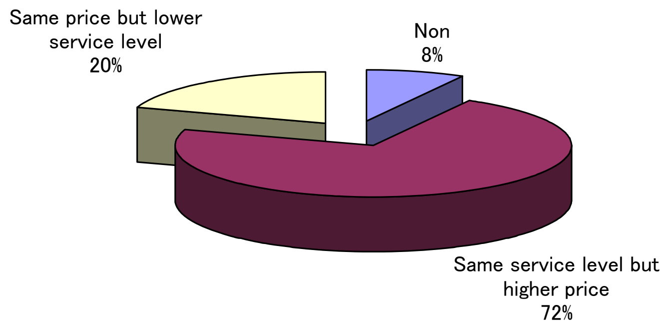
[6] The non-supply cost (GH¢/kWh) using the SBG is determined by dividing the total cost of operating the generator by the power produced by the generator. The industrial-category average is determined by summing the non-supply cost of the individual companies and dividing this total sum by the number of respondents within the category.

Result of estimate

Sixty-seven percent of respondents were of the view that they were paying too much for electricity considering the quality of service. However, the majority (89%) indicated their preparedness to pay more per unit cost of electricity in exchange for a guaranteed and improved quality of service.

When those who stated they would be willing to pay more for better quality service were confronted with the question of whether to maintain their current payment with a lower quality or to maintain the current quality with a higher payment, 72% opted for preserving quality over price, and 20%, for maintaining the current price even though quality would deteriorate.

The result in Figure 7-7 reveals that the majority of respondents are not prepared to tolerate any further deterioration of service quality and are thus willing to pay more to at least maintain the current level of service.



Source: JICA Study

Figure 7-7　Respondent Preference for Improvement in Service Quality

Respondents were also presented with another scenario in which they were asked to indicate how much they would be willing to pay for a better quality of service. Figure 7-8 shows the results. Up to 43% of respondents would be willing to pay from 1.5 to three times as much as at present if power outages and brownouts were to cease completely. More specifically, 26% would be prepared to pay three times as much as their current bill to secure uninterrupted power supply, and 52% would be willing to pay from 1.5 to two times as much if the frequency of outages and voltage fluctuations were reduced.

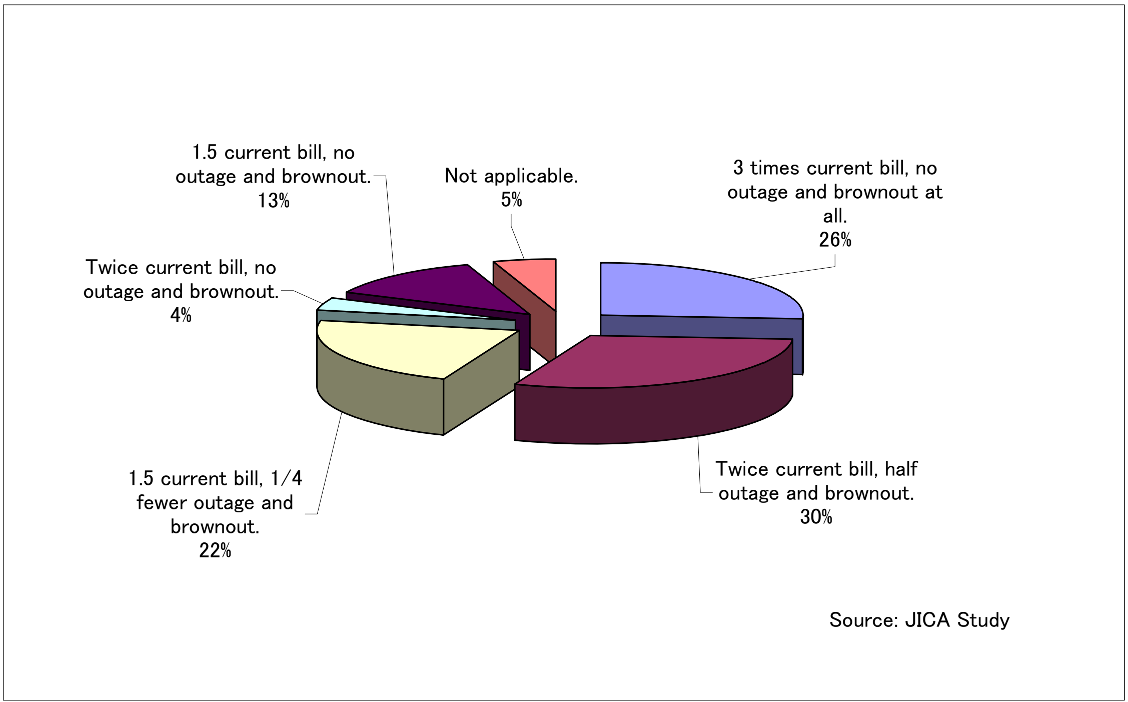


Figure 7-8 Respondent Willingness to Pay for Improved Service Delivery

7.5 Financial Statement Analysis

This section will analyze the financial condition of VRA-NED and ECG, both of which are in charge of the power distribution in Ghana.

7.5.1 Finances of VRA-NED

Below is the profit and loss statement of VRA-NED.

Profit and Loss Account

	2000	2001	2002	2003	2004	2005	2006
	¢'m	¢'m	¢'m	¢'m	¢'m	¢'m	¢'m
Sale of electricity	41,384	74,140	120,000	191,053	236,206	262,077	285,318
Other income	1,783	2,327	3,614	4,152	4,140	5,800	6,939
	43,167	76,467	123,614	195,205	240,346	267,877	292,257
Deduct:							
Operating Costs	45,245	75,461	126,473	216,590	263,487	338,300	371,991
Depreciation	26,507	86,049	126,730	158,802	201,816	203,004	150,465
	71,752	161,510	253,203	375,392	465,303	541,304	522,456
Net Loss for the year	(28,585)	(85,043)	(129,589)	(180,187)	(224,957)	(273,427)	(230,199)

Income Surplus Account

Balance at beginning of year	(2,609)	-7,242	(8,808)	(86,566)	(236,644)	(364,582)	(503,557)
							160,702
Transfer from Capital Surplus	23,988	83,477	52,784	63,077	98,928	134,452	81,185
	21,379	76,235	43,976	(23,489)	(137,716)	(230,130)	396,122
Loss for the year transferred from Profit and Loss Account	(28,585)	(85,043)	(129,589)	(180,187)	(224,957)	(273,427)	(230,187)
Income Surplus carried forward to Balance Sheet	(7,206)	(8,808)	(85,613)	(203,676)	(362,673)	(503,557)	(626,309)

VRA-NED has constantly shown a loss since 2000. The amount of the loss is quite large. The expenditure excluding depreciation has always exceeded the revenue, which means that the losses are not just on the books, but even on a cash base, this entity has been losing money. The annual loss including depreciation is close to the total revenue. On the books, loss has kept on accumulating, with no signs of decrease.

The itemized expenditure is shown in the following table;

Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Analysis by cost element:	¢'m	¢'m	¢'m	¢'m	¢'m	¢'m	¢'m
Purchase of electricity	31,383	57,410	101,645	159,393	201,283	212,960	215,279
Salaries and related expenses	8,713	11,918	15,686	25,348	38,526	80,539	111,084
Material expenses	294	202	290	3,192	4,814	3,106	5,649
Repairs and maintenance	1,114	915	1,884	2,663	5,358	6,194	8,811
Other working costs	3,741	5,016	6,968	9,006	11,513	35,429	31,167
Operating Cost	45,245	75,461	126,473	199,602	261,494	338,228	371,991
Depreciation	26,507	86,049	126,730	158,802	201,816	203,004	150,465
Total Operating Expenses	**71,752**	**161,510**	**253,203**	**358,404**	**463,310**	**541,232**	**522,456**
Power Purchased (MWh)	**330,349**	**355,199**	**382,780**	**423,884**	**480,323**	**501,787**	**505,169**

Power purchase is constantly increasing, with 330GWh in 2000 increasing to 522GWh in 2006. Annual growth has been over 7%, with more than 10% from 2002-2004. This corresponds with the growth in demand. The growth in 2006 is very low at less than 1%. But this has more to do with the supply side than the demand. The drought has posed severe restriction on the power situation. Without this restriction, probably the growth would have been near 10%.

Along with the purchased power, the purchase cost naturally went up, increasing to around 7 times the level of 2000 in 2006. With the increasing generation cost, the wholesale power tariff has also increased, leading to the huge hike.

About 60% of the pre-depreciation expenditure is used for power purchase. This ratio, however, has declined from 80% in 2000. Labor cost, on the other hand, has shown a dramatic increase, from 12.4% in 2000 to 29.9% in 2006. Materials and repairs are also increasing, from a total of 1.7% to 3.9% in 2006.

As the reason for this huge increase in labor cost, the increase of engineers due to the disorderly introduction of SHEP seems to be the main culprit. Another is the annual raise for the staff and workers. However, since there are no external events to justify this huge increase, it would be prudent to take measures to limit this growing demand.

The following table shows the balance sheet of VRA-NED.

Fixed assets show a surprising increase over the years. One reason is the re-evaluation of assets, but another reason is the SHEP. Especially in years around election (2000, 2004), politicians would often try to boost their popularity through providing access to power. The assets created will be forced onto VRA-NED, causing a significant increase in assets. The sudden jump in 2001 clearly points to this, and to an extent, also 2004. However, the asset increase since 2001 seems constant, which is unlikely to be caused by SHEP alone. This needs further study.

	2000	2001	2002	2003	2004	2005	2006
	¢'m	¢'m	¢'m	¢'m	¢'m	¢'m	¢'m
Fixed assets							
Property, Plant and Equipment	448,198	1,741,211	2,467,631	2,924,602	3,514,178	3,340,634	2,292,416
Capital Work in Progress	3,091	3,677	3,949	10,268	15,005	20,422	(63,598)
	451,289	1,744,888	2,471,580	2,934,870	3,529,183	3,361,056	2,228,818
Current assets							
Stocks	6,060	5,321	5,511	12,695	49,450	55,586	62,254
Debtors	27,880	52,843	98,003	165,332	198,699	296,139	278,400
Short term investments	3,175	4,187	5,622	7,319	8,319	8,229	12,221
Cash and bank balances	8,401	15,400	26,931	44,262	66,216	56,197	41,464
	45,516	77,751	136,067	229,608	322,684	416,151	394,339
Creditors: amounts falling due within one year							
Creditors	47,223	89,478	157,540	402,588	381,394	(556,106)	(625,006)
	47,223	89,478	157,540	402,588	381,394	(556,106)	(625,006)
Net current liabilities	(1,707)	(11,727)	(21,473)	(172,980)	(58,710)	(139,955)	(227,668)
Total Assets less Current liabilities	449,582	1,733,161	2,450,107	2,761,890	3,470,473	3,221,101	2,001,150
Financed by:							
V.R.A.Investment Account	50,828	326,354	326,354	203,578	203,578	203,578	203,578
Income Surplus Account	(7,242)	(8,808)	(85,613)	(203,676)	(362,673)	(503,557)	(626,309)
	43,586	317,546	240,741	(98)	(159,095)	(299,979)	(422,731)
Capital Surplus	405,996	1,415,615	2,209,366	2,761,988	3,629,570	3,521,130	2,424,552
Capital and reserves	449,582	1,733,161	2,450,107	2,761,890	3,470,475	3,221,151	2,001,821

Also, there are some strange points in the figures of 2006. The capital work in progress being negative, and the sudden decrease of assets is rather strange. There seems to be some problem with the system, which may have occurred with the integration with the financial system of the VRA as a whole.

The cash flow for 2005 and 2006 is shown in the following table.

	2005	2006
	¢'m	¢'m
Cash Flow from operations	(351,777)	(103,733)
Cash Flow from Investment		
Interest received	(2,066)	(1,411)
Purchase of plant and equipment		
Capital works in progress	4,479	(84,883)
Net cash from investmsnt	2,413	(86,294)
Increase in Cash	(349,364)	(190,027)
Beginning Cash	74,532	64,407
Ending Cash	(10,125)	(10,774)

This also shows some strange cash transaction. The ending cash of 2005 doesn't matching with the beginning cash of 2006, which suggests some cash injection, although the details are not clear. Also, the change in cash doesn't translate into the change in cash balance, which also seem strange. Generally, however, VRA-NED is a money losing entity, and it is only supported drawing from the account set up by VRA itself.

Efforts in Improving the Operation

Usually in distribution, the revenue tends to be hampered by the large amount of system loss and collection delays. Usually, operational improvements aim straight at these issues. In Northern Ghana, however, these issues have been addressed.

The collection ratio is currently at 103%. This is attributed to a one time payment of an large scale overdue customer. As a result, the outstanding collection, which was 246 billion Cedis in 2005 end, has dropped 15.6% to 212.8 billion Cedis. The introduction of prepaid meters also seem to work, although at the moment, its penetration remains at 20% of the costomers.

System loss has also shown improvement. The system loss peaked at 31.4% in 2003, but since then, it has come down to 25.5%, a comparable level to ECG. Various rehabilitation, as well as a program to actually visit and identify the end users, seems to have paid off.

As seen, there are constant efforts to improve the operation. Even with such efforts, the revenue is insufficient to cover power purchase and other costs. The significant reason is the low power tariff. There has been plans to gradually raise the tariff from 2006, but the government announced that the increase for 2006 will be footed by the government. The government, however, failed to pay the difference to VRA-NED, which resulted in further decline of VRA-NED's financial position. In 2007, such policies seem to have been discontinued, but the actual method of raising the tariff has not been clarified. If the proposed tariff raise goes through as planned, it will significantly ease the financial situation of VRA-NED through increased revenues, at least making it possible to cover all the pre-depreciation costs.

7.5.2 Finances of ECG

ECG, covering the more urban southern Ghana, sold a total of 3761GWh in 2005, and purchased 5045GWh to cover this demand. It has roughly about 10 times the size of VRA-NED. The profit and loss statement of ECG is shown below.

	2004 ¢'m	2005 ¢'m
Revenue		
Power Sales	2,550,687	2,730,755
Public lighting levy	1,374	1,508
Expenditure		
Power purchase	2,052,010	2,144,291
Distribution, O&M	67,249	78,377
Administrative	621,921	822,606
Forex gain/(loss)	(32,013)	54,924
Interest pament	(48,554)	(47,338)
Net operationg income	(269,686)	(305,425)
Other income	86,042	66,773
Net profit	(183,644)	(238,652)

While it also shows a loss, the level of that loss is less then 10% of the total revenue, which is nowhere as bad as VRA-NED. The cost structure is mostly power purchase cost.

	2004 ¢'m	2005 ¢'m
Long term Asset		
Fixed asset	5,398,209	5,587,337
Capital work in progress	292,613	359,125
Trade investment	1	1
Total	5,690,823	5,946,463
Current Asset		
Stocks	464,734	593,721
Debtors	1,113,145	1,384,598
Prepayments	82,529	83,985
Securities	56,398	61,799
Cash	226,405	242,805
	1,943,211	2,366,908
Current liabilities		
Creditors and accruals	1,115,377	1,687,736
Long term loans	82,108	241,741
	1,197,485	1,929,477
Net Current Assets	745,726	437,431
Tottal Assets less current liabilities	6,436,549	6,383,894

The balance sheet of ECG is quite normal. Overall, from 2004-5, ECG has generally expanded their operation.

The cash flow of ECG is shown in the following table;

Cash Flow	**2004**	**2004**
	¢'m	¢'m
Cash from Operation	326,069	221,044
Investment		
interest paid	(20,012) -	
interest received	9,629	13,102
dividend received	86	112
fixed asset purchase	(322,899)	(340,434)
fied asset sales	82	1,411
consumer contribution	49,324	52,729
deferred expenditure paid	(1,058)	(6,811)
Net cash from investment	(284,848)	(279,891)
Financing		
Long term loans	36,126	80,648
Long term loan repayment	(16,353)	
Net cash from financing	19,773	80,648
Net cash increase	60,994	21,801
beginning cash	221,809	282,803
ending cash	282,803	304,604

Cash from operation is positive, in spite of the loss shown in the profit and loss statement. The decrease in receivables, the increase in payables, and the sales of stock has brought in significant cash. Various investments for repairs may not be sufficient, but are made on a regular basis, showing little problems. Also, the use of long term loans help to improve the cash position.

Overall, ECG is in a much better financial condition compared to VRA-NED. This is in part due to their operational area, which is much more industrialized. The collection ratio remains at 85.8 percent, but a large portion of the outstanding receivables are incurred by the Ghana Water Corporation Ltd (GWCL) and MDAs. If these were paid up, the collection should reach 96%. Also, the system loss has constantly hovered around 25% since 2000.

ECG is losing money, but not too much. Since tariff was raised in 2006-7, this should have had a good effect on the finances of ECG. If the sales went up by 30%, ECG is likely to turn a profit. Also, the collection from public entities should also help.

On the other hand, the drought since 2006, and the increasing fuel cost may force their financial position to the worse.

Chapter 8 Environmental and Social Considerations for Power Distribution Master Plan

8. 1 Natural and Social Conditions of Ghana

8. 1. 1 Natural Conditions

The ecological zones of Ghana largely consist of the forest zone, the savanna zone, and the forest-savanna transition zone. In addition, wetlands along the coastal area should be counted.

Forest in Ghana is widely distributed from tropical rainforests in the south-west part to dry semi-deciduous forests in the north and west part. The forest zone is 5,517,000 ha (2005) in area and cover about 24.2 % of Ghana's total land area[1]. The forest cover in 1995 was 9,022,000 ha (39.7 %)[2], and thus 3,505,000 ha of the forest decreased in the past decade. The savanna in Ghana can be divided into a coastal savanna and an inland savanna. The former is a zone from Cape Coast to the East, and comprise of grass land and shrub land. The latter is the largest ecological zone in Ghana, and covers from the central to the north. Wetlands, such as mangrove and coastal lagoons, are found along the southern coastal zone.

The Wildlife Division of Forestry Commission holds jurisdiction over protected areas including national parks and wildlife reserves. A map indicating the distribution of the protected areas in Ghana is attached to Appendix 8. 1. These protected areas are designated by the Wildlife Reserves Regulations, but there is no GIS map showing exact locations of these areas at present, according to the Wildlife Division. Almost protected areas are located in the inland areas far from major cities. However, there are 6 wetlands registered under the Ramsar Convention along the eastern coast. Some of them are located around cities such as Accra and Tema (Table 8-1). The locations of the registered wetlands are roughly indicated in Appendix 8.1.

Table 8-1 Ramsar Wetlands in Ghana

Name of Wetland	Location	Area (ha)
Anlo-Keta lagoon complex	Volta (Coastal Area)	127,780
Densu delta	Greater Accra (Coastal Area)	4,620
Sakumo Lagoon	Greater Accra (Coastal Area)	1,340
Songor Lagoon	Greater Accra (Coastal Area)	28,740
Muni Lagoon	Central (Coastal Area)	8,670
Owabi	Ashante (Northwest of Kumasi)	7,260

Source: Ramsar Convention Website ＜http://www.ramsar.org/index_list.htm＞

8. 1. 2 Socio-Economic Conditions

Ghana has tackled with economic reconstruction from 1983, carrying out structural adjustment under

[1] FAO. 2005. Global Forest Resource Assessment. Rome.

the initiatives of the World Bank and IMF. As a result, GDP growth rate from 2004 to 2006 is about 6 %, achieving a comparatively higher rate in Sub-Saharan Africa. Agriculture still remains the main economic activity in Ghana. Major agricultural products include yam, cassava, cocoa, and plantain. 80-90 % of agricultural products are produced by peasant farmers (small farm holdings) who practice rain-fed agriculture. Cocoa is a major export good as well as gold and timber.

Poverty rate in Ghana has recently decreased to 28.5 % in 2005-6, compared to 39.5 % in 1999. Ghana is expected to achieve Millennium Development Goals (i.e. Reduce by half the proportion of people living on less than a dollar a day). However, the poverty rate varies from region to region. Farmers in the savanna zones highly rely on small-scale rain-fed agriculture, and poverty rate of the north, in particular, have not successfully decreased yet. 40 % of the poor are considered living in the northern regions, i.e. Northern, Upper West and Upper East.

8. 2 Legal and Institutional Framework for Environmental and Social Considerations

8. 2. 1 Legal Framework for Environmental Impact Assessment

The legal basis of Environmental Impact Assessment in Ghana is derived from two sources; 1) the Environmental Protection Agency Act, 1994 (Act 490), and 2) Environmental Assessment Regulations, 1999 (LI 1652). The provisions contained in these two legal documents set out the procedures for Environmental Impact Assessment (EIA).

(1) Scope of Environmental Assessment Regulations

The schedule 1 of Environmental Assessment Regulations 1999 clarifies “Undertakings Requiring Registration and Environment Permit” (Schedule 1), while the schedule 2 indicates “Undertakings for Which Environmental Impact Assessment is Mandatory”. Undertakings related to the power sector listed in the schedule 2 are the followings (Section 13, Schedule 2 of Environmental Assessment Regulations 1999).

a. Construction of steam generated power stations;
b. Dams and hydroelectric power schemes;
c. Construction of combined cycle facilities
d. Construction of nuclear-fueled power stations;
e. Erection of power transmission lines.

EIA is not required for power distribution projects according to Environmental Assessment Regulations 1999. In addition, there are no regulations regarding EIA of a Master Plan in Ghana. This Master Plan Study is, therefore, not required to carry out EIA by Environmental Assessment Regulations 1999. This was confirmed by the deputy director of Environmental Audit and Assessment, the Environmental Protection Agency (EPA).

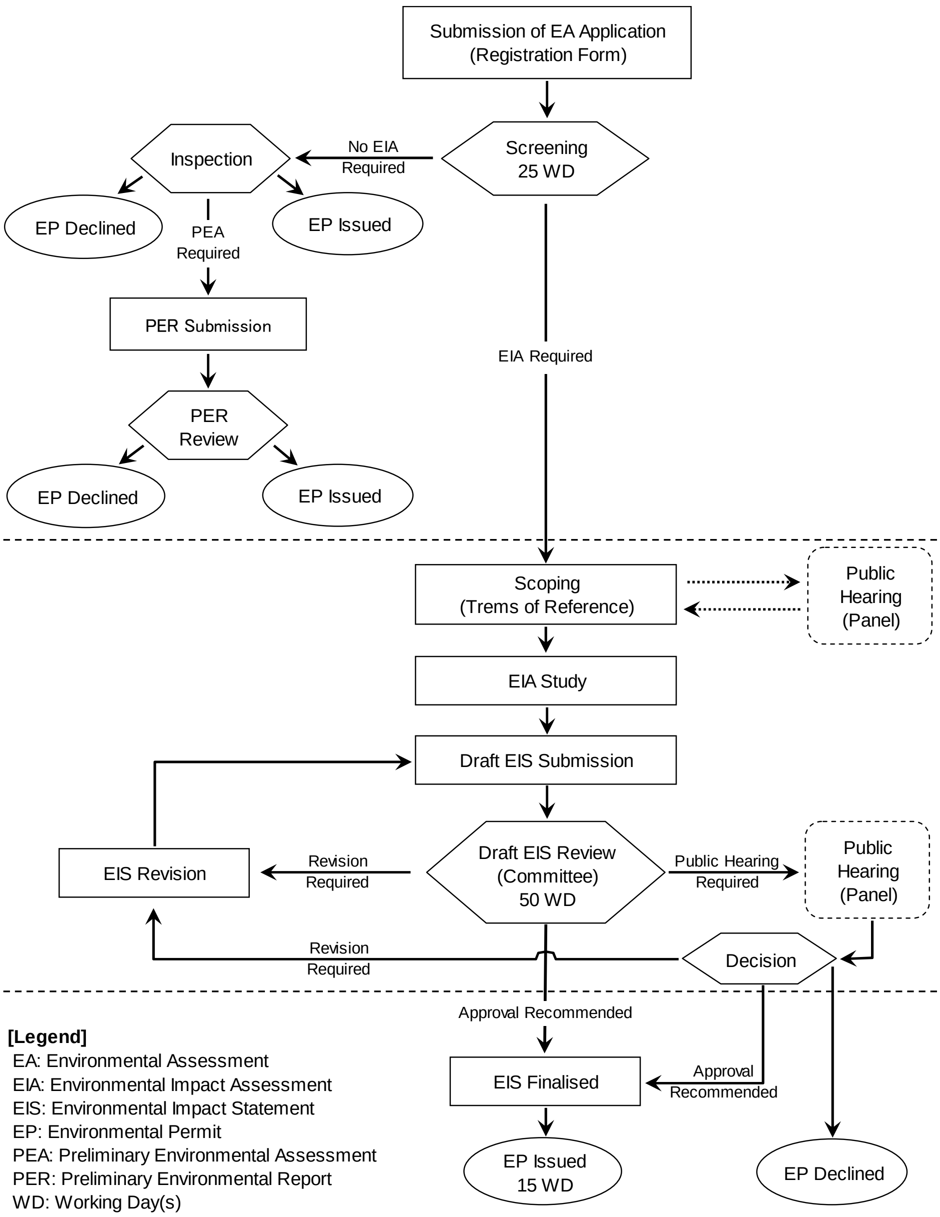
---

[2] FAO. 1997. State of the World’s Forests. Rome.

(2) Project Categorization and Procedures of EIA

A project proponent who initiates an undertaking likely to have adverse impacts on the environment must register the undertaking to EPA in accordance with Environmental Assessment Regulations. After the registration, the undertaking is screened and judged whether EIA is necessary. Even in case that EIA is not required, PEA (Preliminary Environmental Assessment) may be required depending on the significance of predicted impacts. Once EIA is judged to be necessary, the scope of EIA (or Terms of Reference) is determined, and EIS (Environmental Impact Statement) is drafted by the proponent. Public hearings are held in the process of scoping and EIS drafting. Environmental Permit (EP) is issued after EPA's approval of the submitted EIS.

The flow of Environmental Assessment Regulations is indicated below.



Source: Environmental Protection Agency

Figure 8-1 Flow Chart of Environmental Assessment Regulations 1999

(3) Energy Sector Guidelines for Environmental Assessment

EPA and relevant authorities established "Environmental Guidelines for the Energy Sector" in November 2007. The guidelines define requirements for power distribution projects as in the table below.

Table 8-2 Power Distribution Projects in the Energy Sector Guidelines

Undertaking	Description of Undertaking	Procedure
Transmission Lines and Distribution Systems	• Medium voltage lines, 11 kilovolt (kV) and 36 kV (voltage class) inclusive, not passing through environmentally sensitive areas. • Applicable also to all cases of retrofitting or upgrading as well as decommissioning of the stated or described lines.	Registration to EPA
	• Medium to High voltage lines above 36 kV but below 70 kV voltage class, either underground or overhead, not passing through an environmentally sensitive area. • Construction and installation of substations equal and above one (1) MVA in the transmission and distribution networks. • Applicable also to all cases of retrofitting or upgrading as well as decommissioning of the stated or described lines.	PEA
	• Medium voltage lines, 11 kilovolt (kV) and 36 kV (voltage class) inclusive, not passing through environmentally sensitive areas. • High voltage transmission lines, either HVDC (High Voltage Direct Current) or HVAC (High Voltage Alternating Current), either overhead or underground, equal or exceeding 70 kV class. • Retrofitting, upgrading as well as decommissioning included.	EIA
Management of used Transformer oils	• Decommissioning of old transformers with specific reference to handling of polychlorinated bi-phenyl (PCB) additives in transformer oil. • Storage, recycling and disposal of transformer oils • Storage and disposal of chemically treated wooden poles with specific reference to the use of Copper Chrome Arsenic (CCA).	PEA
Distribution system	All commercial dealers, importers and manufacturers of heavy-duty electrical distribution equipment and accessories	Registration to EPA

Source: Prepared by the Study Team based on the Energy Sector Guidelines

The guidelines require projects of constructing medium voltage lines (11 -36 kV) to be registered to EPA. PEA or Preliminary Environmental Assessment is necessary for "construction of medium to high voltage lines (36 kV- 70 kV)" and "construction and installation of substations equal and above 1 MVA in the transmission and distribution networks", while EIA is required for high voltage lines (over 70 kV) projects. Disposals of PCB (polychlorinated bi-phenyl) contaminated oil contained in transformers and CCA (Copper Chrome Arsenic) used for wooden poles must be subject to PEA.

(4) Environmentally Sensitive Areas

Environmental Assessment Regulations 1999 specifies 12 categories of "Environmentally Sensitive

Areas" (ESA) such as national parks, wildlife reserves and sanctuaries, cultural heritages and mangrove areas (Schedule 5 of Environmental Assessment Regulations 1999. See Annex 8. 2 for details). There is no map describing the distribution of ESA according to EPA.

Undertakings carried out in ESA are required to take certain procedures, even if EIA is not usually required. Environmental Assessment Regulations 1999 explicitly defines that 1) clearing of land for community pastures and livestock farms; 2) stone quarries and sand and gravel pits; and 3) construction of pipelines, which are carried out in ESA, must be registered to EPA and obtain environmental permit from EPA (Schedule 1 of Environmental Assessment Regulations 1999).

Even the undertakings other than the above mentioned ones may need registration, PEA and EIA, in case that EPA found certain adverse impacts. Although the criteria are not explicitly indicated in Environmental Assessment Regulations 1999, EPA defines the necessary procedures on a case-by-case basis, taking into account the categories and characteristics of the individual undertakings, and significance of ESA. Proponents of projects likely to be located in ESA, therefore, need to coordinate with EPA in advance.

(5) Environmental Quality Standards

In terms of power distribution projects, it is necessary to pay attention to noise from transformers, though the impacts are not significant. The Ambient Noise Level Standards in Ghana defined by EPA are the following.

Table 8-3 Ambient Noise Level Standards in Ghana

Zone	Description of Area of Noise Reception	Permissible Noise Level in dB(A)	
		6:00 – 22:00	22:00 – 6:00
A	Residential areas with negligible or infrequent transportation	55	48
B1	Educational (school) and health (hospital clinic) facilities	55	50
B2	Area with some commercial or light industry	60	55
C1	Area with some light industry, place of entertainment or public assembly and place of worship such as churches and mosques	65	60
C2	Predominantly commercial areas	75	65
D	Light industrial areas	70	60
E	Predominantly heavy industrial areas	70	70

Source: Environmental Protection Agency

8. 2. 2 Other Legal Frameworks for Environmental and Social Impacts

(1) Legal Framework for Protected Areas such as National Parks and Wildlife Reserves

In Ghana, Wildlife Division of Forestry Commission (FC) holds jurisdiction over national parks, wildlife reserves and protected areas. Regulations related to nature and wildlife protection is as follows.

- Wildlife Reserves Regulations, 1971

- Wildlife Conservation Regulations, 1971
- Wetland Management (Ramsar Sites) Regulations, 1999

Development activities such as clearing of land, hunting of animals and removal of plants are regulated in the areas designated by these regulations, including national parks and wildlife reserves. A person planning to such activities must obtain the permission or approvals of the FC or other relevant authority.

(2) Legal and Policy Framework for Land System

The Ghanaian land system is based on the constitution, statute law and common law. Land title is registered in accordance with the Land Title Registration Law 1986 (PNDCL. 152), and the Ministry of Lands, Forestry and Mines (MLFM) is responsible for the land registration system. The traditional customary and common law should be highlighted to understand Ghanaian land system. The Land Title Registration Law largely defines the following five types of customary law.

1) Allodial title based on customary law
2) Customary law freehold or Usufructuary title
3) Common law freehold
4) Customary tenancies
5) Customary tenure (abunu, abusa, etc.)

In Ghana, such customary and common laws are still effective especially in rural areas. It is, therefore, necessary to pay attention to these laws when acquiring land title.

The Lands Act 1963 (Statutory Way Leaves Act) provides necessary procedures for public land acquisition. In case of land acquisition, the Land Evaluation Board is responsible for evaluation of the necessity of compensation and the amount to be compensated.

(3) Legal and Policy Framework related to Cultural Heritages

As evidenced by the provision of Environmental Assessment Regulations 1999 saying that ESA includes "areas of unique historic, archaeological or scientific interests", the Regulations pay attention to the cultural aspects. Ghana ratified World Heritage Convention[3] in April 1975. "Asante Traditional Buildings" around Kumasi and "Forts and Castles, Volta, Greater Accra, Central and Western" along the coastline are currently designated as world heritage sites.

The National Commission on Culture (NCC) formulated "the Cultural Policy of Ghana" in 2004. The policy states that special attention shall be given to the preservation of traditional sacred groves, monuments, artistic treasures held in chiefly palaces, mausoleums, private homes and all objects with high artistic value. It also declared that NCC, in collaboration with EPA, FC and other related agencies, shall identify sacred forests and other heritage sites and preserve indigenous beliefs and practices associated with them. No natural heritage was designated in Ghana.

3 Convention Concerning the Protection of the World Cultural and Natural Heritage

Table 8-4 World Heritage in Ghana

Name of Heritage	Detail Description	Vicinal cities/ district
Forts and Castles, Volta, Greater Accra, Central and Western	Fort Good Hope (Fort Goedehoop)	Senya Beraku
	Cape Coast Castle	Cape Coast
	Fort Patience (Fort Leysaemhyt)	Apam
	Fort Amsterdam	Abandze near Kormantin
	Fort St. Jago (Fort Conraadsburg)	Elmina
	Fort Batenstein	Butri
	Fort San Sebastian	Shama
	Fort Metal Cross	Dixcove
	English Fort (Fort Vrendenburg)	Komenda
	Fort Saint Antony	Axim
	Elmina Castle (St. George's Castle)	Elmina
Asante Traditional Buildings		Northeast of Kumasi

Source: UNESCO World Heritage Website ＜http://whc.unesco.org/＞

8. 2. 3 Relevant Agencies and Institutions

The organizational structures of ECG and VRA-NED are indicated in the Chapter 2. Thus, the structures of Environmental Protection Agency (EPA) and Forestry Commission (FC) are described in this section.

(1) Environmental Protection Agency

Environmental Protection Agency (EPA) is responsible for Environmental Impact Assessment (EIA). EPA was established by the “Environmental Protection Agency Act, 1994 Act 490” and a subordinate agency of the Ministry of Local Government, Rural Development and Environment. The organizational chart of EPA is attached to Appendix 8. 3.

The section EAA (Environmental Audit and Assessment) of EPA is in charge of EIA. The Study Team carried out the environmental and social consideration study in consultation with the Deputy Director of EAA.

(2) Forestry Commission

Forestry Commission (FC) is responsible for the management of protected areas such as national parks and wildlife reserves. It belongs to the Ministry of Local Government, Rural Development and Environment. FC consists of Forest Services Division, Wildlife Division and Timber Industry Development Division, and Wood Industry Training Center and Resource Management Support Center. It is Wildlife Division that is mainly in charge of the management of protected areas.

8. 3 Principles and Methodology of Environmental and Social Considerations

8. 3. 1 Basic Principles

This study produces a Master Plan for the renewal, reinforcement and extension of power distribution network across Ghana. The Master Plan will include plans for power distribution line extension, construction and reinforcement of primary substations, and construction and reinforcement of sub-transmission line[4]. Although the adverse impacts of the activities are expected to remain limited, certain adverse impacts on the environment and society are predicted. This master plan study, therefore, conduct environmental and social consideration (ESC) study in accordance with JICA guidelines.

The objectives of ESC study at the Master Plan stage are to identify potential impacts at an earlier stage, and to mitigate or avoid serious adverse impacts by taking the impacts into account when determining exact locations and specifications of facilities. Identifying environmental and social impacts prior to the determination of the project details will make it possible to take necessary measures at an earlier stage.

The result of ESC study can be utilized in determining locations and detail specifications of facilities at the stage of feasibility study (F/S). Although Ghana Environmental Assessment Regulations 1999 does not require undertakings related to power distribution network to carry out environmental impact assessment in principle, there are categories of undertakings that are required to conduct Preliminary Environmental Assessment (PEA) or to be registered to EPA. In addition, EPA has the authority to require EIA or other certain procedures, depending on the components of the individual projects.

This Master Plan study is formulated on a certain assumption of locations and details of facilities, but does not specify the exact locations and details of facilities. Detail specifications will be determined in the F/S or Detail Design (D/D) Study. It is at F/S or D/D stage that environmental and social impacts can be appropriately assessed taking into account the local conditions and detail specifications. This ESC study, therefore, focuses on the impacts predicted at a planning stage, and conducts Initial Environmental Examination (IEE). The study pays attention to the following points.

1) Implementation of ESC study incorporating the perspective of Strategic Environmental Assessment (SEA)

   The Study Team conducts ESC study to identify points to be noted prior to the determination of locations and details of project components by predicting the possible environmental and social impacts and considering mitigation measures at the Master Plan stage. The result of the ESC study is incorporated into the Master Plan. The ESC study will contribute to avoidance and mitigation of potential impacts at an earlier stage if significant impacts are predicted.

2) Clarification of points to consider at Feasibility Study Stage

[4] Sub-transmission lines or interconnection lines connect a bulk supply point with a primary substation or between primary substations. The voltage is usually 33kV class (33 kV or 34.5 kV).

This ESC study clarifies points to consider and procedure in an environmental and social assessment at F/S stage. It is also expected to be utilized in F/S as preliminary assessment of potential impacts.

8. 3. 2 Methodology for Environmental and Social Considerations Study

IEE study on impacts predicted at a planning stage was carried out in this ESC study. Potential impacts and mitigation measures were examined based on literature review, sample survey of power facilities, and interviews to stakeholders. The list of sample facilities is the following.

Table 8-5 Sample Facilities surveyed in this ESC study

Facilities	Location/ Name	Status
Bulk Supply Point	Tamale: Tamale BSP	In operation
Primary Substation	Kumasi: Station A and Station B	In operation
	Tema: Dawhenya Substation	Planning
	Elmina: Elmina Substation	In operation
Secondary Substation	Various secondary substations around Accra, Kumasi, Tema, Tamale	In operation
Distribution Line	Distribution lines around Accra, Kumasi, Tema, Tamale	In operation
Sub-transmission Line	Sub-transmission line around Tema and Tamale	In operation

Source: JICA Study

The Study Team, in collaboration with officials of ECG and VRA-NED, conducted scoping of potential environmental and social impacts, and elaborated mitigation measures. The comment from EPA was reflected to the result.

As regards stakeholder meetings, the Study Team decided to hold interview sessions with the representatives of local residents in the district or villages where certain impacts were predicted. This is because, at a Master Plan stage, it is impossible for the Team to identify the residents directly affected by the projects in the Master Plan. The interview aimed to clarify points to consider at F/S stage. The result of the interview sessions can contribute to the elaboration of questionnaires of the stakeholder meetings in F/S.

8. 4 Assessment and Prediction of Environmental and Social Impacts

8. 4. 1 Components of Master Plan

The Master Plans provides a future plan for renewal, reinforcement and extension of power distribution network. Specifically, the Plan includes 1) construction and reinforcement of primary substation, 2) installment of secondary substation, 3) construction and reinforcement of distribution line, 4) construction of sub-transmission line.

(1) Primary Substation

The construction site for a primary substation is 50m x 50m in general, and 200 meters square at maximum. Primary substations are located in or around cities where many customers are living.

The Master Plan includes a plan for the construction and reinforcement of primary substations. It proposes that seven (7) primary substations be newly constructed, and the seven require the acquisition of construction site. Around the candidate site for the newly proposed primary substations, there are no protected areas. In addition, no technical problems are expected if locations described in the Master Plan are moved to several kilometers away. F/S therefore is able to avoid areas which require due attention when determining the locations of the new primary substations

Table 8-6 New Primary Substations Proposed in the Master Plan

Region	Existing Distribution line Name	Candidate Site
Eastern	Tafo	Around Bunso
	Asamankese	Around Asamankese
	Mountains	Around Mountains
Volta	Peki	Around Peki
Western	Manganese	Around Atuabo
Northern	28F3B	Around Toron
Brong Ahafo	Sunyani F8 (27F8B)	Around Chiraa

Source: JICA Study

On the other hand, the reinforcement of a primary substation, unlike the construction, is completed by installing additional transformers in the primary substation. Land acquisition for the reinforcement will not be necessary at present since there are enough spaces for new transformers in the existing substations. However, the detail plan will be determined by F/S, thus there remains potential for the expansion of the site, depending on the result of F/S.

(2) Secondary Substation

Secondary substations are called “pole-mounted transformer”, and are installed on network poles in general. Thus secondary substations will not require any parcel of land for their installation. At secondary substations 11kV class and 33kV class are transformed into 400 V. Main works are installation of new transformers associated with distribution line extension and replacement of transformers associated with the project of voltage increase.

(3) Distribution Line

There are two types of distribution lines, i.e. medium voltage line and low voltage line. Both lines are usually wired on wooden poles, but long-distance medium voltage lines are sometimes wired on steel towers. Certain areas of either side of power lines are “Right of Way”, thus land use is restricted for the purpose of maintenance of lines and safety. The heights of supporting structures in Ghana are 11 m of medium voltage and 9m (Urban area) or 8m (District area) of low voltage.

The Master Plan includes a plan for renewal, reinforcement and extension of power distribution network. The works for the renewal and reinforcement of distribution network consist of voltage increase of existing distribution lines and switches from existing cables to thicker ones. Such works will not cause significant environmental and social impacts. The ESC study, therefore, focuses on the impacts caused by the extension of distribution networks to un-electrified villages.

In terms of a plan for the extension, however, information of un-electrified villages is not fully available. Thus in this Master Plan study, the Study Team conducted a simulation study on the extension of distribution networks, based on available information of 472 un-electrified villages. However, the result cannot indicate the exact route of the extension of distribution networks due to the limited information.

(4) Sub-transmission line

Sub-transmission lines will be necessary associated with the construction or reinforcement of primary substations. Sub-transmission lines include medium voltage lines (33kV class) connecting from a bulk supply point to primary substations and those between primary substations. The sub-transmission lines are in general wired on a small-scale steel towers, but some part may be laid underground. The sub-transmission lines also require Right of Way for the maintenance of the lines. The Master Plan provides a plan for construction of sub-transmission lines as indicated in Table 8-7.

Table 8-7 New Sub-transmission Lines Proposed in the Master Plan

City	Location
Accra	Sub-transmission lines from Bulk Supply Point (H) to Primary Substation (E)
Tema	Sub-transmission lines from Bulk Supply Point (H) to Primary Substation (A)
Kumasi	Sub-transmission lines from Bulk Supply Point (Kumasi BSP) to Primary Substation (KTI)
Tamale	Sub-transmission lines from Bulk Supply Point (Tamale BSP) to the newly proposed Primary Substation
Sunyani	Sub-transmission lines from Bulk Supply Point (Sunyani BSP) to the newly proposed Primary Substation

Source: JICA Study

The Master Plan proposed that all the sub-transmission lines be wired on the route of existing sub-transmission lines or medium voltage distribution lines, thus the construction of these sub-transmission lines will not require land acquisition. However, there remains potential for widening existing route or selecting new route because the detail planning will be made in the F/S.

8. 4. 2 Examination of Alternatives

The following two (2) categories should be taken into account as regards alternatives in this ESC study.

(1) Zero Option Scenario

A zero option scenario here means a case without the Master Plan. In this case, current inefficient power distribution will continue, and may have adverse effects on economic activities and people's lives. In terms of environmental and social impacts, the environmental and social impacts of the zero option scenario need to be compared to those caused by projects in the Master Plan.

Major possible impacts caused by projects in the Master Plan are, as mentioned in the scoping section of 8. 4. 3, the restriction of land use and impacts on the Ramsar sites regarding primary substation construction, and the restriction of land use due to the Right of Way related to distribution and sub-transmission lines. These impacts are, however, expected to insignificant, and the impacts can be easily mitigated by changing location of related facilities. Impacts of PCB and CCA on the environment should be addressed regardless of this Master Plan. Thus, the difference between impacts of the zero option scenario and those caused by projects in the Master Plan is not presumably significant. It can be, therefore, concluded that this ESC study does not need to take into account zero option scenario.

(2) Alternative locations

The impacts caused by projects in the Master Plan significantly vary depending on the location of power distribution facilities. For instance, involuntary resettlement, impacts regarding agriculture on economic activities, and impacts on protected areas and local landscape are typical ones. It is therefore effective to take into account alternative locations so as to avoid such impacts.

The Master Plan roughly indicates locations of new primary substations and routes of new sub-transmission lines for the sake of convenience. However, the detail locations and routes will not be specified until the F/S stage. Therefore, it is necessary to select construction sites and routes in order to avoid or mitigate significant environmental and social impacts.

In case of avoidance of significant areas, locations indicated in the Master Plan may differ by several kilometers from those of the actual construction sites. However, such difference will not cause severe technical problems. It is, therefore, possible to modify the locations roughly indicated in the Master Plan if F/S identifies significant environmental and social impacts. Locations described in the Master Plan may differ by several kilometers from those of the actual construction site so as to avoid the impacts, but such difference will not cause technical problems.

In preparing this Master Plan, the Study Team tried to avoid significant areas such as protected areas and cultural heritages based on available information at the moment. In terms of new sub-transmission lines, utilization of existing routes is proposed to avoid new land acquisition.

In this ESC study, the Master Plan elaborated through such considerations is considered as a standard scenario, and scoping and mitigation measures are considered.

8. 4. 3 Scoping Result

(1) Scoping Result

Scoping of potential environmental and social impacts was carried out according to the four categories of projects included in the Master Plan.

Table 8-8 Scoping Table

Impacts	Overall Rating	Description of Impacts	Primary Substation	Secondary Substation	Distribution Line	Sub-transmission Line
Involuntary resettlement	B	**[Primary Substation]** Primary substations are located in/around cities, and their sites are 50 meters square in general, and 200 meters square at maximum. The Master Plan includes the construction of 3 primary substations in the Eastern Region, 1 in the Volta Region, 1 in the Western Region, 1 in the Northern Region and 1 in Brong Ahafo Region. The density of buildings and agricultural lands is considered high in the candidate sites for these 7 substations. Thus, involuntary resettlement may occur, though the scale will not be so significant. **[Sub-transmission Line]** Involuntary resettlement is not expected because the Master Plan proposes that new sub-transmission lines be constructed along existing routes. However, there remains possibility that F/S finds the necessity of widening of the existing routes or of selecting new routes. In this case, involuntary resettlement may take place. **[Distribution Line]** Distribution lines in Ghana are usually wired along existing road alignments, and avoid barriers such as buildings. It is, therefore, concluded that wiring distribution lines will rarely cause involuntary resettlement. Long-distance medium voltage distribution lines wired on steel towers might cause involuntary resettlement.	B		C	C
Minority / Weak people of society	C	Designated areas for indigenous peoples/ minority groups were not identified in this ESC study. F/S should pay attention to such minorities and, if such residential areas of minorities are found in F/S, it is necessary to avoid adverse impacts on their lives.	C		C	C
Inequality and separation in society	C	**[Primary Substation]** It is prohibited to enter into the site of primary substations. Therefore, the 7 new primary substations proposed in the Master Plan may cause limited separation in society, such as inhibited access to public facilities, depending on the locations and scale of the substations. **[Sub-transmission Line]** There remains possibility that other routes than the existing ones are selected as a result of F/S, though the Master Plan proposes the use of the existing routes. In this case, passage under the sub-transmission lines may be restricted due to the Right of Way. **[Distribution Line]** In terms of distribution lines, the passage may be restricted during construction phase, but it is very rare that passage of people is restricted	C			C

		after the work completion. Thus the impacts will remain insignificant.				
Cultural heritage/ Local landscape	C	**[Primary Substation]** In this ESC study, cultural heritages were not identified around the newly proposed primary substations. However, F/S may identify the local culturally valuable buildings and other cultural heritages. **[Sub-transmission Line]** Accra and Kumasi have various cultural heritages, thus in case of selection of other routes than the existing ones, steel towers of sub-transmission lines may cause landscape problems. **[Distribution Line]** Since long-distance medium-voltage distribution lines are often wired on steel towers, local landscape may be disturbed depending on the selected routes.	C		C	C
Agricultural activity and other economic activity	B	**[Primary Substation]** The Master Plan includes construction of 7 primary substations. The density of buildings and agricultural lands is considered high in the candidate sites for these 7 substations. Thus, economic activities may be affected by, for instance, the acquisition of farm land, though the scale will not be so significant. **[Sub-transmission Line]** There remains possibility that other routes than the existing ones are selected as a result of F/S, though the Master Plan proposes the use of the existing routes. In this case, construction of sub-transmission lines may cause land use restriction during the construction phase or after the work completion due to the Right of Way. **[Distribution Line]** Power distribution lines are usually wired along the existing road alignment, and thus will not cause serious impacts such as land-use restriction. But long-distance medium voltage distribution lines might be wired over farm lands and commercial facilities. In such cases, construction of distribution lines may cause land-use restriction during the construction phase or after the work completion due to the Right of Way.	B		C	C
Infectious disease		The inflow of outside construction workers will be limited since distribution network projects will not require large-scale civil engineering works and ECG has a policy to employ local people. Therefore, the spread of infectious disease is not expected to occur. In addition, water-borne infectious diseases are not expected because large-scale construction works are not expected.				
Accident	C	**[Primary Substation]** It is prohibited to enter into the site of primary substations. Therefore, there are no concerns of accidents involving local residents. **[Sub-transmission and Distribution Line]** Sub-transmission and distribution lines may be broken down or hang down to the ground by disasters. In addition, surreptitious use of power may cause secondary dangers.			C	C
Protected Area	C	**[Primary Substation]** There are no protected areas around the candidate sites for the newly proposed 7 primary substations. Thus, there are no concerns about the impacts on the protected areas. **[Sub-transmission Line]** There are no protected areas around the candidate sites for the new sub-transmission lines proposed in the Master Plan. No impacts on the protected areas are predicted. **[Distribution Line]** In case that distribution lines pass through protected areas, impacts on the flora and fauna, such as electrification of wildlife and tree cutting for the construction works, may take place. However, the scale of tree cutting			C	

		will remain small because distribution lines are in general wired along the existing road alignment. The impacts on Ramsar wetlands along the eastern coastal zone around Accra and Tema might be given due considerations, because the zone has a large population and high electricity demand, and new construction of distribution networks will be expected.				
Geological feature and natural landscape	C	**[Primary Substation]** In this ESC study, geological features and natural landscape were not identified around the candidate sites for the 7 new primary substations. However, F/S may identify the locally valuable features and landscapes. **[Sub-transmission Line]** The newly proposed sub-transmission lines in Accra, Tema and Kumasi have no impacts since no geological features and natural landscapes exist in these cities. One the other hand, the sub-transmission lines in Tamale and Sunyani are the ones connecting from Tamale and Sunyani BSP to newly constructed substations about 20 km away. Depending on the selected routes, geological features and natural landscape may be adversely affected. **[Distribution Line]** Since long-distance medium-voltage distribution lines are often wired on steel towers, geological features and natural landscapes may be disturbed depending on the selected routes.	C		C	
Ecosystem	C	**[Primary Substation]** Construction of new primary substations may have adverse impacts on ecosystem other than protected areas. The impacts include disruption of migration path of wildlife and disturbance of water place for animals. **[Sub-transmission Line]** The newly proposed sub-transmission lines in Accra, Tema and Kumasi have no impacts since no valuable ecosystem exists in these cities. On the other hand, the sub-transmission lines in Tamale and Sunyani are the ones connecting from Tamale and Sunyani BSP to newly constructed substations about 20 km away. Thus the sub-transmission lines may adversely affect valuable ecosystem depending on the selected routes. **[Distribution Line]** Construction of distribution lines may have impacts on the flora and fauna, such as electrification of wildlife and tree cutting for the construction works, may take place.	C		C	
Air Pollution/ Global Warming		Small amount of air pollutants and greenhouse gases will be emitted from vehicles and heavy machines for construction works when constructing primary substations. However, the works will remain small-scale, and operational hours of the vehicles and machines will be short. Therefore the impacts will be ignorable.				
Soil contamination		No soil contamination was predicted by projects included in the Master Plan.				
Waste	B	**[Primary and Secondary Substation]** Renewal and replacement of old transformers may be associated with disposal of old transformers containing PCB. According to a sample survey carried out by EPA, 154 transformers out of 1045 (14.7 %) contained PCB oil. Such PCB oil may cause pollution of the surrounding environment in case of inappropriate disposal and/or storage. **[Distribution Line]** Distribution lines are usually wired on wooden poles in Ghana. These wooden poles treated by pesticides such as CCA. Disposal of waste wooden poles treated by CCA may cause environmental pollution. CCA is widely used to prevent decays of wooden poles, and it is hard to obtain alternative poles at present.	B	B	B	

Noise and vibration	B	**[Primary Substation]** Noise may be emitted from transformers and switches of primary substations. Vehicles and heavy machines for construction works may cause noise and vibration problems, however the duration of construction works is expected to be short, thus the impacts are ignorable.	B			
Chemicals	B	**[Distribution Line]** Wooden poles are usually treated by CCA. Such poles may cause the pollution of the surrounding environment when installing and processing the poles.			B	
Subsidence an Odor		**[Primary Substation]** Reclamation of land for the construction of primary substations will not require large-scale civil engineering works compared to the construction of power plants. Thus, streams and subsoil flows will not be affected by the reclamation. In addition, no past case to cause subsidence by the construction of primary substations was identified. **[Sub-transmission and Distribution Line]** No subsidence and offensive odors are predicted in relation to distribution and sub-transmission lines.				
Radio interference		**[Sub-transmission and Distribution Line]** Causal relations between health damages and electromagnetic waves are not confirmed by WHO and other international organizations. Therefore, health damage will not be predicted when ordinary measures to keep distance from power lines are taken. Another reason of insignificant health damage is that voltages of sub-transmission lines and distribution lines are not high voltage.				

[Legend] A: Significant impact is expected. B: Some impacts are expected
C: Significance of impact is unknown. No Mark: No/Ignorable impact is expected.

Source: JICA Study

(2) Troubles in the Past

It is effective to confirm if there are conspicuous troubles regarding distribution projects and what causes the troubles. In particular, involuntary resettlement, compensation for land acquisition, and noise around primary substations, and noise and emission gas associated with construction works should be given due considerations. The Study Team held a number of interview sessions with personnel of ECG headquarters and regional offices, VRA-NED headquarters and regional offices, and VRA, and district assemblies and chiefs. As a result, no serious troubles were confirmed with respect to distribution projects.

8. 4. 4 Mitigation Measures

(1) Considerations at Master Plan stage

The impacts of projects included in the Master Plan fall roughly into two categories, i.e., the impacts whose significances greatly vary depending on the locations of facilities (e.g. involuntary resettlement, land acquisition, cultural heritages, protected areas and local landscape), and other impacts (e.g. PCB waste oil, CCA treated wooden poles and noises). In terms of the former impacts, basic mitigation measures at the Master Plan stage are to avoid areas with potential significant impacts. More specifically, the Study Team tried to identify areas with potential significant impacts based on map information and information gathered from ECG and VRA-NED regional offices, and then tried to avoid the areas in elaborating the Master Plan.

1) Primary Substation

The Study Team consulted with personnel of ECG and VRA-NED, and identified the categories of areas where facility construction should be avoided. The following categories of areas were identified in the consultations.

a) Areas with high density of houses and commercial facilities
b) Farm land
c) Protected areas (in particular, Ramsar sites along the eastern coast around Accra and Tema, and Ramsar sites of north-west of Kumasi)
d) Cultural heritages (in particular, “Forts and Castles, Volta, Greater Accra, Central and Western” along the coastline and “Asante Traditional Buildings” around Kumasi)
e) Culturally valuable land (sacred groves, shrines, cemeteries, etc.)
f) Local landscapes

In terms of the 7 primary substations newly proposed in the Master Plan, many part of candidate lands are expected to be residential areas and farm lands. F/S, therefore, should pay due attention to the impacts on houses and other buildings and farm lands in selecting the location of the new primary substations.

2) Sub-transmission line and distribution line

The Study Team also identified the areas where construction should be avoided as regards sub-transmission line a distribution line.

a) Areas with high density of houses and commercial facilities (in particular, in case of selecting other routes than the existing ones)
b) Farm land
c) Protected areas (in particular, Ramsar sites along the eastern coast around Accra and Tema, and Ramsar sites of north-west of Kumasi)
d) Cultural heritages (in particular, “Forts and Castles, Volta, Greater Accra, Central and Western” along the coastline and “Asante Traditional Buildings” around Kumasi in terms of extension of distribution lines)
e) Culturally valuable land (sacred groves, shrines, cemeteries, etc.)
f) Local landscapes

The Master Plan proposes that new sub-transmission lines be wired along the existing routes of sub-transmission lines and medium voltage distribution lines, therefore, the possibility of serious problems caused by sub-transmission lines can be considered low.

In terms of rural extension of distribution lines, the Master Plan does not include a plan for the rural extension because of unavailability of data and information. Therefore, the Study Team, at the Master Plan stage, did not make any considerations in terms of route selection of the rural extension.

(2) Mitigation measures at project implementation stage

Project implementation stage can be divided into a Feasibility Study (F/S) phase, a Basic Design Study (B/D) phase and a Detail Design Study (D/D) phase, and a construction phase. Environmental Impact Assessment (EIA) is usually carried out at the F/S phase, and environmental measures elaborated in the EIA are taken into account at the B/D or D/D phase, then the measures are put into practice at the construction phase. This section aims to clarify points to consider at the F/S phase or prior to the F/S phase.

1) Primary substation

In the F/S, field investigation of the candidate sites will be carried out, then the exact locations will be determined. The detail specifications of primary substations will also be determined. Points to consider at the F/S phase are indicated below.

Table 8-9 Mitigation Measures for Primary Substations

Impact	Mitigation Measures at F/S phase
Involuntary resettlement	To prepare alternatives to avoid involuntary resettlement in selecting locations of new primary substations. To ascertain the physical and social conditions of candidate sites through field investigations and consultations with representatives of local residents (e.g. chiefs and opinion leaders) and district assembly members, and then to avoid selecting the sites where involuntary resettlement may occur. In case that involuntary resettlement is unavoidable, to hold consultations with affected people and representatives of local residents, and to obtain their agreement. To formulate and implement a resettlement action plan including compensation, support for rebuilding of people's lives in the relocated places, system for accepting and processing complaints and monitoring mechanism.
Inequality/ separation in society	To confirm existence/nonexistence of concerns about separation in society through consultations with representatives of local residents and district assembly members. In case that serious impacts expected, to consider the change of locations and/or specifications of facilities.
Cultural heritage/ Local landscape	To ascertain existence/nonexistence of cultural heritages and local landscapes through field investigations and consultations with representatives of local residents and district assembly members. To avoid locations around cultural heritages and local landscapes to prevent problems. In case that certain impacts are unavoidable, to take necessary measures such as painting facilities.
Agricultural	To ascertain land use characteristics such as farm land and commercial facilities through

activity and other economic activity	field investigations and consultations with representatives of local residents and district assembly members. To select locations to avoid impacts on local economic activities. In case that certain impacts are unavoidable, to hold consultations with affected people and representatives of local residents, and to obtain their agreement. The compensation must be properly calculated taking into account the actual situations of land such as varieties of agricultural products or the types of commercial activities.
Protected area, Ecosystem	To collect information on protected areas or valuable ecosystems through field investigations and consultations with the regional offices of Forestry Commission and Environmental Protection Agency, even if the candidate sites for new primary substations proposed in the Master Plan are not located around protected areas. To select the locations so as to avoid impacts on protected areas and valuable ecosystems.
Geological feature/ Natural landscape	To ascertain existence/nonexistence of geological features and natural landscapes through field investigations and consultations with the regional offices of Forestry Commission and Environmental Protection Agency, and with representatives of local residents and district assembly members. To select the locations to avoid impacts on the features and the landscapes.
Waste	To properly store PCB waste oil to prevent leakage into the environment until the guidelines and treatment systems are established by the Government of Ghana. The followings are the standards to store PCB wastes specified by Japanese Waste Management Law. ECG and VRA-NED need to properly store PCB waste in reference to the standards. 1) Take necessary measures to prevent the volatilization of PCB such as putting PCB oil into sealed containers, and to prevent exposure of PCB oil to high temperature. 2) Take necessary measures to prevent the decay of containers of PCB waste. 3) Set fences around storage sites. 4) Put a board indicating the followings in a prominent part of storage sites. a) That PCB waste is stored here b) Name of personnel or organization responsible for the storage and its contact information 5) Take necessary measures to prevent splash, leakage, and infiltration into the ground of PCB waste, and emission of offensive odors from PCB waste. 6) Take necessary measures to prevent rats, mosquitoes, flies and other harmful insects.
Noise/ Vibration	To design and arrange facilities of primary substations so as to make noise level within environmental quality standards set by EPA. Enough distance from distribution facilities to the boundary should be ensured. To install low-noise type transformers.

Source: JICA Study

2) Secondary substation

In terms of secondary substations, only PCB oil in old transformers will cause adverse impact.

Table 8-10 Mitigation Measures for Secondary Substations

Impact	Mitigation Measures at F/S phase
Waste	To properly store PCB waste oil to prevent leakage into the environment until the guidelines and treatment systems are established by the Government of Ghana. (See “Waste” section of primary substation.)

Source: JICA Study

3) Sub-transmission lines and distribution lines

Detail specifications of facilities and exact routes of power lines will be determined through line route surveys at the F/S phase. Mitigation measures taken at the F/S phase are the following.

Table 8-11 Mitigation Measures for Sub-transmission and Distribution Lines

Impact	Mitigation Measures at F/S phase
Involuntary resettlement	In terms of sub-transmission lines and distribution lines, possibility of involuntary resettlement can be considered low. However, the following measures may need to be taken. To select sub-transmission line routes that can avoid involuntary resettlement, in case of selecting other routes than the existing ones. To ascertain the distribution of houses in line route surveys, and to formulate plans to avoid the existing houses. To determine routes of long-distance medium-voltage distribution lines to avoid involuntary resettlement, taking the same measures as sub-transmission lines. To formulate and implement a resettlement action plan including compensation, support for rebuilding of people’s lives in the relocated places, system for accepting and processing complaints and monitoring mechanism.
Inequality/ separation in society	To confirm existence/nonexistence of concerns about separation in society through consultations with representatives of local residents and district assembly members. To consider the change of locations and/or specifications of facilities, in case that serious impacts expected.
Cultural heritage/ Local landscape	To ascertain existence/nonexistence of cultural heritages and local landscapes through field investigations and consultations with representatives of local residents and district assembly members. To determine routes of sub-transmission lines to avoid impacts on cultural heritages and local landscapes, in case of selecting other routes than the existing ones. To determine routes of long-distance medium-voltage distribution lines to avoid impacts on cultural heritage and local landscapes, taking the same measures as sub-transmission lines. In case that certain impacts are unavoidable, to take necessary measures such as using underground cables and painting facilities.
Agricultural activity and other economic activity	To ascertain land use situation such as farm land and commercial facilities through field investigations and consultations with representatives of local residents and district assembly members. To determine routes of sub-transmission lines to avoid impacts on local economic activities, in case of selecting other routes than the existing ones. To determine routes of long-distance medium-voltage distribution lines to avoid impacts on

	local economic activities. In case that certain impacts are unavoidable, to consult with people whose economic activities will be restricted, to obtain their agreements, and to make proper compensation. The amount of compensation should be determined taking into account the duration of impacts (i.e. construction phase or operation and maintenance phase), land-use characteristics (farm land or commercial land), and varieties of agricultural products or the types of commercial activities.
Accident	To take safety measures such as regular patrols to avoid secondary danger caused by breakdown of distribution lines and surreptitious use of power.
Protected area, Ecosystem	To collect information on protected areas or valuable ecosystems through field investigations and consultations with the regional offices of Forestry Commission and Environmental Protection Agency To select the routes of distribution lines so as to avoid impacts on protected areas and valuable ecosystems. In case that protected areas and ecosystem are unavoidable, to select the routes that can minimize the scale of land reclamation and tree cutting in consultation with the Forestry Commission and Environmental Protection Agency. To take into account the use of covered cables to prevent electrification of wildlife especially in the areas with high density of wildlife.
Geological feature/ Natural landscape	To ascertain existence/nonexistence of geological features and natural landscapes through field investigations and consultations with the regional offices of Forestry Commission and Environmental Protection Agency, and with representatives of local residents and district assembly members. To select the routes of distribution lines to avoid impacts on the features and the landscapes. In case that certain impacts are unavoidable, to take necessary measures such as painting steel towers.
Waste	There are no legal framework and guidelines for the disposal of wooden poles treated by CCA. The following measures should be taken until the disposal system is established. To make efforts to reduce the amount of waste CCA-treated wooden poles by reusing as supporting materials of poles. To refrain from incineration disposal, and to store properly.
Chemical	To purchase CCA-treated wooden poles from vendors with permits by the Environmental Protection Agency. To minimize processing operations at construction site so as to prevent woodchip from flying into the surrounding environment. To oblige field workers to use masks, goggles and groves to prevent the exposure of the workers to CCA.

Source: JICA Study

8. 4. 5 Monitoring

It is necessary to implement continuous monitoring for the impacts caused by projects included in the Master Plan, and appropriateness of mitigation measures.

(1) Monitoring item

The impacts that should be monitored are identified as follows.

Table 8-12 Monitoring Item

Project Category	Impacts	Monitoring Item
Primary Substation	Involuntary resettlement, Land acquisition	• Occurrence/nonoccurrence of involuntary resettlement and land acquisition • Appropriateness of process to obtain agreements from affected people • Appropriateness of property value assessment • Appropriateness of resettlement process • Progress of resettlement and land acquisition • Progress of support for rebuilding lives of relocated people
	Protected area, Ecosystem	• Existence/nonexistence of impacts on protected areas and valuable ecosystem • Appropriateness and sufficiency of mitigation measures
	Cultural heritage, Local landscape	• Existence/nonexistence of impacts on cultural heritages and local landscapes • Appropriateness and sufficiency of mitigation measures
	PCB waste oil	• Appropriateness of storage system of PCB waste oil
	Noise	• Noise level at site boundary in operation phase
	Safety measures	• Maintenance and inspection of facilities, and prevention of fire breaking
Secondary Substation	PCB waste oil	(Same as primary substation)
Distribution line, Sub-transmission Line	Involuntary resettlement, Land acquisition	(Same as primary substation)
	Protected area, Ecosystem	(Same as primary substation)
	Cultural heritage, Local landscape	(Same as primary substation)
	Waste CCA-treated wooden poles	• Reuse of waste CCA-treated poles as supporting materials • Appropriateness of storage system of waste CCA poles
	CCA-treated wooden poles	• Vendors of CCA-treated poles • Safety measures for construction workers engaging in installation of CCA-treated poles
	Safety measures	• Maintenance and inspection of facilities, and prevention of fires breaking • Prevention measures for accidents of electric shock
Common points	Complaints	• Establishment of system for accepting complaints and records of complaints • Appropriateness of processing complaints

Source: JICA Study

The monitoring items of individual projects can differ depending on the location and other conditions. For instance, if long-distance medium voltage lines are wired around the Ramsar sites, it is necessary to monitor impacts on birds inhabiting in the sites. Impacts to be monitored should be adjusted in reference to predicted environmental and social impacts of individual projects.

(2) Monitoring mechanism

It is essential to establish firm mechanism for the implementation of effective monitoring. However, monitoring mechanisms of ECG and VRA-NED are not sufficient at present. Recommendation on the establishment of monitoring system is made in the section of 8. 4. 6 Environmental Management Plan.

8. 4. 6 Environmental Management Plan

(1) Formulation of Environmental Management Plan

Environmental Assessment Regulations 1999 requires a proponent of undertaking necessary to carry out EIA or PEA to formulate an Environmental Management Plan (EMP). In terms of projects included in the Master Plan, there are some undertakings that PEA is mandatory, while EIA will not be required at present. Specifically, “construction and installation of substations equal and above one (1) MVA in the transmission and distribution networks”, “decommissioning of old transformers with specific reference to handling of polychlorinated bi-phenyl (PCB) additives in transformer oil”, “storage, recycling and disposal of transformer oils”, and “storage and disposal of chemically treated wooden poles with specific reference to the use of Copper Chrome Arsenic (CCA)” should be taken into account.

The Energy Sector Guidelines states that EMP should contain the following at least.

1) Outline for preparing EMP and basic information

2) Potential impacts identification

- Expected environmental impacts (raw materials, disposal method, emission gas and water discharge), etc.

3) Current environmental management practices

- Hazardous waste management, waste oil management
- Minimization of impacts, etc.

4) Occupational health and safety action plan

5) Program to meet requirement

- Management structure and organizational chart (appointment of environmental officer)
- Staff information, training and participation on environmental issues
- Community relations, external information and public participation, etc.

6) Means for implementing and monitoring the EMP

- Compliance with regulations, good practices, and capture of unforeseen impacts

- Voluntary codes

7) Management audit and review

(2) Implementation mechanism of Environmental Management Plan

Both ECG and VRA-NED do not have sufficient environmental management system at present. In ECG, there is a sector manager for safety and environment, but the manager mainly handles safety issues. There is an environmental officer in the Engineering Department of ECG, but the manpower is limited to cover environmental and social issues throughout the ECG service area. In VRA-NED, no staff is appointed as an environmental officer because VRA-NED is one of the subordinate departments of VRA. The Environmental and Sustainable Development Department of VRA gives necessary support for VRA-NED.

It is, therefore, important to reinforce environmental management system of ECG and VRA-NED. Although potential impacts regarding power distribution network are limited, certain impacts caused by construction of primary substations and handling of PBC and CCA waste are predicted. To tackle with such projects appropriately it is necessary to develop mitigation measures and monitoring mechanism, and to take these measures without fault.

ECG and VRA-NED in general utilize the services of consultants in implementation of monitoring and EMP. It is effective to utilize the services of consultants under the limited human resources, but staff of ECG and VRA-Ned should acquire capacity to determine the TOR of consultants and to effectively supervise their activities. Efforts to enhance staff’s capacity are, therefore, critical for the better environmental management system.

The EMP document itself is unmeaningful unless the measures included in the EMP are implemented at field level. Thus the capacity of individual staff, including field engineers, should be enhanced. It is, therefore, necessary to provide information related to EMP to the individual field engineers and technicians, and to develop the training program of environmental conservation for them.

Furthermore, no environmental officer is appointed in the regional offices of ECG and VRA-NED. Therefore, each regional directors need to deepen their understanding towards environmental and social considerations. It is also important for the directors to make efforts to increase staff’s awareness and enhance staff’s capacity related to environmental and social issues.

8. 4. 7 Stakeholder Consultations

(1) Implementation policy of stakeholder consultations

It is impossible to identify Project-Affected Persons (PAPs) since the Master Plan does not specify the exact locations of individual projects. This ESC study, therefore, hold a series of alternative meetings with stakeholders including local farmers, chiefs and district assembly members. The meetings aim to ascertain potential impacts in advance, and to clarify points to consider at the F/S phase.

1) Implementation of alternative stakeholder meetings

In this ESC study, alternative stakeholder meetings with district assembly members, farmers and chiefs in the areas where some projects are expected. The opinions and comments raised in the meetings can be utilized to identify necessary points to be discussed in the stakeholder meetings at the project implementation stage.

2) Clarification of right timing and agenda of stakeholder meeting

It is necessary to hold stakeholder meetings after the locations are specified and PAPs are identified. The ESC study ascertained potential impacts through Initial Environmental Examination (IEE), and then clarified important aspects to be checked in the meetings. The Study Team also shared the process of alternative meetings with the counterparts.

(2) Alternative stakeholder meetings

This ESC study holds a total of three (3) alternative stakeholder meetings with representatives of local residents.

Table 8-13 Outline of Alternative Stakeholder Meetings

Date	Location	Electrification Status	Participants	Expected project
3 Oct 2007	Savelugu Nanton District, Northern Region	Partly electrified	District Assembly Officer (Coordinating Director, and 3 officers)	Extension of Distribution Line
15 Feb 2008	Prampram District, Greater Accra Region	Partly electrified	District Assembly Member, Farmer, Station Master, Stone and Sand Vendor, Student	Construction of Primary Substation and Sub-Transmission Line, Extension of Distribution Line
19 Feb 2008	Elmina District, Central Region	Electrified	EDINA Traditional Council (21 chiefs around Elmina)	Construction of Primary Substation and Sub-Transmission Line

Source: JICA Study

Significant impacts are not necessarily predicted in the areas where these meetings were held. However, listening to representatives of local residents is effective to identify potential impacts and to clarify points to consider. Major comments raised in the meetings are the following.

- Positive impacts of electrification
  - Living standards of local residents greatly improved. **[Savelugu Nanton, Prampram, Elmina]**
  - Electrification activated local economy and increased employment opportunities. **[Prampram]**
  - Electrification enabled agricultural irrigation. **[Prampram]**
  - Street lights improved living conditions and increased safety. **[Prampram, Elmina]**

- Negative impacts of electrification
  - Land-use will be restricted during construction works. Temporary disturbance of living environment will be caused by noise and dust. **[Prampram]**
  - Electricity changed the lifestyle of local residents (staying up late, TV watching). **[Savelugu Nanton]**
- Involuntary resettlement and land acquisition
  - Participants accepted involuntary resettlement and land acquisition as long as enough consultations and compensation were made. **[Savelugu Nanton, Prampram, Elmina]**
  - It is important to consult with land owners with proper title, but the consultations with chiefs and opinion leaders are also critical. **[Savelugu Nanton, Prampram, Elmina]**
- Land and area to be given due considerations in selecting location
  - Sacred grove, shrine, cemetery, cultural heritage, irrigation dam, culturally valuable tree, houses and building, farm land, economic forest should be noted. **[Savelugu Nanton, Prampram, Elmina]**

Many participants expected positive impacts of electrification such as improvement of living standards. Land acquisition and involuntary resettlement are considered acceptable as long as proper consultations and sufficient compensations are made. It should be highlighted that many participants pointed out the necessity of consultations with chiefs and other traditional authorities as well as land owners. In terms of land and area to be given due considerations, sacred grove, shrine and cemetery should be counted in F/S.

(3) Stakeholder meeting at project implementation stage

There are four phases from formulation of Master Plan to implementation of construction works.

1) Master Plan (M/P) phase
2) Feasibility Study (F/S) phase / Basic Design Study (B/D) phase
3) Detail Design Study (D/D) phase
4) Construction phase

Necessary measures regarding stakeholder meetings at each phase are described below.

Table 8-14　Stakeholder Meetings at Each Phase

Phase	Concreteness of Plan	Necessary Measures regarding Stakeholder Meeting
M/P	Exact locations of facilities are not specified	1) To ascertain land-use characteristics and existence/nonexistence of land to be given due considerations, and to identify potential impacts. 2) To consult with representatives of local residents (District Assembly members, chiefs and opinion leaders) and/or the regional offices of Forestry Commission and Environmental Protection Agency, in case that certain candidate sites can be identified. 3) To roughly identify stakeholders to be consulted and points to be consulted at the F/S phase based on the information identified in 1) and 2). In this ESC study, impacts related to involuntary resettlement and land acquisition and cultural heritages (e.g. sacred grove, shrine and cemetery) caused by primary substation construction should be given due attention.
F/S B/D	Exact Locations and specifications of facilities will be determined through field investigations. If f/S cannot specify the details, B/D or other study may be conducted.	1) To identify PAPs through field investigations, and to hold consultations with PAPs to obtain their agreements on project implementation. 2) To hold consultations with people whose lands and properties will be affected, and to obtain their agreements regarding land acquisition and resettlement, in case that land acquisition and resettlement and/or impacts on economic activities are expected in the F/S. 3) To consult with District Assembly members, chiefs and opinion leaders, and to obtain their agreements on project implementation. To collect information on land to be considered (e.g. sacred grove, shrine and cemetery) and land-use characteristics. 4) To consult with the regional offices of Forestry Commission and Environmental Protection Agency, and to collect information on points to consider.
D/D	Detail specifications of individual facilities are determined.	Stakeholder meetings are not expected to be held at D/D phase because locations and specifications are in general determined at F/S phase. However, in case of protracted negotiation related to land acquisition and other issues, continuous consultations will be necessary.
Construction	Construction and installation of facilities	Stakeholder consultations are unnecessary after the initiation of construction works. However, if the construction plan is modified, additional consultations may be necessary. In addition, holding stakeholder consultation is considered effective as part of monitoring activities.

Source: JICA Study

It should be noted that all projects included in the Master Plan will not necessarily be required to hold stakeholder meetings. For instance, construction of distribution networks is not expected to cause significant environmental and social impacts, thus stakeholder meetings are not necessary in general. On the other hand, construction of new primary substations requires acquisition of land, thus, stakeholder meetings are expected to be necessary in many cases.

The stakeholders to be consulted and important aspects to be kept in mind in terms of stakeholder meetings at the F/S stage are indicated below.

1) Stakeholders to be consulted

The following stakeholders should be consulted at minimum.

- Local residents affected by projects
- Local residents whose land and other properties are acquired, and those who are forced to be relocated, including those without land title.
- Chiefs
- Elder people (opinion leader)
- District Assembly and other local government

In particular, agreements from chiefs as traditional authorities are critical to initiate projects. In addition, consultations with the regional offices of Forestry Commission and Environmental Protection Agency will be effective to ascertain the distribution of protected areas and natural ecosystem.

2) Important topics of stakeholder meetings

The following impacts should be taken into account in the stakeholder meetings at the F/S stage since the impacts can be significant.

- Involuntary resettlement
- Impacts on agricultural activities and other economic activities due to land acquisition

It is desirable to mention the following impacts in the stakeholder meetings.

- Impacts on local landscapes
- Inequality/ Separation in society
- Protected area/ Ecosystem
- Geological features/ Natural landscape

8. 5 Points to consider at the Project Implementation Stage

The Master Plan does not specify the exact locations of individual projects. Thus, ESC study should be carried out when the locations are determined at the project implementation stage. This section presents points to consider in conducting ESC study at the project implementation stage.

(1) Execution of necessary procedures of legal framework

Environmental Assessment Regulations 1999 requires certain categories of projects to conduct Preliminary Environmental Assessment (PEA), i.e. “construction and installation of substations equal and above one (1) MVA in the transmission and distribution networks”, “decommissioning of old transformers with specific reference to handling of polychlorinated bi-phenyl (PCB) additives in transformer oil”, “storage, recycling and disposal of transformer oils”, and “storage and disposal of chemically treated wooden poles with specific reference to the use of Copper Chrome Arsenic

(CCA)". In addition, "Medium voltage lines, 11 kilovolt (kV) and 36 kV (voltage class) inclusive, not passing through environmentally sensitive areas" are required to be registered to the Environmental Protection Agency (EPA). It is, therefore, critical to take necessary procedures in consultation with EPA when these projects are carried out.

(2) Environmental and social consideration study in reference to locations

It is necessary to make a scoping report when PEA and ESC study are conducted. When considering the scoping report, environmental and social impacts should be thoroughly examined in reference to the location planning of facilities. In general, a construction site for a primary substation and a route of sub-transmission line and distribution line will be specified at the F/S phase, thus, detail assessment of involuntary resettlement and land acquisition, and impacts on protected areas and ecosystems will become possible.

In the ESC study at the F/S phase, it is necessary to reconsider mitigation measures according to local characteristics, in reference to mitigation measures described in the section 8. 4. 4. If impacts related to land acquisition and involuntary resettlement are predicted, stakeholder meetings should be properly carried out, taking into account the stakeholders and points to consider indicated in the section 8. 4. 7 (3). Traditional authorities such as chiefs and elder people should be given due considerations.

(3) Considerations for alternative locations

In elaborating mitigation measures, the first priority should be put on seeking the alternative locations to avoid potential impacts. In case of unavoidable impacts, measures to minimize the impacts, or mitigation measures such as compensations are taken into account. In terms of projects included in the Master Plan, it is, therefore, essential to avoid locations where serious impacts are predicted, such as areas with high population density, protected areas and valuable landscapes. F/S should prepare more than one option regarding location selection, and determine the final location taking into account environmental and social impacts of each option.

(4) Environmental Management System

In case that projects included in the Master Plan are expected to have certain impacts, it is necessary to establish an Environmental Management Plan that addresses environmental measures and monitoring at the operational and maintenance phase as well as environmental measures at the construction phase. In particular, the reinforcement of the environmental management system of ECG and VRA-NED can be considered become important since proper disposal system of PCB and CCA waste is required to be established. ECG and VRA-NED at present do not poses sufficient environmental management system. Therefore, it is essential for ECG and VRA-NED to establish an effective management system that can handle the whole environmental management cycle, including the formulation, implementation, and evaluation of the management system. Furthermore, providing training courses of environmental conservation to individual engineers and technicians is also important.

Chapter 9 Current Status and Issues of the Distribution Business Management

9.1 Human Resource Development

9.1.1 VRA-NED

(1) Outline of the training system

The NED training system is integrated with that of the VRA. The VRA has standard programs for basic training. If the NED needs a new training, the training coordinator prepares a training plan. Requests for new training are compiled by the training coordinator and sent to the VRA training section in Akuse.

Using its own budget, the NED implements ad hoc training necessary for their specific purpose. The majority of it is new-staff training and carried out by consultants, if necessary. In many cases, ex-officials engage in the training as consultants. Most of this training is related to technical operations.

(2) Training for new-staff

New staff members are compelled to participate in the training.

If hired as technician, they must complete the two-year training program and are then qualified as “technician.” In case of the NED, new staff members must complete seven courses for the operation and maintenance (O&M) of electrical equipment and five courses for line O&M.

If the university graduates are hired as engineers, they must complete the management training after finishing the on-the-job training of the technical division. Through the management training, they learn corporate rules and report writing. Finally, they receive interviews with managers and are assigned to their posts.

(3) Training for the existing staff

To be promoted in the organization, staff members must complete training for individual steps. The aforesaid two-year training program for technicians and the management training for engineers are the first step of the training.

The manager of each section evaluates his/her staff, nominates the persons who will receive training, and makes requests for staff training to the Human Resource Department.

Another way of selecting trainees is to have it done by the organization.   For example, a person nominated for promotion is instructed to receive the requisite training.

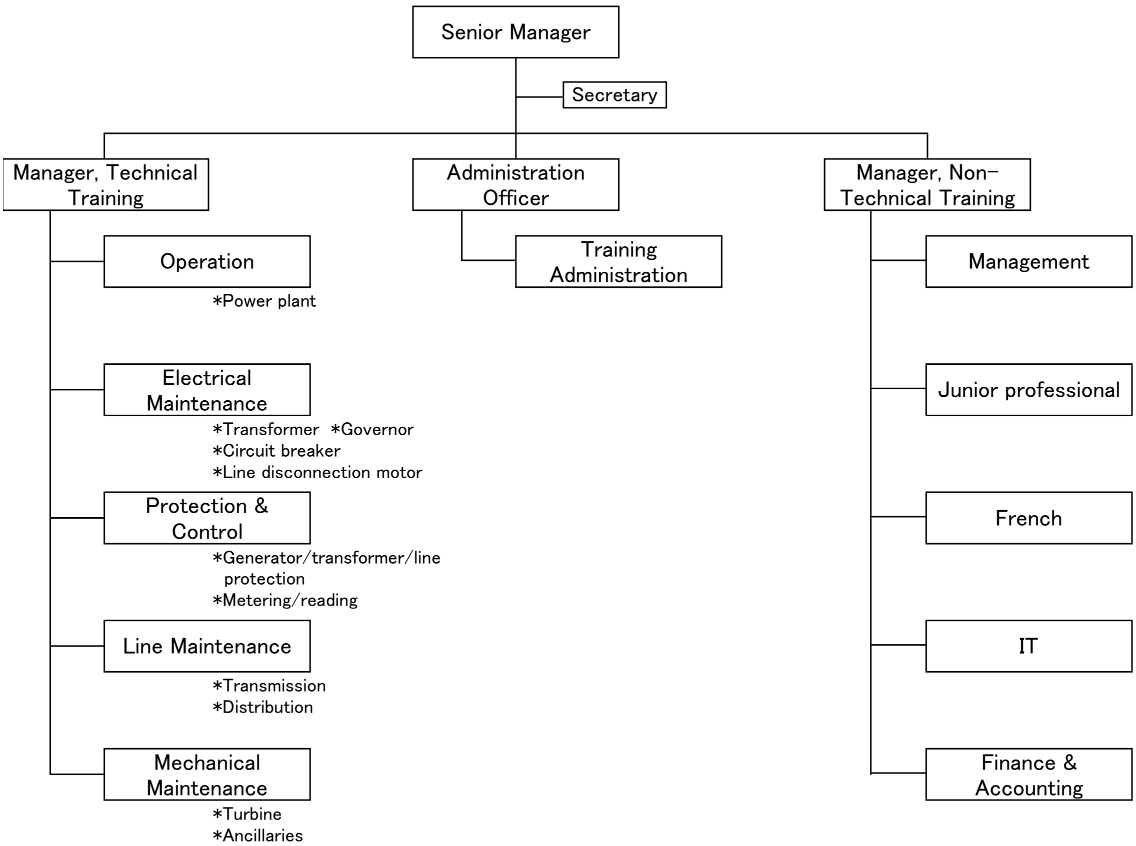
(4) Training Division in Akuse

The training division in Akuse (i.e., in-house training) conducts technical and non-technical training separately.   This training is implemented using the standard program shown in Figure 9-1and Table 9-1.

The majority of the technical training programs are related to power generation, which is the main part of the VRA business.   Training related to the distribution work of the NED is carried out in the line maintenance course.

Meanwhile, for non-technical staff (i.e., staff of the administration division and supporting staff), the division provides training courses in management, the French language, computers, and finance/accounting.

Figure 9-1: Organizational Structure of the Training System



Source: VRA

Table 9-1: In-house Training Courses of the VRA, 2006

Name	Details
Technical Courses	Electrical Maintenance Session, Electrical Distribution Network Operation, Electrical Distribution Equipment Maintenance, Operating Session, Generator Statistic Exciters/Electronic Governors, Thermal Plant Protection and Control, Numerical Protective Relays, Electronic Meters, Fiber Optic Systems, Basic Hydraulic, Alignment, Vibration and Balancing, Lubrication, Basic Welding, Material Handling, Piping and Fire Protection, Plant Maintenance Practice, Workshop Practice, Maintenance Management Refrigeration & AC, Line Maintenance Session, Service Centre Technicians Session
Management and Administrative Courses	Report Writing, Management Training Program, Supervisory Skills, Leadership Skills, Business Planning and Budgeting, Customer Care/Relation/Service, Team Building & Development, Effective Supervision, Human Relations & Communication Skills, Performance Appraisal, Time Management, Performance Monitoring and Evaluation, Senior Staff Orientation Program, Communication Skills, Project Management, Performance Management, Communication and Interpersonal Skills, Training of Trainers, Change Management, Interpersonal Relations, VRA Work Ethics & Core Values, Negotiation and Persuasive Skills, Introduction to Human Resource Management, Post-Graduate Certificate in Organizational Development
Finance Courses	Computron Financial System, Basic Accounting/Finance for Finance Staff, Business Planning and Budgeting, Finance & Material Management
Junior Professional Curses	Secretarial Development, Intermediate Security Course, Clerical & Administrative Course, Defensive Driving, Basic Security for Watchmen, Clerical and Administrative Development, Introduction to Health & Safety, Records Management, Technical French
French Language	Technical French, Refresher Group, Business French
Computer Courses	Basic Computer Skills, Intermediate Computer Skills, Advanced Computer Skills
Local External Courses	

Note: These programs cover 60% of the in-house programs of 2006. Additionally, other programs are prepared based on requests from each field operation.

Source: VRA

(5) Results of the training

In 2006, 1,442 personnel out of the 3,673 eligible staff members participated in the training, for a training rate of 39%.

There are three types of training: VRA in-house, field, and overseas training. The VRA in-house training accounted for the vast majority of the number of trainees at 1,312, followed by field training at 98 and overseas training at 32.

Total cost of the training was GH¢743,000 (US$800,000 or ¥96 million). The majority of this total was occupied by the cost of the overseas training. Needless to say, this is due to the price deference between Ghana and the other countries. The average training cost including all types of training was GH¢515 (US$550 or ¥66,000) per person.

Table 9-2: Results of the VRA Training, 2006

Types	No. of Courses	No. of Staff	Cost (¢)	Cost Ratio
In-house	113	1,312	3,218,074,512	43%
Field	37	98	534,063,400	7%
Overseas	23	32	3,678,841,338	50%
Total	173	1,442	7,430,979,250	100%

No. of the eligible staffs, as of May 2006	3,673
No. of trainees	1,442
Training rate	39%
Average cost of training per person (¢)	5,153,244

Note: ¢ is old cedi. ¢10,000 are equivalent to GH¢1 (one new cedi)

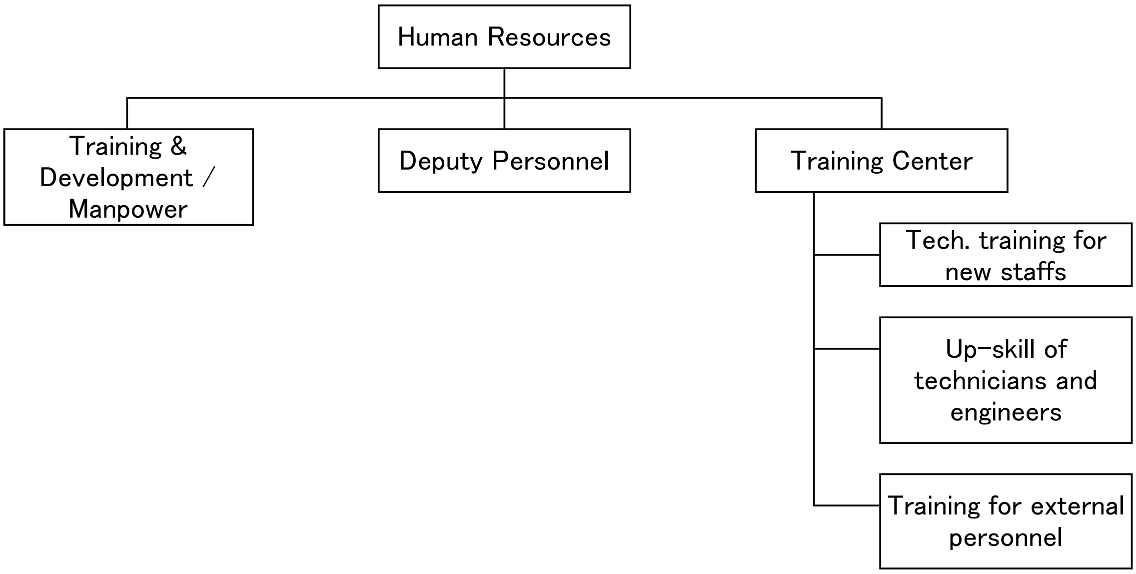
Source: VRA

9.1.2 ECG

(1) Outline of the training system

There are three divisions under the Director of Human Resources: the Training Center providing the technical training, the Training and Development/Manpower providing the training for supporting staff and managers, and the Deputy Personnel’s office, which functions as the secretariat.

Figure 9-2: Structure of the ECG Human Resources Department



Source: ECG

(2) Training Center

Eight trainers engage in technical training. Since the ECG is a distribution company unlike the VRA, all the training is electrical and there is no training for machinery.

The most important task of the Training Center is the training for the newly hired technicians. It trains around 40 new staff members every year. This training is furnished only for technical staff. The center does not provide any specific training for the engineers who graduated from universities; it only instructs them in general corporate rules.

Another important task is to retrain the existing technicians who did not receive the new-staff training. Around half of the trainees are staff members who have been already assigned to field operations without receiving the initial training. The other half are staff members who receive the training to improve their skills.

The center has several problems. One problem is that its facilities are too old and not on a sufficient high level in terms of both quality and quantity, and need upgrading. Another problem is that the training targets only technical staff, and that the center's system is not equipped to provide high-level training including instruction in new technology.

(3) Results of the training

There are two types of training: overseas training and local training at the center. The local training also has three courses: in-house training for new staff members, open course training for which external personnel are also eligible, and a staff facilitation program for the existing personnel. In addition, training services using external consultants are also offered.

The budget for training in 2007 is GH¢1.26 million[1] (US$1.35 million or ¥160 million). While this figure is 70% larger than GH¢743,000 of the VRA budget in 2006, the number of the ECG employees is also proportionately bigger. On the per trainees basis, the budget sizes of the two companies are roughly the same.

Table 9-3: Results of Training, First half of 2007

	No. of Programs		No. of Staff	
	1Q2007	2Q2007	1Q2007	2Q2007
Overseas Training	9	15	40	45
Manager			38	13
Senior staffs			2	32
Local Training			59	420
Open programs	9	7	17	9
Staff facilitation programs	8	3	42	195
In-plant programs	0	3	0	216

Source: ECG

Table 9-4: Budget for Training, 2007

Category	Budget (¢)
Overseas	6,894,790,000
In-house	5,222,530,000
Consultancy service	3,800,000,000
Engineer	200,000,000
Accounting System	2,700,000,000
Human Resources	800,000,000
Audit	120,000,000
Total	12,600,000,000

Source: ECG

[1] ¢12.6 billion

9.1.3 Issues Related to Training

(1) Issues in the Training Center as distribution company

The VRA, which has larger organization[2] and better financial position, has much more comprehensive programs than the ECG. This is true if we observe the whole VRA organization. However, since the major business domain of the VRA is power generation and transmission, we must carefully discuss the direction of how to set up a desirable organizational system for training.

In terms of basic training for technicians working in site operation, the ECG system is well organized. Furthermore, the ECG also provides the new-staff training service for the NED. However, the basic training for new staff members is only one of the training programs in the company. In particular, the issue of how to build the capacities of the senior-class engineers and managers is very important. It is indispensable for a corporate organization to acquire new technology, introduce new management procedures, and absorb new information technology, which is progressing day by day. In this context, the ECG's training system to build up capacity among the existing staff is evidently weak as compared to that of the VRA[3]. The capacity-building program for senior staff including managers must be beefed up.

As discussed internally in the ECG, this is the time to compile a concrete vision for renovation of functions at the Training Center.

One idea is to enrich the training curriculum, which is now limited to the training for technicians (and especially new-staff members), and establish new training programs for senior engineers. To do so, however, would requir solution of the existing problems, i.e., the outdated state of the present facilities and hardware in particular, the small number of books in the library, and relative rack of acquisition of new publications. There is a need to retrain trainers and increase the number of trainers.

(2) Advisable shape of the Training Center upon future reorganization of electric utilities

It is also important to contemplate the advisable shape of the Training Center under the environment of the currently discussed plan for power sector reform and reorganization of distribution companies.

---

[2] If we focus only on the number of employees, the ECG has bigger than the VRA. This is because the power distribution is much labor intensive than generation and transmission.

[3] As mentioned by the participants in the second workshop, the period of the training course for the existing staff is only six months, while that of the VRA is one year.

It would be possible to make the Akuse training division and the ECG Training Center independent and use them as training facilities owned in common by the newly reestablished generation, transmission, and five distribution companies in the future. In this case, the following questions must be considered:

- How can the distribution-line curriculums of the line maintenance program of the VRA training division and the training program of the ECG be integrated?

Is it appropriate to integrate the senior-class engineer and manager training that is the weakness of the ECG training system into their distribution training program? If the distribution companies design a new training program for senior staff members, is it realistic for the ECG Training Center to imperilment it in light of the experience and training results of the center?

(3) Diversification of career paths

For human capacity development, it is necessary to diversify staff career paths. For engineers, there is at present only one career path, i.e., promotion to manager in his or her job-line. Therefore, an engineer receiving a training program must go back to his or her original position.

However, another option for career development must be prepared. For example, the staff members should not have their job-line fixed but be given the chance to choose another career path such as specialist. Giving the staff member a different task after the training will heighten his or her motivation for the job. From the viewpoint of career-path diversification, it is advisable to instate a new system whereby highly skilled engineers serve as trainers in training for newly employed and existing middle-class engineers.

9.2 Setup of the Power Tariff

Low end-user tariff has remained a large problem for the power sector in Ghana. Insufficient investment and the financial difficulty of ECG and VRA-NED has one of its major causes here. As a result, these entities requested a significant tariff increase to PURC. PURC recognized the issue, and started to raise the tariff in steps starting from May 2006.

The average end-user tariff in spring 2006 was 740Cedi/KWh. PURC had planned to raise this figure to 1277Cedi/Kwh over the course of 2 years. The largest increase was to be seen for residential use, where 583Cedi/KWh will be raised to1200Cedi/Kwh, more than double the amount.

Originally, PURC intended to achieve this through a series of raises, first in May 2006, second in August 2006, and finally in November 2007. The gradual raise would have made it easier for the end-user to deal with. However, at the time of the raise in 2006, the government of Ghana has decided to cover the increase with government money. As a result, the end-users never saw the actual increase. This policy was discontinued in 2007, and with the next increase, consumers are likely to be hit by a sudden doubling of the tariff. There seems to be strong resistance, and the outcome is not clear as of this writing.
Another improvement was the narrowing of the life-line tariff, which was kept politically low and was causing a distortion in the demand.

On the whole, it is clear that tariff increase is necessary. It must cover various costs, including the O&M and replacement costs. Currently, PURC is undertaking a study to figure out the proper tariff level, which should affect the overall policy. However, the issue is duly recognized and addressed, which is a good sign.

9.3 Organization for Tariff Collection

9.3.1 VRA-NED

(1) Flow of meter reading and billing

The VRA-NED implements meter reading and billing once a month. Work for meter reading is outsourced to individuals, although the ECG also commissions this task not to people but to a company. This is the deference between the two companies.

Five regional offices (i.e., Tamale, Sunyani, Bolga, Techiman, and Wa) each have their local service offices. Between the 1st and 10th day of each month, the meter reader visits each customer, records the meter reading manually, and brings the record to the local service office. Up to this stage, the record is not digitalized but handwritten.

The regional office certifies the handwritten meter-reading records brought from the local service offices. Here, “certify” means to check to see whether each customer record shows a substantial difference between the current and the previous months, and whether the record contains a figure that is unusual as compared to the average.

The regional office issues bills based on the data input on meter reading. The bills are distributed to meter readers through the local service offices. Each meter reader hands over the bills of the previous month to customers on the occasion of meter reading in the following month.

As regards the scale of this meter reading and billing system, the Tamale regional office, for example, has 20 sub-regions. This sub-region is called a “cycle.” Each cycle is composed of much smaller regional segments called “roots.” There is one meter reader for each root. Each root has about 100 customers, and each cycle, five roots. In the case of Tamale, one regional office controls four or five cycles.

The meter reader is paid based on the number of customers whose meters he/she reads. If he/she makes mistakes in reading three times, the fee is reduced beginning with a next mistake.

The reason why, unlike the ECG, the NED commissions the meter reading and billing work to individuals instead of a company is that it is less expensive and enables direct control over the reading. The local service office concludes a contract with each meter reader.

(2) Organization for tariff collection

Tariff collection is conducted by not the meter readers but the so-called “bonded cashiers” who are also commissioned individually. Their fees are also paid on a performance basis (i.e. amount of money collected).

Unlike the meter reader, the bill collector works five days a week, with Saturdays and Sundays off. This is because of the need to prompt payment by non-paying customers as much as possible.

The bill collector issues a receipt composed of three copies, two of which are carbon copies. One is for the customer, another, the NED, and the last copy, the bill collector.

Once a week, the collected money is brought to the local service office. The bill collector hands over the copy of the receipt to the NED as along with the collected money. All the receipts are recorded in the regional office, and this information is reflected in the bill for the following month (the payment record of the previous month is shown in the bill for the next month).

The money collected by the local service office is deposited in the NED bank account, but the handwritten information on it (i.e., on receipts) is sent to the regional office.

(3) Delayed payment and the current status of uncollected bills

Payment by customers chronically late. Except for the years 2000 and 2006, the amount of money collected for a given month has come to only 70 – 80% of the billed amount in the same month (See Figure 9-3). The reason why this rate is over 100% in 2006 is presumably that one large customer paid the entire previously unpaid bill at once.

The cumulative amount of arrears is equivalent to the amount of the uncollected bills. The ratio of the uncollected bills to the turnover is very high. From 2000 to 2006, there was a large amount of unpaid bills equivalent to 200 days (debtor/sales ratio).

This situation of delayed payment and uncollected bills is worse at the NED than at the ECG as discussed latter on, and it appears that the situation has not improved, judging from past statistics.

In the past, the government and government-owned companies often delayed their payments, but they became to pay on schedule although they pay a lump sum for every quarter[4]. At present, customers who tend to be late in paying are private-sector ones in the residential/commercial and industrial segments.

(4) Measures for unpaid bills

There is a rule that, if a customer is late to pay bills, the utility may stop the power supply after a 30-day grace period. However, large companies often resort to political intervention by asking the government to prevent or halt the power supply suspension, and the rule does not always work effectively.

The VRA-NED is going to introduce the following measures to reduce unpaid bills:

- Replacement of credit meters with prepayment meters. To promote the spread of the latter, the NED will allow differed payment of six months for those customers who are willing to replace the current credit meters with prepayment meters.
- Use of the old credit meters replaced with prepayment meters for rural customers who are not metered at present. For this purpose, the NED will reduce the number of the customers to whom flat rates are applies at present due to the lack of meters.

[4] ECG interview.

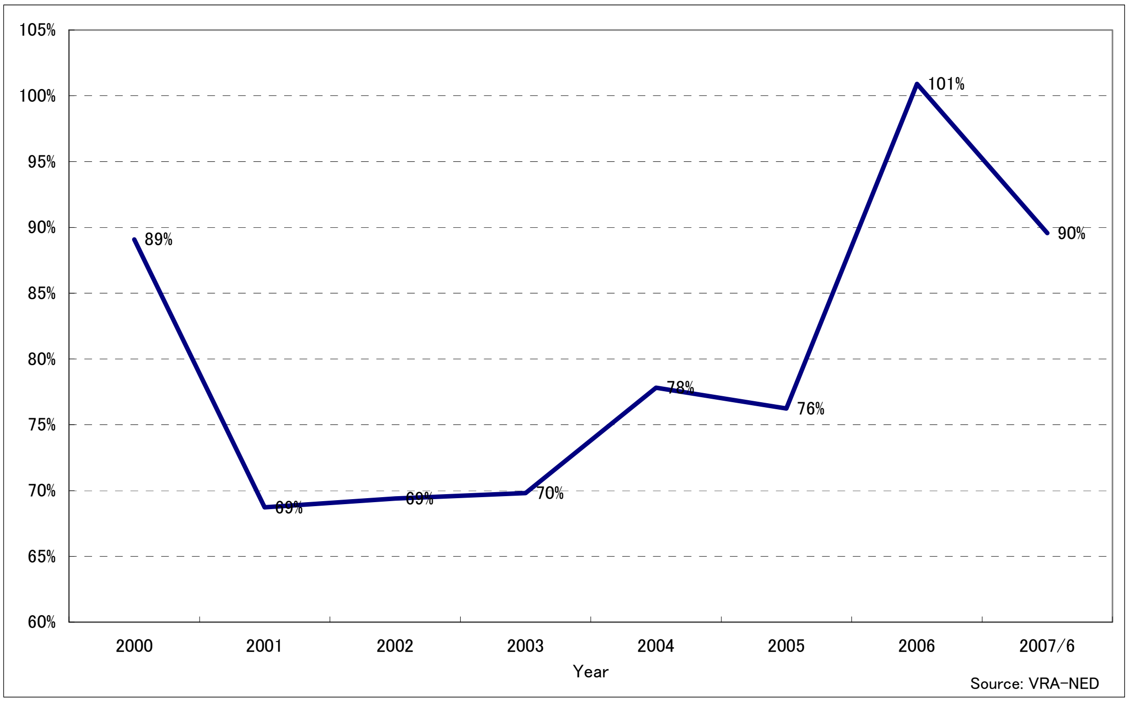


Figure 9-3: Revenue/Sales Ratio of the VRA-NED

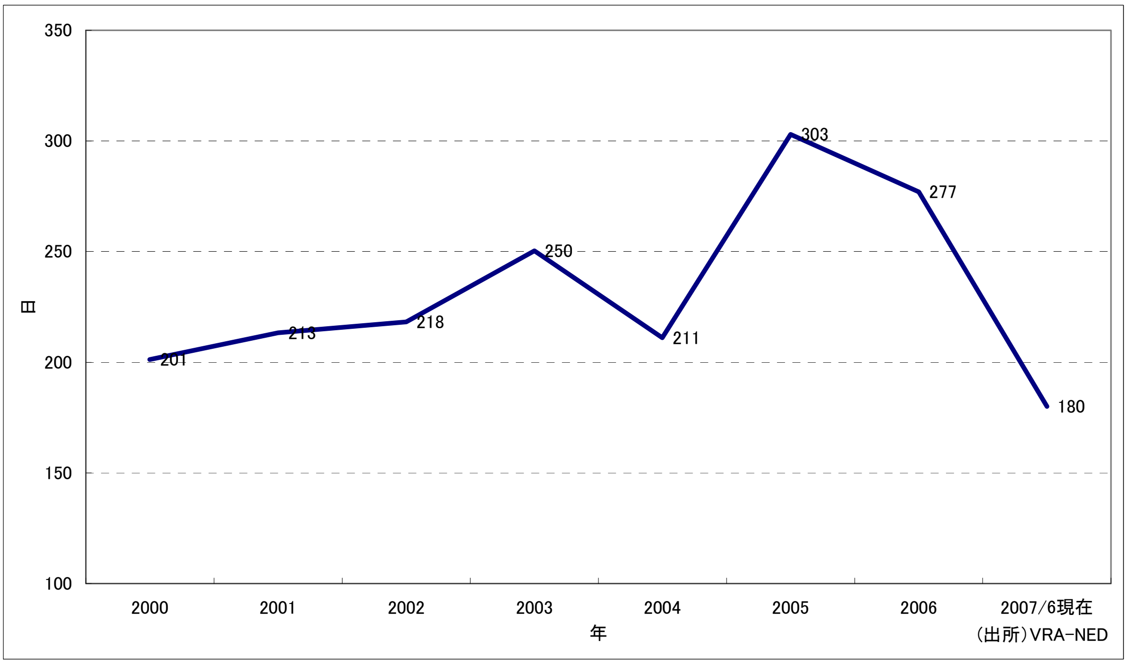


Figure 9-4: Debtors/Sales Ratio of the VRA-NED

Table 9-5: Sales and Debtors Position of the VRA-NED

	2000	2001	2002	2003	2004	2005	2006	June 2007 (GH¢)
Total Sales Position (¢ mil)	44,624	81,002	128,930	203,476	259,732	279,347	289,568	15,580,885
Revenue Collection (¢ mil)	39,751	55,675	89,476	142,056	202,106	212,989	292,191	13,956,120
Revenue/Sales Ratio	89%	69%	69%	70%	78%	76%	101%	90%
End-of-Year Debtors Position (¢ mil)	24,602	47,344	77,064	139,594	204,356	231,834	219,759	234,028
Debtor/Sales Ratio (days)	201	213	218	250	211	303	277	180

Source: VRA-NED

9.3.2 ECG

(1) Flow of meter reading and billing

Credit or prepayment meters are installed at all customers locations.

Meter reading and billing are outsourced. Meter reading is conducted every month, and bills are issued two weeks after the meter reading. A customer receiving a bill pays at the nearest service office. When the customer pays the bill, the ECG checks the bill amount of the month in question by comparing it with that of the previous month.

When a customer receives the bill, he/she must pay it within two weeks. If the payment is not made during this period, power supply will be stopped. Furthermore, if the customer does not pay within the next month, the meter will be removed.

Information on the issuance of bills and the conditions of payment is controlled by computer. Two days after the payment is done, this information is registered on the computer. Disconnection of power at the premises of customers who do not pay their bills is executed based on this information.

(2) Delayed payment and the current status of uncollected bill

Customer payments are usually two or three months late in actuality. The amount of revenue collection in a given month is comes to 80 – 90% of the sales in the same month (See Figure 9-5). Although the situation is slightly better than that at the VRA-NED, more than 10% of the payment is always delayed.

The ratio of cumulative unpaid bills to sales is high. As shown in the statistics for the period 2000 - June 2007, uncollected bills were constantly equivalent to 130 –180 days. However, the debtors/sales ratio exhibits a declining trend over in the last few years.

With regard to the makeup of the customers who are late to pay, the largest group is the customers categorized in the residential/commercial sector, who account for two-thirds of the total. They are followed by private industries, the water utility, and governmental offices.

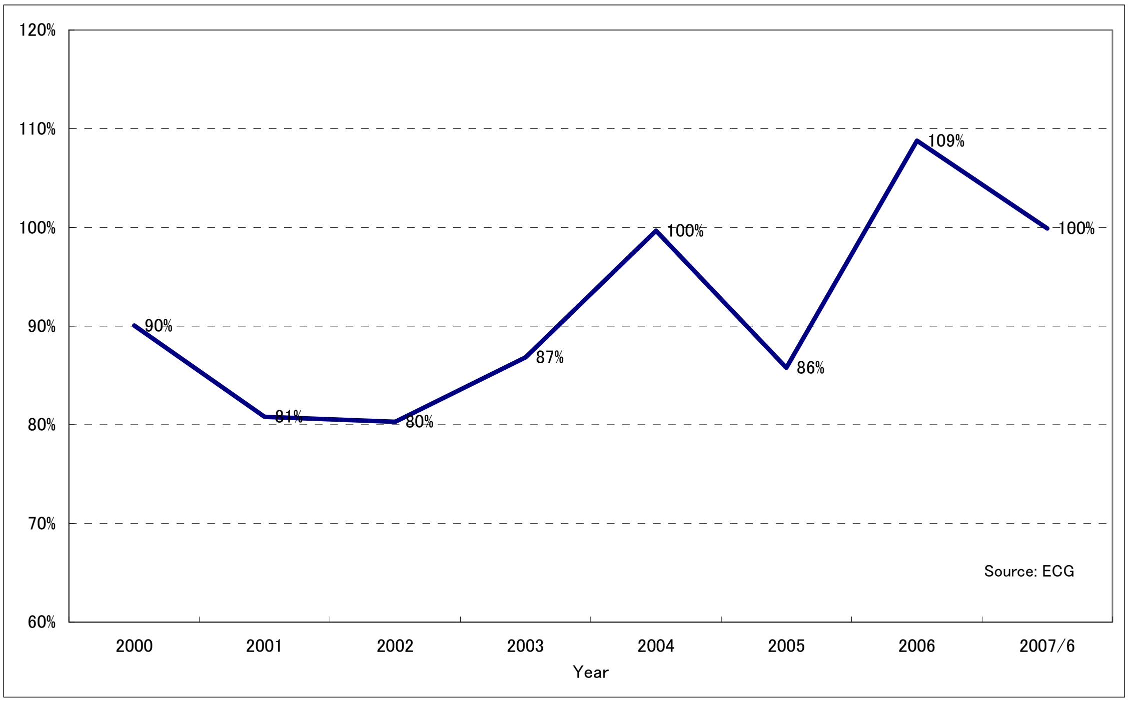


Figure 9-5: Revenue/Sales Ratio of the ECG

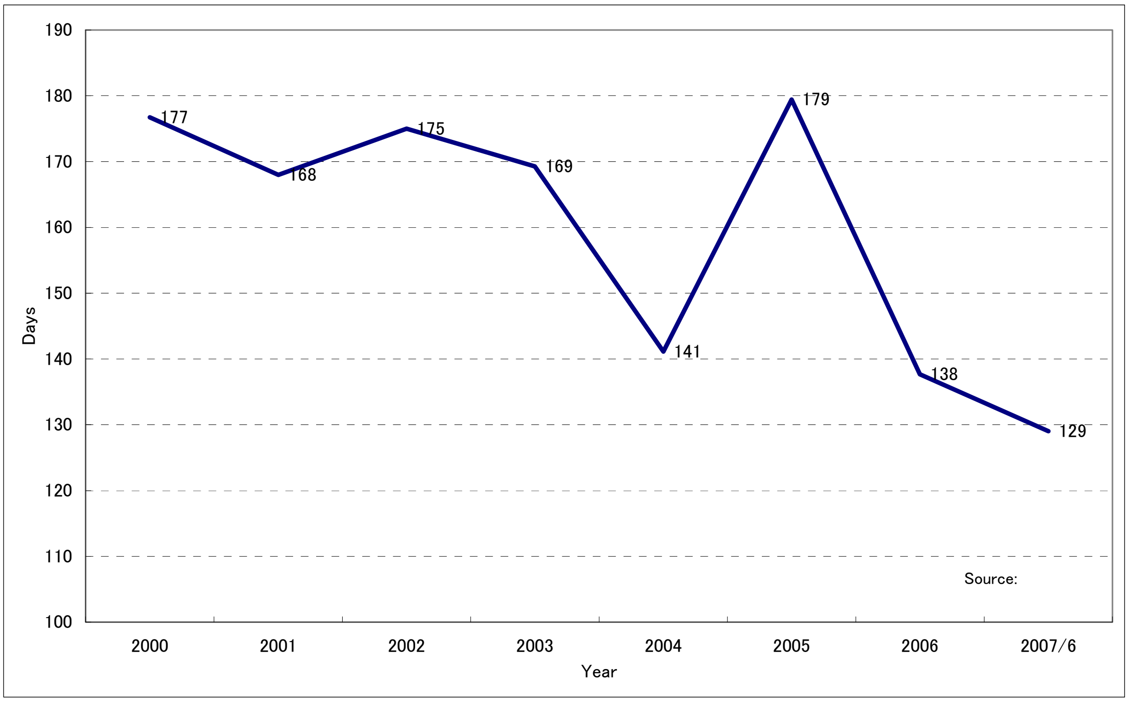


Figure 9-6: Debtor/Sales Ratio of the ECG

Table 9-6: Sales and Debtors Position of the ECG

	2000	2001	2002	2003	2004	2005	2006	June 2007 (GH¢)
Total Sales Position (¢ mil)	591,236	1,089,148	1,675,212	2,433,726	2,746,519	2,963,897	3,112,799	158,239,952
Revenue Collection (¢ mil)	532,499	880,055	1,345,347	2,113,367	2,737,553	2,542,233	3,386,689	158,094,846
Revenue/Sales Ratio	90%	81%	80%	87%	100%	86%	109%	100%
End-of-Year Debtors Position (¢ mil)	286,270	501,339	803,286	1,128,690	1,061,936	1,457,133	1,174,200	112,783,018
Debtors/Sales Ratio (days)	177	168	175	169	141	179	138	129

Source: ECG

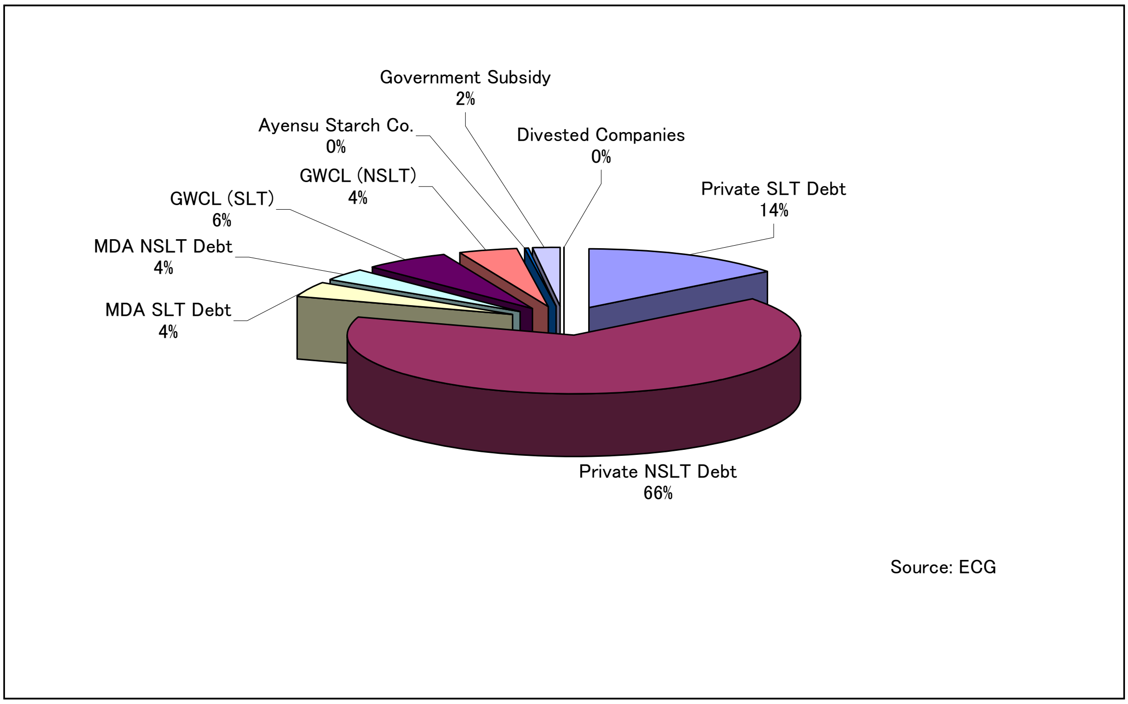


Figure 9-7: ECG Debt Breakdown in June 2007

(3) Measures for unpaid bills

The ECG will introduce the following measures to reduce the amount of unpaid bills:

- Introduction of data loggers to mechanize the meter reading work and save time.
- Expansion of the prepayment meter system. By the end of the next year, meters installed in the household sector will be completely replaced with prepayment meters.
- Establishment of the Revenue Protection Division to reduce the amount of unpaid bills. Measures will be made more effective by synchronizing the information on the status of unpaid bills and the implementation of line disconnection through the information network system. The number of customer service centers will be increased for this purpose.

9.3.3 Issues in the future

Both the ECG and the NED plan to reduce unpaid bill ratio by introducing the prepayment system. This is an appropriate measure because the effectiveness of the prepayment system has been proven in South Africa.

Although new problems as system failure will probably emerge in the actual implementation stage, they must be solved in the system installation program.

9.4 Improving the Financial Condition

In order to improve the financial condition of VRA-NED and ECG, the most important issue is the proper adjustment of the tariff. At the moment, the tariff is insufficient to cover the generation and transmission costs. Under such conditions, no major improvement can be expected.

VRA-NED and ECG are both at a loss. However, ECG's loss is relatively low compared to the sales, and the tariff increase since 2006 may have already had a significant impact already.
Also, looking at their operation, there are significant efforts made. The most significant is the introduction of pre-paid meters. VRA-NED eliminated a huge portion of the problem through this effort. It has also made efforts to visit the users to cope with issues of power theft, leading to lower system loss.

One of the large issues will be SHEP. At present, VRA_NED is forced some unprofitable end users and assets according to whims of pre-election politicians, which have made the situation difficult, causing increased labor costs. By re-considering the SHEP and introducing a more orderly electrification, VRA-NED's situation may improve significantly. Also, ECG will need to take measures to lower the system loss, through timely survey of their actual customers and meter improvements.

9.5 Distribution monitoring (measurements)

9.5.1 Recommended distribution monitoring items

(1) Power demand measurement

Studies of the prospect of reinforcing distribution facilities require monitoring of the power demand.

Generally speaking, measurements are taken at primary substations for the load on transformers and current on each medium-voltage distribution line. The findings serve as the basis for examination for plans to reinforce primary substations and medium-voltage lines.

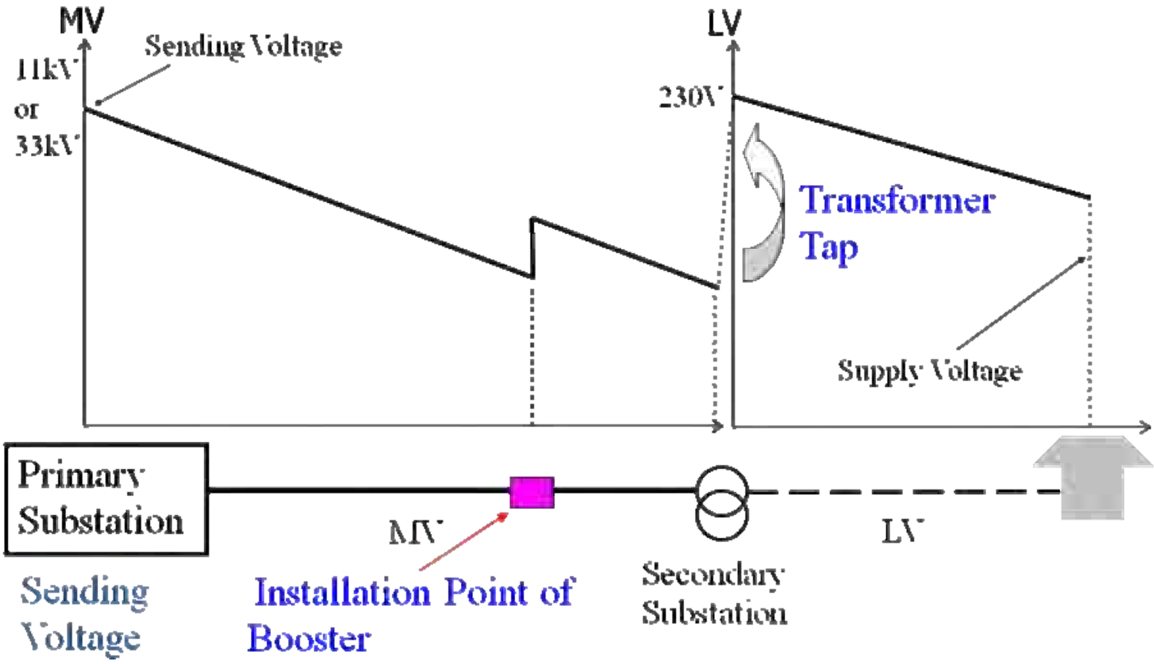
It is also necessary to measure current at distribution substations to provide data for studies of the prospect of reinforcing transformers at these substations and low-voltage distribution lines.

There are many such substations, and it would require a lot of labor to take measurements at each. For this reason, one option would be to make logical calculations of current values from data on customers connected to distribution substations and low-voltage lines. Application of this method, however, requires systematic analysis utilizing ICT.

(2) Voltage measurement

Management of voltage is vital for provision of a high-quality supply of power. Ordinarily, electric utilities establish standards for voltage at low-voltage power reception points. In Ghana, the maximum voltage is 438/253 V, and the minimum, 358/207 V. Therefore, voltage must be managed to see that the value at the utility reception points falls within this scope (i.e., range). Because standards have been set for the voltage scope on low-voltage lines, utilities must, properly speaking, check for conformance with them. Nevertheless, measurement of the reach-through voltage at all reception points would not be a practical option considering the large number of customers. As this suggests, it is important to measure current at reception points efficiently instead of uniformly for all points.

To keep the voltage on low-voltage lines within the standard scope, it is also necessary set target values for and manage the voltage drop on medium-voltage lines. Figure 9-8 shows the concept behind voltage management.



*Measurement of current and voltage with consideration of the characteristics of medium-voltage lines, load/capacity at distribution substations, and demand among customers

Figure 9-8 Voltage management concept

The voltage drop targets are no more than 7 percent at the ECG and 10 percent at the VRA-NED. These figures are only targeted ones. Even if the voltage on medium-voltage lines exceeds them, problems can be avoided by adjusting the tap on the distribution transformer to keep that on low-voltage lines in conformance with the standards. For the purpose of consistency in management, nevertheless, utilities should measure and manage the send-out voltage at primary substations.

9.5.2 Current status and issues

(1) Measurement of power demand

Both the ECG and the VRA-NED measure the power demand at manned primary substations.

When applications are received for new load at distribution substations, measurements are apparently taken of the existing demand to determine whether the load can be connected. It should be noted, however, that the load on transformers varies along with factors such as demand increase among existing customers and changes in the diversity factor along with those in lifestyle pattern. This points to the need for some degree of load management. The options here include periodic load measurement and management by logical calculation.

(2) Voltage measurement

Both the ECG and the VRA-NED measure and record send-out voltage at manned primary substations in units of distribution lines, every hour. Unmanned primary primary substations are equipped with measuring instruments, but apparently do not take regular measurements.

Ordinarily, measurements are not taken of voltage at the ends of medium-voltage lines. The Study includes the calculation of distribution line terminal voltage using simple software and the drafting of plans for reinforcement based on the results. This analysis does not go beyond the level of simple calculation, and the results may not indicate the actual voltage. Therefore, detailed design for construction requires examination of the option of measuring the actual voltage in the interest of a proper level of investment.

Measurements are taken for the reception voltage on low-voltage lines in the event of complaints from customers, for example. It would not be realistic to make periodic checks of the voltage for all customers as noted above, but this does not mean that utilities do not have to manage this voltage. The ECG is performing such management on the basis of data for low-voltage facilities and demand utilizing FACIPLUS, which could presumably be used for this management elsewhere. Another option would be to make checks by measuring the reception voltage on the occasion of connecting new customers to low-voltage distribution lines, for example.

9.6 Setup for distribution facility maintenance

9.6.1 Facility maintenance setup

9.6.1.1 Advisable type of setup

Figure 9-9 shows the general scheme of facility maintenance. Maintenance of distribution facilities, too, can be divided into two basic categories: preventive maintenance (to prevent distribution line failures from occurring) and post-occurrence maintenance (for swift repair in the event of failure). Preventive maintenance may be divided into two sub-categories: planned checks implemented periodically, and special checks implemented in the wake of natural disasters and focused on key points. There are two major methods of making checks: inspection, which consists of examination of individual facilities utilizing tools and instruments, followed by execution of suitable measures as necessary; and patrol, which consists of a visual check of facility exteriors. For post-occurrence maintenance, it is vital to have a setup enabling swift response to the occurrence of failures or trouble and replacement of the facilities requiring it.

(1) Preventive maintenance

Performance of preventive maintenance by making inspections and patrols of individual facilities is important for assurance of public safety and supply reliability. Excessive performance, however, could even have an adverse effect on the business because of the unnecessary expense entailed. Although utilities should perform mainly preventive maintenance for primary substations, whose failure would have a substantial effect on supply reliability, post-occurrence maintenance is the main type for the enormous amount of medium-voltage facilities, excepting those with a direct bearing on public safety. For medium-voltage facilities, any preventive maintenance consists of patrols as a general rule. In application of this approach to Ghana, it would be advisable to adopt the checking of external appearance on patrols as the basic task and to check distribution transformers which would have a significant impact on public safety if their insulation were damaged by examining the insulation oil to see if the insulation has deteriorated.

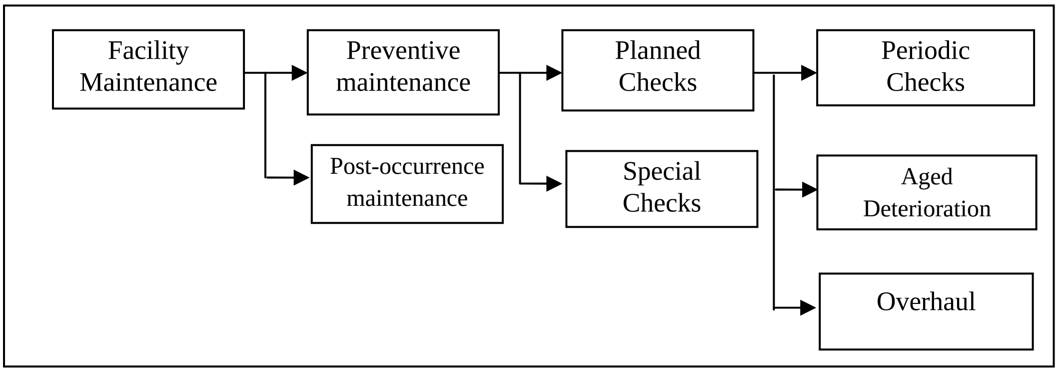


Figure 9-9 Classification of facility maintenance

(2) Post-occurrence maintenance

If the maintenance setup is grounded in post-occurrence maintenance, the utility must make arrangements for swift resumption of service. This underscores the need for advance studies to ascertain the time required to reach sites of failure as well as for provisions enabling response around the clock.

9.6.1.2 Current status and issues

(1) Preventive maintenance

Table 9-7 shows the work prescribed by the ECG and the VRA-NED in this area. The maintenance setup appears to be appropriate, in that the work consists mainly of inspection, testing of action, and overhaul for distribution substations, and patrol for distribution lines. The items of checking on patrols are also completely satisfactory.

At present, inspections are made with a high frequency in Ghana, and are thought to be sufficient as regards maintenance standards. Nevertheless, locations of deterioration discovered on patrols are apparently not promptly repaired in reality. Although some facilities may not require prompt repair depending on the degree of deterioration, the locations discovered should be managed and repaired in good time, as a neglect to do so could lower the morale of personnel making patrols.

Along with the future progress of RE projects, distribution facilities should be installed in rural areas with a dispersed demand. Once this happens, performance of patrols for all facilities in accordance with the existing patrol standards would require a tremendous amount of labor. In these areas, utilities consequently must study prospective measures for cost reduction, such as a lengthening of the patrol interval with consideration of the impact, and consignment of the patrol work to the local community.

In Ghana, the major cities (e.g., Accra, Takoradi, and Tema) are along the coast. Even in areas where distribution facilities are presumably at risk of damage from briny air, however, the ECG utilizes and operates materials in the same way as in other areas. If special measures cannot be taken in the material aspect, the utility ought to bolster its activities of patrol and checking in these areas as compared to others.

Table 9-7　Existing items of maintenance for distribution facilities

Maintenance subjects		ECG		VRA-NED	
		Tasks	Cycle	Tasks	Cycle
Substations (33- & 11-kV)	Safety indications etc.	Inspection Review	Once every year once every 6 year	＜All substations＞ Inspection: Twice every year Weeding: 4 times every year Equipment maintenance: Once every year	
	Breakers	Inspection operating test overhaul	Once every year Once every 2 year Once every 6 year		
	Switches and disconnectors	Inspection overhaul	Once every year Once every 6 year		
	Bus bars	Inspection overhaul	Once every year Once every 12 year		
	Transformers and capacitors	Inspection operating test	Once every year		
	Storage batteries	Inspection operating test overhaul	Once every year		
	Compressed air system	Inspection overhaul	Once every year once every 2 year		
	Fire extinguishers	Inspections, Refilling, CO2 replacement	Once every year Once every 6 year Once every 12 year		
	Ground wires	Requisite maintenance	Once every year		
	Buildings	Requisite maintenance	Once every year		
	Switchboards	Inspections	Once every year		
	Fuses	Inspection overhaul	Once every year Once every6,12 year		
Distribution line routes (including cables)	Supporting structures (wooden/concrete poles and iron towers)	Patrols	4 times every year	* No regulations in the data collected so far, except for the cutting back of vegetation around wooden poles, patrol by helicopter, and measurement of ground wire resistance (once every 4 years)	
	Growth of surrounding foliage	Patrols	4 times every year		
	Line path and slackness	Patrols	4 times every year		
	Interline separation and sepration from ground wires	Patrols	4 times every year		
	Pole transformers	Patrols	4 times every year		
	Insulators	Patrols	4 times every year		

Implementation of periodic patrols once a month in addition to the above.

(2) Post-occurrence maintenance (setup for response to distribution line failures)

In implementation of post-occurrence maintenance for distribution facilities, the key agenda are to curtail outage durations to the minimum and to prevent a decline in supply reliability. To these ends, it is important to have a setup for swift resumption of service in the event of distribution line failure, and to obtain and keep on hand reserve materials for use to resume service.

1) Setup for service resumption after failure

At both the ECG and the VRA-NED, district offices have established shift setups enabling prompt resumption of service in response to failure even after regular hours. They also have made arrangements for communication to allow prompt response even on holidays. For failures on distribution lines occurring at night, the basic policy is to perform repairs on the following day, except in the case of important areas in urbanized districts, for reasons of worker safety. In response to such failures, the core (regional) offices send crews out to repair aerial lines and cables. In some cases, nevertheless, areas that are hard to access in the rainy season must endure long outages, and this is an issue that remains to be addressed further in the future.

2) Reserve materials for service resumption

The district offices have stores of reserve materials including supporting structures (wooden poles), aerial lines, transformers, and insulators. In most cases, however, these articles are stored at locations where they are exposed to the weather. Proper storage and management of the inventory volume are tasks that remain to be tackled.

3) Report in the event of failure

Both the ECG and the VRA-NED have fixed forms for preparation of reports on failures, and reports are made on these forms. However, the forms do not incorporate information required for analysis of the failure data reported and mounting of measures to prevent recurrence. As such, they do not extend to examination of failure data. The following items ought to be incorporated into the form.

- Time of outage occurrence
- Outage duration (with indication of whether the circuit was successfully reopened or was permanently damaged)
- Part at which the failure occurred (distribution facility, line, transformer, etc. causing the failure)
- Cause of failure (deterioration, physical collision, natural disaster, etc.)
- Particulars of response to the failure and method of service resumption

9.6.2 Management of information required for distribution facility maintenance

The information required for maintenance of distribution facilities presumably includes single-line diagrams, map information on medium-voltage lines, and other system information related to these lines as well as attribute information for supporting structures, transformers, and other facilities. Such information is currently often managed on electronic systems thanks to the spread of ICT in recent years, but is also still managed by means of documents and ledgers in many countries.

9.6.2.1 Management of system information for medium-voltage distribution lines

System information on medium-voltage distribution lines constitutes basic data for the drafting of facility plans and for facility operation and maintenance. Its compilation is therefore very important.

Single-line diagrams are used to manage this information, but utilities also need map information (i.e., maps containing system information) for distribution systems, which cover a wide area. Knowledge of the distribution line types and distances as well as the location and capacity of secondary substations from single-line maps enables a rough calculation of power flow to obtain values for current and voltage drop. This information is sufficient for electric circuits. The neglect to reflect system information on maps, however, can cause difficulties in formulation of distribution plans on paper and office issuance of orders for service resumption after distribution line failure. (At present, the distribution engineers at regional offices basically remember which parts of which lines are in which area, and rely on their memory when going into the field.) Therefore, it is preferable to possess both single-line diagrams and system map information for maintenance of distribution facilities.

(1) Single-line diagrams

Distribution systems have a broad physical extension, and it is extremely important to manage (in the form of charts) accurate data for 11- and 33-kV (34.5-kV) distribution lines for not only maintenance but also all other distribution work. At present, both the ECG and the VRA-NED prepare (with Auto-CAD and other tools) and manage single-line diagrams for 11- and 33-kV (34.5-kV) distribution lines. Nevertheless, the following issues have also surfaced and point to a need for improved management.

1) Sure reflection extending to feeders

On some distribution lines, terminal feeders at the ends are not shown on single-line diagrams. The diagrams must be an accurate reflection of the lines, because information extending to the terminals is necessary for facility management and planning for expansion. From now on, the utilities must make it a rule to add information to the diagrams every time a medium-voltage distribution line is extended.

2) Distance information discrepancies

In some cases, there are large discrepancies between the distance shown on the single-line diagrams and the actual distance. Similarly, some diagrams do not show the type of line or have a wrong indication of type. When making patrols of distribution lines, it is important to check whether the diagram information differs from the actual facts of distribution facilities. If discrepancies are found, it is similarly vital to make prompt revisions and see that the information managed on diagrams is accurate.

3) Prompt updating of information

When medium-voltage lines are reinforced or extended, the results are sometimes not added to the single-wire diagrams. Proper information management demands the prompt updating of diagrams when facilities are replaced.

(2) Map information for distribution lines

At both the ECG and the VRA-NED, there is no map information for medium-voltage distribution lines. Such information is of vital importance not only for studies of plans for facility reinforcement and extension but also for facility maintenance.

For example, it assists the specification of locations for patrols of complex distribution lines and in the event of reports of trouble with facilities.

In light of the needs associated with management and updating, it would be more efficient to manage this kind of information in the form of electronic data. The distribution system in Ghana, too, is probably going to become more complicated in the future, and the utilities should embark on this task immediately. In promoting this work, they must utilize geographic information systems (GIS) and consider the compilation of information in conjunction with their plans for ICT application.

9.6.2.2 Facility attribute information

It is important to manage information on distribution facility attributes (e.g., specifications, date of manufacture, etc.) for reference on occasions such as checking capacity relative to the demand and drafting plans for renewal. At present, single-line diagrams at utility offices in Ghana contain information on items such as line thickness and secondary substation capacity, but not on many other items. The offices consequently have to send crews into the field to make checks when such information is needed. As the distribution system expands with an accompanying increase in the load of maintenance and management work, it will presumably take a huge expenditure of labor to continue with the current approach dependent on field trips. For this reason, the utilities must examine the option of managing facility information in offices as well. This information should be managed by means of ICT-based computer systems instead of the more troublesome cards and ledgers. Further in the future, the systems would enable integrated management of both facility information/data and maintenance results, and therefore help to increase levels of efficiency in maintenance work.

In almost all cases, transformers and switches are mounted on supporting structures. As such, it would be more efficient to manage distribution facilities in units of supporting structures, assigning a unique code to each one.

Table 9-8 Information on distribution facilities to be managed (examples)

Facilities	Information to be managed
Supporting structures	- ferroconcrete pole, iron pole, iron tower, wooden pole, etc. - Specification (Height, Design load, etc.) - Month and year of production
Lines (medium voltage)	- Name of feeder - Type (AAAC, ACSR, CVT cable, etc.) - Size - Length
Cables (medium voltage)	- Name of feeder - Type (XLPE, etc.) - Size - Length - Month and year of production
Transformers	- Name of feeder -Type (single-phase transformer, three-phase transformer, etc.) - Capacity - Tap - Month and year of production
Switches	- Name of feeder - Type (air break switch, vacuum break switch, etc.) - Month and year of production

9.7 Plans for ICT utilization

In the distribution business, utilities must manage a lot of customers and facilities. Application of ICT can do much to make the work more efficient. The specific items of ICT application include customer management, load management (transformers, lines, etc.), distribution facility data management, supervisory control and data acquisition (SCADA) systems, and distribution line automation systems.

9.7.1 ICT application items

(1) Customer management

The information needed for management of customers consists of the particulars of contracts and data for the monthly amount of power use or power tariff charges. The amount of power use can be determined by meter-reading in the field. The results provide footing for computerized calculation of tariff charges, followed by collection of the same. The sharing of this information by a plural number of offices is, in addition, effective for provision of better customer services.

In recent years, utilities in some countries have been further streamlining their operations through measures such as the recording of meter data on handsets, which they then use to transfer data to office computers, and having tariff charges paid by credit card.

(2) Load management

The distribution business is characterized by an enormous amount of facilities. It would be extremely difficult to obtain the requisite load current entirely by measurement. For this reason, it is the general practice to manage load by making estimates of the maximum load current based on customer contracts, amounts of power use, diversity factors, and other such data. While there is obviously some discrepancy between the estimated and actual current values as the amount of power use is constantly changing, this approach is sufficient for management of distribution facilities. It should be added that load management can be more efficiently performed in conjunction with customer management.

(3) Distribution facility information management

As noted above, management of information on distribution facilities is important in the aspect of distribution planning and maintenance. Application of ICT is indispensable for this management, given the enormous amount of facilities involved. The use of ICT in facility management would make it possible to easily obtain information on the facilities without sending crews into the field, and help to make operations more efficient.

(4) SCADA systems

In many countries, SCADA systems are being installed for real-time monitoring of the status of facilities to determine items such as power flow at primary substations or medium-voltage lines, and whether switches are closed or open. SCADA systems enable swift and efficient action in normal times or emergencies, and assist efforts to shorten outage durations and otherwise improve the quality of the power supply.

(5) Distribution line automation systems

Like SCADA systems, distribution line automation systems are an effective means of heightening work efficiency and enabling earlier resumption of service after line failures.

Distribution line automation systems are generally defined in terms of two types.

- Systems with an auto recloser function for resetting, after a certain time, substation breakers that had been tripped due to distribution line failure
- Systems enabling real-time monitoring and control of the status of switches along distribution line routes and measurement information

Each type is effective particularly for shortening the duration of outages due to occurrence of distribution line failure.

9.7.2 ICT - current status and issues

(1) Customer data management

The ECG has completed construction of a system for management of customer data, i.e., a customer-based information system (CBIS). This system makes it possible to manage information on customer addresses and tariff charges, and can be accessed as desired. The construction of such a system in the VRA-NED as well would afford a statistical grasp of the status of power use, and therefore assist the formulation of more effective plans for tariffs etc.

(2) Distribution facility information management

At the ECG, facilities (albeit only low-voltage ones) are connected to the Faci-Plus system and networked for management of information on them. Information has already been input for some 80 percent of these facilities, and is to be input for the remainder by the end of 2008. Information for medium-voltage facilities is to be input after this. Management of information on the system level requires input for all facilities, and this task should be finished as early as possible.

(3) Load management

The load of transformers can be managed by linking the status of power use among customers described above (in the section on customer data management) with the distribution facility information. This would enable determination of the degree of transformer margin along with changes in facilities and in the status of power use among customers, and consequently lead to more effective capital investment.

(4) Voltage management

The integration of the aforementioned load management data for each distribution line would enable calculation of the voltage drop on each. This, in turn, would make it possible to determine whether power at the proper voltage is being sent to all customers, and thereby lead to more effective capital investment.

(5) Customer services

A call center is scheduled to be opened in Accra by the end of (fiscal?) 2007. It is to have a staff of about 25 and operate around the clock. It will handle requests from customers as well as complaints about outages and other matters.

(6) SCADA system

A control center has already been built in Accra, and has finished constructing a system enabling remote monitoring and control of 21 of the total of 23 primary substations. The center has a staff of five working in three shifts. Other such control centers are to be built in Kumasi and Takoradi.

(7) Distribution line automation system

Distribution line automation system has installed in 12 substations at Accra. The function of auto-recloser, real time monitoring and remote control of switch installed on distribution line is practiced. If that same system is expanded to other area, it demands 8.05 million USD. This cost is calculated by multiplying the number of uninstalled substation by installation cost per a substation calculated from the total cost of existing system and the number of installed substation.

Chapter 10 Measurement of low-voltage distribution loss

According to the "Guide to Electric Power in Ghana" published in July 2005 by the Institute of Statistical, Social and Economic Research attached to the University of Ghana, loss on transmission and distribution lines in the country came to an estimated 14 percent (3 percent on transmission lines and 11 percent on distribution lines). There is thought to be another approximately 14 percent in non-technical loss. The ECG annual report (2006) asserted that ECG system loss came to 24.26 percent, down 1.18 percentage points from the preceding year.

In this situation, reduction of system loss would appear to be helping to improve the financial dispostion of the ECG and VRA-NED, but the facts in this respect are not necessarily clear. Low-voltage distribution lines in Ghana are characterized by installation of large-capacity distribution transformers at the load center and extension of lines for long distances. This results in a load supply pattern marked by the typical low-load dispersion. Besides lowering the quality of the power supply due to the steep voltage drop, it is thought to be causing a lot of distribution loss. In addition, the use of cable that is of relatively small size for the load current is presumably another factor behind power loss.

Against this background, the Study Team decided to make a measurement of distribution line loss in the actual low-voltage distribution system, and to estimate the level of technical loss by a calculation method, in order to shed light on the facts of both non-technical and technical loss. It is the purpose of these operations to formulate recommendations on the advisable configuration for low-voltage distribution lines in the future.

10.1 Outline of distribution loss and measures to reduce

10.1.1 Classification of distribution loss

Distribution loss may be classified as follows.

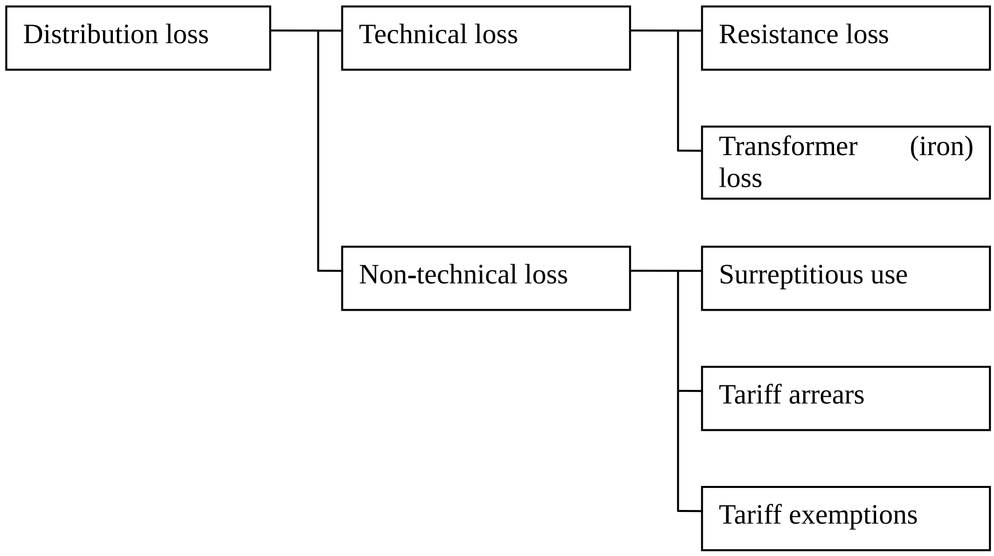


Figure 10-1 Classification of distribution loss

(1) Technical loss

Resistance loss is caused by the electrical resistance of cable and varies in proportion with the square of current. In developing countries, it is thought to be on a generally high level. This is because, even if the demand increases, there is a tendency to refrain from increasing the capacity of transmission and distribution lines, and consequently to supply power in an overload status as well as to unreasonably extend distribution lines in order to curtail costs.

Transformer (iron) loss arises due to the iron cores of transformers. It varies in proportion with the transformer capacity, but is unrelated to the size of load. Even though they have the same capacity, transformers built in recent years have less iron loss than those built 30 or more years ago. There have also appeared low-loss models using an amorphous type of iron core.

(2) Non-technical loss

While the definition of non-technical loss varies with the country, the three basic types are surreptitious use, tariff arrears, and tariff exemptions.

The term "surreptitious use" (power theft) refers to illegal use of power by a customer by means of supply that is not routed through the meter. As a result, this use is not included in the amount of power sales measured by the meter. There are two kinds of tariff arrears (non-collection): 1) that from cases in which the power utility cannot collect charges for the amount of power use measured by the meter (i.e., non-payment) and 2) that caused by mistaken measurement by defective meters. The term "tariff exemptions" refers to the practice of supplying power free of charge to governmental agencies as well as for street lights and other public facilities. In some countries, it is not counted as loss. As viewed from the standpoint of power utilities, however, it is equivalent to loss, because they cannot collect tariff charges, as in the case of other types. In some countries, it is even a factor putting a significant strain on utility management.

10.1.2 Measures to reduce transmission and distribution loss

(1) Technical loss

The table below outlines specific measures to reduce technical loss in distribution systems. Distribution loss requires an area-wise implementation of these measures, which can have an enormous effect for reducing loss. Considering the cost-benefit factor, it would therefore be uneconomical to undertake construction aimed solely at loss reduction; it is the normal practice to execute the measures along with other construction. For this reason, it would be more realistic to view measures for reduction of technical loss with a timeframe of about 10 years as opposed to the shorter term.

The following table presents the findings of analysis and examination in this development study for distribution loss in Ghana.

Table 10-1 Classification of distribution loss

Classification		Causes	Problem points
Resistance loss	33- and 11-kV distribution lines	Low demand density	In rural areas served by the ECG and areas served by the VRA-NED, a low-capacity load is scattered over a wide area, and 33-kV distribution lines are extended for long distances (over 100 km) from BSPs. This invites an increase in resistance loss.
		Improper voltage	Distribution lines that ought to have a voltage of 33 kV considering the line span and amperage still have one of 11 kV, and measures have not been taken to increase it.
		Improper conductor size	Thin cables with a sectional area of 25- or 50-mm2 are used for the trunk parts of distribution lines (in contrast, overly thick cables with a sectional area of 120 mm2 are used at the terminal parts of distribution lines). This is presumably causing a fair amount of resistance loss on trunk lines (in parts where the current is concentrated).

		Triphase imbalance	Considering the send-out current at primary substations, there are thought to be not a few feeders with a triphase imbalance rate of no more than 80 percent. It is estimated that current imbalance is increasing resistance loss.
	Low-voltage distribution lines	Long-distance, low-voltage systems	Even in villages with a fairly large number of customers, in some cases there is only one distribution-use substation (secondary transformer), to which are connected only low-voltage lines that extend for distances ranging from a few hundred meters to one kilometer. This is thought to be causing a lot of resistance loss.
Transformer (iron) loss	Transformers (secondary)	Large-capacity transformers	In areas electrified under RE programs, there are apparently many cases of installation of transformers with an extremely high capacity as compared to the total demand, even in districts that have a small demand at present and no firm prospects for a major increase in the future. (For example, transformers with a capacity in the range of 100 - 200 kVA are installed for low-voltage systems whose load will probably not exceed 20 or 30 kVA even in the future.)

(2) Non-technical loss

Non-technical loss requires specification of causes to determine countermeasures. Surreptitious use can be prevented by switching from bare to covered cable for low-voltage lines to make theft more difficult. It also demands steps in the institutional/systemic aspect, such as a reinforcement of confirmation (detection) by utilities and tougher official penalties for theft. The prospective measures for tariff arrears are a correction of measurement by replacement of defective meters and tighter regulations for collection (e.g., suspension of transmission to customers in arrears). Some African countries are introducing prepaid meters to combat non-payment, and this could help to reduce non-technical loss. In any case, the question of whether or not such measures take immediate effect depends largely on the national circumstances.

10.2 Measurement of low-voltage distribution loss

10.2.1 Methodology of low-voltage distribution loss

(1) Methodology for distribution loss measurement

Power loss is equivalent to the difference between the amount of power transmitted as measured by installing a meter on the transmission end of low-voltage distribution lines and the amount of power consumption as measured by meters on customer premises. It consists of technical loss and non-technical loss. Non-technical loss does not include tariff non-payment by customers. Consumption by customers not installed with meters is not included in the measurement, and additional meters must be installed. If this is too difficult to do, the data must be adjusted accordingly.

Measured transmission-end value - customer power consumption = technical loss + non-technical loss (surreptitious use)

The measurements will be taken once along with meter-reading for tariff collection. Two will be taken in order to reduce measurement error.

Because it would be hard to carry out meter measurements at the same time, this method will unavoidably result in some error due to the difference of measurement times. It was consequently decided to take measurements on the same day and to ignore the time-based difference.

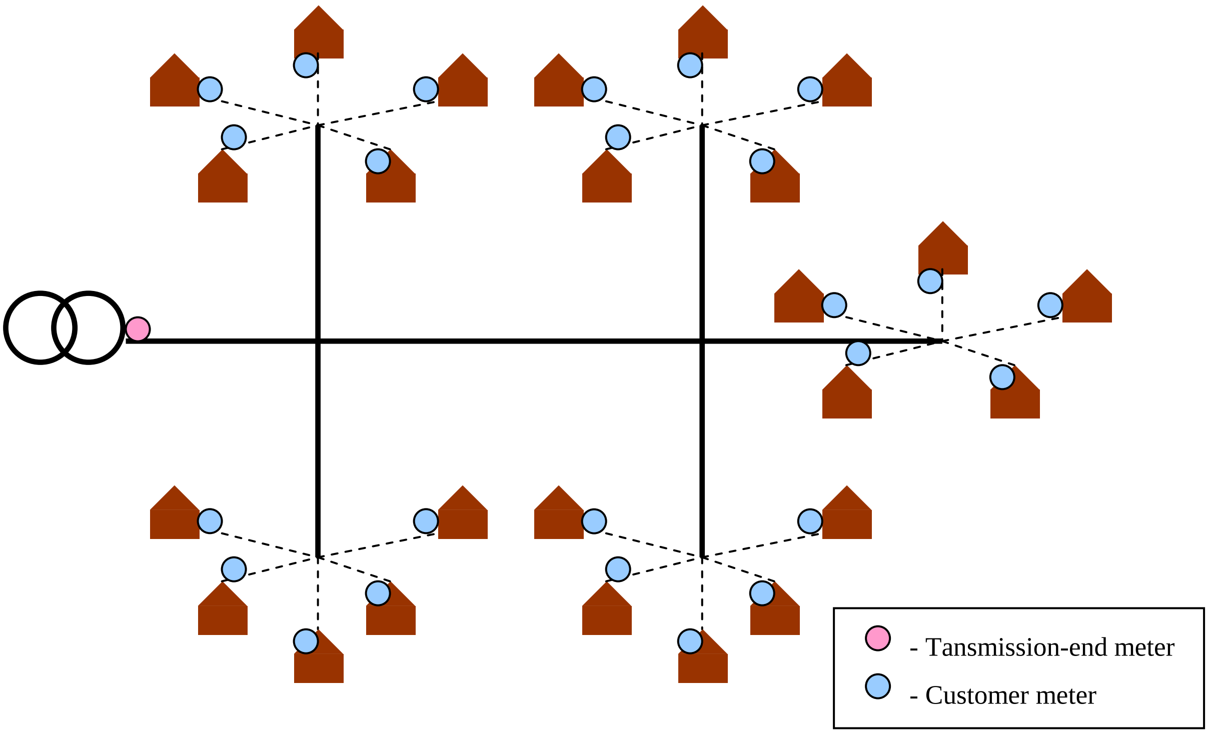


Figure 10-2 Typical diagram of distribution loss measurement

(2) Estimate of technical loss

The most accurate and easy way to ascertain technical loss is to measure low-voltage distribution loss by the method described in the preceding section, in a theft-free situation. Because the presence or absence of theft (surreptitious use) cannot be determined, the Study Team decided to estimate technical loss by means of calculation.

The ECG is conducting a project for input of data for its low-voltage distribution system on FACIPLUS, the software for distribution management. An analysis was made of technical loss in coordination with this project.

The VRA-NED does not have such software, and the Study Team consequently decided to calculate loss based on the low-voltage distribution system diagrams and the results of current measurement. To obtain technical loss by calculation requires determination of current flowing between sections. In the interest of higher accuracy, measurements must be taken at more locations; it would be insufficient to take them at only a few locations. In addition, because current changes each moment, it would be necessary to install recording ampere meters between sections for the measurements. For the Study, technical loss was estimated by making a simple calculation based on the current sent out from distribution substations. This was done in consideration of the VRA-NED's ownership of sufficient calculation equipment and the labor that would be required for measurement of low-voltage loss. As a result, the accuracy may not be very high.

(3) Estimate of non-technical loss

Non-technical loss is expressed by the formula noted in (1), subtract consumption power and technical loss from measurement value. The utilities need to consider measurement for reduction of technical loss.

10.3 Measurement of low-voltage loss and implications and consideration

(1) Measurement of total loss on low-voltage distribution lines

To ascertain the facts of loss on ECG and VRA-NED low-voltage distribution lines, the Study Team made measurements of total loss on 54 feeders, consisting of 39 ECG feeders and 15 VRA-NED feeders. The results are shown in Figure 10.3. The measurements found that the total loss was above 50 percent on 23 of the 54 feeders. It is estimated that this loss was due to error deriving from inability to read the meter values during a certain short-term period or from misreading, i.e., a lack of accurate reading of meters. This finding underscores the difficulty of accurate loss measurement. When the data for these 23 feeders are excluded, the average total loss on the low-voltage distribution lines was 17.1 percent. This figure is the sum of technical loss on low-voltage distribution lines and non-technical loss not counted on meters (such as surreptitious use).

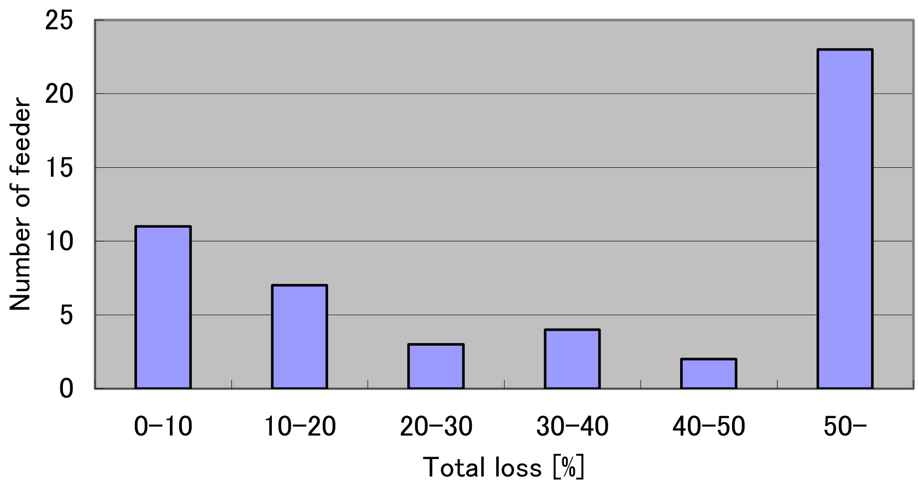


Figure 10-3 Distribution of total loss on low-voltage distribution lines

(2) Calculation of technical loss

Next, the Study Team calculated the technical loss, using a simple method, on the low-voltage distribution lines for which it took the aforementioned measurements. Technical loss is regarded as the sum of the resistance loss values on each span, and is expressed by the following equation.

$$L = (I_1^2R_1 + I_2^2R_2 + I_3^2R_3 + \cdot\cdot\cdot + I_n^2R_n) \times T$$

L : Technical loss (resistance loss) [Wh]

I_n : amperage on each span (based on division of the average current It on the secondary side of the distribution transformer in proportion with the number of customers supplied in each span) [A]

R_n : resistance loss on each span [ohm]

T : measurement time [hours]

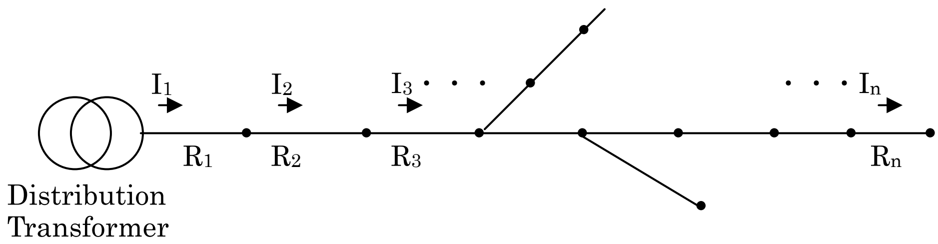


Figure 10.4 graphs the technical loss values calculated by means of this equation. Even on low-voltage lines of virtually the same length to the terminal (line end), the loss rate varies greatly depending on the size of the current or network makeup. This fact indicates the difficulty of establishing a uniform line distance to reduce loss.

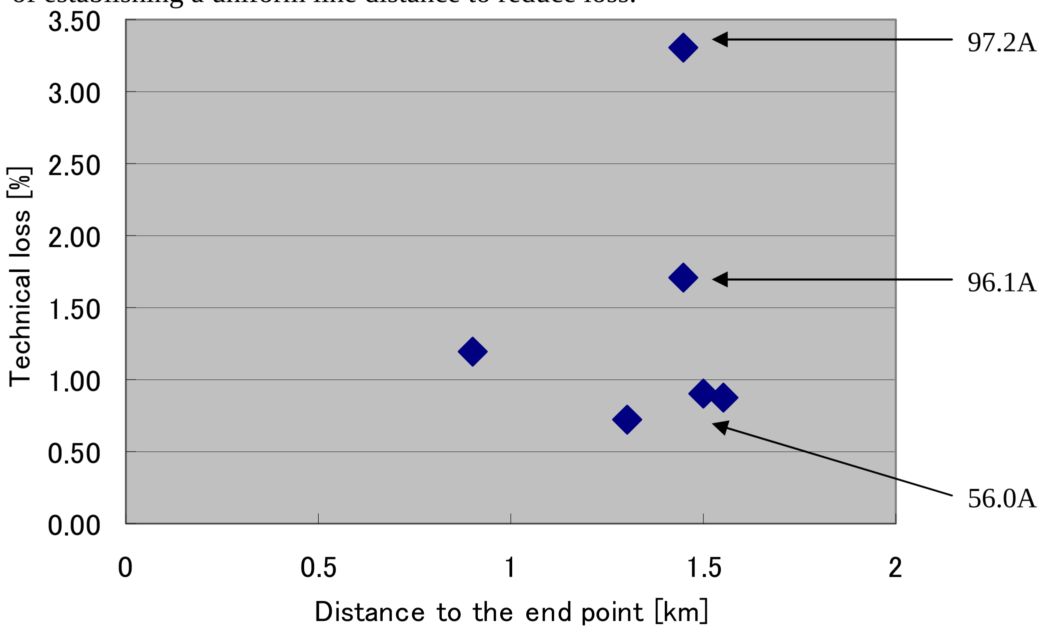


Figure 10-4 Correlation between technical loss and distance to the line terminal

The Study Team then focused on the correlation between voltage drop and technical loss.

For low voltage, Ghana applies a nominal value of 433/250 V, maximum value of 438/253 V, and minimum value of 358/207 V. The maximum and minimum values were presumably fixed for correspondence with that of 400/230 plus or minus 10 percent regulated by the International Electrotechnical Commission (IEC). This amounts to allowance of a voltage drop of up to 17 percent on low-voltage lines, and represents greater toleration for voltage drop than in other standard countries.

Figure 10.5 presents a graph showing the relationship between voltage drop and technical loss on the low-voltage lines for which loss measurements were taken. The drop on distribution lines estimated to have the biggest voltage drop was 25 V. If the voltage at the sending point of the primary substation is on the nominal level, the voltage at the end of the MV line would not present any problem under the standards, but the technical loss reaches a remarkable 7.5 percent. Therefore, proper management of voltage drop could reduce technical loss. For example, If the voltage drop is managed within 6 percent (15 V) would reduce the loss to about 2 percent, assuming that the average drop on all low-voltage distribution lines is 7.5 V (half of 15V).

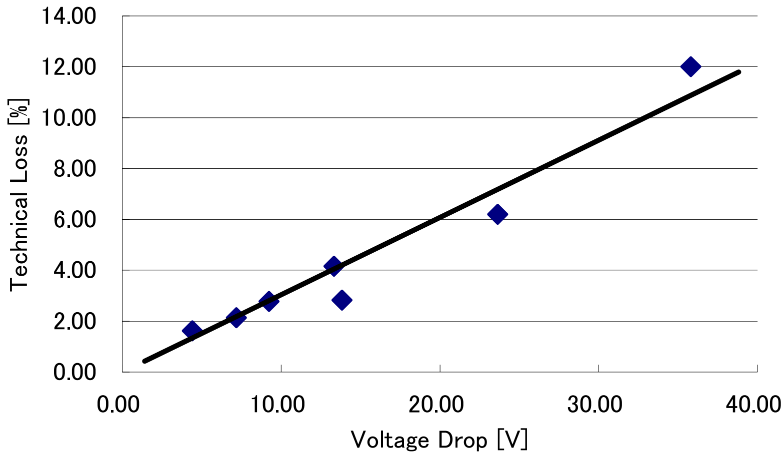


Figure 10-5 Correlation between voltage drop and technical loss

(3) Estimate of non-technical loss

The Study Team estimated low-voltage distribution line non-technical loss, which is not measured by customer meters, based on the difference between the total measured loss and the technical loss obtained in the study. The distribution is shown in Figure 10.6. On almost all feeders, the non-technical loss was in the range of 0 to 10 percent, and averaged about 9.1 percent. However, it may not actually be as low as suggested by this figure, considering the reading error in total loss measurement and the precision of the technical loss measurement. The overall non-technical loss includes measurement error and tariff payment arrears, and therefore is estimated to be above 10 percent.

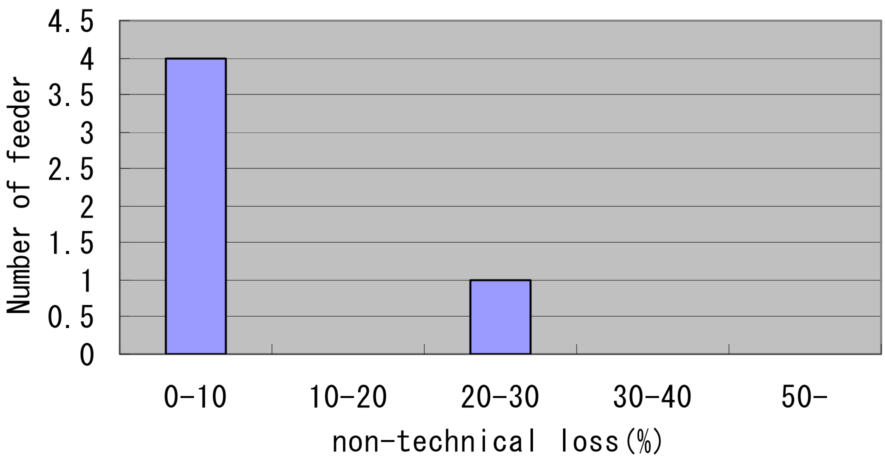


Figure 10-6 Distribution of non-technical loss

The measurement results suggest that the rate of total non-technical loss in Ghana is in excess of the estimated 10-percent level. Reduction of this loss must be regarded as an urgent priority for improvement of business management. Such reduction will demand steady efforts coupled with the sort of measures, for instance, check of surreptitious use, patrol for surreptitious use and urging against customers who has tariff arrears.

Reduction of technical loss will presumably also enable sure management of voltage drop on low-voltage lines. Management of the voltage drop standard to no more than 6 percent may make it possible to lower technical loss to around 2 percent. It should be noted, however, that modification of the existing distribution network configuration only for loss reduction could not be termed an effective means, for financial reasons as well as others. It is advisable that modification of the low-voltage distribution system should be implemented at every opportunity of works, in accordance with the clear design standard.

10.4 Consideration on the other technical losses

(1) Medium-voltage distribution line

The Study Team examined loss on medium-voltage lines on the sites of the case study implemented in this project.

The loss reduction ratios by countermeasures are in the range of one percent to 10 percent. Especially, when countermeasures are for over current, the range becomes wider. The Study Team also examined the loss-reducing effect of a countermeasure, which changes MV voltage from 11kV to 33kV. Based on the results, it estimated that this countermeasure could reduce the loss by about 0.6 percent from the current level of 5.7 percent immediately after the construction. The fact will show that the countermeasure of changing MV voltage is also effective for loss reduction.

Next, the Study Team examined the relationship between medium-voltage line loss and voltage drop, as it did for the low-voltage distribution system. Management of the voltage drop standard to no more than 7 percent (average voltage drop is 3.5 percent) may make it possible to reduce the loss to about 3 percent, though the number of data is too small to analyze.

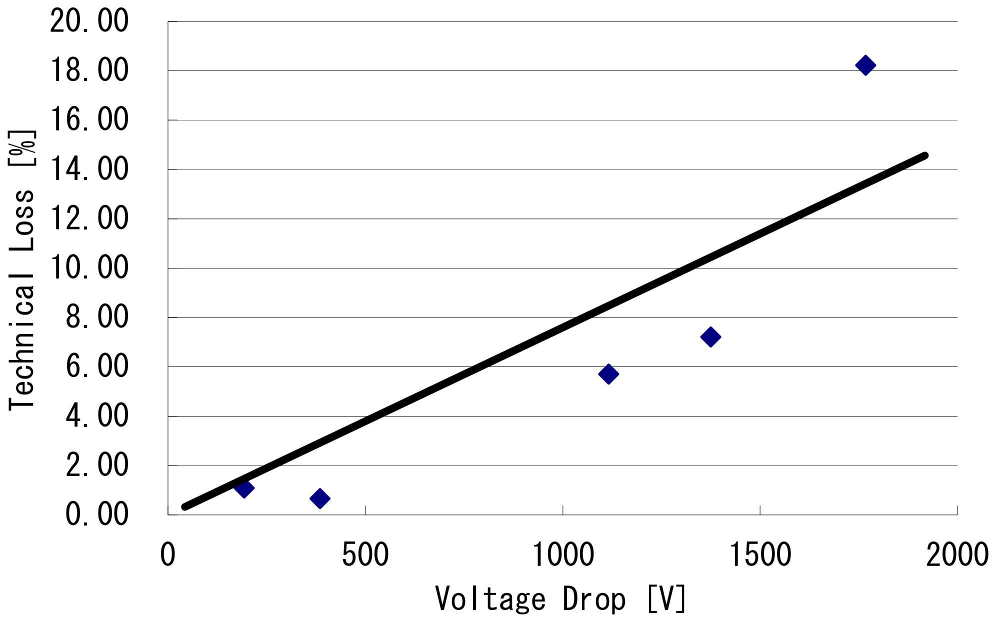


Figure 10-7 Correlation between voltage drop and technical loss of MV line

(2) Sub-transmission lines

For sub-transmission lines, the Study Team examined loss in the ECG system. The examination revealed that technical loss averages about 4 percent in the existing system makeup.

The Study Team then examined the change of loss by implementing countermeasures for primary substations and sub-transmission lines. The result shows that, in spite of demand increase, the loss will reduce to 3.5% in 2007 when most of the countermeasure works will be completed. However, due to the further increase of demand, the loss will come back to 4 percent in 2017 while the average operation current is about 30 to 40 percent of the rated current. From the result, the Study Team considers the room for sub-transmission loss reduction is 0.5 percent, under the present primary sub-station and sub-transmission system.

(3) Conclusion

At present, distribution loss in Ghana is estimated at about 24 percent, and technical loss is thought to occupy about half (12 percentage points) of this. As for the breakdown, sub-transmission lines, medium-voltage distribution lines, and low-voltage distribution lines are each estimated to account for 3 to 5 percentage points. On this basis, the Study Team considered the extent to which the 12-percent level of technical loss could be reduced. As a result, it found possibilities of reducing loss in each facility category, as follows.

(a) Sub-transmission lines: possibility of reducing loss by about approximately 3.5 percent with an operating current of no more than 30 percent of the rated current
(b) Medium-voltage distribution lines: possibility of reducing loss by approximately 3 percent by managing voltage drop to 7 percent (average voltage drop is 3.5 percent)
(c) Low-voltage distribution lines (including service wires): possibility of reducing loss by approximately 2 percent by managing voltage drop to 6 percent (average voltage drop is 3 percent)

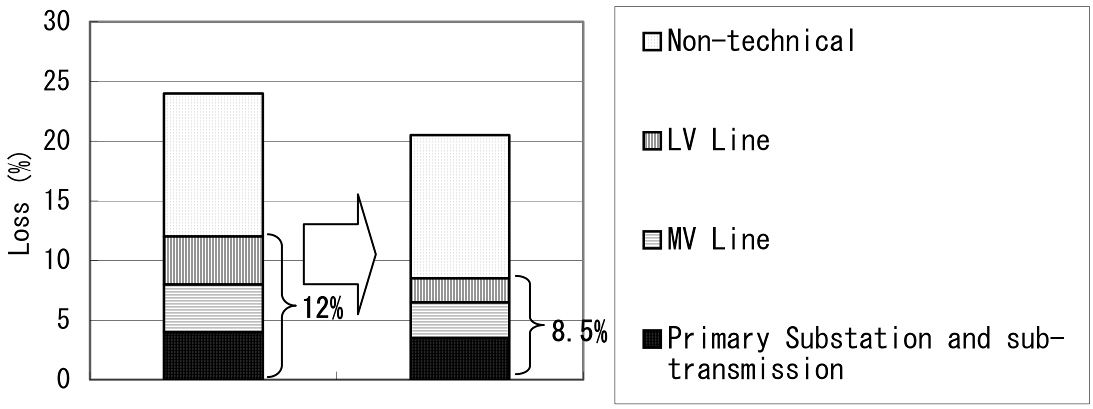


Figure 10-8 Possibility of Technical Loss Reduction

In this way, the 12-percent technical loss may be reduced to about 8.5 percent. It must be noted, however, that the examinations described above are based on results for only a limited number of samples, and do not go beyond the realm of speculation.

Chapter 11 Case Study Implementation and Results

11.1 Implementation

For the purpose of technology transfer to the CP, a case study was implemented concerning the distribution network renewal, reinforcement, and extension. The subjects were the sites identified in the draft plan for this work presented by the CP and the sites of scattered villages that are of a fairly large number and have not been electrified. Although the original plan was to conduct the study with about six such sites, it was decided to select at least one site for each core (regional) office of the ECG and the VRA-NED.

In the study, the locations of distribution lines already, or to be, installed were specified with the use of a global positioning system (GPS) while checking the system with the single-phase diagrams of the counterpart for existing distribution lines. In Ghana, ordinary detailed maps (with a scale of 1:2000, for example) are not in diffusion, and the routes of existing lines are not shown on topographical maps as a result. Furthermore, distribution lines are often not built along roads, and it is consequently often impossible or ineffective to measure each supporting structure interval with a digital measure. Therefore, in many cases, the GPS and related equipment are indispensable for surveying the routes for distribution line renewal, reinforcement, extension, and making rough calculations of the material input and labor.

Design charts for distribution lines should be drawn in accordance with uniform rules such as those below. The mapping should give even people who have not visited the site a good grasp of the plans.

* Example of mapping rules

1) Mapping with north at the top. Indication of north if it is not at the top.

2) Entry of existing facilities, new/replacement facilities, and facilities to be scrapped in mutually different colors

3) Entry of symbols for supporting structures, transformers, switches, and other equipment

4) Entry of the situation in areas traversed by distribution line routes (e.g., road, forest, and presence/absence of transmission line routes)

11.2 Results

Table 11-1 shows the case study results. Appendix 11.2 shows the design diagrams and the results of cost estimation.

Table 11-1 Case study results

Distribution company	Regional office (number of CP participants shown in parentheses)	Outline	
ECG	Accra East	- Use of thicker cable for 11-kV distribution lines for the purpose of renewal and reinforcement	Use of thicker cable is planned because the rate of voltage drop is already about 20 percent at present.
	Accra West	- Installation of a new substation to decline the load of existing substation	Installing New Dansoman substation, It works the load of V10 feeder to decline the load of existing Dansoman substation.
	Tema	- Installation of a new substation to decline the load of existing substation	Installing new substation at Dawhenya, It works the load of Steel Works feeder to decline the load of Steel Works substation.
	Central	- Installation of a new substation to decline the load of existing substation	Installing new substation, It works the load of Elmina feeder to decline the load of Cape Coast substation.
	Western	- Use of thicker cable for 33-kV distribution lines for the purpose of renewal and reinforcement	Use of thicker cable is planned because the rate of voltage drop is large at present. The poles have strength deficit are constructed to new poles.
	Volta (Two)	- Use of thicker cable for 11-kV distribution lines for the purpose of renewal and reinforcement	Use of thicker cable is planned because the rate of voltage drop is already about 18 percent at present. The case study found that some distribution facilities are built in inlets. It was decided to change the distribution route in such cases due to the risk of concrete pole corrosion by seawater and disasters in the event of disconnections.
	Eastern (Three)	- Increase in voltage (from 11 to 33 kV) for distribution line reinforcement	The voltage on the Akwatia BSP Asamankese feeder is to be increased from 11 to 33 kV on the section from the substation to the vicinity of the branch, in light of the plans for extensions on the ends under many RE projects. (Another option to be examined is the installation of a new 33-kV line for en-route bypass.)
	Ashanti East (Three)	- Distribution line extension plan (extension to unelectrified villages)	Medium-voltage distribution lines are to be extended for a distance of about 30 km from the existing Konongo feeder connected to the Konogo substation, for supply to as yet unelectrified villages south of Konongo in the eastern part of Ashanti.

		- Use of thicker cable for the purpose of distribution line reinforcement	In many places, 16-mm2 cable is used for distribution lines in the areas of Nsuta and Manpong (about 35 km north of Kumasi), and this results in steep voltage
	Ashanti West (Two)	- Plan for distribution network extension (to unelectrified villages)	In the Manso area (about 30 km southwest of Kumasi), there are plans for extension of a medium-voltage line from the Manso Nkwanra feeder connected to the Main B substation, which is the nearest distribution line.
		- Installation of a new distribution line to improve supply reliability	The Kokufu feeder connected to the Bekwai substation has a heavy load, and one more feeder is to be installed from the same substation so that some of the load can be shifted to it.
		- Change of the distribution line route (from underground cable to aerial)	The Obuasi substation Tutuka feeder consists of an underground cable buried directly under a road. This can create difficulties, and a change is to be made to an aerial route.
VRA-NED	Tamale (Two)	- Distribution line extension to a new sugar plantation	There are plans for installation of irrigation facilities for large-scale cultivation of sugar cane, with a contracted power supply of 15 MW. In response, the VRA-NED should extend the 33-kV line from the Tamale substation (BSP) and build a new primary substation in the vicinity of the plant to supply power. Two routes are under consideration for the extension, and discussions were held on the relative merits of each.
	Sunyani (Three)	- Distribution line replacement and switch to thicker cable for 11-kV lines for the purpose of reinforcement	At present, the rate of voltage drop is already about 37 percent on the distribution line, and a switch to thicker cable is planned for it. Discussions were held on additional measures to improve the power factor, which is about 80 percent.
		- Installation of a new interconnection line to improve supply reliability (formation of the Sunyani 34.5-kV system into a loop)	The 34.5-kV distribution system (see Note 1) extending from the Sunyani BPS in a loop remains unlinked in two places (in the vicinities of Gambia No. 1 and Tepa). Additional 34.5-kV lines are to be installed at these two places.
	Techiman (Three)	- Use of thicker cable for the purpose of distribution line reinforcement	The trunk sections of the 11-kV lines F1B and F2B in the city of Techiman consist mainly of 50-mm2 cable, which is to be replaced by 120-mm2 cable.
	Bolgatanga (Two (※))	- Use of thicker cable for the purpose of distribution line reinforcement	The trunk sections of the 11-kV lines F1B, F4B, and F6B in the city of Bolgatanga consist mainly of 50-mm2 cable, which is to be replaced by 120-mm2 cable.

(※) Note: Although it was initially planned to implement the study at all five VRA-NED offices, it was decided to omit Wa because a proper site was not found in that area. One CP person from the Wa office participated in the case study implemented in Bolgatanga.