Section 2 Project Scope

Clause1 Overview of projects

Major purpose of projects is to improve distribution loss, so that the following recommended projects are estimated based on Table 4-1-4-1 and 4-1-4-2.

(1) Technical loss reduction projects

Project	Necessary major facilities as scope
① Construction of new distribution feeder	11kV OH feeder 11kV UG feeder
② Avoiding Voltage drop for OH	SVR
③ Shortening of distribution line distance for LV line of OH	Distribution Transformer (DT) of small capacity such as 50KVA
④ Replacing to new DT with low core loss and big Capacity	DT
⑤ Keeping load balance of feeder for 11kV feeder	Upgrading DMS(DAS) (Control center, Substation equipment, communication network, RTU, LBS etc)
⑥ Improvement of Phase unbalance for LV line	Upgrading DMS(DAS) (Control center, Substation equipment, communication network, etc) CT and RTU for LV side of DT/Kiosk/Distributor
⑦ Improvement of power factor By Automatic device or Upgrading DMS(DAS)	Capacitor, RTU, LBS, Distributor Upgrading DMS(DAS) (Control center, communication network)

(2) Non- Technical loss reduction projects

Project	Necessary major facilities
⑧ Metering with AMR	Control center of AMR Communication network Advanced WHM including communication device and SW

In addition, Upgrading DMS (DAS) can improve not only distribution loss but also reliability by outage duration.

Clause2 System configuration

(1) System configuration

The basic system configuration including all of projects (① – ⑧) is shown in Fig. 4-2-2-1.

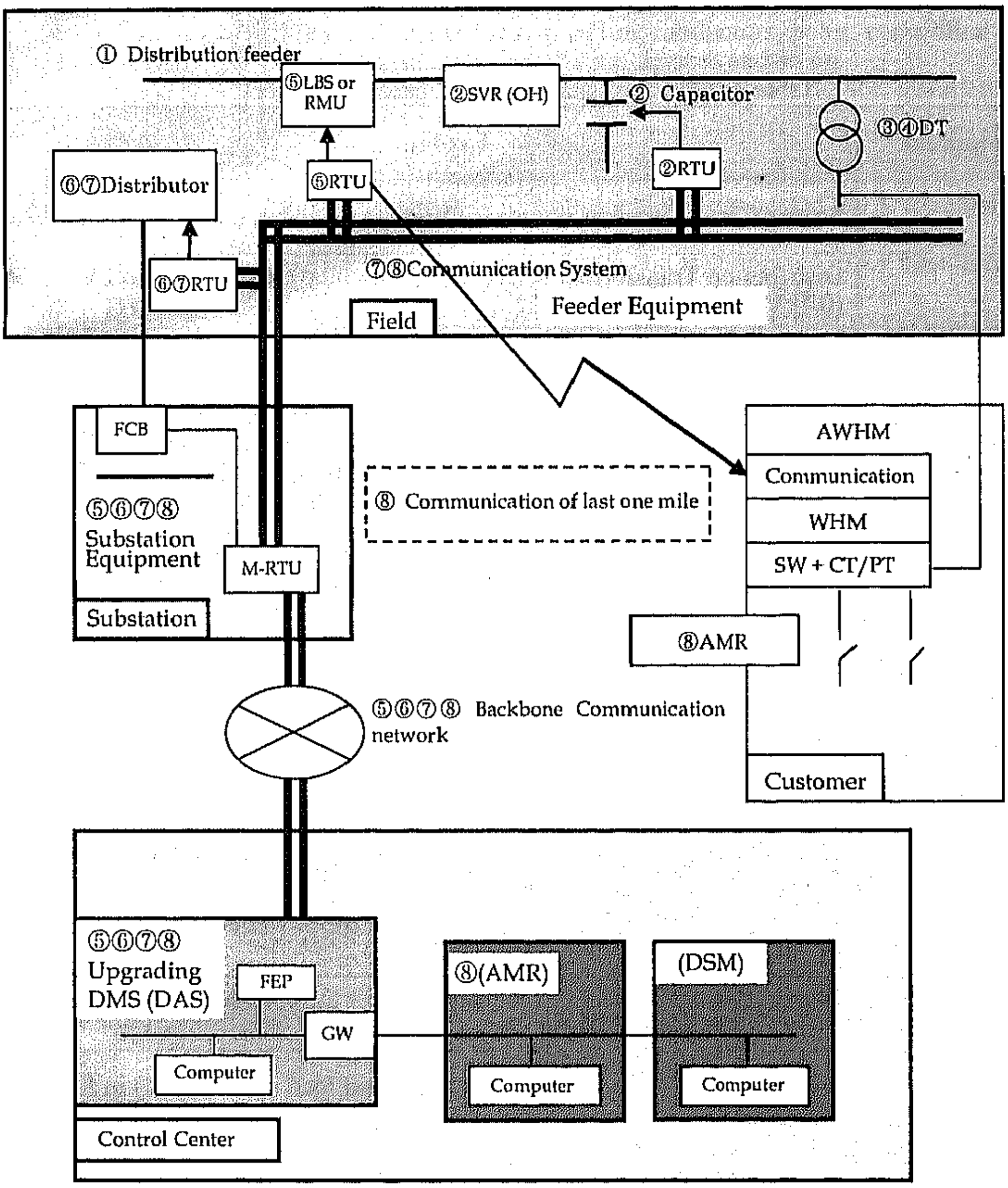


Fig. 4-2-2-1 System configuration of Project

A lot of AWHM data are transmitted to RTU through communication of last one mile (GPRS/ZigBee ets). The gathered data including LBS/RMU/Capacitor/DT are transmitted to the control center through backbone network and M-RTU in substation.
AWHM consists of communication device, WHM, PT/CT and SW for future peak-cut.
In case of applying AMR, the most suitable communication network as recommendation will consists of Fiber optic for Upgrading DMS (DAS) and ZigBee as the last one mile communication between RTU and AWHM.
This communication network will be useful for future projects such as peak-cut by DSM, telecommunication business etc.

As for Fiber optic, the investment cost is large and the installation in existing cable is difficult, so that digital UHF/VHF communication method will be considered in this project.
The detail comparison for communication method shall be carried out under design stage in accordance with route design / connection fee of telephone company / investment cost etc.

Table 4-2-2-1 Explanation of equipment in project

Equipment	Explanation
FCB	Feeder Circuit Breaker is a circuit breaker to switch the fault current.
DT	Distribution Transformer is to change the voltage from 11kV to LV (0.4kV).
FEP	Front End Processor is a data processing system to transfer data and command between the Computer and communication system.
LBS (for OH)	Load Break Switch is a switch of section of feeder installed in OH line.
RMU (for UG)	Ring Main Unit is to switch the section of feeder installed in Kiosk in UG network. The existing switch in RMU will be modified to automatic mechanism if possible. The new RMU is also equipped with automatic switches.
M-RTU	Master Remote Terminal Unit is installed in substation and the function is to control all of Remote Terminal Units under the substation.
RTU	Remote Terminal Unit is a control unit for LBS, RMU, CB in Distributor and LBS for capacitor in the field.
SVR	Step Voltage Regulator is to improve the voltage drop in the end of distribution feeder.
AWHM	Advanced Watt Hour Meter is to implement AMR function and DSM in future with interactive communication.
AMR	Auto Meter Reading system is to measure the power consumption and calculate the tariff automatically.
DSM	Demand Side Management is to cut or shift the peak load by control of AC (Air Conditioner) load etc.
SW	Switch in AWHM is to control the customer load (ex AC load) in future.
CT/PT	Current Transformer / Potential Transformer are to detect the current / voltage in order to measure the power consumption.
GW	Gate-Way is to be able to connect to other systems with different protocol.
DMS	Distribution Management System is to improve the reliability of distribution network and to reduce the distribution loss.
DAS	Distribution Automation System is the same function as DMS.

(2) Component in the project

Table 4-2-2-2 Component of distribution feeder

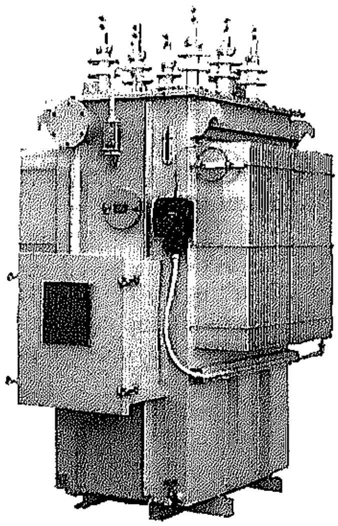
Component	Explanation
11kV feeder	There are two kinds of distribution feeder which are of OH and UG feeder, 11kV OH feeder consists of line conductors, poles, connection devices, insulators, installation devices and so on. 11kV UG feeder consists of cable, connection device, installation devices and so on.
DT	Distribution Transformer (DT) for UG is normally installed in rooms for Kiosk or Distributor and is connected to LV terminal for LV customers. DT for OH is installed on pole and is connected to LV customers through LV SW (with fuse), LV line and WHM. CT can be installed to LV terminal of DT in order to monitor the phase unbalance. The monitoring of LV phase load can also contributes to check the life of DT under overloaded operation and grasp theft by direct tapping.
SVR	SVR is normally installed around the middle of OH distribution feeder in order to improve the voltage drop and to reduce the technical loss by decreasing the load current. (sample) 
Capacitor	11kV capacitor is normally installed near motor load under OH / UG network in order to improve the power factor. LBS such as vacuum switch is installed to the source side of the capacitor and the LBS with RTU can be controlled.

Table 4-2-2-3 Component of Control Center for Upgrading DMS (DAS) and AMR

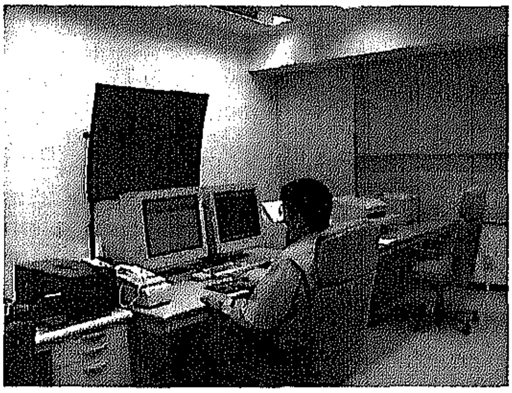
Component	Explanation
Operator's Consoles (Computer and others)	Operator uses the keyboard and the mouse connected to the console for all the operations. Dual type computer is mounted on each console for back-up. At this console, operator can monitor the distribution system status, control the distribution system automatically and manually, and maintain facility data and picture data etc. (Sample) 
Upgrading DMS (DAS) Server	Upgrading DMS (DAS) Server is a sending/receiving computer for the network data between FEP and M-RTU, automatically or by operator's instructions. The Upgrading DMS (DAS) Servers are structured in duplex configuration.
DSM Server	DSM Server is installed at Control center and connected to Upgrading DMS (DAS) Server. DSM Server is also to monitor the peak-load condition in real time and control A.C load through communication network, M-RTU, RTU, S-RTU and Terminal.
AMR Server	AMR Server is also installed at Control center and connected to Upgrading DMS (DAS) server on LAN. AMR Server is to monitor and measure the consumers' power and prepare the accounting/payment data.
Front End Processor (FEP)	FEP is installed at Control Center to connect between the Upgrading DMS (DAS) Servers and M-RTUs installed at each substation, FEP transfers the information of distribution network facility and substation equipment, to the Upgrading DMS (DAS) Servers periodically. In addition, FEP sends to M-RTU the supervisory control information received from the Upgrading DMS (DAS) Servers. The FEP is structured in duplex configuration.
Historical / Database Engineering Server	Historical data processing consists of the following functions: - Historical information management - Report generation - Database Maintenance
Communication Equipment	Communication system between MCC and substations is necessary. Leased lines which consist of optical fiber (single mode) or twisted pair cable (telephone line) are considered.

Table 4-2-2-4 Component of Substation Equipment for DAS

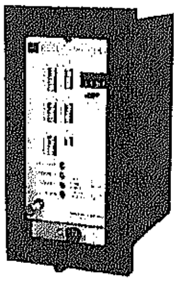
Component	**Explanation**
Master Remote Terminal Unit (M-RTU)	Master RTU is installed in each substation to control all RTUs linking to the feeders of the substation and monitor the substation devices. (Sample) 
Automatic Reclosing Relay for FCB of OH Lines	Automatic Reclosing Relay is installed in existing Feeder Circuit Breaker (FCB) board at substations. This reclosing relay is necessary for OH lines for adopting voltage sensing system. (Sample) 
Transducer (TRD) Board	Transducer board is installed in each substation to measure the voltage and current for the banks and feeders.
Communication Equipment	As for communication system between substation and the field, Fiber Optic equipment, GPRS, leased line and UHF/VHF are considered.

Table 4-2-2-5 Component of Upgrading DMS (DAS) Field Equipment for OH Lines

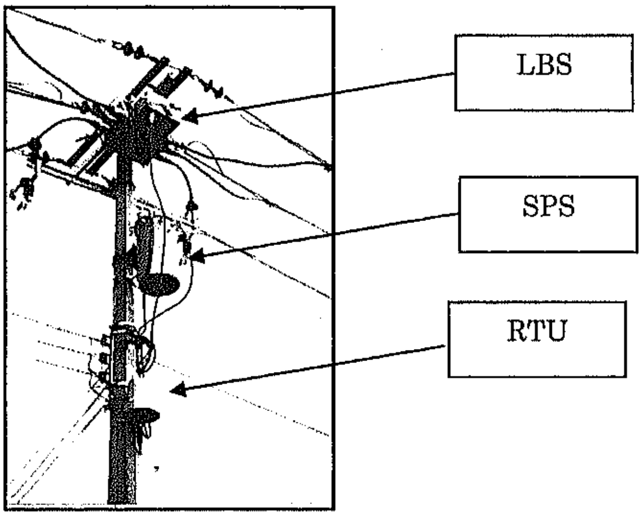
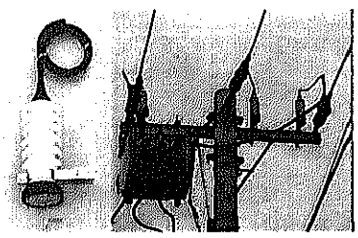
Component	Explanation
Load Break Switch (LBS)	LBS is automatically switching equipment of OH line controlled through RTU. In voltage sensing system, no battery is required. Main functions are as follows. - Automatic operation is performed by the electromagnetic coil operation method. LBS is closed under voltage and will open without voltage automatically. - Manual handles are provided to enable personnel to operate on site. - As for the arc quenching, the vacuum interrupter, which is clean and has excellent switching capacity, had better be adopted. (Sample) 
Switch Power Supply (SPS)	SPS is to supply the power and detect the voltage.
Remote Terminal Unit (RTU)	RTU is to control LBS by receiving command from MCC through M-RTU and sending status data to MCC. Fault Detecting Relay is also built in RTU.
Arrester (for protection against lightning surge)	As the field equipment for OH is installed in outside, the protection equipment against lightning is necessary. Therefore, Arrester should be installed near Upgrading DMS (DAS) field equipment. (Sample) 

Table 4-2-2-6 Component of Upgrading DMS (DAS) Field Equipment for UG Lines

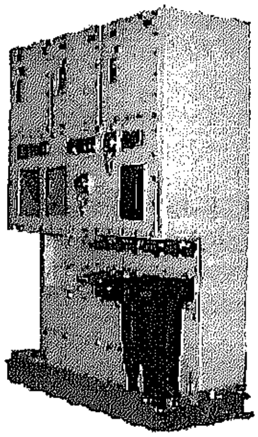
Component	Explanation
Ring Main Unit (RMU) (in Kiosk)	RMU is normally installed in Kiosk and the major functions are to switch the load current for distribution feeder and to break fault current for branch circuits. In the Project, retrofitting for existing manual RMUor new RMU are installed. RMU for Upgrading DMS (DAS) normally consists of two main circuits for automatic LBSs, two CB (Circuit Breaker), RTU and Battery etc. (Sample)  Main functions are as follows. - Detection of fault current - Detecting fault current - Unbalanced load for each phase - Communication and switching under no-voltage - Automatic switching with high speed of less than 1 second - High reliability against water, salt, dust and so on
Remote Terminal Unit (RTU)	RTU is a control system for RMU by receiving command from Upgrading DMS (DAS) through M-RTU and sending status data to MCC. RTU has a fault detecting function as well.
Battery	Current sensing system requires battery for switching of RMU without the distribution line voltage. Battery has to be changed every 2-3 years. Battery charger is also necessary.

Table 4-2-2-7 Component of LV consumer side

Component	Explanation
AWHM	AWHM, which means Meter for AMR is to measure consumers' power consumption and send the data to Control Center through RTU / M-RTU when operator requests. The AWHM consists of WHM, communication device (ZigBee End), CT/PT and SW for control of consumer load such as AC load. The AWHM is installed in / near house due to indoor type.
Communication equipment for last one mile	Communication devices for ZigBee Router are also installed in AWHM and RTU in order to connect to ZigBee End in other AWHM.

(3) Technical review

1) Fault Detecting, Isolation and Restoration (FDIR)
Voltage sensing method is recommendable for OH network and **Current sensing method** is recommendable for UG network.
Refer to Appendix 4.2-1.

2) Communication network
Digital UHF/VHF is recommendable due to the investment cost and easy installation. The detail study to decide the communication network shall be continued to next design stage because the reliability and future expansion of functions (AMR / DSM etc) are considered.
Refer to Appendix 4.2-2.

3) AMR system
Concept of AMR system is introduced in Appendix 4.2-3.

4) LV capacitor
Application of LV capacitor has been promoted in order to improve the power factor. There are problems of LV capacitor as shown in Appendix 4.2-4, so it is recommended to consider the countermeasure against the problems in case of expanding the installation of LV capacitor.

Clause3 Scope and project cost

Proposed scope and project cost for 3 model areas in 3 Distribution companies are introduced as follows and the details of project cost are also explained in Appendix 4.2-5.

(1) Alexandria Distribution Company

Proposed scope and cost in project area (West Alex zone) is shown in Table 4-2-3-1.

Table 4-2-3-1 Proposed scope and cost in project area (West Alex zone)

Scope	Quantity	Cost	
		Foreign MUS$	Local MUS$
1, DT replacement	970 units	30.0	3.0
2, DMS upgrading	1 system	33.5	3.3
3, AMR installation	1 system 200,000 WHM	24.0	1.2
4. Capacitor	100 units (New) 175 units (Existing)	5.6	0.4
5, Communication	-	Included in item 2	Included in item 2
	Total	93.1	7.9

(2) North Delta Distribution Company

Proposed scope and cost in project area (North Dakahlia) is as shown in Table 4-2-3-2

Table 4-2-3-2 Proposed scope and cost in project area (North Dakahlia)

Scope	Quantity	Cost	
		Foreign MUS$	Local MUS$
1, New construction of 11kV feeder	140 feeder	-	-
2, DT replacement	600 units (for UG)	10.2	1.1
3, Small DTs installation	200 units (OH)	3.2	0.3
4, Capacitor and SVR installation	70 units (Capacitor) 150 units (SVR)	8.0	0.8
5, AMR system installation	1 system 600,000 WHM	74.0	7.4
6, Communication upgrading	-	1.0	0.1
	Total	96.4	9.7

(3) North Cairo Distribution Company
proposed scope and cost in project area (Helmya sector) is shown in Table 4-2-3-3

Table 4-2-3-3 Proposed scope and cost in project area (Helmya sector)

Scope	Quantity	Cost	
		Foreign MUS$	Local MUS$
1, DT replacement	1,500 units	32.0	3.2
2, DMS upgrading	1 system	16.2	1.6
3, AMR installation	1 system 600,000	74.0	3.7
4, Capacitor	424 (New) 42 (Existing)	17.4	0.7
5, Communication upgrading	1 system	7.0	0.7
	Total	146.6	9.9

Clause4 Tentative Implementation Schedule

The tentative implementation schedule is estimated as shown in Fig 4-2-4-1 and Table 4-2-4-1 based on experiences. The detail implementation schedule will be determined in the later stage.

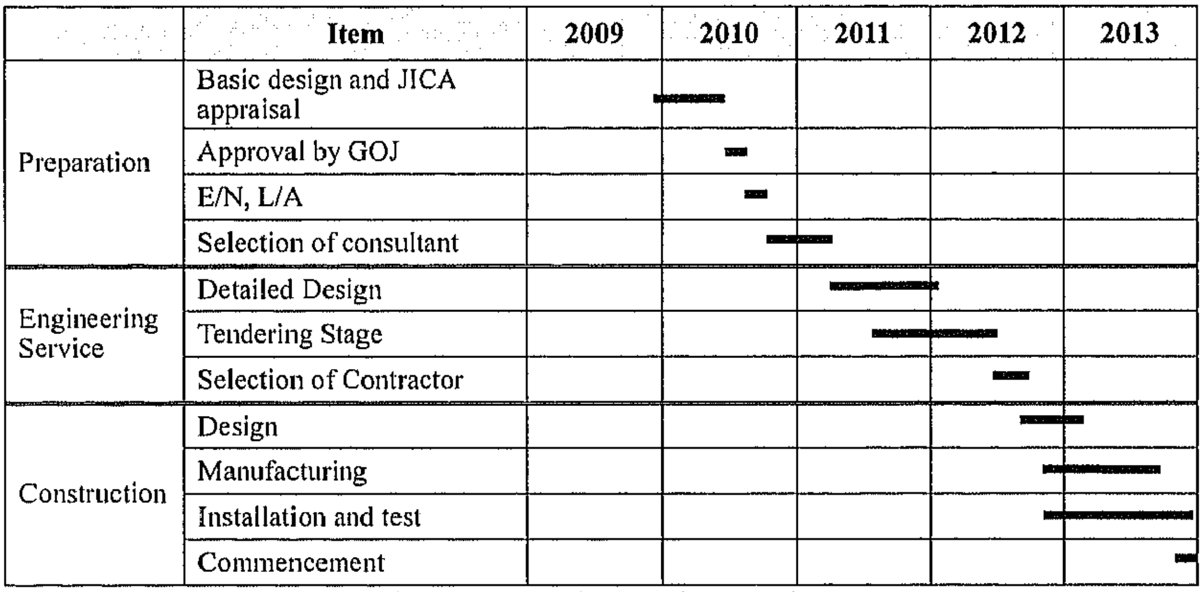


Fig. 4-2-4-1 Implementation Schedule

Table 4-2-4-1 Explanation of Implementation Items

Stage	Item	Scope
Tendering Stage	Preparation Work	(1) Preparation of implementation schedule (2) Preparation of scope of work (3) Coordination for bidding mode and currency
	Preparation of Bidding Document	(1) Instruction to bidder (2) General condition (3) Special condition (4) Technical specification (5) Pricing schedule (6) Technical schedule (7) Bidding drawing
	Promoting Pre-Qualification	(1) Making PQ documents such as experience, personnel expertise, production capacity and financial capability (2) PQ evaluation
	Bid Evaluation	(1) Technical evaluation (2) Commercial evaluation (3) Contract negotiation
Construction Stage	Preparation of Power Interruption Plan	(1) Scheduling construction and coordination with customers
	Project Management	(1) Periodical meeting and report (Monthly report for Power Utility) (2) Management of progress and payment (3) Checking and approval for drawings and documents (4) Review and approval of the programs for manufacture and delivery (5) Performance for factory tests and pre-shipment inspections
	Construction Supervision	(1) Construction supervision and safety management (2) Witness acceptance test and report to Power Utility (3) Check the commissioning test procedures and witness it with Power Utility
	Others	(1) Assistance of Training for O&M (in Japan and in India) (2) Preparation for the List of Defects (3) Completion Report with As-built Drawings and O&M Manuals

Clause5 Procurement Package

Full Tern Key (FTK) is basically recommended but the following packages as option will be recommended to consider in the later stage.

1) Package 1: Modification of existing Kiosk / Distributor
2) Package 2: Distribution Transformer (DT) and Step Voltage regulator / Capacitor
3) Package 3: Upgrading DMS (DAS) and ARM with field equipment including all kind of RTU including communication facilities, LBS and Advanced WHM
4) Package 4: Consulting service including Capacity Building

Section 3 Economic Analysis

Clause1 Expected Benefit by Model project

(1) Expected Effect for technical loss reduction
Technical loss can be improved by the following projects with system/facilities on scope.
1) Reduction project of 11kV feeder loss
1-1 New construction of distribution feeder
1-2 Improvement of Power factor by Capacitor
1-3 Improvement of Voltage drop by SVR
1-4 Improvement of feeder load-unbalance by DAS

2) Reduction project of 11kV DT loss
2-1 Replacement of DT from high loss to low loss type

3) Reduction project of LV line loss
3-1.Shortening of distribution line distance by small capacity DT
3-2.Improvement of LV phase-unbalance

4) Reduction project of Meter loss
4-1.Replacement of Meter from mechanical to electrical (for AMR) type

The current technical loss in 3 Distribution companies can be reduced by promoting the above mentioned projects. The effect of loss reduction by these projects is expected as follows.

a) Effect by reduction project of 11kV feeder loss
a-1: New construction of Distribution feeder
The technical losses are originated in proportion to the square of the load current, so that the reduction of load current is effective for the improvement of technical losses.

New construction of 11kV feeder can contribute to reduce the load current of 11kV feeder.
The load current shall be considered to increase based on growth of consumption.
The growth rate of consumption of each project area in 3 distribution companies is shown in Table 4-3-1-1

Table 4-3-1-1 Growth rate of each project area in 3 distribution companies

	2009/10	20010/11	2011/12	2012/13	Average
West Alex in AEDC	8.1%	8.0%	8.0%	8.0%	8.0%
North Dakhalia in NDEDC	8.6%	5.0%	5.0%	4.5%	5.7%
Helmya in NCEDC	2.5%	3.0%	3.5%	4.0%	3.25%

Data source; Answers from 3 distribution companies for questionnaire

As new construction of 11kV feeder will be implemented as shown in Table 4-3-1-2 / 4-3-1-3 / 4-3-1-4, the load current can be decreased and the technical loss for 11kV line / 11kV DT can be reduced in proportion to the square of the decreased load current.

The % of loss reduction can be calculated as follows.

Load current in 2009: I_1

Load current in 2013 : $I_2 = I_1 \times (1) / (2)$

Loss reduction $= I_1^2 \times Z - I_2^2 \times Z$

% of Loss reduction $= 100 \times [(I_1^2 \times Z - I_2^2 \times Z) / I_1^2 \times Z]$

$= 100 \times [1 - (I_2 / I_1)^2]$

$I_1 = 100\% / 100\% = 1$ (in case that Load current in 2009 is assumed as 100%)

$I_2 = (1) / (2)$

<AEDC>

In case of West Alex zone in AEDC, the growth rate is around 8.0% on average, so that the new construction of 11kV feeders is needed in order to improve 11kV feeder loss by the increment of load current. New construction of 180 feeders in West Alex is recommended, so that the loss reduction can be achieved as follows.

$[1 - (0.84)^2] \times 100\% = 29.4\%$ → 30 % reduction

If the new construction will not be implemented, the loss would be increased up to 85% as follows.

$[1 - (1.36)^2] \times 100\% = -85\%$ → 85 % increment

Therefore, the effect by new construction is around 115% (= 30 + 85) in case of considering the increment of technical loss

<North Delta>

In case of North Dakhalia sector in NDEDC, the growth rate is around 5.7% on average, so that the new construction of feeders is needed in order to improve 11kV feeder loss by the increment of load current. New construction of 140 feeders in North-Dakahlia is recommended, so that the loss reduction can be achieved as follows.

$[1 - (0.835)^2] \times 100\% = 30.3\%$ → 30 % reduction

If the new construction will not be implemented, the loss would be increased up to 56% as follows.

$[1 - (1.248)^2] \times 100\% = -56\%$ → 56 % increment

Therefore, the effect by new construction is around 86% (= 30 + 56) in case of considering the increment of technical loss

<Cairo North>

In case of NCEDC, the growth rate is not so large, so the new construction of feeders is also needed in order to improve the increment of load current per feeder. New construction of 200 feeders in El Helmia is recommended, so that the loss reduction can be achieved as follows.

$[1 - (0.84)^2] \times 100\% = 29.4\%$ → 30 % reduction

If the new construction will not be implemented, the loss would be increased up to 30% as follows.

$[1 - (1.137)^2] \times 100\% = -29.3\%$ → 30 % increment

Therefore, the effect by new construction is around 60% (= 30 + 30) in case of considering the increment of technical loss

Table 4-3-1-2 Load increase in West Alex in AEDC

	2009	2010	2011	2012	2013
(1) Load based on 8.0% growth	100%	108%	116.6%	126.0%	136.0%
(2) feeder Capacity (Nos. of feeder)	100% (291*)	100% (291)	100% (291)	130.9% (381)	161.9% (471)
Load current (%) (1) / (2) x 100	100%	108%	116.6	96.3%	84.0%

(Source: answer for questionnaire)
* *: No. Of West Alex ; 291 feeders*

Table 4-3-1-3 Load increase in North Dakahlia in NDEDC

	2009	2010	2011	2012	2013
(1) Load based on 5.7% growth	100%	105.7%	111.7%	118.1%	124.8%
(2) feeder Capacity (Nos. of feeder)	100% (282*)	100% (282)	100% (282)	124.8% (352)	149.6% (422)
Load current (%) (1) / (2) x 100	100%	105.7%	111.7%	94.6%	83.4%

(Source: answer for questionnaire)
* *: No. Of North Dakhalia = 122 OH feeders + 160 UG feeder*

Table 4-3-1-4 Load increase in Helmya in NCEDC

	2009	2010	2011	2012	2013
(1) Load based on 3.25% growth	100%	103.3%	106.7%	110.1%	113.7%
(2) feeder Capacity (Nos. of feeder)	100% (565*)	100% (565)	100% (565)	112.1% (665)	124.2% (765)
Load current (%) (1) / (2) x 100	100%	103.3%	106.7%	98.2%	91.5%

(Source: answer for questionnaire)
* *: No. Of El Helmya zone = 565 feeders*

a-2: Improvement of power factor by Capacitor

Power factor for each project area in 3 Distribution Companies are as shown in Table 4-3-1-5.

Table 4-3-1-5 Power factor in 3 project areas

Power factor (PF)	West Alex	North Dakhalia	Helmya
PF (daytime)	0.85	0.85	0.89
PF (night time)	0.88	0.89	0.84
Average	0.86	0.86	0.86

In case that Capacitors are installed to 11kV feeder, the power factor can be improved and the technical loss of 11kV feeder can also be reduced. The effect by the control of capacitors is also explained in Appendix 4.1-6.

The loss can be improved around 28% as one example case which the power factor can be improved from 0.85 to 0.95 by installation and control of the Capacitor. In case that the condition of the reduced reactive power is assumed to continue during 20H based on Table 4-3-1-5, the actual reduction of loss is around 23.3% (28% x 20/ 24H) levels.

The location of capacitor is normally installed to around 2/3 load point, so that the improved percentage is around 16% (=23.3 x 2/3).

a-3: Improvement of voltage drop by SVR

In case SVR will be installed on OH feeder, the voltage drop at the end of OH feeder will be improved and the loss in the load side line of SVR can be reduced.

SVR will be installed in OH feeder of North-Dakahlia in NDEDC whose related facilities are as shown in Table 4-3-1-6.

The voltage drop has occurred in OH feeder due to the long distance, so SVR is recommended to install at the middle of OH feeder.

When the voltage drop can be improved around 15% (Max of voltage drop: 15%), 15% of the feeder current can be reduced, so that the technical loss of OH feeder can be improved around 28% [= $(8.5/10)^2 = 0.72 \rightarrow$ 28%].

As SVR will be installed at the middle of the OH feeder, the half of 28% can be reduced.

The loss reduction rate excluding UG is around 9.5% (= 28 x 1/2 x 2.7/4.0).

Table 4-3-1-6 Data and effect in model project area in NDEDC

Item	Data in North-Dakahlia
Nos. of 11kV UG feeder	160
Nos. of 11kV OH feeder	122
Length of 11kV UG feeder	812.5 km
Length of 11kV OH feeder	2161.6 km
UG feeder length on average	5.1 km / UG feeder
OH feeder length on average	17.7 km / OH feeder
Technical Loss of UG feeder	1.3%
Technical Loss of OH feeder	2.7%
Effect of loss reduction of OH feeder	0.38% (= 2.7% x 0.28/2)

Therefore, the technical loss in North-Dakahlia can be reduced up to <u>0.38%</u> by installation of SVR.

a-4: Improvement of feeder load-unbalance by Upgrading DMS (DAS)

Upgrading DMS (DAS) can improve the load balance of feeder by moving overload section to light load feeder. The effect by Upgrading DMS (DAS) is explained in Appendix 4.1-6 and the loss for 11kV line can be reduced around 33%. In case that the unbalanced condition is assumed as 30% in whole feeders, the actual reduction of the loss is around 10% (= 33% x 0.3) levels.

b) Reduction project of 11kV DT loss

b-1: Replacement of DT from high loss to low loss type.

Iron loss of existing DT is around 0.89kW at 500KVA and 1.4kW at 1000KVA. The new Egyptian DT with low core loss is around 0.70 KW at 500KVA and 1.22KW at 1000KVA.

The copper loss of existing DT is around 7.90kW at 500KVA and 14.23kW at 1000KVA. The new Egyptian DT with low copper loss is around 5.46KW at 500KVA and 9.45KW at 1000KVA.

The iron loss is independent from the load current but the copper loss is in proportion to the square of the current. The annual power loss can be determined by multiplying the power loss at the maximum load by the loss factor which is normally obtained with the Buller-Woodrow equations as follows.

$P = 0.7f^2 + 0.3f$ P: Loss factor f: Load factor

As the load factor in Egypt is around 60%, P is around 0.432. Therefore, the Factor for annual loss rate can be calculated as follows.

Copper loss: 0.432

Iron loss : 1.0

Table 4-3-1-7 Loss Calculation at DT

Item	500 KVA		1000 KVA	
	Iron loss	Copper loss	Iron loss	Copper loss
(a) Existing DT	0.89KW	7.90KW	1.40KW	14.23KW
(b) New DT	0.70KW	5.46KW	1.22KW	9.45KW
(a) – (b)	0.19KW	2.44KW	0.18KW	4.78KW
(c) loss factor	1.00	0.432	1.00	0.432
[(a) – (b)] x (c)	0.19KW	1.05KW	0.18KW	2.065KW
(d) Total	1.24 KW		2.24 KW	
Effect (d) / [(a) x (c)]	0.29 (29% reduction)) [= 1.24 / (0.89x1.00 + 7.9x0.432)]		0.30 (30% reduction) [= 2.24 / (1.4x1.00 + 14.23x0.432)]	

Therefore, approximate 30% of technical loss caused by high loss DT can be reduced by replacing to low loss DT.

As DT in AEDC and NCEDC has been operated under overload condition (around 90%), the loss factor "P" is around 0.837.

Therefore, DT under overload condition in AEDC and NCEDC is recommended to replace high loss / small capacity DT to low loss / large capacity DT in order to reduce the technical loss moreover.

P = 0.7f2 + 0.3f P: Loss factor f: Load factor

In case of f = 0.9 at 500kVA, P is of 0.837.

Copper loss: 0.837, Iron loss: 1.0

In case of f=0.45 at 100kVA, P is of 0.277

New DT of 1000kVA / Existing DT of 500kVA

(1.22x 1.0 + 9.45 x 0.277) / (0.89 x 1.0 + 7.9 x 0.837) =

0.536

Therefore, around 50% of DT loss in AEDC and NCEDCcan be reduced by low loss and large capacity DT.

c) Reduction project of LV line loss

c-1: Shortening of distribution line distance by small capacity DT

In case of UG network, the length of LV line is not so long and the installation space of DT for UG is limited, so it is not effective to replace from DT of large capacity to DT of small capacity.

In case of OH network, the length of LV line is long and there is no limitation for installation of DT, so that it is effective to replace from DT of large capacity to small capacity in order to shorten the LV line length.

It is assumed that the length of LV line can be shortened about 30% - 50% (loss reduction = 30% as assumption) by replacing from large capacity to 100KVA DT

c-2: Improvement of LV phase-unbalance

LV line loss for 3 project areas are shown in Table 4-3-1-8.

Table 4-3-1-8 LV line loss for 3 project areas

	West Alex in AEDC	North Dakhalia in NDEDC	Helmya in NCEDC
LV line loss(%)	2.19	1.1	2.3

There are large phase unbalance loss in AEDC and NCEDC but there is no unbalance loss in NDEDC. Most of the difference means phase unbalance loss because LV line length in NDEDC is longer than AEDC and NCEDC.

Therefore, the loss by phase unbalance is assumed more than 50% in LV line loss in AEDC and NCEDC.

The phase unbalance can be detected and improved by Upgrading DMS (DAS) as follows.

- CT is assembled to each phase of LV line of DT
- RTU is also installed to DT including existing Kiosk
- The phase unbalance data is transmitted to control center of Upgrading DMS (DAS) through RTU and communication network
- The report for phase unbalance is made by CPU in control center
- Maintenance crew can change the phase connection of consumers based on the report

As Upgrading DMS (DAS) can not improve all of phase unbalance, the half of phase unbalance (more than 50%) can be reduced as assumption. Therefore, LV loss can be assumed to reduce around 30%.

d) Reduction project of Meter loss

d-1: Replacement of Meter from mechanical to electrical (for AMR) type

Existing Watt Hour Meter (WHM) is normally of mechanical type whose consumption power is around 3VA. WHM for AMR is of electrical type and the consumption power is around 1VA, so that the meter loss can be reduced around more than 60% (1/3 = 0.67) if the existing WHM will be replaced to electrical WHM for AMR.

e) Conclusion of technical loss reduction in 3 project areas
The current technical loss in model zones (Sectors) can be reduced by adopting the proposed projects based on above mentioned reason, so that the technical loss can be realized as shown in Table 4-3-1-9, 4-3-1-10 and 4-3-1-11.

Table 4-3-1-9 Effect for reduction of technical loss in West Alex zone in AEDC

	Location	Loss	Item	Loss reduction	Loss after project
Technical loss	11kV feeder	0.32	~~New construction of 11kV feeder~~	~~0.11 (△34%)~~	0.24
			Capacitor	0.05 (△16%)	
			Improvement of load unbalance	0.03 (△10%)	
	11kV DT	5.36	Low loss and large capacity DT	2.68 (△50%)	2.68
	LV line	2.19	Improvement of phase unbalance	0.66 (△30%)	1.53
	Meter (WHM)	0.51	Low loss WHM for AMR	0.31 (△60%)	0.20
	TOTAL	8.38	-	3.73 (△44%)	4.65

Therefore, Technical losses in AEDC can be expected to attain to 4.65% from 8.38% when the above mentioned projects will be promoted and be covered with all model area (West Alex zone) in AEDC.

As for NDEDC, the technical loss of North Dakhalia sector as model project area can be reduced from 6.70% to 4.75% by adopting the recommended projects.

As for NCEDC, the technical loss of Helmya sector as model project area can also be reduced from 12.2% to 6.90%.

Table 4-3-1-10 Effect for reduction of technical loss in North- Dakahlia in NDEDC

	Location	Loss	Item	Loss reduction	Loss after project
Technical loss	11kV feeder	4.0	~~New construction of 11kV feeder~~	~~1.20 (△30%)~~	2.98
			Capacitor	0.64 (△16%)	
			SVR for OH	0.38 (△10%)	
			~~Improvement of load unbalance~~	~~0.40 (△10%)~~	
	11kV DT	1.2	Low loss DT	0.36 (△30%)	0.84
	LV line	1.1	Shortening LV line by small DT	0.33 (△30%)	0.77
	Meter (WHM)	0.4	Low loss WHM for AMR	0.24 (△60%)	0.16
	Sub TOTAL	6.7	-	1.95 (△29%)	4.75

Table 4-3-1-11 Effect for reduction of technical loss in Helmya sector in NCEDC

	Location	Loss	Item	Loss reduction	Loss after project
Technical loss	11kV feeder	1.8	~~New construction of 11kV feeder~~	~~0.54 (△30%)~~	1.33
			Capacitor	0.29 (△16%)	
			Improvement of load unbalance	0.18 (△10%)	
	11kV DT	7.2	Low loss and large capacity DT	3.60 (△50%)	3.60
	LV line	2.3	Improvement of phase unbalance	0.69 (△30%)	1.61
	Meter (WHM)	0.9	Low loss WHM for AMR	0.54 (△60%)	0.36
	Sub TOTAL	12.2	-	5.30 (△43%)	6.90

(2) Expected effect for non-technical loss reduction

Non technical losses can be improved by AMR because AWHM in AMR can monitor theft action/operation. In case that these projects can cover whole area in model zone, the non technical loss by Meter problem and theft can be reduced as shown in the following Tables.

< In case of theft problem >

AWHM can detect to open the cover for theft or manipulation and to drop instantaneously the supply voltage by direct connection works, so that non-technical loss can be reduced. In addition, the theft by direct connection can be monitored by Upgrading DMS (DAS) and AMR as follows.

- Upgrading DMS (DAS) can monitor the power consumption (A) of LV line at DT.
- AMR can monitor the power consumption (B) for all of consumers connected to the DT.
- Operator can grasp the difference between (A) and (B) and can specify the theft consumer.

Upgrading DMS (DAS) can monitor load / consumption of DT, and AMR can monitor consumption of consumers connected to the DT, so that the difference by theft can be estimated. Therefore, this project using Upgrading DMS (DAS)/AMR can make a pressure to consumers, so that the non-technical loss will be expected to improve more and more effective. After the theft consumer is specified, the maintenance crew can visit and survey the theft by using the detecting instrument such as connection detector etc.

< In case of Meter problem >

CT / PT are assembled in AWHM, so that the defects of circuitry in CT/PT are not occurred.

Performance of electrical type for AWHM is excellent compared with existing mechanical type. In addition, the alarm will be send to computer for AMR when occurrence of the performance trouble, so that the loss by non performing meter can be reduced.

Mistake of the meter reader can be improved by auto meter reading using computer and electrical devices in AWHM.

Table 4-3-1-12 Effect for reduction of non-technical loss in West Alex in AEDC

Non-technical losses		(a)Current loss in model divisions (by Indian case)	(b) West Alex in AEDC (a) x 5.38/9.0	(b)Reduction by Projects	Target in model divisions (a) – (b)
Meter	Non performing meter	0.47	0.28	0.28 (100%)	0
	Under performing meter	0.28	0.16	0.08 (50%)	0.08
	Defects of circuitry in CT/PT	1.33	0.80	0.80 (100%)	0
	Mistake of meter reader	2.37	1.42	1.42 (100%)	0
Theft	Pilferage by manipulation of meters	0.47	0.28	0.28 (100%)	0
	Energy theft by direct tapping	2.37	1.42	0.71 (50%)	0.71
	Direct connection without meters	1.7	1.02	0.51 (50%)	0.51
Total Non-technical losses		9 %	5.38%	4.09 % (76%)	1.29 %

Table 4-3-1-13 Effect for reduction of non-technical loss in North –Dakhalia in NDEDC

Non-technical losses		(a)Current loss in model divisions (by Indian case)	(b) North Dakhalia (a) x 5.3/9.0	(b)Reduction by Projects	Target in model divisions (a) – (b)
Meter	Non performing meter	0.47	0.28	0.28 (100%)	0
	Under performing meter	0.28	0.16	0.08 (50%)	0.08
	Defects of circuitry in CT/PT	1.33	0.78	0.78 (100%)	0
	Mistake of meter reader	2.37	1.40	1.40 (100%)	0
Theft	Pilferage by manipulation of meters	0.47	0.28	0.28 (100%)	0
	Energy theft by direct tapping	2.37	1.40	0.70 (50%)	0.70
	Direct connection without meters	1.7	1.00	0.50 (50%)	0.50
Total Non-technical losses		9 %	5.3 %	4.02 % (76%)	1.28 %

Table 4-3-1-14 Effect for reduction of non-technical loss in Helmya in NCEDC

Non-technical losses		(a)Current loss in model divisions (by Indian case)	(b) Helmya (a) x 5.6/9.0	(b)Reduction by Projects	Target in model divisions (a) – (b)
Meter	Non performing meter	0.47	0.29	0.29 (100%)	0
	Under performing meter	0.28	0.18	0.09 (50%)	0.09
	Defects of circuitry in CT/PT	1.33	0.83	0.83 (100%)	0
	Mistake of meter reader	2.37	1.47	1.47 (100%)	0
Theft	Pilferage by manipulation of meters	0.47	0.29	0.29 (100%)	0
	Energy theft by direct tapping	2.37	1.48	0.74 (50%)	1.74
	Direct connection without meters	1.7	1.06	0.53 (50%)	0.53
Total Non-technical losses		9 %	5.60 %	4.24 % (76%)	1.36 %

The current non-technical loss in West Alex in AEDC is 5.38% and can be expected to improve up to 1.29% by promoting this project.
The current non-technical loss in North-Dakahlia in NDEDC is 5.3% and can be expected to improve up to 1.28% by promoting thi s project.
The current non-technical loss in Helmya in NCEDC is 5.6% and can be expected to improve up to 1.36% by promoting this project.
In case of Helmya sector, the quantity of the consumer is too many, so that the investment of AWHM is huge. Therefore, the AWHM will be applied only to El Helmya zone in Helmya sector as 1st stage, the quantity of which is around 50% in Helmya sector. The project cost for Helmya sector can be reduced but the effect to increase the non-technical loss will be reduced up to 38%.

(3) Summery of Distribution loss reduction
Total loss reduction for 3 project areas is summarized as follows.

Table 4-3-1-15 Summery of Distribution loss reduction for 3 model areas

Model Project area in Distribution Company	Type of loss	Current loss	Loss after projects*
West Alex in AEDC	Technical	8.38 %	4.65 %
	Non-technical	5.38%	1.29 %
	TOTAL	13.76%	5.94 %
North-Dakahlia in NDEDC	Technical	6.70%	4.75 %
	Non-technical	5.30%	1.28 %
	TOTAL loss	12.0%	6.03 %
Helmya in NCEDC	Technical	12.2 %	6.90 %
	Non-technical	5.60%	1.36%
	TOTAL	17.8%	8.26 %

** This effect is assumed that AWHM will be installed to all of consumers in project area.*

(4) Expected effect for outage reduction of distribution feeder by Upgrading DMS (DAS)

According to AEDC, NDEDC and NCEDC, the outage durations of distribution network for 3 model areas were recorded as shown in Table 4-3-1-16, 4-3-1-17 and 4-3-1-18.

Table 4-3-1-16 Current Outage Duration and Possibility of Reduction by Upgrading DMS (DAS) in West Alex in AEDC

Facility of Fault	Current Outage Duration (min/y,customer)	Effect by Upgrading DMS (DAS) (H) *	Target outage duration after Upgrading DMS (DAS)	Possibility of Reduction by Upgrading DMS (DAS)
SAIDI	146	116	30	Reduction is possible. Reduction effect is ruled by the model.

(Source: by AEDC)
** Effect is influenced by the condition of model*

Table 4-3-1-17 Current Outage Duration and Possibility of Reduction by Upgrading DMS (DAS) in model area (North Dakahlia Sector) in NDEDC

Facility of Fault	Current Outage Duration (min/y,customer)	Effect by Upgrading DMS (DAS) (H) *	Target outage duration after Upgrading DMS (DAS)	Possibility of Reduction by Upgrading DMS (DAS)
SAIDI	428	340	88	Reduction is possible. Reduction effect is ruled by the model.

(Source: North Dakahlia data by NDEDC) ** Effect is influenced by the condition of model*

Table 4-3-1-18 Current Outage Duration and Possibility of Reduction by Upgrading DMS (DAS) in Helmya in NCEDC

Facility of Fault	Current Outage Duration (min/y,customer)	Effect by Upgrading DMS (DAS) (H) *	Target outage duration after Upgrading DMS (DAS)	Possibility of Reduction by Upgrading DMS (DAS)
SAIDI	462	367	95	Reduction is possible. Reduction effect is ruled by the model.

(Source: by NCEDC) ** Effect is influenced by the condition of model*

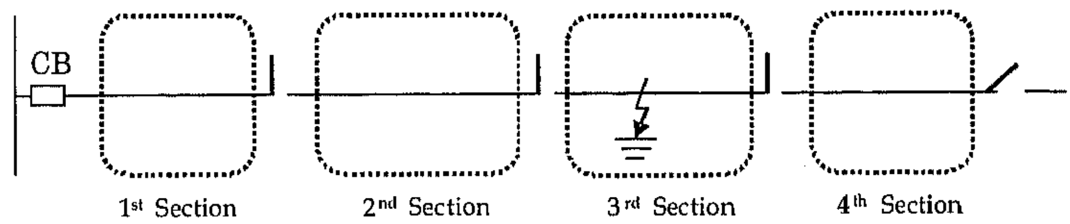
1) Reduction of Outage Duration Caused by 11 kV Feeder Fault including DT Fault

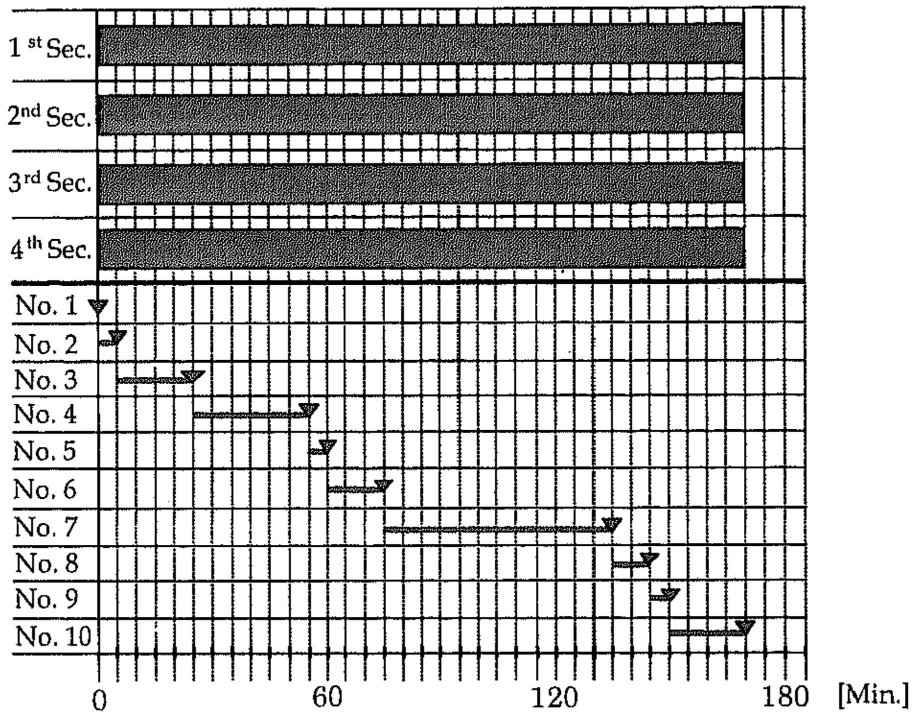
<Modeling of Reduction of Outage Duration>

Generally, outage duration has various reasons and various restoration time each and all. To simplify the outage duration mechanism, all 11kV feeder fault including DT fault is represented by the following models (before and after model) as shown in Fig 4-3-1-1.

<Restoration Model of 11 kV OH Line before Upgrading DMS (DAS)>

The following model shows the standard configuration of 11 kV OH line before Upgrading DMS (DAS). In case that a fault happens at the third section in distribution line, procedure of outage restoration and duration of outage in each section can be graphically indicated as follows. Total duration for complete restoration is estimated at 170 minutes in all sections.





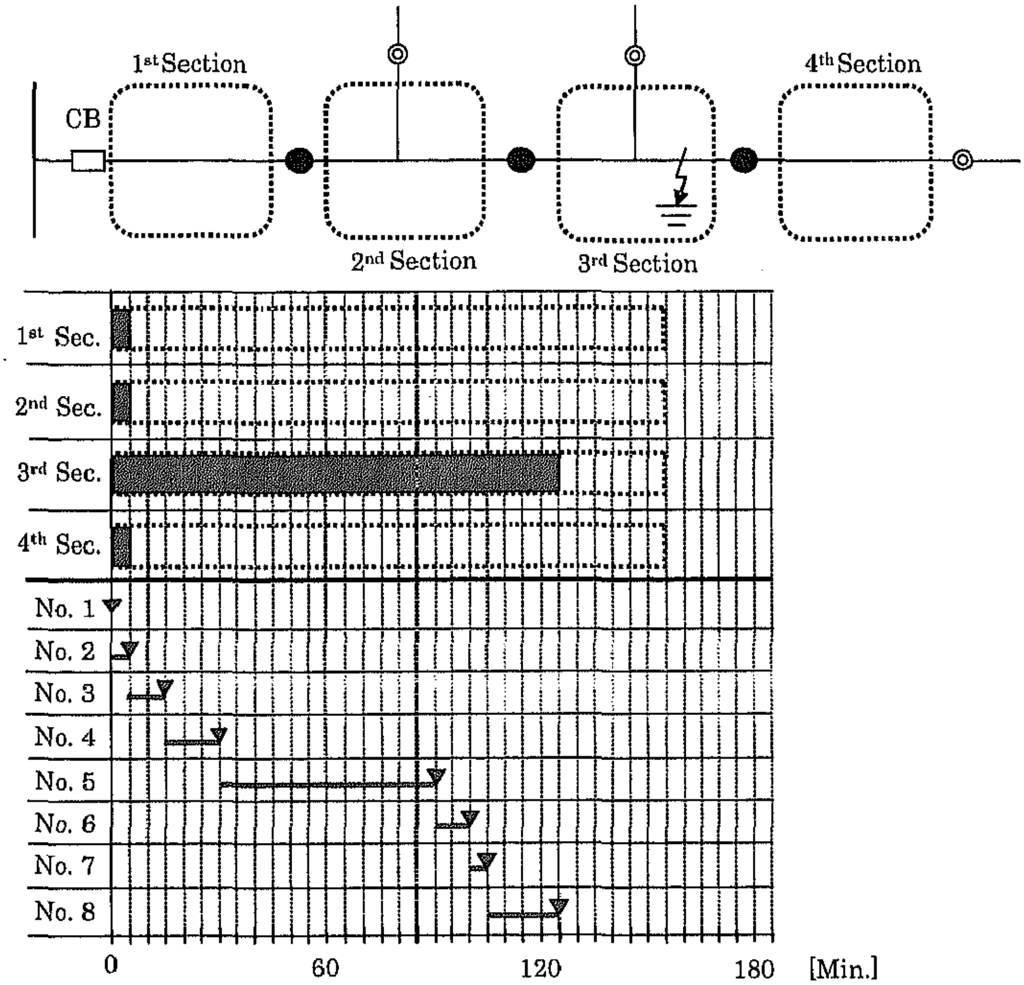
No	Affairs	Elapsed Time (Minutes)	
1	Circuit Breaker at 66kV/11kV s/s trip	0	-
2	Notice from EETC to EDC by phone	5	(+5)
3	Staffs at "Unit" are organized and go to the site	25	(+20)
4	Finding the faulty section to isolate	55	(+30)
5	Isolate the faulty section to restore	60	(+5)
6	Finding the faulty point to restore	75	(+15)
7	Repairing the faulty point	135	(+60)
8	Inspect the repairing work	145	(+10)
9	Trial charge to check the condition of faulty point	150	(+5)
10	Commercial charge	170	(+20)

Fig. 4-3-1-1 Restoration Model of 11KV OH Line before Upgrading DMS (DAS)

<Restoration Model of 11 kV OH Line after Upgrading DMS (DAS)>

The following model in Fig 4-3-1-2 shows the standard configuration of 11kV OH line after Upgrading DMS (DAS) introduction. In case that a fault happens at the third section in the D/L, procedure of outage restoration and duration of outage in each section can be indicated graphically as follows. Total duration by complete restoration is estimated at 125 minutes in the fault section. The remaining healthy sections can be restored within 5 minutes.

As for underground network, the system configuration using OH LBS for Upgrading DMS (DAS) is similar as OH network, so the effects by Upgrading DMS (DAS) is assumed to be equal to the OH restoration procedure.



No	Affairs	Elapsed Time (Minutes)	
1	Circuit Breaker at 66kV/11kV s/s trip	0	-
2	DAS detects the fault, isolates the faulty section and makes changeover procedure	5	(+5)
3	Staffs at "Unit" are organized and go to the site	15	(+10)
4	Finding the faulty point to restore	30	(+15)
5	Repairing the faulty point	90	(+60)
6	Inspect the repairing work	100	(+10)
7	Trial charge to check the condition of faulty point	105	(+5)
8	Commercial charge	125	(+20)

Fig. 4-3-1-2 Restoration Model of 11 kV OH Line after Upgrading DMS (DAS)

<Restoration Model of 11kV UG Line after Upgrading DMS (DAS)>

As for 11kV UG line, the network topology is similar as OH network as shown in Fig 4-3-1-3, so that the reduction of outage duration is assumed the same as the effect of OH network.

<Reduction of Outage Duration in 11 kV Feeder and DT>

Based on the reduction model of 11 kV feeder fault including DT fault, Average Outage Duration of One Feeder can be decreased to 20.6% from original outage duration as calculated below.

In case of OH/UG fault, Average Outage Duration of One Feeder (OH/UG) is,
170 minutes → 35.0 minutes (=(125+5+5+5)/4)
Weighted Average Outage Duration of One Feeder (mixed) is,
(35.0/170)x100% = 20.6%

Here, reduction of Average Outage Duration of One Feeder is converted to reduction of Average Outage Duration of Each Customer at the equal value as explained below.

Interrupted Customers Hours
= (Average Outage Duration of Each Customer) x (Total No. of Customers)
= (Average Outage Duration of One Feeder) x (No. of Feeders) x (Average Customers of One Feeder)
Total No. of Customers = No. of Feeders x Average Customers of One Feeder
∴ Average Outage Duration of Each Customer = Average Outage Duration of One Feeder

This means that Average Outage Duration of Each Customer caused by also decreases to 20.6% from the original outage duration by introduction of DAS.

In other words, Average Outage Duration of Each Customer after installation of DAS will be reduced with 116 minutes out of original outage duration [=146 minutes x (100%-20.6%)] in AEDC.
In case of NDEDC, the reduction of outage duration is of 340 minutes out of original outage duration [= 428 minutes x (100% - 20.6%)].
In case of NCEDC, the reduction of outage duration is of 367 minutes out of original outage duration [= 462 minutes x (100% - 20.6%)]

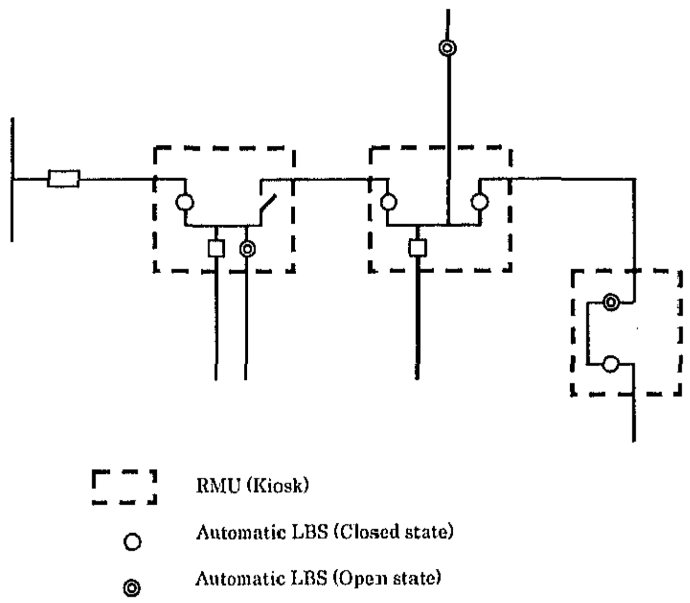


Fig 4-3-1-3 11kV Underground network applied Upgrading DMS (DAS)

Clause2 Financial and Economic Analysis

This clause explains financial and economic analyses (tentative) for the proposed project. The detail analyses as well as cost estimates will be conducted in the later stage.

(1) Financial Analysis

1) Pre-conditions for Financial Analysis

In order to evaluate the projects from the distribution company's financial point of view, a financial analysis was conducted with taking following assumptions.

1. Project commissioning is in 2013.
2. Project life is 2 years construction period and 30 years operation period.
3. Financial benefit is calculated for the distribution company. So the financial benefit is defined as increase of the distribution company's revenue or decrease of the distribution company's expenditure.
4. Both technical loss and non-technical loss sustain at the level in 2009 until the commissioning year. The losses are reduced by the project in the commissioning year, and the reduced losses will sustain at the same level during the operation period.
5. In case without the project, both the technical loss and the non-technical loss will sustain at the level in 2009 before and after the assumed commissioning year.
6. Sales energy in the commissioning year is estimated from the forecasted growth rate on the average with applying the distribution losses.
7. For operation and maintenance, followings are considered:
   - Assuming that general operation and maintenance costs (O&M) is needed in any case "with" or "without" the project, the general O&M cost is not considered in cash flow analysis.
   - For spare parts, 3% of financial cost is considered in every 5 years.
   - Replacement of a Remote Terminal Unit (RTU) is considered in 20th operation year, in case of the Option 3.
8. Financial benefits are estimated using the average electricity tariff and the average purchase price of each company. The tariff and the purchase price are assumed to increase by 5% annually from the 1st construction year until the 5th operation year.
9. Basically, all the costs adopted in financial evaluation accrue to the project's executing agency. On the other hand, the evaluation should be carried out "real resource cost" basis at present time, and therefore the price escalation is excluded from project cost (financial cost).
10. Exchange rate of 5.5 LE/US$ (=0.182US$/LE) as of Oct. 2009 is applied.

Financial benefits are estimated annually with taking account of annual sales energy during the operation period. Financial benefits by the proposed project are categorized as follows.

■ <u>Financial benefit by reduction of technical loss and non-technical loss</u>

Reduction of technical loss and non-technical loss contribute to increase of electricity sales. The financial benefit by reduction of the losses is estimated by the following formula.

Increase of revenue = Increase of electricity sales x Average tariff

Where,

Increase of electricity sales = Annual electricity sales / (1- Total Loss) x Loss reduced

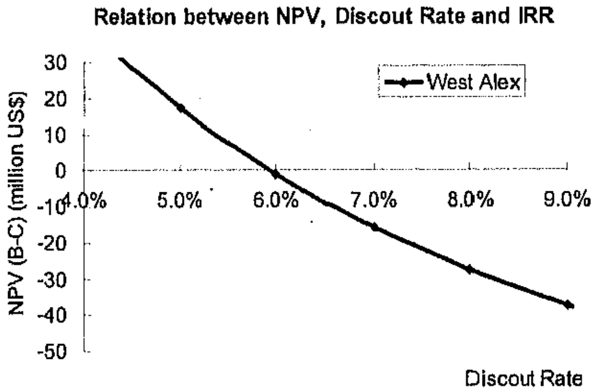
■ Financial benefit by reduction of outage duration

Reduction of outage duration can affect increase of electricity sales. Financial benefit by reduction of outage duration is estimated by the following formula.

Increase of revenue = Increase of electricity sales x Average tariff

Where,
Increase of electricity sales = Annual electricity sales x (Reduction of outage duration/ 8,760hrs)

Financial evaluation of the projects is based on a cash flow of financial costs and benefits analyzed. Financial Internal Rate of Return (FIRR) is introduced as a financial index to evaluate financial feasibility of the project. The IRR is an interest rate at which the costs of the investments lead to the benefit of the investment. Under this interest rate, net present value (B-C) becomes zero. The position of the IRR is shown in the following graph.



The FIRR is defined as following equation.

$$\sum_{t=1}^{t=T} \frac{Cft}{(1+Rft)^t} = \sum_{t=1}^{t=T} \frac{Bft}{(1+Rft)^t}$$

Where,
T = Last year of the project life
Cft = Annual Cash flow of the financial cost for the project at the year t
Bft = Annual Cash flow of the financial benefit for the project at the year t
Rf = Financial Internal Rate of Return

2) Financial analysis for the project in West Alex
a) Main features of the project area and the project effect, West Alex
The proposed scope for West Alex is as shown in Table 4-2-3-1. Project cost was tentatively set at 125.0 million US$ for the analyses, assuming engineering services, tax and contingency in addition to the cost in Table 4-2-3-1.

Consumed energy in West Alex is 999GWh in 2008 (2008/2009), and total distribution loss is 13.76%. According to the AEDC's forecast by 2013, the consumed energy in West Alex will grow by 8% annual growth rate on the average. From the consumed energy and the distribution loss, sales energy in 2013 (2013/14) is estimated at 1,266GWh.

With taking account that the area is newly developing, further energy growth until 2028 was assumed by 8% of annual growth rate for the estimation of financial benefit. Then, 1.5million US$ of maintenance cost was considered in cash flow analysis in addition to the spare parts.

DMS upgrading :		37.0 million US$
AMR installation :		25.2 million US$
	Total	62.2 million US$

62.2 million US$ @ 2% = 1.2 million US$ per annum
(Round up 1.5 million US$)

The technical loss and the non-technical loss are 8.38% and 5.38% respectively. As effects of the project, 44% of the technical loss and 76% of the non-technical loss were estimated to be reduced (Refer to Table 4-3-1-9 and Table 4-3-1-12). Current outage duration of 146minutes/year was estimated to be reduced to 30minutes/year by the project. (Refer to Table 4-3-1-16)

Main features of the area and the project are summarized in Table 4-3-2-1.

Table 4-3-2-1 Main Features of the Project Area and Project Cost, West Alex

Basic data of the area:		**Description**	**Note**
Project target area		West Alex, AEDC	
Averaged Tariff in 2009		0.188 LE/kWh (= 3.42 US Cent/kWh)	Data Source: EEHC
Averaged Purchase price from transmission company in 2009		0.119 LE/kWh (= 2.16 US Cent/kWh)	
Consumed energy	2008 (2008/09)	999 GWh	
Sales energy	2008 (2008/09)	862 GWh [1]	
	2013 (2013/14)	1,266 GWh [2]	
	2028 (2028/29)	4,016 GWh [3]	
Distribution losses	Technical	8.38%	Data Source: EEHC (2009)
	Non-Technical	5.38%	
	Total	13.76%	
Outage Duration		146 minutes/year	
Project description:			
Project cost [4]		125.0 million US$	
Distribution losses after project	Technical	4.65% (△44%)	Refer to: Table 4-3-1-9 Table 4-3-1-12
	Non-Technical	1.29% (△76%)	
	Total	5.95%	
Outage Duration after project		30 minutes/year (△116 minutes / year)	Refer to: Table 4-3-1-16

1) Derived from consumed energy with taking account losses
2) Derived from consumed energy forecast with taking account assumed losses..
3) Derived from 8% annual growth rate assumed
4) Assuming Engineering Services, Tax and Contingency

b) FIRR calculation, West Alex
As explained as a pre-condition, the price escalation was not considered for the financial analysis, and financial cost was set at 121.6 million US$. The average tariff is 0.188LE/kWh, and the average purchase price from Transmission Company is 0.119LE/kWh in 2009 respectively. Financial benefits by reduction of distribution loss and reduction of outage duration were calculated with applying the assumption that the tariff and the purchase price will increase by 5% annually from the 1st construction year until the 5th operation year. Formulas to calculate the benefits are as shown in the previous sub-clause, Clause 3, (1), 1) Pre-conditions for Financial Analysis.

Based on the conditions and assumptions, FIRR of the project is 5.9%. Detailed calculation sheet are enclosed in Appendix 4.3-1.

A financial index (n) explained in the following formula was also introduced in this study.

$$n \quad \frac{\text{Project cost (financial)}}{\text{Averaged financial revenue before deducting O\&M cost}}$$

Item	Description
Financial Cost [1)]	121.6 million US$
FIRR	5.9%
n	9 years

1) Not considered price contingency

c) Sensitivity analysis on FIRR, West Alex
Subject to unforeseen changes of the project cost and the financial revenue in the future, a sensitivity analysis on FIRR was carried out in order to clarify the influence of such situation changes to the financial evaluation. Result of the sensitivity analysis on FIRR is summarized as follows.

Fluctuation of the project cost

	Financial Cost
■ Base Case	121.6 million US$
■ +10% increases	133.7 million US$
■ -10% decreases	109.4 million US$

Fluctuation of the financial revenue

	Financial Revenue[1)]
■ Base Case	4.5 million US$
■ +10% increases	5.0 million US$
■ -10% decreases	4.1 million US$

1) The financial revenue in the commissioning year is shown for reference

Under the above cases, FIIR fluctuates from 7.5% to 4.4%, which exceeds the assumed soft loan interest of ODA scheme. Consequently, the project will have some financial viability under the applied conditions and the assumptions.

Case		FIRR	Note
Project Cost	Financial Revenue		
+10%	+10%	6.0%	
+10%	Base Case	5.3%	
+10%	-10%	4.4%	
Base Case	+10%	6.7%	
Base Case	Base Case	5.9%	Base Case
Base Case	-10%	5.1%	
-10%	+10%	7.5%	
-10%	Base Case	6.7%	
-10%	-10%	5.8%	

3) Financial analysis for the project in North Dakhalia
a) Main features of the project area and the project effect, North Dakhalia
The proposed scope for North Dakhalia is as shown in Table 4-2-3-2. Project cost was tentatively set at 131.1 million US$ for the analyses, assuming engineering services, tax and contingency in addition to the cost in Table 4-2-3-2.

Consumed energy in North Dakhalia is 1,986GWh in 2008 (2008/09), and total distribution loss is 13.0%. According to the NDEDC's forecast by 2013, the consumed energy in North Dakhalia will grow by 5.7% of annual growth rate on the average. *From the consumed energy and the distribution losses, sales energy in 2013 (2013/14)* is estimated at 2,306GWh.

Technical loss and non-technical loss are 6.7% and 5.3% respectively. As effects of the project, 29% of the technical loss and 76% of the non-technical loss were estimated to be reduced (Refer to Table 4-3-1-10 and Table 4-3-1-13).

Current outage duration is 428minutes/year in 2009. Since DAS has been already installed in North Dakhalia by NDEDC, DAS installation is not included in this project. Therefore, project effect doesn't consider outage duration after the project.

Main features of the area and the project are summarized in Table 4-3-2-2.

Table 4-3-2-2 Main Features of the Project Area and Project Cost, North Dakhalia

Basic data of the area:		**Description**	**Note**
Project target area		North Dakhalia	
Averaged Tariff in 2009		0.204 LE/kWh (= 3.709 US Cent/kWh)	Data Source: EEHC
Averaged Purchase price from transmission company in 2009		0.146 LE/kWh (= 2.655 US Cent/kWh)	
Consumed energy	2008 (2008/09)	1,986 GWh	
Sales energy	2008 (2008/09)	1,748 GWh [1]	
	2013 (2013/14)	2,306 GWh [2]	
Distribution losses	Technical	6.70%	Data Source: EEHC (2009)
	Non-Technical	5.30%	
	Total	13.00%	
Outage Duration		428 minutes/year	
Project description:			
Project cost [3]		131.1 million US$	
Distribution losses after project	Technical	4.75% (Δ29%)	Refer to: Table 4-3-1-10 Table 4-3-1-13
	Non-Technical	1.27% (Δ76%)	
	Total	6.02%	
Outage duration after project		N.A	

1) Derived from consumed energy with taking account of losses
2) Derived from consumed energy forecast with taking account of assumed losses..
3) Assuming Engineering Services, Tax and Contingency

b) FIRR calculation, North Dakhalia
As explained as a pre-condition, the price escalation was not considered for financial analysis, and financial cost was set at 127.5 million US$. The average tariff is 0.188LE/kWh, and the average purchase price from Transmission Company is 0.119LE/kWh in 2009 respectively. Financial benefits by reduction of distribution loss were calculated with applying the assumption that the tariff and the purchase price increase by 5% annually from the 1st construction year until the 5th operation year. Formulas to calculate the benefits are as shown in the previous sub-clause, Clause 3, (1), 1) Pre-conditions for Financial Analysis.

Based on the conditions and assumptions, FIRR of the project is 3.5%. Detailed calculation sheet are enclosed in the Appendix 4.3-2.

A financial index (n) explained in the following formula was also introduced.

$$n \quad \frac{\text{Project cost (financial)}}{\text{Averaged financial revenue before deducting O\&M cost}}$$

Item	**Description**
Financial Cost [1]	127.5 million US$
FIRR	3.5%
n	16 years

1) Not considered price contingency

c) Sensitivity analysis on FIRR, North Dakhalia

Subject to unforeseen changes of the project cost and the financial revenue in the future, a sensitivity analysis on FIRR was carried out in order to clarify the influence of such situation changes to the financial evaluation.

Result of the sensitivity analysis on FIRR is summarized as follows.

Fluctuation of the project cost

	Financial Cost
■ Base Case	127.5 million US$
■ +10% increases	140.2 million US$
■ -10% decreases	114.7 million US$

Fluctuation of the financial revenue

	Financial Revenue[1)]
■ Base Case	6.7 million US$
■ +10% increases	7.3 million US$
■ -10% decreases	6.0 million US$

The financial revenue in the commissioning year is shown for reference

As to the base case and the optimistic cases, such as decrease of project cost and increase of financial revenue, FIRR fluctuate from 3.5% to 5.2%. Those exceed the assumed soft loan interests of ODA scheme.

Case		FIRR	Note
Project Cost	Financial Revenue		
+10%	+10%	3.5 %	
+10%	Base Case	2.7 %	
+10%	-10%	1.9 %	
Base Case	+10%	4.3 %	
Base Case	Base Case	3.5 %	Base Case
Base Case	-10%	2.7 %	
-10%	+10%	5.2 %	
-10%	Base Case	4.4 %	
-10%	-10%	3.5 %	

4) Financial Analysis for the project in El Helmya

a) Main features of the project area and the project effect, El Helmya

The proposed scope for Helmya is as shown in Table 4-2-3-3. Project cost was tentatively set at 190.7 million US$ for the analyses, assuming engineering services, tax and contingency in addition to the cost in Table 4-2-3-3.

Consumed energy in El Helmya is 4,538GWh in 2008 (2008/09), and total distribution loss is 17.8%. According to the NCEDC's forecast by 2013, the consumed energy in El Helmya will grow by 3.25% of annual growth rate on the average. From the consumed energy and the distribution losses, sales energy in 2013 (2013/14) is estimated at 4,377GWh.

Technical loss and non-technical loss are 12.2% and 5.6% respectively. As effects of the project, 43% of the technical loss and 38% of the non-technical loss were estimated to be reduced (Refer to Table 4-3-1-11 and Table 4-3-1-14). Current outage duration of 462minutes/year was estimated to be reduced to 95minutes/year by the project (Refer to Table 4-3-1-18).

Main features of the area and the project are summarized in Table 4-3-2-3.

Table 4-3-2-3 Main Features of the Project Area and Project Cost, Helmya

Basic data of the area:		**Description**	**Note**
Project target area		Helmya	
Averaged Tariff in 2009		0.200 LE/kWh (= 3.660 US Cent/kWh)	Data Source: EEHC
Averaged Purchase price from transmission company in 2009		0.149 LE/kWh (= 2.727 US Cent/kWh)	
Consumed energy	2008 (2008/09)	4, 538 GWh	
Sales energy	2008 (2008/09)	3,730 GWh [1]	
	2013 (2013/14)	4,377 GWh [2]	
Distribution losses	Technical	12.20%	Data Source: EEHC (2009)
	Non-Technical	5.60%	
	Total	17.80%	
Outage Duration		462.0 minutes / year	
Project description:			
Project cost [3]		190.7 million US$	
Distribution losses after project	Technical	6.90% (△43%)	Refer to Table 4-3-1-11 Table 4-3-1-14
	Non-Technical	3.47% (△38%)	
	Total	10.37%	
Outage Duration after project		95 minutes/year (△367 minutes / year)	Refer to Table 4-3-1-18

1) Derived from consumed energy with taking account of the losses
2) Derived from consumed energy forecast with taking account of the assumed losses.
3) Including Engineering Services, Tax and Contingency

b) FIRR calculation, Helmya

As explained as a pre-condition, the price escalation was not considered for financial analysis, and financial cost was set at 185.7 million US$. The average tariff and the average purchase price from Transmission Company are 0.200LE/kWh and 0.149LE/kWh in 2009 respectively. Financial benefits by reduction of loss and reduction of outage duration were calculated with applying the assumption that the tariff and the purchase price increase by 5% annually from the 1st construction year until the 5th operation year. Formulas to calculate the benefits are as shown in the previous sub-clause, Clause 3, (1), 1) Pre-conditions for Financial Analysis.

Based on the conditions and assumptions, FIRR of the project is 8.2%. Detailed calculation sheet are enclosed in the Appendix 4.3-3.

A financial index (n) explained in the following formula was also introduced.

$$n \quad \frac{\text{Project cost (financial)}}{\text{Averaged financial revenue before deducting O\&M cost}}$$

Item	Description
Financial Cost [1)]	185.7 million US$
FIRR	8.2%
n	10 years

1) Not considered price contingency

c) Sensitivity analysis on FIRR, Helmya
Subject to unforeseen changes of the project cost and the financial revenue in the future, a sensitivity analysis on FIRR was carried out in order to clarify the influence of such situation changes to the financial evaluation.

Result of the sensitivity analysis for the FIRR is summarized as follows.

Fluctuation of the project cost

	Financial Cost
■ Base Case	204.3 million US$
■ +10% increases	185.7 million US$
■ -10% decreases	167.1 million US$

Fluctuation of the financial revenue

	Financial Revenue[1)]
■ Base Case	16.6 million US$
■ +10% increases	18.2 million US$
■ -10% decreases	14.9 million US$

1) The financial revenue in the commissioning year is shown for reference

Under the above cases, the FIRR fluctuates from 10.5% to 6.1% as shown in the followings, which exceeds the assumed soft loan interest of ODA scheme. Consequently, the project will have some financial viability under the applied conditions and the assumptions.

Case		FIRR	Note
Project Cost	Financial Revenue		
+10%	+10%	8.2%	
+10%	Base Case	7.2%	
+10%	-10%	6.1%	
Base Case	+10%	9.3%	
Base Case	Base Case	8.2%	Base Case
Base Case	-10%	7.0%	
-10%	+10%	10.5%	
-10%	Base Case	9.3%	
-10%	-10%	8.1%	

(2) Economic Analysis

1) Pre-conditions for Economic Analysis

The economic analysis appraises the project under study in terms of an entire national economy by comparing and measuring its economic costs and benefits.
In order to evaluate the project from the Egyptian national economy point of view, the economic analysis was conducted with taking the following assumptions.

1. Project commissioning is in 2013.
2. Project life is 2 years construction period and 30 years operation period.
3. Benefits that are categorized into the following items are applied for economic analysis.
   - Willingness to Pay
   - Increase of Export
   - Decrease of Import
   - Saving Domestic Project
4. Both technical loss and non-technical loss sustain at the level in 2009 until the commissioning year. The losses are reduced by the project in the commissioning year, and the reduced losses will sustain at the same level during the operation period.
5. In case without the project, both technical loss and non-technical loss will sustain at the level in 2009 before and after the assumed commissioning year.
6. Sales energy in the commissioning year is estimated from the forecasted growth rate on the average with applying the distribution losses.
7. For the operation and maintenance, followings are considered:
   - Assuming that general operation and maintenance cost (O&M) is needed in any case "with" or "without" the project, the general O&M cost is not considered in cash flow analysis.
   - For spare parts, 3% of economic cost is considered in every 5 years.
   - Replacement of a Remote Terminal Unit (RTU) is considered in 20th operation year, in case of the Option 3.
8. Economic cost means an expense in viewpoint of the national economy, where the cost items related taxes are not considered as the actual expenses in view of the national economy, because the costs are transferred to the national income finally, and are not influence on the cash flow balance in the national economy. Tax and price escalation are not considered for economic analysis (economic cost)
9. Exchange rate of 5.5 LE/US$ (=0.182US$/LE) as of Oct. 2009 was applied.

Economic benefits are estimated annually with taking account of annual sales energy during the operation period. Economic benefits by the proposed project are categorized in the followings.

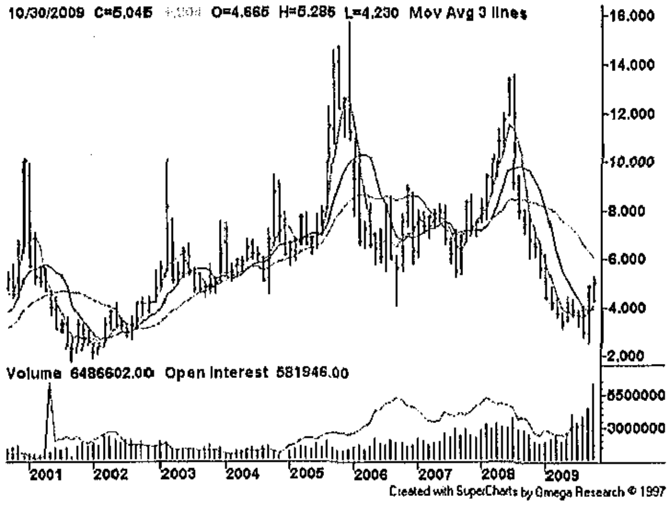
■ Benefit by reduction of technical loss

Reduction of technical loss contributes to saving fuel consumptions at thermal plants.
A gas thermal plant, which dominates Egyptian system, is considered as an alternative plant for evaluation of the economic benefit. Economic benefit by reduction of technical loss is estimated by following formula.

Saving fuel consumption = Decrease of electricity loss x
Cost of alternative plant (GAS) per kWh

Where,
Decrease of electricity loss = Annual electricity sales / *(1- Loss) x Loss reduced*

The cost of the alternative plant was calculated assuming 40% of thermal plant efficiency and gas price. According to the NYMEX, gas unit price have been fluctuating between 4US$ and 12US$ per MMBTU mainly in recent 5 years. In this study, the unit price of 7US$ per MMBTU was assumed as the base case.



■ <u>Benefit by reduction of non-technical loss</u>

In this study, the average electricity tariff was applied as the willingness to pay in order to evaluate economic benefit by reduction of non-technical loss. The benefit is estimated by the following formula.

Willingness to Pay = Increase of electricity sales x averaged Tariff

Where,
Increase of electricity sales = Annual electricity sales / (1- Loss) x Loss reduced

The average electricity tariff is assumed to increase by 5% annually from the 1st construction year until the 5th operation year.

■ <u>Benefit by reduction of outage duration</u>

Reduction of outage duration can contribute to the avoidance of interruption of economic activities. Assuming the 2,000US$/MWh of un-served energy cost as the EEHC's standard procedure, economic benefit by reduction of outage duration is estimated by following formula.

Benefit by reduction of outage duration = Reduction of un-served energy x Un-served energy cost

Where,
Reduction of un-served energy = Annual electricity sales x (Reduction outage duration/ 8,760hrs)

The economic evaluation of the projects is based on the cash flow were calculated as an economic indexes.

The ERR is defined as following equation.

$$\sum_{t=1}^{t=T} \frac{Ct}{(1+R)t} = \sum_{t=1}^{t=T} \frac{Bt}{(1+R)t}$$

Where,

T	=	Last year of the project life
Ct	=	Annual cash flow of the economic cost at the year t
Bt	=	Annual benefit at the year t
R	=	Economic Internal Rate of Return (EIRR)

In general, the discount rate for capital establishment used by international lender organizations such as the World Bank and the Asian Development Bank applied to developing countries is between 8.0% and 12%, and the average value (10%) is normally adopted. The economic evaluation in this study assumes that the discount rate in Egypt is 10.0%.

Results of the economic evaluation are summarized in the following sub-paragraphs.

2) Economic analysis for the project in West Alex

a) EIRR calculation, West Alex

Main features of the project area and the effect by the project are as shown in Table 4-3-2-1. As explained as a pre-condition, price escalation and tax were not considered for the economic analysis, and economic cost was set at 111.5 million US$.

Formulas to calculate the economic benefits are as shown in the previous sub-clause, Clause 3, (2), 1) Pre-conditions for Economic Analysis. Based on the conditions and assumptions, EIRR of the project is 9.3%. Detailed calculation sheet are enclosed in the Appendix 4.3-1.

With taking account that the area is newly developing, further energy growth until 2028 was assumed by 8% of annual growth rate for the estimation of financial benefit. And, 1.5million US$ of maintenance cost was considered in cash flow analysis in addition to the spare parts.

Item	**Description**
Economic Cost [1)]	111.5 million US$
EIRR	9.3%

1) Not considered price contingency and tax

b) Sensitivity analysis on EIRR

Subject to unforeseen changes of the project cost and the financial revenue in the future, a sensitivity analysis on EIRR was carried out in order to clarify the influence of such situation changes to the economic evaluation. Result of the sensitivity analysis on EIRR is summarized as follows.

<u>Fluctuation of the project cost</u>

	Economic Cost
■ Base Case	111.5 million US$
■ +10% increases	122.7 million US$
■ -10% decreases	100.4 million US$

Fluctuation of the fuel cost of alternative thermal power

		Fuel unit price
■	Base Case	7.0 US$/MMBTU
■	+10% increases	7.7 US$/MMBTU
■	-10% decreases	6.3 US$/MMBTU

Under the above cases, the EIRR fluctuates from 10.7% to 8.0% as shown in the followings, which indicates similar value with 10% of the assumed discount rate for Egypt. The project is relatively viable in the view of economic.

Case		EIRR	Note
Project Cost	Fuel Cost		
+10%	+10%	9.0%	
+10%	Base Case	8.5%	
+10%	-10%	8.0%	
Base Case	+10%	9.8%	
Base Case	Base Case	9.3%	Base Case
Base Case	-10%	8.8%	
-10%	+10%	10.7%	
-10%	Base Case	10.2%	
-10%	-10%	9.7%	

3) Economic analysis for the project in North Dakhalia

a) EIRR calculation, North Dakhalia

Main features of the project area and the effect by the project are as shown in Table 4-3-2-2. As explained as a pre-condition, price escalation and tax were not considered for economic analysis, and economic cost was set as 116.9 million US$.

Formulas to calculate the economic benefits are as shown in the previous sub-clause, Clause 3, (2), 1) Pre-conditions for Economic Analysis. Based on the conditions and assumptions, EIRR of the project is 5.4%. Detailed calculation sheet are enclosed in the Appendix 4.3-2.

Item	**Description**
Economic Cost [1)]	116.9 million US$
EIRR	5.4%

1) Not considerd price contingency and tax

b) Sensitivity analysis on EIRR, North Dakhalia

Subject to unforeseen changes of the project cost and the financial revenue in the future, a sensitivity analysis on EIRR was carried out in order to clarify the influence of such situation changes to the economic evaluation. Result of the sensitivity analysis on EIRR is summarized as follows.

Fluctuation of the project cost

		Economic Cost
■	Base Case	116.9 million US$
■	+10% increases	128.6 million US$
■	-10% decreases	105.2 million US$

Fluctuation of the fuel cost of alternative thermal power

		Fuel unit price
■	Base Case	7.0 US$/MMBTU
■	+10% increases	7.7 US$/MMBTU
■	-10% decreases	6.3 US$/MMBTU

Under the above cases, the EIRR fluctuates from 6.7% to 4.2% as shown in the followings.

Case		EIRR	Note
Project Cost	Fuel Cost		
+10%	+10%	4.9%	
+10%	Base Case	4.5%	
+10%	-10%	4.2%	
Base Case	+10%	5.7%	
Base Case	Base Case	5.4%	Base Case
Base Case	-10%	5.0%	
-10%	+10%	6.7%	
-10%	Base Case	6.4%	
-10%	-10%	6.0%	

4) Economic analysis for the project in Helmya

a) EIRR calculation, Helmya

Main features of the project area and the effect by the project are as shown in Table 4-3-2-3. As explained as a pre-condition, price escalation and tax were not considered for economic analysis, and economic cost was set as 170.3 million US$.

Formulas to calculate the economic benefits are as shown in the previous sub-clause, Clause 3, (2), 1) Pre-conditions for Economic Analysis. Based on the conditions and assumptions, EIRR of the project is 16.1%. Detailed calculation sheet are enclosed in the Appendix 4.3-3.

Item	Description
Economic Cost [1)]	170.3 million US$
EIRR	16.1%
NPV [2)]	84.6 million US$
B/C [2)]	1.5

1) Not considered price contingency and tax
2) Based on 10% of discount rate

b) Sensitivity analysis on EIRR, Helmya

Subject to unforeseen changes of the project cost and the financial revenue in the future, a sensitivity analysis on EIRR was carried out in order to clarify the influence of such situation changes to the economic evaluation. Result of the sensitivity analysis on EIRR is summarized as follows.

Fluctuation of the project cost

	Economic Cost
■ Base Case	170.3 million US$
■ +10% increases	187.3 million US$
■ -10% decreases	153.3 million US$

Fluctuation of the fuel cost of alternative thermal power

	Fuel unit price
■ Base Case	7.0 US$/MMBTU
■ +10% increases	7.7 US$/MMBTU
■ -10% decreases	6.3 US$/MMBTU

Under the above cases, the EIRR fluctuates from 19.1% to 13.7% as shown in the followings, which exceed 10% of the assumed discount rate for Egypt. Consequently, the project will have economic viability under the applied conditions and assumption.

Case		EIRR	Note
Project Cost	Fuel Cost		
+10%	+10%	15.6%	
+10%	Base Case	14.6%	
+10%	-10%	13.7%	
Base Case	+10%	17.2%	
Base Case	Base Case	16.1%	Base Case
Base Case	-10%	15.1%	
-10%	+10%	19.1%	
-10%	Base Case	17.9%	
-10%	-10%	16.8%	

(3) Saving the fuel consumption at Thermal Plant (GAS)

Reduction of technical loss by the project will decrease electricity loss, and contributes to saving fuel consumption at thermal plant. Decrease of electricity loss by reduction of technical loss is estimated by following formula.

Decrease of electricity loss = Annual electricity sales / (1- Loss) x Loss reduced

In order to evaluate the decrease of electricity loss, equivalent power plants corresponding to the decrease of electricity losses are calculated by following formula.

$$\text{Equivalent power plant} = \frac{\text{Decrease of electricity loss (technical)}}{\text{8,760hrs x pf}}$$

Where,

pf = Plant factor of assumed plant
In this study, 60% was assumed.

Table 4-3-2-4 summarizes the decrease of electricity loss (technical) and equivalent power plant for each project. For ease of reference, applied data and results of financial and economic analysis are summarized in Table 4-3-3-5.

Table 4-3-2-4 Saving the fuel consumption at Thermal Plant (GAS)

	West Alex	North Dakhalia	Helmya
Decrease of electricity Loss:			
- During operation period[1]	4,088GWh	1,533GWh	8,463GWh
- Annual average	136GWh/year	51GWh/year	282GWh/year
Equivalent power plant[2]	25.9MW	9.7MW	53.7MW

1) Above excludes the benefits by reduction of non-technical loss and reduction of outage duration
2) Equivalent Power Plant was calculated assuming 60% of Plant Factor.

Table 4-3-2-5 Summary of financial and economic analysis

Basic data of the area:		AEDC	NDEDC	NCEDC
Project target area		West Alex	North Dakhalia	Helmya
Averaged Tariff in 2009		0.188 LE/kWh (= 3.42 US Cent/kWh)	0.204 LE/kWh (= 3.709 US Cent/kWh)	0.200 LE/kWh (= 3.660 US Cent/kWh)
Averaged Purchase price from transmission company in 2009		0.119 LE/kWh (= 2.16 US Cent/kWh)	0.146 LE/kWh (= 2.655 US Cent/kWh)	0.149 LE/kWh (= 2.727 US Cent/kWh)
Consumed energy	2008 (2008/09)	999 GWh	1, 986 GWh	4, 538 GWh
Sales energy	2008 (2008/09)	862 GWh [1]	1,748 GWh [1]	3,730 GWh 1)
	2013 (2013/14)	1,266 GWh [2]	2,306 GWh [2]	4,377 GWh 2)
	2028 (2028/29)	4,016 GWh [3]	---	---
Distribution losses	Technical	8.38%	6.70%	12.20%
	Non-Technical	5.38%	5.30%	5.60%
	Total	13.76%	12.00%	17.80%
Outage Duration		146 minutes/year	428 minutes/year	462 minutes / year
Project description:				
Project cost [4]		125.0 million US$	131.1 million US$	190.7 million US$
Distribution Losses after project	Technical	4.65% (△44%)	4.75% (△29%)	6.90% (△43%)
	Non-Technical	1.29% (△76%)	1.27% (△76%)	3.47% (△38%)
	Total	5.95%	6.02%	10.38%
Outage Duration after project		30 minutes/year (△116 minutes / year)	N.A	95 minutes/year (△367 minutes / year)
Financial Analysis: FIRR		5.9%	3.5%	8.2%
Economic Analysis: EIRR [5]		9.3%	5.4%	16.1%
Saving fuel consumption at Thermal Power Plant				
Decrease of electricity (Annual average)		136Wh/year	51GWh/year	282GWh/year
Equivalent power plant		25.9MW	9.7MW	53.7MW

1) Derived from consumed energy with taking account of the losses
2) Derived from consumed energy forecast with taking account of the assumed losses.
3) Derived from 8% annual growth rate assumed
4) Assuming Engineering Services, Tax and Contingency
5) Calculated based on fuel price of 7 US$/MMBTU

Section 4 Capacity Development and Tariff

Clause1 Capacity Development

The model projects can be classified into following two terms.

<To Reinforce Distribution System>
- New construction of 11kV UG feeder
- Capacitor (New installation, Using existing capacitor)
- Replacement of DT from 500kVA/high loss to 1000KVA/low loss

<To enhance Distribution Control System>
-Improvement of load unbalance by LBS of DAS
-WHM (Replace from mechanical to electrical WHM)
- AMR system

It's necessary to enhancement capacity to manufacture low loss modules and construct facilities effectively regarding former one and to operate and maintain control system with understanding the system, regarding later one.
Egyptian side is interested in manufacturing low loss DTs, Improvement of load unbalancing by LBS of DAS and AMR system. In the case, following capacity building option in Table 4-4-1-1 would be notified.

Table4-4-1-1 Capacity Development Option

Model Project	Capacity Development Option
Low Loss DT	Site visit to & discussion with Japanese manufactures Design & technology capacity building
Improvement of Load Unbalancing & AMR system	Site visit to & discussion with Japanese DAS manufacture & power utilities Technology, operation & maintenance capacity building

Clause2 Appropriate Tariff structure

Having studied the current status of EEHC and power business of Egypt, the following changes to tariff system may be worth consideringed;

(1) Tariff revision to promote DSM
Fig. 3-1-4-8 in Chapter 3 shows that the peak hour is approximately 30% higher than the lowest demand. A specific TOU can be designed by dividing a day into peak and off peak hour and assign certain tariff respectively. By doing so, EEHC can target dinnertime demand to reduce it. For instance, 19:00 to 22:00 is defined as the peak hour and the remaining day as the off peak. Peak tariff can provisionally be 30% higher than the usual tariff and off peak tariff can be 30% cheaper. Since Distribution Companies are experimentally installing ARM, provisional TOU tariffs can be tested with these customers who have AMR. Based on these test results, EEHC can finalize the TOU design to country-wide application.
However the tariff system already set high for lighting demand to suppress the lighting demand increase. Furthermore, the public lighting must be paid by the government, therefore revising/increasing the tariff for public lighting has limited or no impact to

general public.Tariff modification should be aimed to cope with increased AC demand, while current evening demand spike and flat demand in daytime suggest that AC is not widely diffused. TOU introduction does not have to be proactive against AC diffusion forecast. It should be reactive.

(2) Tariff revision for the power company to be independent
EEHC is still heavily subsidized as shown in Fig. 4-1-6-1. EEHC could consider increasing all energy tariffs by approximately 3.5pt for every kwh consumption regardless of customer group. This is an initial requirement for the power company to be an independent business. However, we understand that the power tariffs are often designed in consideration of political reasons. The subsidy being provided could be a result of such political matters and research mission refrains from opining on political matters.

Section5 Environmental and Social Consideration

Clause1 Relevant Laws, Regulations and Guidelines

(1) Strategic Environmental Assessment
Egypt has no legal system on Strategic Environmental Assessment.

The JICA Guidelines for Environmental and Social Considerations (JICA, 2004) suggests environmental consideration in an early project stage. It suggests Strategic Environmental Assessment as follows.

"JICA introduces the concept of Strategic Environmental Assessment (SEA) when conducting Master Plan studies, etc., and works with the recipient governments to address a wide range of environmental and social factors from an early stage. JICA makes an effort to include an analysis of alternatives on such occasions. (1.4 Basic Principles regarding Environmental and Social Considerations 2. Measures for environmental and social considerations are implemented at an early stage.)"

(2) Environmental Impact Assessment
The legal system on Environmental Impact Assessment (EIA) in Egypt is laid down by the Environmental Law and Executive Regulation. The Environmental Law (Law Number 4 of 1994) states that the environmental impact of certain establishments or projects must be evaluated before any construction works are initiated or a license is issued by the competent administrative or licensing authority. The Executive Regulation of Law Number 4 of 1994 identifies establishments or projects that are subject to an Environmental Impact Assessment. The Environmental Effect Assessment Principles and Procedures Guide (Egyptian Environmental Affairs Agency, Ministry of State for Environmental Affairs, January 2009) defines the projects by Categories A, B, and C. Category A requires no EIA report. Category B requires a scoped EIA report. Category C requires a full EIA report. Although establishment of electric transmission lines are categorized as B as shown in Table 4-5-1-1, it means transmission lines which has high towers. Low voltage transmission lines managed by the distribution companies are not included in Category B. According to the guideline, this electricity project will be categorized as A[1].

[1] EPS had the meeting with EEAA on Jan 5, 2010 and confirmed.

Table 4-5-1-1 EIA Category of Energy and Infrastructure Projects

Category	Project Type	
Category B	1. Energy	Establishment of operation stations and electric transmission lines
		Solar energy station
	2. Infrastructure	Water desalting stations
		Maintenance of the quay
		Maintenance of shipyard docks (dry and floating docks) for ships
		Purification works for main sewage channels
		Irrigation and sewage water projects
Category C	1. Energy	Electric power generation stations using thermal energy
		Electrical interconnection between continents
		Electric power generation stations using water energy
		Electric power generation stations including their networks
		Electric power generation stations using nuclear fuel
		Electric power generation stations using wind or solar energy and their networks
	2. Infrastructure	Sewage treatment station including sanitation networks
		General desalination stations
		Port pavement
		Establishment of airports and their corridors and airstrips
		Transport systems and highways including metro, bridges and tunnels
		Highways in cities
		Establishment of railway stations
		Commercial, petroleum, mining, and free ports
		Establishment of sewers
		Irrigation, sewage water, dams and ( ) projects

Source: EEAA, 2009

Clause2 Impact Assessment for the Projects of the applied projects

(1) Project information
Applied eight projects are studied for impact assessment. Table 4-5-2-1 shows outlines of the projects.

(2) Study area
The study area is model areas including El Helmya (North Cairo), West Alex (Alexandria), and North Dakhalia (North Delta).

(3) Anticipated Environmental Impact

According to the scoping table (Table 4-5-2-2), five negative impacts are anticipated. Assessed impacts are shown in Table 4-5-2-3.

1) Pollution by hazardous waste

Replaced old distribution transformers might cause pollution. The estimated number of old transformers is around 4,000. It is known that some types of transformers contain PCBs or SF6. However, the possibility would be very low in terms of this project because transformers with PCBs have been prohibited in Egypt. The study team also confirmed that the three distribution companies are not using transformers which contain PCBs. SF6 is usually used for high voltage transformers, but not for low voltage ones. Thus pollution by hazardous waste might occur, but the risks are low.

2) Industrial waste

2,002 distribution transformers (DTs) and 1.3 million Watt Hour Meters (WHMs) will be replaced with new ones. The removed DTs and WHMs will be carried to demolition places and separated into recycle materials and waste. Old oil will also be collected by oil companies. Thus industrial waste will not be a serious problem.

3) Space acquisition

Small space for electric pole will be needed when 11kV OH feeders are constructed. If the area for the pole is private land, the distribution company concerned has to sign a rental space contract with the owner. Although many poles are planned, possibilities of involuntary resettlement are very low. Then space acquisition will not be a serious problem.

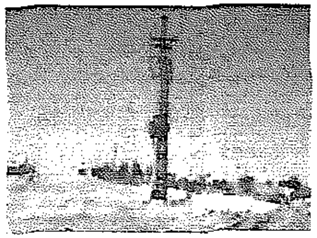
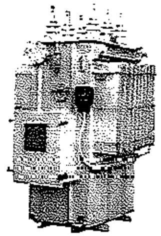
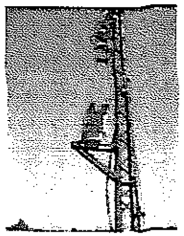
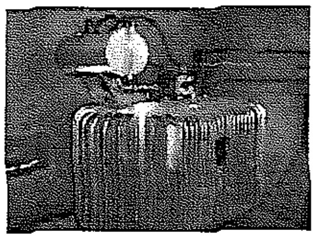
4) Impact on lifelines

Underground oil pipelines, water lines, and gas pipelines might be destroyed by earth work for underground feeder. Although such possibility is high, rehabilitation work can be done in a relatively short time. Thus the impact on lifelines would not be serious.

5) Impact on cultural assets

Earth work for underground feeder might destroy unknown buried cultural assets. However, such earth work is to be done neither deeply nor widely. Thus possibilities of an impact on cultural assets are low.

Table 4-5-2-1 Outline of the projects of long list

	Project	Image	Outline of the Project	Location	Project Size	Space Acquisition	Industrial Waste
Expansion of electricity area	(1) Construction of 11kV OH/UG feeder		Construct 15m poles and lines or 2m underground lines.	Along the road	OH line 2124km, UG line 1878km.	If it is private land, rental contract must be signed.	-
	(2) Installing Step Voltage Regulator (SVR) of OH feeder		Install SVR on the poles.	On the poles	226 SVR (At most 1/feeder (17.7km))	No space acquisition needed on the poles	-
	(3) Installing Distribution Transformers (DTs)		Install the equipment in the Kiosk.	New Kiosk	2002 DT (About 5/feeder (10km))	If it is private land, rental contract must be signed.	-
Upgrading of existing area	(4) Replacement of old DTs		Replace existing DTs with new low-loss DTs	In the existing Kiosk	4000 points		Old DTs (with insulated oil and iron)

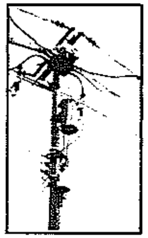
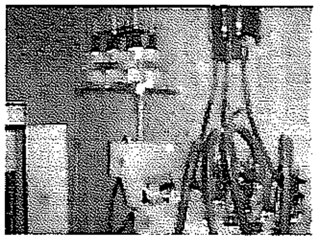
	Project	Image	Outline of the Project	Location	Project Size	Space Acquisition	Industrial Waste
	(5) Installing Upgrading DMS (DAS) control center system		Install computers in the room.	Upgraded Control System	400 m^2		
	(6) Installing equipment related to Upgrading DMS (DAS)		Monitoring devises and communication tools	In the new Kiosks, poles and substations	7000 points	Space should be in the power company's building or substation.	
	(7) Replacement with advanced WHM for AMR		Install AMR for each customer.	Each house	1.3 million points	-	Old meters (iron, copper and glass)
	(8) Installation of Capacitor		Install the equipment in the Kiosk.	In the existing Kiosks	500 points	No need to acquire additional space if existing Kiosks are used.	

Table 4-5-2-2 Scoping Table

Category	Item	Expansion of electricity area			Upgrading of existing area				
		(1) New construction of 11kV OH/UG feeder	(2) Installing SVR(Step Voltage Regulator) of OH feeder	(3) Installing DT(Distribution Transformer)	(4) Replacement of old Distribution Transformer	(5) Installing Upgrading DMS (DAS) control center system	(6) Installing equipment related to Upgrading DMS (DAS)	(7) Replacement Advanced WHM for AMR	(8) Installation of Capacitor
Natural environment	Air								
	Water								
	Soil								
	Waste				(a)			(b)	
	Accidents								
	Water usage								
	Climate change								
	Ecosystems								
	Biodiversity								
Social impacts	Migration of populations and involuntary resettlement								
	Local economic factors such as employment and livelihood								
	Utilization of land and local resources	(c)		(c)					
	Social institutions such as social infrastructure and local decision-making institutions								
	Existing social infrastructures and services	(d)							
	Vulnerable social groups such as the poverty level and indigenous peoples								
	Equality of benefits and losses and equality in development process								
	Gender								
	Children's rights								
	Cultural heritage	(e)							
	Local conflict of interests								
	Infectious diseases such as HIV/AIDS								

Table 4-5-2-3 Impact Assessment

Environmental Impact	Project	Type	Nature	Magnitude	Extent	Timing	Duration	Uncertainty	Reversibility	Significance
(a) Pollution by hazardous waste	(4) Replacement of old Distribution Transformer	Biophysical	Direct	Low	Regional	Immediate	Permanent	Low likelihood	Irreversible	Unimportant
(b) Industrial waste	(7) Replacement Advanced WHM for AMR	Biophysical	Direct	Low	Regional	Immediate	Permanent	Low likelihood	Reversible	Unimportant
(c) Space acquisition	(1) New construction of 11kV OH/UG feeder (3) Installing DT(Distribution Transformer)	Social	Direct	Low	Local	Immediate	Permanent	High probability	Reversible	Unimportant
(d) Impact on lifelines	(1) New construction of 11kV OH/UG feeder	Social	Direct	Moderate	Local	Immediate	Temporary	Middle probability	Reversible	Unimportant
(e) Impact on cultural assets	(1) New construction of 11kV OH/UG feeder	Social	Direct	Low	Local	Immediate	Permanent	Low likelihood	Irreversible	Unimportant

(4) Suggestions for mitigation and monitoring

1) Confirmation of waste management system

A hazardous waste management system should be confirmed during the detailed design stage. If hazardous substances are found, a reliable hazardous management system is needed.

2) Monitoring on waste management

Monitoring on waste management is recommended during the construction stage. Monitoring should be on whether decomposed old equipments are properly separated, and whether industrial waste is treated properly.

3) Survey on cultural assets

Before construction, a survey on cultural assets is recommended. If there is a possibility of buried cultural property, negotiation and agreement with regulatory authorities will be needed.

List of Appendix

Appendix 3:

Appendix 3.1-1 Screening Curve Method

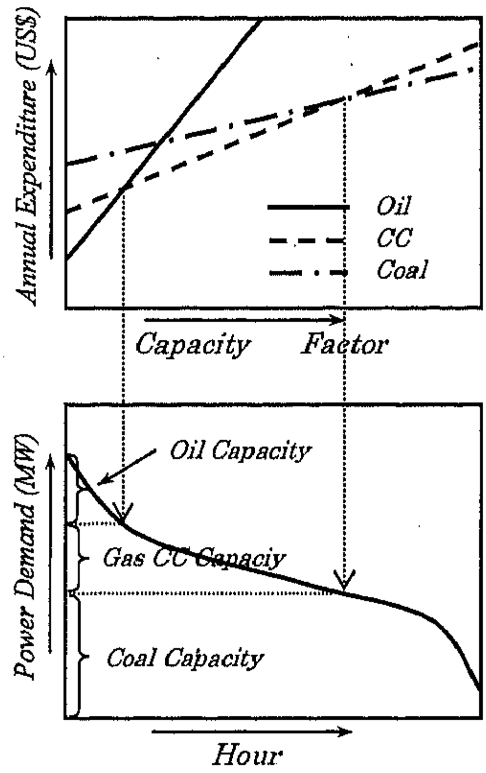
Appendix 3

Appendix 3.1-1 Screening Curve Method

【Screening Curve Method】

The right hand chart shows you the idea of the screening curve. It consists of an annual expenditure graph and a yearly duration curve of peak power demand.

The horizontal axis indicates the capacity factor and the vertical axis indicates the annual expenditure by each power plants. Consequently y intercept means the fixed costs and the gradient of line means the variable costs, which is almost equal with the fuel costs, respectively. For this example, in lower range of the capacity factor, oil fired thermal plants have the lowest annual expenditure and show the best economic performance. As the capacity factor increases, the economical advantage shifts to Gas CC and coal fired thermal plants.



Reflecting the capacity factor at the shifting point of the economical advantage, we can find which sort of power plants should meet which range of the power demand. And simultaneously we can obtain the most economical generation mix, so-called the best generation mix. For this example, the optimal generation mixture can be achieved by using oil fired thermal generation to supply peak load, which involves short periods of operation, coal fired thermal generation to supply base load, which involves long operating hours, and Gas CC to supply middle load, which is positioned midway between the two.

This analyzing method is to find power capacity combination which can minimize generation costs. Since they utilize natural gas as most of all fuel for thermal power plant in Egypt, the cost minimum combination almost means the most effective combination for use of the fuel. Consequently the team employs this method when analyzing energy efficiency of comprehensive power plant.

Appendix 3:

Appendix 3.1-2 Effect of the Energy Efficiency of Installing Energy Storage System (Battery System)

Appendix 3.1-2 Effect of the Energy Efficiency of Installing Energy Storage System (Battery System)

This is a case study of installing the energy storage battery system for electric power system.

Typical Egyptian distribution system is shown below in Fig.1

In this case battery storage system shall be installed at the distributor point. This shall have effect to energy efficiency for both MV main feeder and substation transformers/primary transmission lines. Another reason is capacitance of the distributor point shall be suitable for the battery energy storage system.

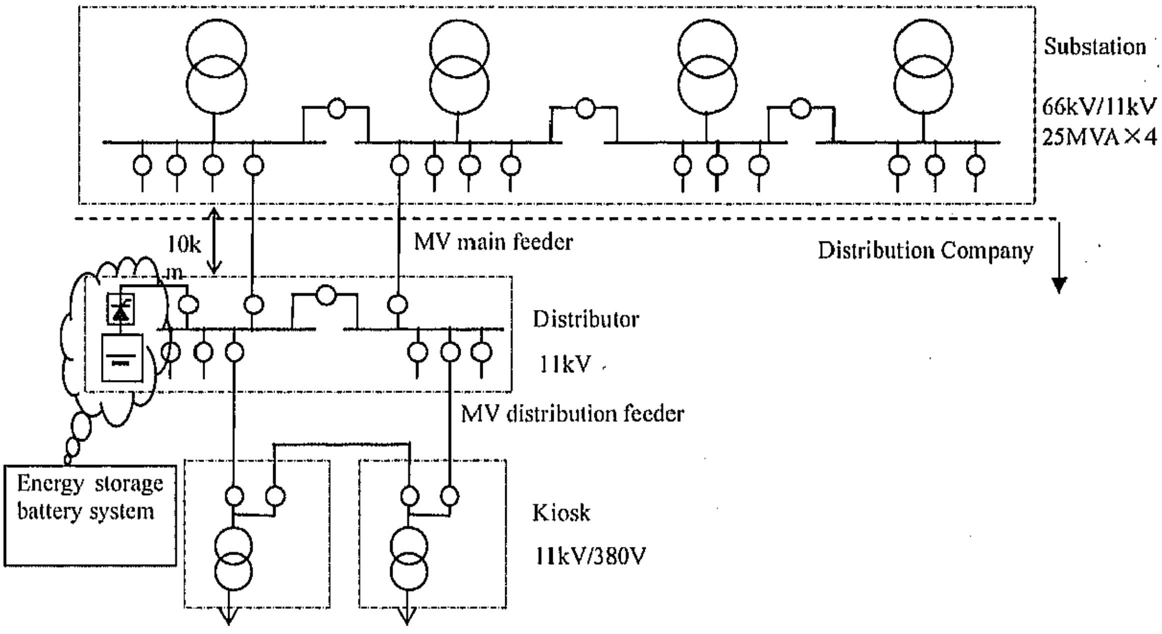


Fig.1. Typical Distribution System in Egypt

According to the daily load curve data of the Alexandria Distribution Company, typical distribution load curve at the distributor of Egyptian urban district shall be like as shown in Fig. 2.

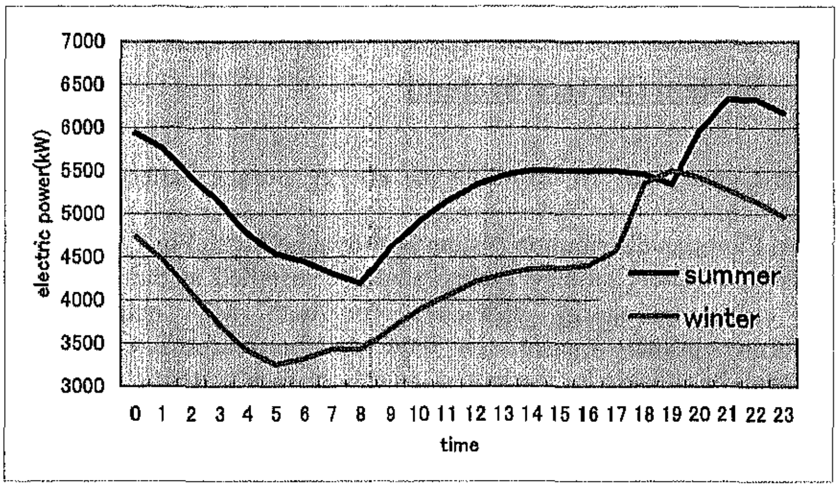


Fig.2 Typical Daily Load Curve of Distribution Line at the Distributor Incoming Feeder

Here, as a study, The battery energy storage system will be installed at the distributor point. *The capacitance of the system shall be 7,200kWh battery and 1,000kW power* conditioning system. (PCS: converter - inverter)

Study results of the simulation for operating energy storage system are shown below in Fig. 3 and Fig. 4.

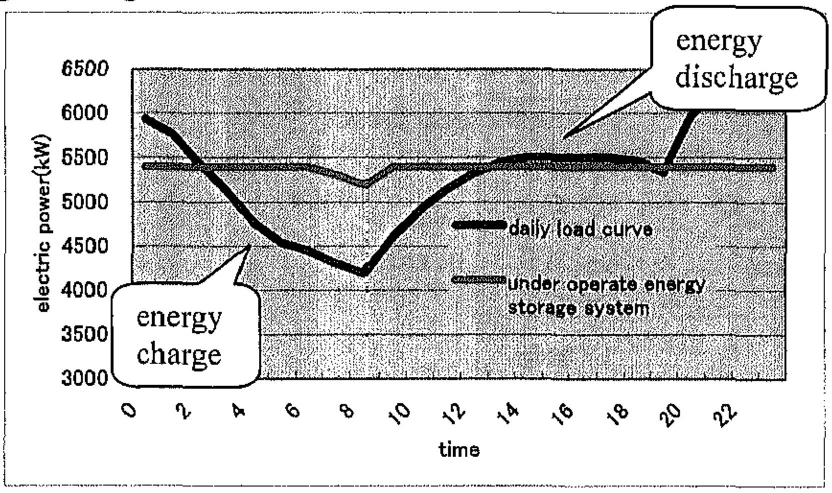


Fig.3 Effect of the Energy Storage Battery System in Summer Daily Load Curve

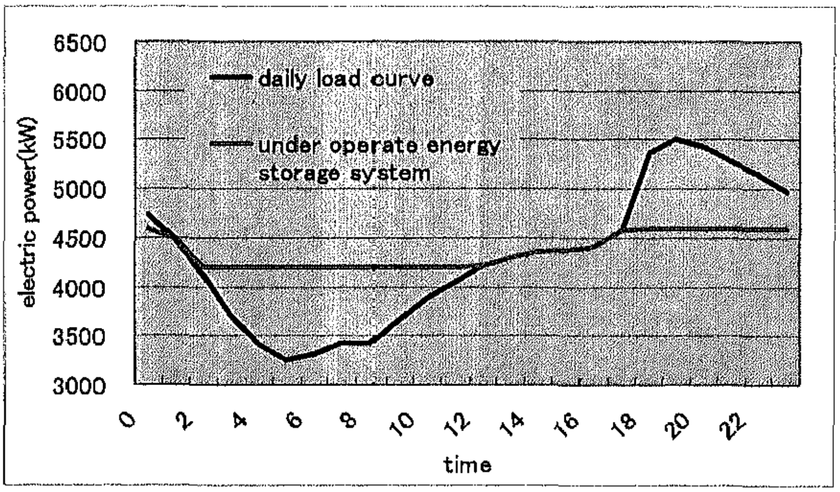


Fig.4 Effect of the Energy Storage Battery System in Winter Daily Load Curve

Daily peak loads shall have reduction of approximately 1,000kW.
This will reduce the main feeder line loss and transformer loss as well.
In despite of the increase of the load every year, no enlargement of transformers and distribution lines will be needed, which may also lead to unnecessity of the power generators.
Although the batteries and the PCSs have converter loss and energy storage loss, energy storage battery system can also compensate reactive power to have the power factor to be going near 1.0 at the distributor point. Then the current loss of the main MV feeder shall have more reduction.
In this simulation case, the loss of the battery storage system and loss reduction of the main MV feeder shall be as shown below in Table 1, considering the MV feeder as XLPE in size 400mm^2 and length of 5km. Power factor shall be about 0.75 only at time of heavy load.

Table.1. Battery Storage Loss and Feeder Loss Reduction in this Simulation Model

	Battery storage loss	Feeder loss reduction
Summer daily curve	1,700kWh/day	960kWh/day
Winter daily curve	1,500kWh/day	830kWh/day

Considering the transformer losses of substation or primary transmission losses, and could operate the system more smartly, the battery loss will turn out to be less than this simulation, where the total battery loss shall be near zero.

Installing energy storage system is not only for reducing distribution loss, but also an effective countermeasure for over loaded facilities. It shall be expected to improve facility utilization ratio and can postpone rebuilding or reinforcing of the facilities.
And it shall also be expected of the same effect as above to the primary network transmission lines when energy storage systems are installed distributed to many of the distribution lines rather than to be installed concentrated in one place.
Moreover, it shall be applied for improvement of fuel consumption of power station by leveling the operation and effective utilization of renewable energy when the large-scale energy storage systems are installed through out the country.
In the present circumstances, energy storage system shall cost more than 20million LE for 1000kW system. When at installation, it is necessary to study effect of reducing cost for electrical network then decide the type of energy storage and the optimum capacity of energy storage system.
In these days, energy storage system is needed in many uses such as electrical vehicle, smart grid network, etc. Along with the mass production, the cost of energy storage system is expected to go down.

Appendix 4:

Appendix 4.1-1 Environmental and Social information of three distribution companies

Appendix 4

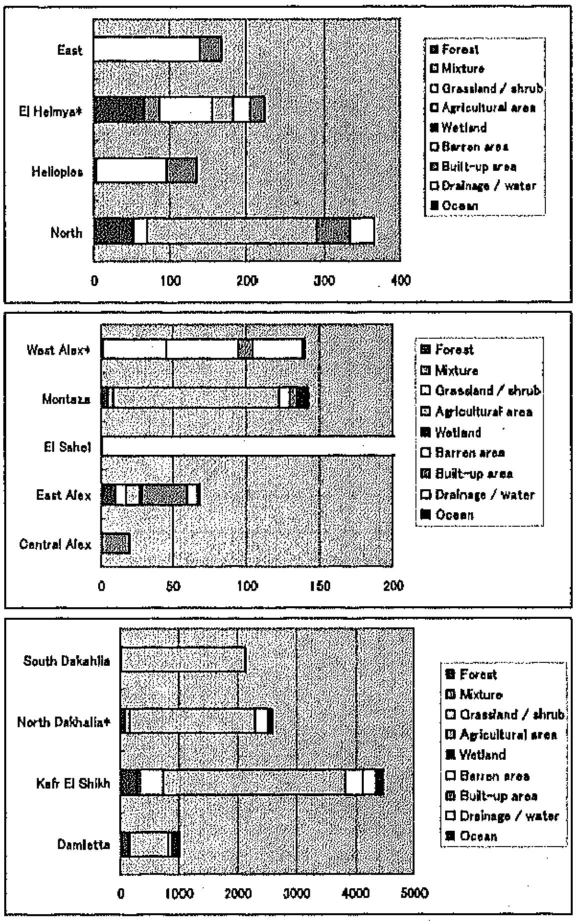
Appendix 4.1-1 Environmental and Social information of three distribution companies

1) Transportation and utilities

All the model areas have primary and secondary roads and railroads. Figure 2 shows main roads and railways in the model areas.

2) Land use

According to the land use data by the International Steering Committee for Global Mapping (ISCGM), types of land use in El Helmya include Forest, Grassland, Agricultural Area and Build-up Area. West Alex includes Grassland, Barren Area, and Built-Up Area. Most of the North Dakhalia is Agricultural Area. Land use rate by sector is shown in Figure 1. Figure 3 is a land use map.

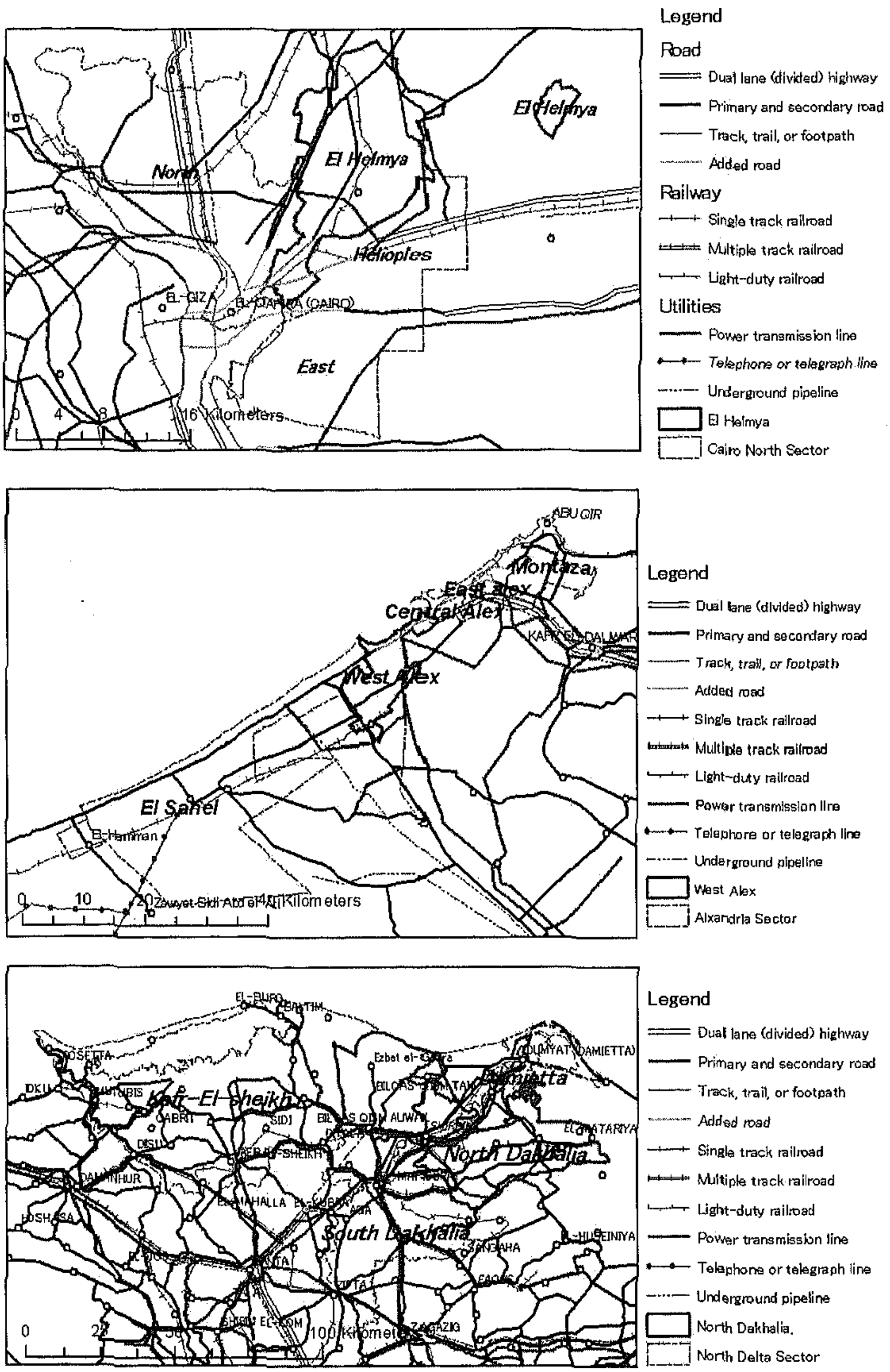


(Source: Global Map Version 0, ISGM)

Fig. 1 Land Use by Sector

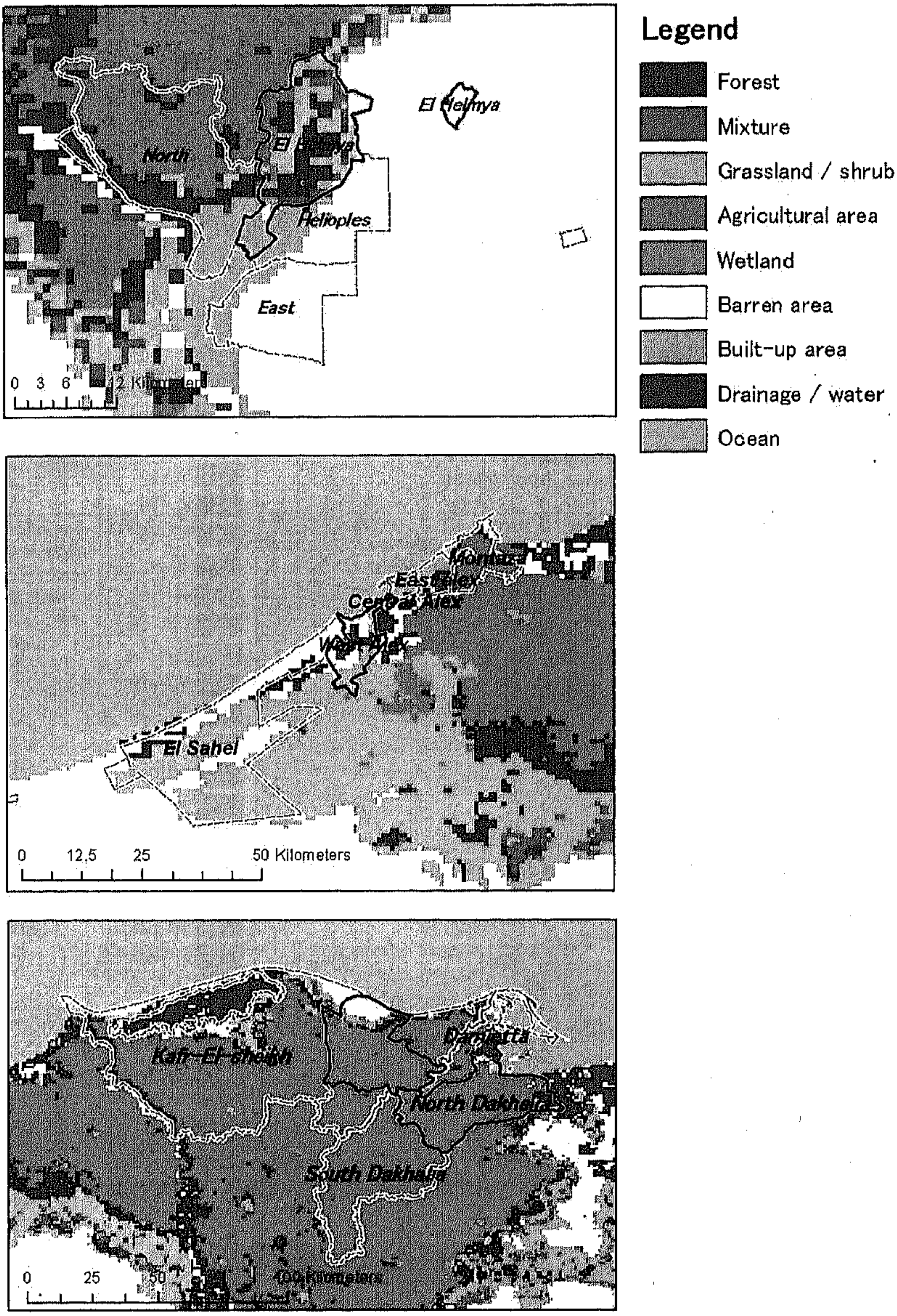
3) Geography

According to the geography data by the ISCGM, the three model areas are flat. The elevation of El Helmya is between 1 to 30m. The elevation of West Alex and North Dakhalia is less than 10m. Figure 4 is an elevation and drainage map.



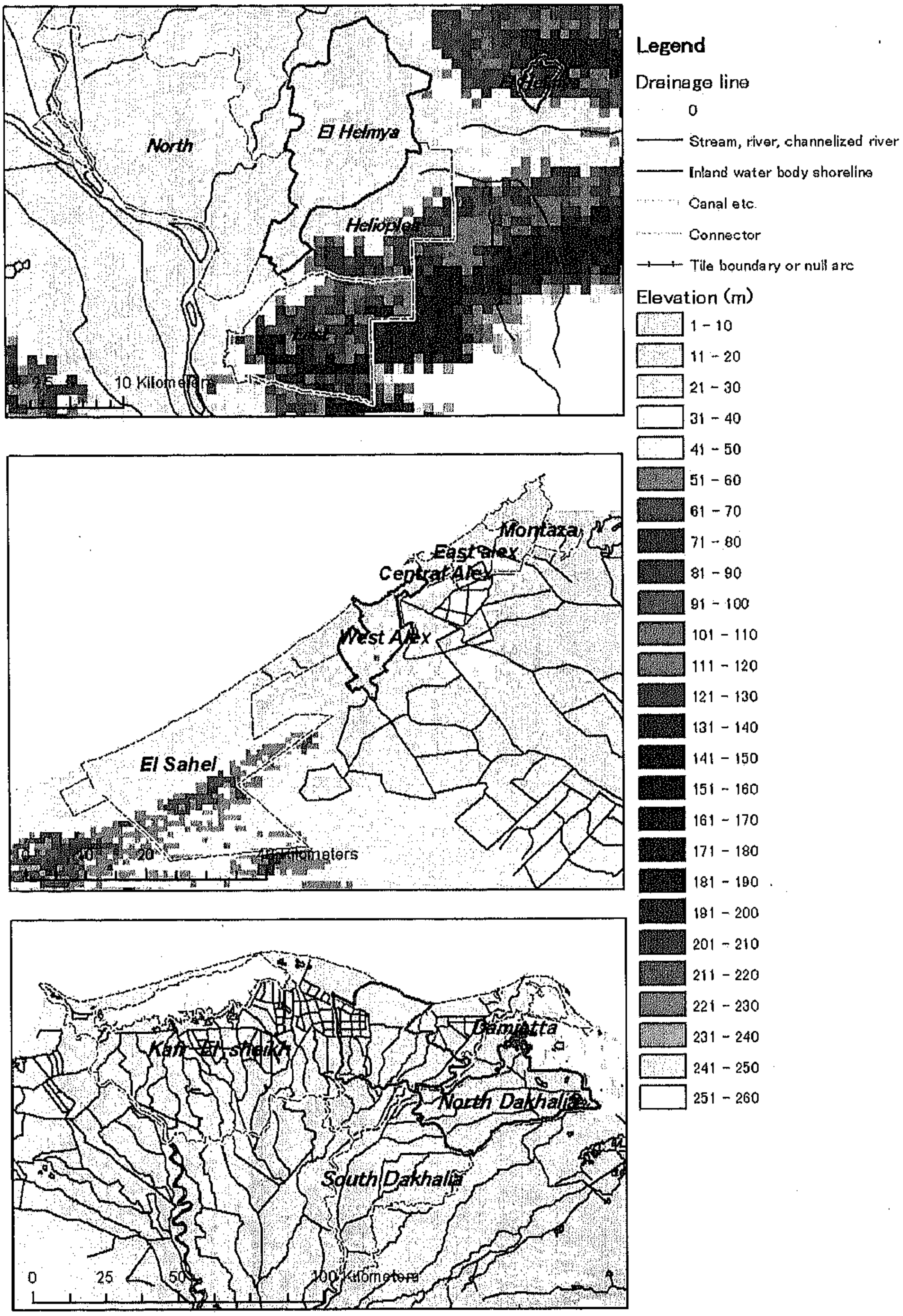
(Source: The Digital Chart of the World <GeoCommunity>)

Fig. 2 Transportation and Utility



(Source: Global Map Version 0 <ISGM>)

Fig. 3 Land Use Map



(Source: Global Map Version 0 <ISCGM>)

Fig.4 Elevation and Drainage Lines