III-9 Power System Operation

1. Power Flow Analysis

(Existing condition)

Actual power flow of each transmission line in the MEA at the time of peak load of the whole system is tabulated each month in the System Controlling Department.

For the purpose of planning, the MEA performs power flow calculations using computer.

(Results of analysis)

(1) Normal power flow

Power flow diagram of the MEA power system at 15:00 o'clock, September 12, 1979, is shown in Fig. 42. On the basis on this diagram and transmission facilities data of the MEA, a comparison was made of the safety current of the transmission line and the actual load current of each transmission line outgoing from terminal station.

The ratios of load current to transmission line allowable current are as shown in the table below. 70% of the existing transmission lines are operated at less than 50% of load current ratio.

Each existing transmission line was checked and no case exists which will be a problem from the standpoint of power flow.

Unit: Number of circuit
Date: p.m. 3:00 Sep. 12, 1979

Safety current (Ampere) \ Ratio of load current (%)	Less than 30	31~40	41~50	51~60	61~70	71~80	81~90	Total
790 (MCM795)	3	3		3	1	1	1	12
1,580 MCM795 2 wires	4	1	3	1				9
3,160 MCM795 4 wires	2							2
Total	9	4	3	4	1	1	1	23

Note : Ratio of load current $= \frac{\text{load current}}{\text{safety current}}$ (%)

(2) Impedance map and fault calculation example (69 kV System)

An impedance map was prepared for the MEA 69 kV system to which the power supply system of the EGAT is connected, and the result is given in Fig. 43, "Impedance Map of MEA System". The impedances at 69 kV buses of terminal stations facing the power source side are given in the table below.

Positive phase 100 MVA base (1980)

Substation	Impedance (%)	Substation	Impedance (%)
NORBKK	$3.575\underline{/89.4^\circ}$	BKKNOI	$6.820\underline{/89.2^\circ}$
LAPRAO	$6.898\underline{/89.0^\circ}$	SOUBKK	$3.284\underline{/89.2^\circ}$
BAKAPI	$7.009\underline{/89.1^\circ}$	BAPLEE	$5.062\underline{/87.7^\circ}$

Using these impedances as bases, fault calculations were made of fault currents and fault voltages during 3-phase short-circuiting at the incoming ends of 7 distribution substations of the 69 kV system supplied from Bangkapi Substation. The results as given in Fig. 44 show that the fault current which was approximately 12,000 A at the outgoing structure of Bangkapi Substation and was about 7,000 A at the incoming ends of the distribution substations.

On the other hand, the momentary current capacity of a 69 kV transmission line, AAC 400 mm^2 (corresponding to 795 MCM) will be:

with current impression for 0.1 sec.	117,600 A
with current impression for 0.2 sec.	83,000 A
with current impression for 0.5 sec.	52,600 A

Comparing the fault current and current capacity of transmission line, no problem is found under existing conditions.

The required interrupting capacity is 3,045 MVA at the 69 kV bus of South Bangkok where the maximum fault current flow occurs in the entire system. The capacity of circuit breakers of MEA for 69 kV is 5,000 MVA as a standard so that there will be no problem.

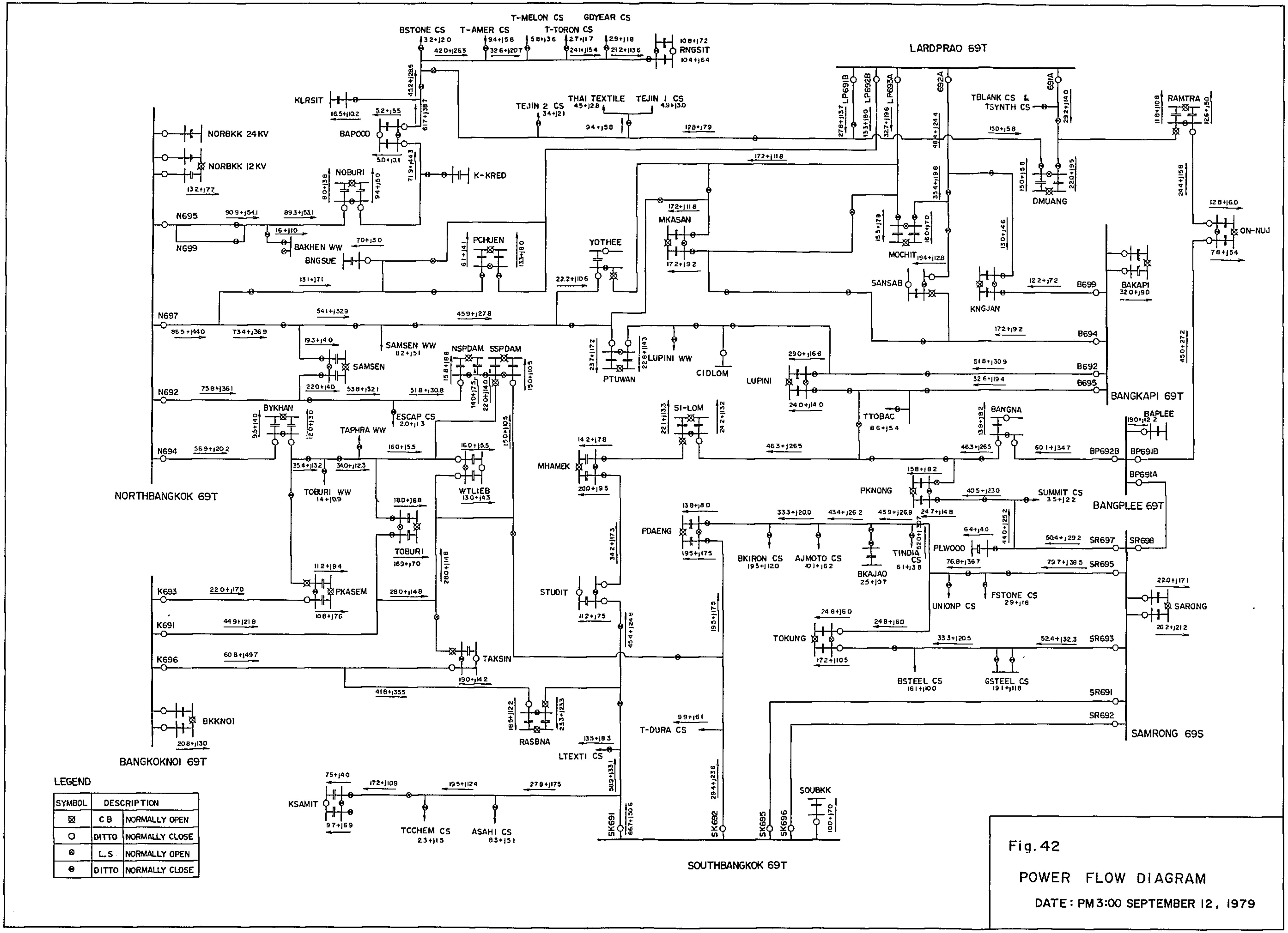
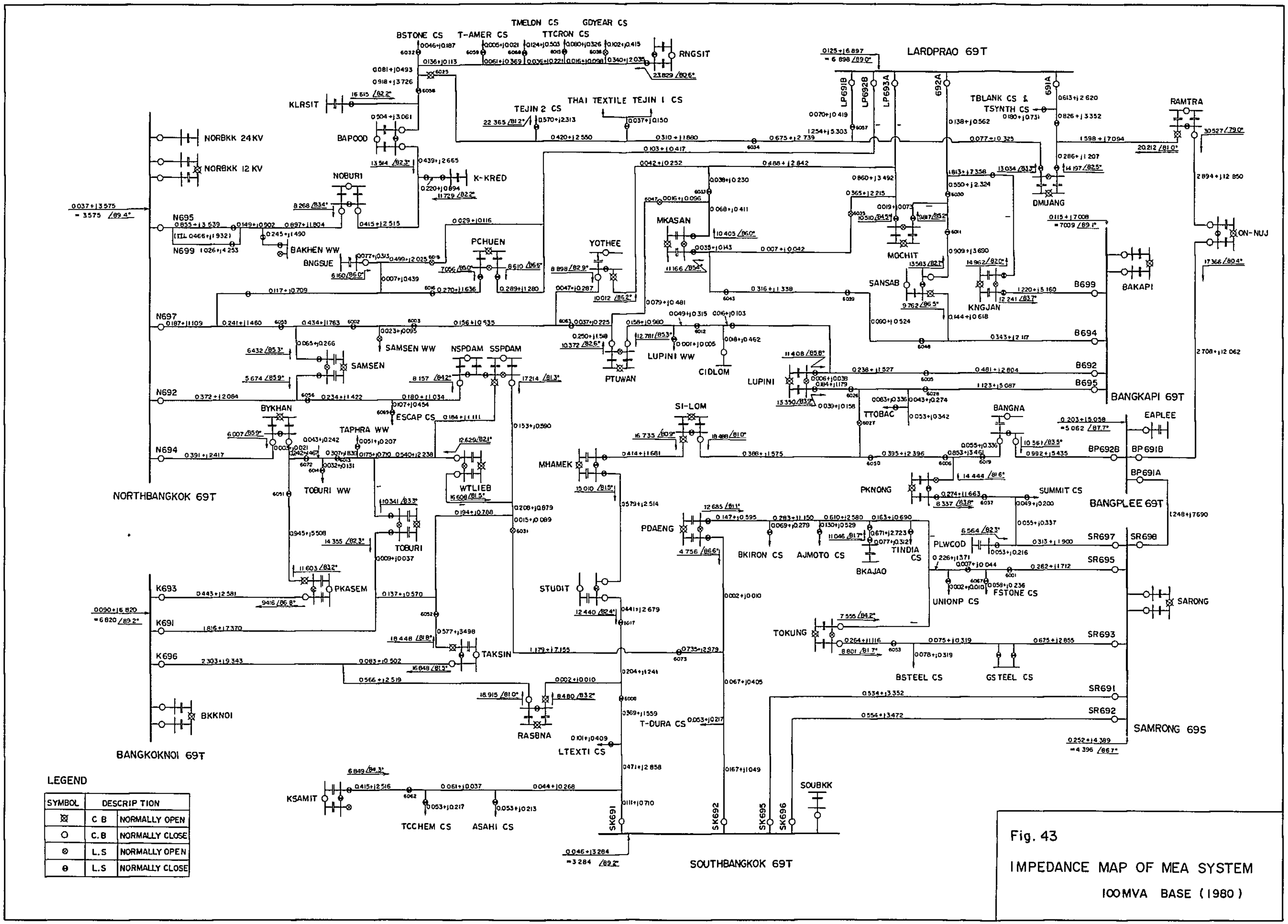


Fig. 42

POWER FLOW DIAGRAM

DATE: PM 3:00 SEPTEMBER 12, 1979



LEGEND

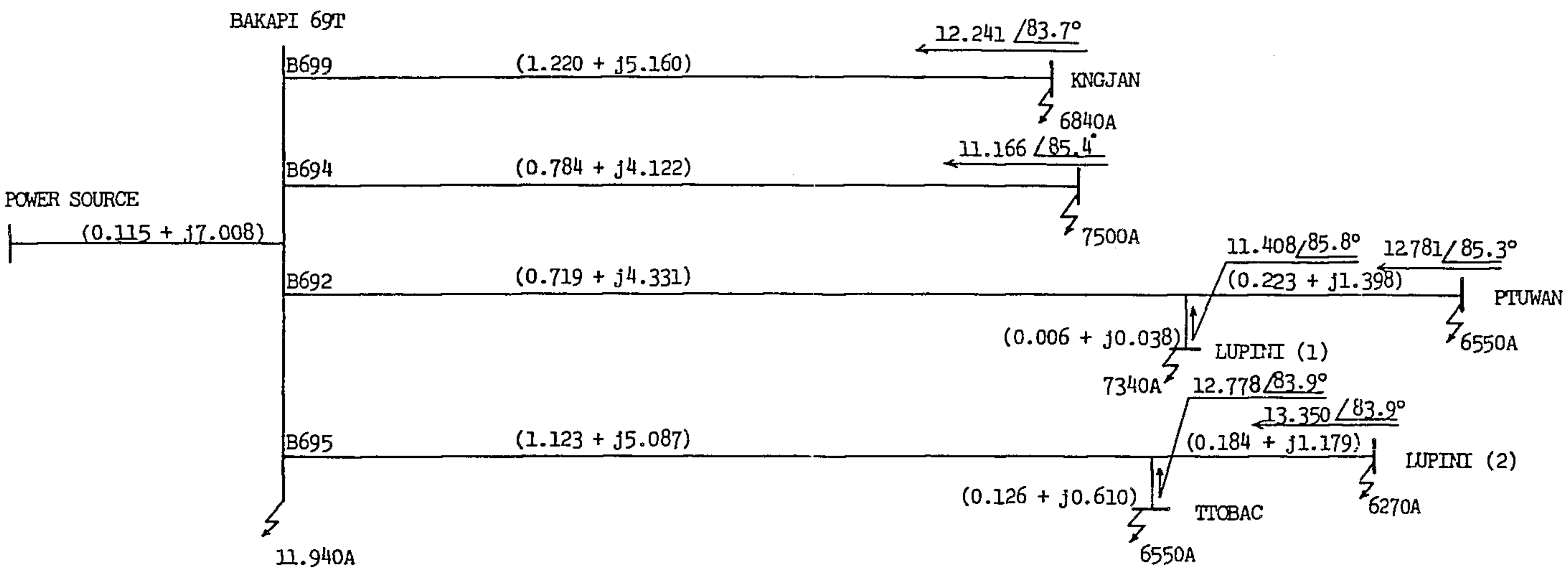
SYMBOL	DESCRIP TION	
⊠	C B	NORMALLY OPEN
O	C.B	NORMALLY CLOSE
⊗	L.S	NORMALLY OPEN
⊖	L.S	NORMALLY CLOSE

Fig. 43

IMPEDANCE MAP OF MEA SYSTEM

100MVA BASE (1980)

FIG 44 FAULT CALCULATION (three-phase short-circuit)



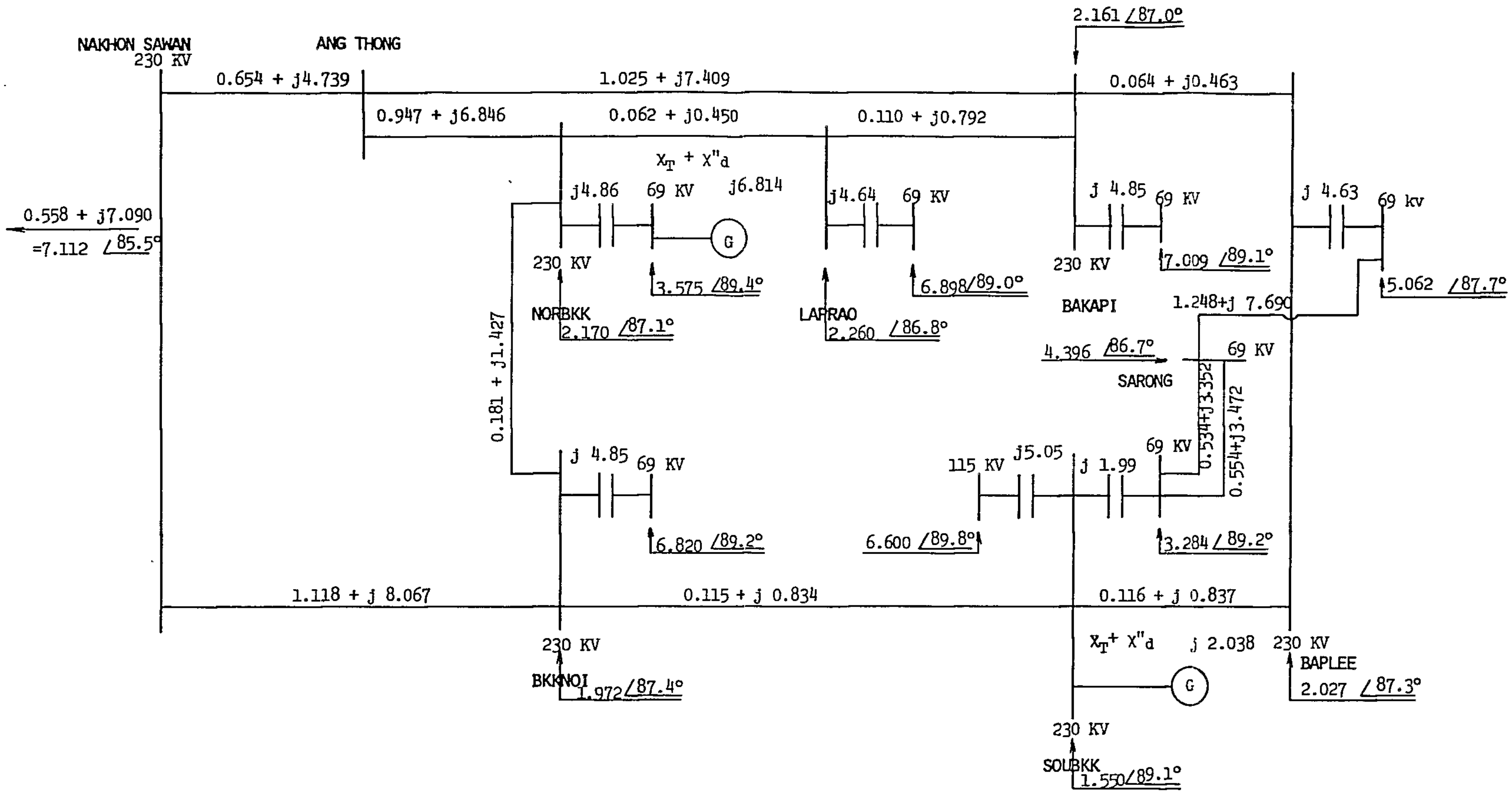
Calculation Results

Fault location	Fault current (A)	Voltage during fault (%)						
		BAKAPI	KNGJAN	MKASAN	PTUWAN	LUPINI(1)	LUPINI(2)	TTOBAC
BAKAPI	11940	0	0	0	0	0	0	0
KNGJAN	6840	43	0	43	43	43	43	43
MKASAN	7500	37	37	0	37	37	37	37
PTUWAN	6550	45	45	45	0	11	45	45
LUPINI (1)	7340	39	39	39	0	0	39	39
LUPINI (2)	6270	48	48	48	48	48	0	9
TTOBAC	6550	45	45	45	45	45	5	0

Notes;

1. Figure in parenthesis shows power source impedance (%) and line impedance (%) (100 MVA Base)

2. Fault current = $\dfrac{100 \times 1{,}000 \text{ (kVA)}}{\sqrt{3} \times 69 \text{ (kV)} \times Z \text{ (\%)}} \times 100$ (A)



Positive phase % impedance
(100 MVA base)

2. Voltage Control

(Existing condition)

Voltage to customer and target operating voltages of the MEA system are controlled according to the following table.

(1) Target operating voltage

Unit: volt

Nominal System Voltage	240/416	12,000	24,000	69,000	115,000
Target operating voltage					
Voltage at substation bus					
– Min.		11,200	22,400		
– Max.		11,800	23,600		
Service voltage to customer					
– Min.	214	10,900	21,800	66,000	110,300
– Max.	231	11,800	23,600	70,800	117,900
Target operating voltage during fault					
Voltage at substation bus					
– Min.		11,100	22,200	67,200	112,300
– Max.		12,000	24,000	72,500	121,000
Service voltage					
– Min.	209	10,800	21,600	65,400	109,300
– Max.	239	12,000	24,000	72,500	121,000

(2) Allowable voltage drop in distribution line

Allowable voltage drop is regulated by standard as below, and Fig. 45 and Fig. 46 show typical profile.

Primary (12 kV)

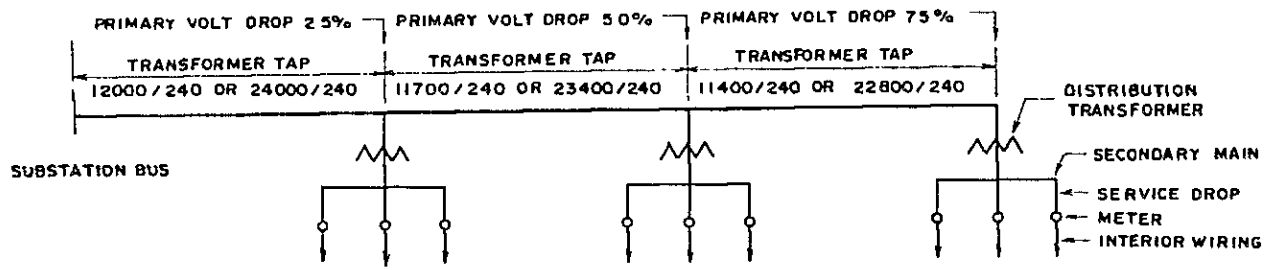
	Heavy load	Light load
Substation bus	11,800	11,200
Primary voltage drop	900	270
Line end voltage	10,900	10,930

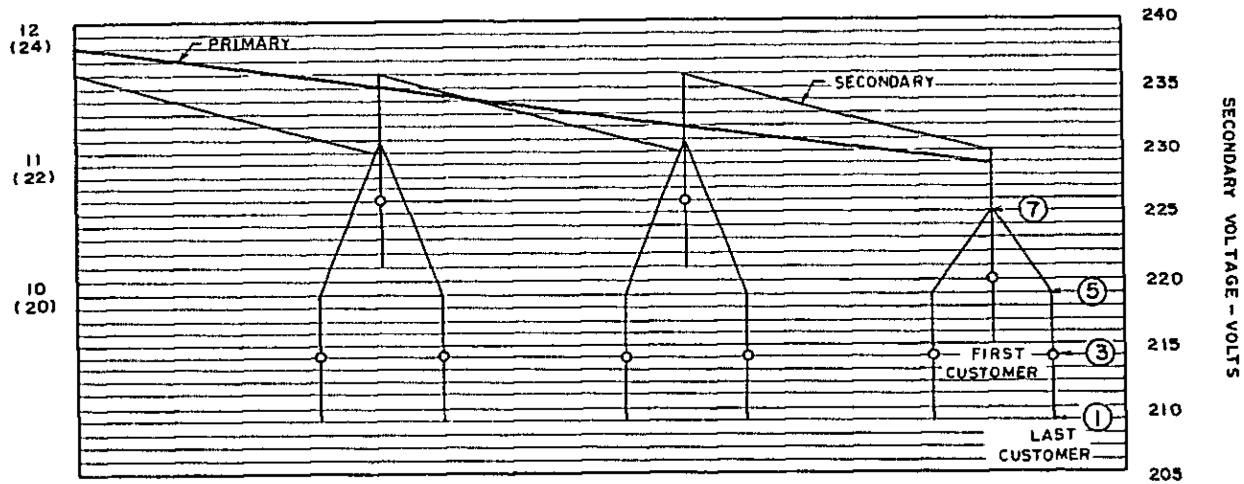
Note: In case of 24 kV system above figure must be doubled.

Secondary (240/416 V)

	Heavy load		Light load	
	Maximum	Minimum	Maximum	Minimum
Inner voltage drop of pole transformer	5	5	1	1
Secondary voltage of transformer	231	225	231	221
Voltage drop at the secondary line	12	6	2	2
Voltage at the secondary line end	219	219	229	219
Voltage drop of service wire	5	5	1	1
Terminal voltage of WHM	214	214	228	218
Voltage drop of interior wiring	5	5	1	1
Utilization voltage of interior wiring end	209	209	227	217

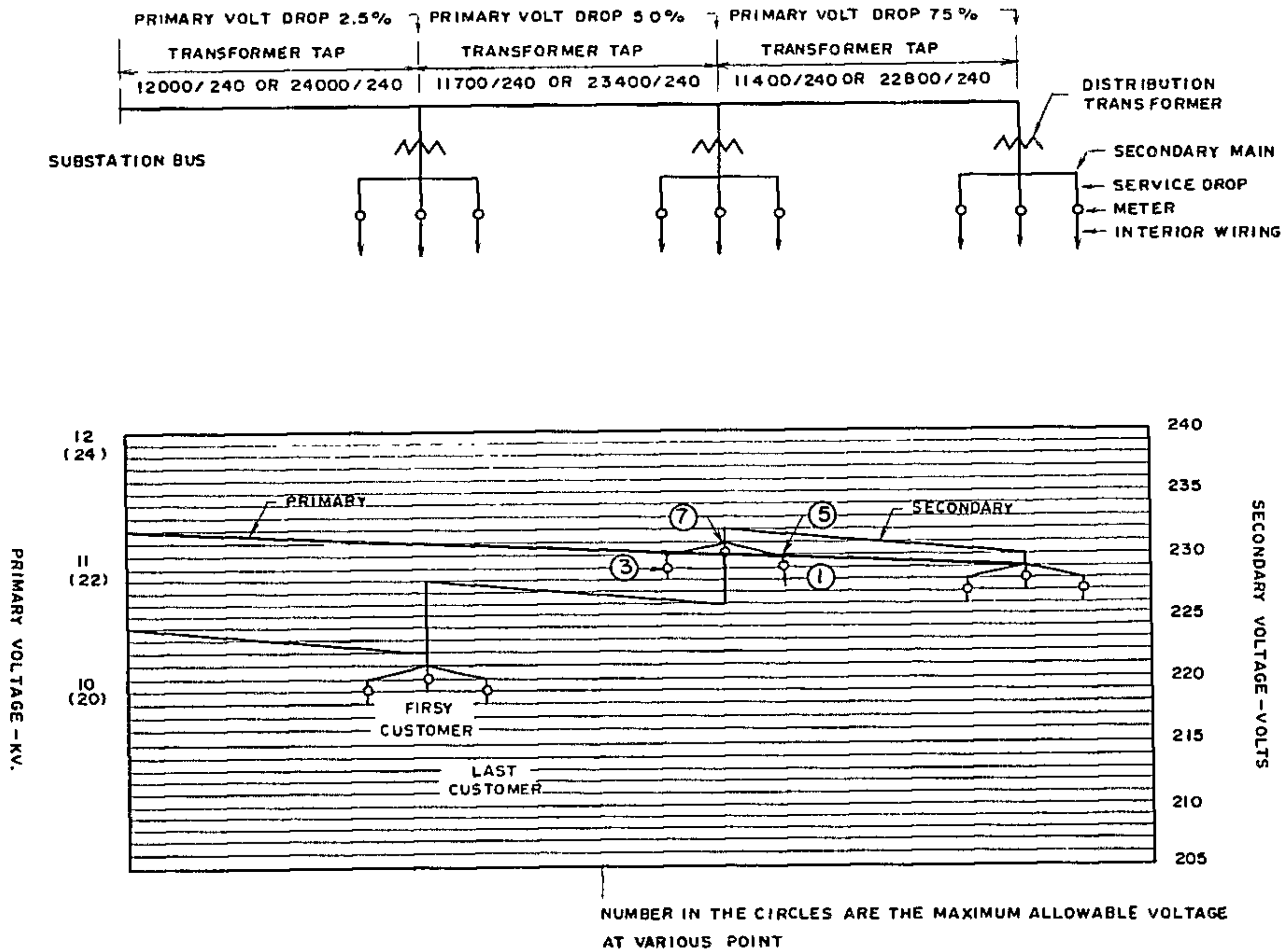
FIG 45 TYPICAL VOLTAGE PROFILE DURING HEAVY LOAD PERIOD





NUMBER IN THE CIRCLES ARE VOLTAGE LIMIT AT VARIOUS POINT

FIG. 46 TYPICAL VOLTAGE PROFILE DURING LIGHT LOAD PERIOD



(3) Selection of tap of primary winding of distribution transformer

Distribution transformer has five taps in primary winding at 12,000 V, 11,700 V, 11,400 V, 11,000 V and 10,800 V.

Selection of tap is regulated as follows.

	Trans. tap
Up to and including 2.5% in primary voltage drop from substation	.... 12,000/240
2.5 ~ 5.0% 〃 〃	.... 11,700/240
5.0 ~ 7.5% 〃 〃	.... 11,400/240

(4) Voltage unbalancing

The percentage of voltage unbalance among three phases should not exceed 2.5%.

where

$$\% \text{ unbalance} = \frac{\text{Maximum deviation from average voltage}}{\text{Average voltage of three phases}} \times 100$$

(Results of analysis)

(1) Voltage drop at end of transmission line is as shown in the table below.

Unit: Number of circuit
Date: p.m. 3:00, Sep. 12, 1979

Ratio of voltage drop (%)	Less than 2	2.1 ~3	3.1 ~4	4.1 ~5	5.1 ~6	6.1 ~7	7.1 ~8	8.1 ~9	9.1 ~10	More than 10	Total
Existing number of circuit	14	3	2				2			2	23

According to the table above, the voltage drops are 4% or less in 83% of 23 transmission lines.

Transmission lines with voltage drop exceeding 10% are the following:

Transmission line serving Silom from Bang Plee Substation	.... 11.7%
Transmission line serving Rangsit from North Bangkok Substation	.... 11.2%

(2) The existing standard is established in accordance with "Voltage rating for electric power system and equipment" of ANSI (American National Standard Institute) C84, 1-1970.

However, there are some points which require clarification, such as how the voltage standard and how the service voltage to customers are maintained. The MEA does not make periodic measurement of the service voltage at the consuming end. This may be probably because the MEA believes that voltage drop would not exceed the allowable limit insofar as the load on the transformer is within the limit of the transformer capacity.

However, the above approach, if used, is not helpful to optimization of the voltage standard because the distribution pattern of load varies from time to time. In Japan, voltage drop for customer service at each load point is checked and controlled by computer and, if and when necessary, actually measured. It is therefore advisable that the MEA should also consider adoption of the voltage control system for check and confirmation by periodic voltage measurement on problematic points on the distribution system.

There are two alternatives to be considered as the applicable method of voltage control.

a. Actual voltage measurement by recording voltmeter on the sampling taken from customers.

b. Calculation of voltage drop as a part of distribution transformer load control system.

(3) Fluctuation in system voltage is generally normal, except one or two substations. It is because main transformers of distribution substations have automatic tap changer.

However, voltage flickering is now occurred at few areas, so that we recommend that if voltage flickering is originated in the load fluctuation of the big customer, anti-flickering equipment should be installed on big customer's own responsibility.

3. Load Dispatching Operation

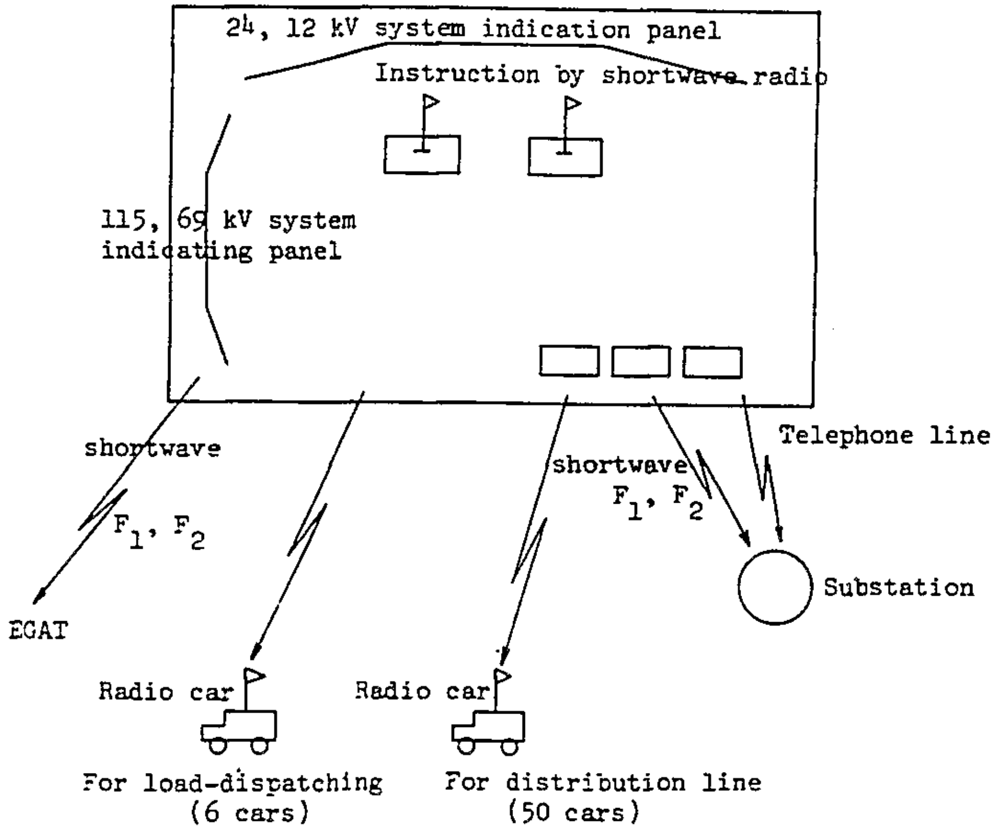
(Existing condition)

Load dispatching operations at the MEA are carried out from a dispatching center at the MEA head office. Communication with EGAT, MEA substations and district offices are made expeditiously by telephone and radio (2 bands of shortwave available).

Communication with patrol radio cars is made by 2 bands of shortwave.

Such status is shown in Fig. 47,

Fig. 47 Load-dispatching Center of the MEA Head Office

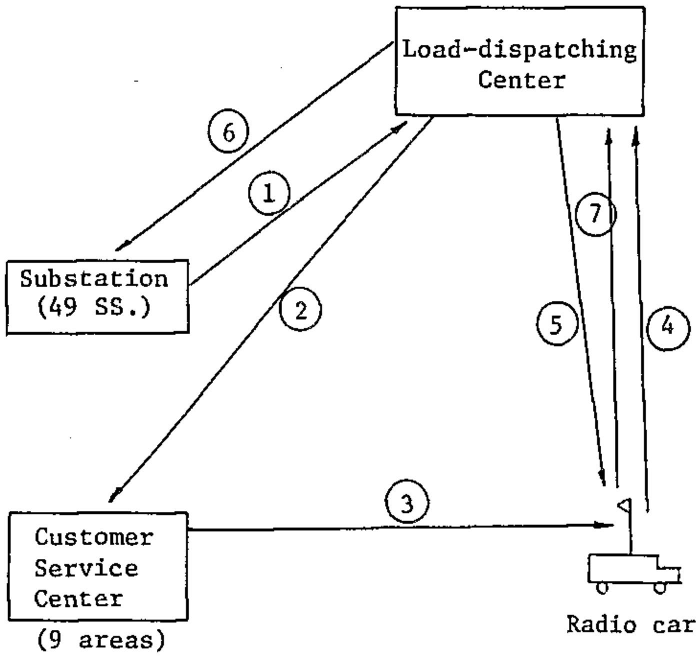


To fulfil service responsibility 24 hours a day, four groups are on duty in the dispatching room in three shift pattern. One group consists of two dispatchers and two technicians.

Normal procedure in case of fault occurrence on distribution line is shown in Fig. 48.

On the other hand, work is going ahead for remote supervision and control of various substations in a new dispatching center under construction inside of Chidolom substation. After completion of this center, it will contribute greatly to improve reliability and operation of MEA's system.

Fig. 48 Normal Procedure in case of Fault Occurrence on Distribution Line



The following steps are taken to locate fault and to recover the fault.

1. Situation of fault (name of feeder, tripped relay, etc.) is reported to dispatching center. (Sometimes, customer inform district office.)

2. Dispatching center gives such information to district office.

3. District office sends out maintenance crew.

4. They report on arrival at the scene.

5. Dispatching center gives order to maintenance crew to locate fault section, while keeping contact with substation concerned. In case of permanent fault, maintenance crew switch off the sectional switches to cut off the fault section from the line, and switch in interlinked switches to supply energy to non-fault sections.

6. Dispatching center gives order to close the circuit breaker of the feeder, after cutting off of fault section.

7. Maintenance crew locate trouble spot, and repair the trouble. After repair work is finished, each switch is operated to recover to normal operation status.

(Results of analysis)

The MEA is constructing a new control center equipped with a computer, and it is expected that supply reliability will be greatly improved once this center is completed. Such plan is natural considering the social responsibility of the MEA, and this is thought to be an epoch-making and significant step for the MEA to modernize its operations.

In this case, procedure of load dispatching will become more simple, as follows:

(Existing)

(Individual substation)

Supervision → Calling → Communication, Discussion →

Judgement → Dispatching order → Receiving → Operation

(Individaul substation)

(After improvement)

Supervision —— Direct connection → Operation

The expected benefits by such improvement are quick response, proper handling, efficient operation of facilities and labor savings.

Fundamental condition of improvement is capability to centrally carry out remote supervision, recording and control of individual substations. By this method, supply reliability will be greatly improved.

One thing to be studied is that when the number of substations to control increase in the future, there will arise the difficulty of control if multiple faults occur simultaneously. At such time, provision of district control offices should be studied.

4. Maintenance of Facilities

(Existing condition)

In the MEA regulations or standards for maintenance works of facilities are not established.

Patrol, inspection and measurement are carried out from time to time on subtransmission lines and distribution lines only in principal area.

Usually, irregular status of facilities are reported by money collector or meter reading man and sometimes by customer.

When a construction work is needed, the MEA staff examine the existing status in detail for the sake of designing procedure.

This is an opportunity to identify irregular status, including overloading of distribution transformer, big voltage drop, overcurrent of line, damage of facility, change of environmental condition, etc.

For purpose of easy maintenance, MEA installed several CSP (completely self protecting) type of distribution transformer which has an indication lamp for overloading. But, overloading indicated by lamp is found and reported by money collector or meter reading man or by customer.

Inspection of wooden pole and checking of grounding resistance of grounding devices are also not executed periodically.

(Results of analysis)

Facilities for transmission, substation and distribution, respectively possess important functions and the effects of faults occurring at these facilities are considerable.

Further, because of the nature of electrical facilities, there must be adequate thought given to safety measures for protection of the lives and property of the public and employees.

Therefore, thorough considerations must be given in planning and designing for construction.

However, in order to properly maintain the functions of facilities and to secure safety and preclude accidents, maintenance works on a day-to-day basis must be carried out.

Regarding this point, the MEA has established standards for various facilities, educated its employees, and has made every effort to fulfil its role as an electric utility enterprise.

The labor and expense required for maintenance are tremendous, but it is very important to maintain the proper upkeep and operation of facilities and to locate promptly problems in existing facilities.

III-10 Utilization Factor of Facilities

(Existing condition)

Facilities of the MEA System are well coordinated from the standpoint of installed capacity. But utilization factor of facilities under normal operation is low. As indicated in Table 13 the utilization factor is an average of 55.7% for distribution transformer at substations and 62.0% in distribution feeders.

In the MEA, a major problem hereafter will be to upgrade utilization factor without degrading service reliability, that is, to improve the efficiency of investment for facilities.

Table 13 Utilization Factor

September 1979

* Distribution Substation

Utilization Factor	No. of D/S	%
0 ~ 40%	6	14.0
~ 50	5	11.6
~ 60	16	37.2
~ 70	9	20.9
~ 80	5	11.6
~ 90	2	4.7
~ 100		
More than 100%		
Total	43	100

- Averaged monthly utilization factor: 55.7%
- Detailed data are shown in Appendix 11.

* Distribution Feeder

Utilization Factor	No. of Feeder	%
0 ~ 10%	11	4.0
~ 20	3	1.1
~ 30	14	5.0
~ 40	21	7.6
~ 50	24	8.7
~ 60	33	11.9
~ 70	53	19.1
~ 80	57	20.6
~ 90	39	14.1
~ 100	15	5.4
More than 100%	7	2.5
Total	277	100

- Average utilization factor: 62.0%
- Detailed data are shown in Appendix 12.

(Results of analysis)

1. Utilization Factor of Transformers at Substations

In general, the utilization factor should be considered in relating to system reliability. If the utilization factor is low, it means that there is a reserve in capacity, and it is possible to take over a part or all of the load of another facility out-of service due to fault. It may be said that reliability is high, but on the other hand, it may be said to be uneconomical from the aspect of effective utilization of facilities.

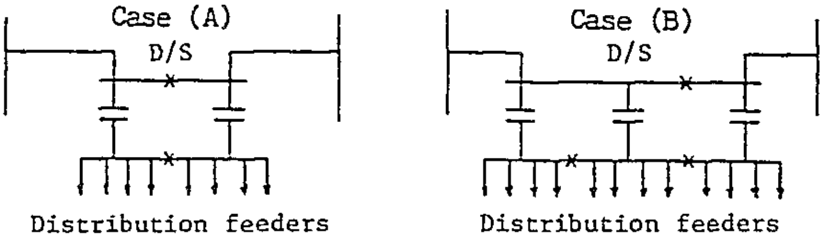
Utilization factor of transformer at substation is deeply related to composition of distribution system. In the MEA's facility standard, two banks system is normal and distribution system is radial type. (Fig. 49, Case A) Therefore, if the full load of a bank out-of service is to be taken over, the normal load of each transformer must be less than half of rated capacity. In this case, utilization factor of transformer can not exceed 50%.

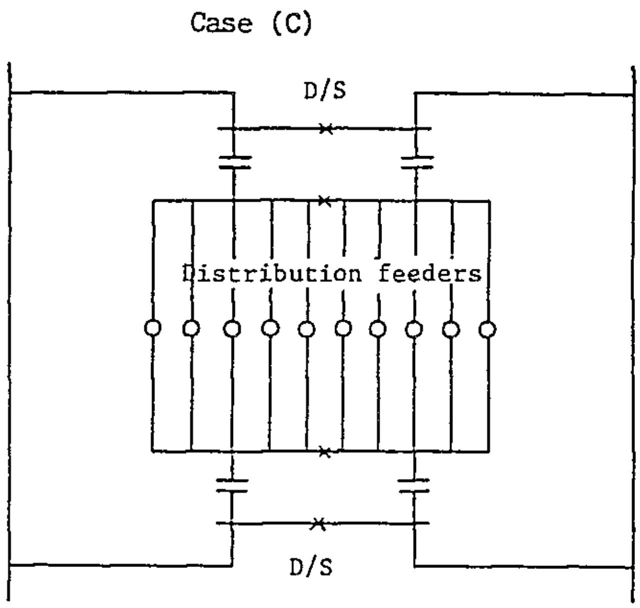
If a substation has three banks (Fig. 49, Case B), each transformer can be operated at 67% of rated load at maximum to take the full load of a bank an out-of service. In this case, utilization factor of these three transformers becomes 67%.

In the same manner, if distribution feeders supplied from two substations are completely interlinked (Fig. 49, Case C), utilization factor can be raised up to 75% with the same condition of reliability. In case of full interlinkage of feeders from four substations (Fig. 49, Case D), each transformer can be operated at 88% of utilization factor.

The MEA must make studies to revise its facility standards including increase of bank at each substation and strengthening of interlinkage of distribution feeders for the sake of improvement of utilization factor.

Fig. 49 Pattern of System Composition



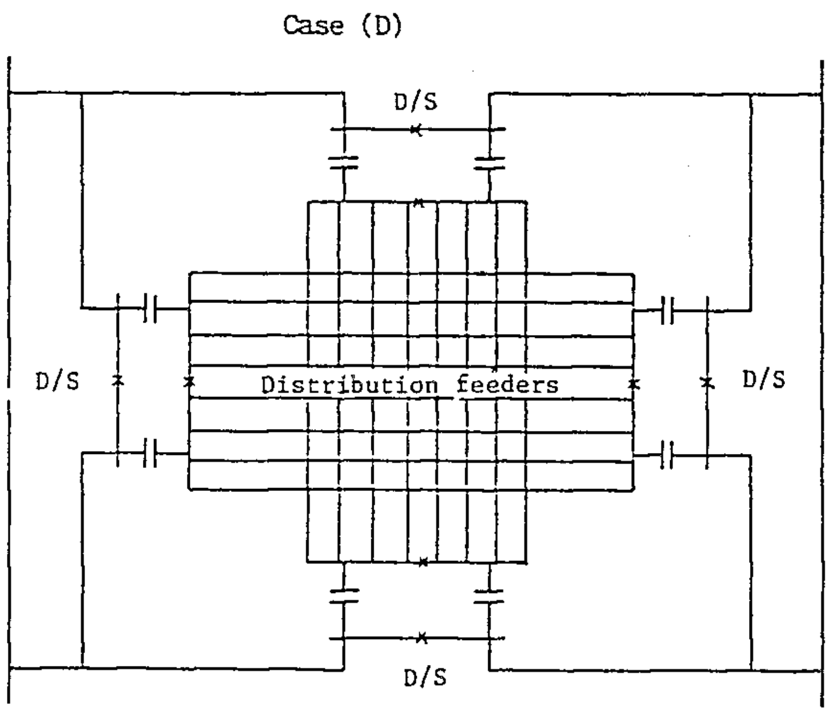


Note:

Distribution transformer

× Disconnecting switch

o Interlinked switch



Note :

This configuration is the same as case (C), but has four (4) substations.

2. Utilization Factor of Distribution Feeders

(1) Calculation of utilization factor of each feeder was done under the conditions below.

a. Capacity of feeder

Outgoing distribution lines from substation are mainly underground cables which are connected to the overhead conductor of main trunk line. These underground cables normally have equivalent or bigger capacity than main trunk line. Therefore, capacity of feeder is limited by allowable current of main trunk line. But, it is necessary to have some allowance of capacity by limiting the maximum load of a feeder under normal operation. Under such consideration the following values will be the capacity of feeder.

Capacity of Feeder

Voltage / Size of Conductor	12 kV	24 kV
336.4 MCM	8 MVA	16 MVA

b. Load of feeder

Recorded data of peak load in 1979 is used, and kW is converted to kVA by use of power factor.

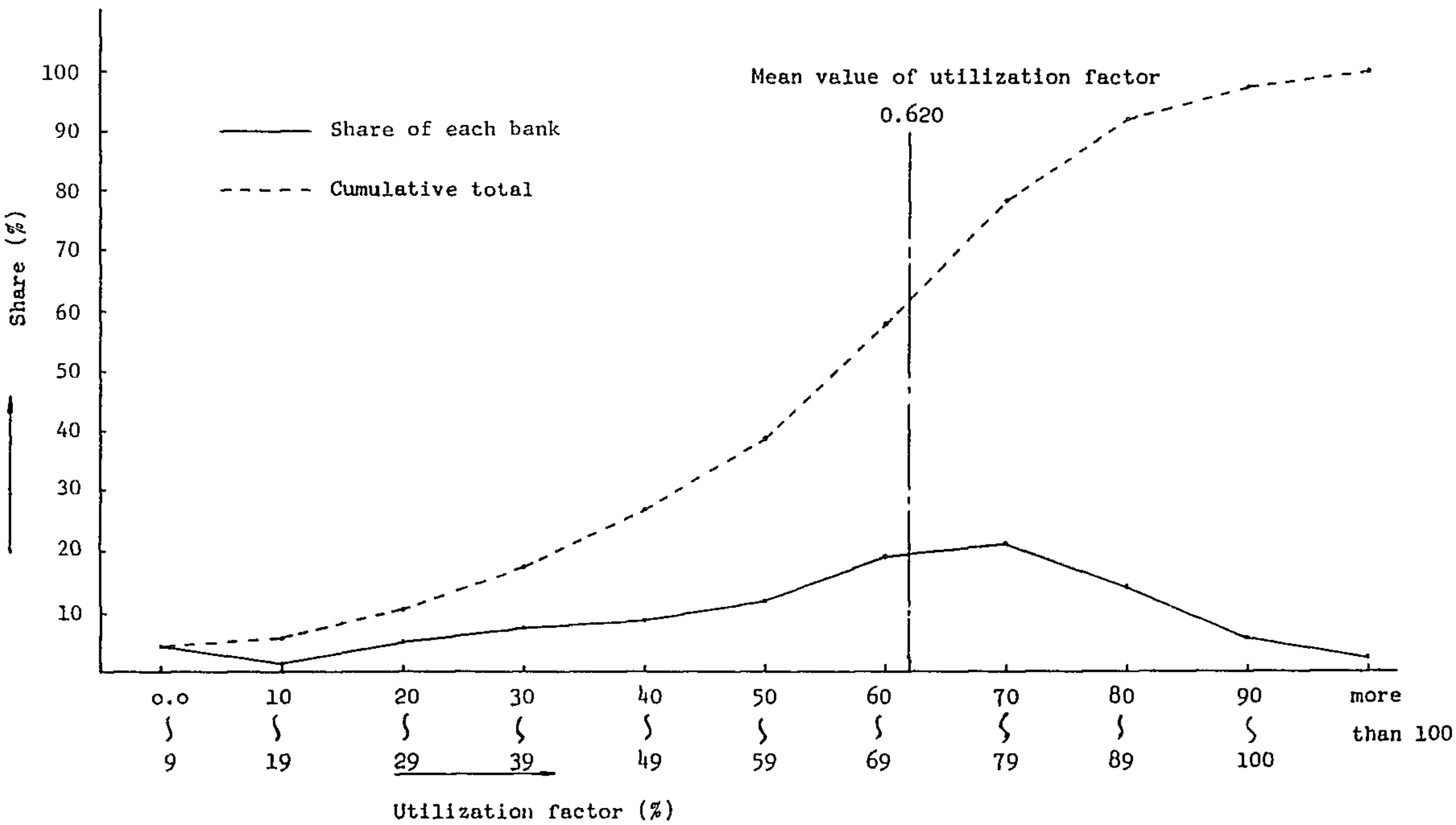
c. Utilization factor of feeder

Utilization factor of each feeder is calculated by the following equation:

$$\text{Utilization factor} = \frac{\text{Load of feeder}}{\text{Capacity of feeder}} \ (\%)$$

The results of calculation of utilization factor of each existing feeder are shown in Table 13 and Fig. 50. The average value is 62.0%.

Fig. 50 Utilization Factor of Existing Distribution Feeder, Sept. 1979



(2) Managing policy and utilization factor

Theoretically, utilization factor changes according to the MEA's managing policy. Three cases are shown in Table 14.

(3) Feeders in low utilization factor

17.7% of all feeders are being operated at less than 40% UF. The reason for such low utilization factor was studied.

Generally saying, there are two different ways to install new feeders.

When a new substation comes into operation, the required number of feeders are installed at the same time. After that feeders are installed, corresponding to growth of demand.

(4) Interlinkage of distribution feeders

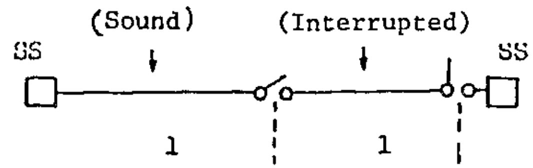
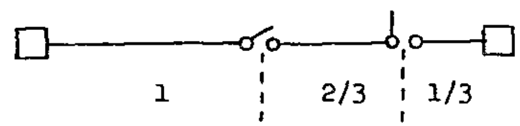
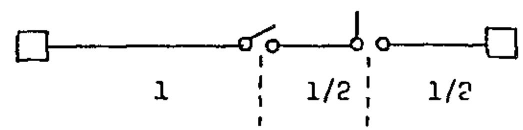
As above-mentioned, feeders of the MEA have enough surplus capacity for interchange of power. It means that service reliability will be improved effectively by interlinking of distribution feeders, and at the same time, utilization factor of substation transformer will be improved.

The following matters should be studied.

a. Installation of distribution line switch which can be operated onload

b. Automatic operation or remote control of those switches

Table 14 Policy and Utilization Factor

Policy for operation	Remarks	Utilization factor (%)	
		Without emergency operation	With emergency operation
1. Supply all of interrupted load		50	62.5
2. Supply 2/3 of interrupted load		60	75
3. Supply 1/2 of interrupted load		66	82

Note; Allowable current of main trunk line is taken to be the following value:

Normal : 400A

Emergency : 500A

IV. APPENDICES

Appendix 1 List of Big Customers

As of Sep. 1979

PL. Area	Name of Customer	Annual Energy Consumption (MWh)	Maximum Demand (MW)	Category[1]
Q00	Lucky Tex	99,084	13.5	L.B.
〃	TH. Durable Textile	81,576	10.4	L.B.
〃	Aji-No-Moto	68,544	10.1	L.B.
〃	Asahi Caustic Soda	68,083	8.4	S.R.
〃	B.K.K Iron & Steel Works	48,415	19.5	S.R.
〃	TH. Central Chemical	15,510	2.6	L.B.
TTL	6	381,212		
D10	TH. American Textile	70,488	10.3	L.B.
〃	TH. Melon	45,512	6.2	L.B.
〃	TH. Textile	34,272	4.9	L.B.
〃	TH. Teijin	29,394	5.2	L.B.
〃	TH. Teijin 2	24,246	3.6	L.B.
〃	Teijin Polyester	23,706	10.1	L.B.
〃	Good Year Factory	12,846	3.2	L.B.
〃	TH. Bridge Stone	6,150	3.4	L.B.
TTL	8	246,614		
R00	G.S. Steel	103,163	20.1	S.R.
〃	B.K.K Steel Industry	72,887	17.4	S.R.
〃	TH.-India Steel	21,440	8.2	S.R.
〃	U.S. Summit	18,476	4.7	L.B.
〃	Fire Stone Factory	16,211	3.4	L.B.
TTL	5	232,177		
S30	Samsen Water Works	63,132	8.9	L.B.
M20	TH. Synthetic Textile	32,113	4.5	L.B.
P10	TH. Tobacco Monopoly	24,706	8.6	L.B.
M20	TH. Blanket Factory	22,488	3.2	L.B.
T20	Thonburi Water Works	10,608	1.5	L.B.
W20	ESCAP	6,968	2.4	L.B.
D20	Bangkhen Water Works	1,341	2.0	L.B.
TTL	7	161,356		
GTTL	26	1,021,359		

Note: 1) L.B. means large business.
S.R. means special rate.

Appendix 2 Comparison of the Customer's Return after Installation of Customer Owned Capacitor

The tariff system of MEA has an item of penalty charge for low power factor below 85%, but hasn't an item of discount charge for high power factor beyond 85%.

On the other hand, in Japan for instance, one percent of the demand charge is added for every one percent below 85%, and one percent of the demand charge is reduced for every one percent beyond 85%.

The customer's return after installation of customer owned capacitor is compared between two kinds of tariff system mentioned above. Comparison is made under the following calculation condition and the result is shown below.

(Calculation condition)

1. Contract KW is 100 KW

2. Monthly energy consumption is 36,000 KWh
and maximum 15-minutes demand is 75 KVAR

Comparison of Power Factor Charge & Cost

1.	Customer's Charge				
	(1) Demand charge	95 x 100	=	9500	Baht
	(2) Energy charge	50 kwh x 0.81	=	40.5	Baht
		150 kwh x 0.80	=	120	Baht
		200 kwh x 0.79	=	158	Baht
		35,600 kwh x 0.78	=	27.168	Baht
		Subtotal	=	28.086.5	Baht
	(3) Power factor charge (75−63) x 7		=	84	Baht
		Total	=	37.670.5	Baht
2.	After installed customer owned capacitor (50 kVA) .... installation cost about 20,000 Baht.				
	Case a	Penalty charge only (existing)			
		Customer's return	=	84	Baht
		Recovery term of cost	=	238	months
	Case b	Penalty charge and discount charge			
		Power factor charge (25−63) x 7	=	minus 266	Baht
		Customer's return	=	84+266 = 350	Baht
		Recovery term of cost	=	57	months

Appendix 3. Coordination of capacity of substation facilities - 1/2

Location		Rated capacity: Transformer	Rated capacity: Circuit breaker	Rated capacity: Current transformer	Rated capacity: Disconnecting switch	Required capacity: Maximum current (A)	Required capacity: Interrupting capacity of circuit breaker (MVA)	Ratio: Circuit breaker, Rated current / Required max. current	Ratio: Circuit breaker, Rated capacity / Required breaking capacity	Ratio: Current transformer, Rated current / Required max. current	Ratio: Disconnecting switch, Rated current / Required max. current
Bangna SS.	Trans. No.1	1-3φ 30/40 MVA	1600A 3950MVA	3-200×400 : 5//5A		344	1789	4.6	2.2	1.2	
	Line No.1		" "	3-750×1500 : 5//5A		688	"	2.3	"	2.2	
	Line No.2		" "	" "		"	"	"	"	"	
	Bus tie				1250A	344					
Bangyeekhan SS.	Trans. No.1	1-3φ 30/40 MVA	1260A 3500MVA	3-400/200 : 5/5A		344	2005	3.6	1.7	1.2	
	Trans. No.2	" "	" "	" "		"	"	"	"	"	
	Line No.1		" "	3-1200/800/600/400/200 : 5/5A		688	"	1.8	"	1.7	
	" No.2		" "	" "		"	"	"	"	"	
	Bus tie				1200A 61KA	344					3.5
Lumpini SS.	Trans. No.1	1-3φ 30/40 MVA	1200A 1800MVA	3-600/400/300/200/100 : 5//5A	600A 20KA	344	1871	3.5	0.96	1.7	1.7
	" No.2	" "	" "	" "	" "	"	"	"	"	"	"
	Line No.1				" "	688					0.9
	Line No.2				" "	"					"
	Bus tie				" "	"					~~"~~
	Bus tie				" "	344					1.7
Mochit SS.	Trans. No.1	1-3φ 30/40 MVA	1200A 2500MVA	3-600/400/300/200/100 : 5/5A	600A 20KA	344	1733	3.5	1.4	1.7	1.7
	" No.2	"	" "	" "	" "	"	"	"	"	"	"
	Line No.1				" "	688					0.9
	" No.2				" "	"					"
	Bus tie				" "	344					1.7
Mahamek SS.	Trans. No.1	1-3φ 30/40 MVA	2000A 5000MVA	{3-2000/1500/1200/800 : 5A 3-600/400/300/200/100 : 5A	600A 20KA	344	1067	5.8	4.6	{5.8 1.7	1.7
	" No.2	"	" "		" "	"	"	"	"		"
	Line No.1				" "	688					0.9
	" No.2				" "	"					"
	Bus tie				" "	344					1.7
Prakanong SS.	Trans. No.1	1-3φ 30/40 MVA	2000A 5000MVA	{2000/1500/1200/800 : 5A 600/400/300/200 : 5A	600A 20KA	344	1522	5.8	3.2	{5.8 1.7	1.7
	" No.2	"	" "		" "	"	"	"	"		"
	Line No.1				" "	688					0.9
	" No.2				" "	"					"
	Bus tie				600A 40KA	344					1.7

Appendix 3. Coordination of Capacity of Substation Facilities - 2/2

Location		Rated capacity				Required capacity		Ratio of rated capacity to required capacity			
		Transformer	Circuit breaker	Current transformer	Disconnecting switch	Maximum current (A)	Interrupting capacity of circuit breaker (MVA)	Circuit breaker: Rated current / Required max. current	Circuit breaker: Rated capacity / Required breaking capacity	Current transformer: Rated current / Required max. current	Disconnecting switch: Rated current / Required max. current
Pathumwan SS.	Trans. No.1	1-3φ 30/40 MVA	2000A 5000MVA	3-600/400/300/200/100 : 5// 5A	600A 66KA	344	1859	5.8	2.6	1.7	1.7
	" No.2	"	" "	" "	" "	"	"	"	"	"	"
	Line No.1			3-2000/1500/1200/800 : 5// 5A	2000A "	688				2.9	2.9
	" No.2			" "	" "	"				"	"
	Bus tie				" "	344					5.8
Samsen SS.	Trans. No.1	1-3φ 30/40 MVA	2000A 5000MVA	{3-2000/1500/1200/800 : 5A	600A 20KA	344	2278	5.8	2.2	{5.8	1.7
	" No.2	"	" "	3-600/400/300/200/100 : 5A	" "	"	"	"	"	1.7	"
	Line No.1				" "	688					0.9
	" No.2				" "	"					"
	Bus tie				" "	344					1.7
North sapandam SS.	Trans. No.1	1-3φ 30/40 MVA	2000A 5000MVA	3-600/400/300/200/100 : 5// 5A	400/800A 20KA	344	1818	5.8	1.0	1.7	2.3
	" No.2	"	" "	" "	" "	"	"	"	"	"	"
	Line No.1		" "	3-2000/1500/1200/300 : 5// 5A	2000A 66KA	1376	"	1.5	"	1.5	1.5
	Line No.2		1200A 1800MVA	" "	" "	"	"	"	"	"	"
	Bus tie				" "	1032			"		1.9
South sapandam SS.	Trans. No.3	1-3φ 30/40 MVA	2000A 5000KVA	3-600/400/300/200/100 : 5// 5A	400/800A 20KA	344	1818	5.8	1.0	1.7	2.3
	" No.4	"	" "	" "	" "	"	"	"	"	"	"
	Line No.3		1200A 1800MVA	3-2000/1500/1200/800 : 5// 5A	2000A 66KA	1376	"	0.8	"	1.5	1.4
	" No.4		2000A 5000MVA	" "	" "	"	"	1.9	"	"	"
	Bus tie				" "	1032					1.9
Silom SS.	Trans. No.1	30/40 MVA	1200A 3500MVA	3-200×400 : 5// 5A		344	1227	3.4	2.8	1.1	
	" No.2	"	" "	" "		"	"	"	"	"	
	Line No.1		" "	3-1200 : 5// 5A MR		688	"	1.7	"	1.7	
	" No.2		" "	" "		"	"	"	"	1.7	
	Bus tie										
Sansab SS.	Trans. No.1	1-3φ 30/40 MVA	2000A 3500MVA	3-400/200 : 5// 5A		344	1562	5.8	2.2	1.2	
	Line No.1		" "	3-1200/800/600/400/200 : 5// 5A		"	"	"	"	3.5	
	" No.2		" "	" "		"	"	"	"	"	
	Bus tie				1600A	"					4.6
Watlieb SS.	Trans. No.1	1-3φ 30/40 MVA	1200A 1800MVA	3-600/400/300/200/100 : 5// 5A	600A 20KA	344	1568	3.5	1.1	1.7	1.7
	" No.2	"	" "	" "	" "	"	"	"	"	"	"
	Line No.1		2000A 5000MVA	3-2000/1500/1200/800 : 5A	" "	688	"	5.8	3.2	5.8	0.9
	" No.2		" "	" "	" "	"	"	"	"	"	"
	Bus tie				" "	344					1.7
	" "				" "	"					"

Appendix 4 General Information of Surveyed Substations

No.	Name of Substation	Terminal or Distribution Substation	Type	Existing Transformer MVA x unit	Space for 3rd bank
1	Bang kapi	T/S	Outdoor	40 x 2	Yes
2	Makasan	D/S	Outdoor	40 x 2	〃
3	Chidlom	T/S	Indoor	50 x 2	No
4	Yohti	D/S	Indoor	40 x 1	〃
5	Taksin	D/S	Indoor	40 x 1	〃
6	Sathupradit	D/S	Indoor	40 x 1	Yes
7	Bangplee	T/S	Outdoor	24 KV 40 x 1	〃
8	Paknam	D/S	Outdoor	115/24 KV 40 x 2	〃
9	Watlieb	D/S	Outdoor	40 x 2	〃
10	Sapandam	D/S	Outdoor	40 x 4	No
11	Lumpini	D/S	Outdoor	40 x 2	Yes
12	Pathumwan	D/S	Outdoor	40 x 2	〃
13	Mahamek	D/S	Outdoor	40 x 2	〃
14	Silom	D/S	Indoor	40 x 2	No
15	Mochit	D/S	Outdoor	40 x 2	Yes
16	Sansab	D/S	Indoor	40 x 1	〃
17	Bangna	D/S	Indoor	40 x 1	No
18	Prakanong	D/S	Outdoor	40 x 2	〃
19	Bangyeekhan	D/S	Indoor	40 x 2	〃
20	Samsen	D/S	Outdoor	40 x 2	Yes
21	Pracha chuen	D/S	Outdoor	40 x 2	〃
22	North bangkok	T/S	Outdoor	24 KV 40 x 1 12 KV 20 x 2	〃
23	Lard plao	T/S	Outdoor	–	〃
24	Klong jan	D/S	Outdoor	20 x 2	〃
25	Tong kung	D/S	Outdoor	40 x 2	〃

No.	Name of Substation	Terminal or Distribution Substation	Type	Existing Transformer MVA x unit	Space for 3rd Bank
26	South bangkok	T/S	Outdoor	20 x 1	Yes
27	Bang pu	D/S	Outdoor	115/24 40 x 1	"
28	South bang plee	Future plan			
29	Samrong	D/S	Outdoor	40 x 2	No
30	Bangkok noi	T/S	Outdoor	20 x 2	Yes
31	Pechkasem	D/S	Outdoor	20 x 2	"
32	Thonburi	D/S	Outdoor	40 x 2	"
33	Onnuj	D/S	Outdoor	115/24 40 x 2	No
34	Ramintra	D/S	Outdoor	115/24 40 x 2	"
35	Nonburi	D/S	Outdoor	20 x 2	Yes
36	Bang pood	D/S	Outdoor	20 x 2	"
37	Klong rangsit	T/S	Outdoor	–	"
38	Rangsit	D/S	Outdoor	40 x 2	"
39	Dong muan	D/S	Outdoor	40 x 2	No
40	Bangkurachao	D/S	Outdoor	10 x 1	Yes
41	Prapradaen	D/S	Outdoor	40 x 2	"
42	Klong sanpasamit	D/S	Outdoor	20 x 2	"
43	Rasuluran	D/S	Outdoor	40 x 2	Yes
44	Klang kred	Temporary	Outdoor	20 x 1	No
45	Lard plakao	D/S	Outdoor	Under construction	"
46	Prasanmit	D/S	Outdoor	Under construction	"
47	Sipraya	D/S	Indoor	Land purchase only	"
48	Sailom	D/S	Indoor	Future plan	"

Appendix 5 Calculation of Strength of Concrete Pole

(1) Basic conditions of calculation

a. Specification of pole

Length of Pole	18.5 m	20.0 m	22.0 m
Size of top of pole	20 cm x 20 cm	25 cm x 25 cm	25 cm x 25 cm
Size of base pole	36.2 x 36.2	44 x 44	46 x 46
Strength for bending moment	10.0 t-m	14.0 t-m	14.0 t-m

b. Wind pressure load

1) Electric wire

Wind velocity $V = 60$ mile/hour $= 26.82$ m/sec
$P_c = 0.0025\ V^2$
$= 9\ (LB/Ft^2) = 44\ (kg/m^2)$

2) Pole

$P_t = 0.004\ V^2$
$= 14.4\ (LB/Ft^2) = 70\ (kg/m^2)$

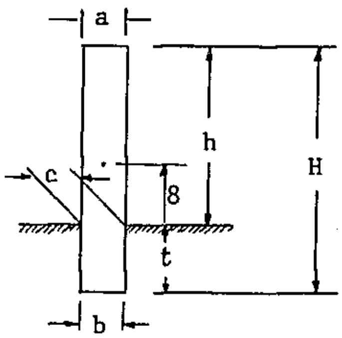
3) Insulator and attachments

Suspension type connection ..... 13 kg/l supporting point
Strain type connection .... 29 kg/l supporting point

c. Vertical load

Compressive strength of concrete pole is very high, therefore vertical load and strength were not checked.

(2) Bending moment by wind pressure of pole



Width at GL $C = \frac{(b-a)h}{H} + a$

Projected area to wind pressure

$$A = \frac{(a+c)\cdot h}{2}$$

Position of center of gravity

$$g = h - \frac{h}{3}\left(\frac{2c+a}{c+a}\right)$$

Bending moment of section at ground level

$$Mp = P_p \cdot A \cdot g$$

		Symbol	Unit	H = 18.5 m	H = 20.0 m	H = 22.0 m
Size of each part	Width at top	a	m	0.20	0.25	0.25
	Width at base	b	m	0.362	0.44	0.46
	Setting depth	t	m	(2.00) 3.00	(2.00) 3.00	(2.00) 3.00
	Width at GL	c	m	(0.3445) 0.3357	(0.421) 0.4115	(0.4409) 0.4314
	Height from GL	h	m	(16.5) 15.5	(18.00) 17.00	(20.00) 19.00
	Height of center of gravity	g	m	(7.5202) 7.0956	(8.2355) 7.8083	(9.079) 8.657
Projected area to wind pressure		A	m²	(4.4921) 4.1517	(6.039) 5.6228	(6.909) 6.4733
Wind pressure of pole		P_PA	kg	(314.5) 290.6	(422.7) 393.6	(483.6) 453.1
Bending moment at GL		M_P	kg-m	(2.364.7) 2,062.1	(3,481.2) 3,073.3	(4,390.9) 3,922.8

(3) Allowable bending moment by wind pressure on conductors

Each size of pole has a specific strength against bending moment. Therefore, bending moment by conductors should be less than a limited value.

The limit is;

$$M_i = M - M_p$$

where M = Strength of pole

M_p = Bending moment by wind pressure on pole

$$M_{18.5} = 10{,}000 - \frac{(2364.7)}{2061.2} = \frac{(7635.3)}{7937.9} \text{ kg-m}$$

$$M_{20} = 14{,}000 - \frac{(3481.2)}{3073.3} = \frac{(10518.8)}{10926.7} \quad ''$$

$$M_{22} = 14{,}000 - \frac{(4390.9)}{3922.8} = \frac{(9609.1)}{10077.2} \quad ''$$

( ) . . . . . Setting depth 2 m

(4) Bending moment by wind pressure of conductors

a. Size and type of pole

Fig. 5-1 shows detailed size of each type of pole.

b. Wind pressure of conductors

Total wind pressure of conductors is:

$H_c = P_c \cdot D \cdot S + P_i$

where D = Outer diameter of conductor

S = Length of one span

Subtransmission line 80 m

Distribution line 40 m

P_i = Wind pressure of insulator

Suspension 13 kg

Strain 29 kg

P_c = Wind pressure of conductor .... 44 kg/m^2

Following shows wind pressure of conductor with suspension type insulator.

Kind of conductor	Outer diameter (mm)	Length of Span (mm)	Wind pressure PcDS (kg)	Wind pressure Pi (kg)	Wind pressure of conductor (kg)
5/16" GW	7.9375	80	27.94	0	27.94/1 wire
795 AAL	26.0645	80	91.75	13	104.75/1 wire
2 x 795 AAL	"	80	165.15	13	178.15/2 wire
795 x 2C AAL	"	80	183.50	26	209.50/2 wire
3 x 336.4 HT.DL	16.9164	40	89.32	0	89.32/3 wire
SL wire	9.8044	40	17.26	0	17.26/1 wire
Neutral line of LT	16.4338	40	28.92	0	28.92/1 wire
3 x 336.4 LT.DL	20.8788	40	110.24	0	110.24/3 wire
Communic. cable	48.260	40	84.94	0	84.94/1 wire

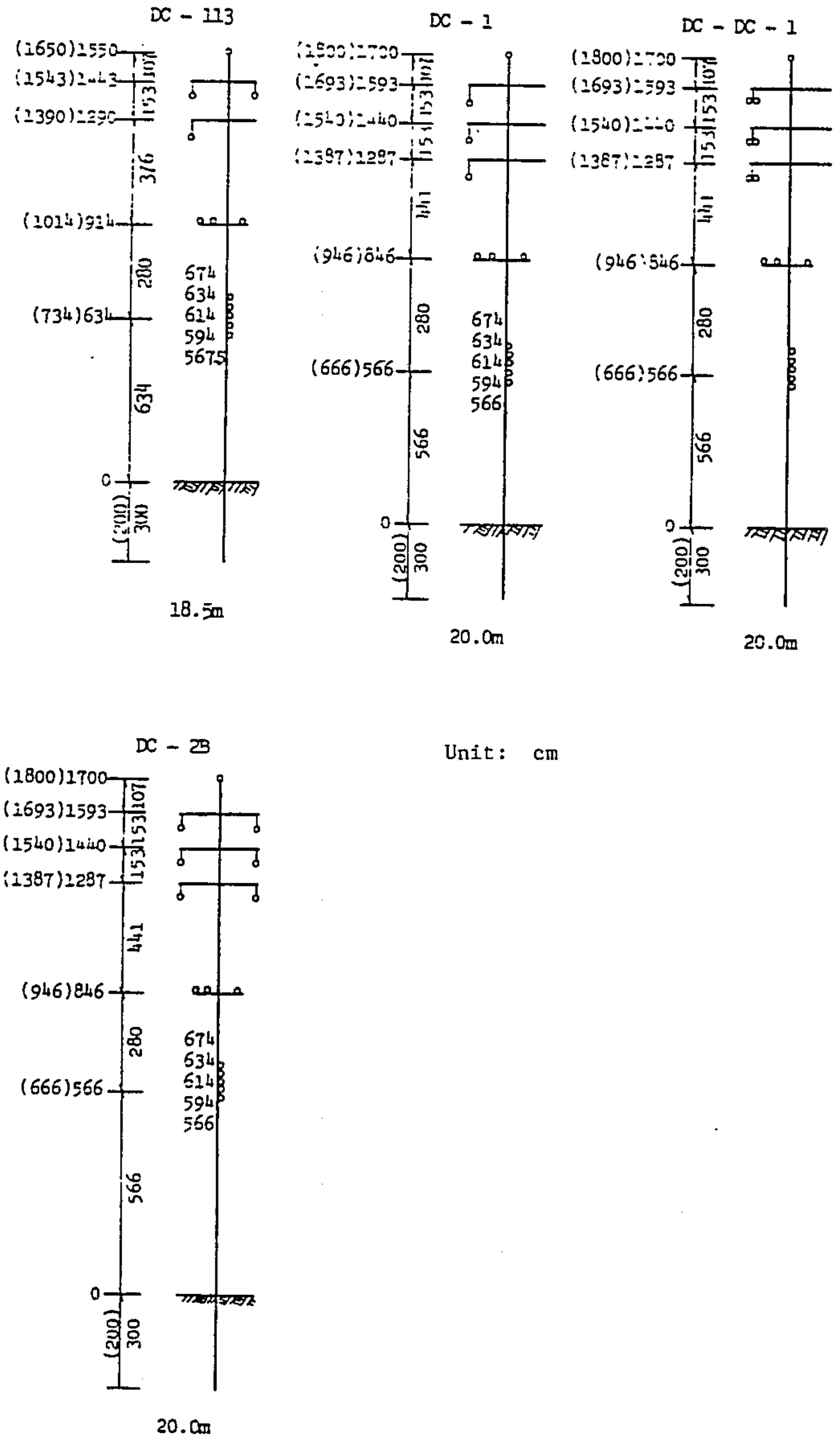
Note:

(1) 2 x 795 AAL ..... Double wiring of 795 AAL.
According to JEC-127, above value was calculated as 90% of that of single conductor.

(2) 795 x 2C AAL ..... 2 circuits of 795 AAL

(5) Results of calculation of bending moment by wind pressure of conductors
The following tables (No. 1 ~ No. 3) shows the results of calculation of bending moment by wind pressure of conductors.

Fig. 5-1 Size and type of pole



Unit: cm

No. 1 Setting depth 3.0 m

Conductor		DC-1B (18.5 m)		DC-1 (20 m)		DC-DC-1 (20 m)		DC-2B (20 m)	
	Wind pressure (kg)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)
5/16" GW.	27.94	15.50	433.07	17.00	474.98	17.00	474.98	17.00	474.98
795 AAL	104.75	12.90	1351.275	15.93 14.40 12.87	1668.668 1508.4 1348.133				
2 x 795 AAL	178.15					15.93 14.40 12.87	2837.93 2565.36 2292.79		
795 x 2C AAL	209.50	14.43	3023.085					15.93 14.40 12.87	3337.335 3016.80 2696.265
3 x 336.4 H. D/L	89.32	9.14	816.385	8.46	755.647	8.46	755.647	8.46	755.647
SL wire	17.26	6.74	116.332	6.74	116.332	6.74	116.332	6.74	116.332
L. D/L neutral	28.92	6.54	189.137	6.54	189.137	6.54	189.137	6.54	189.137
3 x 336.4 L. D/L	110.24	6.34	698.922	6.34	698.922	6.34	698.922	6.34	698.922
Communication cable	84.94	5.675	482.035	5.66	480.760	5.66	480.760	5.66	480.760
Total			7110.241		7240.979		10411.859		11766.178
Limit (Paragraph (3))		(18.5 m)	7937.9	(20 m)	10926.7	(20 m)	10926.7	(20 m)	10926.7
Tolerance			1.11		1.50		1.04		0.92
Check			O.K		O.K		O.K		NO

Note;

$$\text{Tolerance} = \frac{\text{Limit of bending moment by conductor}}{\text{Total bending moment by conductor}}$$

No. 2 Setting depth 3.0 m

Conductor		DC-1B (20 m)		DC-1 (22 m)		DC-DC-1 (22 m)		DC-2B (22 m)	
	Wind pressure (kg)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)
5/16" CW.	27.94	17.0	474.98	19	530.86	19	530.86	19	530.86
795 AAL	104.75	14.4	1508.4	17.93 16.40 14.87	1878.168 1717.9 1557.633				
2 x 795 AAL	178.15					17.93 16.40 14.87	3194.230 2921.660 2649.091		
795 x 2C AAL	209.50	15.43	3232.585					17.93 16.40 14.87	3756.335 3435.800 3115.265
3 x 336.4 H. D/L	89.32	10.64	950.365	10.46	934.287	10.46	934.287	10.46	934.287
SL wire	17.26	8.24	142.222	8.74	150.852	8.74	150.852	8.74	150.852
L. D/L neutral	28.92	8.04	232.517	8.54	246.977	8.54	246.977	8.54	246.977
3 x 336.4 L. D/L	110.24	7.84	864.282	8.34	919.402	8.34	919.402	8.34	919.402
Communication cable	84.94	7.175	609.445	7.66	650.640	7.66	650.640	7.66	650.640
Total			8014.796		8586.719		12197.999		13740.418
Limit (Paragraph 3)		(20 m)	10926.7	(22 m)	10077.2	(22 m)	10077.2	(22 m)	10077.2
Tolerance			1.36		1.17		0.82		0.73
Check			O.K		O.K		NO		NO

Note;

$$\text{Tolerance} = \frac{\text{Limit of bending moment by conductor}}{\text{Total bending moment by conductor}}$$

No. 3 Setting depth 2.0 m

Conductor		DC-1B (18.5 m)		DC-1 (20 m)		DC-DC-1 (20 m)		DC-2B (20 m)	
	Wind pressure (kg)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)
5/16" GW.	27.94	16.5	461.01	18.0	502.92	18.0	502.92	18.0	502.92
795 AAL	104.75	13.9	1456.025	16.93 15.40 13.87	1773.418 1613.15 1452.883				
2 x 795 AAL	178.15					16.93 15.40 13.87	3016.08 2743.51 2470.94		
795 x 2C AAL	209.50	15.43	3232.585					16.93 15.40 13.87	3546.835 3226.300 2905.765
3 x 336.4 H. D/L	89.32	10.14	905.705	9.46	844.967	9.46	844.967	9.46	844.967
SL wire	17.26	7.74	133.592	7.74	133.592	7.74	133.592	7.74	133.592
L. D/L neutral	28.92	7.54	218.057	7.54	218.057	7.54	218.057	7.54	218.057
3 x 336.4 L. D/L	110.24	7.34	809.162	7.34	809.162	7.34	809.162	7.34	809.162
Communication cable	84.94	6.675	566.975	6.66	565.700	6.66	565.700	6.66	565.700
Total			7783.111		7913.849		11304.928		12753.298
Limit (Paragraph 3)			7635.30		10518.80		10518.80		10518.80
Tolerance			0.98		1.32		0.93		0.82
Check			NO		O.K		NO		NO

Note;

$$\text{Tolerance} = \frac{\text{Limit of bending moment by conductor}}{\text{Total bending moment by conductor}}$$

Appendix 6 Wind Pressure of Insulator

(1) MEA's design criteria for wind pressure of insulator

In MEA's design criteria, wind pressure of insulator is decided to be 6 LB per ft^2. This value is equivalent in unit of kg/m^2 to;

$$P = 6 \times \frac{0.4536}{(0.0254 \times 12)^2} = 29.3\ (kg/m^2)$$

Therefore, wind pressure of a supporting point is calculated as follows:

$P_i = p \times A$

where A = projected area (m^2)

Strain support .... P_i = 6.3 kg/l supporting point

Suspension support .... P_i = 13.6 kg/l supporting point

These values appear to be too small, but they do not influence greatly the result of calculation of bending moment at ground level of pole.

(2) Comparison of design criteria for wind pressure

MEA adopts 60 mile/hour as design standard of wind velocity. It is equivalent to 26.8 m per second. In Japan, we are using 40 m/sec. The difference between MEA's and Japan's criteria is shown in the following table.

In MEA's criteria, wind pressure of pole seems to be somewhat bigger than Japan, and that of insulator is smaller than Japan.

	Japan	MEA	
Wind velocity	40 m/sec	60 mile/h = 26.8 m/sec.	
	Electric Standard of Japan.	Calculated in portion to square of wind velocity (Japanese method)	Criteria of MEA
Concrete pole (Rectangular)	120 Kg/m²	54 Kg/m²	14.4 LB/FT² = 70 Kg/m²
Steel pole (Double bracing)	220 〃	99 〃	
Steel pole (Single bracing)	240 〃	108 〃	
Steel tower (Steel pipe)	170 〃	76 〃	
Steel tower (Angle steel)	290 〃	130 〃	
Conductor (Single)	100 〃	45 〃	9 LB/FT² = 44 Kg/m²
Conductor (Multi)	90 〃	41 〃	
Insulator	140 〃	63 〃	6 LB/FT² = 29.3 Kg/m²
Insulator (69 KV suspension)	30 Kg/point	13 Kg/point	6.3 Kg/point
Insulator (66 KV tension)	65 〃	29 〃	13.6 〃

Appendix 7 Strength of Distribution Pole

(1) Calculation condition

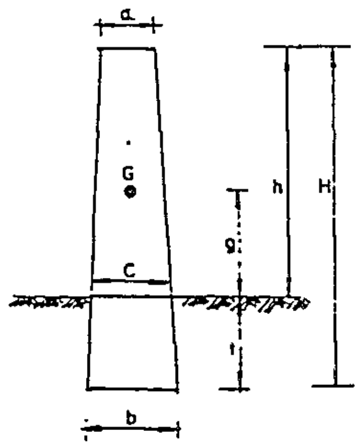
		12.0 m	14.0 m
a.	Size	12.0 m	14.0 m
	Size of top	16.18 x 18.55	17.50 x 20.00
	Size of base	25.27 x 28.55	28.00 x 31.56
	Bending strength	3.5 t-m	4.15 t-m

b. Wind pressure
   Conductor 43.941 kg/m^2
   Pole 70.306 kg/m^2

c. Vertical load . . . . Not calculated

(2) Allowable bending moment of pole

a. Wind pressure of pole



Width at ground level

$$C = \frac{(b-a)}{H} h + a$$

Projected area of wind pressure

$$A = \frac{a+c}{2} \cdot h$$

Height of center of gravity

$$g = h - \frac{h}{3}\left(\frac{2c+a}{c+a}\right)$$

Bending moment at ground level

$$M_p = P_F \cdot A \cdot g$$

		Symbol	Unit	H = 12.0 m	H = 14.0 m
Size	Top of pole	a	m	0.1618	0.1750
	Base of pole	b	m	0.2527	0.2800
	Setting depth	t	m	1.75	2.0
	Width at ground level	c	m	0.2394	9.2650
	Height from G.L.	h	m	10.25	12.0
	Height from center of gravity	g	m	4.7944	5.5909
Projected of wind		A	m^2	2.0561	2.640
Wind pressure of pole		P_F.A	kg	144.56	184.8
Bending moment at G.L.		M_P	kg-m	693.11	1033.20

b. Limitation of bending moment by conductor

$M_f = M - M_p$

M = Bending strength of pole

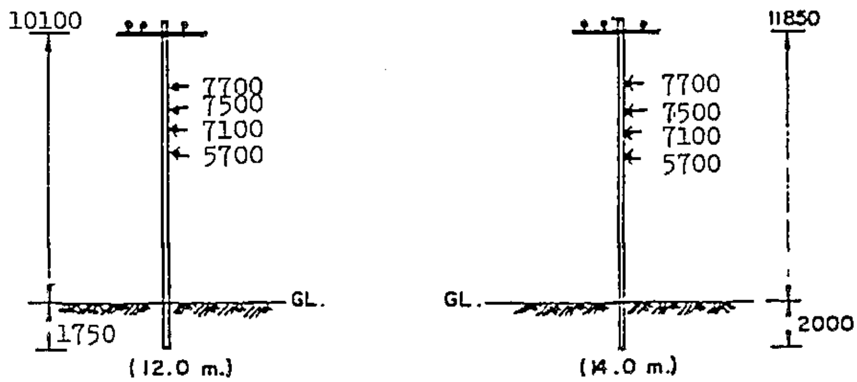
M_p = Bending moment by pole

$M_{12} = 3500 - 693.11 = 2806.89$ (kg-m)

$M_{14} = 4150 - 1033.20 = 3116.80$ (kg-m)

(3) Bending moment by conductors

a. Layout of conductors (in mm)



b. Wind pressure by conductors

i) $H_c = P_c \cdot D \cdot S$

where D = Outer diameter of conductor

S = Span (40 m)

P_c = Unit pressure 44 kg/m^2

ii) Wind pressure by conductors

Type of Conductor	Outer Diameter of Conductor	Span	Wind Pressure
3 x 336.4 H.T.	16.92 mm	40 m	89.34 kg
3 x 795 MCM H.T.	26.06	40	137.60
SL Wire	9.19	40	16.17
Neutral L.T.	15.24	40	26.82
3 x 336.4 L.T.	19.28	40	101.79
Communication Cable	48.26	40	84.94

c. Bending moment by conductors

Conductor		H = 12.0 m		H = 14.0 m	
Kind of Conductor	Wind Pressure	h (m)	Mc (kg-m)	h (m)	Mc (kg-m)
3 x 336.4 H.T. 3 x 795 MCM H.T. SL Wire Neutral L.T. 3 x 336.4 L.T. Communication Cable	89.34 (137.60) 16.17 26.82 101.79 84.94	10.10 (10.10) 7.70 7.50 7.10 5.70	902.33 (1389.76) 124.51 201.15 722.71 484.16	11.85 (11.85) 7.70 7.50 7.10 5.70	1058.68 (1630.56) 124.51 201.15 722.71 484.16
Total			2434.86 (2922.29)		2591.21 (3163.09)
Allowable Bending Moment			2806.89		3116.80
Check			OK (No)		OK (No)

Appendix 8. Dismantling of secondary network

(1) Introduction

MEA has been operating secondary network distribution system by overhead low tension lines covering 8.5 km^2 in the service area of Sapandam and Watlieb substation, which is very crowded town area of metropolis Bangkok. In accordance with rapid increase of energy demand, distribution facilities in this area will be forced to expand year by year in the future.

But, network protector which must be attached to distribution transformer, has become extremely expensive, and it is a big burden to MEA.

Under such situation, we recommend to dismantle this network system and construct a conventional radial type distribution system which do not need network protector.

In this report, we have some consideration about what is the problem and the method to dismantle the existing system without causing serious interference to consumers.

(2) Problems of dismantling of existing system

The following are problems which would appear after dismantling the system.

a. Some transformer will become overloading because of unsuitable separation of low tension line.

b. Supply voltage to some consumer will drop because of unsuitable separation of low tension line.

c. When a feeder or a transformer is out due to fault, it will take more time to recover than existing condition.

d. More strict control of transformer loading must be exercised.

(3) Method of dismantling

As countermeasure of above a and b, the following must be especially taken into consideration:

Extent of loading of each isolated transformer.
Break-off point of low tension lines.

a. Theoretical Consideration

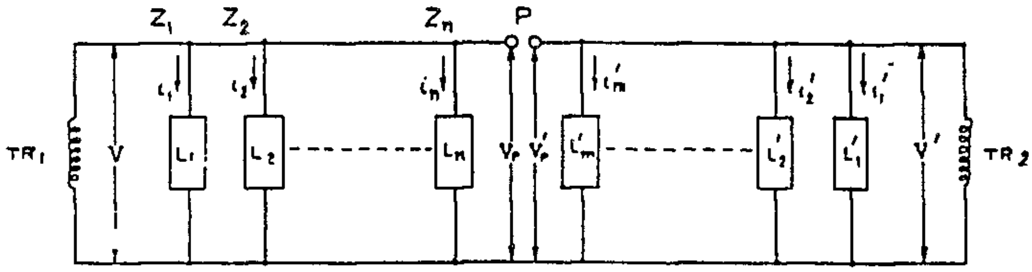


Fig. 8-1

In Fig. 8-1 low tension line is cut off at point P.

TR	= Transformer
L, L'	= Load at each pole
i, i'	= Load current
Z, Z'	= Line impedance between each pole

Line voltage at P is

$$TR_1 \text{ side} \quad V_p = V - D_p \qquad (D_p = \text{Line drop at P})$$

$$= V - \left\{ Z_1 \sum_{p=1}^{n} i_p + Z_2 \sum_{2}^{n} i_p + \cdots\cdots + Z_n i_n \right\} \qquad \cdots\cdots①$$

$$TR_2 \text{ side} \quad V'_p = V' - \left\{ Z'_1 \sum_{p=1}^{m} i'_p + Z'_2 \sum_{2}^{m} i'_p + \cdots\cdots + Z'_m i'_m \right\} \qquad \cdots\cdots②$$

If line current $I = 0$ at point P before cutting off, then

$$V_p = V_p' \qquad \cdots\cdots③$$

Under the assumption that

i) TR_1, TR_2 are both fed from the same substation and same bay.
ii) Line impedance of 12 kV primary line between substation and TR_1, TR_2 are approximately the same. (It means the same distance from substation and same size of cable.)

iii) Low tension line is uniform in size, wiring formation and distance of each span.

$$V = V', \qquad Z_n = Z'_m = Z$$

and

$$\sum_{p=1}^{n} i_p + \sum_{2}^{n} i_p + \cdots\cdots\cdots + i_n = \sum_{n=1}^{n} n.i_n$$

$$\sum_{p=1}^{m} i'_p + \sum_{2}^{m} i'_p + \cdots\cdots\cdots + i'_m = \sum_{m=1}^{m} m.i'_m$$

From ① ② ③ and above,

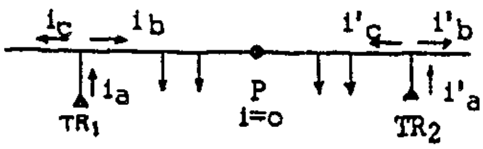
$$V_p = V'_p$$

$$\therefore V - Z\left\{\sum_{n=1}^{n} n \cdot i_n\right\} = V - \left\{\sum_{m=1}^{m} m \cdot i'_m\right\} = [NI] \quad \cdots\cdots\cdots ④$$

④ is basic condition for $I = 0$.

b. How to cut off low tension line

i) Checking of location of transformer



Normally, P exists on line between TR_1 and TR_2 (Fig. 8-2)

Fig. 8-2

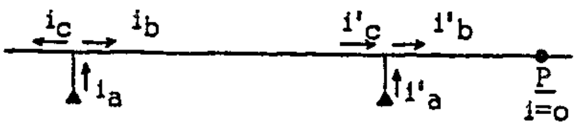


Fig. 8-3

When a transformer is not installed at suitable position load-wise, P appears on the outside of TR_1, TR_2. (Fig. 8-3)

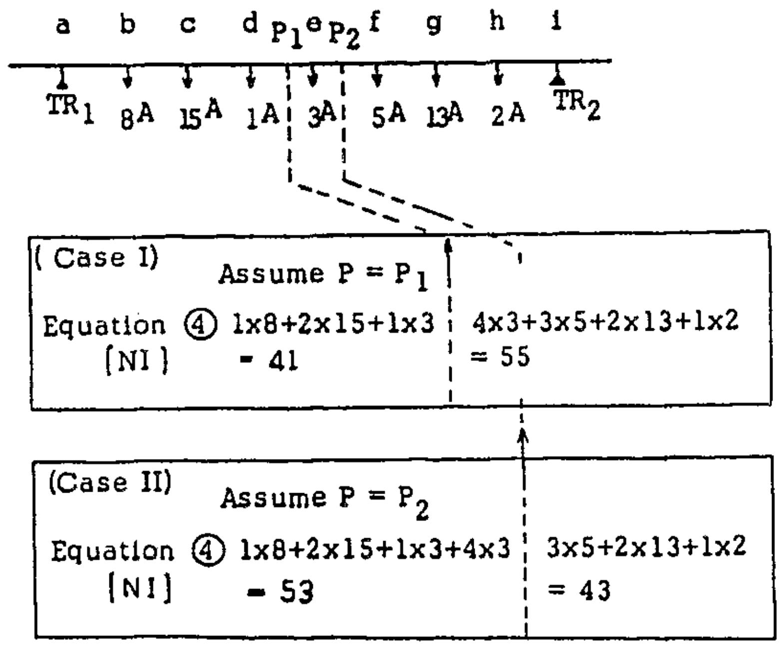
Therefore, it should be checked that

$$|i_a| \geqq |i_b| + |i_c|$$

ii) How to find zero-current point P

a) Measurement of service wire current

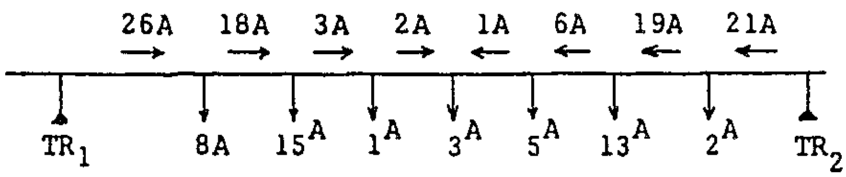
Fig. 8-4



It is clear that pole e is zero-current point, and a better method is to cut off the low tension line at TR_2 side of pole e. (Case II)

b) Measurement of line current

Fig. 8-5



- Measure line current at any pole.
- Move to next pole until current meter indicates minimum value.

c) Measurement of line voltage

Same as b), measure line voltage at each pole, and find the largest line drop point.

d) kWh method

If data is available of consumers who are served from each pole, the load at each pole can be estimated. And in the same manner as a), point P can be located.

e) Cut and try method

After estimation of zero-current point, cut off low tension line at a point, and measure the line voltage at both sides. If the two values are appreciably different, cut-off point should be moved to another point.

Service interruption to consumer can be avoided by this method, but if big current is flowing at the point, this method will have some difficulty and problem.

f) Others

The type of measuring equipment to check the direction of current flow should be studied separately.

c. Loading of each transformer after dismantling

Maximum load of each feeder in network area is equivalent to 40 – 60% of total capacity of transformers which are connected to each feeder. Therefore, it is estimated that each transformer is installed at suitable position.

Accordingly, each transformer may be loaded to maximum load before dismantling. After dismantling, utilization factor of transformer will be in 60% – 70% though there will be some diversion factor among transformers.

(4) Notes for execution of dismantling work

a. During the course of dismantling work, it is very important that each transformer should be separated off one by one pace with each feeder because the remaining network must be operated smoothly when a feeder is out due to fault.

b. Method of cutting off of low tension line as aforementioned is theoretical. In practice, considering the geographical condition or M-O ease, it is not necessary to strictly find actual zero-current point P.

(5) Management and maintenance after dismantling of network system

a. Periodical measurement of line current, line voltage, and consumer terminal voltage must be made in regular way to prevent overloading and large voltage drop.

b. Delay of restoring service is unavoidable in radical type system. Therefore,

i) Every feeder (underground cable) must be interlinked at some point.

ii) To shorten the time of restoration work of fault transformer, vehicle and required materials must be in stand-by status at all time.

(6) Conclusion

The foregoing is a description on how to dismantle a network systemand to convert into conventional radial type system.

It appears easy to perform this work in theory or in paper plan. But actually it is accompanied by many difficulties. Therefore, cutting off of transformer must be done very carefully one by one, always endeavoring to find the most suitable way.

Appendix 9. Interlinking method of distribution feeders after dismantling of secondary network system

(1) Introduction

Secondary network system has the merit that power supply is not interrupted even if a feeder or a transformer is out due to fault. By dismanting, of this system, such merit will be lost, and therefore it becomes necessary to take the following countermeasures;

a. Feeders should be interlinked with each other for purpose of quick change over to sound feeder.

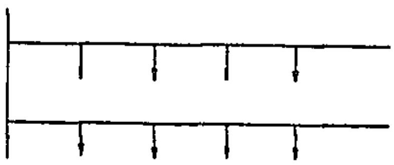
b. Maintenance vehicle and spare transformer should be on a stand-by status at all times.

c. Low tension line would be interlinked also by low tension switch at the cutting-off point.

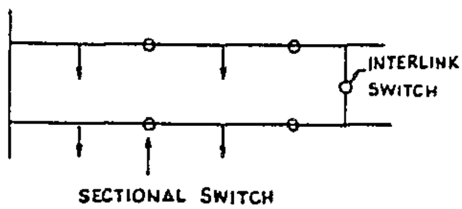
(2) Formation of primary distribution system

The following four types of system formation can be considered.

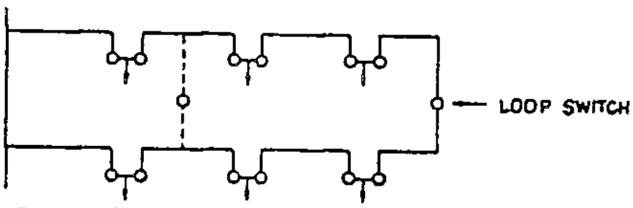
a. Radial system



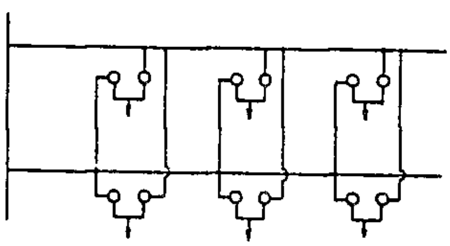
b. Sectional interlink system



c. π-loop interlink system



d. Spare feeder system

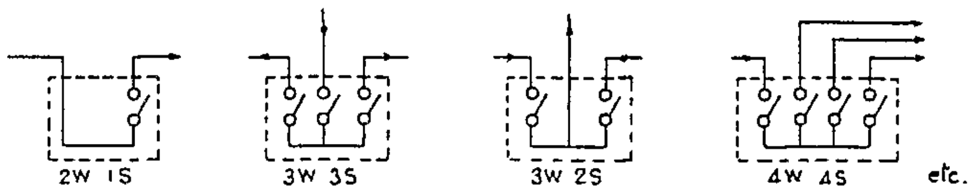


Among the above four types, c or d is expected to provide better reliability than a and b. In case of c, it has to be borne in mind that the size of conductor becomes small at the end part of feeder through which interchange power would be supplied. Installation of a tie switch (dotted line in figure) is a better way to solve this problem.

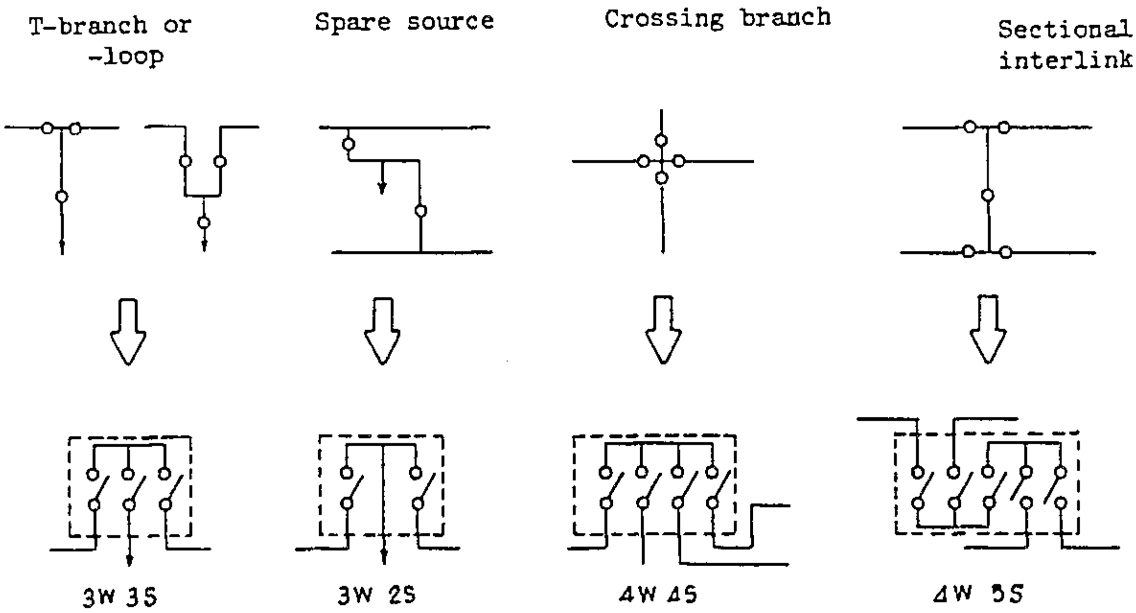
(3) Multi-circuit switch for primary distribution line

Recently, multi-circuit type of switch has become popular especially in underground distribution system.

Circuit formation by multi-circuit switch is as follows:



Application to actual circuit is, for instance, as follows ;



(4) Mounting space of multi-circuit switch

a. Underground

Switch is mounted in a man-hole. As a result of checking dimensions, this switch can be mounted in MEA's man-hole, which is shown in DWG No. 2411 of MEA Underground Distribution Construction Standard.

b. Outdoor

Smart and compact type of cubicle is mounted on pavement or in a park. This type has the advantage over man-hole type of being operated quickly and easily.

c. Indoor

Indoor mounting is possible in case that new big consumer (12 kV supply) agrees to provide a part of his space to equip MEA's multi-circuit switch. In case of existing consumer (not new consumer), MEA must extend the power cable, and it is difficult to get consumer's approval to equip the switch in his premise.

d. Pole-mounted

In order to mount a switch on a pole, the cable must be extended. Furthermore, there is the problem of appearance of facility. Therefore, this method should be applied only in case that another method is not possible.

(5) Matters to be considered in design

a. In a network area, there are many high voltage feeders. For this reason, when the network is dismantled, each transformer will be most probably connected to different feeders. Therefore, at time of fault, it is easy to switch over the transformer to another feeder. This advantage should be utilized in the design of a new system.

b. The unit capacity of a transformer in the existing network area is 500 kVA. Therefore, when a fault occurs in a system of one transformer, the influence caused by it would encompass a wide area. Therefore, in the design of a new system, adoption of the aforementioned π loop system or spare line system should be studied in order to maintain supply reliability.

c. In making the decision of type of switching device for high voltage feeder, study of outdoor type and indoor type should be made for each switch.

d. From the standpoint of maintenance of service reliability, interlinking work of high tension feeders should be performed before cutting-off low tension distribution lines.

(6) Problems to be solved

a. It is necessary to check at each site the possibility of installation of multi-circuit switch.

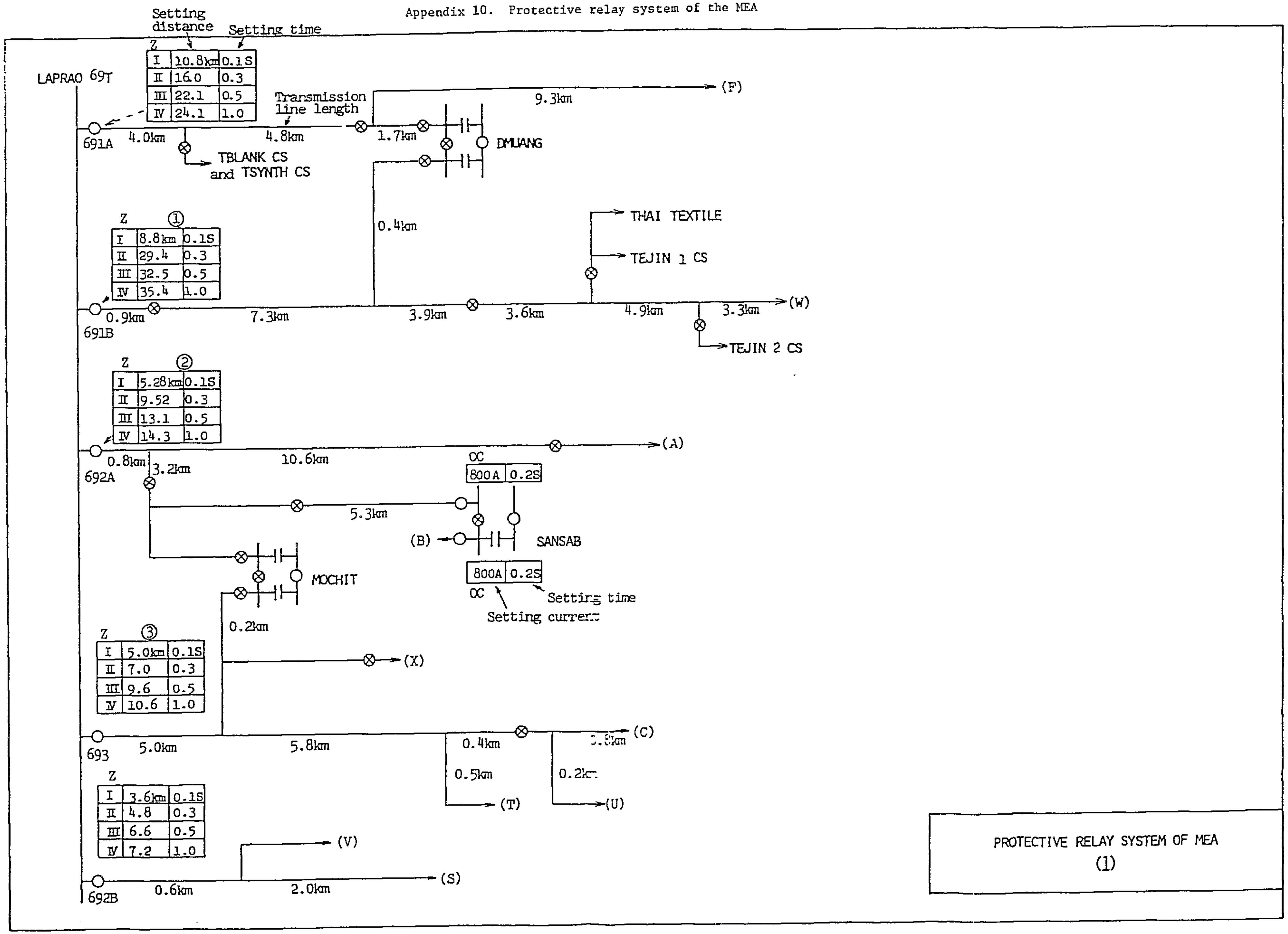
b. More than 400 units of multi-circuit switches are needed to complete such system.

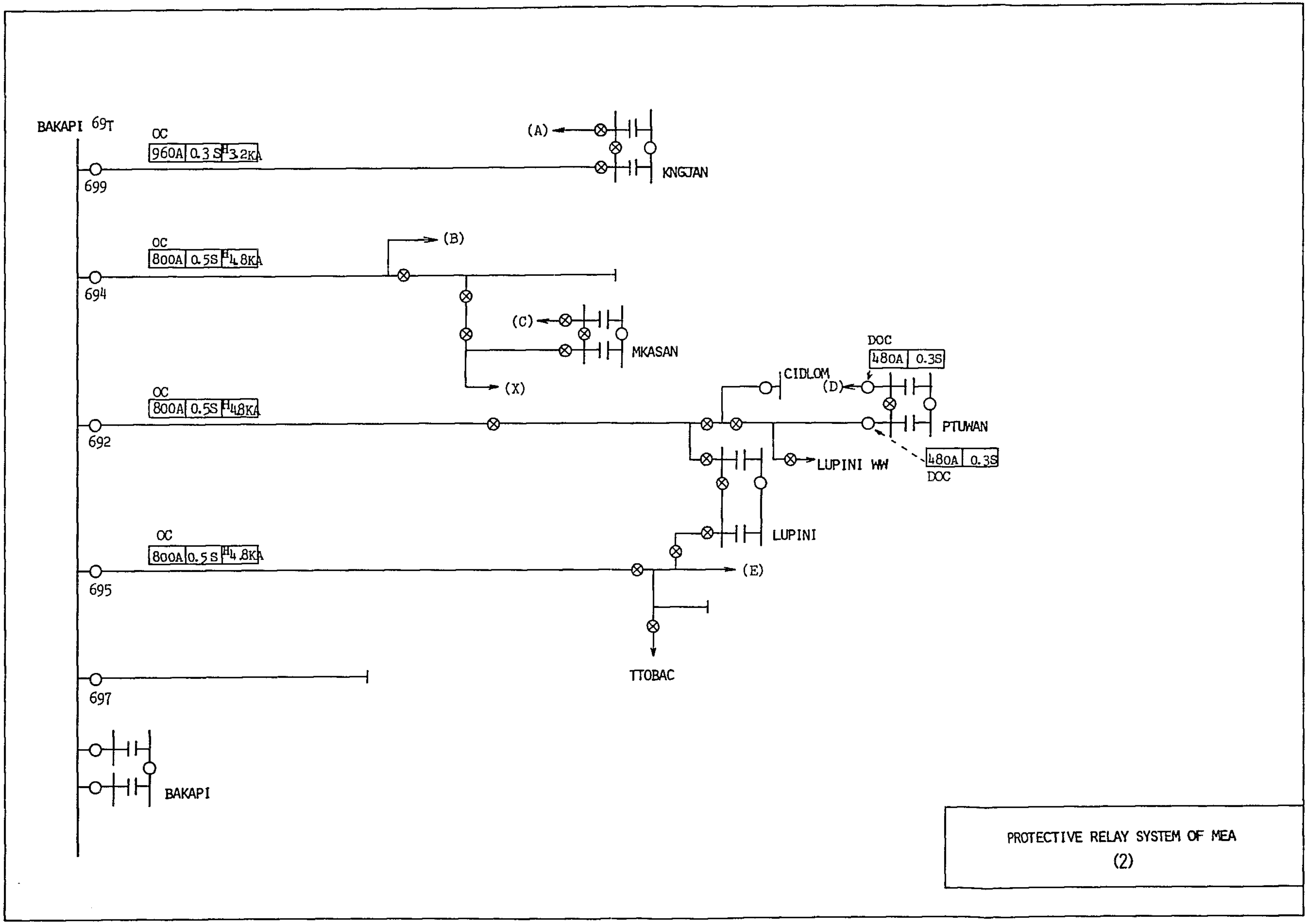
c. Existing multi-circuit switches have prefabricated terminal connectors which can be connected to only CV cable. MEA's cables in this area inlcude PILC (lead-covered paper-insulation cable). Connection method of PILC with multi-circuit switch should be studied.

Appendix 10. Detailed study of protective relays of the MEA

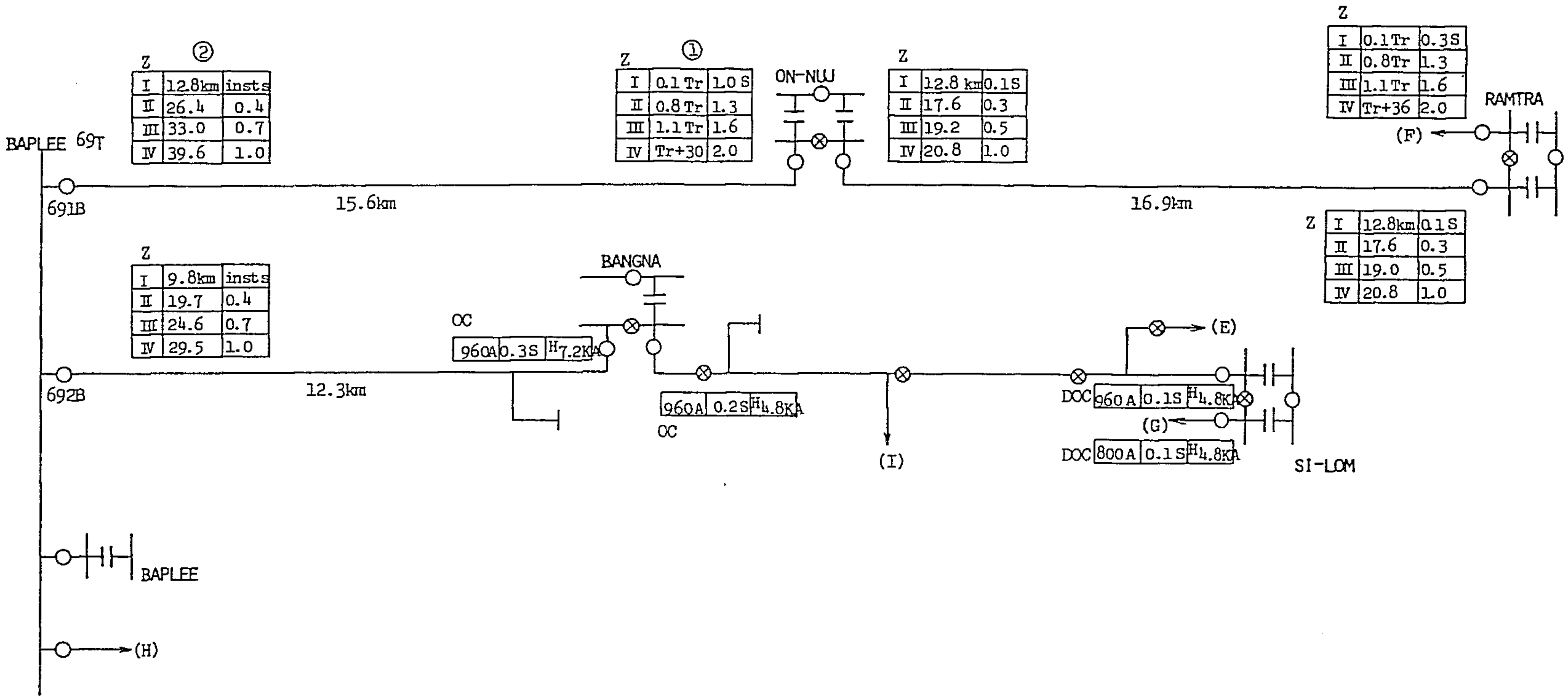
Each protective relays equipped on the MEA power system is checked and analyzed in the following diagrams (1) ~ (8). Results of analysis are described as notes on every diagrams.

Appendix 10. Protective relay system of the MEA



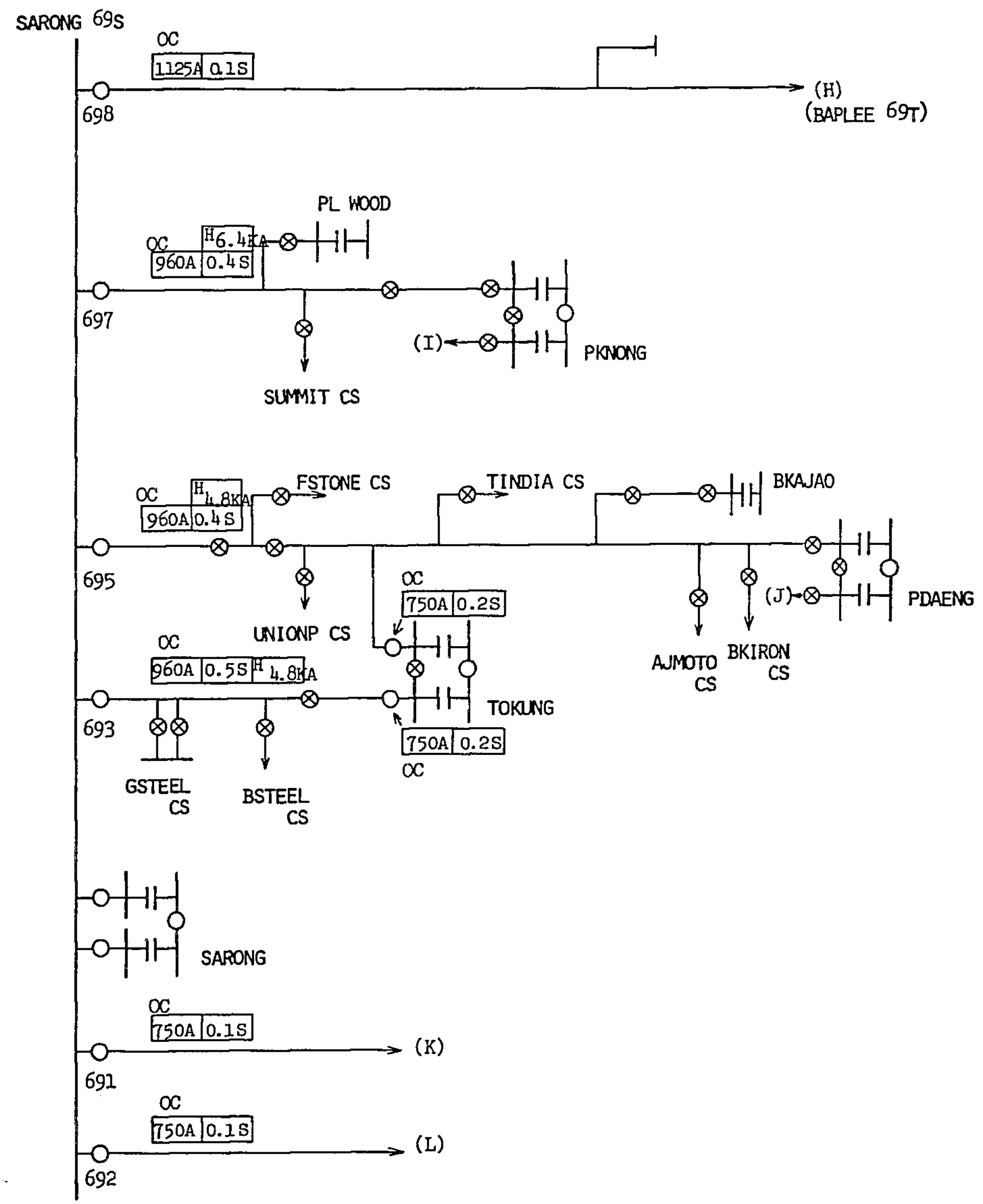


PROTECTIVE RELAY SYSTEM OF MEA
(2)

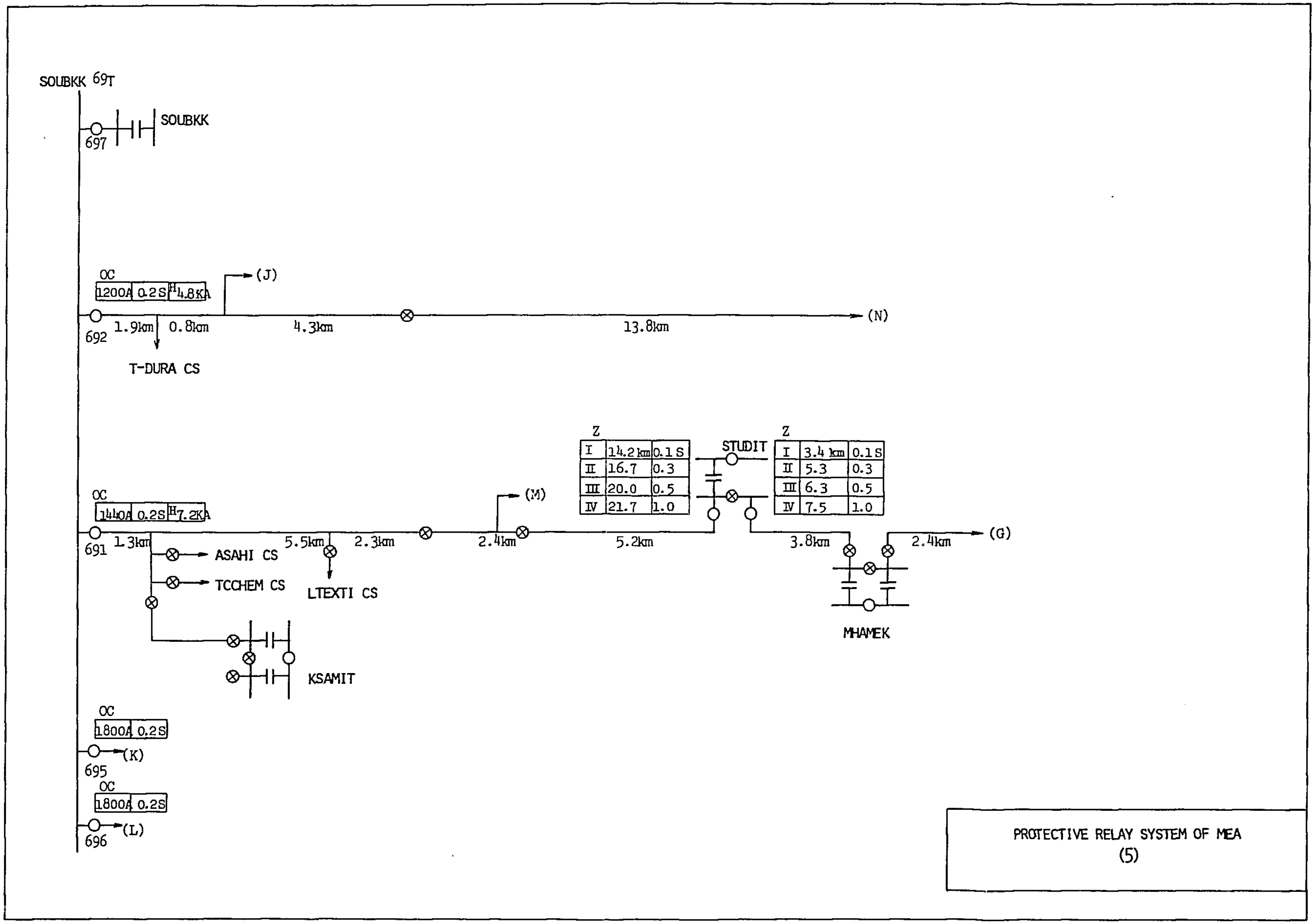


PROTECTIVE RELAY SYSTEM OF MEA

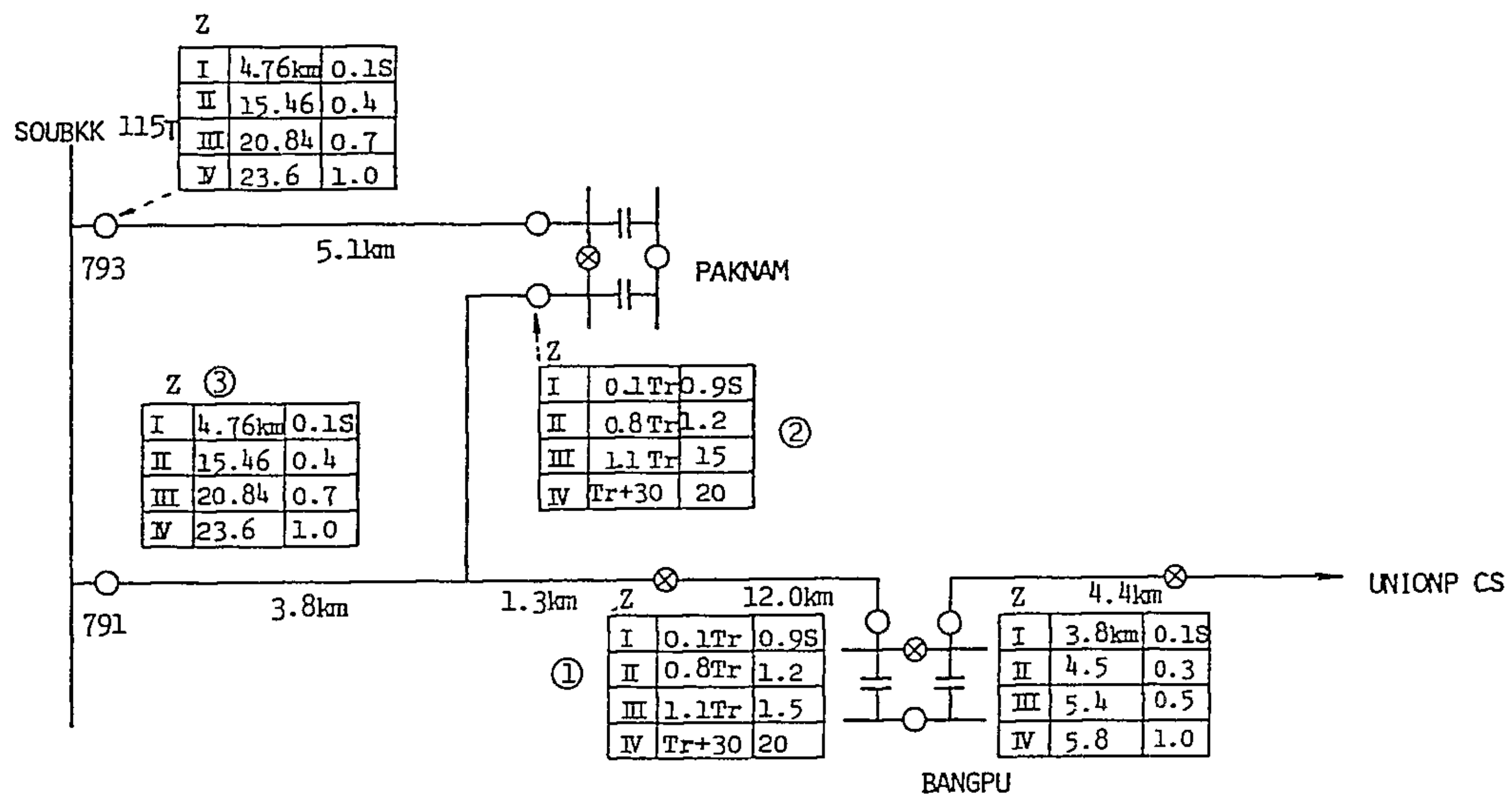
(3)



PROTECTIVE RELAY SYSTEM OF MEA
(4)

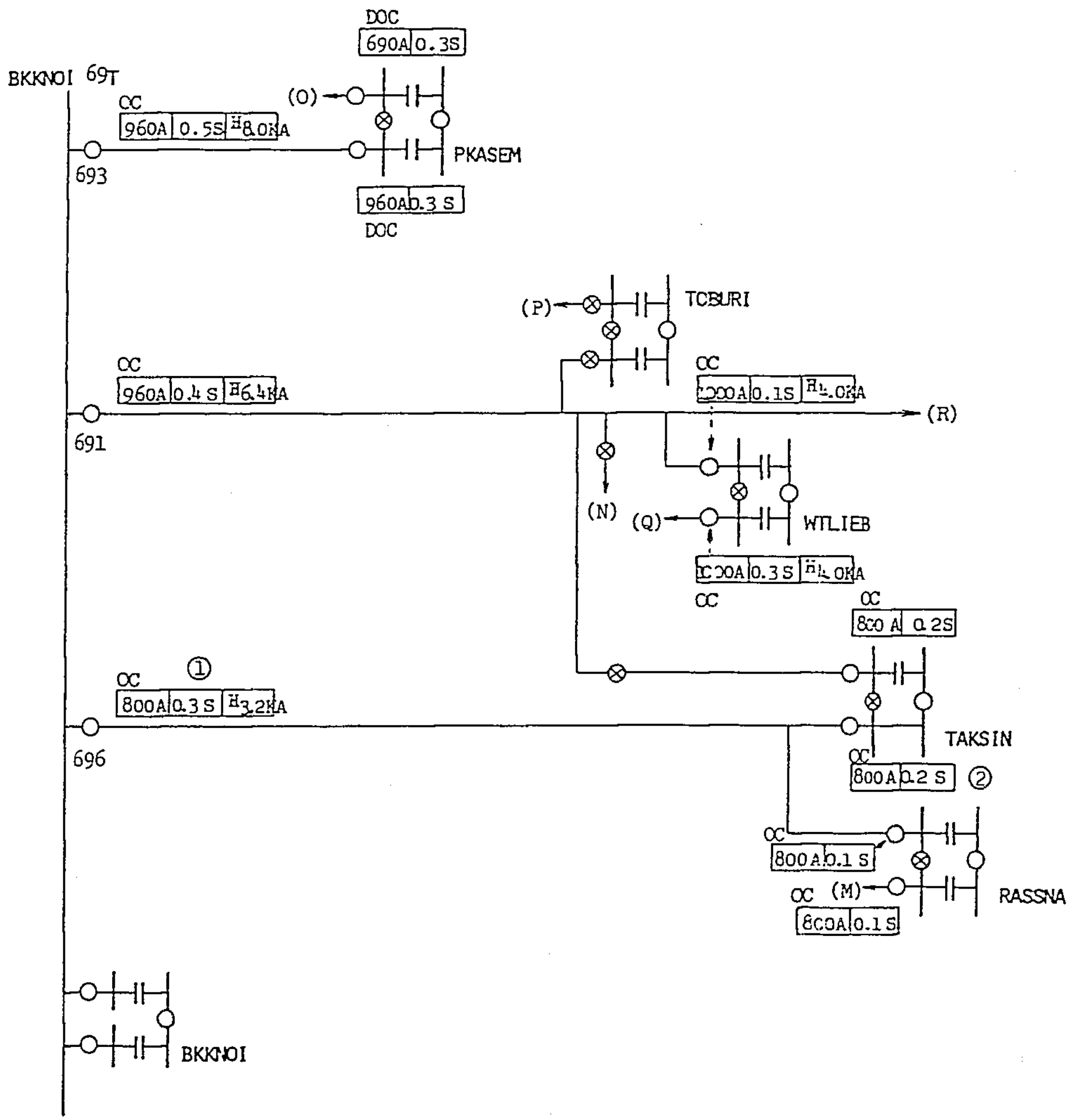


PROTECTIVE RELAY SYSTEM OF MEA
(5)



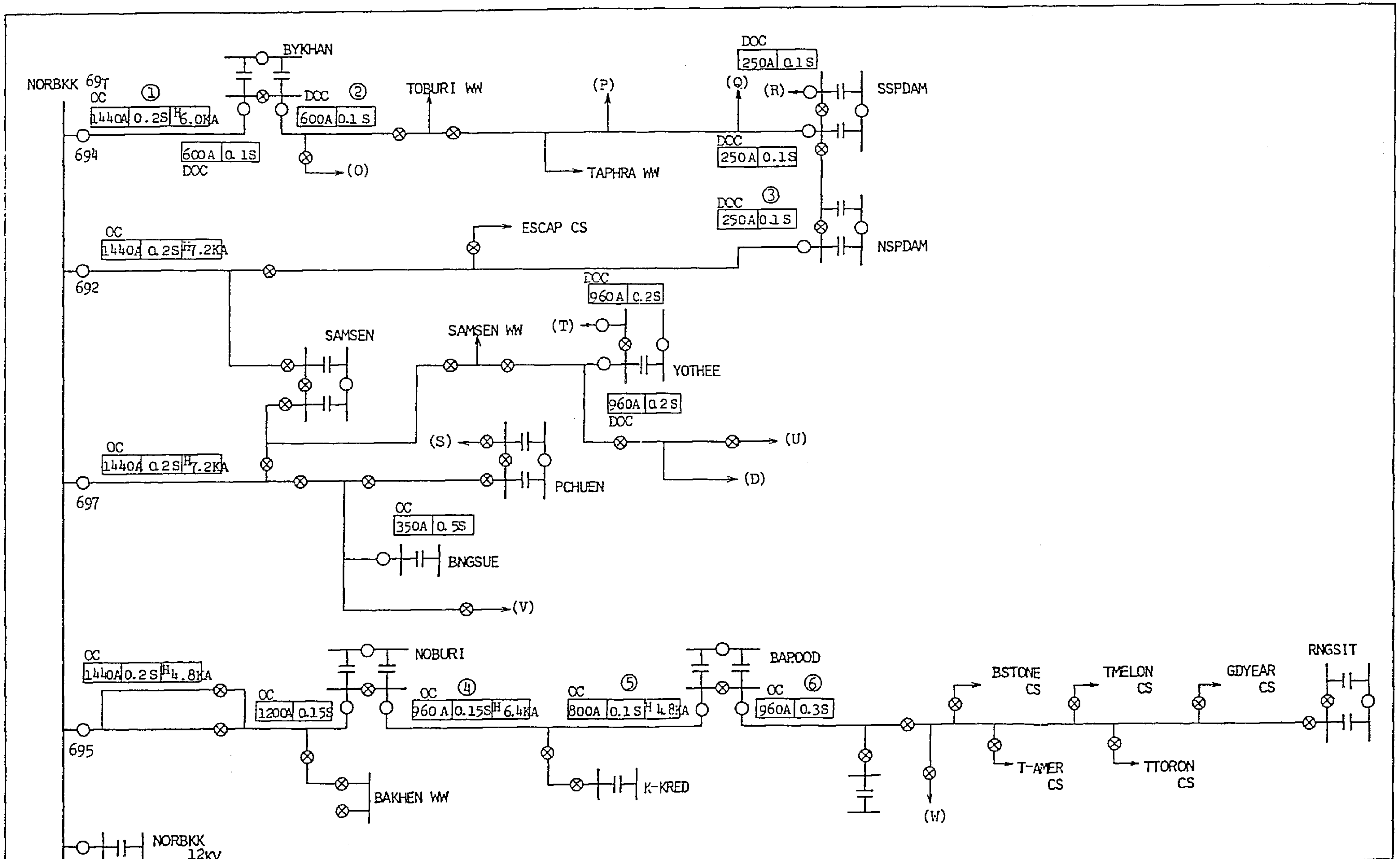
PROTECTIVE RELAY SYSTEM OF MEA

(6)



PROTECTIVE RELAY SYSTEM OF MEA

(7)



PROTECTIVE RELAY SYSTEM OF MEA
(8)

Appendix 11 Utilization Factor of Existing Substations

The results of comparisons of transformer capacities and loads as of 15.00 o'clock, September 12, 1979 for 43 distribution substations are as indicated in Table 11-1.

a. The average transformer utilization factor for all of the transformers at 43 distribution substations was 50.2%.

b. There is a wide range on utilization factors of distributions as indicated in the table below.

Unit: Number of substation·
Sept. 12, 1979

Number of Bank	Utilization Factor (%) / Substation Capacity	Less than 30	31~ 40	41~ 50	51~ 60	61~ 70	71~ 80	Total Number of Substation
1	10 MVA	1	–	–	–	–	1	2
	20 or 22.4 MVA	–	1	–	–	1	–	2
	40 MVA	–	2	1	3	1	–	7
2	20 MVA	–	–	–	–	–	–	0
	40 MVA	1	1	1	1	3		7
	80 MVA	3	3	8	6	3	2	25
Total		5	7	10	10	8	3	43

c. If a substation having 2 banks is being operated at less than 50% utilization factor, load transfer can be done quickly in case of outage of a transformer.
17 out of 43 substations surveyed are in such condition.

d. At 26 other substations, when a distribution transformer should go out, there will be cases where switching of load to another substation will be necessary.

Table 11-1 Utilization Factor of Substation

Substation	SS. Cap (MVA)	Bank Cap (MVA)	Bank Max Load (MW)	Bank Max Load (MVAR)	Bank Max Load (MVA)	Bank UTF (%)	Total Load (MVA)	Average UTF (%)
BKKNO1 (K)	40	20	12.8	7.4	15.0	75.0	24.5	61.3
		20	8.0	5.6	9.7	48.5		
BAKAPI (B)	80	40	14.0	3.0	14.3	35.7	33.2	41.5
		40	18.0	6.0	19.0	47.5		
BANGNA (BG)	40	40	13.8	8.2	16.1	40.0	16.1	40.0
BNGSUE (BS)	10	10	7.0	3.0	7.6	76.0	7.6	76.0
BYKHAN (BY)	80	40	9.5	4.0	10.3	38.8	22.6	28.3
		40	12.0	3.0	12.4	31.3		
BAPOOD (BD)	40	20	5.2	5.5	7.6	38.0	11.5	28.7
		20	5.0	0.1	5.0	25.0		
BKAJAO (BC)	10	10	2.5	0.7	2.6	26.0	2.6	26.0
BAPLEE (BP)	40	40	19.0	12.2	22.6	56.5	22.6	56.5
BANGPU (BU)	80	40	30.0	10.1	31.6	79.0	43.9	54.9
		40	10.8	6.1	12.4	31.0		
CIDLOM (CL)	–	–	–	–	–	–	–	–
DMUANG (D)	80	40	15.0	5.8	16.1	40.2	40.0	50.0
		40	22.0	9.5	24.0	60.0		
KLRSIT (KR)	40	40	16.5	10.2	19.4	48.5	19.4	48.5
KSAMIT (KS)	40	20	7.5	4.0	8.5	42.5	20.4	51.0
		20	9.7	6.9	11.9	59.5		
K-KRED (KK)	20	20	–	–	–	–	–	–
KNGJAN (KJ)	40	20	13.0	4.6	13.8	68.9	27.8	69.5
		20	12.2	7.2	14.2	70.8		
LUPINI (L)	80	40	29.0	24.0	37.6	94.1	61.2	76.5
		40	16.6	14.0	21.7	54.3		
LAPRAO (LP)	–	–	–	–	–	–	–	–
MOCHIT (M)	80	40	16.0	7.0	17.5	43.7	34.8	43.5
		40	15.0	7.8	16.9	42.3		
MKASAN (MS)	80	40	17.2	11.8	20.9	52.1	40.3	50.4
		40	17.2	9.2	19.5	48.8		
MHAMEK (MM)	80	40	20.0	9.5	22.1	55.4	38.3	47.9
		40	14.2	7.8	16.2	40.5		

Substation	SS. Cap (MVA)	Bank Cap (MVA)	Bank Max Load (MW)	(MVAR)	(MVA)	Bank UTF (%)	Total Load (MVA)	Average UTF (%)
NORBKK (N)	40	20	6.6	4.0	7.7	38.6	15.3	38.3
		20	6.6	3.7	7.5	37.8		
NOBURI (NR)	40	20	8.0	3.8	8.9	44.3	19.5	48.8
		20	9.4	5.0	10.9	53.2		
ON-NUJ (NU)	80	40	12.8	6.0	14.1	35.3	23.5	29.3
		40	7.8	5.4	9.5	23.7		
PLWOOD (PL)	22.4	22.4	6.4	4.0	7.5	33.5	7.5	33.5
PAKNAN (R)	80	40	30.0	10.1	31.7	79.1	43.9	54.9
		40	10.8	6.1	12.4	31.0		
PDAENG (Q)	80	40	19.5	17.5	26.2	65.5	41.9	52.4
		40	13.8	8.0	16.0	39.9		
PKNONG (P)	80	40	15.8	8.2	17.8	44.5	46.6	58.3
		40	24.7	14.8	28.8	72.0		
PTUWAN (PM)	80	40	23.7	17.2	29.3	73.2	56.2	70.3
		40	22.8	14.3	26.9	67.3		
PKASEM (PS)	40	20	11.2	9.4	14.6	73.1	27.8	69.5
		20	10.8	7.6	13.2	66.0		
PCHUEN (PC)	80	40	13.3	8.0	15.5	38.8	22.9	28.6
		40	6.1	4.1	7.3	18.4		
PASSNA (RN)	80	40	18.5	12.2	22.2	55.4	54.6	68.3
		40	23.3	23.0	32.7	81.8		
RNGSIT (RS)	80	40	10.8	7.2	13.0	32.4	25.2	31.5
		40	10.4	6.4	12.2	30.5		
RAMTRA (RT)	80	40	11.8	10.8	16.0	40.0	29.1	36.4
		40	12.6	5.0	13.6	33.9		
SAMSEN (S)	80	40	22.0	4.0	22.4	55.9	42.1	52.6
		40	19.3	4.0	19.7	49.3		
SARONG (SR)	80	40	22.0	17.1	27.9	69.8	61.6	77.0
		40	26.2	21.2	33.7	84.3		
STUDIT (SA)	40	40	11.2	7.5	13.5	33.7	13.5	33.7
SSPDAM (SD)	80	40	15.0	10.5	18.3	45.8	44.7	55.9
		40	22.0	14.5	26.3	65.9		
NSPADAM	80	40	14.0	7.5	15.9	39.7	34.0	42.5
		40	15.8	8.8	18.1	45.2		
SOUBKK (SK)	20	20	10.0	7.0	12.2	61.0	12.2	61.0

Substation	SS. Cap (MVA)	Bank Cap (MVA)	Bank Max Load (MW)	(MVAR)	(MVA)	Bank UTF (%)	Total Load (MVA)	Average UTF (%)
SI-LOM (SL)	80	40	22.1	13.3	25.8	64.5	53.3	66.7
		40	24.2	13.2	27.6	68.9		
SANSAB (SS)	40	40	19.4	12.8	23.2	58.0	23.2	58.0
TOBURI (T)	80	40	18.0	6.8	19.2	48.1	37.5	46.9
		40	16.9	7.0	18.3	45.7		
TOKUNG (TK)	80	40	24.8	6.0	25.5	63.8	45.1	56.4
		40	17.2	10.5	20.2	50.4		
TAKSIN (TS)	40	40	19.0	14.2	23.7	59.3	23.7	59.3
WTLIEB (W)	80	40	16.0	5.5	16.9	43.7	30.6	38.3
		40	13.0	4.3	13.7	34.2		
YOTHEE (TY)	40	40	22.2	10.6	24.6	61.5	24.6	61.5
TOTAL	2,642.4						1,326.9	50.2

Note: 1. Bank UTF = Bank utilization factor
2. Average UTF = Average utilization factor
3. These data are value as of September 12, 1979.

Appendix 12 Utilization Factor of Existing Feeders

Sept. 12, 1979 '/9

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
BANKKAPI	B11	12	AAL 336.4 MCM	8	4.666	0.583
	B12	12	〃	8	2.751	0.343
	B13	12	〃	8	1.842	0.230
	B14	12	〃	8	2.498	0.312
	B16	12	〃	8	2.457	0.307
	B21	12	〃	8	5.136	0.642
	B23	12	〃	8	6.030	0.753
	B24	12	〃	8	6.321	0.790
	B25	12	〃	8	6.420	0.803
BANGKOK NO1	K12	12	〃	8	5.561	0.695
	K13	12	〃	8	5.561	0.695
	K14	12	〃	8	6.798	0.850
	K22	12	〃	8	5.150	0.644
	K23	12	〃	8	5.943	0.743
BANGK POOD	BD11	12	〃	8	3.157	0.395
	BD12	12	〃	8	2.210	0.276
	BD13	12	〃	8	1.815	0.227
	BD14	12	〃	8	1.578	0.197
	BD21	12	〃	8	0.113	0.014
	BD23	12	〃	8	2.974	0.372
BANG YEE KHAN	BY11	12	〃	8	5.987	0.748
	BY12	12	〃	8	0.211	0.026
	BY13	12	〃	8	6.786	0.848
	BY21	12	〃	8	6.621	0.828
	BY22	12	〃	8	5.794	0.724
	BY23	12	〃	8	4.552	0.569
BANG PU	BU411	24	〃	16	6.728	0.421
	BU412	24	〃	16	13.662	0.854
	BU413	24	〃	16	12.642	0.790
	BU421	24	〃	16	6.645	0.415
	BU422	24	〃	16	0.369	0.023
BANG SUE	BS11	12	〃		Spare	
	BS14	12	〃	8	8.105	1.013

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
BANG NA	BG11	12	AAL 336.4 MCM	8	4.320	0.540
	BG13	12	〃	8	3.919	0.490
	BG22	12	〃	8	6.029	0.754
	BG23	12	〃	8	4.020	0.503
BANG KRACHAO	BC12	12	〃	8	1.621	0.203
	BC21	12	〃	8	4.357	0.544
BANG PLEE	BP411	24	〃	16	7.245	0.453
	BP412	24	〃	16	0.201	0.012
	BP421	24	〃	16	6.842	0.428
	BP422	24	〃	16	9.458	0.591
DONMUANG	D12	12	〃	8	6.920	0.865
	D13	12	〃	8	7.327	0.916
	D14	12	〃	8	6.003	0.750
	D21	12	〃	8	6.513	0.814
	D22	12	〃	8	5.495	0.687
	D23	12	〃	8	6.992	0.874
	D24	12	〃	8	6.207	0.776
KLONG RANGSIT	KR411	24	〃	16	9.915	0.620
	KR421	24	〃	16	10.114	0.632
	KR431	24	〃	16	7.139	0.446
KLONG SANPA SAMIT	KS11	12	〃	8	4.364	0.546
	KS12	12	〃	8	5.610	0.701
	KS21	12	〃	8	6.615	0.827
	KS22	12	〃	8	6.013	0.752
	KS23	12	〃	8	1.203	0.150
KONG JAN	KJ11	12	〃	8	5.080	0.635
	KJ12	12	〃	8	0.111	0.014
	KJ13	12	〃	8	4.339	0.542
	KJ14	12	〃	8	8.575	1.072
	KJ21	12	〃	8	7.666	0.958
	KJ22	12	〃	8	4.269	0.534
	KJ23	12	〃	8	5.628	0.704

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
LUMPINI	L11	12	AAL 336.4 MCM	8	5.013	0.627
	L12	12	〃	8	5.213	0.652
	L13	12	〃	8	4.111	0.514
	L14	12	〃	8	6.015	0.752
	L15	12	〃	8	7.017	0.877
	L16	12	〃	8	7.620	0.953
	L21	12	〃	8	6.783	0.848
	L22	12	〃	8	4.658	0.582
	L23	12	〃	8	4.455	0.557
	L24	12	〃	8	4.252	0.532
	L25	12	〃	8	7.695	0.962
	L26	12	〃	8	3.747	0.468
MAKKASAN	MS11	12	〃	8	2.949	0.369
	MS12	12	〃	8	5.506	0.688
	MS13	12	〃	8	7.865	0.983
	MS14	12	〃	8	2.261	0.283
	MS15	12	〃	8	3.834	0.479
	MS21	12	〃	8	2.781	0.348
	MS22	12	〃	8	5.665	0.708
	MS23	12	〃	8	4.429	0.554
	MS24	12	〃	8	4.119	0.515
	MS26	12	〃	8	2.472	0.309
MAHAMEK	MM11	12	〃	8	6.068	0.759
	MM12	12	〃	8	6.674	0.834
	MM13	12	〃	8	6.472	0.809
	MM14	12	〃	8	4.855	0.607
	MM15	12	〃	8	3.544	0.443
	MM21	12	〃	8	3.164	0.396
	MM22	12	〃	8	5.148	0.644
	MM23	12	〃	8	3.362	0.420
	MM24	12	〃	8	6.724	0.841
	MM26	12	〃	8	0.395	0.049
MO-CHIT	M11	12	〃	8	5.466	0.683
	M12	12	〃	8	5.150	0.644
	M13	12	〃	8	5.163	0.645
	M14	12	〃	8	4.853	0.607
	M21	12	〃	8	7.032	0.879
	M22	12	〃	8	1.980	0.248
	M23	12	〃	8	5.546	0.693

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
MO-CHIT	M24	12	AAL 335.4 MCM	8	4.358	0.545
NONTHABURI	NR11	12	"	8	5.781	0.723
	NR13	12	"	8	4.794	0.594
	NR21	12	"	8	3.096	0.387
	NR23	12	"	8	2.271	0.284
	NR24	12	"	8	6.813	0.851
NORTH BANGKOK	N12	12	"	8	6.919	0.865
	N13	12	"	8	7.326	0.916
	N14	12	"	8	4.376	0.547
	N22	12	"	8	3.969	0.496
					–	
					–	
ON-NUJ	NU411	24	"	16	6.326	0.395
	NU412	24	"	16	5.905	0.369
	NU421	24	"	16	3.796	0.237
	NU422	24	"	16	0.421	0.026
	NU423	24	"	16	1.265	0.079
PAKNAM	R412	24	"	16	8.495	0.531
	R413	24	"	16	8.495	0.531
	R422	24	"	16	7.432	0.465
	R423	24	"	16	11.679	0.730
PATHUWAN	PM11	12	"	8	4.738	0.592
	PM12	12	"	8	5.529	0.691
	PM13	12	"	8	5.529	0.691
	PM14	12	"	8	6.220	0.777
	PM15	12	"	8	7.108	0.889
	PM21	12	"	8	7.392	0.924
	PM22	12	"	8	6.663	0.833
	PM23	12	"	8	6.246	0.781
	PM24	12	"	8	5.831	0.729
PRAKANONG	P11	12	"	8	5.001	0.625
	P12	12	"	8	6.329	0.791
	P13	12	"	8	4.900	0.613
	P14	12	"	8	6.023	0.753
	P21	12	"	8	7.888	0.986

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
PRAKANONG	P22	12	AAL 336.4 MCM	8	6.113	0.764
	P23	12	〃	8	6.804	0.851
	P24	12	〃	8	5.916	0.740
	P26	12	〃	8	5.718	0.715
PETCHKASEM	PS11	12	〃	8	2.986	0.373
	PS12	12	〃	8	2.688	0.336
	PS13	12	〃	8	4.978	0.622
	PS14	12	〃	8	5.874	0.734
	PS21	12	〃	8	5.234	0.654
	PS22	12	〃	8	4.914	0.614
	PS23	12	〃	8	7.265	0.908
PRACHACHUEN	PC11	12	〃	8	7.400	0.925
	PC12	12	〃	8	6.284	0.786
	PC13	12	〃	8	5.776	0.722
	PC22	12	〃	8	5.980	0.748
	PC23	12	〃	8	5.879	0.735
PRAPRADAENG	Q11	12	〃	8	5.204	0.651
	Q12	12	〃	8	6.412	0.802
	Q13	12	〃	8	6.878	0.860
	Q14	12	〃	8	5.204	0.651
	Q21	12	〃	8	6.337	0.792
	Q22	12	〃	8	8.448	1.056
	Q23	12	〃	8	8.226	1.028
PLY WOOD	PL11	12	〃	8	4.863	0.608
	PL12	12	〃	8	3.546	0.443
RASBURANA	RN11	12	〃	8	7.592	0.949
	RN12	12	〃	8	4.801	0.600
	RN13	12	〃	8	4.913	0.614
	RN14	12	〃	8	8.822	1.103
	RN21	12	〃	8	6.677	0.834
	RN22	12	〃	8	5.286	0.661
	RN23	12	〃	8	6.677	0.835
	RN24	12	〃	8	6.492	0.811
	RN26	12	〃	8	3.246	0.406
RAMINTRA	RT411	24	〃	16	4.472	0.279
	RT412	24	〃	16	6.880	0.430

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
RAMINTRA	RT413	24	AAL 336.4 MCM	16	1.205	0.075
	RT421	24	〃	16	7.185	0.449
	RT422	24	〃	16	3.593	0.225
	RT423	24	〃	16	3.593	0.225
RANGSIT	RS414	24	〃	16	0.398	0.025
	RS421	24	〃	16	12.653	0.791
	RS422	24	〃	16	11.428	0.714
	RS423	24	〃	16	3.674	0.230
SAMRONG	SR11	12	〃	8	7.238	0.905
	SR12	12	〃	8	5.027	0.628
	SR13	12	〃	8	3.821	0.478
	SR14	12	〃	8	7.841	0.980
	SR15	12	〃	8	6.434	0.804
	SR21	12	〃	8	5.290	0.661
	SR22	12	〃	8	6.269	0.784
	SR23	12	〃	8	8.228	1.028
	SR24	12	〃	8	8.425	1.053
	SR26	12	〃	8	4.311	0.539
SAMSEN	S11	12	〃	8	4.447	0.556
	S12	12	〃	8	4.268	0.534
	S13	12	〃	8	5.054	0.632
	S14	12	〃	8	6.064	0.758
	S16	12	〃	8	5.660	0.708
	S21	12	〃	8	5.255	0.657
	S22	12	〃	8	6.064	0.758
	S23	12	〃	8	5.559	0.695
	S24	12	〃	8	3.638	0.455
	S25	12	〃	8	5.660	0.708
SILOM	SL11	12	〃	8	3.881	0.485
	SL12	12	〃	8	2.588	0.324
	SL13	12	〃	8	6.569	0.821
	SL14	12	〃	8	4.379	0.547
	SL16	12	〃	8	6.271	0.784
	SL21	12	〃	8	5.092	0.637
	SL22	12	〃	8	5.194	0.649
	SL23	12	〃	8	6.111	0.764
	SL24	12	〃	8	5.194	0.649
	SL25	12	〃	8	6.416	0.802

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
SOUTH BANGKOK	SK11	12	AAL 336.4 MCM	8	5.723	0.715
	SK12	12	"	8	6.132	0.767
	SK13	12	"	8	2.861	0.358
TONGKUNG	TK11	12	"	8	7.468	0.934
	TK12	12	"	8	5.890	0.736
	TK13	12	"	8	6.837	0.855
	TK14	12	"	8	5.890	0.736
	TK16	12	"	8	5.153	0.644
	TK21	12	"	8	5.032	0.629
	TK22	12	"	8	6.851	0.856
	TK23	12	"	8	6.405	0.801
	TK24	12	"	8	3.203	0.400
THONBURI	T11	12	"	8	6.867	0.858
	T12	12	"	8	5.453	0.681
	T13	12	"	8	7.262	0.908
	T14	12	"	8	7.070	0.884
	T16	12	"	8	4.040	0.505
	T21	12	"	8	6.795	0.849
	T22	12	"	8	5.895	0.737
	T23	12	"	8	6.295	0.787
	T24	12	"	8	6.794	0.849
	T25	12	"	8	6.694	0.837
TAKSIN	TS11	12	"	8	5.877	0.735
	TS13	12	"	8	6.687	0.836
	TS16	12	"	8	5.268	0.659
	TS21	12	"	8	6.485	0.811
	TS22	12	"	8	2.229	0.279
TOTHI	YT11	12	"	8	3.952	0.494
	YT12	12	"	8	4.965	0.620
	YT16	12	"	8	6.282	0.785
	YT22	12	"	8	4.864	0.608
	YT24	12	"	8	3.039	0.380
	YT25	12	"	8	3.242	0.405
KLANG KRED	KK411	24	"	16	1.176	0.074

Substation	Distribution Feeder	Voltage (kV)	Conductor of Main Trunk Line	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
SAN SAB	SS12	12	AAL 336.4 MCM	8	5.302	0.663
	SS14	12	〃	8	6.650	0.831
	SS22	12	〃	8	4.303	0.538
	SS24	12	〃	8	3.685	0.461
	SS25	12	〃	8	4.853	0.607
SATHUPRADIT	SA12	12	〃	8	4.245	0.531
	SA22	12	〃	8	4.541	0.568
	SA25	12	〃	8	5.824	0.728

Substation	Distribution Feeder	Voltage (kV)	Conductor of Underground Cable	Feeder Capacity MVA (A)	Feeder Load MVA (B)	Utilization Factor (B/A)
WATLIEB	W11	12	500 mcm (x) (p)	8	4.850	0.606
	W12	12	〃 〃	8	3.959	0.495
	W13	12	〃 〃	8	3.167	0.396
	W14	12	〃 〃	8	5.618	0.702
	W21	12	〃 〃	8	5.543	0.693
	W22	12	〃 〃	8	4.355	0.544
	W23	12	〃 (x)	8	4.256	0.532
	W24	12	(x) (p)	8	4.355	0.544
SOUTH SAPANDAM	SD11	12	(p)	8	6.313	0.789
	SD12	12	〃 〃	8	5.72	0.715
	SD13	12	〃 〃	8	5.128	0.641
	SD14	12	〃 (x)	8	2.861	0.358
	SD21	12	〃 (p)	8	6.213	0.777
	SD22	12	〃 (x) (p)	8	5.524	0.691
	SD23	12	〃 〃	8	6.115	0.764
	SD24	12	〃 (p)	8	5.72	0.715
NORTH SAPANDAM	SD31	12	〃 (x)	8	4.914	0.614
	SD32	12	〃 (x) (p)	8	3.079	0.385
	SD33	12	〃 (x)	8	4.914	0.614
	SD34	12	〃 〃	8	2.258	0.282
	SD41	12	〃 〃	8	6.105	0.763
	SD42	12	〃 〃	8	4.003	0.500
	SD43	12	〃 〃	8	0.021	0.003
	SD44	12	〃 〃	8	5.604	0.701
	SD46	12	〃 〃	8	2.602	0.325
			Total mean utilization factor = 171.788/277 = 0.620			

Appendix 13. Composition of subtransmission line system

(1) Types of composition of subtransmission system

Generally speaking in large cities a group of distribution substations are supplied power by subtransmission lines from the power source bus of terminal substations. In this case, several basic patterns of subtransmission line system can be considered.

These basic patterns are normally modified to fit the peculiar conditions of the area in which the system is to be constructed. Therefore, many cases can be considered for the composition of subtransmission line system. In this report, 3 types of basic composition of subtransmission line systems have been studied, and the features and characteristics of each type have been compared.

a. Tapped tie system

In order to permit every distribution substation to receive power from 2 different power source bus, "π" type connection from subtransmission line.

b. Feeder transformer system

A system where each transformer in distribution substration is supplied power from power source bus by separate subtransmission line.

c. Double cirucit T branch system

All subtransmission lines are double circuit strung parallel and every distribution substation is connected to each circuit by "T" branch.

Generally speaking, each of these systems have their peculiar features and characteristics in respect of construction cost, reliability, operation, performance and other features. Therefore, the decision to adopt any one of these systems would probably be influenced by policy consideration concerning which advantages would be recognized among the peculiar features and characteristics each system has. However, a relatively detail comparison of the 3 systems are given in the following chapter.

(2) Comparison where every distribution substation is served by the same system

In order to identify the basic features and characteristics each of the 3 systems have, a model of group of distribution substations in a given area is prepared, and on the assumption that this group of distribution substations are served by a uniform subtransmission line system from among the 3 systems, the investment costs, reliability and other features were compared. In this case, location model of distribution substations were devided into downtown area (A area), suburb area (B area) and remote area (C area), and each of the 3 systems in those areas were compared.

The items compared were composition model, equipment and materials, investment cost, system reliability and operating characteristics. In the estimate of required equipment and materials and investment cost, only those items of equipment and materials which would charge in quantity according to the type of systems were considered, and those which are common for the 3 systems were not included in the estimates.

In selecting the composition models, it was assumed that A area would be served from 3 terminal substations by a combination of underground and overhead subtransmission lines, B area by overhead subtransmission lines served from 2 power source bus, and C area by overhead subtransmission line served from 1 power source bus.

a. Comparison of the 3 systems for A area

Location model of distribution substations in A area is assumed to be as follow:

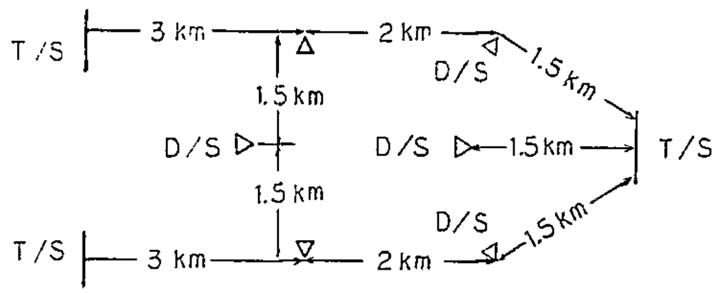


Table 13-1 gives composition models of subtransmission lines for each of the 3 systems and comparison of investment costs, system reliability and other features.

As shown in Table 13-1, investment cost is the least for feeder transformer system, and the investment cost becomes greater for tapped tie system and the most costly for double circuit T branch system.

From the standpoint of system reliability, there is great difference between feeder transformer system and the other 2 systems. In the case of feeder transformer system, fault in 1 circuit of subtransmission line will result in power interruption to 1 transformer only, whereas in the case of the other 2 systems, fault in 1 circuit of subtransmission line will cause power interruption to 2 or 4 transformers. However, in the feeder transformer system it is not possible to switch over to another power source in case of power interruption and there will be continuous power interruption until the fault in the line is remedied, but in the other 2 systems the duration of power interruption is only the operating time of circuit breaker to switch over to another power source. This same condition is applicable in case of fault in bus of terminal substation.

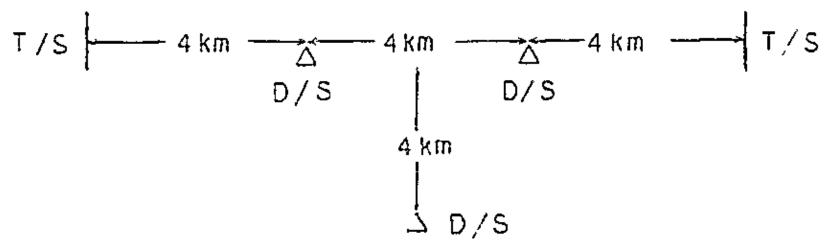
Whether to place emphasis on the area affected by power interruption or the duration of interruption is a matter of policy decision, but it is believed that social impact will be less when the duration of power interruption is short.

Double circuit T branch system is a duplicated structure, therefore, switch over to another line can be done in a short time in case of fault in the line and bus of terminal substation, but the demerit is the large investment cost compared to the other 2 systems.

Taking the above described factors into account, it is thought that the feeder transformer system is better for A area. This system in A area should be composed of overhead and underground lines. If overhead subtransmission line only is used for the feeder transformer system, what must be considered is that the occurrence fault is much greater than underground cable. Conversely, if the system is composed only of underground cable, these would be the advantage of less occurrence of fault, but difficulties will be encountered in installing additional outgoing lines at the terminal substation to cope with growth of demand and the cost will be big. Therefore, what should be considered is the introduction of unit system which is described in Chapter (4) in the expansion of the subtransmission network that is basically composed of feeder transformr system.

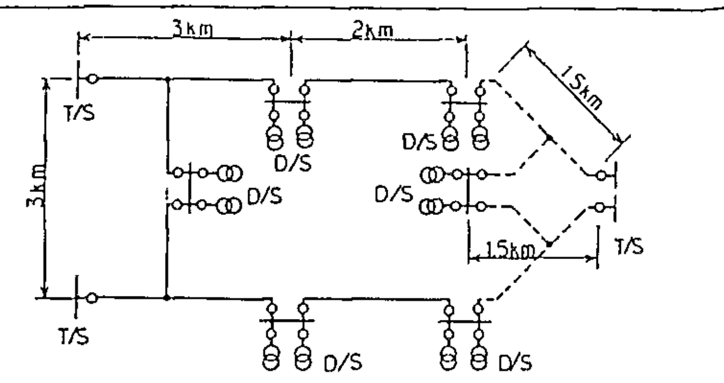
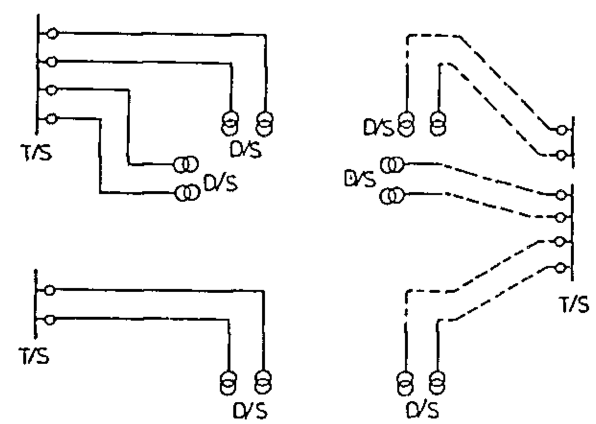
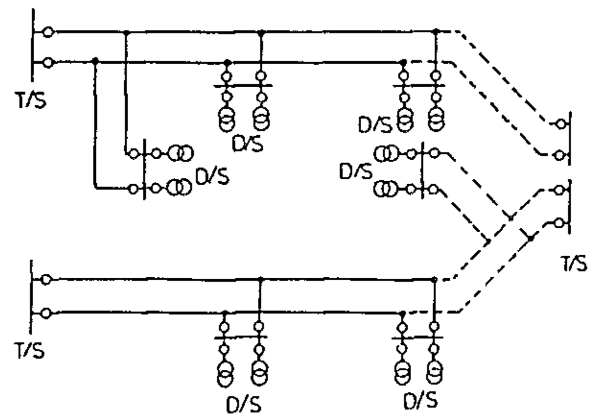
b. Comparison of system in B area

The location model of distribution substations in B area is given in the diagram below, and the comparison that was made for A area was conducted. The results are shown in Table 13-2.

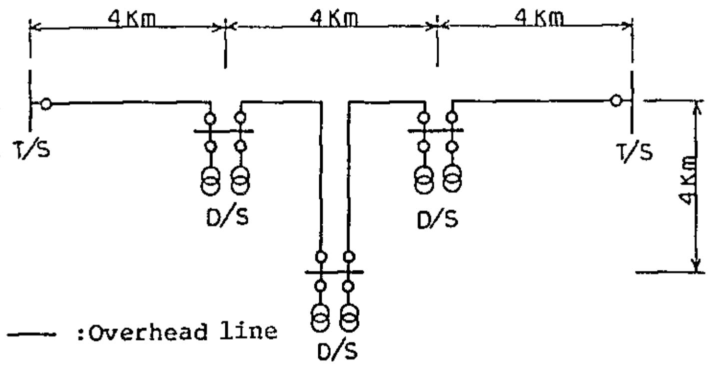
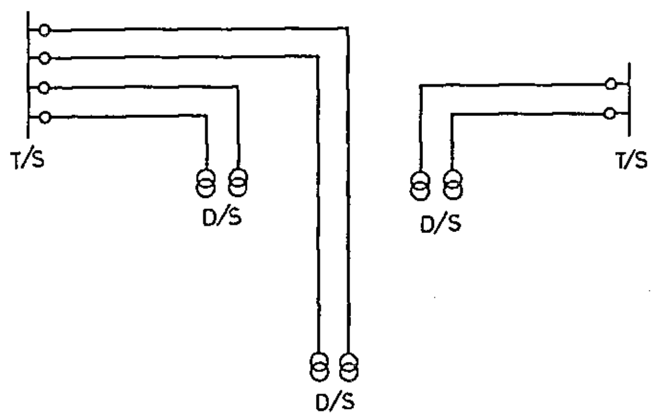
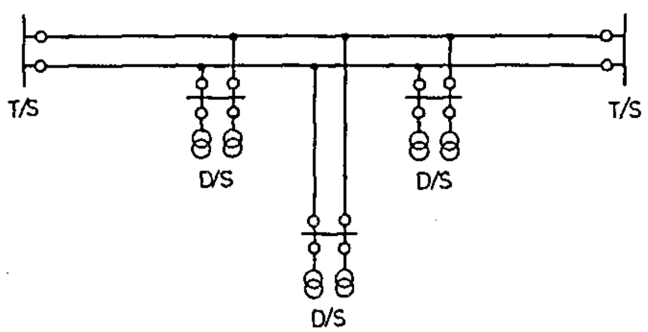


As seen in the table, the investment cost of feeder transformer system is the smallest which is the same for A area. In consideration of the fact that the occurrence of fault in overhead line is relatively high there arises the problem of reliability. Tapped tie and double circuit T branch systems can solve the problem of prolonged power interruption caused by fault. From the standpoint of investment cost, the tapped tie system is advantageous.

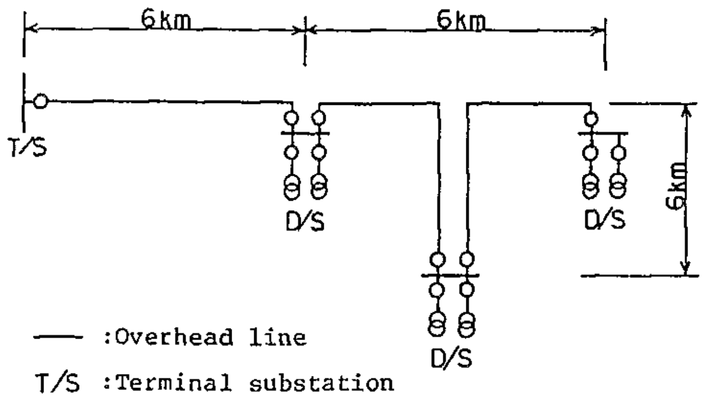
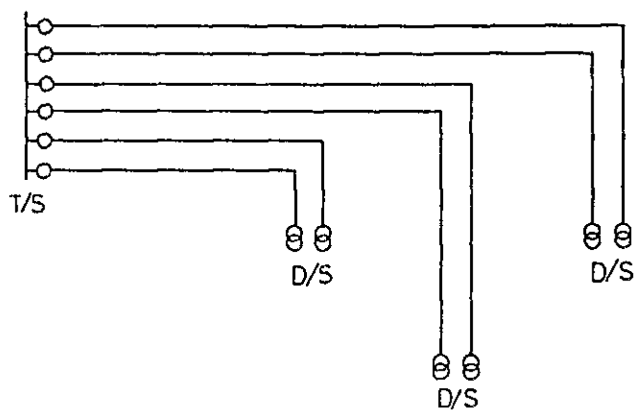
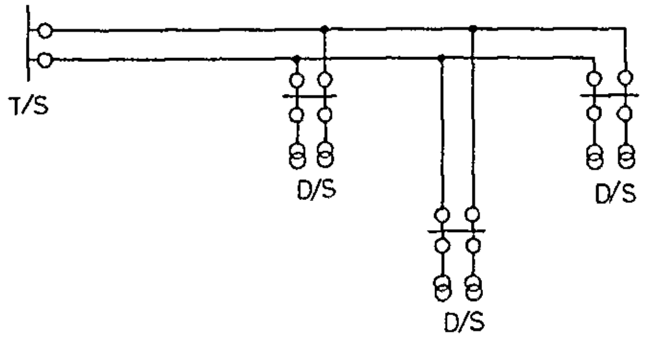
Table 13-1 Comparison of system in A area

Type of system	Connection model	Required facilities and costruction cost			Reliability, operation etc.
			Overhead line	Underground line	
Tapped tie	 ---- : Underground line —— :Overhead line T/S :Terminal substation 8 :Transformer D/S :Distribution substation O :Circuit breaker	Subtransmission line	795MCM AA,1cct-5km. 2x795MCM AA,1cct-6km.	1600sq.mm Cu/PEX,1cct-3km. 500sq.mm Cu/PEX,1cct-1.5km. 795MCM AA,1cct-2km.	1. Outage of 1 cct of subtransmission line will cause power interruption to 1 or 2 distribution substations, but possible to switch over to other power source in a short time. 2. To switch over, operation of CB in other substation is necessary. 3. Branching off from underground cable is necessary.
		Substation switching and measuring facilities	6 Line Feeders (2000A CB, etc) 2 Line Feeders (800A CB, etc) 6 Trans. Feeders (800A CB, etc) 3 Bus Tie (800A LS,etc)	same as left.	
		Construction cost	TC.59,121 x 10^3.	TC.88,608 x 10^3.	
			G.TTL TC.147,729 x 10^3.		
Feeder transformer		Subtransmission line	120sq.mm HAl,2cct-9km.	150sq.mm Cu/PEX,2cct-4.5km.	1. During outage of 1 cct of subtransmission line, 1 bank cannot be saved. 2. During fault in bus of secondary side of transformer, countermeasure needed to open CB in terminal substation. 3. Number of outgoing lines from terminal sub-station will increase.
		Substation switching and measuring facilities	6 Line Feeders (800A CB,etc)	same as left.	
		Construction cost	TC.29,448 x 10^3.	TC.80,892 x 10^3.	
			G.TTL TC.110,340 x 10^3.		
Double circuit T-branch		Subtransmission line	2x400sq.mm TAl,2cct-4.5km. 2x795MCM, AA, 2cct-3.5km. 795MCM, AA, 2cct-1.5km.	800sq.mm Cu/PEX,2cct-3km. 500sq.mm Cu/PEX,2cct-0.75km. 2x795MCM, AA,2cct-2km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to live line in short time. 2. Operation of CB to switch over is possible only at the substation with power interrup-tion. 3. Branching off from underground cable is necessary.
		Substation switching and measuring facilities	4 Line Feeders (2000A CB, etc) 6 Line Feeders (800A CB, etc) 6 Trans. Feeders (800A CB, etc) 3 Bus Tie (800A LS,etc)	same as left.	
		Construction cost	TC.73,754 x 10^3.	TC.117,316 x 10^3.	
			G.TTL TC.191,070 x 10^3.		

Tabel 13-2 Comparison of system in B area

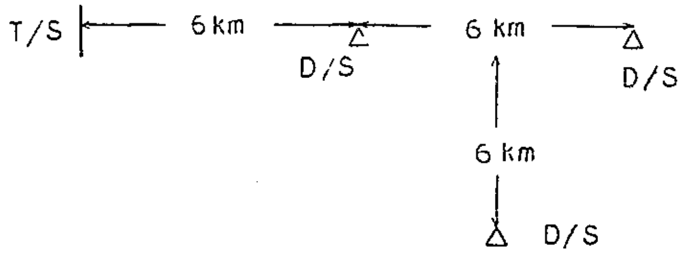
Type of system	Connection model	Required facilities and construction cost		Reliability, operation etc.
Tapped tie	 —— :Overhead line T/S :Terminal substation D/S :Distribution substation O :Circuit breaker 8 :Transformer	Subtransmission line	2x400sq.mm TAl, 1cct-8km. 2x795MCM AA, 1cct-4km. 2x795MCM AA, 2cct-4km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other power source in short time. 2. To switch over, operation of CB in other substation necessary
		Substation switching and measuring facilities	8 Line Feeders (2000A, CB, etc) 6 Trans. Feeders (800A, CB, etc) 3 Bus Tie (2000A, LS,etc)	
		Construction cost	TC.84,358 x 10^3.	
Feeder transformer		Subtransmission line	120sq.mm HAl, 2cct-18km.	1. During outage of 1 cct of subtransmission line, 1 bank cannot be saved. 2. During fault in bus of secondary side of transformer, countermeasure needed to open CB in terminal substation. 3. Number of outgoing lines from terminal substation will increase.
		Substation switching and measuring facilities	6 Line Feeders (800A, CB, etc)	
		Construction cost	TC.51,444 x 10^3.	
Double circuit T-branch		Subtransmission line	2x400sq.mm TAl, 2cct-8km. 2x795MCM AA, 1cct-4km. 2x795MCM AA, 2cct-4km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time. 2. Operation of CB to switch over is possible only at the substation with power interruption.
		Substation switching and measuring facilities	4 Line Feeders (2000A, CB, etc) 6 Line Feeders (800A, CB, etc) 6 Trans. Feeders (800A, CB, etc) 3 Bus Tie (800A, LS, etc)	
		Construction cost	TC.98,099 x 10^3.	

Tabel 13-3 Comparison of system in C area

Type of system	Connection model	Required facilities and construction cost		Reliability, operation etc.
Tapped tie	 —— :Overhead line T/S :Terminal substation D/S :Distribution substation O :Circuit breaker 8 :Transformer	Subtransmission line	2x400sq.mm TAl, 1cct-6km. 795MCM AA, 1cct-3km. 2x795MCM AA, 1cct-3km. 2x795MCM AA, 2cct-6km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 3 distribution substations. Restoration not possible until fault point is remedied.
		Substation switching and measuring facilities	6 Line Feeders (2000A, CB, etc) 6 Trans. Feeders (800A, CB, etc) 3 Bus Tie (2000A,LS, etc)	
		Construction cost	TC.84,834 x 10^3.	
Feeder transformer		Subtransmission line	120sq.mm HAl, 2cct-33km.	1. During outage of 1 cct of subtransmission line, 1 bank cannot be saved. 2. During fault in bus of secondary side of transformer, countermeasure needed to open CB of terminal substation. 3. Number of outgoing lines from terminal substation will increase.
		Substation switching and measuring facilities	6 Line Feeders (800A, CB, etc)	
		Construction cost	TC.88,104 x 10^3.	
Double circuit T-branch		Subtransmission line	2x400sq.mm TAl, 2cct-6km. 2x795MCM AA, 1cct-9km. 2x795MCM AA,2cct-3km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time. 2. Operation of CB to switch over only possible at the substation with power interruption.
		Substation switching and measuring facilities	2 Line Feeders (2000A,CB, etc) 6 Line Feeders (800A, CB, etc) 6 Trans. Feeders (800A, CB, etc) 3 Bus Tie (800A, LS, etc)	
		Construction cost	TC.94,288 x 10^3.	

c. Comparison of system in C area

Location model of distribution substation in C area is given in the following diagram. The system will be served from one power source. The results of comparison of the 3 systems are given in Table 13-3.



In Table 13-3, the model indicated as tapped tie system is not a tapped tie system, but is a system where 1 circuit of subtransmission line is tied into distribution substations by "π" connection. From the standpoint of reliability the feeder transformer system is not desirable. Corresponding to the degree of reliability required in the area, "π" connection method or double circuit T branch system is recommended.

(3) Comparison of the 3 systems for connection to new distribution substation in an existing tapped tie system.

Comparisons were made for the application of the 3 systems to supply power to a new distribution substation in an existing tapped tie system. The items compared are composition model, required equipment and materials, reliability and operating characteristics. In this study, the estimates for required equipment and materials and investment costs were made for only those equipment and materials that will change in quantity according to the 3 systems, and equipment and materials that are common in the 3 systems were not included in the estimate.

The assumption used in the preparation of the composition models is that A area will use a combination of underground cable and overhead line, and B and C area will use overhead subtransmission lines to supply power to new distribution substations.

a. Comparison of system in A area

The location model given in Chapter (2)-a was used as the location of existing and new distribution substations in A area. The 2 substations located in the center of the said model were assumed to be the new distribution substations. Table 13-4 gives a comparison of the 3 systems.

Investment cost of feeder transformer system is the lowest among the 3 systems, but this system has the problem of supply reliability as described in Chapter (2)-a. In the tapped tie system because of the insufficient current carrying capacity of existing underground cable it is not possible to tap off from the table to serve a new distribution substation. For this reason another cable must be installed and this would be costly.

b. Comparison of system in B area

The location model given in Chapter (2)-b was used for the location of distribution substations in B area. The substation appearing at the bottom of the said model was assumed to be the new distribution substation. The results of comparison are given in Table 13-5.

c. Comparison of system in C area

The location model given in Chapter (2)-c was used for the location of distribution substations in C area. The substation indicated in the bottom of the said model was assumed to be the new distribution substation. The results of comparison are given in Table 13-6.

Tabel 13-4 Comparison of system in A area

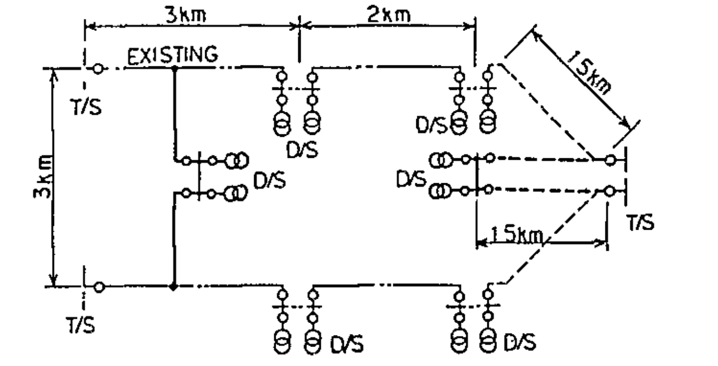
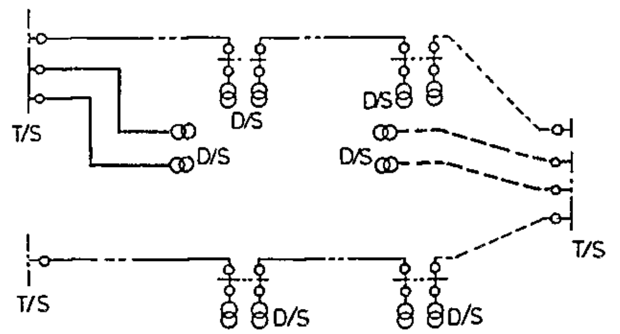
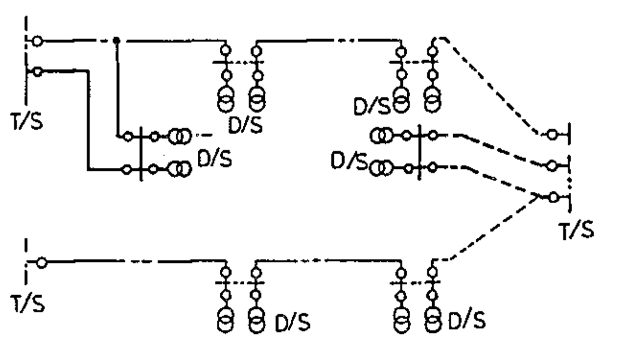
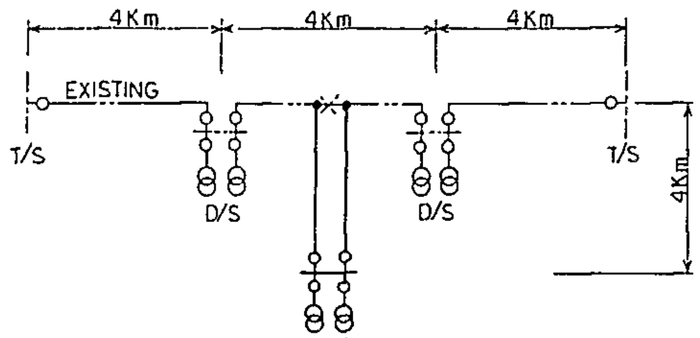
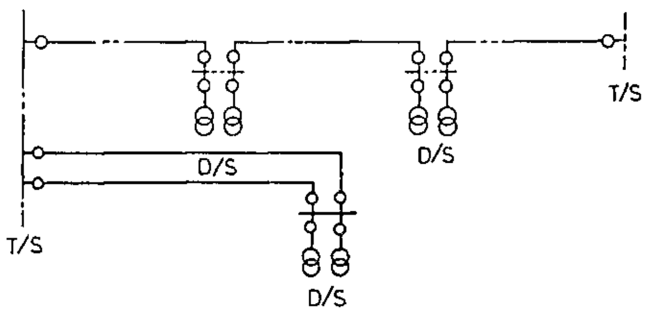
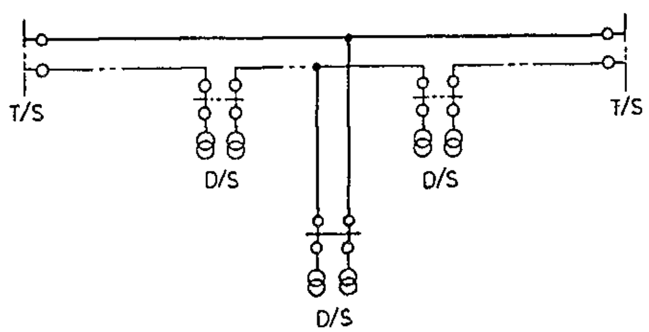
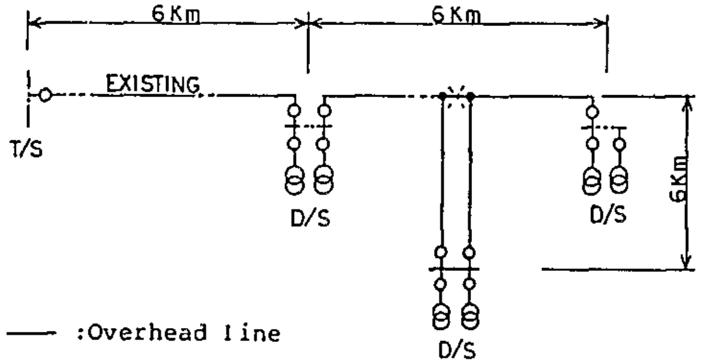
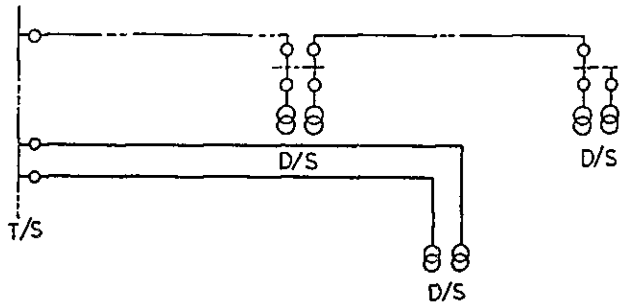
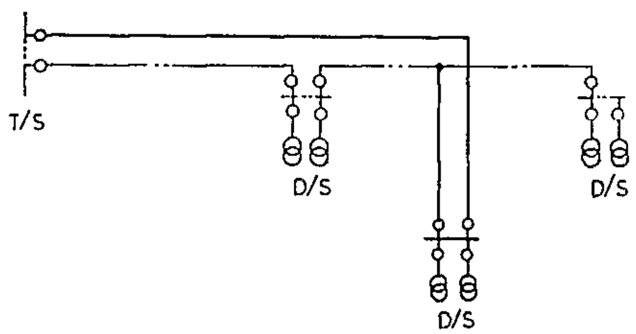
Type of system	Connection model	Required facilities and costruction cost			Reliability, operation etc.
			Overhead line	Underground line	
Tapped tie	 ---- : Underground line —— :Overhead line T/S :Terminal substation 8 :Transformer D/S :Distribution substation O :Circuit Breaker breaker	Subtransmission line	795MCM AA, 1cct-3km.	500sq.mm Cu/PEX, 2cct-1.5km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time. 2. To switch over, operation of CB in other substation is necessary. 3. Branching off from existing cable not possible of carrying capacity of cable.
		Substation switching and measuring facilities	2 Line Feeders (800A, CB, etc) 2 Trans. Feeders (800A, CB, etc) 1 BUs Tie (800A, LS, etc)	same as left.	
		Construction cost	TC.14,225 x 10^3.	TC.36,047 x 10^3.	
			G.TTL. TC.50,272 x 10^3.		
Feeder transformer		Subtransmission line	120sq.mm HAl, 2cct-3km.	150sq.mm Cu/PEX, 2cct-1.5km.	1. During outage of 1 cct of subtransmission line, 1 bank cannot be saved. 2. During fault in bus of secondary side of transformer, countermeasure necessary to open CB of terminal substation. 3. Number of outgoing lines from terminal substation will increase.
		Substation switching and measuring facilities	2 Line Feeders (800A, CB, etc)	same as left.	
		Construction cost	TC.9,816 x 10^3.	TC.26,802 x 10^3.	
			G.TTL. TC.36,618 x 10^3.		
Double circuit T-branch		Subtransmission line	Size-up to. 2x400sq.mm TAl, 2cct-1.5km. New. 795MCM AA, 2cct-1.5km.	500sq.mm Cu/PEX, 2cct-1.5km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time. 2. Operation of CB to switch over is possible only at the substation with power interruption.
		Substation switching and measuring facilities	1 Line Feeder (2000A, CB, etc) 2 Line Feeders (800A, CB, etc) 2 Trans. Feeders (800A, CB, etc) 1 Bus Tie(800A, LS, etc)	same as left.	
		Construction cost	TC.19,328 x 10^3.	TC.38,755 x 10^3.	
			G.TTL. TC.58,083 x 10^3.		

Table 13-5 Comparison of system in B area

Type of system	Connection model	Required facilities and construction cost		Reliability, operation etc.
Tapped tie	 —— :Overhead line T/S :Terminal substation D/S :Distribution substation O :Circuit breaker 8 :Transformer	Subtransmission line	Rearrangement. 2x400sq.mm TAl,1cct-8km. 2x795MCM AA, 1cct-4km. New. 2x795MCM AA, 2cct-4km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time. 2. To switch over, CB in other substation must be operated.
		Substation switching and measuring facilities	2 Line Feeders (2000A, CB, etc). 2 Trans. Feeders (800A, CB, etc) 1 Bus Tie (2000A, LS, etc)	
		Construction cost	TC. 39,854 x 10^3.	
Feeder transformer		Subtransmission line	New. 120sq.mm HAl, 2cct-10km.	1. During outage of 1 cct of subtransmission line, 1 bank cannot be saved. 2. During fault in bus of secondary side of transformer, countermeasure needed to open CB of terminal substation.
		Substation switching and measuring facilities	2 Line Feeders (800A, CB, etc).	
		Construction cost	TC. 26,924 x 10^3.	
Double circuit T-branch		Subtransmission line	Size-up. 2x400sq.mm TAl,2cct-8km. 2x795MCM AA,2cct-4km. New. 795MCM AA,1cct-4km.	1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time. 2. Operation of CB to switch over is possible only at the substation with power interrution.
		Substation switching and measuring facilities	2 Line Feeders (2000A,CB, etc) 2 Line Feeders (800A,CB, etc). 2 Trans. Feeder (800A,CB, etc). 1 Bus Tie (800A, LS,etc).	
		Construction cost	TC. 55,429 x 10^3.	

Tabel 13-6 Comparison of system in C area

<table>
<tr><th>Type of system</th><th>Connection model</th><th colspan="2">Required facilities and construction cost</th><th>Reliability, operation etc.</th></tr>
<tr><td rowspan="3">Tapped tie</td><td rowspan="3">

—— :Overhead line
T/S :Terminal substation
D/S :Distribution substation
O :Circuit breaker
8 :Transformer</td><td>Subtransmission line</td><td>Size-up to.
2x400sq.mm TAl, 1cct-6km.
2x795MCM AA, 1cct-3km.
New.
2x795MCM AA, 2cct-6km.</td><td rowspan="3">1. During outage of 1 cct of subtransmission line, power interruption will occur at 1 or 2 distribution substations. Restoration not possible until fault point is remedied.</td></tr>
<tr><td>Substation switching and measuring facilities</td><td>2 Line Feeders (2000A, CB, etc)
2 Trans. Feeders (800A, CB, etc)
1 Bus Tie (2000A,LS, etc)</td></tr>
<tr><td>Construction cost</td><td>TC.44,907 x 10^3.</td></tr>
<tr><td rowspan="3">Feeder transformer</td><td rowspan="3">
</td><td>Subtransmission line</td><td>New.
120sq.mm HAl, 2cct-15km.</td><td rowspan="3">1. During outage of 1 cct of subtransmission line, 1 bank cannot be saved.
2. During fault in bus of secondary side of transformer, countermeasure needed to open CB of terminal substation.</td></tr>
<tr><td>Substation switching and measuring facilities</td><td>2 Line Feeders (800A, CB, etc)</td></tr>
<tr><td>Construction cost</td><td>TC.39,144 x 10^3.</td></tr>
<tr><td rowspan="3">Double circuit T-branch</td><td rowspan="3">
</td><td>Subtransmission line</td><td>Size-up to.
2x400sq.mm TAl, 2cct-6km.
2x795MCM AA, 2cct-6km.
New.
795MCM AA, 2cct-6km.</td><td rowspan="3">1. During outage of 1 cct of subtransmission line power interruption will occur at 1 or 2 distribution substations, but possible to switch over to other line in short time.
2. Operation of CB to switch over is possible only at the substation with power interruption.</td></tr>
<tr><td>Substation switching and measuring facilities</td><td>1 Line Feeder (2000A, CB, etc)
2 Line Feeders (800A, CB, etc)
2 Trans. Feeders (800A, CB, etc)
1 Bus Tie (800A, LS,etc)</td></tr>
<tr><td>Construction cost</td><td>TC.50,911 x 10^3.</td></tr>
</table>

(4) Underground system

a. Features of underground transmission line

In considering the composition of a underground subtransmission line, it is essential to study a completely different composition than an overhead transmission system. Because, in an overhead transmission system, heat radiation is simple and it is easy to enlarge the transmission capacity. Also, it is simple to branch off along the route and to replace conductors. In contrast to the above system, underground subtransmission line has the following features;

- Construction cost of a underground system is higher than an overhead system.

- Transmission capacity of a underground cable is smaller than an overhead line of identical cable size.

- Branching off along the route and replacement of cable is costly.

- Less accidents compared to overhead line caused by exterior factors such as lightning strike, vehicles and trees.

b. Various methods in composition of underground transmission system

i) Feeder transformer system

This system is the most simple composition of a underground transmission system. Terminal substation and distribution substation are connected by one cable for each bank of transformer. The features of this system are as follows:

- Circuit breaker is installed in the terminal substation, thus dispensing circuit breaker in the distribution substation and bus bar interconnecting transformers.

- Outage of 1 circuit will result in outage of 1 bank.

- Addition of transformers in the distribution substation corresponding to load growth results in the installation of additional cables and circuit breakers in the terminal substation.

- Protection cannot be provided on the secondary side of transformer in the distribution substation.

To cope with the situation described above, the following measures must be taken.

– Outage of 1 circuit

Provision must be made to supply power to the distribution line from another bank in case of outage of 1 circuit. For this purpose, maximum continuous load of transformer must be restricted and operated at a low utilization factor, (2 banks – utilization factor about 55% and 3 banks-utilization factor about 73%) or provision must be made so that power can be easily received from another distribution substation through the distribution network.

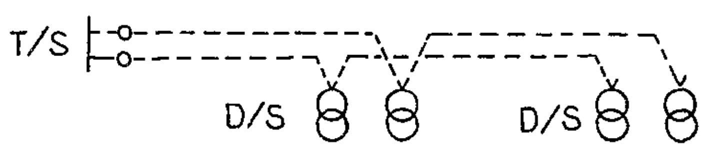
– Provision to increase number of outgoing lines from terminal substations
At the time of construction of terminal substation, multi-channel conduits should be installed and space set aside for installation of additional circuit breakers on the outgoing side.

– Countermeasures against fault on secondary side of transformer
Signal transmission equipment should be installed between terminal substation and distribution substation so that transfer interrupting of circuit breaker in terminal substation can be performed in case of fault on secondary side of transformer.

A modified feeder transformer system is that power can be received from 2 terminal substations. In this case when trouble develops in 1 terminal substation, power can be received from the other terminal substation, and when trouble develops in 1 cable, it can be isolated and power can be received from another cable. This system enhances reliability but the cost is greater.

ii) Unit system

In cities where the load density is high, the number of distribution substations will increase, and outgoing facilities will increase especially in a feeder transformer system. Taking the above said matter into consideration adoption of unit system will be preferable. Unit system, is a modified feeder transformer system where one feeder supplies a number of transformers. A circuit diagram is as shown below.



In this system, the number of outgoing facilities is minimal, but in this case outage of 1 circuit will cause power interruption to all transformers connected to that circuit. However, power interuption to one bank of transformer will be at each distribution substation so that the countermeasure to be taken is the same as that for outage of 1 circuit described above.

A modification of this system is to install a circuit breaker on the primary side of each transformr to prevent outage of all transformers receiving power from the same feeder in case of fault in 1 transformer. Also, a system is adopted so that power can be received from 2 terminal substations.

iii) Tapped tie system

In this system, a transfer bus is installed in the distribution substation so that in case of outage of 1 circuit, power can be received from the other circuit. By making provision to receive power from 2 terminal substations, this will enhance the reliability of the system, but will entail more cost for the bus bar and cable (size of cable will be large in order to serve 2 or more banks).

In order to reduce the capital cost, the circuit breaker in the distribution substation is dispensed and a bus system with line switch only can be made. However, in this case when the number of distribution substations increase, the size of cable from the terminal substation must be enlarged and these will result a limit to the carrying capacity of one circuit of underground cable.

c. Comparison of various systems

As described in the foregoing the various system have their own features. Table 13-7 gives a comparison of the various system, and from the 4 models given in the said table, Fig. 13-1 was prepared which gives the cost for each of the models using lengt of subtransmission line (L) between each substation as a parameter.

It will be noted in Fig. 13-1 that the shorter the length (L) Model No. 1 (feeder transformer system) gives the least cost, but as facilities are added to enhance reliability the cost rises.

When "L" reaches above a certain value, the costs of duct and cable rise, and the cost of Models Nos. 2 and 3 (unit system) exceed the cost of Model No. 4 (tapped tie system).

It should be noted that the values at the intersecting points of the cost lines for unit system and tapped tie system in Fig. 13-1 are based on the conditions applied for calculating the costs of each model. However, as a general trend, the following can be said:

- Reliability of feeder transformer system is low. However, the cost is low.
- Cost of unit system and tapped tie will be governed by the length of duct and cable.
- For cases where the number of distribution substations increases or for cases other than the models given in Table 13-7, it is necessary to compare costs for each case.

Table 13-7 Comparison of underground subtransmission systems

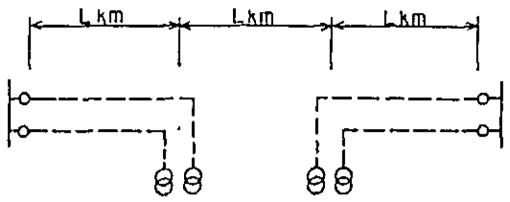
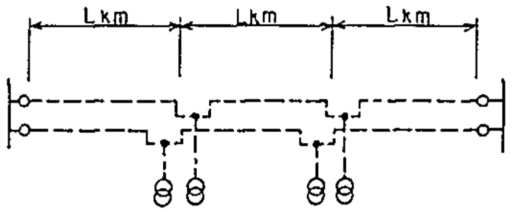
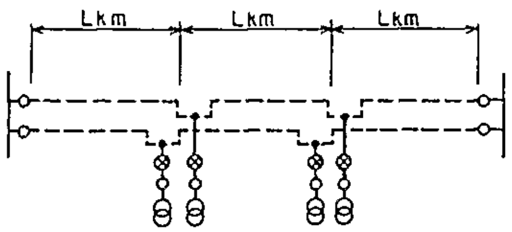
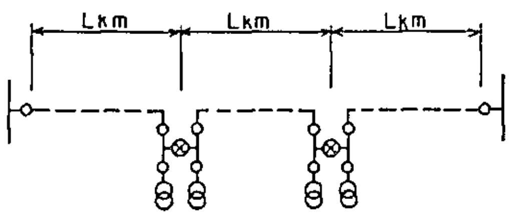
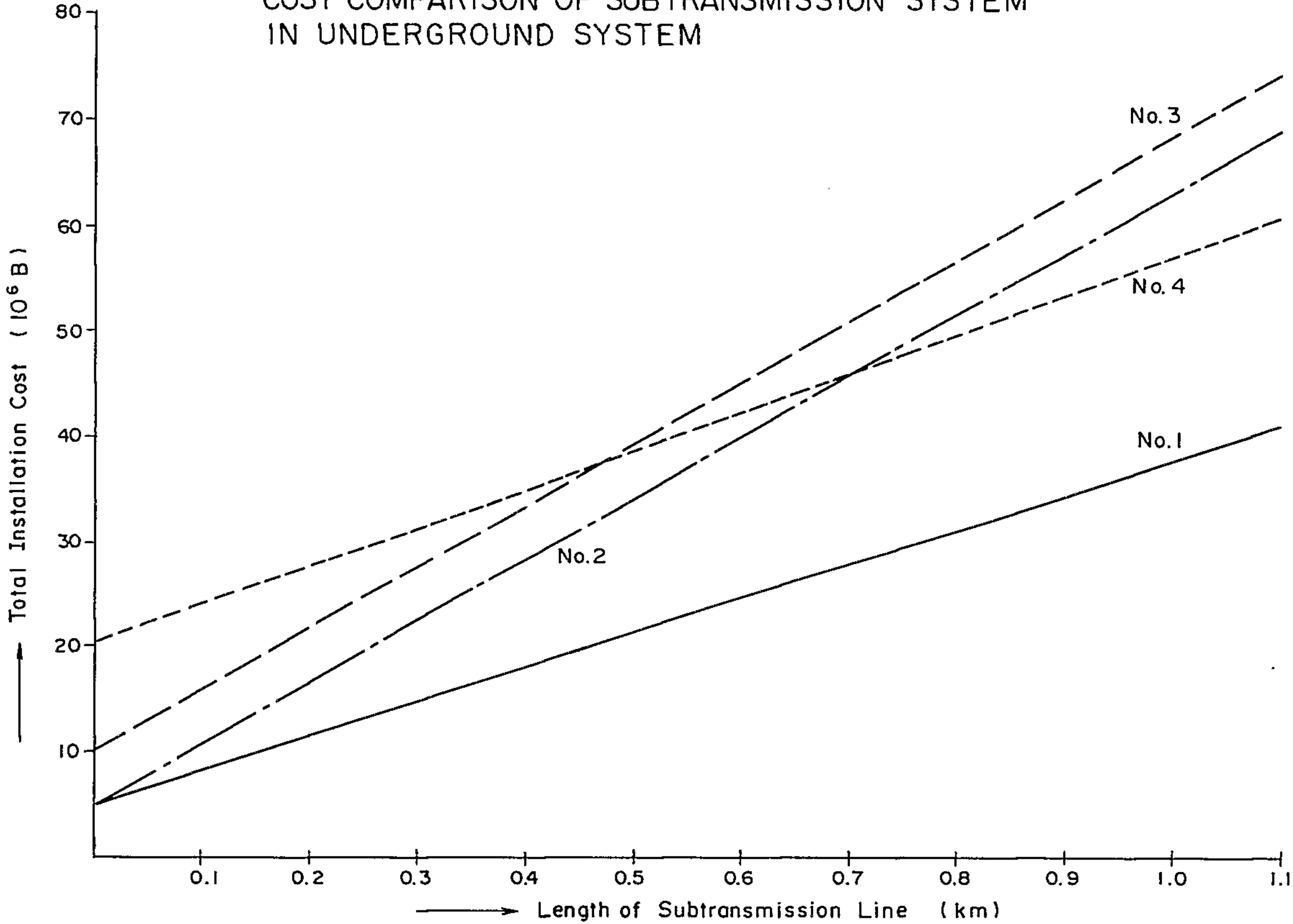
Connection model	Required facilities and construction cost	Feature of each system
No.1. Feeder transformer system 	Subtransmission line. 150sq.mm Cu/PEX, 2cct-2xL km. Substation. 4 Line Feeders (800A, CB, etc). Total construction cost. TC.(4,968 + 32,640 x L) x 10^3.	1. 1 feeder and 1 transformer - circuit breaker and bus bar at distribution substation are dispensed. 2. Transfer interruting equipment are needed at time of fault on 2ry side of transformer. 3. Outage of 1 feeder will result in power interruption to 1 transformer.
No.2. Unit system-(1) 	Subtransmission line. 800sq.mm Cu/PEX, 2cct-2xL km. 150sq.mm Cu/PEX, 2cct-L km. Substation. 4 Line feeders (800A, CB, etc) Total construction cost. TC. (4,968 + 57,884 x L) x 10^3.	1. 1 feeder connected to 2 transformers - circuit breaker and bus bar dispensed at each substation. 2. Interconnecting feeder installed between distribution substations and each transformer interconnected to 2 terminal substations. 3. Transfer interruting equipment needed at time of fault in 2ry side of transformer. 4. Outage of 1 feeder will cause power interruption to 2 transformers, but by isolating fault section, power can be supplied to all transformers. 5. Outage of 1 transformer will cause simultanious outage of other transformers.
No.3. Unit system-(2) 	Subtransmission line. 800sq.mm Cu/PEX, 2cct-2xL km. 150sq.mm Cu/PEX, 2cct- L km. Substation. 8 Line feeders (800A, CB, etc) Total construction cost. TC. (9,936 + 57,884 x L) x 10^3.	1. Install circuit breaker for transformer protection to Unit System (1). 2. Transfer interrupting equipment not required. 3. Outage of 1 transformer will not affect other transformers.
No.4. Tapped tie system 	Subtransmission line. 1600sq.mm Cu/PEX, 1cct-2xL km. 800sq.mm Cu/PEX,1cct- L km. Substation. 6 Line Feeders (2000A, CB, etc) 4 Trans. Feeders (800A, CB, etc) 2 Bus Tie (2000A, LS, etc) Total construction cost. TC. (20,592 + 36,347 x L) x 10^3.	1. Install circuit breaker for subtransmission line and bus bar at each distribution substation. 2. 1 circuit of subtransmission is sufficient, but cable size will be big. 3. During outage of 1 feeder, power can be received from other feeder. 4. Outage of 1 transformer will not affect other transformers.

FIG 13·1

COST COMPARISON OF SUBTRANSMISSION SYSTEM IN UNDERGROUND SYSTEM



(5) Examples of system composition in Japan

System composition of subtransmission lines of 9 private utilities companies of Japan is given in the following Table 13-8.

Table 13-8 Examples of system composition in Japan

Name of power company	Overhead system	Underground system	Remarks
Hokkaido	2 cct, "T" branch	Combination of 2 power sourch "π" connection and 2 cct "T" branch	
Tohoku	"	---	Very small underground system
Tokyo	"	Unit system	Large consumers, SS are π loop system
Chubu	"	Feeder transformer system	Large consumers, SS are π loop system
Hokuriku	"	---	Very small underground system
Kansai	"	2 power source π connection	large consumer, combination of π loop connection and 2 cct T branch
Chugoku	"	Combination of 2 power source connection and unit system	
Shikoku	"	Unit system	
Kyushu	"	2 power source, connection	

As seen in the Table 13-8, composition of underground subtransmission system differs from district to district, and in each case, the history of expansion is related to the sitting condition and load characteristics in each district. Therefore, there is no common system for the 9 companies.

The several companies which adopt the unit system and Chubu which adopt the feeder transformer system control their totally unmaned distribution substations remotely from terminal substations. These systems are adopted after strengthening the enterconnection to permit interchange of power on the distribution lines and installing all required control equipment.

Should the MEA adopt the feeder transformer system or unit system, adequate studies should be made on the basis of the same approach taken in Japan.

For the overhead subtransmission lines, all of the Japanese utilities commonly adopt 2 circuits "T" branch system. In Japan, the utilities normally use a 2 circuit tower for exclusive use for subtransmission lines. Therefore, the normal pattern is 2 circuits running parallel which is the most convenient system. In case of the MEA, concrete poles for common use of subtransmission line and distribution line are located along the side of roads. Because of buildings and other structures enroute, there are more 1 circuit routes which makes it easier to adopt the tapped tie system.

(6) Conclusion

a. Expansion in the downtown area (A area)

The tapped tie system adopted by the MEA is effective only when overhead subtransmission lines are strung on the same support with distribution lines. With the progress in urbanization, even of 1 circuit only can be strung on 1 route, a tapped tie system composed of 1 circuit π loap is economic and a very reliable system. However, in this system with the growth of demand, many additional circuits will become necessary and it is thought restrictions may be imposed by the bearing strength of supports to string larger diameter conductors. This phenomena will first appear in the downtown district where the load density is high and load growth is large. In this district, new lines will have to be underground cable. Underground cable have different characteristics than overhead line, and therefore as described in section (4), it will become essential to study a system based on the principle of feeder transformer system. With the expansion of the underground system, it would not be economic to discard the existing overhead lines. From the standpoint of aesthetic consideration, the requirement may be to place subtransmission lines underground, in such event distribution lines must also be placed underground to achieve the full aesthetic results.

It is believed that placing of lines underground will be confined to certain areas only. Therefore, the existing overhead lines should be put to the maximum use in the future, and it would be beneficial to expand the system by adopting the tapped tie system for both the underground and overhead circuits.

In consideration of the above situation, expansion of subtransmission system in A area should be a combination of underground and overhead lines utilizing existing facilities and appropriatly combining into the system underground feeder transformer system for new distribution substitutions to be constructed near terminal substations.

b. Expansion in urban area (B area)

In B area, it is thought that some sections may be served by underground cable, but a greater part of the area will be served by overhead lines. Fault occurrence is much higher for overhead lines compared to underground cables and for reasons that it would be difficult to achieve a complete interconnection of distribution lines in B area, the adoption of feeder transformer system is not desirable. As a rule, system expansion should be by the tapped tie system, and when the number of distribution substantions become great, it would be advisable to change over to double circuit T branch system.

c. Expansion in rural area (C area)

In C area as the distance between distribution substation and terminal substation is long, it is often not possible to receive power from 2 power source bus. It is evident that reliability is low in a 1 circuit system radiating in all directions. In order to compensate the weakness of this system, it is desirable to adopt double circuit T branch system when the need arise.

Appendix 14. Study of distribution voltage

(1) Study of distribution voltage in cities of Japan

Generally speaking, the optimum distribution voltage in a given district is determined by the load density and demand composition in that district. However, it is normal that the demand in large cities will grow rapidly corresponding to economic growth and the pattern in the composition of demand will change too.

A study was conducted in Japan concerning distribution voltage and distribution system to assure a stable and uninterrupted supply of electricity corresponding to those changing conditions.

The Ministry of International Trade and Industry created a committee known as "Committee to Study Countermeasures against Excessive Concentration of Load" which was composed of staff of the Ministry and experts of nine electric utility companies to study the problem of distribution voltage in cities. This committee submitted its final report to the government in May 1971.

In the following paragraph-(2), a part of that report is given.

(2) Load density and distribution voltage

With the development of cities, the growth of demand for electricity is remarkable. Particularly, in the central part of cities, the load density is extremely high and it has become a great problem to expand facilities, maintain reliability, maintain and operate facilities and to maintain safety. If the present distribution system (6 KV/200 V) is continued in the central part of cities, it is thought difficult to maintain a stable supply of electricity, and therefore, new distribution voltages were studied.

As a result of comprehensive studies of:-

- present and future prospect of load density
- present technological level
- relationship with existing facilities

the conclusion is that 22 KV/400 V is the most desirable for excessively high load density cities.

This 22 KV/400 V distribution voltage is an effective distribution system for high load density district, but it cannot be said to be advantageous for all high load density districts because it would be influenced by composition of load and density of load.

Using load density and load composition as parameters, an economic comparison was made by changing the classification of customer supply voltage according to contract demand. The result give the pattern shown in Fig. 14-1. In Fig. 14-1, when the load density exceeds P MW/Km^2, then it would be optimum to supply all customers at either 22 KV or 400 V. The value of P will change with the pattern of load composition.

If the load composition in the central part of Tokyo is applied the result is as shown in Fig. 14-2. Using Fig. 14-2 as a basis, at a certain load density value, say at 100 MW/Km^2, it is assumed that distribution voltage is standardized at 22 KV/400 V. The merit of adopting 22 KV/400 V in this case would appear only when a spot load of over 750 KW is supplied by the system.

Fig.14-1 Advantageous zone diagram
(Normal pattern)

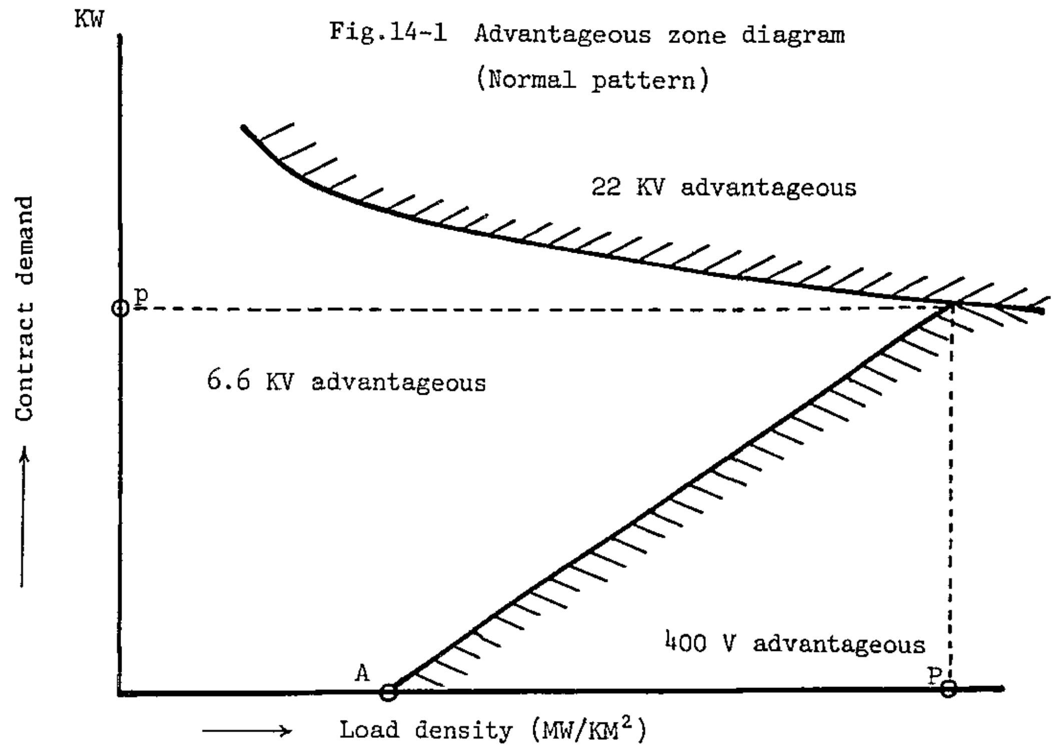
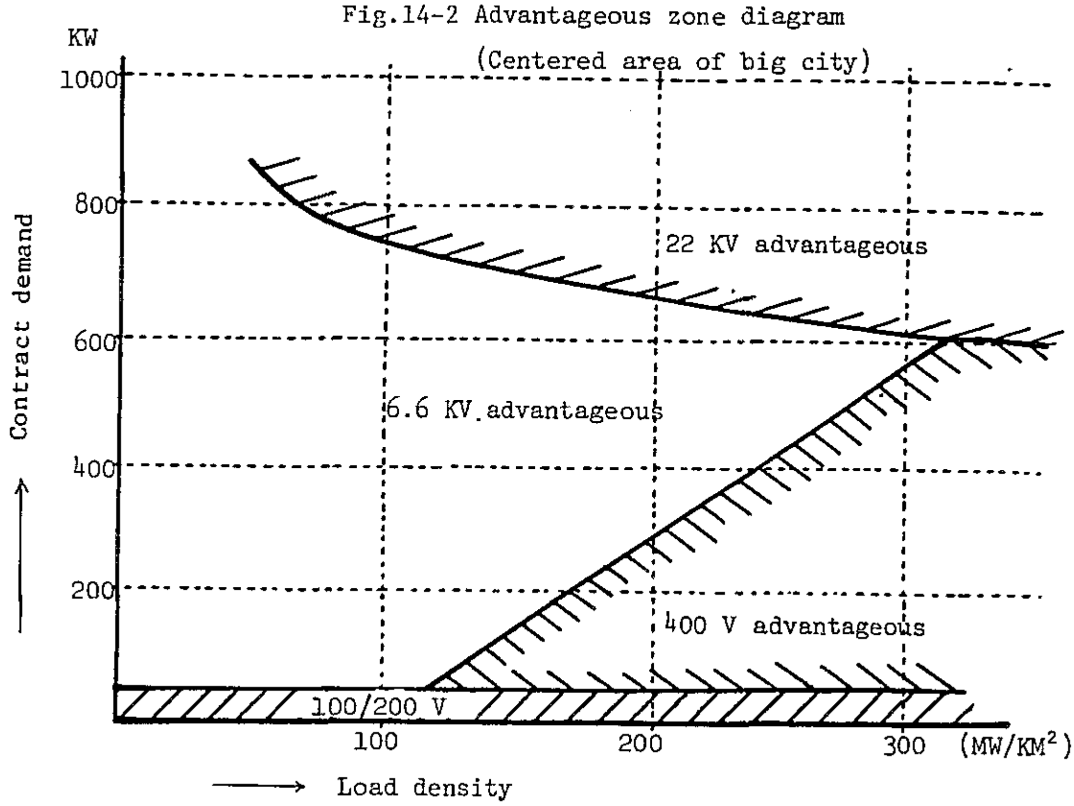


Fig.14-2 Advantageous zone diagram
(Centered area of big city)



The ratio of spot load to the said 100 MW/Km^2 load density is small, and therefore, it can be said that there would be no merit in adopting 22 KV/400 V.

With the growth of load density beyond 100 MW/Km^2, the advantage will increase to supply customers at 22 KV/400 V, and if load density goes beyond 300 MW/Km^2, 22 KV/400 V distribution system will be advantageous for all customers.

This means that at a certain value of load density between 100 MW/Km^2 and 300 MW/Km^2, the merit and demerit of adoption of 22 KV/400 V distribution system will balance.

To find the marignal value of load density for 22 KV/400 V distribution system, the committee made 3 case studies of distribution systems on the basis of the existing situation of an area approximately 50 Km^2 in the central part of Tokyo.

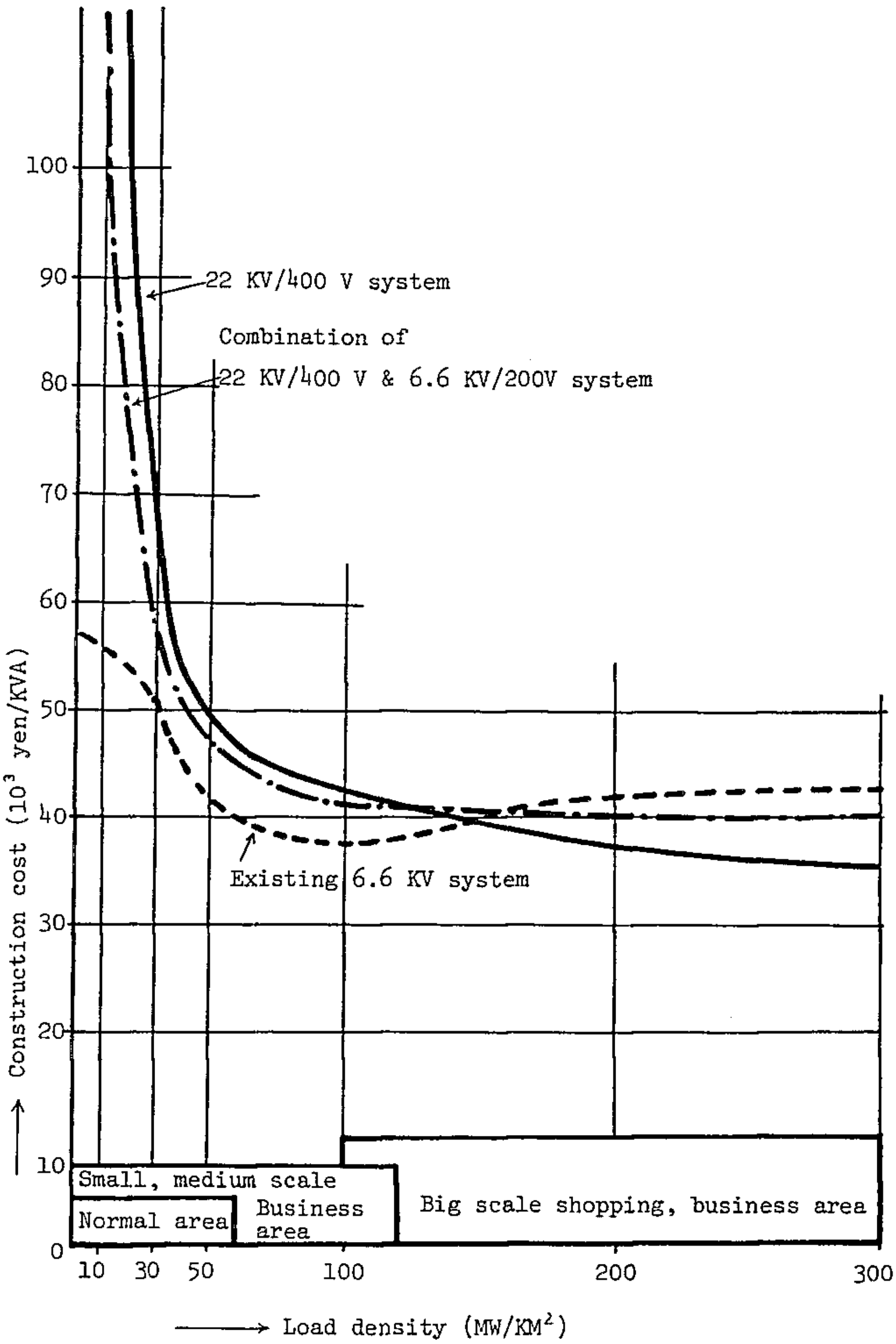
These are:-

- 22 KV/400 V
- Combination of 22 KV/400 V and 6 KV/200 V
- 6 KV/200 V (present system)

Fig. 14-3 gives the investment cost per KVA for the 3 distribution voltages stated above. It will be seen in Fig. 14-3 that the merit of 22 KV/400 V distribution voltage appears when the load density exceeds the 150 MW/Km^2 range.

The foregoing is a study made for distribution voltage in Japan. If this result is applied to MEA's system, the following can be said. The present load density of MEA's system is an average of 8 MW/Km^2 (maximum 20 MW/Km^2) in the central part of Bangkok city (A area). According to the load forecast, in the 20 years future, the estimated load density is an average of 20 MW/Km^2 (maximum 60 MW/Km^2). Therefore, from the standpoint of the economics of distribution voltage, there appears no need to step-up the voltage to 24 KV in the next 20 years.

Fig.14-3 Comparison of construction cost



(3) Trial calculations of construction costs of 12 KV and 24 KV distribution systems based on models (These calculations have no relation whatsoever with the report of the committee mentioned eralier)

a. Basic conditions for the comparison

i) Standard facilities

The standard facilities used in the comparison are those presently used by MEA and there are given in the following table.

Standard Facilities

	12 KV	24 KV
D/S capacity	2 x 40 MVA	2 x 40 MVA
Subtransmission line conductor size	2 x 795 MCM	2 x 795 MCM
D/S outgoing cable size	Cu 650 MCM	Cu 650 MCM
D/S feeder number	12	6
Overhead conductor size	AA 336.4 MCM	AA 336.4 MCM
Spot load cable size	CU 650 MCM	Cu 650 MCM

Note: D/S = distribution substation

ii) Service area of a distribution substation and models of subtransmission line and distribution line

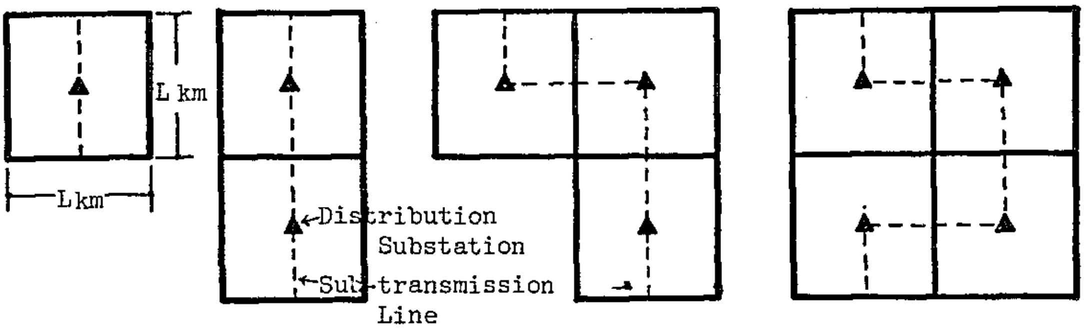
- Service area of a distribution substation is a square with one side being ℓ km.
- Subtransmission line length of a distribution substation is ℓ km. (See Fig. 14-4)
- Outgoing feeder from distribution substation is underground cable and connects into overhead line as shown in Fig. 14-5.
- Overhead distribution line is constructed at spacing of $\ell/6$ km apart. (See Fig. 14-5)
- Distribution line for spot loads are all underground cable of π loop system and are connected to spot load distribution line of adjacent distribution substation. (See Fig. 14-6)
- Spot loads are over 1,000 KW for 12 KV distribution line and over 2,000 KW for 24 KV distribution line.

iii) Calculation criteria

If load density is taken as D MW/km^2, the calculation criteria is as given in Table 14-1.

Principal calculation criteria corresponding to changes in load density are given in Fig. 14-7.

Fig.14-4 Model of sub-transmission line



Length of subtransmission line per one distribution substation is ℓ km.

Fig.14-5 Model of distribution line

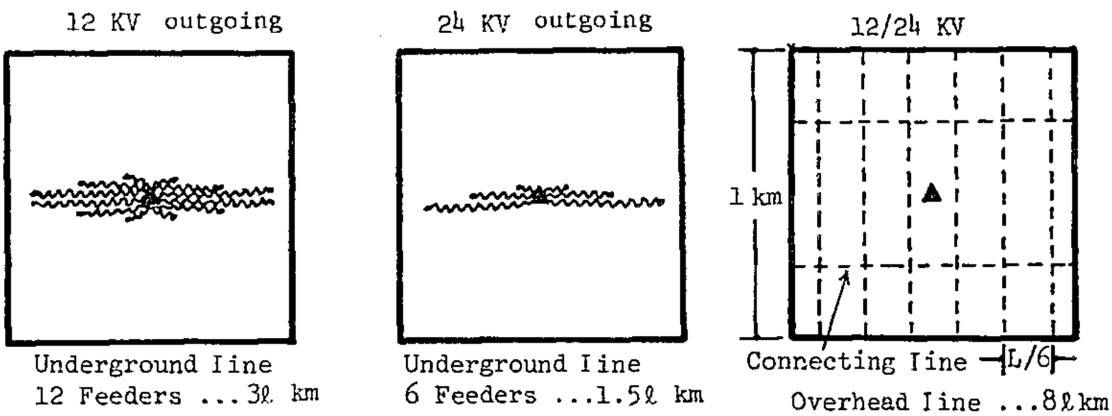


Fig.14-6 Model of special line for spot load

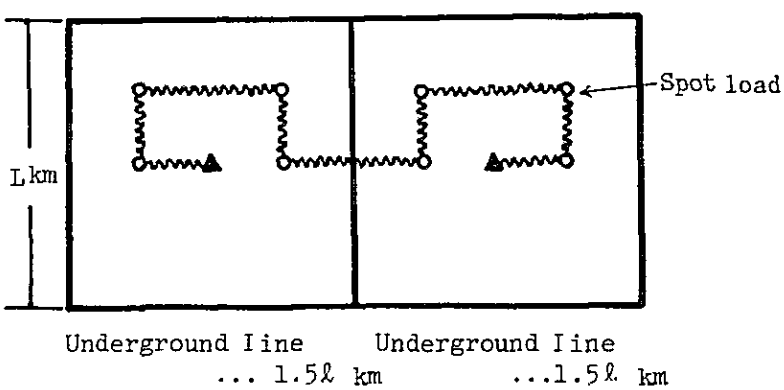
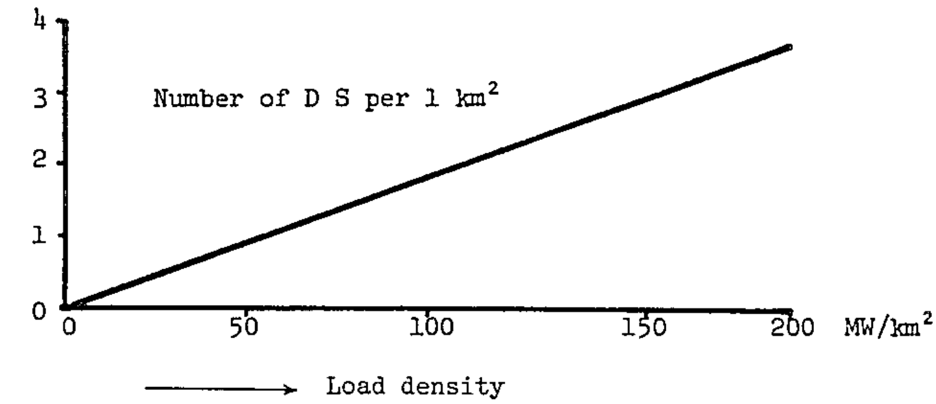
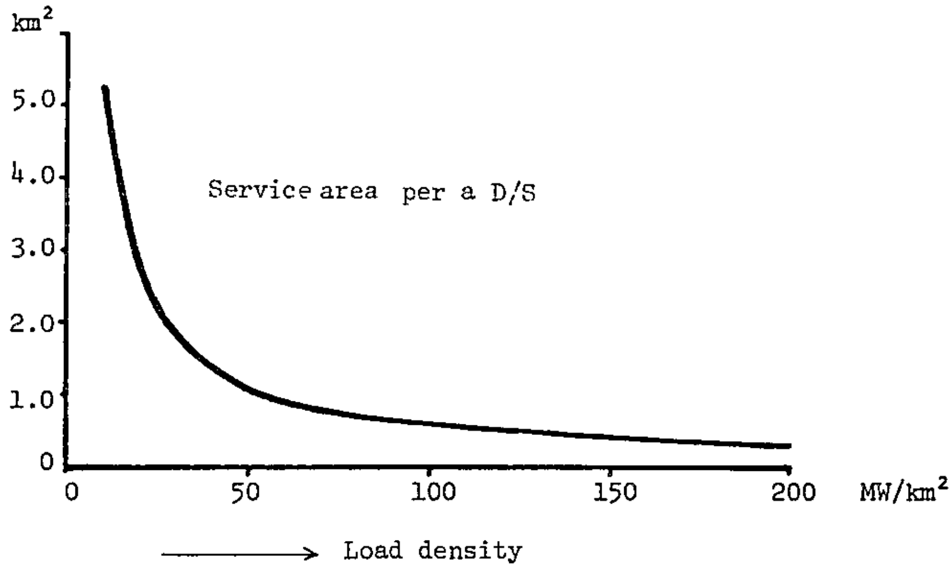


Fig.14-7 Calculation criteria





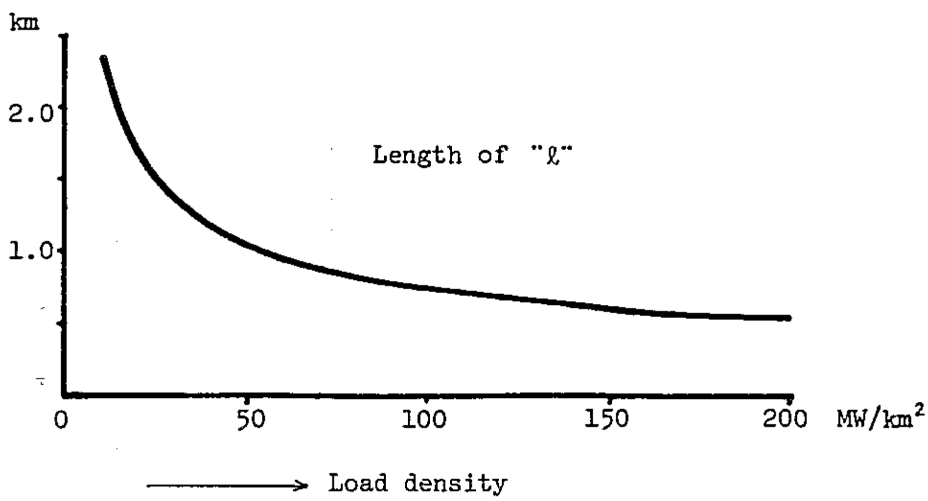


Table 14-1 Calculation criteria

	12 KV	24 KV	Remarks
Load density (MW/Km^2)	D	D	
No. of D/S per Km^2	$N = \frac{D}{\alpha}$	$N = \frac{D}{\alpha}$	α = 80 MVA x P.F. x D/S utilization factor
Service area per D/S (Km^2)	1/N	1/N	
1 side (Km) ofsservice area of a D/S (Km)	$\ell = \sqrt{1/N}$	$\ell = \sqrt{1/N}$	
Outgoing underground line length of a D/S (Km)	3ℓ	1.5ℓ	
Overhead distribution line length of a D/S (Km)	8ℓ	8ℓ	
Distribution line transformer capacity of a D/S (MVA)	$R = \frac{80\ MVA}{\beta}$	$R = \frac{80\ MVA}{\beta}$	$\beta = \frac{\text{distribution Tr. U.F}}{\text{P.F x D/S U.F}}$
Underground line length for spot load of a D/S (Km)	$1.5\ell.m_1$	$1.5\ell.m_2$	m_1, m_2 means number of distribution lines for spot loads

(Note 1) D/S = distribution substation
P.F. = power factor

(Note 2) Calculation of number of distribution lines for spot loads (m_1 and m_2)
When the load density in cities become high, spot loads of contract demand of 1,000 KW or 2,000 KW and greater will increase.
Taking the spot load factor (Spot load/Total load of a D/S) in Japan as reference, the assumed spot load factor in Bangkok is shown in Fig. 14-8.
On the basis of this percentage (%), the values of spot loads corresponding to demand forecast are calculated, and the required number of 12 KV and 24 KV distribution lines to supply spot loads is computed.

iv) Calculation method of construction cost

On the basis of the unit construction cost of each facility given in Table 14-2, the calculation method of construction cost would be according to a) and b).

Table 14-2 Unit cost of each facility

Unit: 10^3 B

	Unit	12 KV	24 KV
Distribution substation	No.	S_1	S_1
69 KV subtransmission line	cct. Km	t	t
Underground distribution	"	u_1	u_2
Overhead distribution line	"	h_1	h_2
Distribution transformer	MVA	d_1	d_2
Distribution line equipment	MVA	e_1	e_2

a) 12 KV distribution system

Construction cost per distribution substation (C_1')

$$C_1' = S_1 + \ell.t + 3\ \ell u_1 + 8\ \ell h_1 + R\ (d_1 + e_1) + 1.5\ \ell m_1 u_1$$

Construction cost per MW

$$C_1 = \frac{C_1'}{\text{demand in a D/S}}\ 10^3\,\text{B/MW}$$

b) 24 KV distribution system

Construction cost per distribution substation (C_2')

$$C_2' = S_2 + \ell t + 1.5\ell u_2 + 8\ell h_2 + R\ (d_2 + e_2) + 1.5\ \ell.m_2.u_2$$

Construction cost per MW

$$C_2 = \frac{C_2'}{\text{Load in a D/S}}\ 10^3\,\text{B/MW}$$

b. Calculation results of construction cost

Using the unit construction cost of facilities given in the "The Fifth" of MEA' the results of calculation of construction cost (10^3B/MW) of 12 KV and 24 KV system for each load density are given in Fig. 14-9. It will be noted in the Fig. that when the load density is less than around 120 MW/Km^2 the 12 KV system is advantageous and that the 24 KV system is advantageous when the load density is over 120 MW/Km^2.

c. Distribution line voltage drop and distribution loss

i) Voltage drop

Calculation of maximum voltage drop in the distribution line using the abovementioned model reveal that at a load density of 10 MW/Km^2, the voltage drop is about 150 V for the 12 KV system and about 100 V for the 24 KV system.

Corresponding to the growth of load density, the length of distribution lines will get shorter and the voltage drop will become smaller than the above values, therefore, there are no problems.

ii) Evaluation of energy loss in distribution system

Annual energy loss in distribution system was calculated by using the same model as in the case of "i)" above. Energy loss is evaluated on the evaluated per Kwh loss (unit price of energy purchased from EGAT). The 24 KV line loss is less than the 12 KV line loss, but the 24 KV transformer loss is more than the 12 KV one. Therefore, the evaluated value of 24 KV total loss is almost equal to the 12 KV total loss. Consequently, there will be no great influence on the economic comparison made in para (b), Calculation Results of Construction Cost.

Fig.14-8 Forecast of spot load rate

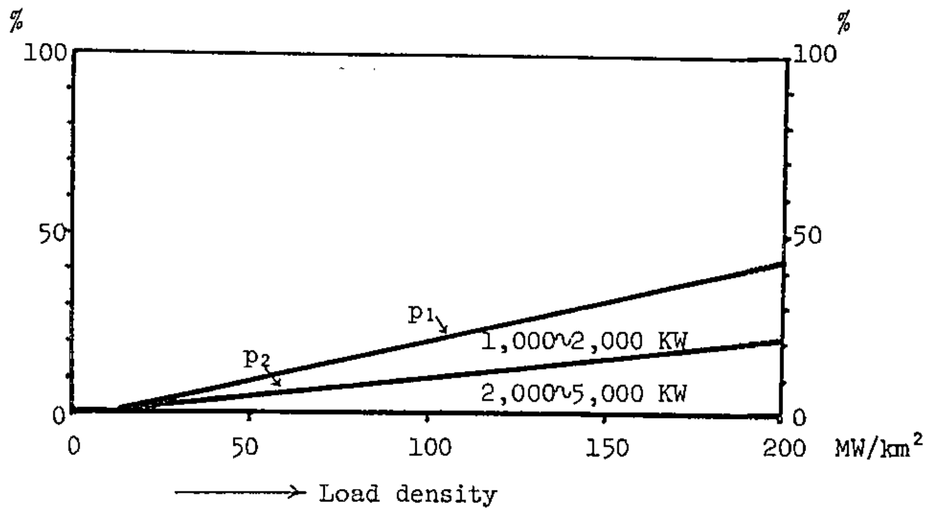
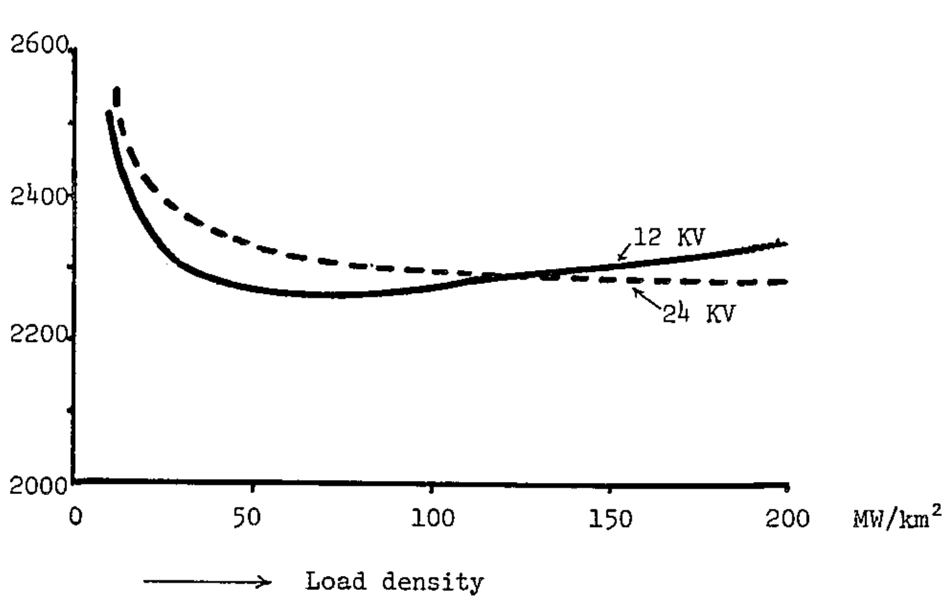


Fig. 14-9 Construction cost



Appeneix 15. Comments regarding constructon standards & design criteria

(1) Introduction

MEA possesses detailed construction standards and design criteria (hereafter called "Standards") concerning construction of overhead subtransmission lines, overhead distribution lines, underground distribution lines and substations. The advantages of these "Standards" are that designing can be simplified and materials standardized, and so far as seen from the standpoints of performances in construction and operation in the past, these "Standards" are functioning effectively, while moreover, it seems that there have not been very great inconsistencies.

However, these "Standards" were established approximately 20 years ago, and although it appears that modifications such as partial revisions and additions have been made since then, on the whole, fairly old technologies make up the basis, and a review is necessary since there is a considerable difference from today's level of technology.

Bangkok has grown rapidly into a large metropolis; it is expected that this trend will become even more prominent in the future, and it is readily imaginable that because of accompanying enlargement in equipment scale and changes in environmental conditions, it will not be possible to keep up relying only on the present "Standards".

Here, the current "Standards" must be examined from the above-mentioned viewpoints, and matters which have been noticed or have invited questions are mentioned below.

It might be added that practically all of the current "Standards" have specifications expressed by figures and tables, and details such as the bases of selection and thinking are not described. Consequently, since it was not possible to point out whether individual tables and figures were appropriate, the "Standards" of MEA were grouped under a number of items and a check was made based on the present "Standards" and knowledge obtained from MEA.

Further, with regard to substation facilities, construction standards of the kind mentioned above were not available. MEA's purchase system for substation equipment depends on individual design for each stations.

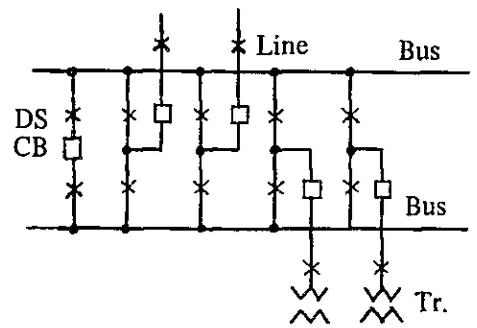
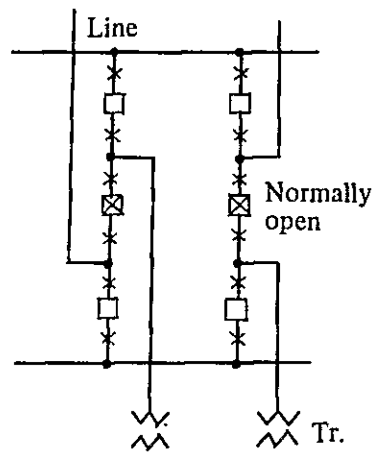
However, with the scale of the system having become large as at present and considering that it will become larger in the future, it is necessary for the specifications of individual pieces of equipment in a substation to be decided based on an authorized concept.

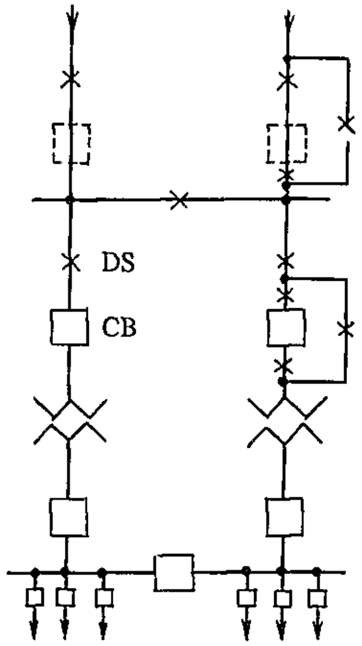
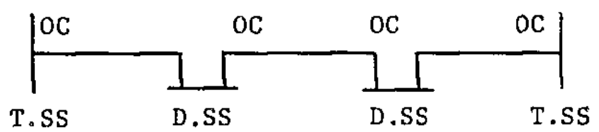
Substations will be constructed in large number in the future, and with regard to works and materials required at all substations, improvement in economic properties should be aimed for through standardization.

(2) General

Current standard	Suggested revision	Reasons, justifications, etc.
a. Standards for Electrical Equipment The MEA standards have been established based on ANSI (American National Standards).	Some standards should be modified according to IEC (International Electrotechnical Commission).	Some parts of ANSI do not fit the prevailing situation in Thailand. Examples: 1) Frequency in the U.S.A. is 60 Hz whereas in Thailand it is 50 Hz. 2) The distribution system voltage levels of MEA are 12 kV and 24 kV, whereas the corresponding voltage levels of ANSI are 15 kV and 25 kV, and if ANSI were to be applied without modification, it would be specifications with overinsulation, so that it would be economically disadvantageous.

(3) Substation

Current standard	Suggested revision	Reasons, justifications, etc.
a. Terminal Substation		
i) Double bus, double circuit breaker system.	Double bus, single circuit breaker system.  	Many circuit breakers are required, therefore, it is uneconomical.
ii) 1-1/2 bus system.  	Middle-installed circuit breaker out of 3 CB is operated as normally closed condition.	To obtain the effect of high-reliability operation which is the characteristic of the 1-1/2 bus system.
b. Distribution Substation		
i) Standard capacity of distribution substation. The unit capacity of a main transformer of a distribution substation is to be 40 MVA, and 2 units are installed.	The unit capacity of a main transformer is to be 20 MVA or 40 MVA, and the number of units installed is to be 3 units.	The appropriate unit capacity of a main transformer and the number of units installed must differ according to the load requirement.
ii) Main circuit configuration.	a) It is unified to install a circuit breaker at incoming transmission line side. b) Circuit breaker on the secondary side of the main transformer is eliminated and load break switch is installed.	Substation load is changed-over simply and rapidly so that supply reliability can be improved. The circuit breaker on the primary side of the main transformer can be used in common. (In case of fault at the secondary side of the main transformer, the circuit breaker on the primary side can be operated.)

Current standard	Suggested revision	Reasons, justifications, etc.
69 kV (115 kV) Incoming transmission line  12 kV (24 kV) Distribution line	c) Bypass circuit for circuit breaker inspection is eliminated.	The bypass circuit is unnecessary if power is supplied through another circuit during inspection of the line-side circuit breaker. The bypass circuit will be unnecessary if inspection of the circuit breaker on the primary side of the main transformer is done during light load and the load of the transformer to be out is supplied through a different transformer or the distribution line from another substation.
iii) Allowable short-circuit capacity. The rated breaking capacities of existing circuit breakers for 69 kV are the following: 1,800, 2,500, 3,500 MVA	Allowable short circuit capacities are determined.	When the electric power system is expanded in the future, the short-circuit capacity of the power system will be increased and become larger than the rated breaking capacities of circuit breakers. In such case, by regulating operation of the power system in a manner that the short-circuit capacity will be lower than the allowable short-circuit capacity, or by adopting a high impedance voltage for the 230–69 kV tie transformer, it will be unnecessary to increase the rated breaking capacities of circuit breakers.
iv) Transmission line protection.  	With regard to 69 kV transmission line protection relays for transmission substations and some distribution substations, installation standards for distance relays are established.	It can be operated easily, while it is possible to accurately eliminate faulted equipment quickly, damage of faulted equipment is minimized, and fluctuation in the power system during faults is reduced.
v) Automatic restorator Automatic restorator are not adopted.	Automatic restorators of substations at time of transmission line fault are adopted.	In case of power outage of a substation by faulting of transmission line, receiving transmission line can be changed-over quickly and accurately.

Current standard	Suggested revision	Reasons, justifications, etc.
vi) Distribution cubicles		
Indoor-type distribution cubicles are employed.	Outdoor-type cubicles are adopted.	Building space can be made smaller, and building construction cost reduced.
vii) Soundproofing (Noise protection)		
Soundproofing is not employed.	Soundproofing such as soundproof barriers and soundproof chambers are adopted for distribution substations in urban areas.	Complaints from neighborhood residents can be eliminated.

(4) Transmission Lines

<table>
<tr><th>Current standard</th><th>Suggested revision</th><th>Reasons, justifications, etc.</th></tr>
<tr>
<td>a. Conductors

i) Kind of conductor (Dwg. No. 3602)

Only hard-drawn aluminum stranded conductor (AAC), 795 MCM is used.</td>
<td>Thermo-resistant aluminum alloy stranded conductor (TAAC), 795 MCM is added.</td>
<td>① Although outside diameter, weight and mechanical properties of TAAC are equal to those of AAC of identical size, the transmission capacity can be increased by 1.6 times with existing supports since the allowable conductor temperature is high (AAC: 90°C, TAAC, 150°C)

② Where double conductor will be necessary with AAC there are cases when single conductor will suffice in case of TAAC (range of 85 MW – 135 MW if for 69 kV), and an economic merit is obtained.</td>
</tr>
<tr>
<td>ii) Current carrying capacities (Dwg. No. 3602)

AAC 795 MCM
Normal condition 800 A
Emergency condition 960 A</td>
<td>A reexamination should be made considering the meteorological satistics data (air temperature, wind velocity, solar radiation energy, etc.) of Bangkok and the present conductor performance (allowable conductor temperature, etc.).</td>
<td>
<table>
<tr><th></th><th></th><th>MEA</th><th>Japan</th></tr>
<tr><td>Current carrying capacity</td><td></td><td></td><td></td></tr>
<tr><td>Normal</td><td>I_1 (A)</td><td>800</td><td>795</td></tr>
<tr><td>Emergency</td><td>I_2 (A)</td><td>960</td><td>1,064</td></tr>
<tr><td>Ambient temperature</td><td>T (°C)</td><td>40</td><td>40</td></tr>
<tr><td>Wind velocity</td><td>v (m/sec)</td><td>0.61</td><td>0.5</td></tr>
<tr><td>Solar radiation energy</td><td>w (w/cm²)</td><td>0</td><td>0.1</td></tr>
<tr><td>Emissivity of conductor surface</td><td></td><td>0.5</td><td>0.9</td></tr>
<tr><td>Allowable conductor temperature</td><td></td><td></td><td></td></tr>
<tr><td>Normal</td><td>t_1 (°C)</td><td>80</td><td>90</td></tr>
<tr><td>Emergency</td><td>t_2 (°C)</td><td>100</td><td>120</td></tr>
</table>

On comparison of the current carrying capacities and calculation conditions of AAC 795 MCM of MEA and Japan the results are as shown above and the following can be said:

– Since the ambient temperature and solar radiation energy in Bangkok should present more unfavorable conditions than in Japan, it is necessary to review the above factors including wind velocity considering the meteorological statistics data.

– Regarding allowable conductor temperature, the values adopted in Japan can be recommended judging from present conductor performances.</td>
</tr>
<tr>
<td>iii) Sag (Dwgs. No. 3604, 3605)

a) Sag table</td>
<td></td>
<td></td>
</tr>
</table>

Current standard	Suggested revision	Reasons, justifications, etc.
A sag table is provided only for the case of ruling span of 125 m.	Sag tables should be prepared for several cases of ruling span other than 125 m.	① It is difficult for ruling spans of all sections to be made 125 m. ② Since both sag and tension differ if ruling span differs, there will be adverse effects on support strength, clearance, etc. with conditions as at present.
b) Initial sag and final sag		
Creep of 0.06–0.07% between initial sag and final sag is taken into account.	It is recommended that reexaminations of creep quantities be carried out with sag observations on lines of relatively long periods of time elapsed after construction and comparisons made with initial sag and final sag according to calculations.	① Although the creep of AAC is 0.05–0.06%, there is actually the same effect as prestretching during the pulling operation and the creep after finishing the sagging operation will become approximately one half the above. ② If creep larger than actual were to be assumed in sag and tension calculations, the actual final tension will be larger than the design value, and a load greater than the design value will be applied to supports.
iv) Spacers (Dwg. No. 3715)		
Performed spacers (flexible type) are adopted.	It is recommended that semi-rigid type spacers comprising bolt-nut type clamps and bar-type bodies be adopted.	Electromagnetic attraction due to short-circuiting current will act on spacers as compressive and tensile forces. Particularly, electromagnetic attraction acts on spacers as longe compressive forces and the presently-used performed spacers will not be capable of withstanding the forces.
b. Insulators		
i) Number of 5-3/4" x 10" suspension insulaors (Dwg. No. 3003)		
a) Standard Design 69 kV 4 – 7 pieees 115 kV 6 – 10 pieces	69 kV 4 pieces 115 kV 6 pieces	① The number of insulators should be that determined by expected maximum switching surge irrespective of crossarm quality. ② At places of large swing angles and line deflection angles clearances should be secured inserting rods at the grounding sides of insulator assemblies instead of increasing insulators.
b) Anti-contamination design None	A contamination map is prepared. The number of insulators are determined by the amount of contamination (equivalent salt deposit density).	① It is imaginable that there is considerable marine contamination since Bangkok is located close to the sea. ② Since it is liable for flashover faults to occur with contaminated insulators as withstand voltages are lowered, anti-contamination designing should be done to prevent faults and raise transmission line stability.
ii) Restriction on use of suspension strings		

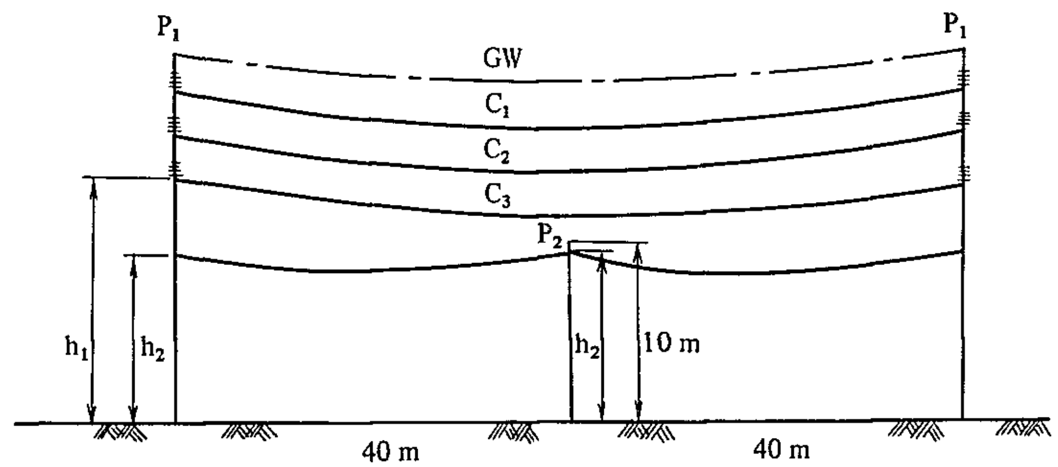
Current standard	Suggested revision	Reasons, justifications, etc.
ii) Suspension strings are used even for medium angle structures. It appears there are no restrictions on use according to line deflection angle but with restriction being according to swing angle, and up to a fairly large (about 70° maximum) swing angle is allowed.	Use of suspension strings are restricted to tangent structures and structures with extremely small deflection angles (places of line deflection angles up to about 2°C, and swing angle of suspension string under condition of no wind not more than about 20°C).	At present, lengths of crossarms at right and left of small-angle and median-angle structures are varied and locations of guy attachment decided determining swing direction of suspension string to be the direction of action of transverse load due to line deflection, but troubles such as clearances between conductor and structures or guys becoming insufficient will occur with suspension strings swinging in the reverse direction in case of strong wind blowing in the opposite direction.
c. Others		
i) Arcing horns Arcing horns are presently not provided.	Arcing horns are attached upon increasing the numbers of insulators on strings in standard designs by one each. Voltage / Arcing Horn Spacing / Number of Insulators 69 kV / 55 cm / 5 pieces 115 kV / 77 cm / 7 pieces	① Fairly severe lighting occurs frequently in the Bangkok area. ② In the event of lighting stroke on a transmission line, when there is no arcing horn lightning current will flow along the surface of the insulator string and insulators are liable to be damaged.
ii) Crossarms Wood crossarms and steel crossarms are being used.	All crossarms are changed to steel, and moreover, they are grounded.	Wood crossarms involve the following defects: – Scatter in strengths is great. – Deterioration with time is severe in addition to which there is great variation in service lives. – Grounding fault detection is difficult. – There is risk of burning due to leakage current when insulation by insulators becomes defective.
iii) Minimum conductor clearances. Minimum conductor clearances between conductors and various objects based on H-30 of NESC are given in Dwg. No. 3002.	A reexamination should be made comparing with the current NESC.	It is annotated that the current standard of MEA is based on H-30 of NESC, but the values are different from those of the current NESC. As an example, on comparisons of the clearances between transmission lines and high- and low-voltage distribution lines, the differences below can be recognized. — / 69 kV / 115 kV Current MEA Standard / 1.47 m / 2.06 m Current NESC / 1.99 m / 2.45 m Japanese Engineering Standard (Reference) / 2.12 m / 2.72 m

Current standard	Suggested revision	Reasons, justifications, etc.
iv) Vertical clearance between lowest conductor of transmission line and distribution pole. Vertical clearances are as shown in Table 15-1 when calculated from assembling dimensions of structures and conductor sag.	a) The supporting points of the lowest conductors of transmission lines on common poles for transmission and distribution lines (DC-1, DC-DC-1) is raised 50 cm, or b) The heights above ground of distribution poles is lowered by 50 cm.	Common poles (P_1) for transmission and distribution lines and distribution poles (P_2) are arranged as shown in Fig. 15-1. As shown in Table 15-1, with DC-1 and DC-DC-1, when the temperature is 80°C the clearance between the lowest conductor of the transmission line and distribution pole will become 1.28 m and smaller than the minimum clearance of 1.47 m.

Table 15-1 Vertical clearance between lowest conductor of transmission line and distribution line

Type of Common Pole	h_1 (m)	h_2 (m)	Temp. (°C)	Sag (m)	Vertical clearance (m)	
					from dis. line conductor	from distribution pole
DC-1, DC-DC-1	12.50	9.50	37.8 (100°F)	0.82	2.18	1.68
			80	1.22	1.78	1.28
			150	1.73	1.27	0.77
DC-1B	14.05	9.21	37.8 (100°F)	0.82	4.02	3.52
			80	1.22	3.62	3.12
			150	1.73	3.11	2.51

Fig. 15-1 Longitudinal profile of joint-use section of transmission and distribution lines



(5) Distribution Line

Current	Suggested revision	Reasons, justifications, etc.
a. Overhead Distribution Line		
i) Strength of concrete pole Pole length / Allowable bending moment (ground level) 12 m 3.5 ton-meter 14 m 4.15 ton-meter	Strength of concrete pole is increased. For example: 12 m 4.5 ton-meter 14 m 5.5 ton-meter	a) The strength of supports is adequate under conditions of standard pole arrangement for high-tension single circuit, but there are no allowances in the allowable strength, and strength would be insufficient if any equipment or conductors were installed on the pole. b) It is getting difficult day by day to secure right-of-way for distribution line, so that it is necessary to adopt high-tension double circuit arrangement.
ii) High-tension distribution conductor Trunk line 336.4 MCM bare aluminum conductor (BAC) Branch line 4/0 AWG BAC 2/0 AWG BAC #2 AWG BAC Specific sections only Spaced aerial cable, Al	In the central part of the city, semi-insulated conductors are strung and aesthetic poles with narrow profile are adopted. (Note) It is necessary for aesthetic poles suited to Bangkok to be contemplated and appropriate pole arrangement hardware and insulation methods at joints to be selected.	As buildings, signboards, etc. are located close to high-tension distribution lines in the central part of the city, electric shocks to people and fault of distribution lines can be minimized by adopting of semiinsulated conductors. At the same time, narrow profile design and vertical conductor arrangement are to be adaptable, so that aesthetic poles can be employed.
iii) Distribution line switch a) Manual-operating switch Single-pole disconnecting switches are used for trunk lines, while drop-fuse cutouts are used for branch lines.	Three-pole simultaneous on-off-type load break switches, of which rated currents are 100–600 A, are adopted. Air-, vacuum- and gas-type load break switches are selected and used based on the operating condition.	It is necessary for a disconnecting switch to switch in a power stoppage condition somewhere along a distribution line, and it takes much time to sectionalize the faulted section. By installing 3-pole simultaneous on-off-type switches it is possible to shorten the fault recovering time.
b) Automatic section switch These are being used only for a limited number of customers.	Automatic section switches are installed on the distribution lines, and a system for distribution-line automatic sectionalizing at fault is applied.	By sectionalizing the faulted section of distribution lines automatically, system reliability can be improved considerably.
iv) Distribution transformer a) Rated capacity (kVA)		

Current standard	Suggested revision	Reasons, justifications, etc.
Rated capacity of transformers is 5, 10, 15, 25, 37.5, 50, 75, 100, 167, 333, 500, 750, 1000 kVA, and there are also 133, 150, 200, 300, 630 kVA. Especially, there are many customer-owned transformers of capacities other than the above.	With regard to customer-owned transformers, certain standard is established and make the customers to comply with the standards.	Customer-owned transformers amount to 44% of the distribution transformer capacity in the MEA service area, and losses will be great if inferior transformers are installed, which also is a factor to cause distribution line fault, and this will result in trouble for customers.
b) Installation method		
Pole mount is mainly employed.	In addition to the pole amount, rented space mount, ground mount and also underground mount are applied in the urban areas.	As for the pole mount, hazards due to proximity to buildings and complaints of neighborhood residents due to noise from the transformer will arise, and these will be avoided by applying the installation method stated left column.
v) SVR (Step-up voltage regulator) for distribution line SVR is not adopted.	SVRs are installed somewhere along the long-distance distribution lines, where voltage drops are great, to improve the distribution voltage.	In case of excessive voltage drops in long-distance distribution lines, construction costs would be high, and therefore, it would be uneconomical to increase the sizes of conductors as a countermeasure. By installing step-up voltage regulators along the lines, voltages can be improved economically.
vi) Others		
a) Crossarm		
Wooden crossarms are being used.	Lightweight steel crossarms are adopted.	Trouble due to rotting of wooden crossarms can be prevented, and replacement costs can be reduced.
b) Pole sign plates		
Pole sign plates are not adopted.	Luminous pole sign plates are attached on concrete poles along heavy-traffic roads.	Prevention of distribution line fault due to collisions by vehicles.
b. Underground Distribution Line		
i) Varieties of underground cable		
Single-core 650 MCM Cu XLPE Single-core 500 MCM Cu XLPE Single-core 350 MCM Cu PILC Single- or three-core 4/0 AWG Cu PILC Single- or three-core 2/0 AWG Cu PILC	a) Three-core triplex cross-linked polyethylene (XLPE) cable is adopted.	In case of simultaneous drawing-in of 3 single-core cables into one duct line, tension imbalance will be produced, and tension is concentrated on a specific cable only, and this will result in straining insulation material. Tension will be made uniform if triplex cable is adopted, and this is installed easily. Further, the triplex cable has the advantages below compared with a three-core common-sheath type. ① Current capacity is approximately 10% greater. ② Weight is 5–10% lighter.
	b) Steel tape armored cable is adopted (at places where urban streets are in good order and buried objects are regulated).	Shortening of work periods of cable laying and reduction of laying costs.

Current standard	Suggested revision	Reasons, justifications, etc.
ii) Underground duct line		
Asbestos-cement pipe (concrete encased) and steel pipe.	a) Lightweight steel pipe, fiberglass reinforced plastic pipe (FRP), cured plastic pipe, etc. are adopted for underground duct line materials. Particularly, fiberglass reinforced plastic pipe is adopted in case of common laying on bridges.	Excavation of streets for duct work obstructs traffic in urban areas. By using duct line materials which are strong and lightweight it will be possible to complete digging, piping and backfilling within a short period of time.
	b) At places with large numbers of outgoing duct lines such as substation, culverts are adopted.	Particularly, if fiberglass reinforced plastic pipe is used in laying on a bridge, there will be little effect on bridge strength because of lightness of weight, while there will be no risk of corrosion.
iii) Manhole		
Placed-in-site manhole	Prefabricated manholes are developed.	Shortening of work periods in urban areas similarly to the above.
iv) Underground switch and on-ground switch		
Underground switches and on-ground switches are not adopted.	Underground multi-circuit switches (sub-mergible) and on-ground multi-circuit switches are adopted.	By sectionalizing the faulted section or working section of underground line, or by supplying the power to the load side beyond the said sections, system reliability can be improved. Also, additional underground line can be branched easily from a multi-circuit switch.

(6) Reference

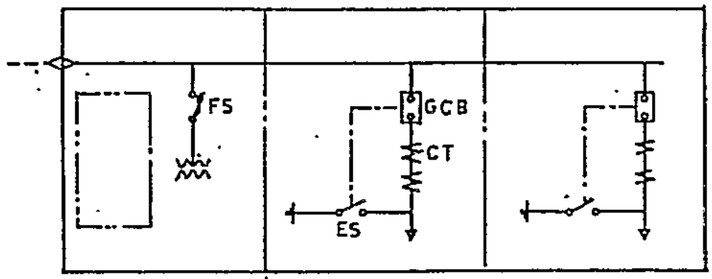
G − 1	Values Comparison of Two Standards
S − 1	24-KV Outdoor Cubicle
S − 2	Sound-proof Chamber for Main Transformer
T − 1	Performance of High Conductivity Thermo-resistant Aluminium Alloy Conductor
D − 1	Aethetic Distribution Pole (1)
D − 2	Aethetic Distribution Pole (2)
D − 3	12-KV Manual-operating Load Break Switch (Air-breaking type)
D − 4	15-KV Manual-operating Load Break Switch (Vacuum-breaking type)
D − 5	12-KV Automatic Load Break Switch (Air-breaking type)
D − 6	Capacity and Size of Distribution Transformer Station
D − 7	Voltage Regulator for 24-KV Distribution Line
D − 8	Luminous Pole Sign Plate
D − 9	Triplex Cross-linked Polyethylene Cable and Steel Tape Armoured Cable
D − 10	Light-weight Steel Pipe for Underground Distribution Line
D − 11	Cured Plastic Pipe for Underground Distribution Line
D − 12	Fiberglass Reinforced Plastic (FRP)-Pipe and FRP Composite Pipe for Under-groudd Distribution Line
D − 13	Flexible Pipe for Underground Distribution Line
D − 14	Prefabricated Manhole
D − 15	Installation Example of Underground Distribution Equipment
D − 16	Multi-circuit Switch for Underground Distribution Line (Ground mount) .... Air-breaking type
D − 17	Multi-circuit Switch for Underground Distribution Line (Underground mount) .... Gas-breaking type

G-1 Values Comparison of Two Standards (ANSI/IEC)

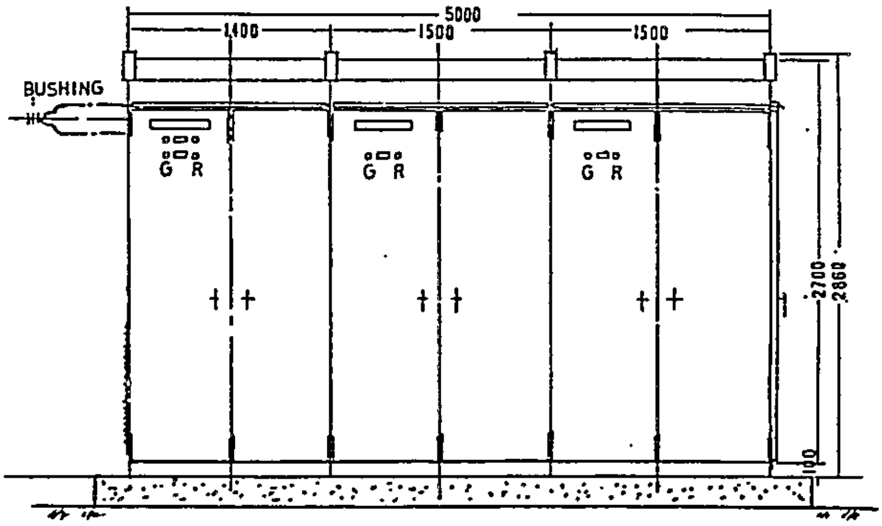
	ANSI	IEC
12 KV Three phase distribution transformer Insulation class Basic impulse insulation level	 15 A 95 KV	 12 75 KV
24 KV Three phase distribution transformer Insulation class Basic impulse insulation level	 25 150 KV (MEA ... 125 KV)	 24 125 KV
12 KV Outdoor air switch Rated maximum voltage Rated impulse withstand voltage (To earth and between poles of switch)	 15.5 KV 110 KV	 12 KV 75 KV
24 KV Outdoor air switch Rated maximum voltage Rated impulse withstand voltage (To earth and between poles of switch)	 25.8 KV 150 KV	 24 KV 125 KV

S - 1 24-KV Outdoor Cubicle

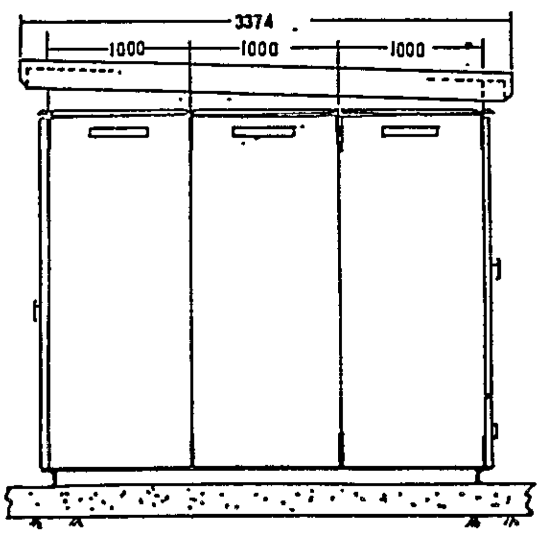
Unit : mm



One Line Connection



Front View

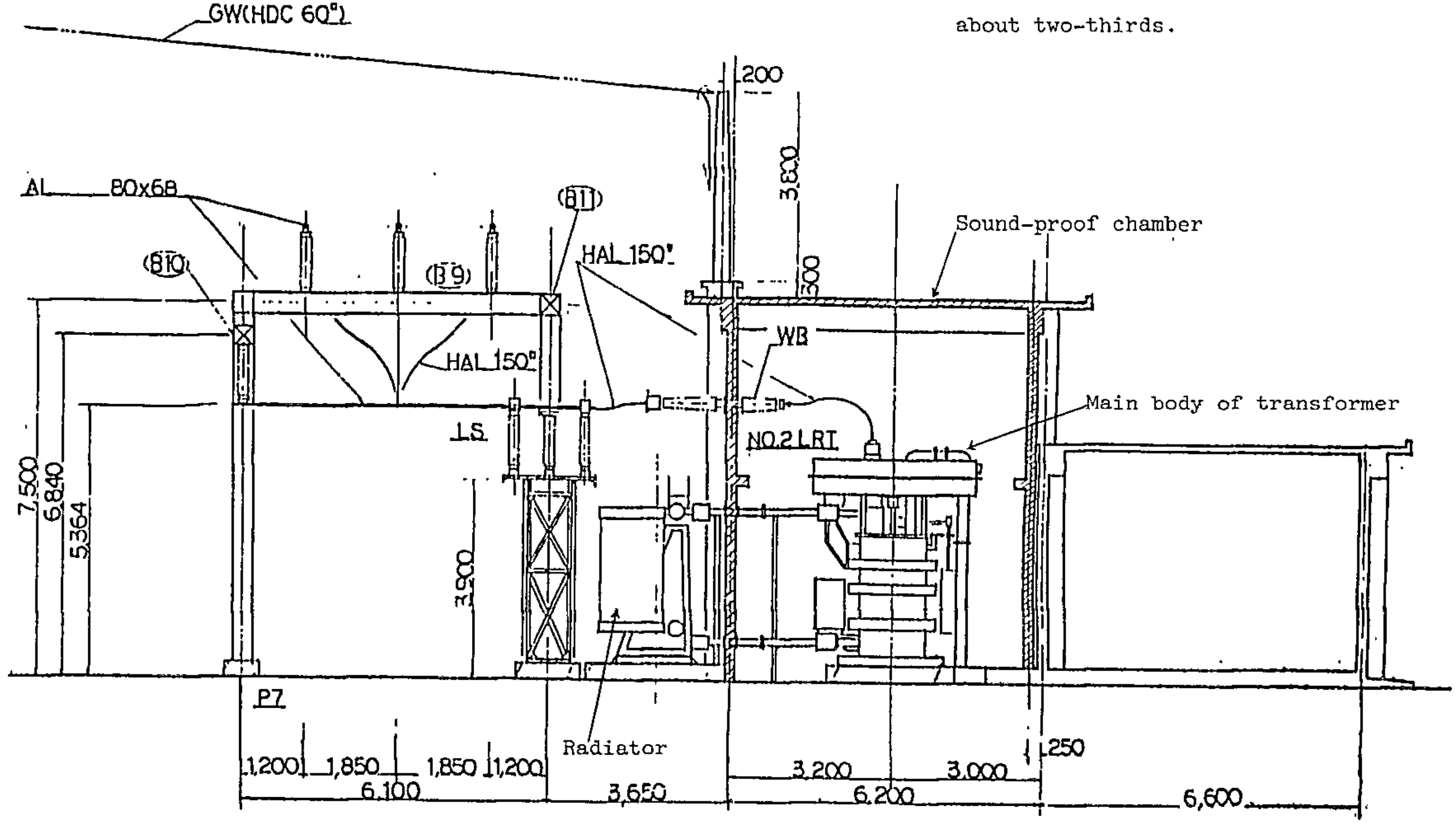


Side View

S - 2 Sound-proof Chamber for Main Transformer

Unit : mm

Note ; Transformer noise will be reduced to about two-thirds.



T - 1 Performance of High Conductivity Thermo-resistant Aluminium Alloy Conductor

The performance of this conductor (TAL) is shown below.

I. Properties

Table 1 compares an ordinary aluminium conductor (HAL), and the high conductivity thermo-resistant aluminium alloy conductor.

Table 1

Properties	HAL	TAL
Melting point (°C)	660	660
Specific heat at 20°C	0.22	0.22
Coefficient of linear expansion (°C^{-1})	23x10^{-6}	23x10^{-6}
Specific dencity (g/cm^3)	2.7	2.7
Tensile strength (kg/mm^2)	16–19	16–19
Elongation (250 mm) (%)	2 – 4	2 – 4
Coefficient of elasticity (kg/mm^2)	approx. 6,300	approx. 6,300
Electric conductivity at 20°C	61	60
Thermal coefficient of electric resistance (°C^{-1})	0.0040	0.0040

II. Practical performance at normal temperature

The high conductivity thermo-resistant aluminium alloy conductor is almost equal to the other conductors in tensile strength, and other performance.

Table 2 shows comparison of the typical properties of these conductors, 4.0 mm in diameter.

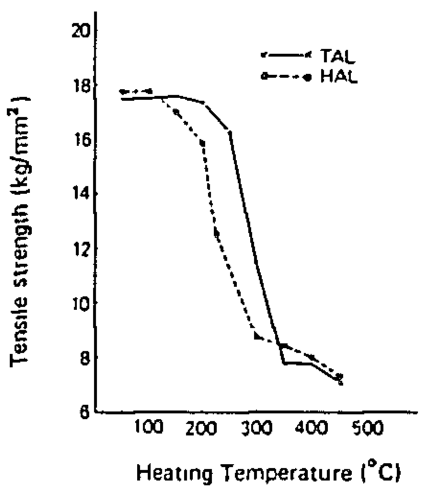
Table 2

		Tensile strength kg/mm^2	Elongation (250 mm) %	Conductivity %
TAL	max.	18.49	3.4	60.7
	min.	17.69	2.6	60.3
	mean	18.12	3.1	60.5
HAL	max.	18.55	3.3	62.5
	min.	17.68	2.6	62.3
	mean	18.10	3.0	62.4

III. Annealing characteristics

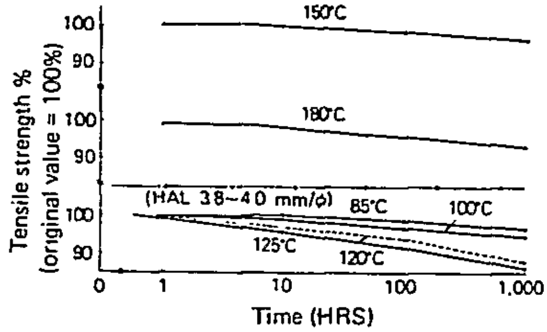
Fig. 1 shows the tensile strength of the conductors (HAL and TAL) heated for one hour at varied temperatures, and Fig. 2, their tensile strength after heating for a long time, which is a problem in actual operation of transmission lines.

Fig. 1 4.0mmφ Annealing Characteristics after 1 hr. heating



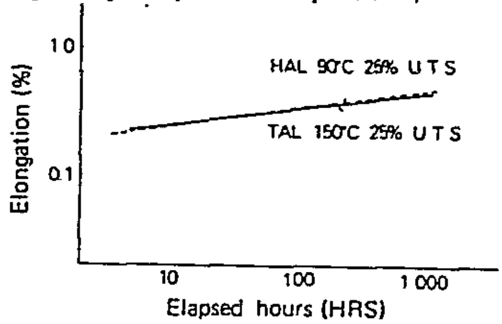
From these figures it is known that the TAL has remarkable thermo-resistant characteristics for HAL. Therefore the continuous allowable operation temperature can be adapted at 150°C, compared with 90°C at HAL, and the short time allowable operation temperature can be adapted at 180°C.

Fig. 2 TAL 4.0 mmφ Annealing Characteristics after long time heating



The creep characteristics of the conductors is shown in Fig. 3.

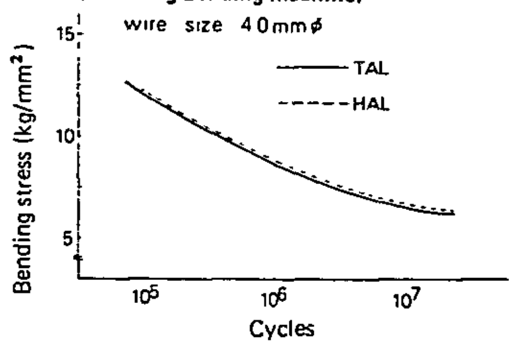
Fig. 3 High temperature creep 4.0 mmφ



IV. Vibration fatigue characteristics

Fig. 4 shows the vibration fatigue characteristics of the conductors examined by rotary bending tester. The TAL is equivalent to HAL.

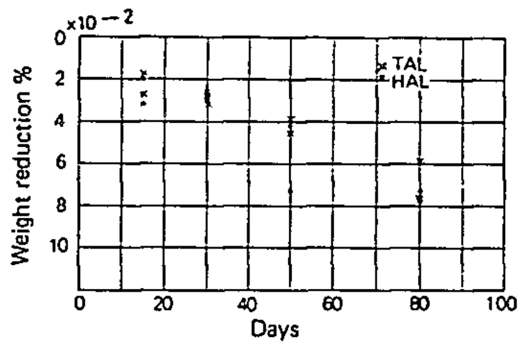
Fig. 4 Vibration fatigue characteristics (Rotating bending machine)



V. Corrosion resistance

In salt-water spray and chlorine tests, the TAL proved to be practically equal in corrosion resistance to HAL.

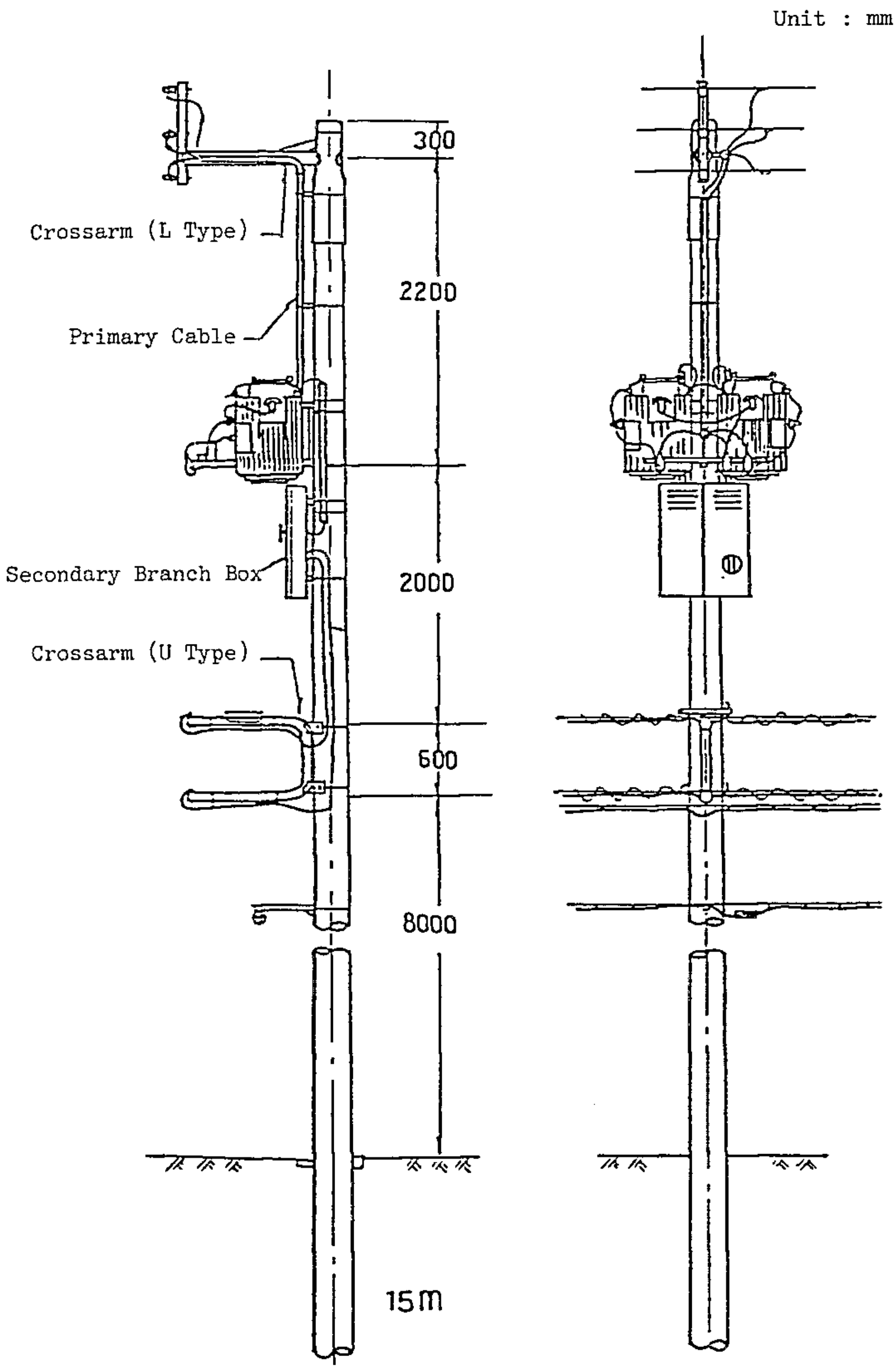
Fig. 5 Weight reduction due to corrosion in salt spray chamber



CONCLUSION

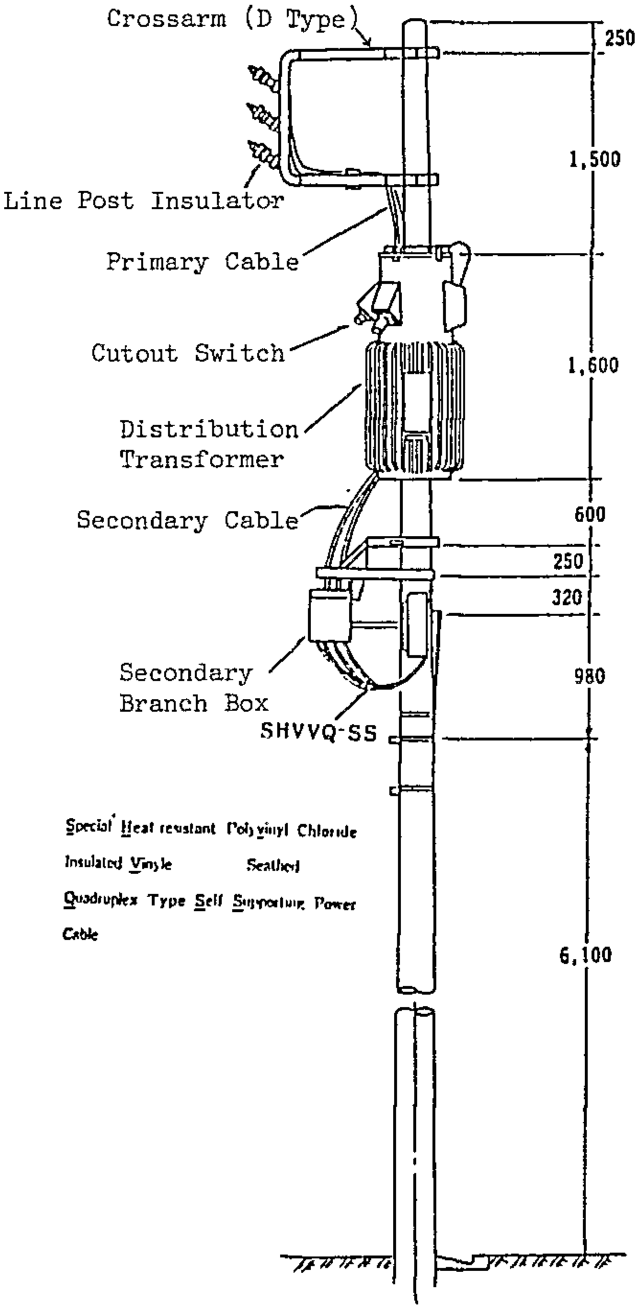
From the foregoing it is evident that, the TAL can be used up to the continuous allowable temperature of 150°C and the short-time allowable temperature of 180°C.

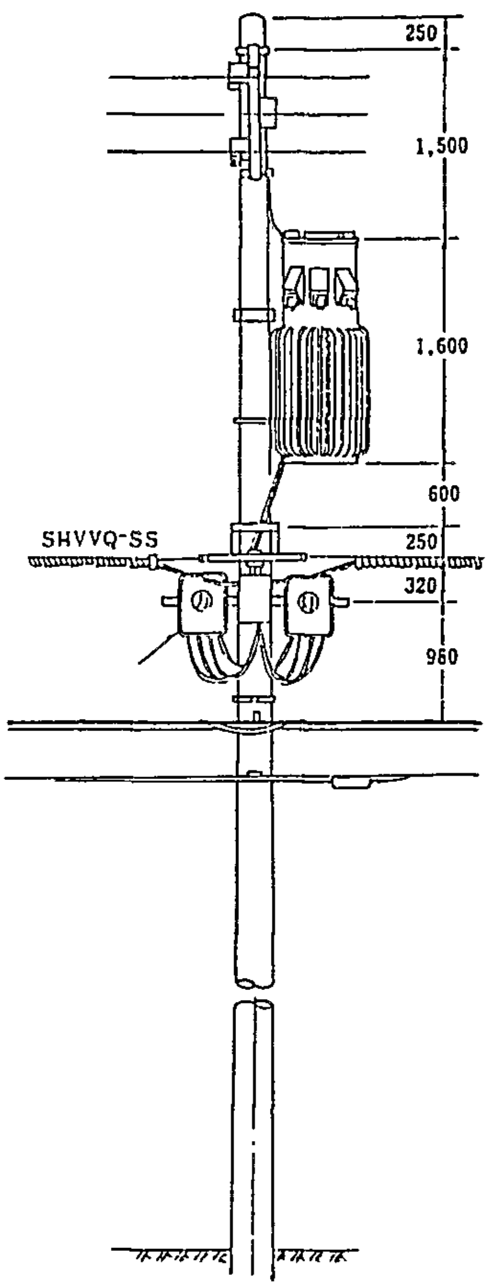
D - 1 Aethetic Distribution Pole (1)

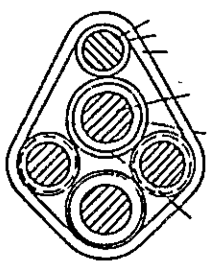


D - 2 Aethetic Distribution Pole (2)

Unit : mm

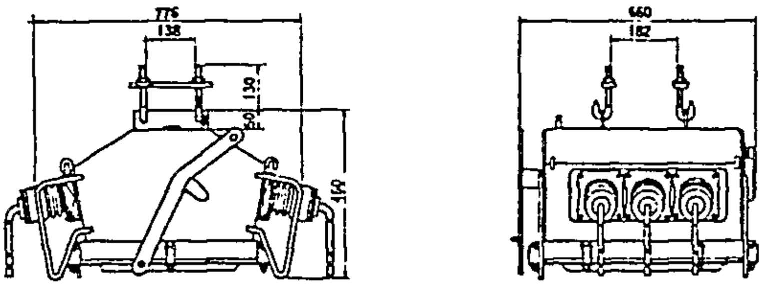




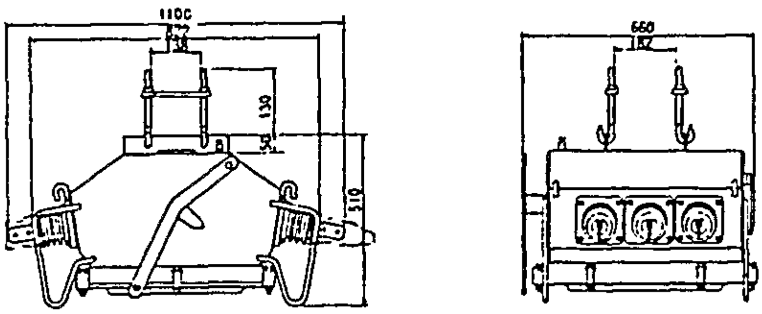


D - 3 12-KV Manual-operating Load Break Switch (Air-breaking type)

Unit : mm



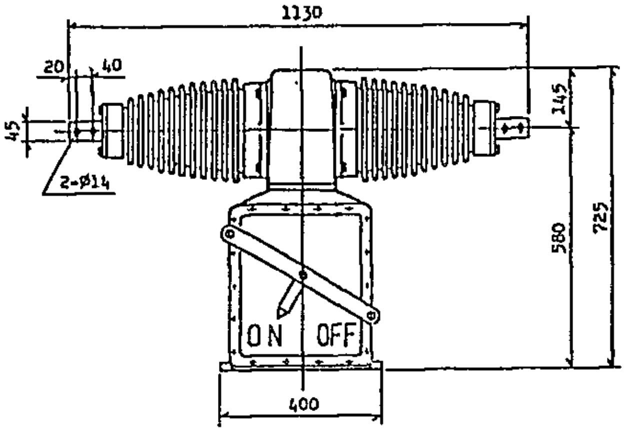
Ampacity	Lead wire	Weight
200A	80mm^2	78kg
400A	125mm^2	81kg

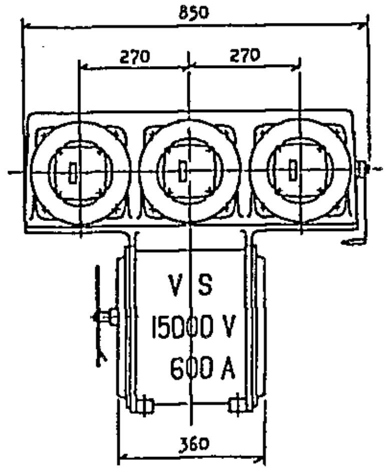


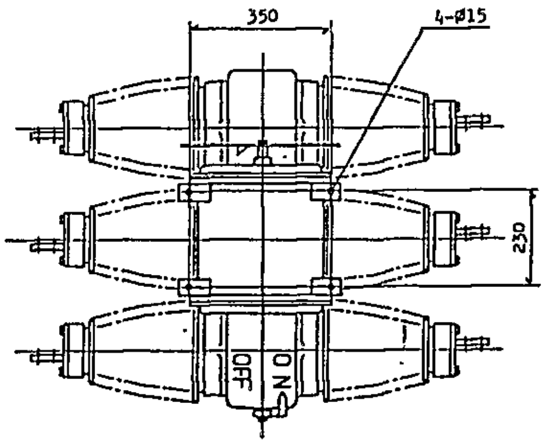
Amapcity	Weight
600A	92kg

D - 4 15-KV Manual-operating Load Break Switch (Vacuum-breaking type)

Unit : mm



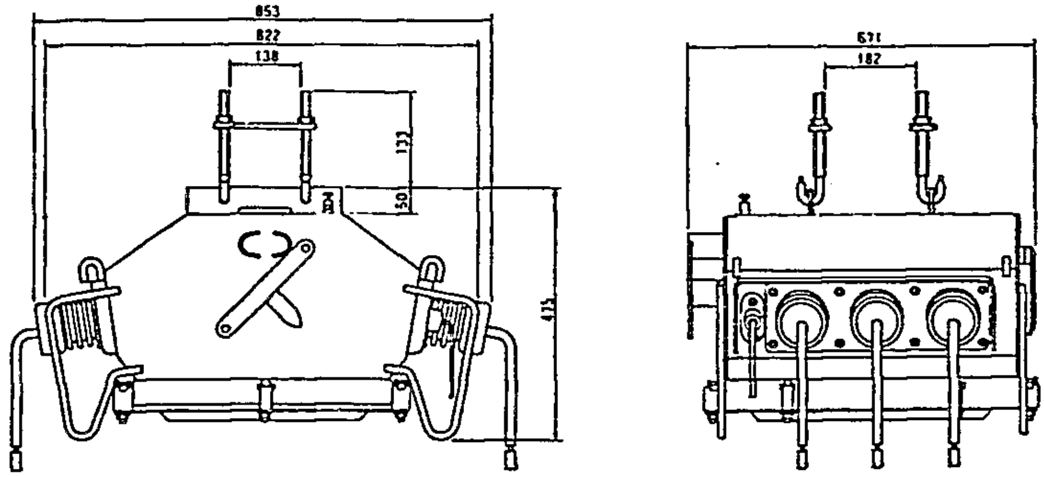




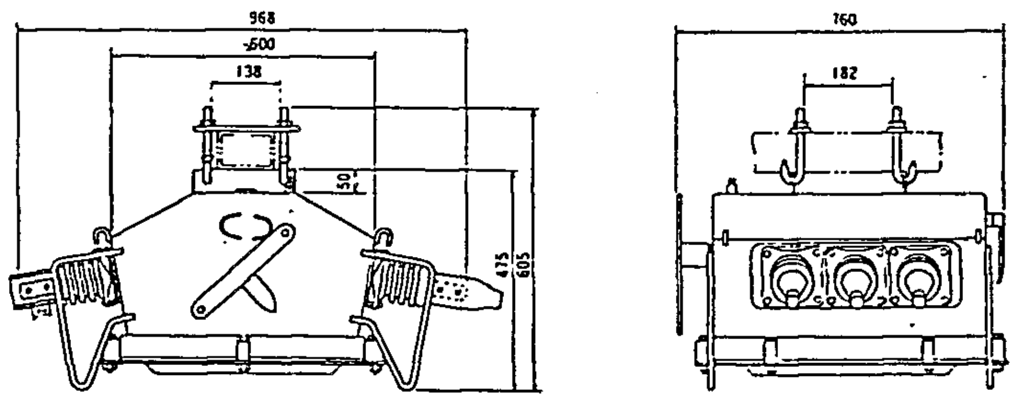
Rated voltage	15000 V
Rated current	600 A
Short - time current	25 kA
Peak making current	63 kA
Basic impulse level	95 kV
Weight	230 kg

D - 5 12-KV Automatic Load Break Switch (Air-breaking type)

Unit : mm



Ampacity	Lead wire	Weight
200A	80mm^2	110kg
400A	125mm^2	115kg

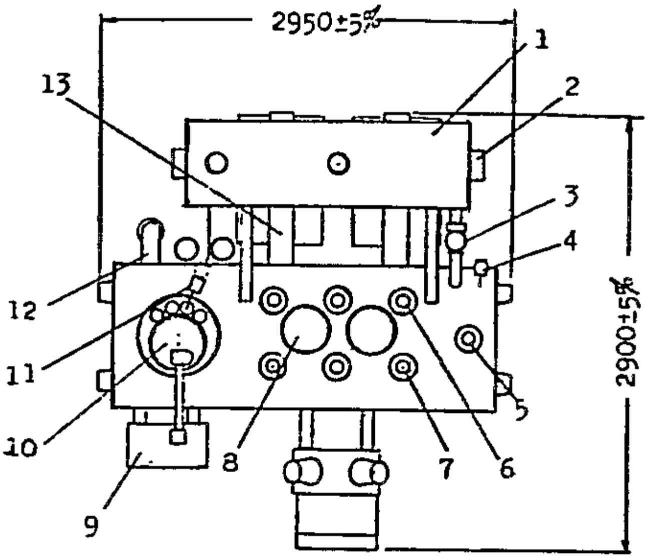


Ampacity	Weight
600A	120kg

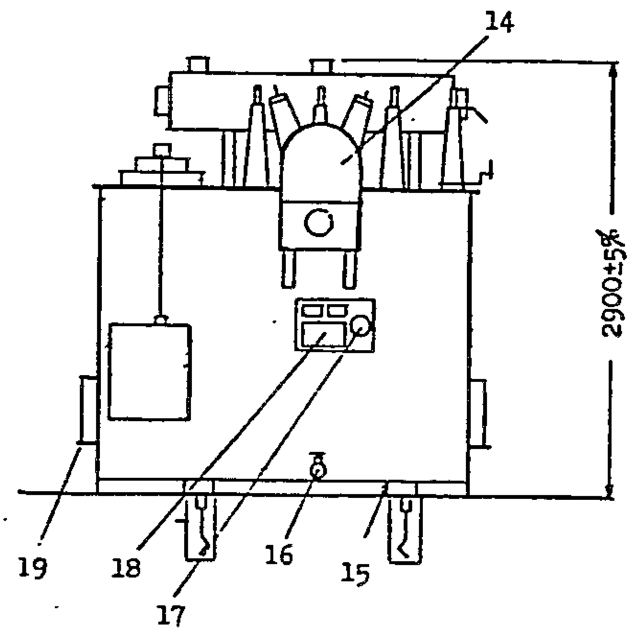
D - 6 Capacity and Size of Distribution Transformer Station

		Capacity of Transformer (KVA)													Size of Transformer Station								
															Under-road type			On-road type			In-house type (rented room)		
		125	160	200	250	260	315	400	500	630	750	800	1000	2000	depth (m)	width (m)	height (m)	depth (m)	width (m)	height (m)	depth (m)	width (m)	height (m)
FEDERAL GERMANY	Berlin							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Dortmund							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Düsseldorf							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Essen							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Hamburg							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Hannover							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Munich							o		o								2.9	2.0	1.8	4.5	3.5	2.3
	Stuttgart							o		o								2.9	2.0	1.8	4.5	3.5	2.3
UNITED KINGDOM	Bristol						o		o									3.4	2.1	2.1	5.0	4.0	2.5
	London								o		o				3.66	3.05	2.44	3.66	3.05	2.47	3.66	3.05	2.44
AUSTRIA	Vienna (Wien)				o			o		o								4.0	3.0	2.8	6.0	4.0	3.0
BELGIUM	Antwerp (Anvers)	o			o			o										{3.0 {4.0	3.0 3.54	3.0 3.2	5.5	3.5	2.8
	Brussels (Bruxelles)				o			o		o					5.81	2.31	2.31	5.31	2.31	2.31	4.0	3.5	2.15
DENMARK	Copenhagen								o									1.8	1.8	1.83	2.89	2.65	2.35
SPAIN	Barcelona (ENHER)				o			o		o					4.2	4.2	4.2	3.9	3.0	7.90	4.2	4.2	4.4
	Barcelona (FECSA)				o			o		o					3.5	5.0	3.0	5.0	4.0	3.0	3.0	3.5	2.8
	Barcelona (HEC)					o		o		o					7.0	4.5	4.0	7.0	4.5	4.0	6.0	4.5	4.0
	Bilbac				o			o		o					8.9	4.3	3.0	6.5	4.0	3.0	6.5	4.0	2.8
	Madrid (H.E.)				o			o		o					6.45	2.70	2.5				5.0	5.0	2.5
	Madrid (U.E.)				o			o		o											6.0	4.0	3.0
	Seville (Sevilla)				o			o		o								5.0	5.0	3.5	5.0	4.0	3.2
	Valencia				o			o		o					8.1	2.8	3.0	2.9	5.4	3.25	8.0	3.0	3.25
FRANCE	Lyons		o		o										6.1	2.7	2.6	4.6	2.7	2.6	4.6	2.7	2.6
	Marseilles		o		o			o										3.7	3.2	2.6	5.0	4.0	2.5
	Paris							o		o		o			6.3	3.2	2.5				6.5	4.0	3.0
HOLLAND	Amsterdam	o			o			o										1.5	1.5	2.7	3.0	2.5	2.6
	The Hague (Den Haag)			o			o											3.5	2.5	2.8	3.5	3.5	2.7
	Rotterdam						o	o		o								{2.9 {1.5	2.2 1.5	3.3 2.8	2.7	2.7	2.7
ITALY	Genoa (Genova)				o			o															
	Milan (Milano)		o		o			o													4.0	4.0	3.5
	Rome (Roma)		o		o			o										2.8	1.8	3.3	5.0	4.0	3.0
	Turin (Torino)		o		o										4.5	3.5	2.8	4.5	3.5	2.8	4.5	3.5	2.8
POLAND	Wroclaw						o		o									6.0	6.0	3.5	6.0	5.0	3.0
PORTUGAL	Lisbon (Lisboa)				o			o		o													
SWEDEN	Stockholm				o								o	o				8.0	5.0	2.7 +0.65	8.5	5.0	3.0 +0.65
SWITZERLAND	Zurich												o		15.4	11.0	4.5	4.8	1.4	3.0	11.0	4.5	3.1

D - 7 Voltage Regulator for 24-KV Distribution Line



Plane View



Front View

THREE PHASE

ON-LOAD VOLTAGE REGULATOR

ONAN OUTDOOR USE

THROUGH PUT	8,002	kVA
FREQUENCY	50	Hz
INPUT VOLTAGE	23.1-17.6 (21 TAPS)	kV
OUTPUT VOLTAGE	23.1	kV
TOTAL WEIGHT	11,500 kg±5%	
OIL QUANTITY	3,400 Lit±5%	

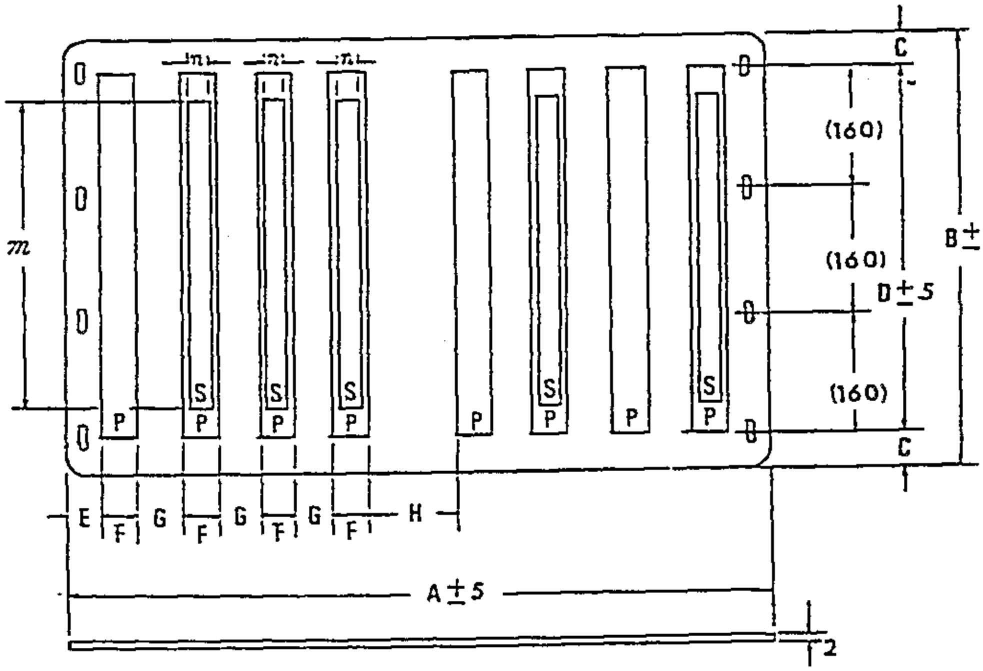
LEGEND

1. CONSERVATOR
2. OIL LEVEL GAUGE
3. BUCHHOLZ RELAY
4. OIL FILTER VALVE
5. NEUTRAL BUSHING
6. INPUT BUSHING
7. OUTPUT BUSHING
8. HANDHOLE
9. MOTOR DRIVEN OPERATING BOX
10. ON-LOAD TAP-CHANGER
11. OIL FLOW RELAY
12. PRESSURE-RELIEF DEVICE
13. RADIATOR
14. POTENTIAL TRANSFORMER
15. EARTHING TERMINAL
16. OIL DRAIN VALVE
17. OIL THERMOMETER
18. NAMEPLATE
19. JACK BOSS

D - 8 Luminous Pole Sign Plate

a. Pole sign plate

Unit : mm

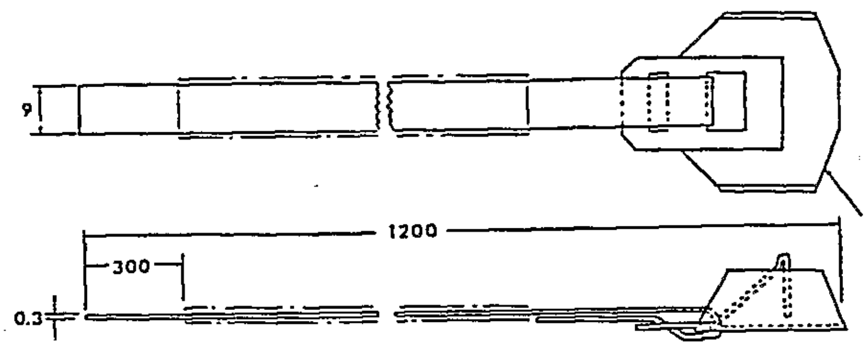


S : Scotch Light (Yellow)

P : Polyethylene Tape (Yellow)

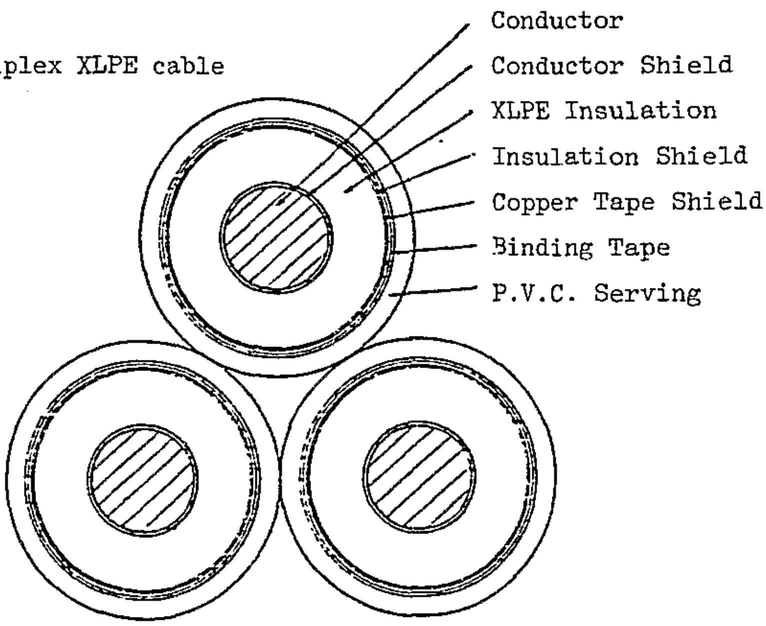
A	B	C	D	E	F	G	H	m	n
700	600	66	480	33	38	44	62	400	20
500	300	25	250	23	28	31	44	200	20

- Scotch Light is applied by a special process.
- Reflection by Scotch Light is called directional reflection, which means it reflects a beam of light back along its original path from all directions.

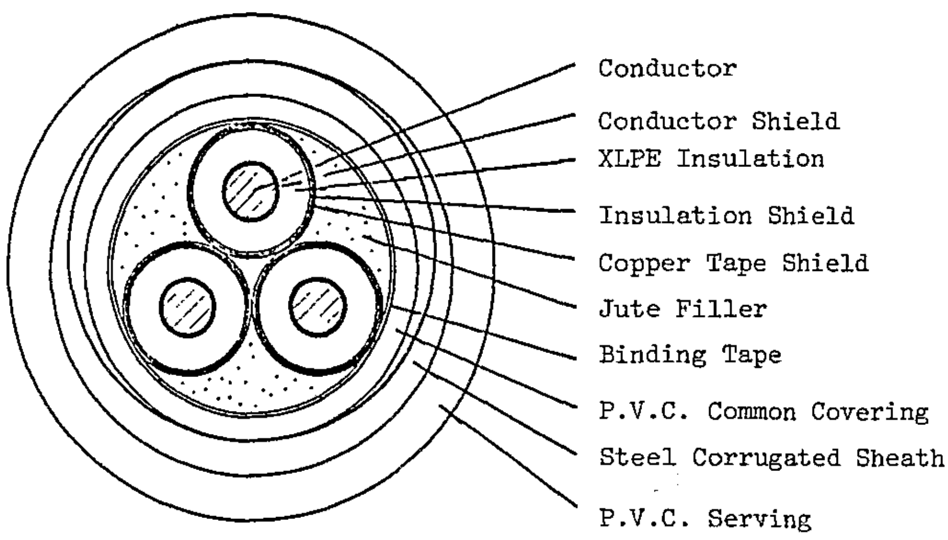


D - 9 Triplex Cross-linked Polyethylene Cable and Steel Tape Armoured Cable

a. Triplex XLPE cable



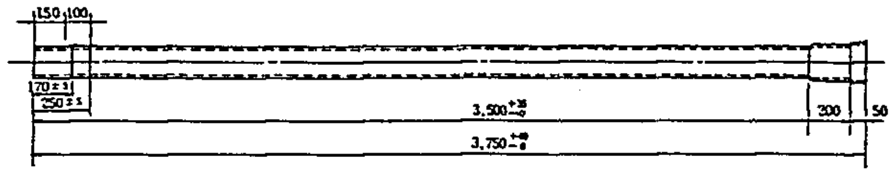
b. Steel tape armoured XLPE cable



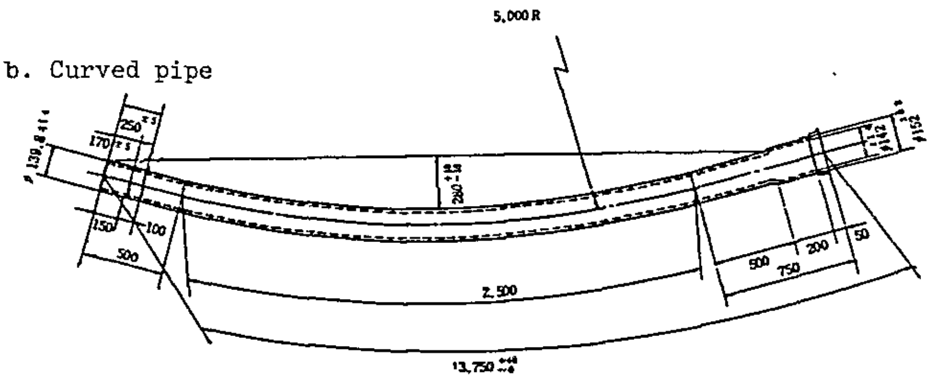
D - 10 Light-weight Steel Pipe for Underground Distribution Line

a. Straight pipe

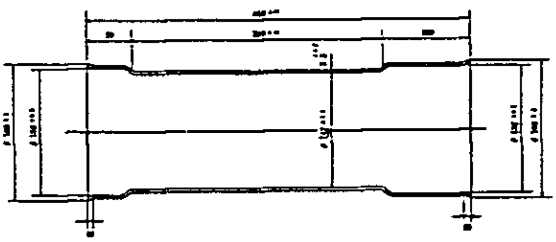
Unit : mm



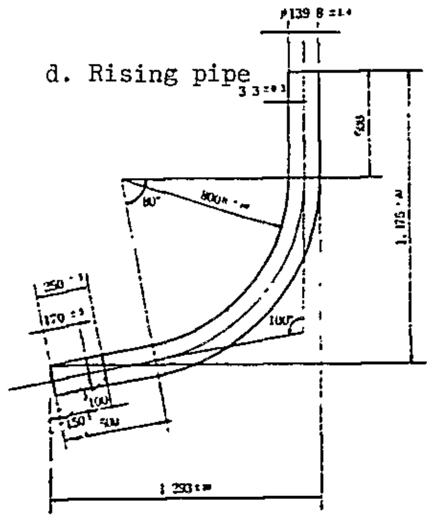
b. Curved pipe



c. Joint pipe

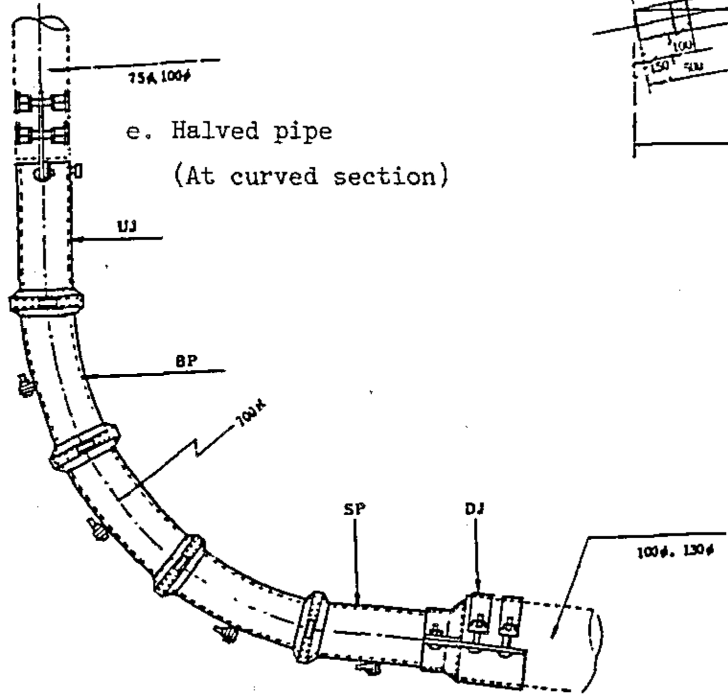


d. Rising pipe

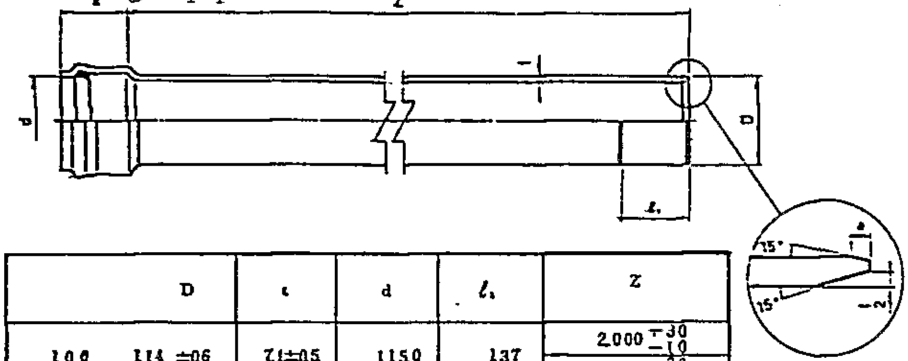


e. Halved pipe

(At curved section)



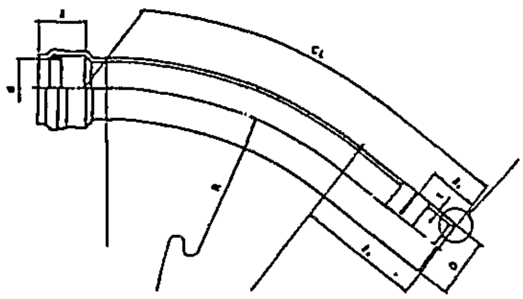
a. Straight pipe



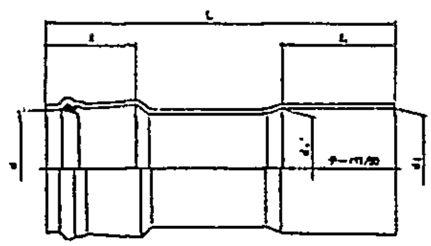
	D	t	d	l_1	Z
100	114 ±0.6	7.1±0.5	115.0	137	$2{,}000^{+30}_{-10}$
					$5{,}000^{+30}_{-10}$
125	140 ±0.8	7.5±0.5	141.2	145	$2{,}000^{+30}_{-10}$
					$5{,}000^{+30}_{-10}$
150	165 ±1.0	9.6±0.7	166.3	156	$2{,}000^{+30}_{-10}$
					$5{,}000^{+30}_{-10}$
200	216 ±1.30	11.0±0.7	217.4	180	$2{,}000^{+30}_{-10}$
					$5{,}000^{+30}_{-10}$

Unit : mm

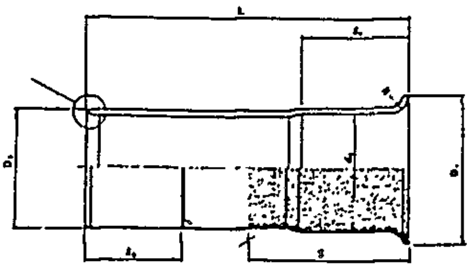
b. Curved pipe



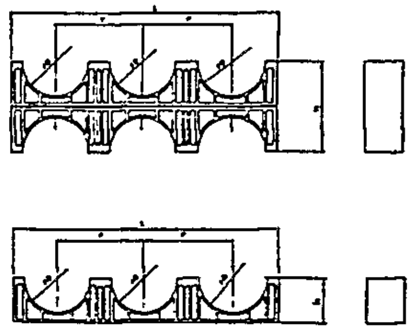
c. Joint pipe



d. Bell-mouthed pipe

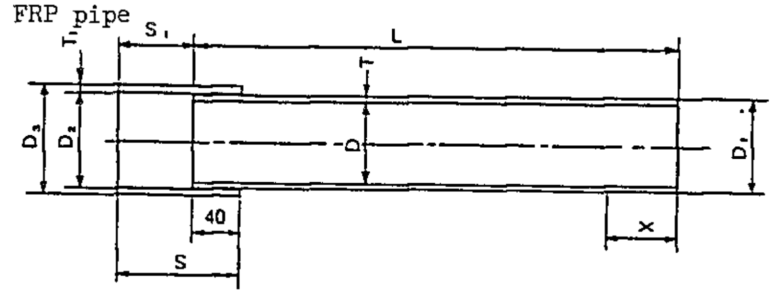


e. Sleeper



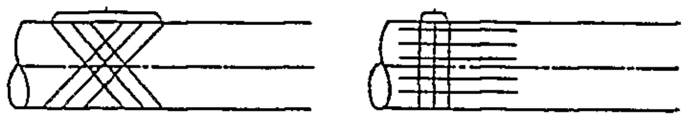
D - 12 Fiberglass Reinforced Plastic (FRP) Pipe and FRP Composite Pipe for Underground Distribution Line

a. FRP pipe

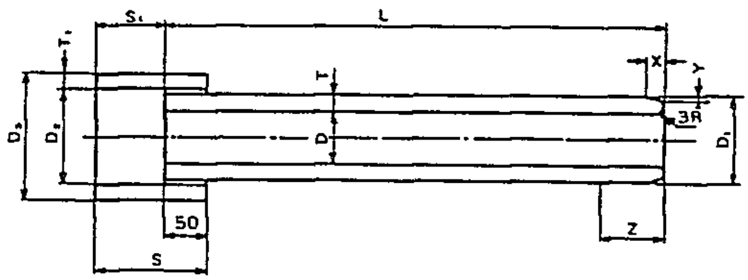


	D	-T	D_1	D_2	T_1	D_3	S	S_1	X	L	Kg	
100	100	4	108	116	4	124	110	70	73		2.4	0.30
125	125	4	133	141	4	149	110	70	73	4000	2.9	0.36
150	150	4	158	166	4	174	110	70	73	6000	3.5	0.42
200	200	5	210	218	5	228	120	80	83		5.8	0.76
250	250	5	260	268	5	278	120	80	83		7.2	0.93

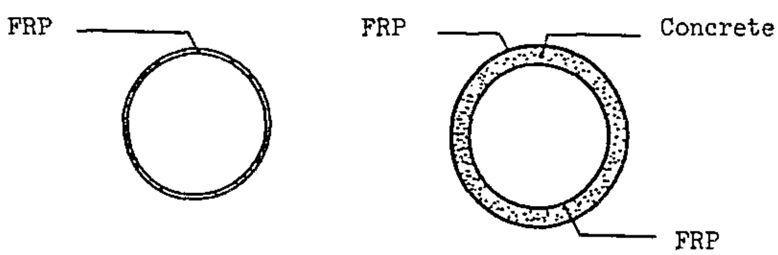
Winding method of glassfiber



b. FRP Composite pipe

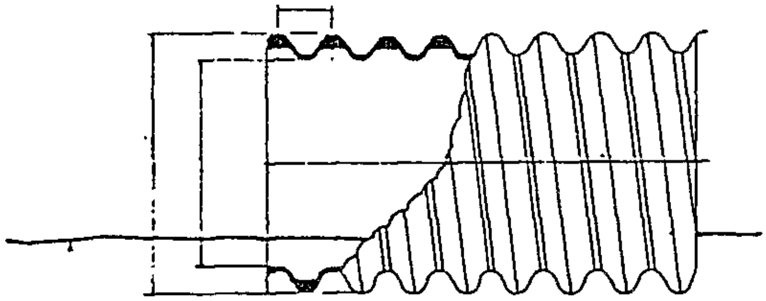


	D	T	D_1	D_2	T_1	D_3	S	S_1	X	Y	Z	L	Kg	
100	100	10	120	130	10	150	130	80	10	3	83	1000	6.9	1.1
125	125	10	145	155	10	175	130	80	10	3	83	2000	8.5	1.3
150	150	12	174	184	12	208	130	80	10	3	83		12.2	1.9
200	200	15	230	240	15	270	140	90	10	3	93	4000	20.3	3.4
250	250	18	286	296	18	332	140	90	10	3	93		30.3	5.0



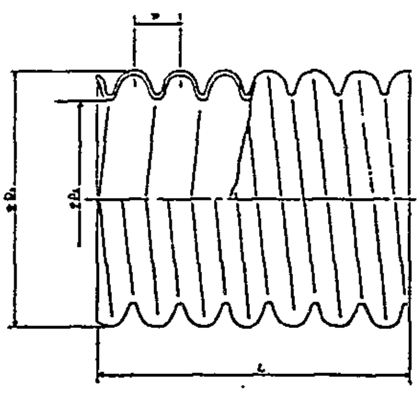
D - 13 Flexible Pipe for Underground Distribution Line

a. Straight pipe

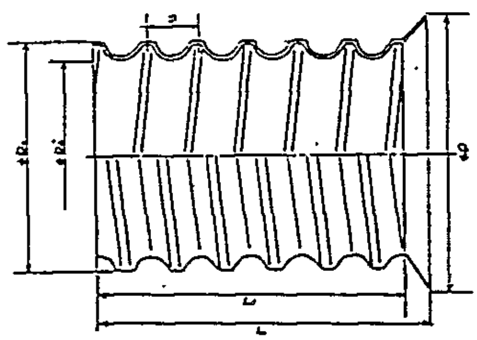


Nominal diameter (mm)	Outer " (mm)	Inner " (mm)	Pitch (mm)	Weight (kg/m)	Standard length per coil(m)	Standard O D and height of coil (m)
100	127	100	25.5	1.2	50, 100	2.3 X 0.8 (s,1=100)
125	156	125	35	1.4	50	2.3 X 0.5
150	190	150	40	1.9	50	2.3 X 0.75
200	250	200	50	3.8	30	2.3 X 0.75

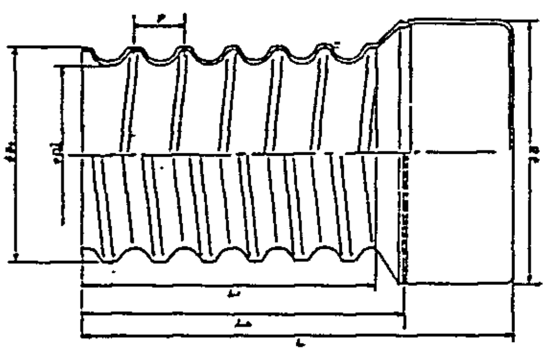
b. Joint pipe



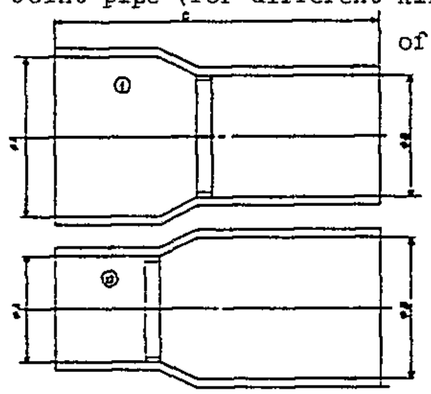
c. Bell-mouthed pipe



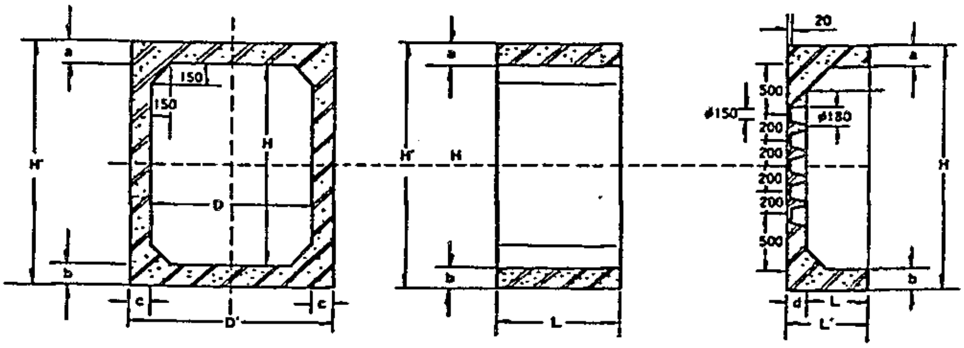
d. End-capped pipe



e. Joint pipe (for different kind of pipes)



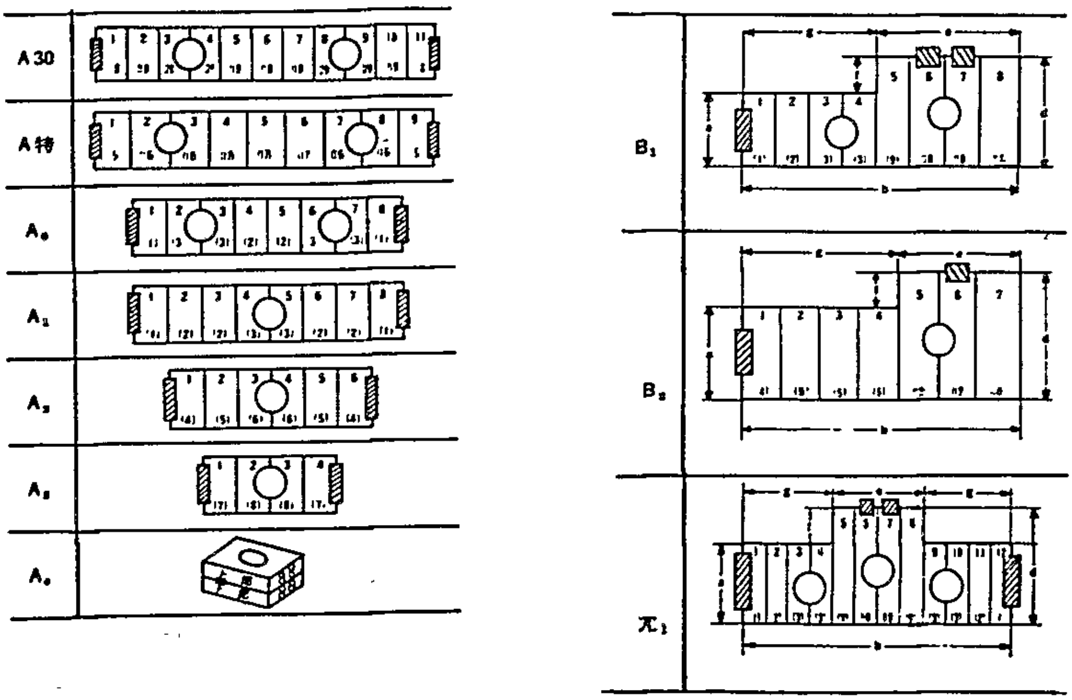
D - 14 Prefabricated Manhole



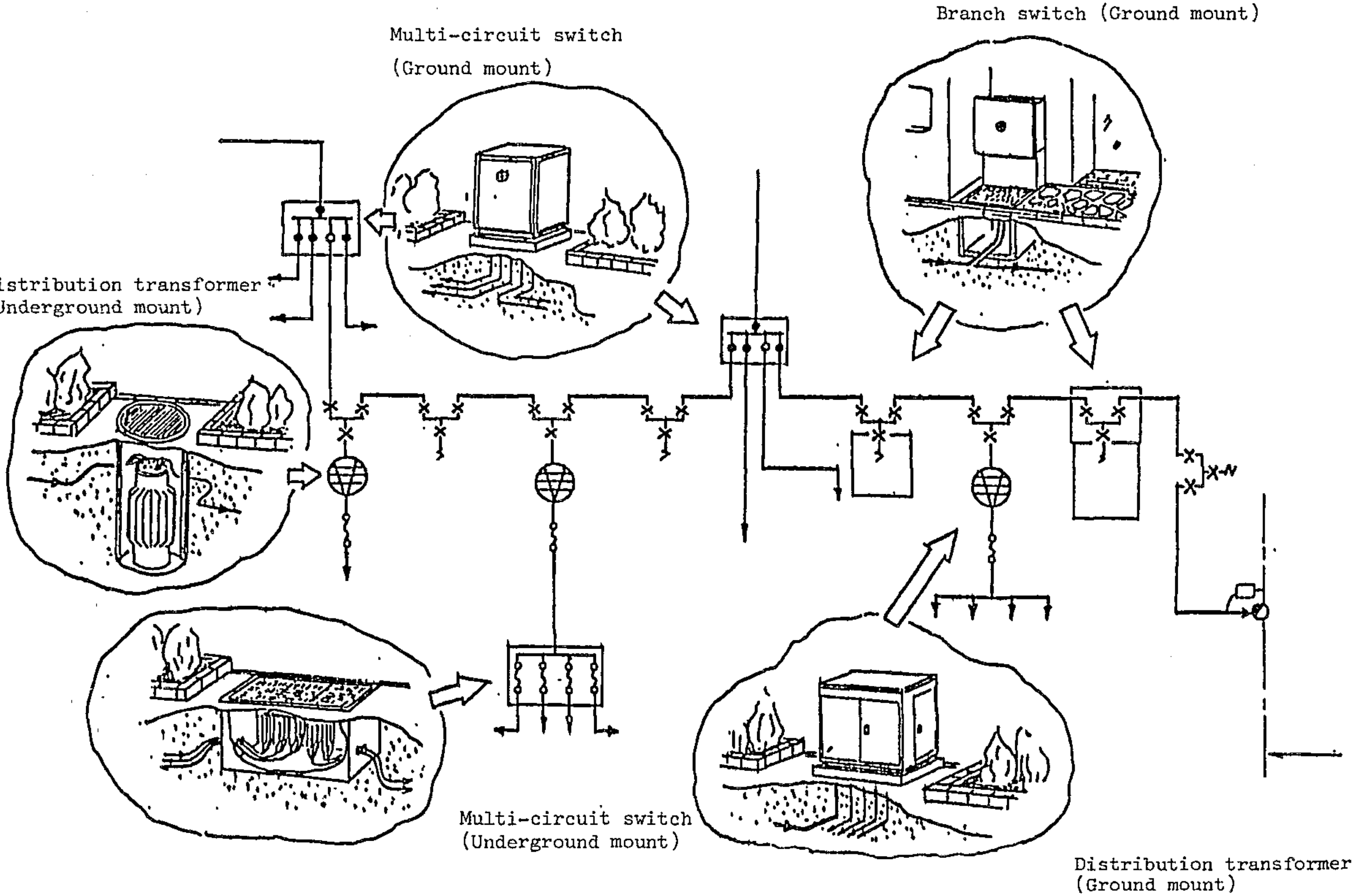
	D mm	H mm	L mm	D' mm	H' mm	L' mm	a mm	b mm	c mm	d mm	kg
1	1,800	1,800	460	2,160	2,160	600	180	180	180	140	3,060
2	1,800	1,800	600	2,160	2,160		180	180	180		2,120
3	1,800	1,800	850	2,160	2,180		200	180	180		2,930
4	1,500	1,800	460	1,780	2,080	600	140	140	140	140	2,370
5	1,500	1,800	600	1,780	2,080		140	140	140		1,510
6	1,500	1,800	900	1,780	2,140		200	140	140		2,370
7	1,300	1,800	500	1,580	2,080	640	140	140	140	140	2,250
8	1,300	1,800	1,000	1,580	2,140		200	140	140		2,480

Unit : mm

Combination

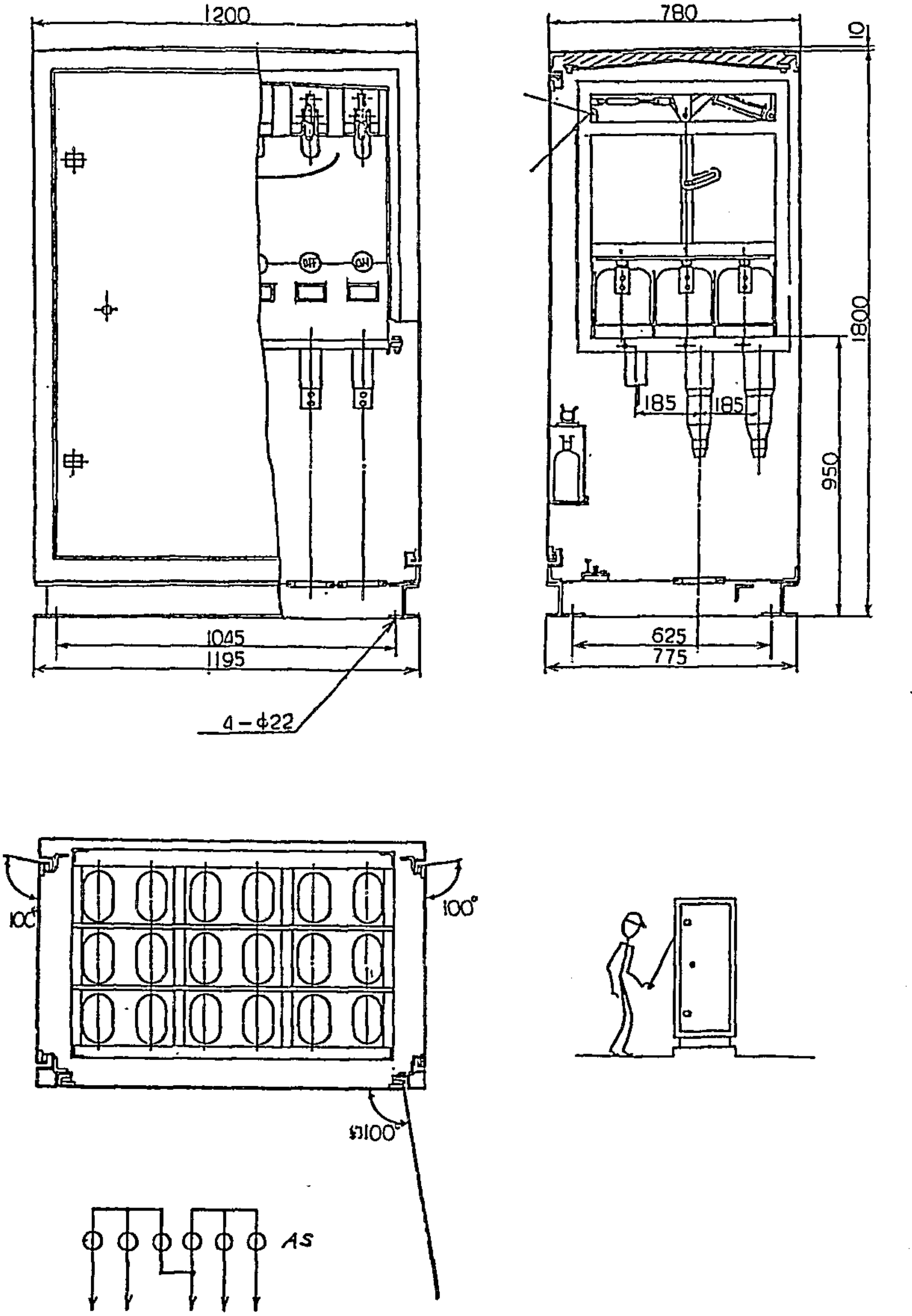


D - 15 Installation Example of Underground Distribution Equipment

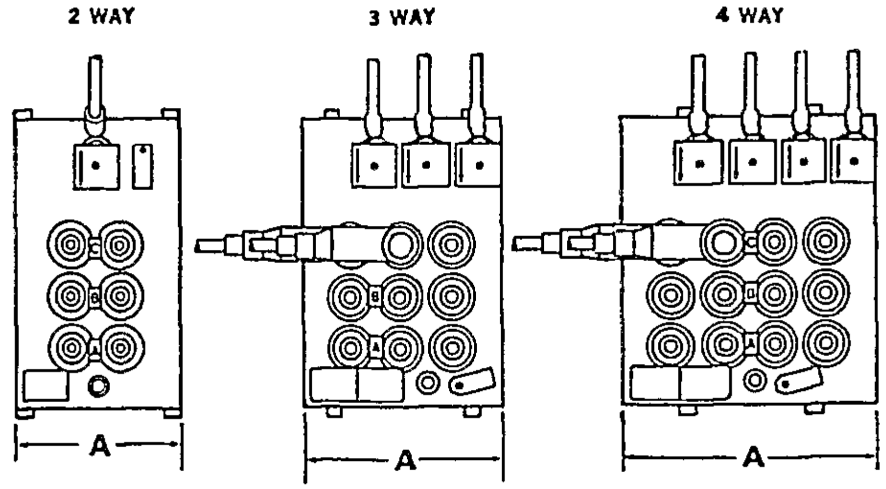


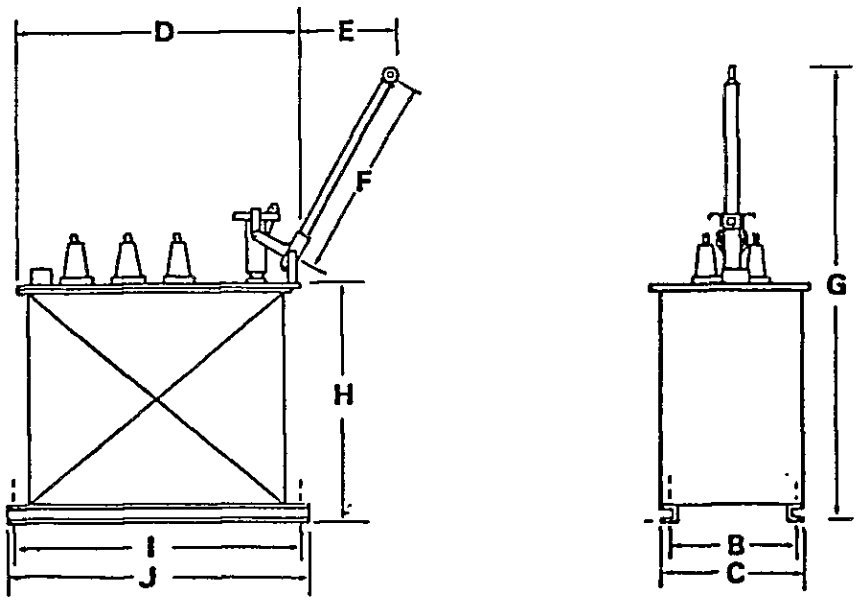
D - 16 Multi-circuit Switch for Underground Distribution Line
(Ground mount) . . . . . Air-breaking type

Unit : mm



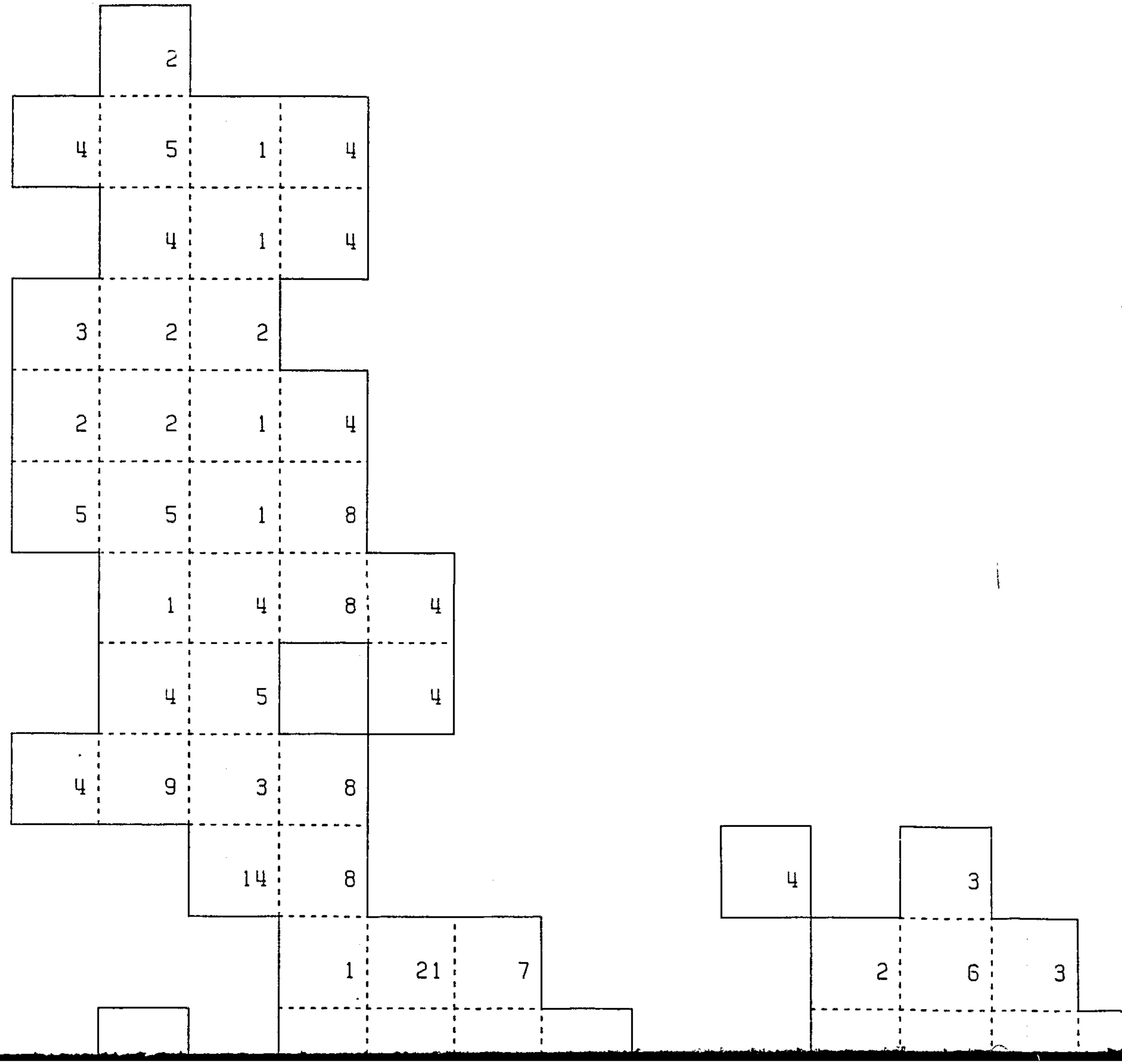
D - 17 Multi-circuit Switch for Underground Distribution Line
(Underground mount) . . . . . Gas-breaking type (Submergible)



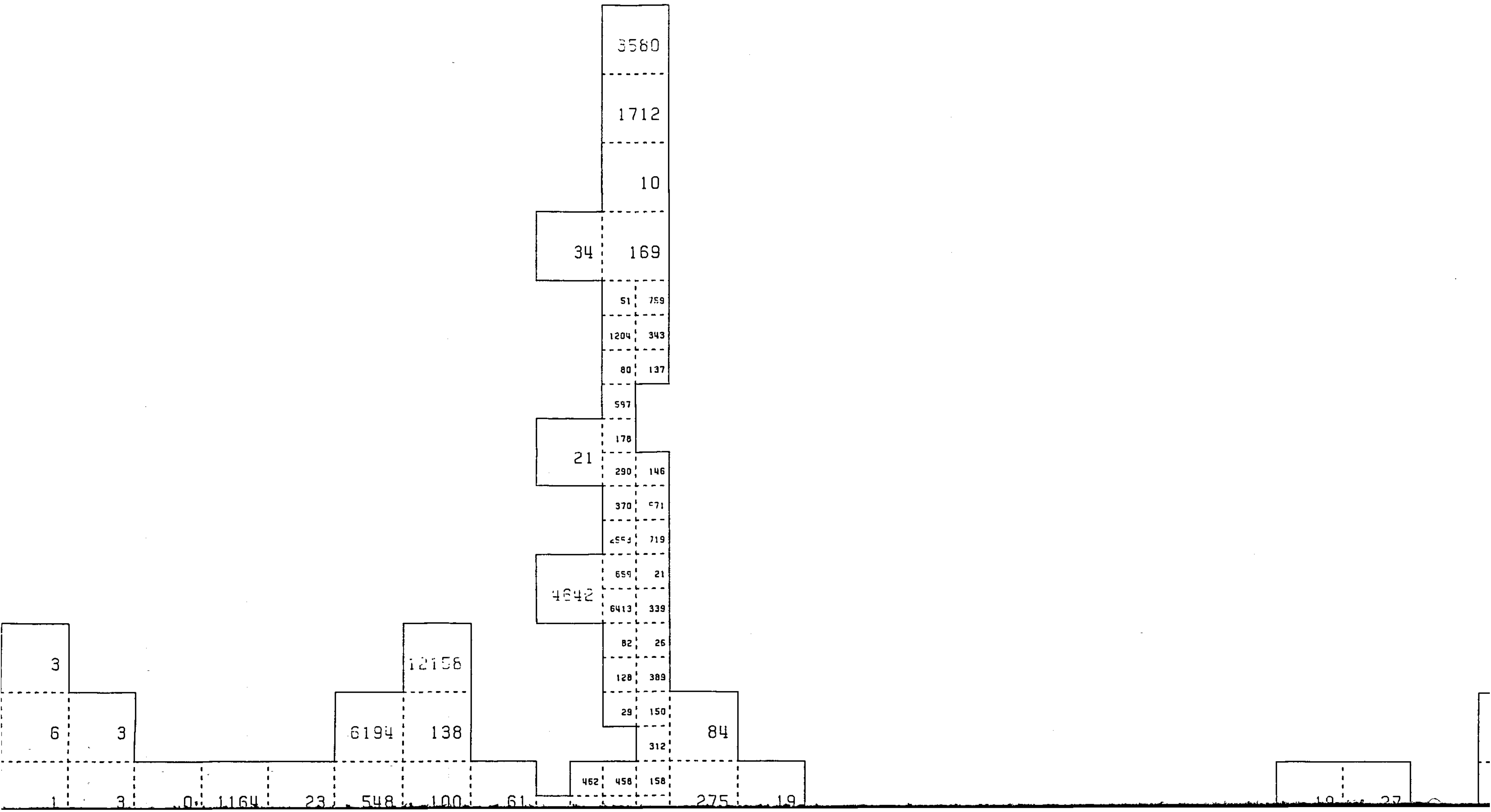


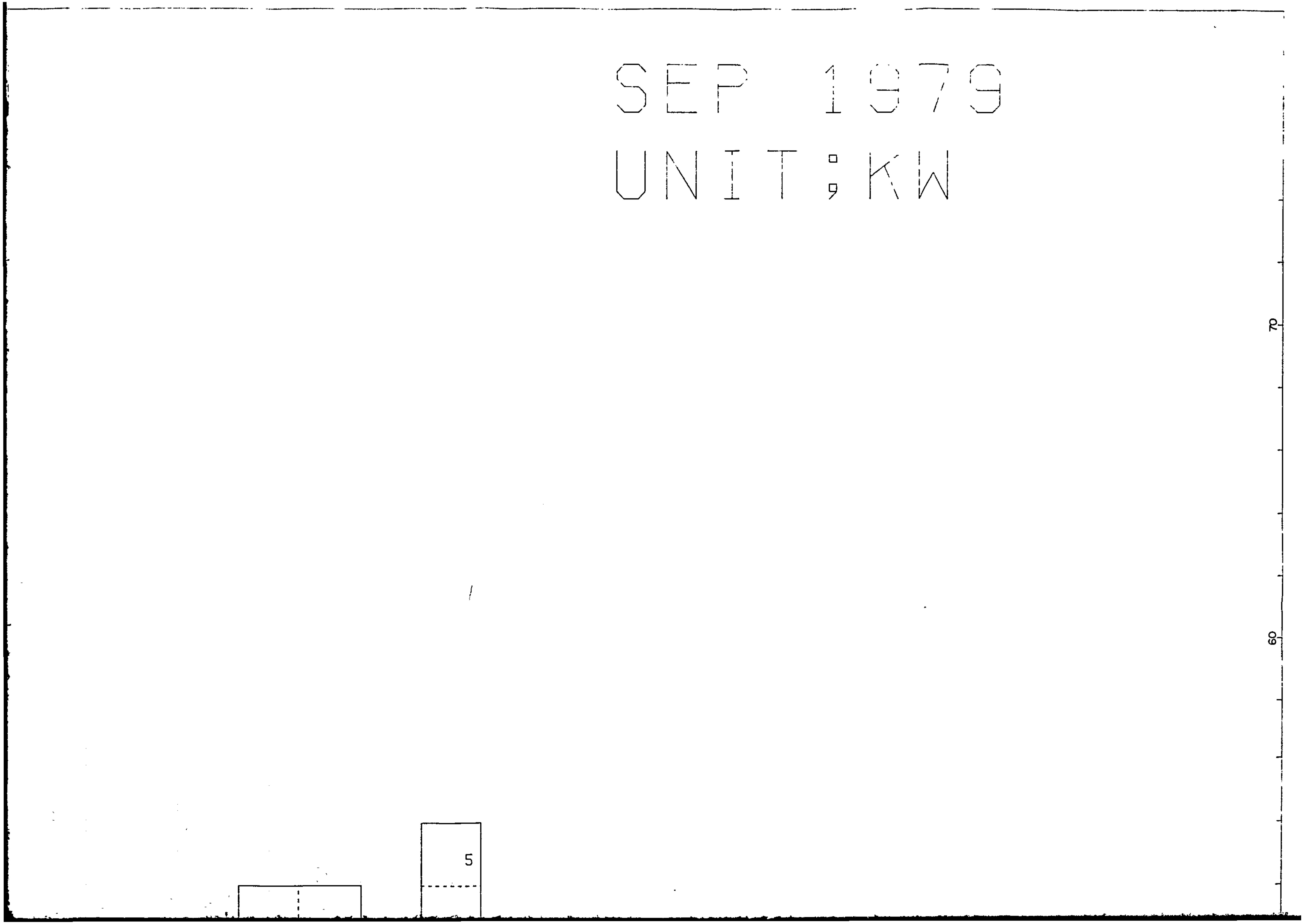
<table>
<tr><th>Dimensions</th><th>A</th><th>B</th><th>C</th><th>D</th><th>E</th><th>F</th><th>G</th><th>H</th><th>I</th><th>J</th><th>WEIGHT (Approx.)</th></tr>
<tr><td>TWO-WAY</td><td>420</td><td rowspan="3">330</td><td rowspan="3">360</td><td rowspan="3">710</td><td rowspan="3">310</td><td rowspan="3">610</td><td rowspan="3">1200</td><td rowspan="3">590</td><td rowspan="3">720</td><td rowspan="3">760</td><td>70 kg</td></tr>
<tr><td>THREE-WAY</td><td>510</td><td>140 〃</td></tr>
<tr><td>FOUR-WAY</td><td>635</td><td>180 〃</td></tr>
</table>

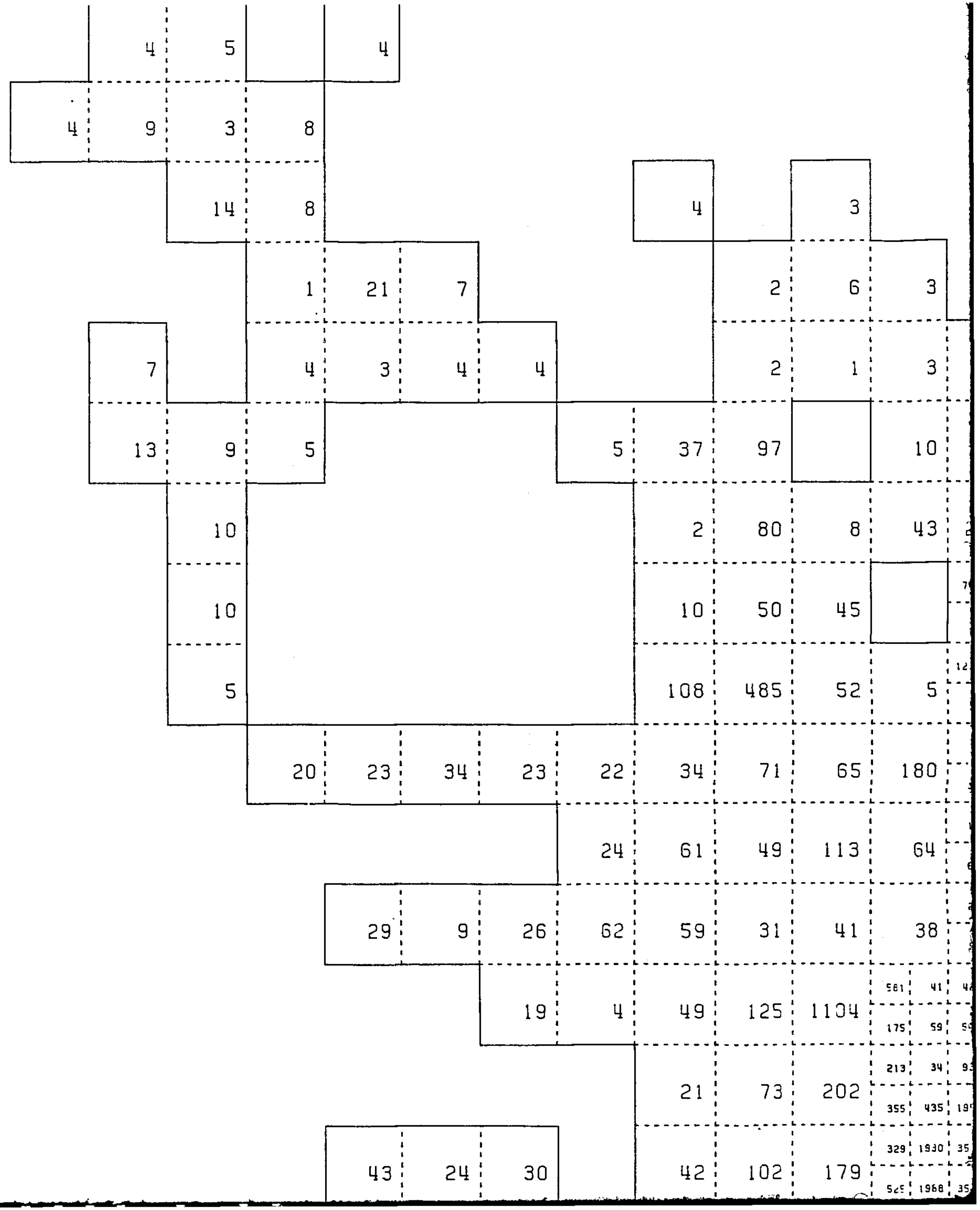
APPENDIX 16 LOAD DENSI

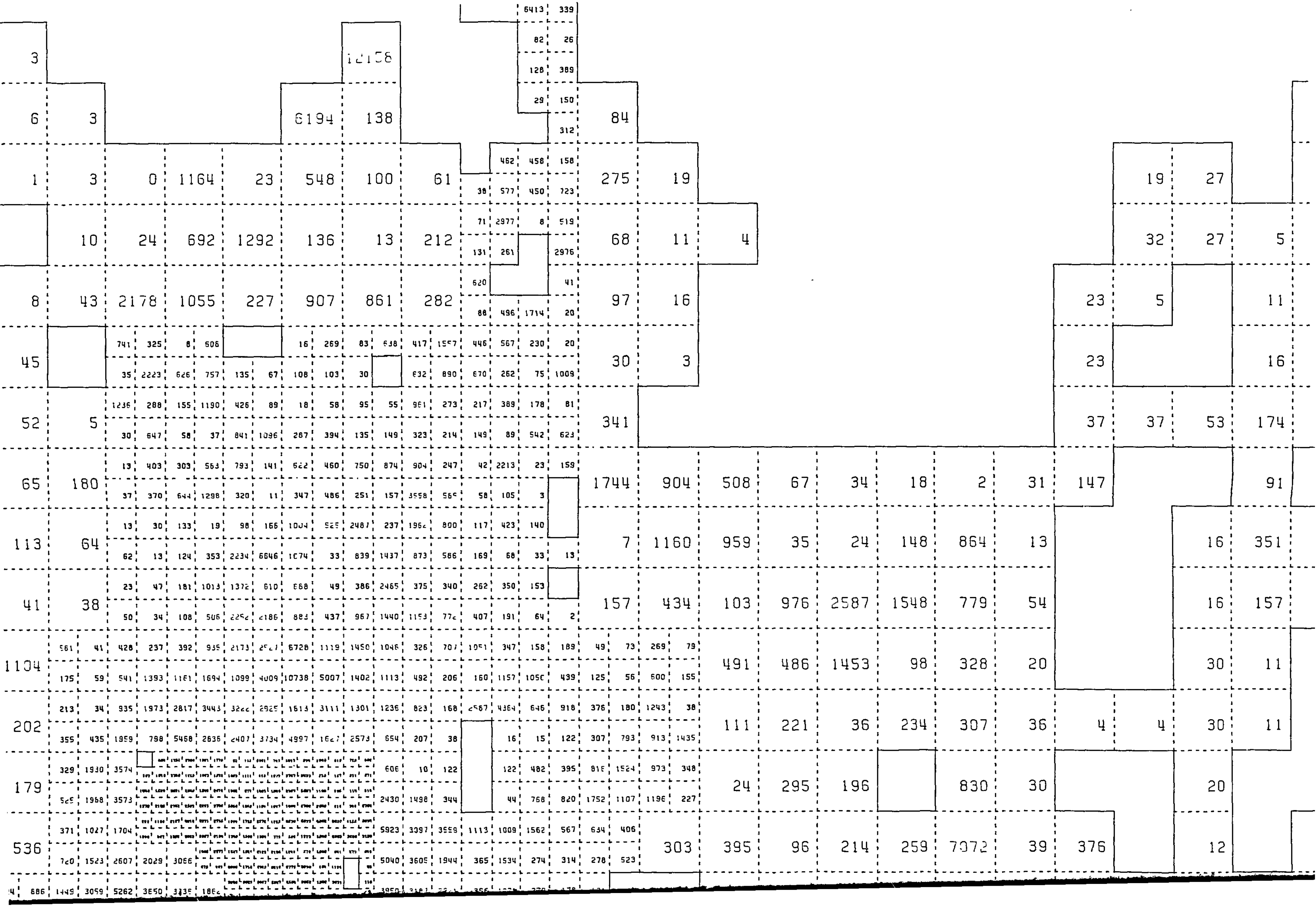


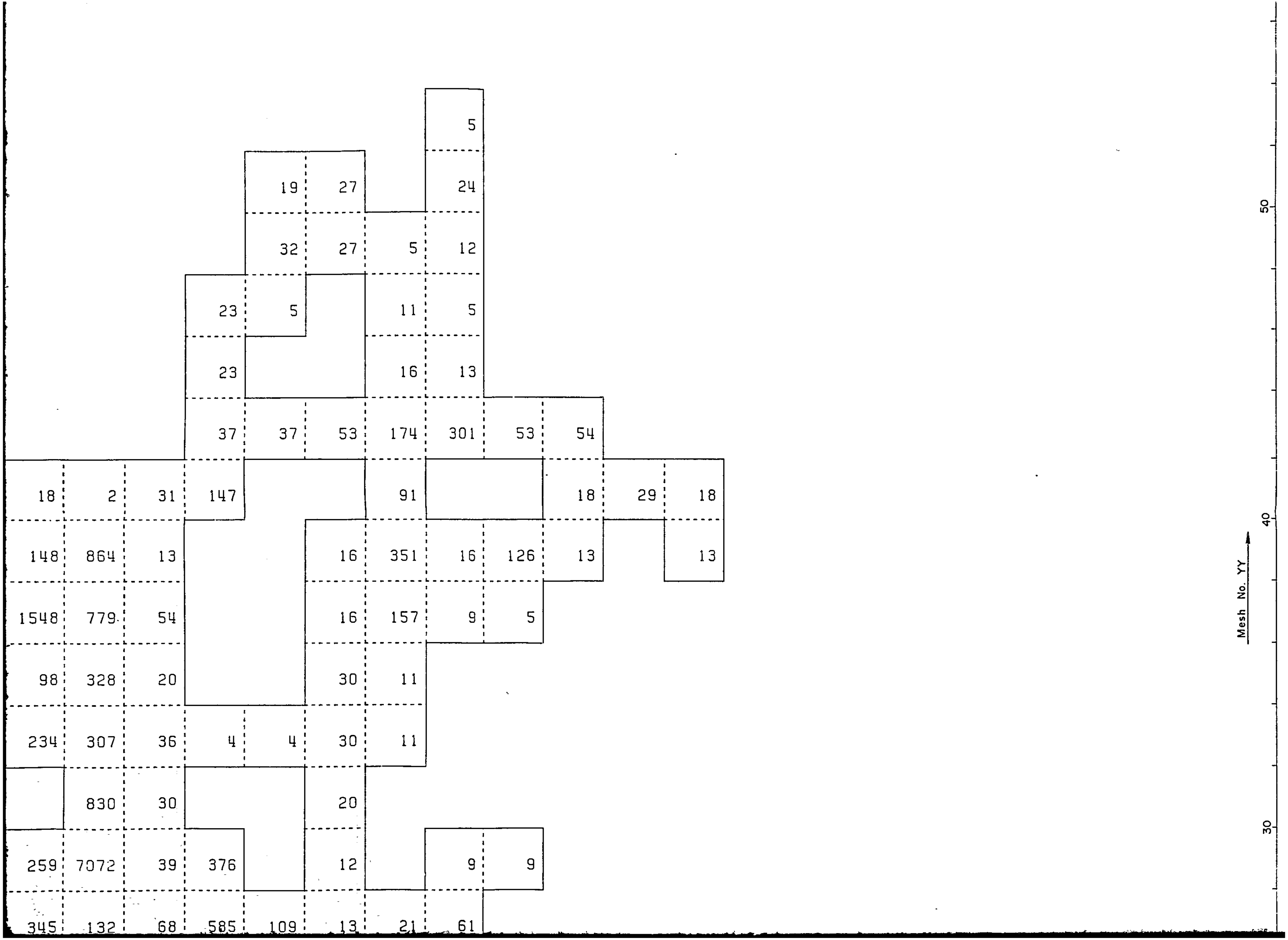
NSITY MAP OF MEA

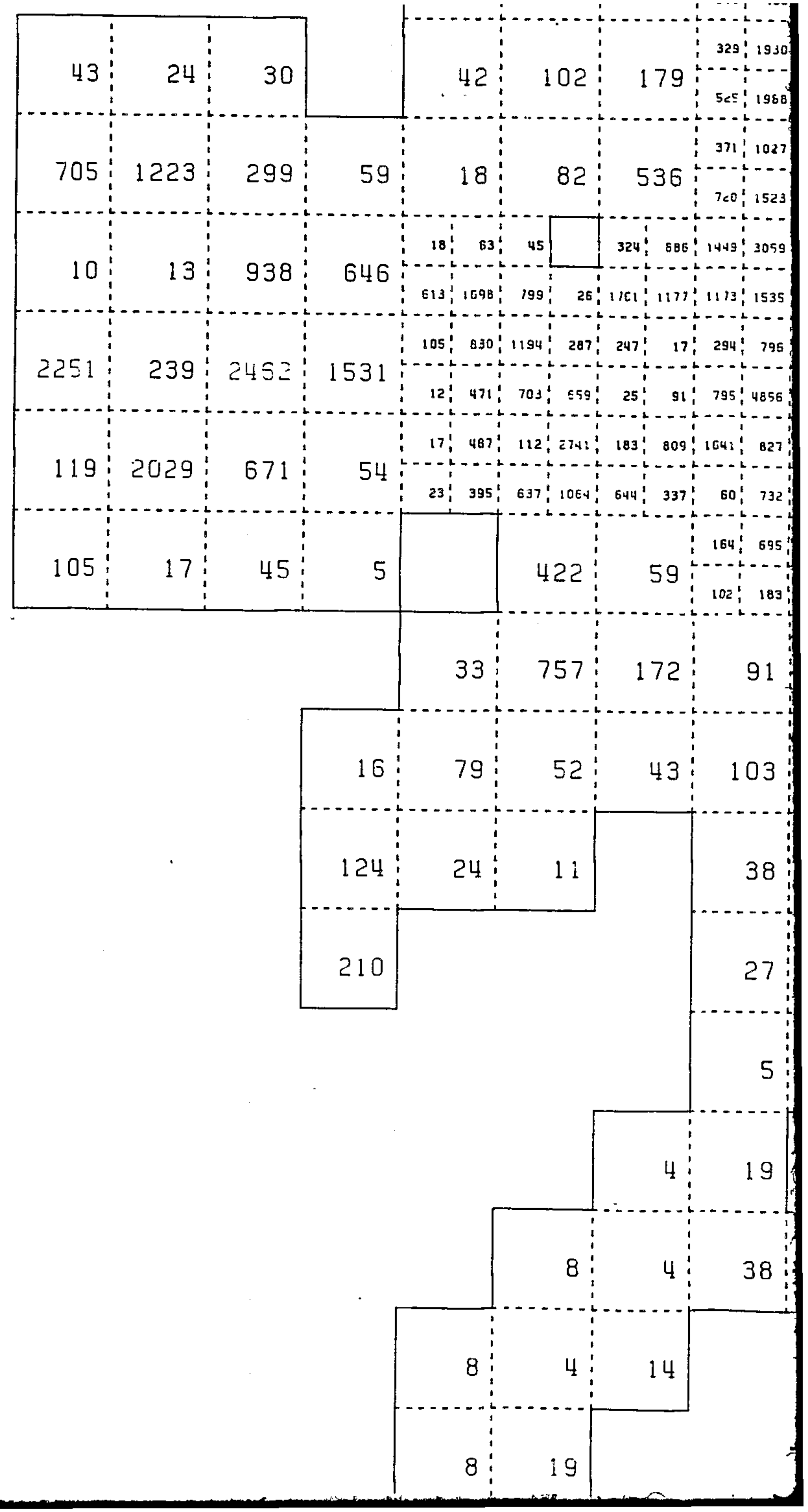



SEP 1979
UNIT:KW
70
60
5


4 5 4
4 9 3 8
14 8 4 3
1 21 7 2 6 3
7 4 3 4 4 2 1 3
13 9 5 5 37 97 10
10 2 80 8 43
10 10 50 45
5 108 485 52 5
20 23 34 23 22 34 71 65 180
24 61 49 113 64
29 9 26 62 59 31 41 38
19 4 49 125 1104 561 41 175 59
21 73 202 213 34 355 435
43 24 30 42 102 179 329 1930 525 1968

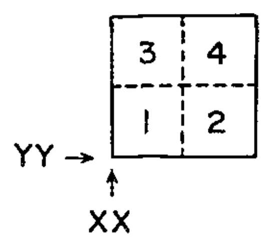



5
19 27 24
32 27 5 12
23 5 11 5
23 16 13
37 37 53 174 301 53 54
18 2 31 147 91 18 29 18
148 864 13 16 351 16 126 13 13
1548 779 54 16 157 9 5
98 328 20 30 11
234 307 36 4 4 30 11
830 30 20
259 7072 39 376 12 9 9
345 132 68 585 109 13 21 61
50
40
30
Mesh No. YY



(Note)

(1) 0.5 x 0.5 Km^2 Mesh No. XXYY − 1



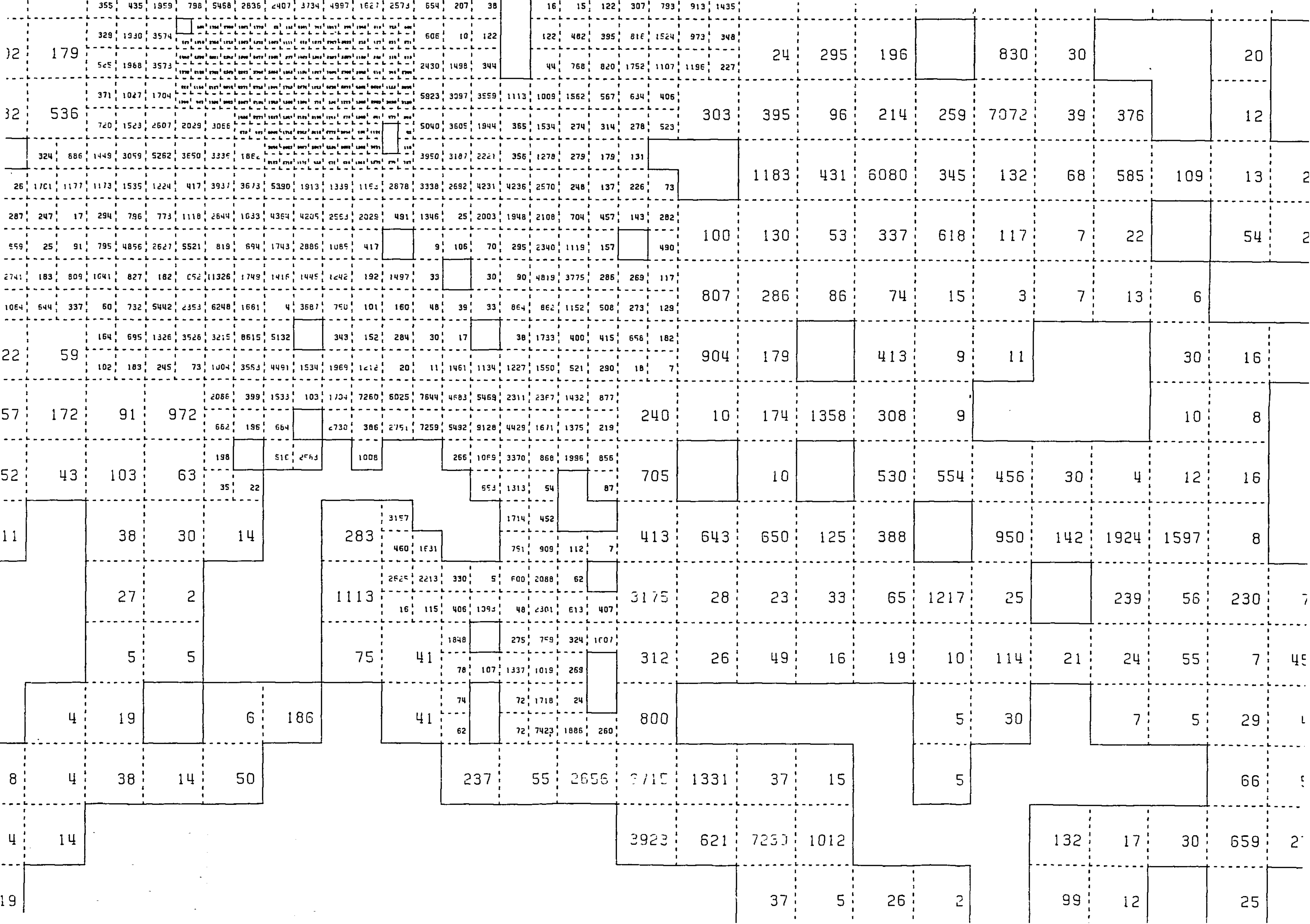
〃 − 2

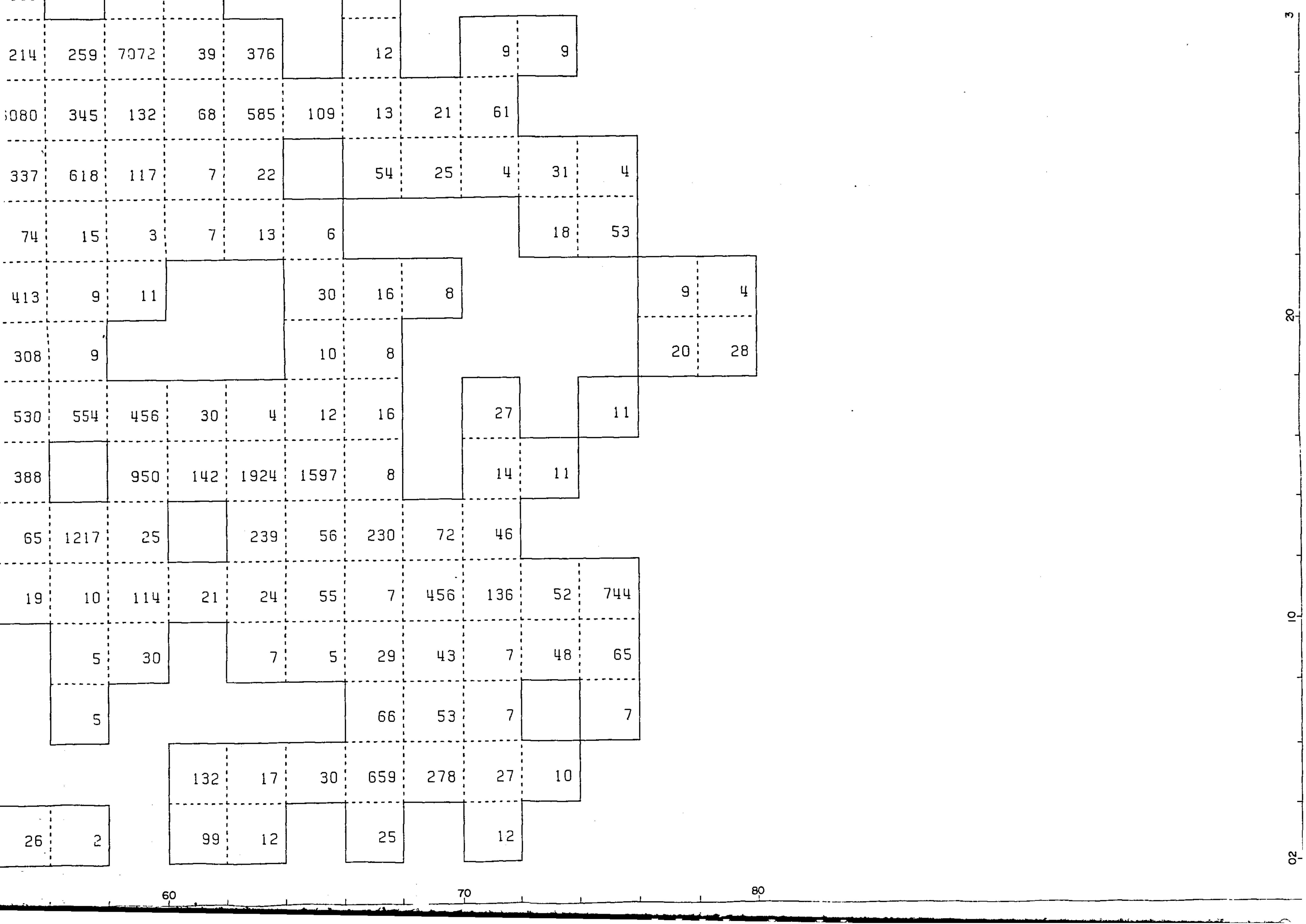
〃 − 3

〃 − 4

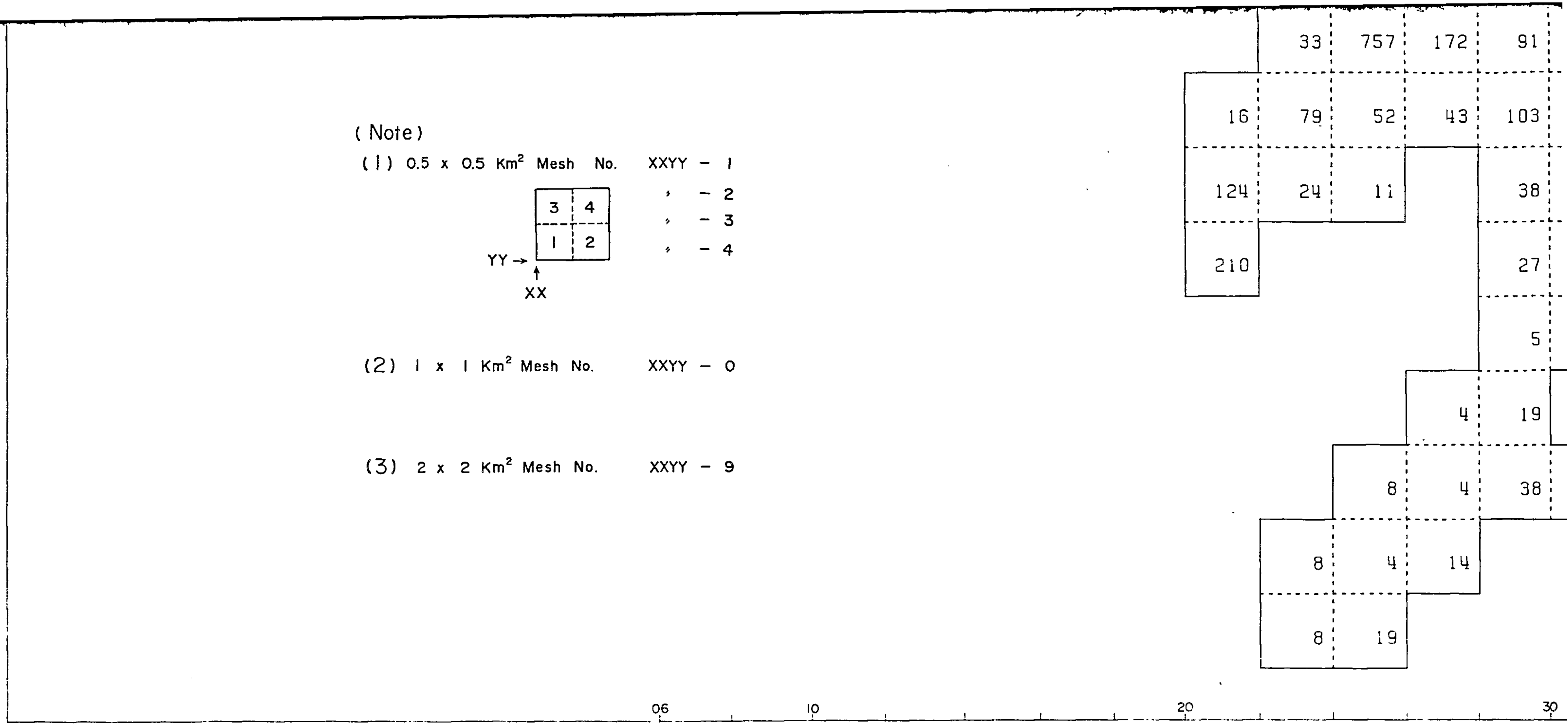
(2) 1 x 1 Km^2 Mesh No. XXYY − 0

(3) 2 x 2 Km^2 Mesh No. XXYY − 9

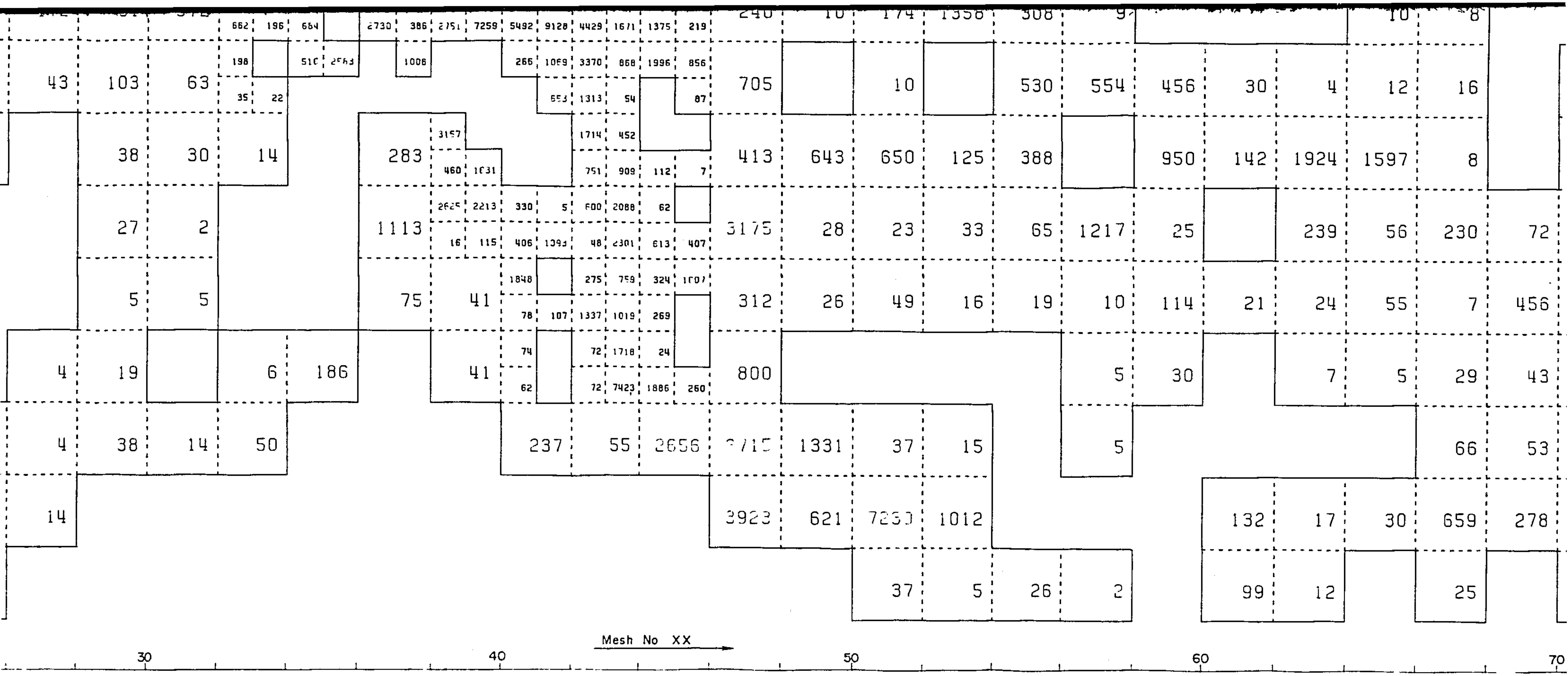

179 24 295 196 830 30 20
536 303 395 96 214 259 7072 39 376 12
1183 431 6080 345 132 68 585 109 13
100 130 53 337 618 117 7 22 54
807 286 86 74 15 3 7 13 6
59 904 179 413 9 11 30 16
172 91 972 240 10 174 1358 308 9 10 8
43 103 63 705 10 530 554 456 30 4 12 16
38 30 14 283 413 643 650 125 388 950 142 1924 1597 8
27 2 1113 3175 28 23 33 65 1217 25 239 56 230
5 5 75 41 312 26 49 16 19 10 114 21 24 55 7
4 19 6 186 41 800 5 30 7 5 29
4 38 14 50 237 55 2656 1331 37 15 5 66
14 3923 621 1012 132 17 30 659
37 5 26 2 99 12 25

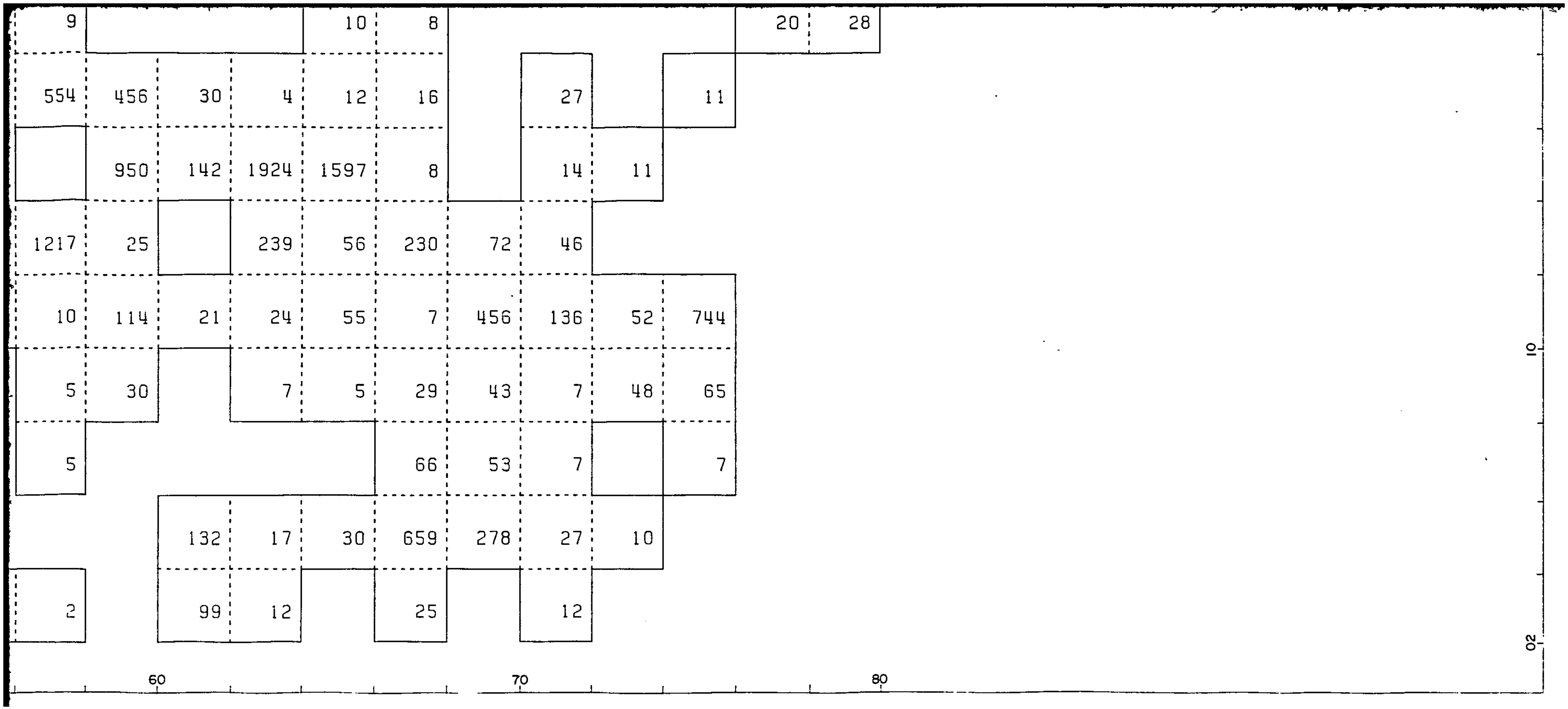


214 259 7072 39 376 12 9 9
080 345 132 68 585 109 13 21 61
337 618 117 7 22 54 25 4 31 4
74 15 3 7 13 6 18 53
413 9 11 30 16 8 9 4
308 9 10 8 20 28
530 554 456 30 4 12 16 27 11
388 950 142 1924 1597 8 14 11
65 1217 25 239 56 230 72 46
19 10 114 21 24 55 7 456 136 52 744
5 30 7 5 29 43 7 48 65
5 66 53 7 7
132 17 30 659 278 27 10
26 2 99 12 25 12
60
70
80
20
10



(Note)
(1) 0.5 x 0.5 Km² Mesh No. XXYY – 1
" – 2
" – 3
" – 4
3 4
1 2
YY →
XX
(2) 1 x 1 Km² Mesh No. XXYY – 0
(3) 2 x 2 Km² Mesh No. XXYY – 9
33
757
172
91
16
79
52
43
103
124
24
11
38
210
27
5
4
19
8
4
38
8
4
14
8
19
06
10
20
30


43 103 63 705 10 530 554 456 30 4 12 16
38 30 14 283 413 643 650 125 388 950 142 1924 1597 8
27 2 1113 3175 28 23 33 65 1217 25 239 56 230 72
5 5 75 41 312 26 49 16 19 10 114 21 24 55 7 456
4 19 6 186 41 800 5 30 7 5 29 43
4 38 14 50 237 55 2656 1331 37 15 5 66 53
14 3923 621 1012 132 17 30 659 278
37 5 26 2 99 12 25
Mesh No XX
30
40
50
60
70


9
10
8
20
28
554
456
30
4
12
16
27
11
950
142
1924
1597
8
14
11
1217
25
239
56
230
72
46
10
114
21
24
55
7
456
136
52
744
5
30
7
5
29
43
7
48
65
5
66
53
7
7
132
17
30
659
278
27
10
2
99
12
25
12
60
70
80
10
20

APPENDIX 17 LOAD DENSITY MAP OF MEA (A AREA) SEP 1979

UNIT;KW

	894	1758	2320	1651	1779	52	185	2881	743	1417	934	1348	810	729	802
383	1816	3750	1229	1563	1932	1893	1111	669	1073	3747	2433	539	157	931	971
1448	1526	3031	2549	1946	2078	1382	977	1493	1928	2397	5807	1109	205	114	218
1379	2128	2762	2503	2263	3746	5058	1959	1104	1027	1404	2700	2849	616	346	2764
222	1188	2127	4614	4371	2735	1084	1729	2572	1229	6530	5933	4852	2620	1155	2034
1060	462	1392	2023	5867	6104	1349	1560	1864	776	596	1223	1939	2563	3220	3128
				1485	2377	1627	1925	2123	2166	1248	570	1980	941	473	948
				679	463	2080	1712	2329	9212	6775	2030	604	1126		43
						3246	8625	6857	5547	4584	2052	1962	3631		118
						2123	5710	1176	459	575	626	1058	1573	974	787

Mesh No. XX: 31, 32, 33, 34, 35, 36, 37, 38, 39

Mesh No. YY: 27, 28, 29, 30, 31, 32

JICA