6-4 RECOMMENDED SAMPLING SCHEDULE, PLACES AND METHOD

6-4-1 Sampling Schedule

Coal gasification facilities prepared by JICA have been installed at Serpong in FY 1986. Mechanical and process test run using bulk coal samples taken in the Northwest Banko area in FY 1986 have also been carried out in the last quarter of the same year.

Regular coal gasification tests using different coal samples are planned to be carried out in FY 1987 divided into two stages. The first stage of the test will be done at the beginning of the fiscal year using coal samples taken in FY 1986, which are stored at Serpong.

The Second stage of the test is planned to be carried out in the second half of FY 1987. Coal samples for this test shall be taken in the same year in order to avoid deterioration of coal quality during storage.

Considering rainy season in the South Sumatra which start from September in normal year, coal sampling work for taking samples to be used at the second stage has to be completed by the end of August, 1987 if possible.

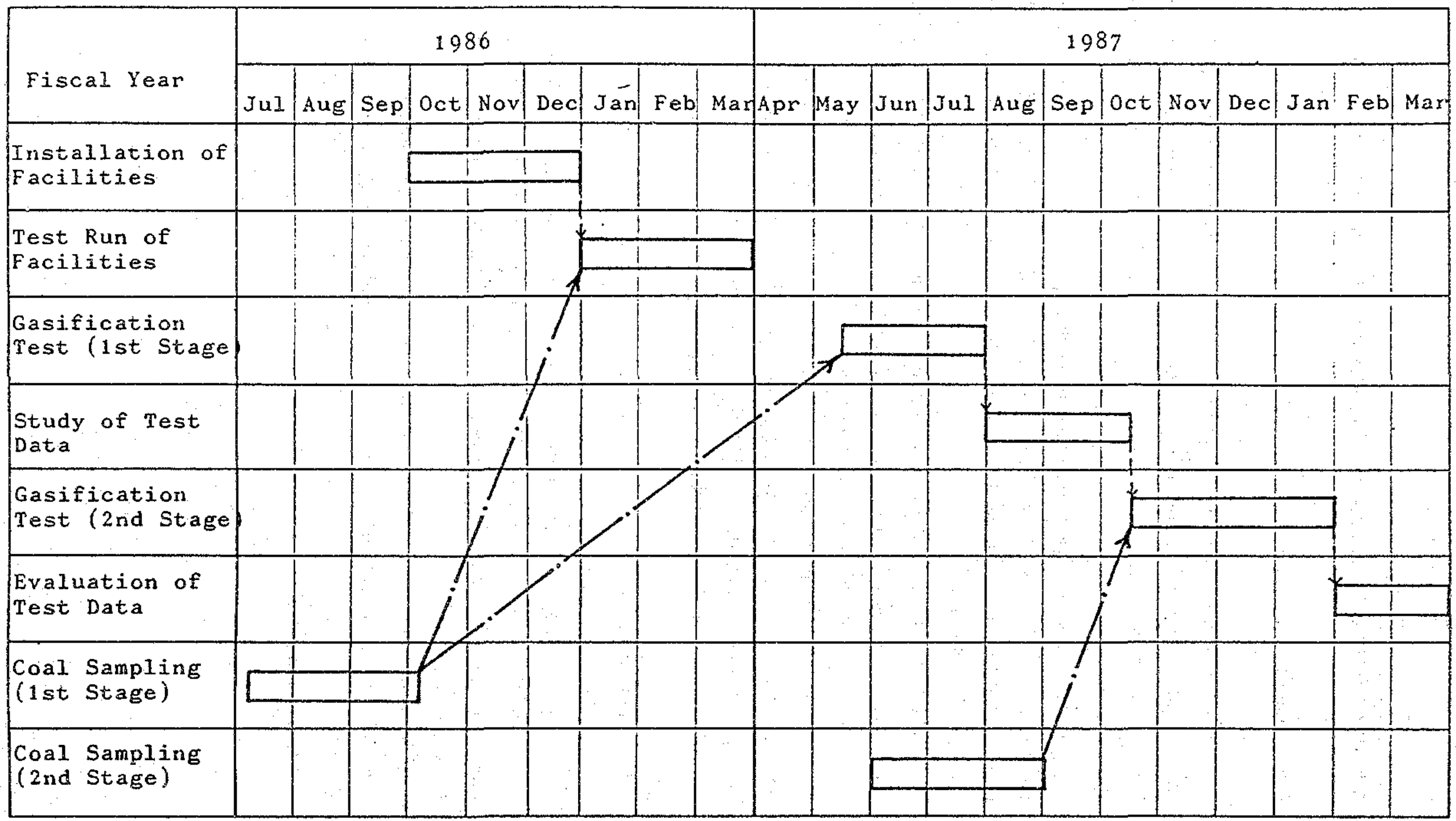
Fig. 6-4-1 shows timetable of coal gasification tests and sampling.

6-4-2 Sampling Places

Coal samples for the regular gasification tests in the first stage were taken in the Northwest Banko area in FY 1986, because coal seams in this area occur in most appropriate conditions and have been investigated in detail among the areas to be studied.

Considering results of geological survey and reconnaissance carried out in the remaining areas so far, no suitable sites for coal sampling have been found in the West Banko, East and West Suban Jeriji areas. No access road is found in the West Central Banko area.

Fig. 6-4-1 Timetable of Coal Gasification Test and Sampling



On the contrary, coal seams are distributed widely and exposed fairly well in several places near the existing road in the Central Banko and North Suban Jeriji areas as aforementioned. Consequently, it is recommended that coal samples for the gasification tests in the second stage have to be taken in these two areas in FY 1987.

However, the existing access roads from the paved road to the proposed sampling sites will be in the worst conditon when it rains. Therefore, seveal parts of the road have to be repaired before and during the sampling work to maintain the road in good condition for transportation.

(1) Central Banko Area

Coal samples to be taken in the area are; A1 and A2 (Mangus) Seams, B1 and B2 (Suban) Seams, and C (Petai) Seam.

The proposed sites for the sampling which are the top favorite among several places investigated in FY 1986 are selected as follows;

A1 Seam : Eastern part of the area
A2 Seam : Western part of the area
B1 Seam : Central part (Test Pit 1) of the area
B2 Seam : Western part of the area
C Seam : Eastern part of the area

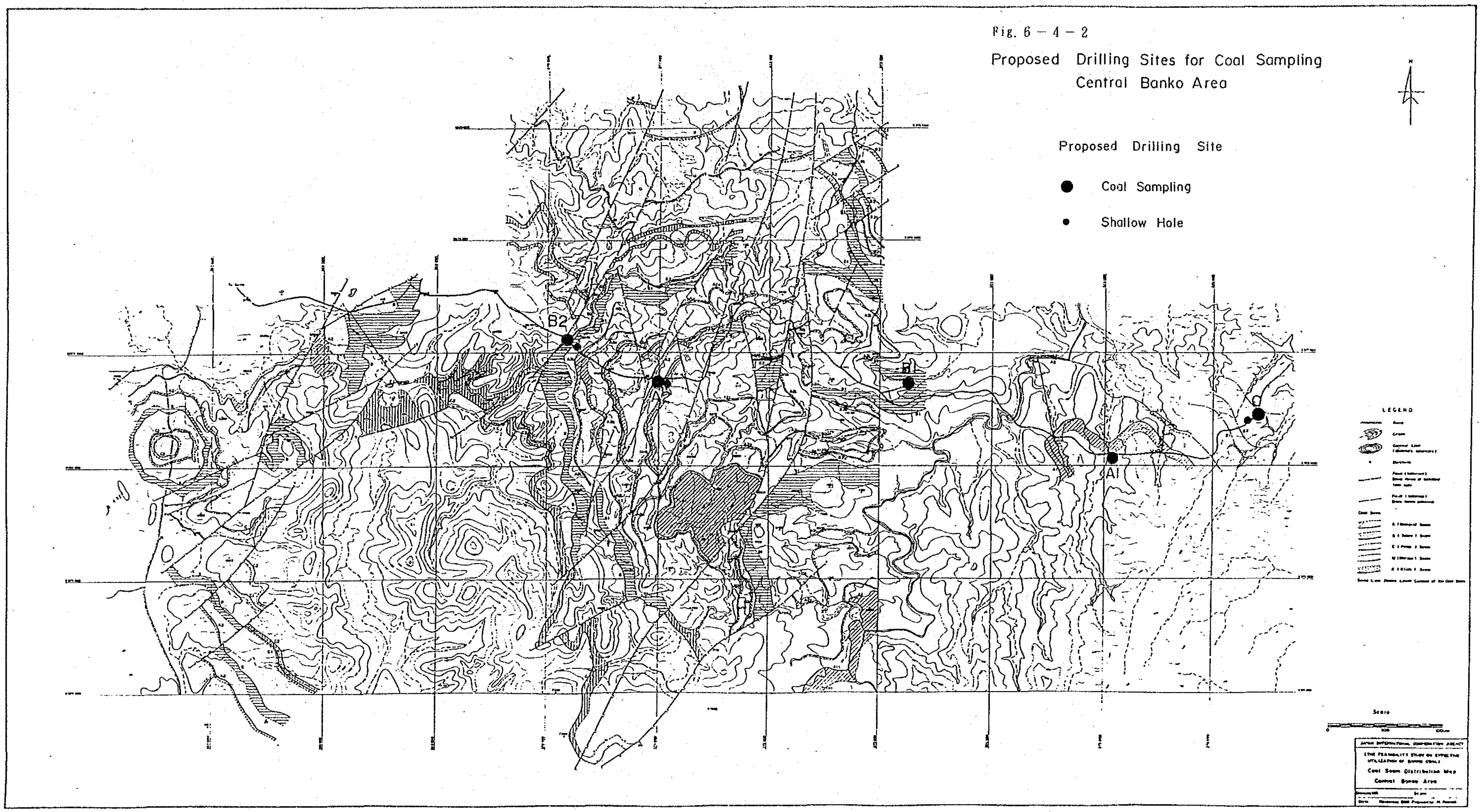
Thickness of overburden at the proposed sites for A1 and B1 seams was confirmed during geological survey in this year. Thickness of overburden at the proposed sites for A2 and B2 seams has to be confirmed by shallow-hole drilling prior to selecting favorite spots for them.

Sub-outcrop of C seam in the eastern part of the area has also to be confirmed by shallow hole drilling in the beginning of the fieldwork in FY 1987.

Proposed drilling sites for coal sampling in the area are shown in Fig. 6-4-2.

Fig. 6 — 4 — 2

Proposed Drilling Sites for Coal Sampling
Central Banko Area



(2) North Suban Jeriji Area

Coal samples to be taken in this area are Jelawatan, Enim I and Enim II Seams.

The proposed sites for the sampling are selected in the western part of the area on the basis of reconnaissance done in this year. Fig. 6-4-3 shows proposed drilling sites in the area.

Thickness of overburden at the proposed sites for Jelawatan, Enim I and Enim II Seams has been already confirmed by shallow-hole drilling in this year.

6-4-3 Sampling Method

Coal samples to be taken in FY 1987 will be as follows;

i) Central Banko Area : Total 1,000 kilograms from five different coal seams

ii) North Suban Jeriji Area : Total 1,000 kilograms from three different coal seams

The samples will be taken using drilling machine equipped with large diameter core barrel (O.D. 131 mm, I.D. 101mm) as same as that used in this year.

Table 6-4-1 shows details of the core drilling plan for the sampling.

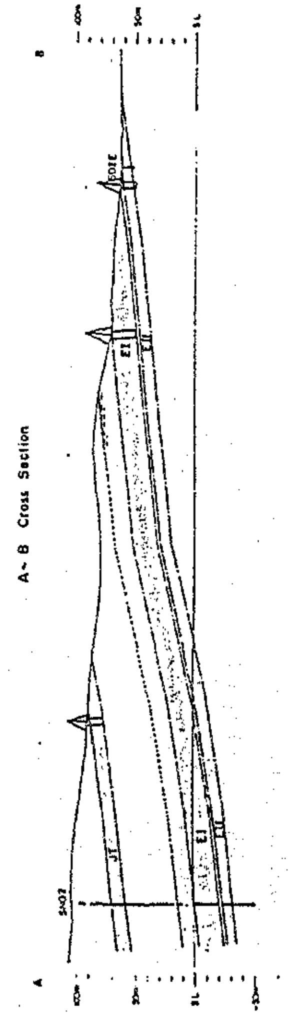
Two sets of drilling machine are required for the sampling work in FY 1987 as the work is carried out in two areas apart each other, the Central Banko and North Suban Jeriji areas.

Actual working days required for taking above-mentioned coal samples are estimated on the basis of the following conditions;

Working system	: 8 hrs/shift, 2 shifts/day
Drilling performance	: 4 m/shift
Removing from site to site	: 2 days
Shifting borehole at the site	: 1 shift
Efficiency of machine	: 85%
Safety factor	: 90%

Fig. 6 - 4 - 3

Proposed Drilling Sites for Coal Sampling
North Suban Jerjij Area



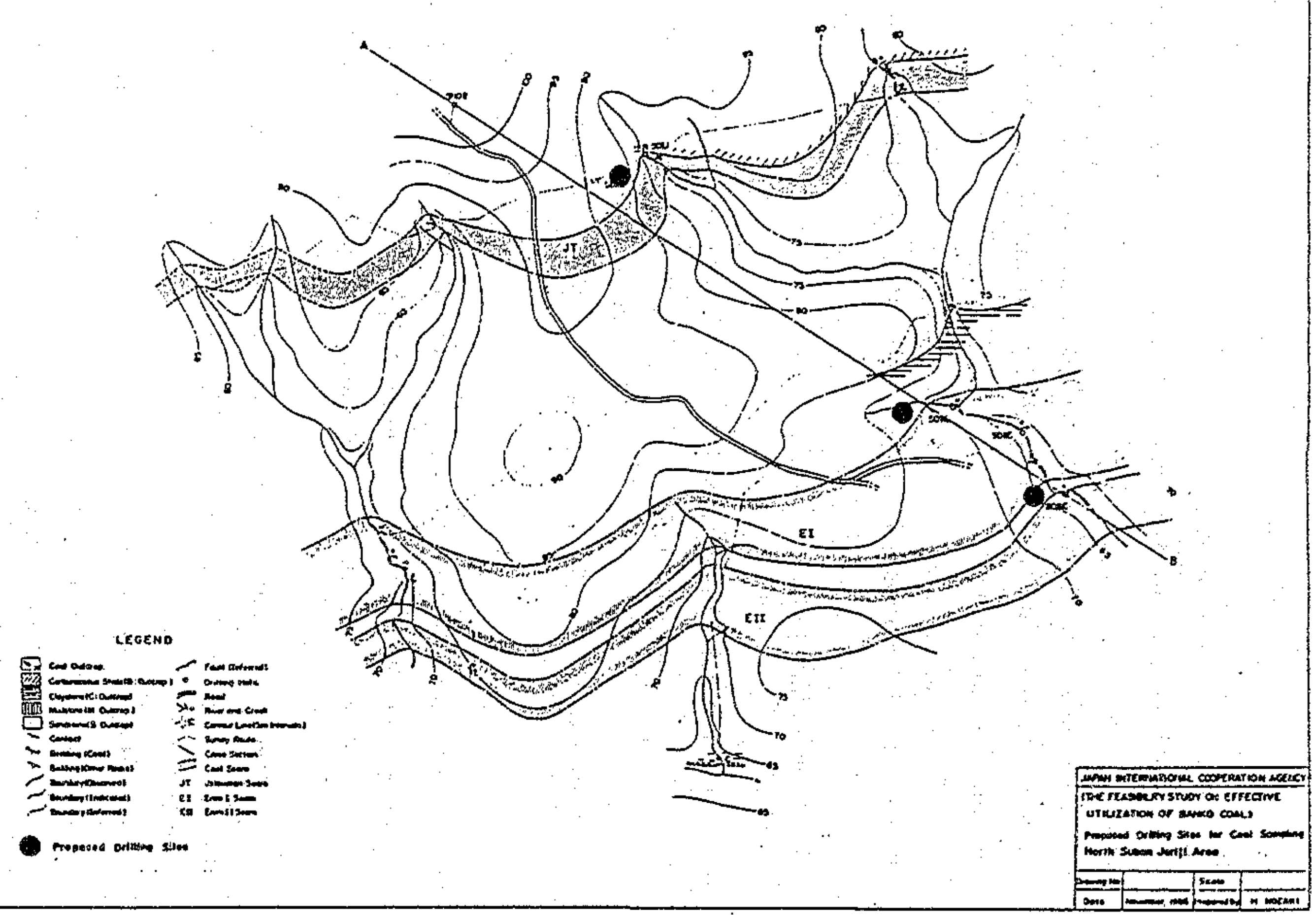


Table 6-4-1 Core Drilling Plan for Sampling

Area	Coal Seam	Drilling Length per Hole			Weight of Coal		Required Number of Hole	Total Drilling Length		
		Overburden (m)	Coal (m)	Total (m)	Hole (kg)	Total (kg)		Overburden (m)	Coal (m)	Total (m)
Cetral Banko	A1 (Mangus)	5	15	20	109.2	218	2	10	30	40
	A2 (")	"	5	10	36.4	218	6	30	30	60
	B1 (Suban)	"	15	20	109.2	218	2	10	30	40
	B2 (")	"	5	10	36.4	218	6	30	30	60
	C (Petai)	"	15	20	109.2	218	2	10	30	40
	Sub Total	-	-	-	-	1,090	18	90	150	240
North Suban Jeriji	Jelawatan	5	10	15	72.8	291	4	20	40	60
	Enim I	"	20	25	145.6	436	3	15	60	75
	Enim II	"	10	15	72.8	291	4	20	40	60
	Sub Total	-	-	-	-	1,018	11	55	140	195
Total		-	-	-	-	2,108	29	145	290	435

Remarks : 1. Core diameter = 101 mm
2. Specific gravity of coal = 1.3
3. Weight of coal per 1 m drilled = 10.4 kg
4. Core recovery = 70 %

i) Central Banko area : Total 55 days

i) Central Banko area	:	Total 55 days
Drilling	:	40 days
Shifting	:	7 days
Removing site	:	8 days

ii) North Suban Jeriji area	:	Total 40 days
Drilling	:	32 days
Shifting	:	4 days
Removing site	:	4 days

Taking field experience in this year into consideration, fieldwork for coal sampling in FY 1987 will be around two months.

Besides drilling work, road repair and maintenance are very important to perform effective and smooth sampling work in the next year. Distance of unpaved road to be maintained in the Central Banko area is around 12 kilometers and that in the North Suban Jeriji area is around 10 kilometers. Road repair at the beginning and end of the work will require each 3 days for the both areas. Road maintenance for 2 days per time will require one time for the North Suban Jeriji area and two times for the Central Banko area during the work. Consequently, bulldozer has to be rent for total about 20 days.

Additional parts and accessories for large diameter coring listed in Table 6-4-2 are required for the work in FY 1987, because a part of those prepared by JICA in this year have been worn away during the work executed, besides two sets of the drilling machine is going to be used.

Table 6-4-3 shows required number of staffs, laborers, machines and their accessories which shall be provided by the Indonesian counterpart for the sampling work in FY 1987.

Table 6-4-2 Required Accessories and Parts for Large Diameter Core Drilling

Article	Specification	Quantity
Double tube core barrels	SK-3, OD.131 mm, ID.101mm	1 Pc
Metal bits	SK-3, 131 mm	7 Pcs
Core lifters	SK-3, 131 mm	4 Pcs
Core lifter cases	SK-3, 131 mm	4 Pcs
Outer tube	SK-3, 131 mm	1 Pc
Inner tube (upper)	SK-3, 131 mm	1 Pc
Inner tube (lower)	SK-3, 131 mm	1 Pc
Outer extension tube	SK-3, 131 mm	1 Pc
Inner extension tube	SK-3, 131 mm	1 Pc
Casing metal shoes	142 mm	4 Pcs
F.J Casing pipes	JIS, 142 mm, 3 M	3 Pcs
Casing head	142 mm	1 Pc
Wing bit	146 mm, NW-C	1 Pc
Metal reamers	SK-3, 131 mm	4 Pcs

Table 6-4-3 Required Number of Staffs, Laborers, Machines and Accessories

	Item	Number	Term	Remarks
Staff and laborers	Resident manager	1	2 months	
	Well site geologist	2	- do. -	
	Logistic	1	- do. -	
	Mechanic	2	- do. -	
	Surveyor	1	- do. -	
	Drillers	5	- do. -	1 for shallow hole drilling
	Local laborers	30	- do. -	
Machine and accessories	Core drilling machine	2 set		Spindle I.D.: more than 93 mm engine output: 30 ps including standard accessories with following machines 1) drilling mast (tripod, effective height 5.5 m, load capacity 5 tons, head pully diameter 250 mm) 1 unit 2) mud pump (capacity: more than 87 l/min at 20 kg/cm^2, with standard accessories and 10-15 ps engine) 3) water supply pump (with 5-7 ps engine and stardard accessories) 4) mud mixer (capacity 100-200 l, with 5-7 ps engine) 5) lowering/lifting tools (hoisting wire rope with safety clevis tongs and wrenched)
	Shallow hole drilling machine	1 set		Koken SB-3C with water pump and accessories
Supplies	Materials and tools	1 set		Used drums:stakes;fuel oil;lubricant;grease;hand tools;plastic sacks etc.
Rent	4 wheel drive car	2-3 units		
	Bulldozer	20 days		

7. PRELIMINARY EVALUATION OF ECONOMIC FEASIBILITY

7-1 COAL MINING COST

7-1-1 Preface

Preliminary estimation of coal mining cost was carried out and reported in the "Interim Report for the Feasibility Study on Effective Utilization of Banko Coal in the Republic of Indonesia" published in May, 1985, by the hands of the Japan International Cooperation Agency. (See page 174-208 of the above mentioned report, hereinafter referred to as the 1985 JICA report)

However, some of mining parameters such as stripping ratio, wheathering loss, geological loss and mining loss were roughly set forth to estimate coal mining cost, based on general information obtained in 1984 (the First stage of the Study), in case of the 1985 JICA report.

Some of such important mining parameters were made clearer by the survey work and core drilling carried out in 1985 and 1986 and the survey results carried out by the Ministry of Mines and Energy, the Directorate General of Mines, the Directorate of Coal (hereinafter referred to as DOC) also played an important role to make clear the matter.

Although coal mining cost shall be investigated in detail, as one part of the feasibility study on effective utilization of Banko coal which will be carried out in the first half of 1988 fiscal year, coal mining cost was reviewed conceptually in the report, taking the latest technical data and circumstances sharply changed, into account and reinvestigating some parameters used in the 1985 JICA report.

7-1-2 Main parameters to estimate coal mining cost

(1) Coal reserves

A systematic investigation of the Banko coal field was carried out from June 1975 to August 1977 by Shell Mijnbouw Maatschanppij BV (hereinafter referred to as Shell).

Thereafter DOC, consulted with Kinhill-Otto Gold Joint Venture (hereinafter referred to as K-OG) carried out an additional exploration programme.

Survey report prepared by Shell and their core drilling data including coal analysis data were presented the JICA survey team through the good offices of Agency for the Assessment and Application of Technology (Badan Pengakajian Dan Penerapan, Hereinafter referred to as BPPT) and DOC.

The above-mentioned data had been reviewed and utilized to prepare "the Interim Report II on the Feasibility Study on effective Utilization of Banko coal in the Republic of Indonesia (FY 1985)" published by JICA in May 1986 (hereinafter referred to as the 1986 JICA report).

Important points of the above-mentioned data were summarized in the 1986 JICA report (See page 103-106 and 114-123).

The essence of theme was recorded anew here. (See Table 7-1-1)

Coal analyses results carried out by the hands of Mineral Technology Development Center (Direktorat Jenderal Restambangan Umun, Pusat Pengembangan Teknologi Mineral, hereinafter referred to as PPTM) and of Indonesian counterparts of the Effective Utilization of Banko Coal project are almost the same level as ones carried out by Shell, though they vary widely and moisture is a little bit low (25%), compared with results obtained by Shell and on the almost same level with results done by K-OG.

35 effective shallow holes (hole length is between 11.5M and 20.0M) and one deep hole from the surface to the bottom of C coal seam were drilled in 1985 to check thickness of overburden and to get coal sample for analyses. (See page 124 to 128 of the 1986 JICA report)

In 1986 fiscal year, 25 large diameter (core diameter: 101mm) core drilling holes were driven to get coal sample for coal gasification tests under the jointed project between Japan and Indonesia, "Effective Utilization of Banko Coal" project.

It may be too early to conclude by saying as follows based on results obtained from the limited number of drilled holes, but some conservative consideration should be applied on

i) thickness of coal seams (especially A_1 and B_1) because some drilled holes driven newly, close by the existing holes did not show the same thickness of coal as existing holes.

ii) specific gravity of coal because core recovery of some newly drilled holes close to existing holes were low, due to penetration into disturbed zone.

The above-mentioned matters will be studied in sensitivity analysis of coal mining cost in the study, because waste stripping will be getting higher and coal mining cost will be influenced if thickness of coal seams turns out to be thinner and/or specific gravity to be lower than the values estimated before.

(2) Hydrology and Hydrogeology

K-OG report shows weather conditions, hydrology and hydrogeology in the North-West Banko area as follows:

i) average annual rainfall is about 3,200mm and 1,400mm of it is evaporated
ii) mean temperature is 28^{o}C
iii) the Air Kiahan Besar/Air Bintan system which outer catchment area is 10.4Km^2 will yield approximately Qmax = 140 m^3/s after 100-year, 3-hours downpour at the point where the creeks enter the mining area.
iv) about 70m^3/s of maximum runoff rate was observed in the Air Kiahan Besar with six stream gauges.
v) all strata are water-saturated.
vi) overburden/coal seam sequence forms a multi-aquiferous system of low to very low permeability and coal has the highest permeability among them.
vii) about 1.4Mpa of pressure heads will be prevailing in the B/C interburden at the deepest point of the pit.
viii) it is almost certain that large quantity of groundwater will not percolate into the pit, however carefully thought-out measure is needed.

Waste-dump-heap area, pit dewatering facilities, diverted water conduits, dams and diverted waterway were investigated following the above-mentioned valuable information.

(3) Geotechtonics

K-OG stated in their report regarding slope of response as follows.

The steriles behave like materials between hard soil an soft rock. Large failures are defect-controlled. Drainage-supported long-term slope angles in all sterile sections are 21-22^{o} at H=20m, and 14^{o} at H=100m in the A_1 overburden. Coal slopes are 60-70^{o}. Overall slope of 25-30^{o} between the A_1 and B_2 seams are probably stable with effective drainage.

Prior to excavation, the steriles and coal may be loosened in part or in general. Dumping of waste is possible at an overall slope inclination of 5:1 (H:V), if supported by an external layer and base drainage.

Minable coal tonnage is influenced by pit depth and ultimate pit slope strikingly. It will be practicable to dig down. Beyond 100 meters below the surface, set by Shell as the lowest digging limit to increase minable coal tonnage, though stripping ratio also gets higher.

Needed annual coal tonnage at the throwing mouths of three coal gasifiers (excluding stand-by one) is about 2.2 million tons (dry bases), on the other hand. (see 1986 JICA report page 199)

Therefore needed annual tonnage of run-of-mine coal will be about 2.6 million tons, considering mining loss in the pit and, transportation and treatment loss from the pit to the entrance of coal gasifiers, when moisture content on the belt conveyor between the mine and the plant, is 25%.

Minable coal tonnage in the planned pit by Shell is 106 million tons, when ultimate pit slope is 15%, within 100 meter below the surface, and then, the planned coal gasification plant will be able to operate exceeding the limit of 30 years.

K-OG recommended the following specification for haul roads on materials at North-West Banko area which California Bearing ratios are very low.

	in case of wheel loading	
	40,000lbs	100,000lbs
CBR 80% fine crushed rock	150mm thickness	150mm thickness
CBR 80% coarse crushed rock	170mm thickness	270mm thickness
CBR 20% laminated beds oxided coal	730mm thickness	1,100mm thickness
Coal sub-base		
CBR 3% subgrade		

Design of Surface mine haulage roads - a manual" published by United States Bureau of Mines was referred to investigate haul road pavement in case of the conceptual coal mining cost estimation.

Table 7-1-1 Thickness, Coal Reserves and Coal Quality of Each Coal Seam in the North-West Banko area

(1) Thickness of Coal Seams

Thickness / Coal Seam	Maximum		Minimum		Average	
	Coal seam	Inter-burden				
Mangus (A_1)	12.1M		4.6M		9.2M	
		22.8M		10.3M		16.7M
Mangus (A_2)	11.8M		8.4M		10.4M	
		15.3M		11.4M		13.3M
Suban (B_1)	13.7M		9.5M		12.5M	
		12.3M		1.3M		6.9M
Suban (B_2)	5.5M		4.2M		-	
		43.5M		28.1M		36.3M
Petai (C)	12.4M		10.4M		11.5M	
Total	55.5M	91.9M	37.1M	51.1M	43.6M	73.2M

(Note 1) Depended on Shell data

(Note 2) K-OG set forth the following average coal seam thickness in their reports

A_1: 7.3M; A_2:9.8M; B_1:12.7M; B_2:4.5M; C_1:5.1M; C_2:6.2M

(2) Coal Reserves within Planned Pits and Minable Coal Tonnage

ultimate pit slope / coal seam and inter /over burden	coal reserves within the planned pit 15°		coal reserves within the planned pit 20°		minale coal tonnage within the planned pit 15°		minale coal tonnage within the planned pit 20°	
	Mt	Mbm³						
overburden		147.37		126.78		147.37		126.78
A1	23.66		23.17		23.66		23.17	
		34.55		33.22		34.55		33.22
A2	28.50		28.02		28.50		28.02	
		27.91		27.19		27.91		27.19
B1	39.48		38.58		39.48		38.52	
		20.18		19.98		20.18		19.98
B2	14.95		14.90		14.95		14.90	
		107.53		105.77		51.37		51.40
C	41.45		40.81		18.43		18.38	
total	148.04	337.34	145.48	313.04	125.02	281.38	123.05	258.57
stripping ratio	--		--		bank M³ 2.25 : ton 1		2.10 : 1	

(Note 1) Depended on Shell Data

(Note 2) The above mentioned coal reserves and minable coal tonnage based on the following precondition

i) specific gravity: 1.28

ii) maximum pit depth to C_2 coal seam: 100 meter from the surface

(Note 3) Figures in the left and right column show coal tonnage shown in million tons and over/interburden volume in million bank m³ respectively.

(3) Coal Reserve Estimated by DOC and K-OG

Coal seam	Coal reserve (million M3)	Coal tonngage (million tons)
A1	50.64	63.81
A2	82.51	103.96
B1	120.86	152.28
B2	47.89	60.34
C1	63.31	79.77
C2	79.24	99.84
TOTAL	445.45	560.00

(Note 1) Depended on DOC and K-OG

(Note 2) The above mentioned tonnage is geological measured reserves up to 250 meter depth (maximum 150 meter of overburden about the uppermost coal seam) based on 1.26 of specific gravity of coal seam.

(Note 3) Estimated stripping ratio is 2.31 bank m^3: 1 ton

(Note 4) K-OG adds the following supplementary explanation on coal reserves in their report.

The northern and central zones of the North-West Banko coal field are most suitable for mine planning and operation due to more favourable structural conditions (dip is rather gentle) and the absence of large faults.

(4) Coal Quality by Shell

coal seam	analy-sed by	total moisture		sulphur	ash(d)	VM(daf)	CV Kcal/kg	
		calcu-lated	analy-sed	(d) %	%	%	(daf)	(net)
A_1	1	29.00	30.00	0.57	8.20	40.70	7,240	4,310
	2	-	28.50	0.54	8.45	50.50	7,329	4,460
	1	29.40	30.00	0.23	5.00	48.60	7,275	4,490
A_2	2	-	29.00	0.25	6.90	49.40	7,304	4,485
		(28.50)						
	1	29.00	30.00	0.27	5.90	48.40	7,295	4,460
B_1	2	-	28.50	0.27	5.85	48.60	7,323	4,590
	1	-	30.00	1.09	6.50	47.90	7,310	4,590
B_2	2	-	28.00	1.18	7.60	49.30	7,319	4,440
	1	26.20	30.00	0.97	8.00	48.40	7,410	4,430
C	2	-	27.50	1.13	8.85	49.50	7,457	4,595

(Note 1) Coal analyses results of group 1 were obtained by the hands of Shell in 1983, and group 2 coal analyses were carried out by Shell in 1979 and P.T. Geoservices in 1980.

(Note 2) Shell also investigated sodium oxide contents in ash and coal substance in situ, which should be watched carefully because of its boiler damage properties, and drew the following conclusion.

(1) 6,000PPM of sodium oxide contents in coal substance (from 0% over to 18% in ash) is nearly the maximum limit.

(2) Reverse mutual relation exists between total ash percent and sodium oxide contents (%) in ash.

(3) Sodium oxide contents in coal substance increase in portion to vertical depth from the surface.

(5) Coal Quality by DOC and K-OG

Coal seam	Moisture %	Sulphur %	Ash %	VM %	CV Kcal/kg gross	net
A_1	25.4	0.56	9.5	32.6	4,645	4,322
A_2	25.8	0.17	4.9	33.7	4,993	4,655
B_1	26.2	0.21	5.0	33.5	4,974	4,631
B_2	26.1	0.58	6.2	32.7	4,898	4,560
A_1-B_2	25.9	0.33	6.2	33.2	4,893	4,555
C_1	24.3	0.82	7.2	33.6	4,874	4,660
C_2	24.6	0.60	6.0	33.5	5,069	4,736
A_1-C_2	25.5	0.42	6.3	33.3	4,974	4,593

The North-West Banko coal is sub-bituminous B and C (corresponding to hard brown coal) with low ash percentage in general (average in situ is 6.3%, including C coal seam), low sulphur content (0.4%) relatively low volatiles (33%) low bed (total) moisture. (25-26%)

(Note 1) K-OG explained coal quality in their report as follows: medium hardness (37-54 Hardgrove Units) and relatively high calorific values (CV net: 18-20Mj/Kg)

Sodium oxide content averages 4.5-6% throughout the whole deposit, but with local peaks exceeding 6% Na_2O.

7-1-3 Mining

(1) General

The north-west Banko block lies in the south-eastern direction of the town of Tanjung Enim of South Sumatra. Coal Seam consits of Mangus, Suban and Petai coal seam and Mangus devides into two parts upper Mangus (A_1) and lower Mangus (A_2) coal seam throughout the North-West Banko and Suban coal seam also splits into two parts, upper Suban (B_1) and lower Suban (B_2) in almost all area of the North-West Banko.

Petai coal seam devides into upper Petai (C_1) and lower Petai (C_2) in the southern area of the said block.

Thickness of coal seam is between 6M and 16M. The seam general strike is north to south, and dip varies from 5^o to 15^o towards the west.

Outcrops or of coal seam lie scattered in creeks and suboutcrops are checked by drilling or pitting along the western flank of two anticline structures. (See Fig. 6-4-2)

Mining operation shall be started in the vicinity of the middle of the block, western side of the folded zone, then working faces shall be enlarged into horizontal and vertical directions.

Pit will be formed at 60 meters below the sea level after working faces sink down to the said level.

All excavated waste will be heap outside of the pit on two independent waste dumping-heaping area located eastern side of the deposit.

Two haul roads will be constructed in the southern and northern side of the pit.

Waste dumping-heaping inside the pit shall be considered in the second half of mine life in order to minimize area for waste dumping-heaping, outside of the pit and to reclaim digged out area.

(2) Mining method and equipment

Broken Hill Proprietary Co., Ltd., (hereinafter referred to as BHP) is operating a coal mine in the Hunter Valley of New South Wales by a quite unique multi-bench excavation method using shovels and trucks, which operates multiple coal seams likewise coal field in South Sumatra.

It would be wiser to follow the above mentioned mining method in case of the conceptual coal mining cost estimation, too. (See Fig. 7-1-1)

Continuous mining method combined with shiftable belt conveyors can be used however heavy machines such as BWE and shiftable belt conveyors cannot bear comparison with shovel and truck on movability.

Movability is most important factor, in the case of rather thin multiple coal seams, in order to minimize proceeding stripping volume and then operate the mine feasible, by moving machines from the lower level to the higher level or contrarily from higher level to the lower level very often.

Furthermore, mines which excavate rather thin coal seams are fated to excavate useful material (coal) and useless material on the same bench every shift, however if two lines of belt conveyor are not installed on the same bench, or adopted different haul system for coal and waste (for example, belt conveyor haul system to waste and truck haul system to coal) both materials cannot be dug at the same time and then, utilization of loading machines is forced to fall down and then operating cost gets higher, or initial investment must be increased, in order to keep utilization of digging machines on the same level.

Scrapers are also not advantageous because of the long haul distance.

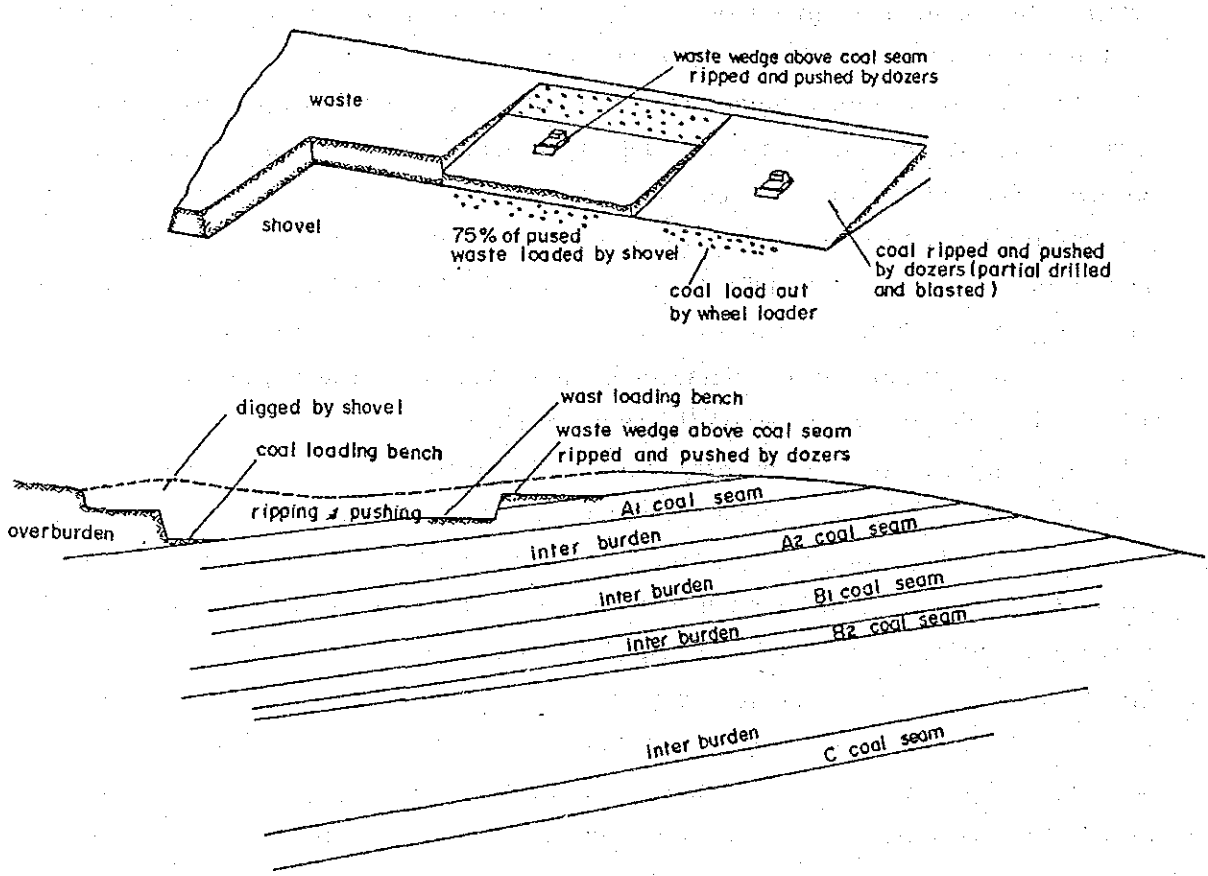
Therefore, electric shovels combined with trucks are chosen to dig, load and haul waste for the conceptual coal mining cost estimation, for the above mentioned reasons, and rather small capacity of machines are chosen within the limit of possible at the first stage of operation, however, when working faces sink down into lower level or approach to the northern or southern extremity of the deposit and then haul roads get longer and longer, and the renewal of machines are necessary, it is advisable to exchange small machines for bigger ones in order to offset the increased operating cost in proportion to operators' or drivers' experience on the large capacity machienes.

Coal are loaded into trucks with track-type front-end loaders on the bench floor level, after ripping and pushing by dozeres. Partial blasting will be needed to make ripping action easy.

Waste wedges above coal also ripped and pushed by dozers. (see Fig. 7-1-1)

Some core drilling work in the expected mining area shall be carried out every year before mining, in order to draw the detailed mining plan and carry out minig work, economically and smoothly.

Fig. 7-1-1 Idealized Mining System in Three Dimensions



(note) working places will be developed horizontally and vertically

Fig. 7-1-2 Pit Outline at the Begnining of Production Period

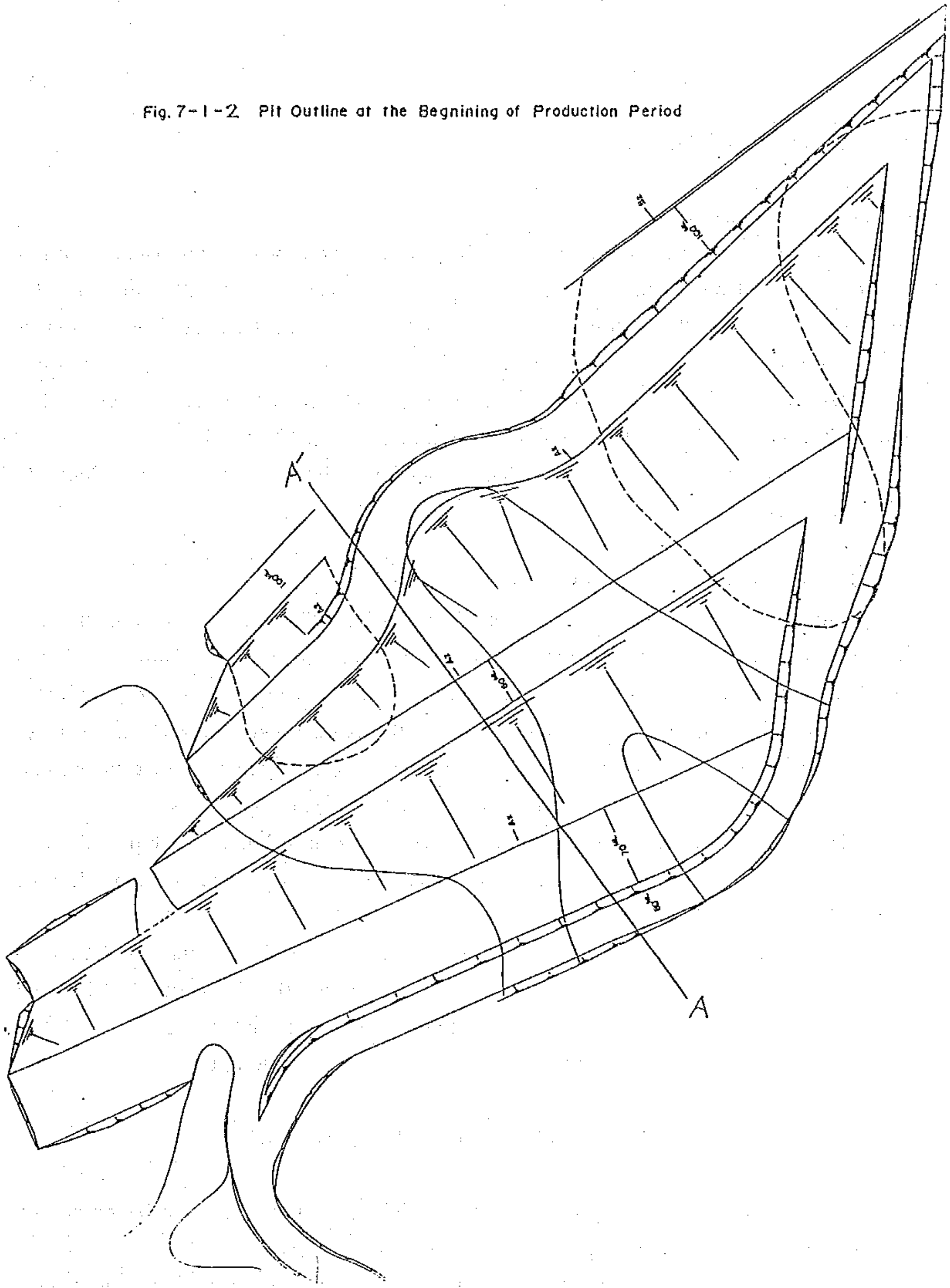
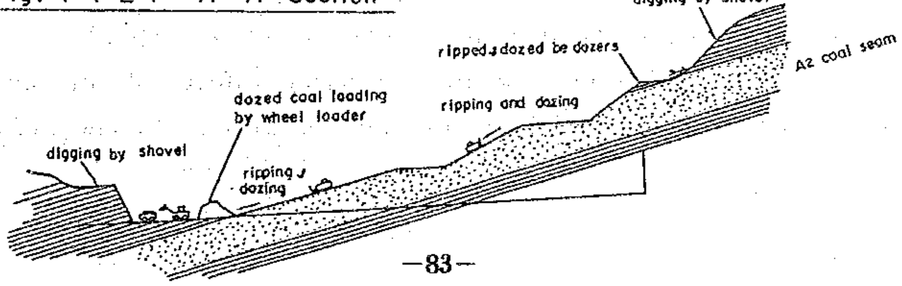


Fig. 7-1-2-1 A—A' Section



7-1-4 Production Schedule

(1) Needed tonnage of run-of-mine

Yearly needed tonnage of run-of-mine for methanol production was estimated based on 25% of moisture contents on the belt conveyor between the mine and the plant, considering, 7% of dilution factor and 5% of mining loss, as follows: yearly needed tonnage of run-of-mine: 2,700 x 10^3 tons , total needed tonange of run-of-mine within the project life (after considering production decrease caused by the start of production in the first and second year: 79,400 x 10^3 tons)

Therefore the annual run-of-mine production schedule shown in the Table 7-1-2 was chosen.

(2) Needed waster stripping volume

Minable coal tonnage estimated by Shell (up to 100 meters below the surface, ultimate pit slope is 15°) is about 280 million tons as shown in the Table 7-1-1 and needed coal tonnage in situ excepted dilution factor from the tonnate, shown in (1) is about 740 million tons therefore, pit will not be needed to sink down up to 100 meters below the surface when only methanol production is investigated, and then, stripping ratio was estimated at 1.63 bank m^3: 1 ton.

However, coal production shall be enlarged if urea production or power plant operation owned by the coal gasifcation plant, independent of power-supply line of PLN.

Increasing in production will be discussed in the sensitvity analysis (see 7-1-11) because the pit must be sunk down to deeper level vertically within the licensed horizontal area, and then the matter is related to waste stripping ratio.

The annual waste stripping volume is shown in the Table 7-1-2.

7-1-5 Needed Number of Main and Subsidiary Mining Machines

Annual needed numbers of main and subsidiary mining machines based on the above mentioned consideration is shown in the Table 7-1-3.

The following parameters were considered in calculating the above mentioned needed numbers of main mining machines.

Annual working days: 345 days (under 8 hrs. - 3 shifts system)

Annual average utilization factor, considering unfavorable influence on the work, caused by heavy rain during the rainy season on efficiency: 67%

7-1-6 Support Faclities

1) Coal stockyard facilities

Mined out coal will be hauled to the stockyard contiguous to the hopper of the coal transportation belt-conveyor system. From the mine site to the coal gasification plant, by trucks.

The coal stockyard has the capacity of 100,000 tons, and one stacker and one reclaimer with belt conveyor system and some dozers and front-end-loaders will be posted in order to treat coming and outgoing coal.

2) Buildings and other structures

The following buildings and other strucures were considered in the conceptual coal mining cost investigation.

(1) mine office: fully air conditioned; furnished with needed of fine furnitures and utensils
(2) guest hosue: fully air conditioned; furnished with needed furniture and utensils
(3) engineering room: fully air conditioned, funished with needed office furniture, utensils and facilities
(4) training center: partially air conditioned; furnished with needed facilities
(5) machine shops including heavy vehicle service shop (with pits), light vehicle workshop (with pits); tyre repair and storage; blacksmith's shop; engine reconditioning service and painting shop (with needed facilities which all service and repair can be done by the mine itself)
(6) electric service station (-do-)
(7) warehouse; furnished with needed utensils and facilities
(8) fuel oil storage tanks
(9) Powder magazine
(10) outside fenced storage yard (11) garage

Furthermore, the following items were also considered in the investigation.

(1) reconstruction of the approach road from Tanjung Enim to the mine site
(2) power distribution line from the main substation to each facilities within the mine
(3) water storage facilities and supply system
(4) temporary arrangement at the beginning of the pre-production period

Table 7-1-2 Annual Production Scheduyle

Period	Pre-production				Production											
Year	-3	-2	-1	Sub-total	1	2	3	4	5	6	7	8	9	10	11	12
Run-of-mine	–	–	50	50	2200	2700	2700	2600	2700	2600	2700	2700	2600	2700	2600	2700
Waste	–	2500	5000	7500	2100	2600	2700	3200	3300	3100	3900	3900	3800	3900	3800	4600
Stripping ratio	–	–	–	–	0.96 : 1	0.96 : 1	1.00 : 1	1.23 : 1	1.22 : 1	1.19 : 1	1.44 : 1	1.44 : 1	1.46 : 1	1.44 : 1	1.46 : 1	1.70 : 1

Production															
13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
2700	2600	2700	2600	2700	2700	2600	2700	2600	2700	2700	2600	2700	2600	2700	2700
4600	3200	4400	4500	4400	5200	5000	5200	5000	52600	5200	5000	5200	5000	3300	3300
1.70 : 1	1.69 : 1	1.67 : 1	1.69 : 1	1.93 : 1	1.93 : 1	1.92 : 1	1.93 : 1	1.92 : 1	1.93 : 1	1.93 : 1	1.92 : 1	1.93 : 1	1.92 : 1	1.22 : 1	1.22 : 1

Production			
29	30	Sub-total	Total
2700	2600	79400	79450
2600	2500	121700	129200
0.96 : 1	0.96 : 1	153 : 1	163 : 1

(Note l) Run of mine: 10^3 tons
Waste: 103 bank m^3

Table 7-1-3 Needed Numbers of Main and Subsidiary Mining Machines

Item	Specification	Pre-production				Production																														
		−3	−2	−1	Sub total	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Electric shovels	1100KW, $22M^3$, 23 tons		2		2									1																				
Waste trucks	460HP, $23,8M^3$, rear dump		6		6	2	2				2	1		1		3	1		1		4	1		2		2	1		3					
Dozers	300HP, track-type		2		2																													
Mobile drill rigs	Track-mounted			3	3																													
Air compressors	Portable, 25.5m3/min, 270HP			3	3																													
Core drilling machines	150m, 7.5HP	2			2																													
Wheel loader	559HP, $9.6M^3$		1	1	2									1																				
Coal trucks	460HP, $44.5M^3$, rear dump		2	2	4	1			1											1			1				1				1			
Dozer	390HP with ripper		3	2	5	2																												
Bucket hoe			2		2																													
Wheel loader	380HP, $6.0M^3$		2		2																													
Water carrier	6000 ℓ		2		2																													
Buel air carrier	6000 ℓ		2		2	2																												
Dump truck	7 tons		2	2	4																													
Mobile crane	80 tons		3	2	5																													
Crucking plant	truck-mounted		1		1																													
Rack breaker	hydraulic, truck-mounted		1		1																													
Dewatering pump			1	3	3																													
Substation			2		2				5	3			1	1	1	2	1		1	1		2												
Pick up		3	5	7	15														1															
4-wheel drive car		3	4	3	10														1															
Motor			2	1	3	1													1															

(Note 1) Figures in each year show numbers of machines to be procured in the said year.
(Note 2) Needed numbers of machines to be replaced are not included in the above mentioned figures.

It was premised on the assumption that electic power is supplied from the power plant by PLN at the main substation at mine site, but the said substation construction cost is borne by the mine.

The expenses to acquire the ownership of land (compensation money) were also considered in the investigation, tanking Indonesian laws related and quite complicated custom on the matter in Indonesia into account.

3) town site

Construction costs of primary school, junior high school, hospital, mosques, canteens and some recreational facilities (such as tennis court, basket court, and swimming pool which also serve as water reservoir, in the case of fire) were considered in the investigation besides construction costs of housing facilities and dormitories for staffs, workers and foreign consultants.

Needed numbers of housing facilities and dormitories which will be constructed by the company were estimated, based on the following factors (see Table 7-1-4).

Maximum numbers of employees

(1) of locally available employees who have their own houses near the minesite, and then, do not need housing facilities prepared by the company. They will be compensated with housing allowance.

(2) of unmarried employees, most of them will live in dormitories prepared by the company.

(3) of employees, who will build their own houses by themselves, or rent houses in the vicinity of the mine or buy houses from RERMNAS. Housing allowance will be paid to such employees.

Table 7-1-4 Planned Number of Housing Facilities Prepared by the Company

	Foreigners	Senior Staffs	Junior Staffs	Labours	Total
Dormitories	1 (20 persons)	1 (5 persons)	1 (135*1 persons)	1 (155 persons)	3
Houses	–	48	38*1	164	250

(Note 1) Including housing facilities for highly experienced workers

7-1-7 Mine Organization and Needed Number of Employees

It was assumed that a wholly state-owned company would be established newly in order to manage and operate the Banko coal gasification project and then the mine would be operated by the hands of one of departments of the said company (See Fig. 7-1-3). Maximum needed numbers of staffs and workers classified by education level or technical experience level are estimated as shown in Table 7-1-5.

Fig. 7－1－3　炭鉱の組織図

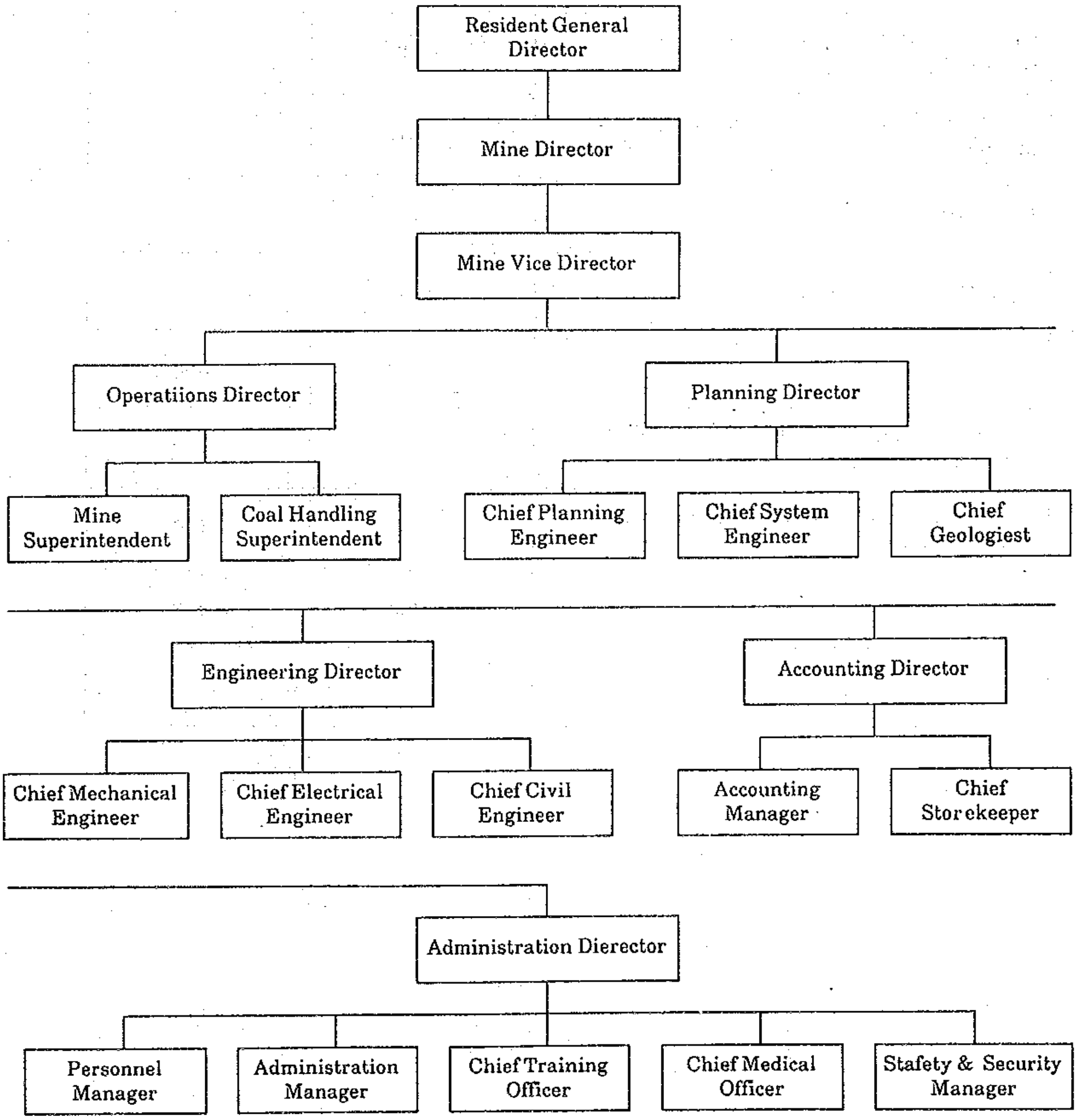


Table 7-1-5 Maximum Needed Number of Staffs and Workers, Classified by Level or Technical Experience Level Education

Classification	Mining	Other than Miing
Graduates including persons finished the course of junior college	22	31
Highly experienced persons on heavy earth moving machine operation	373	
Light truck drivers	105	
Semi-skilled workers	372	
Un-skilled workers	128	289
Persons finished the course of senior high school or same level		130
Persons finished the course of junior high school or same level		100
Total	1000	550
Grand total	1550	

7-1-8 Technical Assistance and Training

The mine will be constructed by the hands of a foreign consultants company, and personnel required for mine operation will be trained by the said consultants company during pre-production period, machines procured and facilities completed will be transferred from the said foreign consultants company to the wholly state-owned company at the end of pre-production period together with trained staffs and workers.

Operation assistance carried out by the said foreign consultants company also will be necessary at least 10 years after starting operation.

After making a decision to drive the project forward before starting construction work, the following work shall be done by the said foreign consultants comapny.

1) Making detailed design for mine and support facilities to develop the mine

2) Making tender specifications, evaluation for documents presented by suppliers and/or contractors and selection of suppliers and contractors concerned

All the above mentioned costs were appropriated in the cost estimation.

7-1-9 Capital Cost Estimation

Needed capital costs (initial investment costs and replacement costs) were estimated, based on the above considerations, as shown in Table 7-1-6.

Furthermore, circulating fund sufficient for half a year mine operation (about U.S.\$13,000 x 10^3) will be needed in order to

1) keep the proper stock for needed supplies (especially imported goods)
2) cover production costs of stocked coal at mine site
3) and for stop-gap fund to cover time gap between production time of final products and their encashing time

Table 7-1-6 Summary of Estimated Investment Cost

US$ 1,000

	Pre-production				Production																															Total
	−3	−2	−1	Sub total	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Sub-total	
Stripping		7,720		7,720	1,320	1,320	–	3,960	920	2,640	4,820	–	6,040	–	5,540	2,640	–	5,280	2,840	7,260	5,640	–	6,600	–	8,580	3,960	3,760	8,580	–	8,580					90,280	98,000
Mining	220	3,920	3,160	7,300	1,500	–	–	4,360	2,470	1,500	–	–	5,350	2,470	2,190	–	–	5,350	2,910	1,720	440	–	5,350	2,910	2,190	880	–	5,790	2,910	1,940					52,230	59,530
General and common use	69	4,878	6,373	11,320	5,000	–	69	478	523	380	–	109	1,238	533	180	330	1,449	1,518	773	400	80	109	1,428	913	189	140	69	518	373	190					16,980	28,300
Sub total	289	16,518	9,533	26,340	7,820	1,320	69	8,798	3,913	4,520	4,820	109	12,628	3,003	7,910	2,970	1,449	12,148	6,523	9,380	6,160	109	13,378	3,823	10,950	4,980	3,829	14,888	3,283	10,710					159,490	185,830
Coal stack yard		3,887	5,133	9,020									1,320										4,540												5,860	14,880
Incidential facilities		12,509	2,160	14,669				367	333		557	198	2,649	1,962	21			367	2,462	198			2,649	1,962			181	764	531						15,201	29,870
Building & structures		2,630	5,260	7,890																															–	7,890
Townsite	1,260	10,005	3,017	14,282	503	503	503	503	503	503	503	503	503	503																					5,030	19,312
Temporary facilities and construction	87	1,418	912	2,417																															26,091	2,417
Sub total	1,347	30,449	16,482	48,278	503	503	503	870	836	503	1,060	701	44,72	2,465	21			367	2,462	198			7,189	1,962			181	764	531						185,581	74,369
Total	1,636	46,967	26,015	74,618	8,323	1,823	572	9,668	4,749	5,023	5,880	810	17,100	5,468	7,931	2,970	1,449	12,515	8,985	9,578	6,160	109	20,567	5,785	10,950	4,980	4,010	15,652	3,814	10,710						260,199
Mining[*1]	476	7,818	14,613	22,907																																
Land acquisition	1,000	750	1,000	2,750	(750)	(500)																														
Project management	4,213	6,221	6,221	16,655	(5,134)	(5,134)	(5,134)	(5,134)	(5,134)	(3,075)	(3,075)	(3,075)	(3,075)	(3,075)																						
Training	825	5,066	2,120	8,011																																
Total	6,514	19,855	23,954	50,323	(5,884)	(5,634)	(5,134)	(5,134)	(5,134)	(3,075)	(3,075)	(3,075)	(3,075)	(3,075)																					(42,295)	(42,295)
Total	8,150	66,822	49,969	124,941	8,323	1,823	572	9,668	4,749	5,023	5,880	810	17,100	5,468	7,931	2,970	1,449	12,515	8,985	9,578	6,160	109	20,567	5,785	10,950	4,980	4,010	15,652	3,814	10,710					185,581	260,199
					(5,884)	(5,634)	(5,134)	(5,134)	(5,134)	(3,075)	(3,075)	(3,075)	(3,075)	(3,075)																					(4,229)	(42,295)

7-1-10 Operating Cost Estimation

The operating cost was estimated at the throwing mouth of belt conveyor from the mine site to the plant because the said transportation cost was included in the methanol production cost (See 1986 JICA report)

Estimated operating cost based on the above mentioned consideration is shown in Table 7-1-7.

The mine will be operated and managed by one of the wholly state-owned companies, and needed funds to develop and operate the mine will be provided from the National Treasury year by year as occasion demands, after assessment of the budget applied by the company.

Generated profits also will be restored to the National Treasury.

Therefore, income tax was not considered and then, idea of depreciation to calculate income tax was not introduced in the operating cost estimation.

Paid interest was not considered by the same reason.

It was expected in the operating cost estimation that import duties were exempted, and only the following two kinds of taxes were considereed.

1) real estate tax

2) value added tax to expenses and/or payment generated in Indonesia.

7-1-11 Sensitivity Analysis on the Operating Cost

A little bit but quite important difference is found partially on coal thickness and specific gravity between survey results carried out by Shell and one done by JICA-BPPT-PPTM joint team newly.

However, it is not still high time to draw the final and definite conclusion now, and the matter should be investigated carefully, taking much time, therefore, in the operating cost estimation simple sensitivity analysis was carried out, on the case that waste stripping ratio increases for some reason (for example, actual thickness of coal seams and/or coal specific gravity in situ is lower than ones estimated by Shell; coal seams are cut and disappeared by faults and others) at a certain percentage.

Coal production shall be increased in the case of urea production and power plant operation, but in the operating cost estimation, and the pit shall be sunk down to the lower level in case of production increase, and stripping ratio grows higher.

Sensitivity analysis was also investigated on the increase of stripping ratio, about the matter.

Two tables attached (Table 7-1-8 and Table 7-1-9) are results of sensitivity analysis, id est, both tables show the influence of increase of waste stripping ratio and coal production on the operating cost respectively.

Meanwhile, when project's own power plant is prepared and operated in the case of methanol production, additional tonnage of coal is needed, so with urea production.

Coal mining cost will be lower by the result of production increase, however, stripping ratio may increase, because the pit must be sunk down to the lower level to take much more coal.

Direct mining costs in each case are as follows:

Methanol production : \$7.25/ton

Urea/production : \$6.82/ton

Additional initial investment and investment for machines and equipment replacement are necessary when coal production is enlarged and they are estimated as follows.

period -	pre-production	production
amount 10^3\$	4973	68590

(Note) Additional housing facilities may be necessary as coal production increases, because the numbers of workers who engage in direct work, id est, mining, waste stripping and coal handling, shall be increased.

However, the increase of housing facilities was not considered assuming that increased labours could find their houses, elsewhere outside of town site prepared by the company.

The mine will be managed actually under one of the wholly state-owned companies as mentioned above, however, mining cost including depreciation and interest was also estimated at \$14.48/ton for the convenience of a person who is familiar with such indication of the cost, supposing the case that the mine is managed by the non-governmental organization.

IRR of base case (see the 1986 JICA report page 224) will be 11.4% compared with 13.5%, estimated in the 1986 JICA page 228)

Table 7-1-7 Summary of Estimated Operating Cost

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Per ton $/ton
Labour expenses	3,543	3,630	3,638	3,668	3,685	3,660	3,733	3,733	3,715	3,733	3,715	3,788	3.788	3,763	3,780	3,763	3,835	3,835	3,810	3,835	3,810	3,835	3,835	3,810	3,835	3,810	3,685	3,685	3,639	3,613	112,198	1.41
Supplies expenses	8,232	9,230	9,311	9,608	3,807	3,526	10,302	10,302	10,103	10,302	10,103	10.879	10,879	10,597	10,797	10,597	11,373	11,373	11,093	11,373	11,093	11,373	11,373	11,093	11,373	11,093	9,807	9,807	7,405	7,272	307,477	3.87
Power cost	693	718	720	728	733	726	746	746	741	746	741	762	762	755	759	755	755	775	768	775	768	775	775	768	775	768	733	733	718	718	22,455	0.28
Construction cost	395	468	1,507	454	496	1,445	419	419	1,245	447	406	1,258	419	406	1,286	358	369	930	358	397	919	369	369	919	397	310	319	250	250	241	17,825	0.23
Sub total	12,863	14,046	15,176	14,458	14,721	15,357	15,200	15,200	15,804	15,228	14,865	16.687	15,848	15,521	16.622	15.473	16,352	16,913	16,029	16,380	16,590	16,352	16,352	16,590	16,380	15,981	14,544	14,475	12,003	11,845	159,956	5.79
Labour expenses	659	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	677	20,292	0.26
Power cost	318	327	327	327	327	327	527	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	9,801	0.12
Supplies expenses	1,220	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	1,226	36,774	0.46
Sub total	2,197	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	2,230	66,867	0.84
Labour expenses	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	61,900	0.65
General exclusive expenses	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	217	6,510	0.08
Real estate tax	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	34,230	0.43
Account paid to outside contractors	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	5,850	0.08
Land acquisition expenses	750	500																													1,250	0.02
Project management expenses	5,134	5,134	5,134	5,134	5,134	3,075	3,075	3,075	3,075	3,075																					41,045	0.62
Sub total	9,167	8,917	8,417	8,417	8,417	6,358	6,358	6,358	6,358	6,358	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	40.785	1.78
Total	24,227	25,193	25,823	25,105	25,368	23,945	23,788	23,788	24,392	23,816	20,478	22,200	21,361	21,034	22,135	20,986	21,865	22,426	21,542	21,893	22,103	21,865	21,865	22,103	21,893	21,494	20,057	19,988	17.516	17,358	667,607	8.41
Cost per ton $/ton	11.01	9.33	9.56	9.66	9.40	9.21	8,81	8,81	9.38	8.82	7.88	8.22	7.91	8.09	8.20	8.07	8.10	8.31	8.29	8.11	8.50	8.10	8.10	8.50	8.11	8.27	7.43	7.40	6.49	6.68	8.41	

Table 7-1-8 Influence of Increase of Waste Stripping Ratio on the Operating Cost

Period	Year	Case 1				Case 2				Case 3			
		Increase of waste stripping		Cost increase		Increase of waste stripping		Cost increase		Increase of waste stripping		Cost increase	
		Volume	Ratio	Amount	per ton	Volume	Ratio	Amount	per ton	Volume	Ratio	Amount	per ton
		×10³M²	Bank M³: ton	×10³$	$/ton								
	1	12,170	011:1	205	0.09	630	0.29:1	614	0.28	1,050	1.48:1	1,023	0.47
	2	260	0.10:1	253	0.09	780	0.29:1	760	0.28	1,300	0.48:1	1,266	0.47
	3	270	010:1	263	0.10	810	030:1	789	0.29	1,350	0.50:1	1,316	0.49
	4	320	01 2:	312	0.12	960	0.37:1	935	0.36	12,600	0.62:1	1,558	0.60
	5	330	0.12 1	302	0.12	930	0.36:1	906	0.35	1,550	0.60:1	1,510	0.58
	6	310	0.12:1	302	0.12	930	0.36:1	906	0.35	1,550	0.60:1	1,510	0.58
	7	390	0.14:1	380	0.14	1,170	0.43:1	1,140	0.42	1,950	0.71:1	1,899	0.70
	8	390	0.14:1	380	0.14	1,170	0.43:1	1,140	0.42	1,950	0.71:1	1,899	0.70
	9	380	0.15:1	370	0.14	1,140	0.44:1	1,110	0.43	1,900	0.73:1	1,851	0.71
	10	390	0.14:1	380	0.14	1,170	0.43:1	1.140	0.42	1,950	0.72:1	1,899	0.70
	11	380	0.15:1	370	0.14	1,140	0.44:1	1,110	0.43	1,900	0.73:1	1,851	0.71
	12	460	0.17:1	448	0.17	1,380	0.51:1	1.344	0.50	2.300	0.85:1	2.240	0.83
	13	460	0.17:1	448	0.17	1,380	0.51:1	1,344	0.50	2.300	0.85:1	2.240	0.83
	14	440	0.17:1	429	0.17	1,320	0.51:1	1,286	0.49	2,200	0.85:1	2,143	0.82
	15	450	0.17:1	438	0.16	1,350	0.50:1	1.315	0.49	2.250	0.83:1	2,192	0.81
	16	440	0.17:1	429	0.17	1,320	0.51:1	1,286	0.49	2,200	0.85:1	2,143	0.82
	17	520	0.19:1	506	0.19	1,560	0.58:1	1,519	0.56	2,600	0.96:1	2,532	0.94
	18	520	0.19:1	506	0.19	1,560	0.58:1	1,519	0.56	2,600	0.96:1	2,532	0.94
	19	500	0.19:1	487	0.19	1,500	0.58:1	1,461	0.56	2,500	0.96:1	2,436	0.94
	20	520	0.19:1	506	0.19	1,560	0.58:1	1,519	0.56	2,600	0.96:1	2,532	0.94
	21	500	0.19:1	487	0.19	1,500	0.58:1	1,461	0.56	2,500	0.96:1	2,436	0.94
	22	520	0.19:1	506	0.19	1,560	0.58:1	1,519	0.56	2,600	0.96:1	2,532	0.94
	23	520	0.19:1	506	0.19	1,560	0.58:1	1,519	0.56	2,600	0.96:1	2,532	0.94
	24	500	0.19:1	487	0.19	1,500	0.58:1	1,461	0.56	2,500	0.96:1	2,436	0.94
	25	520	0.19:1	506	0.19	1,560	0.58:1	1,519	0.56	2,600	0.96:1	2,532	0.94
	26	500	0.19:1	487	0.19	1,500	0.58:1	1,461	0.56	2,500	0.96:1	2,436	0.94
	27	330	0.12:1	321	0.12	990	0.37:1	964	0.36	1,650	0.61:1	1,607	0.60
	28	330	0.12:1	321	0.12	990	0.37:1	964	0.36	1,650	0.61:1	1,607	0.60
	29	260	0.10:1	253	0.90	780	0.29:1	769	0.28	1,300	0.48:1	1,266	0.47
	30	260	0.10:1	244	0.90	750	0.29:1	731	0.28	1,250	0.48:1	1,218	0.47
	Total	12,170	0.15:1	11,851	0.15	36.510	0.46:1	35,560	0.45	60,850	0.77:1	59,309	0.75

(Note) Waste stripping volume increase during pre-production period is not included in the above mentioned figures.

Table 7-1-9 Influence of Coal Produciton Increase on the Operating Cost

Period	Year	Case 1			Case 2			Case 3		
		Production	Production cost		Production	Production cost		Production	Production cost	
			Amount	Per son		Amount	Per son		Amount	Per son
		10³ tons	10³ $	$/ton	10³ tons	10³ $	$/ton	10³ tons	10³ $	$/ton
	1	2420	24490	10.12	2860	25016	8.75	3300	25542	7.74
	2	2970	25516	8.59	3510	26161	7.45	4050	26806	6.62
	3	2970	26146	9.68	3510	26791	7.63	4050	27436	6.77
	4	2860	25416	8.89	3380	26037	7.70	3900	26659	6.84
	5	2970	25619	8.65	3510	26336	7.50	4050	26981	6.67
	6	2860	24256	9.33	3380	24877	7.36	3900	25499	6.54
	7	2970	24111	8.12	3510	24756	7.05	4050	25401	6.27
	8	2970	24111	8.12	3510	24756	7.05	4050	25401	6.27
	9	2860	24703	8.64	3380	25324	7.49	3900	25946	6.65
	10	2970	24139	8.13	3510	24784	7.06	4050	25429	6.28
	11	2860	20789	7.27	3380	21410	6.33	3900	22032	5.65
	12	2970	22523	7.58	3510	23168	6.60	4050	23813	5.88
	13	2970	21684	7.30	3510	22329	6.36	4050	22974	5.67
	14	2860	21345	7.46	3380	21966	6.50	3900	22588	5.79
	15	2970	22458	7.56	3510	23103	6.58	4050	23748	5.86
	16	2860	21297	7.45	3380	21918	6.48	3900	22540	5.78
	17	2970	22188	7.47	3510	22833	6.51	4050	23478	5.80
	18	2970	22749	7.66	3510	23394	6.66	4050	24039	5.94
	19	2860	21853	7.64	3380	22474	6.65	3900	23096	5.92
	20	2970	22216	7.48	3510	22861	6.51	4050	23506	5.80
	21	2860	22414	7.84	3380	23035	6.82	3900	23657	6.07
	22	2970	22188	7.47	3510	22833	6.51	4050	23478	5.80
	23	2970	22188	7.47	3510	22833	6.51	4050	23478	5.80
	24	2860	22416	7.84	3380	23035	6.82	3900	23657	6.07
	25	2970	22216	7.48	3510	22861	6.51	4050	23506	5.80
	26	2860	21807	7.62	3380	22426	6.63	3900	23048	5.91
	27	2970	20380	6.86	3510	21025	5.99	4050	21670	5.35
	28	2970	20311	6.84	3510	20956	5.97	4050	21601	5.33
	29	2970	17839	6.01	3510	18484	5.27	4050	19129	4.72
	30	2860	17671	6.18	3380	18290	5.41	3900	18912	4.85
	Total	87340	677111	7.75	103220	696072	6.74	119100	715050	6.00

7-2 UREA PRODUCTION COST

7-2-1 Objective of the Study

This study was carried out in order to grasp the outline of the methanol/urea co-production from Banko coal in terms of its financial viability and profitability on the basis of the master plan case 2-A (see Fig. 9-2-5) executed in the strategic study stage (FY1984).

The same production rate of synthesis gas (509 x 10^3 Nm^3/h) from Banko coal to methanol in the Interim Report II (1985) are given to produce 1.3 million tons/year of methanol and 0.56 million tons/year of urea in this study.

Three cases for sales price of urea are assumed under fixed price of methanol in order to survey the effect on IRR* (Internal Rate of Return) of this project.

Assumption of economic factors such as production schedule, finance and raw material cost is same as those in the study in FY1985.

Note*) For details, see the Interim Report II (1985), page 218-219.

7-2-2 Outline of Coal to Methanol/Urea Plant

(1) Design Basis

1) Methanol Production Rate : 1,300,000 ton/year (4,060 ton/day)
2) Urea Production Rate : 560,000 ton/year (1,750 ton/day)
3) Annual Operation Days : 320 days/year
4) Plant Location : Tanjung Priok
   (For details, see the Interim Report II (1985), Page 187-188)
5) Products Specification:

Methanol	:	Chemical Grade (99.9% pure)
Urea	:	Chemical Grade (99.8% pure)

6) Feed Coal Specification:

C, %	:	27.4
V.M., %	:	32.8
Ash, %	:	4.8
Mo, %	:	35.0
Total, %	:	100.0
HV, kcal/kg	:	4,430

7) Coal Receiving : Bunker Hopper at Mine Site

8) Products Shipping : Plant Gate

9) Utilities : All the utilities except raw water and coal are generated inside the plant

Conditions:

HP St'm	:	480°C, 65 kg/cm^{2}G
MP St'm I	:	350°C, 40 kg/cm^{2}G
MP St'm II	:	250°C, 40 kg/cm^{2}G
LP St'm	:	155°C, 3.5kg/cm^{2}G
BFW	:	110°C, 55 kg/cm^{2}G
C. Water	:	30°C(Supply)/37°C(Return)

(2) Plant Configuration

Fig. 7-2-1 shows the overall block flow diagram of methanol/urea production complex.
The component facilities are listed in Table 7-2-1.
The main process and systems in the complex are described in the following pages.

(3) Belt Conveyor System

See the Interim Report II (1985), Page 192-197.

(4) Coal Gasification

1) Process Flow Diagram
See Fig. 7-2-2.

2) Process Description
See the Interim Report II (1985), pge 198.

3) Major Equipment
See the Interim Report II (1985), page 200.

(5) Methanol Production

1) Process Flow Diagram
See Fig. 7-2-3.

2) Process Description
See the Interim Report II (1985), page 201.

3) Major Equipment

Specifications and the number of units of major equipment are listed in Table 7-2-2.

(6) Ammonia/Urea Production

1) Process Flow Diagram

See Fig. 7-2-1, Fig. 7-2-4 and Fig. 7-2-5.

2) Process Description

The ammonia/urea plant consists of the following process steps:

o Dust Removal and 1st Compression

o Co-Shift Conversion

o Acid Gas Removal

o Nitrogen Washing

o Ammonia Synthesis

o Urea Synthesis

o Evaporation and Prilling

i) Dust Removal and 1st Compression

The raw gas leaving the gasifier at 3 kg/cm^2G contains 50 mg/Nm^3 dust.

The dust content in the raw gas is reduced to 5 mg/Nm^3 and this gas is compressed to 50 kg/cm^2G.

ii) CO-Shift Conversion

In order to increase hydrogen content in the raw gas, carbon monoxide is hydrolized into carbon dioxide and hydrogen in the converter as expressed in the following formula:

$$CO + H_2O = CO_2 + H_2 + \Delta H$$

To keep the catalyst bed at a proper temperature, process steam or product gas is used to disspate the reaction heat. Shift conversion hydrolyzes also COS to H_2S.

iii) Acid Gas Removal

The Rectisol process using cold methanol as the solvent consists of an acid gas absorber, CO_2 stripper, H_2S stripper, and distillation tower.

The feed gas containing about 38% of CO_2 and a small amount of H_2S (55 ppm) is supplied to the acid gas absorber where CO_2 and H_2S are readily scrubbed by contacting with cold methanol resulting in 10 ppm of CO_2 in the treated gas. The treated gas from the absorber is sent to the nitrogen washing unit at a temperature of -50°C.

After CO_2 and H_2S gas dissolved in the fat solvent are recovered separately through CO_2 and H_2S strippers, the learn solvent is recyded to the absorber.

The recovered CO_2 gas (99% purity) is utilized as raw material for urea synthesis.

iv) Nitrogen washing

The gas from the acid gas removal unit still contains 10 ppm of CO_2 and methanol mist. Since these impurities sometimes causes plugging in the process, it is to be adsorbed by molecular sieves.

The gas free from impurities is cooled and supplied to the N_2 washer where CO, methane, etc. are scrubbed by liquid nitrogen. The treated gas leaving the top of the N_2 washer is mixed with a certain amount of nitrogen to meet the suitable H_2/N_2 ratio for NH_3 synthesis.

v) NH_3 Synthesis

After compressed and heated to 210 kg/cm^2G and 135°C, the feed gas is sent to the NH_3 converter. Ammonia is produced by the following reaction:

$$3H_2 + N_2 = 2HN_3 + \Delta H$$

The effluent leaving the reactor at a temperature of 330°C is cooled through steam generator, feed gas preheater and chillers.

The cold effluent is introduced to the gas-liquid separator where product ammonia is separated from the unconverted gas.

The product ammonia is pumped to storage at -33°C and the unconverted gas is recycled to the converter.

vi) Urea Synthesis

Urea synthesis is expressed in the following equations.

$$CO_2 + 2NH_3 = NH_4CO_2NH_2 + \Delta H$$

$NH_4CO_2NH_2 = NH_2CONH_2 + H_2O - \Delta H$

CO_2 and liquid NH_3 produced in the upstream units are pressurized and introduced to reactor section. The reactor section consists of reactor, stripper, carbamate condenser and HP scrubber where urea synthesis takes place via carbamate formation.

The operating condition of the reactor is at about 140 kg/cm^{2}G and 180-185°C.

Produced urea from the stripper is depressurized to 3 kg/cm^{2}G and sent to LP recirculation section in which unconverted mixtures associated with the product urea is recovered and recyded to HP scrubber in the form of carbamate.

vii) Evaporation and prilling

The urea solution coming from the recirculation stage contains about 72 percent by weight of urea.

This solution is concentrated to 99.8 percent urea in two steps under vacuum.

The resultant molten stream is prilled with the aid of rotating prilling bucket.

3) Major equipment

Specifications and the number of units of major equipment are listed in Table 7-2-3.

(7) Utility Requirement

See Table 7-2-4.

Table 7-2-4 Utility Requirement

Coal	137 T/h (external supply)
Raw water	3,200 T/h (ditto)
Electricity	121,600 kw (internal supply)
Cooling Water	82,000 T/h (ditto)
BFW	1,537 T/h (ditto)
HP Steam	693 T/h (ditto)

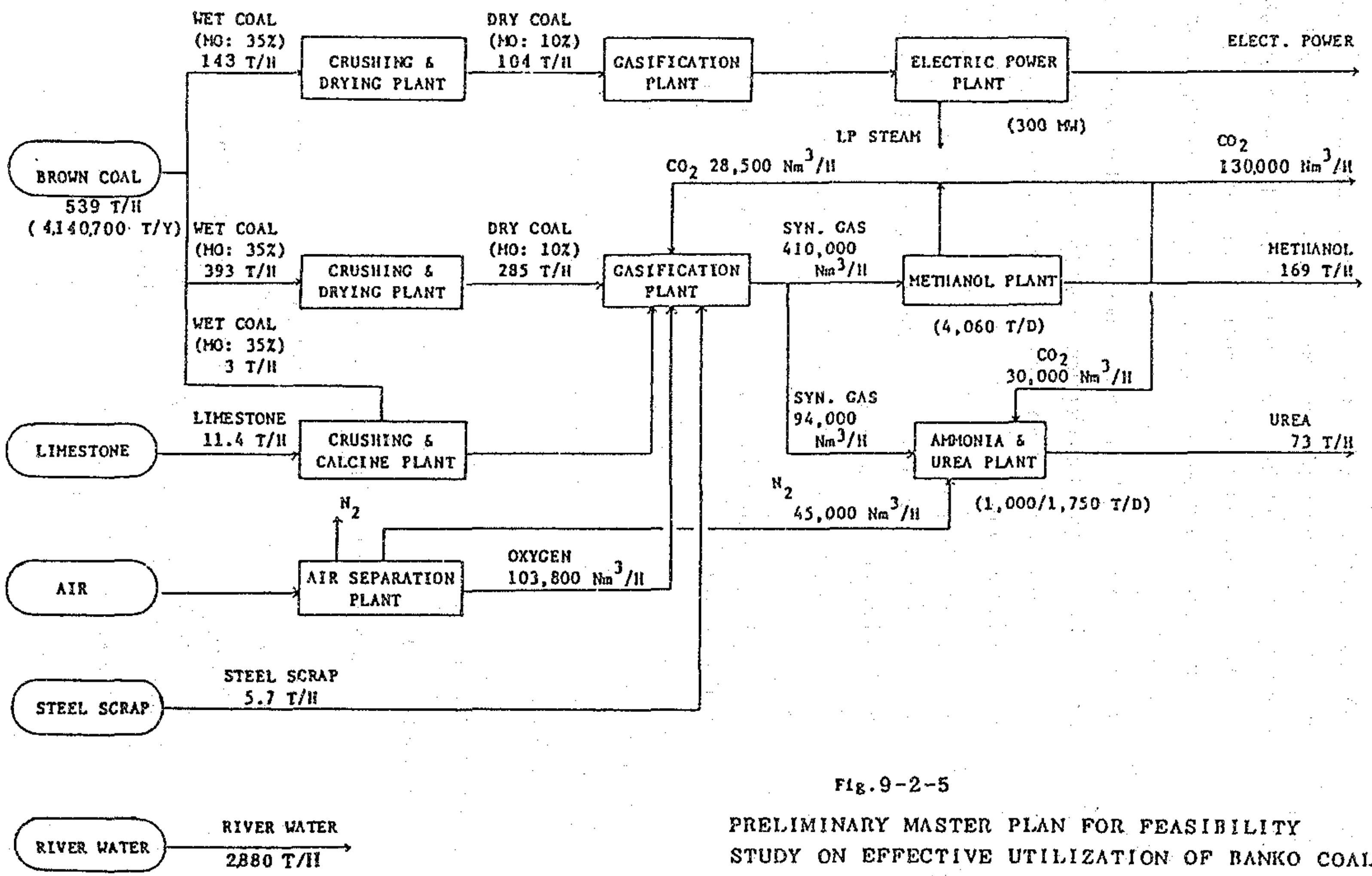
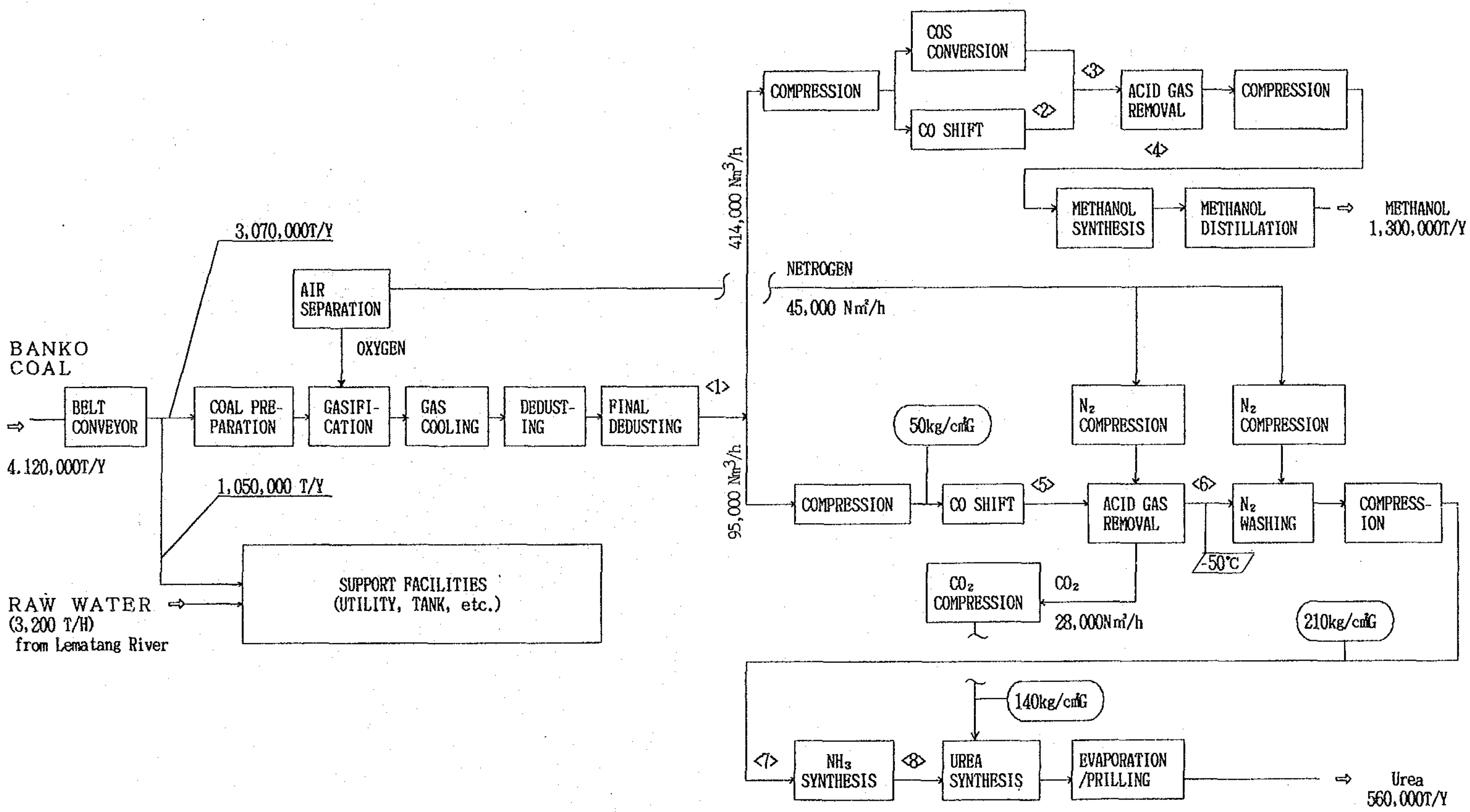


Fig.9-2-5

PRELIMINARY MASTER PLAN FOR FEASIBILITY STUDY ON EFFECTIVE UTILIZATION OF BANKO COAL

CASE 2-A

Fig. 7-2-1 OVERALL BLOCK FLOW DIAGRAM
(METHANOL/UREA CO-PRODUCTION)



OVERALL MATERIAL BALANCE

Stream	<1>	<2>	<3>	<4>	<5>	<6>	<7>
Flow Rate $10^3Nm^3/h$	509.2	353.8	540.3	410.6	147.8	89.2	110.3
Composition							
CO, vol.%	60.2	1.2	21.5	28.4	3.0	5.0	<1ppm
H_2, "	35.1	60.1	51.5	67.7	58.2	94.6	75.0
CO_2, "	4.3	38.4	26.7	3.5	38.5	<10ppm	-
N_2, "	0.4	0.3	0.3	0.4	0.3	0.4	25.0
H_2S/COS, vol.ppm	65/22	55/-	66/-	-/-	55/-	-/-	-/-

	<8>
Flow Rate, ton/h	41.7
Composition	
NH_3, wt.%	≧99.8
H_2O, "	≦ 0.2

Table 7-2-1 Plant Configuration

1) Belt Conveyor System

Primary Crusher/Feeder
Overland Coal Conveyor

2) Coal Gasification

Coal Storage and Handling
Coal Pretreatment
Coal Gasification
Gas Cooling/Dedusting
Calcination

3) Methanol Plant

Gas Compression
Gas Treating
Methanol Synthesis
Methanol Distrillation

4) Ammonia/Urea

Gas Compression
Gas Treating
Ammonia Synthesis
Urea Synthesis
Urea Prilling
Refrigeration System

5) Air Separation Plant

Air Separation
Liquid Oxygen Tank
Liquid Nitrogen Tank

6) Utility System

Power Generation
Power Distribution
Stream Boiler
Water Cooling
Raw Water Intake/Pretreatment
Instrument/Plant/Air Supply

7) Pollution Control/Safety System

Waste Water Treatment
Solid Waste Disposal
Flare/Blowdown
Fire Fighting

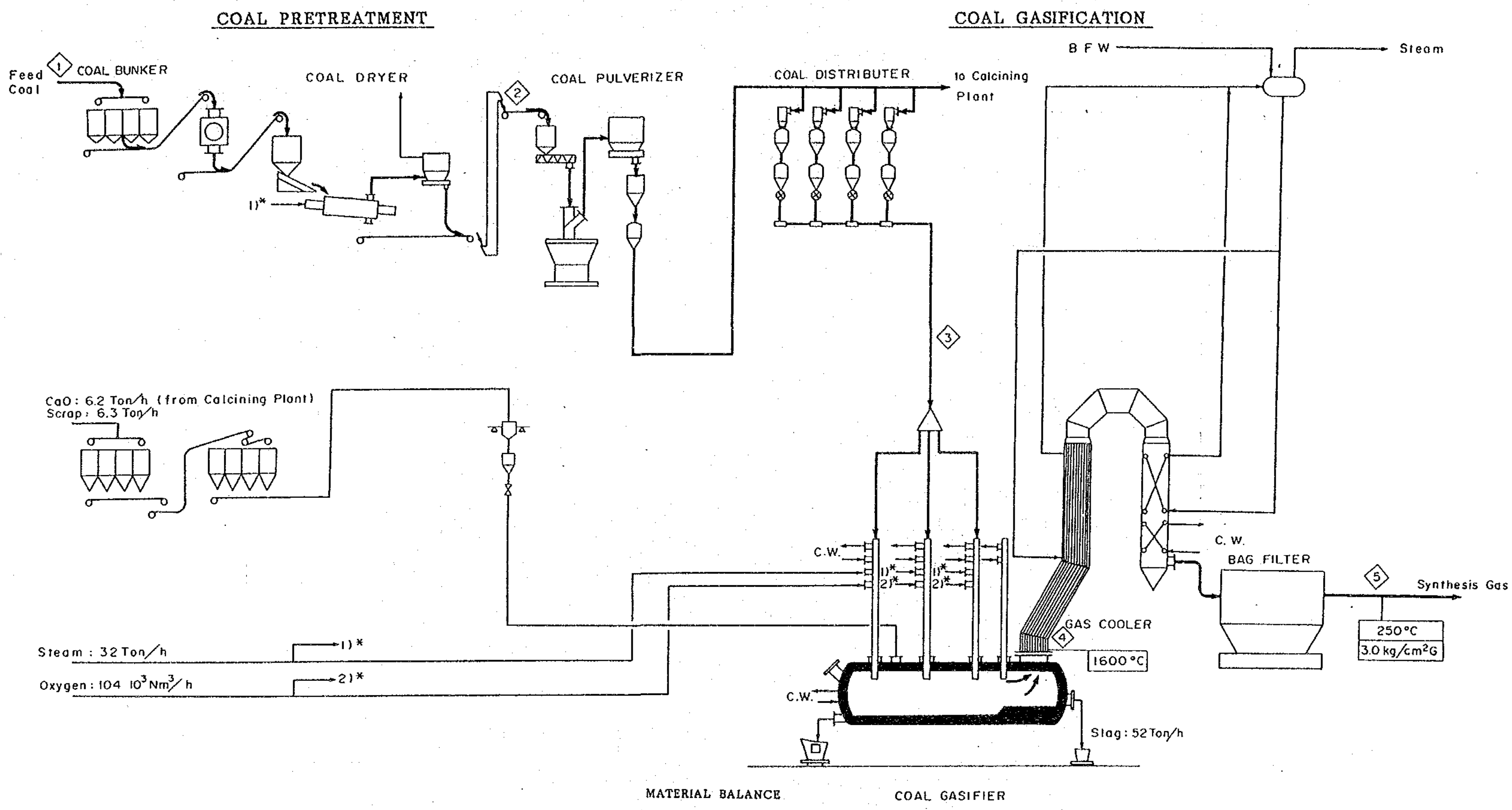
8) Storage

Product Tank
Chemicals Tank
LPG Tank
Fuel Oil Tank
Lubricating Oil Tank

9) Service Facilities

Administration Office
Laboratory
Warehouse
Accommodation
Canteen
Cafeteria
Leisure Center
Mosque
Communication System
Maintenance Shop
Portable Water Supply

Fig. 7-2-2 SIMPLIFIED PROCESS FLOW DIAGRAM
- COAL PRETREATMENT GASIFICATION -

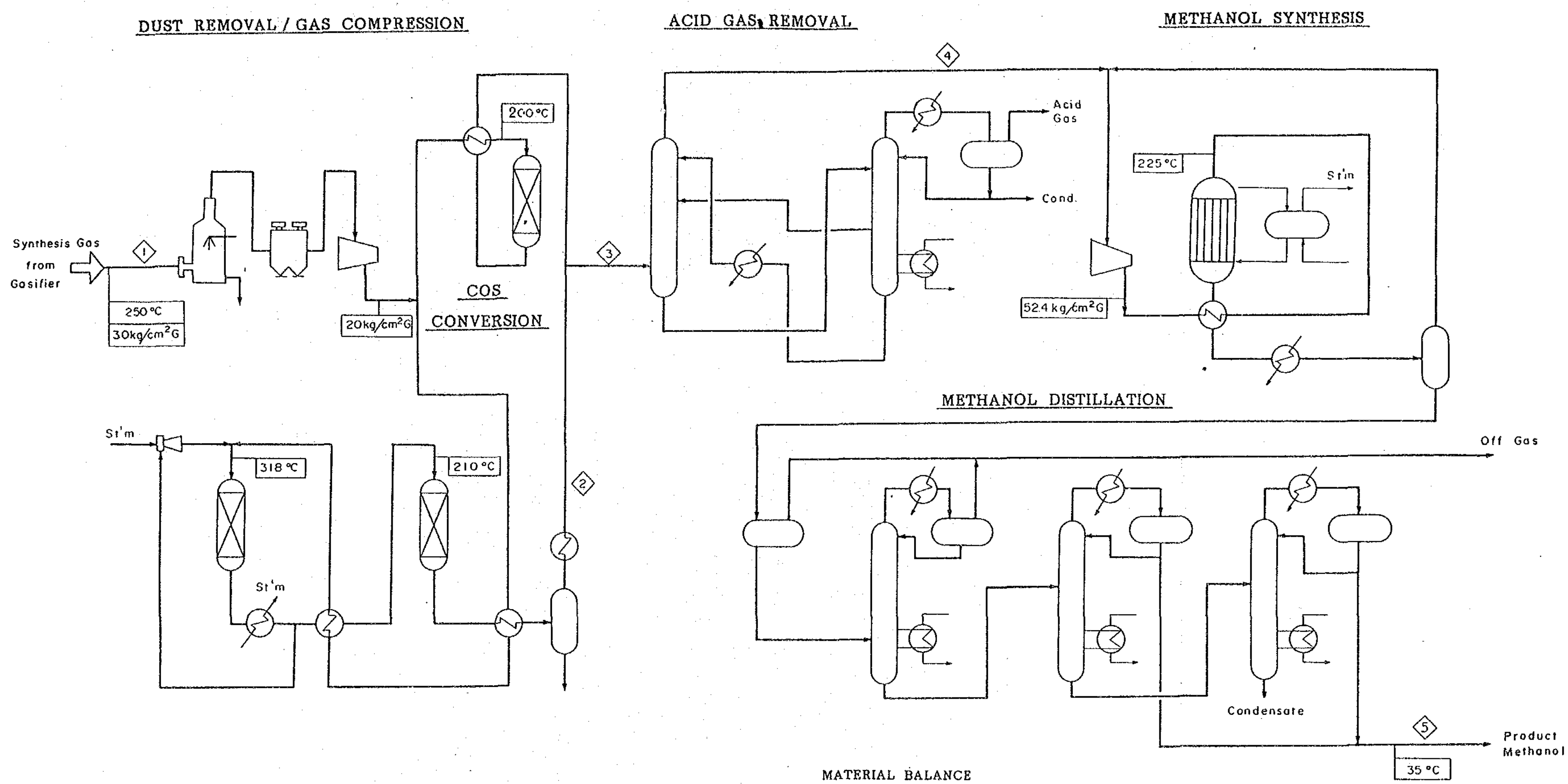


MATERIAL BALANCE

	①	②	③
Coal Rate, Ton/h	399	305	285
Moisture, %	35	15	10
Size, mm	< 40	< 3	-74 (>70%)

	④	⑤
Gas Rate (Dry), $10^3Nm^3/h$	509.2	509.2
Comp. CO, vol%	60.2	60.2
H_2, "	35.1	35.1
CO_2, "	4.3	4.3
N_2, "	0.4	0.4
H_2S/COS, ppm	65/22	65/22
T.S, "	87	87
Dust, g/Nm^3	25.0	0.01 - 0.05

Fig. 7-2-3 SIMPLIFIED PROCESS FLOW DIAGRAM
- GAS PRETREATMENT · METHANOL PRODUCTION -



MATERIAL BALANCE

	①	②	③	④
Flow Rate (Dry), $10^3 Nm^3/h$	414.2	353.8	540.3	410.6
Comp. CO, , vol %	60.2	1.2	21.5	28.4
H_2, , "	35.1	60.1	51.5	67.7
CO_2 , "	4.3	38.4	26.7	3.5
N_2, , "	0.4	0.3	0.3	0.4
H_2S/COS, ppm	65/22	55/-	66/-	-
Dust , g/Nm^3	0.01	-	-	-

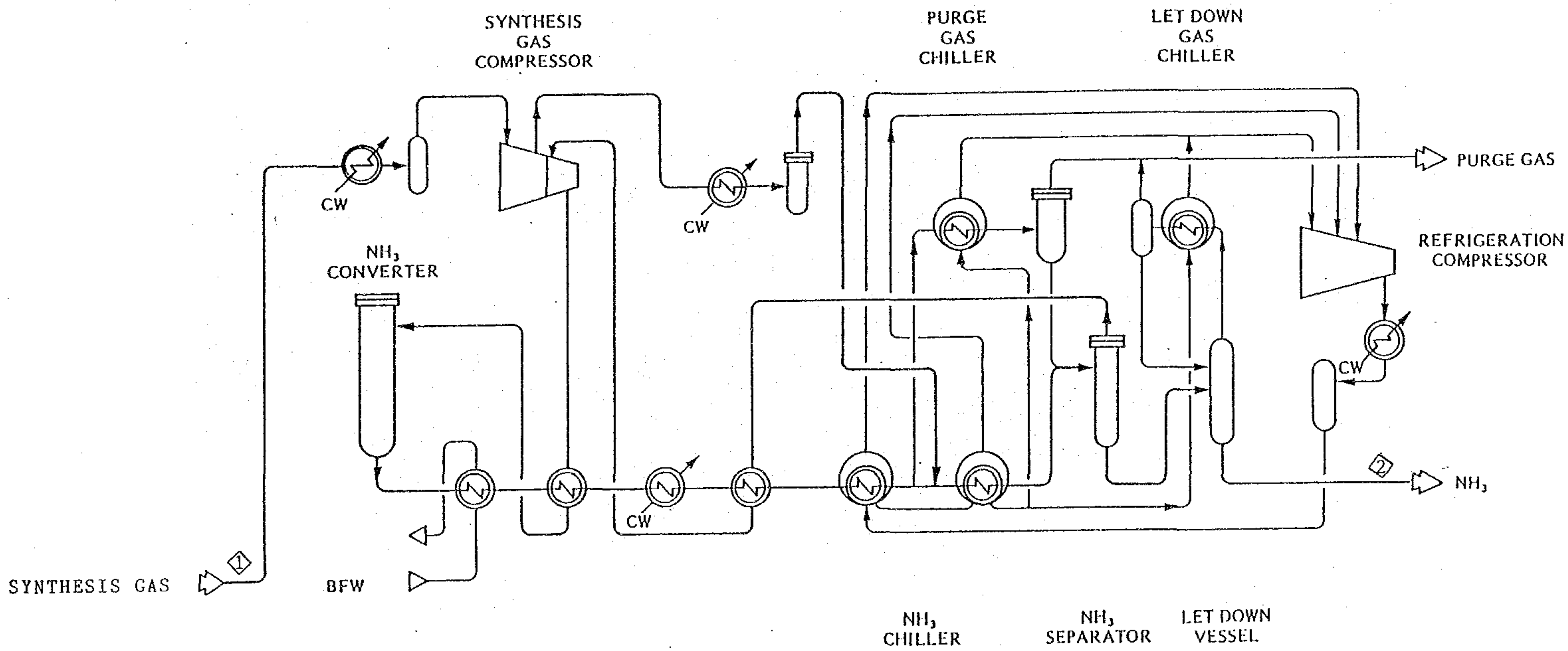
	⑤
Flow Rate, Ton/h	169.4
Comp. CH_3OH, wt%	≧ 99.9
Inerts, "	-
H_2O, "	≦ 0.1

Table 7-2-2 Major Equipment
(Methanol Production Section)

Description	Q'ty	Specification		
Dedusting (3 trains)		Capacity	;	139,000 Nm^3/h/train
o Dust Washer	3+1S	Dust, In/out	;	50/5 mg/Nm^3
CO Shift (2 trains)		Capacity	;	114,000 Nm^3/h/train
o High Temp. Converter	2	CO, In/Out	;	59.6/1.2 vol.%
o Low Temp. Converter	2	Type	;	Vertical, Cylindrical with catalyst
COS Hydrolysis (2 trains)		Capacity	;	95,000 Nm^3/h/train
COS Converter	2	COS, In/Out	;	50/0.1 ppm
Acid Gas Removal (2 trains)		Capacity	;	275,000 Nm^3/h/train
o Absorber	2	CO_2, In/Out	;	26.1/3.5 vol.%
o Regenerator	2	H_2S, In/Out	;	200/0.1 ppm
Methanol Synthesis (2 trains)		Capacity	;	206,000 Nm^3/h/train
o Methanol Reactor	2	Type	;	Vertical, Cylindrical with Catalyst
Methanol Distillation (2 trains)		Capacity	;	2,100ton/h-Methanol/Train
o Pre-run Column	2	Type	;	Vertical, Cylindrical with Tray
o Pressure Column	2			
o Pressureless Column	2			

Fig. 7-2-4 SIMPLIFIED PROCESS FLOW DIAGRAM
- AMMONIA PRODUCTION -

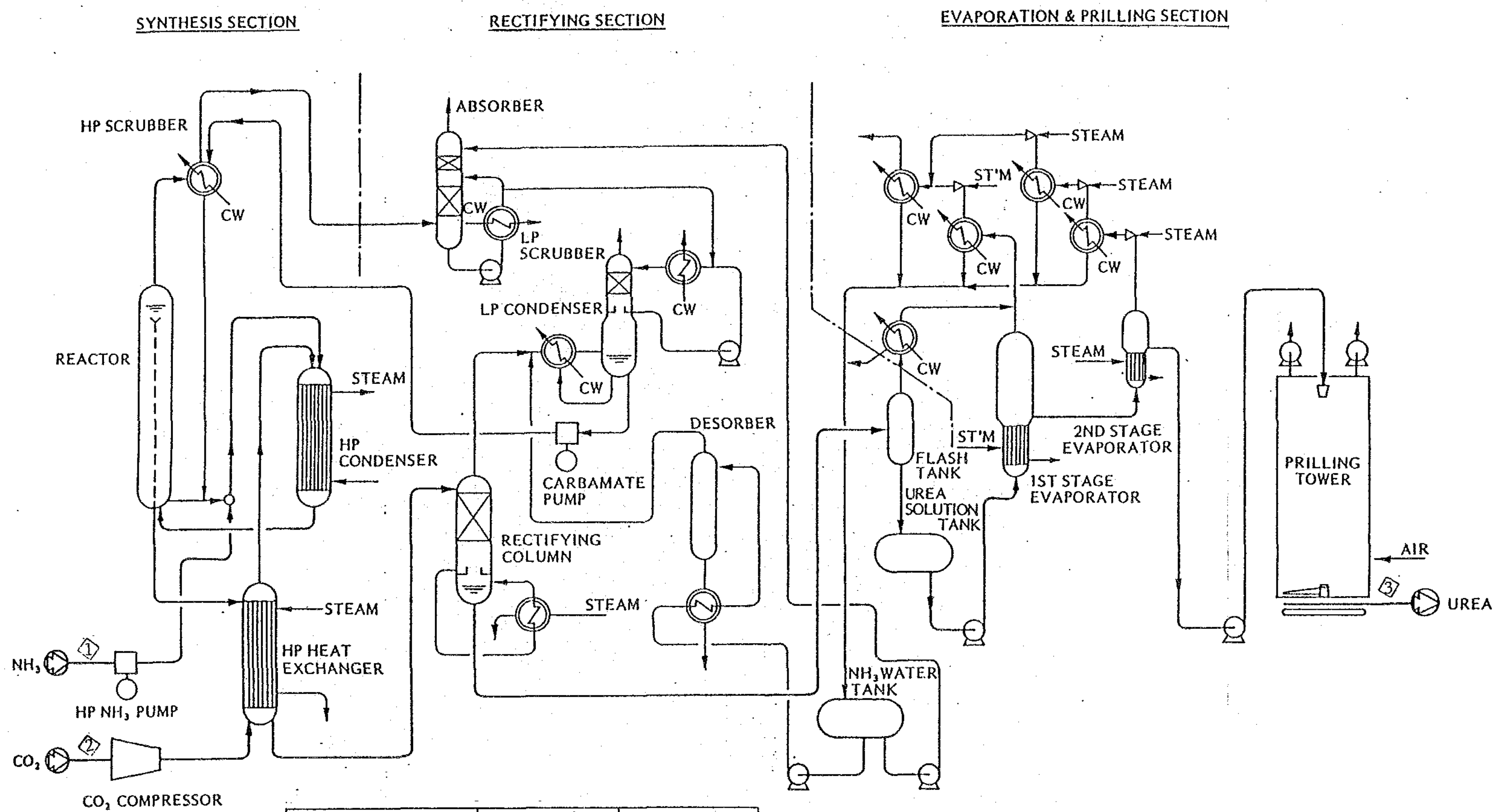
NH_3 SYNTHESIS SECTION



	①
Flow Rate, $10^3 Nm^3/H$	110.3
Composition	
CO, Vol %	< 1ppm
H_2, "	75.0
N_2, "	25.0

	②
Flow Rate, Ton/H	41.7
Composition	
NH_3, wt %	≧ 99.8
H_2O, "	≦ 0.2

Fig. 7-2-5 SIMPLIFIED PROCESS FLOW DIAGRAM
- UREA PRODUCTION -



	①	②
Flow Rate, Ton/H	41.7	55.0
Composition		
NH_3, wt%	≧ 99.8	
CO_2, "		≧99.9
H_2O, "	≦ 0.2	≦ 0.1

	③
Flow Rate, Ton/H	72.9
Composition	
$(NH_2)_2CO$, wt%	≧ 99.7
H_2O , "	≦ 0.3

Table 7-2-3 Major Equipment
(Ammonia/Urea Production Section)

Description	Q'ty	Specification		
Dedusting		Capacity	;	95,000 Nm^3/h
o Dust Washer	1	Dust,In/Out	;	50/5 mg/Nm^3
CO Shift		Capacity	;	95,000 Nm^3/h
o High Temp Converter	1	CO,In/Out	;	60.2/3.0 vol.%
o Low Temp Converter	1	Type	;	Vertial, Cylindrical with Catalyst
Acid Gas Removal		Capacity	;	148,000 Nm^3/h
o Acid Gas Absorben	1	CO_2,In/Out	;	38.5 vol.%/<10 vol.ppm
o CO_2 Flash Column	1	H_2S,In/Out	;	55 vol. ppm/ -
o H_2S Flash Column	1			
o Methanol Rectifier	1			
Nitrogen Washing				
o Washing Column	1	Capacity	;	89,200 Nm^3/h
	1	CO,In/Out	;	5.0 vol.%/<1 vol.ppm
NH_3 Synthesis		Capacity	;	41.7 ton/h as Product NH_3
o NH_3 Converter	1	Type	;	Vertical, Radial FLow with Catalyst
Urea Synthesis		Capacity	;	72.9 ton/h as Product Urea
o Reactor	1	Type	;	Vertical, Cylindrical

(8) Plant Layout

The exact layout cannot be determined in this stage, but the image of the layout as well as the required area will be of help to the study in the final step.

In this regards, the plant layout is roughly estimated as shown in Fig. 7-2-6.

7-2-3 Financial Analysis

Financial viability and profitability of the project was evaluated by means of financial statements* and internal rate of return (hereafter referred to as IRR) on total project investment.

*Projected Profit & Loss Statement
Projected Cash Flow Statement
Projected Balance Sheet

(1) Assumptions

1) Production Schedule

i) Annual Production:

Methanol : 1,300,000 ton (Chemicla grade)
Urea : 560,000 ton (ditto)

ii) Plant Construction Period: 1990-1993 (4 years)

where 30% Completion at the end of 1990
60% Completion at the end of 1991
80% Completion at the end of 1992
100% Completion at the end of 1993

iii) Project Life : 1994-2023 (30 years)

where 70% of full operation in 1994
85% of full operation in 1995
100% of full operation in 1996 and after

iv) Annual Operation Days : 320 days

2) Finance

Same as that in the feasibility study on methanol prodution in 1985. (For details, see the Interim Report II (1985), page 214-215.)

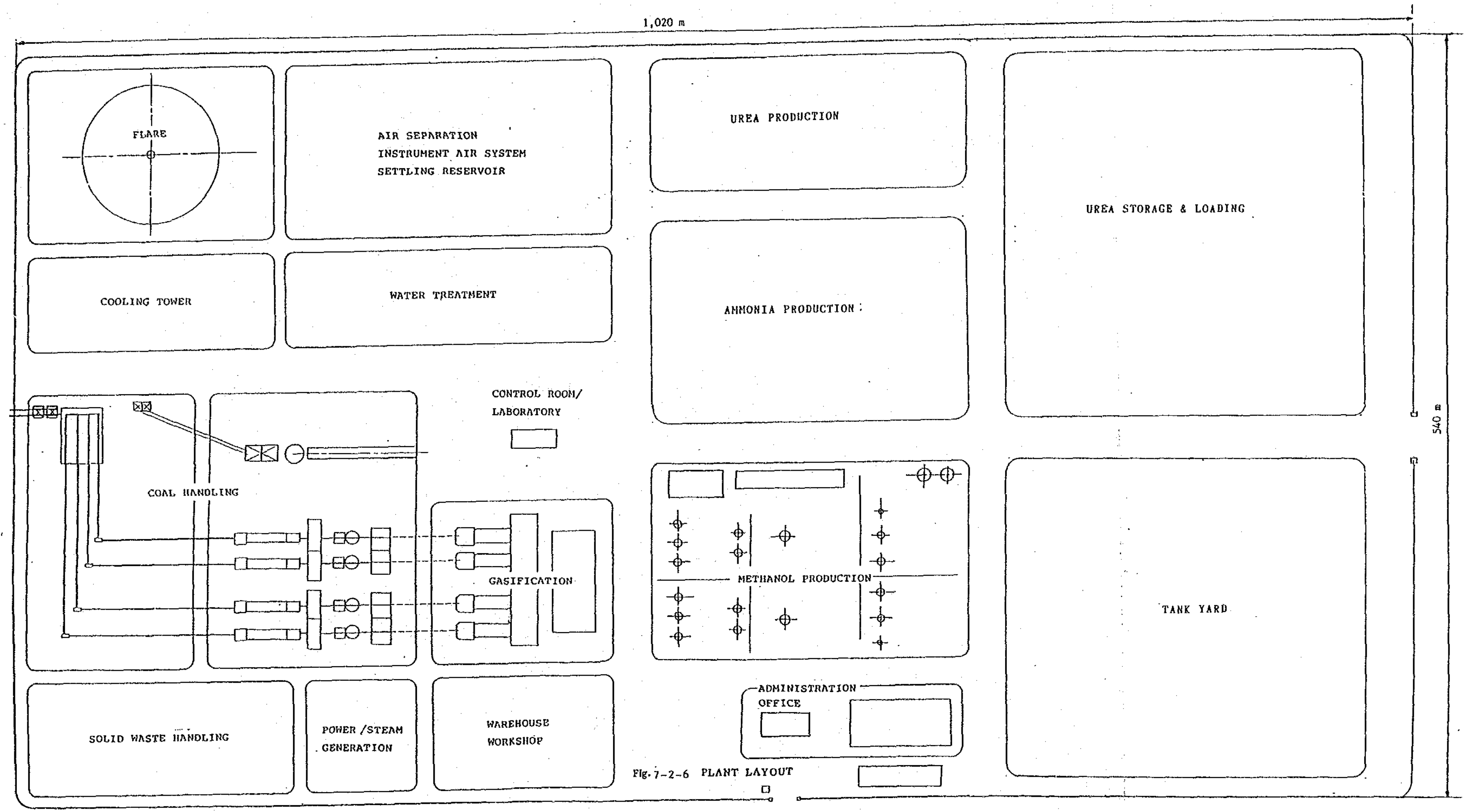


Fig. 7-2-6 PLANT LAYOUT

3) Escalation

No escalation is assumed.

4) Price and Costs

i) Sales Price of Methanol and Urea

Case U-1:	Methanol	194 Rp/kg (35 ¥/kg)
	Urea	111 Rp/kg (20 ¥/kg, 100 $/T)
Case U-2:	Methanol	194 Rp/kg (35 ¥/kg)
	Urea	166 Rp/kg (30 ¥/kg, 150 $/T)
Case U-3:	Methanol	194 Rp/kg (35 ¥kg)
	Urea	222 Rp/kg (40 ¥/kg, 200 $/T)

Note*) Sales price of methanol was assumed referring to the base case of methanol production study in 1985.

As to the urea price, three cases were estimated from the worldwide trend in recent years.

ii) Capital Investment Costs

a) Fixed-capital Investment:

	10^6 Rupiah	(10^6 Yen)
Coal Gasification	369,500	(66,700)
Coal Transportation	43,200	(7,800)
Methanol Plant	162,900	(29,400)
Urea Plant	154,000	(27,800)
Support Facilities	354,600	(64,000)
Equipment Transportation	63,700	(11,500)
Contingency	57,600	(10,400)
Total	1,205,500	(217,600)

b) Working capital:	56,925	(10,275)

Note*) Working captal is added as cash-inflow at the end of the project.

c) Start-up Expense:	7,003	(1,264)
d) Operator Training Cost:	3,213	(580)

Note*) Table 7-2-5 shows the investment schedule.

Table 7-2-5 Investment Schedule

Yen	1990	1991	1992	1993
Fixed Capital	30%	30%	20%	20%
Working Capital	-	-	-	100%
Start-up Expense	-	-	-	100%
Operator Training	-	-	-	100%

iii) Annual expense

a) Fixed Costs

o Depreciation and Amortization 1)*

	Period Years	Amount 10^6 Rupiah /Year	(10^6 Yen/Year)
• Boiler, Power Plant, Cooling Tower, Buildings	15	20,127	(3,633)
• Others	10	108,968	(19,669)
o Maintenance		28,463	(5,137)
o Insurance		11,385	(2,055)
b) Variable Costs			
o Raw Material(Coal) 2)*		67,734	(12,226)
o Superviser and Operating Labor			
• Foreign Staff 3)*			
• Local Labor		3,346	(604)
o Catalyst and Chemicals		3,324	(600)
c) Plant Overhead Costs		12,997	(2,346)
d) Administration Expenses		6,499	(1,173)

Note*): 1) Capital investment for the plant construction including expenses and interests during construction period is depreciated and amortized based on straight line method.

2) In the strategic study in FY1984, mining cost was estimated at \$13.88/ton-coal. In this study, \$14.85/ton-coal is assumed as raw material costs by adding 7% to the mining cost as overhead.

3) Foreign staff decrease in number as the project proceeds.

Table 7-2-6 Costs for Foreign Staffs

Op. Year	1st	2nd	3rd	4th	5th	6th-30th
Year	1994	1995	1996	1997	1998	1999-2023
% on 1st year	100	70	50	30	10	0
Cost, 10^6 rupiah/year	9,651	6,756	4,825	2,895	965	0
(Cost, 10^6 yen/year)	(1,742)	(1,219)	(871)	(523)	(174)	(0)

5) Evaluation criteria

i) Financial Statement

a) Profit and Loss Statement

b) Cash Flow Statement

c) Balance Sheet

ii) IRR on Total Project Cost before Tax

(For details, see the Interim Report II (1985), page 218-219.)

(2) Results and Evaluation

1) Results

Results are summerized in Table 7-2-7.

As far as IRR is concerned, Case U-3 can compare with the base case of methanol production carried out last year.

Profit and loss statement and cash flow statement of Case U-3 are shown in Table 7-2-8 and Table 7-2-9.

Table 7-2-7 Results of Financial Analysis

Case	U-1	U-2	U-3	(Reference) Base Case
Sales Price of Products	Methanol 194 Rp/kg Urea 111 Rp/kg (100 $/T)	Methanol 194 Rp/kg Urea 166 Rp/kg (150 $/T)	Methanol 194 Rp/kg Urea 222 Rp/kg (200 $/T)	Methanol 194 Rp/kg
IRR on Total Investment	10.6%	12.3%	13.8%	13.5%
First Year to Have Profit before Tax (Year from Operation Starts)	6th	3rd	3rd	3rd
Clear off of Accumulated Loss (Year from Operation Starts)	12th	7th	4th	5th
Pay off of All the Debts (Year from Loan Raised)	14th	12th	12th	12th
Minimum Sales Price (IRR=Interest Rate)	Methanol 194 Rp/kg Urea 33.4 Rp/kg (30.2 $/T)			143 Rp/kg

Table 7-2-8 Profit and Loss Statement of Case U-3

(Unit: 10^9 Rupiah)

Year	OP Year	REVENUE	EXPENDITURE					PROFIT			Retained
			Variable Cost	Fixed Cost	General	Interest Paid	Total	Before Tax	(Tax)	Net Profit	Earning
1994	1	263.3	62.7	168.9	19.5	84.6	335.8	- 72.5	0	- 72.5	- 72.5
1995	2	319.8	70.5			77.9	336.8	- 17.1	0	- 17.1	- 89.6
1996	3	376.2	79.2			66.6	334.3	41.9	0	41.9	- 47.7
1997	4		77.3			52.4	318.2	58.0	4.7	53.2	5.6
1998	5		75.4			38.9	302.7	73.5	33.8	39.7	45.3
1999	6		74.4			27.2	290.0	86.2	39.6	46.5	91.8
2000	7					16.3	279.1	97.0	44.6	52.4	144.2
2001	8					5.4	268.3	107.9	49.6	58.3	202.5
2002	9					0	262.8	113.3	52.1	61.2	263.7
2003	10			168.9			262.8	113.3	52.1	61.2	324.9
2004	11			60.0			153.9	222.3	102.3	120.0	444.9
2005	12						153.9	222.3	102.3	120.0	564.9
2006	13						153.9	222.3	102.3	120.0	685.0
2007	14						153.9	222.3	102.3	120.0	805.0
2008	15			60.0			153.9	222.3	102.3	120.0	925.1
2009	16			39.8			133.7	242.4	111.5	130.9	1,056.0
2010	17										1,186.9
2011	18										1,317.8
2012	19										1,448.7
2013	20										1,579.6
2014	21										1,710.5
2015	22										1,841.5
2016	23										1,972.4
2017	24										2,103.3
2018	25										2,234.2
2019	26										2,365.1
2020	27										2,496.0
2021	28										2,626.9
2022	29										2,757.8
2023	30	376.2	74.4	39.8	19.5	0	133.7	242.4	111.5	130.9	2,888.7
	Total	11,116.0	2,225.2	2,587.0	584.9	369.3	5,766.5	5,349.5	2,460.8	2,888.7	

Table 7-2-9 Cash Flow Statement of Case U-3

(Unit: 10^9 Rupiah)

Year	OP Year	INVESTMENT	Profit Before TAX	Depreciaiton/ Amortization	Interest Paid	CASH FLOW	DCF (Base; 1985)
1990		- 361.7	-	-	-	- 361.7	- 189.3
1991		- 361.7	-	-	-	- 361.7	- 166.3
1992		- 241.1	-	-	-	- 241.1	- 97.4
1993		- 308.2	-	-	-	- 308.2	- 109.4
1994	1	-	- 72.5	129.1	84.6	141.2	44.1
1995	2	-	- 17.1		77.9	189.9	52.0
1996	3	-	41.9		66.6	237.6	57.2
1997	4	-	58.0		52.4	239.5	50.7
1998	5	-	73.5		38.9	241.5	44.9
1999	6	-	86.2		27.2	242.4	39.6
2000	7	-	97.0		16.3		34.8
2001	8	-	107.9		5.4		30.6
2002	9	-	113.3		0		26.9
2003	10	-	113.3	129.1			23.6
2004	11	-	222.3	20.1			20.7
2005	12	-	222.3				18.2
2006	13	-	222.3				16.0
2007	14	-	222.3				14.1
2008	15	-	222.3	20.1			12.4
2009	16	-	242.4	0			10.9
2010	17	-					9.5
2011	18	-					8.4
2012	19	-					7.4
2013	20	-					6.5
2014	21	-					5.7
2015	22	-					5.0
2016	23	-					4.4
2017	24	-					3.9
2018	25	-					3.4
2019	26	-					3.0
2020	27	-					2.6
2021	28	-					2.3
2022	29	-				242.4	2.0
2023	30	-	242.4	0	0	299.4	2.2
	Total	- 1,272.7	5,349.5	1,391.6	369.3	5,894.7	0

2) Evaluation

i) The effect of IRR on the sales price of urea is not so high under fixed price of methanol (194 Rp/kg, 35 ¥/kg) because of low production ratio of urea to methanol.

ii) The sales price of urea is necessary to set at about 190 \$/T (211 Rp/kg) to gain 13.5% of IRR which is equal to the Base Case of methanol producton (Fig.7-2-7).

Though product transportation is out of scope in this study, urea should be transported to stockyard at Palembang by truck or train if it is exported.

Approximately 0.15 \$/T·Km is assumed as inland transportation cost of urea referring to that of methanol.

The FOB cost at Palembang will be around 215 \$/ton including 25 \$/ton of inland transportation cost assuming that the distance between the plant site and Palembang is 170 Km. On the otherhand, international FOB price in 1984 was 170-180\$/ton at 30\$/bbl of crude oil price.

It is not hopeful to export urea products in the circumstances of present market.

Fig. 7-2-8 shows relationship between price of urea and methanol imported in Japan and crude oil exported by OPEC.

iii) The economic of urea production is inferior to that of methanol, and therefore it can be concluded that case 2 of the master plan (co-production of methanol and urea) will be eliminated from further study in the 3rd stage.

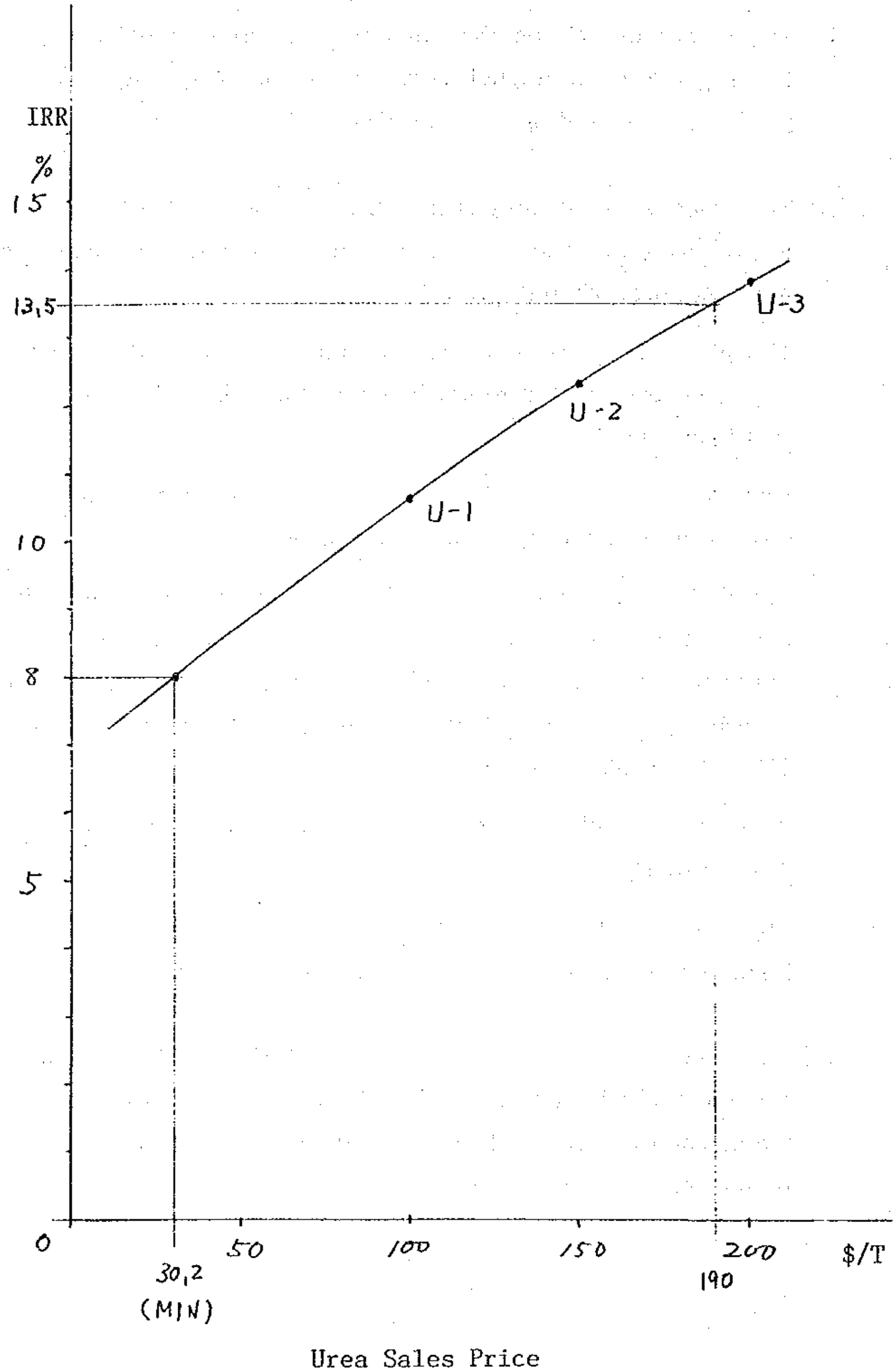
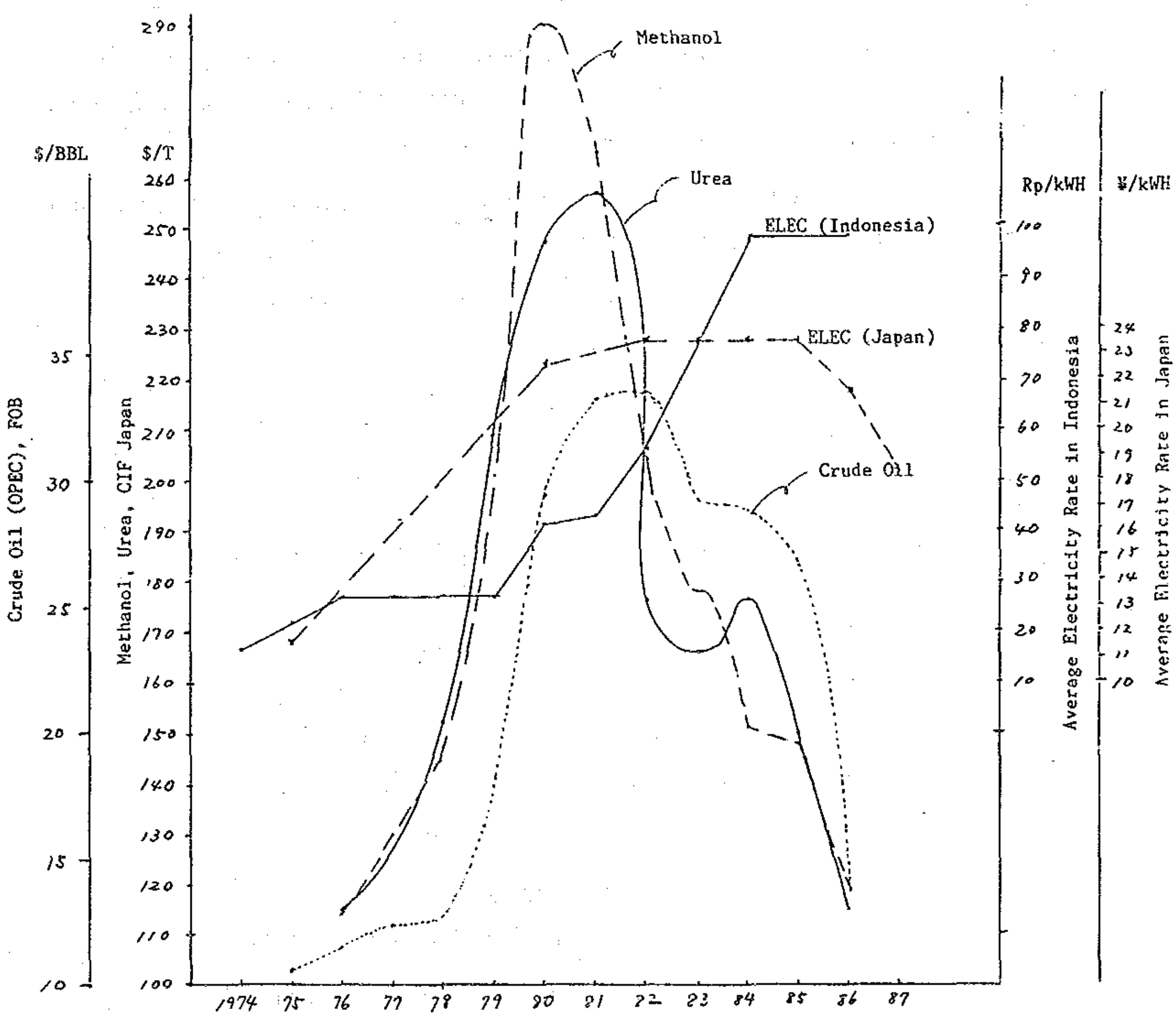


Fig. 7-2-7 IRR VS Urea Sales Price

Fig. 7-2-8 Shifts in Price of Crude Oil (FOB OPEC), Methanol and Urea (CIF Japan), and Electricity Rate in Indonesia and Japan



7-3 ELECTRICITY GENERATION COST

7-3-1 Objective of the Study

This study was carried out for the purpose of preliminary evaluation on the case of electricity generation from Banko coal through gasification.

The same quantity of coal (495 T/H) consuming in the methanol project (FY1985) is gasified and generated in the power plant. However, the actual consumption rate of coal is 66% of that in methanol case, since the average load factor of power plant in Indonsia is forecasted to be 66%.

Four cases for sales price of electricity which is supplied to Jakarta and adjacent area of the power plant, are assumed.

Assumption of economic factors such as production schedule, finance and raw material cost is same as those in the study in FY1985.

7-3-2 Outline of Power Plant

(1) Design Basis

1) Type of Power Plant : Combined Cycle Generation

2) Generating Power:

Gross Generating Power	:	900 MW
Available Generating Power	:	855 MW
Net Generating Power	:	835 MW
(Power to Gasification Plant	:	20 MW)

3) Annual Operation Days : 320 days/year

4) Plant Location : Tanjung Priok
(For details, see the Interim Report II (1985), P.187-188.)

5) Electricity Transmission : Switchyard of Power Plant
Note*) Electricity will be sold to PLN.

6) Feed Coal Specification:

C, %	:	27.4
V.M., %	:	32.8
Ash, %	:	4.8
Mo., %	:	35.0

Total, %	:	100.0
HV, Kcal/kg	:	4,430

7) Coal Receiving : Bunker Hopper at Mine Site

8) Utilities : All the utilities expect raw water and coal are generated inside the plant

Conditions:

HP St'm	:	480°C, 65 kg/cm^{2}G
MP St'm	:	250°C, 40 kg/cm^{2}G
LP St'm	:	155°C, 3.5kg/cm^{2}G
BFW(I)	:	110°C, 5 kg/cm^{2}G
BFW(II)	:	110°C, 55 kg/cm^{2}G
C. Water	:	30°C(Supply)/37°C(Return)

(2) Plant Configuration

Fig.7-3-1 shows the scope of coal gasification and electricity generation complex devided into seven blocks each of which has its individual function.

The component facilities in each block are listed in Table 7-3-1. The main process and systems in the complex are described in the following pages.

(3) Belt Conveyor System

See the Interim Report II (1985), page 192-197.

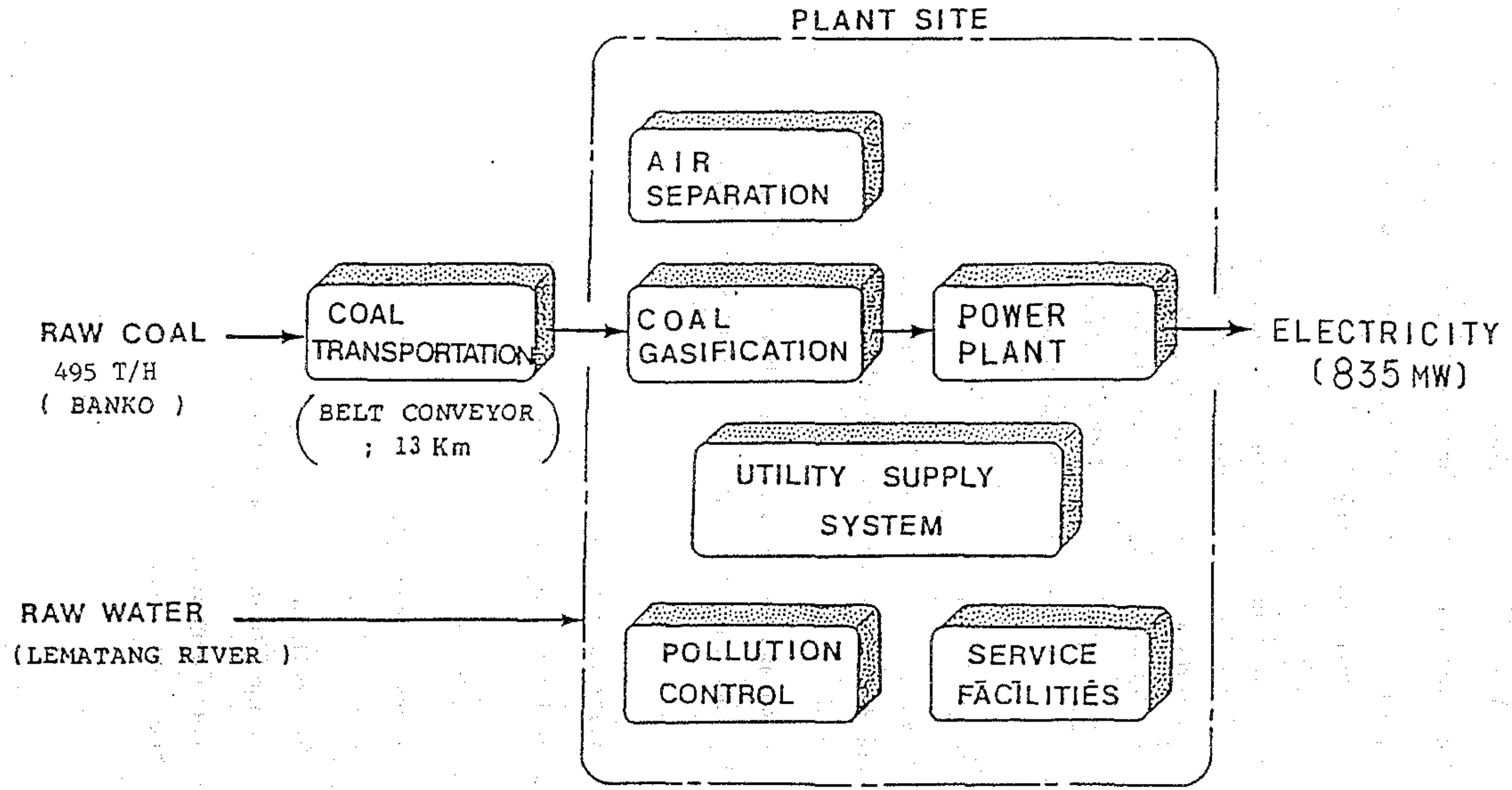
(4) Coal Gasification

1) Process Flow Diagram
See Fig.7-3-2.

2) Process Description
See the Interim Report II (1985), page 198

3) Major Equipment
See Table 7-3-2.

Fig. 7-3-1 Overall Block Flow Diagram



* Component facilities consisting each block are listed in Table 7-3-1

Table 7-3-1 Plant Configuration

1) Belt Conveyor System

   Primary Crusher/Feeder
   Overland Coal Conveyor

2) Coal Gasification

   Coal Storage and Handling
   Coal Pretreatment
   Coal Gasification
   Gas Cooling/Dedusting
   Calcination

3) Air Separation Plant

   Air Separation
   Liquid Oxygen Tank
   Liquid Nitrogen Tank

4) Power Plant & Utility System

   Gas Turbine/Generator
   Steam Turbine/Generator
   Heat Recovery Steam Generator (HRSG)
   HP & LP Steam Circuit
   Power Distribution
   Water Cooling
   Raw Water Intake/Pretreatment
   Instrument/Plant Air Supply

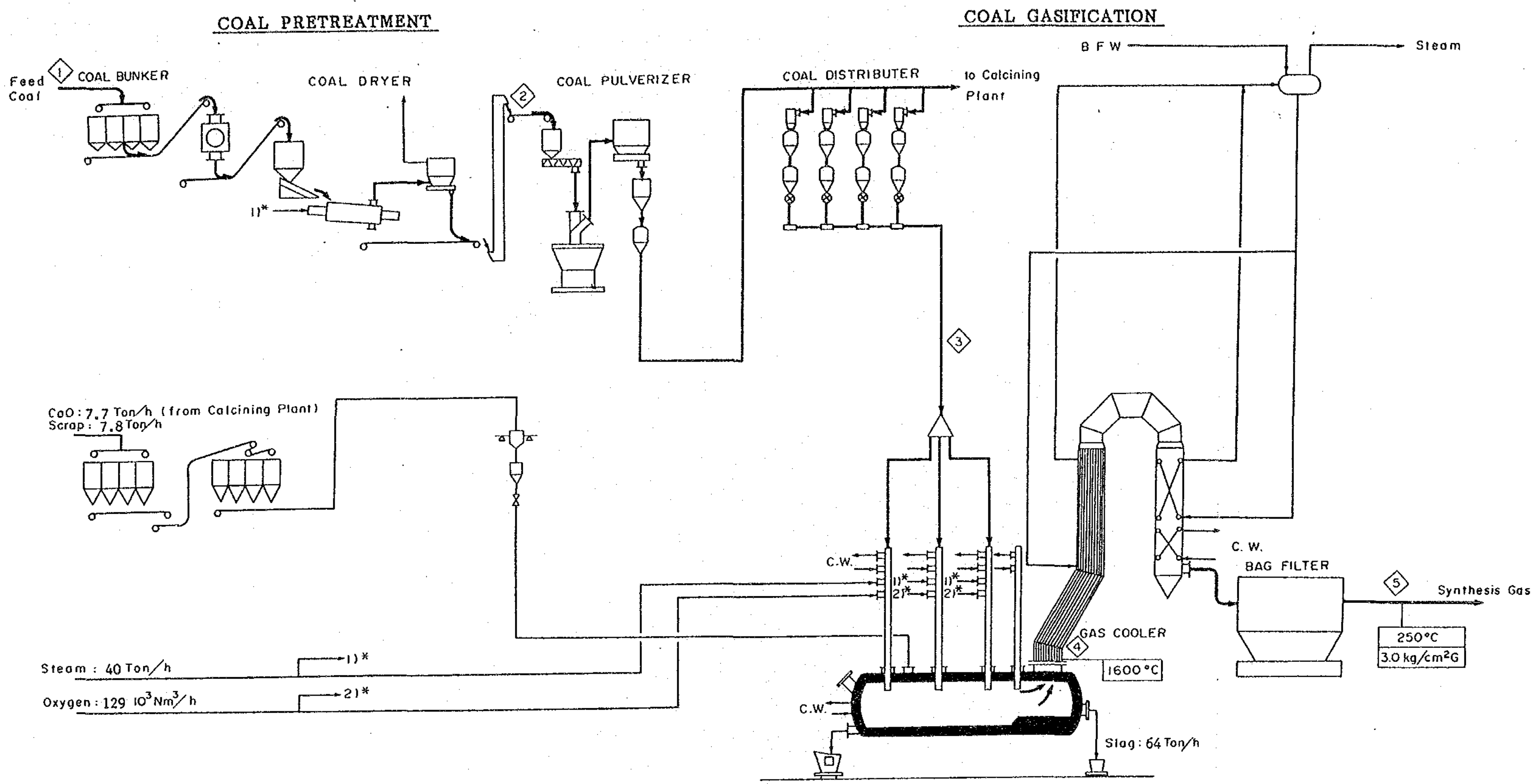
5) Pollution Control/Safety System

   Waste Water Treatment
   Solid Waste Disposal
   Flare/Blowdown
   Fire Fighting

6) Service Facilities

   Administration Office
   Laboratory
   Warehouse
   Accommodation
   Canteen
   Cafeteria
   Leisure Center
   Mosque
   Communication System
   Maintenance Shop
   Portable Water Supply

Fig. 7-3-2 SIMPLIFIED PROCESS FLOW DIAGRAM
- COAL PRETREATMENT GASIFICATION -



MATERIAL BALANCE COAL GASIFIER

	1	2	3
Coal Rate, Ton/h	495	378	353
Moisture, %	35	15	10
Size, mm	< 40	< 3	-74 (>70%)

	4	5
Gas Rate (Dry), $10^3 Nm^3/h$	630	630
Comp. CO, vol%	60.2	60.2
H_2, "	35.1	35.1
CO_2, "	4.3	4.3
N_2, "	0.4	0.4
H_2S/COS, ppm	65/22	65/22
T.S, "	87	87
Dust, g/Nm^3	25.0	0.01 - 0.05

Table 7-3-2 **Major Equipment**
(Coal Gasification)

Description	Q'ty	Capacity	Specification
1. Coal Handling Section			
1.1 Primary Crusher	5	120 T/H	Dimension: 3,560W x 2,690L x 1,890H Weight: 30 T/unit
1.2 Dewatering Drum	5	100 T/H	Dimension: 4,800 ø x 29,000L Weight: 540 T/unit
1.3 Coal Pulverizer	5	80 T/H	Dimension: 5,300 ø x 8,300H Weight: 280 T/unit
2. Gasification Process Section			
2.1 Gasifier	4+1	100 T/H coal	Shell dimension: 5,400ø x 17,700H Weight: 670 T/unit
2.2 Ladle	4	290 Tonnes	Dimension: 4,800ø x 6,700 H Weight: 65 T/unit
2.3 Ladle Crane	1	450 Tonnes	Span: 14,000 mm Weight: 670 T/unit
3. Gas Treatment Section			
3.1 Radiation Cooler	4+1	170 KNm3/H	Dimension: 4,100ø x 30,600H Weight: 450 T/unit
3.2 Convection Cooler	4+1	170 KNm3/H	Demension: 4,100ø x 17,300H Weight: 450 T/unit
3.3 Heat Exchanger	4+1	170 KNm3/H	Dimension: 4,100ø x 20,400H Weight: 540 T/unit

(5) Power Plant

1) Process Flow Diagram

See Fig. 7-3-3.

2) Process Description

a) The plant comprises three combined cycle blocks. Each consists of two 100 MW class gas turbines (Fig.7-3-4), two heat recovery steam generators (HRSG) and a steam turbine (Fig.7-3-5).

b) The gas turbine/generator packages convert about 31% of the fuel energy into electric power and release almost all the remainder as waste heat in the exhaust gas at about 530°C. This wasted energy is recovered for use as heat. The heat recovery steam generator (HRSG) positioned on the exhaust paths reduce the exhaust temperature to about 130°C and recover the gas turbine losses by converting them into steam. The stream is used to drive steam turbines to generate additional power and process steam. Thus the gross efficiency of power plant becomes about 45%.

c) The HRSG is of dual pressure system and produces two different pressure steams.

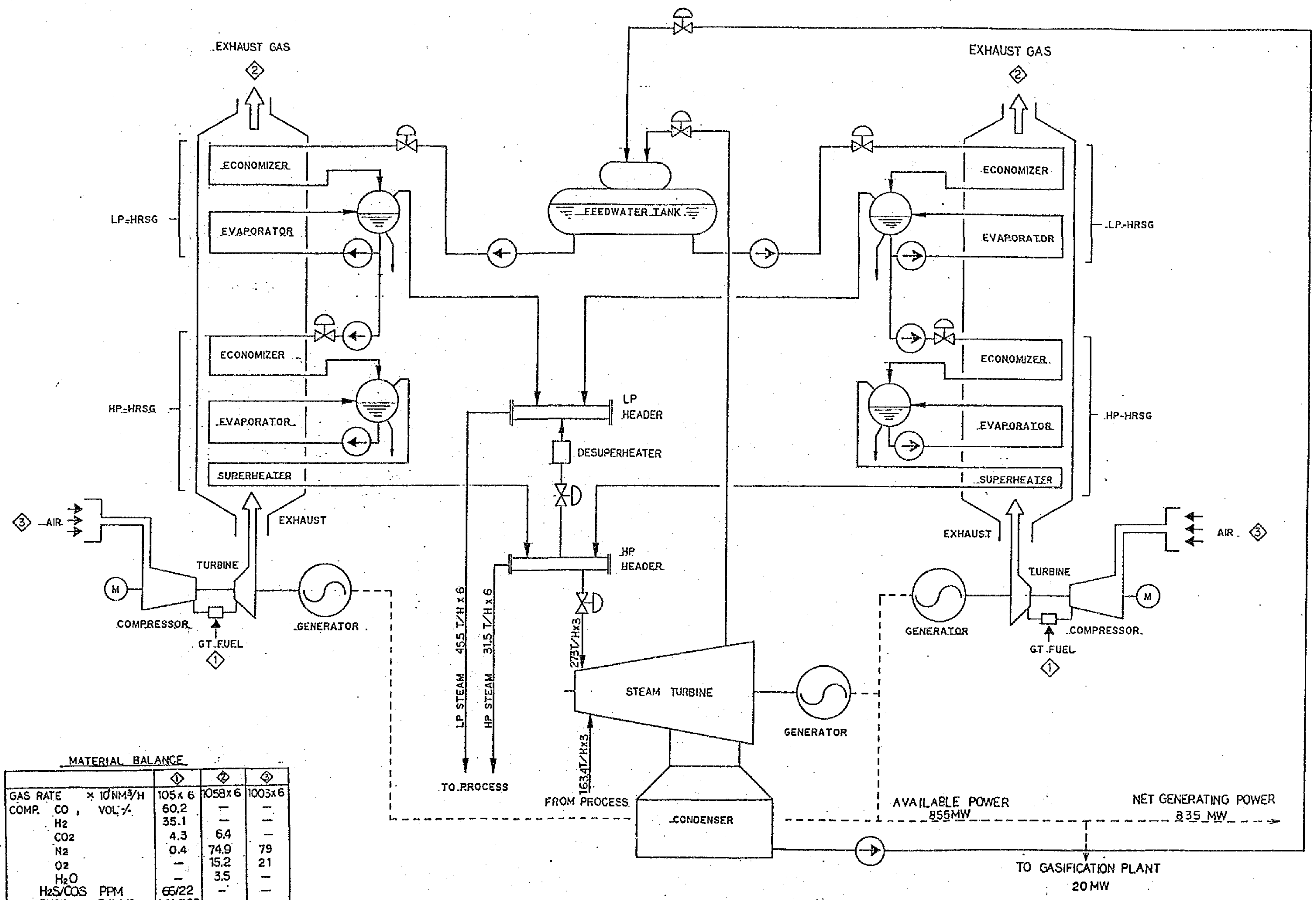
HP steam:	65 kg/cm^2G x 480°C
LP steam:	3.5kg/cm^2G x 155°C

The feedwater is first heated in feedwater tank and then in the LP economizer. Evaporation takes place in forced circulation LP evaporator and transferred to the process. HP part of the HRSG has the same system as that of LP part, though superheater is furnished in this case, and is placed in series in the exhaust gas stream. A part of HP steam is transferred to the process and the remainder is used to drive steam turbine. MP steam (40 kg/cm^2G x 250°C) is input to the intermediate stage of the steam turbine.

3) Major Equipment

Specifications and the number of units of major equipment are listed in Table 7-3-3.

Fig. 7-3-3 SIMPLIFIED PROCESS FLOW DIAGRAM
- POWER PLANT -



MATERIAL BALANCE

		①	②	③
GAS RATE	× 10 NM^3/H	105x 6	1058x 6	1003x 6
COMP. CO,	VOL %	60.2	—	—
H_2		35.1	—	—
CO_2		4.3	6.4	—
N_2		0.4	74.9	79
O_2		—	15.2	21
H_2O		—	3.5	—
H_2S/COS	PPM	65/22	—	—
DUST,	G/NM^3	0.01-0.05	—	—

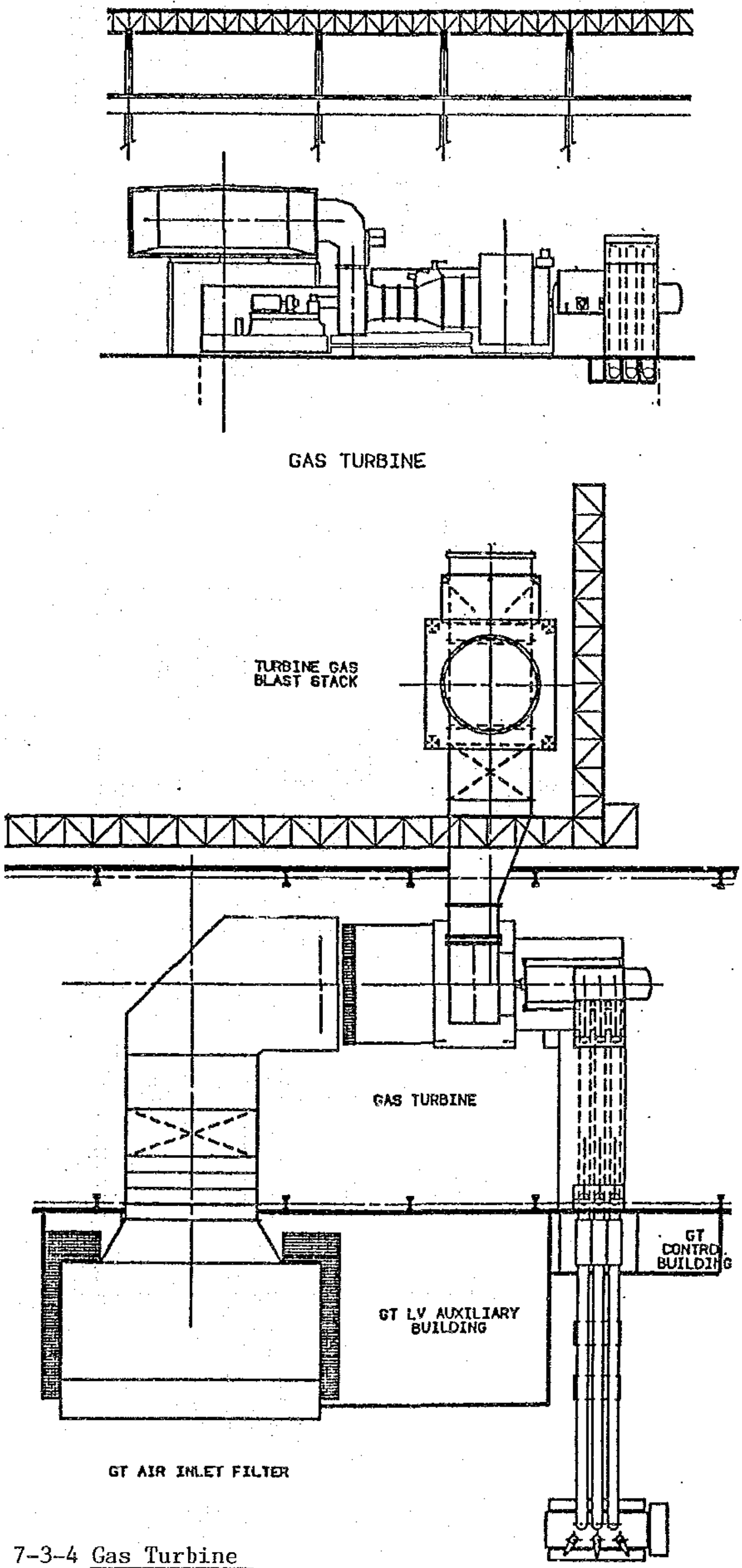


Fig. 7-3-4 Gas Turbine

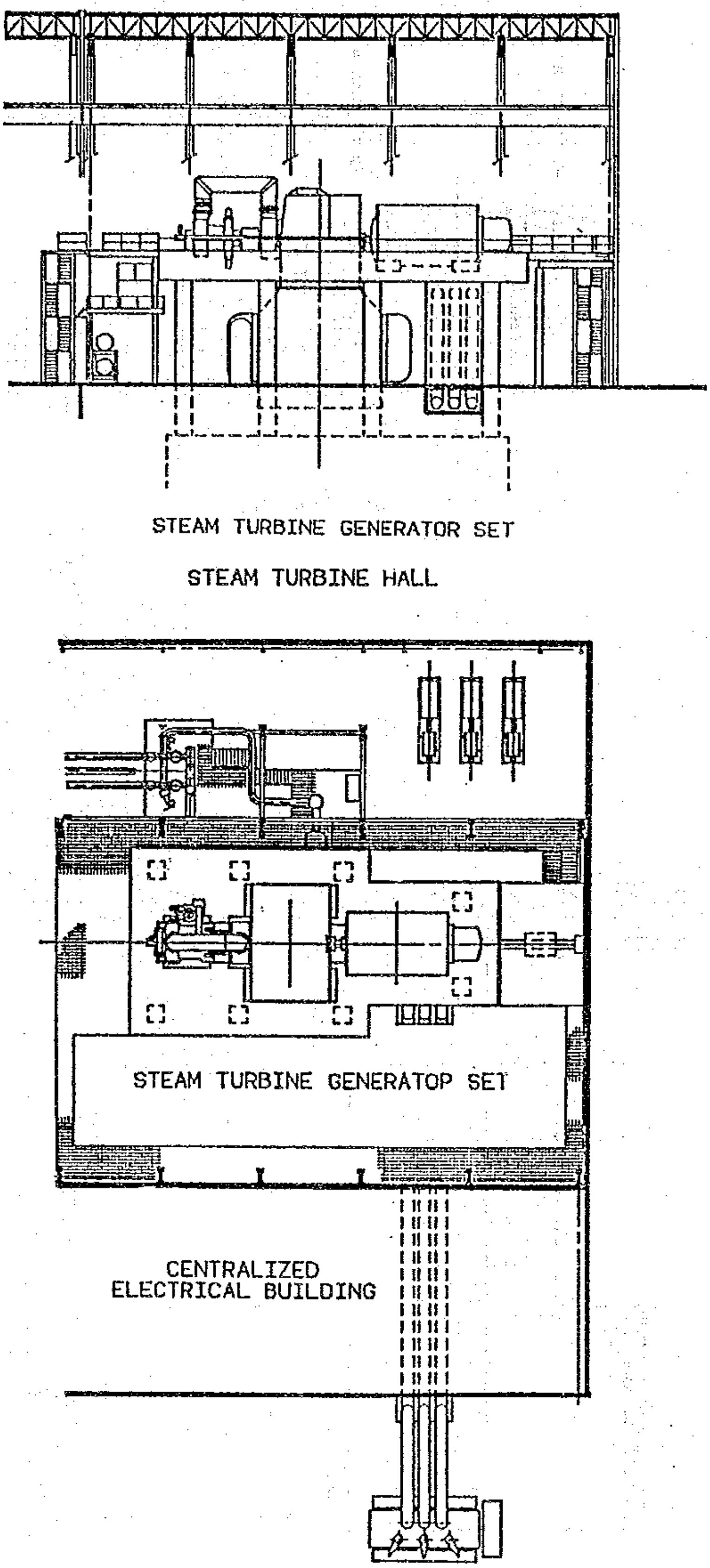


Fig. 7-3-5 Steam Turbine

Table 7-3-3 Major Equipment

Description	Q'ty	Specification
Gas turbine/generator package	6	100 MW
Heat recovery steam generator	6	HP: 65 kg/cm^2G x 480°C x 168t/h LP: 3.5kg/cm^2G x 156°C 46t/h
Steam turbine/generator unit	3	100 MW
Steam condenser	3	390 t/h x 722 mmHgV
Vacuum pump	3	722 mmHgV
Condensate pump	9 (3 standby)	215 m^3/h x 100m
Feedwater tank	3	10 m^3
HP feedwater pump	9 (3 standby)	200 m^3/h x 750 m
LP feedwater pump	9 (3 standby)	250 m^3/h x 75m
Cooling tower	1	100,000 t/h
Fuel gas compressor unit	6	115,000 Nm^3/h x 17 kg/cm^2
Demineralized water plant	1	100 t/h
Raw water pump	3 (1 standby)	1,630 t/h x 30m
Feed water pump for gasification	2 (1 standby)	640 t/h x 550m

(6) Utility Requirement

See Table 7-3-4 and Fig. 7-3-6.

Table 7-3-4 Utility Requirement

Coal	495 T/h (external supply)
Raw Water	2,960 T/h (ditto)
Electricity	835,000 Kw (outside supply)
ditto	20,000 kW (internal supply)
Cooling Water	119,100 T/h (ditto)
BFW	1,703 T/h (ditto)
HP Steam	189 T/h (ditto)
LP Steam	273 T/H (ditto)

(7) Plant Layout

The exact layout cannot be determined in this stage, but the image of the layout as well as the required area will be of help to the study in the final step. In this regards, the plant layout is roughly estimated as shown in Fig. 7-3-7 and Fig. 7-3-8.

7-3-3 Financial Analysis

Financial viability and profitability of the project was evaluated by means of financial statements* and internal rate of return (hereafter referred to as IRR) on total project investment.

* Projected Profit & Loss Statement
Projected Cash Flow Statement
Projected Balance Sheet

(1) Assumptions

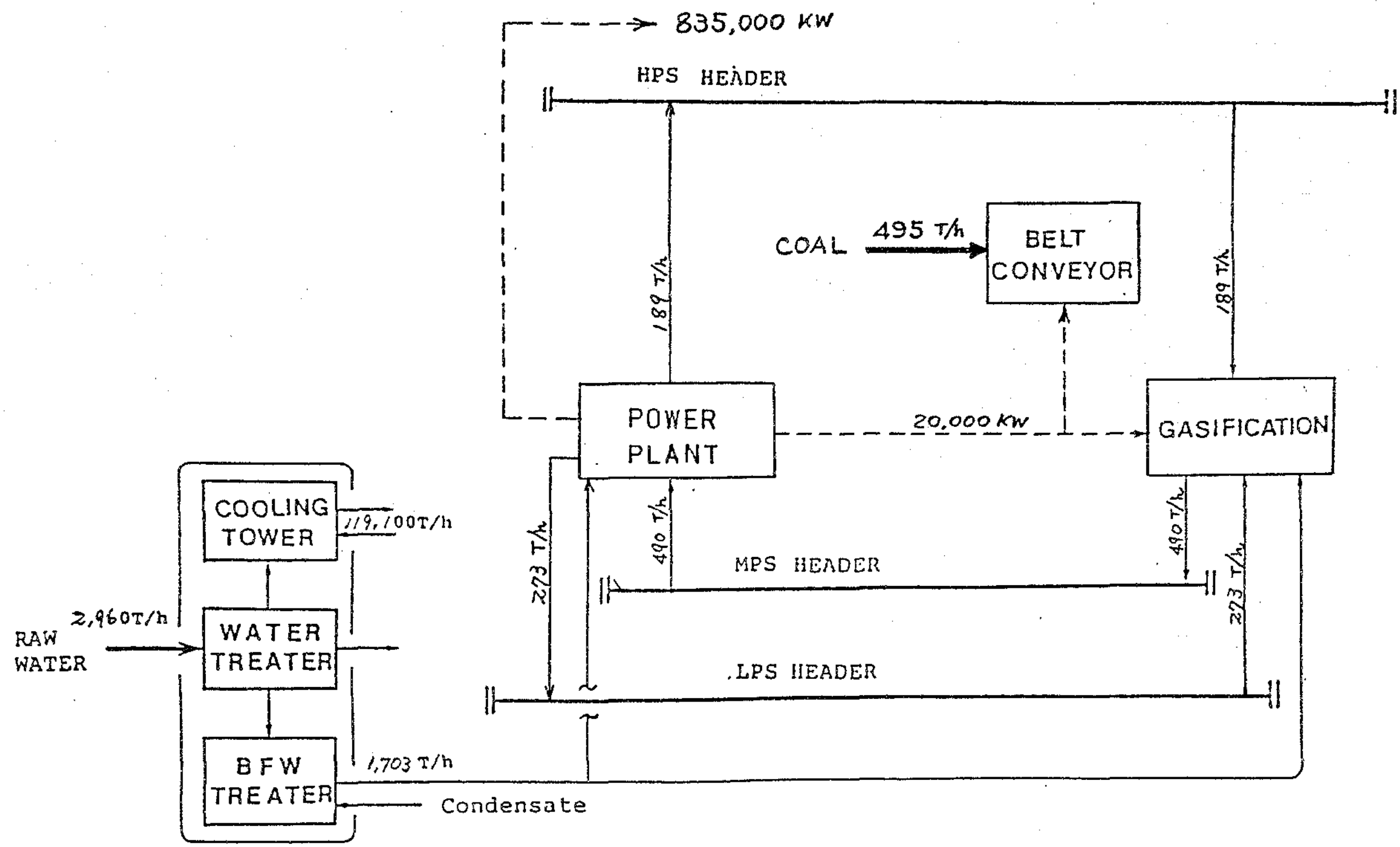
1) Electricity Generation Schedule

i) Net Generating Power : 835 MW

ii) Average Load Factor : 66 %

Note*): Average Load Factor was assumed with reference to the information from PLN (Table 7-3-5).

Fig. 7-3-6 Utility Flow Diagram



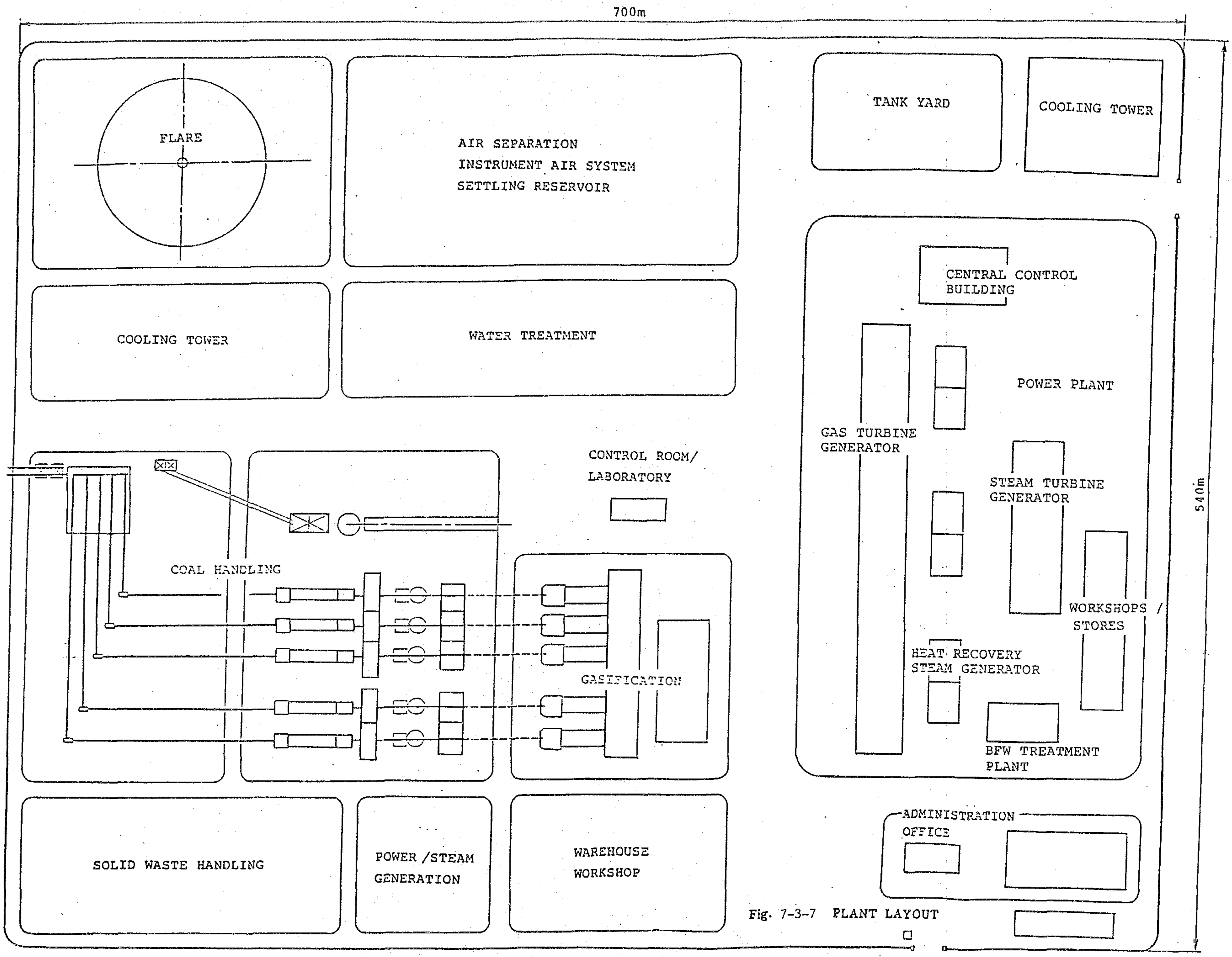
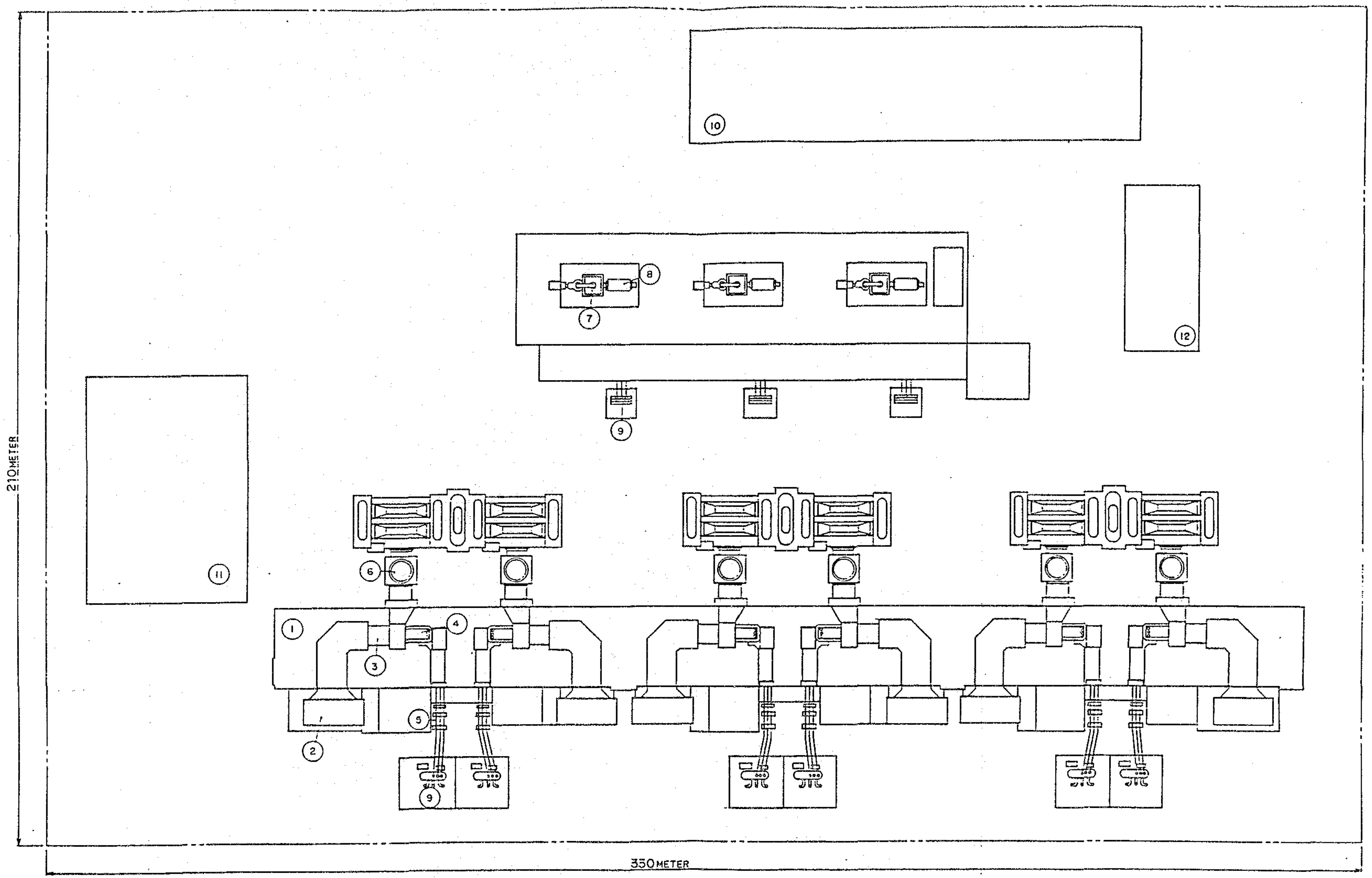


Fig. 7-3-7 PLANT LAYOUT



1	GAS TURBINE BUILDING	6	BYPASS STACK	11	CENTRAL CONTROL BUILDING
2	AIR INTAKE FILTER	7	STEAM TURBINE	12	WATER TREATMENT PLANT
3	GAS TURBINE	8	GENERATOR		
4	GENERATOR	9	TRANSFORMER		
5	ISOLATED PHASE BUS DUCTS	10	WORKSHOP AND STORES		

Fig. 7-3-8 POWER PLANT LAYOUT

Table 7-3-5 Forecast of Supply and Demand for Electricity

	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94
Demand (GWH)											
for Household Use	4,525	5,449	6,041	6,932	8,436	9,874	11,683	13,613	15,282	17,194	19,404
for Commercial & Service Use	2,653	3,217	3,774	4,458	5,285	6,278	7,315	8,525	9,935	11,581	15,502
for Industrial Use	3,223	3,842	5,730	7,361	9,974	10,528	12,363	14,393	16,649	19,166	21,986
Total Demand (GWH)	10,404	12,508	15,545	18,751	22,594	26,690	31,361	36,531	41,866	47,942	54,893
Growth Rate (%)	14	20	24	21	20	18	18	16	15	15	14
Transmission Loss (%)	21	20	20	19	18	17	16	15	15	15	15
Supply (GWH)	13,162	15,704	19,442	23,161	27,709	32,154	37,335	42,978	49,254	56,402	64,580
Av. Load Factor (%)	65	65	65	66	66	66	66	66	65	65	65
Max. Generating Power (MW)	2,311	2,744	3,391	4,036	4,819	5,596	6,492	7,467	8,642	9,930	11,424

	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04
Demand (GWH)										
for Household Use	20,674	22,542	24,689	26,582	28,716	31,457	34,516	37,929	41,746	46,029
for Commercial & Service Use	16,383	18,762	21,499	24,650	28,281	31,618	35,364	39,571	44,296	49,608
for Industrial Use	25,941	29,608	33,796	38,582	44,056	49,201	54,964	61,421	68,659	76,779
Total Demand (GWH)	62,997	70,192	79,984	89,815	101,052	112,227	124,844	138,920	154,701	172,415
Growth Rate (%)	15	13	13	12	13	11	11	11	11	12
Transmission Loss (%)	16	16	16	16	16	16	16	16	15	15
Supply (GWH)	74,896	84,315	94,929	106,504	119,845	133,080	147,908	164,460	182,794	203,742
Av. Load Factor (%)	66	66	66	66	66	66	66	66	66	66
Max. Generating Power(MW)	13,036	14,677	16,502	18,505	20,825	23,112	25,626	28,496	31,679	35,320

Source: PLN

$$\text{Av. Load Factor} = \frac{\text{Av. Generating Power}}{\text{Net Generating Power}} \times 100$$

iii) Plant Construction Period: 1990-1993 (4 years)

where 30% Completion at the end of 1990
60% Completion at the end of 1991
80% Completion at the end of 1992
100% Completion at the end of 1993

iv) Project Life : 1994-2023 (30 years)

where 70% of full operation in 1994
85% of full operation in 1995
100% of full operation in 1996 and after

v) Annual Operation Days : 320 days

2) Finance

Same as that in the feasibility study on methanol production (FY1985). (For details, see the Interim Report II (1985), page 214-215.)

3) Escalation

No escalation is assumed.

4) Price and Costs

i) Ex-Power Plant Price of Electricity

Supply to Jakarta:

Case E-5 : 43 Rp/kwH(7.76 ¥/kwH)
Case E-6 : 53 Rp/kwH(9.57 ¥/kwH)

Supply to Adjacent Area:

Case E-4 : 64 Rp/kwH(11.55 ¥/kwH)
Case E-1 : 78 Rp/kwH(14.08 ¥/kwH)

Note*) Ex-Power Plant Price was assumed referring to the electric rate in Indonesia as of April 1984 (Table 7-3-6) and estimated sales cost. Estimation of price in each case is shown in Table 7-3-7.

Table 7-3-6 Rate Table of Electricity

April, 1984

US.$ 1 = Rp.998,-

※ No.	Code of Tariff	Contracted Power	Demand Charge Rp/kVA	Energy Charge Rp/kWh	Projected Average Revenue Rp/kWh
1.	S_1	to 200 VA	*)		
2.	S_2	250 VA to 200 kVA	2,100	43,50	60.57
3.	R_1	250 VA to 500 VA	2,100	70,50	85.19
4.	R_2	501 VA to 2200 VA	2,100	84,50	98.41
5.	R_3	2201 VA to 6600 VA	3,080	126,50	156.42
6.	R_4	6601 VA to over	3,680	158,00	184.10
7.	U_1	250 VA to 2200 VA	3,680	134	160.10
8.	U_2	2200 VA to 200 kVA	3,680	150	185.73
9.	U_3/MV	201 kVA & over	2,300	P = 158 OP = 99	123.17
10.	U_4	-	-	307	307
11.	I_1	to 99 kVA	2,300	P = 106 OP = 66	93.97
12.	I_2	100 kVA to 200 kVA	2,300	P = 100 OP = 62,50	85.51
13.	I_3/MV	201 kVA & Over	2,100	P = 96,50 OP = 60,50	75.88
14.	I_4/HV	5000 kVA & Over	1,970	P = 81,50 OP = 52	61.13
15.	G_1	250 VA to 200 kVA	3,680	96	120.86
16.	G2/MV	201 kVA. & Over	1,970	P = 99 OP = 65	84.92
17.	J	-		76,50	76.50
		Average			98.315

*) Tariff S1: 100 VA = Rp.2.510,-/month
150 VA = Rp.3.765,-/month
200 VA = Rp.5,025,-/month

Note : P = Peak Hours (18.00 - 22.00)
OP = Off Peak Hours (22.00 - 18.00)

Jakarta, March1,1984.

※

1.	S_1		to 200 VA	Tariff S_1 for small Consumer (low voltage)
2.	S_2	250 VA	to 200 KVA	Tariff S_2 for social Institutions (low voltage)
3.	R_1	250 VA	to 500 VA	Tariff R_1 for simple Residential service (low voltage)
4.	R_2	501 VA	to 2200 VA	Tariff R_2 for small Residential service (low voltage)
5.	R_3	2201 VA	to 6600 VA	Tariff R_3 for medium Residential service (low voltage)
6.	R_4	6601 VA	& Over	Tariff R_4 for big Residential service (low voltage)
7.	U_1	250 VA	to 2200 VA	Tariff U_1 for small Commercial service (low voltage)
8.	U_2	2201 VA	to 200 KVA	Tariff U_2 for medium Commercial service (low voltage)
9.	U_3/ HV	201 kVA	to Over	Tariff U_3/HV for big Commercial service (medium voltage)
10.	U_4			Tariff U_4 for Temporary service (low voltage)
11.	I_1		to 99 KVA	Tariff I_1 for Industrial & Hotel service (low voltage)
12.	I_2	1000 kVA	to 200 KVA	Tariff I_2 for Industrial & Hotel service (low voltage)
13.	I_3/HV	201 kVA	& Over	Tariff I_3 /HV for Industrial & Hotel service (medium voltag
14.	I_4 / HV	5000 KVA	& Over	Tariff I_4 /HV for Industrial service (high voltage)
15.	G_1	250 VA	to 200 KVA	Tariff G_1 for office service (low voltage)
16.	G_2 /HV	201 kVA	& Over	Tariff G_2 /HV for office service (medium voltage)
17.	J			Tariff J for Street Lighting service (low voltage)

Table 7-3-7 Sales Price and Cost Estimation of Electricity

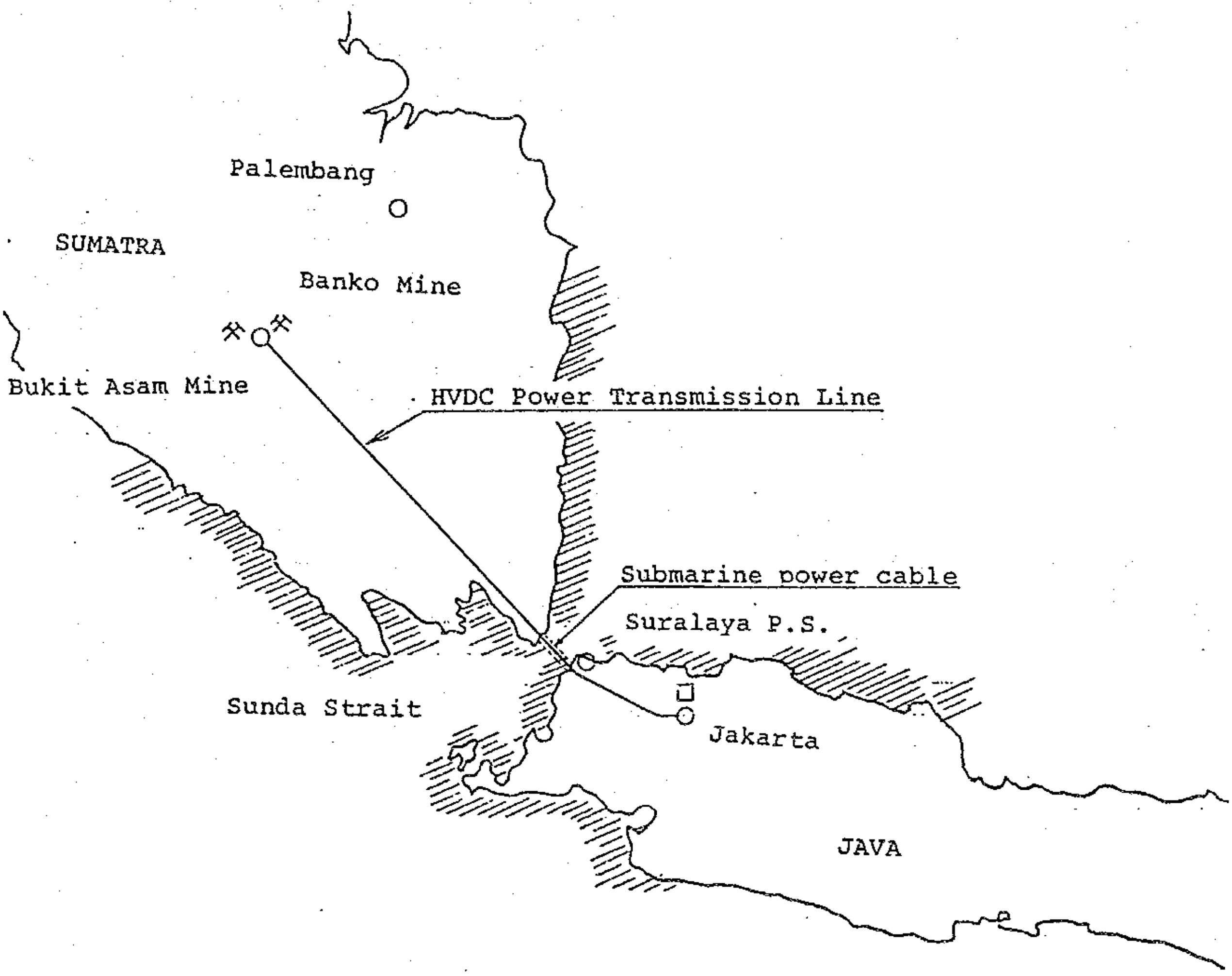
(Unit: Rp/kwH)

Case	Case E-5	Case E-6	Case E-4	Case E-1
Average Sales Price of PLN ①	98			
Administration and Distribution Cost of PLN	30%	20%	20%	20%
Transmission Loss*1	15%	15%	15%	0%
Sub-total ②	45% 44	35% 34	35% 34	20% 20
Transmission Cost to Java*2 ③	11	11	-	-
Total ② + ③ = ④	55	45	34	20
Ex-Power Plant Price ① - ④	43	53	64	78

(note *1) Refer to Table 7-3-5

(note *2) As for power transmission line system between Banko area and West Java (550 km) including a submarine power cable section in Sunda strait (30 km), HVDC system is advantageous from technical and economical point of view compared with AC power transmission line system and also in case of the existance of submarine power cable bring more advantage (Fig. 7-3-9). And its cost is estimated about 11 Rp/kwH (Fig. 7-3-10).

Fig. 7-3-9 HVDC Power Transmission

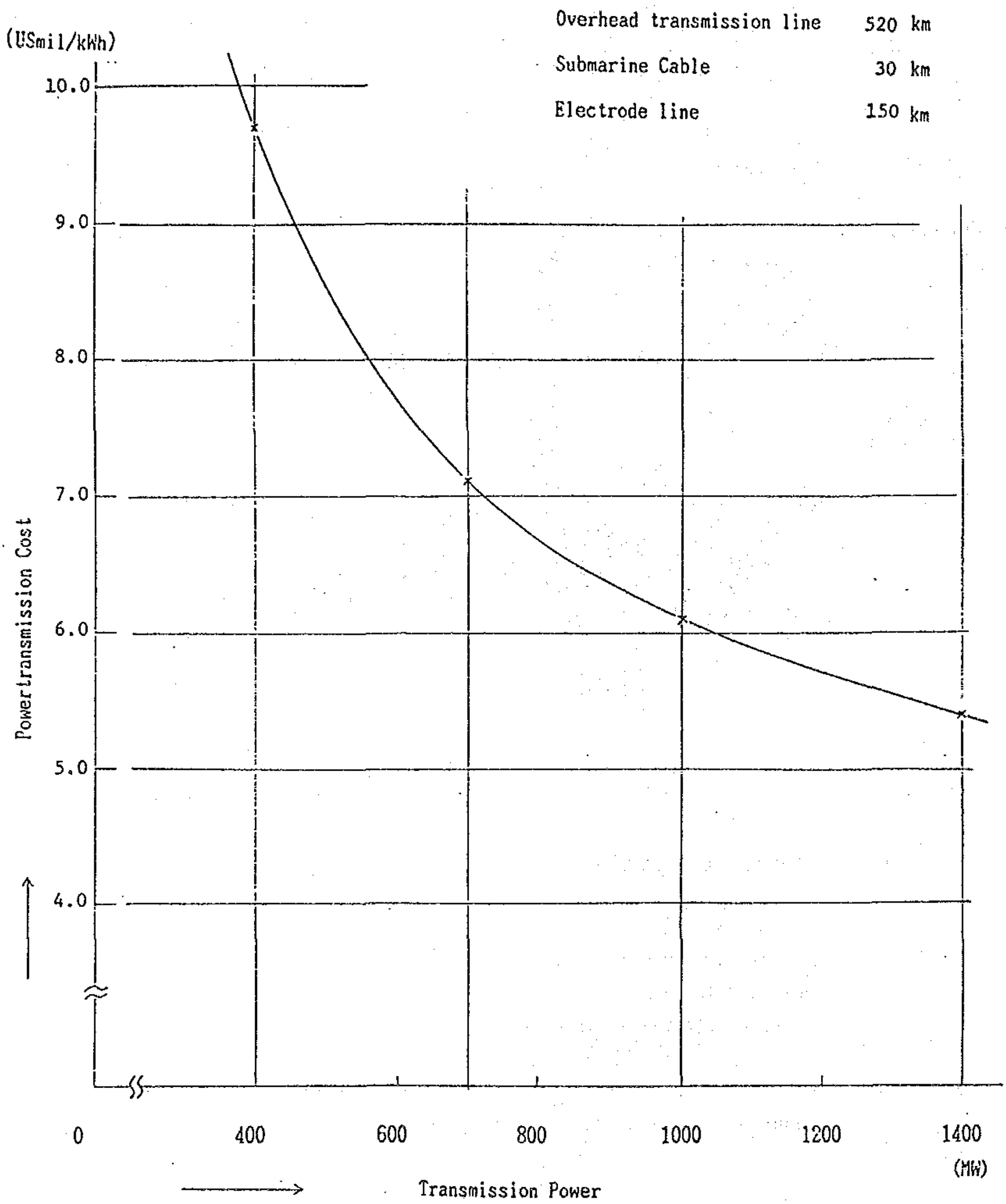


HVDC Power Transmission Line

Overhead line : 520 km
Submarine power cable : 30 km
Sea depth at
the submarine cable
crossing route : 50 m

Source: Electric Power Development Co.

Fig. 7-3-10 South Sumatra-Java HVDC Transmission



Source: Electric Power Development Co.

ii) Capital Investiment Costs

a) Fixed-capital Investment:

	10^6 Rupiah	(10^6 Yen)
Coal Gasification	461,500	(83,300)
Coal Transportation	41,000	(7,400)
Power Plant/Support Facilities	304,200	(54,900)
Equipment Transportation	89,200	(16,100)
Contingency	44,300	(8,000)
Total	940,200	(169,700)

b) Working capital: 39,100 (7,058)

Note*) Working capital is added as cash-inflow at the end of the project.

c) Start-up Expense: 4,300 (777)

d) Operator Training Cost: 2,400 (430)

Note*) Table 7-3-8 shows the investment schedule.

Table 7-3-8 Investment Schedule

	1990	1991	1992	1993
Fixed Capital	30%	30%	20%	20%
Working Capital	-	-	-	100%
Start-up Expense	-	-	-	100%
Operator Training	-	-	-	100%

iii) Annual expense

a) Fixed Costs

o Depreciation and Amortization 1)*

	Period	Amount	
	Years	10^6 Rupiah /Year	(10^6 Yen/Year)
• Boiler, Power Plant, Cooling Tower, Buildings	15	18,986	(3,427)
• Others	10	79,900	(14,422)
o Maintenance		21,163	(3,820)
o Insurance		8,465	(1,528)
b) Variable Costs			
o Raw Material(Coal) 2)*		41,285	(7,452)
o Superviser and Operating Labor			
• Foreign Staff 3)*			
• Local Labor		2,476	(447)
o Chemicals		404	(73)
c) Plant Overhead Costs		9,934	(1,793)
d) Administration Expenses		4,970	(897)

Note*): 1) Capital investment for the plant construction including expenses and interests during construction period is depreciated and amortized based on straight line method.

2) In the strategic study in FY1984, mining cost was estimated at $13.88/ton-coal. In this study, $14.85/ton-coal is assumed as raw material costs by adding 7% to the mining cost as overhead.

3) Foreign staff decrease in number as the project proceeds.

Table 7-3-9 Costs for Freign Staffs

Op. Year	1st	2nd	3rd	4th	5th	6th~30th
Year	1994	1995	1996	1997	1998	1999-2023
% on 1st year	100	70	50	30	10	0
Cost, 10^6 rupiah/year	7,457	5,220	3,729	2,237	746	0
(Cost, 10^6 yen/year)	(1,346)	(942)	(673)	(404)	(135)	(0)

5) Evaluation Criteria

i) Financial Statement

a) Profit and Loss Statement

b) Cash Flow Statement

c) Balance Sheet

ii) IRR on Total Project Cost before Tax

(For details, See the Interim Report II (1985), page 218-219.)

(2) Results and Evaluation

1) Results

Results are summerized in Table 7-3-10.

As far as IRR is concerned, Case E-4 is equal to the base case of methanol production carried out in 1985.

Profit and loss statement and cash flow statement of Case E-4 are shown in Table 7-3-11 and Table 7-3-12.

Table 7-3-10 Results of Financial Analysis

Case	Supply to Jakarta		Supply to Adjacent Area		(Reference) Base Case
	E-5	E-6	E-4	E-1	
Ex-plant Price of Electricity	43 Rp/ kwH (7.76 ¥ /kwH	53 Rp/ kwH (9.57 ¥ /kwH)	64 Rp/ kwH (11.55 ¥ /kwH)	78 Rp/ kwH (14.08 ¥ kwH)	Methanol 194 Rp/kg (35 ¥/kg)
IRR on total Investment	6.9 %	10.3 %	13.5 %	17.0 %	13.5%
First Year to Have Profit before Tax (Year from Operation Starts)	11th	7th	3rd	2nd	3rd
Clear off of Accumulated Loss (Year from Operation Starts)	28th	13th	5th	2nd	5th
Pay off of All the Debts (Year from Loan Raised)	28th	15th	12th	12th	12th
Minimum Sales Price (IRR = Interest Rate)	46 Rp/kwH (8.31 ¥/kwH)				143 Rp/kg (25.9 ¥/kg)

2) Evaluation

i) The ex-power plant price of electricity is necessary to set at about 64 Rp/kwH (11.55 ¥/kwH) to gain 13.5% of IRR which is equal to the Base Case of methanol production (Fig.7-3-11). Though the case of supply to adjacent area of plant may be feasible, the case of supply to Jakarta is not, because of transmission cost and loses. IRR of Cases E-5 and E-6 which are the case of supply to Jakarta results in 6.9% and 10.3% respectively.

ii) It is clear that there is no relationship between electricity rate in Indonesia and crude oil price as shown in Fig. 7-2-8, becuase of her policy matter for electricity.
On the other hand, since the source of electricity in Japan largely depends on imported energy such as natural gas, petroleum and uranium, electricity rate is going fall since mid-1986.

iii) The long-term forecast on demand for electricity in Indonesia is shown Table 7-3-5.

There is need to expand generating capacity continuously in accordance with high growth rate of demand. So, in order to evaluate the economic feasibility of this study, the expansion plan of power plant capacity in Indonesia including possibility of average load factor to be improved should be investigated in detail.

Table 7-3-11 Profit and Loss Statement of Case E-4

(Unit: 10^9 Rupiah)

Year	OP Year	REVENUE	EXPENDITURE					PROFIT			Retained Earning
			Variable Cost	Fixed Cost	General	Interest Paid	Total	Before Tax	(Tax)	Net Profit	
1994	1	189.6	39.1	128.5	14.9	65.8	248.3	- 58.7	0	- 58.7	- 58.7
1995	2	230.3	43.1			60.9	247.4	- 17.2	0	- 17.2	- 75.8
1996	3	270.9	47.9			52.6	243.9	27.0	0	27.0	- 48.8
1997	4		46.4			42.0	231.8	39.1	0	39.1	- 9.7
1998	5		44.9			31.3	219.6	51.3	19.1	32.2	22.5
1999	6		44.2			21.4	209.0	61.9	28.5	33.4	55.9
2000	7					12.6	200.2	70.7	32.5	38.2	94.1
2001	8					4.2	191.8	79.1	36.4	42.7	136.8
2002	9					0	187.6	83.3	38.3	45.0	181.8
2003	10						187.6	83.3	38.3	45.0	226.8
2004	11			128.5			107.7	163.2	75.1	88.1	314.9
2005	12			48.6			107.7	163.2	75.1	88.1	403.1
2006	13						107.7	163.2	75.1	88.1	491.2
2007	14						107.7	163.2	75.1	88.1	579.3
2008	15			48.6			107.7	163.2	75.1	88.1	667.5
2009	16			29.6			88.7	182.2	83.8	98.4	765.9
2010	17										864.3
2011	18										962.7
2012	19										1,061.1
2013	20										1,159.5
2014	21										1,257.9
2015	22										1,356.3
2016	23										1,454.6
2017	24										1,553.0
2018	25										1,651.4
2019	26										1,749.8
2020	27										1,848.2
2021	28										1,946.6
2022	29										2,045.0
2023	30	270.9	44.2	29.6	14.9	0	88.7	182.2	83.8	98.4	2,143.4
	Total	8,005.5	1,325.6	1,972.7	447.1	290.8	4,036.2	3,969.3	1,825.9	2,143.4	

Table 7-3-12 Cash Flow Statement of Case E-4

(Unit: 10^9 Rupiah)

Year	OP Year	INVESTMENT	Profit Before TAX	Depreciaiton/ Amortization	Interest Paid	CASH FLOW	DCF (Base; 1985)
1990		- 282.1	-	-	-	- 282.1	- 150.0
1991		- 282.1	-	-	-	- 282.1	- 132.2
1992		- 188.0	-	-	-	- 188.0	- 77.7
1993		- 233.8	-	-	-	- 233.8	- 85.2
1994	1	-	- 58.7	98.9	65.8	106.0	34.0
1995	2	-	- 17.2		60.9	142.6	40.4
1996	3	-	27.0		52.6	178.5	44.5
1997	4	-	39.1		42.0	180.0	39.6
1998	5	-	51.3		31.3	181.5	35.2
1999	6	-	61.9		21.4	182.2	31.1
2000	7	-	70.7		12.6		27.4
2001	8	-	79.1		4.2		24.2
2002	9	-	83.3		0		21.3
2003	10	-	83.3	98.9			18.8
2004	11	-	163.2	19.0			16.6
2005	12	-	163.2				14.6
2006	13	-	163.2				12.9
2007	14	-	163.2				11.3
2008	15	-	163.2	19.0			10.0
2009	16	-	182.2	0			8.8
2010	17	-					7.8
2011	18	-					6.8
2012	19	-					6.0
2013	20	-					5.3
2014	21	-					4.7
2015	22	-					4.1
2016	23	-					3.6
2017	24	-					3.2
2018	25	-					2.8
2019	26	-					2.5
2020	27	-					2.2
2021	28	-					1.9
2022	29	-				182.2	1.7
2023	30	-	182.2	0	0	221.3	1.8
	Total	- 986.0	3,969.3	1,083.8	290.8	4,397.0	0

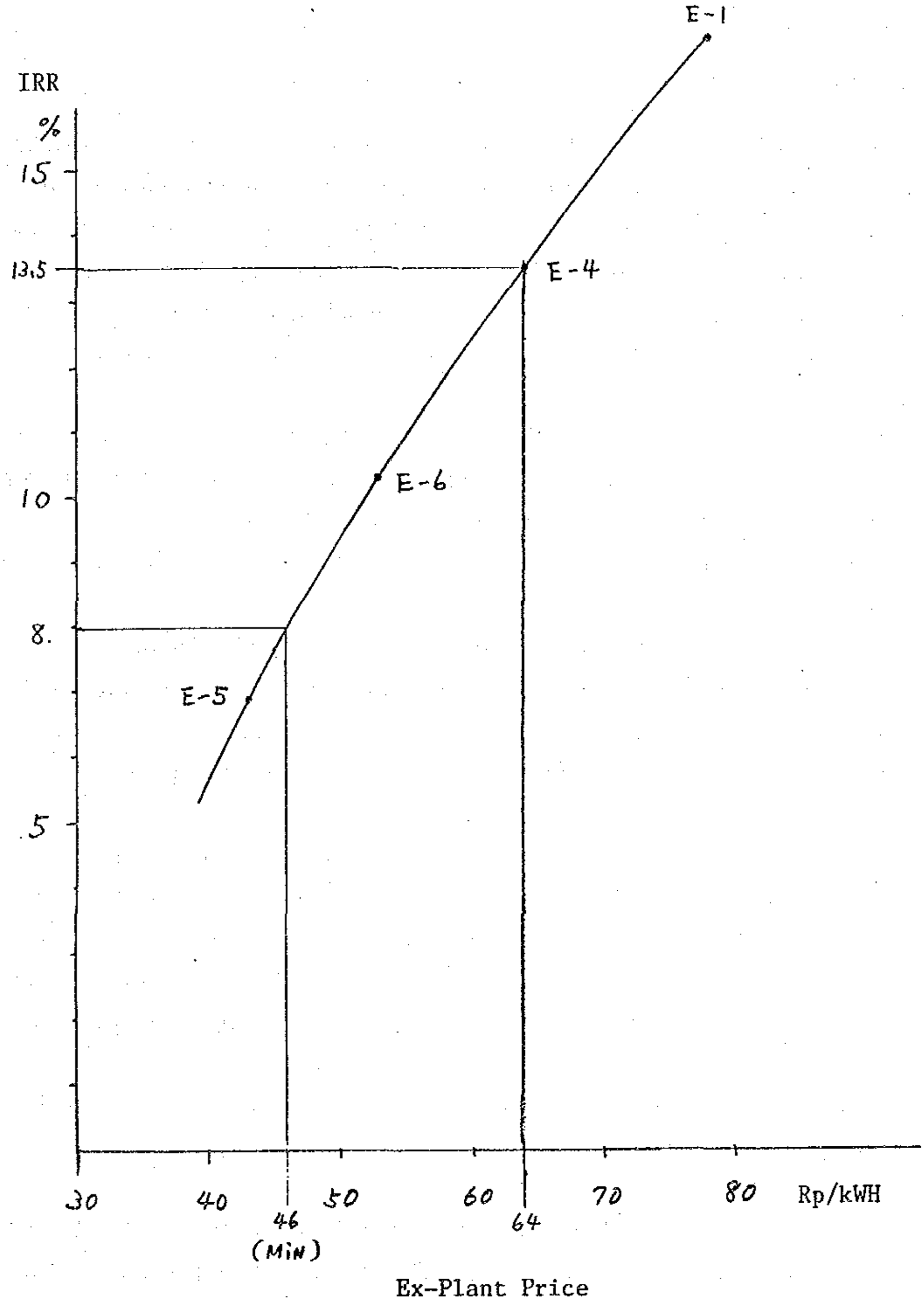


Fig. 7-3-11 IRR VS Ex-Plant Price of Electricity

8. INVESTIGATION OF THE MARKET FOR FINAL PRODUCT

(Study on Market for Fuel Alcohol and its Supply System in Indonesia)

8-1 BACKGROUND OF THE STUDY

8-1-1 Background of the Study

As to the utilization of fuel alcohol, such R & D activities as blending methanol into gasoline and neat use for automotive fuels have been carried out in West Germany, Sweden, France and U.S.A. etc. Blended use has already been in commercial stage in some countries. Also in Japan, converting diesel type engine to methanol fueled engine as well as methanol blending into gasoline has been carried out in order to achieve reduced NOx-goal in exhaust gas and diversify energy sources.

In Brazil, so-called "Pro-Alcohol Program" has been promoted since Nov. 1975 to establish increased production of alcohol (ethanol) for both fuel use and chemical use mainly from introducing alternative energy sources to oil.

Fuel use of methanol and ethanol might conclusionally be said to be in commercial stage.

Indonesia has the fundamental policy to preserve such abundant mineral resources as oil and natural gas for foreign currency. For this policy, introducing such alternative energy sources as coal, geothermal and mini-hydro as well as reducing domestic oil demand has been vigorously promoted aiming at expanding export capability of oil and natural gas.

As to alcohol, national alcohol committee has been organized in 1980 and alcohol program (mainly from cassava) has been carried out from those three view points of (1). development of agricultural economy, (2). diversification of population from Java through rural development outside Java and (3). upgrading research capability of BPPT throgh acquiring ethanol producing technology from biomass.

On the other hand, methanol plant in Bunyu started operation in 1986 and the feasibility study how to utilize methanol from Banko coal has been conducted since 1984.

As to utilization of alcohol for fuel use, blended use of methanol in gasoline type engines and neat use in engines including diesel engine in the future and also blended use of ethanol in gasoline type engines have been considered to be promising. On the other hand, utilizing methanol for diesel power genertion and gas turbine generation has seemed to be one of promising fields. Though concrete consuming pattern of petroleum products has not been clear in detail, the converting conventional fuels to other fuels in industrial and household sectors might have substantial impacts on demand for oil products.

In the domestic demand for oil products, automotive gasoline, kerosene and diesel oil has 17%, 30% and 30% respectively. Therefore, introducing fuel alcohol in domestic petroleum market (esp. gasoline, kerosene and diesel oil) might have substantial impacts (both direct and indirect) on national economy.

Based upon above mentioned background of this study, the Government of Indonesia asked the Government of Japan to conduct a study on the market and supply system for fuel ethanol.

According to the master plan of the 1st stage of "Feasibility Study of Effective Utilization of Banko Coal in the Republic of Indonesia", there is one recommendation that utilizing methanol in diesel power generator and automotive diesel engines like city bus might be promising idea in the future and therefore, the study in more detail is urgently required.

8-1-2 Objective of the Study

The objective of the Market Study is to survey the possibility of effective utilization of fuel alcohol (methanol, ethanol and/or their mixture) in transportation sector, power generation sector, industrial sector and household sector in Indonesia, and to establish an appropriate master plan for introduction of fuel alcohol, including its supply.

8-1-3 Scope of the Market Study

Possibility of substituting conventional petroleum products like gasoline, kerosene and diesel oil etc. in Indonesia shall be examined in such four consuming sector as (1) Transportation Sector, (2) Power Generation Sector (3) Industrial Sector (4) Household Sector from those view points of technical possibility, economics, safety and environment.

Following works shall be carried out for possible introduction of fuel alcohol.

1) Survey on market and demand in Indonesia
2) Sketching an appropriate supply system
3) Examining specification or required qualities of fuel alcohol
4) Examining safety as a fuel
5) Establishing a master plan for introducing fuel alcohol
6) Evaluating impacts of introducing fuel alcohol

8-1-4 Schedule of the study

The schedule of each mission was as follows,

1st mission: June 17 - June 26, 1986

The mission explained the whole outline of this study and asked positive cooperation from Indonesia Counterpart.

2nd mission: Aug. 15 - Sep. 10, 1986

In 2nd mission, several plant visits such as diesel power plant in Kupang, refineries of Cilacap, Balikpapan and Dumai were included.

8-2 INTERNATIONAL TRENDS OF FUEL ALCOHOL INTRODUCTION

With the world oil crisis in 1973 as a momentum, research and development on petroleum-alternative fuels have been energetically carried out for energy sources in all industries. As an alternative for meeting energy needs, particularly for automobiles, alcohol fuels are considered the most promising. Namely, various countries have shown keen interest in fuel alcohol, especially in fuel methanol, as a preferable alternative automobile fuel, because fuel alcohol can feasibly be stabilized and used as an alternative fuel, and a steady supply can be secured at a competitive price, moreover, features such as the easy of applying it to automobile engines, higher thermal efficiency as a fuel, easy of use, reduced environmental impact, and increased safety make it attractive.

In fact, expectations for fuel methanol, a product derived from natural gas and coal, are high. At present, methanol is used in one million vehicles and distributed at ten thousand service stations in Brazil. Furthermore technical know-how has been accumulated from fleet tests on thousands of methanol vehicles in the U.S. and European countries.

Fuel Methanol is used by mixing it, at a low ratio with, gasoline or as "neat" or in high blend (100 to 85%). The first method is used in the U.S. and Europe, by mixing 3% methanol with gasoline to produce a high-octane, lead free gasoline.

For the latter method, large-scale fleet tests for determining the applicability of neat or high-blend fuel methanol to gasoline engines are being carried out in the U.S. and Erurope. It is expeted that fuel methanol will yield better performance than gasoline engines and a cleaner exhaust gas. Further tests are being conducted to verify startability at low temperatures and durability of some engine parts, but technical problems are few in this respect.

For using metanol fuel in diesel engines, on the other hand, various technical system are being studied. Research and development, though on a small scale, are being carried out, including practical-use tests for methanol fuel uses in buses, trucks, etc.

Fuel alcohol can be used not only in automobiles but also in various industries and for power generation. Viewed from the timing and scale of its use, metahnol for power generation is as feasible as that for automobile use. Methanol fuel for power generation is used either in small-output power generation employing converted gasoline engines or in small - or medium - scale power generation using diesel engines, or in large-output power generation using gas turbines and steam turbines. In the former two methods, it is easy to transfer the technical know-how acquired from using automobile engines in the same way as with the current reciprocating engines.

For power generation with the gas turbine and boilers (for steam turbines and process and industrial furnaces), R&D on the technical feasibility were already completed several years ago, and no difficult technical problems were found. For modified gas turbines, there are still many unsolved problems, such as the durability of the catalyst. It is considered in some quarters that, in order to lower the cost of methanol and to achive a smooth initial introduction, large-output power generation with the modified gas turbine is the most effective.

8-2-1 Utilization Technology of Fuel Alcohol in Vehicle Engines

The major conditions required for alternative energy in vehicles use are given below.

- o Must have high energy density and must be easily movable as energy for moving vehicle.
- o Must provide excellent vehicle performance and must be easy to use.
- o Must provide lower exhaust gas emission.
- o Must be lower fuel price and system cost.
- o Must show no problems with safety and maintainability.
- o Must provide a long-term stable supply and be widely distributable.

Against this background, the Volkswagen Corporation compared various kinds of energy on its passenger car "Golf," and judged that alcohol fuels were promising for spark ignition type engines.(1)

Methanol is produced from natural gas or coal, which permits a long-term stabilized supply. It can employ a high-compression ratio due to its high octane value and it permits dilution combustion, thereby yielding high efficient combustion and cleaner exhaust gas. Since the technical knowledge of methanol is advanced, it is a promising candidate for an alternative automobile fuel.

(1) Characteristics of Alcohol Fuels and Their Problems

Table 8-2-1 shows comparisons between characteristic values of metanol and ethanol and petroleum-based fuels, and indicates the following features of the repective fuels (the ◎ mark represents an item advantageous to alcohol; the ● mark represents an item disadvantageous to alcohol):

● Since alcohol has a low calorific value per unit volume (liquid), it makes the size of the fuel tank and fuel pump larger.

◎ In spite of a low calorific value per unit volume (liquid), the calorific value of miaxture of alcohol gas and air is nearly the same as that of petroleum-based fuels. Also the cooling action of inlet air due to the large latent heat of alcohol improves its engine's volumetric efficiency. These two factors increase its engine output.

◎ The high octane number of alcohol permits a high compression ratio and also a boosted pressure rise by a supercharger in gasoline base engines.

Table 8-2-1 Physical Properties of Oxygen-containing Compounds (42)

		Gasoline	Methanol	Ethanol	MTBE	10% mehtanol blending	10% ethanol blending	7% MTBE blending	Light oil
Chemical formula		$C_4 \sim C_{12}$ mixture	CH_3OH	C_2H_5OH	$C_5H_{12}O$				$C_4 \sim C_{16}$
Molecular weight		100 ~ 105	32.0	46.1	88.1				—
Composition	Carbon	85 ~ 88	37.5	52.1	68.1				
	Hydrogen	12 ~ 15	12.6	13.1	13.7				
	Oxygen	~ 0	49.9	34.7	18.2				
	C/H ratio	5.6 ~ 7.4	3.0	4.0	5.0				
Specific gravity	15/4 ℃	0.70 ~ 0.78	0.793	0.789	0.747				0.830
Reid vapor pressure	37.8 ℃ lb/in²	7 ~ 15	4.6	2.5	7.8				—
Boiling point	℃	27 ~ 227	64.4	78.5	55.2				90% point <350
Dissolving quantity to water		240 ppm	≈ ∞	≈ ∞	6.9 %				—
Dissolving quantity of moisture		88 ppm	∞	≈ ∞	1.4 %				—
Kinetic viscosity	37.8 ℃ cSt	0.57	0.47	0.85	~ 0.31				
Lower calorific value	Kcal/kg	≈ 10,500	4,770	6,880	8,830	9,890	10,060	10,040	10,300
	Kcal/ℓ	≈ 7,720	3,770	5,040	6,270	7,330	7,450	7,620	8541
Carburetion latent heat	Kcal/kg	≈ 83	280	220	77	104	98	83	Abt. 60
	Kcal/ℓ	≈ 60	220	175	57	76	76	62	
Theoretical air/fuel ratio	(kg/kg)	14.3 ~ 14.8	6.4	9.0	11.7	13.7	14.0	14.4	14.8
Air/fuel mixture lower calorific value	Kcal/kg	660 ~ 690	645	638	660				652
Air/fuel mixture carburetion latent heat	Kcal/kg	≈ 5.4	37.8	22.0	6.1				Abt. 3.8
Octane number	Research method	90 ~ 92	107 ~ 109	107 ~ 109	117	≈ 95.5	≈ 95	≈ 93	—
	Motor method	82 ~ 84	89	90	102	≈ 86	84.5 ~ 86	84.5 ~ 85	—
Cetane value		≈ 12	3	8	—				45~50
Ignition point		≈ −45	11.1	12.8	− 27.8				>50
Automatic firing temperature		≈ 280	467	424	460				
Combustion limit (in air: vol. %)		1.4 ~ 7.6	6.7 ~ 36.0	4.3 ~ 19.0	1.6 ~ 8.4				1.0~6.0
Laminar-flow combustion speed	cm/s	≈ 38	52						—

Note: Gasoline mixed in regular gasoline; specific gravity: 0.736; RON: 90 to 92; MON: 82 to 84; lower calorific value: 7,729 kcal/ℓ.

- Since its cetane number is lower than that of diesel oil, a technical corrective measure for promoting ignition is necessary when it is used for a diesel engine.
- In low temperatures, its boiling point is higher than the initial boiling point of gasoline, its carburetion latent heat is greater and its low-temperature startability tends to deteriorate.

◎ Its broad combustion lean limits permit lean combustion, and owing to its fast combustion rate, an improvement in the thermal efficiency and a decrease in NOx can be expected.

◎ Its combustion product contains only a small amount of deposits, and it discharges no soot, sulfur products and lead.

◎ Its exhaust gas contains less products which react photochemically and gives only a low emission of multiple aromatic hydrocarbon.

- It discharges much formaldehyde, but this can be coped with by an oxidation catalyst.
- Wear may be caused by its low viscosity at portions where lubrication by the fuel itself is required. It also corrodes certain kinds of metal and rubber.
- It absorbs moisture and causes layer separation.
- Since it gives out nonluminous flames, it may pose a problem in detecting a fire.

In the following, major problems posed by alcohol fuels and their solutions are given:

(Problem 1) Cetane Number Is Low

This matter is problem only for diesel engine base and will be explained in detail in the Section 8-2-1-(3) "Utilization Technology on the Diesel Engine Basis."

Technical corrective measure for promoting ignition is necessary.

(Problem 2) Low-temperature Startability Is Poor

Low-temperature startability in poor when the methanol content is 100% or highly concentrated.(3) The startability can be improved by an increase in the vapor pressure through the addition of gasoline, etc., although there is a difference between the kinds of engines.

Other corrective measures are also studied such that gasoline is temporarily injected or suction air is heated with an electric heater only at the time of starting.

(Problem 3) Wear and Corrosion

It has been reported that the low viscosity of the methanol fuel has caused wear on the plunger of the fuel pump, valve seat of the injection nozzle, etc.. In some cases, this trouble has been corrected by performing forced lubrication using a small amount of lubricants.

Methanol develops formic acid, when it is oxidated by air or reacts with water that it has absorbed. This formic acid corrodes metals having a comparatively higher ionization trend, such as Al, Zn, Pb and Mg as well as acrylic resin and urethane rubber. Therefore, caution is requred in selecting materials for the fuel system, such as the fuel tank,. pipe, hose, pump and nozzle. For instance, the previous Terneplate (plated steal by 15% Sn and 85% Pb) steel plates used for the fuel tank were replaced with tinplated or stainless steel plates, and aluminum and bronze for the fuel pump were nickel-or cadmiumplated.

It was also reported that wear in the gasoline engine interior occurred occasionally in connection with operations in winter and cold-area.(5)(6),

For "spark assist," diesel engines may be burning of spark plug and to early, deterioration of performance.(73) To cope with such problems, an appropriate improvement for the plug and further confirmation of the plug life are necessary.

(Problem 4) Layer Separation

Since alcohol has a hygroscopic property, it is unavoidable that alcohol mixes with water. However, when alcohol-mixed gasoline is put into practical use, the gasoline mixure causes layer separation, an upper layer consisting of gasoline and a lower layer of an alcohol-water mixture, because moisture is not dissolved in hydrocarbon. This layer separation more easily occurs in lower alcohol, is conspicuous, particularly in methanol, and is more to occur when th e temperature is low.

When layer separation occurs, the octane number of the upper-layer gasoline drops to cause knocking, and the water-containing lower-layer methanol comes into direct contact with metal, thereby sometimes accelerating the aforesaid metallic corrosion by galvanic corrosion.

This layer separation can be ameliorated through the combined use of higher alcohol such as propanol and a compatible agent such as MTBE, as shown in Fig. 8-2-1.

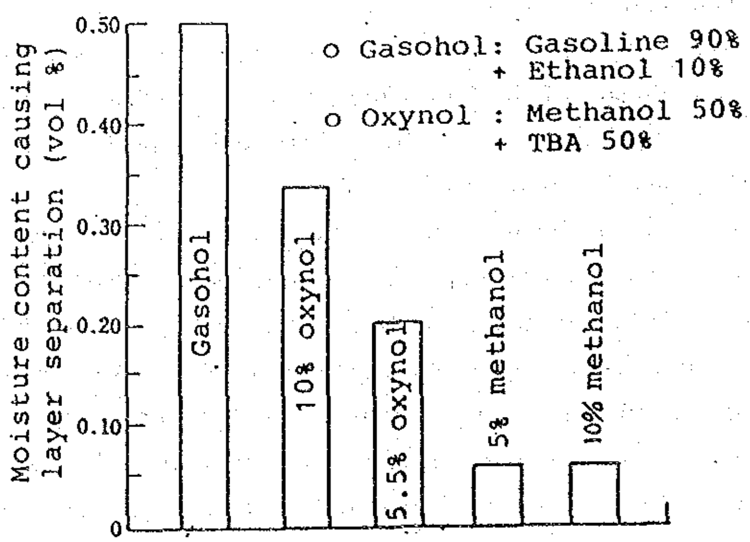


Fig. 8-2-1 Layer Separation of Alcohol Fuel due to Moisture (45)

To cope with the above-mentioned characteristics and problems of alcohol fuels, research facilities and enterprises in many countries are carrying out research and development on gasoline and diesel engines. Table 8-2-2 and Table 8-2-3 show the situation of technology for developments, the gasoline-alternative use and diesel-oil alternative use respectively. For the former, large-scale running tests have been conducted, the required engine modification is not so extensive, and degree of technological maturity is considerably higher (Table 8-2-4(6)(9)).

In the diesel engine basis of the latter case, degree of technological maturity is lower than that of gasoline engine basis and the development will proceed more extensively for several types of diesel engine basis. In the following, these technologies will be described by dividing them broadly into a gasoline basis and diesel basis.

Table 8-2-2 Developing Condition of Gasoline Alternative Utilization Technologies

Kind and Concept of Utilization Technology	Basic Study			Developing Study				
				For cars			For industrial use	
	Combustion method	Exhaust cleaning method	Others	Engine system	Vehicle system	Fleet test	Engine/vehicle system	Fleet test
Gasoline alternation Neat/near-neat use Homogenization method	Santa Clara Univ. JARI GM Ethanol V	SWRI Wisconsin Univ. Achen Institute of Technology TOYOTA		RICARDO	NISSAN TOYOTA MATSUDA MITSUBISHI	FORD VW BMW GM PORSHE D.Benz		
Same as above Laminar air-intake method	Hokkaido Univ. FORD PORSHE			JARI				
Same as above Reforming method	RIT Waseda Univ. TOYOTA Texas Univ.		Wisconsin Univ.	NISSAN SERI JARI VW GM MATSUDA				

Table 8-2-3 Developing Condition of Diesel Fuel Alternative Utilization Technologies

Kind (Concept) of Utilization Technique			Basic Study: Combustion method	Basic Study: Exhaust cleaning method	Developing Study, For cars: Engine system	Developing Study, For cars: Vehicle system	Developing Study, For cars: Car running test	Developing Study, For industrial use: Engine/vehicle system	Developing Study, For industrial use: Fleet test
Dual-fuel injection method			Hokkaido Univ. MITSUBISHI	SWRI/EPA			VOLVO Aachen I.T. KHD JARI	MWM (Methanol)	
Forced firing method	Spark method	Intra-cylinder direct injection	Hokkaido Univ. Santa Clara Univ., Indian Oil Research Institute MITSUBISHI SWRI (AFFMSDE) Japan Clean Engine Ltd.	SWRI/EPA			MAN JARI		KOMATSU
Forced firing method	Spark method	Gasification and premixing method					D.Benz		
Forced firing method	Glow method	Intra-cylinder direct injection method	MITSUBISHI Aachen I.T. KHD						CATERPILLAR
Forced firing method	Glow method	Laminar air-intake method							
Forced firing method	Glow method	2-cycle auto ignition method		GM			GM/DDA		
Reforming method							JARI		

Table 8-2-4 Developing Condition of Fuel Alcohol Utilization Technologies (8) (9)

Main Application	Utilization Technique Particulars			Kind of Study and Step in Development: 1 Basic study (engine bench test) Basic study in which single cylinder engine is used and optimum factors of methanol engine such as combustion method, fuel supply method, exhaust gas cleaning method, lubrication method and starting method are searched.	2 Applied study (engine dynamo) Examination of application to commercial vehicle Refining of multi-cylinder engine system	3 Development study (chassis dynamo test) Examination of applicability and practicability as vehicle system performance, exh.ust and drivability of vehicle	4 Feasibility study (commercial vehicle running and fleet tests; Confirmation of suitability and practicability from the aspects of durability, reliability, safety and social demands (air and noise pollution control)	5 Merchandising study Advanced study for enhancing marketability, quality and reliability to meet market
Gasoline alternation	Neat/near-neat utilization method	Homogenizing method: Carburetor system; Injection system	Turbo / NA					G1
		Laminar air-intake method						
	Neat utilization/ reforming method				G2			
	Others	Mixed utilization						
Diesel oil alternation	Fumigation method	Carburetor system / Injection system						
	Near-neat utilization method / Dual-fuel injection method	Dual-pump and dual-injection method	Swirl chamber / Antechamber / Direct injection				D1	
		Dual-pump and single-injection method						
	Neat utilization and forced firing method	Spark assist method	Cylinder injection (Swirl chamber / Antechamber / Direct injection) / Pre-mixing injection			Spark		
						Glow	D2	
		Auto ignition method						
	Neat utilization/ reforming method	Neat-utilization fumigation method			D3			
	others	Firing-promotive addition method						
		Mixed utilization						

(2) Utilization Technology on a Gasoline Engine Basis

Utilization technology of fuel alcohol in the category of spark ignition engines have virtually been established regarding both the low blend alcohol fuel (M3 or low) and the neat or higher blend (M85 or above) alcohol fuel.

Table 8-2-5 Regulation on Contents of Alcohol, etc. (EPA) (47)

(1) General Rules
- o For oxygenates other than methanol, oxygen concentration in mixed gasoline shall be 2 wt% max.
- o For metanol, it shall be 0.3 vol% max.
- o When the compatible agent of more than C_4 or its equivalent is mixed, it shall be 3.5 vol% max.

(2) In other cases EPA makes individual examination and grants a waiver.

Condition of waiver granting by EPA to oxygenates

O-containing fuel	Allowable amount miscible in gasoline: Oxygen concentration	Allowable amount miscible in gasoline: Allowable amount	Contents	Date of waiver	Remarks
Ethanol		10.0max		78. 12. 16 82. 4. 5	EPA waiver was obtained through the Energy Policy and Conservation Act.
General Rules MTBE Aliphatic alcohol Aliphatic ether	2.0max 2.0max 2.0max 2.0max	Abt. 11.0 max.	→ (In actual practice, restriction to about 6 % is enforced due to the problem of peculiar odor.)	80. 10. 10 81. 7. 28	Methanol shall be excluded. Porpyl alcohol, butyl alcohol, etc. t-amyl methyl ether, etc.
Arconol	3.5	Abt 16.0max	GTBA (t-butyl alcohol of gasoline grade)	81. 11. 16	ARCO
Methanol		0.3			General Rules
Methanol + class C_4 alcohol		3.5	A mixture of methanol and alcohol of C_4 or above at equal volumetric ratio	81. 7. 28	General Rules
Oxinol 50	3.5	Abt. 9.5	A mixture of methanol and GTBA at 1:1 (vol %)	81. 11. 16	ARCO社
Oxinol	3.5	Abt. 9.0max	Fuel in which methanol content in GTBA is below 50 vol %.	81. 11. 16	ARCO社
Petrocoal		Total alcohol quantity: 15 % max. Methanol quantity: 13 % max.	A mixture of methanol and C_4 alcohol at a ratio of 6.5:1 or below (vol %) to which an anti-corrosive agent is mixed.	81. 10. 5	American Methyl Corp
Du Pont	3.7		Methanol (5 % or below) + Compatible agent (2.5 % or above) + Anti-corrosive agent (DGOI-100)	85. 1. 14	Recommended compatible agent: Methanol, and butanol, propanol and GTBA also can be used.

To solve the problem of layer separation and to minimize the modification of current engines, the U.S. has enacted regulations shown in Table 8-2-5 for low blend. The utilization of oxygen-containing fuels in major countries is shown in Table 8-2-6, which suggests that the 3 to 5% alcohol-fuel mixture has no significant oil- alternation effects and exercises no faborable effect on engine performance, that is, improvement in thermal efficiency and lowering of exhaust emission, and only the lead-removing or lead-decreasing effect can be slightly expected. For improving the octane number, MTBE (compound of methanol and isobutylene) seems to have a higher possibility than the alcohol-fuel mixture.

The neat alcohol fuel gives higher thermal efficiency per calorific value than the gasoline fuel, which may be due to the following causes.(23)

- o It has a higher octane number and permits an incrase in the compression ratio.
- o Lean-burn combustion is possible and combustion speed in high.
- o The combustion gas temperature is low and heat loss is minimal.

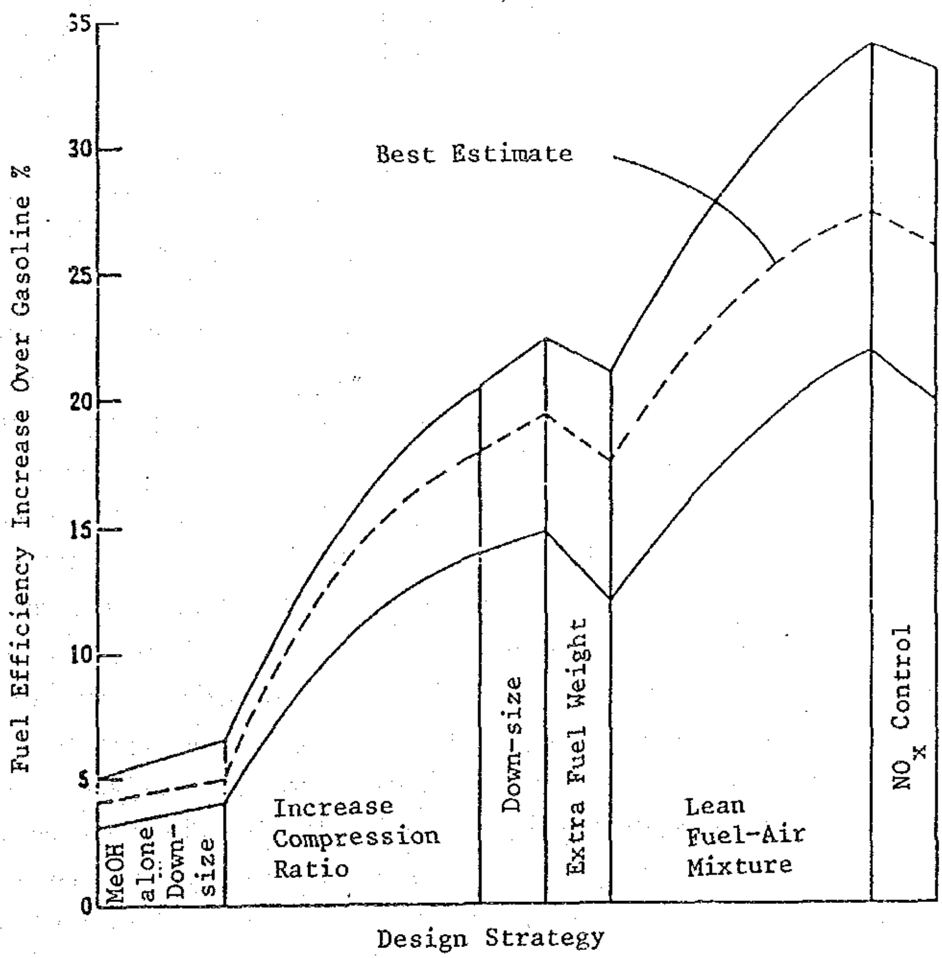


Fig. 8-2-2 Fuel Efficiency Increae Over Gasoline

Fig. 8-2-2 shows the possibility of raising the thermal efficiency of the alcohol fuel to 25%. In the commercial car test using a Mazda test engine running at 1,500 rpm and with a mean effective pressure of 3 kg/cm^2, the alcohol fuel improved in thermal efficiency by about 10% over the gasoline fuel, including the effect of raising the compression ratio from 9 to 11.8, as shown in Fig. 8-2.3(b).(46)

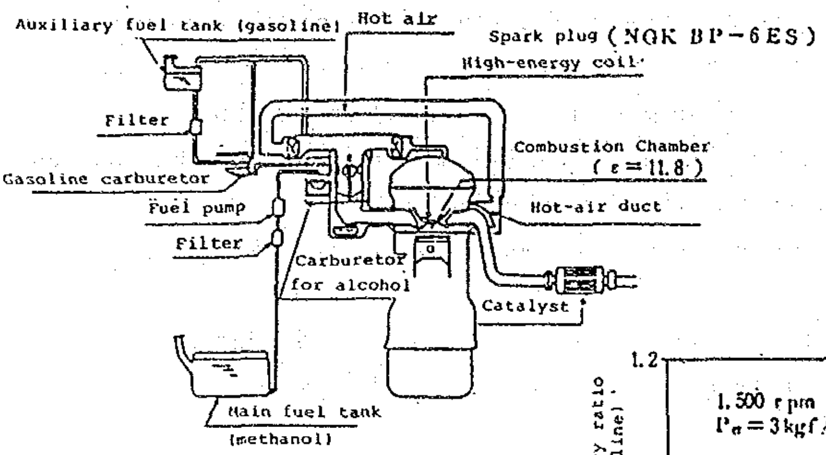


Fig. 8-2-3(1) Engine System for Using Methanol (46)

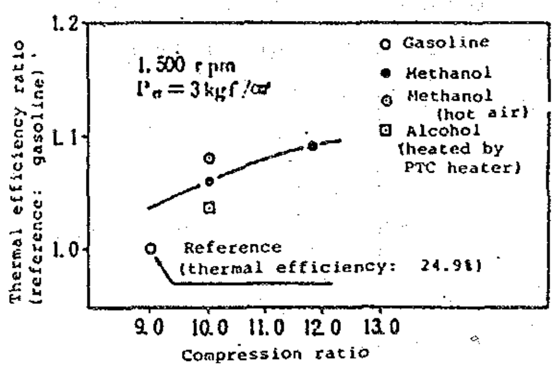


Fig. 8-2-3(b) Thermal Efficiency (46)

As a preliminary to the fleet test by the Ministry of Transport, a 30,000-km test on Mitsubishi Forte van was carried out. The test on the vehicle shown in Fig. 8-2-4 was conducted using the current engine and parts, except a newly designed and installed gasoline tank--which was to be used for starting only--and a carburetor. The results of the 30.000-km test during three months from January to March 1986 are shown in Fig.8-2-5(a) to 5(d). NOx is about one-third, and considerable reductions in HC and CO can be seen. Aldehyde emission from the test car shows a 50% increase at the initial period of running and a 3- to 4-fold increase at the termination of running, over those figures of a gasoline vehicl, but is far lower than the aldehyde emission of a diesel vehicle. Fuel consumption per liter was 5.7 km, which was 1.8-fold compared with 10.3 km for the gasoline vehicle. Fuel consumption per calorific value for methanol was 1.5 km/1,000 kcal, which was 13% better than the value for gasoline, that is, 1.33 km/1,000 kcal.

Toyota has converted its electronically controlled engine into a diluted combustion engine, and its Calina recorded a 10 mode fuel consumption of 17.7 km/l (gasoline equivalent), and Calina's NOx emission cleared 1986 regulations. In city and highway travelling modes, Calina also showed excellent fuel consumption and exhaust gas characteristics(32). Further, clogging of the injection nozzle was corrected by the use of a ball, and the problem of operability by the vapor lock during the hot season was solved by additionally installing a fuel pump in the tank (56). One of the most significant problems in using alcohol fuels on gasoline engine basis was low temperature startability; therefore, large-scale fleet tests were carried out in cold regions of the U.S. and Europe.

In the use of neat or high-concentration methanol and ethanol as gasoline alternatives, there have been problems, but they may be considered, as mentioned above, to have been solved by state-of-the-art technology. Many fleet tests have proved that fuels alcohol show low exhaust-gas emission, and no serious problem in

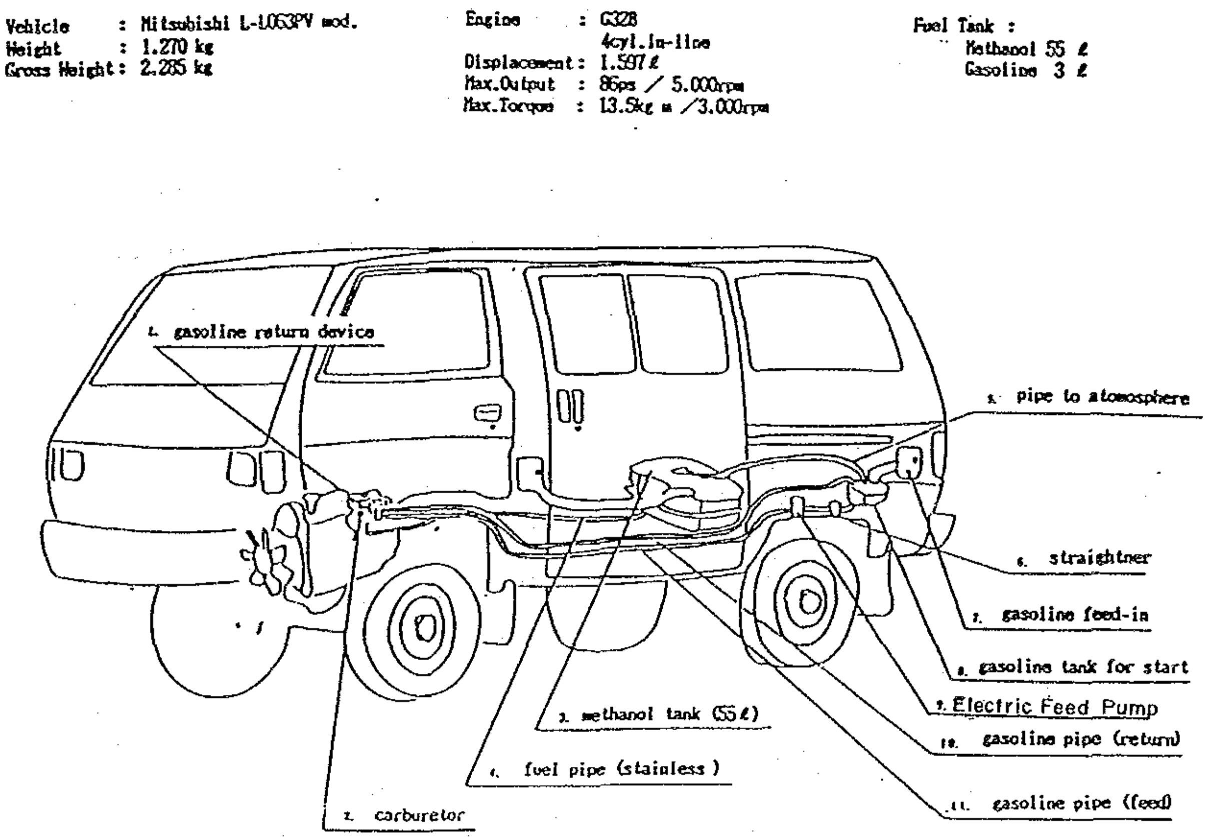


Fig. 8-2-4 Vehicle Fueled with 100% Methanol Used in Fleet Test by Bureau of Environmental Preservation, Tokyo Metropolitan Government

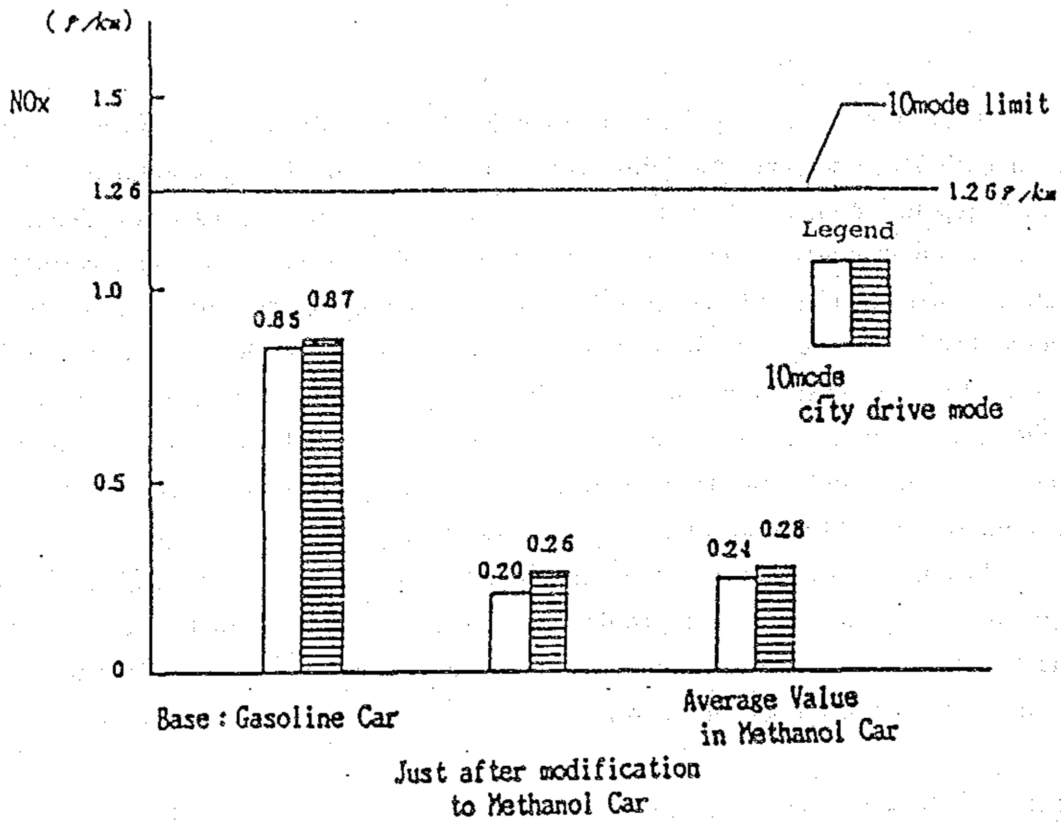


Fig. 8-2-5 (a) Nitrogen Oxides Emissions

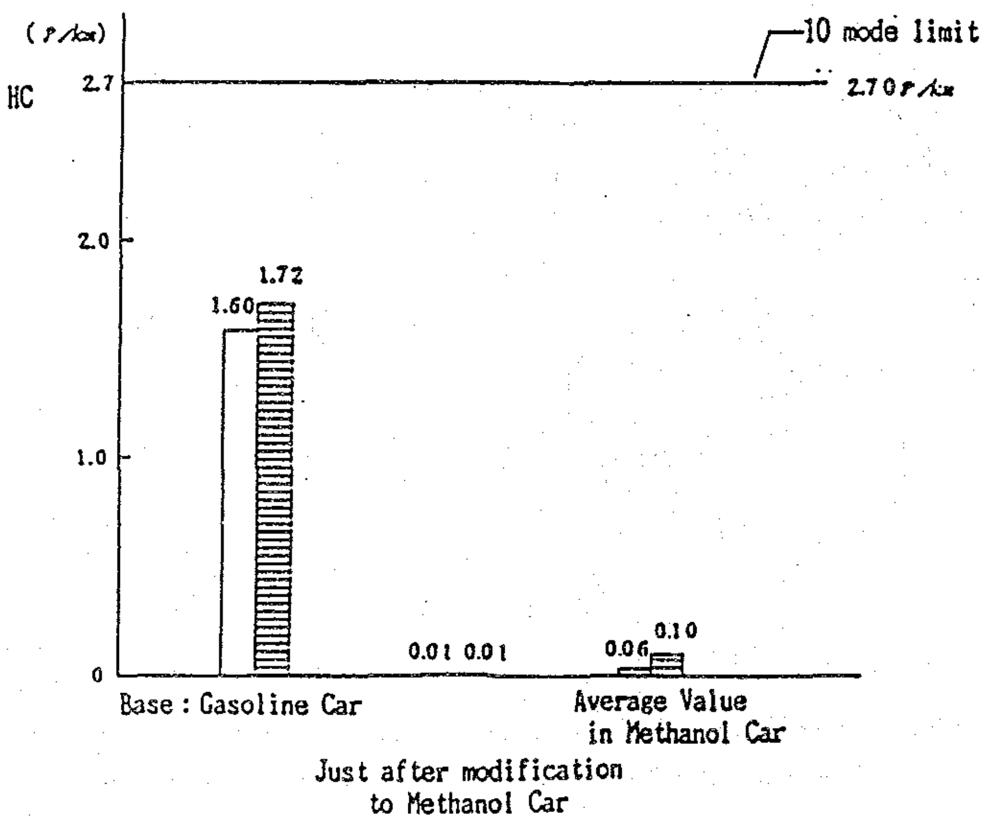


Fig. 8-2-5 (b) Hydro Carbon Emission

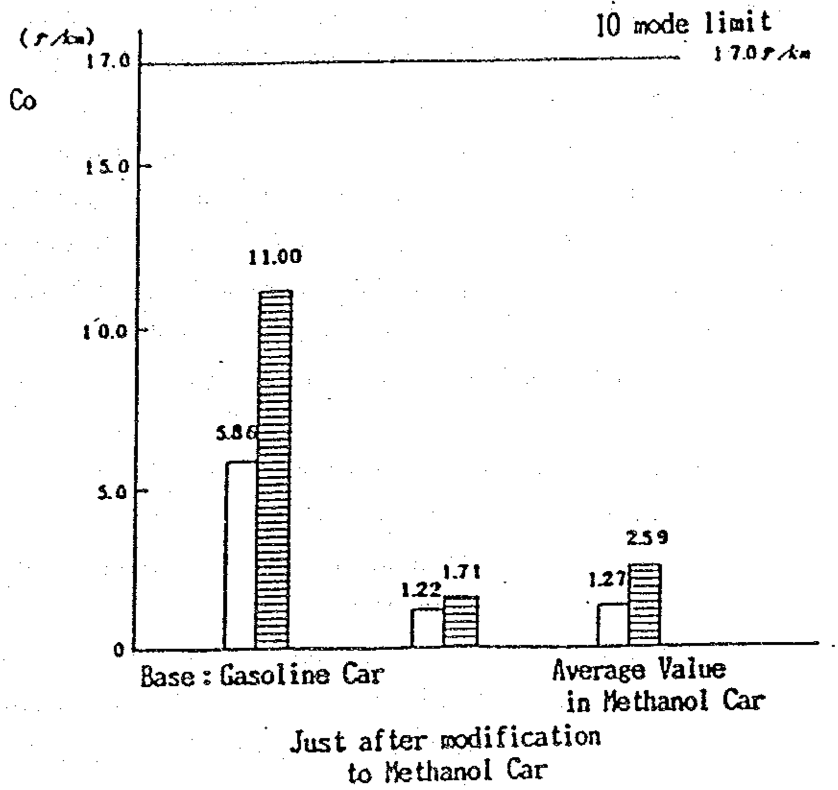


Fig. 8-2-5 (c) Carbon Monoxide Emissions

Aldehyde : (mg/km)	Gasoline Car	Methanol Car					
		Just after mod.	Average (A)~(D)	after 5,000km (A)	after 10,000km (B)	after 20,000km (C)	after 30,000km (D)
10 mode *	2.68	5.15	6.65	4.25	4.36	8.97	9.03
11 mode	14.38	131.91	191.19	179.17	165.20	270.12	150.25
City Drive	1.51	1.38	4.52	2.12	2.76	6.49	6.69

*Diesel Car M15 mode (Close to 10 mode) 25 ~ 40 mg/km

Fig. 8-2-5 (d)

opertion will occur. In the practical use of alcohol fuels, however, fuel supply poses a problem, and in order to solve this problem, FFV (Flexible Fuel Vehicle) has been developed[57][58][60][61][63][85].

The above vehicle permits the use of pure methanol, pure gasoline, and a mixture of both by a single vehicle. The attention of the development was focussed, in particular, on the TNO sensor developed in the Netherland, which optically detects whether the fuel in use is 100% methanol or pure gasoline through the help of the color difference[66]. A carburetor was developed which permited the use of any of methanol, gasoline or gaseous fuel and was put to a fleet test.[56,63]

A test was conducted in India to use methanol on 2-cycle small-sized engines for motorcycles and scooters, and methanol at M90 showed excellent performances in output and exhaust emission gas. Particularly, when the compression ratio was increased from 8.1 to 9.4, the fuel consumption of methanol showed an improvement of 11% to 20%; and in the 6,000-km scooter test, the fuel consumption of M90 was 23 km/l (gasoline equivalent: 43 km/l) over 36 km/l of gasoline. There was no problem with the operability of M90, except the difficulty of starting at a temperature below 10°C.

An attempt is being made in which methanol is reformed into CO and H_2, using the exhaust heat of the engine, and the CO and H_2 were supplied to the engine, thereby significantly improving thermal efficiency including the recovery of the exhaust energy. The decomposition reaction in this case and the resultant decomposition gas generation increment are as follows:

$$CH_3OH \xrightarrow{\text{Endothermic}} 2H_2 + CO \quad \text{Cal. increase } 22\%$$

$$CH_3OH + H_2O \xrightarrow{\text{Endothermic}} 3H_2 + CO_2 \quad \text{Cal. increase } 15\%$$

The system is shown in Fig. 8-2-6. The combustible range of the hydrogen gas contained in the reformed gas is wide, and lean-burn combustion is possible. However, during a full load operation, an abnormal combustion such as back fire is liable to occur.

VW has developed a system for heating the reactor with a methanol burner to improve low-temperature startability. Its thermal efficiency has been improved by 20-30% compared with gasoline and by 5 to 10% compared with liquid methanol. NOx has been significantly reduced owing to lean-burn combustion, and the discharge quantity of the incompletely burnt fraction has dropped compared with that of liquid methanol.