

Chapter 5

Diagnostic Evaluation of Power Plant Facilities

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Chapter 5 Diagnostic Evaluation of Power Plant Facilities

5.1 Review of Process, Operation and Maintenance

5.1.1 Existing boiler facilities

(1) Capacity of boiler facilities

There are 10 boilers in PPSA. Seven of these boilers are generating high-pressure steam for power generation (hereinafter called high-pressure boilers).

The conditions of high-pressure steam are as follows:

pressure	139	ata
temperature	540	°C

No.1, No.2 and No.3 boilers are made in Czechoslovakia and their capacities are 320 t/h. No.4, No.5, No.6 and No.7 boilers are made in Poland and their capacities are 420 t/h.

The total generating capacity (No.1 - No.7) is 2,640 t/h. No.8 boiler is generating steam at 35 and 18 ata at a temperature of 400°C, and its capacity is 220 t/h.

No.9 and No.10 are generating steam at 18 ata at a temperature of 270°C, and the capacity of No.9 and No.10 is 60 t/h.

The main specifications of these boilers are summarized in Table 5.1-1.

(2) Kinds of steam and usage of generated steam

There are 7 pressure levels ; 139 ata, 70 ata, 45 ata, 35 ata, 18 ata, 7.5 ata and 1.2 ata, as shown in Figure 5.1-1 (Diagram of steam supply system).

The usage and main specifications of generating steam are summarized in Table 5.1-2.

There are 5 steam turbines in PPSA for power generation.

The main specifications are listed in Table 5.1-3. 90% of 139 ata high-pressure steam generated by 7 high-pressure boilers is used as driving source for power generation. Several kinds of steam (35 ata, 18 ata, 7.5 ata, 1.2 ata) are extracted from these turbines. 70 ata, 45 ata, 35 ata, 18 ata and 7.5 ata steams are directly supplied to each main pipeline from depressurization of the 139 ata steam through the reducing valves.

(3) Existing facilities of No.1, No.2 and No.3 boilers

The boiler facilities of 00320No.1, 00320No.2 and 00320No.3 are studied in this section. However, as all terms such as boiler manufacturer, design steam generation capacity, design steam temperature and design steam pressure are the same, the 00320No.3 boiler which is under consideration for revamping will be studied as a typical case.

The 00320No.3 boiler is a general purpose one comprising a combustion system including combustion air supply, heat recovery system from combustion gas and a flow system of boiler feed water and boiler water. Simplified Flow Diagram is shown in Figure 5.1-2.

1) Combustion section

Combustion air is supplied by forced blowers. After being pre-heated by the steam air heater, heat is exchanged with combustion flue gas in the Jungstrome type air-heater and the temperature is raised to about 240°C.

A steam air heater is installed to prevent corrosion in the Jungstrome and flue gas duct.

Combustion fuels in PPSA are vacuum residue, off gas, tar and diesel oil.

Consumption percentages of each fuel based on equivalent typical fuel heating value (7,000 kcal/kg) are shown in Table 5.1-4.)

Table 5.1-4 FUEL CONSUMPTION OF BOILERS IN PPSA

Kind of Fuel	Percentage	Note
Vacuum Residue	97.7 %	Burning in normal operation
Off Gas	2.6 %	Balancing
Tar	0.5 %	Phenol tar
Diesel Oil	0.2 %	Flushing of vacuum residue oil line

Source: PPSA

Note : Details of the fuels are shown in Table 5.6-1.

2) Boiler feed water and boiler water section

After chemical decarbonation of the Vistula river water by adding Ca(OH)_2 and FeSO_4 , one part of treated water is supplied for cooling water and the rest for boiler feed water (hereinafter called B.F.W).

The river water for B.F.W is introduced to the demineralizer. After filtrating raw water in the demineralizer, organic materials, anions and cations in the raw water are removed by ion exchange resins. Details of the demineralizer are described in Section 5.5. The water treated in the demineralizer is then introduced as boiler feed water to the preheating section.

(a) Quality of B.F.W and boiler water (hereinafter called B.W.)

The quality of B.F.W is checked 3 times per day and the quality of B.W is checked by manual analysis every 2 hours.

The control target figures for quality of B.F.W and B.W are shown in Table 5.1-5.

**Table 5.1-5 THE CONTROL TARGET FIGURES FOR QUALITY OF B.F.W.
AND B.W.**

		target quality	actual data
[Boiler Feed Water]			
pH	[-]	8.5-9.5	8.5-9.2
hardness	[mg-CaCO ₃ /l]	0.0	0.0
oil and fat	[mg/l]	max 0.3	0.0-0.3
dissolved O ₂	[mg-O ₂ /l]max	0.02	0.02
total iron	[mg/l]	max 0.035	0.02-0.03
total Copper	[mg/l]	max 0.003	0.002-0.003
N ₂ H ₄	[mg/l]	0.05-0.10	0.05-0.10
conductivity	[μ S/cm]	-	-
SiO ₂	[mg/l]	max 0.0	0.010-0.025
[Boiler Water]			
pH	[-]	9.0-9.5	9.2-9.5
total evapo- ration residue	[mg/l]	-	-
P ₂ O ₅ ⁻³	[mg/l]	1.5-3.0	1.5-3.0
SiO ₂	[mg/l]	0.3-0.4	0.2-0.4

Source: PPSA

This Table shows that actual data of all items are satisfied target values and these target values are almost the same as Japanese standard 'JIS B 8223'.

(b) Preheating of B.F.W

B.F.W is preheated through gland leakage steam condenser and low pressure steam heater and fed to deaerator. It is then preheated to around 185°C by high pressure steam heater.

(c) Deaeration

Two deaerators are installed in No.3 boiler and dissolved oxygen in B.F.W is removed by direct contact heating with steam.

The content of dissolved oxygen in deaerated water is 0.01-0.03 mg-O₂/l. The two deaerators are operated in series.

(d) Chemical injection

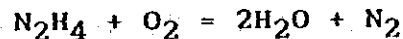
Quality of B.F.W of high pressure boiler is strictly controlled by adding chemicals.

The kinds of injection chemicals and injection points are shown in Figure 5.1-3. The purposes of each chemical is as follows :

a) N_2H_4 (hydrazine)

Since existence of dissolved oxygen in boiler feed water causes iron to corrode, scale formation and interference of heat transfer through heat exchanger tubes, it is normally necessary to maintain oxygen concentration under $0.002 \text{ mg-O}_2/\text{l}$ for high pressure boilers.

Physical treatment, only such as deaeration in deaerator, is not sufficient, so chemical treatment is applied. Hydrazine (N_2H_4) is injected into suction line of feed pump(s) of deaerator and dissolved oxygen is removed as shown in the following reaction :



Unreacted or excess hydrazine is decomposed at around $230-330^\circ\text{C}$ and NH_3 and N_2 are produced.

If hydrazine is added excessively, pH will be increased and go over the upper limit of pH. Therefore, it is better for residual content of hydrazine to be controlled under 0.01 mg/l .

b) NH_3 (Ammonia)

When dissolved oxygen is fully removed, corrosion does not occur. However, there are some possibilities of oxygen invasion in cases of start-up, low load operation and sea water leakage from condenser tubes. NH_3 injection at outlet of deaerator keeps pH of boiler water between 8.5-9.5 and lessens the possibility of corrosion.

c) Na_3PO_4 (Sodium Phosphate)

Na_3PO_4 is added to inhibit scale formation caused by salts in B.F.W. Na_3PO_4 reacts with Ca^{2+} and Mg^{2+} and produces Ca/Mg salts. These salts are precipitated. When these salts are precipitated in B.W, they are deposited as sludge. The sludges is blown outside by B.W-blow operation.

3) Section of heat recovery from combustion gas

Temperature of combustion gas in combustion chamber of No.3 boiler is 1,400-1,900°C. Heat of combustion gas is recovered through water screens, second-, third- and first-superheater and economizer.

Temperature of combustion gas is decreased to around 350°C at outlet of economizer. This combustion flue gas is utilized as heat souce of combustion air and emitted from stack at 150°C.

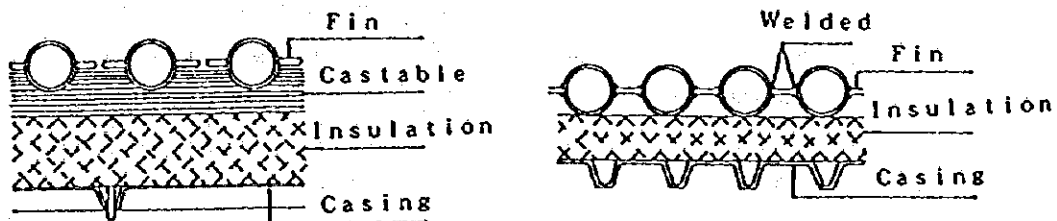
Sootblowers which are normally installed in boilers burning heavy oil are not installed in No.1, No.2 and No.3 units. Economizer tubes are installed in a staggered arrangement.

4) Structure of boiler combustion chamber

The frame of water screen wall of 00320 No.1, 00320 No.2 and 00320 No.3 is shown in Figure 5.1-4. Outside diameter of tubes is 60 mm(5mm-thickness) and these tubes are attached with fins of 22.5 mm height. The tubes are laid at 130 mm pitch so that there are open spaces of 25 mm between the front ends of fins.

Therefore, a balanced draft control system is applied to maintain the pressure of the combustion chamber below atomospheric pressure.

Figure 5.1-4 CROSS SECTIONAL DRAWING OF WATER SCREEN WALL



5.1.2 Matters to be pointed out, evaluations and countermeasures regarding the boiler facilities

(1) Boiler capacity

The boiler capacity is discussed in section 5.1.5 considering relation between capacity and operation rate.

(2) Steam pressure control system

The steam pressure control system is discussed in section 5.3.

(3) Boiler facilities (00320 No.1-00320 No.3)

1) Matters to be pointed out

(a) Combustion section

The combustion section is discussed in section 5.2.

(b) B.F.W and B.W section

The flow of B.F.W and B.W section is the same as other general high pressure boilers. Therefore, there are no comments to be pointed out in this section.

(c) Section of heat recovery from combustion gas

The flow system of combustion gas heat recovery is the same as high pressure boilers in Japan except there are not any sootblowers in superheaters, economizers and Jungströme.

This has caused the gradual fouling of heat transfer tubes, decreasing boiler efficiency and causing the temperature of combustion gas to increase. When the outlet temperature of the third superheater and economizer rises above the design temperature, the boilers have to be stopped to clean the fouled tubes.

(d) Structure of combustion chamber

When the structure of water screen is not a welded type and the pressure of the combustion chamber is controlled below atmospheric by balanced draft, there are some possibilities of air invasion into the chamber. Therefore, when castable refractories are cracked, the boiler casing internally exposed to combustion gas is externally cooled by outside air and suffers corrosion damage.

2) Evaluation of the matters to be pointed out and necessary countermeasures

(a) Combustion section

The combustion section is discussed in section 5.2.

(b) B.F.W and B.W section

The flow of B.F.W and B.W section is the same as other general high pressure boilers. Therefore, no countermeasures are necessary.

(c) Section of heat recovery from combustion gas

Main subject to be pointed out is that no sootblowers are installed in superheaters, economizer and Jung Strom.

It is necessary that sootblowers are installed at the locations as shown in Figure 6.2-1 to keep tubes clean. In general, not a staggered but a checker arrangement is used in an economizer of boilers burning heavy fuel oils. Whether the staggered arrangement is converted to a checker arrangement or not is decided considering the degree of tube fouling and maintainability.

(d) Structure of combustion chamber

It is better to convert the structure of water screen to a welded type if possible. To convert the present type of water screen to a welded type, present openings between fins are connected by welding and then tubes are connected by 70 mm plates.

When fin length is longer, the temperature at front end of fins rises and fins are affected by high temperature oxidation.

It was reported that the front ends of 22.5 mm fins of No.3 boiler were actually affected by high temperature oxidation and the clearance of fin opening was extended to more than 25 mm which was prescribed on the drawing. It is not recommended to connect existing tube fins by welding.

Finlength of 63.5 mm diameter heat transfer tubes of typical welded boilers is around 19 mm.

Therefore, conversion of the structure of water screen to a welded type means the replacement of the boiler. It is better that the boilers run in the actual structures as long as possible and new boilers be constructed in the future.

5.1.3 Present boiler operation

(1) General review of boiler operation

The test run data of No.3 boiler is not available, thus this review is based on the test run data of No.2 boiler. The test run data of No.2 boiler is shown in Table 5.1-6, 5.1-7 and 5.1-8. This data was for loads of 57%, 84%, 87% and 99% of the rated capacity.

In the case of 99 % load, fuel was pre-heated to 181°C and B.F.W was pre-heated to 183°C. Combustion air was pre-heated to 50°C by steam air heater and to 244°C by Jung Strom.

Combustion flue gas temperature was 353°C at outlet of economizer. Flue gas was heat exchanged through Jungstrom and emitted at 156°C to stack.

(2) Amount of fuel consumption in 1992

Total amount of fuel consumption in 1992 is shown in Table 5.1-9 and actual figures of steam generation of each boiler in 1992 are shown in Table 5.1-10.

Following is a summary of these tables.

- 1) Total amount of fuel consumption in power plant section of PPSA was 636,557 t/y. Fuel consumption in January was maximum, 75,586 t/month and in July was minimum, 30,520 t/month.

- 2) Based on the test run data of No.2, fuel consumption per 1 ton steam generation is calculated and summarized in Table 5.1-11.

Table 5.1-11 FUEL CONSUMPTION OF NO.2 BOILER

Boiler load	Fuel consumption
57 % load	70.0 kg/t-Steam
84 % load	68.9 kg/t-Steam
99 % load	69.7 kg/t-Steam

Source: PPSA

- (3) Amount of monthly steam generation and boiler load in 1992

- 1) Total amount of steam generation from all boilers in 1992 was 9.448 million-ton/y (herring after MM-ton/month).
- 2) Maximum steam demand was in January and the amount of steam generation from all boilers in January was 1.094 MM-ton/month with an hourly average of 1,470 t/h.
- 3) Minimum amount of steam demand was in July and the amount of steam generation from all boilers in July was 0.495 MM-ton/month with an hourly average of 666 t/h.
- 4) Maximum amount of steam generation was 0.223 MM-ton/month (hourly average: 300 t/h) in October from 00420 No.6 boiler.
This represented means 71% load of the rated capacity.
- 5) Maximum load of 00320 No.3 boiler was 0.173 MM-ton/month in December and hourly average was 232 t/h. This represented 73% load of the rated capacity.

- 6) The monthly average loads of high pressure boilers in operation are as follows:

Table 5.1-12 MONTHLY AVERAGE LOADS OF HIGH PRESSURE BOILERS IN 1992

boiler No.	Average load(t/h)	rated capacity(%)
No.1	222	69
No.2	233	73
No.3	235	73
No.4	268	64
No.5	249	59
No.6	260	62
No.7	306	73

Source: PPSA

- 7) The monthly average loads of low pressure boilers in operation are as follows:

Table 5.1-13 MONTHLY AVERAGE LOADS OF LOW PRESSURE BOILERS IN 1992

boiler No.	Average load(t/h)	rated capacity(%)
No.8	45	75
No.9	44	73
No.10	82	37

Source: PPSA

(4) Boiler operating hours and load in 1992.

Monthly operating hours of each boiler are shown in Table 5.1-14.

The following is a summary of the table.

- 1) The operating hours of 00420 No.4 boiler were the longest, 7,065 hrs/y among 7 boilers.

- 2) The operating hours of 00320 No.2 boiler was the shortest, 2,930 hrs/y. Its yearly operating rate was 33.4%.
- 3) The average operating hours of high-pressure boilers were 5,229 hrs and its yearly service ratio was 60.0%.
- 4) The sum of operating hours of 3 low-pressure boilers were 1,878 hrs. The average operating hours per one boiler was 626 hrs and its yearly service ratio was 7.0%.
The operating hours of 00220 boiler were 1,770 hrs.
The operating hours of OK060 No.1 and OK060 No.2 are 71 hrs and 31 hrs.

(5) Number of start-up operations

Number of start up operations of high-pressure boilers in 1992 are listed in Table 5.1-15. Start up operations were done 63 times in 1992. The reasons for start up operation of high pressure boilers are listed in following Table 5.1-16.

Table 5.1-16 THE REASONS FOR START UP OF HIGH PRESSURE BOILERS IN 1992

reasons	number of start up
1. after maintenance	34
2. after hot stand-by	18
3. after cold stand-by	2
4. after emergency shut down	9
total	63

Source: PPSA

Hot stand-by means troubles without cooling down operation.
Trouble without shut down maintenance and cold stand-by

means trouble with fire cut and cooling down operation. 00320 No.2 boiler and 00420 No.5 boiler were started up most frequently, 12 times, and 00420 No.6 boiler the least frequently, 3 times.

According to the report of PPSA, the main reasons of shut down of high pressure boilers are as follows :

1) Fouling on heat transfer tubes

Heat transfer tubes were fouled after 1000 hrs operation at the present of load between 60% and 75%. Heat transfer efficiency dropped due to the lack of a sootblower and the richness of dust and unburned mist caused by burning vacuum residue.

Therefore, the temperature of combustion flue gas rises and when it reaches the limit of the materials, the boiler is stopped and maintained.

When the outlet temperature of the third superheater goes above 880°C or that of the economizer goes above 400°C, the boiler is stopped.

2) Sulfuric acid corrosion on boiler casing

Water screens of 00320 No.1 to No.3 boilers, as shown in Figure 5.1-4, are not welded structures so that the combustion flue gas is in contact with the rear side of boiler casings, causing the condensation of dilute sulfuric acid at a lower temperature than the dew point of acid, eventually making holes by corrosion.

When a 3% sulphur content fuel is burnt and the oxygen content in the combustion chamber is assumed to be about 3%, the content of SO₃ is about 40 ppm. In this case the dew point of acid is assumed to be 140°C.

3) Sulfuric acid corrosion on Jungstrome and water screen

Jungstrom is so structured, being separated into 2 rooms by seal plates, that combustion air at about 50°C and combustion flue gas at about 350°C continuously pass through the rotating heat transfer elements and exchange heat. Therefore, some areas will be cooled below the dew point of acid and exposed to severe corrosion by dilute sulfuric acid.

The temperature of combustion flue gas downstream is so decreased, to around 150°C, that if cooled externally, the temperature of duct surface is decreased below the dew point of acid and corrosion by dilute sulfuric acid occurs on duct surface.

5.1.4 Matters to be pointed out, evaluations and countermeasures regarding present boiler operation

(1) Matters to be pointed out;

1) The boiler efficiency is discussed in Section 5.4 and the operation rate is in 4) and 5) of this section.

2) Fuel consumption

Fuel consumption per 1 ton steam generation is 68.9-70.0 kg.

This value is 5% worse than other values of Japanese boilers burning vacuum residue.

3) Monthly steam generation and boiler load

According to the data in 1992, each boiler ran at about 70% load. Because the boiler efficiency is influenced by boiler load, it is better that boilers of base load run at

the load of maximum efficiency. It is assumed from the data of Table 5.1-7 that the load of maximum efficiency is 75% - 85%. Therefore, present boiler load is a bit low.

4) Operating time

The average yearly operating time was 5,229 hrs according to the data in 1992. This means that boilers were working 60% of the time. In general, facilities such as boilers run continuously except when inspection and maintenance is required by regulations.

5) Number of start up operations

63 start up operations is too many. The matters to be pointed out regarding present boiler operation are that continuous operating time is short and number of shut downs in operation is too high (shut downs are too frequent). These matters have to be solved for modernization of the boiler section.

(2) Evaluations of the matters to be pointed out and necessary countermeasures

1) The boiler efficiency is discussed in clause 5.4 and the operation rate in 4) and 5) of this section.

2) Fuel consumption

The countermeasures for improvement of fuel consumption are discussed in Section 6.2.

3) Monthly steam generation and boiler load

As mentioned in (1)-3) of section 5.1.6, it is better for boilers to run at the load of maximum efficiency.

(a) Load setting of boiler operation

The amount of steam generated in January was the maximum and the hourly average rate was 1,470 t/h.

This represents only a 56% load even in January. When boilers are modernized and boilers can run continuously for a year, it is possible that one high pressure boiler is not required when boilers run at a load of maximum efficiency.

One sample of boiler load balance which is automatically adjusted by load adjustment boilers even if a boiler running at maximum load suddenly stops, is shown in Table 5.1-17.

Table 5.1-17 ONE SAMPLE OF BOILER LOAD BALANCE AT THE CASE 1,470 T/H OF TOTAL STEAM DEMAND

boiler number	load	% of rated load
No.1	260 t/h	80% of rated load
No.2	260 t/h	80% of rated load
No.3	out of use	
* No.4	316 t/h	75% of rated load
* No.5	316 t/h	75% of rated load
* No.6	318 t/h	76% of rated load
No.7	out of use	

Note: * means for load adjustment

According to the forecast of PPSA, the steam demand will increase by 15%. In this case the amount of necessary steam generation will be 1,700 t/h and it will be able to meet the required amount by loading-up No.1-No.7 boilers.

(b) Non-use of low pressure boilers

The total operating hours of 3 low pressure boilers was 1,878 hrs/y. Each operating period was too short. OK060 No.1 and No.2 boilers generate 18 ata steam which can be supplied through the reducing valves or by extracting from turbines. 00220 boiler generates 45 ata steam which cannot be supplied by extracting from turbines. When extraction condensing turbines are installed, 45 ata steam is extracted and existing low pressure boilers are possibly out of use.

4) Numbers of start up operations

As boilers in oil refineries in Japan run continuously except for periods of shut down for inspection required by regulations, one start up operation including shut down operation is possible.

Countermeasures for frequent shut downs are as follows:

(a) Fouling on heat transfer tubes

There are 2 countermeasures. The first is restricting the formation of substances related to fouling by preventing unburning (Improvement of combustibility). The second is removing the foul substances deposited on the tubes.

Improvement of combustibility is discussed in clause 5.2.

Installation of sootblowers on superheaters, economizer and Jung Strom of boilers burning heavy fuel oils is effective at remove fouling materials. Sootblowers are installed on superheaters, economizer and Jung Strom of Japanese boilers burning heavy fuel oils and are working effectively, enabling the boilers to run continuously for 2 years.

It is recommended that Jungstromes are installed at the locations shown in Figure 6.2-1.

(b) Sulfuric acid corrosion on boiler casing

As mentioned in (5)-2) of section 5.1.5, it is impossible to stop corrosion at the stage when corrosion on boiler casing occurs unless sulfuric acid dewed and adhered on the casing is completely removed. Therefore, it is difficult to recommend any countermeasures at this stage.

It is not difficult to repair corrosion holes of casing during operation of boiler. It is better for existing facilities to be in use as long as possible.

(c) Sulfuric acid corrosion on the heat transfer elements of Jungstrom and the duct

The operational data on the air preheat section are shown in Figure 5.1-5. This figure is a summary of Table 5.1-7 regarding the air preheat section.

Combustion air is preheated at the steam air heater and further heated through Jungstrom by heat contained in combustion gas. As combustion gas contains SO_3 , the conditions against corrosion become very severe in an environment at temperatures below the dew point.

Figure 5.1-5 OPERATIONAL DATA ON AIR PREHEAT SECTION

	Combustion air temperature	Combustion gas temperature
Ambient temperature	15°C	
	↓	
Outlet temperature of steam air heater	50°C	
	↓	
		↑
Air inlet/Gas outlet temperature of jungstrome	50°C	156°C
	↓	↑
Air outlet/Gas inlet temperature of jungstrome	244°C	353°C
	↓	↑

If the duct is completely insulated, sulfuric acid corrosion does not occur. However, because the skin temperature of the duct is actually lower than that of combustion gas, it is safer if the control temperature of the duct is fixed at around 160°C, taking allowances into consideration.

The data was taken at an ambient temperature, at 15°C. In PPSA's winter, the outlet temperature of steam air heater will be lower than that at 15°C. Therefore, it is necessary that the capacity of the steam air heater is increased to keep the temperature of elements higher than the lowest control limit to avoid sulfuric acid corrosion on the heat transfer elements of Jungstrom. A chart of the lowest control limit temperature of elements is shown in Figure 5.1-7. As shown clearly in this Figure, it is necessary that the outlet temperature of steam air heater is raised to 105°C.

5.1.5 Existing facilities for electricity supply

(1) Generator capacity (refer to Table 5.1-3)

There are 5 generators in PPSA. All turbines are extraction back pressure turbines.

The capacity of each generator is 55 MW. No.1-No.3 are made in Czechoslovakia and No.4 and No.5 are made in Poland.

The flow system of electricity in PPSA is shown in Figure 5.1-7. The bus bar of electricity flow is 30 kv. Incoming electricity of 110 kv is received through 4 transformers (capacity: 75 MVA).

Electricity is generated at 10.5 kv and transformed to 30 kv and is supplied to the bus bar.

(2) Electricity balance

Monthly electricity balance in 1992 is shown in Figure 5.1-8.

Maximum amount summing consumption and outside sale was around 110×10^3 MW·h/month in January. This represents a the total average power generation of 148 MW·h/h and a per generator power generation of 30 MW·h/h.

Maximum amount of purchased electricity was around 56×10^3 MW·h/month in August. Electricity consumption in August was around 85×10^3 MW·h/month. Generated electricity was in August was around 29×10^3 MW·h/month. This represents an average power generation of 39 MW·h/h. Only one generator in operation is enough to meet the demand.

5.1.6 Evaluation of existing facilities for electricity supply

(1) Generator capacity

5 Generators (55 Mw per generator) are enough. However, all driving turbines are extraction back pressure turbines so that the actual amount of electricity generation depends on steam demand.

As clearly shown in Figure 5.1-8, the operation rate of generators is high in winter when the steam demand is large. It is low in summer when the steam demand is lower and only one generator operation is enough to meet the demand.

As mentioned above, the main point is the strong effect of steam demand. To be free from the effect, the installation of an extraction condensing turbine is discussed in PPSA.

(2) Electricity balance

The evaluation of electricity balance is described in Section 6.3.

5.1.7 Present steam supply system

(1) Low pressure supply system

The major characteristic of Figure 5.1-1, Steam & Electricity Flow, is that all reducing valves for low pressure steam are taken out of 139 ata steam header. Steam of 35 ata, 18 ata, 7.5 ata and 1.2 ata are supplied by extracting from steam turbines and through reducing valves.

70 ata steam is supplied only through reducing valves and 45 ata steam is supplied from 00220 boiler and through reducing valves.

5.1.8 Matters to be pointed out, evaluations and countermeasures regarding present steam supply system

(1) Matters to be pointed out

1) Reducing valves

Reducing valves are exposed to such severe conditions such as high temperature and large pressure differences and the water injection part incurs thermal shock. Also, the configurations of the valves are complicated and their cost is high.

It is not normal practice that all low pressure steam is supplied through reducing valves from the steam of the highest pressure, such as PPSA, because the higher pressure difference valves require higher grade materials and additional measures against erosion due to the severe temperature conditions.

2) 45 ata steam supply

The demand for 45 ata is about 40 t/h lower than the 220 t/h of boiler capacity, so that 00220 boiler efficiency is assumed to be low.

(2) Evaluations of the matters to be pointed out and necessary countermeasures

1) Reducing valves

The system of stepwise pressure reduction, such as from 139 ata to 70 ata and from 70 ata to 45 ata, provides easier operating conditions for the reducing valves.

It is recommended that a conventional system, such as stepwise pressure reduction, be applied at the time when existing reducing valves have to be replaced.

2) 45 ata steam supply

The countermeasure against this matter is discussed in section 5.1.6.

(3) Steam-Electric balance

In order to increase electric power generation in the summer season, there are two effective generation systems.

1) Condensing turbine generator system

This system is under consideration by PPSA now.

The evaluation against this system is described in Chapter 6 Section 6.3 regarding extraction condensing turbine.

2) Gas turbine generator system

This system is widely adopted in order to solve the problem of peak load. Since a big amount of hot exhaust gas which contains a large quantity of oxygen is generated in this

system, it is required that waste heat of gas turbine exhaust gas is recovered.

In general, the oxygen concentration in the flue gas is about 14-15 vol % and the temperature of turbine exhaust gas is about 520-530°C. Therefore, some fuel is added to this hot exhaust gas and the heat of the exhaust gas is recovered in the waste heat boiler. The steam generated from this boiler is used as deriving fluid for extraction-back pressure turbine generator. This system is called a gas turbine combined system.

However, the fuel used in this gas turbine is restricted to the light fuel such as fuel gas, LPG, gas oil and others. Consequently, it is considered that the condensing turbine generator system is more suitable than gas turbine generator system for PPSA.

Table 5.1-1 THE MAIN SPECIFICATION OF BOILERS IN PPSA

	Manufacturer	Manuf. (Year)	Install. (Year)	Evaporation Rate	Steam Press.	Steam Temp	BFW Temp
No. 1	I. Brnenska (CSRS)	1964	1966	320	139	540	195
No. 2	"	1964	1966	320	139	540	195
No. 3	"	1967	1969	320	139	540	195
No. 4	FK. Raciborz	1970	1971	420	139	540	230
No. 5	"	1973	1974	420	139	540	230
No. 6	"	1975	1976	420	139	540	230
No. 7	"	1980		420	139	540	230
No. 8	Wagner Biuro	1976	1977	220	43	400	105
No. 9	FK. Raciborz	1962	1963	60	18	270	105
No. 10	"	1962	1963	60	18	270	105

Source ; P.P.S.A.

Table 5.1-2 THE USAGE AND MAIN SPECIFICATION OF STEAM

	Service	Req. Press.	Req. Temp.	Req. Quantity
139 ata Steam	Generator	135 ata	535°C	1,900 t/h
	Plastic Extruder	- ata	-°C	- t/h
70 ata Steam	Ethylene Oxide Unit	75 ata	450°C	28 t/h
45 ata Steam	Ethylene Oxide Unit Cracking Unit	45 ata	450°C	180 t/h
35 ata Steam	heating	35 ata	290°C	200 t/h
18 ata Steam	heating	18 ata	250°C	400 t/h
7.5 ata Steam	heating	7.5 ata	205°C	300 t/h
1.2 ata Steam	heating	1.2 ata		
[Break down of usage for heating]				
			(Max. Value)	
	Steam Central Heating	1.2 ata	°C	105 t/h
		7.5 ata	°C	200 t/h
		18 ata	°C	280 t/h
	Preheating of Air	7.5 ata	°C	220 t/h
	Preheating of BFW	1.2 ata	°C	205 t/h
		7.5 ata		200 t/h
		18 ata		280 t/h
		35 ata		300 t/h
	Preheating of Fuel	18 ata	°C	280 t/h
		35 ata		300 t/h
	Preheating of Raw Water	7.5 ata	°C	220 t/h

Source: PPSA

Table 5.1-3 THE MAIN SPECIFICATION OF STEAM-TURBINES IN PPSA

No.	Manufacturer	Manuf. (Year)	Install. (Year)	Capacity MW	Steam Temp °C	Steam Press. ata	Max. Steam Flow Rate t/h	Extract Steam ata	Max. Extract Flow Rate t/h
No. 1	I.Emenska(CSRS)	1964	1966	55	535	130	312	7	220
No. 2	"	1967	1969	55	535	130	312	44	20
No. 3	"	1964	1966	55	535	130	412	7	220
No. 4	Zamech-Elblag	1970	1971	55	535	130	420	44	20
No. 5	"	1973	1974	55	535	130	420	18	155
								29	19
								41	20
								18	155
								29	19
								41	20

Source ; P.P.S.A.

Table 5.1-6 OPERATING DATA OF BOILER (00-320 NO.2) (1/2)

Measuring Item	Unit	Number of Measurements					
		1	2	3	4	5	6
Generated Power Generated Power (Relative) *	MW %	132.23 57.0	193.21 84.0	193.21 84.0	200.02 87.0	228.31 99.0	
Generated Steam	t/hr	181.0	263.0	263.0	272.0	311.0	
Steam Temperature @ behind NO.1 S.H. @ before NO.2 S.H. @ behind NO.2 S.H. @ Boiler Discharge	°C °C °C °C	410 / 408 483 / 485 465 / 464 533	405 / 390 491 / 492 466 / 457 534	404 / 390 493 / 492 464 / 458 534	405 / 410 486 / 493 465 / 461 535	408 / 410 488 / 482 460 / 457 535	
Steam Pressure	MPa	13.01	13.1	13.1	13.1	13.1	
Cooling Water Quantity	t/hr °C	11.8 185	26.0 182	25.5 182	21.0 182	28.0 183	
Boiler Feed Water Temperature (Before Boiler) Pressure	°C MPa	185 15.2	182 15.0	182 15.0	182 15.0	183 15.5	
Steam for Burners Temperature Pressure	°C MPa	310 0.81	310 0.82	310 0.82	310 0.82	290 0.90	
Fuel No. Of used Burners Pressure Temperature Heating Value Content of Total Wet Ash Total S	- MPa °C kJ/kg % % %	9 1.20 179 40,612 trace 0.04 2.20	10 1.20 182 40,612 trace 0.04 2.20	10 1.20 182 40,612 trace 0.04 2.20	10 1.20 179 40,612/33892 trace/0.50 0.04 / 0.05 2.20 / 0.01	13 1.20 181 40,612 trace 0.04 2.20	
Steam for Burners Temperature Pressure	°C MPa	310 0.81	310 0.82	310 0.82	310 0.82	290 0.90	
Air Temperature Suction Stack Outlet of SIM-Air HR Outlet of Jungstrom	°C °C °C	13.3 52 222	14.0 52 228	14.0 52 232	14.0 50 233	18.0 50 244	
Flue Gas (Draft) (Temperature) Outlet of Combustion Room Before Economizer Boiler Outlet Outlet of Combustion Room Before Economizer Boiler Outlet	mmAg mmAg mmAg °C °C °C	- - 52 - 42 800 312 137.0	- 6 - 55 - 44 990 318 141.0	- 6 - 59 - 42 960 328 148.0	- 5 - 56 - 40 925 327 147.0	- 1 - 86 - 35 1,015 353 156	

Table 5.1-6 OPERATING DATA OF BOILER (00-320 NO.2) (2/2)

Measuring Item	Unit	Number of Measurements					
		1	2	3	4	5	6
(CO Content) Before Economizer Boiler Outlet	mol %	0.003	0.004	0.021	0.006	0.013	
	mol %	0.002	0.028	0.015	0.004	0.009	
(CO ₂ Content) Before Economizer Boiler Outlet	mol %	0.003	0.004	0.021	0.006	0.013	
	mol %	0.002	0.028	0.015	0.004	0.009	
(Black Degree) Boiler Outlet	-	1 / 1	1 / 4	1 / 1	1 / 1	1 / 1	
Flue Gas Blower Loading ***	A	20 / 22	23 / 21	23 / 22	25 / 23	37 / 37	

Source ; P.P.S.A.

Note ;

* ; Nominal Heat Capacity of Boiler = 231.01 MW

** ; Phenol Tar = 1,500 kg/hr

*** ; Left side / Right side of Boiler

Table 5.1-7 FLUE GAS BALANCE OF BOILER (00-320 NO.2)

Measuring Item	Unit	Number of Measurements					
		1	2	3	4 **	5	6
Generated Power (Relative)	MW %	132.23 57.0	193.21 84.0	193.21 84.0	200.02 87.0	228.31 99.0	
Generated Steam	t/hr	181.0	263.0	263.0	272.0	311.0	
Steam Temperature @ behind No.1 S.H. @ before No.2 S.H. @ behind No.2 S.H. @ Boiler Discharge	°C °C °C °C	410 / 408 483 / 485 465 / 464 533	405 / 390 491 / 492 466 / 457 534	404 / 390 493 / 492 464 / 458 534	405 / 410 486 / 493 465 / 461 535	408 / 410 488 / 482 460 / 457 535	
Steam Pressure	Mpa	13.01	13.1	13.1	13.1	13.1	
Boiler Feed Water (Before Boiler)	Temperature Pressure	185 15.2	182 15.0	182 15.0	182 15.0	183 15.5	
Fuel	No. of used Burners Pressure Temperature Heating Value	9 1.20 179 40,612	10 1.20 182 40,612	10 1.20 182 40,612	10 1.20 179 40,612/33892	13 1.20 181 40,612	
Steam for Burners	Temperature Pressure	310 0.81	310 0.82	310 0.82	310 0.82	290 0.90	
Air Temperature	Suction Stack Outlet of SIM-Air HTR Outlet of Jungstrom	13.3 52 222	14.0 52 228	14.0 52 232	14.0 50 233	18.0 50 244	
Heat Capacity Heat Provided to Boiler in Fuel Heat Provided to Boiler in Steam Amount of Fuel	MW MW MW t/hr	132.23 147.31 0.08 12.67	193.21 209.23 0.11 18.12	193.21 211.61 0.11 18.30	200.02 218.44 0.11 17.66	228.31 250.18 0.12 21.69	
Total Efficiency of Boiler Accuracy of Efficiency Calculated Outlet Losses Uncompleted Burning Losses Radiation & Conduction Losses	% % % % %	89.77 1.409 9.617 0.014 0.601	92.35 0.844 7.107 0.136 0.411	91.31 0.992 8.204 0.080 0.411	91.57 0.863 8.011 0.023 0.397	91.26 0.984 8.348 0.048 0.348	

Source ; P.P.S.A.

Note * ; including heat in heated air
 ** ; additionally burned Phenol tar in amount , 1.50 t/hr

Table 5.1-8 ENERGY BALANCE OF BOILER (00-320 NO.2)

Measuring Item	Unit	Number of Measurements					
		1	2	3	4 **	5	6
Generated Power	MW	132.23	193.21	193.21	200.02	228.31	
Generated Power (Relative)	%	57.0	84.0	84.0	87.0	99.0	
Generated Steam	t/hr	181.0	263.0	263.0	272.0	311.0	
Steam Temperature	°C	410 / 408	405 / 390	404 / 390	405 / 410	408 / 410	
	°C	483 / 485	491 / 492	493 / 492	486 / 493	488 / 482	
	°C	465 / 464	466 / 457	464 / 458	465 / 461	460 / 457	
	°C	533	534	534	535	535	
Steam Pressure	MPa	13.01	13.1	13.1	13.1	13.1	
Fuel	No. of used Burners	9	10	10	10	13	
	Pressure	1.20	1.20	1.20	1.20	1.20	
	Temperature	179	182	182	179	181	
	Heating Value	40,612	40,612	40,612	40,612/33892	40,612	
Air Temperature	Suction Stack	13.3	14.0	14.0	14.0	18.0	
	Outlet of SW-Air HTR	52	52	52	50	50	
	Outlet of Jungstrom	222	228	232	233	244	
Heat Capacity	MW	132.23	193.21	193.21	200.02	228.31	
Heat Provided to Boiler in Fuel	MW	147.31	209.23	211.61	218.44	250.18	
Heat Provided to Boiler in Steam	MW	0.08	0.11	0.11	0.11	0.12	
Amount of Fuel	t/hr	12.67	18.12	18.30	17.66	21.69	
Air for Burning	Nm ³ /kg	10.712	10.712	10.712	10.712	10.712	
Dry Flue Gas	Nm ³ /kg	10.090	10.090	10.090	10.090	10.090	
Wet Flue Gas	Nm ³ /kg	11.391	11.391	11.391	11.391	11.391	
Excess Air	-	1.421	1.061	1.112	1.112	1.095	
Excess Air in Flue Gas before Jungstrom	-	1.536	1.102	1.203	1.171	1.171	
Excess Air in Flue Gas after Jungstrom	-	2.221	1.532	1.694	1.669	1.669	
Unlight in Jungstrom	10 ³ x Nm ³ /hr	30.549	28.067	29.008	29.008	29.820	
Theoretical Amount of Hot Air	10 ³ x Nm ³ /hr	135.72	194.15	196.04	196.04	232.30	
Amount of Net Air	10 ³ x Nm ³ /hr	192.84	206.08	218.05	218.05	254.43	
Amount of Net Flue Gas before Jungstrom	10 ³ x Nm ³ /hr	217.02	226.23	248.18	248.18	286.79	
Amount of Net Flue Gas after Jungstrom	10 ³ x Nm ³ /hr	308.70	309.70	344.51	344.51	402.39	
Amount of Leakage Air through Jungstrom	10 ³ x Nm ³ /hr	91.68	83.47	96.33	96.33	115.61	

Source ; P.P.S.A.

Note * ; Regarding to Air Content in Flue Gas after Jungstrom

Table 5.1-9 FUEL CONSUMPTION ON BOILERS IN 1992

unit : ton/Month

Boiler	320 No. 1	320 No. 2	320 No. 3	420 No. 4	420 No. 5	420 No. 6	420 No. 7	220 No. 8	60 No. 9	60 No. 10	Total
January	10,740	—	12,140	9,330	13,030	13,800	14,070	2,407	—	68.9	75,586
February	9,220	—	11,670	13,112	7,880	11,200	9,140	2,683	—	68.9	64,974
March	2,300	—	10,050	14,410	5,150	14,360	14,100	2,480	110	68.9	63,029
Sub-Total	22,260	—	33,860	36,852	26,060	39,360	37,310	7,570	110	68.9	203,451
April	—	—	10,370	13,392	5,350	11,500	13,396	141	—	66.9	54,216
May	—	—	9,600	11,000	10,550	12,388	670	—	—	66.9	44,275
June	—	—	9,770	9,500	3,850	4,450	9,008	—	—	62.9	36,641
Sub-Total	—	—	29,740	33,892	19,750	26,338	23,074	141	—	—	134,935
July	—	4,180	9,915	11,600	N.O.N	643	4,120	—	—	61.5	30,520
August	1,560	8,600	8,730	10,184	N.O.N	4,550	N.O.N	1,650	160	62.9	35,497
September	10,280	6,454	1,750	12,600	7,404	2,076	N.O.N	134	—	66.7	40,765
Sub-Total	11,840	19,234	20,395	34,384	7,404	7,269	4,120	1,784	160	—	106,590
October	11,400	8,900	—	7,460	14,920	15,031	—	186	—	67.6	57,965
November	9,450	11,400	3,000	7,330	9,540	13,290	9,030	693	28	70.0	63,831
December	11,366	5,050	12,373	3,770	12,120	12,890	12,420	—	—	69.8	70,059
Sub-Total	32,216	25,350	15,373	18,560	36,580	41,211	21,450	879	28	—	191,647
Total	66,316	44,584	99,368	123,688	89,797	116,178	85,954	10,374	298	—	636,557

Source ; P.P.S.A.

Table 5.1-10 STEAM PRODUCTION ON BOILERS IN 1992

unit : ton/Month

Boiler	320 No. 1	320 No. 2	320 No. 3	420 No. 4	420 No. 5	420 No. 6	420 No. 7	220 No. 8	60 No. 9	60 No. 10	Total (t/hr)
January	150,460	—	170,694	136,742	193,002	200,450	208,416	33,920	—	69.6	1,470
February	135,280	—	166,303	191,150	115,157	162,910	132,792	36,420	—	69.6	1,399
March	33,865	—	150,972	208,194	74,238	209,950	203,687	35,610	1,460	69.2	1,234
Sub-Total	319,605	—	487,969	536,086	382,397	573,310	544,895	105,950	1,460	69.5	
April	—	—	159,628	201,732	79,552	170,498	196,420	2,020	—	48.5	1,125
May	—	—	147,174	165,764	156,590	181,520	9,579	—	—	69.2	888
June	—	—	160,273	156,391	60,346	69,246	135,289	—	—	67.0	808
Sub-Total	—	—	467,075	523,887	296,488	421,264	341,288	2,020	—	—	
July	—	84,853	166,192	173,208	—	9,339	61,581	—	—	68.9	666
August	23,369	132,448	145,058	170,918	—	69,307	—	24,030	2,290	67.5	763
September	153,941	96,888	25,783	189,674	111,503	30,650	—	1,990	—	68.6	848
Sub-Total	177,310	314,189	337,033	533,800	111,503	109,296	61,581	26,020	2,290	—	
October	167,505	133,074	—	116,341	214,044	222,961	—	2,700	—	69.2	1,152
November	135,243	160,154	43,512	107,857	132,355	192,323	129,222	10,000	406	71.0	1,267
December	162,117	74,089	172,758	54,419	172,792	187,062	179,587	—	—	70.7	1,349
Sub-Total	464,865	367,317	216,270	278,617	519,191	602,346	308,809	12,700	406	—	
Total	961,780	681,506	1,508,347	1,872,390	1,309,579	1,706,216	1,256,573	146,690	4,156	879	AVG 1,079

Source : P.P.S.A.

Table 5.1-14 BOILER LOAD AND OPERATING TIME OF EACH BOILER IN 1992

Boiler	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEP.	upper column		OCT.	generated steam		Total
										lower column	operating time		operating time	t/hr	
00320 No.1	245	227	192	-	-	-	-	184	235	243	224	224	224	224	4188
	615	596	176	-	-	-	-	127	655	689	605	605	725	725	
00320 No.2	-	-	-	-	-	-	195	225	235	267	235	240	240	240	2930
	-	-	-	-	-	-	436	588	412	488	683	313	313	313	
00320 No.3	240	239	226	245	211	233	225	242	248	-	245	232	232	232	6476
	710	635	669	651	697	689	739	599	104	-	178	745	745	745	
00420 No.4	316	276	299	301	223	261	233	250	263	253	253	283	283	283	7065
	411	656	697	671	734	599	743	684	720	460	426	192	192	192	
00420 No.5	266	253	329	255	211	209	-	-	261	295	246	268	268	268	5191
	726	455	329	312	724	289	-	-	428	725	539	644	644	644	
00420 No.6	309	260	282	284	244	216	191	262	222	300	278	268	268	268	6270
	649	628	744	600	724	320	49	265	138	744	691	698	698	698	
00420 No.7	280	253	306	292	213	247	237	-	-	-	282	297	297	297	4482
	724	486	665	673	45	542	260	-	-	-	458	604	604	604	
OKO60 No.1	-	-	46	-	-	-	45	43	-	-	45	45	45	45	71
	-	-	32	-	-	-	2	27	-	-	4	4	4	4	
OKO60 No.2	-	-	-	-	-	-	-	43	-	-	45	-	-	-	30
	-	-	-	-	-	-	-	26	-	-	4	-	-	-	
00220	88	84	80	70	-	-	-	87	71	84	94	84	84	84	1777
	411	435	447	29	-	-	-	278	28	32	117	117	117	117	
AVERAGE LOAD	1470	1399	1234	1125	888	808	666	763	848	1152	1267	1349	1349	1349	
MAX LOAD	1645	1500	1395								1400	1475	1475	1475	
REMARKS															

Source : P.P.S.A.

Table 5.1-15 NUMBER OF START UP OF EACH BOILER IN 1992
 Type I II III IV I II III IV I II III IV I II III IV I II III IV
 Number of Start after Maintenance after HOT stand-by after Cold stand-by after Emergency Shut Down

Boiler	00320 No. 1				00320 No. 2				00320 No. 3				00420 No. 4				00420 No. 5				00420 No. 6				00420 No. 7				Total								
	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV									
January	-	1	-	-	-	1	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	4
February	1	1	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	5
March	-	-	-	-	-	1	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	3
April	-	-	-	-	-	1	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
May	1	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1	5
June	1	-	-	-	2	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
July	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
August	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	5
September	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	1	-	-	5
October	-	1	-	-	-	1	-	-	-	-	-	-	1	1	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6
November	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3
December	1	-	-	-	-	-	-	-	-	-	-	-	3	1	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	10
Total	5	4	0	0	7	4	0	1	3	4	0	4	5	2	0	1	9	2	1	0	2	0	0	1	3	2	0	1	3	2	1	2	1	2	1	2	63
Total	9				12				11				8				12				3				8				63								
REMARKS	TYPE I (Number of Start after Maintenance)																												34								
	TYPE II (Number of Start after Hot Stand-by)																												18								
	TYPE III (Number of Start after Cold Stand-by)																												2								
	Type IV (Number of Start after Emergency Shut Down)																												9								

Source ; P.P.S.A.

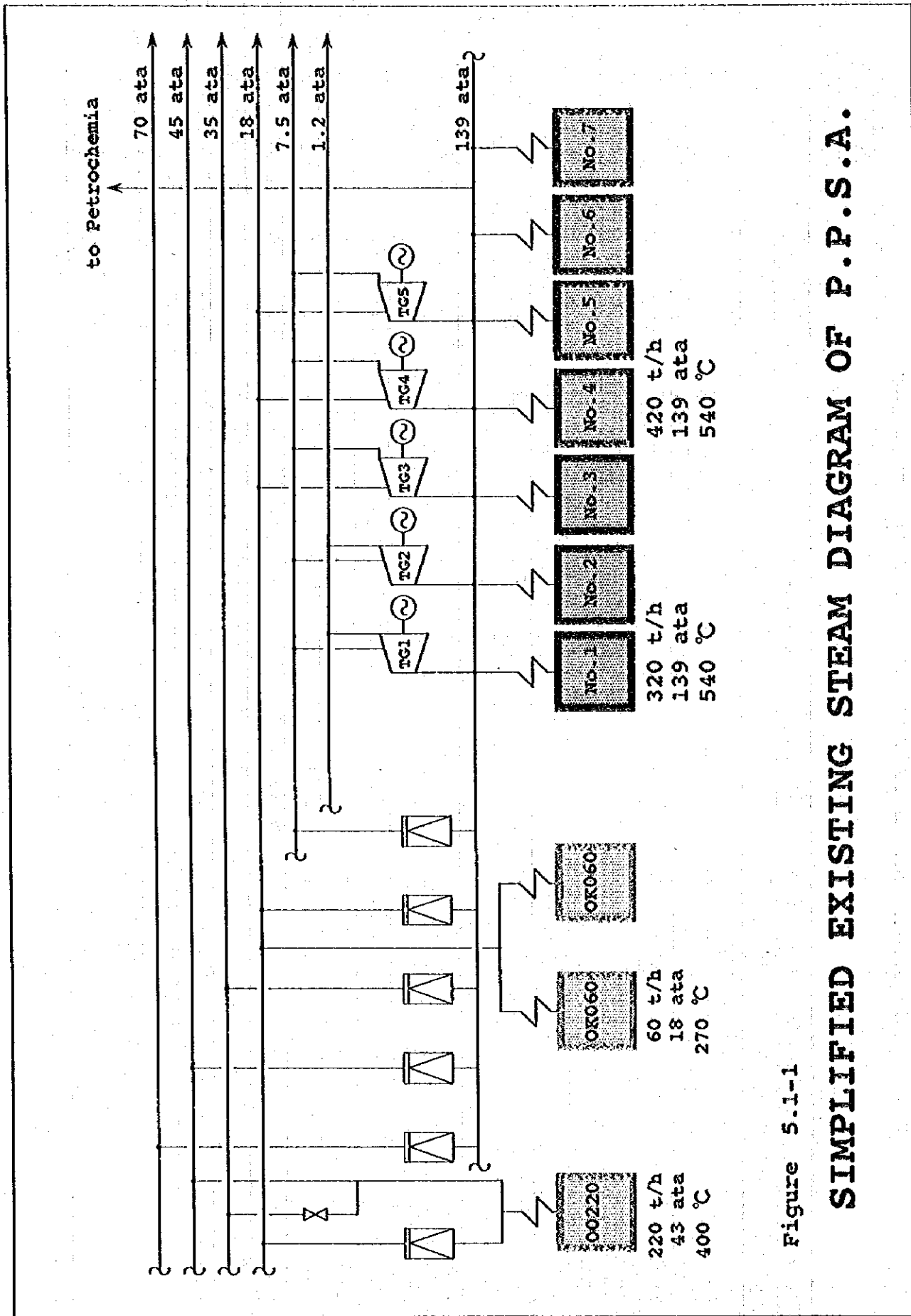
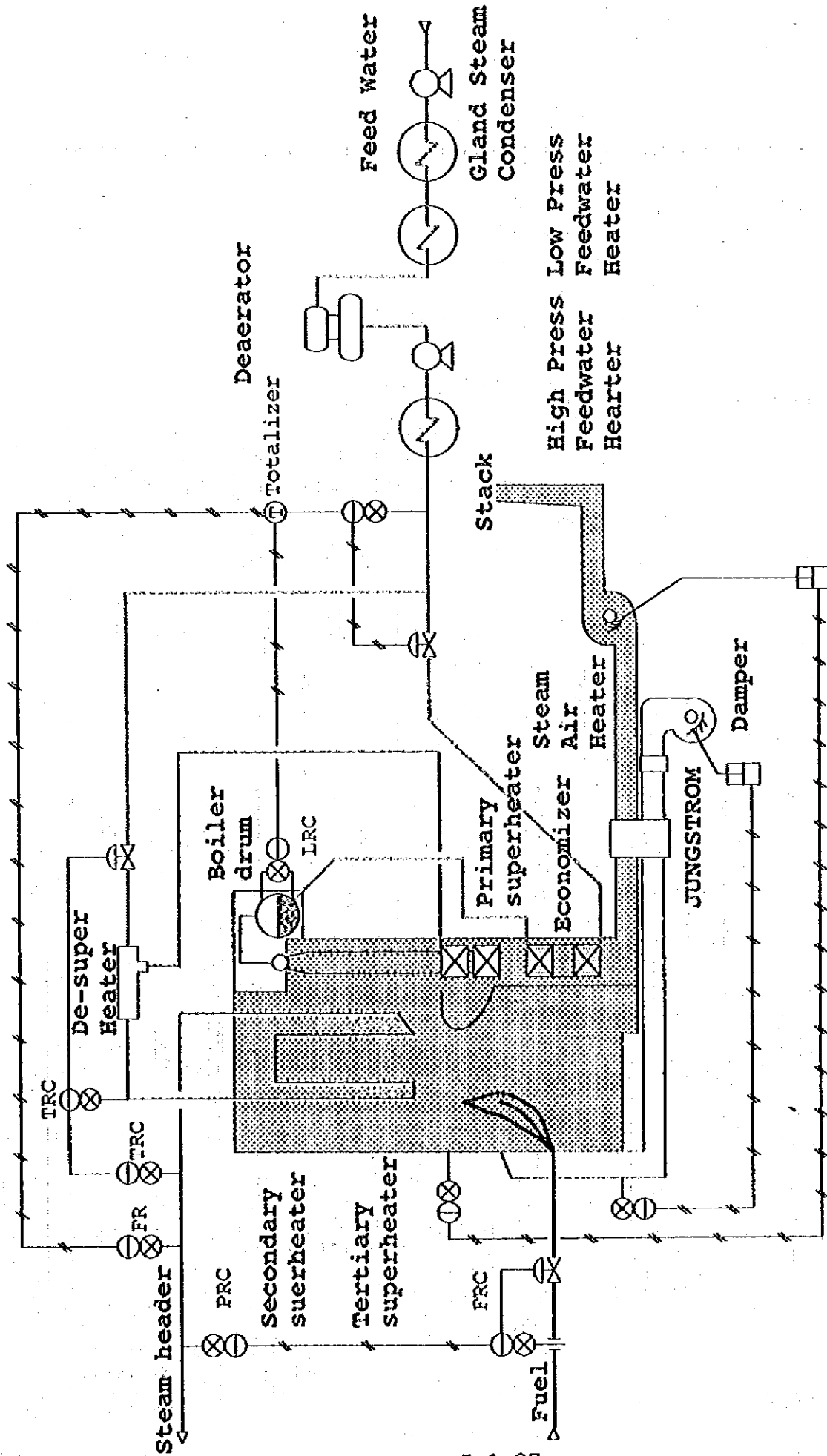


Figure 5.1-1

SIMPLIFIED EXISTING STEAM DIAGRAM OF P.P.S.A.

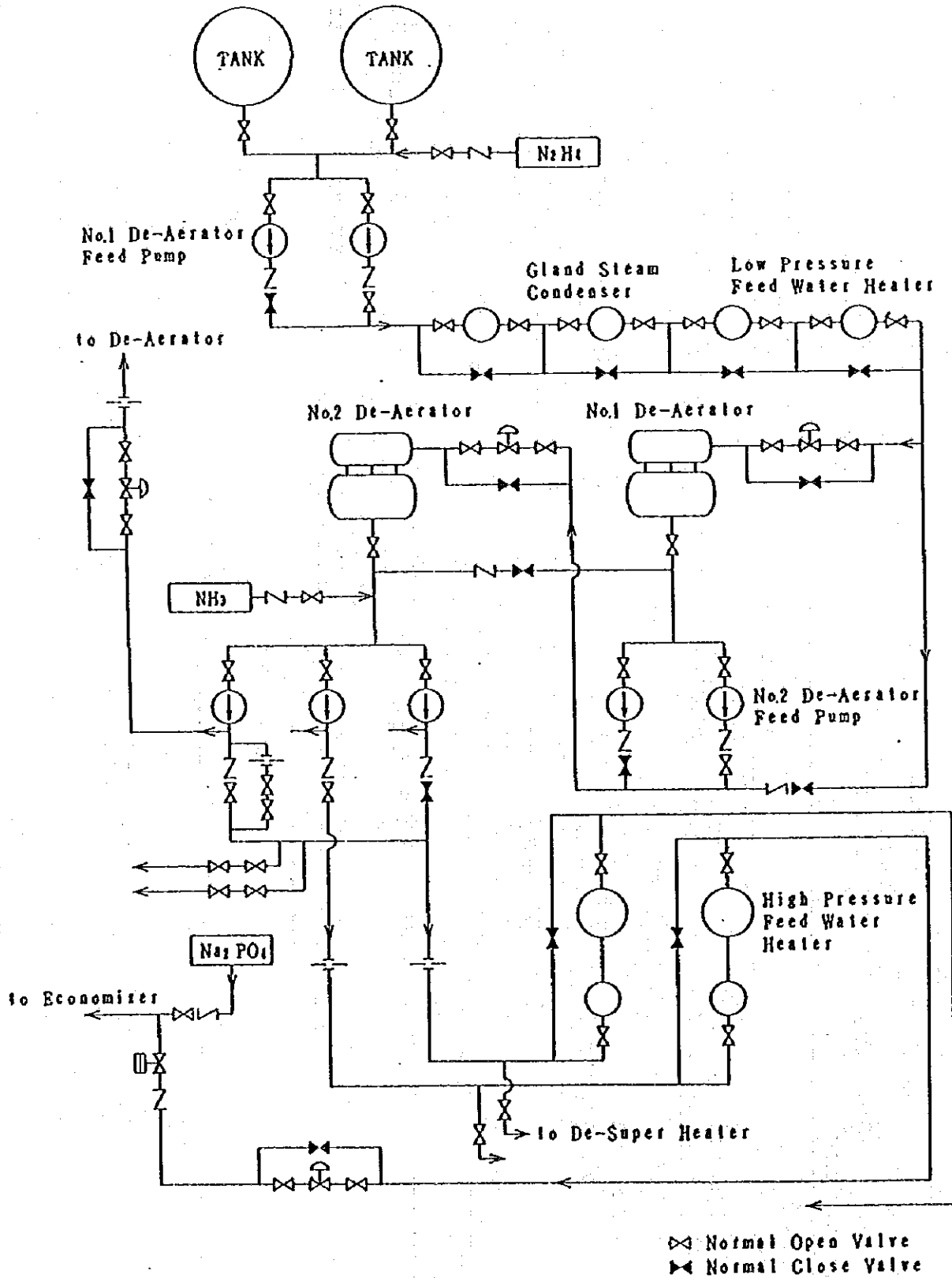


5.1-37

Figure 5.1-2

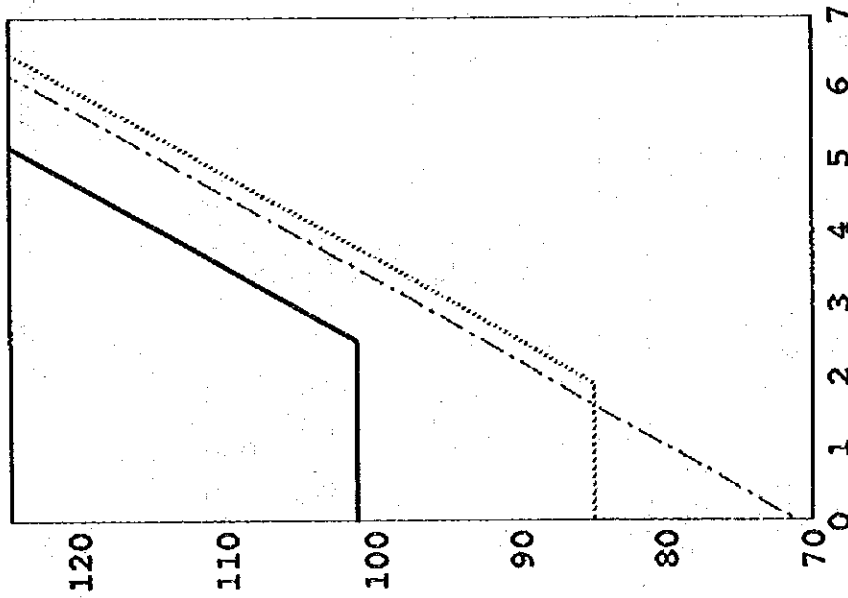
SIMPLIFIED FLOW DIAGRAM OF BOILER

Figure 5.1-3 CHEMICAL INJECTION POINT OF BOILER WATER SYSTEM



Source ; P.P.S.A.

Allowable Temperature of Heating Elements of Jungstrom



— Vanadium Rich Oil
- - - Vanadium Free Oil
..... Fuel Gas

Sulfur Concentration in Fuel (wt%)

Figure 5.1-6

CORRELATION BETWEEN ALLOWABLE TEMPERATURE OF HEATING ELEMENTS OF JUNGSTROM AND SULFUR CONCENTRATION IN FUEL

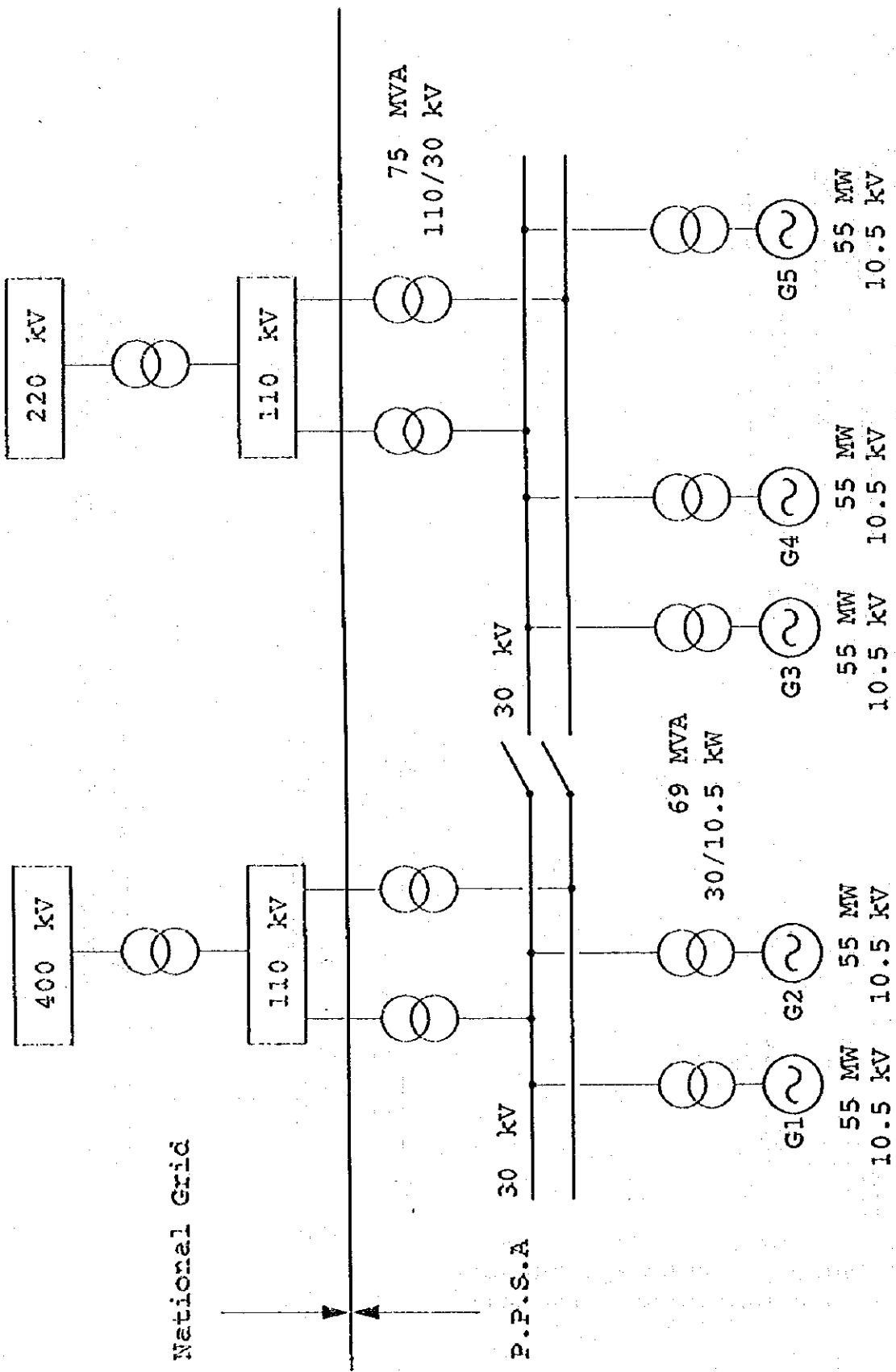
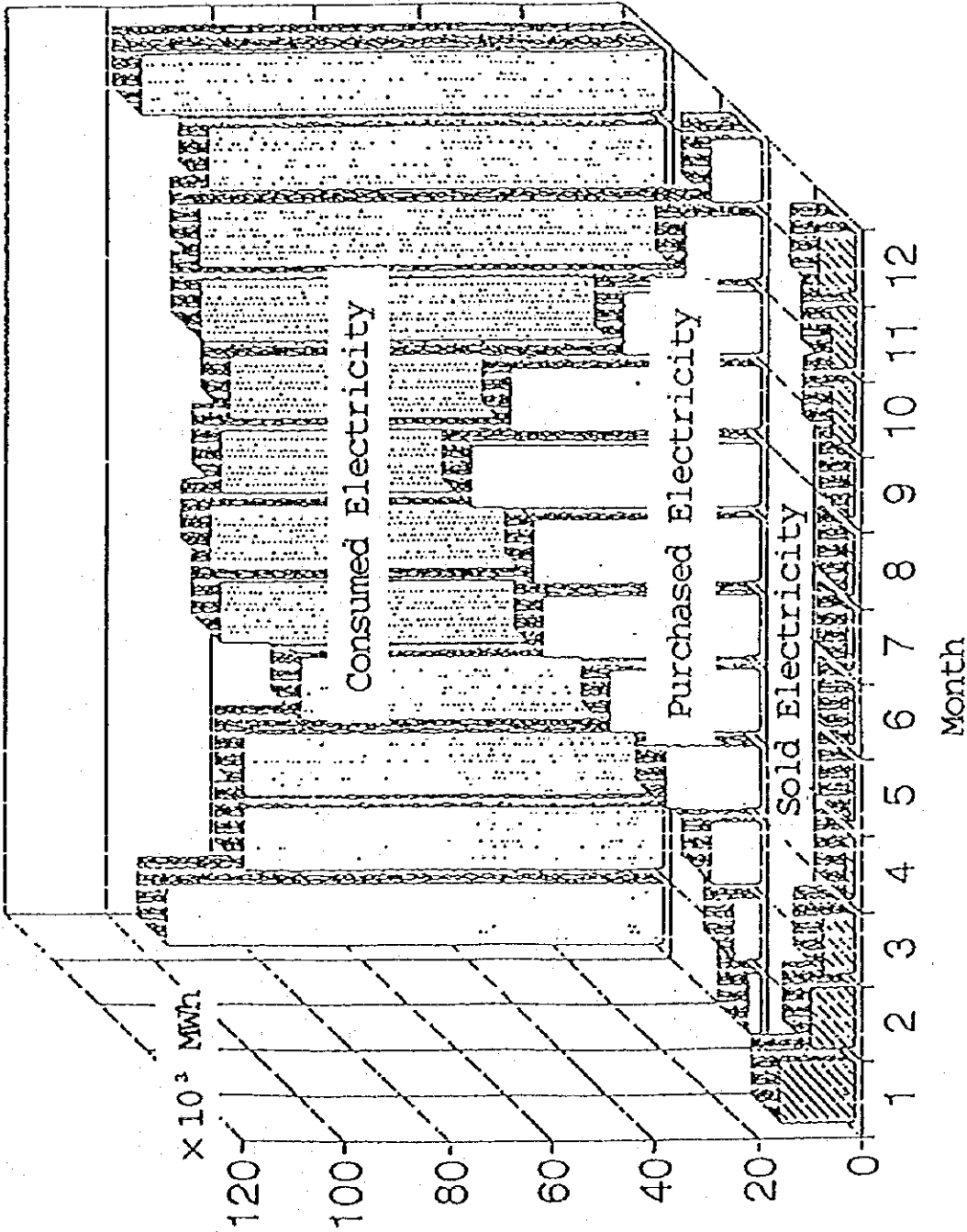
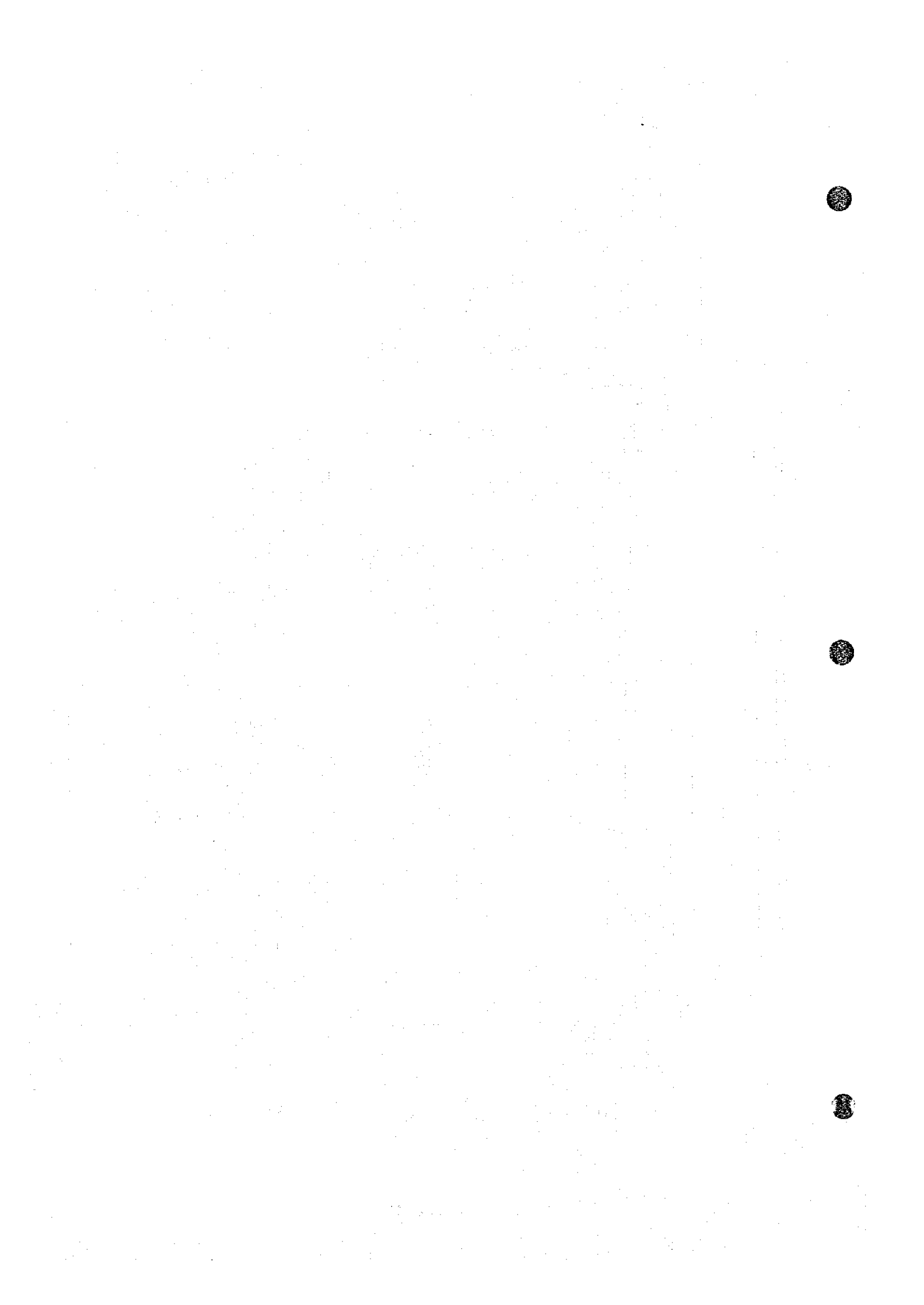


Figure 5.1-7 EXISTING SINGLE LINE DIAGRAM OF PPSA

Figure 5.1-8 ELECTRICITY BALANCE OF PPSA IN 1992



Source : P.P.S.A.



5.2 Diagnostic Evaluation on Combustion Method and Control System

5.2.1 Present combustion method

Vacuum residue forms 97% of total fuel consumption as shown in Table 5.1-4. Details of fuels in PPSA are described in Section 5.6.

Some low NO_x burners are attached to reduce NO_x emission. According to the fact made clear in PPSA, the original design temperature of combustion chamber was 1,900°C. After changing burners to low NO_x burners, outlet temperature of combustion chamber decreased to 1,400°C. Consequently, unburned tars attached to heat transfer tubes and became clinker. As a result of clinker formation, elaborate work is necessary for cleaning and restoring the fouled tubes.

Combustion burner for vacuum residue oil installed in 00320 No.2 boiler is illustrated in Figure 5.2-1. A fabrication drawing of burner tip is shown in Figure 5.2-2.

A steam (18 ata, 310°C) is used for the burner as fuel atomizing steam. The amount of steam consumed as atomizing steam is 2.6 to 3.9 wt% of fuel consumption.

5.2.2 Matters to be pointed out, evaluations and countermeasures regarding present combustion method

(1) Matters to be pointed out

It is important for a boiler as a combustion facility to solve the matter of unburnt tars adhering and clinkered on heat transfer tubes. The combustion conditions of boilers in PPSA are severe because of using vacuum residue oil as fuel. However, as boilers burning the same fuels in Japan run continuously for a year, as shown in Table 5.2-1, it is possible for boilers in PPSA to run for a year.

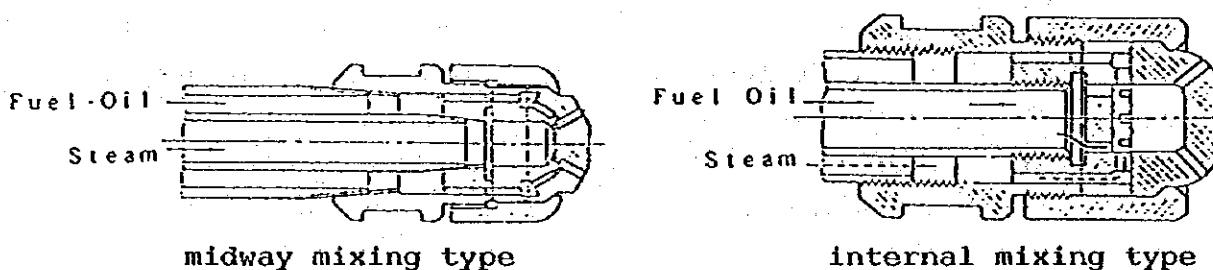
(2) Evaluations of the matters to be pointed out and necessary countermeasures

1) Amount of atomizing steam and configuration of burner tip

Burner tip of midway mixing type without mixing chamber is used in PPSA. Configuration of burner tip of midway mixing and internal mixing are shown in Figure 5.2-3.

Both tips are widely used for heavy fuels, particularly for heavier fuels such as vacuum residue.

Figure 5.2-3 COMPARISON WITH BURNER TIPS OF MIDWAY MIXING TYPE AND INTERNAL MIXING TYPE



The burner tip of midway mixing type has the advantage of using a lesser amount of atomizing steam compared with the internal mixing type. Actual amount of atomizing steam in PPSA is very small, i.e. 2.6-3.9 wt% of fuel consumption. According to the experience of long run heavy fuel combustion in Japan, the amount of atomizing steam of midway mixing type burner tip was around 13 wt%.

Vacuum residue oil was burnt in Japan in the case shown in Table 5.2-1 and burner tips of internal mixing type were used.

The amount of atomizing steam for heavy fuel combustion was around 13 wt% and other burner tips, of which atomizing

steam can be fed at around 20 wt% was used when burning vacuum residue.

As nozzle numbers of burner tip for oil burning in PPSA are large, such as 12, the shape of flame is assumed to be continuous film. To improve combustibility of burning heavy fuel oils it is necessary to decrease number of nozzles and to facilitate the supply of combustion air. Following is summary of the above:

The countermeasure against combustion system is that the amount of atomizing steam be increased to around 13 wt% so that atomization of fuel will be improved.

(3) Countermeasures against NOx emissions

Combustibility is discussed considering NOx emissions. When combustibility is too high, temperature of flame rises and NOx emissions are increased.

Slow burning occurs and flame shape and brightness are instantly changed at the burners which are called low NOx burners. These factors cause local heating on heat transfer tubes. Therefore, the investigation of local heating is necessary in mutual cooperation with boiler manufacturers.

However, it is necessary to carry out modification of detail configurations by trial and error.

According to results regarding NOx emissions burning vacuum residue in Japan, the lowest emission level is around 150 ppm at the rated load even using low NOx burners. As discussed in section 5.7, the allowable NOx emission is as low as 105 ppm at the rated load. This value is not decided yet, and it is assumed to be difficult to attain the goal with the improvement of combustion method alone. Therefore, it is considered appropriate to pursue burner combustibility and deal with NOx emission with denitrification facilities in the future.

5.2.3 Present control system

(1) Combustion air control

In Figure 5.1-2 [Simplified Flow Diagram of Boiler], the present combustion control system is included.

As described in item (3) of Section 5.1.1, balanced draft control is used in No.1-No.3 boilers because the structure of water screen is not a welded type and the pressure of combustion chamber is kept below atmospheric pressure by the damper of induced blower of combustion gas.

The pressure of wind box of combustion air is controlled by damper of forced draft blower. When steam generation has to be rapidly increased, the control system works such that first fuel supply increases and then combustion air increases. The system is controlled such that combustion air supply will delay rapid steam generation.

(2) Steam pressure control

According to the present P & ID, it is possible that fuel is able to be increased responding to steam pressure fluctuation. When air to fuel ratio control is applied, measurement of combustion air flow is necessary. However, no flow meter for combustion air is installed. (Flow meter is not always necessary in the case of constant load.)

5.2.4 Matters to be pointed out, evaluations and countermeasures regarding present control system

(1) The matters to be pointed out

If No.3 boiler is operated without load fluctuation, no further discussion on present control system is necessary. But in the load adjustment boilers which automatically adjust the pressure fluctuation of steam header, there is some possibility of incomplete combustion and flame extinguishment the case where combustion air is not sufficient due to rapid load fluctuation, for example during emergency shut down of the other boilers.

(2) Evaluations of the matters to be pointed out and necessary countermeasures

Air to fuel ratio control is necessary for load adjustment boilers. Conceptual flow of this system is shown in Figure 5.2-4.

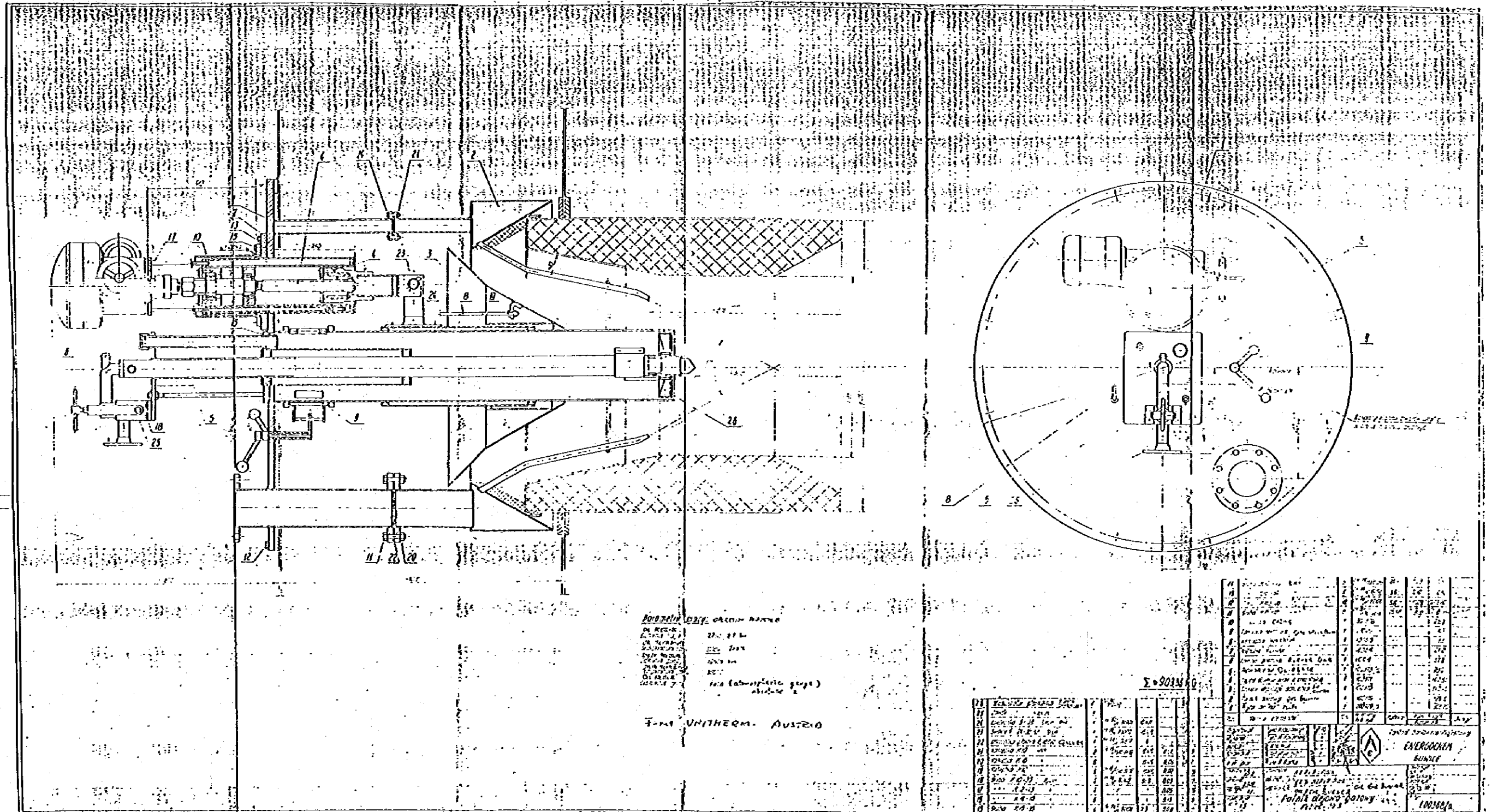
This system is applied to the boilers to whose structure a water screen is welded. The water screens of No.4- No.7 are a welded type, and if these boilers are used as load adjustment and No.1- No.3 are used as base load, there are no matters to be pointed out.

Table 5.2-1 EXAMPLE OF ACTUAL DATA ON VACUUM RESIDUE OIL COMBUSTION

Item	Actual Operating Data of One Japanese Boiler **		00320 No.3 Boiler in PPSA
	Reduced Crude Oil	Vacuum Residue Oil	
Fuel Oil			Vacuum Residue Oil
Heating Value of Fuel Oil	9,900	10,130	9,560 ~ 10,030
Fuel Oil Consumption per 1 ton Steam Generated	65.1	65.0	68 ~ 70
Atomizing Steam ratio for Fuel Oil	13.0	20.0	2.6 ~ 3.9
Steam Consumption in Boiler Plant	31.0	30.6	
O ₂ Concentration at the Outlet of Jungstram	1.9	2.1	7.8
Flue Gas Temperature at the Outlet of Jungstram	132	145	155
Typical Data of Fuel Properties			
Specific Gravity	0.975	1.017	0.990
Kinetic Viscosity at 100 °C	45.0	800.0	-
Pour Point	0.0	45.0	-
Carbon	85.2	85.0	85.4
Hydrogen	10.9	10.2	10.7
Sulfur	3.7	4.4	max 3.0
Nitrogen	0.24	0.35	-
Ash	0.02	0.03	0.1
Residual Carbon	16.2	20.0	-
Vanadium	46	80	-
Nickel	10	39	-
Sodium	10	25	-

Source ; K.Horino, Nenryo oyobi Nensyo (Fuel & Combustion) 47 (8) 625-704, (1980)

Figure 5.2-1 ASSEMBLY DRAWING OF OIL GAS BURNER



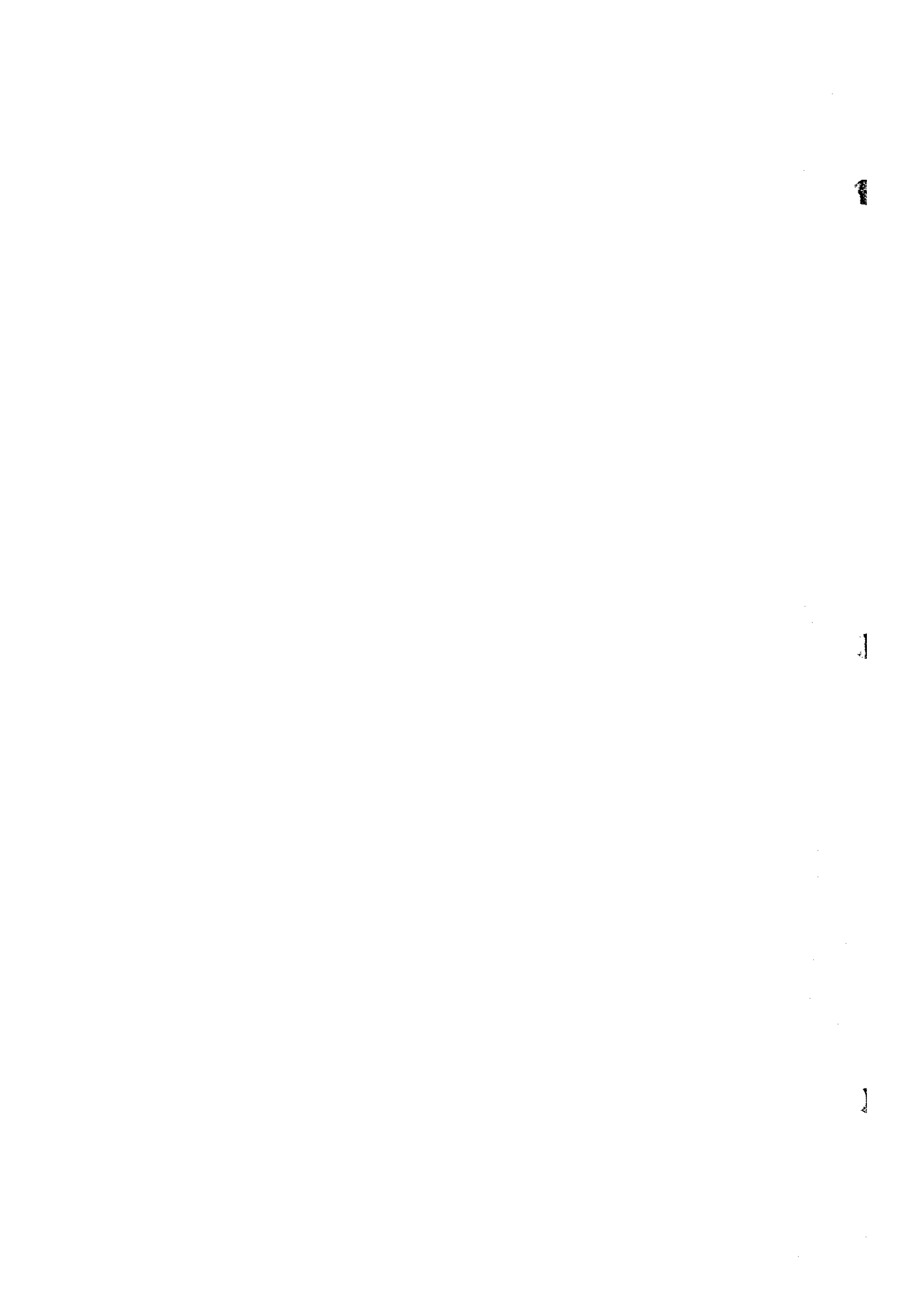
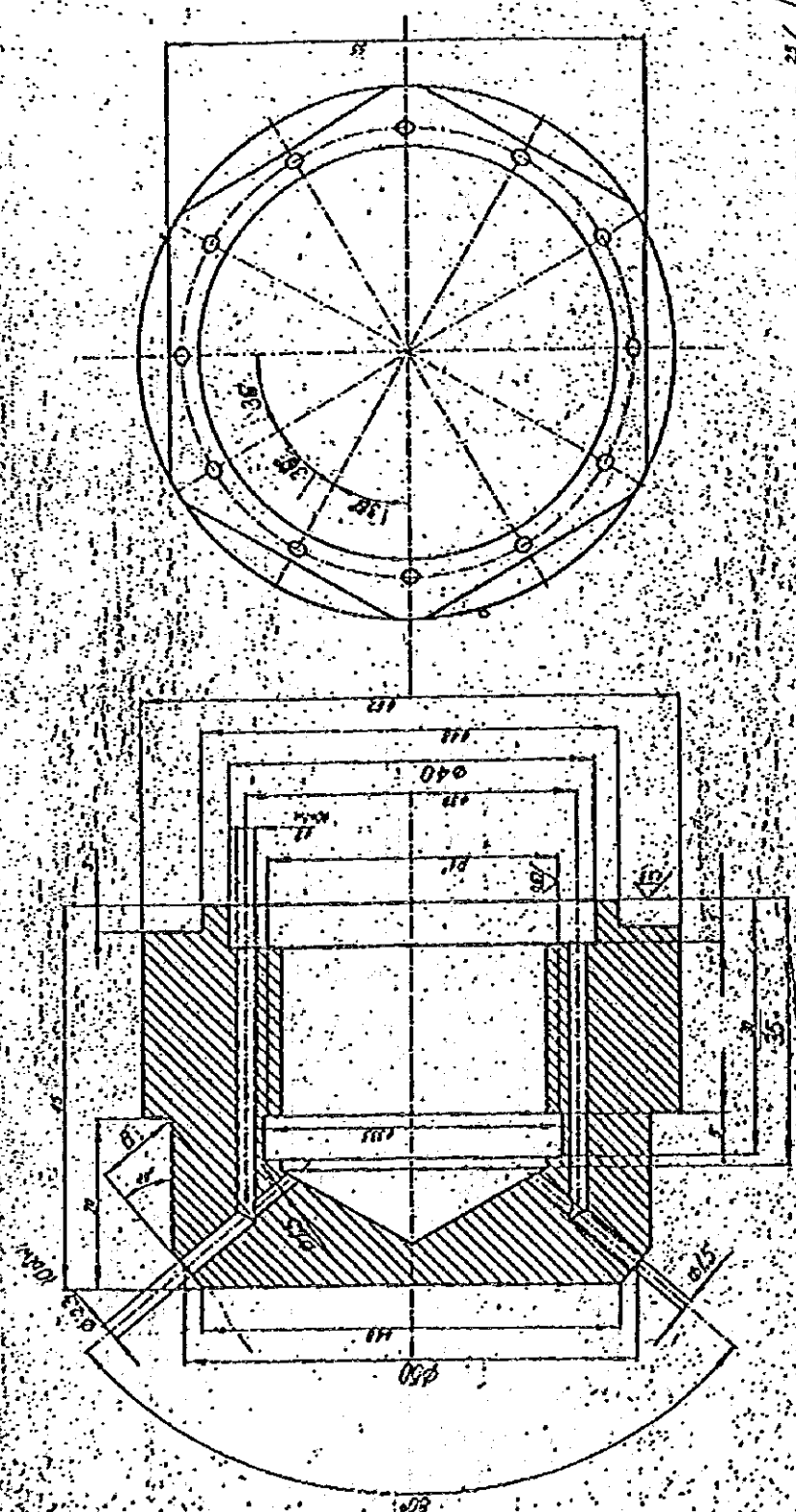


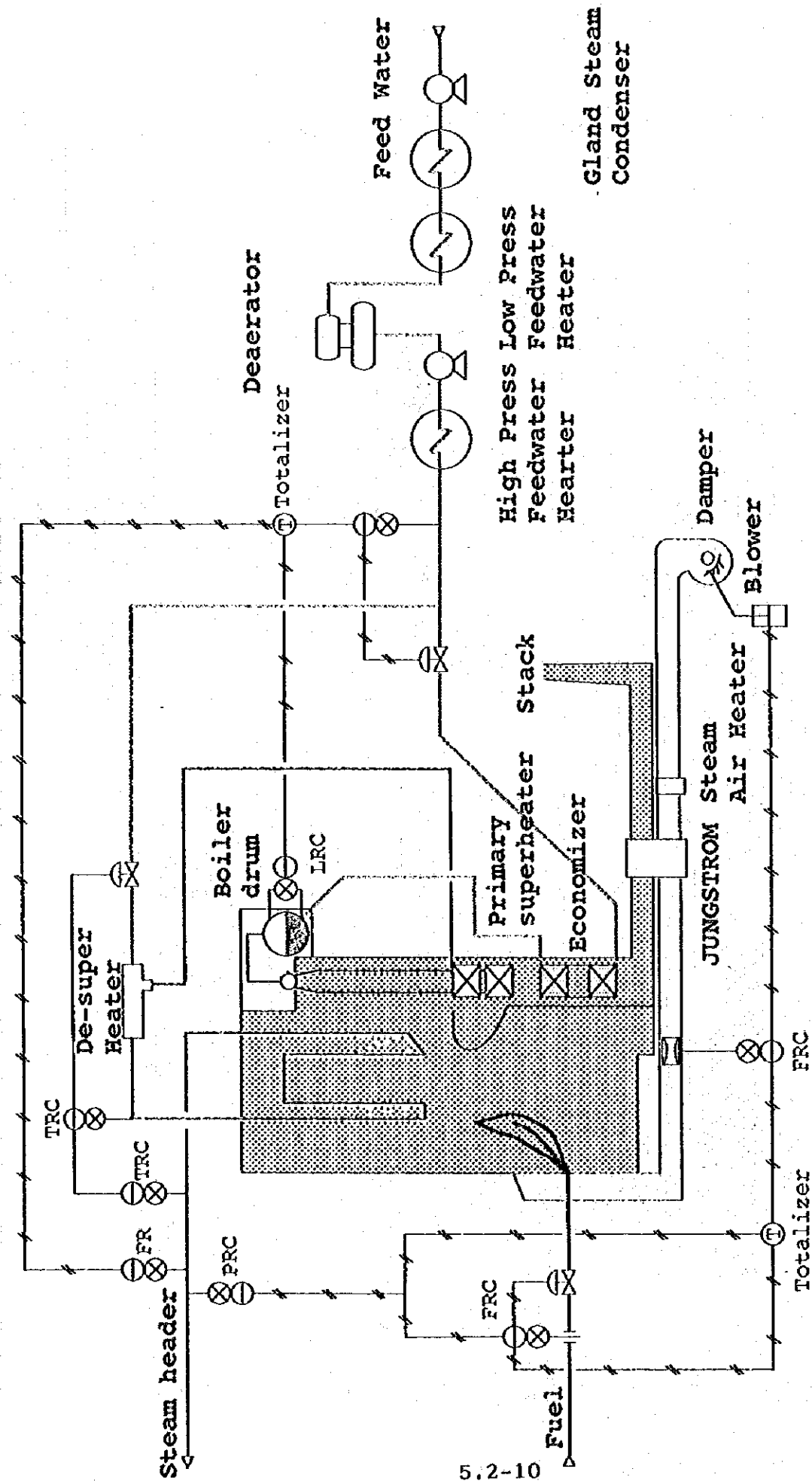
Figure 5.2-2 DETAIL DRAWING OF BURNER TIP



1/3
2/3
3/3

Nazwisko	Podpis	Data	Nazwa EC MZRIP PŁOCK Materiał 3H13
Konstruktor	Kontrola		
Wykonanie	Int. A. Adamczuk	22.01.1982	
Weryfikacja	Int. M. Głowacki		
Podziękowanie	Dysza palnika - wersja A palnik do kotłowni produkcyjnej - KMK-3		Nazwa Burner Top Materiał K.040A

Uwagi:
 1. Główni wykonawcy:
 2. Główni wykonawcy:
 3. Jednego wykonawcy.



5.2-10

Figure 5.2-4
 FLOW DIAGRAM OF BOILER (Forced Draft Type)

5.3 Review of Requirements for Steam and Electric Power

5.3.1 Current steam specification

There are seven kinds of steam used in PPSA: 139 ata, 70 ata, 45 ata, 35 ata, 18 ata, 7.5 ata and 1.2 ata.

139 ata steam is used for the steam turbine for the power generation in PPSA.

Figure 5.1-2 shows the relationship between steam pressure generated in PPSA and extracted steam pressure of steam turbines for electric generators. The specification of seven kinds of steam is shown in Table 5.1-2.

5.3.2 Evaluation for the specification of the steam

(1) Steam Specification for turbine used for power generation

1) Comparison with Japanese specification

Table 5.3-1 shows the general steam condition used for industrial power generation in Japan.

Table 5.3-1 GENERAL STEAM CONDITION FOR INDUSTRIAL POWER GENERATION IN JAPAN

steam pressure	steam temperature
42 atg	400 - 440°C
60 atg	440 - 480°C
88 atg	480 - 510°C
102 atg	510 - 538°C
127 atg	538°C

Source: Seminar of turbine and generator, published by Thermal & Nuclear Power Society. (1978)

Although there is no condition listed for 139 ata steam, in Table 5.3-1, the temperature 540°C would be proper for 139 ata steam.

2) Comparison with Geissler's recommended equation

Generally speaking, the higher the steam pressure and temperature, the greater the expected efficiency of power generation.

However, it is probable to have reverse effectiveness for small scale plants; for example, a small increase in electric power output compared to the the increase of steam pressure and higher cost investment for boiler feed water pumps.

Geissler's recommended equation is often used to evaluate the economic steam pressure for turbines used for power generation.

Geissler's recommended equation is expressed as follows :

$$P = K/G \quad (\text{Eq.5.3-1})$$

Here, P = economic steam turbine inlet pressure ($\text{kg/cm}^2\text{G}$)

K = constant (usually 8 - 12)

G = flow rate at turbine inlet (t/h)

Figure 5.3-1 shows the plot of actual steam turbine condition with steam inlet pressure on the horizontal axis and steam flow rate on the vertical axis. The three curves are drawn in Figure 5.3-1 for three constants, i.e., 8, 10, and 15.

The constant k ($= 8$) seemed to be applied for the extraction turbine judging from this figure. Steam condition for PPSA is plotted with the mark \odot in the same figure. It is understood that the condition of the turbines used in PPSA is almost the same steam condition as used in industry.

Therefore, it could be said that the steam conditions in PPSA are reasonable.

For the steam used for turbines, quality control of the steam is required in addition to the steam temperature and steam pressure. The water quality control in the steam drum is therefore important. However, the steam quality is controlled nicely as discussed in item (3) in the Section 5.1.5.

(2) Steam Specification for heating

1) Pressure and Temperature

As long as steam has enough pressure and temperature for the process, there is nothing in particular to point out. Since there are seven kinds of steam in PPSA, required steam for the process would be easily selected.

2) Quality of the steam

Pure water branched at the upstream of the injection point of boiler chemical (Sodium Phosphate) is used at the desuperheater from 139 ata steam to 70 ata and 45 ata steam.

Therefore, there is no problem with the quality of these steams.

Regarding the steam of 35 ata, 18 ata, 7.5 ata and 1.2 ata, they are obtained by the extraction of the power generation turbines.

Since the quality of 139 ata steam is adequately controlled, these steams have no problem to be pointed out.

5.3.3 Specification of power generators

PPSA has five 55 MW power generators as shown in Figure 5.1-2.

The specification of the five power generators are shown in Table 5.3-2.

Table 5.3-2 SPECIFICATION OF POWER GENERATORS IN PPSA

Item	Value
Generated Power	55 MW
Voltage	10.5 kV
Frequency	50 + 0.5 Hz
Power factor	0.80 -

Source: PPSA

Note : per one generator

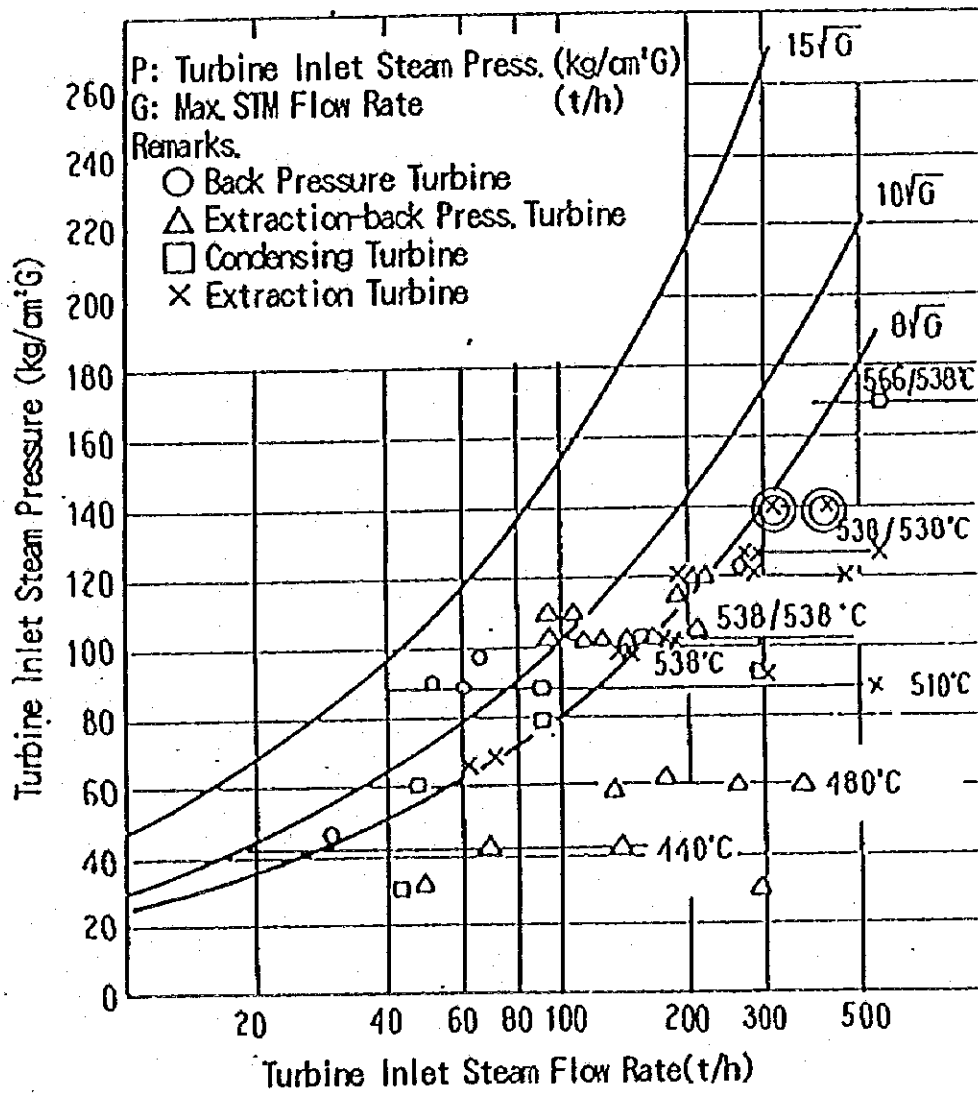
5.3.4 Evaluation of the power generator

Generated power is increased to 30 kV and transmitted to the bus in PPSA.

Generated voltage is general.

There is nothing additional to be pointed out.

Figure 5.3-1 STEAM PRESSURE AND STEAM FLOW RATE AT THE STEAM TURBINE INLET





5.4 Diagnostic Evaluation on the Energy Balance and Fuel Efficiency

5.4.1 Energy balance of existing boiler

The energy balance of 99% rated load based on the test run data shown in Table 5.1-7, 5.1-8 and 5.1-9 is calculated.

Some normal operation data, not including in these tables, were provided by PPSA at the time of second site visit, and were used in this energy balance calculation.

(1) Input heat

1) Combustion heat of fuel (Q_{I1})

$$Q_{I1} = Q_{HV} \times W_{FUEL}$$

As the heating value of fuel is 40,612 kJ/kg = 9,708 kcal/kg and the amount of fuel consumption is 21,690 kg/h,

$$Q_{I1} = 9,708 \times 21,609 = 210.57 \times 10^6 \text{ kcal/h}$$

where

$$Q_{HV} = \text{heating value} \quad (\text{kcal/kg})$$

$$W_{FUEL} = \text{amount of fuel consumption} \quad (\text{kg/h})$$

2) Sensible heat of fuel (Q_{I2})

$$Q_{I2} = W_{FUEL} \times C_{p \text{ FUEL}} \times (t_{\text{FUEL}} - t_{\text{amb}})$$

As the specific heat of fuel is 0.45 kcal/(kg·°C),

$$Q_{I2} = 21,690 \times 0.45 (181-18) = 1.59 \times 10^6 \text{ kcal/h}$$

where

$$C_{p \text{ FUEL}} = \text{specific heat of fuel} \quad (\text{kcal}/(\text{kg} \cdot ^\circ\text{C}))$$

$$t_{\text{FUEL}} = \text{temperature of fuel} \quad (^\circ\text{C})$$

$$t_{\text{amb}} = \text{ambient temperature} \quad (^\circ\text{C})$$

3) Sensible heat of air (Q_{I3})

$Q_{I3} = W_{\text{FUEL}} \times V_{\text{C-AIR}} \times m \times C_{p \text{ AIR}} \times (t_{\text{air}} - t_{\text{amb}})$
 As the theoretical amount of air is $10.712 \text{ Nm}^3/\text{kg}$ and the excess air ratio is 1.095 according to the Table 5.1-9,

$$Q_{I3} = 21,690 \times 10,712 \times 1.095 \times 0.31 (50 - 18)$$

$$= 2.52 \times 10^6 \text{ kcal/h}$$

where

- $V_{\text{C-AIR}}$ = theoretical amount of air (Nm^3/kg)
- m = excess air ratio (-)
- $C_{p \text{ AIR}}$ = specific heat of fuel of air ($\text{kcal}/(\text{kg} \cdot ^\circ\text{C})$)
- t_{AIR} = temperature of air ($^\circ\text{C}$)

4) Sensible heat of boiler feed water (Q_{I4})

The amount of injection steam into the desuperheater is assumed to be 2% of the amount of steam generation.

Therefore, the amount of injection steam into the desuperheater is $311,000 \times 0.02 = 6,220 \text{ kg/h}$.

The amount of water injection into the desuperheater is represented by the following formula:

Amount of water injection

$$= (W_{\text{D.S.H-STM}} \times h_{\text{D.S.H-STM}} + (W_{\text{STM}} - W_{\text{D.S.H-STM}}) \times h_{2\text{s.H-STM}} - W_{\text{STM}} \times h_{3\text{s.H-STM}}) / (h_{2\text{s.H-STM}} - h_{\text{D.S.H-WTR}})$$

where

- $W_{\text{D.S.H-STM}}$ = amount of injection steam to De-Superheater (kg/h)
- $h_{\text{D.S.H-STM}}$ = enthalpy of injection steam to De-Superheater ($\text{kcal}/(\text{kg} \cdot ^\circ\text{C})$)
- W_{STM} = amount of steam generation (kg/h)
- $h_{2\text{s.H-STM}}$ = enthalpy of steam out from 2nd Superheater ($\text{kcal}/(\text{kg} \cdot ^\circ\text{C})$)
- $h_{3\text{s.H-STM}}$ = enthalpy of steam out from 3rd Superheater ($\text{kcal}/(\text{kg} \cdot ^\circ\text{C})$)

$h_{D.S.H-WTR}$ = enthalpy of injection water (kcal/(kg·°C))

Therefore, the amount of injection water is calculated as follows :

$$\begin{aligned} \text{amount of injection water} &= \{6,220 \times 684 + (311,000 - 6,220) \times \\ &\quad 768 - 311,000 \times 761\} / (768 - 134) \\ &= 2,610 \text{ (kg/h)} \end{aligned}$$

Here, the sensible heat of boiler feed water is shown by the following formula:

$$\begin{aligned} \text{sensible heat of boiler feed water} &= (W_{BFW} - W_{D.S.H-WTR}) \times (h_{D.S.H-BFW} - h_{BFW}) \\ &\quad + W_{D.S.H-WTR} \times (h_{D.S.H-WTR} - h_{BFW}) \end{aligned}$$

where

W_{BFW} = amount of boiler feed water (kg/h)

h_{BFW} = enthalpy of boiler feed water (kcal/(kg·°C))

$W_{D.S.H-WTR}$ = amount of injection water into D.S.H (kg/h)

$h_{D.S.H-WTR}$ = enthalpy of injection water (kcal/(kg·°C))

Therefore,

$$\begin{aligned} Q_{I4} &= (311,000 - 2,610) \times (183 - 10) + 2,610 \times (134 - 10) \\ &= 53.68 \times 10^6 \text{ Kcal/h} \end{aligned}$$

5) Heat of atomizing steam (Q_{I5})

The amount of atomizing steam is considered to be 4% of the fuel consumption. The enthalpy of the atomizing steam is estimated to be 724.5 kcal/h from the steam table.

Therefore, the heat of the atomizing steam is calculated as follows :

$$Q_{I5} = 21,690 \times 0.04 (724.5 - 18) = 0.613 \times 10^6 \text{ Kcal/h}$$

The calculation results of heat input are summarized in Table 5.4-1.

Table 5.4-1 BREAK DOWN OF HEAT INPUT

heat input	amount of heat input	%
combustion heat of fuel	210.57 x 10 ⁶ Kcal/h	78.3%
sensible heat of fuel	1.59 x 10 ⁶ Kcal/h	0.6%
sensible heat of air	2.52 x 10 ⁶ Kcal/h	0.9%
sensible heat of feed water	53.68 x 10 ⁶ Kcal/h	20.0%
heat of atomizing steam	0.61 x 10 ⁶ Kcal/h	0.2%
Total heat input	268.97 x 10 ⁶ Kcal/h	100.0%

(2) Output heat

1) Heat of generated steam (Q₀₁)

The enthalpy of the generated steam is estimated from the steam table to be 819.01 kcal/(kg·°C)).

Therefore, the heat of generated steam is calculated as follows :

$$Q_{01} = 311,000 \times (819.01 - 18) = 249.11 \times 10^6 \text{ Kcal/h}$$

2) Dry base heat contents of flue gas (Q₀₂)

According to the P&I D provided, heat held in the leaking air must be taken into account as the thermometer for flue gas is installed downstream from the bypass duct of Jung Strom so that the heat held in dry flue gas is represented with the following formula:

$$Q_{02} = W_{\text{FUEL}} \times V_{\text{D-FG}} \times C_{p \text{ FG}} \times (156-18) + (V_{\text{AIR}}/22.4) \times C_{p \text{ AIR}} \times (156-18)$$

where

W_{FUEL} = fuel consumption (kg/h)

V_{D-FG} = dry flue gas volume per fuel (Nm³/kg)

C_{p FG} = specific heat of flue gas (kcal/(kg·°C))

V_{AIR} = amount of leaking air (Nm³/kg)

C_{p AIR} = specific heat of air (kcal/(kg·°C))

Therefore,

$$Q_{02} = 21,690 \times 10.090 \times 0.33 \times (156-18) + (115,610/22.4) \times 7.00 \times (156-18) = 14.95 \times 10^6 \text{ Kcal/h}$$

3) Heat of steam in flue gas (Q_{03})

There are two kinds of steam, one is from combustion reaction and the other is atomizing steam.

Therefore, the heat of steam in flue gas is shown with the following formula;

$$Q_{03} = W_{\text{FUEL}} \times (V_{\text{W-FG}} - V_{\text{D-FG}}) \times C_{p \text{ STM}} \times (156-18) + W_{\text{FUEL}} \times 0.13 \times h_{\text{delta}}$$

where

W_{FUEL} = fuel consumption (kg/h)

$V_{\text{W-FG}}$ = amount of wet flue gas per fuel (Nm^3/kg)

$V_{\text{D-FG}}$ = amount of dry flue gas per fuel (Nm^3/kg)

$C_{p \text{ STM}}$ = specific heat of steam ($\text{kcal}/(\text{kg} \cdot ^\circ\text{C})$)

h_{delta} = enthalpy of steam (kcal/kg)

Therefore,

$$Q_{03} = 21,690 \times (11.391 - 10.090) \times 0.45 \times (156-18) + 600 \times 2,820 = 3.44 \times 10^6 \text{ Kcal/h}$$

4) Blow loss (Q_{04})

As continuous blow of boiler water is not performed at present,

$$Q_{04} = 0.0$$

5) Other loss (Q_{05})

The other loss is a thermal loss due to radiation and thermal conduction is calculated from the difference between from the difference between heat input and heat output as follows:

$$Q_{05} = (Q_{I1} + Q_{I2} + Q_{I3} + Q_{I4} + Q_{I5}) - (Q_{O1} + Q_{O2} +$$

$$Q_{03} + Q_{04} = 2.84 \times 10^6 \text{ kcal/h}$$

The calculation results of heat output are summarized in Table 5.4-2.

Table 5.4-2 BREAK DOWN OF HEAT OUTPUT

heat output	amount of heat output	%
heat of generated steam	$249.11 \times 10^6 \text{ Kcal/h}$	92.6%
dry base heat of flue gas	$14.95 \times 10^6 \text{ Kcal/h}$	5.6%
heat of steam in flue gas	$3.44 \times 10^6 \text{ Kcal/h}$	1.3%
blow loss	$0.00 \times 10^6 \text{ Kcal/h}$	0.0%
other loss	$1.46 \times 10^6 \text{ Kcal/h}$	0.5%
Total heat output	$268.97 \times 10^6 \text{ Kcal/h}$	100.0%

(3) Circulating heat

1) Heat amount obtained by steam air heater (Q_{R1})

$$V_{\text{AIR}} = W_{\text{FUEL}} \times V_{\text{C-AIR}} \times m$$

$$Q_{R1} = V_{\text{AIR}} \times C_p_{\text{AIR}} \times (T_{\text{SAH-OUT}} - T_{\text{SAH-IN}})$$

where

$$V_{\text{AIR}} = \text{amount of combustion air (Nm}^3\text{/h)}$$

$$V_{\text{C-AIR}} = \text{amount of theoretical air per fuel (Nm}^3\text{/kg)}$$

$$m = \text{excess air rate (-)}$$

$$T_{\text{SAH-OUT}} = \text{outlet temperature of Steam Air Heater (}^\circ\text{C)}$$

$$T_{\text{SAH-IN}} = \text{inlet temperature of Steam Air Heater (}^\circ\text{C)}$$

$$V_{\text{AIR}} = 21,690 \times 10.712 \times 1.095 = 254,416 \text{ Nm}^3\text{/h}$$

$$Q_{R1} = 254,416 \times 0.31 \times (50-18)$$

$$= 2.524 \times 10^6 \text{ Kcal/h}$$

2) Heat obtained by air heater (Q_{R2})

$$Q_{R2} = V_{\text{AIR}} \times C_p_{\text{AIR}} \times (T_{\text{SAH-OUT}} - T_{\text{SAH-IN}})$$

$$T_{\text{AH-OUT}} = \text{outlet temperature of Air Heater (}^\circ\text{C)}$$

$$\begin{aligned}
 T_{AH-IN} &= \text{inlet temperature of Air Heater } (^{\circ}\text{C}) \\
 Q_{R2} &= 254,416 \times 0.31 \times (244-50) \\
 &= 15.301 \times 10^6 \text{ Kcal/h}
 \end{aligned}$$

(4) Performance values

1) Heat load at combustion chamber (Q_1)

$$Q_1 = (Q_{I1} + Q_{I2} + Q_{R1} + Q_{R2}) / V_{CC}$$

where

V_{CC} = volume of a combustion chamber (m^3)

$$\begin{aligned}
 Q_1 &= (210.57 + 1.59 + 2.524 + 15.301) \times 10^6 / 1470 \\
 &= 156,452 \text{ kcal}/(\text{m}^3\text{h})
 \end{aligned}$$

2) hourly equivalent amount of steam generation (F_1)

$$F_1 = \{W_{STM} \times h_{STM} - (W_{BFW} \times h_{BFW} + W_{D.S.H-WTR} \times h_{D.S.H-WTR})\} / 538.8$$

where

h_{STM} = enthalpy of steam generated ($\text{kcal}/(\text{kg}^{\circ}\text{C})$)

Therefore,

$$F_1 = \{311,000 \times 819.01 - (311,000 \times 183 + 2,610 \times 134)\} / 538.8 = 366,461 \text{ kg/h}$$

3) converted evaporation ratio (F_2)

$$F_2 = F_1 / (W_{FUEL} + W_{FG})$$

where

W_{FG} = oil equivalent amount of fuel gas (kg-FOE/h)

Therefore,

$$F_2 = 366,461/21,690 = 16.895 \text{ kg-stm/kg-fuel oil}$$

4) Boiler efficiency (F_3)

$$Q_{O-HTR} = W_{FUEL} \times C_p \text{ oil} \times (T_{O-HTR \text{ out}} - T_{O-HTR \text{ in}})$$

$$F_3 = (F_1 \times 538.8 + Q_{\text{BLOW}}) \times 100 / (Q_{I1} + Q_{I5} + Q_{R1} + Q_{\text{O-HTR}})$$

where

Q_{BLOW} = heat recovered from blow boiler water (Kcal/h)

$Q_{\text{O-HTR}}$ = heat obtained by oil heater (Kcal/h)

$T_{\text{O-HTR out}}$ = outlet temperature of oil heater ($^{\circ}\text{C}$)

$T_{\text{O-HTR IN}}$ = inlet temperature of oil heater ($^{\circ}\text{C}$)

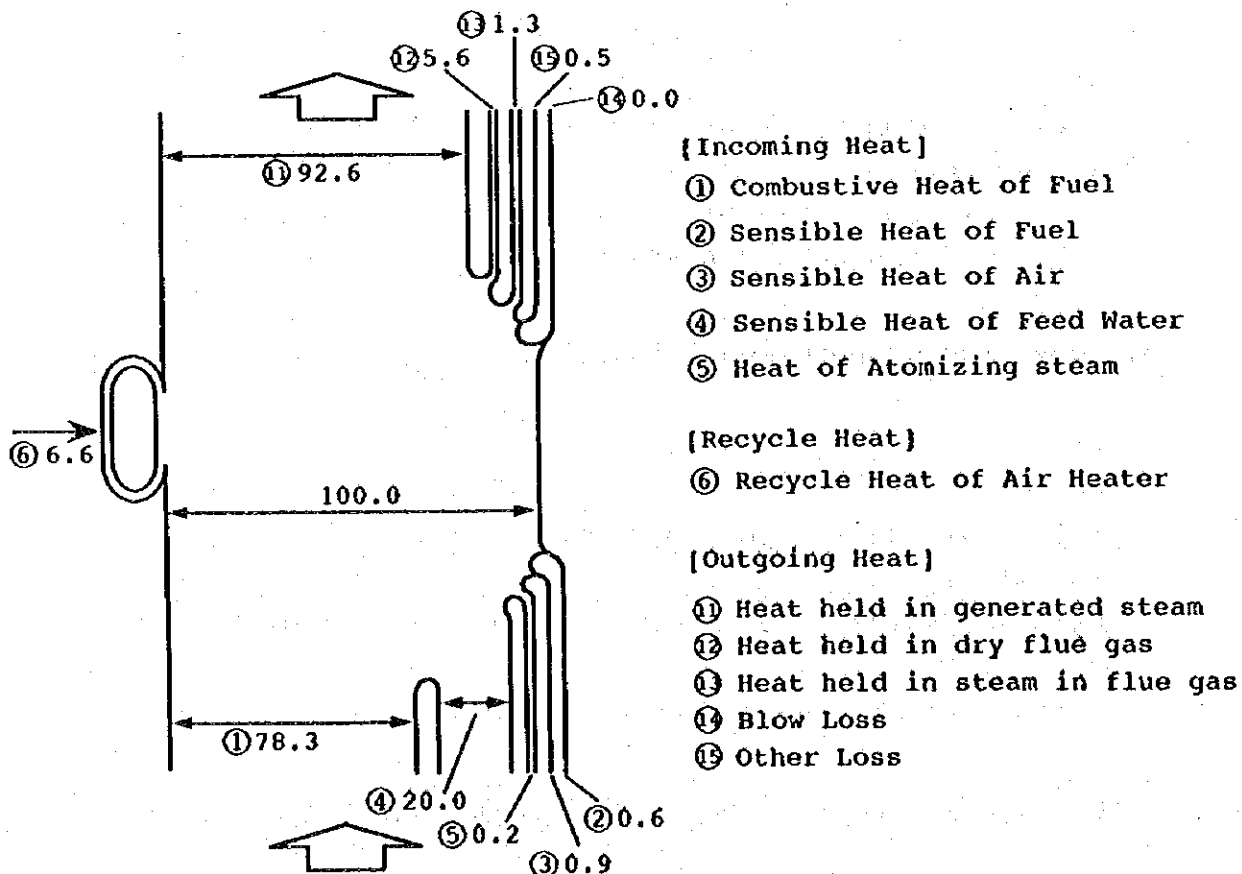
Therefore,

$$Q_{\text{O-HTR}} = 21,690 \times 0.45 \times (190-183) = 0.068 \times 10^6 \text{ Kcal/h}$$

$$F_3 = (366,461 \times 538.8 + 0.068 \times 10^6) \times 100 / (210.57 + 0.613 + 2.524 + 0.068) \times 10^6 = 92.4 \%$$

The calculation results of the heat balance are shown in Figure 5.4-1.

Figure 5.4-1 HEAT BALANCE OF NO.2 BOILER IN PPSA



5.4.2 Review of the result of energy balance

Boiler efficiency is affected by the temperature and pressure of generated steam. The general level of efficiency is 91-94% as a standard of lower calorific value base on a boiler which generates 540°C steam. As calculated in section 5.4.1, the boiler efficiency in PPSA was 92.4% so that when the test run operation was done, the boilers run normally. The result of energy balance is reviewed comparing Japanese result of burning vacuum residue.

(1) Input heat

As shown in Figure 5.4-1, the ratio of combustion heat of fuel in the item of input heat is 78.3%, which is about by 5% higher than the compared case. This is attributable to the low sensible heats of combustion air and B.F.W. To decrease the ratio it is necessary to increase preheat capacity. When preheat capacity is increased, the following items are improved.

- 1) Corrosion by dilute sulfuric acid on the heat transfer elements of Jung Strom and the downstream of ducts due to the low temperature at outlet of steam air heater of combustion air

2) Amount for electricity generation

Demand of low pressure steam for preheat causes increase of steam extraction from generators and increases electricity generation.

(2) Output heat

In the item of output heat, the heat held in generated steam is 92.6%, which is about 3% lower. This is attributable to the large heat loss from the dry flue gas. This is caused by the high (353°C) temperature of the combustion gas introduced to the Jung Ström. There is a possibility that the efficiency of heat transfer of the boiler tubes is degraded due to the lack of soot blowers in the boiler.

5.5 Evaluation of the Present Air Pollution Control, Boiler Feed Water Treatment System and Waste Water Treatment Facility

5.5.1 Review of environmental control measures

As shown in Table 2.0-10, the emission volume of SO₂, NO_x and dust in the power plant are approximately 71%, 66% and 55% respectively in the total emission volume of PPSA. Therefore in order to reduce the total emission volume of PPSA, it is advisable to reduce the emission volume in the power plant.

Also, the emission in the power plant as seen in Table 5.5-1 and 5.5-2, SO₂ exceeds the limit value both in 1992 and 1993, and in the case of NO_x in 1993.

(1) Current situation of SO₂ and NO_x emission

Table 5.5-2 shows the calculation result of SO₂ concentration (g/GJ) and emission amount (kg/h) based on heating value and consumption of fuel in each capacity of boilers.

The major assumption for calculating SO₂ and NO_x emissions are as shown below (see Table 5.1-9 for details).

- Operation rate : 99%
- Fuel consumption : 21.69 t/h (@320 t/h boiler)
- Heating value : 41,000 kJ/kg
- Dry flue gas : 10.090 Nm³/kg
- Sulfur content : 2.8 wt%
- NO_x generation : 254 vol ppm (@4% O₂ concentration)

1) Current situation of SO₂ emission

When comparing SO₂ measurement values by PPSA with calculation values as shown in Table 5.5-2, the measurement values of PPSA are about half of the calculation values. In the event that comparison is made on SO₂ measurement values by PPSA with local standards which are add-on standards set forth by local government and becoming more stringent year after year, the measurement values exceed the local standard both in 1992 and 1993.

In case of comparison with the national standard, the measurement values have cleared the standard (1,720g/GJ) effective up to the end of 1997, but cannot clear the standard (170g/GJ) to be effective on and after 1998.

2) Current situation of NO_x emission

Calculation is made based on the estimated value of 254 vol ppm which is said to be an average NO_x emission in the common boilers for use in power generation in PPSA. The result of the calculation conforms to the measurement values in good manner.

The measurement values of PPSA have cleared the local standard in 1992, but cannot clear the standard in 1993, since a much stricter standard is applied in 1993.

In view of the national standard, the measurement values of PPSA cannot clear it in either year.

(2) Measures for reduction of SO₂ and NO_x emission

1) Measures for reduction of SO₂ emission

Refer to Paragraph 5.7.1.

2) Measures for reduction of NOx emission

Refer to Paragraph 5.7.2.

(3) Problems of environmental protection

In view of SO₂ emission, the current emission amount of the power plant is unable to clear the local standard. Therefore, in order to fully clear the local standard as well as the national standard to be set forth, an emission limit about 1/10 (170g/GJ) of the current value (1,720g/GJ), it will 1/10 of sulfur content (<0.3 wt%) compared to the current one (2.8 wt%), or to install a desulfurization unit.

As for NOx, since the local standard has a trend to become more stringent year after year and it is difficult to cope with this trend just by use of low NOx combustion system, installation of denigration unit is worth consideration in order to fully meet the standard in the future.

Sooner or later, PPSA will be forced to take effective measures for environmental protection even if it is difficult in terms of production costs, the best countermeasure shall be planned from now on in close cooperation with the authorities concerned.

Table 5.5-1 AIR POLLUTION LIMIT & EMISSION VALUE OF POWER PLANT

IN PPSA

Item	Emitter Symbol	Emitter Location	Emitter Dimension H(m)XD(m)	Pollutants	Emission Limit value		Emission value	
					1992 (kg/h)	1993 (kg/h)	1992 (kg/h)	1993 (kg/h)
1	BEM 198	Collective chimney for boiler No.1 & No.2	140m x 4.74 m φ	Dust SO ₂ NO _x CO HC-aliph. HC-arom.	71.12 1236.98 283.12 326.26 39.44 9.10	71.12 618.44 117.18 326.26	17.6 1466.0 203.7 10.0 20.5 5.12	13.2 1355.4 228.0 10.0 15.2 3.8
2	BEM 199	Collective chimney for boiler No.3 & No.4	140m x 4.74 m φ	Dust SO ₂ NO _x CO HC-aliph. HC-arom.	82.23 1430.14 327.35 376.46 45.59 10.51	82.23 715.07 135.32 376.46	19.6 1668.0 220.85 10.0 25.75 6.46	14.4 1477.7 238.0 10.0 22.5 5.6
3	BEM 200	Collective chimney for boiler No.5, No.6 & No.7	220m x 5.9m φ	Dust SO ₂ NO _x CO HC-aliph. HC-arom.	140.01 2435.10 557.37 639.99 77.51 17.88	140.01 1217.55 230.19 639.99	32.4 2305.0 342.0 15.0 46.5 11.7	23.4 2400.0 372.0 15.0 44.7 11.1
4	BEM 201	Tank Zb-1 & 2		HC-arom.	0.35	0.35		
5	BEM 202	Tank Zb-3 & 4		HC-aliph. HC-arom.	0.071 0.021	0.071 0.021		
6	BEM 228	Tank Zb-123 & 124		HC-aliph. HC-arom.	0.07 0.084	0.07 0.084		
7	BEM 229	Tank Zb-5.6 & 7		HC-aliph. HC-arom.	0.017 0.065 0.009	0.017 0.065 0.009		

(Note) shows substances exceeding permitted limit

Table 5.5-2 CALCULATED EMISSION VALUE OF SO₂ & NO_x IN POWER PLANT

Item	Unit	320 t/h Boiler		420 t/h Boiler	
		1992	1993	1992	1993
1	SO ₂				
National standard (valid to Dec 31, 1997)	g/Gj	1.720	1.720	1.720	1.720
National standard (valid after Dec 31, 1997)	g/Gj	170	170	170	170
Local standard	Kg/h	618.44	309.22	811.70	405.85
Real emission measured by PPSA	g/Gj	1.228	1.140	1.228	1.132
Real emission measured by PPSA	Kg/h	733	677.7	935	800
Calculated emission by fuel heating value	g/Gj	1.366	1.366	1.366	1.366
Calculated emission by fuel consumption	Kg/h	1,215	1,215	1,594	1,594
2	NO _x				
National standard (valid to Dec 31, 1997)	g/Gj	160	160	160	160
National standard (valid after Dec 31, 1997)	g/Gj	160	160	160	160
Local standard	Kg/h	141.56	58.59	185.79	76.73
Real emission measured by PPSA	g/Gj	170.6	192	163	175
Real emission measured by PPSA	Kg/h	101.5	114	119	124
Calculated emission by fuel heating value	g/Gj	128	128	128	128
Calculated emission by fuel consumption	Kg/h	114.2	114.2	149.9	149.9

Note: NO_x is calculated based on the value of 254 vol ppm in the conversion value of 4% O₂, which is regarded to be a mean value in case of liquid fuel combustion like PPSA, and also converted to NO₂ equivalent value.

shows substances exceeding permitted limit

5.5.2 Present conditions of boiler feed water treatment system

(1) Capacity of boiler feed water treatment system the boiler feed water treatment system of PPSA consists of three systems as shown in Table 5.5-3, with a total capacity of 1,540m³/h.

Table 5.5-3 CAPACITY OF BOILER FEED WATER TREATMENT SYSTEM

System	No. of Trains	Capacity of Trains	Name of Trains	Total Capacity
1st System				800m ³ /h
2nd System	3	80m ³ /h	A, B, C	240m ³ /h
3rd System	5	100m ³ /h	D, E, F, G, H	500m ³ /h
Total Capacity				1,540m ³ /h

Source: PPSA

Of the above, the facilities covered by this study are the 2nd system (Trains A, B, C) and 3rd system (Trains D, E, F, G, H).

(2) Pre-treatment system

The raw water is taken from the Vistula River and the pre-treatment system for the boiler feed water treatment system is provided as shown in Figure 5.5-1. The pre-treatment system consists of an accelerator for decarbonation and coagulation and a gravity type filter (using sand and gravel) to reduce the turbidity and color, and remove suspended solids. The quality of the pre-treated water is as shown in the Column "Decarbonated Water K-2" of Table 5.5-4.

(3) Boiler feed water treatment system

1) Composition of System

The present boiler feed water treatment system consists of 8 trains as shown in Figure 5.5-2. The composition of these trains is shown in Figure 5.5-3. Noteworthy features here are the difference in the order of the ion exchange resin towers between the 2nd system (A, B, C trains) and 3rd system (E, F, G, H trains) and their type, namely, multi-stage type. The sequential order of each tower is as shown in Table 5.5-5 below.

Table 5.5-5 SEQUENTIAL ORDER OF EQUIPMENT IN
BOILER FEED WATER TREATMENT SYSTEM

Train	A, B, C	D, E, F, G, H
Sequential Order		
1.	Filter	Filter
2.	Organic matter adsorption	Strong cation exchange resin
3.	Strong cation exchange resin	Organic matter adsorption
4.	Weak anion exchange resin	Weak anion exchange resin
5.	CO ₂ removal	CO ₂ removal
6.	Strong cation exchange resin	Strong cation exchange resin
7.	Strong anion exchange resin	Strong anion exchange resin
8.	SiO ₂ removal	SiO ₂ removal

Source: PPSA

Further, data on the resin used, filling volume, make-up ratio, chemical consumption, regeneration waste water volume in each ion exchange resin tower, are summarized in Table 5.5-6.

2) Ion exchange resin regeneration method

The partial sequential order from 3 through 7 of Table 5.5-5 above is shown in Figure 5.5-3. The special features of the ion exchange resin regeneration in PPSA are as follows:

- a) The regeneration is done by the cocurrent flow method
- b) The cation exchange resin and anion exchange resin are regenerated at different intervals.
- c) Although both the cation exchange resin and anion exchange resin have plural radicals, they are separately regenerated.

3) Waste water from boiler feed water treatment system

The volume of waste water from the boiler feed water treatment system is shown in Table 5.5-7. Its nature is not clear because there is no pertinent analytical data.

**Table 5.5-7 PERCENTAGE OF WASTE WATER FROM
BOILER FEED WATER TREATMENT SYSTEM**

Filter	46%
Organic Matter Adsorption Tower	11%
Strong Cation Exchange Resin Tower	15%
Weak Anion Exchange Resin Tower	23%
Strong Anion Exchange Resin Tower	4%
SiO ₂ Removal Tower	1%

Source: PPSA

Further, as to the facility layout, the acid and alkaline waste water pipes are connected to the same waste water line.

5.5.3 Points at issue, evaluation and measures to be taken on boiler feed water treatment system

(1) Capacity of boiler feed water treatment system

PPSA has a high pressure boiler facility with a steam generation capacity of 2,640t/h, in addition to petrochemical polymer facilities. Based on this, the boiler feed water treatment capacity of 1,540m³/h seems to be adequate.

Further, the small capacity of between 80 and 100m³/h of each system also seems to be adequate, considering the very severe nature of the raw water.

The quality of boiler feed water produced at the present boiler feed water treatment facility is shown in Table 5.5-8. It satisfactorily meets the requirement as feed water for the power plant steam boiler.

(2) Pre-treatment system

The quality of the pre-treated water is far inferior, as raw water for boiler feed water treatment facilities, to that of the raw water generally used in Japan, but it is within the acceptable limit for the production of boiler feed water.

(3) Boiler feed water treatment facility

1) Composition of systems

The composition of the systems is as shown in Table 5.5-5. The location of the CO₂ removal tower seems to be a slight problem. Originally, a CO₂ removal tower is for physically removing CO₂ so as to reduce the load of the ion exchange resin, and its efficiency is remarkable under such low pH conditions as 5.0 pH or less. Under the present facility conditions, where the ion exchange capacity of the strong cation exchange resin tower on the primary side is lowered, the capacity of the CO₂ removal tower might be also lowered. In such case, the load of the anion resin tower might increase.

Therefore, it is desirable to replace the sequential order of 4. and 6, namely, the weak anion resin tower and the strong cation resin tower, respectively.

2) Ion exchange resin regeneration method

The chemical consumption at the time of ion exchange resin regeneration is as shown in Table 5.5-6(3/3). The point at issue concerning the present facility is the excessive consumption of regeneration chemicals. Several measures can be considered in order to reduce the consumption of regeneration chemicals. Their details are mentioned in paragraph 6.1.2 of Chapter 6.

a) Selectivity of ion exchange resin

Where ion resin is used, its selectivity is very important. Because of differences in ion selectivity, the ion exchange layers are formed according to the water flow direction, in the order of $\text{Ca}^{+2} > \text{Mg}^{+2} > \text{Zn}^{+2} > \text{K}^{+} > \text{NH}_3^{+} > \text{Na}^{+} > \text{H}^{+}$ with regard to cation resin, and

$\text{SO}_4^{-2} > \text{NO}_3^- > \text{CrO}_4^{-2} > \text{Cl}^- > \text{HCO}_3^- > \text{SiO}_2^-$ with regard to anion resin.

These ionic sequences, showing their affinity, are called "exchange potentials".

Accordingly, there may be leaks at the break through point in the order of Na^+ , Mg^{+2} , Ca^{+2} from the cation towers, and SiO_2^- , HCO_3^- , Cl^- from the anion towers.

b) Regeneration level and ion exchange capacity

"Regeneration level" means the regeneration agent consumption volume converted to 100% purity. For example, in the case of the regeneration of 1l (1 liter) of resin using 100g of hydrochloric acid, the "regeneration level" is 100-HCl/1-Resin. The ion exchange capacity of resin changes depends on the "regeneration level". The ion exchange resin is very expensive, and unnecessarily excessive capacity may result in high costs. On the other hand, the cost of the regeneration agent constitutes the major part of the water treatment facility operating cost. Therefore, it is very important to make a comprehensive judgement after studying the following factors, for the construction of a competitive facility.

- i) Raw water quality as design condition
- ii) Resin to be selected and Break through capacity
- iii) Regeneration level

c) Regeneration interval

The regeneration interval is basically determined depending on the break through capacity and filling volume of the resin. Generally, cation break operation which determines the regeneration timing by detecting Na- leakage using a water analyzer is carried out.

Otherwise, in a water treatment facility which is designed to produce water of the same volume per cycle from the cation tower and anion tower, the regeneration operation is carried out at the time when the water production volume has reached the designated water production volume, or ion break has been detected. If contact efficiency is constant, the regeneration interval will not influence the regeneration agent volume used per lm^3 pure water, but will largely influence the production yield of pure water.

d) Regeneration efficiency

The factor mentioned in b) above is related to the capacity of the boiler feed water treatment system. Apart from this, the factor which is related to contact efficiency is also extremely important. For example, there are two different regeneration methods: the countercurrent regeneration method and cocurrent regeneration method. In the case where the regeneration is done using regeneration agent of the same volume, the countercurrent regeneration method allows a larger volume of ion exchange and a purer water production than the cocurrent regeneration method, which is the conventional technology. The regeneration methods and their ionic composition distribution at the water production and the regeneration stages are shown in Figure 5.5-4. From this figure, it is clear that the countercurrent regeneration method allows a purer water production because of a smaller volume of Na^+ (SiO_2^{-2} in the case of anion resin) compared to the cocurrent flow regeneration method.

3) Waste water from the boiler feed water treatment system

The percentage of waste water from each equipment of the boiler feed water treatment system is as shown in Table 5.5-7. This table shows that it is an imperative requirement to recover the filter drain in order to improve the actual drain volume of $1.40\text{m}^3/\text{h}$ per pure product water. Although the concentration of suspended solid in the backwash water of the filter is high, as the ion concentration is the same as that of the raw water, the backwash water of the filter is generally recovered as raw water after the removal of suspended solids by a centrifugal separator.

Further, in order to reduce the waste water volume during the regeneration of ion exchange resin, it is necessary to recover the purge water after the replacement of the substitution of the chemical agent.

4) New trend of waste water treatment system

In ANNEX 7, one example of boiler feed water treatment system which has high efficiency water in-take and regeneration, is attached.

5.5.4 Present condition of waste water treatment in power plant

The power plant site is provided with two facilities: a neutralization facility for the waste water from the boiler feed water treatment system and a treatment facility for the sanitary water. There are no other treatment facilities for other waste water.

It is designed in such a manner that all waste water other than storm water flows into the main pipe of System 1 header of the waste water of the oil refinery and petrochemical plants, and rain water flows into the main

rain water header coming from the oil refinery area. Both waste waters are finally treated in the central general waste water treatment facility as shown in Figure 5.5-5.

5.5.5 Points at issue, evaluation and measures to be taken regarding the waste water treatment in power plant

(1) Waste water produced in power plant

Shown below is the waste water generally produced in the power plant.

- Waste water from boiler feed water treatment system
- Dust collector cleaning water
- Air preheater cleaning water
- Chemical cleaning water
- Turbine room floor drain
- Boiler room floor drain
- Boiler blow water
- Condenser cooling water
- Drain from around fuel-related equipment
- Sanitary water
- Rain water from power plant site

(2) Waste water treatment in power plant site

In public power station plants, waste water treatment facilities for their exclusive use are generally provided, and the waste water produced in such power plant as shown in (1) above are completely treated in the aforementioned waste water treatment facilities so that waste water of a quality which meets the standard value can be discharged. However, as this power plant is only part of the PPSA complex and there is a central general waste water treatment facility, it is not necessary to provide a

dedicated waste water treatment facility exclusively as is done for a public power plant. However, as to alkaline or acidic waste water, such as boiler blow water, dust collector cleaning water, air pre-heater cleaning water, chemical cleaning water, and so on, it is better to neutralize them within the power plant site before sending them into the main header. This will help prevent troubles such as corrosion of the main header pipe and also reduce the load of the central general waste water treatment facility.

Table 5.5-4 TOTAL ANALYSIS OF VISTULA RIVER, COOLING WATER AND DECARBONATED WATER

TECHNICAL PROPERTY	UNIT	RAW WATER FROM VISTULA RIVER			COOLING WATER K-1			DECARBONIZED WATER K-2		
		MIN	MAX	AVR	MIN	MAX	AVR	MIN	MAX	AVR
Turbidity	mg/L	13	55.0	36.0	8.0	22.5	16.0	3.0	8.5	4.6
Color	mg/L	19	66.0	35.0	12.5	31.5	21.0	5.0	12.5	7.0
Reaction "p"	PH	7.6	8.9	8.2	7.9	9.0	8.6	9.7	10.6	10.0
Basicity "M"	mmol/L	0.0	0.2	0.04	0.0	0.35	0.12	0.4	1.0	0.58
Basicity "N"	mmol/L	2.35	3.5	2.9	1.8	3.3	2.55	0.8	1.7	1.20
Total Hardness	mmol/L	9.9	15.8	13.2	3.8	13.7	11.9	6.2	11.2	8.5
Carbonate Hardness	mmol/L	7.0	9.8	8.2	5.0	13.1	7.6	2.2	4.7	3.7
Calcium Hardness	mmol/L	7.2	12.7	10.0	5.3	10.8	9.05	3.9	9.9	6.8
Magnesium Hardness	mmol/L	2.2	5.5	3.2	1.7	3.5	2.85	0.4	3.8	1.8
Ca	mg/L	66.0	116.0	91.5	48.7	98.0	83.0	36.0	90.0	61.6
Mg	mg/L	6.8	24.2	12.8	7.7	15.5	12.4	2.9	16.5	8.05
Total Fe	mg/L	0.225	0.85	0.56	0.17	0.68	0.29	0.05	0.18	0.10
Fe (+2)	mg/L	0.085	0.45	0.34	0.085	0.28	0.15	0.02	0.16	0.047
Mn	mg/L	0.17	0.46	0.31	0.07	0.32	0.225	0.07	0.22	0.12
Na	mg/L	25.0	116.0	55.4	27.0	146.0	61.2	26.0	146.0	62.8
K	mg/L	3.0	5.7	4.4	1.0	6.1	4.25	2.6	6.1	4.1
Cl (-)	mg/L	45.0	164.0	99.9	45.0	260.0	117.2	50.0	260.0	115.5
SO4 (-2)	mg/L	50.3	70.8	62.6	51.7	90.4	71.1	54.8	105.3	73.4
Silica	mg/L	0.22	14.2	7.6	0.37	18.7	7.2	0.82	14.2	6.1
PO4 (-3)	mg/L	0.10	0.72	0.38	0.05	0.36	0.23	0.0	0.13	0.057
NO3 (-)	mg/L	0.13	5.9	1.73	0.28	2.71	1.39	0.1	2.15	1.13
NO2 (-)	mg/L	0.019	0.094	0.066	0.007	0.435	0.071	0.060	0.167	0.073
N in NH3	mg/L	0.19	0.74	0.425	0.05	0.55	0.334	0.05	0.76	0.332
Oxidity	mgO2/L	7.3	15.5	11.1	5.2	9.9	6.9	3.2	5.0	4.2
COD	mgO2/L	28.0	89.6	58.8	24.0	67.6	45.2	19.6	65.6	33.8
Cu	mg/L	0.065	0.47	0.138	0.05	0.21	0.109	0.02	0.1	0.0375
Phenoles	mg/L	0.0006	0.014	0.0024	0.0006	0.0044	0.0017	0.0003	0.0025	0.0013
HC	mg/L	0.15	1.1	0.45	0.05	0.22	0.142	0.025	0.2	0.104
Detergents	mg/L	0.0	0.3	0.055	-	4.4	0.56	-	0.0	0.0
CO2	mg/L	0.0	17.6	5.5	0.0	23.7	9.9	0.5	8.5	4.7
Total Suspended Sodic	mg/L	15.3	36.9	25.2	2.5	15.6	6.7	0.0	4.7	3.3
Mineral Suspended	mg/L	4.8	20.5	14.2	1.8	8.9	3.2	0.0	4.4	1.4
Light (evaporated) Solid	mg/L	5.0	20.7	11.0	0.7	723.0	466.0	280.0	662.0	403.0
Dry Residue	mg/L	355.0	702.0	468.0	353.0	576.0	386.0	240.0	534.0	328.0
Ash	mg/L	204.0	558.0	353.0	289.0	576.0	386.0	240.0	534.0	328.0
Losses during Heating	mg/L	36.0	208.0	115.0	40.0	147.0	80.0	22.0	143.0	75.0
F (-)	mg/L	-	-	-	-	-	-	-	-	-
Al	mg/L	0.002	0.023	0.0087	-	-	-	-	-	-

Source: PPSA

Table 5.5-6 OPERATING DATA OF BOILER FEED WATER SYSTEM (1/3)

[Pre-treating Section]

Charge Rate(m ³ /h)	-	
Temperature (°C)	-	
pH(-)	-	
Floccurant Name	-	
Floccurant Inject.(g/m ³)	-	
Space Velocity of Clarifier(m/h)	-	
Retention Time(min)	-	
Filter Arrangement	parallel	series
Space Velocity of Filter(m/h)	-	
Criteria of Backwash	-	
Frequency of Backwash	-	
Point ① (Filter Outlet)	(see next page)	

[Demineralizer]

(1) Cation Tower	A,B,C	D,E,F,G,H
Ion Exchange Resin	<u>Wofatit KPS</u>	<u>Wofatit KPS</u>
Filling Amount(1)	8,500 × 2	12,600
Treating Capacity(m ³ /Cycle)	1,300 × 2	2,100
Make up Ratio(%/Year)	5 %	5 %
Point ② (C-Tour Outlet)	(see next page)	
(2) Decarbonator		
Packing Thickness(m)	2.8	2.8
Point ③ (Decarb.Outlet)	(see next page)	
(3) Anion Tower	A,B,C	D,E,F,G,H
Ion Exchange Resin	<u>Amberlite IRA 910</u>	<u>Amberlite IRA 910</u>
Filling Amount(1)	7,400	11,200
Treating Capacity(m ³ /Cycle)	5,000	7,500
Make up Ratio(%/Year)	5 %	5 %
Point ④ (A-Tour Outlet)	(see next page)	

[Silica Polisher]

(1) Silica Polisher	A,B,C	D,E,F,G,H
Ion Exchange Resin	<u>Wofatit KPS/MB</u>	<u>Wofatit KPS/MB</u>
Ion Exchange Resin	<u>Wofatit SEW/MB</u>	<u>Wofatit SEW/MB</u>
Filling Amount(1)	1,800	3,500
Filling Amount(1)	3,600	7,000
Treating Capacity(m ³ /Cycle)	28,000	36,000
Make up Ratio(%/Year)	5 %	5 %
Point ⑤ (SiO ₂ P.Outlet)	(see next page)	

Table 5.5-6 OPERATING DATA OF BOILER FEED WATER SYSTEM (2/3)

Design Base

[Water Examination]

	Point①	Point②	Point③	Point④	Point⑤
pH	+	-	-	-	+
Turbidity(-)	-	-	-	-	-
COD(mg/l)	+	-	-	-	+
Elect. Conductivity(μ S/cm)	-	-	-	-	+
Ca(mg-CaCO ₃ /l)	+	-	-	-	+
Mg(mg-CaCO ₃ /l)	+	-	-	-	+
Na(mg-CaCO ₃ /l)	+	-	-	-	+
K (mg-CaCO ₃ /l)	-	-	-	-	-
Total Cation(mg-CaCO ₃ /l)	-	-	-	-	-
HCO ₃ (mg-CaCO ₃ /l)	+	-	-	-	-
SO ₄ (mg-CaCO ₃ /l)	-	-	-	-	-
Cl (mg-CaCO ₃ /l)	-	-	-	-	+
NO ₃ (mg-CaCO ₃ /l)	-	-	-	-	-
CO ₂ (mg-CaCO ₃ /l)	-	+	+	-	-
SiO ₂ (mg-CaCO ₃ /l)	+	-	-	+	+
Total Anion(mg-CaCO ₃ /l)	-	-	-	-	-

Operation

	Point①	Point②	Point③	Point④	Point⑤
pH	10.5	-	-	-	6.8
Turbidity(-)	-	-	-	-	-
COD(mg/l)	5.0	-	-	-	1.5
Elect. Conductivity(μ S/cm)	-	-	-	-	0.2
Ca(mg-CaCO ₃ /l)	120	-	-	-	0.00
Mg(mg-CaCO ₃ /l)	20	-	-	-	0.00
Na(mg-CaCO ₃ /l)	50-250	1.0	-	-	0.2
K (mg-CaCO ₃ /l)	-	-	-	-	-
Total Cation(mg-CaCO ₃ /l)	-	-	-	-	-
HCO ₃ (mg-CaCO ₃ /l)	0-2.0	-	-	-	-
SO ₄ (mg-CaCO ₃ /l)	-	-	-	-	-
Cl (mg-CaCO ₃ /l)	-	-	-	-	-
NO ₃ (mg-CaCO ₃ /l)	-	-	-	-	-
CO ₂ (mg-CaCO ₃ /l)	-	200.0	10.0	-	-
SiO ₂ (mg-CaCO ₃ /l)	5-10.0	-	-	0.5	0.03
Total Anion(mg-CaCO ₃ /l)	-	-	-	-	-

Table 5.5-6 OPERATING DATA OF BOILER FEED WATER SYSTEM (3/3)

[Regeneration of Ion Exchange Resin]

[Demineralizer]

(1) Cation Tower

Regenerant Concentration(wt %)	HCl	33 wt %
Regeneration Conc.(WT %)	about HCl	5 wt %
Regeneration Temp. (°C)		15 - 25 °C
	A,B,C	D,E,F,G,H
Product(m ³ /Cycle)		
HCl Consumption(g/l-Resin)	80	92
Reg. Waste Water(m ³ /Cycle)	140	160

(2) Anion Tower

Regenerant Concentration(wt %)	NaOH	45 wt %
Regeneration Conc.(WT %)	about NaOH	4 wt %
Regeneration Temp. (°C)		15 - 25 °C
	A,B,C	D,E,F,G,H
Product(m ³ /Cycle)		
NaOH Consumption(g/l-Resin)	80	80
Reg. Waste Water(m ³ /Cycle)	135	185

[Silica Polisher]

(1) Silica Polisher

Regeneration Conc.(WT %)	about HCl	5 wt %
Regeneration Temp. (°C)		15 - 25 °C
	A,B,C	D,E,F,G,H
Product(m ³ /Cycle)		
HCl Consumption(g/l-Resin)	142	170
Reg. Waste Water(m ³ /Cycle)	100	200
Regenerant Concentration(wt %)	NaOH	46 wt %
Regeneration Conc.(WT %)	about NaOH	4-5 wt %
Regeneration Temp. (°C)		15 - 25 °C
NaOH Consumption(g/l-Resin)	97	120
Reg. Waste Water(m ³ /Cycle)	57	53

HCl Consumption = 0.696 kg/m³ -Demineralized Water

NaOH Consumption = 0.898 kg/m³ -Demineralized Water

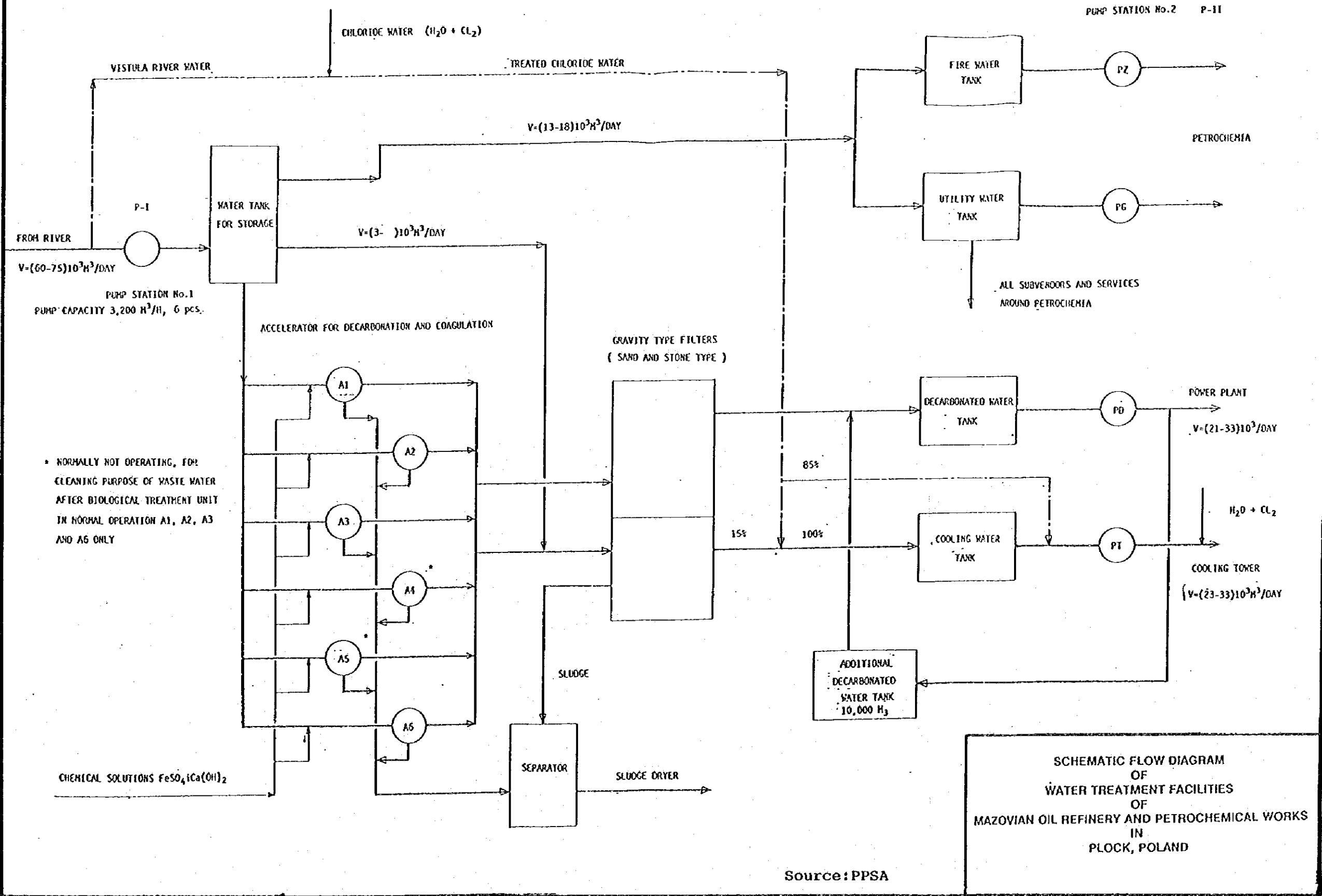
NaCl Consumption = 0.011 kg/m³ -Demineralized Water

Table 5.5-8 QUALITY OF BOILER FEED WATER

Item	Quality
SiO₂	0.025
Hardness	none
Fe	0.02 mg/L
Cu	0.005mg/L
Oxydizable	5.0mg KMnO₄/L
pH	8.5 - 9.2
Na	0.1 mg/L
Oil	none
Electric Conductivity	0.2μS/cm

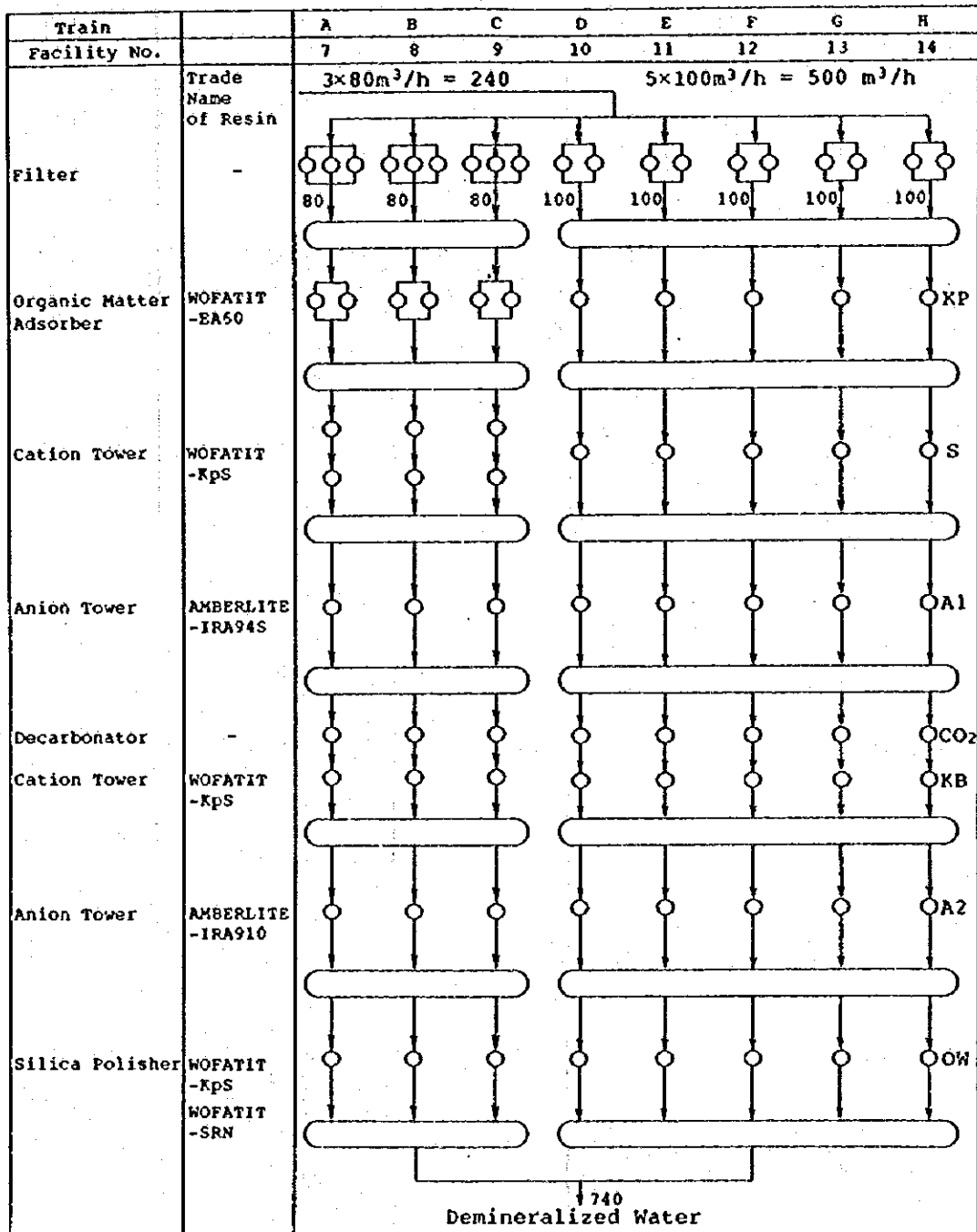
Source: PPSA

Figure 5.5-1 SCHEMATIC FLOW DIAGRAM OF WATER TREATMENT FACILITIES



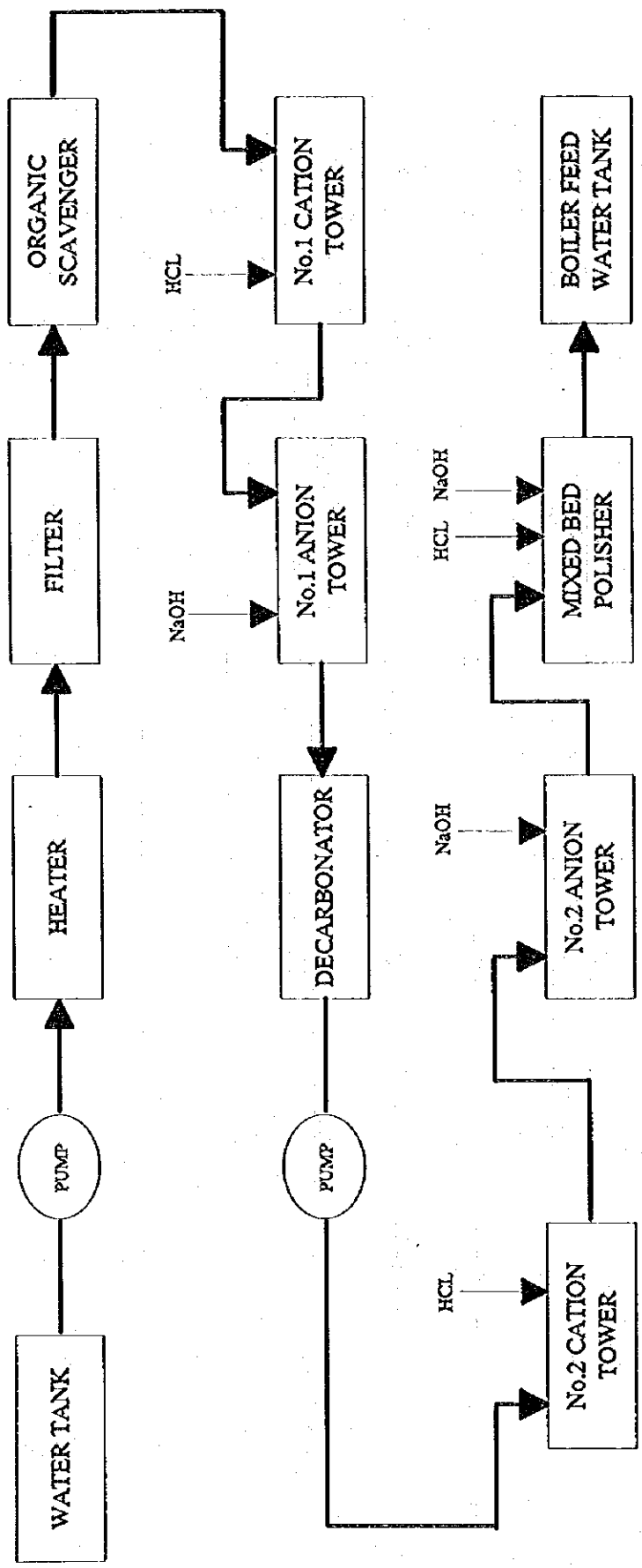
SCHEMATIC FLOW DIAGRAM OF WATER TREATMENT FACILITIES OF MAZOVIAN OIL REFINERY AND PETROCHEMICAL WORKS IN PLOCK, POLAND

Figure 5.5-2 SCHEMATIC FLOW DIAGRAM OF CURRENT DE-MINERALIZER FACILITIES



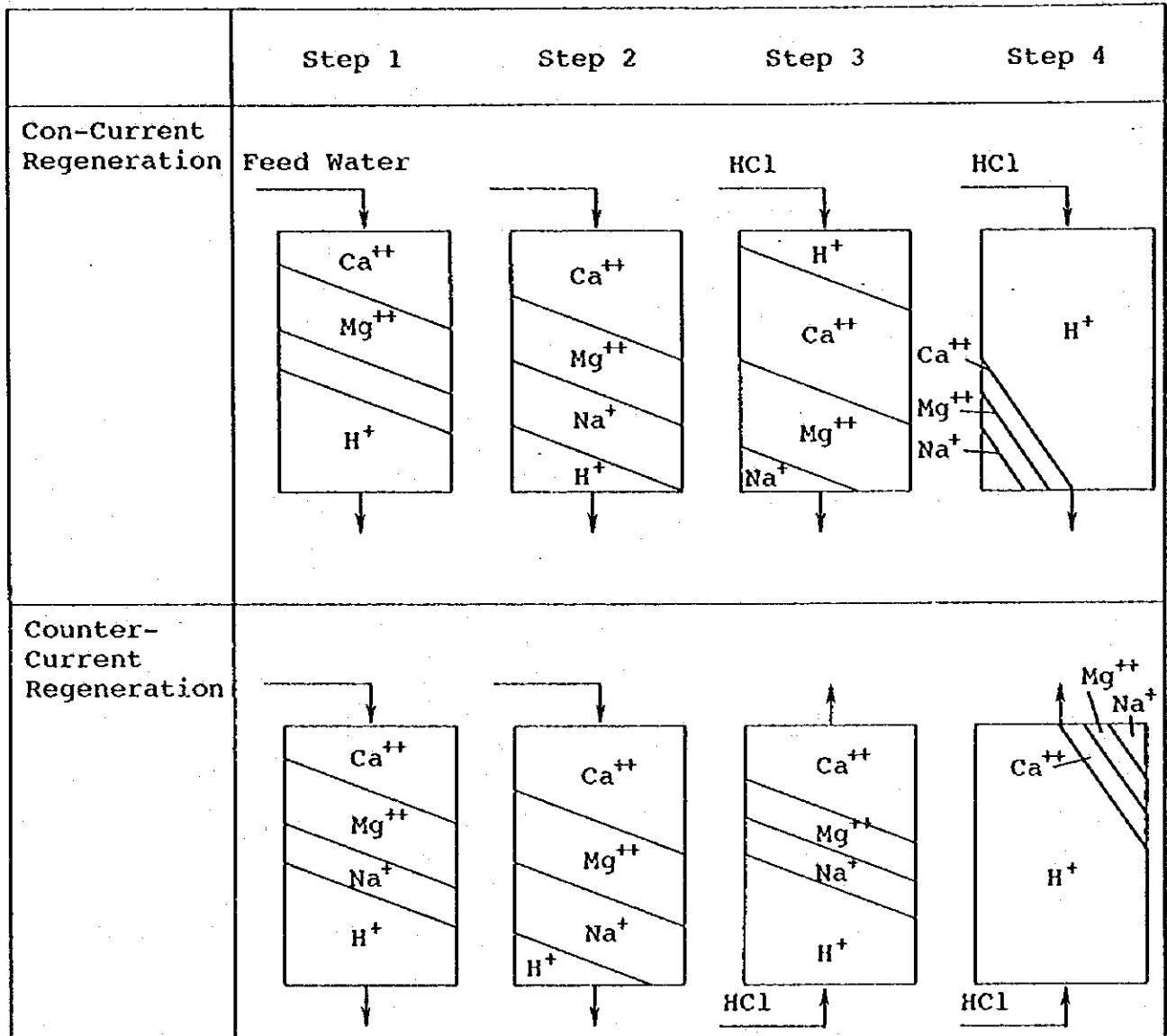
Source: PPSA

Figure 5.5-3 SCHEMATIC FLOW DIAGRAM OF BOILER FEED WATER TREATMENT FACILITY



SCHEMATIC FLOW DIAGRAM
 OF
 BOILER FEED WATER TREATMENT FACILITY
 OF
 MAZOVIAN OIL REFINERY AND PETROCHEMICAL WORKS
 IN
 PLOCK, POLAND

Figure 5.5-4 THE COMPARISON BETWEEN CON-CURRENT AND COUNTER CURRENT REGENERATION



Step 1 : Operation

Step 2 : End of Operation

Step 3 : Regeneration

Step 4 : End of Regeneration



5.6 Review of Type and Quality of Fuel

5.6.1 Current fuel used in PPSA

(1) Type of fuel used in 1992

There are four types of fuel used in PPSA, i.e., Vacuum residue, fuel gas, diesel oil and phenol tar.

Table 5.6-1 shows actual consumption for each type of fuel in 1992. In this table, actual fuel consumption and standard fuel equivalent consumption which is converted to the standard fuel (heating value : 7,000 kcal/kg) are compared.

Table 5.1-4 shows the consumption for each fuel based on standard fuel in 1992. The rate of fuel consumption of vacuum residue oil is 96.7% and high pressure boilers are generally vacuum residue oil fired boilers.

(2) Quality of fuel

PPSA has used refined Ural Crude Oil so far. However, it is obvious that Crude oil from the Middle East will be more refined in the future.

Therefore, the new specification was added recently and used for this Feasibility study. Table 5.6-2 shows the quality data and specification of fuel oil.

Table 5.6-2 QUALITY DATA AND SPECIFICATION OF FUEL OIL

Item	actual data(2.1'94)	future specification
heating value (kJ/kg)	-	40,00042,000
specific gravity	-	-
sulfur (wt %)	2.78	max. 3.0
nitrogen (wt %)	0.57	-
Residual Carbon	-	-
Asphalten (wt %)	4.76	-
V (wt ppm)	117	220 (3)
Ni (wt ppm)	39	-
Viscosity	2.5°E @ 190°C	-

Source: PPSA

Note : () shows specification in 1992.

5.6.2 Evaluation of fuel

In addition to the heating value, content of sulfur, nitrogen, residual carbon and etc. in fuel are important factors to evaluate. These factors have a large effect on the emission of air pollution and corrosion of fuel gas system.

Here, each material in fuel is reviewed.

(1) Sulfur

Sulfur in fuel becomes SO_x when burned. This SO_x causes acid rain and problems to human health.

In particular, SO₃ becomes sulfuric acid by dissolving in water. It is known that part of SO₂ becomes SO₃ by being oxidized in the atmosphere. Therefore, the total amount of SO₂ is regulated by law.

It is required to reduce sulfur content in the fuel or to desulfurize the flue gas in order to reduce SO₂ emission to the atmosphere.

PPSA has a plan to install a flue gas desulfurization process (hereinafter FGD process) for the boilers from No.4 to No.7.

At the same time, the flue gas ducts from No.1 - No.3 boilers will be joined with FGD process. The capacity of FGD is $110 \times 10^4 \text{ Nm}^3/\text{h}$ - 2 trains. These capacities are equivalent to about 2,400 t/h boiler steam generated in the case of 3 % oxygen content in flue gas.

Accordingly, flue gas of 90% from all high pressure boilers in PPSA will be able to treat in these FGD process, when O_2 concentration in flue gas for all high pressure boilers will be reduced to approximately 3%.

Here, O_2 concentration in flue gas from present No.1 - No.3 are very high because of internal leakage in Jungstrom. (The amount of leaked air is estimated to be about $12 \times 10^4 \text{ Nm}^3/\text{h}$ per one boiler.)

Consequently, the replacement of the Jungstroms are very effective measures to utilize the abilities of FGD process.

(2) Nitrogen

Conversion to NO_x from fuel depends on the operation and combustion conditions and, generally, is about 50%, while all the sulfur in the fuel is converted to SO_2 and SO_3 . NO_x is classified into 2 types, One is NO_x generated by nitrogen in the air (so called Thermal NO_x) and the other is generated in the fuel (so called Fuel NO_x).

NO_x content is influenced by excess air ratio, boiler load, nitrogen content in the fuel, structure of combustion chamber (two stage combustion, flue gas recirculation etc.), type of burner (low NO_x burner) etc..

Therefore it is recommended to understand the following correlations for each boiler in terms of NO_x emission by test runs and to operate with as low NO_x emission as possible.

- 1) Correlation between oxygen content in the boiler flue gas. Oxygen content shall be measured at the upstream of the Jungstrome.

2) Correlation between NOx content and boiler load.

3) Correlation between NOx content and load balance of upper, middle and lower burners.

Even though the conversion to NOx from fuel is about 50%, nitrogen content in the fuel is not disregarded in case of severe regulation of NOx emission.

Since Ural Crude Oil, the main crude oil for PPSA, contains less nitrogen compared to Middle East Crude Oil, it is preferable for fuel.

However, imports of Middle East Crude Oil are estimated to increase in the future. Since the countermeasure for this is to determine the best combustion conditions for minimum NOx emission because no de-NOx plant is planned now. The correlations recommended above should be grasped at an early stage.

For example, if the nitrogen content in the fuel is increased by 0.1%, then fuel NOx would be increased by about 25 ppm.

Here, actual data of nitrogen content in fuel of PPSA shown in Table 5.6-2 is 0.57 wt %. This value is 0.20% higher than Japanese example of vac residue oil fired boiler. Consequently, it is considered that NOx concentration in flue gas are approximately 50 vol ppm higher than Japanese actual data

(3) Vanadium

It is known that high temperature corrosion is accelerated by the existence of vanadium in ash, if the fuel contains vanadium in large quantities.

So far it is reported that no high temperature corrosion was found in PPSA. This may be due to low vanadium content in the fuel.

However, vanadium content in the fuel will increase because of increased import of Middle East Crude Oil in the future, and accordingly PPSA forecasts the increased vanadium

emission after 1993 as shown in Figure 5.7-2.

In the above situation, it is necessary to provide countermeasures against high temperature corrosion. Since there is no process to remove vanadium from fuel, vanadium content in fuel is fixed by the crude oil which is refined at the atmospheric distillation units.

As the magnesium compound reacts with vanadium compound easily and increases the melting point of ash by a little addition of the anticorrosion additive, application of an anti-corrosion additive which contains magnesium compound as a main compound, is the main stream.

Ash on the boiler tube has a tendency to exfoliate and accumulate at the bottom of the boiler furnace. This exfoliation is estimated to be caused by the sootblower.

Generally speaking, the magnesium type anticorrosion additive is injected with the ratio of magnesium to vanadium (Mg/V) of 2 : 1.

Therefore, more injection of the additive is required for fuel which contains higher vanadium content. This means that it is effective for anti-corrosion but the additive may bring some disadvantage such as lowering efficiency by the adhesion of ash leading to a higher flue gas temperature if there are no sootblowers installed.

Sootblowers are an essential equipment in the case of application of the anti-corrosion additives (not only for boiler tubes but also for Jungstrome).

(4) Residual carbon (Conradson Carbon)

In Japan, Conradson Carbon is grasped as the property for residual carbon of heavy fuel. On the other hand, in PPSA asphalten content is grasped. Residual carbon has very much to do with the combustibility of fuel oil, so residual carbon influences the dust content in the flue gas.

It is assumed that Conradson carbon value is more than 20 wt %, when asphalten content is 4.76 wt % shown in Table 5.6-1.

Accordingly it is considered that the residual carbon in fuel oil in PPSA is the same or easy grade compared with the Japanese example.

Figure 5.6-1 shows the correlation between Conradson carbon content and dust content in the flue gas.

(5) Viscosity

The viscosity of fuel is another property that has very much to do with the combustibility. Here, Figure 5.6-1 shows the correlation between fuel temperature and kinetic viscosity.

It is assumed that the fuel used in PPSA is milder than Japanese example in terms of combustibility.

However, the heavier vacuum residue oil becomes, the more sulfur content in fuel oil increases. If the sulfur content in fuel oil increase, SO_2 emission from the process heater such as atmospheric distillation units will be increased.

Accordingly, the sulfur content in fuel oil will actually be reduced in the future.

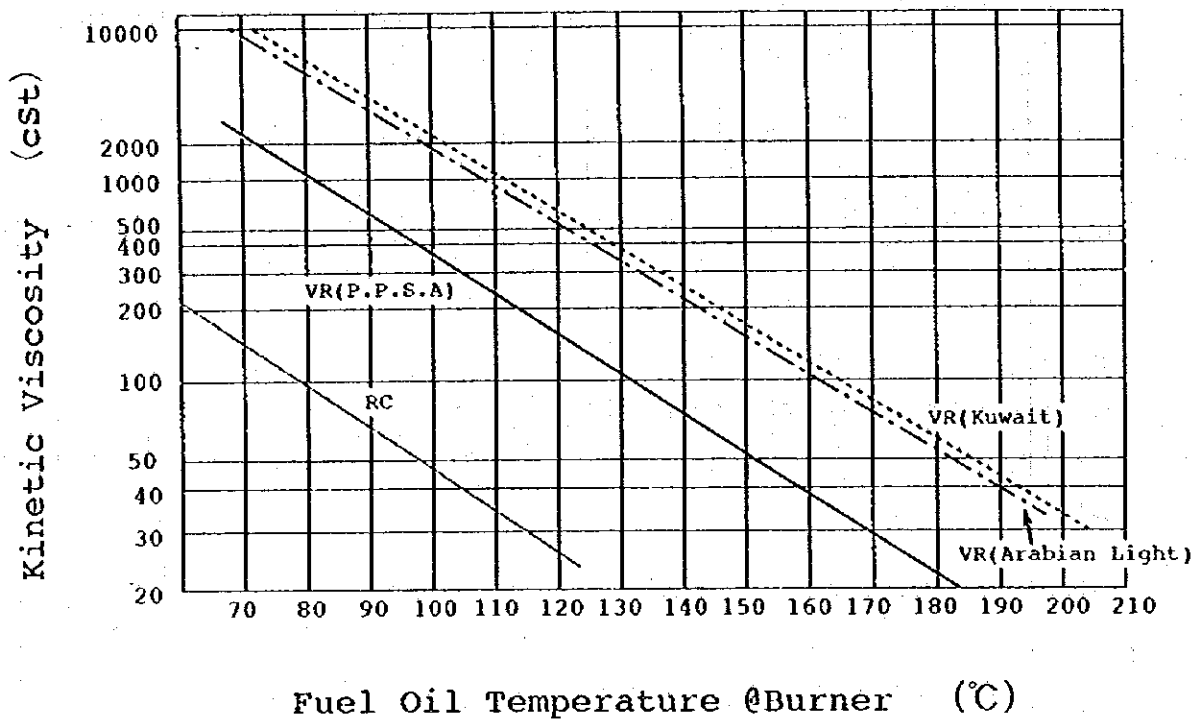
Table 5.6-1 THE AMOUNT OF FUEL CONSUMED IN 1992

Standard : Standard Fuel (7,000 kcal/kg)
 Real : Real Fuel

	VAC Residue		GAS		Diesel Oil		Tars		Total
	Standard	Real	Standard	Real	Standard	Real	Standard	Real	
Plan Month	283,434	206,670	6,636	3,871	500	350	—	—	290,520
I	105,055	75,517	556	341	93	66	251	200	105,955
II	89,854	64,905	330	202	149	108	314	250	90,649
III	87,397	62,960	222	151	121	84	465	370	88,205
Sub total	282,308	203,382	1,108	694	363	258	1,030	820	284,809
Plan Month	233,952	120,590	3,008	1,755	500	350	—	—	237,460
IV	5,040+69,825	3,645+50,504	989	737	78	57	645	530	5,040+71,537
V	61,234	44,208	1,815	1,071	26	18	538	450	63,613
VI	50,619	36,578	3,457	1,821	95	66	602	510	54,773
Sub total	181,678+5040	131,290	6,261	3,629	199	141	1,785	1,490	189,923
Plan Month	42,136	30,458	4,988	3,054	246	168	533	454	47,903
VII	49,198	35,434	4,650	2,482	182	132	276	235	54,306
VIII	56,237	40,701	1,718	903	121	84	217	190	58,293
IX	147,571	106,593	11,356	6,439	549	384	1,026	879	160,502
Sub total	262,450	190,324	4,458	2,421	361	254	1,037	935	268,306+1,816
Plan Month	80,733	57,897	1,648	866	102	70	518	475	83,001
X	85,692+1,816	62,438+1,323	1,404	738	142	106	458	410	87,696+1,816
XI	96,025	69,989	1,406	817	117	98	61	50	97,609
XII	262,450	190,324	4,458	2,421	361	254	1,037	935	268,306+1,816
Sub total	463,986+5040	334,672+3645	7,369	4,323	562	399	2,815	2,310	474,732+5,040
1 st half	611,557+5040	441,265+3645	18,725	10,762	1,111	783	3,841	3,189	635,234+5,040
2 nd half	874,007+6856	631,589+4968	23,183	13,183	1,472	1,037	4,878	4,124	905,833+6,856
total									

Source ; P.P.S.A.

Figure 5.6-1 CORRELATION BETWEEN FUEL OIL TEMPERATURE AND KINETIC VISCOSITY



Source ; K.Horino , Asphalt Combustion Test ,
 Idemitsu Sekiyu Gizyutsu , 23 (6) 45-53 (1980)

5.7 Review of Level of Emission and Effluent from the Plant

5.7.1 Present emission amounts of air pollutant

SO₂, NO_x, dust, CO, aliphatic hydrocarbon and aromatic hydrocarbon are registered as air pollutants. The regulated maximum emission value and actual emission values of each material in 1992 and 1993 are shown in Table 5.7-1. The actual amounts of emission and fees in proportion to pollutant emission of these materials are shown in Table 5.7-2.

The regulated maximum emission values and actual emission values of each material for No.1 - No.3 boiler are summarized as follows.

g/GJ is used as unit for national regulated value and kg/h is used for local regulated value.

(1) SO₂ emission

National regulated value	(Valid to 31 Dec. '97)	1,720	g/GJ
	(After 31 Dec. '97)	170	g/GJ
	Actual value	('92) 1,228	g/GJ
Local regulated value for '92		618.44	kg/h
	Actual value	('92) 733	kg/h
Local regulated value for '93		309.22	kg/h
	Estimated value	('93) 677.7	kg/h

(2) NO_x (Equivalent of NO₂) emission

National regulated value	(Valid to 31 Dec. '97)	160	g/GJ
	(After 31 Dec. '97)	160	g/GJ
	Actual value	('92) 170.6	g/GJ
Local regulated value for '92		141.56	kg/h
	Actual value	('92) 101.85	kg/h
Local regulated value for '93		58.59	kg/h
	Estimated value	('93) 114	kg/h

However, local regulated value for NOx emission is not decided yet, and is now under deliberations.

(3) Dust emission

National regulated (Valid to 31 Dec. '97)	-	g/GJ
value (After 31 Dec. '97)	-	g/GJ
Actual value ('92)	15	g/GJ
Local regulated value for '92	35.56	kg/h
Actual value ('92)	8.8	kg/h
Local regulated value for '93	35.56	kg/h
Estimated value ('93)	6.6	kg/h

(4) CO emission

National regulated (Valid to 31 Dec. '97)	-	g/GJ
value (After 31 Dec. '97)	-	g/GJ
Actual value ('92)	8.4	g/GJ
Local regulated value for '92	163.13	kg/h
Actual value ('92)	5	kg/h
Local regulated value for '93	163.13	kg/h
Estimated value ('93)	5	kg/h

(5) Aliphatic Hydrocarbon emission

National regulated (Valid to 31 Dec. '97)	-	g/GJ
value (After 31 Dec. '97)	-	g/GJ
Actual value ('92)	17.2	g/GJ
Local regulated value for '92	19.72	kg/h
Actual value ('92)	10.25	kg/h
Local regulated value for '93	-	kg/h
Estimated value ('93)	7.6	kg/h

(6) Aromatic Hydrocarbon emission

National regulated (Valid to 31 Dec. '97)	-	g/GJ
value (After 31 Dec. '97)	-	g/GJ
Actual value ('92)	4.3	g/GJ
Local regulated value for '92	4.55	kg/h
Actual value ('92)	2.56	kg/h
Local regulated value for '93	-	kg/h
Estimated value ('93)	1.9	kg/h

5.7.2 Emission level of air pollutant

(1) SO₂

The amount of SO₂ emission is determined by the content of sulfur in the fuel and the amount of fuel consumption. Therefore, there are two countermeasures to reduce SO₂ emission. One is the reduction of the content of sulfur in the fuel and the other is the removal of SO₂ from the combustion flue gas.

When the fuel with a heating value of 41,000 kJ/kg is burnt, allowable maximum sulphur content of the fuel is 3.55 wt % in order to keep the national regulated maximum emission value, 1.720 g/GJ. Present sulfur content in the fuel is around 3 wt%. However, in case the national regulated maximum emission value is reduced to 170 g/GJ or 1/10 after 1998, either fuel conversion to low sulphur or adoption of FGD process will be necessary. The concentration of sulfuric components in fuel actually used was 2.5% in 1992 and 2.3% at the first half of 1993.

According to the emission standards of the Ministry of Environment, the allowance of emission will necessitate either the change of fuel or FGD process.

The capacity of FGD process for 00420 No. 4 through No. 7 boilers are 1100,000 Nm³/h x 2 trains and the flue gas ducts from No.1 - No.3 are joined with FGD ducts.

(2) NO_x

Nitrogen oxides in combustion flue gas are NO₂ and NO, hence called NO_x. In ordinary exhaust gas from a boiler, NO occupies 95% of the volume. Both nitrogen in fuel and in combustion air contribute to NO_x formation.

The emission standards of the Ministry of Environment adopt the value of 160 g-NO₂/GJ for the boilers at PPSA.

When the heat value of fuel, the logical air amount and the amount of dry exhaust gas are chosen as 41,000 kJ/kg, 10.712 Nm³/kg and 10.090Nm³/kg respectively, the emission concentration of NO_x in the conversion value of 4% O₂ becomes 254 vol ppm. On the other hand, the agreement with the Plock prefecture specifies the total emission of each boiler as in the examples of 00320 No. 1 through No. 3 boiler where the permitted emission from June 6, 1991 through December 29, 1992 was 141.56 KG/H. This value will be 253 vol ppm if an operation at the rated load as shown in Chart 5.1.1 is assumed. However, the value is 58.59 kg/h in 1993 and corresponds to 105 vol ppm when evaluated as the conversion value of NO₂ in the conversion value of 4% O₂.

However, these value are not decided yet, but now under deliberation. Accordingly, PPSA presented target value for this study shown in Table 5.7-3.

Table 5.7-3 TARGET VALUES FOR NO_x TO BE REDUCED

Capacity	under 50 MW	over 50 MW
Modernization	120 g/GJ	160 g/GJ
Newly installation	90 g/GJ	120 g/GJ

Source: PPSA

Here, No.1 - No.3 boilers are over 50 MW. Accordingly, the target value for this modernization study is 160 g/GJ. In the case of Japan, the control limits against the existing facilities are different depending on the location, and the values are between 150 - 180 vol ppm. In the Japanese example of the vacuum residue oil fired boiler, NOx concentration is around 160 vol ppm when the nitrogen content in fuel is 0.35 wt %. This boiler adopted some measures to reduce NOx such as corner-firing, 2 stage combustion, and tilting burners.

Here, measures such as 2 stage combustion and corner firing are suitable for newly installed facilities because these measures require large scale reconstruction of existing boilers.

Actually, it is suitable to replace low-NOx burners for existing boilers. In generally, it is possible to reduce the level to about 200 ppm by adoption of low NOx burners. However, it will probably be a limit of 250 ppm in the case of PPSA, because the nitrogen content of fuel used in PPSA as shown in Table 5.6-2 is 0.57 wt % is a very high level. Accordingly, it is expected to satisfy the target value in Table 5.7-3 by adoption of low-NOx burners.

In general, the following measures are adopted.

1) Remodeling of a burner tip

This is the most simple facility as a measure against NOx. Though some difference in efficiency exist depending on operational conditions, 20 to 30% improvement can be expected for heavy oil combustion.

2) Adoption of biased combustion method

The combustion temperature is controlled by using upper and lower burners, each of which requires different amount of

oil, thus achieving NOx reduction. With a proper burner combined, the improvements mounting to 40 to 45% were demonstrated in some examples.

3) Steam spray

The steam atomizing method is devised to lower flame temperature by blowing vapor into a combustion air duct, reducing the concentration of oxygen in combustion air to retard combustion and allow the steam to attract heat. Although this method demonstrates NOx reduction until the concentration of oxygen reaches 19%, further reduction than 18% adversely lowers the reduction effect. Since this method has high operation cost, it is used in such cases as a short term measure at the time of high load and a backup measure. The improvement in the case of heavy oil combustion was 12 to 13%.

4) Low NOx burner

When measures described in the above 1), 2) and 3) are not sufficient to attain the goal, the measure will extend to a burner change. This method exhibits 15 to 20% improvement over the method in 2).

5) 2 stage combustion

In this method, 90 to 95% of logical air amount is introduced through a burner inlet and 10 to 20% of air necessary for combustion is introduced through an air inlet provided at the upper part of a burner. The more the air through the burner inlet is reduced, the higher NOx reduction is achieved, but an excessive reduction results in combustive instability and frequent generation of dust. The stage combustion method exhibits 15 to 25% improvement.

6) Recirculation of exhaust gas

This method allows a portion of combustion flue gas to mix with combustion air and reduce the concentration of O_2 , enabling moderate combustion to lower the combustive temperature and achieve NO_x reduction. The more the recirculating gas increases, the greater the reduction effect becomes possible, but the excessive recirculation makes the combustion unstable so that 20 to 30% of the combustion air is considered to be the limit. The reduction effect by recirculation exhibits 5 to 50% variation, indicating its dependence on each furnace.

(3) Dust

Dust in flue gas exhausted from oil fired boilers contains oil ash in fuel, unburned carbon and a very small amount of SO_3 mist. The particle size of this dust is about 1 - 3 μm , and this is much smaller than dust particles exhausted from coal fired boiler.

The amount of unburned carbon generated in an oil fired boiler is influenced by the combustibility of the burner. For example, countermeasures against NO_x emissions such as described in (2) of 5.7.2 aim mild combustion, so these countermeasures are antagonistic to control dust emission. As shown in Table 5.7-1, the limit value of dust emission from No.1 - No.3 boilers permitted by local authority in 1992 and 1993 is 35.56 kg/h. This value is equivalent to about 150 mg/Nm^3 under the rated load as dust concentration in the flue gas.

On the other hand, the emission level in 1993 is 6.6 kg/h. This value is equivalent to about 28 mg/Nm^3 at the rated load.

Therefore, there is no problem with dust emission at the present.

However, it is clear that the amount of dust emission is strongly influenced of O₂ content in flue gas and Conradson carbon content in fuel oil.

Accordingly, reduction of dust emission may be highlighted in the future on the following ground.

1) Increasing Conradson carbon content in fuel oil

When Middle East Crude is refined much more at PPSA in the future, Conradson carbon content in fuel oil will be increase. Under same operating condition such as O₂ concentration in flue gas and so on, as Conradson carbon content increases, so does dust emission.

2) Reinforcing countermeasures of NO_x reduction

When Middle East Crude is refined more, nitrogenous components in fuel oil will increase, and therefore countermeasures of NO_x reduction become more severe. Reinforcing countermeasures of NO_x reduction means increasing dust emission.

3) Installation of soot blower

Installation of soot blower is indispensable to maintain stable and continuous operation throughout the year. The soot blower will be operated once or twice a day. Long refracting soot blowers are suitable for each superheater zone and economizer zone. At least 5 units will be required for these zone. Estimated operating time of the long refracting type blower is about 10 min.. Fixed position rotating blowers are suitable for the heating element of the Jungstrom, and estimated operating

time is about 50 min..

Here a part of dust in flue gas adheres on the inside wall of the flue gas duct and stack and grows into a layer. Accordingly, there is a possibility that a part of the dust layer is stripped, when these soot blowers are operated, because velocity at flue gas duct and stack increase instantly when one soot blower start. Therefore it is required to make sure of the direction of wind before start of soot blower.

(4) CO

Amount of CO generated in oil fired boiler is under influence of combustibility too.

In Japan, it was once tried to install CO analyzer in flue gas system in order to check combusting condition.

However it was determined that an O₂ analyzer was enough to check combusting condition.

Figure 5.7-1 shows the correlation between O₂ content and dust content in combustion flue gas as one example.

This figure shows that O₂ control in flue gas is possible to control both concentrations of dust and CO in flue gas.

As shown in Table 5.7-1, the limit value of CO emission from No.1 - No.3 Boiler permitted by local authority in 1992 and 1993 is 163.13 kg/h. This value is equivalent to about 544 vol ppm of CO concentration in flue gas at the rated load.

Actual emission level of CO in 1993 is 5.0 kg/h.

This value is equivalent to about 17 vol ppm at the rated load.

There is no problem with CO emission at present.