LAKHRA COAL AND POWER DEVELOPMENT PROJECT REVIEW

3910487 PDAAT-155
IAN-44693

VOLUME I REPORT

APRIL 1983

PREPARED FOR:

UNITED STATES AGENCY FOR INTERNATIONAL DEVELOPMENT

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3910487 PD-AAT-155

IAN-44693

LAKHRA COAL STUDY

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SECTION 1

EXECUTIVE SUMMARY

1.1 INTRODUCTION

Pakistan's growing demand for electricity is rapidly outpacing its electric generation capacity. This power short-fall is rapidly approaching serious, if not critical, proportions. Load shedding of up to 500 MW was required in 1981/82 and is expected to reach 1,000 MW by 1983/84. One major reason is because of the uneven electric generation of installed hydroelectric capacity. Rainfall and glacial melt are seasonal and water is primarily used for irrigation. Shortages of natural gas for industry have led to a national policy prohibiting further use of this resource for power generation. Fuel oil is imported with a large foreign exchange demand and one that could be the subject of future supply disruptions.

Hence, the use of indigenous coal resources is a primary option as a fuel for thermal electric power plants in Pakistan. Preliminary geological investigations of a 26-square kilometer (km) section of the Lakhra Coal Field, located 45 km northwest of Hyderabad (Figure 1.1-1), indicate that this section alone contains sufficient economically recoverable coal to fuel several hundred megawatts of electric power generation capacity. In addition to the Lakhra reserve, there are other coal deposits in Pakistan; efforts are currently underway, with support from the World Bank and others, to better define the extent, quality, and development prospects of Pakistan's coal resources.

Over the past 15 years, the Government of Pakistan (GOP), with some assistance from foreign governments, has conducted several studies to examine the technical feasibility and costs of generating electric power using Lakhra coal. The results of these studies were not sufficiently conclusive to convince the GOP that a Lakhra coal mine supplying coal to a steam-electric power plant was a technically sound and economically attractive investment.

In response to a formal request from the GOP, the United States Agency for International Development (USAID) agreed to support a thorough reexamination of the technical feasibility and costs of such a project. USAID designed the study to be a collaborative effort of a U.S. contractor working with two Pakistan organizations, Pakistan's Water and Power Development Authority (WAPDA), and the Pakistan Mineral Development Corporation (PMDC). The intent was to involve these Pakistan organizations thoroughly in the examination of key technological and economic issues and in the formulation of the study results. The participants would also be exposed to modern large-scale coal production and power generation technology currently being used in the United States and would gain firsthand knowledge of the coal technology that can be applied in a Lakhra Coal Facility. In view of the potential national importance of such a project, USAID also arranged for senior GOP officials to review the results of this study. By this method, a well informed decision could be made on the advisability of implementing a Lakhra Coal Facility Project.

Study activities began in the fall of 1982. Stone & Webster Engineering Corporation (SWEC) was retained by USAID to provide specialized knowledge in coal mining, coal handling, and power generation technology. A joint WAPDA, PMDC, SWEC analytical team was formed in October 1982. Data collection and field visits in Pakistan followed immediately. Analytical activities in SWEC Boston headquarters were combined with visits to U.S. coal mines and power generation plants in December and January. Initial findings were reviewed with senior GOP and USAID officials in January 1983. These findings were sufficiently positive, so that WAPDA management decided to propose to the Pakistan Planning Commission that a Lakhra Coal Facility project be included in Pakistan's Sixth Five-year Economic Development Plan. Accordingly, the study activities were extended through April 1983 to expand certain analyses, to plan in more depth the project's implementation, and to provide technical and other support to the authorization of the project.

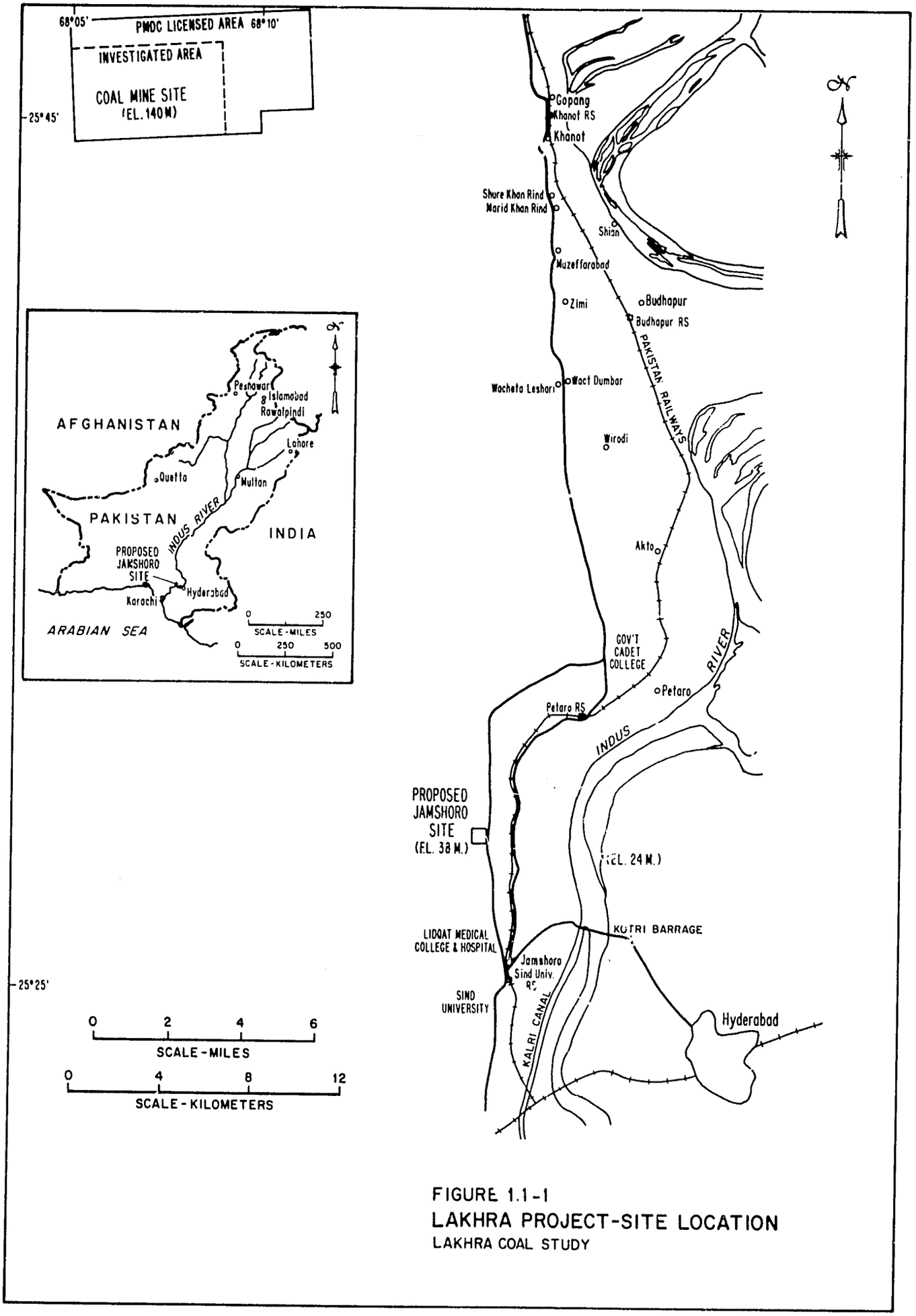

FIGURE 1.1-1
LAKHRA PROJECT-SITE LOCATION
LAKHRA COAL STUDY

1.2 STUDY APPROACH

The ground rules established by USAID required that key officials from WAPDA and PMDC work with SWEC counterparts participating in every phase of the study. Mining and power engineers from SWEC spent three weeks in Pakistan gathering data and refining the scope of the study. Following this trip, WAPDA's Director of Fuels and Efficiency, PMDC's Chief Mining Engineer and PMDC's Deputy Chief Geologist came to the United States and spent approximately two months participating in the analysis and preparation of the written report. Two weeks before the presentation of the draft report, WAPDA's Chief Engineer - Thermal, and Resident Engineer at Quetta's Power Station came to review and comment on the study before final preparation. In addition, the WAPDA officials visited several coal-fired power stations, while the PMDC officials visited numerous surface and underground mining operations.

The study team used the geological data developed by previous investigators to assess independently the quality and extent of the Lakhra Coal Reserve. No new field exploration or core drilling activities were to be conducted.

In January of 1983, the study team presented preliminary findings concerning a 300-MW facility to senior GOP officials and to USAID. After this presentation, SWEC was asked to develop planning and scheduling summary networks and cash expenditure schedules for both the 300-MW facility and a 600-MW facility incorporating two identical 300-MW power plants. In addition, the team was asked to assist WAPDA and PMDC in preparing in Pakistan the PC-1 Report to be submitted to the GOP for inclusion of the Lakhra Project in the Sixth Five-year Economic Development Plan.

The study team took a pragmatic approach in the design of the Lakhra Facility, emphasizing that this would be the first application in Pakistan of large-scale coal production and power generation technology. Only proven and reliable technology with extensive operating experience would be recommended for Lakhra. Designs that improved system reliability, maintainability, and operability were generally favored to those that reduced plant costs. Moreover, designs were selected to comply with the GOP's policy of encouraging domestic economic growth while minimizing foreign exchange commitments. Consequently, designs that allowed equipment manufacture in Pakistan were selected whenever possible and labor-intensive designs were generally favored to capital-intensive ones.

The following specific issues were addressed in this study:

1. Extent of coal reserves in the delineated area

2. Acceptability of coal quality

3. Type of mining methods

4. Beneficiation of Lakhra coal

5. Environmental protection

6. Power plant siting

7. Power plant design parameters

8. Minimum implementation schedule

9. Capital costs

10. Unit costs of delivered coal and busbar electricity

11. Comparison of power generation alternatives

12. Transfer of technology and training needs

The examination of each issue resulted in the findings described in Section 1.3 of this report.

1.3 DETAILED FINDINGS

1.3.1 Coal Reserves

As shown in Figure 1.1-1, the Lakhra Area is 45 km north northwest of Hyderabad (Pakistan's third largest city), 20 km west of the Indus River and 112 meters above the Indus flood plain. The area consists of flat-topped hills and is essentially barren except for a few shrubs and bushes but no trees. The population is sparse consisting mainly of nomads who graze their herds during the wet season.

The present estimate of proven, recoverable reserves based on field data reported by previous consultants* in the delineated area of the Lakhra coal field is 64.4 million metric tons. This estimate will be increased substantially if subsequent mining experience indicates that stripping ratios exceeding 1:15 can be justified. Increasing the maximum ratio to 1:20 will increase recoverable coals within the delineated area by 30 to 40 percent. The present estimates are therefore sufficient to support a coal production rate of 2 million metric tons per year for the scheduled 30-year life of the power generating station. A 300-MW unit, burning coal of the quality indicated in Section 1.3.2 would consume 1.4 million metric tons per year.

The prospects for finding further reserves of recoverable coal in areas adjacent to the delineated area are considered favorable. In particular, an extension of the western boundary of the delineated area, where stratigraphical conditions appear least disturbed and where mining conditions are most favorable, appears to offer good prospects that substantial additions to the present estimates will be proven. This could also eliminate the need for an underground mine, at least for the first 300-MW facility. It is, therefore, desirable that field drilling be undertaken as soon as possible because a finding of substantial additional reserves will have a major impact on the present plans for designing mining operations.

1.3.2 Coal Quality

An average analysis of coal in the delineated area, based on borehole analyses data reported by previous consultants*, follows:

	As-Received Basis
Moisture	25.0 percent by weight
Ash	19.3 percent
Volatile Matter	28.8 percent
Fixed Carbon	26.9 percent
	100 percent

*See "Feasibility Report for Lakhra Coal Mining Power Station," February, 1981; Japan International Cooperation Agency.

Total Sulfur	5.95 percent
Calorific Value (HHV)	15,890 KJ/Kg (6,830 Btu/lb)

ASTM standards rank this coal as Lignite A, bordering on Sub-bituminous C.

The quality parameters are subject to considerable variation both within and between the coal seams. Thus, total sulfur is reported to vary in the range 3.3 to 9.8 percent and contains a substantial proportion in pyritic form. Iron oxides, present in substantial quantity in the coal ash, vary from 17 to 71 percent. Other minerals present include varying quantities of gypsum, which is visible as intercalated bands in the coal seams.

The combined presence of high iron, and pyritic and inorganic sulfur contents raises problems relating to slagging and corrosion in steam generators, which will require special attention in boiler design.

The coal is readily subject to spontaneous combustion. This finding is based on the direct experience of private coal producers mining coal from the same seams in adjacent lease areas and by laboratory tests carried out by previous consultants. These observations confirm the well-known propensity of low rank coals to spontaneous combustion, which is usually enhanced by the presence of iron pyrites. This behavior of the coal in all aspects of mine design and operation, coal handling, and storage will require particular attention.

The study team and experts at SWEC met with several major U.S. boiler manufacturers to discuss problems associated with the quality of Lakhra coal. The conclusions from these discussions were that a Lakhra coal-fired steam generator could be designed and operated without experiencing abnormal outages if the following occurred: (1) representative samples of Lakhra coal were made available for detailed investigation, (2) boiler designs appropriate to the slagging corrosion and erosion propensities of the coal were employed and, (3) proper boiler operating and maintenance procedures were followed. The discussions emphasized the importance of obtaining representative samples so that these preliminary conclusions could be confirmed by additional data specifically oriented to the problems identified.

1.3.3 Mining Methods

A review of the available geological and geotechnical data confirmed that mining factors such as seam continuity, faulting, depth of cover, seam thicknesses, and interseam separations divided the delineated area into three blocks: one western block and one larger eastern block having stripping ratios favorable for surface mining; and a small central block suitable only for underground mining. Further investigation of mining methods applicable to the surface minable blocks indicated that truck and shovel or combination dragline with truck and shovel operations, were feasible. The strata are not suitable for mining by bucketwheel excavators. Cost, delivery schedules and job

creation are issues that favor the truck and shovel method at the present time.

Present underground mining plans are based on a combination of handloading and mechanized longwall operations employing retreating sequences. A principal factor controlling the design of an underground mine is the propensity to spontaneous combustion of the coal in situ. This requires the minimization of exposed faces and ribs of the coal seams in active and passive areas of the mine, and in abandoned and sealed areas. An additional factor is the need to maximize coal recoveries because of the limited reserve base available. These factors tend to favor longwall mining methods over pillar and stall operations.

1.3.4 Coal Beneficiation

A review of all the available data indicates that beneficiation of the coal by washing is not justified and that cleaning should be limited to the removal of visible rock dilution by hand-picking. Previous investigators* reported washability data determined by laboratory testing of ten borehole core samples taken from representative areas of the delineated area. It is recommended that further work be done. The washability data were obtained under conditions much more favorable than can be provided in practical operations. Even so, the results show that the coal is extremely difficult to wash by available commercial processes. Indicated yields are low and improvements in ash and sulfur contents are marginal for the resulting losses. Disposal of a refuse still containing substantial thermal values would also be a serious problem because of spontaneous combustion.

1.3.5 Environmental Protection

In the absence of Pakistan environmental protection criteria, the study team found that guidelines issued by the World Bank offered the most practicable environmental protection criteria available for the Lakhra Facility. The degree of protection was found to be consistent with Pakistan's level of economic development.

The highest uncontrolled 24-hour ambient air concentration of SO_2 produced by a 300-MW facility burning Lakhra coal containing 6 percent sulfur, as-received by the steam generator, was estimated to be 226 micrograms per cubic meter (ug/m^3). The corresponding maximum concentration of SO_2 allowed by the World Bank guidelines is 500 ug/m^3. Thus, flue gas desulfurization (FGD) is not required on the first 300-MW unit. The need for FGD on subsequent units should be assessed prior to the consideration of more units at Jamshoro.

Based on the particulate stack emission limit of 150 milligrams per cubic meter (mg/m^3) and the maximum 24-hour ambient air particulate concentration of 500 ug/m^3 specified by the World Bank Guidelines, the required removal efficiency for the electrostatic precipitator at the Lakhra power plant burning Lakhra coal containing 20 percent ash on an

*See "Feasibility Report for Lakhra Coal Mining Power Station," February, 1981; Japan International Cooperation Agency.

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as-received basis is 99.3 percent. This is a practical level to achieve with conventional equipment.

1.3.6 Power Plant Siting

Out of four sites examined by the previous investigators, Jamshoro is the preferred site (see Figure 1.1-1) for the power plant(s)*. Table 1.3-1 indicates the factors included in the site selection study and comparative capital and operating cost effects.

An evaporative heat rejection system employing mechanical draft cooling towers incurs a slightly lower lifetime cost and a significantly lower initial capital cost than the once-through system proposed by previous investigators.

A dedicated railway and unit train is the preferred mode for transporting coal from the mines at Lakhra to the Jamshoro site. The railway will be about 50 km long. The rolling stock consists of one diesel locomotive and approximately fifty 40-metric ton railcars manufactured in Pakistan. The possibility of converting from diesel to electric drive should be considered at an early stage of project implementation.

As long as cooling towers are used, sufficient space and cooling water are available at Jamshoro to support Lakhra coal-fired generation capacity expansion in excess of 2,000 MW.

1.3.7 Power Plant Design Parameters

The net capacity of the first coal-fired power plant at Jamshoro should be 300 MW. This size is compatible with WAPDA's system with a maximum system capacity of 3,225 MW (in early 1982) and a maximum unit capacity of 210 MW (Unit 3 at Guddu). The coal reserves in the delineated mine area appear to be sufficient to support 500 MW of Lakhra coal-fired generation capacity for 30 years. Moreover, the coal production potential of the Lakhra field is likely to be an order of magnitude higher than that for the delineated area. Thus, the prospect of adding two 300-MW units at Jamshoro appears favorable pending detailed geological investigations two determine the adequacy of the coal reserves.

Turbine throttle steam conditions at the maximum guaranteed load should be 12,515 kilopascals (kPa) (1,800 psig) and 538°C (1,000°F). These conditions are consistent with U.S. steam generator design practice for accommodating the expected slagging and corrosion characteristics of Lakhra coal. Moreover, these conditions are typical of the larger thermal units in WAPDA's current system. Thus, operating and maintenance personnel have sufficient experience to manage a power plant operating at these steam conditions.

Net station heat rate is estimated to be 11,510 kilojoules per kilowatt hour (kJ/kWh) (10,900 Btu/kWh) based on a wet bulb temperature of 27°C,

*The four sites are Lakhra (mine mouth), Khanot, Petaro, and Jamshoro.

a boiler efficiency of 82.3 percent, and an auxiliary power consumption of 10 percent of gross turbine-generator output.

Physical layout of the power plant will allow multiple duplication of the first 300-MW unit and the ability to retrofit FGD equipment.

1.3.8 Implementation Schedule

A 54-month implementation schedule is practical. The realization of this schedule is contingent upon the following:

- Present market conditions prevail for equipment supply.
- Technology transfer and training do not become critical paths.
- Pakistan institutional structure is organized to accommodate multifaceted project implementation.
- Financing of equipment and services does not become the critical path.

1.3.9 Capital Costs

The total capital cost of the 300-MW Lakhra Coal Facility excluding import duty, escalation, and interest during construction, expressed in millions of January 1983 dollars, is the following:

	Foreign Exchange	Local Currency	Total
300-MW Facility	260.8	218.2	479.0

Details of the capital costs estimates are provided in Tables 1.3-2 and 1.3-3. All costs were determined for a facility producing, handling, and burning the Lakhra coal specified in Section 1.3.2. To enhance the reliability of the estimate, manufacturers of major equipment were asked to quote a present day (January 1983) price for their equipment. These prices were compared with SWEC in-house cost data and modified as required to provide the most realistic estimate of an actual price quoted in a competitive bidding situation. The price of labor and material provided locally were estimated in rupees (Rs). All prices on foreign materials and labor were estimated in dollars. The exchange rate used was Rs.12.75 = one dollar. This cost estimate includes indirect costs, such as WAPDA and PMDC administrative costs, engineering services, housing and community related facilities for the mining and power plant labor forces, and infrastructural facilities such as telecommunications, water supply, and roads.

The savings in obtainable capital cost, expressed in millions of January 1983 dollars, with a second duplicate unit of identical design is:

	Foreign Exchange	Local Currency	Total
Savings on duplicate 300-MW facility	58.0	72.5	130.5

These estimated savings assume that a decision to install a second duplicate unit is made not later than 12 months after the project start date.

On the basis of two units, authorized sequentially, the capital cost of the two unit 600-MW facility is (in millions of January 1983 dollars):

	Foreign Exchange	Local Currency	Total
600-MW Facility	463.6	363.9	827.5

Import duty is charged by GOP at 40 percent of the delivered price of foreign equipment. Total capital expenditures including import duty increase and are shown as a column item in the summary of capital cost estimates shown in Table 1.3-4.

1.3.10 Unit Costs of Delivered Coal and Busbar Electricity

The cost of coal delivered to the 300-MW power plant in January 1983 dollars is estimated to be $34 per metric ton ($31/short ton). The busbar cost of electricity delivered to the WAPDA grid by a 300-MW power plant in January 1983 dollars is estimated to be 4.8¢/kWh. These cost estimates do not include escalation and interest during construction.

If a second 300-MW unit is constructed, the estimated cost of delivered coal will be reduced by approximately 10 percent, while the cost of electricity will be reduced by roughly 15 percent.

If import duty is levied on foreign equipment, the cost of coal for the first 300-MW facility increases by 7 percent and the cost of electricity rises by 15 percent.

1.3.11 Comparison of Power Generation Alternatives

The cost of generating electricity with Lakhra coal is 30 percent less expensive than that obtainable using imported oil at $28 per barrel. Although the generation costs using Lakhra coal or imported coal are comparable, use of imported coal will consume an additional $34 million dollars of foreign exchange each year of plant operation. Furthermore, generating electricity with the Lakhra coal would employ an additional 1,900 Pakistanis and initiate the development of a modern large-scale coal industry in Pakistan. Details of these costs are shown in Table 1.3-5.

1.3.12 Transfer of Technology and Training Needs

The transfer of technology begun during the cooperative study efforts should be continued and significantly expanded. The needs include the following:

1. Training of Pakistan personnel to acquire experience in the use of technologies to be applied in the Lakhra Coal Facility, especially those unfamiliar to them.

2. Organizational capabilities of Pakistan institutions to provide effective project management and reliable operations of the operating facilities.

TABLE 1.3-1

ECONOMIC COMPARISON OF POWER PLANT SITES

All costs are expressed in millions of January 1983 dollars. Escalation, interest during construction, and import duty are not included.

Evaluated Capital Costs	Alternative 1: Once-Through/ Jamshoro	Alternative 2: Cooling Tower/ Jamshoro	Alternative 3: Cooling Tower/ Minemouth	Alternative 4: Air-Cooled/ Minemouth
Condenser	3.0	3.0	3.0	25.3
Cooling Towers	NA	4.0	4.0	NA
Circulating Water Piping & Pumps	36.0	2.0	2.0	NA
Cooling Tower Makeup System	NA	13.0	67.0	NA
Railway & Cars	11.0	11.0	NA	NA
Transmission Line	NA	NA	6.3	6.3
Total Evaluated Capital Cost	50.0	33.0	82.3	31.6
Evaluated Lifetime Operating Costs				
Coal Transportation	3.0	3.0	NA	NA
Auxiliary Power Penalty	6.1	9.1	11.6	17.4
Back Pressure Penalty	Base	9.3	9.3	55.8
Total Evaluated Lifetime Operating Costs	9.1	21.4	20.9	73.2
Total Evaluated Lifetime Costs	59.1	54.4	103.2	104.8
Difference	4.7	Base	48.8	50.4

TABLE 1.3-2

CAPITAL COST ESTIMATE FOR 300-MW
COAL PRODUCTION FACILITY

All costs are expressed in thousands of January 1983 dollars. Escalation, interest during construction, and import duty are not included.

Item	Foreign Component	Local Component	Total
East Open Pit	16,339	21,656	37,995
West Open Pit	16,256	25,028	41,284
Underground Mine	7,630	13,661	21,291
Coal Prep./Handling	2,072	4,988	7,060
Surface Facilities	387	1,816	2,203
Railway and Cars	825	10,040	10,865
Colony	0	15,686	15,686
Engineering	12,500	2,196	14,696
Subtotal	56,009	95,071	151,080
Contingency	8,401	14,261	22,662
Total Capital Cost, 1/83	64,410	109,332	173,742

NOTE:

1. Equipment cost includes the cost of erection, spare parts, shipping, inland transport, and insurance.

TABLE 1.3-3

CAPITAL COST ESTIMATE FOR
FIRST 300-MW POWER PLANT

All costs are expressed in thousands of January 1983 dollars. Escalation, interest during construction, and import duty are not included.

Item	Foreign Component	Local Component	Total
Land and Site Prep.	0	455	455
Coal Handling	7,437	510	7,947
Ash Handling	10,269	660	10,929
Cooling System	6,356	9,660	16,016
Turbine and Aux.	26,754	715	27,469
Boiler and Aux.	60,817	3,160	63,977
Precipitator and Aux.	10,682	840	11,522
Chimney	323	2,553	2,876
Boiler and Turbine Bldg.	2,698	9,694	12,392
Yard and Civil Work	4,728	6,600	11,328
Office Bldg.	3,128	1,948	5,076
Spare Parts	6,690	60	6,750
Erection Charges	9,438	17,715	27,153
Supv./Maint. for 1 Yr.	300	200	500
Lease of Equipment	0	12,500	12,500
Colony	0	8,518	8,518
Subtotal	149,620	75,788	225,408
Engineering and Consult.	31,800	3,400	35,200
WAPDA Admin.	0	11,253	11,253
Contingencies	14,963	7,578	22,541
Forward Handlg. & Trans.	0	7,000	7,000
Insurance During Constr.	0	3,900	3,900
Total Capital Cost, 1/83	196,383	108,919	305,302

NOTE:

1. Estimate was itemized according to WAPDA format for PC-1 Report.

TABLE 1.3-4

SUMMARY OF CAPITAL COST ESTIMATES

Capital Cost Estimates Expressed in Millions of Dollars	Foreign Component	Local Component	Total Excluding Import Duty	Import Duty	Total Including Import Duty
o 300-MW (Net) Power Plant	196.4	108.9	305.3	61.5	366.8
o 300-MW Coal Production Facility	64.4	109.3	173.7	17.4	191.1
Total 300-MW Facility	260.8	218.2	479.0	78.9	557.9
o First 300-MW (Net) Power Plant	196.4	108.9	305.3	61.5	366.8
o Second 300-MW (Net) Power Plant	149.2	78.5	227.7	53.5	281.2
o 600-MW Coal Production Facility	118.0	176.5	294.5	26.2	320.7
Total 600-MW Facility	463.6	363.9	827.5	141.2	968.7
Capital Cost Estimates Expressed in Millions of Rupees					
o 300-MW (Net) Power Plant	2504.1	1388.5	3892.6	784.1	4676.7
o 300-MW Coal Production Facility	821.1	1393.6	2214.7	221.9	2436.6
Total 300-MW Facility	3325.2	2782.1	6107.3	1006.0	7113.3
o First 300-MW (Net) Power Plant	2504.1	1388.5	3892.6	784.1	4676.7
o Second 300-MW (Net) Power Plant	1902.3	1000.9	2903.2	682.1	3585.3
o 600-MW Coal Production Facility	1504.5	2250.4	3754.9	334.1	4089.0
Total 600-MW Facility	5910.9	4639.8	10550.7	1800.3	12351.0

NOTES:

1. Capital cost estimates include direct costs, indirect costs, and an allowance for indeterminate costs based on prices quoted for January 1983. Escalation and interest during construction are not included in these estimates. Exchange rate: Rs. 12.75 = 1.00 Dollar.

2. Coal production facilities include coal transportation facilities.

3. The 300-MW and 600-MW coal production facilities incorporate different designs. Thus, the total cost of each facility is provided separately.

4. The two 300-MW power plants employ identical designs. Thus, the incremental cost of the second 300-MW power plant is provided.

TABLE 1.3-5

ECONOMIC COMPARISON OF ALTERNATIVES

All costs are expressed in millions of January 1983 dollars. Import duty, interest during construction, and escalation are not included.

Costs	Lakhra Coal	Imported Oil	Imported Coal
1. Annual Fixed Capital Charges[1]			
Domestic	14.5	10.5	13.1
Foreign	20.8	15.0	18.7
Total:	35.3	25.5	31.8
2. Annual Fuel Cost[2,3]			
Domestic	38.4	0.0	0.0
Foreign	6.8	84.6	42.8
Total:	45.2	84.6	42.8
3. Annual Operation & Maintenance Cost			
Domestic	4.1	2.7	4.1
Foreign	4.0	2.7	4.0
Total:	8.1	5.4	8.1
4. Total Annual Generation Cost			
Domestic	57.0	13.2	17.2
Foreign	31.6	102.3	65.5
Total:	88.6	115.5	82.7
5. Unit Generation Cost[2]	4.8¢/kwH	6.3¢/kwH	4.5¢/kwH

NOTES:

1. Includes interest and sinking fund depreciation costs for a capital recovery period of 30 years. Annual interest rates used are 13 percent for domestic debt and 10 percent for foreign debt.

2. Based on the output from a 300 MW power plant, operated in 1983 at full load for 70 percent of the year (i.e., 6,132 hours per year).

3. The 1983 fuel prices used in this comparison are:

Lakhra Coal	$2.37/10^6$ kJ ($34/metric ton)
Imported Coal	$2.46/10^6$ kJ ($70/metric ton)
Imported Oil	$4.91/10^6$ kJ ($28/bbl)

1.4 CONCLUSIONS

1. The Lakhra Facility

The initial 300-MW Lakhra Coal Facility should consist of the following:

- A three-section mine within the delineated mine area in the Lakhra coal field; the east and west sections -- open pit mines; the central section -- underground;
- Surface coal preparation facilities;
- A colony for miners and mine support personnel;
- A new dedicated railway for coal transport about 35 km in length between Lakhra and Jamshoro;
- Coal receiving, storage and handling facilities and a 300-MW net capacity coal-fired, steam turbine power plant located at WAPDA's Jamshoro site;
- Electrical connection facilities to WAPDA's existing transmission network;
- An intake water system located at the Kotri Barrage on the Indus River and a makeup water line to the Jamshoro site of a size sufficient for evaporative cooling towers; and
- A colony at the Jamshoro site for plant construction and plant operation and maintenance personnel.

2. Technical Feasibility

The design, construction, and operation of the Lakhra Facility is technically feasible. Proven technologies and methods can be supplied in the mining, coal transport and power plant elements of the facility. Extensive experience exists in the application and use of these technologies and methods.

3. Economic Feasibility

The Lakhra Facility is economically competitive with other power generation alternatives for meeting Pakistan's growing requirements for electricity. Electricity generation costs would be significantly less with Lakhra coal than with imported oil and comparable to imported coal. Exploiting domestic Lakhra coal will save millions of dollars in foreign exchange each year, thousands of Pakistanis will be employed, and a modern coal industry will emerge.

4. Environmental Feasibility

The Lakhra project can be implemented so that its emissions will meet World Bank guidelines and have a minimum impact on the environment.

5. Institutional Organization

The institutional structure to efficiently support the implementation and operation of the Lakhra Facility does not currently exist in Pakistan. An institutional organization is required that has the authority to effectively manage the design, construction, and operation of the facility.

6. Implementation Schedule

A 54-month implementation schedule is practical to adopt. Thus, the Lakhra Facility can help satisfy Pakistan's urgent need for power generation capacity as early as 1988.

7. Technology Transfer

The implementation of the Lakhra coal project requires a substantial amount of large-scale, coal-based technology transfer and adaptation. New related industrial activities in Pakistan, having the potential for a significant impact on national economic growth, would soon follow.

8. Pakistan Coal Industry Growth and Modernization

The demonstration by the Lakhra Facility of large-scale coal field development and production, the building of a coal mining infrastructure, and the generation of a large-scale demand for domestic coal can lead to the following:

- Development of other Pakistan coal fields,
- The availability and use of lower cost coal for other energy applications, and
- Future expanded use of coal fuels for electricity generation.

Such a program provides a solid foundation that enables the nation to enlist the many resources and capabilities of its private sector.

9. Second 300-MW Unit

Cost considerations clearly support the construction of a second identical coal-fired unit at the Jamshoro site. The initial operation date of a second unit should be scheduled 1 to 3 years after the initial operation date of the first Lakhra unit pending the proof of sufficient coal reserves by additional geological investigations. Achievement of the associated cost savings requires a decision to install a second unit within 9 months of the project start date.

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1.5 RECOMMENDATIONS

The Water and Power Development Authority has recommended to the Government of Pakistan (GOP) that the Lakhra Coal Facility be included as a project in Pakistan's Sixth Five-year Economic Development Plan covering the period 1983-1988. The following recommendations are directed at the implementation of a project to design, construct, and commission the Lakhra Facility:

Institutional

1. Establish a Lakhra Project Implementation Organization* within the GOP. This organization should be responsible for the complete implementation and eventual operation of the Lakhra Facility. It should also be capable of planning, implementing, and overseeing the operation of all future coal-fired power generation projects in Pakistan.

2. Staff the Lakhra Project Implementation Organization with highly-qualified, experienced personnel. Specialized training for the staff should be defined and carried out according to individual needs and responsibilities. Provide appropriate professional and financial incentives to assure long-term commitments by the personnel being trained.

3. Review manpower development, training, and other technology transfer programs underway or planned in Pakistan to determine the extent to which these programs can be used to meet the training and technology transfer requirements of the Lakhra project. Take measures to ensure that Pakistan corporations in the private sector have the opportunity to participate in these human resource development and technology transfer programs. Consider the appropriate components of the USAID Energy Planning and Development Project as a source for this training need.

4. Begin at the earliest practical date the coordination of the Lakhra project with other activities at the Jamshoro site.

5. Provide supplementary support for the Lakhra Project Implementation Organization to enhance its capabilities in the specialized functions listed below:

   - Project management and planning
   - Engineering and design
   - Equipment procurement, inspection, expediting, and transportation
   - Construction management

* Commonly referred to as the "Coal Cell" within the GOP.

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- Acceptance testing and start-up
- Operations planning and management

Technical

The following technical activities need to be undertaken as soon as practical:

1. Obtain a representative large-scale coal sample from the Lakhra Field for analysis and use in the design of the Lakhra Steam Generator.

2. Conduct detailed geological investigations required to establish the final mine area and mine design.

3. Install environmental monitoring equipment at the Jamshoro site and collect data to acquire the baseline data needed to determine subsequent requirements for plant effluent control.

4. Survey route(s) for railway, road, water, and power lines to the Lakhra Mining Area.

5. Establish area contour lines and obtain preliminary soils data from the area of the Jamshoro site for use as input to foundation design and plant layout.

6. Develop equipment specifications for the steam generator, steam turbine, and electric shovels.

7. Prepare project and purchasing procedures and specifications to be used in procuring services and in purchasing the major equipment as quickly as practical.

8. Prepare schedule networks of all major project activities soon after project authorization and make the requirements for maintaining these schedules known to all management and approval authorities.

9. Decide within nine months after project start date whether a second 300-MW power plant will be included in the project, and plan the production capacity of the mine accordingly.

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SECTION 2

INTRODUCTION

2.1 BACKGROUND

Pakistan's growing demand for electricity is rapidly outpacing its electric generation capacity. This power short-fall is rapidly approaching serious, if not critical, proportions. Load shedding of up to 500 MW was required in 1981/82 and is expected to reach 1,000 MW by 1983/84. A primary reason lies in the uneven electric generation of installed hydroelectric capacity since rainfall and glacial melt are seasonal and the priority on water use is in irrigation. Shortages of natural gas for industry have lead to a national policy prohibiting further use of this resource for power generation. Fuel oil is an imported fuel with a large foreign exchange demand and one that could be the subject of future supply disruptions.

Hence, the use of indigenous coal resources is a primary option as a fuel for thermal electric power plants in Pakistan. Preliminary geological investigations of a 26-square kilometer section of the Lakhra Coal Field, located 45 kilometers northwest of Hyderabad (Figure 1.1-1), indicate that this section alone contains sufficient economically recoverable coal to fuel several hundred megawatts of electric power generation capacity. In addition to the Lakhra reserve, there are other coal deposits in Pakistan and efforts are currently underway, with support from the World Bank and others, to better define the extent, quality, and development prospects of Pakistan's coal resources.

Over the past 15 years, several studies have been conducted by the Government of Pakistan (GOP), with some assistance from foreign governments, to examine the technical feasibility and costs of generating electric power using Lakhra Coal. The results of these studies were not sufficiently conclusive to convince the GOP that a Lakhra coal mine supplying coal to a steam-electric power plant was a technically sound and economically attractive investment.

In response to a formal request from the GOP, the United States Agency for International Development (USAID) agreed to support a thorough reexamination of the technical feasibility and costs of such a project. USAID designed the study to be a collaborative effort of a U.S. contractor working with two Pakistan organizations, Pakistan's Water and Power Development Authority (WAPDA), and the Pakistan Mineral Development Corporation (PMDC). The intent was to involve these Pakistan organizations thoroughly in the examination of key technological and economic issues and the formulation of the study results. The participants would also be exposed to modern large-scale coal production and power generation technology currently being used in the U.S. and would gain first hand knowledge of the coal technology that can be applied in a Lakhra Coal Facility. In view of the potential national importance of such a project, USAID also arranged for senior GOP officials to review the results of this study. In this fashion, a well informed decision could be made on the advisability of implementing a Lakhra Coal Facility project.

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Study activities began in the fall of 1982. Stone & Webster Engineering Corporation (SWEC) was retained by USAID to provide expertise in coal mining, coal handling, and power generation technology. A joint WAPDA, PMDC, SWEC analytical team was formed in October 1982. Data collection and field visits in Pakistan followed immediately. Analytical activities in SWEC Boston headquarters were combined with visits to U.S. coal mines and power generation plants in December and January. Initial findings were reviewed with senior GOP and USAID officials in January 1983. These findings were sufficiently positive, so that WAPDA management decided to propose to the Pakistan Planning Commission that a Lakhra Coal Facility project be included in Pakistan's Sixth Five-Year Economic Development Plan. Accordingly, the study activities were extended through April 1983 in order to expand certain analyses, plan in more depth the project's implementation and provide technical and other support to the authorization of the project.

2.2 STUDY APPROACH

The ground rules established by USAID required that key officials from WAPDA and PMDC work with SWEC counterparts participating in every phase of the study. Following a three-week trip to Pakistan by SWEC mining and power engineers to gather data and refine the scope of the study, WAPDA's Director of Fuels and Efficiency, PMDC's Chief Mining Engineer and PMDC's Deputy Chief Geologist came to the U.S. and spent approximately two months participating in the analysis and preparation of the written report. Two weeks before the presentation of the draft report, WAPDA's Chief Engineer - Thermal, and Resident Engineer at Quetta's Power Station came to review and comment on the study before final preparation. In addition, the WAPDA officials visited several coal-fired power stations, while the PMDC officials visited numerous surface and underground mining operations.

The study team used the geological data developed by previous investigators to independently assess the quality and extent of the Lakhra Coal Reserve. No new field exploration or core drilling activities were to be conducted.

Following the study team's presentation of preliminary findings concerning a 300-MW facility to senior GOP officials and to USAID in January of 1983, SWEC was asked to develop planning and scheduling summary networks and cash expenditure schedules for both the 300-MW facility and a 600-MW facility incorporating two identical 300-MW power plants. In addition, the team was asked to assist WAPDA and PMDC in preparing in Pakistan the PC-1 Report to be submitted to the GOP for inclusion of the Lakhra Project in the Sixth Five-year Economic Development Plan.

The study team took a pragmatic approach in the design of the Lakhra Facility, emphasizing the fact that this would be the first application in Pakistan of large-scale coal production and power generation technology. Only proven and reliable technology with extensive operating experience would be recommended for Lakhra. Designs that improved system reliability, maintainability, and operability were generally favored to those that reduced plant costs. Moreover, designs were selected to comply with the Pakistan Government's policy of encouraging domestic economic growth while minimizing foreign exchange commitments. Consequently, designs which allowed equipment manufacture in Pakistan were selected whenever possible and labor-intensive designs were generally favored to capital-intensive ones.

The specific issues addressed in this study follow:

1. Extent of coal reserves in the delineated area

2. Acceptability of coal quality

3. Type of mining methods

4. Beneficiation of Lakhra Coal

5. Environmental protection

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6. Power plant siting

7. Power plant design parameters

8. Minimum implementation schedule

9. Capital costs

10. Unit costs of delivered coal and busbar electricity

11. Comparison of power generation alternatives

12. Transfer of technology and training needs

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2.3 DESCRIPTION OF LAKHRA AND JAMSHORO AREA

The Lakhra and Jamshoro area is shown on Figure 2.3-1. The preferred site for the power plant is 13 km (8.1 mi) northwest of Hyderabad and 3 km (1.9 mi) west of the Indus River. The coal mining area is 45 km (27.9 mi) north-northwest of Hyderabad and 20 km (12.4 mi) (12.4) west of the Indus. Hyderabad is on the east side of the Indus, 160 km (99.4 mi) east-northeast of Karachi. These cities are connected by a railway mainline and a good highway. Hyderabad is the third largest city in Pakistan and has a population of about 2 million. The Lakhra coal mine area is 112 m (367.4 ft) above the Indus flood plain and consists of low, flat-topped hills of Laki limestone with slopes and valleys of Ranikot formation and Basal Laki laterite. The area is barren with a few shrubs and bushes and no trees. The population is very sparse, consisting mainly of nomads who graze their herds during the brief wet season. The Jamshoro area, 10 m (32.8 ft) above the Indus flood plain, forms the east side of the Lakhra anticline and is covered with Laki limestone containing quantities of marlstone and shale. The small village of Bada is east of the proposed Jamshoro site but the nearest dense population center is south-southeast of the site at Hyderabad. The area west of Jamshoro is virtually unpopulated. The district of Hyderabad is the least active seismic region; the maximum seismic factor for buildings in the area is 1/20 g. The mean temperatures for Hyderabad range from 15 to 21°C (59 to 70°F) in December, January, and February, and from 21 to 32°C (70 to 90°F) in the remaining months. The mid-day temperatures are 4 to 9°C (39 to 48°F) above these mean temperatures. The maximum and minimum temperatures recorded in Hyderabad from 1961 to 1979 were 48°C (118°F) and minus 2.2°C (28°F).

The relative humidity ranges from 30 to 70 percent with rare highs and lows of 80 and 25 percent.

The wind is southwest in the summer and from the northern quadrant during the 3 winter months. Sandstorms occur in the summer and a maximum wind velocity of 27 m/s (60.4 mph) has been recorded.

The annual rainfall is 30.4 cm (12 in.) and occurs torrentially in a few days, mainly in June through August.

The Indus River flows north to south on the east side of the region and is largely untrained in this area, its location changing and depth varying considerably during the year. The two most reliable fixed locations for supplying water year round are the west bank at Jamshoro and the Kotri barrage vicinity.

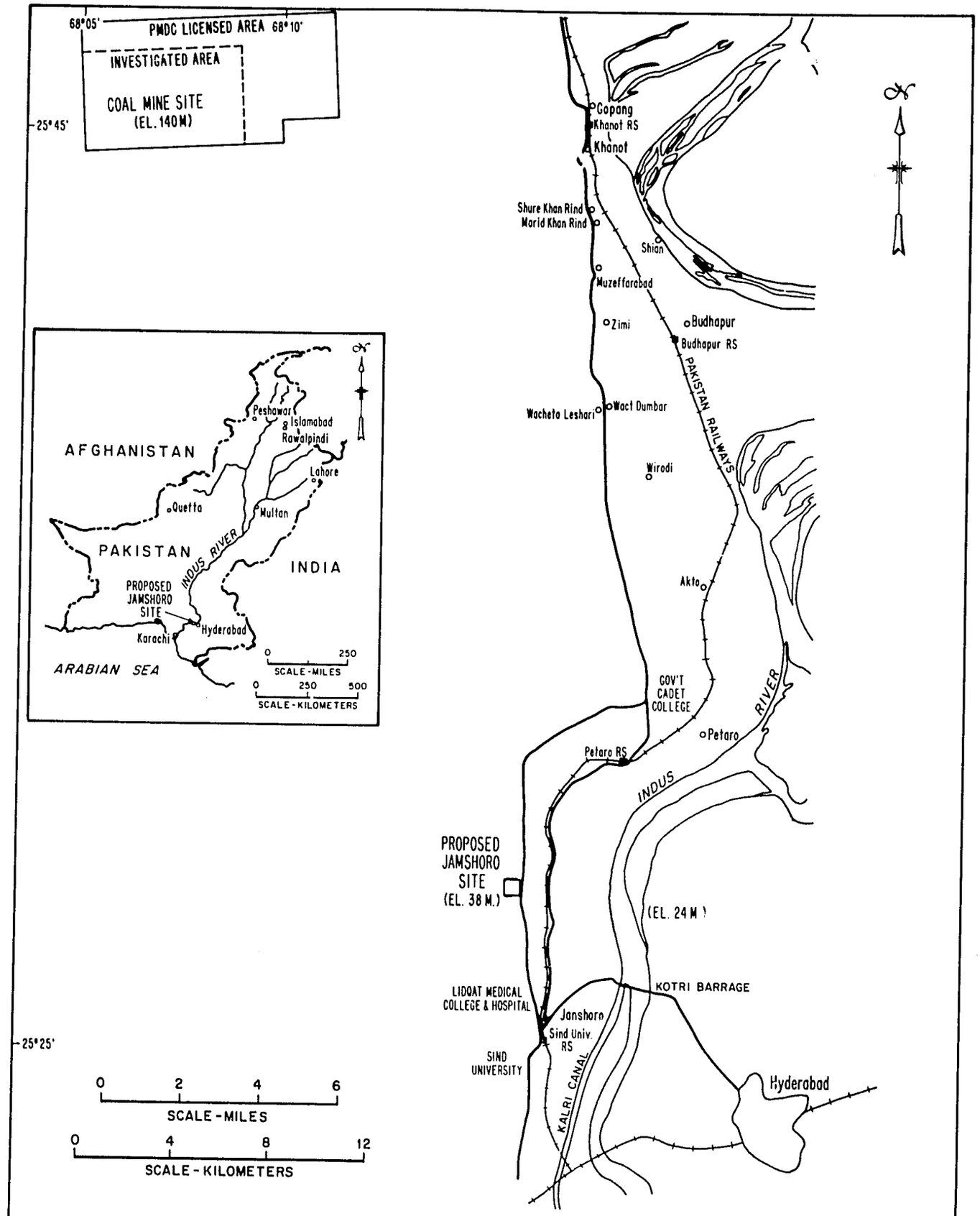

FIGURE 2.3-1
LAKHRA PROJECT-SITE LOCATION
LAKHRA COAL STUDY

2.4 HISTORY OF PREVIOUS STUDIES OF PRODUCTION AND UTILIZATION OF LAKHRA COAL

In 1855, Baluch nomads reportedly struck a 2.4-m (7.9 ft) seam of coal at a depth of 12.5 m (41.0 ft) while sinking a water well at Lakhra. During the 1940's and 1950's, the Burmah Oil Company and the Pak-Hunt International Oil Company encountered coal cuttings near the surface while drilling for oil at Lakhra. In 1960, Hunting Survey Corporation reported lignite seams up to 1.67 m (5.5 ft) thick at a depth of 19.5 m (64.0 ft) and recommended further exploration.

The Geological Survey of Pakistan, in collaboration with the United States Geological Survey, subjected the area to systematic geological investigation during the early 1960's; 34 sites were drilled and 10 coal seams were discovered. The Lailian is the most important of these because it is fairly persistent and has an average thickness of 1.1 m (3.6 ft). Although problems of seam correlation and the absence of an obvious base for stratigraphical correlation were encountered, this work resulted in theoretical reserves of 217,728,000 tonnes (240,001,570 tons) over an area of 207 km^2 (80 mi^2) of which 19,958,400 tonnes (22,000,144 tons) were considered proven. The investigation showed the coal to be a higher rank lignite with a high pyritic sulfur content in the range of 3 to 7 percent. Underground mining appeared economically feasible and further work was recommended to establish the feasibility of surface mining.

The West Pakistan Industrial Development Corporation (WPIDC) performed topographical and geological mapping, concentrating on a 155-km^2 (59.8-mi^2) area. They arranged industrial tests to be carried out by Lurgi Gesellschaft GmbH and the Japan Consulting Institute. These tests showed that the coal was generally unsuitable for hard coke production but was suitable for thermal power generation.

In 1966-1967, WPIDC engaged Biura Projektow Przemystu Weglowego Biuro Projecktow of Gliwice, Poland, to perform a mining and power station feasibility study. The study established that underground longwall operations could produce 907,200 tonnes (1,000,007 tons) per year to supply a 250-MW power station and recommended further exploratory drilling. The mining scheme was labor intensive, offering prospective employment for more than 1600 persons.

For some years after 1967, political factors and competition from other energy sources (hydroelectric, natural gas, and cheap imported oil) delayed further consideration of the Lakhra coal development. The oil supply crisis of 1973 and subsequent price escalation regenerated interest in the Lakhra resource. In 1974, at the request of WAPDA, the Canadian International Development Agency conducted a reconnaissance study of the Lakhra coal field and an associated thermal power station.

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In 1976, PMDC submitted a PC-1 scheme for a Lakhra Coal Mining Project while WAPDA submitted a PC-1 scheme for a 250-MW power station to use the Lakhra coal. In subsequent discussions with the Pakistan Government, it was decided to integrate the two schemes; a working committee was established and WAPDA was appointed the executive agency for the overall project.

In March 1978, a joint Japanese mission comprised of the International Cooperation and International Trade Institutes was requested to assign a team to undertake feasibility studies, and financial and technical assistance for mine and power plant development. The mission recommended a two-part program based on a review of the available data and reports:

1. Detailed exploration, including drilling, in the southwestern part of the block of PMDC licenses to determine geological and mining conditions and to confirm coal reserves reported by PMDC on the basis of an exploration program implemented during 1974 and 1976.

2. Feasibility studies for coal mining and the power plant if the exploration program proved coal reserves suitable for power generation.

The drilling program was performed in the second-half of 1979 and results reported by mid-1980; 50 holes were drilled to supplement the 22 holes drilled in earlier studies for WPIDC/PMDC. Detailed studies of the mine, power plant, and transportation systems were completed and reported by February 1981.

During 1982, the United States Government undertook to provide military, technical, and financial aid to Pakistan. Assistance in the overall energy development program under the auspices of USAID is an important part of this aid. The Lakhra Coal/Power Project is a component of this program.

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SECTION 3

TECHNOLOGY TRANSFER

3.1 TECHNOLOGY

A broad ranging technology transfer program should be implemented in conjunction with the Lakhra Coal Facility Project. Classroom training should be combined with on-the-job training. It should include cooperative programs with the engineer designers, equipment suppliers, operating power plants and coal mines, and in some cases, with specialty service suppliers. It needs to emcompass all project activities from project conceptualization through mine/plant acceptance and start-up and the ongoing mine/plant operations and maintenance. It needs to include both "headquarters" and "on-site" activities. The program should be designed to strengthen the capability of Pakistan's private sector to provide the Lakhra Facility with replacement equipment and supplies initially, and eventually coal, pending the development of its coal production facilities.

Measures should be taken to ensure that Pakistan participants in these technology transfer activities will be willing to make a long-term commitment to the project such that the investment in their education remains available to Pakistan throughout the project's duration.

The Lakhra project should be the centerpiece of this technology transfer program. However, a comprehensive program is of such breadth that it could overly burden the project. Therefore, training and other manpower development programs underway or planned in Pakistan or in USAID's generic programs need to be used to supplement those technology transfer activities of the Lakhra project.

The Lakhra Project and associated GOP programs should be designed to have maximum impact on:

- Modern project management and cost and schedule control methods
- Modern engineering design methods
- Quality assurance and inspection methods
- Modern mining engineering and mine operations
- Manpower training programs planning and execution
- Emission control technologies and impact assessment methods

- Systematic preparation of facility inspection, acceptance testing, initial operations, and on-going operations and maintenance

These technology transfer programs require implementation in cooperation with the engineering designer, major equipment suppliers, mine development manager, and the construction manager.

Owing to the ground rules initially established by USAID, the technology transfer program was begun when WAPDA and PMDC officials came to the United States to participate in the preparation of the study and visit several operating mines/power plants in the United States. A description of these site visits is provided in the following section.

3.2 SITE VISITS

3.2.1 Power Generation

The WAPDA power team consists of:

- Mr. Khawaja Daood
  Chief Engineer, Thermal Plant
  Team Leader

- Mr. G.M. Ilias
  Director, Fuel & Efficiency
  Team Member

- Mr. Fazal-ur-Rehman
  Team Member

Mr. G.M. Ilias arrived in Boston November 26, 1982; the other two members of the power team arrived January 2, 1983. The places visited by the group during their stay in the United States are described below.

Power Stations

1. Brayton Point Power Station

Brayton Point Power Station is near Boston, Massachusetts. Units 1 & 2 are 250 MW each and Unit 3 is 650 MW. All have been converted from oil to coal. The modifications included installation of rigid frame electrostatic precipitators (ESP) on all the units to comply with the particulate emission levels prescribed by the Commonwealth of Massachusetts. Unit 3, originally designed with a pressurized furnace, was converted to a balanced draft furnace by adding induced draft fans. This required some stiffening of the boiler to withstand the negative pressure. New coal feeding, coal handling, and ash disposal systems were installed. The sulfur content of the coal is low and the power station is old. Therefore, it falls outside the environmental protection law which requires a flue gas desulfurization (FGD) system.

2. North Valmy Power Station

North Valmy Power Station is in Nevada. Here, one 250-MW unit is operating and another 250-MW unit is under construction. The station utilizes coal from the State of Utah, transported by an 805-km (500-mi) unit train system. This power plant uses bag filters instead of precipitators to remove particulates. The sulfur content is low and no FGD system has been installed because the plant was built at a time when FGD was not mandatory.

3. Big Bend Power Station

Big Bend Power Station is in Tampa, Florida. It has three 450-MW units each using coal with 2 percent sulfur. All three units have ESPs for particulate removal but no FGD system. The fourth unit now under construction will be provided with an FGD system.

4. San Miguel Power Station

San Miguel Power Station is near San Antonio, Texas. It has a single 400-MW unit operating on a minemouth. The mine is owned and operated by the utility. The coal has sulfur ranging from 1.2 to 3 percent. An ESP for particulate removal and a limestone FGD system for sulfur dioxide removal are operating in the power plant.

5. Canal Power Station

Canal Power Station is on Cape Cod, south of Boston. It has a 588-MW unit operating on super-critical pressure, using a once-through drumless boiler, and another 602-MW unit operating on a 16,548-kPa (2400-psig) cycle with a drum-type boiler. Both boilers use furnace oil and are filtered with an ESP system. Westinghouse Reaction Turbines, which have a record of high efficiency and high availability, are used in both units.

Boiler Manufacturers

Discussions have been held with all the leading boiler manufacturers in the United States; i.e., Combustion Engineering, Babcock & Wilcox, and Foster & Wheeler. Well before each meeting, they were provided with the analysis of coal taken from representative samples given in the Japanese International Cooperation Agency Report. Each manufacturer suggested that the Lakhra Coal with high sulfur and high ash could be used for power generation provided a conservatively designed boiler is adopted. In other words, the furnace should be large enough to allow a low heat release rate in the furnace plane area, relatively higher excess air to suit the high iron content in the ash, a low flue gas velocity to avoid erosion, a low gas temperature at the furnace exit, and a relatively high temperature at the chimney exit.

Each of the three manufacturers strongly recommended steam conditions of 12,411 kPa/538°C (1800 psig/1000°F) [main steam]/538°C (1000°F) [reheat steam]. All believe that a conservative boiler design with these steam conditions would substantially reduce the chances of slagging, fouling, corrosion, and erosion on the fire side of the boilers. Moreover, this cycle will be easier for the WAPDA staff, who are familiar with identical temperatures and pressures at the gas-fired station of

Guddu, to handle. Each boiler manufacturer gave budgetary prices for the boiler units they proposed in the 300-MW range.

Turbine Manufacturers

The General Electric Facility located in Lynn, Massachusetts, was visited to see the latest turbine designs in the range of 300 to 600 MW and to get budgetary prices for a 300 MW unit.

Stone & Webster Engineering Corporation Specialists

Various SWEC specialists made presentations on the following subjects:

- Boiler design
- Electrostatic precipitators and bag houses
- Flue gas desulfurization equipment
- Coal and ash handling equipment
- Air cooled condensers
- Reaction versus impulse turbines
- Houston Power Plant model and model workshop
- SWEC's Reference Plant

3.2.2 Coal Production

Table 3.2-1 summarizes the visits and discussions of the mining members of the Pakistani power team.

TABLE 3.2-1

TECHNOLOGY TRANSFER

RECORDS OF VISITS AND MEETINGS

Date	Organization	Areas Studied and Discussed
12/1/82	Commercial Testing & Engineering Company	Various analysis techniques
		Various methods of sampling
		Role of sampling and analysis in exploration and development of mines
		Method of preparing slides for minerological studies and its importance
12/7/83	Powder River Basin and Bighorn	Overflew Powder River Basin to study the layout of the mines and surface arrangements.
	Wyodak Resources Development Corporation and Power Plant	Overburden drilling and stripping
		Coal recovery
		Coal haulage
		Overburden back filling
		Surface grading
		Interburden removal
		Minute study of machinery operation
		Discussions of maintenance schedules, especially preventive maintenance
		Discussion regarding use of various machinery combinations for varying conditions
		Discussions of procedures for land reclamation and the range survey

TABLE 3.2-1 (Cont)

Date	Organization	Areas Studied and Discussed
12/8/82	Belle Ayre Mines Black Thunder Mines and Cordero Mines	Quarry operations Important features for designing high walls and box cut Discussion regarding various patterns of drill holes, charging, and blasting, including the role of primer in various positions Examined the combinations of the various machines from economic point of view Use of gelitine in charging purpose
12/9/82	Deeker Coal Mines	Various quarry operations Use of machinery and efficiency Sampling procedure from run of mine on the order of 10,000 short tons per day (9070 tonnes)
12/14/82	San Miguel Lignite Mines & Power Plant	Operation of easy mine to take care of thin seams and small over and interburden Use of dragline
12/15/82	Utah International Navajo Mine	Discussions regarding explosive casting Dragline for stripping Large front-end loader for coal handling
12/16/82	Black Mesa and Kayenta Mines	Operations of dragline working in multiple seams Coal mined by shovel and front end loader Tour of special coal samping system

TABLE 3.2-1 (Cont)

Date	Organization	Areas Studied and Discussed
12/16/82	Black Mesa and Kayenta Mines (Cont)	Transportation of coal in the form of slurry up to 273 miles (440 Km) through pipes of 18 in. (46 cm) 12 in. (30 cm) diameter
12/20/82	Colorado School of Mines	Role of geostatistical studies in mineral exploration and development
		Discussion of various types of roof bolting, especially swellex bolts
		Visit to school labs for research on drilling compressive and shear strength of rocks and the behavior of rocks due to the varying environmental conditions
		Discussions on reserve calculations; polygon method of special interest
12/21/82	Snow Mass Coal Mines	Use of roof bolts and cable in stratified deposits
		Use of Dossco m/c for the expeditious operations of tunneling
		Use of wire mesh with regard to safety
		Use of cable to avoid the premature collapse of pillars
12/22/82	Porta Drills and Teton	Operations of various makes of Porta Drills (rotary type)
		Discussion regarding modern exploration equipment
		Execution mode of exploration projects in the United States and cost analysis

TABLE 3.2-1 (Cont)

Date	Organization	Areas Studied and Discussed
		Comparative cost of coring and noncoring holes
12/22/82	Porta Drills and Teton (Cont)	Use of geophysical studies to conduct operations economically and expeditiously
12/23/82	Geotechnical Studies Discussion with Mr. G. Briery	Factors to be considered for safe and economical workings during traveling operations including: Arch action Lining/ground interaction Failure criteria Behavior of the fault and location of the tunnel with regard to the fault
12/29/82	Discussion with Mr. G. Briery	Discussions of the use of principles above with regard to a weak roof and floor and the various remedies Use of resine bolts in weak strata
	Film on various makes of Dossco	Discussion of operations of the various makes of Dossco m/cs
12/30/82	Euclid Manufacturing Company (film show)	Operations of various mining machinery such as shovel, front end loader, stripper, dozers, and trucks of various capacities
	Commercial Testing & Equipment Company	Discussion regarding setting up a lab and costs of various lab equipment
1/4/83	Eastern Associated Coal Corporation Mine	Visited the face 500 ft (154 m) long with a seam thickness of 8 ft. (2.4 m). Dowty Shields were being used for support and caving was done in the goaf area

TABLE 3.2-1 (Cont)

Date	Organization	Areas Studied and Discussed
1/4/83	Eastern Associated Coal Corporation Mine (Cont)	Double drum type shearer was moving on conveyor through sprockets; i.e., Rack-a-track haulage
1/5/83	VEPCO - Laural Run Mining Company	Face length - 600 ft (183 m)
		Seam thickness - 8 ft (2.4 m)
		Dowty Shields
		Rack-a-track haulage
		Mavor shearer
1/6/83	Dowty Factory	Constructional and functional details of Dowty Shields
		Various tests the shields are subjected to before supply
		Conveyors and Constructional details

SECTION 4

ENVIRONMENTAL PROTECTION

4.1 SUMMARY

As a condition of project funding, the World Bank requires that a proposed facility demonstrate compliance with a series of emission/effluent guidelines and impact limits covering virtually all environmental media. These criteria were adopted by the Bank to ensure that the environmental impact of its projects is within reasonable limits. The Asian Development Bank (ADB) has adopted no such criteria, but urges project proponents to design their facilities in accordance with World Bank Guidelines. USAID specifies no emission-impact limits to projects it supports, but it requires that an assessment be performed to ensure that facility design incorporates reasonable environmental safeguards.

For the Lakhra Project, World Bank Guidelines apply to both the power generation and mining operation. Areas of particular concern include fugitive dust, stack emissions, onsite and offsite noise levels, restoration criteria for the mine area, liquid effluents, and solid waste disposal. Sections 4.5 and 4.6 describe these criteria and the relevant systems used to achieve compliance with the standards.

SWEC's analysis indicated that air pollution was the area of greatest potential environmental difficulty for the Lakhra plant principally with regard to the impact of the facility's stack emissions on ambient air quality. Major objectives were to determine whether the facility required use of a flue gas desulfurization system to achieve compliance with ambient sulfur dioxide limits, and to assess the degree of removal efficiency required for the electrostatic precipitator to achieve compliance with ambient particulate guidelines. An atmospheric dispersion simulation analysis was performed in order to assess the subject control requirements. The results of the analysis, which utilized a United States Environmental Protection Agency (EPA) screening model, are summarized in Table 4.1-1. This table also tabulates World Bank emission/ambient air quality guidelines and summarizes the results of the Japanese International Cooperation Agency (JICA) impact assessment which recommended use of a flue gas desulfurization system to remove 90 percent of the sulfur dioxide emission from 50 percent of the facility's flue gas stream.

SWEC's analysis indicated that a flue gas desulfurization system is not required to achieve compliance with World Bank ambient air quality guidelines. Further, a scrubber is not required if the JICA impact predictions are compared with the World Bank Guidelines. SWEC's analysis also indicates that an electrostatic precipitator with a 99.3 percent removal efficiency, which complies with the World Bank emission guideline for particulates, is adequate to comply with the bank's ambient standard. Section 4.6 provides details of the SWEC analysis.

TABLE 4.1-1

AIR QUALITY ANALYSIS SUMMARY

Pollutant	World Bank Guidelines: Site Categorization	World Bank Guidelines: Emission Standard (ug/m³)	World Bank Guidelines: Ambient Air Quality Standard 24-Hr (ug/m³)	World Bank Guidelines: Ambient Air Quality Standard Annual (ug/m³)	WAPDA/PMDC/SWEC: Emissions (mg/m³)	WAPDA/PMDC/SWEC: Highest Predicted 24-Hr Ambient Concentrations (ug/m³)	JICA: Highest Predicted 24-Hr Ambient Concentrations (ug/m³)
	POWER PLANT						
Particulates	Urban	100	500	100	Not applicable	Not applicable	Not available
	Rural	150	500	260	150	22.5	Not available
Sulfur Dioxide	Inside Plant Fence	Not applicable	1000	100	Not applicable	Not applicable	Not available
	Outside Plant Fence	Not applicable	500	100	Not applicable	226	Without FGD 377 With FGD 207
	MINE						
Particulates	Outside Mine Fence at Ground Level	Not applicable	260	75			

4.2 POLLUTION CONTROL IN DEVELOPING COUNTRIES

Economic growth in developing nations will require increased energy production for industrial facilities and transportation. Since the Arab oil embargo of 1973-1974 and the concommitant escalation in oil prices, more nations are turning towards alternative energy sources like coal or coal-derived fuels as their primary energy source. However, the increased use of coal will require appropriate environmental planning. Environmental controls in facility design must be integrated to mitigate unacceptable environmental impacts. Some potential, harmful impacts associated with increased coal use are disruption of traditional land uses (such as agricultural areas appropriated for mine development); high localized concentrations of air pollutants such as sulfur dioxide, dust, and nitrogen oxides; and cooling water impacts on fisheries.

The extent of control systems that a developing nation can afford is an important issue since public health, national economy, and worker safety must be considered. Pakistan cannot be expected to employ control programs analogous to those utilized in highly industrial countries. However, incorporation of a moderate degree of environmental protection as a design consideration in new industrial facilities would benefit emerging nations in the long-term.

Recognizing that the long-term cost of environmental cleanup outweighs the incremental cost of providing reasonable safeguards in new facility design, many emerging nations have created environmental planning agencies. The function of these groups is to create national environmental protection programs commensurate with local economic constraints. The following paragraphs summarize the status of the environmental planning and control activities for new industrial projects of India, Indonesia, and the Phillipines, with emphasis on coal mining and coal combustion. These countries which have developed environmental programs in response to industrialization pressures. While these programs are not necessarily models for other countries, they are examples of how other developing nations have begun to provide environmental safeguards for their industrialization.

India

USAID prepared an environmental profile for India (Draft Environmental Report on India, March 1980) which indicates that the country's environmental control program is very limited and decentralized. Principal environmental legislation appears to deal with natural resource management; e.g., forest and soil conservation and fisheries and wildlife management. The principal national authority, the National Committee on Environmental Planning (NCEP), a branch of the Department of Environment (DOE), functions primarily as a research group. It identifies broadly based environmental problems, such as human settlements, and develops recommendations for mitigation strategies "in the context of growth and distribution of population and economic development." No formal environmental assessment statute had been enacted at the time of this study; however, the government indicates that such analyses are performed "as a matter of policy" by either NCEP or DOE. Impact statements are requested for large (approximately 1000 MW) thermal power plants.

The Indian Standards Institute has published water quality standards which have served as the basis for establishment of effluent limits for industrial sources and sewer discharges. India does not appear to have adopted emission or ambient criteria for any other form of pollutant discharge.

In mid-1981, a volunteer group, the Centre for Science and Environment, formed in New Delhi to document the changing environment in India. Their report, State of India's Environment-1982; A Citizen's Report, is intended to be the first of a series of annual reports documenting the effects of pollution, soil erosion, deforestation, etc., on the Indian people. A summary of the report was published in the New Scientist, November 25, 1982. The report addressess all current aspects of India's environment including forest management, health, dam construction, habitat, atmosphere, water, and soil erosion. The document paints a very bleak picture of India's environment. Further, it indicates that the country's current institutional structure for pollution control is plagued by poor implementation of existing legislation, inadequate laws in most areas, and lack of an explicit national policy.

The Phillippines

According to a USAID Draft Environmental Report on the Phillippines (January 1980) the principal environmental problems this nation faces are deforestation and soil erosion, urban water and air pollution, and habitat loss. A series of Presidential Decrees in 1977 established a National Environmental Protection Council (NEPC) whose charter includes oversight of the environmental impact assessment (EIA) process for new industrial and government projects. NEPC also is required to identify project types and geographic regions which may be environmentally critical. Such projects, or projects sited in such regions, require an Environmental Compliance Certificate based on an EIA before they can proceed.

Additional decrees throughout the 1970s established new, or clarified the role of existing, government agencies to oversee protection of both renewable and nonrenewable natural resources. Decrees establishing a framework for development of air quality and air pollution emission standards, noise control standards, and water quality and effluent standards also were issued during this period. No emission/effluent limits or standards have been adopted.

Indonesia

As a matter of state policy, Indonesia's Ministry of Development, Supervision and the Environment, in concert with other ministries, is responsibile for ensuring that the environmental assessment process is part of project planning. However, according to the United Nations Regional Office for Asia and the Pacific in Bangkok, "the most significant EIAs completed in Indonesia have been for internationally funded water resource development projects and have benefited from the technical assistance of highly qualified expatriate and local environmental specialists". Comprehensive EIA guidelines have not been approved by the ministry. However, sectorial guidelines have been issued by other agencies, reflecting Indonesia's decentralized approach to industrial pollution control. Although the framework for a comprehensive control program

appears to be in place, the lack of adequate staff and the decentralization of authority severely limit the program's effectiveness.

Environmental goals, such as criteria for setting standards and policies on hazardous industrial by-products, have generally not been established in Indonesia. Even where guidelines exist, as in the areas of drinking water and ambient water quality, serious obstacles hinder their effectiveness. Problems are both procedural and technical in nature. For example, water quality standards were established without adequate attention to how the coupled effluent discharge limits were to be attained. Consequently, discharge limits generally have been ignored and water quality standards have not been achieved. An effort to revise these standards is underway and an industrial pollution control management plan has been proposed and is likely to be adopted. Refer to G.G. Grubbs, Indonesia's Industrial Pollution Control Program: Assessment and Working Agenda, July 1982. Concern for environmental protection currently is emerging at the highest levels of government in Indonesia.

4.3 CURRENT STATUS OF ENVIRONMENTAL REGULATION IN PAKISTAN

In Pakistan, no environmental standards have been established to protect the health of the people and to ensure clean air or water. The greatest pollution problems today are associated with vehicular exhaust, particularly in congested areas. Cement and scattered chemical plants also generate some pollution, but there are no arrangements to check the emission levels or ground level concentrations.

Recently, the Government of Pakistan created an Environmental Protection Division. The division circulated draft legislation for comments to agencies in the country which produce or utilize various sources of energy. This draft legislation requires careful scruntiny before it is passed.

Pakistan has stressed the substitution of oil for gas in existing power plants and industries and the use of indigenous coal to meet future power requirements. This has created a need to formalize the environmental protection regulations. Due to the high sulphur and ash content of Pakistani coal, steps should be taken to control air, ground, and water pollution. This report provides as many guidelines as possible to assist WAPDA and the Government of Pakistan in formulating their policies.

4.4 WORLD BANK AND UNITED STATES AGENCY FOR INTERNATIONAL DEVELOPMENT GUIDELINES

The ADB has advised the WAPDA/PMDC/SWEC Team that it does not require an environmental assessment or specify emission/effluent guidelines as criteria for project funding. However, the ADB recommends incorporation of World Bank emission/effluent guidelines into facility design to mitigate potential environmental impacts caused by the project.

One of the responsibilities of the World Bank Office of Environmental Affairs (OEA) is to evaluate the adequacy and effectiveness of pollution control measures taken by developers of industrial projects seeking World Bank funds. Both environmental effects and worker health and safety are considered. The OEA Environmental Guidelines (March 1981) provide an overview of specific pollutants and/or industries. They are intended to be flexible enough to allow site-specific application. The guidelines describe permissible pollutant levels but allow for deviations from these levels given appropriate rationalization.

No environmental guidelines have been developed specifically for steam electric generating plants although specific occupational health and safety guidelines exist. With regard to pollutant-based guidelines, usually one set of standards applies to all industries producing a given pollutant. Therefore, judgement must be used when applying the standards to a particular project. Finally, no numerical standards have been developed for many of the environmental considerations which are noted. Such factors will be incorporated into design and construction efforts and will result in some cost to the project. However, in general they represent small costs relative to total project cost and cannot be quantified at this early stage of project development.

The World Bank Environmental Guidelines were reviewed and the following sections were considered relevant to the project:

- Dust Emissions
- Effluents, Disposal of Industrial Wastes
- Effluents, Liquid, Land Disposal, and Treatment
- Electrostatic Precipitators
- Mining - Strip (Surface)
- Mining - Underground (Coal)
- Noise
- Secondary Environmental Effects
- Sulfur Dioxide Emissions - General Pollution by Sulfur Dioxide

After review, quantitative standards were applied as proposed in the guidelines or in modified form as discussed in Section 4.5. That section also discusses qualitative considerations briefly.

Funding for major industrial projects also can be sought from the USAID. Based on requirements of the Foreign Assistance Act, USAID established procedures to ensure the integration of environmental factors into the decision making process. These procedures (22CFR216) also are consistent with Executive Order 12114 and implement the requirements of the National Environmental Policy Act. It is important to note that these procedures are for USAID use and, therefore, not directly applicable to a developer. However, they do indicate the kind of environmental information USAID considers for activities which it finances.

No design criteria or performance standards are established by USAID procedures; thus, no facility costs are directly associated with such factors. It would appear advantageous, however, for a developer seeking USAID funding to incorporate environmental review and assessment into the facility planning, siting, and design process. Documenting these activities and the impact mitigation measures incorporated into facility design should assist USAID in its review and could enhance project acceptance. For the present project, no attempt has been made to interpret the impact of USAID procedures on facility design since environmental considerations have been integrated into project planning. This appears to meet the intent of the procedures. The proposed design of environmental controls are based on World Bank Guidelines, and will exceed USAID guidelines.

4.5 ENVIRONMENTAL CRITERIA

The scope of work of this study requires that a facility design be established incorporating any items, including environmental controls, which significantly impact overall project cost. The environmental control costs vary greatly, depending principally on the level of required control. Control levels are based on a combination of standard engineering practice and pertinent environmental standards or design criteria. Since the Government of Pakistan has not established environmental standards yet and since the project may be funded (in part) by the World Bank, World Bank emission/effluent and impact guidelines have been used to the extent possible to identify principal control items and their cost.

The following sections summarize the environmental standards or design criteria applied to the conceptual designs of the mine and power plant for the Lakhra/Jamshoro project. Where numerical standards other than the OEA's are used or where qualitative design criteria have been established, a rationale is provided to better define the criterion and its effect on facility cost.

4.5.1 Power Generation

Environmental guidelines for power plants cover all significant facility-environment interfaces. Potential impacts result from air emissions, liquid effluents, solid waste, noise, and secondary factors such as population influx, social service demands, and additional water consumption.

<u>Air Emissions</u>

Combustion of fossil fuels by stationary and mobile sources is the principal worldwide source of anthropogenic air pollution. Contaminants are formed by thermal oxidation of fuel impurities such as sulfur and nitrogen, and through incomplete combustion of the fuel source's carbonaceous matter. Other fuel impurities, such as trace metals, are also sources of atmospheric pollution. Emissions of particulate matter from coal-fired generating stations also result from handling the fuel and from erosion of the storage piles due to atmospheric turbulence.

Principal direct emissions from a thermal power station include sulfur and nitrogen oxides, and particulate matter. To mitigate the recognized effects of these contaminants on human health, vegetation, buildings, etc.; emissions generally are vented through a stack, so atmospheric dispersion dilutes the exhaust plume before it reaches ground level. Many stack contaminants are transformed chemically during dispersion. For example, secondary pollutants such as sulfates, nitrates, etc., are formed. These latter species affect health, vegetation, etc. They also are thought to play a significant role in the process of acidic deposition. The rates of emission are governed by emission and ambient standards. Emission standards apply to allowable concentrations at a source of the emission, e.g., stack, and ambient standards apply to the allowable concentrations of the pollutant at ground level. World Bank Guidelines have been established for only two pollutants; particulates and sulfur dioxide. The permissible pollutant levels are considered achievable at reasonable cost by readily available control procedures. The World Bank has suggested no criteria for

oxides of nitrogen emissions. Consequently, this study did not address NOx emissions and ground level impacts.

Dust (Particulates)

Table 4.5-1 presents ambient standards recommended by the World Bank for dust (particulates). These recommendations are based on the estimate that adverse human health effects begin when dust concentrations exceed 80 ug/m^3 annually. Adverse effects on materials and vegetation can begin at 60 ug/m^3 (annual basis).

Pollution controls such as ESPs are suggested to meet the guidelines. The requisite control efficiency of such a device is determined through an atmospheric dispersion modeling analysis to relate the facility's emissions to resultant ground level impacts. Table 4.5-1 indicates that these emissions are limited to 100 mg/m^3. However, a stack exit concentration of 150 mg/m^3 is acceptable if the plant is located in a rural area such as Jamshoro, where the dust concentration at ground level inside the plant fence meets World Bank Guidelines, and the maximum annual concentration outside the plant is less than 260 ug/m^3. The latter was selected as the design basis.

Sulfur Dioxide

World Bank Guidelines limit the sulfur dioxide ambient air quality impact for new plants (Table 4.5-1). Compliance with these limits also is determined through an atmospheric dispersion modeling analysis.

The height of the facility's stack is included in the inputs to the dispersion modeling analysis. EPA regulations require that this height should correspond to Good Engineering Practice (GEP), defined by Section 123 of the Clean Air Act Amendments of 1977 as, "The height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." This definition identifies the minimum stack height at which significant adverse aerodynamic effects are avoided. This criterion was adopted to establish the minimum height of the stack.

Requisite sulfur dioxide emission reductions can be achieved by application of control techniques such as flue gas desulfurization and coal washing. Increasing stack height raises the pollutant discharge point, which reduces ground level concentrations.

Liquid Effluents

Using coal for electricity generation will produce waste water associated with the disposal of ash and other solid wastes. Waste waters vary in quantity, quality, and the amount of treatment required for either reuse or discharge.

The World Bank effluent criteria along with United States standards were reviewed in order to generate the project specific standards shown in Table 4.5-2. These standards represent limits which, in SWEC's judgement,

provide reasonable protection of ground, surface, and drinking water supplies in the project area.

In each case, these effluents can be collected and treated by a variety of available methods to achieve the stated limits.

In addition to chemical characteristics of liquid effluents, waste heat generated by the operation of various water-cooled equipment also must be considered. The general World Bank guidelines will be adopted conditionally. These guidelines state that the temperature of the diluted effluent should not be more than 3°C (37°F) higher than that of the receiving waters except within a mixing zone defined on a case-by-case basis. However, if the receiving water temperatures are determined to be 28°C (82°F) or less, the guideline allows the diluted effluent temperature to be a maximum of 5°C (41°F) above that of the receiving waters except within a mixing zone, also defined on a case-by-case basis. This guideline appears to apply to use of water from the Indus River. An alternative procedure is offered in the guidelines whereby a maximum allowable stream temperature is calculated from the optimum and lethal temperatures for potentially affected species. However, absence of any authentic data on presently occurring species in the Indus River and their thermal tolerances precludes the use of this option.

The guidelines include no provision for a mixing zone. In countries with established stringent thermal effluent standards, the allowable mixing zone is most frequently specified as a maximum allowable surface isotherm. The acceptance of a proposed mixing zone size is based on the scientific judgement of aquatic ecologists taking into consideration the thermal tolerance for local species of aquatic life.

Solid Waste

Solid wastes which will be produced from the combustion of coal include furnace bottom, economizer hopper and fly ash, and a small amount of raw water and waste water treatment sludges consisting primarily of chemical precipitants. Assuming an ash distribution of 70 percent fly ash and 30 percent furnace bottom ash, the estimated annual ash production of the plant is 173,000 metric tons (191,000 tons) per year of fly ash and 74,500 metric tons (82,000 short tons) per year of bottom and economizer ash when 1.3 million metric tons (1.4 million tons) of coal are burned per year. These wastes require proper disposal so as not to contaminate nearby water courses, groundwater, and the air.

The design and operation of the landfill should minimize environmental effects. In general, a landfill (or ash deposit yard) will be located above the 100-year flood plain, if possible, and constructed so that run on of rain water from uncontaminated areas cannot occur. The active areas of the landfill should be minimized to reduce the amount of contaminated run off. Temporarily and permanently finished areas of the landfill should be covered with soil suitable for growth of vegetation both to minimize contaminated runoff and fugitive dust emissions. Run off from active portions should be collected via ditches in a runoff collection pond sized for at least a 10-year, 24-hour storm event. Run off should be treated for suspended solids and pH, if required, before it is discharged. The

landfill may require a clay liner or an alternative liner depending on the quality and location of groundwater.

Noise

Acoustical criteria are recommended to minimize annoyance to people living in the area (property line sound level) and to minimize employee hearing loss (occupational noise exposure). These criteria were developed based on the World Bank Guidelines, the engineering feasibility of meeting the criteria, and the occupational noise exposure criteria of the United States and European countries.

Property Line

A criterion of L_{dn} = 55 dBA is recommended for the nearest residential area in accordance with the World Bank Guidelines. The L_{eq} is the energy average, A-weighted sound level with a 10 dB weighting applied to the night time levels. This is equivalent to a constant (24-hour) sound level of L_{eq} = 49 dBA. This level will protect against outdoor speech interference and will minimize, although not necessarily eliminate, annoyance. Since the uncontrolled sound level from a coal-fired plant could be 65 dBA at 300 m (984 ft) either a considerable distance between the plant and residential property line (which can be determined through noise propagation models) or exterior noise controls will be necessary to achieve the L_{eq} 49 dBA criterion.

Occupational Exposure

An occupational noise exposure criteria goal of 85 dBA with a maximum level of 90 dBA is recommended to minimize potential loss of employee hearing. This level represents a compromise between the World Bank recommendation of L_{eq} = 75 dBA for an 8-hour work day, which protects employees from all hearing loss, and the engineering feasibility of achieving these levels. The sound levels in power plants are typically 90-100 dBA without noise mitigation. These levels can be reduced to 85-90 dBA with a moderate amount of noise control engineering.

Many European countries use the 85 dBA criteria level. Although the United States Occupational Safety and Health Administration standard allows continuous exposure to 90 dBA for an 8-hour period, the 85 dBA criteria offers significantly better protection.

The costs of noise control engineering are expected to be approximately 1 percent of the cost of the plant.

Secondary Effects

The influx of construction and operating personnel and the presence of the power plant will result in significantly higher demands on local services such as water supply, power, hospitals, police, and food supply. Planning should take place early in project development to anticipate and provide for these new demands. The actual means of mitigating potential impacts will depend on local standards. In general, urban areas tend to be less affected by these new demands than rural, undeveloped regions.

4.5.2 Coal Production

Environmental guidelines for strip mines (open pit) deal primarily with sediments and erosion control. Noise, dust, and secondary effects also should be considered. For underground mines; dust, mine drainage, solid waste, and secondary effects can require control. Similar factors are relevant to coal preparation plants, if steps are taken to wash or treat coal before it is used in a boiler.

Air Emissions

Dust generated by construction and operation of the mine contributes to ambient levels of suspended particulates and other constituents associated with the dust. The World Bank cites EPA guidelines for avoiding effects of dust (260 ug/m^3 maximum 24-hour concentration, no more than once a year), and suggests ambient guidelines of 100 ug/m^3 measures as an annual geometric mean and 500 ug/m^3 as a maximum 24-hour concentration.

The impact of emissions from coal preparation plants should be limited to 75 ug/m^3 (annual geometric mean) and 260 ug/m^3 (24-hour maximum) outside the mine fence at ground level. No guideline is given for dust in the underground mine, but dust suppression by conventional methods (water sprays) is anticipated. Similarly, conventional, relatively inexpensive methods will be implemented to control fugitive dust from the coal transfer operation and the coal preparation plant. These methods include partial or full enclosure of the conveyors, water sprays, baghouses, or other dust collection devices. The Guidelines suggest monitoring dust concentrations, but monitoring, other than to ensure worker safety, is probably not warranted for the mine site, given its remote location and the sparse population at Lakhra.

Liquid Effluents

The World Bank has established effluent quality limitations for both surface and underground mines. Table 4.5-3 presents these limitations for the quality of run off and drainage from surface mining operations.

Monitoring of these effluents, is not anticipated, other than for use in defining operating procedures, since effluents should be limited in quantity and readily treatable to achieve guideline values.

Acid mine drainage for underground mines and coal preparation plant effluents are subject to similar limitations (Table 4.5-4).

Solid Waste

Overburden initially removed from surface mines or the tunnels of underground mines and refuse from coal preparation plants represents a volume of material to be stored or permanently disposed of on land near the mine site. The potential for leachate and surface run off should be considered and care taken to avoid pollution of surface or groundwater. Placement and design of the disposal area provide opportunities to mitigate potential impacts. Surface drainage should be treated, if required, according to liquid effluent guidelines.

Noise

Given the nature of the proposed mine site, noise considerations primarily relate to occupational noise exposure. Residential exposure will become a consideration only if a colony is established for workers close to the mine boundary. Based on the assumption that residences will not be located close to the mine, the criteria recommended for the plant (i.e., the goal of 85 dBA for worker exposure) are recommended for the colony also.

Reclamation

In many developed countries, the disturbed area is normally restored to a condition at least approaching the premining state. This is particularly significant where the land is prime agricultural property. In that case, the extent of the reclamation effort should be sufficient to permit agricultural use after mining.

According to World Bank Guidelines, reclamation should include restoration of basic contours and should be performed within 3 years of mining. In the case of Lakhra, additional requirements for restoration of disturbed land would be very limited as the area is practically a desert and presently unproductive. Should a decision be made to create a productive, post-mining land use, water resource projects would be necessary. Other steps could also be taken to retain soils, enhance the nutrient content, and grow crops or other forms of vegetation. Depending on the area reclaimed, the extent and type of water resource project, and the selected land use, such as program can be costly.

Secondary Impacts

Consideration of secondary impacts involves identification of existing socioeconomic conditions, identification of infrastructure requirements for the anticipated residents and planning for accomodating workers and their families with minimal disruption to the local villages. In remote areas without a significant socioeconomic infrastructure, the existing villages can be overwhelmed by the influx of workers, their families, and associated personnel. Basic housing and service needs are immediate and evolve over the project life. Planning, based on the local standards as well as laborer expectations, is a prerequisite for satisfactorily dealing with the many potential concerns. With a work force of the size anticipated for the mine (2000-5000), a new village as large as or larger than existing villages in the vicinity, will have to be established. In setting up a new village, the opportunity exists to totally plan for the new population's needs and thereby mitigate many impacts to the region. Such planning should start well in advance of the actual development activity and should consider the needs of other existing population as well as those who will be relocating into the area.

TABLE 4.5-1

WORLD BANK AIR POLLUTION GUIDELINE STANDARDS

Pollutant	Source	Stack Emission Standard (mg/m^3)	Ambient Air Quality Standards 24 Hr (ug/m^3)	Annual (ug/m^3)
Dust (particulates)	Stack	100	500	100
	Outside Plant Fence	150	500	260
Sulfur Dioxide	Inside Plant Fence	-	1000	100
	Outside Plant Fence	-	500	100
Dust	Coal Preparation Plant (outside mine fence) at ground level)	-	260	75

TABLE 4.5-2

RECOMMENDED EFFLUENT LIMITS: POWER GENERATION

Rainfall runoff from the coal pile and the solid waste disposal area:	
Total Suspended Solids (mg/l)	50
pH	6-9
Equipment leaks, demineralizer regenerations, system blowdowns (boiler and bottom ash), and floor drainage:	
Total Suspended Solids (mg/l)	30 avg 100 max
pH	6-9
Oil and Grease (mg/l)	20
Equipment cleaning wastes (air preheater, boiler, chemical cleaning, etc):	
Total Suspended Solids (mg/l)	30 avg 100 max
pH	6-9
Total Iron (mg/l)	1.0
Total Copper (mg/l)	1.0

TABLE 4.5-3

RECOMMENDED EFFLUENT LIMITS: SURFACE MINING OPERATIONS

Total Suspended Solids (mg/l)	30-100
pH	6-9
Total Iron (mg/l)	4-7
Alkalinity	Greater than the acidity
Soluble Toxicants	None

TABLE 4.5-4

RECOMMENDED EFFLUENT LIMITS: UNDERGROUND MINING OPERATIONS/COAL PREPARATION PLANT

Total Suspended Solids (mg/l)	70
pH	6-9
Total Iron (mg/l)	4
Total Magnesium (mg/l)	4

4.6 RECOMMENDED AIR POLLUTION CONTROL

As discussed in Section 4.4, the World Bank established guidelines regarding air pollution emissions and air quality impact for projects supported by its funds. A preliminary, conservative atmospheric dispersion screening analysis was performed as part of this study to provide an estimate of the control requirements necessary to comply with these guidelines. The specific objective of the analysis was to determine the necessary controls, if any, to preclude adverse ambient particulate and sulfur dioxide impacts from the power plant stack. A detailed discussion of this analysis follows.

Particulates

Since the proposed plant is to be located in a rural area, the emission limit of 150 mg/m^3 was used. Therefore, an analysis was performed to determine whether this rate is adequate to achieve compliance with the allowable ambient particulate concentrations given in Table 4.6-1. The EPA screening model PTPLU was executed with hypothetical meteorological data to estimate maximum 1-hour particulate concentrations in the vicinity of the project site. An EPA factor of 0.4 was applied to the 1-hour concentrations to estimate 24-hour values. For the purpose of this analysis, the background concentration of particulate matter was assumed to be close to zero because the site is rural with very little industry and other sources of pollution in the vicinity. The dust particles existing naturally in the area, whose concentrations vary widely during dust storms, have been ignored in the calculations.

The PTPLU modeling analysis indicated that the highest ground level particulate concentration associated with the 150 mg/m^3 emission limit would be 22.5 ug/m^3 (24-hour average), which is well below the World Bank allowable ground level concentration limit of 500 ug/m^3 (outside the plant boundaries).

Sulfur Dioxide

The World Bank Guidelines specify ambient standards for sulfur dioxide; there is no emission rate requirement. Uncontrolled sulfur dioxide emissions are estimated to be 31 kg/kcal (17.3 $lb/10^6$ Btu) based on an average sulfur concentration in the Lakhra coal of 5.88 percent. This rate was used as input to PTPLU to estimate highest 1-hour sulfur dioxide impact from the plant in the project area. The EPA factor of 0.4 was applied to these predictions to estimate 24-hour concentrations. The analysis excludes consideration of the variability of sulfur in coal. A zero sulfur dioxide background was assumed in the analysis, again due to the relatively undeveloped nature of the site.

PTPLU was used to determine the locations and magnitudes of maximum sulfur dioxide concentrations for each atmospheric stability class. Hence, the analysis must assume persistence of a given stability throughout a 24-hour period and, according to current EPA guidelines, must use the highest predicted concentration to calculate worst case concentrations. Modeling of specialized meteorological conditions, such as the summertime monsoon and nocturnal inversions, is not possible with PTPLU because of changes in stability during a 24-hour period cannot be considered.

Thus, as shown in Table 4.6-1, stability Class A at a hypothetical wind speed of 0.61 m/s (1.37 mph) suggests a maximum 24-hour ground level concentration of 2462 ug/m^3. If this condition occurred, a stack gas cleanup system with an 80 percent removal efficiency would be required to achieve compliance with the World Bank 500 ug/m^3 guideline. However, persistence of stability Class A, the most unstable mixing class of the atmosphere would probably occur for no more than 8-10 hours per day. Thus, a more representative stability class, the so-called neutral condition (D), was selected as the basis for estimating worst case 24-hour impacts. The results of this analysis for wind speed conditions of 3.11 m/s (6.96 mph) and 6.22 m/s (14 mph), (Table 4.6-1) are well below the World Bank's ambient guideline. Therefore, based on this preliminary screening analysis, no sulfur removal systems are required for the Lakhra facility.

The study performed for WAPDA by JICA recommended use of a flue gas desulfurization system with a 90 percent removal efficiency to treat 50 percent of the flue gas. The maximum ground level concentration in this analysis was predicted to be 377 ug/m^3 slightly above the United States ambient 24-hour standard of 365 ug/m^3, but well below the World Bank Guideline of 500 ug/m^3. The results of the JICA analysis are shown in Table 4.6-2. The atmospheric stability class actually used was not provided in the JICA report; however, SWEC believes the study also was performed for the D stability case.

JICA design parameters also were input to the PTPLU dispersion model to determine whether any difference in impact predictions would be achieved using this more current EPA atmospheric dispersion modeling procedure than that employed by JICA. The maximum predicted concentration for the facility using the PTPLU model with the Japanese design parameters, is 155 ug/m^3 (Table 4.6-2). Again this is considerably lower than the Japanese estimate of 377 ug/m^3. Differences in the dispersion model predictions are likely due to the more current assumptions with regard to atmospheric dispersion techniques incorporated in the EPA model.

Therefore, at this time, no flue gas desulfurization system should be included in the current project cost estimate. However, space should be allowed for such a system pending a more comprehensive dispersion modeling analysis and field measurement program. A scrubber would be required if the 3-hour United States ambient air quality standard was to be used as the design basis. The ramifications of operating a future flue gas desulfurization system also should be considered in the design/layout/specification of the waste water treatment and ash handling systems and the waste disposal area.

Ambient Monitoring System

The limited atmospheric dispersion modeling analysis performed by SWEC, concluded that a single 300 MW facility at Jamshoro would have a maximum 24-hour sulfur dioxide impact of 226 ug/m^3 compared with the World Bank's 500 ug/m^3 Guideline. This concentration estimate was based on assumed meteorological conditions, since onsight data were not available at the time of the analysis. Similarily, the analysis did not consider sulfur-in-fuel variability. Based on SWEC analysis, including consideration of the limitations of the PTPLU algorithms, it was concluded that a decision on the use of a flue gas desulfurization (FGD) system could, and should, be

deferred until: (1) an onsite meteorological data collection system is deployed, and (2) a more comprehensive atmospheric dispersion analysis is performed. Space was therefore left for an FGD system in the facility layout.

Should a second 300 MW unit, identical to that analyzed in SWEC's study be constructed at Jamshoro, predicted 24-hour sulfur dioxide concentrations will approximately double, to approximately 90 percent of the World Bank's Guideline. Given the limitations of the analysis procedures, it is SWEC's judgement that an FGD system would probably be required in this case. However, the required removal efficiency for the system, and engineering considerations of whether it should be applied only to Unit 2 or to the combined emissions from Unit 1 and 2, can only be resolved once the onsite meteorological data collection program has been implemented. If the station is ultimately expanded to 1200 MW, an FGD system will be required to comply with the World Banks Guidelines; however, the requisite removal efficiency, etc, must similarily be determined through use of the onsite meteorological information.

The study team therefore, recommends that an ambient monitoring system be established to determine current background air quality levels at the plant site. This baseline would be used for post-construction operation determination of the actual impact of the facility. The recommended network would consist of two to four fully equipped ambient monitoring stations capable of continuous measurement of sulfur dioxide, particulate matter, and oxides of nitrogen at predetermined places. A single fully instrumented meteorological station also should be established at the site to obtain site specific data for use in future impact analyses. A particulate and meterological network also should be installed at the mine site.

TABLE 4.6-1

UNCONTROLLED SULFUR DIOXIDE AMBIENT IMPACT CONCENTRATION
(PTPLU/SWEC)

Stability	Wind Speed (m/s)	(ft/sec)	24-Hr Concentration (ug/m^3)	Distance (km)	(miles)
A	0.61	2.00	2462	1.68	1.04
D	3.11	10.20	205	29.94	18.59
D	6.22	20.40	226	17.51	10.87

TABLE 4.6-2

JICA DESIGN PARAMETERS: AIR QUALITY IMPACT ANALYSES

JICA

Stability	Wind Speed (m/s)	(ft/sec)	24-Hr Concentration (ug/m^3)	Distance (km)	(miles)
--	3	9.8	210	29.6	18.4
--	6	19.7	377	13.9	8.6

PTPLU/SWEC

D	3	9.8	80.4	47.08	29.24
D	6	19.7	131.1	22.85	14.19
D	15.01	49.24	155.0	11.24	6.98

SECTION 5

COAL PRODUCTION

5.1 INTRODUCTION

The discussion of coal production requires consideration of coal reserves; coal quality; physical and geological characteristics of the coalfield; appropriate mining methods; coal beneficiation and handling; transportation; and the costs and economics associated with these activities.

Since coal mining and preparation inevitably impact the environment, it is necessary to consider how these activities must be conducted to mitigate or control the effects on the environment within some framework of statutory or recommended standards. In the present study, there are no statutory regulations governing the mining of coal at Lakhra by surface or underground operations, or the handling and preparation of coal in surface facilities. Therefore, these activities have been planned within, and in accordance with, environmental standards specified by the World Bank and described in Section 4.4. The costs associated with these procedures are integral to the coal production costs.

The present study consists of a review of data collected and methods of coal production proposed by earlier investigations. There has been no fieldwork, apart from a brief site visit, and no possibility of obtaining additional data relating to the Lakhra Coal Field by further field investigations in the study period. The study, therefore, employs such data as is available from WAPDA and PMDC as of October-December 1982, and with minor additions, is essentially that obtained in the February 1981 Japan International Cooperation Agency (JICA) Report. Where alternative methods are proposed, they are based on the same data, which have been critically reviewed.

The remainder of this section discusses coal production, preparation, and transportation.

5.2 COAL RESERVES

The present area of investigation shown in Figures 5.2-1 and 5.2-2 consists of leases held by PMDC extending over 26 km^2 [approximately 6 x 4.3 km] lying at the center of the Lakhra Coal Field, which extends over about 480 km^2 [approximately 40 x 12 km]. Section 2.1 describes the Lakhra area.

Within the 26 km^2 (10mi^2) lease area, a total of 84 drillholes provided the present data on reserves. Of these, 34 holes were drilled prior to 1979 by the Pakistan Geological Survey assisted by the United States Geological Survey and by WAPDC/PMDC. The remaining 50 holes were drilled in 1979/1980 during investigations by the JICA who also completed a topographical survey of the lease area and its environs.

The detailed results of this survey, including the drilling and testing program, are presented in the JICA Report and need not be restated here. The methodology of the survey and field drilling program has been studied and it is concluded that the work was carried out competently and in accordance with standard industry practices. Drill cores were transported to Japan for detailed laboratory investigations of coal analysis, washability, grindability, etc., and for rock mechanical testing. The remaining cores are stored at the Geological Department of the University of Hyderabad, where they were inspected by members of the SWEC team. A few cores in an area of suspected bad roof conditions, in the vicinity of borehole JS39, were returned to the United States for further visual examination.

The limited field investigations were supplemented by visits to private underground mines in the Lakhra Coal Field located south and west of the PMDC lease area. These visits enabled team members to observe associated topographical, stratigraphical, seam structure, and underground mining conditions in the general area. Some channel seam samples, including associated rock dilution, were taken and returned to the USA for testing, and analysis. The results are reported in Exhibit I.

The coal seams investigated in the earlier studies occur in the Upper and Lower Beds of the Lower Ranikot Formation. The main seams of importance and interest in the present study occur in the Upper Coal Bearing Beds, which contain a maximum of 11 seams or rider seams in 5 coal zones. In the JICA report these are referred to as Numbers 1 to 5 in ascending order; i.e., No. 1 being the deepest zone. No further reference will be made to coal zones L1, L2, and L3 of the Lower Coal Bearing Beds.

Calculations of the theoretical reserves in the JICA report were based on the following assumptions:

- Surface mining methods would recover coal down to seam thicknesses of 0.5 m.

- Underground methods would recover coal down to seam thicknesses of 0.75 m.

The determination of whether seams were categorized as surface minable or underground mineable was based on technico-economic mining factors, which, for general cases, cannot be stated with precision. The general criteria

used was the stripping ratio, defined as the number of cubic meters of rock overburden which must be removed in order to recover 1 metric ton of coal. For multiple seam mining, the ratio is calculated from total seam thicknesses and overburden plus interseam burden thicknesses.

The economic factors depend on a complex assessment of the nature of overburden, amount of blasting required, stripping machines and methods employed, overburden haul distances, reclamation methods, etc, and the relative quality and utilization of the coal produced. In a given resource area, stripping ratios exceeding 1:4 may be viewed unfavorably for low rank coals. In other areas, stripping ratios as high as 1:30 may be viewed favorably for valuable low-volatile, low sulfur coking coal.

Since the Lakhra Coal Field is currently Pakistan's largest coal resource, the stripping ratio has an important bearing on project economics. In earlier studies, it was assumed that the economic cutoff point for surface mining would occur at average stripping ratios exceeding 1:15.

Therefore, an analysis of the drilling data was made for stripping ratios as follows:

Up to 1:12
1:12 to 1:15
1:15 to 1:20

The maximum average stripping ratio considered for calculations was 1:15 for surface minable reserves. Ratios exceeding 1:20 were categorized as minable only underground. Reserves in the range 1:15 to 1:20 fell into the intermediate zone for resolution in the light of later mining experience. This approach is rational and provides the basis for the estimation of coal reserves for strip mining summarized in Table 5.2-1.

The table shows that theoretical reserves for surface mining total a little over 100 million metric tons of which 63,425,000 metric tons are available at stripping ratios less than 1:15.

In the case of underground mining, the technico-economic limits of seam mineability are set with seam thickness as the prime factor. Scarcity and economic worth of the coal are treated as secondary factors. Seam thickness sets severe physical limits on machines, equipment, and corresponding mining methods, so that a generally recognized limit is a minimum thickness of 0.75 m.

Table 5.2-2 summarizes theoretical coal reserves within the PMDC lease area that are potentially recoverable by underground mining, using a minimum seam thickness of 0.5 m as the cut-off point. Reserves total 29,800,000 metric tons, of which 29,522,000 are in seams exceeding 0.75 m in thickness.

Since the criteria for surface mineable and underground mineable seams are not mutually exclusive, there is some overlap in the total tonnages shown in Tables 5.2-1 and 5.2-2. Coal recovery is better in surface mining. Surface mining should be given priority because it can often be employed where poor roof or floor conditions exist or where the presence of multiple seams severely limits underground mining methods.

On this basis, employing a maximum average stripping ratio of 1:15 and a minimum seam thickness of 0.75 m for underground mining, the combined analysis of Tables 5.2-1 and 5.2-2 results in the following estimates of theoretical reserves:

By Surface Mining	65,498,000	metric tons
By Underground Mining	14,284,000	metric tons
Total	79,782,000	metric tons

Recoverable reserves are estimated from theoretical reserves after applying factors to allow for uncertainty in the geological data and the recovery efficiency of the mining methods employed. The geological safety factor is a function of adequacy and accuracy of borehole data and is considered to be high for the present investigation. The JICA Report employs a factor of 0.90 and this appears reasonable in the circumstances. However, certain areas were excluded when boundaries for the reserve calculations within the overall lease data were determined, although borehole data indicate the presense of coal seams in these areas. These calculations apparently were based on two assumptions: that the seams are too deep for surface mining, and that floor or roof conditions, principally loose sandstone in the roofs of the seams, render underground mining too risky and difficult. These assumptions are believed to be over-cautious. The calculations of reserves may be modified by actual mining experience. The coal excluded from the calculation may be easily mineable by hybrid methods. Augering and punch mining are examples of hybrid methods that can supplement conventional mining practices so coal can be produced economically. If these previously excluded areas are included in the reserve base, the theoretical reserves increase by at least 10 percent.

Surface mining methods are proposed in Section 5.8. Operating experience demonstrates that such methods can recover coal seams down to at least 0.2 m thickness even in the case of multiple seam and bench working. The mining recoverability factor for surface mining is, therefore, predicted to be 0.90, substantially higher than the 0.70 factor indicated in earlier studies. Underground mining methods are proposed in Section 5.9. An overall recovery factor of 0.65 for underground mining which employs longwall operations with barrier pillar recovery by pillar splitting during final retreat operations is somewhat conservative. On this basis, recoverability factors are:

Surface Mining	0.90 x 0.90 = 0.81
Underground Mining	0.90 x 0.65 = 0.585

Recoverable reserves are:

By Surface Mining	53,053,000	metric tons
By Underground Mining	8,356,000	metric tons
By Hybrid Methods	3,000,000	metric tons
Total	64,409,000	metric tons

The adjusted reserves and recovery factors are sufficient to support a production rate of 2 million metric tons per year for the 30-year conventional life of a power generating station.

These recoverable reserves will be increased further if mine operating experience indicates that stripping ratios exceeding 1:15 can be economically justified. Increasing the ratio to 1:20 will increase recoverable reserves by 30 to 40 percent.

TABLE 5.2.-1

RUN-OF-MINE COAL RESERVES FOR OPEN CUT MINING
(Metric Tons)

Specific Gravity 1.5

Strip Ratio	Description		West	Central	East	Total
1:10 and less (West)	Area	$10^3 m^2$	1,744			1,744
	Average Total Thickness	m	6.30			6.30
	Theoretical Reserves	$10^3 t$	16,487			16,487
	Recovery Percentage	%	72			72
	Recoverable Reserves	$10^3 t$	11,871			11,871
	Bank Overburden Volume	$10^3 m^3$	119,358			119,358
	Average Strip Ratio		7.23			7.23
1:12 and less (East)	Area	$10^3 m^2$			3,103	3,103
	Average Total Thickness	m			4.54	4.54
	Theoretical Reserves	$10^3 t$			21,139	21,139
	Recovery Percentage	%			72	72
	Recoverable Reserves	$10^3 t$			15,220	15,220
	Bank Overburden Volume	$10^3 m^3$			221,916	221,916
	Average Strip Ratio				10.50	10.50
1:10 to 1:15 (West)	Area	$10^3 m^2$	609		3,714	4,323
	Average Total Thickness	m	5.10		3.79	3.98
	Theoretical Reserves	$10^3 t$	4,660		21,139	25,799
	Recovery Percentage	%	72		72	72
1:12 to 1:15 (East)	Recoverabel Reserves	$10^3 t$	3,355		16,713	20,068
	Bank Overburden Volume	$10^3 m^3$	54,831		298,007	352,838
	Average Strip Ratio		11.77		14.10	13.68
1:17 and less (Central)	Area	$10^3 m^2$		1,874		1,874
	Average Total Thickness	m		4.27		4.27
	Theoretical Reserves	$10^3 t$		11,990		11,990
	Recovery Percentage	%		72		72
	Recoverable Reserves	$10^3 t$		8,633		8,633
	Bank Overburden Volume	$10^3 m^3$		174,509		114,509
	Average Strip Ratio			14.55		14.55
1:17 to 1:20 (Central)	Area	$10^3 m^2$		1,111	3,039	4,150
	Average Total Thickness	m		3.76	3.63	3.66
	Theoretical Reserves	$10^3 t$		6,270	16,536	22,806
	Recovery Percentage	%		72	72	72
1:15 to 1:20 (East)	Recoverable Reserves	$10^3 t$		4,514	11,906	16,420
	Bank Overburden Volume	$10^3 m^3$		111,745	273,804	385,549
	Average Strip Ratio			17.82	16.56	16.50

Specific Gravity 1.5

Strip Ratio	Description		West	Central	East	Total
Total	Area	$10^3 m^2$	2,353	2,985	9,856	15,194
	Average Total Thickness	m	5.99	4.08	4.12	4.40
	Teoretical Reserves	$10^3 t$	21,147	18,260	60,887	100,294
	Recovery Percentage	%	72	72	72	72
	Recoverable Reserves	$10^3 t$	15,226	13,147	43,839	72,212
	Bank Overburden Volume	$10^3 m^3$	174,189	286,254	793,727	1,254,170
	Average Strip Ratio		8.24	15.67	13.04	12.50

SOURCE:

JICA Report, February 1981

TABLE 5.2-2

RUN-OF-MINE RESERVES FOR UNDERGROUND MINING
(Metric Tons)

Specific Gravity 1.45

Lease Area	Description		Workable Thickness (meters) 3.5 to 3.0	3.0 to 2.54	2.5 to 2.0	2.0 to 1.5	1.5 to 1.0	1.0 to 0.75	0.75 to 0.5	Total
Central										
No. 1 & No. 2	Area	($10^3 m^2$)	120	499	1,128	1,803	922	112	70	4,654
	Average Workable Thickness	(m)	3.18	2.70	2.22	1.76	1.37	0.88	0.63	1.89
	Theoretical Reserves	($10^3 t$)	554	1,956	3,623	4,595	1,830	143	64	12,765
	Recovery Percentage	(%)	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)	252	890	1,648	2,091	833	65	29	5,808
No. 3	Area	($10^3 m^2$)					318	815	140	1,273
	Average Workable Thickness	(m)					1.11	0.91	0.67	0.93
	Theoretical Reserves	($10^3 t$)					510	1,073	135	1,718
	Recovery Percentage	(%)					45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)					232	488	61	781
Total	Area	($10^3 m^2$)	120	499	1,128	1,803	1,240	927	210	5,927
	Average Workable Thickness	(m)	3.18	2.70	2.22	1.76	1.30	0.90	0.65	1.69
	Theoretical Reserves	($10^3 t$)	554	1,956	3,623	4,595	2,340	1,216	199	14,483
	Recovery Percentage	(%)	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)	252	890	1,648	2,091	1,065	553	90	6,589
East										
No. 1 & No. 2	Area	($10^3 m^2$)		70	354	1,088	1,621	166	22	3321
	Average Workable Thickness	(m)		2.63	2.21	1.71	1.32	0.93	0.66	1.54
	Theoretical Reserves	($10^3 t$)		267	1,134	2,691	3,095	223	21	7,431
	Recovery Percentage	(%)		45.5	45.5	45.5	45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)		121	516	1,225	1,408	102	10	3,382
No. 3	Area	($10^3 m^2$)		278	888	1,373	185	110	65	2,899
	Average Workable Thickness	(m)		2.65	2.22	1.71	1.31	0.91	0.63	1.88
	Theoretical Reserves	($10^3 t$)		1,067	2,858	3,407	351	145	59	7,887
	Recovery Percentage	(%)		45.5	45.5	45.5	45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)		485	1,300	1,550	160	66	27	3,588
Total	Area	($10^3 m^2$)		348	1,242	2,461	1,806	276	87	6,220
	Average Workable Thickness	(m)		2.64	2.22	1.71	1.32	0.92	0.63	1.70
	Theoretical Reserves	($10^3 t$)		1,334	3,992	6,098	3,446	368	80	15,318
	Recovery Percentage	(%)		45.5	45.5	45.5	45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)		606	1,816	2,775	1,668	168	37	6,970

Specific Gravity 1.45

Lease Area	Description		Workable Thickness (meters) 3.5 to 3.0	3.0 to 2.54	2.5 to 2.0	2.0 to 1.5	1.5 to 1.0	1.0 to 0.75	0.75 to 0.5	Total
Grand Total	Area	($10^3 m^2$)	120	847	2,370	4,264	3,046	1,203	297	12,147
	Average Workable Thickness	(m)	3.18	2.68	2.22	1.73	1.31	0.91	0.65	1.69
	Theoretical Reserves	($10^3 t$)	554	3,290	7,615	10,693	5,786	1,584	279	29,801
	Recovery Percentage	(%)	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
	Recoverable Reserves	($10^3 t$)	252	1,496	3,463	4,866	2,633	721	127	13,559

SOURCE:

JICA Report, February 1981

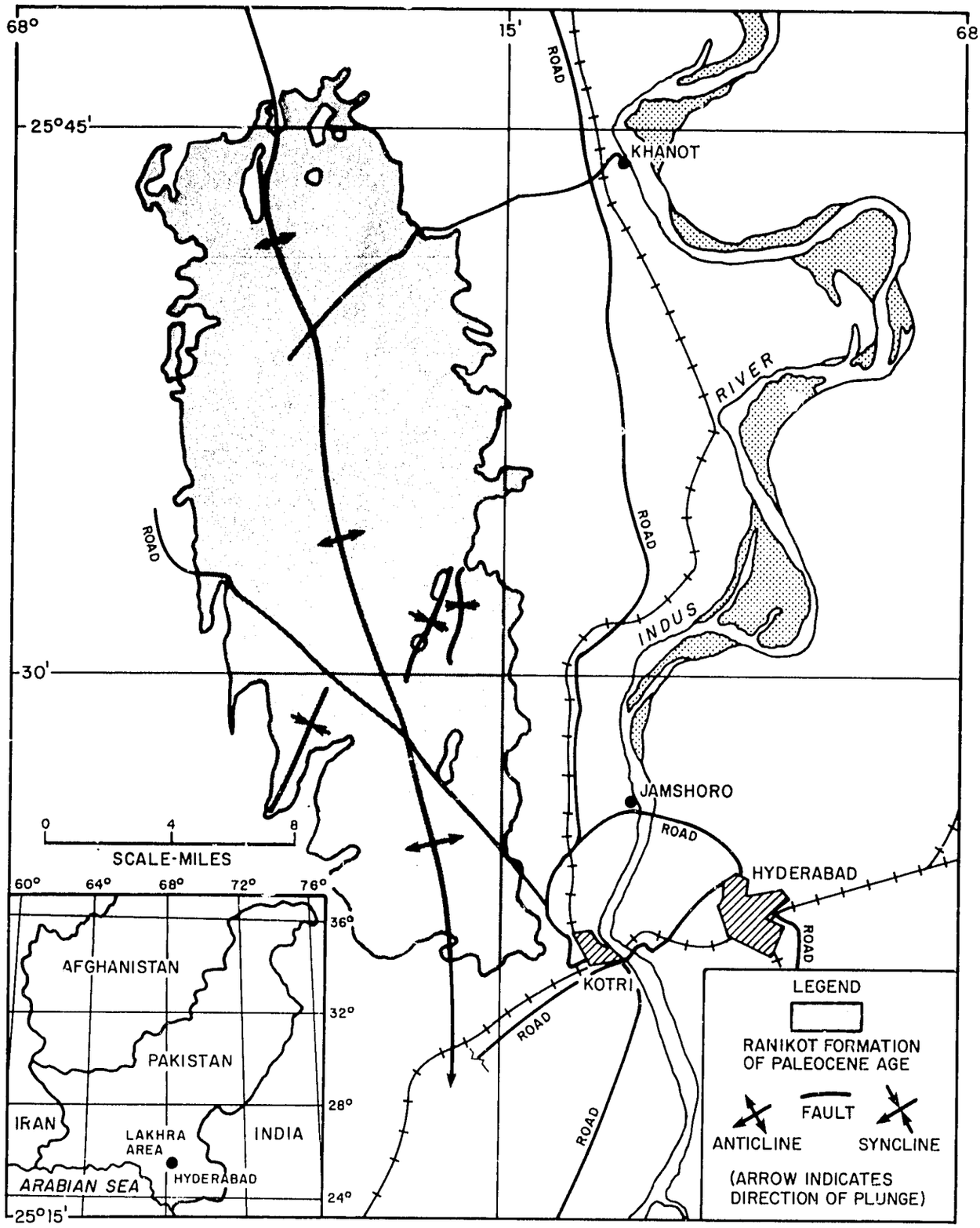

FIGURE 5.2-1
REGIONAL LOCATION MAP
LAKHRA AREA

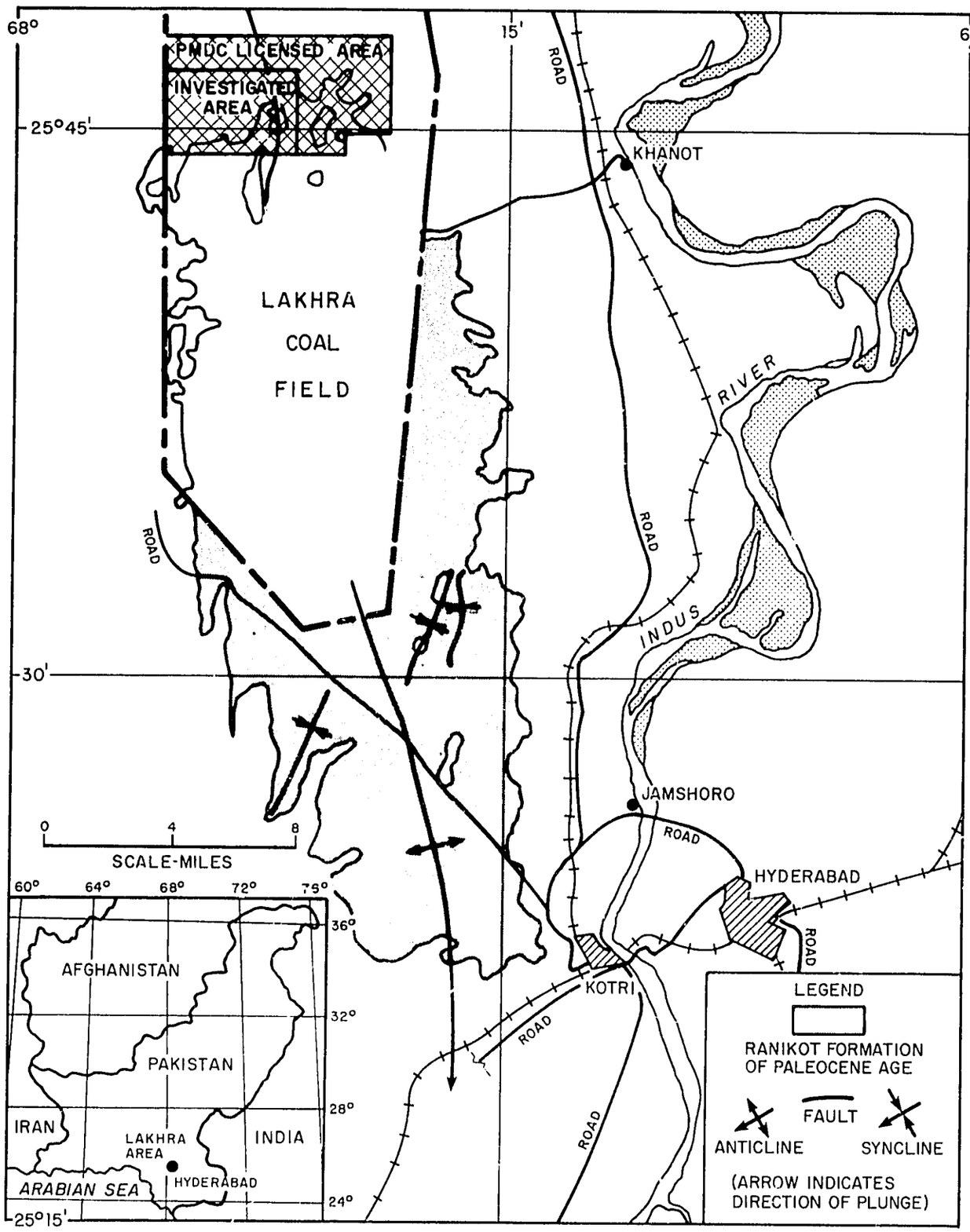

FIGURE 5.2-2
WAPDA/PMDC PROJECT AREA
LAKHRA AREA

5.3 MINING GEOLOGY

The geological features of the PMDC lease area have been described fully in earlier reports by PMDC and JICA. The present study has not indicated the need for any major changes in the earlier interpretations. The coal seams of interest occur in the Upper Coal Bearing Beds of the Lower Ranikot Formation and are consistent with the gently anticlinal nature of the Lakhra Coal Field; i.e., in the north-south direction. The coal seams investigated in the western part of the PMDC lease area are virtually horizontal. Eleven seams form five distinct coal zones. All the zones from No 1 to No 5 show well developed coal seams in the western part of the investigated area. However, in the eastern part, zones No 4 and No 5 are poorly developed and No 1 and No 2 tend to merge.

The main geological factors governing the mining of the deposit are:

- Faulting
- Depth of overburden
- Strata conditions above and below seams
- Vertical seam separations
- Continuity and thickness of seams.

Certain areas in the north of the investigated area and an identifiable area in the southwestern part have no coal or only poorly developed seams. The main coal occurrences therefore fall into a small western area and a larger eastern area. Two major faults, referred to as A and B1 in the previous studies, trend northwest and further serve to divide the investigated area. Fault A further demarcates the western area, marking the eastern edge of the southwest barren area. Fault B1 and a subsidiary fault, B2, split the eastern part. Hence, the coal bearing area is divided naturally into three blocks which have been termed the west, central, and eastern in the JICA report (Figure 5.3-1). The minimum and maximum depth of coal seams in the blocks are as follows:

Block	Depth of Seam Minimum m	Depth of Seam Maximum m
Western	32	75
Central	60	126
Eastern	43	107

The overburden stripping ratios are such that the western block is surface mineable; the central block, particularly in its southern part, is suitable only for underground mining; and the eastern block is an intermediate zone in which both surface and deep mining; methods may be applicable. But this is further complicated by the fact that strata east of Fault B1/B2 indicates loose sand in the sandstone joining the roof of Numbers 1, 2, and 3 coal zones. Hence, there may be zones in which the stripping ratios are too high for economic surface mining but in which roof conditions are too bad for underground mining. This problem can be addressed in the light of mining experience as mining operations move toward these zones. Unconventional mining methods may be required in order to produce the recoverable coal.

The coal reserves in these three blocks have already been discussed in the previous section and in Tables 5.2-1 and 5.2-2.

Rock mechanical properties of the overburden and inter-seam partings, obtained during the earlier investigations, are summarized in Table 5.3-1.

Observations made during visits to underground mines in areas adjoining the investigated area are as follows.

Roof Rock

Mudstone roof was soft and difficult to hold in some areas. Practical experience indicates that any form of blasting will have an adverse effect on roof control.

Bottom Rock

While soft, it nevertheless appeared capable of holding roof pressures acting on the faceline. Careful attention will have to be paid to grading operations at the face in order to control the mining horizon.

Stability

Faceline conditions will be determined by mode of operation, which must be designed to maintain the best possible roof conditions if good working conditions and constant production rates are to be obtained. Faceline roof collapse zones must be kept within design parameters.

Ground Control

will be achieved by providing adequate barrier pillar support around major slopes and main entries.

Gas Emissions

The coal seams have insignificant emissions of methane, which is consistent with the geological age and rank of the coal.

Subsidence

Will be controlled, to some extent, by packwalls remaining after retreat mining and by placing barrier pillars along main entries. At the depths encountered, overall subsidence is expected to be in 70 - 80 percent range. Subsidence in likely to be evidenced by ground cracks to the surface.

Groundwater

The drilling program did not reveal the presence of significant aquifers. The coal seams are reported by PMDC to contain approximately 30 percent of in situ moisture and it is possible that the seams themselves are aquifers. However, historical mining experience of private mining companies in areas immediately south and west of the investigated area do not indicate that underground water is a problem. These mines operate pillar and stall working. However, since major caving is associated with longwall operations and resulting strata disturbance, some ingress of water during

the monsoon season may occur and should be considered in mine planning. Mining over a large contiguous area could result in some accumulation of water in the mined out areas. It could also change the transmissivity of the aquifiers themselves, resulting in ponding in active areas.

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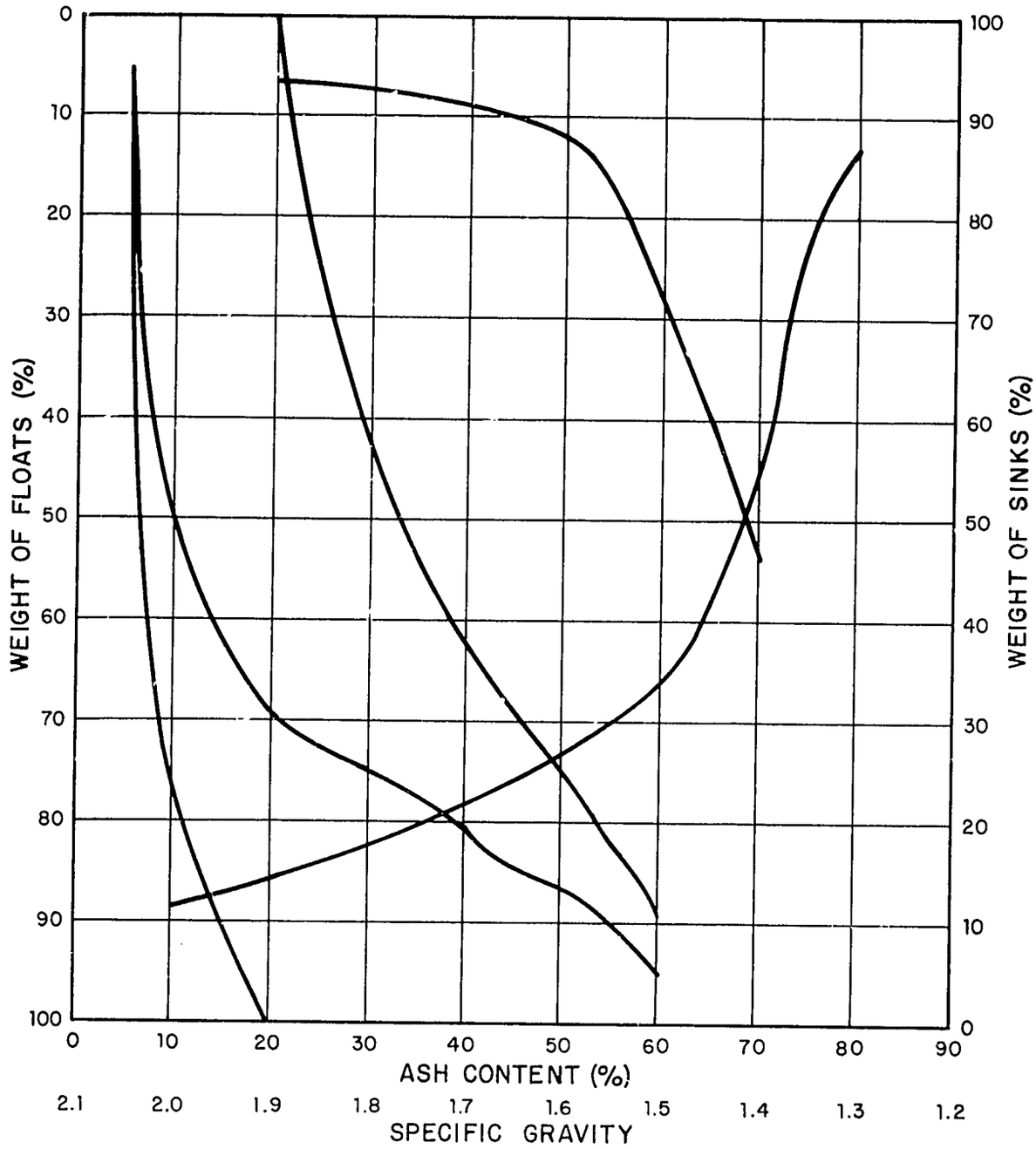
TABLE 5.3-1

SUMMARY OF ROCK TESTS IN STRATIGRAPHIC SUCCESSION

Stratigraphy		Rock	Weight of the Unit Cubic Volume (t/m³)	Effective Porocity (%)	Super-sonic Velosity (m/s)	Untaxial Compressive Strength (kg/cm²)	Tensile Strength (kg/cm²)	Numbers of Samples
Laki Limestone		Limestone	2.36-2.59	15.84-3.53	3,780-5,250	141.9-957.3	30.5-70.5	11
		Chalk and Sandy Limestone	1.93-2.26	57.61-5.05	2,650-2,960	122.5-142.1	6.1-11.4	3
Upper Ranikot	Upper Shell Beds	Claystone and Siltstone	1.79-2.43	52.13-29.13	1,080-3,190	43.0-312.6	3.9-10.4	4
		Sandstone	1.70-2.39 (2.65) [1]	60.99-19.96 (6.74) [1]	1,240-4,160 (4,890) [1]	22.7-323.0 (1,142.3) [1]	4.0-24.5 (89.0) [1]	14
Lower Ranikot	Upper Coal-Bearing Beds	Claystone and Siltstone	1.88-2.07	65.2-38.2	885-1,390	9.2-141.3	3.9-13.1	6
		Sandstone	1.76-2.11	58.7-27.26	1,010-2,950	5.2-59.6	1.2-9.5	7
	Lower Shell and Coal-Bearing Beds	Claystone and Siltstone	2.70	38.5	3,550	278.9	-	1
		Sandstone	2.05-2.26 (2.60)	51.6-26.4 (5.20)	1,210-2,140 (5,470)	82.1-164.6 (1,790.4)	6.8-18.2 (67.2)	4

NOTE:

[1] Conglomeratic Sandstone



SAMPLE: LAKHRA COAL EXPLORATION DRILL HOLE
10 HOLES COMPOSITE

SIZE: -10MM

SOURCE: JICA REPORT, 1981

FIGURE 5.3-1
WASHABILITY CURVE
LAKHRA COAL STUDY

5.4 COAL QUALITY

Existing data on the quality of the coal mineable in the investigated area is based on the analyses of drill cores obtained in the 1979/1980 JICA program. This program included the determination of 90 proximate analyses on air dried core samples, 30 ultimate analyses including forms of sulfur, and a similar number of ash fusion tests and ash analyses. The results are summarized in Tables 5.4-1 through 5.4-4.

Additionally, tests were made to determine grindability (Hardgrove), washability, and autoxidation (spontaneous combustion).

5.4.1 Moisture Content

PMDC reports that in situ seam moisture content is 30 percent. After mining and exposure to air, this moisture content falls quite rapidly so that fresh-wrought coal, after preparation and delivery to the power generating plant, is predicted to have a moisture content of 25 percent.

The JICA investigations indicated that air-dried (equilibrium) moisture contents were in the 5.5 to 14.6 percent range.

5.4.2 Mineral Content

The average ash content of the coal is 19.3 percent as reviewed. This ash is made up of inherent coal ash and extraneous minerals which are known to contain thin intercalated veins of clays and calcium sulfate. The range of ash analysis is shown in Table 5.4-3 and is notable for unusually high ranges of iron and sulfate content. No trace element analysis was reported in the JICA report. However, analyses for those elements were carried out on samples taken from existing underground mining immediate south of the eastern block of the PMDC lease area. These are reported in Exhibit I and include analyse for arsenic cadium, mercury and fluorine. These analyses do not indicate abnormal concentrations of problem elements.

The type of atmosphere corresponding to the ash fusion temperatures shown in Table 5.4-4 was not reported in the JICA Report. Because of the unusually high iron content, it may be expected that oxidizing or reducing atmospheres will have a significant differential effect on the measured fusion temperatures, and this is confirmed by results reported in Appendix 14.

The combined presence of high total sulfur, high pyritic content, and the presence of substantial quantities of gypsum was interpreted as a potential for serious corrosion and slagging problems on the fire-side of utility boilers. These factors have been specially examined in relation to boiler design.

The Hardgrove Grindability Index is in the 59 to 97 range, which is higher than commonly found in lignites and sub-bituminous coals. Therefore, no significant grinding problems for pulverized fuel firing are indicated.

5.4.3 Spontaneous Combustion

Low rank coals, particularly if they contain significant quantities of pyrites, have long been recognized as being susceptible to spontaneous combustion. In this respect Lakhra coal is a prime suspect. Special tests involving rates of oxygen absorption by the coal and heating rates due to autoxidation were made during the JICA investigations. The tests confirmed a substantial propensity to spontaneous combustion. This characteristic of the coal has significant impact on planning mining operations, because it becomes essential to avoid unnecessary exposure of exposed coal faces and ribs to air currents in standing or worked-out areas of the mine, particularly in underground workings. However, even in surface operations, the ignition of exposed seams and loose coal can present serious problems of control if the situation is neglected.

Visits to existing private mines in the Lakhra area and discussions with the mine operators indicated that underground workings could be operated over periods of years without spontaneous combustion problems arising, provided that appropriate sealing and protective measures were followed.

Several alternative methods of control have been considered including segregation of reserve areas into discrete blocks of mineable coal to be exploited over limited time periods and the construction of fly ash pack walls using treated timber ribs and manufactured cinder blocks. Heavy concentrations of inert rock dust should also be applied to roads and expected this during active operations.

5.4.4 Coal Washability

Accurate determination of washability of coal seam(s) requires the testing of samples of substantial size taken from numerous locations in the seam area. The number of samples or sub-samples is determined by the inherent variability of the seam characteristics and quality, the possibility of dilution by roof, floor or parting materials, and related factors.

Washability data can be applied to the design of the washplant following washing trials, in an industrial pilot or test plant, on quantities of the test coals. Hundreds or even thousands of tonnes of representative coal samples are required.

Where washing characteristics are known to be difficult or where dilution materials known to cause washing problems are known to be present (e.g., clays), a decision concerning the ultimate washability of the coal is based on large scale trials. Implementation of these trials before pit development requires that necessary quantities of test coals be obtained from adits, box cuts, or test shafts.

In the case of Lakhra, where no historical data on washability or washplant operation are available, these procedures would be imperative.

The JICA study included some determinations of laboratory washability data made on drill cores. Ten separate tests were conducted. The standard washability tests (float and sink) for the 10-hole composite are presented in Table 5.4-5 and the corresponding washability curves are presented in Figure 5.3-1.

In general, the results show that the coal is very difficult to wash. Reasonable yields of clean coal would require a separating cutpoint of S.G. 1.8 to be employed, which is considerably higher than the range of 1.4 to 1.6 commonly found in commercial plants. At lower gravities, the quantity of near-gravity material (a useful indication of washability) increases very rapidly so that separation efficiencies fall off equally rapidly and adequate control of the process would be very difficult to maintain.

Laboratory tests were carried out on samples crushed below a top size of 10 mm. The resulting washability data shows considerably better results than would be obtained if the material were crushed to a top size of 50 mm, which is the usual commercial practice.

It is noteworthy that even with this favorable precrushing step, the extent of improvement obtained was marginal. The raw coal ash was reduced from 19.7 percent to 12.0 percent. The total sulfur content was reduced by an average of 38 percent; i.e., from 9.6 percent to 5.9 percent. With a higher top size in the raw coal feed (2 in. x 0), (5 cm x 0) these results would be much less favorable.

At the present time, no final decision can be made as to the feasibility of washing this coal. Assuming reasonably satisfactory levels of ash and sulfur reduction could be obtained, washing would be justified by substantially lower electric power generation costs. These would result from the lower ash loadings and stack gas scrubbing requirements to remove sulfur gases. In the United States this balance of options is still the subject of intense debate, even in cases where the improvement in quality by washing of particular coals has been clearly established. Some recent papers discussing this situation are presented in Appendix 3. At this time the recommended coal preparation is limited to handpicking of visible rock from an oversize fraction screened at 50 mm (2 inches) from the ROM coal, followed by recrushing the cleaned product to 50 mm x 0 (2 inch x 0) and adding it back to the underflow to provide the overall prepared product for transport to the power plant.

TABLE 5.4-1

AVERAGE PROXIMATE ANALYSES
(As Received Basis)

	Percent
Moisture	25.0
Ash	19.3
Volatile Matter	28.8
Fixed Carbon	26.9
Total	100.0
HHV Btu/lb	15,890 kJ /kg (6830 Btu/lb)
Total Sulfur	5.95

The following ranges of analyses were found for air-dry coal:

	Range	
Moisture (%)	5.5 - 14.6	
	14,655 - 24,540 kJ/kg	6,300 - 10,500 Btu/lb
Total Sulfur	3.3 - 9.78[1]	

The coal rank (ASTM) corresponding to these analyses results is indicated to be Lignite A, bordering on Sub-bituminous C.

NOTE:

[1] Spot values as high as 18.1 percent have been reported

a2

TABLE 5.4-2

RANGE OF ULTIMATE ANALYSES
Percent by Weight

Element	Moisture, Ash-Free Basis
Carbon	58.5 - 72.4
Hydrogen	4.5 - 5.8
Oxygen	14.4 - 22.3
Nitrogen	0.9 - 1.4
Sulfur	2.4 - 9.8
Forms of Sulfur	
Pyritic	1.26 - 6.32
Sulfate	0.32 - 2.28
Organic	0.77 - 3.73

TABLE 5.4-3

RANGE OF ANALYSES OF ASH
Percent by Weight

Compound	Range
Silicon Dioxide	8.0 - 44.4
Aluminum Trioxide	9.5 - 28.8
Ferric Oxide	17.3 - 70.8
Calcium Oxide	1.3 - 12.5
Magnesium Oxide	0.9 - 5.0
Sodium Oxide	0.4 - 2.4
Potassium Oxide	0.3 - 2.0
Sulfate	1.9 - 7.5

TABLE 5.4-4

ASH FUSION CHARACTERISTICS*

	Temperature (°F)	Temperature (°C)
Initial Deformation	2280-2600	1250-1430
Hemispherical	2370-2640	1300-1450
Flow	2460-2640+	1350-1450+

NOTE:
* Type of atmosphere not specified

TABLE 5.4-5

FLOAT AND SINK TEST

SAMPLE: Lakhra Coal Exploration Drill Hole
10-Hole Composite

DATE: 1979

Size: -10mm

Specific Gravity	a Weight (%)	a Ash (%)	b $\frac{\Sigma Wn-1 + Wn}{2}$	c $\Sigma W-A$	d $\Sigma W-A$	e ΣW	f $\frac{\Sigma W-A}{\Sigma W}$	g Total W-A $-\Sigma W-A$	h $\frac{100}{-\Sigma W-A}$	i $\frac{8}{h}$	j ±0.1 SG
-1.30	11.93	5.42	5.97	64.66	64.66	11.93	5.42	1,904.37	88.07	21.62	
1.30 ~ 1.35	9.09	5.77	16.47	52.45	117.11	21.02	5.57	1,851.92	78.98	23.45	
1.35 ~ 1.40	23.07	6.55	32.55	151.11	268.22	44.09	6.08	1,700.82	55.91	30.42	53.94
1.40 ~ 1.50	21.73	11.67	54.98	254.17	522.39	65.87	7.93	1,446.64	34.13	42.39	29.14
1.60 ~ 1.70	4.92	31.72	75.69	156.06	826.54	78.15	10.58	1,142.50	21.85	52.29	8.97
1.70 ~ 1.80	4.05	39.25	80.17	158.96	985.50	82.20	11.99	983.54	17.80	55.25	7.45
1.80 ~ 1.90	3.41	43.95	83.90	149.87	1,135.37	85.61	13.26	833.67	14.39	57.93	6.41
1.90 ~ 2.00	3.00	51.38	87.11	154.14	1,289.51	88.61	14.55	679.53	11.39	59.66	
2.00 ~ +	11.39	59.66	94.30	679.53	1,969.03	100.00	19.69	.00	.00	.00	

SOURCE:

JICA Report, 1981

5.5 HISTORY OF CONCEPTUAL DESIGN

Existing proposals for mining coal at Lakhra have, at least since 1967, followed a typical evolutionary progress utilizing additional information about the extent of the reserves, faulting within the investigated areas, depths of seams and stripping ratios, roof and floor conditions, and other significant characteristics. The first mining concepts, reported in the Polish studies in 1967, proposed that production rates of 1 million metric tons per year were feasible by underground operations employing single-entry longwall mining methods. Studies by the Canadian International Development Agency, reported in 1977, tentatively proposed an integrated mining operation in which surface mining methods, employing truck and shovel operations, would exploit the western part of the investigated area and underground mining, initially operating continuous miners, would produce coal in the central and eastern parts. These studies emphasized the need for additional data to be obtained from additional explotation programs prior to finalization of mine plans. On the basis of a further, intensive exploration program, the JICA Report of February 1981 presented a detailed mining plan incorporating truck and shovel surface mining methods and underground longwall mining methods whose operations featured single-entry panel deployment, hand loading procedures, and retreat sequences.

The JICA plan has been further examined in this study as a basis for carrying out the objectives of the study team as described in Section 2.2. In relation to coal production rates, the following are necessary to support a 300-MW electric power generating plant:

- Confirm technical and economic feasibility of the mining plans.
- Effect reductions in capital cost requirements compared with the JICA Report.
- Minimize foreign exchange capital requirements by making fullest use of equipment and materials available in Pakistan.
- Maximize use of local labor consistent with reasonable standards of mechanization, and technical and operating efficiency.
- Observe environmental controls and practices for coal mining and preparation that are consistent with standards recommended by international financing institutions for developing countries.

5.5.1 Summary and Review of JICA Mining Plan

The mining plan proposed by JICA requires the extraction of 36,780,000 metric tons of run-of-mine coal (33,500,000 metric tons of clean coal as received) from No. 1, 2, 3, and 5 coal seams of the PMDC-investigated area. The reserve area is described in Sections 5.1, 5.2, and 5.3 of this report, and is further divided into three sub-areas on the basis of mining methods appropriate to the natural conditions of these blocks, as shown in Figure 5.5-1.

Central Block

The central block contains mineable reserves in No. 1 and 3 seams that range from 85 m to 123 m deep with overburden in excess of ratios suitable for surface mining. The No. 2 and 5 seams are too thin for underground mining in this central block; the No. 1 and 3 seams will be mined by underground mining methods. Primary production procedure in the JICA plan feature retreating longwalls using handloading techniques; development of mains, submains, and longwall endgates feature modified conventional mining procedures.

Primary access to the No. 1 seam would be developed for the No. 1 seam and would feature two parallel-inclined slopes from the surface. At the bottom of the slopes, two main entries would be developed to the north and two main entries developed to the south in order to provide for the deployment of two longwalls equipment sections in several successive parallel panels in each respective subsector, according to predetermined schedules.

Subsectors in the No. 1 seam would be isolated to minimize the danger of spontaneous combustion while affording reserves for sustained consistent production of approximately 250,000 metric tons per year for 27 years, including some contribution from the No. 3 seam during the 1990s. Production at substantially lower rates would be scheduled to begin in 1986 as the mains and gate entries are developed.

From underground access in the mains of the No. 1 seam in the northern section, inclined shafts would be raised to the No. 3 seam level and that mine level would be developed. Mine cars would be dropped to the No. 1 seam mains to transport the coal.

After the mine had been fully deployed, there would be three longwall sections. Two would be operated while a third would be made ready for the next move. Up to six conventional development sections, which would also recover barrier pillars and chain pillars would be operated at all times.

East and West Blocks

The east block contains mineable reserves in the No. 1, 2, and 5 seams, the deepest ranging from 45 m to 91 m with an average stripping ratio of 1:14. The west block contains mineable reserves in the No. 1, 2, 3, and 5 seams, the deepest ranging in depth from 33 to 90 m, with an average stripping ratio of 1:8.6.

The overall mining ratio is 1:11. Common open pit (area type) mining methods employing trucks and shovels would be used to exploit each seam as it is encountered. Multiple benches, developed from the surface and initial open areas, would be established by placing excess spoil on an outside storage area. When a sufficient void had been created to provide an adequate open pit area at the deepest seam, mass balance could be established by depositing spoil in the mined area. Both subsections would be developed using these techniques, although each would operate independently. Similar procedures and equipment would be used in the respective subsectors, although the eastern sector is expected to last longer than the western sector because it contains more reserves. Combined

output from the two surface mining complexes is expected to produce 1,150,000 metric tons clean coal when full deployment has been attained.

Discussion

The plan contains advantages and disadvantages, which are briefly summarized below.

Advantages

1. Presents a simple and direct approach to the mining problem; it is cautious and conservative in determining recoverable reserves and excludes potentially difficult mining areas. It is, therefore, an understatement of the case.

2. Proposes mining methods that do not require elaborate planning and engineering.

3. Presents a detailed analysis of equipment requirements.

4. Simplifies scheduling by separating operations in the surface and underground sectors.

5. Presents a fundamentally sound method of analyzing capital and operating costs, based on detailed design.

Disadvantages

1. Does not adequately investigate all potentially mineable reserves; it does not consider alternative mining methods appropriate to difficult conditions.

2. Makes surface mining entirely dependent on diesel-operated haulers and proposes surface mining equipment that is not optimized with regard to productivity and operating costs.

3. Has not sufficiently considered the potential for utilizing equipment and materials of Pakistani origin.

4. Presents plans for underground mining that are subject to the following criticisms:

   - Development, as scheduled, could destroy significant areas of potentially mineable coal in No. 3 seam as a result of premature development in the No. 1 seam below.

   - The inclined slopes, as proposed, are inadequate to serve overall access and ventilation requirements of the fully deployed mine because hoisting of mine cars will become a major production bottleneck and ventilation losses will exceed those predicted.

   - Proposed longwall layouts and development schedules are likely to encounter ground control and development

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limitations that will prevent use of the headgate and tailgate concepts, as presented.

- Spontaneous combustion and fires occurring in worked out panels close to pit bottom could cause loss of the entire mine if longwall panels near shaft bottom are worked out ahead of remote panels.

- Proposed longwall configurations, including staggered face development, are not in accordance with current practices, and will cause difficulties in the control of the caving operation and cannot be operated with the equipment proposed.

- Haulage systems are limited and will eventually create materials transportation bottlenecks. Better and more suitable equipment is available.

- In general, there is too much spare equipment and scheduled replacements are too frequent.

5. Does not allow sufficient scope and opportunity for the training of miners and supervisors. Such training will be essential for the efficient and safe use of new mining practices.

6. Presents a cost analysis which, which while fundamentally sound in method, is based on a detailed design rather than flexible conceptual design parameters that are more appropriate at this stage of project development. Consequently, some critical cost elements have been omitted. The analysis, as presented, is too detailed to facilitate the basic decision-making which will become necessary as this project is further developed.

5.5.2 Mine Plan Elements and Conceptual Changes

This subsection discusses specific elements of the JICA mining plans and considers alternatives. Each alternative is selected on the basis of the guidelines followed by the study team. They are, therefore, essentially concerned with improving the efficiency of operations consistent with maximizing the use of labor, and in reducing overall capital and operating costs.

The approach was to treat the surface and underground mines as an integrated project in order to reduce estimated capital costs. By developing the underground mine from surface mine excavation, it was possible to reduce overall slope development costs. The northeast corner of the open pit in the western reserve block was considered an entry point for the slopes to the underground mine. By developing the open pit to its fullest depth 50 m (165 ft), it was possible to reduce the vertical distance to be traversed by the slopes from 78 m to 28.0 m. As stated in the JICA Report, this means an overall reduction in the slope lengths of 60 percent. This will mean a substantial reduction in capital costs for this portion of the project.

One major advantage of developing the underground mine from the surface mine in the western reserve block is that slope excavation will intersect

mineable reserves in the No. 3 seam first and it will be possible to develop these reserves at an earlier time than the JICA plan provided. This will permit development programs for both seams to be carried out simultaneously as illustrated in Figure 5.5-2. It will allow early production in the No. 3 level and permit training faces to be set up to give miners an early opportunity to gain experience of longwall operations. Another advantage of the plan is that normal mining practice dictates that upper seams should be mined out before lower seams to avoid man-made geological safety problems when mining two adjacent levels.

By entering from the northwest pit, it will be possible to drive the main levels in a southeasterly direction with all the longwalls being located to the east of the main levels. This will permit the longwall panels to have an extended life and reduce the number of panels that will have to be developed as well as reduce the number of face equipment changes.

From a brief study of the in-situ reserves, it may also be possible to extend the main levels to the north and the east in order to recover more local reserves. Restructuring the deployment of the mains and the subsequent rechecking of panel completion opens new concepts for recovery of additional reserves. The JICA plan was basically limited by time-distance factors determined by the production capabilities of handloading longwalls.

The new mining concept affords a compromise of mechanical-power and manpower operations which will be achieved by operating two different types of longwalls. One features handstripping while the other uses standard mechanical power for ripping coal from a straight faceline. Production will exceed original design parameters because mechanical longwall units automatically operate on a three-shift cycle of production, whereas handstripping produces coal only during the dayshift. Partial mechanical power reduces the number of handstripping faces that will be required to produce an equivalent amount of coal. This, in turn, reduces the overall capital outlay required for face lines, while exceeding the original productive capacity.

Underground Mining

Access

The JICA plan does not consider that a large open pit excavation from the west surface mine is very close to the northwest sector of the underground mine boundary. Vertical proximity is even more important when the high development costs of inclined shafts are considered. Three alternatives can be considered to the central access from proposed inclined shafts.

1. Eliminate inclined shafts entirely and excavate a boxcut to the No. 1 seam level at the approximate location of the presently preferred incline shafts. A conceptual view of this boxcut is shown in Figure 5.5-3.

2. Reschedule the surface mine excavation at the north end of the west pit in order to reach the No. 1 seam to the east of the main fault between the western reserve block and the central reserve block. From the slopes, which will intersect the No. 3 seam

first, development in that seam will be initiated, then the slopes would be advanced to the No. 1 seam level. Further considerations to total development of the No. 1 seam mine from this location could be compared with alternatives for additional access from the south. A typical view of this boxcut and inclined slope arrangement is shown in Figure 5.5-4.

3. Provide for a second surface mine access boxcut at the south end of the surface mine in the eastern reserve block. From this access, a second underground mine could be opened in the No. 1 seam.

The major advantages and disadvantages of these alternatives are listed below.

Advantages

1. Boxcuts offer relatively unlimited access when compared to tunnel type inclined shafts (slopes).

2. High construction costs associated with inclined shafts (slopes) construction are minimized

3. All aspects of haulage, ventilation supply, and other logistical elements are simplified.

4. Surface excavation is faster than development of inclined shafts.

5. Overall boxcut access is cheaper from both capital and operational considerations.

6. Operating limitations and costs will be diminished.

7. More major areas can be opened up at a given time.

8. Potential safety hazards and intrinsic dangers of inclined shaft closures are minimized.

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Disadvantages

1. Surface mine equipment will need to be committed to this task during construction.

2. Surface excavation of the boxcut limits backfill area so outside storage is required to account for volumetric negative mass balance.

3. Other surface operations must be delayed until boxcuts are finished.

Access must be provided for manways; transport routes; ventilation and logistics routes and causeways for pumping, piping, and other mine support elements. This access is limited when slopes are used, even though inclined slopes are less restrictive than vertical shafts. Slopes from boxcuts are restrictive as a direct function of their length and should be kept as short as possible if they cannot be eliminated.

Boxcuts

The advent of boxcuts eliminates restriction to all or part of the vertical elevation access to the coal seam. Obviously, this will reduce expensive shaft construction costs and eventual operating costs. If this can be a trade-off with excavation that has to be undertaken during surface mining operations, the economic advantages are significant. Table 5.5-1 lists the comparative data for access from surface mine excavation and the JICA inclined slopes. Figure 5.5-4 illustrates the conceptual idea of access from this boxcut.

Figure 5.5-3 shows a conceptual view of a typical boxcut excavation. Because excavation at deeper levels presents diminishing returns as a function of depth, some economic cutoff may occur before the excavation has achieved essential depth. This cutoff can be determined precisely when detailed mine design is being performed.

In any case, it is important that some type of boxcut be considered as a form of access. The location and number of boxcuts will be determined by fundamental design criteria and comparative analysis of advantages and disadvantages.

Inclined Slopes from Boxcuts

Although the proposed inclined shafts (slopes) will be shorter, by about 350 m, than the JICA plan required, similar advantages and disadvantages will prevail. However, the alternative plan places the inclined slopes nearer the center of mass of the No. 3 seam reserves and achieves access to this mineable seam earlier in the development process.

The alternative plan, therefore, provides for rapid development of the primary incline to No. 3 seam level with a continuous miner operated by a contractor. When the level has been achieved, a conventional mining unit will be employed to develop the main panel entries at slope bottom while the continuous miner will be used to develop the auxiliary slope from the surface to the No. 3 seam level.

Once both inclined slopes are completed to the No. 3 seam level, the continuous miner will develop both slopes to the No. 1 seam level. It will then be used for mains development along with the conventional equipment.

It is important that inclined slope development progress more quickly than the JICA plan provided in order to achieve limited production capacity sometime during the second year of mine life. To achieve this, continuous haulage featuring a telescoping tail conveyor and belt conveyor has been selected, which will accelerate inclined slope development. Because a conveyor will eventually be required to haul coal in the main slope, it could be installed during, and used for development of the main inclined slopes. This conveyor would ultimately be used elsewhere underground or would be used as a cross conveyor from No. 3 seam to the main incline.

The continuous miner will be employed to develop most of the mains. It should work in the No. 1 seam to develop remote mains during the period when the No. 3 seam is being mined and is being used for training the longwall crews.

It is clear that development of remote mains is essential in both seams during the first year of mine life before introduction of the handloading longwall. The continuous miner and several conventional mining units will provide considerable production from this development.

Mains should be developed in coal alone, unless the seam thickness drops below about 1.5 m. In these areas, it is appropriate to take top or bottom rock for haulage clearance, ventilation cross section, and rail gradient. Ventilation cross section is not nearly as critical if a second access is the developed in the southwest area of the east pit.

The entries can be supported with square sets; some could be made of wood, particularly if a second access is to be developed later. Mine car haulage can be used in development of the mains. Telescoping conveyor equipment will bridge the gap between the continuous miner and the track load out station which will be located in the last open boxcut.

Development of endgate entries will be discussed in succeeding sections but the procedures will be similar to development of the mains. Conventional equipment will be used for this purpose during the early years, when the continuous miner is engaged in mains development.

It is anticipated that all these development activities will operate 3 shifts per day, 6 days per week.

Auger Mines and Short Adits

The extent of surface and underground mining reserve blocks cannot and should not be finalized without additional data. Generally speaking, surface mining should retain preferential consideration and surface mining exploitation should stop only at the beneficial economic cutoff, or where underground mining becomes more profitable. There may be a substantial interface zone where natural conditions prohibit conventional underground mining. In these zones, the reserves could be exploited by some type of highwall auger mining or by adapting special underground methods for complementing surface mines. Several mechanized techniques are available. Further details are provided in Appendix 4.

The economic cutoff, where underground mining becomes more cost effective than surface mining, is direct function of labor costs. When labor costs are low, underground mining becomes favored at more shallow depths and this condition applies to Lakhra.

With this in mind, it is essential that mine planners consider alternative designs for putting drift-adit mines into surface mine sidewalls. Provided roof conditions allow, a good deal of additional reserves can probably be recovered in this manner. If the practice is not prohibited by roof conditions, drift-adits can be advanced up to about 610 m (2000 ft) with handloading practices and conventional mining techniques, and minimal mechanization. Depending upon the initial success of one panel of these adits, the potential is virtually unlimited and the opportunity to develop numerous parallel drift-adit mines will be very economically attractive. Even longwall panels can be developed to a limited extent; and any degree of mechanization will simply improve productivity over the basic plan.

A serious consideration of the punch mine concept should be one of the foremost objectives of alternative mine plans. The potential for utilization of additional personnel in the development of additional reserves is not only feasible, but desirable.

Haulage and Transportation

The coal transport systems should be based upon optimized transport modes from each area of the mine complex. Basically, adverse grades, such as the inclines, should feature belt haulage. Adverse access areas with restricted space, such as headgate entries, should feature belt haulage. Long hauls, high volume concentration of coal, and areas of segregation, such as the mains where longwalls are operating, should feature track haulage using trolley power. All surface areas, including transport from surface mines, should feature track haulage. The size of locomotives and mine cars should be designed so they can be used throughout the complex although special considerations could be made for surface locomotive and surface mine cars.

Panel conveyors should probably be limited to 915 m (3000 ft) per single conveyor but greater lengths can be achieved by tandem installation of two

or more conveyors. Two tandem conveyors should suffice for the longest practical longwall panel.

Underground Transport

The basic underground transport system is a narrow gauge railroad as in the JICA plan. A narrow gauge railroad will be installed at the surface facilities of the mine, down the inclines, and throughout the mains. This railroad can extend into the gate entries of the longwall panels. The JICA plan does not provide for a trolley system; it features battery-powered locomotives. A battery-charging station would be installed at the bottom-connecting crosscut of the two inclines. In the proposed alternative, an electrified trolley system will be installed on all main railroad structures.

In the JICA plan tippler mine cars of approximately 1-metric-ton size have been designed for use throughout the mine for coal transport. Special flat bed cars have been prescribed for transport of supplies. The JICA plan calls for 200 mine cars and 10 material cars. The proposed alternative features larger mine cars, approximately 3 to 5 metric ton capacity, with either trippler, bottom dump or rotary dump capability (to be determined in the detailed design).

Special design of supply cars, which are usually introduced for convenience where costs are labor intensive, is not required. Arrangements for personnel transportation, however are required. Personnel can be transported in open mine cars on the mains and in the endgate entries.

Belts will be installed on the incline and in the headgate entries. From the headgates the conveyor will discharge into mine cars. The mine cars will be pulled in trips of 10 to 50 cars and dumped at the bottom of the incline. Coal will be fed onto the incline conveyor and carried to the surface inside the boxcut. It will be conveyed or trucked out of the boxcut where it will be transferred to the surface mine transformation to the surface facilities areas. The JICA plan provides surface haulage by belt conveyor. This is still an alternative for consideration at the detailed planning stage.

It is important that the underground mine surface transportation system be compatible with the surface mines transport system. Wherever narrow gauge railroads are installed, it is recommended that transportation should be by trolley systems. Battery and diesel power are usually selected only for convenience. It is widely recognized that battery power is best adapted for mines without ready access to power sources, situations where costs are extremely labor intensive, and cases where rail structures will be altered frequently and will not remain in place for extended periods. None of these cases apply to the Lakhra mines. Diesel locomotion is generally selected where fuel is plentiful, extreme mobility is required, and long cross-country routes are involved. These conditions do not apply to the proposed mine complex.

Face Haulage

In the JICA plan and the proposed alternative plan, coal will be removed from the longwall face by armored chain conveyor. The conveyor is designed

to be advanced, as the face advances, by hydraulic rams, (these have not been included in the JICA study). If a plow or shearer is used on a mechanized longwall, the machine can ride the conveyor frame. The conveyor is designed to flex during movement but must be straight during operation. The head and tail sections must be anchored securely in order to keep the conveyor straight. The conveyor featured in the JICA plan is of approximate 100 metric tons (110.23 short tons) per hour capacity, which is basically oversized for handstripping. With a mechanized longwall, prescribed capacity will be about 200 metric tons per hour.

The face conveyor is capable of headgate elevation in order to discharge by gravity onto a stage loader conveyor or onto a belt conveyor tailpiece. General arrangements are illustrated in Figure 5.5-5 and a typical face conveyor is illustrated in Figure 5.5-6. If mine cars are used in the headgate entry, a staging conveyor will be used to mitigate surges and to intermittently load mine cars one at a time. The staging conveyor can be described as a feeder which is a stage feeder designed to satisfy track haulage loadout requirements. A typical staging conveyor is shown in Figure 5.5-7.

The staging conveyor will discharge directly onto the belt tailpiece. The belt conveyor will feature an extra long tailpiece so that it can be retreated once daily between shifts; its overall length will be adequate to accomodate the retreat of the face conveyor. Its capacity will be greater than, or equal to, that of the face conveyor.

The use of belt conveyors in the headquate reduces the overall machinery requirements by simplifying the loadout process. However, it increases the overall sophistication of the transport system. To push the longwall panels to their maximum extent, the headgate conveyors, each a maximum of 915 m (3000 ft), can be operated in tandem. In general, the same number of laborers will be required to clean and care for belt conveyors as are planned for a track system. Conveyor moves are probably less complex than corresponding moves of a chain conveyor, stage loader, and a section of narrow gauge railroad.

Endgate Haulage

The basic advantages of belt conveyors over track haulage in the endgate are outlined below. They essentially center around greater flexibility, better adaption to adverse natural conditions, and rapid deployment capabilities.

Advantages of Conveyors

1. Consistent reliability of haulage capacity with no cyclic breaks.

2. Roof control is better because entries can be made narrower (this is true even if a track is provided for personnel and materials.)

3. Moves are simpler and involve less machinery.

4. Conveyors operate well on adverse grades.

5. Surges do not affect belt conveyors, usually.

6. Track run arounds are not required and entries can be squared off at intersections.

Advantages of Track Haulage

1. Mine cars provide for segregation of mined products.

2. Mechanical outages are not of serious impact on face production.

3. Fewer skilled personnel are required.

4. Personnel and materials can be transported easily.

5. Trip time is minimal.

While the JICA plan used battery-powered locomotives, the alternative plan features trolley-powered locomotion right to the intersection of the most remote panels tailgate and the main entries. A typical cross section of a gate entry is shown in Figure 5.5-8.

Main Haulage

As in the JICA plan, alternative plans call for use of track haulage in the mains. Regulation narrow gauge railroad will be installed with switches, parallel passing tracks, and turn outs to satisfy volumetric requirements for transport of coal, personnel, and materials. The JICA plan contains 7 battery locomotives, two hundred 1-metric-ton tippler cars, and 10 special material cars. In this system, the capacity-to-volume ratio is 1:4 and somewhat undersized, requiring turnaround of each car twice on each production shift, at a minimum. In practice, it is seldom possible for every car to be turned around that frequently. Also, battery locomotion is not best adapted to design criteria for the project. Special cars are not essential for materials transport, but special rail-truck sets are required for machinery moves. It is also essential to have special transport for officials, managers, and repair parts. Track maintenance crews can use hand-operated flat cars and scooters. Mine cars should be at least 3 to 5 metric tons in capacity and can be either tippler dump, rotary dump, or bottom dump, depending on local preference in the design of dumping units. The alternative plan, which features up to 1200 metric tons per day of production requires at least 400 metric tons of mine car capacity. This will enable planned turnaround of each car one time per shift and will feature 8-hour surge capacity.

Slope Haulage

The JICA plan prescribes track haulage up the incline powered by rope hoists. This system is likely to become a major constriction in the transport system and place unnecessary constraint on face production operations.

The recommended alternative is for a conveyor to be fed at the bottom of the incline with a mechanical feeder from a mine car discharge bin. The

capacity of this conveyor should be in excess of 300 metric tons per hour. The surge bin should hold at least 50 metric tons to accommodate a 10-car trip. The conveyor will discharge into a 100-metric ton surge bin at the surface inside the boxcut. A conveyor or coal trucks will be used to carry coal out of the boxcut where it will be discharged to another bin which will, in turn, be used to load 5- to 10-metric-ton mine cars used for surface haulage. These bins can operate by gravity. Final selection of boxcut-to-surface procedures have been deferred to detailed design.

Hoist capabilities will be provided to service the narrow gauge railroad, material cars, repaired mine cars, equipment, and trucks. It could also be used in the event of conveyor belt failure. Typical cross sections are illustrated in Figures 5.5-9 and 5.5-10.

Surface Haulage of Coal and Overburden

During the first half of the century, trolley-powered, narrow gauge railroads were widely used in mines. Many surface operations in Europe also operated these railroads, although the practice was never fully adopted in the United States because of rising labor cost. Narrow gauge railroads were labor intensive because mine cars, trolley cars, wooden sleepers, switchgear, and other facilities had to be maintained and operated manually, automatic devices being limited. Operating costs were low because locomotives and mine cars are relatively simple machines. They offer a distinct opportunity for low-cost transport that will utilize local personnel and materials at Lakhra. Because electricity is used, imports of diesel fuel are also minimized.

At the detailed design stage, alternative haulage plans should be devised to implement extensive narrow gauge rail systems to transport coal from the top of all mining excavations including surface mines and underground boxcuts. Design alternatives for out-of-pit haulage featuring narrow gauge rail on each bench should be considered as serious alternatives. All aspects of trolley-powered narrow gauge railroads should be explored in detail.

Coal Production Methods

The coal production schedule developed in the JICA plan underestimates the potential of underground mining. Once a decision is made and capital expended to develop a mine, it is almost impossible to limit underground production from a longwall mine to 250,000 metric tons per year. To minimize capital, maximize manpower potential, and make use of local materials, the proportion of coal mined by underground methods should be increased. Several advantages and disadvantages should be considered:

Advantages

- Methods are more labor intensive.
- Methods are less dependent on weather conditions.
- Exploitation by two fundamental mining methods are able to produce relatively large amounts of coal from a variety of naturally occurring reserve conditions.

- More personnel will be trained in skills that can be widely exploited in Pakistan.

- Less surface mine machinery will be required, reducing initial capital costs.

Disadvantages

- There may be a tendency to develop areas where surface mining could be better employed in the future.

- More reserves may be at risk of spontaneous combustion.

- Productivity estimates are less reliable for underground mines because they depend more on mining conditions and manpower than machines.

- Development schedules are more complicated when underground mines produce larger quantities.

Underground Production Procedures

In the alternative mine plan, five distinct types of production procedures may be employed; each will be discussed separately below. These are listed in order of productive capacity during a typical production year.

- Mechanized longwall
- Handloading longwall
- Continuous miner
- Conventional equipment
- Punch mines

Mechanized Longwall

The alternative mine plan calls for utilization of a longwall plow or shearer in retreating longwall configuration in parallel panels. Details have not yet been developed to deviate from the panel sizes and configuration advised in the JICA plan, although there is need to revise the support barrier design. The panel schedule must also be revised.

A typical longwall equipment section will operate on three shifts per day in a continuous cycle of cut, support, and retreat. When a panel is complete, the section will be moved as quickly as possible to the next successive panel.

Certain procedures are basic to all longwall units and are illustrated in Figures 5.5-11 through 5.5-13. A faceline pillar-point stable will be cut at each end of the face, using power drills and coal picks. This excavation will intersect and deflect the stress line farther into the center of the face and will increase the tendency of the coal to slough away from the face as the plow contacts the free face. The machine is drawn from side to side and rips coal across the entire length of the face from roof to floor. This coal is carried away by the armored conveyor. The machine will cut in both directions so the procedure is repeated in the opposite direction until a flat face has been excavated from roof to floor.

The armored face conveyor is equipped so the lead edge tends to lift and scoop coal from the floor; therefore, it is only advanced when its effective carrying capacity is significantly diminished by the increasing distance from the face, roughly one conveyor width. Roof supports are usually shifted forward at the same time, although the two operations are relatively independent. Roof supports are arranged in double alternate sets; thus, one set can be advanced into the face while the second set is withdrawn from the roof. The JICA plan did not provide this feature.

Packwalls will be constructed at the same rate of retreat as the longwall face. The belt conveyor will be retreated once per day to maintain terminal placement at the discharge point of the face conveyor. The haulage system will be retreated from the tailgate well out by the faceline retreat.

As previously discussed, mechanized mining leads to better roof conditions, a faster rate of advance, and greater productivity. One mechanized face can produce the equivalent of two handstripping faces, while manpower is only slightly reduced in the proposal plan.

Mechanized faces produce on three shifts; required maintenance will be performed on shift and between shifts.

Scheduled repairs will be performed on weekends and scheduled overhauls will be implemented during panel moves.

To obtain a faster return on investment and produce coal more quickly, advancing longwalls may be considered. By using advancing sections alternately with retreating face lines, the same entries can be used. The maingate of one advancing section used in conjunction with the tailgate of another, would serve as main and tailgates for the retreating section in between.

If this sytem is adopted, the areas of spontaneous combustion and roof supports will require further attention.

1. Spontaneous Combustion

   Because of the length of time the mined out advancing face waste area would be exposed to the atmosphere, great care must be taken to ensure that the sealing arrangements are properly carried out.

2. Roof Supports

   Using such a system will mean greater roof pressures on the main and tailgate to be used for the retreat face line. This is because the strata above the mined seam tend to settle down. The roof supports may have to be constructed of steel to combat this greater force. This would increase the overall costs for roof supports. However, these supports will be salvaged as the face retreats, and will be used for future longwall panels. The use of shearers will increase production per shift, improve roof conditions, and be carried out over three shifts per day. Typical prop and bar supports are shown in Figure 5.5-14.

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The JICA Report shows an operating plan for a staggered face line. This is directly opposed to the fundamental principal of modern longwall mining.

One of the principle reasons for the successful operation of longwalls is the maintenance of a straight line to have constant roof pressure through the face and to have regular relief of pressure along a straight breakline in the overburden.

Also, coal clearance becomes a problem by having a continually curving conveyor. Conveyor creep is another problem associated with conveyor curves.

Handloading Longwall

In handstripping, a normal 24-hour cycle consists of the following activities:

Night Shift - Undercut, drill, and blast face.
Day Shift - Loads out coal and services faceline equipment.
Afternoon Shift - Moves conveyor forward and sets wastepacks.

The JICA report does not mention undercutting the face, which is an important preparation step. The basic principle involved is the creation of an additional free face and the use of the overhead weight to assist explosives fracturing of the coal. Without undercutting, the maximum effect of the explosives is reduced. Undercutting also helps reduce the required force to be applied by explosives, subsequently less force is transmitted into the roof.

One disadvantage of handstripping is that it may expose an area of roof (1.2m x 122m) for a long period without adequate support. This is not good when working in adverse conditions.

The rate of production of 450 metric tons per shift can be obtained by operating two facelines producing approximately 225 metric tons per shift each. The rate of advance per shift per face would be 1.22 m. Coal would only be produced on the day shift, because the cycle is limited in its capabilities. The most manpower intensive shift is the day shift, with fewer miners being required on the afternoon and night shifts. The latter are essentially repair and preparation operations. Estimated manpower requirements are therefore total 84 men per operating face per day.

Continuous Miner

A standard drum rigger type continuous miner will operate within one heading of mains or gate entries until reaching the next projected crosscut. At this crosscut, it will turn, mine to the adjacent entry, retreat to the orifice entry, and cut it to the next crosscut, etc. Track, trolley, and roof supports will be advanced in cycle with the continuous miner. The power boxes will be advanced the distance of each open crosscut and will be outbye positioned outbye the track loadout station. The continuous miner will load mine cars that will be positioned with a small

locomotive. The machine cuts the coal out and loads it on to a heading conveyor.

Method 4

A short belt conveyor or mobile bridge conveyor could be adapted to supplement and speed up this operation. One shuttle car could also be effectively employed.

Roof control will consist of temporary hydraulic props and permanent square sets. Wood will be used for permanent support whenever conditions permit.

Conventional Equipment

Conventional equipment will feature a gate-end loader, drills, and jackhammers (coalpicks). Only the power mode is to be changed, as electro-hydraulic units are preferred to accomplish drilling.

The mining sequence is:

1. Drill and blast the face heading
2. Extend temporary supports
3. Load out the loosened material
4. Set permanent roof supports

Several different methods may be employed, as follows:

Method 1

Drill and blast: This cycle requires several maneuvers of individual operations.

- Drills with legs
- Mechanical shovels
- Conveyors
- Manual labor for roof supports
- Forepoling

Method 2

Uses advancing face line headings that advance at the same rate as the face. Because the coal has already been extracted, only the remaining top section of the roadway has to be removed.

In this case, the waste rock can be used for rib side packs in both main and tailgate entries.

Method 3

Makes use of some form of mechanized equipment, such as a continuous miner, which can be used in the full face development required in retreat mining. The elimination of explosives is a safety plus feature. The machine cuts the coal out and load it on to a heading conveyor.

An extra safety feature is that the roof conditions are not distrubed. The machine can also be employed to lift steel beams into place to give the miners safe gound to work in.

Method 4

A fourth option, with advancing face lines, is also possible employing either drill and blast or continuous miners. This system entails having the main and tail roads 30 m in advance of the face line. This eliminates the restrictions put on normal development, where gate ends can only be advanced at the same rate as the face line. This method also provides waste rock which can be used immediately in ribside packs.

The advantage of using a continuous mining is that the machine can carry out both mining and loading operations. This eliminates the use of drills and legs, explosives, and a gate end loader.

Punch Mines

From surface mine access, two parallel entries will be developed as far as practicable and as roof and floor conditions allow, using conventional techniques. From these entries, room-and-pillar retreat will be accomplished or a modified longwall will be installed.

Ventilation of Underground Mines

General

Longwall mining in Europe uses single entries for all sections, whereas in the United States, a minimum of three parallel entries is required on each side of a longwall panel. This requirement arises out of interpretation of the present mining laws. In single entries, the air route is simple and straightforward with few places for bypassing. This is an important consideration in mines subject to a high risk of spontaneous combustion. It requires that the conveyor and other transportation systems operate in the principal air courses, a condition that is specifically forbidden by United States law, which requires that conveyor systems operate in separate entries that have minimized air currents.

North American Mining Consultants, Inc., conducted a major study and comparison of United States and European systems for the United States Department of Energy. The report discusses all aspects of single-versus-triple entry systems and is a major source of information on all types of longwall operations. A copy of this report has been given to WAPDA/PMDC. (Additional copies may be obtained from NTIS: Report No. DOE/DE-AC01-77-ET-12558.)

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Ventilation Practice

Portable fans will be employed in development of headings. While developing the two slopes, two fans will be required, one for each road. When the No. 3 seam level has been achieved a crosscut will be driven. This will be necessary to provide easy access to either slope; it will act as a sump, if necessary, and also house electrical gear. It also will provide a circular air flow. This means that the fans, initially installed at the surface, can be moved down to the crosscut. All vent tubes can be dismantled and stored for use as the slopes develop down to the bottom level hence resulting in a substantial saving in the cost of buying air vents. When the foot of each slope is reached, another crosscut will be driven to connect the two slopes. The fans and vents will be dismantled and taken to the foot of the slopes for use in ventilating the main headings.

At this point, the main surface ventilation fans can be brought into operation, at a reduced level, to provide ventilation through the main slopes. Similar methods can be applied to developing the panel headings as applied to the drifts. Both headings will be developed the distance of one standard chain pillar, connected with a crosscut, fans and vent tubes will be moved up, and the cycle repeated. When the main is fully developed, the principal air flow will be as shown in Figure 5.5-15. Each section will be fitted with adjustable rectangular doors to supply the correct amount of air to each section, in accordance with good mining practices.

Main Ventilation

The coal transportation system will be housed in return airways for health and safety reasons. Any dust generated will then have the shortest route to travel to the surface. Coal will flow with the air current, hence reducing dust disturbance during transportation. Any smoke from a fire hazard will travel the shortest distance out of the mine. Normally, few employees will be required to work in the return airways. Supply materials, whenever possible, will travel via the main intake airway. The return airway of the longwall panels will house both conveyors and railroads. The main return airways will house only the railroad. Standard overcast structure doors and regulators will provide suitable splits and control of the ventilation current.

Seals

Permanent seals along the longwall ribs will be required to seal off any air flow into the waste area to prevent the possibility of causing spontaneous combustion. This work will have to be done with care and the resulting seals will have to be adequately maintained. The construction of such seals is shown in Figures 5.5-16 and 5.5-17. Either cinder block structure or timber packs will be filled with fly ash. These packs will be spaced out at predetermined distances. The spacer between will be blanketed-off with brattice (cloth) and in-filled with fly ash. To avoid the use of flammable material in a potential fire risk area, the less timber used the better. When each longwall panel is worked out, it should have a permanent fire-resistant seal built at the entrance of each heading.

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Note: The present study does not require a detailed description of the logistics of surface and underground mining operations. However, these will be an essential and central feature of detailed mine design and operations planning. Detailed procedures and descriptions will be prepared for mine construction; haulage management; resupply; dewatering; ventilation; equipment and face moves; communications; power supply; coal handling, preparation, and storage; rail loadout; recruitment and training of personnel.

Production Equipment

A large variety of stationary and mobile equipment is required for underground mining operations. The lists of equipment necessary, and equipment specifications, will be prepared as a major part of the detailed design and mine planning. The provision of a comprehensive and adequate schedule of spares and productive supplies forms an important part of this exercise.

Surface mining depends on mobile plant equipment, which requires comprehensive spare parts lists and the continuous availability of production and maintenance supplies.

Mine planning will include the provision of central stores, mechanical and electrical repair workshops, carpenter shops, explosives stores, oil and water supplies, and all necessary facilities to support a mining complex comprising surface and underground mining operations.

Underground

Principal equipment and installed facilities required will include:

1. Producing units
   - Continuous miner
   - Mobile bridge conveyor or telescoping conveyor
   - Rock drills
   - End/side loaders
   - Shuttle car
   - Roof bolters
   - Ploughs/Shearers
   - Armored face conveyors
   - Stage conveyors and gate loaders
   - Undercutters
   - Compressed air supply
   - Pneumatic jacks and picks
   - Hydraulic rams

2. Roof Support
   - Steel arches, beams, and sets
   - Timber sets
   - Hydraulic props and bars

3. Transport System
   - Main hoist
   - Conveyors
   - Electric mine locomotive

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- Trolley
- Mine cars, including special personnel and equipment trucks
- Spotter hoits
- Car dump unit
- Pulleys, ropes, hoists
- Transfer units bins

4. Ventilation
    - Seals
    - Main fan installation
    - Auxiliary fans and tubes
    - Overcasts doors

5. Electric Equipment
    - Typical cables
    - Substation and power distribution units
    - Transformers and circuit breakers
    - Cables and cable splicing equipment
    - Battery charging stations
    - Trolley systems and equipment

6. Communications
    - Telephone and line signal equipment
    - Mobile radio
    - Trolley Communication

7. Miscellaneous Items
    - Lighting
    - Fire Protection
    - Rescue equipment
    - Brattice
    - Tubing and pipe
    - Small tools

Surface

Principal equipment for the surface mines is summarized in Table 5.5-2.

Production Scheduling and Manpower Requirements

The coal requirement for a 300-MW electric power generating station burning coal of quality indicated in Table 5.4-1 is calculated to be 1.4 million metric tons per year. The project schedule is based on a 54-month period, commencing in June 1983, with full coal production being attained by January 1988. This development schedule is reasonable and can be achieved with the alternative mining plans described in this report. It is shown schematically in Figure 7-3.

Bearing in mind that the surface mines described will be the first such installations in Pakistan and that the underground development and longwall operations are more mechanized than existing practices, the training of miners and their supervisors is a crucially important element of the early development years. The installation of efficient and safe working

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practices and the development of good "pit sense" by the miners takes time and requires careful planning and supervision.

A preliminary production schedule has been prepared and is presented in Table 5.5-3. This table also provides manpower estimates for the development years and subsequent years of full production.

Productivity figures for coal production will be as follows:

West Open Pit	10.21 metric tons/shift
East Open Pit	6.62 metric tons/shift
UG Mine	1.3 metric tons/shift
Overall	4.2 metric tons/shift

Total labor force for the mines will be 1235 men, including management and supervision.

TABLE 5.5-1

COMPARISON OF SLOPE DRIVING FROM SURFACE AND BOXCUT

	Central JICA Slopes	N.W. Boxcut Access with Slopes
Number of Slopes	2 + 2	2
Length, m	2 (462) = (924 m)	2 (158.5) = 317
Raise to No. 3 Seam, m	2 (66) = (132 ft)	
Excavation of Surface Site, m^3	76,455	3,264,400(1)
Underground Incline Rate of Advance, m/day	2.7	2.7
Time to Complete, days	337 + 48	116
Cost of Slopes(2), $ ($6560/m)	6,064,000 + 864,000	2,080,000
Cost of Extra Excavation, $	122,000	100,000
Total Costs, $	7,050,000	2,180,000

NOTES:

1 Cost of excavating this boxcut access is included in surface mine overburden cost and not included as a cost against this phase since it must be removed regardless of underground operations.

2 Assumed underground cost of developing openings is the same.

TABLE 5.5-2

EQUIPMENT LIST FOR SURFACE MINES

East Pit Capital Item	Units Required [1]	Unit Cost [2]	Equipment Life (Yr)	West Pit Capital Item	Units Required [1]	Unit Cost [2]	Equipment Life (Yr)
(10-cu yd)³ 7.6-m³ Electric Loading Shovel	2	1555	30	(10-yd³) 7.6 m³ Electric Loading Shovel	2	1555	30
68-metric-ton End Dump	8	443	7	68-metric-ton End Dump Trucks	8	443	7
280-kW R.T. Dozer	2	412	5	280-kW R.T. Dozer	2	412	5
(9-in.) 23-cm Rotary Drill Diesel/Electric	1	463	10	(9-in.) 23-cm Rotary Drill Diesel/Electric	2	463	10
Mounted (5-in.) 12.7-cm Rotary Drill Truck	1	330	10				
4.5-metric-ton Bulk ANFO Truck	1	40	4	4.5-metric-ton Bulk ANFO Truck	1	40	4
300-kW Crawler Dozer with Ripper	2	453	3	300-kW Crawler Dozer with Ripper	2	453	3
75-kW (2-1/4-cu yd³) 1.72 m³ R.T. FEL	5	82	4	75-kW (2-1/4 yd³) 1.72 m³ R.T. FEL	5	82	4
7.6-m³ End Dump Truck	15	30	4	7.6-m³ End Dump Truck	15	30	4
250-kW Crawler Dozer with Ripper	1	330	3	250-kW Crawler Dozer with Ripper	1	330	3
75-kW (4-yd³) 3.1 m³ R.T. FEL	2	82	4	75-kW (4-yd³) 3.1-m³ R.T. FEL	3	82	4
13.6-metric-ton End Dump Truck	8	30	4	13.6-metric-ton End Dump Truck	10	30	4
185-kW Road Grader	2	289	5	185-kW Road Grader	1	289	5
15,000-l Water Truck	3	50	4	15,000-l Water Truck	2	50	4
300-kW Crawler Dozer with Ripper	1	453	3	300-kW Crawler Dozer with Ripper	1	453	3

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TABLE 5.5-2 (Cont)

East Pit Capital Item	Units Required [1]	Unit Cost [2]	Equipment Life (Yr)	West Pit Capital Item	Units Required [1]	Unit Cost [2]	Equipment Life (Yr)
(21-yd) 16 m³ Tandem Scraper	1	525	4	(21-yd)³ 16-m³ Scraper	1	525	4
100-kW Flatbed Truck	3	30	4	100-kW Flatbed Truck	3	30	4
100-kW Fuel Truck	1	35	4	100-kW Fuel Truck	1	35	4
100-kW Lube Truck	1	40	4	100-kW Lube Truck	1	40	4
100-kW Mechanic Truck	2	30	4	100-kW Mechanic Truck	2	30	4
100-kW Fire Truck	2	40	4	100-kW Fire Truck	1	40	4
100-kW Welding Truck	1	40	4	100-kW Welding Truck	1	40	4
Tractor and Lowboy	1	103	10	100-kW Tow Truck 50-kW Farm Tractor	1 2	30 25	4 4
4.5-metric-ton Hydra Crane	1	65	10	32-metric-ton Truck Crane	1	25	10
1-metric-ton Mechanical/ Electrical Truck	2	72	3	1-metric-ton Mechanical/ Electrical Truck	2	72	3
Light Duty Pickup Truck	10	8	3	Light Duty Pickup Truck	10	8	3
(3/4-ton) 0.7-metric-ton 4-Wheel-Drive Truck	5	13	3	(3/4-ton) 0.7-metric-ton 4-Wheel-Drive Truck	5	13	3
50-kW Farm Tractor	2	25	5				
12-kW Portable Light Plants	10	12	5	12-kW Portable Light Plants	10	12	5
(12-in.) 30.5-cm Crissifulli Pumps P.T.O.	2	10	10	(12-in.) 30.5-cm Crissifulli Pumps P.T.O.	2	10	10
Mounted (4-in.) 10.2-cm Diesel Pumps - R.T.	2	9	10	Mounted (4-in.) 10.2-cm Diesel Pumps - Skid	2	25	10
Production Office Trailer	1	30	15	Production Office Trailer	1	30	15

TABLE 5.5-2 (Cont)

East Pit Capital Item	Units Required [1]	Unit Cost [2]	Equipment Life (Yr)	West Pit Capital Item	Units Required [1]	Unit Cost [2]	Equipment Life (Yr)
Pit Communications	Lot	100	10	Pit Communications	Lot	100	10
Miscellaneous Pit Equipment	Lot	150	10	Miscellaneous Pit Equipment	Lot	150	10
Pit Electric System	Lot	750	30	Pit Electric System	Lot	750	30

NOTES:

[1] Based on full production

[2] All costs in thousands of dollars

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TABLE 5.5-3

COAL PRODUCTION AND MANPOWER SUMMARY [1]

300-MWe Power Plant

Mining Year	West Open Pit			East Open Pit			Underground			Mine Totals		
	ROM Coal Metric (Tons)	Officers	Workers	ROM Coal Metric (Tons)	Officers	Workers	ROM Coal Metric (Tons)	Officers	Workers	ROM Coal Metric (Tons)	Officers	Workers
1	-0-	21	160	-0-	21	156	-0-	6	30	-0-	48	346
2	62,900	24	179	33,800	24	172	15,000	30	250	111,700	78	601
3	142,700	26	197	76,900	26	200	100,000	40	360	319,600	92	757
4	298,000	29	215	160,700	29	205	130,000	50	480	588,700	108	900
5	363,400	29	215	196,600	29	230	150,000	60	600	710,000	118	1,405
6	771,000	30	224	514,000	30	230	250,000	69	652	1,535,000	129	1,106
7	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
8	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
9	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
10	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
11	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
12	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
13	756,000	30	224	504,000	30	230	275,000	69	652	1,535,000	129	1,106
14-23	7,560,000	30	224	5,040,000	30	230	2,750,000	69	652	15,350,000	129	1,106
24-33	7,560,000	30	224	5,040,000	30	230	(8 1/2 years) 2,337,500	69	652	14,937,500	129	1,106
Total	22,050,000			14,590,000			7,657,500			44,297,500		

NOTE:

[1] Includes equipment maintenance manpower. Personnel associated with coal preparation plant and railway facilities are not included in this table.

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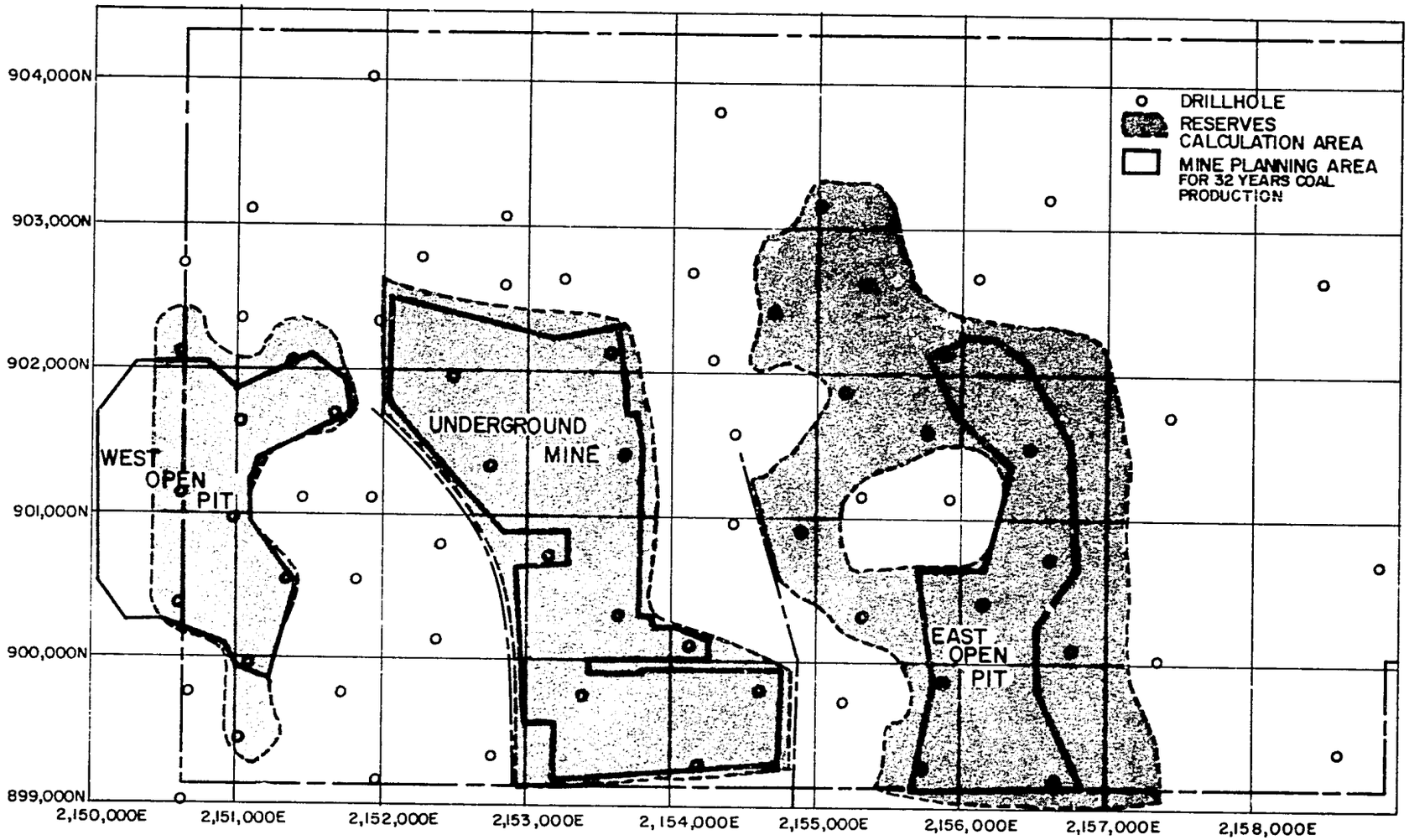

0 1 2
SCALE-KILOMETERS

SOURCE: JICA REPORT

FIGURE 5.5-1
MINE PLANNING AREA
LAHKRA COAL STUDY

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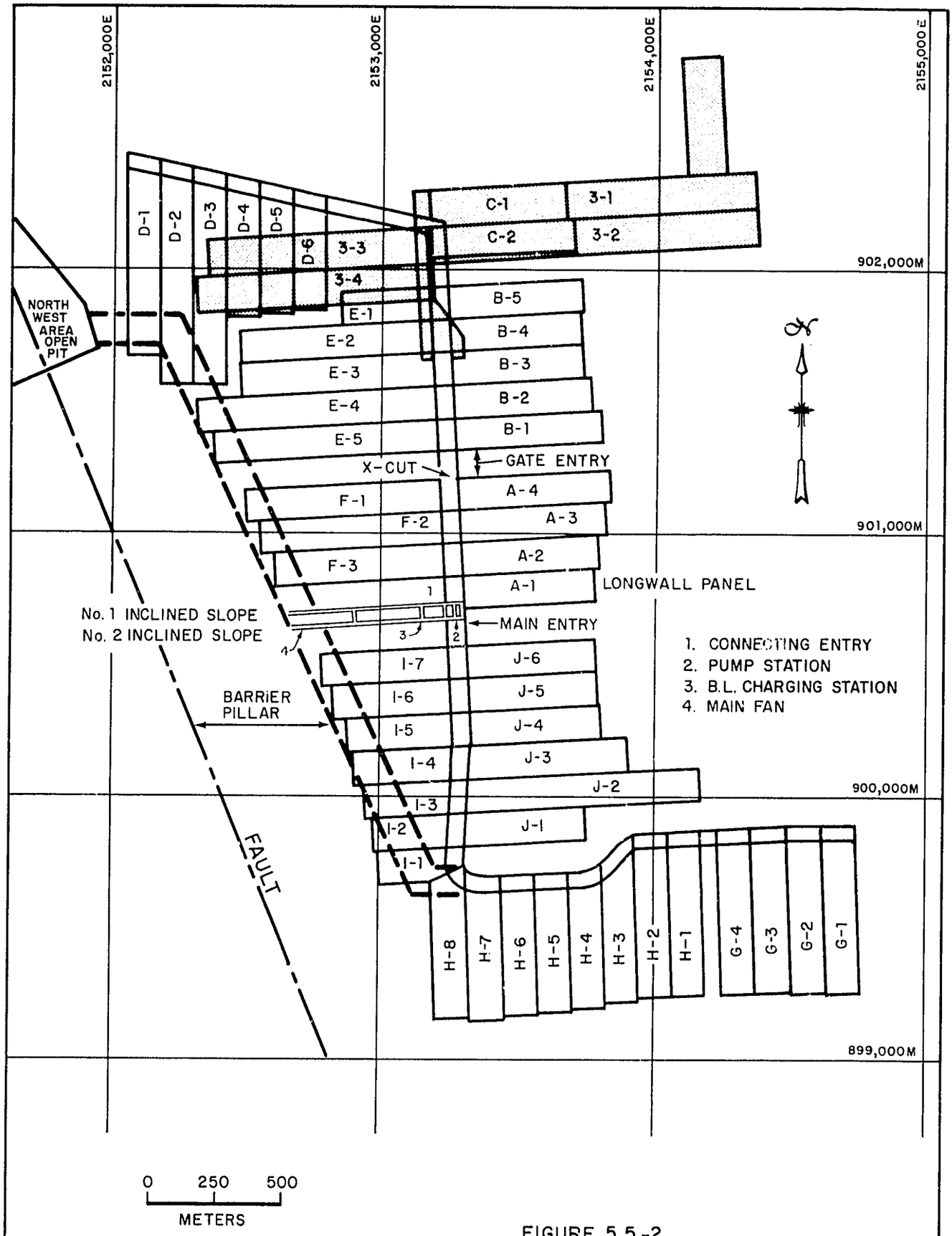


FIGURE 5.5-2
NO. 1 SEAM MINING LAYOUT
LAKHRA COAL STUDY

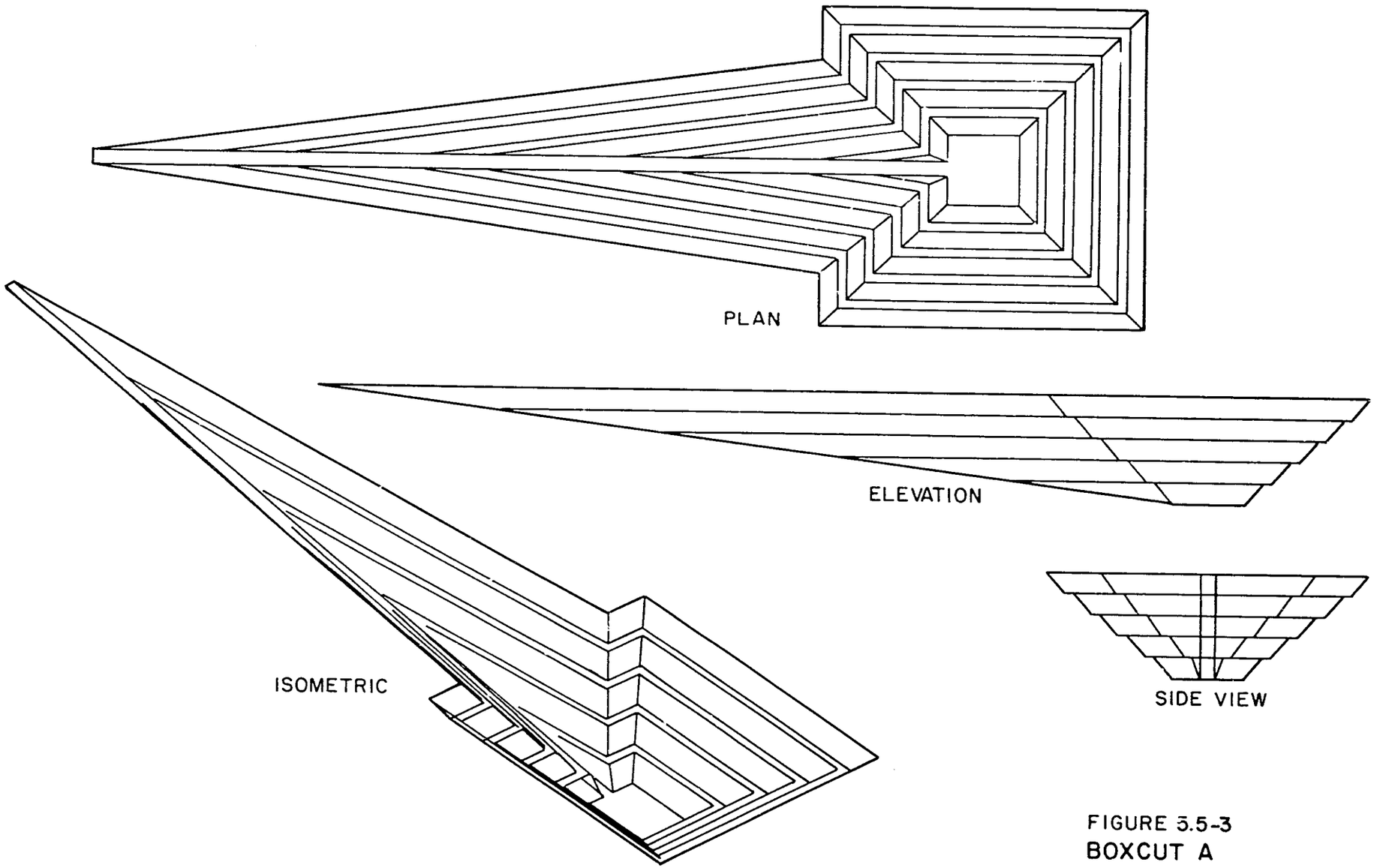


FIGURE 5.5-3
BOXCUT A
LAKHRA COAL STUDY

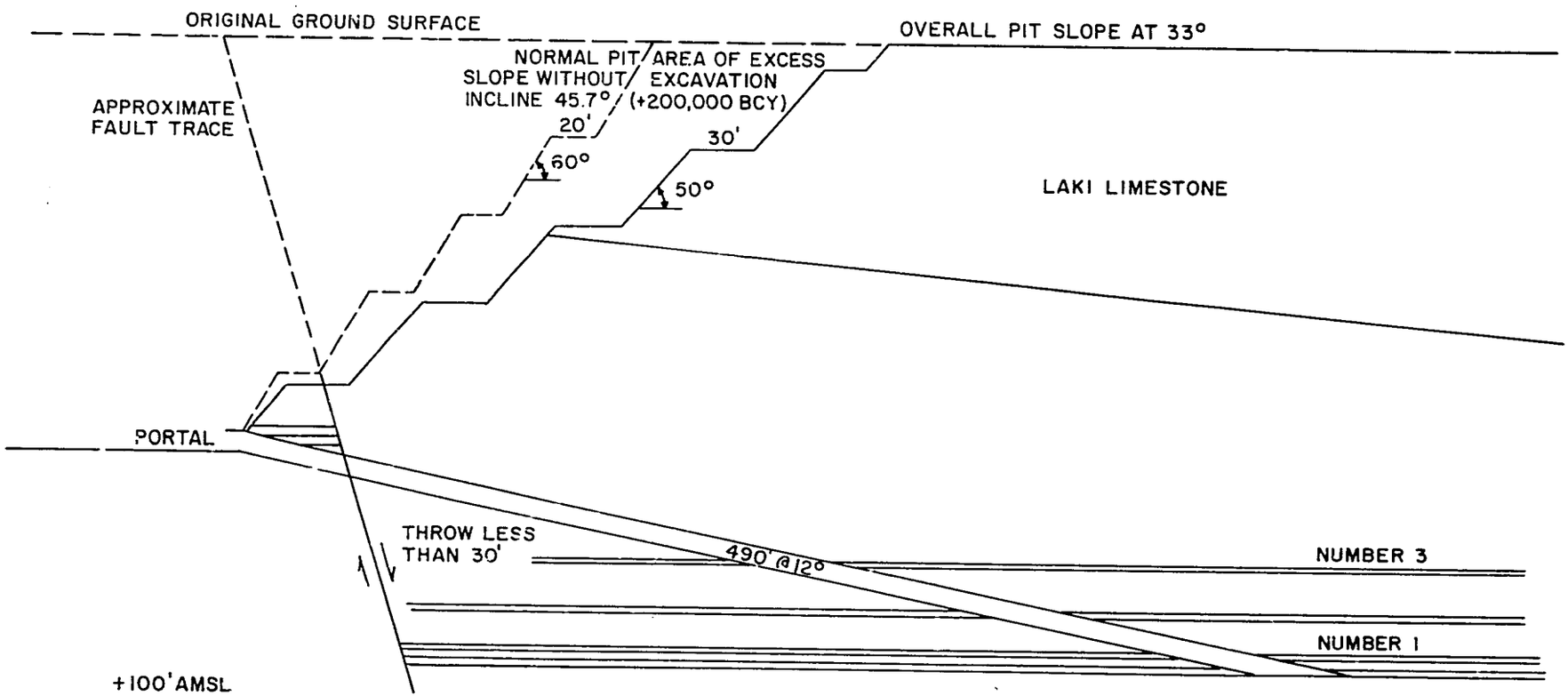


FIGURE 5.5-4
CROSS-SECTION THROUGH
WEST PIN N.E. BOXCUT ACCESS VIA
INCLINE TO UNDERGROUND WORKINGS
LAKHRA COAL STUDY

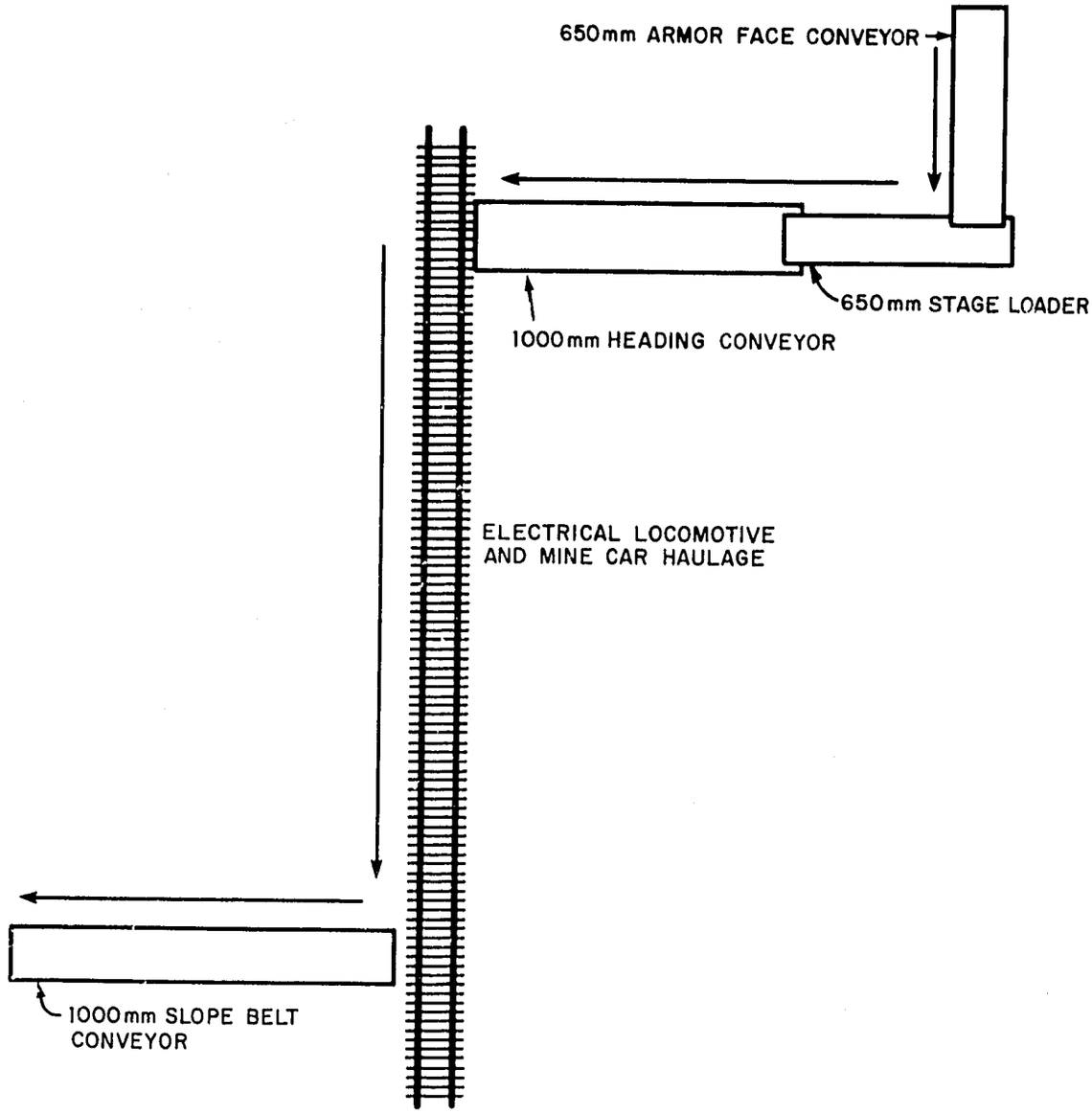


FIGURE 5.5-5
TYPICAL LONGWALL
TRANSPORTATION SYSTEM
LAKHRA COAL STUDY

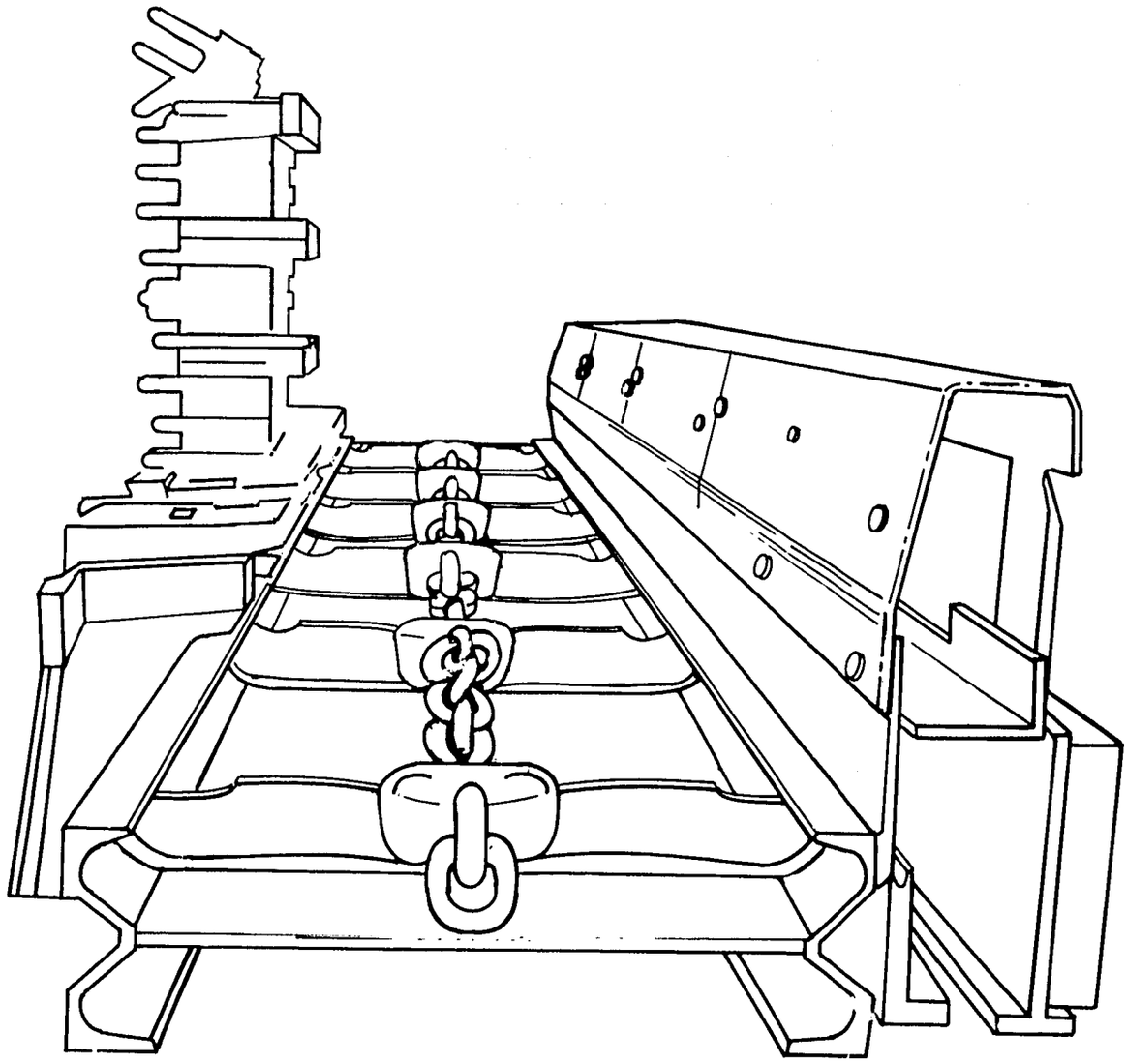


FIGURE 5.5-6
PLOW AND FACE CONVEYOR
LAKHRA COAL STUDY

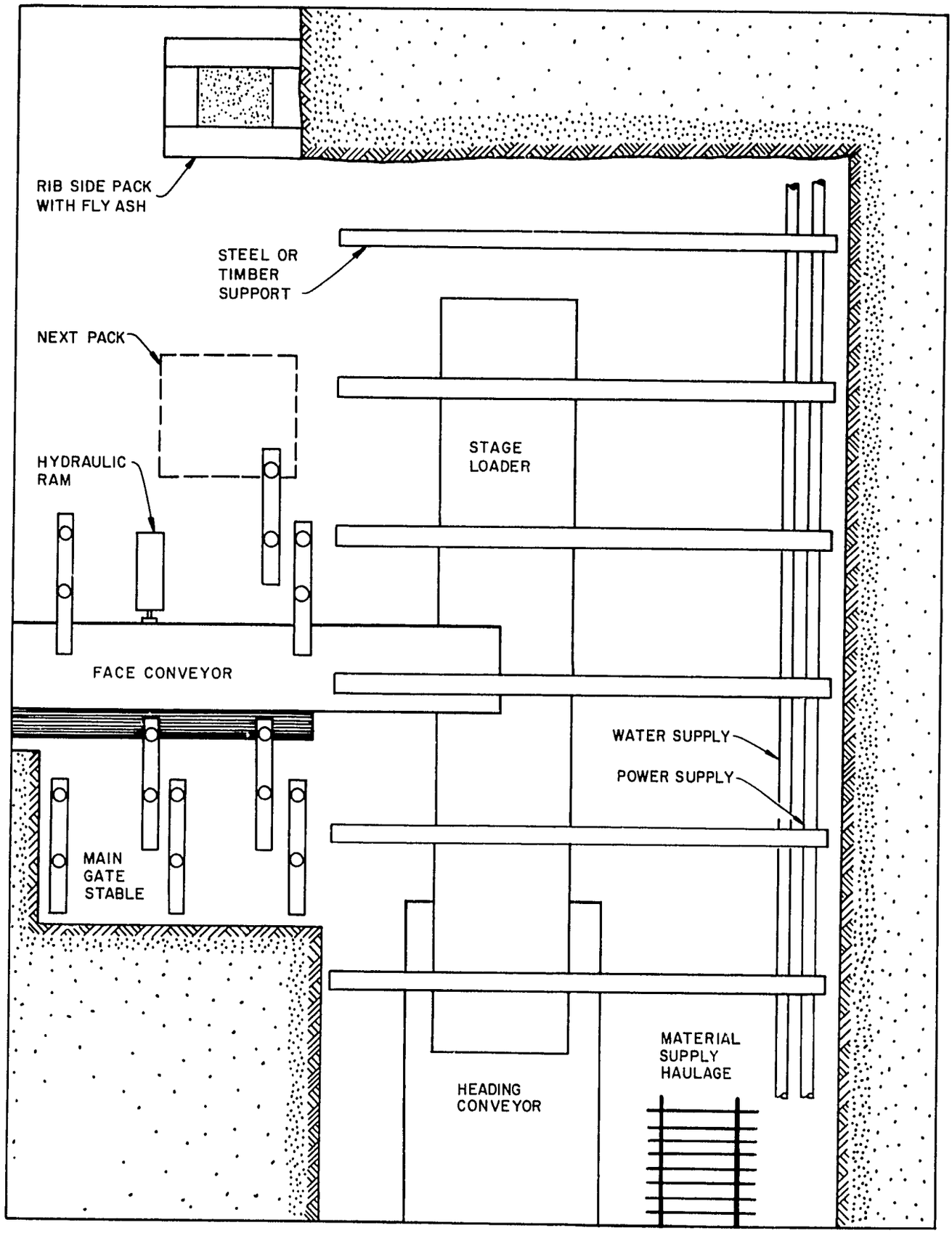


FIGURE 5.5-7
PLAN VIEW OF TYPICAL MAIN GATE
LAKHRA COAL STUDY

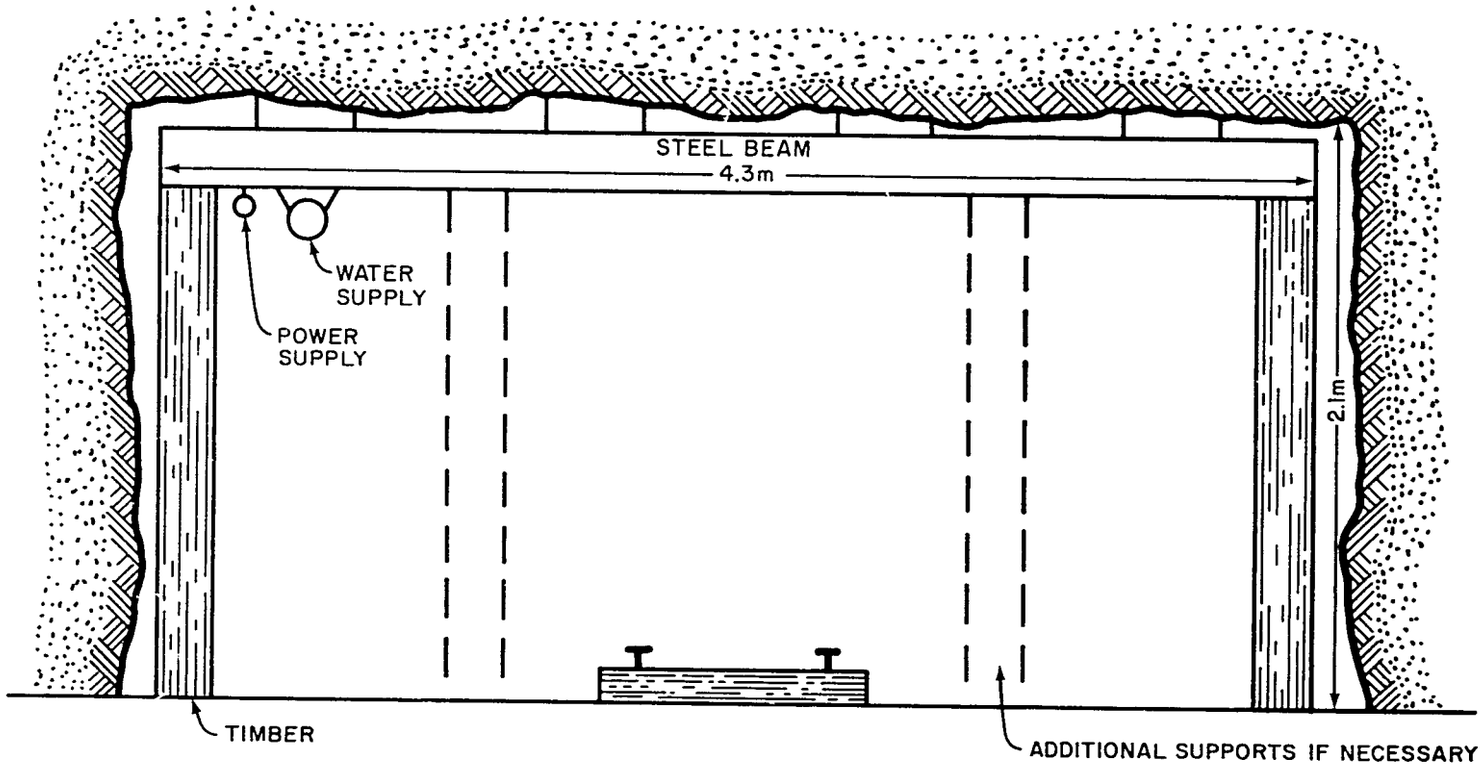


FIGURE 5.5-8
CROSS SECTION OF TYPICAL TAIL GATE ENTRY
LAKHRA COAL STUDY

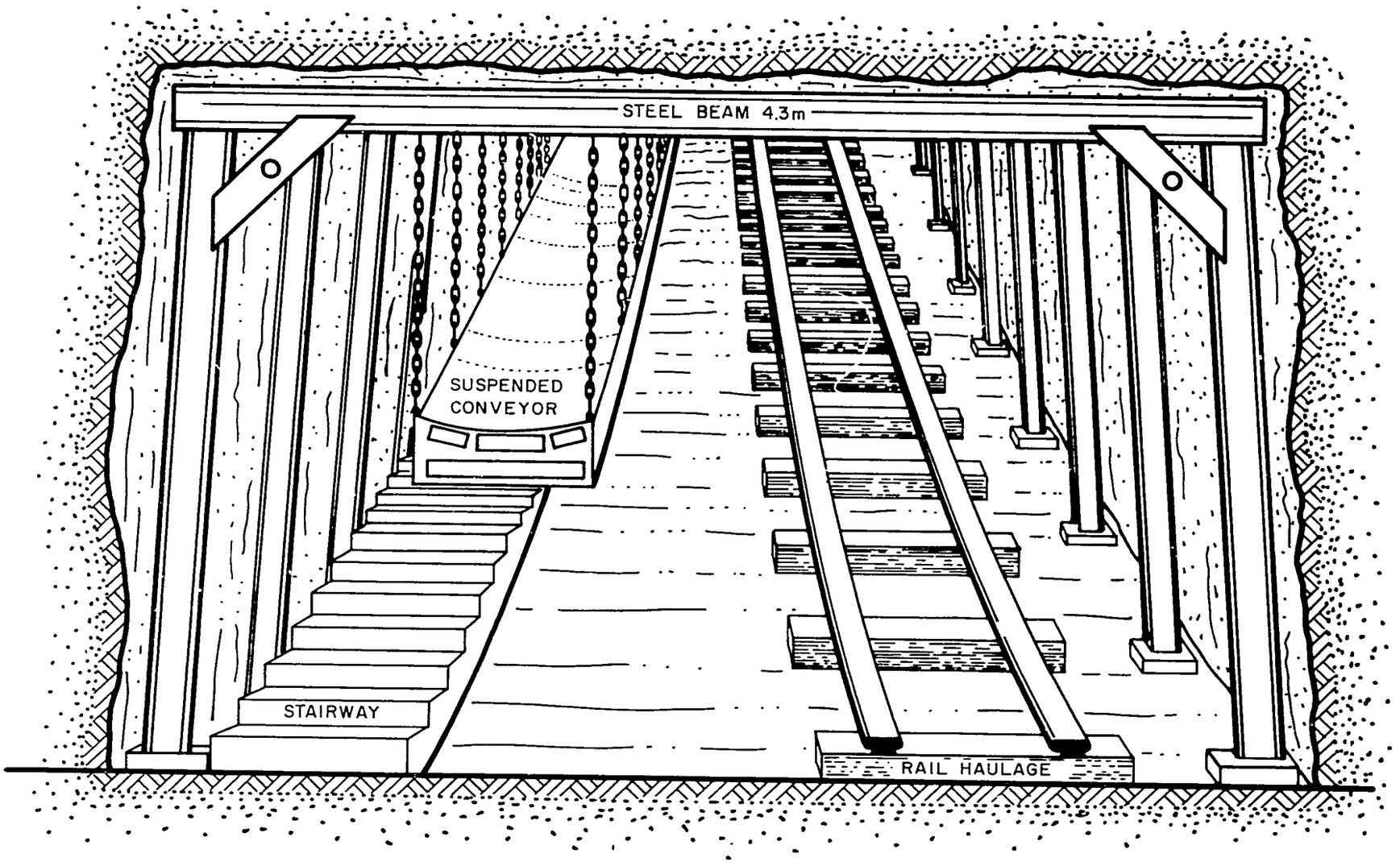


FIGURE 5.5-9
CROSS-SECTION OF MAIN SLOPE
LAKHRA COAL STUDY

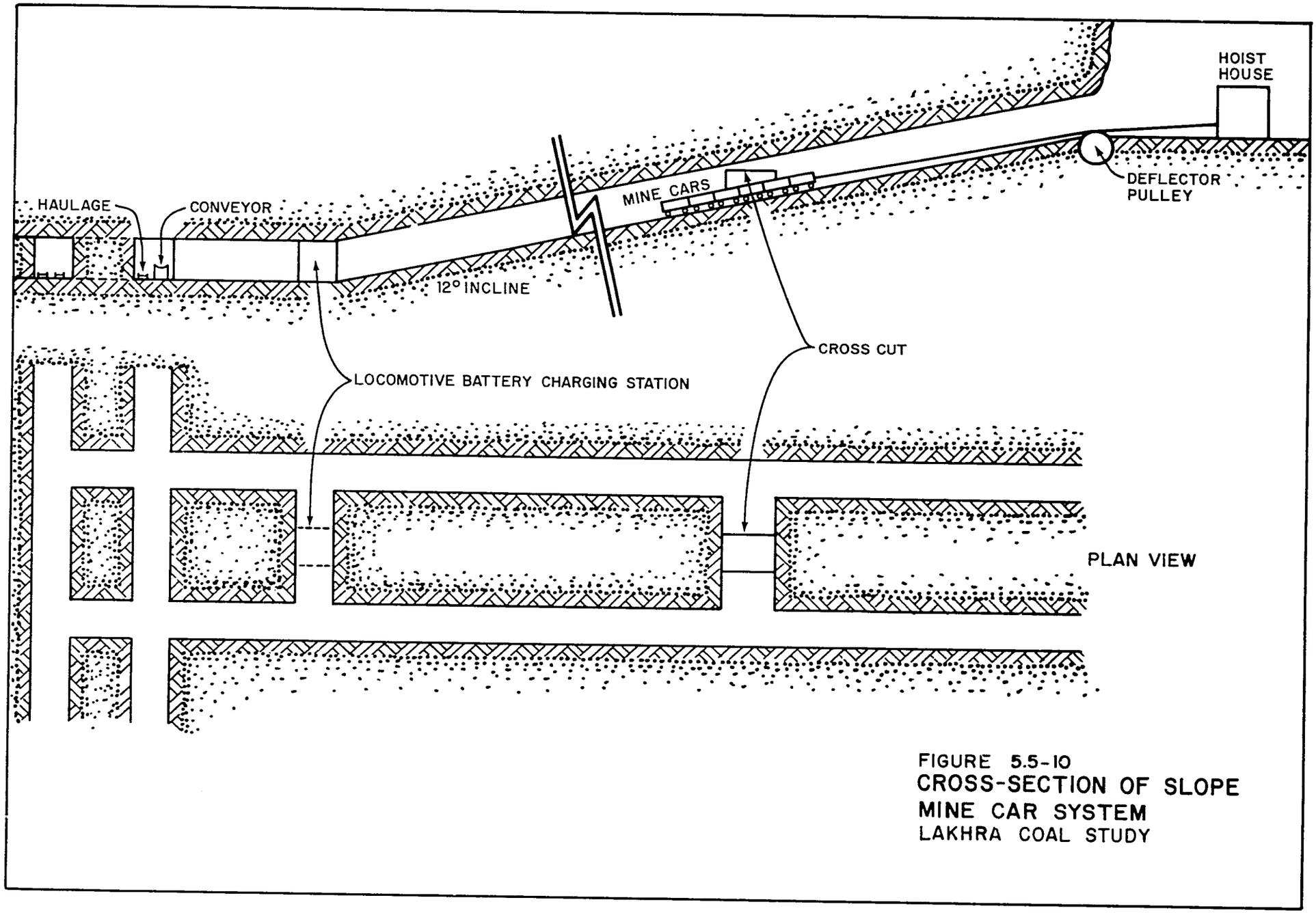


FIGURE 5.5-10
CROSS-SECTION OF SLOPE
MINE CAR SYSTEM
LAKHRA COAL STUDY

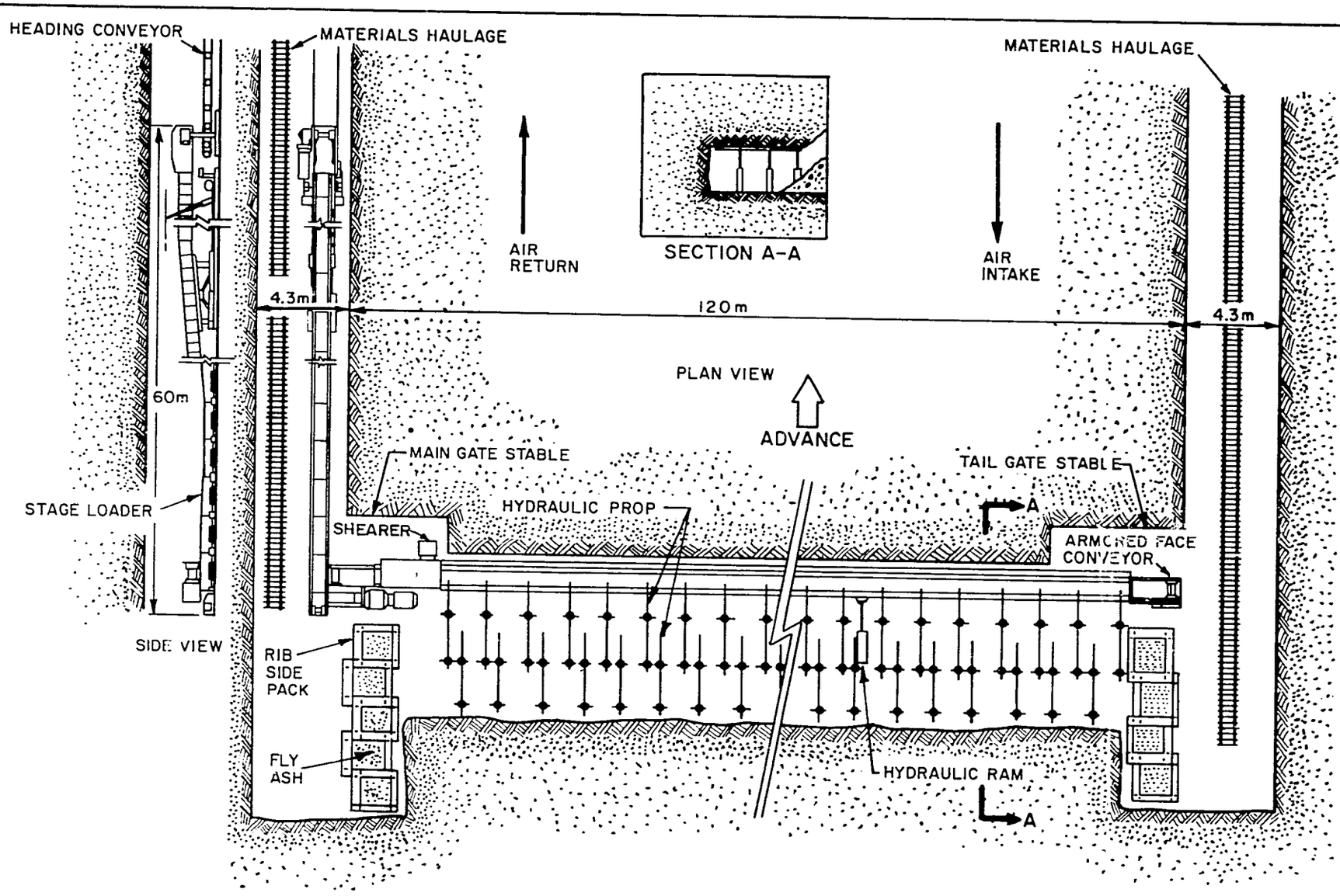


FIGURE 5.5-11
PHASE I LONGWALL MINING PLAN LAYOUT
PARTIAL MECHANIZATION/LABOR INTENSIVE
LAKHRA COAL STUDY

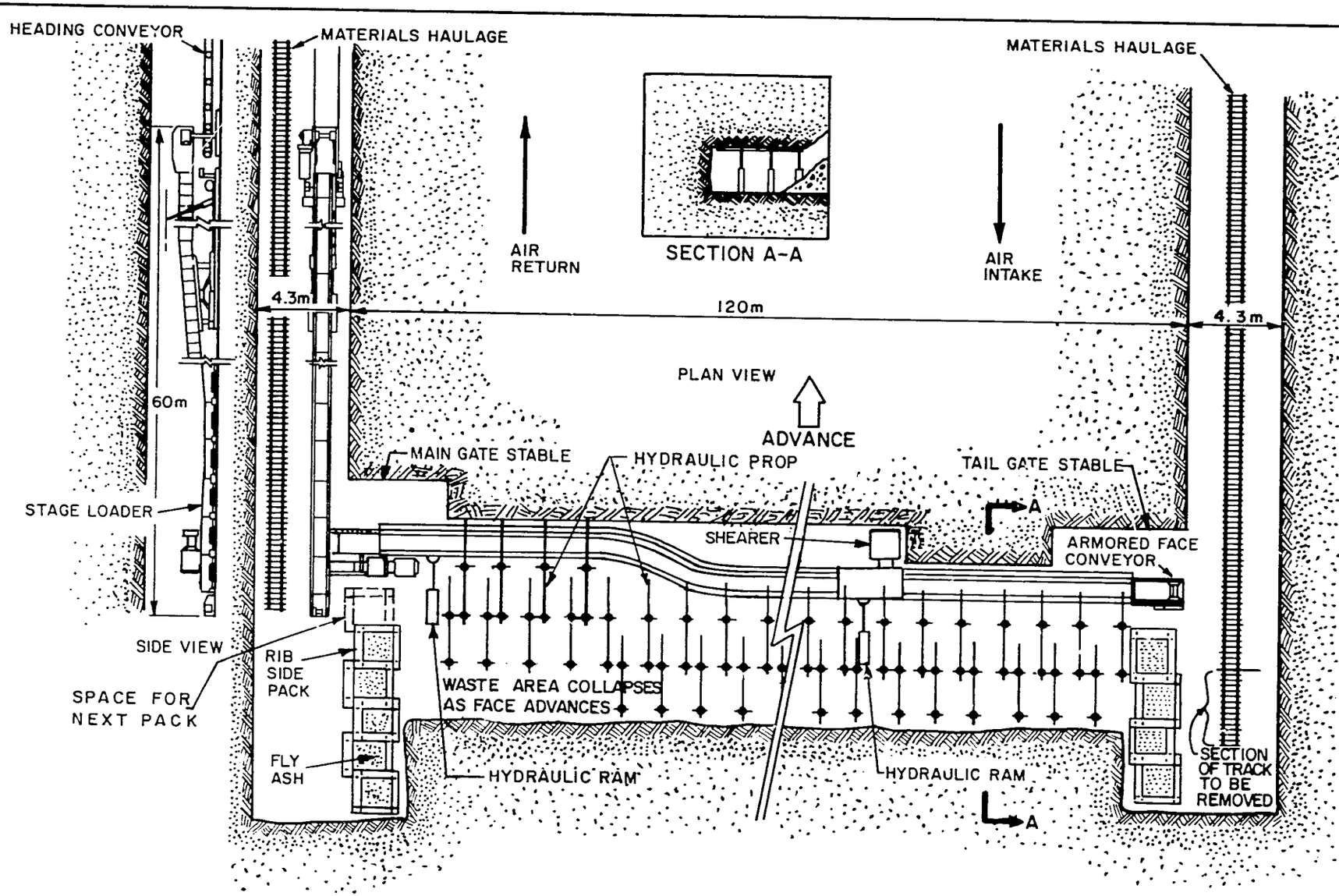


FIGURE 5.5-12
PHASE II LONGWALL MINING PLAN LAYOUT
PARTIAL MECHANIZATION/LABOR INTENSIVE
LAKHRA COAL STUDY

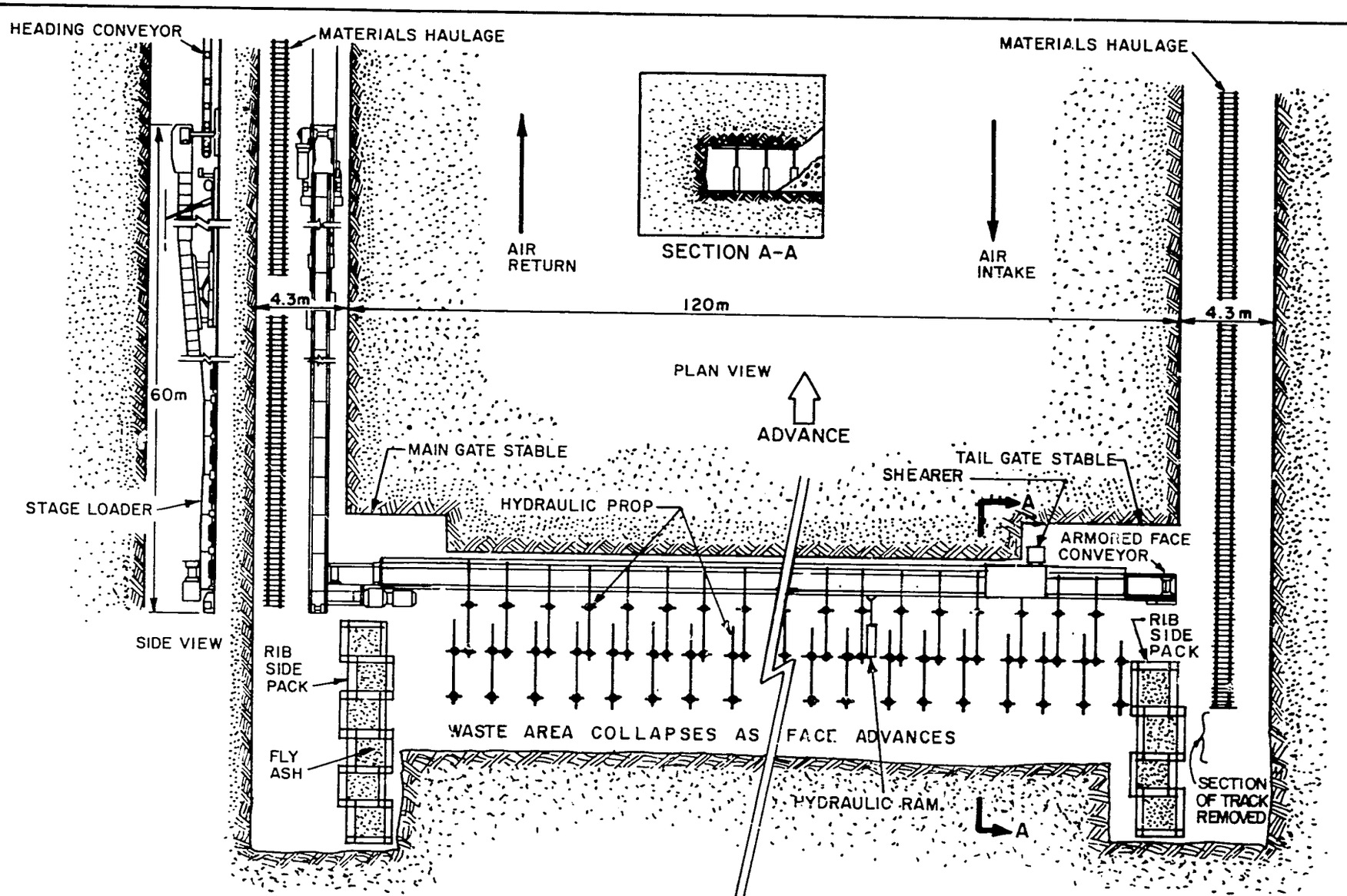


FIGURE 5.5-13
PHASE III LONGWALL MINING PLAN LAYOUT
PARTIAL MECHANIZATION/LABOR INTENSIVE
LAKHRA COAL STUDY

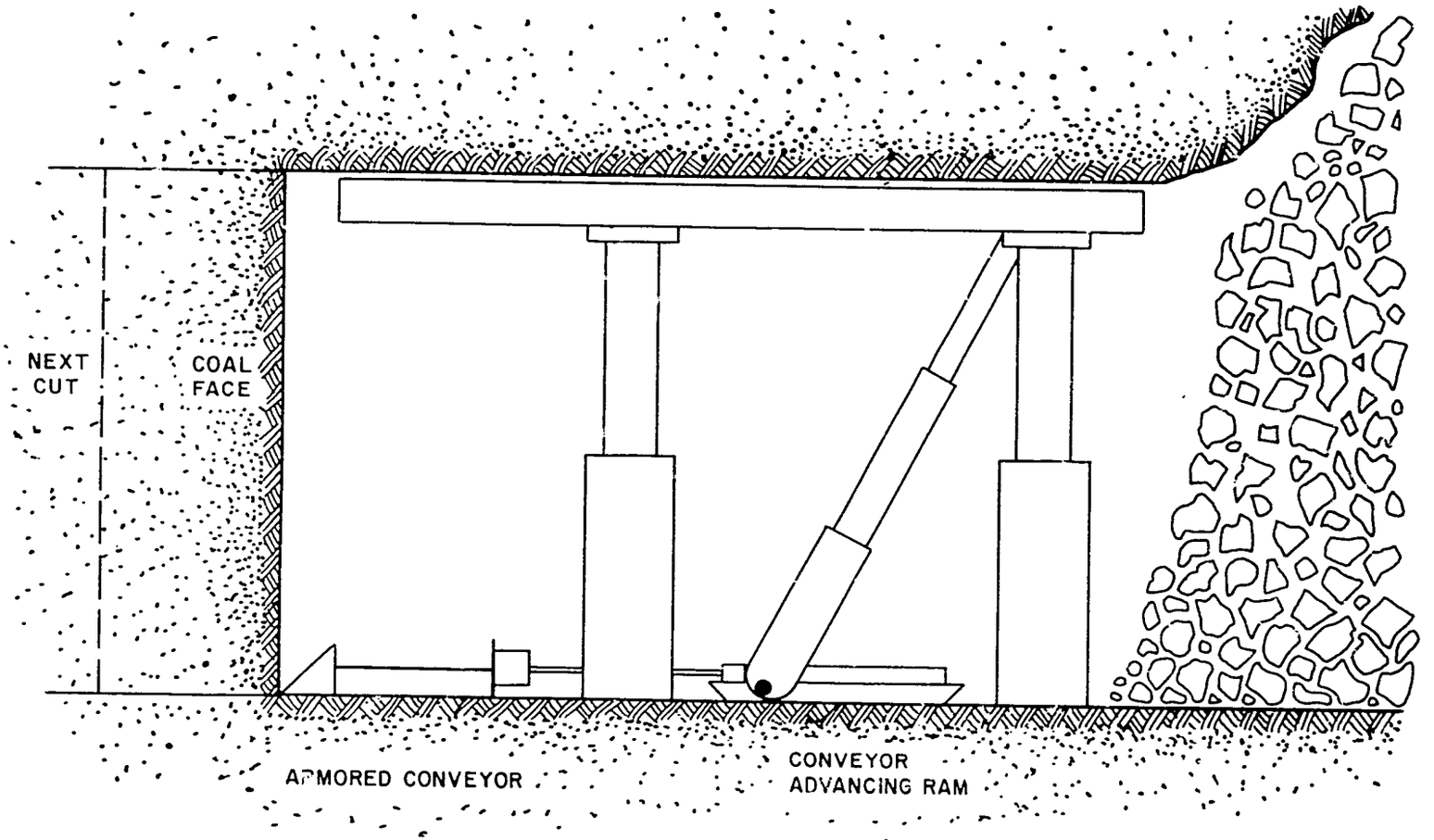


FIGURE 5.5-14
CROSS-SECTION OF PARTIAL MECHANIZATION
INTENSIVE LONGWALL FACELINE
LAKHRA COAL STUDY

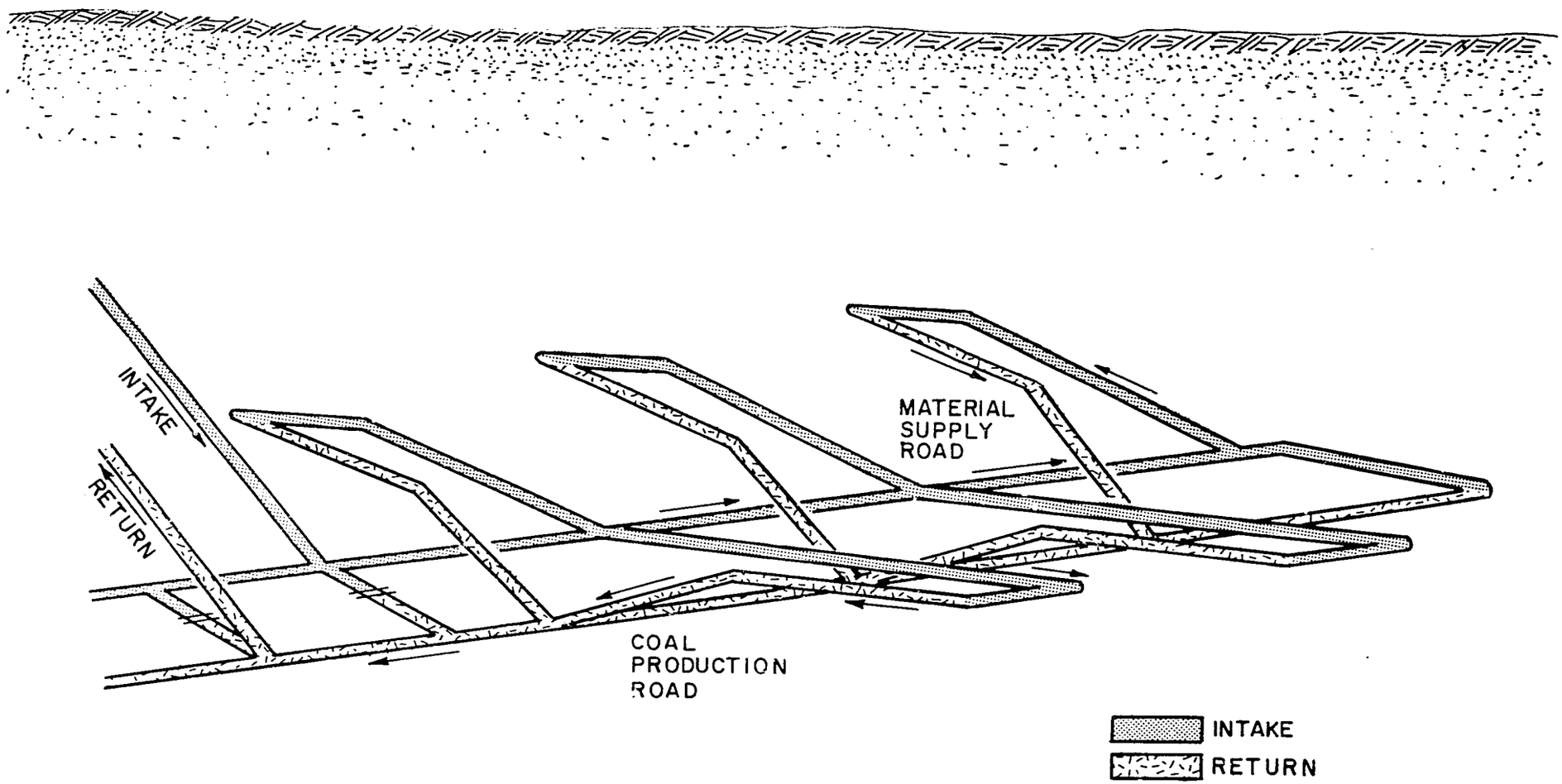


FIGURE 5.5-15
TYPICAL VENTILATION FLOW DIAGRAM
LAKHRA COAL STUDY

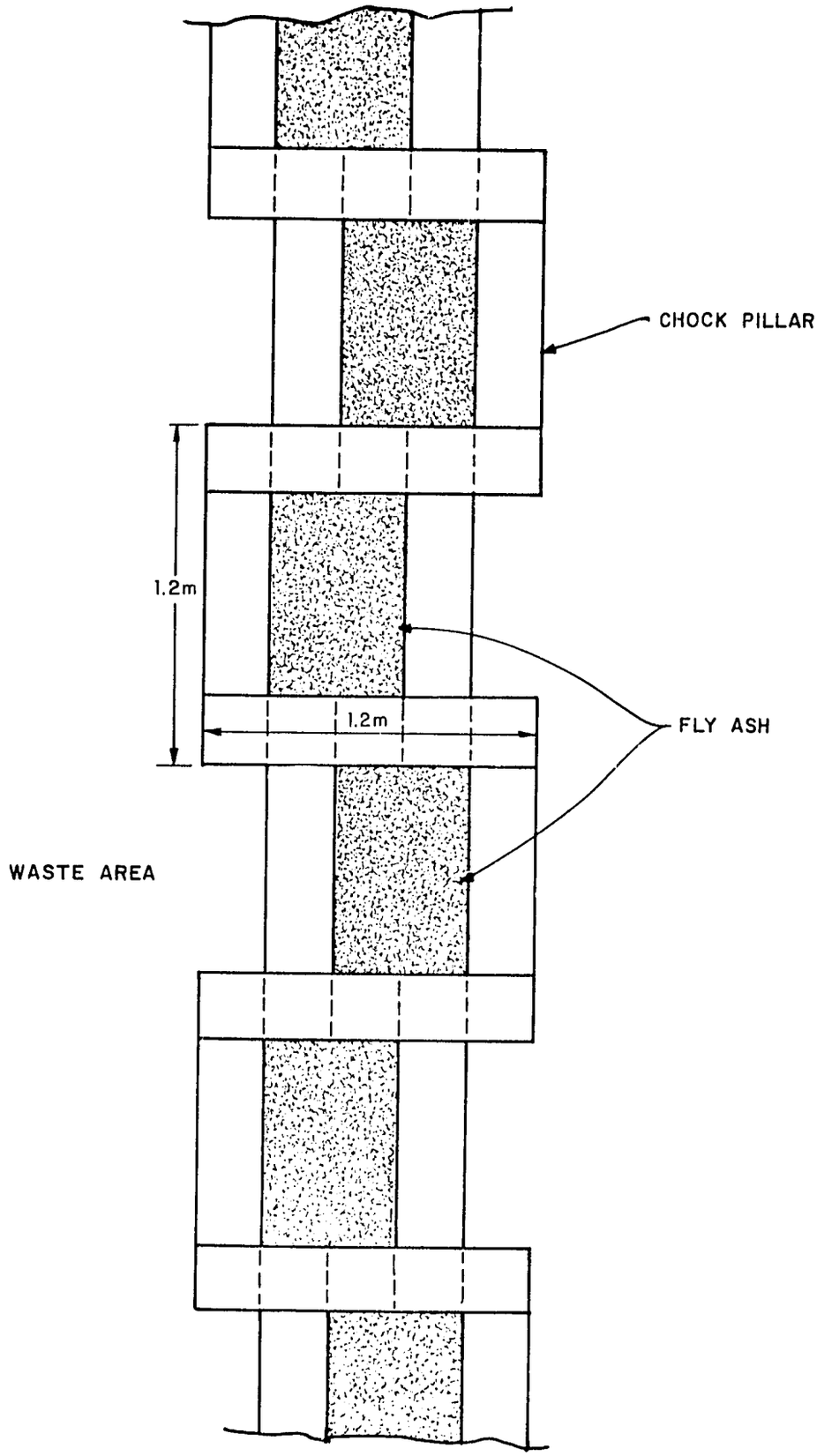
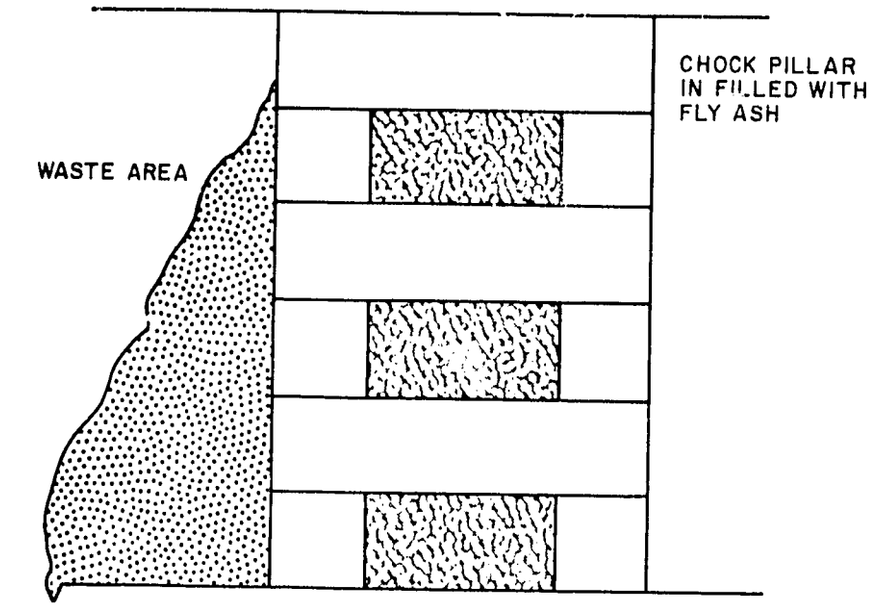


FIGURE 5.5-16
PLAN VIEW OF MINE SEAL
LAKHRA COAL STUDY



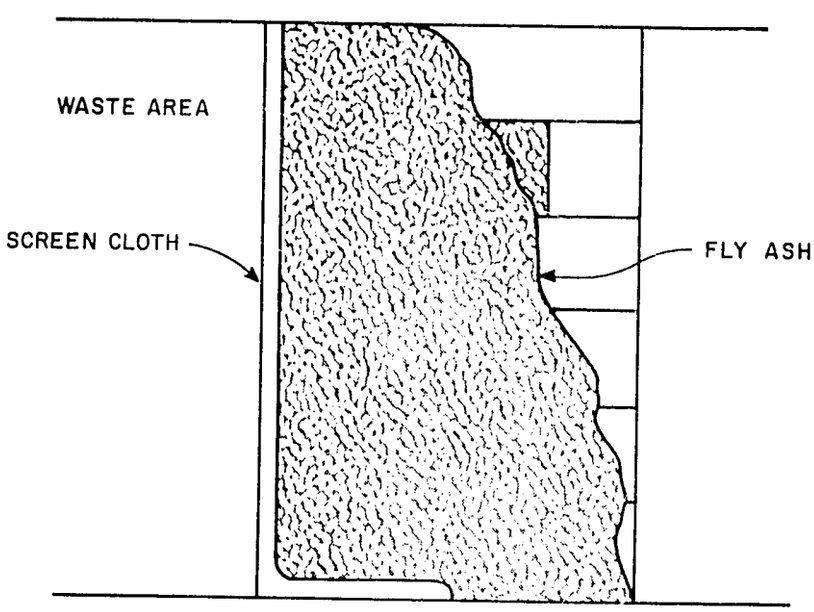


FIGURE 5.5-17
CROSS-SECTION OF TYPICAL MINE SEAL
LAKHRA COAL STUDY

5.6 COAL PREPARATION AND HANDLING

The primary aims of preparing ROM coal for use are:

- Reduction and control of lump size within limits imposed by subsequent handling, transportation, and use.
- Removal of extraneous mineral matter, usually referred to as control of ash content.
- Control of moisture content within specified limits usually determined by handling and use requirements and by pumping of mine working.

Desulfurization

Even where coal has been prepared to meet applicable specifications for size ash and moisture contents, it may still be dirty by environmental standards. In this case, the most important and universal contaminant is sulfur. During subsequent combustion, the sulfur in the coal is almost entirely converted to gaseous products which, unless removed, end up as stack gas emissions. There are no available commercial methods for the complete removal of sulfur from coal prior to combustion. The best that commercial washing methods can achieve is some reduction in sulfur and, in the United States, recent investigations have shown that this removal is highly dependent on the nature of the particular coal and rarely achieves removal better than 40 percent.

The costs of coal cleaning, which are dependent upon the method of cleaning employed, must therefore be considered as an offset against the costs of ultimate particulate removal and flue gas desulfurization at the power plant.

The available options of employing some degree of pre-combustion cleanup as opposed to leaving all cleanup to the post-combustion, flue gas treatment stage has been the subject of intense debate in the United States in recent years. It can be confidently asserted that no general agreement or consensus yet exists. Further information on the status of this debate is provided in two recent papers contained in Appendix 3. There is general agreement, however, that each particular case defines detailed examination on its own merits; this prescription applies to the Lakhra project.

Coal Preparation at Lakhra

The washability characteristics of Lakhra coal are not yet known in sufficient detail to permit decisions to be made on the depth of cleaning and attendant costs.

Limited washability data, obtained in the JICA study from tests made on drill cores, and laboratory conditions considerably more favorable than would pertain in practice, are not encouraging. The coal is extremely difficult to clean adequately by available commercial processes.

While this opinion can clearly be tested in the future as further information becomes available, the indicated and prudent course to follow at the present time for preparing Lakhra coal is as follows:

- Reduce ROM coal to handleable size. Employ feeder-breakers to reduce raw coal received to a top size of 15-20 cm.

- Screen the product at some convenient size in order to separate lumps from small coal. A useful size for this purpose is 4-5 cm.

- Remove all visually recognizable rock and shale from the oversize coal by manual (handpicking) methods.

- Crush the cleared oversize to below 4-5 cm and add back to the primary underflow coal.

- Pass the prepared coal forward to storage and load-out to coal transporation system to power plant.

- Pass removed rock and shale to load-out for removal to and disposal in surface mines and backfill areas.

This scheme essentially corresponds to that prepared in the JICA report. However, that scheme is considered to be over-elaborate and contains a number of intermediate storage silos that are not essential for ensuring the smooth flow of the separate streams of coals from the east and west surface mines and the central undergrond mine.

Also, while a small strategic stockpile of prepared coal supply at the mine is a prudent provision, there is no particular reason for isolating this stockpile from the principal coal flow system, unless it has to be large in relation to production rates.

The size of a prepared coal pile at the mine is chiefly dictated by:

- Possibility of, frequency, and duration of production stoppage in the overall system.

- Effects of inclement weather.

These points were discussed specifically with senior management of WAPDA, PMDC, and Pakistan Railways with the following outcome:

- The possibility of serious and prolonged interrruptions of normal operations by labor disputes can be discounted.

- Damage to transportation systems caused by the worst condition is repairable within a matter of days.

On this basis, a surge storage capacity equivalent to 5 days production of the mines was decided to be adequate. A storage pile of this size could be usefully included in the normal coal flow system, providing the storage capacity ahead of final transportation loadout.

Such a stock pile system also provides an efficient coal blending system since it has been demonstrated that coal movements with such piles are capable of substantially homogenizing coals of different qualities from separate supply sources.

A reduction in capital and operation costs as compared with the JICA proposal has been achieved by:

- Elimination of unnecessary surge storage in costly silos.
- Placing all units of the coal handling system above grade wherever possible to avoid problems and exposure of excavated constructions, stormwater pumping, etc.

In other respects, the prepared plan described in Section 5.10 is similar to the JICA Report.

Location of Coal Preparation Plant

The JICA Report proposes that the coal preparation plant and surface facilities for the mines be located in the south-central part of the PMDC-investigated lease area because the area chosen was declared barren of coal reserves and was conveniently located to receive coal from and provide materials to the mines.

This proposal is sound in principle if the area is found to be actually barren and further drilling investigations verify the absence of mineable coal. One remaining reservation concerns the location of service roads, coal haul roads, transmission lines, and water supply in relation to the underground mines. Employment of longwall mining methods will cause subsidence of the overlying surface by amounts of perhaps 75-80 percent of the thickness of coal extracted. This will have a corresponding effect on surface facilities and it will, therefore, be necessary to relocate them over surface locations corresponding to barrier pillars underground or away altogether from the underground workings.

5.7 COAL HANDLING AND TRANSPORTATION

Decisions concerning coal transportaion between mine site and electric power generating station require consideration of the following factors:

- Intervening topography
- Distances
- Existing transportation infrastructure
- Quantity
- Delivery rates
- Comparative costs

The options for power plant siting to utilize Lakhra coal included the following locations:

- Lakhra
- Khanot
- Jamshoro

Figure 5.2-1 presents relative locations and distances.

The results of siting studies for the power plant have indicated that for generation capacities up to and greater than 600 MW, Jamshoro is the preferred location.

The present study assumes construction of a 300-MW electric power generating stating requiring 1.4 million metric tons of coal per year. A coal requirement for 600 MW is, therefore, 2.8 million metric tons assuming average quality parameters indicated in Table 5.4-1.

Possible transportation modes considered for Lakhra/Jamshoro are:

Method 1

Construction of a rail link from Lakhra to Khanot to join existing Pakistan Railways line; construction of a link between the main line and Jamshoro.

Method 2

Construction of a separate, dedicated rail line between Lakhra and Jamshoro

Method 3

Transportation by road (truck)

Method 4

Overland conveyor system

Method 5

Aerial ropeway

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Method 6

Coal slurry pipeline

Methods 1 and 2 involve similar distances of new track construction but the direct route of Method 2 will provide for a much shorter total haul and consequent reduction in operating costs. It is also independent of main line operations. The costs of operation will be directly related to the tonnage hauled, so that overall transportation costs will be reduced substantially if more units are added in later years at Jamshoro.

Method 3 would require 200-300 truck round trips per day and would be a heavy user of diesel fuel. Although it is labor intensive and vehicles manufactured in Pakistan could be used, operating costs are inherently higher than rail transport modes and this option has not been considered further.

Capital costs of overland conveyor, aerial ropeway, and slurry pipeline have been estimated for a direct link for Lakhra to Jamshoro.

Comparison of capital costs is summarized in Table 5.7-1, which indicates that Method 2 is the most favorable option in terms of capital costs and this method has been adopted.

A description of work for this scheme is given in Section 5.12.

TABLE 5.7-1

COMPARISON OF PRELIMINARY CAPITAL COST ESTIMATES
FOR TRANSPORTATION ALTERNATIVES

Option		Total Cost (Jan. 1983 $)
1.	Railway Lakhra Khanot/Jamshoro, including rail cars	8,580,000[1]
2.	Railway Lakhra/Jamshoro, including rail cars and locomotive	8,000,000
3.	Overland conveyor, including structural, controls, electrical, and erection costs	43,000,000
4.	Overland aerial openway, including structural, controls, electrical, and erection costs	14,700,000[2]
5.	Overland slurry pipeline, including slurry preparation, dewatering, and pumping of activities	143,000,000

NOTES:

[1] Locomotive provided by Pakistan Railway; negotiated freight costs; in other cases, freight charges will be direct cost.

[2] For 875,000 metric tons per year capacity

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5.8 DESCRIPTION OF SURFACE MINING METHODS

5.8.1 General

In order to employ the local labor force and to further utilize equipment that can be produced in Pakistan, smaller sizes of equipment were chosen for nearly every phase of the surface mining operation. Bedford trucks, manufactured in Pakistan, will be utilized as coal and interburden/parting haulers, service vehicles, and support vehicles. A 7.6-meter^3 (10.0-cubic yard) dump body will be utilized for handling parting removal between seams and a 13.5-metric-ton dump body will be used for coal haulage. Other Bedford models can be equipped to carry fuels, lubes, explosives, mechanics' tools, and equipment.

The production split between both pits should be made after considering:

- Reserves
- Blending of coals for quality
- Averaging overburden stripping quantities
- ROM coal production costs
- Optimized production rate by underground mining

Multiple intermittent coal seams are not usually a problem to recover in surface mines. With truck/shovel overburden stripping methods, benches can be adjusted to recover these coal seams. To some extent, these interfaces will have an effect on recoveries that will vary with seam thickness. The use of smaller-sized equipment facilitates this multi-seam coal mining.

When the pits are fully developed, a haulback pattern of overburden backfilling will be utilized with truck haulage proceeding around developed benches to the designated dump points.

5.8.2 Mining Methods

The total system is illustrated in Figure 5.8-1 and is applicable to both east and west surface mines.

Surfaces Preparation

In most cases, little or no surfaces preparation is necessary. Any vegetation present must be cleared; loose sand that will hamper bench drilling and development must be removed by dozer and scraper or by loading into small trucks and hauled to a designated overburden storage area.

Overburden Bench Development

After the surface has been prepared, a large-diameter blast hole drill will drill out blast hole patterns to develop approximately 15-m benches in the overburden. Three drills will be needed; one in each pit, plus a third to provide a capacity for drilling in hard limestone or to assist in drilling the excess overburden developed in the east pit. A dozer will prepare drill sites for the large drills on an as-needed basis.

Overburden Removal

After blasting, 7.6-m^3 electric shovels will load rock into 42-m^3 mechanical-drive end dump trucks. Initially, while the pit development proceeds, the overburden will be hauled to a designated stock pile area outside the active coal mining limits. This development phase will include full development of all active working benches in overburden, coal, and interburden as well as the boxcut development for the underground access. All of this development work has been capitalized in the economic analysis.

When the initial pits and overburden stockpiles are fully developed, a direct haulback pattern of overburden backfilling will be utilized with truck haulage proceeding by ramps to the designated dump points, as shown on Figure 5.8-1.

Coal Mining

The coal will be ripped by a dozer before loading with the 3-m^3 front-end loaders, which will discharge into 15-metric ton Bedford dump trucks. The coal will be loaded from several coal benches developed on the mineable coal seams. A total of 5 front-end loaders and 18 Bedford dump trucks will be operating in coal removal in the east and west pits.

Interburden Removal

The removal of partings and interburden will be in sequence with coal removal. This material will also be ripped to break it up for handling by 1.7-m^3 front-end loaders which will discharge into 7.6-m^3 Bedford dump trucks. Five front end loaders and 15 trucks are provided for deployment between the east and west pits for this work phase.

Roads, Ramps, and Coal Cleaning

Equipment provided for these tasks include dozers with rippers, scrapers, roadgraders, and water trucks. This construction equipment will be utilized in groups or singly as needed for any construction tasks common to the surface mining operation.

Final Surface Recontouring

Trucks will dump overburden material as backfill and the surface of the deposited material will be graded by dozer. A final surface configuration and revegetation plan most suited to the needs of this area will be selected.

5.8.3 Planning Studies

When a detailed operational plan is being developed, many aspects must be considered. Some previous studies did not take into account alternate access to underground coal mining areas. The JICA Report was quite conservative. However, the surface mine plan presented in the JICA Report was adopted as the basic development plan for the single 300-MW power plant case, with adjustments only for a different equipment mix and for underground access.

Detailed operational planning of surface mining should include:

1. Alternate overburden removal methods; i.e., dragline and truck shovel combinations, mechanical miner for coal removal. One problem relating to large size draglines is that their increased delivery and erection times compared with electric shovels may not meet project scheduling.)

2. Various forms of pit sequencing and layout.

3. Railroad haulage for overburden and coal hauls.

4. RCM truck dump in the pit with conveyor haulage to crusher with conveyor advance as the pit advances.

5. A detailed study of the three proposed mines (east, west, U.G.) to optimize the sequence of mining relevant to mining economics.

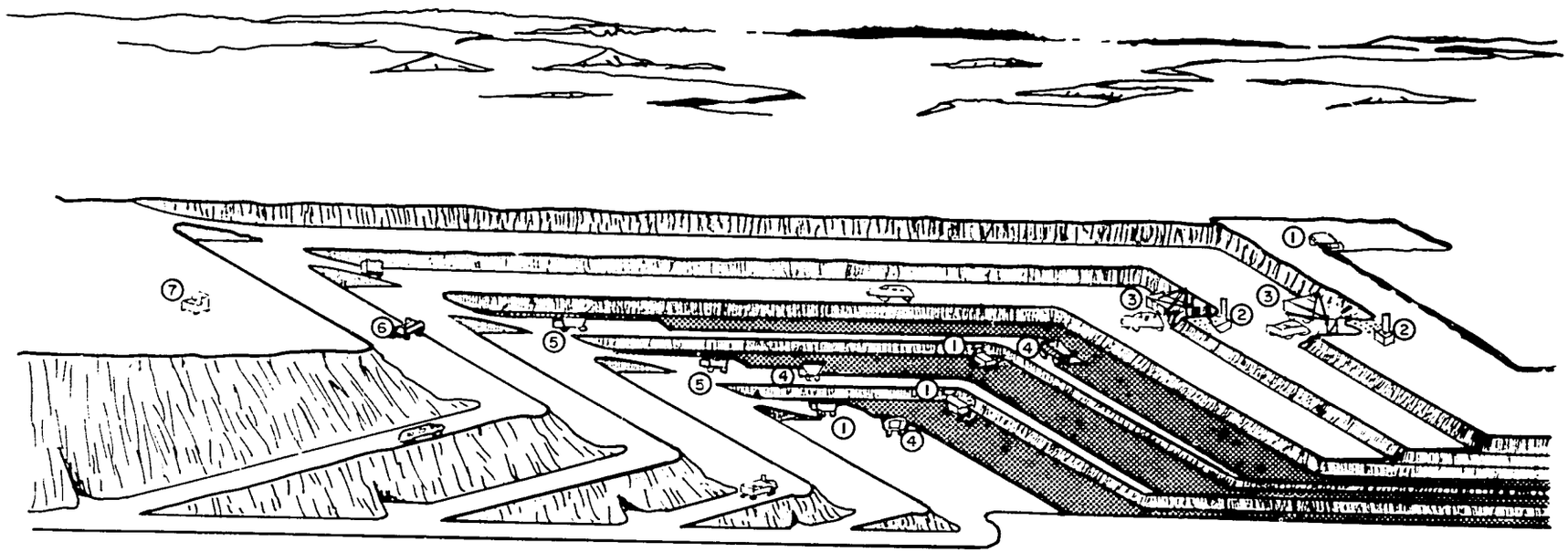
6. Alternate coal recovery systems in the peripheral areas of both underground and surface mires. These should include "punchmining", augering, the use of thin seam miners or other appropriate equipment to recover coal in marginal situations.

7. Placing of surface facilities to avoid their location over economically recoverable coal beds.

8. Mineability of peripheral reserve areas.

9. The most desirable reclaimed surface for an enhanced future use of the land.

All these activities are an integral part of the detailed mine plan and need not require separate studies or additional time and delay to the coal delivery dates as required by the power plant.



LEGEND:

① SURFACE PREPARATION
② OVERBURDEN DRILLING
③ OVERBURDEN STRIPPING
④ COAL RECOVERY LOADER
⑤ COAL HAULAGE
⑥ OVERBURDEN BACKFILLING
⑦ SURFACE GRADING
⑧ INTERBURDEN REMOVAL

FIGURE 5.8-1
CONCEPTUAL MINING PLAN
SURFACE COAL MINE (PMDC), LAKHRA, SIND, PAKISTAN-HAUL BACK METHOD
LAKHRA COAL STUDY

5.9 DESCRIPTION OF UNDERGROUND MINING METHODS

5.9.1 General

Underground coal production, using modifications and alternatives devised to improve the JICA Plan, includes one mechanized longwall face, one hand-loading longwall face, one continuous miner developing main entries and panel entries, and conventional units featuring endgate loaders and handloaders. Because these methods can be combined in numerous ways, there are a number of options for mine development and attendant production rates that will depend upon the schedule selected. The mine will be designed to produce 275,000 metric tons of ROM coal per year, but if all the methods are used together at any one time, production could be considerably higher, being equivalent to more than 600,000 metric tons per year.

5.9.2 Transport System

The mode of transportation from the faces to the open slope heading at the pit bottom will be as follows:

Face line	-	650-mm-wide armored face conveyor
Headings	-	650-mm stage loader on to a 1000 mm heading conveyor
Main level	-	electric locomotives and 5-metric ton bottom dump mine cars
Slope	-	1000-mm belt conveyor

This combination will allow maximum use of manpower while maintaining a steady coal flow. Storage bunkers will be provided at the heading transfer point and the slope bottom to provide transfer capacity in case of breakdown in any part of the system. These bunkers also smooth out coal flow and improve system efficiency.

Personnel and materials will ride the mine cars. Special rail trucks will be provided for underground equipment moves and rapid transport of mine officials.

Steel will be used for roof support in the slopes and at main levels, where long life use is required. Timber will be used for panel entries, where a shorter operational life is required.

It is possible to increase production from the surface mine areas by drift adits (punch mines) or auger mining of the highwall. It is expected that such methods will have particular importance in the eastern open pit. Plans for these supplementary mines will then be integrated into the open pit schedules.

5.9.3 Basic Design Criteria

1. Development of two sets of access boxcut-inclines with intercepts of the Nos. 3 and 1 seams.

2. Slopes will be -12° from the horizontal, and approximately 150 m long. Main air intake slope will carry pipes and power supply. Return air intake will carry haulage.

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3. Main haulage system designed for a maximum capacity of 2,125 metric tons per day of ROM coal produced by:

   - One mechanized longwall producing 400 metric tons per shift, 3 shifts per day, 6 days per week.

   - One handloading longwall producing 250 metric tons per day, one producing shift and two repair and preparation shifts per day.

   - One continuous mining unit driving mains and panel entries operating 3 shifts per day and producing 180 metric tons.

   - Room-and-pillar conventional mining sections which will drive panel entries and will be used for pillar splitting during retreat featuring two endgate loaders. Production will be 55 metric tons per shift, 3 shifts per day.

4. All timber used for roof support and construction of cribs and packwalls to be treated with fire retarding chemicals.

5. Slopes and main entries will be supported by steel square sets, supplemented by timber trusses.

6. Panel entries and endgates will be supported by timber square sets and roof trusses.

7. Mechanized longwall rate of retreat will be 4.1 m per day for 3-shift production and 2.7 m per day for 2-shift production.

8. Handloading longwall rate of retreat will be 85 cm per day for single-shift production.

9. Continuous miner rate of advance will be 45 to 60 m per day in a 1.5-m coal seam cutting 4.3-m-wide entries.

10. Conventional entry development is assumed to be approximately 130 m per shift.

11. Productivity per underground worker is assumed to be 3.3 ton per manshift.

12. Machine availability is assumed to be 85 percent.

13. Longwall equipment availability is assumed to be 75 percent.

14. Repairs will be carried out as mechanical failures occur.

15. Maintenance will be carried out between shifts and on shift as needed. Major equipment changes and replacements will be performed during panel and face-to-face moves.

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5.10 DESCRIPTION OF COAL PREPARATION AND SURFACE FACILITIES

Coal from surface mines will be delivered to the coal storage and rail load-out facility in the mine area by Bedford rear dump trucks (Figure 5.10-1).

Trucks will unload to an above-ground 150-metric-ton truck hopper, with truck ramp from grade. A grating at the hopper will prevent lumps larger than 60 cm from passing into the hopper. These oversize lumps will have to be broken up on the grating before dropping into the hopper.

At the outlet of the truck hopper, a combination crusher-feeder will control the rate of flow at 400 metric tons/hr and reduce all coal to a minus 15 cm) product.

A 800-mm belt conveyor will transport the coal from the truck dump to a processing building where it will be screened for removal of all plus 5-cm material. Oversize will then pass over a 1000-mm picking conveyor where noncombustible (ash) materials will be manually removed. Oversized coal will discharge from this conveyor to a crusher for reduction to a minus 5 cm product. All screened coal, as well as that passing through the crusher, will discharge to a common belt conveyor for transport to the coal storage pile.

In addition to trucked coal, the coal from an underground mine will be delivered to the facility at a maximum of 100 metric tons/hr. This coal will be introduced to the system at the screen located in the process building.

All processed coal will be delivered to the storage pile over a 800 mm belt conveyor. This conveyor will discharge through a lowering well, creating a conical shaped pile of 20,000-metric-ton capacity (5 days of plant production).

Reclaim from the storage pile will be by a combination of gravity and bulldozing. Approximately 30 percent of the pile will be reclaimed by gravity through the four normal reclaim hoppers and feeders with the remainder being bulldozed to these same hoppers. A fifth hopper and feeder will be installed at the base of the lowering well to provide for cleanout of the well. All coal reclaimed through the hoppers and feeders will be discharged to a 1400-mm belt conveyor which will transport it to a 200-metric-ton rail loading surge bin at the rate of 1800 metric ton/hr.

Coal from the surge bin will be gravity loaded into rail cars at the 1800 metric ton/hr) rate filling a 46-car train in approximately 1-1/4 hours. The single train will make two daily round trips between the mine and the power plant, delivering the daily mine output of 4,000 metric tons.

A track scale(s) will be placed as to weigh empty incoming cars and full outgoing cars.

Noncombustible materials removed from the coal flow at the processing building will be conveyed over a 800-mm belt conveyor to a 60-metric-ton refuse storage bin.

Refuse from the storage bin will be loaded into trucks for disposal at the mines surface mines backfill area.

The area for the coal storage pile will be approximately 70 m in diameter. An impervious liner will be provided beneath the coal pile. Around the pile will be gravity fed, lined, runoff collection trenches leading to a waste equalization pond.

The preparation plant building is a structural steel, building with metal roof and reinforced concrete foundation and ground level floor slab. The building will be approximately 90 m long x 23 wide x 12 m high.

An explosives storage facility will be provided. It will be a structural steel building with metal siding and roofing and reinforced concrete foundation and ground level floor slab. The building will be sized for the storage of 200 metric tons of bulk of ammonium nitrate and will also include a railroad siding discharge and unloading dock.

A general service building will be finished. This building will be of structural steel with metal roofing and siding, with a reinforced concrete foundation and ground level floor slab. The building will be sized to include warehouse space, mechanical and electrical workshops, offices, change and locker rooms with toilet facilities, and coal handling system control room.

Diesel fuel storage for 1,900,000 liters will be provided. This will also include all necessary reinforced concrete foundations.

Reinforced concrete foundations will be provided for support of all conveyor support structures. The truck dump hopper pit will be constructed above grade with a truck ramp from grade to the hopper level. The pit will be approximately 6 m square x 12 m deep.

A retaining wall will be included to hold the fill used in making the truck ramp. The pit and retaining wall will be of reinforced concrete construction.

The reclaim tunnel under the storage pile will be below grade, Figure 5.10-2. It will be approximately 7 m wide x 6 m deep x 60 m long with a sump, escape tunnel, and conveyor tunnel to grade. The conveyor tunnel will be 3 m wide x 2.5 m deep x 75 m long. The escape tunnel will be 1.8 m wide x 2.5 m deep x 14 m long. The complete tunnel structure will be of reinforced concrete.

Fire protection and service water will be provided in the coal handling and storage areas. It will include all piping, valves, fittings, instrumentation, hydrants, hose, supports, excavation, and backfill.

All necessary hoists and monorails required for servicing the coal handling equipment will be provided.

All electrical equipment including cable, conduit, controls, lighting, grounding, switchgear, motor control centers, etc will be provided.

Sump pumps, including all piping, fittings, hangers, etc, for piping to coal pile runoff collection pond will be included.

All chute-work and reclaim bins will be of type 304 L stainless steel. The truck hopper and 200-metric-ton surge bin will be of Cor-Ten steel with 10-gage type 304 L stainless steel liners. The 60-metric-ton refuse bin will be Cor-Ten steel.

All conveyors located above ground will be covered with 1/2 curved hoods. All elevated conveyors will also be furnished with a walkway on one side for access.

A magnet for tramp iron removal supported from trolleys will be located at the discharge of the conveyor, from the truck hopper to the screen house.

Belt scales will be provided at the conveyor from the truck hopper to the Process-Screen house, the conveyor to the storage pile, and the reclaim conveyor to the rail surge bin. These scales will be used for inventory information.

Two bulldozers are included for work around the coal storage pile.

An itemized equipment list is provided in Table 5.10-1.

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TABLE 5.10-1

COAL PREPARATION AND LOAD-OUT
EQUIPMENT AND INSTALLATION LIST

Item	Quantity
100-metric ton truck hopper, including grizzly and gates	1
Vibratory feeders at 450 and 500 metric tons/hr, including chutes and supports	2
Miscellaneous steel for platforms and stairs at track hopper	Lot
1000 mm belt conveyor, including hood, walkway, truss, vents, chute, loading skirt, etc.	1 (115 m with truss) (50 m without truss)
1000 mm belt scale	1
Lowering well - 2 m diameter x 25 m high	Lot
Reclaim feeder at 350 and 700 metric tons/hr including chutes and support	10
Reclaim hoppers, including grizzly and gates (1 m^2)	9
1000 mm belt conveyor, including hood, truss, vents, walkway, chute, loading skirts, etc.	2 (32 m with truss) (135 m without truss)
700-metric tons/hr crusher, including drive and chute to conveyor	2
1000 mm magnet with trolley support	2
12 m x 9 m x 17 m high crusher house (Open structure with roof, including floor levels and stairs)	Lot
1000 mm belt conveyor including hood, truss, vents, walkway, chute, loading skirt, etc.	2 (190 m with truss) (185 m without truss)
1200 mm tripper belt conveyor, including traveller tripper, loading skirts, etc.	2 (50 m)
Control system, including all controls, wiring, etc.	Lot
Electrical, including all lighting, motor	Lot

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TABLE 5.10-1 (Cont)

Item	Quantity
controls, centers, etc.	
280 kw rubber-tired wheeldozers	2
System hoists and trolleys	Lot
Sump Pumps	Lot
Fire protection system	Lot
Dust collection and ventilation	Lot
Car shaker	1
Car shaker support	Lot
Diesel fuel storage (1,900,000 l)	Lot
Explosives storage facility for 200-metric ton ammonium nitrate storage. To include railroad siding and unloading dock.	Lot
Building, including superstructure and substructure; also, warehouse space, mechanical and electrical workshops, offices, change room and lockers, toilet facilities, control room, etc. Shops to include all necessary tools, machines, hoists, etc. for a complete installation. All buildings to include all necessary water, electrical, air, etc.	Lot

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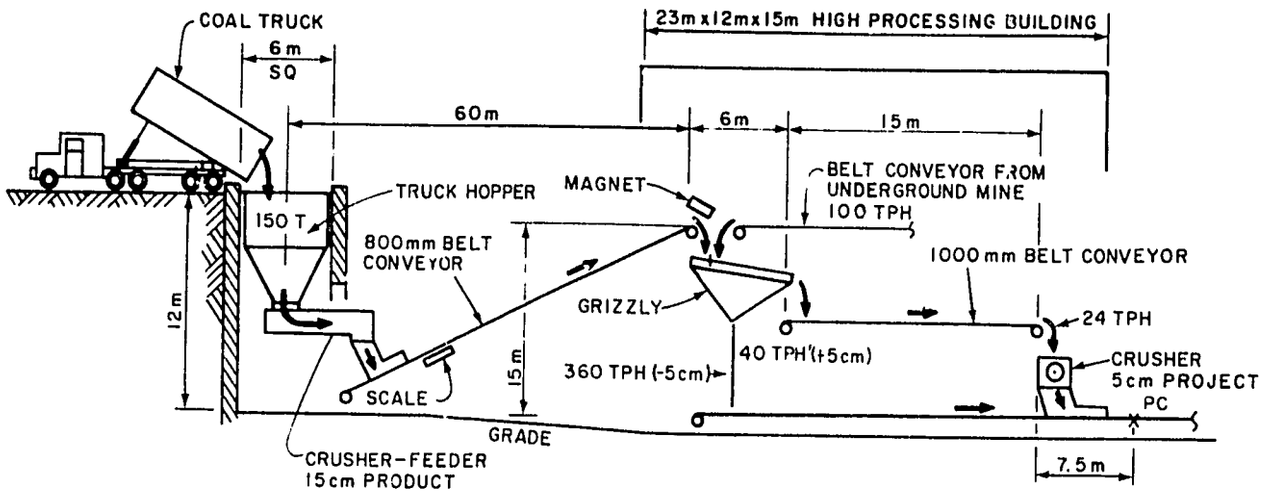
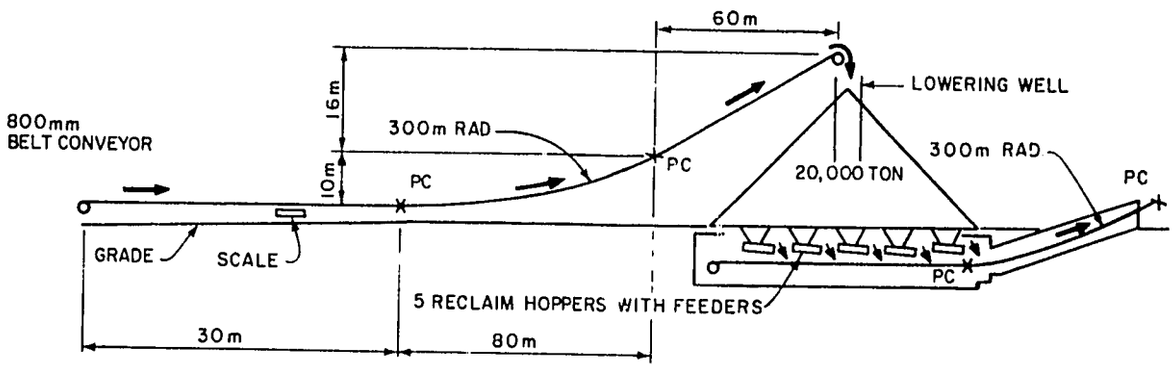




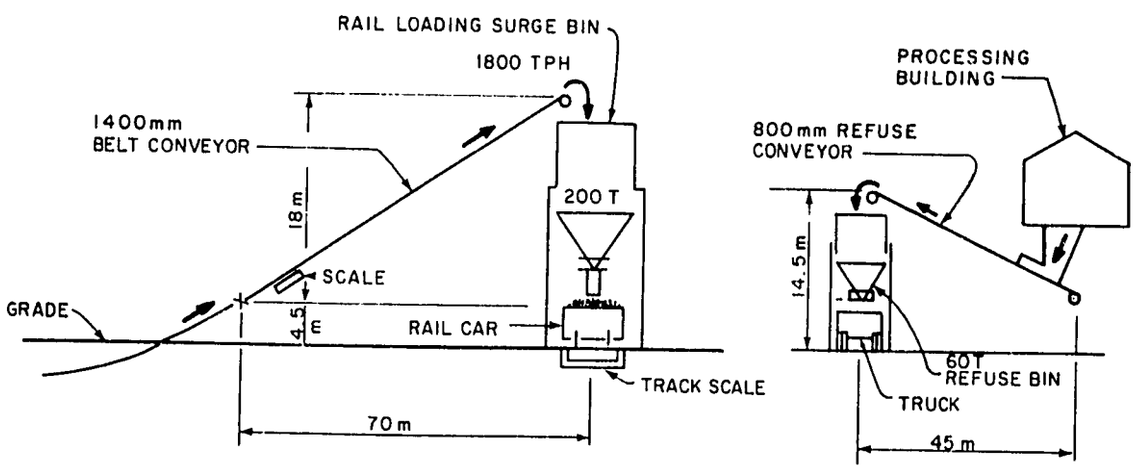
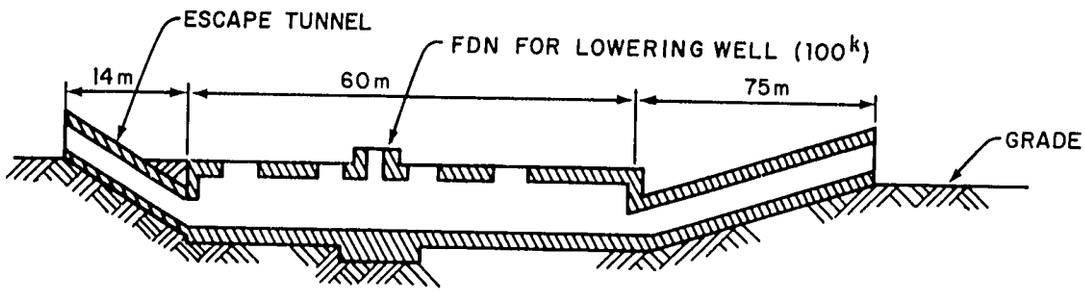


FIGURE 5.10-1
COAL HANDLING AT THE MINE
LAKHRA COAL STUDY



TUNNEL ROOF TO SUPPORT D-8 BULLDOZER (50k)
ALSO 20,000 TON PILE

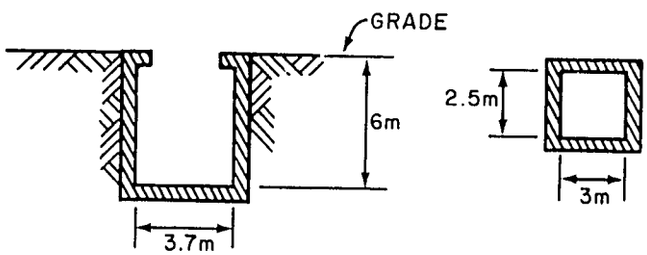


FIGURE 5.10-2
RECLAIM TUNNEL AND ESCAPE TUNNEL
LAKHRA COAL STUDY

5.11 DESCRIPTION OF COAL TRANSPORTATION FACILITIES

Coal will be transported between the coal mine and power plant by dedicated unit train. Train will consist of a locomotive and forty-six 44-metric-ton bottom dump hopper cars. The train will make two deliveries a day totalling 4000 metric tons for a single unit. Should the power plant be expanded to two units, train deliveries will necessarily increase to three a day, with the unit train increasing in size to 62 railcars.

Five rail cars will be furnished as spares with each 46-car train. A sixth spare car will be added when the train is expanded to 62 cars. These spares will permit the removal of cars from the train for maintenance purposes.

The rail line between the mine and the power plant will be about 35 km and will link with the Pakistan Railways main line at Jamshoro. It will follow the gradient of the terrain in order to hold cuts and fills to a practical minimum. The operations of the rail line will be independent of the National Railroad and will be dedicated to the transportation of coal.

SECTION 6

POWER GENERATION

6.1 POWER PLANT SIZE AND TYPE

The need for additional power generation capacity in Pakistan is well established. At the end of 1982, WAPDA was being forced to shed up to 500 MW during peak loading periods in the winter. Moreover, electric demand forecasts for Pakistan predict an increase in peak system demand of approximately 10 percent per year. This means that WAPDA's generation capacity must be increased by over 300 MW each year to meet projected load growth. The amount of reserve capacity needed to establish a satisfactory system reliability must be added to this. The total potential generation capacity at Lakhra depends on the amount of coal at Lakhra that can be extracted economically.

The quantity of proven recoverable reserves in the 26-square-kilometer area under investigation at Lakhra is 64.409 million metric tons (71 million short tons) (see Section 5), which will support roughly 460 MW of Lakhra coal-fired generation capacity for 30 years, operating at a capacity factor of 70 percent. Thus, 600 MW of generation capacity at Lakhra would require approximatley 84 million metric tons of coal. Based on the arguments set forth in Section 5, it is safe to assume that the additional 20 million metric tons of coal required will be proven to exist once the existing field is extended westward. If not, stripping ratios could be increased to obtain the additional coal required.

The number of units examined in this study is limited to two identical 300-MW units vs. a single 600-MW unit. SWEC's in-house cost information indicates that the capital cost of a single 600 MW unit would be approximately 15-20 percent lower than the capital cost of two 300 MW units. The offsetting advantage of installing two 300 MW units is improved system availability. During both forced and scheduled outages of one unit, the other unit is available to generate electricity (except in rare circumstances when both units are forced out of service during the same period). Consequently, the amount of reserve system capacity required to maintain a fixed system availability is lower with two 300-MW units than with one 600-MW unit.

The amount of system reserve capacity that should be available to replace capacity forced out of service is usually at least as large as the largest unit on the system. Thus, if two 300-MW units are installed at Lakhra, only 300 MW of reserve capacity would be required in the system. However, if the single larger unit were installed, the reserve capacity requirements would double to 600 MW. While WAPDA might not adopt this particular planning criteria, the above discussion provides an indication of how the number of units at Lakhra affects the cost of providing system reserve capacity required to maintain a constant system reliability.

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In addition, availability statistics collected in the United States indicate that for a single unit, plant availability decreases as unit size increases. While the exact amount by which the availabilities of the one-unit versus two-unit plant differs is a strong function of plant design and the operation and maintenance program, it is reasonable to assume that WAPDA could expect a significant increase in kilowatt-hours generated by a two-unit facility.

An indication of the value of plant availability is provided by calculating the cost of replacing Lakhra coal-based generation with imported oil-fired generation. Basing the calculation on the same economic data used in Section 8, the value in January, 1983, of a 1 percent reduction in total plant availability over the life of a 300-MW plant is roughly $25 million. The cost of increasing system reserve capacity to maintain constant system reliability and the hidden cost of increasing foreign exchange requirements should be added to this figure.

Therefore, it is recommended that two identical 300-MW coal-fired power plants be installed at Lakhra with the second unit installed 1 to 3 years after the first, provided the coal reserves are available. This would enable the Lakhra Mines to maintain continuous operation even during the 10-to-12-week-long major overhaul of the first turbine of 300 MW, which generally is expected to occur 3 years after a commissioning date. If the second 300-MW unit is not ready by that time, it would be required to operate the mine at significantly reduced capacity.

Two units of 300 MW each with a 1 to 3-year time-lag between Units 1 and 2 would offer many advantages to WAPDA, summarized as follows:

1. The design effort for the first unit could be utilized for the second unit of the same size.

2. The second unit would be appreciably cheaper. Although WAPDA would retain the option to buy it pending project approval by the Government of Pakistan.

3. The availability of power units will be greater and the mining operation will continue without stop.

4. Spare parts for the two units can be shared.

Brief descriptions of the power plant and major equipment are provided below.

Description of the Power Plant

- Subcritical, tandem compound, two flow reheat turbine generator with seven stages of steam extraction for feedwater heating and static excitation system. Enclosed turbine building with cranes, etc.

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- Balanced draft, pulverized coal-fired, single reheat steam boiler; open boiler house except for burner firing area and tripper gallery consisting of coal conveyor system over the coal bunkers.

- Electrostatic precipitator arranged on one-level between the air preheater and the chimney.

- Chimney with concrete shell and brick liner.

- Coal storage and handling system

- Wet ash sluicing system for furnace bottom ash and economizer ash; and pneumatic pressure system for dry precipitator fly ash.

- Offsite ash disposal landfill.

- Closed cycle cooling water system with concrete mechanical draft cooling towers and vertical pumps.

- Makeup water intake system with bar racks, traveling water screens, and vertical pumps located on the Indus River near Kotri Barrage and makeup water storage pond at Jamshoro site.

- Three-level building for administrative offices, labs, shops, water and wastewater treatment equipment; and onsite wastewater evaporation pond.

- Diesel generator for emergency power only. (No blocks start capability).

- Computer for data acquisition and monitoring.

- A 500 kV switchyard already exists at Jamshoro site. Extension of switchyard, if required for Lakhra Power Plant, will be assessed during the detailed engineering phase of the project.

- Space provisions for a possible future wet limestone flue gas desulfurization system.

- Area provisions for FGD waste processing to stabilize dewatered sludge with fly ash and lime, if installed in future.

Turbine Plant

- Tandem compound, two flow, reheat steam turbine, 333 MW (Gross), 300 MW (Net), 3000 rpm, operating pressure: 12,515 kPa (1800 psig) main steam and reheat temperature: 538°C (1000°F), with seven stages of steam extraction to be installed in an enclosed turbine building with cranes, etc.

- Main steam, reheat steam and extraction steam piping systems, etc.

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- Single-shell, two-pass, single-pressure, divided water box condenser, with nonferrous tubes and 3 minute hotwell storage capacity. Two full-size condenser air removal pumps.

- Two 100-percent capacity motor-driven feedwater pumps.

- Three 50-percent capacity single speed, motor-driven, vertical condensate pumps.

- Two one-half 7th point and two one-half 6th point low pressure heaters in the condenser neck; one 5th point heater with heater drain pump, and one 4th point heater. All heaters will be horizontal with stainless steel tubes.

- One deaerator and deaerator storage tank with 5-minute storage capacity.

- One 2nd and one 1st point high pressure horizontal heaters with stainless steel tubes.

- Lube oil purification system for the main turbine.

- Closed component (secondary) cooling water system using condensate, with two full-size pumps and two full-size heat exchangers getting cooling water from the primary raw circulating water system.

- Two full-size instrument air compressors; and two full-size service air compressors.

- 300 MW generator, 11 to 16 kV generated voltage, 0.85-0.90 power factor, 3000 rpm with static excitation system, rectifiers, voltage regulation system and hydrogen cooling system.

Electrical Equipment

- 360-390 MVA, 500/11-16 kV, 3-phase transformer and isolated phase bus duct from generator to main transformer.

- Nonsegregated phase bus duct from two half-size normal station service transformers 25 MVA, 11-16/6.9 kV, to auxiliary buses.

- Nonsegregated phase bus duct from two half-size reserve station service transformers to auxiliary buses.

- Two 6.9 kV switchgear buses.

- Two 4.16 kV switchgear buses.

- Load center unit substations utilizing metal-class switchgear and dry type or liquid filled transformers.

- Low voltage motor control centers as required.

- One diesel generator and associated controls for emergency power, without block start capability.

- Two station batteries and static battery chargers.

- One uninterruptible power supply.

- Intraplant communications system consisting of a staff calling/public address system.

Boiler Plant

- Drum type, balanced draft, pulverized coal-fired, single reheat steam boiler, suitable for generating steam at 12,515 kPa (1800 psig), 538°C (1000°F) main steam and 538°C reheat steam.

- Five pulverizers, one as a spare; coal silos; trippers and conveyors (sized for two units); and gravimetric feeders.

- Two one-half capacity motor-driven, single speed, forced draft fans with inlet vane control; two one-half capacity steam-heated air heaters; two one-half capacity, motor-driven, single speed, primary air fans with inlet vane control for transporting pulverized fuel to burners; all housed in fan room with inlet silencers.

- Two one-half capacity, trisector, air preheaters.

- Fuel oil for ignition and flame stabilization.

- Soot blowing by steam.

Precipitator Area

- Cold electrostatic precipitator arranged on one level. Two rigid frame-insulated chambers; redundant field; weather enclosure of hoppers and overtop of precipitator; and precipitator control building.

- Two one-half capacity motor-driven, two-speed induced draft fans with inlet vane controls.

Chimney

- Concrete shell.

- Brick liner.

- Provisions for space for locating annulus pressurization system with two full-size fans in case an FGD System is installed in the future.

Coal Handling and Storage Area

- All coal handling equipment sized for two 300-MW units.
- Rail unloading system consisting of an underground track hopper with vibratory feeders at the hopper outlets.
- Single hooded conveyor from track hopper to lowering well at 4- or 5-day storage pile.
- Reclaim from storage pile by gravity and bulldozing through hoppers and feeders.
- Two hooded conveyors from storage pile feeders to opensided crusher house with two crushers.
- Two enclosed conveyors from crusher house to two in-plant tripper conveyors.
- Dust suppression, ventilation, service water and fire protection systems.

Ash Handling Area

- Closed loop wet ash sluicing system for bottom ash, pyrites, and economizer ash removal. Water impounded hoppers; pyrites holding tank; jet pumps; piping, two dewatering bins each sized for 32-hour storage at full load, two settling ponds; surge pond; two full-size low pressure ash sluice pumps; and two full-size high pressure ash sluice pumps. Discharge from dewatering bins to conveyor, with truck as backup, for transport to offsite ash disposal land fill.
- Dry pneumatic pressure system for precipitator fly ash. Two full-size blowers; air lock feeders; piping; and concrete silo sized for 2 days storage at full load. Discharge from silo to conveyor, with truck as backup, for transport to offsite ash disposal land fill.

Cooling Tower and Circulating Water System

- Single concrete mechanical draft cooling tower.
- Two one-half capacity vertical wet type pumps in separate bays; panel screens; all located at cooling tower.
- Concrete cyclinder circulating water intake and discharge pipelines between the cooling tower and the turbine building.
- Coated carbon steel circulating water intake and discharge lines at equipment connections and encased in concrete within the main powerhouse building area.

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- Cooling tower electrical building; and cooling tower chemical feed building for chlorine, acid, and scale-prevention systems.

- Blowdown pipeline to surface discharge structure at Indus River.

Makeup Intake System

- Enclosed intake structure on Indus River; four reinforced concrete pump bays; each of two bays has stoplogs, bar racks, a through-flow travelling water screen, a screenwash pump, and a full-size (for one unit) vertical wet pit makeup water pump; third and fourth bays for future Unit No. 2 equipment. Also included is an overhead bridge crane, chlorination facilities, and trash rake and car.

- Two pipelines between the intake structure and the onsite makeup water storage pond and clarification system. From the storage pond, water will normally be supplied to the cooling tower and service water system. Backup supply to component cooling water heat exchangers for unit shutdown cooling requirements.

Structural

- All foundations consist of reinforced concrete spread foundations on soil.

- Main powerhouse building construction of structural steel framing and girts; interior partitions of concrete block, and metal panel; upper floors of grating (concrete used only where required for equipment maintenance and/or support); metal roof deck with asphalt and gravel roofing; two passenger/freight elevators; rolling steel doors; hollow steel doors with hardware; and nonenclosed stairways.

Service and Office Building

- Multi-level building adjacent to and contiguous with the powerhouse, sized for two units.

- Ground floor consists of lobby and receptionist area; labs; tool room, machine, weld, and electrical shops; storage; auxiliary boilers; and water and wastewater treatment equipment.

- Second floor consists of offices; training room; lunchroom; instrument shop; lockers; and showers.

- Third floor, or other area, based on requirements.

- Service water produced by processing river water through one outdoor clarifier sized for two-unit flow and two gravity

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filters each sized for one-unit flow (with space provisions for a third filter to be installed with Unit 2).

- Potable water produced by processing service water through two activated carbon filters each sized for one-unit flow and adding hypochlorite solution.

- Demineralized water produced by processing service water through two activated carbon filters each sized for one-unit flow (with space provisions for a third filter to be installed with Unit 2) and two trains of weak base anion, strong acid cation, strong base anion, and mixed bed ion exchange vessels. Each train is sized for one-unit flow. A decarbonator, downstream of the strong acid action vessels, is common to both trains.

Controls

- Control building with three floors and a temporary end wall for expansion to a two-unit control building. Ground floor consists of switchgear and electrical equipment test and maintenance area; mezzanine level consists of cable spreading area, battery room and dc equipment room; operating level consists of control room, computer room, and relay room.

- Main control board and panels for integrated boiler and turbine controls.

- Auxiliary panels for control and/or monitoring in control room for ash handling, coal handling, cooling water, fire protection, soot blowers, raw water make-up and blowdown systems. All other control panels are local.

- Computer for data acquisition and monitoring.

Yard and Miscellaneous

- Onsite roads and railroads.

- Security system with gatehouse, and perimeter fence with motor-operated main gate and closed circuit TV to main control room.

- Heating, ventilating, and air conditioning as required.

- Cathodic protection as required.

- Lighting as required.

- Heat tracing as required.

- Oily waste collection system.

- Lined wastewater treatment pond.

- Makeup water storage pond.
- Fire protection system.
- Storm drainage system.
- Unit located on Jamshoro site with level topography requiring minimum site clearing and grading; groundwater is low (no dewatering required during construction); and site is not within flood plain.
- Sanitary waste treatment system.

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6.2 SITE SELECTION

In the past several years, the following significant reports were prepared by different agencies evaluating site selection for the installation of a Lakhra coal-fired power plant:

1. Canadian International Development Agency (CIDA) Reconnaissance Study and Evaluation of Lakhra Lignite Deposits and Associated Thermal Power Station, Hyderabad, 1976-77

2. WAPDA Report on Site Selection, 1973

3. Zaffar Associates of Pakistan and PCR of U.K., 1975-76

4. Japan International Cooperation Agency (JICA) Feasibility Study on Lakhra Coal Mining and Power Station Project, 1981

All four reports recommended Jamshoro as the preferred location. The WAPDA/PMDC/SWEC team reviewed these reports and the logic and relative values of the quantative and qualitative data used. The Petaro and Khanot sites have no significant advantages and the major disadvantage of inadequate cooling water. Therefore, a detailed economic evaluation of the Jamshoro and the Minemouth Lakhra sites was conducted as summarized in Table 6.2-1. The qualitative advantages and disadvantages of the two sites are described below.

6.2.1 Minemouth Lakhra

The site is 45 kilometers north-northwest of Hyderabad and 20 kilometers west of the Indus River at Khanot (Figure 2.3-1). The elevation is 140 meters above mean sea level and 110 meters above the Indus River. The site is fairly flat and level, flood-free, and of good load-bearing characteristics.

The advantages are:

1. Coal transportation costs would be minimal.

2. Ash disposal in the depleted open coal mines would require minimum transportation cost.

The disadvantages are:

1. There is no source of water at this site for plant operation, cooling, or domestic use. The high cost of delivering water to the site more than offsets the low cost of coal transportation. The use of an air cooled condenser also was considered. An air-cooled condenser has the serious disadvantage of increasing the turbine back pressure which decreases full load output, particularly in the summer months, and increases auxiliary power consumption, thus increasing the fuel costs for a given power plant output.

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2. There is no electrical distribution system in the mining area, so approximately 48 kilometers of 220 kV (2 circuit) power lines would be required to connect the Lakhra Power Station to the 500 kV Jamshoro substation at a capital cost of $6.3 million. There also would be line losses associated with this transmission.

3. Due to the lack of an electrical system in the area, black-start equipment would be required at the site. This would include a gas turbine and associated oil tanks and equipment.

4. There are no communities in the mining area. This would make it more difficult to recruit and retain qualified personnel to operate and maintain the plant. Establishing a colony with social amenities would be the highest cost for this location. A large number of WAPDA employees would require residential accommodations and an infrastructure, including a school, medical facilities, and a market. This would require a capital cost of approximately $11 million more than a smaller colony at the Jamsboro site. This cost would be partially offset by a higher operating cost at the Jamshoro site due to rent and transportation expenses for employees living in Hyderabad working at Jamshoro.

5. Higher salaries may have to be paid to employees at the mine-mouth site than at the Jamshoro site to compensate for less desirable living conditions.

6.2.2 Jamshoro

The site is 13 kilometers northwest of Hyderabad and 3 kilometers west of the Indus River (Figure 2.3-1). The elevation is 38 meters above mean sea level and 14 meters above the Indus River. The site is flat, level, flood-free, and of good load-bearing characteristics.

The advantages are:

1. Adequate water is available throughout the year from the upstream side of Kotri Barrage.

2. The site is adjacent to the 500 kV Jamshoro substation. Costly construction of transmission lines will not be necessary. Additional equipment will not have to be purchased for black-start capability.

3. The proximity to the city of Hyderabad will simplify greatly the task of providing and retaining good experienced personnel.

4. If a reliable market can be established for the ash, purchasers could remove it from the site economically. The proximity to the highway would be advantageous.

5. Infrastructure, e.g., railway station, hospital, schools, universities, and shopping area, already exist close to the site.

The disadvantages are:

1. Coal must be transported 40 kilometers by rail involving a capital expenditure of $8 million for the unit-train delivery system, plus an associated lifetime evaluated operating cost of $3 million for transportation.

2. If a reliable market could not be found for ash, it would have to be transported and disposed of near the site by belt conveyor or truck at a cost to the power plant.

Environmental considerations and alternative coal transportation modes are evaluated in Sections 4 and 5, respectively. These evaluations do not change Jamshoro as the recommended preferred site.

In summary, of the two potential sites for locating a coal-fired power plant, Jamshoro has an economic advantage of approximately $50 million (January, 1983) over the minemouth site in addition to the sociological advantages outlined above. Therefore, SWEC recommends Jamshoro as the preferred site for the Lakhra Power Plant(s).

TABLE 6.2-1

ECONOMIC COMPARISON OF POWER PLANT SITES
All costs are expressed in millions of January 1983 dollars.

Evaluated Capital Costs	Alternative 1: Once-Through/ Jamshoro	Alternative 2: Cooling Tower/ Jamshoro	Alternative 3: Cooling Tower/ Minemouth	Alternative 4: Air-Cooled/ Minemouth
Condenser	3.0	3.0	3.0	25.3
Cooling Towers	NA	4.0	4.0	NA
Circulating Water Piping & Pumps	36	2.0	2.0	NA
Cooling Tower Makeup System	NA	13.0	67.0	NA
Railway & Cars	11.0	11.0	NA	NA
Transmission Line	NA	NA	6.3	6.3
Total Evaluated Capital Cost	50.0	33.0	82.3	31.6
Evaluated Lifetime Operating Costs (2)				
Coal Transportation	3.0	3.0	NA	NA
Auxiliary Power Penalty (3)	6.1	9.1	11.6	17.4
Back Pressure Penalty (4)	Base	9.3	9.3	55.8
Total Evaluated Lifetime Operating Costs	9.1	21.4	20.9	73.2
Total Evaluated Lifetime Costs	59.1	54.4	103.2	104.8
Difference	4.7	Base	48.8	50.4

TABLE 6.2-1 (Cont)

	Alternative 1: Once-Through/ Jamshoro	Alternative 2: Cooling Tower/ Jamshoro	Alternative 3: Cooling Tower/ Minemouth	Alternative 4: Air-Cooled/ Minemouth
Technical Data				
Auxiliary Power Consumption (kW)				
Circulating Water Pumps	2030	2240	2240	NA
Make-up Pumps	NA	140	970	NA
Fans	NA	660	660	5800
Total	2030	3040	3870	5800
Back-Pressure (in.HgA)	2.75	3.5	3.5	8.0
Differential Net Station Heat Rate (Btu/kWh)	Base	110	110	659

NOTES:

1. All costs are expressed in millions of January 1983 dollars.

2. Evaluated lifetime costs are based on a 30 year operating period, an escalation rate of 7 percent per year, and a discount rate of 12 percent per year.

3. Auxiliary power penalty =
(Total auxiliary power consumption)($3,000/kW)

4. Back-pressure penalty =
(Diffential Net Station Heat Rate) $84,600/Btu/kWh

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6.3 STEAM CONDITIONS

The following power plant design parameters will be established in this section:

- Reheat or nonreheat turbine cycle
- Turbine throttle pressure
- Turbine throttle and reheat temperature

Reheat Cycle

Reheating steam exiting the high pressure turbine stage to throttle temperature increases cycle efficiency by approximately 5 percent. Many studies have shown that the additional capital cost of the reheat system is less than the operating efficiency advantages for power plants with capacities in excess of 100 MW. Consequently, a reheat cycle is recommended for the Lakhra Power Plant.

Turbine Throttle Pressure

The two most common generated steam turbine throttle pressures for 300 MW coal-fired power plants currently installed in the United States are 12,515 kPa (1800 psig) and 16,653 kPa (2400 psig) for subcritical cycles. At constant throttle and reheat temperature, an increase in throttle pressure from 12,515 kPa to 16,653 kPa improves cycle efficiency by approximately 2 percent. The difference in the capital cost of power plants of equal capacity incorporating 12,515 kPa and 16,653 kPa turbine cycles is small. The increase in cost for pressure and functional reasons related to a 16,653 kPa plant is partially offset by a reduction in power plant equipment size due to the reduction in mass and volume flow rates. The net result is that, economics favor the higher pressure, more efficient cycle.

However, several important technical considerations outweigh the economic advantage associated with the 16,653 kPa cycle for this particular application.

The first consideration favoring the 12,515 kPa cycle is related to the severe slagging and high temperature corrosion characteristics of the Lakhra coal ash. Because the ratio of superheat to latent heat is lower for a 12,515 kPa cycle, a gas temperature leaving the furnace and entering the superheater of from 100°F to 150°F lower is possible with the lower pressure cycle. This permits all superheater and reheater surface to be shielded from most of the direct flame radiation, minimizing both ash deposits and corrosion effects. The possibility of slag falls from pendant surface hanging over the furnace also is minimized.

Another technical consideration favoring the 12,515 kPa cycle is related to water-side corrosion. Water-side corrosion can occur in water-walls in the high heat absorption areas where a high percent by volume of steam exists. Small amounts of solids in the boiler water can concentrate on the inside of the tubes in these areas, resulting in

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internal corrosion and overheating of the tubes. This can occur at any pressure but is a significantly greater problem at 16,653 kPa than at 12,515 kPa.

A further concern is related to turbine deposition for a given concentration of solids and other impurities in boiler water. The carryover of solids in the steam to the turbine is significantly greater at the higher throttle pressure. Turbine efficiency and, ultimately, turbine life are affected adversely by this carryover. In order to minimize the carryover at 16,653 kPa, it is absolutely necessary to maintain extremely low levels of boiler water concentration at all times. There is little room for operator leeway. Further, when condenser leakage occurs, it is frequently necessary to take the unit offline. Therefore, the study team recommends that the Lakhra Power Plant be designed for the 12,515 kPa throttle pressure.

Turbine Throttle and Reheat Temperature

The two most common steam turbine throttle (and reheat) temperatures for 300 MW, 12,515 kPa power plants currently installed in the United States are 538°C (1000F) and 510°C (950°F). At a throttle pressure of 12,515 kPa, a 28°C reduction in both the throttle and reheat steam temperature reduces cycle efficiency by a total of 1.5 to 2 percent. Economics favor the more efficient cycle operating at 538°C. Based on present knowledge of the coals, it is believed that a cycle of 12,515 kPa/538°C/538°C is feasible with a conservatively designed boiler. After further tests of coal samples, this cycle should be analyzed again, particularly with regard to superheat and reheat temperature, and changed, if necessary.

6.4 BOILER ISLAND DESIGN

The boiler island recommended for the Lakhra Power Plant has been divided into five major systems:

1. Coal handling
2. Steam generator
3. Ash handling and disposal
4. Particulate removal
5. Flue gas desulfurization

6.4.1 Recommended Coal Handling System

Figure 6.4-1 shows the recommended coal handling system. Coal will be delivered at the power plant by a captive unit-train consisting of a locomotive and 46 bottom dump hopper cars each with a capacity of 44 metric tons (44 tons). The train will make two deliveries a day, totaling 3680 metric tons for a single unit of 300 MW net capacity. With the addition of a second unit of equal size, train deliveries will be increased to three a day and the unit-train increased to 62 cars.

Rail cars will be unloaded individually to a 90 metric ton underground track hopper at the rate of approximately one car every 3 minutes. A car shaker may be employed to assist in maintaining this rate. Vibratory feeders at the track hopper outlets will control the rate of unloading at 900 tons per hour and will deliver lignite to a 1000 mm takeaway conveyor.

The 1000-mm belt conveyor will transport the lignite from the track hopper to the storage pile. This conveyor will discharge through a lowering well, creating a conical pile of 20,000 metric tons capacity (5 days of power plant consumption).

For reliability, a dual conveyor system will be provided from the storage pile to the in-plant silos. Reclaim from the storage pile will be a combination of gravity and bulldozing. Approximately 30 percent of the pile will be reclaimed by gravity through the four normal hoppers and feeders above each reclaim conveyor with the remainder being bulldozed to these same hoppers. A separate hopper and feeder will be installed at the base of the lowering well to provide for cleanout of the well. All coal reclaimed through the hoppers and feeders will be discharged to one of the two 1000-mm reclaim belt conveyors that will transport it to a crusher house. Each conveyor line will handle coal at 635 metric tons per hour.

At the crusher house, lignite will be reduced in size to a minus 1.9 cm product before being sent to the plant silos. Two crushers, one in each conveyor line, will be included for reliability.

After crushing, lignite will be discharged to one of two 1000-mm belt conveyors and sent to the power plant. At the power plant, lignite will be distributed to in-plant silos over one of two tripper conveyors with traveling trippers.

Each conveyor line, from the storage pile to the in-plant silos, will be sized to provide sufficient capacity to supply coal to two 300 MW units. This will ensure full load operation of two units even with one conveyor line out of service.

The area for the lignite storage pile will be approximately 70 m in diameter for one unit. With the addition of a second unit, this area will increase to approximately 100 m x 100 m. An impervious liner will be provided beneath the lignite pile. Gravity fed, lined, runoff collection trenches will circle the area and drain to a waste evaporation pond.

The crusher transfer house will be a structural steel, open-sided building with a metal roof and reinforced concrete foundation. The building will be 9 m wide x 9 m long x 12 m high.

The conveyor gallery and transfer house at the power plant will be structural steel buildings with metal siding and roofing. The gallery will include a floor with tripper slot and will be 7.6 m wide x 1.2 m long x 4.6 m high. The transfer house will be 9 m wide x 12 m long x 9 m high.

In-plant lignite storage silos will be included. Their number and size will suit the projected requirement.

A yard building of structural steel and metal siding and roofing with reinforced concrete foundation and floor slabs will be provided. This building will include facilities for maintenance of equipment and bulldozers, offices; control room; change room with lockers, toilet facilities, etc.

Reinforced concrete foundations will be provided for support of conveyor belts.

The track hopper pit will be below grade. The pit will be approximately 12 m long x 6 m wide x 11 m deep with a stairwell and conveyor tunnel to grade. The tunnel will be 3 m wide x 2.4 m deep x 30 m long. The pit, stairwell, and tunnel will be of reinforced concrete and will include a sump.

The reclaim tunnel under the storage pile will be below grade. It will be approximately 6 m wide x 6 m deep x 60 m long with a sump; the escape tunnel will be 1.8 m wide x 2.4 m deep x 13.7 m long. The complete tunnel structure will be of reinforced concrete.

Fire protection and service water piping will be provided in the lignite handling and storage area. It will include all piping, valves, fittings, instrumentation, hydrants, hoses, supports, excavation, and backfill.

All necessary hoists and monorails required in the lignite handling system will be provided.

All dust collection equipment necessary for removal of dust at conveyor transfers, as well as ventilation of all enclosed pits, tunnels, bins, and conveyor galleries will be provided.

All electrical equipment, including cable, conduit, controls, lighting, grounding, switchgear motor control centers, etc., will be provided.

Sump pumps, including all piping, fittings, hangers, etc., for piping to evaporation pond will be included.

All chute work and reclaim hoppers will be of Type 304 L stainless steel. The track hopper will be of Cor-Ten steel with 10 gauge Type 304 stainless steel liners.

All conveyors located above ground will be covered with 3/4 curved hood. All elevated conveyors also will be furnished with a walkaway on one side.

A belt scale will be provided at the conveyor going from the track hopper pit to the storage pile.

A magnet with trolleys will be located at the discharge of the belt conveyor feeding to the crusher.

A vibrating car shaker with support tower to assist rail car unloading will be furnished at the track hopper.

Two bulldozers for work around the lignite storage pile will be included.

Appendix 7 presents a generic discussion of coal handling considerations.

6.4.2 Recommended Steam Generator Design

A pulverized coal, drum-type, natural circulation, balanced draft steam generator is recommended for the Lakhra Coal Power Plant for the following reasons:

1. The maximum practical size for both the stoker and fluidized bed combustion steam generators is about 25-30 MW while the required size is 300 MW. In addition, excessive quantities of sulfur in the coal and iron/iron pyrites in the ash eliminate the cyclone boiler from further consideration.

2. The drum-type circuitry design is preferred because it is easier to operate under transient loading and requires less vigilant feedwater treatment than the once-through design. It is more forgiving of operator error.

3. All steam generator manufacturers recommended natural circulation for a turbine throttle pressure of 12,515 kPa at guaranteed rating.

4. A balanced draft furnace is recommended to improve availability and facilitate maintenance.

Appendix 6 presents a generic discussion of steam generator design.

Operating Problems and Solutions

Based on the Lakhra coal and ash analyses provided in Section 5.4 the following conclusions are offered regarding the impact of the coal and ash analyses on steam generator design.

1. The relatively high moisture content will reduce the steam generator efficiency. This and the low heating valve will increase the boiler island size and, therefore, the boiler island capital cost.

2. The high ash loading of the Lakhra steam generator must be recognized in the design to minimize ash erosion.

3. The relatively high quantities of sulfur in the coal and iron/iron pyrites in the ash must be recognized in the design to eliminate excessive slagging, fouling, and corrosion.

The discussion that follows addresses the four principal operating problems associated with burning Lakhra coal in a pulverized coal-fired steam generator and measures to solve each.

Erosion

According to the Lakhra coal analysis, about 20 percent of the coal is ash. For this type of coal, approximately 30 percent of the ash will exit the steam generator at the bottom of the furnace as bottom ash. The remaining 70 percent passes through the convective section, the air preheater, and finally the electrostatic precipitator, where approximately 99 percent of it is removed. A relatively small portion of the fly ash will fall out of the economizer and air preheater hopper. This means that the superheater, reheater, economizer, and air preheater surface will be subjected to approximately 31 metric tons of fly ash loading per hour when the power plant is operating at rated load. If allowed to travel at excessive velocities, this amount of ash loading would quickly erode all unprotected tubes in its path.

The fly ash constituent that is the most abrasive and consequently the most erosive is crystallized silicon dioxide, or quartz. Since the Lakhra coal analysis reports heavy quartz banding, the steam generator must be designed to minimize erosion problems. Since fly ash erosion rate is generally considered to be proportional to the third or fourth power of flue gas velocity, potential erosion problems can be controlled by designing the convection pass large enough to keep the gas velocities low.

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Corrosion

Whereas erosion can be considered a mechanical reduction of the surface, gas-side corrosion is a chemical process with a similar impact on the affected surface. Gas-side corrosion in steam generators can be categorized as follows:

1. High temperature corrosion

2. Waterwall corrosion

3. Low temperature corrosion

High temperature, gas-side corrosion occurs on superheater and reheater surfaces which are typically at temperatures in the vicinity of 600°C for the 12,515 kPa/538°C/538°C turbine cycles. Waterwall corrosion takes place at tube temperatures in the 300°-400°C temperature range. In general, high temperature corrosion can be reduced by lowering metal and gas temperature. Waterwall corrosion can be reduced by maintaining an oxidizing atmosphere in the burner zone.

Low temperature corrosion can occur primarily at the back end of the boiler, starting with the air preheater, if flue gas attains the dewpoint that could lead to the formation of sulfuric acid. This low temperature corrosion can be inhibited by increasing flue gas temperature with heated combustion air.

Additional approaches to minimizing corrosion-related problems are:

1. Metalizing the tubes prone to corrosion by spraying a corrosion resistant material, e.g., chrome, on the affected surface.

2. Attaching replaceable protective shields to tubes.

3. Adding limestone or dolomite.

4. Removing sulfur and ash prior to combustion (coal washing).

All of these approaches have some financial impact. All can be implemented after the steam generator has been designed and operated. Therefore, it is recommended that the Lakhra steam generator be installed without the above modifications. If corrosion is found to be a significant problem, a corrosion-protection program can be developed.

Slagging

The formation of slag deposits is caused mainly by physical transport of molten or partially fused particles entrained in the gas stream. When the particles strike the wall or tube surface, they are chilled and solidified. Strength of attachment is influenced by the temperature and physical contour of the surface, direction, force of impact, wetting characteristics of the slag, and ash chemistry. This occurs primarily on radiant heat transfer surfaces. Slagging normally takes place in the furnace and convective surface exposed to radiant heat transfer.

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Fouling

The volatile constitutents in coal, e.g., sodium sulfate, cause fouling. These constituents condense on fly ash particles and on boiler tubes in areas where the temperatures are such that they remain liquid. They react chemically with fly ash, other deposits, and the flue gas to form bonded deposits, primarily on convective heat transfer surfaces. Fouling normally takes place in the convection passes of the steam generator.

Slagging and fouling indexes developed from the Lakhra ash analysis indicate that Lakhra coal can be classified as having severe slagging characteristics, primarily because the high iron content effectively reduces ash fusion temperature. However, this coal possesses medium fouling characteristics due to the relatively low sodium content.

Appropriate unit design and careful location of soot blowers can mitigate slagging and fouling problems effectively.

It is strongly recommended that all superheater and reheater surface areas be located behind the furnace nose instead of directly above the furnace; e.g., a "pendant" or "hanging" superheater. With this arrangement, superheater slagging is less likely to occur and deposits are less likely to fall from this surface, dropping the full length of the furnace (somewhere in the vicinity of 30 m) and potentially damaging furnace ash hopper tubes.

In the past, some boiler manufacturers have used flue gas and tempering to control gas-side temperatures. However, due to problems associated with operating a recirculation fan in a hot, ash-laden environment, this approach is not recommended for the Lakhra Power Plant.

In conclusion, the following measures should be adopted to prevent ash slagging problems:

1. Superheater and reheater surface is located behind the furnace nose.

2. Cycle pressure of 12,515 kPa.

3. Conservative system of sootblowers with proper attention paid to soot blower spacing and location.

4. Convective pass tube-side spacing wide enough to ensure proper cleanability.

5. Conservative convection pass design to ensure low gas velocities.

6. Proper operation and maintenance program.

Recommended Tests on Representative Coal Samples

It is very important that the steam generator manufacturer knows as much as possible about the full range of coals to be burned in the unit throughout its scheduled life. Economic and technical tradeoffs are made during the design phase to determine the best possible design for the range of coals to be burned. Without detailed coal and ash analyses representing the full range of coals to be burned, serious operating problems could develop resulting in plant shutdown and further use of oil-fired generation. It is strongly recommended that a consultant perform detailed coal and ash tests on several Lakhra coal samples representing the full range of coals to be burned. These samples should be obtained by performing more thorough drilling in the mine area as soon as possible.

A representative list of the types of analyses to be performed on the Lakhra coal samples is provided below.

- Coal and Ash Analyses

  Complete coal and ash analyses should be performed, including a proximate analysis, ultimate analysis, sulfur analysis, determination of higher heating value, and ash analysis (Table 6.4-1).

- Burning Profile

  A plot of weight loss rate (expressed in mg/minute) vs temperature should be developed for Lakhra coals. This plot would be used as a fingerprint and compared with other fingerprints of coals with which the steam generator manufacturers are familiar. Coals with similar fingerprints generally will have similar combustion characteristics.

- Pyrite Size Distribution

  The distribution of pyrite material (FeS_2) in the coal should be determined in order to indicate the difficulty of removing pyrites in the pulverizer. If enough coal is available (on the order of 1 ton), abrasion tests can be performed to determine potential erosion problems in pulverizer and combustion equipment.

- Ash Fusion Temperatures

  One of the more important tests that should be performed determines the slagging propensity of the coal ash. As a minimum, the temperatures at which the coal ash initiates deformation and becomes fluid, both in an oxidizing (oxygen rich) and reducing (oxygen deficient) environment, are required. This test would provide a good indication of how the Lakhra coal will slag in the region up to the highest burner level (the reducing zone) and the region from the highest burner level to the top of the furnace (the oxidizing zone).

- Hardgrove Grindability Index vs Moisture and Sintering Strength

  Two additional tests commonly performed on unknown coals are the Hardgrove Grindability Index vs Moisture Test, which determines how the coal grindability varies with moisture (a relationship that varies radically from coal to coal) and the Ash Sintering Strength Test, which measures coal ash's hardening characteristics.

6.4.3 Recommended Particulate Removal System

The high sulfur content (5.95 percent on an as-required basis) of the Lakhra coal is the predominant factor affecting the selection and size of the particulate collection equipment for this application. The impact of particulate loading and fly ash sodium content is minimized by the high sulfur content.

Based on SWEC's experience in particular and on that of industry in general, a cold side rigid frame electrostatic precipitator (ESP), with a specific collection area of 1 square meter per actual cubic meter per minute of flue gas, is recommended. Utilizing the modified Deutsch-Anderson precipitator design analysis equation, ESP data, including specific collection area values from actual SWEC installations, were modified for Pakistani design conditions and requirements.

To meet the World Bank emission standards (see Section 4), the ESP must meet a particulate collection efficiency of 99.3 percent.

A flow of 28,300 cubic meters per minute of flue gas at 350°F from the air heater outlet passes through the ESP. Approximate precipitator dimensions, exclusive of the inlet and outlet nozzles, are 27 m long x 37 m wide, including outside platforms, and 24 m high from the top of the weather enclosure to the hopper outlet flange.

Ash will be conveyed by pipe line to a storage silo. This silo will act as a surge bin for belt conveyor or truck loading, and silo will be sized to hold approximately 48 hours of ash production, or about 1500 tons.

6.4.4 Recommended Ash Handling and Disposal Systems

<u>Recommended Bottom Ash Handling System</u>

Lakhra coal has an approximate ash content of 20 percent on an as-received basis. It is assumed that 30 percent of the total ash will be collected as bottom ash. While the plant is operating at rated load, coal consumption is 220 metric tons per hour. Thus, bottom ash will be collected at about 13 metric tons per hour.

Removal of bottom ash from the furnace should be continuous, using a submerged drag chain conveyor (Figure 6.4-2). This conveyor would be located below the boiler bottom opening. It would consist of a water-filled horizontal trough section where ash is collected, sintered, and fractured; an inclined section where water is permitted to drain

from the ash; and a continuously operating drag chain conveyor section for removal of ash from below the boiler.

In addition to boiler bottom ash, ash from the economizer and the air preheater hoppers should be collected in the submerged drag chain. This ash should be collected initially from the hoppers by continuously-operating, dry, drag chain conveyors; discharged through air lock rotary valves; and dropped by gravity to the submerged drag chain.

Ash discharged from the submerged drag chain conveyor should pass through a clinker grinder or crusher for size reduction to a minus 5 cm product.

After crushing, ash will be conveyed by belt conveyor to a storage and decanting bin. This bin will act as a surge bin for truck or belt conveyor loading. While being held in the bin, the ash will be allowed to drain further to simplify handling on belt conveyors or in trucks. This bin will be sized to hold approximately 48 hours of ash production, or 620 metric tons.

The water system for the bottom ash removal system should be closed loop with approximately 95 liters per minute of makeup to replace water lost in the ash and to evaporation. The water system would consist of heat exchangers to maintain a temperature below 66°C in the conveyor through circulating pumps, and water treatment for pH control. Water drained from the storage and decanting bin would be collected in a sump and returned to the closed loop system.

Normally ash will be transported offsite to a disposal area by belt conveyor. However, provision should be made to load trucks from the storage and decanting bin as emergency backup. Both bottom ash and fly ash will be handled on the same belt conveyor. Fly ash should be layered on the belt first and then bottom ash layered on top.

The ash storage and dewatering bin will be supported above grade on structural steel with truck room provided below the discharge chute.

Reinforced concrete foundations will be provided for support of the bin.

Controls for the bottom ash system should be located at the submerged drag chain conveyor and at the storage and dewatering bin.

Recommended Fly Ash Handling System

Lakhra coal has an approximate ash content of 20 percent. Of the total ash, it is assumed that approximately 70 percent will be collected as fly ash. This will include all ash at the precipitator. Coal consumption at rated load is 220 metric tons per hour. Thus, the total fly ash collected will be about 31 metric tons per hour.

The fly ash removal system should be of the pressurized pneumatic type with air lock valves located at each precipitator hopper (Figure 6.4-3). Two blowers, one serving as emergency standby, should provide conveying air.

Removal of fly ash will be continuous, with the system repeating the sequence after all hoppers have been emptied. The system should be capable of handling 75 metric tons per hour, thus allowing for surges or unexpected maintenance. Ash will be conveyed by pipeline to a storage silo. This silo will act as a surge bin for belt conveyor or truck loading. This silo will be sized to hold approximately 48 hours of ash production, or approximately 1500 metric tons. The silo should include a bag filter for removal of conveying and displaced air, ash fluidization at the silo base, and an ash conditioner for treating ash with water before discharging to belt conveyor or truck.

Ash will normally be transported offsite to a disposal area by the same belt conveyor that handles the bottom ash. However, provision should be made to load trucks from the silo as emergency backup. Both fly ash and bottom ash should be handled on the same belt conveyor. Fly ash should be layered on the belt first, then bottom ash layered on top.

Controls for the fly ash system should be located at the precipitator control room and at the fly ash silo. The silo should be supported above grade on structural steel with truck room provided between grade and the unloader level. Reinforced concrete foundations are required for support of silo.

Recommended Ash Disposal System

Solid wastes produced by the plant will consist primarily of ash. When 1.4 million metric tons of coal is burned annually, the estimated total annual production of ash is 270,000 metric tons, of which 189,000 metric tons is fly ash and 81,000 metric tons is bottom ash. Small amounts of solid waste also will be produced from the sanitary waste drying beds and the evaporation pond.

There are several disposal alternatives available for ash. They include landfill at or near the plant site, ponding at or near the plant site, disposal at the mine, or reuse by the cement industry (fly ash and bottom ash) or as road subbase (bottom ash).

It is likely that some or all the ash produced at the plant can be reused but, due to changing market conditions over the life of the plant an alternative disposal method must be available. A landfill near the site was selected as the most appropriate for present planning purposes.

The other disposal options were not selected for several reasons. Ponding would require a wet sluicing flyash system. This wets the ash, limiting its reuse potential since it would be unusable for cement production. A wet sluice system also would produce a large amount of wastewater requiring treatment for suspended solids and heavy metals. Mine disposal was not selected because it is more expensive than landfilling. It would require special side dump rail cars dedicated to ash handling. The coal cars would not be used since the ash could set up in the cars during the monsoon season, causing handling problems. During the dry portions of the year severe dusting would occur. Also, dedicated earth moving equipment would be required at the mine for the ash disposal so as not to interfere with the mine operation.

In designing the landfill, capital and operating cost estimates were based on several assumptions. First, it was assumed that the site would be 1.5 km from the plant. Second, a 61 cm conveyor would be used to transport the ash to the site. Portable conveyors should be used to transport the ash to various parts of the landfill. Third, a liner would not be required due to the arid ambient conditions. Fourth, all contaminated runoff would be collected in an evaporation pond and either reused for dust control or allowed to evaporate. The landfill was sized for 60 hectares (150 acres), with a final height of approximately 12 m. The landfill would have 3-1 side slopes with 6-m-wide benches at every 6-m rise in elevation. The landfill would be developed in yearly increments, each averaging about 5 acres. The evaporation pond would be sized to handle the flow from 4 hectares (10 acres), or two yearly sites. As portions of the landfill were permanently or temporarily completed, they would be covered with half a meter of top soil taken from the next active portion.

The expected equipment requirements for the landfill are shown in Table 6.4-2. These requirements are based on an 8-hour day, 6-day workweek for the conveyors and a 16-hour day, 6-day workweek for the landfill operation.

6.4.5 Future Installation of a Flue Gas Desulfurization System

Based on the criteria outlined in Section 4, a flue gas desulfurization system (FGD) is not required initially. However, an air quality monitoring program is recommended to determine the effects of discharging SO_2 to the environment. The initial design of the Lakhra Coal Power Plant should make all necessary provisions for retrofitting a future FGD system with minimum disruption to the existing facility.

Recommended Flue Gas Desulfurization System for Lakhra

The trend in the United States indicates a strong preference for limestone FGD systems over other processes. The primary reason for this trend is favorable economics. Also, most experience has been gained on limestone FGD systems, which have been subjected to extensive investigations. Therefore, a limestone FGD system producing a stabilized sludge suitable for landfill is recommended for Lakhra if an FGD system is found to be necessary at some future date.

The total present day capital cost* of a limestone FGD system installed at Jamshoro removing approximately 80 percent of the SO_2 in the flue gas would be approximately $57 million, (January, 1983). Tables 6.4-2 through 6.4-7 provide technical data on the operation and maintenance of a limestone FGD system at Jamshoro. It should be noted that the personnel requirements provided in Table 6.4-4 are for a facility located and operated in the U.S. With labor rates significantly less in Pakistan, the personnel requirements for a limestone FGD system at Jamshoro would be significantly greater.

* Includes all direct and indirect material and installation cost. Does not include escalation, interest during construction, and import duty.

Alternative FGD systems, such as wet lime, double alkali, and Wellman-Lord, are being installed but do not have the same degree of commercial operation as the limestone system. In addition, cost evaluations conducted by SWEC for several utility clients have indicated that these processes have a higher total evaluated cost than the limestone technology.

The limestone FGD system producing gypsum is similar in capital cost to the limestone FGD system producing stabilized sludge. The operating costs of a gypsum-producing system may be reduced by the sale of gypsum and fly ash. However, prior to making assumptions about the value of these products, a thorough survey of the station area should be undertaken in order to determine the available buyers and possible selling price. Since the value is unknown, no credit should be taken for the sale of these products.

The limestone-producing gypsum FGD system, whether commercial grade or disposable grade, produces a chloride purge stream which creates an environmental disposal problem. For this technical reason, the stabilized sludge system is favored.

Retrofit Considerations

The impact of a retrofitted FGD system can be minimized if the original design and layout of the site includes provisions for a retrofitted FGD system. Provisions should be made for equipment real estate, operation and maintenance real estate, layout space during construction, access during construction, electricity supply and terminal point, stabilized sludge transportation routes, flue gas duct from exit of existing ESP, and flue gas duct connecting to the stack penetration.

The FGD system can be retrofitted behind the existing stack with minimum impact on the operation of the boilers. During scheduled outages of the boilers, the FGD system ductwork from the existing ESP and ductwork to the stack penetration can be connected.

The original stack should be designed to deal with the cooler flue gas from the retrofitted FGD system. For this project, a reheat system is not recommended. Since the flue gas is high in sulfur content, to reheat above the acid dew point temperature would be prohibitive in cost. Therefore, if an FGD system is retrofitted and the stack is carbon steel or stainless steel lined, the sulfuric acid condensation will cause severe stack damage and eventual failure. A fiberglass reinforced stack liner would not be employed for this plant because of the high (166°C) outlet flue gas temperature. At lower temperatures, an FRP stack liner would have good resistance to sulfuric acid corrosion.

If an FGD system is anticipated, the original stack liner should be constructed of acid-resistant brick and mortar. Some utilities in the United States have employed an acid resistant brick liner coupled with a

* Includes all direct and indirect material and installation cost. Does not include escalation, interest during construction, and import duty.

pressurized annulus between the liner and the concrete shell in an effort to minimize acid migration through the brick liner to the concrete shell.

The FGD system would become a major user of service water for pump seals, mist eliminator, etc. The service water system could either be initially sized to handle the future demand from the FGD system, or a separate service water system could be built for the FGD system. Estimated water consumption rates indicate that the FGD demand for service water would increase the size of the service water system by over 50 percent. Since clarifiers and filters are relatively inexpensive, easy to obtain modular systems, it was determined that a separate service water system should be provided with the FGD system if the FGD system is added later.

The addition of an FGD system to the plant increases solid waste production by about 350 percent. The effect this has on the operation of the landfill is to increase the number of bulldozers working at the landfill site and to increase the size of the landfill. Assuming a constant landfill height of 12 m. Table 6.4-7 shows the increased land requirements.

With the installation of an FGD system, the landfill conveyor would operate continuously (whenever the power plant is in operation), instead of just 8 hours per day, 6 days per week, as is required for ash disposal without FGD.

The active portion of the landfill would increase from 2 to 5 hectares per year. The operation of the landfill would include layering of the bottom ash with the FGD stabilized sludge. Since the permeability of the stabilized sludge will be lower than fly ash (10^{-6} to 10^{-7} compared with 10^{-5} cm/sec), the potential for groundwater contamination will be reduced. The size of the evaporation pond will increase from about one-half hectare to one hectare in size.

Appendix 7 presents a generic description of five proven FGD systems.

TABLE 6.4-1

MAJOR EQUIPMENT REQUIREMENTS FOR LANDFILL

Equipment	Quantity or Length
Conveyors:	
Overland Permanent Conveyor	3,230 m
Portable Conveyers	550 m
Radial Stacker	2
Vehicles[1]	
Bulldozers	3
Scrapers	1
Graders	1
Fuel Truck	1
Water Truck	1
Welder's Truck	1
Mechanic's Truck	1
Supervisor's Truck	1
Maintenance Trucks	2

NOTE:

1. Vehicle requirements are based on an 8-hour day, 6-day workweek conveyor operation and a 16-hour, 6 day workweek landfill operation.

TABLE 6.4-2

FLUE GAS DESULFURIZATION MAJOR EQUIPMENT LIST

Absorber Section	
Absorber Towers	3
Recycle Tank	3
Recycle Pump	9
Quencher Pump	6
Mist Elimination Tank	3
Mist Elimination Pump	6
Limestone Day Silo	2
Weigh Feeder	2
Ball Mill	2
Limestone Slurry Transfer Tank	2
Limestone Slurry Transfer Pump	4
Limestone Feed Tank	2
Limestone Feed Pump	4
Sludge Stabilization Section	
Thickener	1
Thickener Underflow Pump	2
Reclaim Water Tank	1
Reclaim Water Pump	2
Fly Ash Surge Silo	1
Lime Silo (Multibin)	1
Fly Ash Conveyor	1
Lime Conveyor	1
Bottom Ash Conveyor	1
Sludge Surge Tank	1
Filter Feed Pump	4
Vacuum Filter	2
Filtrate Tank	1
Filtrate Pump	2
Filter Discharge Conveyor	2
Pug Mill Mixer	2
Mixer Discharge Conveyor	2
Radial Stacker Conveyor	1
Macronaflow Emergency Dump Pond	1
Limestone Storage Section	
Hopper/Feeder	1
Stock Out Conveyor	1
Ninety Day Limestone Pile	1
Reclaimer Conveyor	1
Solid Waste Disposal*	
Bulldozers	2

NOTE:

* In addition to vehicles required for ash landfill.

TABLE 6.4-3

FLUE GAS DESULFURIZATION SYSTEM
REAL ESTATE REQUIREMENTS[1]

Plant Section	Area (Hectares)
10-Day Limestone Storage Section	0.2
Limestone Slurry Preparation Section	0.1
Absorber Section	0.5
Sludge Stabilization Section 4	1.4
Total Real Estate Area	2.1

NOTE:

1. Does not include any roads, reagent conveyor systems, or piping connecting absorber section with the sludge stabilization section. Also does not include the very large area required for ultimate waste disposal. However, this disposal area is not required to be located onsite. See Section 6.7 for an overall plot plan showing the real estate requirements with relation to the power station.

TABLE 6.4-4

FLUE GAS DESULFURIZATION SYSTEM ANNUAL OPERATIONAL AND MAINTENANCE PERSONNEL FOR A FACILITY INSTALLED AND OPERATED [1]

Manpower Type	FGD Absorber	FGD Sludge	Limestone Handling	Landfill Operation [2]	Total
Skilled Operators	8	4	3	NA	15
Skilled Maintenance	5	3	2	NA	10
Less Skilled Maintenance	3	2	1	NA	6
Lab and Clerical	1	1	1	NA	3
Supervisor	1	1	1	NA	3
Vehicle Operators [3]	NA	NA	NA	35	35
Skilled Laborers [4]	NA	NA	NA	4	4
Unskilled Laborers	NA	NA	NA	3	3
Total	18	11	8	42	79

NOTES:

1. Figures shown represent human resources specifically required for operation and maintenance of the FGD system within the defined battery limits during the year. Figures do not include maintenance personnel for the generating station scheduled shutdown maintenance or maintenance personnel from the plant machine shop, engineering office, and power plant warehouse and procurement offices. Figures are based on a total operation 24/day, 7 day/week operating schedule, assuming an annual average four shifts per day.

2. Landfill area human resources are based on 24 hour day, 7 day/week conveyor operation and 16 hour day, 6 day week landfill operation.

3. Vehicle operators include ten truck drivers and front end loader, bulldozer, scraper, and grader operators.

4. Skilled laborers include welders, supervisors, and mechanics.

5. These manpower requirements are in addition to those associated with ash landfill.

6. This staffing plan is typical of an FGD facility located in U.S. Figures should be increased to account for lower labor rates in Pakistan.

TABLE 6.4-5

FLUE GAS DESULFURIZATION SYSTEM ANNUAL UTILITY REQUIREMENTS[1]

Utility Consumption	Annual Average
Electricity (kWh/yr)	8.38×10^7
Water (l/yr)	8.44×10^8

NOTE:

1. Utility values are based on a 70 percent plant capacity factor. Utility requirements for the sludge stabilization system is included. Utility calculations are based on the assumption that utilitites are available at the FGD battery limits.

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TABLE 6.4-6

FLUE GAS DESULFURIZATION SYSTEM ANNUAL REAGENT AND BY-PRODUCT QUANTITIES (1)

Reagent	Quantity (metric tons/yr)
Limestone	280,000
Lime	15,000

NOTES:

1. Values are based in a 70 percent plant capacity factor.
2. Stabilized sludge includes dewatered FGD waste, lime additive, and all dry fly ash from the precipitator.

TABLE 6.4-7

LANDFILL REQUIREMENTS
WITH FGD

Year in Life of Plant When FGD Begins Service	Landfill [1] (Hectares)
0	156
5	150
10	122
15	106
20	90
25	74
30	60

NOTE:

1. With constant height of 12 meters for 30-year life of plant.

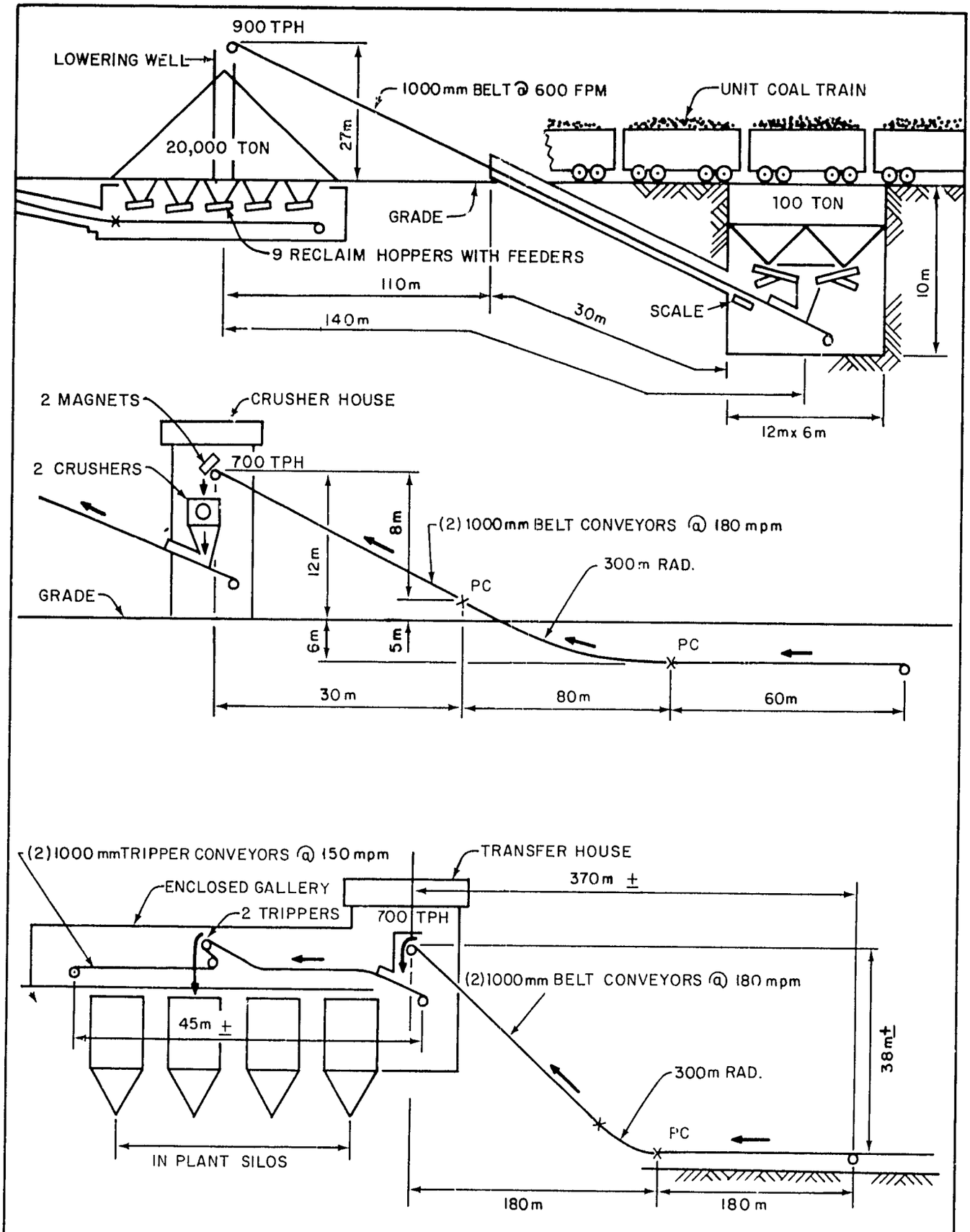

FIGURE 6.4-1
RECOMMENDED COAL HANDLING SYSTEM
LAKHRA COAL STUDY

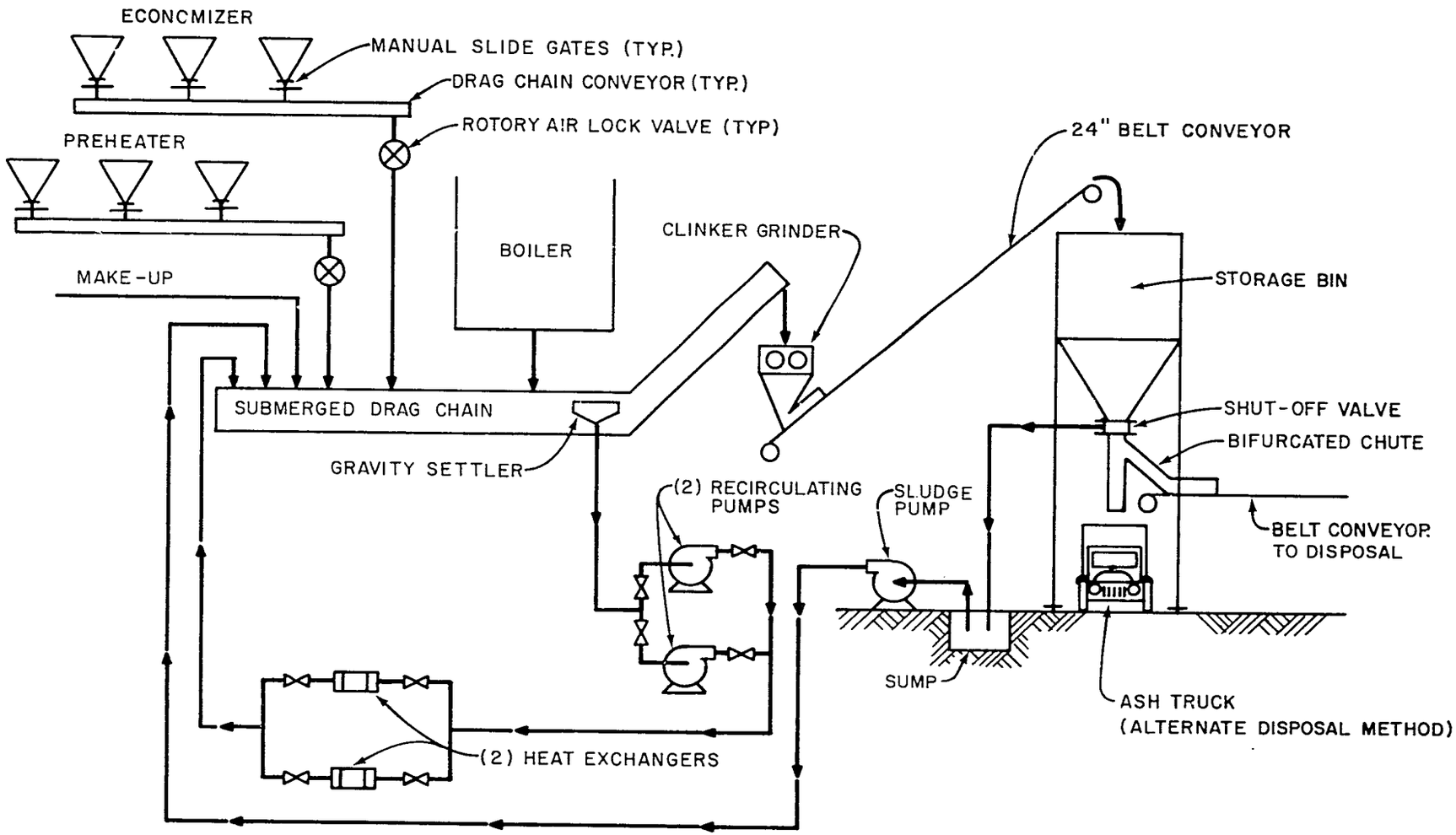

FIGURE 6.4-2
RECOMMENDED BOTTOM ASH HANDLING SYSTEM
LAKHRA COAL STUDY

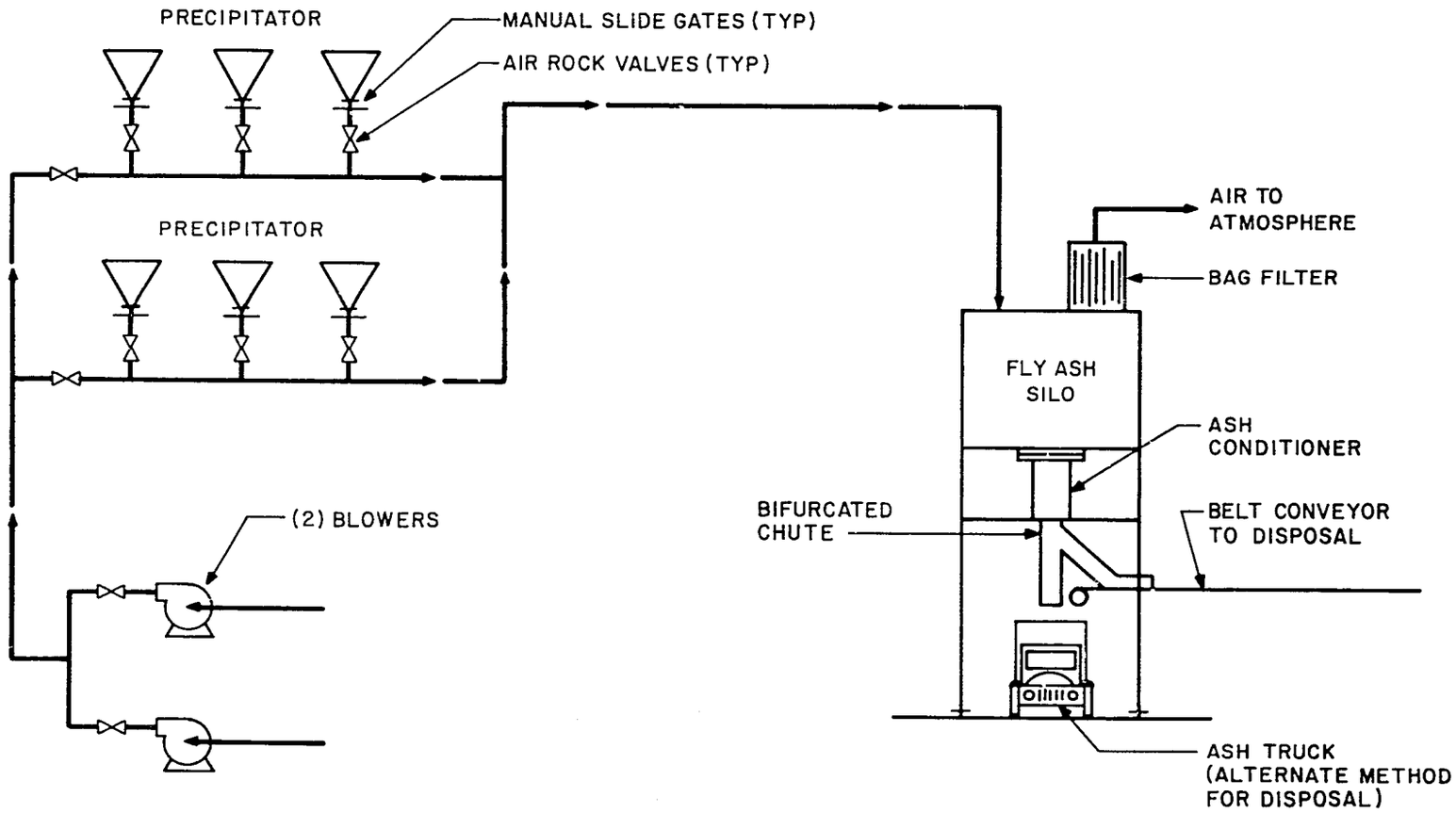

FIGURE 6.4-3
RECOMMENDED FLY ASH HANDLING SYSTEM
LAKHRA COAL STUDY

6.5 TURBINE ISLAND DESIGN

For the purposes of this discussion, the turbine island is broken down as follows:

- Turbine Cycle
- Switchyard
- Heat Rejection System
- Water and Wastewater Treatment

Design recommendations for each are offered in this section along with a brief discussion and schematic diagram of turbine island mass and energy flows at rated conditions. Since WAPDA personnel are familiar with the turbine island recommended for the Lakhra Power Plant, only brief descriptions of the various equipment and systems are provided.

6.5.1 Turbine Cycle

The turbine cycle includes the steam turbine and generator, condenser, deaerator and feedwater heating system, condensate and feedwater systems, and the main steam, hot reheat, cold reheat, and extraction steam systems.

The steam turbine recommended for the Lakhra Power Plant is a tandem compound, double flow machine running at 3000 rpm with 85.1-cm (33 1/2 inch) last stage blades. Seven stages of uncontrolled steam extraction are provided for feedwater heating. This turbine normally comes with four high pressure throttling valves upstream of the high pressure turbine section to regulate steam flow rate through the turbine, and one intercept valve upstream of the intermediate pressure turbine section to stop reheat steam flow during a turbine trip condition. The electric generator is a 3-phase, 50-Hz, 3000-rpm machine.

Rated steam conditions are 12,515 kPa and 538°C at the intermediate pressure turbine section inlet. At valves wide open, with rated pressure and temperatures and at the maximum expected back-pressure of 3.5 inches HgA (corresponding to the maximum expected wet bulb temperature of 27°C), the electrical output at the generator terminals is 333 MW.

For the 12,515 kPa Lakhra turbine cycle, seven feedwater heaters are recommended, consisting of two high pressure heaters, four low pressure heaters, and a deaerator. Nonreturn valves on the extraction steam lines are recommended.

Single feedwater heater strings are used for low pressure heaters outside the condenser neck, and double strings are used for neck heaters. The two lower stages of half-size heaters, located in the condenser neck, extract steam from both low pressure cylinders of the two-flow turbine. The high pressure heaters consist of a single string of heaters, capable of passing 100 percent of the feedwater flow with a bypass capability of 100 percent.

Feedwater heaters are available in both vertical and horizontal designs. The lowest pressure heaters which will operate with steam condensing below atmospheric pressures under certain load conditions, are usually located horizontally in the condenser neck to facilitate ease of draining and to save valuable floor space. The remaining heaters can be installed in either the horizontal or vertical position.

Basic to each feedwater heater cycle arrangement is the determination of the optimum drain arrangement for each cycle. Low pressure heater drains can be: 1) dumped directly to the condenser, 2) subcooled and dumped to the condenser, 3) subcooled and cascaded to the next lowest pressure heater, or 4) pumped ahead into the condensate system. The recommended low pressure heater drain arrangement has the 5th point heater pumped forward, and the two lowest pressure heater drains (6th and 7th point heaters) dumped to the condenser. For high pressure heater drains, cascading to the next heater and ultimately to the deaerator is recommended.

The recommended surface condenser is the shell and tube type with 90/10 copper nickel tubing. The number of passes, tube diameter and length, etc, will be determined as more specific information on the turbine cycle becomes known.

The recommended arrangement for the boiler feed pump and driver is three half-size, motor-driven feed pumps with no booster pump. This arrangement will provide excellent reliability, operability, and maintainability.

6.5.2 Switchyard

A 500-kV switchyard exists at Jamshoro. The station step-up transformer is included in the Lakhra power plant scope. The need for additional switchyard equipment will be assessed during the design phase of the project.

6.5.3 Heat Rejection System

An evaporative heat rejection system for the Lakhra Power Plant at Jamshoro was selected by the WAPDA/PMDC/SWEC Team (Section 6.2). It consists of a circulating water system, an evaporative cooling tower, and a makeup water system. The design circulating water flow rate is 470,000 lpm. Two half-size circulating water pumps are located downstream of a concrete counterflow, mechanical draft cooling tower.

The makeup water system will provide total power plant water requirements. The design makeup water system flow rate is 19,000 lpm. Two full-size vertical makeup water pumps are recommended to ensure acceptable system reliability under the severe service conditions caused by the extremely high turbidity of Indus River water. The pumps are located in a pit, adjacent to the Kotri Barrage, to ensure a reliable low water level and to avoid flooding problems that occur upstream next to the plant. Each pump has its own intake. Two low pressure makeup water lines are provided from the pumping intake structure to the power plant to ensure high reliability.

6.5.4 Water and Wastewater Treatment

Water Treatment

Makeup water requirements for the plant include makeup to the cooling water system, service water for pump seals, fire protection, and equipment washing; demineralized water for boiler feed; and potable water. The only reliable source of water for plant is the Indus River.

WAPDA has substantial experience treating Indus River water at Guddu, Sukkur, and Hyderabad. Normally employed clarification and demineralization processes should be employed for Lakhra.

Wastewater

Wastewater produced by a coal-fired power plant includes floor and equipment drainage; boiler blowdown; demineralizer regeneration wastes (makeup water treatment wastewater); metal cleaning wastes such as air preheater washes, boiler chemical cleaning wastes, and rainfall runoff from the coal pile; and other materials handling areas. These wastewaters vary in strength, quantities, and frequency of production. The type of wastewater treatment used depends on the potential for reuse of treated wastewaters, discharge effluent limitations, site specific criteria, and economics. Wastewater constituents requiring removal are suspended solids, oil and grease, and heavy metals such as iron and copper. In addition, several wastewater flows have to be neutralized because of extreme pH. Potential reuses are makeup to the bottom ash sluice system and the makeup to the FGD system, if it is added later. In order to discharge some of the wastewaters away from the power plant, chemical precipitation of heavy metals is necessary.

Three treatment methods were considered:

1. The different wastewaters can be combined in an equalization pond and treated together. This type of treatment includes an equalization pond, chemical addition for pH adjustment and/or for precipitation of metals, clarification, pH neutralization, and discharge.

2. The wastes can be segregated into individual treatment systems, each suited to the respective waste characteristics.

3. In areas with large evaporation rates and no land limitations, wastes can be treated in an evaporation pond. High strength wastes that require the most treatment can be sent to such a pond. Other, lower strength wastes that require minimal treatment can be treated elsewhere, then reused or discharged. If land is inexpensive, an evaporation pond is less expensive than other forms of treatment (Figure 6.5-1).

Since land is available at the Jamshoro site and the yearly evaporation rate is high, an evaporation pond was chosen for the station wastewater treatment system. All wastewater, except floor and equipment drainage and boiler blowdown, will be sent to the pond. Floor and equipment drainage typically has a low concentration of dissolved constituents,

but may be contaminated intermittently with suspended solids, oil, and grease. Those will be removed by an oil/water separator. If suitable, the oil/water separator effluent will be reused in the plant as makeup to the bottom ash system. Otherwise, it will be discharged.

Water Treatment System

Water treatment systems include clarification of Indus River water prior to use as makeup to the cooling water system, processing of Indus River water into plant service water by chlorination, clarification, and filtration; the processing of service water into boiler makeup water using sand filters or activated carbon filters and cation, anion, and mixed bed ion exchange units and the production of potable water from service water by use of activated carbon filters and chlorination.

Recirculating Cooling System Water Treatment

A summary of water chemistry characteristics of the Indus River has been provided but is not sufficiently detailed to form the basis for specifing treatment requirements. However, some general conclusions can be derived. The makeup to the cooling system will require suspended solids removal, since the high sediment load in the Indus River will probably cause the makeup pond water to have an unacceptably high suspended solids concentration.

This treatment will consist of chlorination using a gaseous chlorination feed system which includes gaseous chlorine storage tanks, two 100-percent evaporators, two 100-percent chlorinators, ejectors, piping, valves, and a control panel, and clarification by using one 100-percent clarifier/thickener with integral chemical feed of polyelectrolytes and/or other coagulating chemicals.

The amount of treatment the cooling water receives is dependent on the concentration factor used and the water chemistry of the makeup water. Minimum treatment will consist of chlorination using a system similar to the one for chlorination of makeup water, and acid addition for alkalinity reduction. The acid addition system would consist of a storage tank, two 100-percent chemical feed pumps, piping, valves, and a control panel. Further treatment (i.e., side steam softening) may be required if a large concentration factor were used.

Service Water System

Indus River water will be chlorinated using a sodium hypochlorite feed system consisting of a storage tank and chemical feed pumps, clarified by using one 100-percent-capacity clarifier/thickener with integral chemical feeds of polyelectrolytes and/or other coagulating chemicals, and filtered by three 50-percent-capacity dual-media gravity filters.

The service water system will remove suspended solids, turbidity, and some organics from the river water, making it suitable for plant use.

The system is sized to produce 1500 lpm net. Product water is used for service water, pump seal water, and makeup to the boiler makeup demineralizer system and the potable water system.

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Clarifier/thickener underflow will be pumped to the wastewater evaporation pond.

Boiler Makeup Demineralizers System

The function of this system is to produce deionized water for use as makeup to the boiler. Service water is processed through an active carbon filter to remove chlorine, suspended solids, and some organics. The water is then treated using a weak base anion exchange vessel for additional organics removal, a cation, a strong base anion, and mixed bed ion exchange vessels to remove TDS to a residual concentration of less than 0.1 ppm. The treatment train also includes a decarbonator, located between the cation and strong base anion exchange units for CO_2 removal.

The system consists of two complete 50-percent-capacity trains. Each train includes an activated carbon filter; weak base anion, cation, strong base anion, and mixed bed ion exchange vessels; a common decarbonator vessel to both trains; sulfuric acid and sodium hydroxide regeneration equipment; a control panel; piping; valves; and instrumentation. Each train is sized to produce 360 lpm for a total system capacity of 720 lpm. The system capacity is based on producing demineralized water at a rate of 4 percent of the main steam flow rate. Steam soot blowing is assumed.

Regeneration wastes from the system are discharged to the wastewater evaporation pond.

Potable Water System

The potable water system produces water for domestic needs from service water. Service water is first treated by activated carbon filters for suspended solids and organics removal. A chemical solution of sodium hypochlorite is then added to the water before use to eliminate any residual pathogenic organisms.

The system consists of a storage tank, feed pumps, two 100-percent activated carbon filters, and a sodium hypochlorite feed system including a chemical storage/feed tank, metering pumps, pipe, valves, and instrumentation.

Waste Treatment System

The waste treatment system for the station is designed to treat station wastes to the limitations listed in Section 4. Station wastes include: cooling tower blowdown, sanitary wastes, clarifier blowdown, makeup demineralizer system wastes, floor and equipment drainage, coal pile and other materials handling areas rainfall runoff, boiler blowdown, metal cleaning wastes, and boiler chemical cleaning wastes.

Cooling Tower Blowdown

Treatment of cooling tower blowdown will depend on the concentration factor used in the cooling tower. Treatment could range from no treatment if a low concentration factor was used to evaporation in the

evaporation pond if a large concentration factor was employed. Design of this treatment system cannot be performed until a detailed design of the recirculating water cooling system is completed.

Sanitary Wastes System

Sanitary wastes are treated using extended aeration activated sludge package units. Sludge from the system is further processed through a digestor and finally dewatered on sludge drying beds.

The system consists of two 50-percent aeration tanks, two 50-percent clarifiers, two 50-percent chlorine contact tanks, four 50-percent air blowers, one digester, hypochlorite feed equipment, sludge drying bed, control panel, piping, valves, and instrumentation.

The sanitary system is designed to treat approximately 120,000 liters per day.

Sludge will be removed from the drying beds periodically, and disposed of in the ash landfill.

Floor and Equipment Drainage Treatment System

Drainage from floors and equipment is treated by a corrugated plate oil/water separator to remove oil and grease prior to discharge or reuse.

This waste treatment system includes a corrugated plate oil/water separator with 1500-liter oil reservoir, one 190 lpm sludge pump, two 380 lpm vertical centrifugal effluent pumps, piping, valves, and instrumentation.

Boiler Blowdown

After temperature reduction, blowdown from the main boiler is discharged directly to the floor drains without any treatment. Characteristics of the boiler blowdown are such that discharge limitations can be met without any chemical treatment.

Wastewater Evaporation Pond

Wastes, which could have high total dissolved solids and/or high concentrations of metals such as iron are routed to an evaporation pond. These wastes include makeup demineralizer, regeneration wastes, metal cleaning wastes such as air preheater washes and boiler fireside washes, boiler chemical cleaning wastes, laboratory drains, chemical area drains, service water clarifier thickener blowdown and runoff from the coal pile and other materials handling areas, as required. The evaporation pond will be located next to the coal pile so that coal pile runoff will flow by gravity to the pond. The pond will be 9 acres in size and 5 feet deep to contain runoff from the monsoon rains that occur in this area of Pakistan. The pond also will be lined with an impervious material to minimize groundwater contamination. Sludge will be removed periodically and disposed of in the ash landfill.

6.5.5 Turbine Cycle Performance

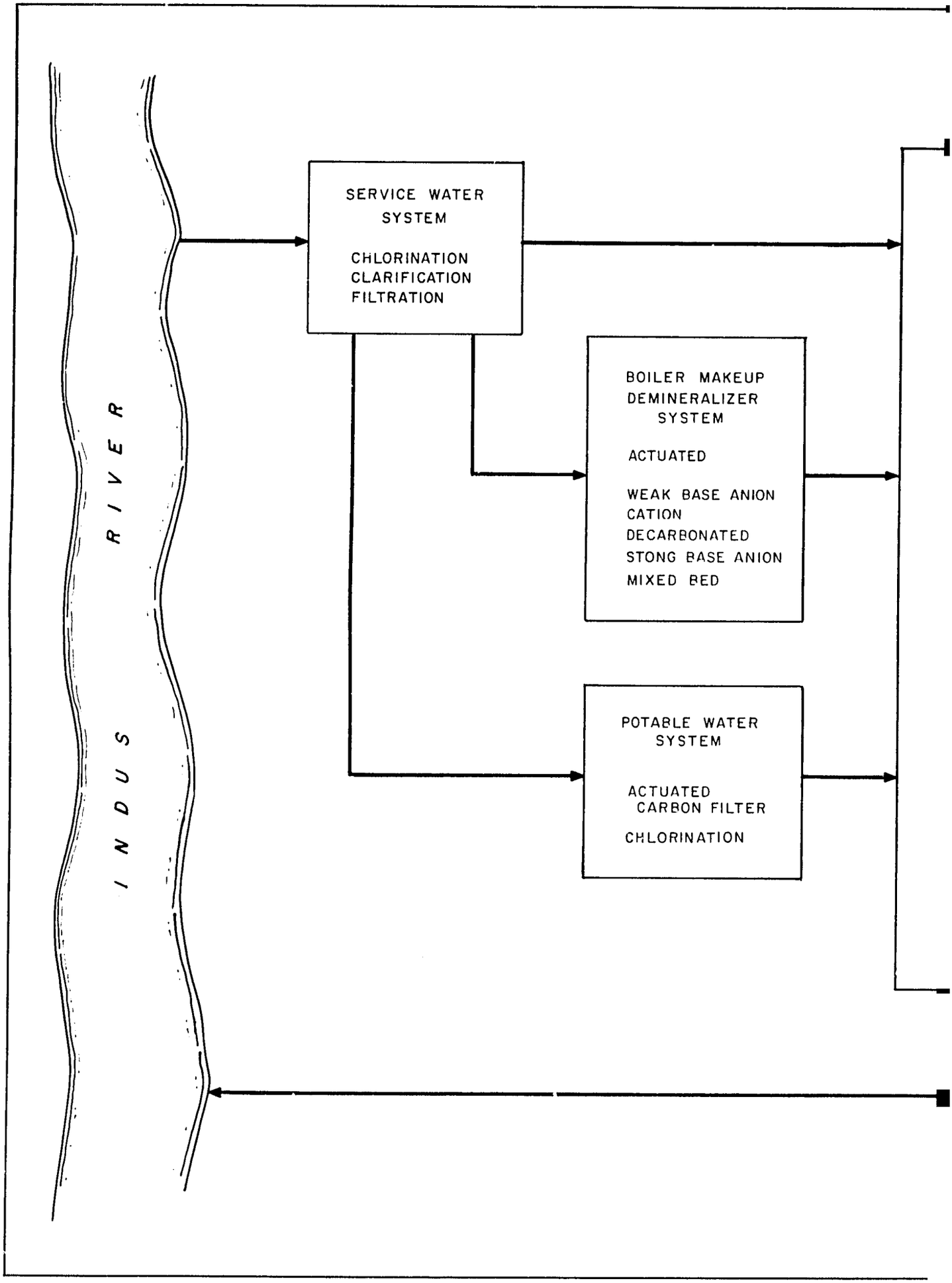
The preliminary heat balance diagram is presented on Figures 6.5-2 and 6.5-3 in SI and English units. The diagrams provide mass and energy flows while the power plant is generating 300 net MW and operating at turbine valves wide open (VWO), rated steam conditions, and a design back-pressure of 8.9 cm (corresponding to a design wet bulb temperature of 27°C and a cooling tower approach of -12°C). The quantity of auxiliary power required by power plant equipment is 10 percent of gross turbine generator output, which is typical for low rank coal-fired power plant without FGD. The steam generator efficiency burning the design Lakhra coal at rated output is 82.3 percent.

The performance of the Lakhra coal-fired power plant can be summarized as follows:

- Net station output = 300 MW
- Net station heat rate = 11,510 kJ/kWh (10,900 Btu/kWh)
- Gross turbine cycle heat rate at the design back-pressure of 3 1/2 inches HgA = 8528 kJ/kWh (8077 Btu/kWh)
- Gross turbine-generator output = 333 MW
- Total power plant auxiliary power requirements, including motor driven boiler feed pump = 33 MW
- Steam generator efficiency = 82.3 percent*

During the design phase of the project, specific component and overall cycle performance is revised as more detailed information is received from manufacturers of particular equipment in the cycle, and pressure drops are calculated for actual piping layouts. Subsequent revisions would also include requirements for combustion air preheating and partial load performance.

* Based on a temperature of the flue gas exiting the air preheater of 330°F.


INDUS RIVER
SERVICE WATER SYSTEM
CHLORINATION
CLARIFICATION
FILTRATION
BOILER MAKEUP DEMINERALIZER SYSTEM
ACTUATED
WEAK BASE ANION
CATION
DECARBONATED
STONG BASE ANION
MIXED BED
POTABLE WATER SYSTEM
ACTUATED CARBON FILTER
CHLORINATION

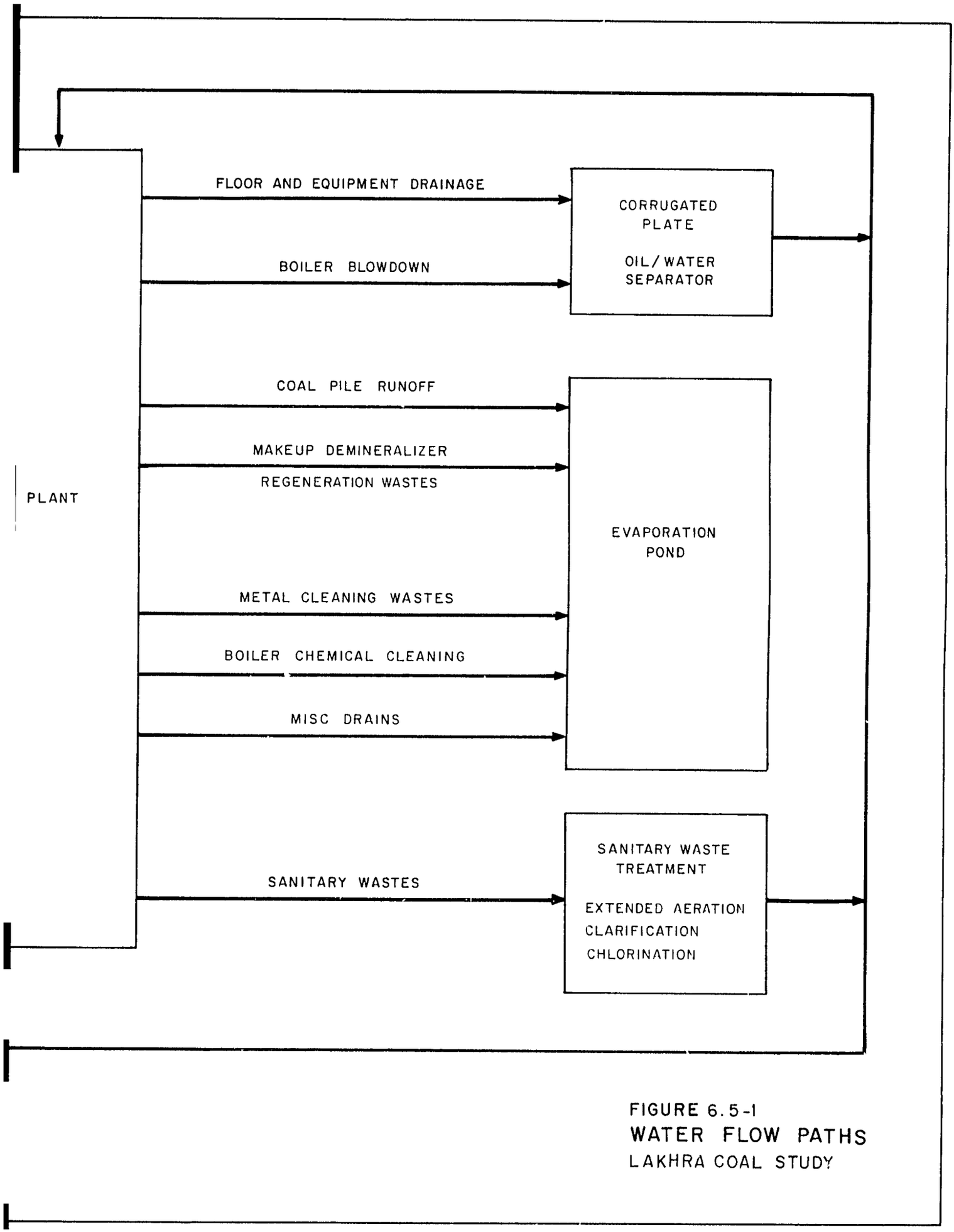
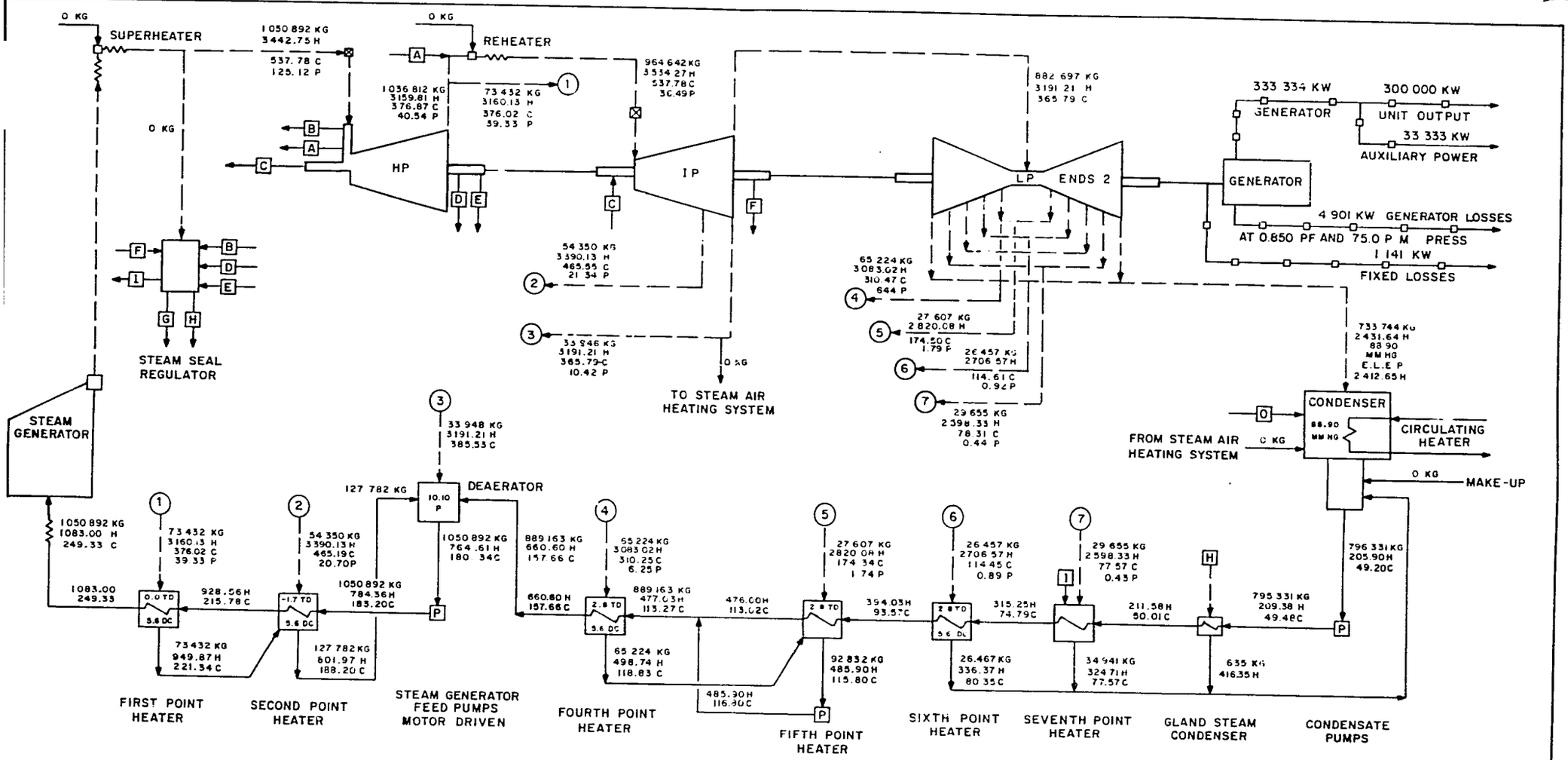


FIGURE 6.5-1
WATER FLOW PATHS
LAKHRA COAL STUDY



HEAT RATE ESTIMATION

ASSUMPTIONS = STEAM GENERATOR EFFICIENCY 82.3 PERC

PRESSURE DROP IN EXTRACTION STEAM LINES 3.0 PERC

AUXILIARY POWER PERCENT OF GENERATION 10.0 PERC

$$\text{UNIT HEAT RATE} = \frac{\text{STEAM GENERATOR DUTY}}{\text{UNIT OUTPUT X STEAM GENERATOR EFFICIENCY}} =$$

LEAKAGES

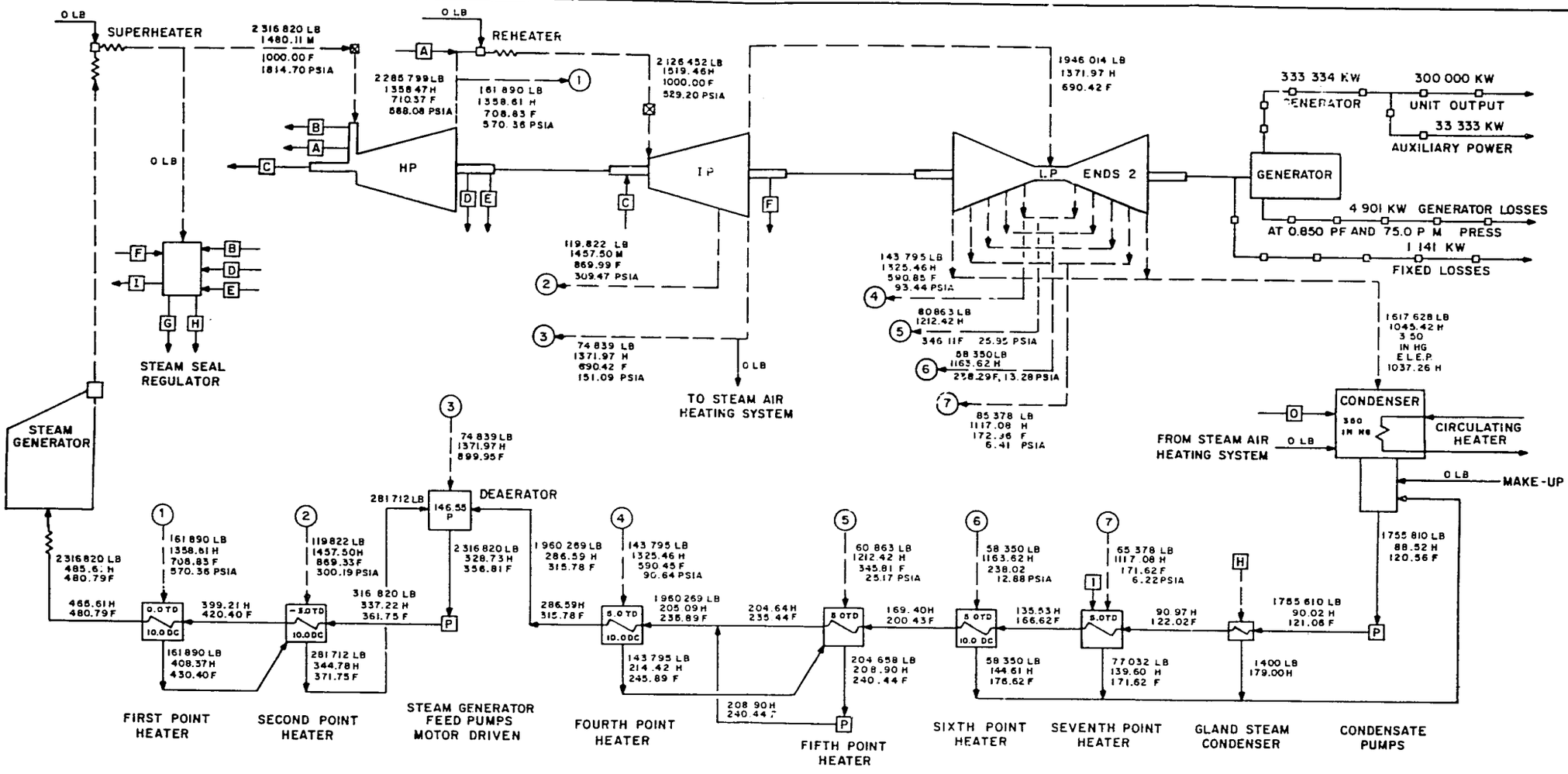
	FLOW	ENTHOLPY
A	1 163	3442.75
B	471	3442.75
C	7746	3386.58
D	3069	3159.81
E	1631	3159.81
F	1294	3191.21
G	544	3186.71
H	635	3186.71
I	5286	3186.71

LEGEND:

STEAM
WATER
POWER
AIR
GAS
FUEL
CONTROL VALVE

KG = FLOW, KILOGRAMS PER HOUR
H = ENTHALPY, KILOJULES PER KILOGRAM
C = TEMPERATURE, DEGREES CELSIUS
P = PRESSURE, BAR, ABSOLUTE P
MM HG = PRESSURE, MILLIMETERS OF MERCURY (10.0 C), ABSOLUTE
KW = POWER, KILOWATTS
⊠ = THROTTLE OR INTERCEPT VALVE

FIGURE 6.5-2
S.I. UNITS
LAKHRA COAL STUDY



HEAT RATE ESTIMATION

ASSUMPTIONS = STEAM GENERATOR EFFICIENCY 82.3 PERC

PRESSURE DROP IN EXTRACTION STEAM LINES 3.0 PERC

AUXILIARY POWER PERCENT OF GENERATION 10.0 PERC

$$\text{UNIT HEAT RATE} = \frac{\text{STEAM GENERATOR DUTY}}{\text{UNIT OUTPUT} \times \text{STEAM GENERATOR EFFICIENCY}} =$$

LEAKAGES

	FLOW	ENTHALPY
A	2563	1480.11
B	1039	1480.11
C	17077	1455.97
D	6766	1358.47
E	3598	1358.47
F	2853	1371.97
G	1200	1370.04
H	1400	1370.04
I	11654	1370.04

LEGEND:

STEAM
WATER
POWER
AIR
GAS
FUEL
CONTROL VALVE

M = FLOW, POUNDS PER HOUR
H = ENTHALPY, BTU PER POUND
F = TEMPERATURE, DEGREES FAHRENHEIT
P = PRESSURE, LB PER SQUARE IN. ABSOLUTE
IN HG = PRESSURE, INCHES OF MERCURY ABSOLUTE
KW = POWER, KILOWATTS

⊠ = THROTTLE OR INTERCEPT VALVE

FIGURE 6.5-3
BRITISH UNITS
LAKHRA COAL STUDY

6.6 INSTRUMENTATION AND CONTROL

United States Experience

The United States practice is to centralize controls, start, and operate from a central control room. The reasons for this practice are:

- To achieve better control and coordination of larger, more complex, and more interactive installations.
- To minimize the number of plant operators.
- To provide a better environment for operators, and electronic control equipment.

The primary objectives of the central control room operator are:

- To maintain the plant in a safe condition.
- To control the generation of power by monitoring system displays, and manipulating equipment associated with those systems essential for power generation.

In general, instrumentation for control functions is independent of that used for indication and alarm. Signal levels are 4-20 mAdc or 3-15 psi. No process or instrument air lines are brought into the central control room.

Local controls are primarily pneumatic, and are used for final operators and simple systems not requiring operator action for extended periods of time (approximately 4 hours or longer).

Alternatives

Alternatives generally revolve around the type and sophistication of control equipment used. Client input is vital in this area since it will impact operation, maintenance, and overall plant philosophy.

The evolution of control equipment/systems over the past 20 years has spawned a number of fundamentally different designs, such as pneumatics, magnetic amplifiers, electronics (both transistor and integrated circuits), centralized computer control systems, and microprocessor-based distributed control systems. Pneumatics, magnetic amplifiers, transistorized electronic controls, and integrated circuit electronic controls are systems where each function is performed by a dedicated piece of hardware. The centralized computer systems and the microprocessor-based distributed control systems are software systems which may be programmed for any function. The software systems may utilize a data highway to multiplex remote signals and cathode ray tube (CRT) operator consoles.

Designs incorporating magnetic amplifiers and transistorized electronics are obsolete. Pneumatic controls are applied to simple local control loops but are not generally used for central station combustion control. The majority of systems installed over the past 5-10 years have utilized

integrated circuit electronic components for both continuous control systems and sequential control systems.

Trends

The trend of central station controls is toward microprocessor-based distributed control systems. The advantages of this approach are:

- Flexibility in design of control functions.
- Capability of handling both continuous and sequential control systems.
- Reduced control panel space if CRT operator stations are used.
- Reduced installation costs if multiplexing is included.

The disadvantages are:

- Lack of standards which would allow mixing of equipment from various manufacturers.
- Limited operating experience.

Recommendation

The operation of all equipment vital to power generation and boiler protection should be from the central control room. The central control room also should monitor the operation of all equipment and provide audio/visual alarms for abnormal conditions. Equipment and systems which are not vital to power generation or safety related should be locally started and operated.

Instrumentation for control, indication, and alarm should be separate. Local controls and final operators should be pneumatic. Although the latest technology is microprocessor-based distributed control systems, it is recommended that the major control systems be of the integrated circuit electronic component type. A small plant data collection system should be provided for monitoring, logging, and recording sequence of events.

To facilitate operation, training and maintenance instrumentation and control equipment should be standardized. This should include both manufacturer and models. Additionally, a 2-year supply of spare parts should be provided.

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6.7 POWER PLANT ARRANGEMENT

6.7.1 General

The design concept offered in this section provides utilities with a predesigned, carefully conceived plant, permitting complete flexibility in choosing plant size (generation and physical), fuel, equipment arrangement, and steam cycle. The adaptation of these concepts will be applied to meet the economic and technical requirements of the Lakhra/Jamshoro site.

6.7.2 Plot Plan

The plot plan (Figure 6.7-1) for the Jamshoro site shows a proposed arrangement for a 300 MW fossil power plant utilizing coal shipped by a dedicated railroad from the coal mine. The new rail system is assumed to enter the station west of the area reserved for the switchyard. The main axis for the turbine building runs north and south. Sufficient space has been allowed between the turbine building and the switchyard to allow installation of the transmission lines with turning towers to the switchyard. Space for future plant expansion has been provided south of Unit 1. This area also can be utilized for construction laydown. A rail spur from the existing line is recommended, this will allow shipment of construction material to the plant site with a tie-in to the coal mine rail. In order to optimize the site arrangement, it is recommended that the metelled road be relocated slightly east. The mechanical draft cooling towers are located east of the plant. This location is based on existing wind rose data and should preclude fogging of the plant and switchyard for a substantial portion of the year.

6.7.3 Station Arrangement

The two-unit station arrangement shown on Figure 6.7-2 incorporates the slide-along concept as much as is practical. Therefore, the arrangement of Unit 1 is duplicated for a future Unit 2 except for the control complex, which is common to both units. Half the control room complex is constructed with Unit 1 and the remainder with the second unit.

In general, most Unit 1 drawings can be used for Unit 2, provided duplicate equipment is purchased. All equipment locations are identical and therefore all piping and ductwork are duplicated, including the pipe stress analysis effort. The common control complex causes some cable tray routing differences between the two units.

The turbine generator shaft centerline is arranged perpendicular to the boiler to stack centerline. The boilers are shown with the coal silos/pulverizing equipment locations at the front of the boiler.

A future SO_2 scrubbing system is shown beyond the stack. The induced draft ducting between the fans and stack can be arranged to allow future addition of the scrubbing equipment without modifications to the existing arrangement or equipment.

The arrangement drawings indicate a completely enclosed control complex, turbine room, and boiler area. For the Jamshoro site, which can be

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dusty at times, it is recommended that the turbine building be enclosed to facilitate maintenance and operation. In addition, it is recommended that the boiler house be open except for the burner firing area and the tripper gallery.

A common truck or rail access/hatch opening is provided between the Unit 1 and Unit 2 turbine buildings. This arrangement allows use of a single crane to serve both units.

The station arrangement shows a single flue chimney for each unit. If a future second unit were to be constructed shortly after the first, consideration should be given to a single chimney with dual flues, one flue serving each unit.

Turbine Room Arrangement

The turbine generator (Figures 6.7-3 through 6.7-8) is a tandem compound, two casing, single reheat, two flow exhaust machine. Included with the turbine generator are the gland steam sealing, lubricating oil, and electrohydraulic fluid systems; the generator hydrogen seal oil unit; stator cooling system; and generator leads cooler.

The condenser used for equipment layout is a two pass, divided water box, shell unit. The condenser tubes are arranged transverse to the turbine-generator centerline.

Three half-capacity condensate pumps are provided. Each pump has a simplex inlet basket strainer. Pump withdrawal access is through the operating floor, utilizing the turbine room crane.

Two full-capacity air removal pumps are indicated on the drawings. A steam jet air ejector system with inter- and after-condensers can be installed instead of the mechanical pumps.

Seven stages of feedwater heating are shown consisting of four low pressure heaters, a deaerator, and two high pressure heaters.

The 7th and 6th point heaters are located in the condenser necks.

The 4th point heater drains are cascaded to the 5th point heater. The combined drains are pumped to the condensate stream downstream of the 5th point heater. The 6th point heaters drain directly to the condenser. The 7th point heaters drain to the condenser via a loop seal.

The deaerator, with its storage tank, is shown located in the auxiliary bay. A 5-minute feedwater storage capacity is provided in the storage tank.

Heater shell and tube bundle removal spaces, as applicable, are shown on the drawings.

Two half-capacity, motor-driven, multistage boiler feed pumps are located on the ground floor of the auxiliary bay.

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Two full-size component cooling water heat exchangers and pumps are shown on the ground floor.

Two full-capacity instrument air compressors with receivers are on the ground floor in the auxiliary bay.

A turbine room crane is shown for the two units. A crane for the second unit is optional. The main hook is rated for approximately 100 metric tons, and the auxiliary hook for 25 metric tons. The crane capacity should be based upon the heaviest piece to be lifted after erection.

The turbine oil tank is located at the mezzanine level. The tank is provided with two full-capacity lube oil coolers, two ac and one dc motor-driven oil pumps, and associated control apparatus. The pump and oil cooler withdrawal access is shown on Figures 6.7-3 through 6.7-8.

A lube oil purifier is below the turbine oil tank on the ground floor. A curb is provided around the oil tank to contain nuisance spills.

The clean and dirty lube oil storage tanks, together with space for drum storage, are outside the turbine room wall in an adjoining structure. Access is provided through the turbine room wall and from the yard into the storage room. Storage outside the turbine room reduces possible damage from an oil fire.

Boiler Area Arrangement

The boiler is arranged with five pulverizers-silos along the front of the furnace. This arrangement is conventional for units to about 600-MW capacity utilizing a maximum of six pulverizers. With more than six pulverizers, an arrangement with half the pulverizers on one side of the boiler and half on the other side of the boiler may be desirable to shorten primary air ducts and coal pipes, and minimize width of the unit.

Actual boiler design requires a complete analysis of the fuel to be burned. Therefore, variations in physical size will occur when the boiler is specified and purchased for a specific site. The reference fossil power plant concept does not standardize on size of boiler, but has developed a conceptual arrangement that will be adapted or projectized to a client's specific requirements.

Boiler

A drum-type boiler has been used for Figures 6.7-3 through 6.7-8. It is a reheat balanced draft unit arranged to be fired with pulverized coal, welded wall construction is utilized.

Two Ljungstrom tri-sector regenerative air heaters are shown. The tri-sector design eliminates the need for a primary air water-air heater as the primary section is in a hotter zone than the secondary air section. This arrangement also permits obtaining the high primary air temperature required for burning high moisture coals.

Two half-capacity, single-speed, forced draft fans are provided, and located in a fan room with its respective primary air fan. The fan rooms are provided because of environmental noise abatement considerations. An optional wall is shown on the drawings which divides the room into two separate fan rooms.

Two half-capacity, two-speed, induced draft fans are provided and are located between the stack and the precipitator.

A cold precipitator designed for 150°C gas is provided. The design gas velocity is 1.5 mps maximum.

The control complex shown in Figure 6.7-11 is for a two-unit station with a central, common control complex for both units. The complex, located between the two units' turbine rooms and the auxiliary bays. Half the complex is constructed with the first unit and the remainder with the second unit.

The control complex contains the control, relay, computer, dc equipment, switchgear, and battery rooms, as well as the cable spreading area. The control room is on the operating floor level contiguous with the auxiliary bays of the two units. The relay room is adjacent to the control room with the computer room adjacent to the relay room.

The area on the mezzanine level under the control, relay, and computer rooms is reserved for cable spreading, with the exception of the dc equipment room. The 6.9 kV and 4.16 kV switchgear for each unit is under the cable spreading area on the ground floor. Excellent access for cable routing is obtained. These areas are exclusively devoted to electrical work and should result in substantial savings in construction man-hours.

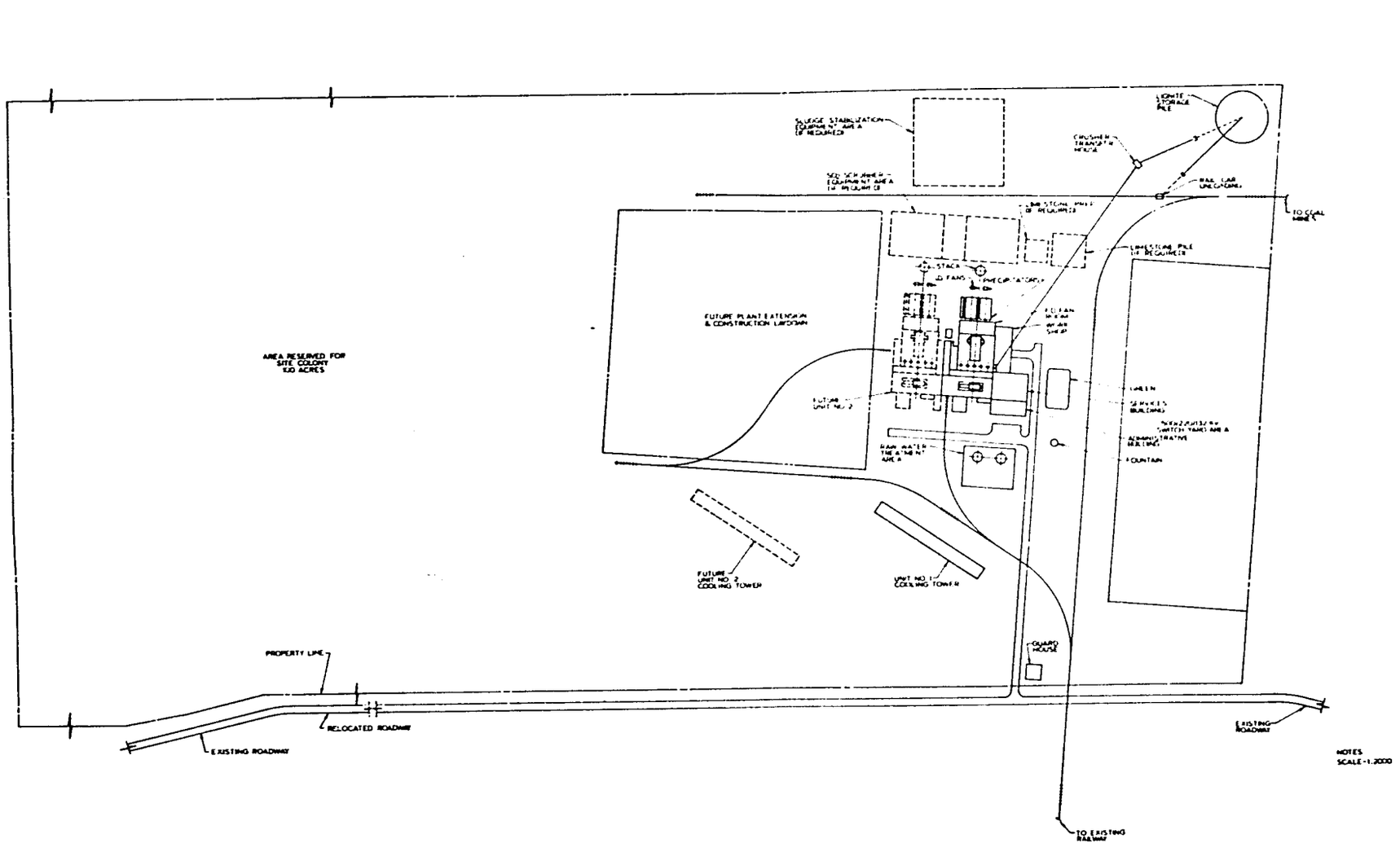
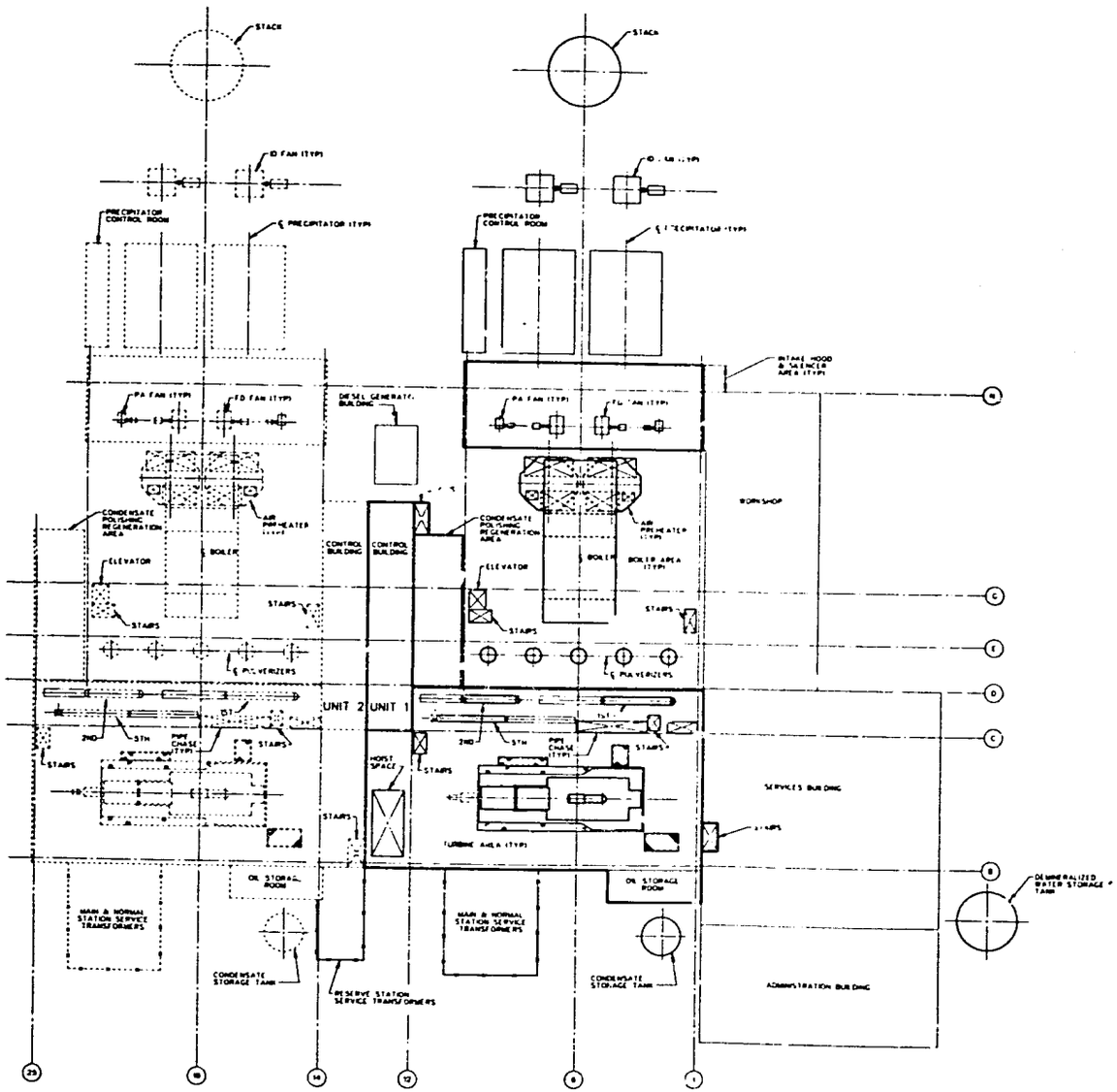


FIGURE 6.7-1
PLOT PLAN
LAKHRA COAL STUDY



NOTES

1. THE POWER BLOCK CONSISTING OF THE TURBINE AREA, BOILER AREA AND CONTROL BUILDING HAS BEEN DEVELOPED IN ACCORDANCE WITH THE PREFERRED LAYOUT CONCEPTS AND DESIGN STUDIES. THESE ARE SHOWN IN HEAVY LINES.
THE ADMINISTRATION BUILDING, SERVICES BUILDING, DIESEL GENERATOR BUILDING, WORKSHOP AND PRECIPITATOR WILL BE DEVELOPED BASED ON CLIENT AND SITE REQUIREMENTS. THESE AREAS ARE SHOWN IN LIGHT LINES.

REFERENCE DRAWINGS

1. MACHINE LOCATION - BOILER AREA	EM-202 SERIES
2. MACHINE LOCATION - TURBINE AREA	EM-203 SERIES
3. GENERAL ARRANGEMENT - CONTROL BUILDING	EE-1516

FIGURE 6.7-2
STATION ARRANGEMENT
LAKHRA COAL STUDY

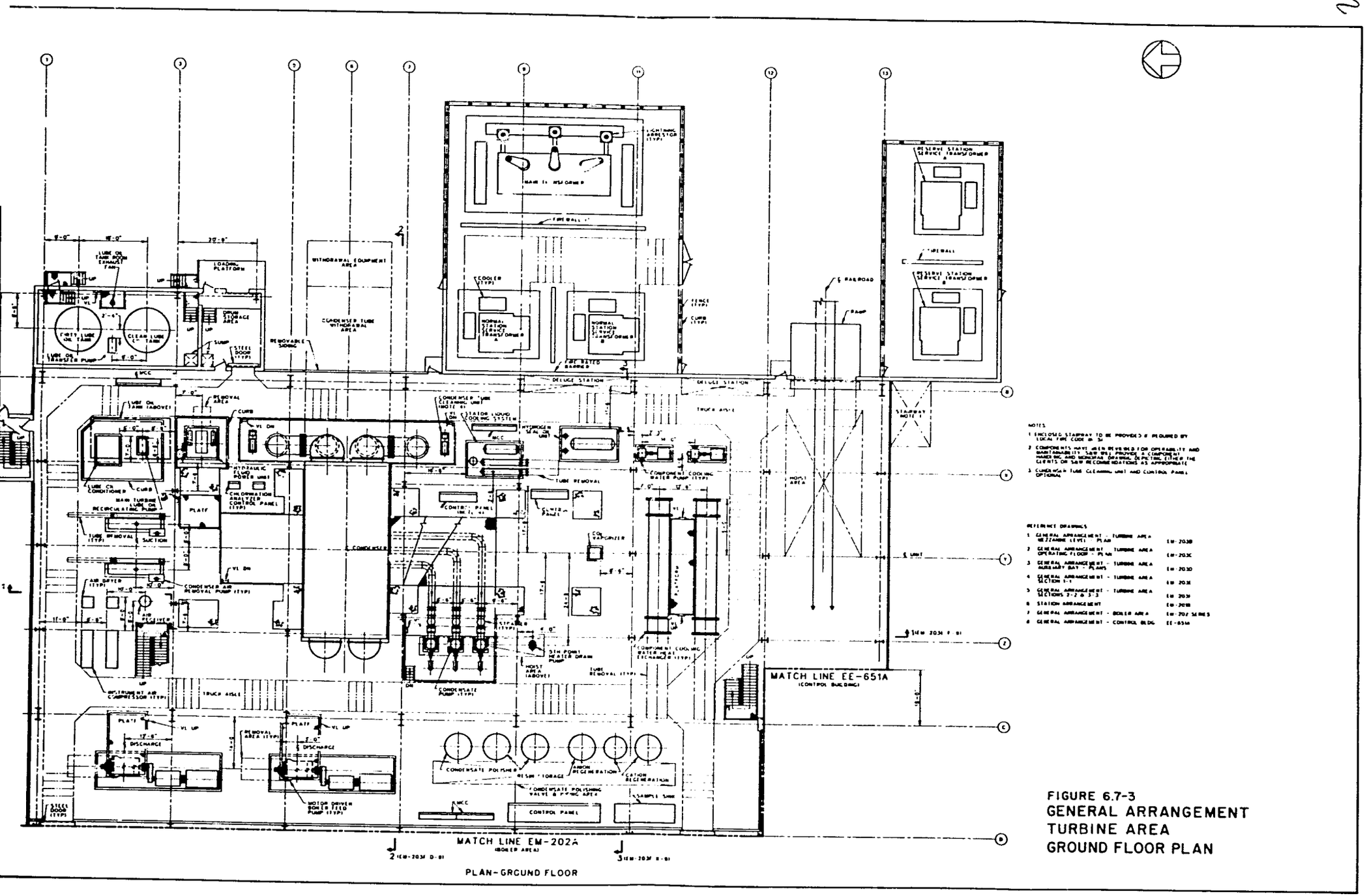
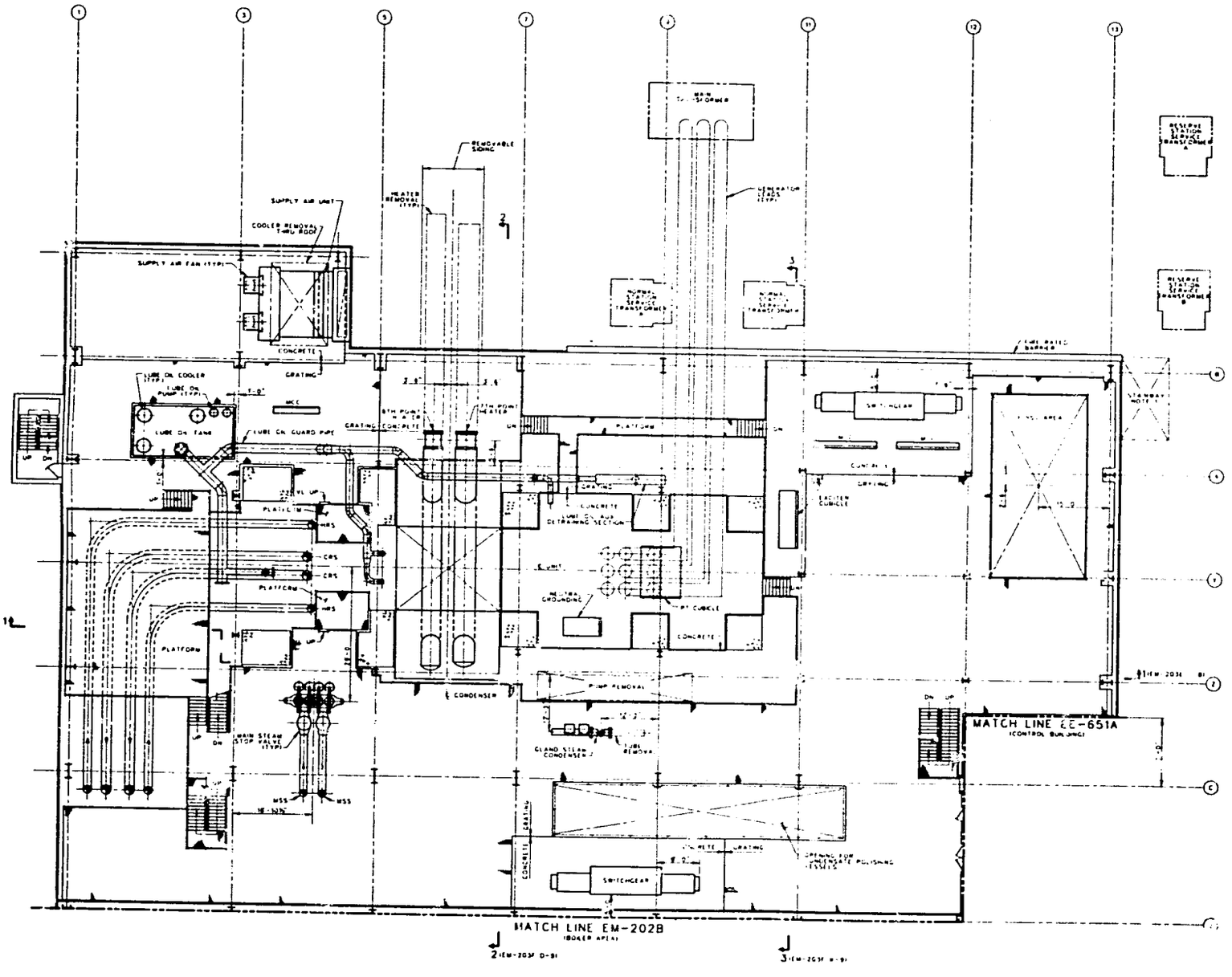
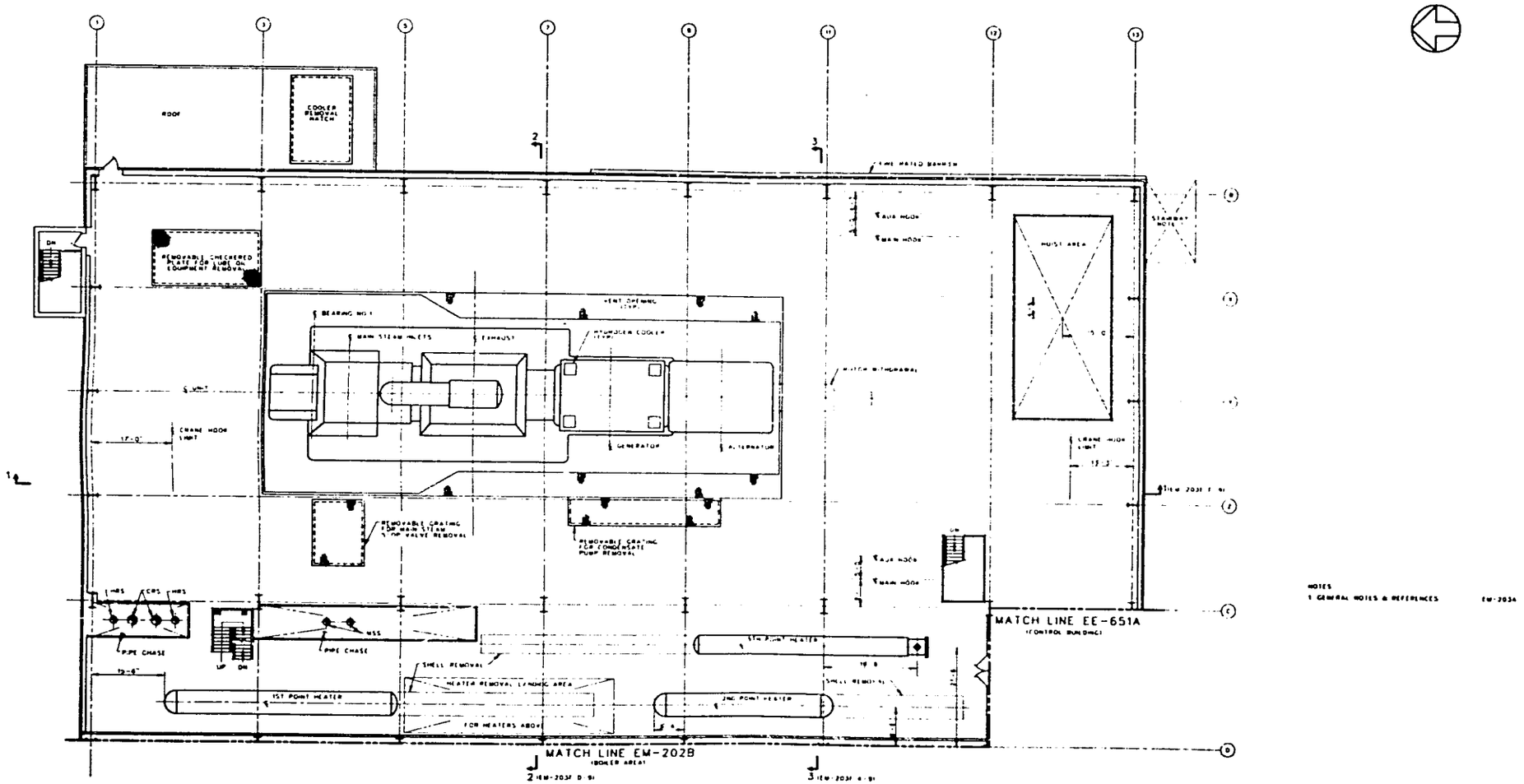


FIGURE 6.7-3
GENERAL ARRANGEMENT
TURBINE AREA
GROUND FLOOR PLAN



NOTES
1 GENERAL NOTES & REFERENCES EM-203A

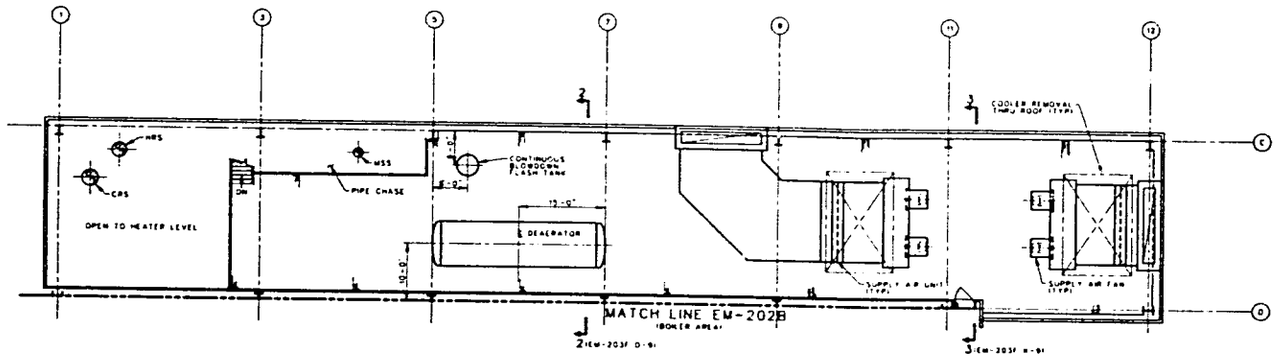
FIGURE 6.7-4
GENERAL ARRANGEMENT
TURBINE AREA
MEZZANINE LEVEL PLAN



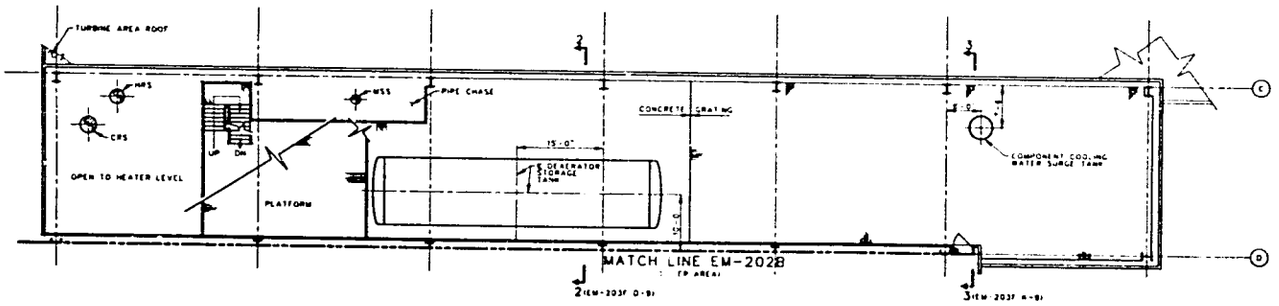
PLAN–OPERATING FLOOR

NOTES
1. GENERAL NOTES & REFERENCES EM-2034

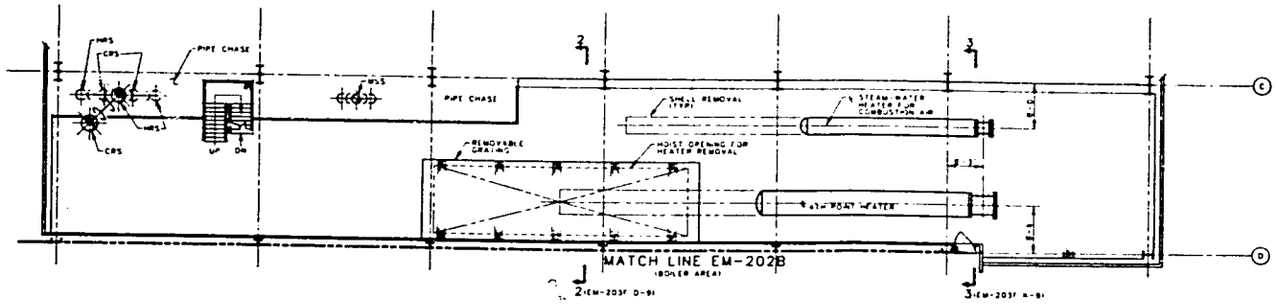
FIGURE 6.7-5
GENERAL ARRANGEMENT
TURBINE AREA
OPERATING FLOOR



PLAN-DEAERATOR LEVEL



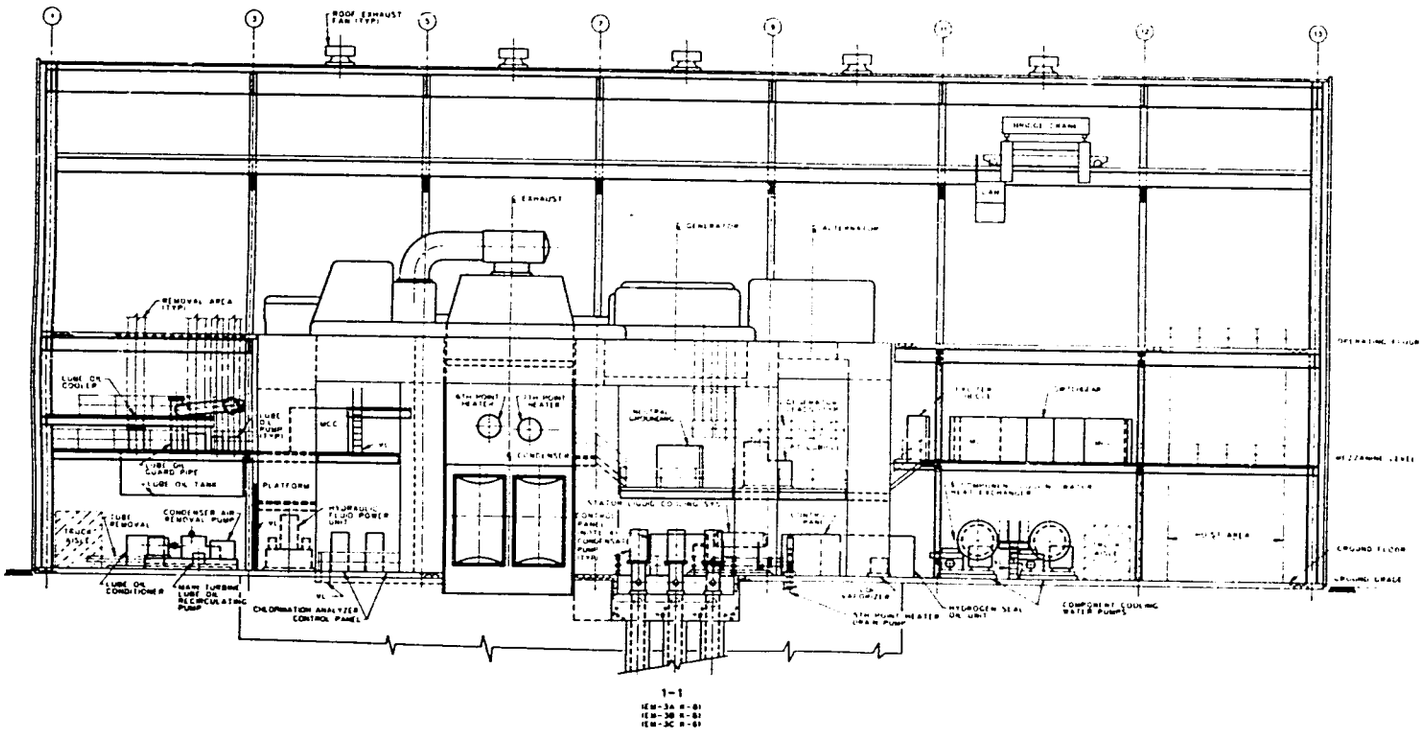
PLAN-DEAERATOR STORAGE TANK LEVEL



PLAN-HEATER LEVEL

NOTES:
1. GENERAL NOTES & REFERENCES EM-203A

FIGURE 6.7-6
GENERAL ARRANGEMENT
TURBINE AREA
AUXILIARY BAY PLANS
LAKHRA COAL STUDY



NOTES

1 GENERAL NOTES & REFERENCE DRAWINGS EM-203A

FIGURE 6.7-7
GENERAL ARRANGEMENT
TURBINE AREA, SECTION 1-1
LAKHRA COAL STUDY

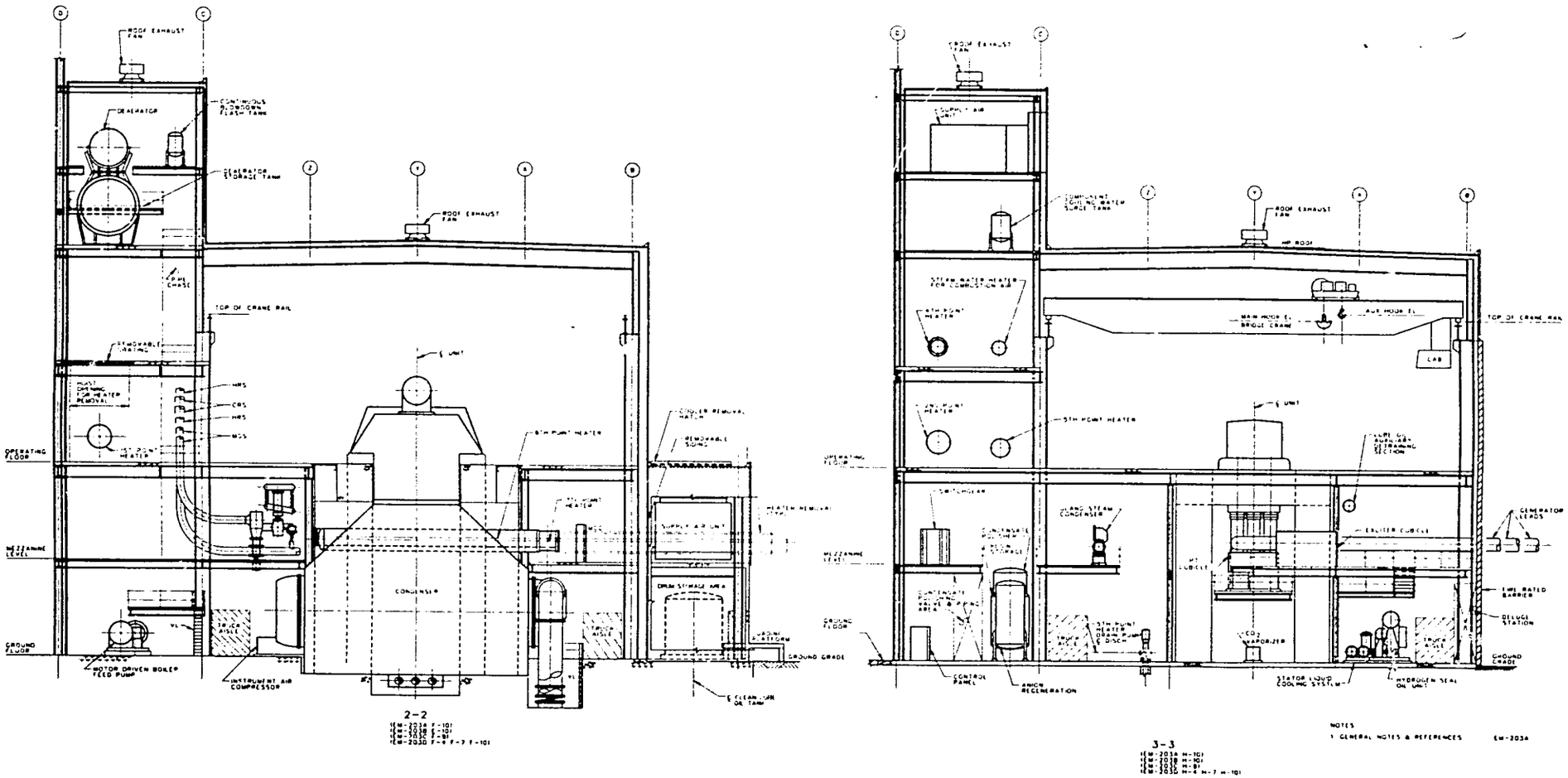
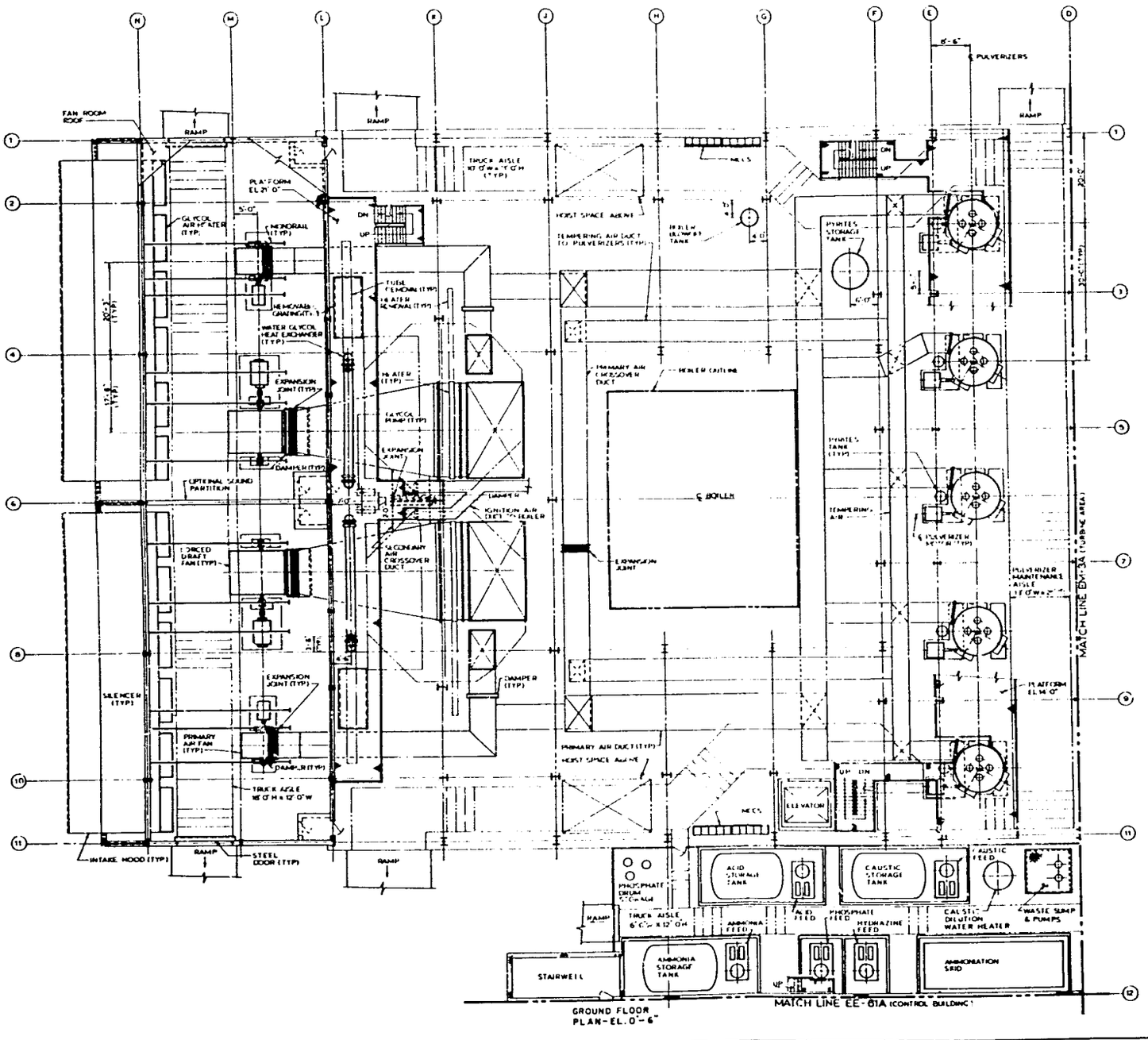


FIGURE 6.7-8
GENERAL ARRANGEMENT
TURBINE AREA
SECTIONS 2-2 & 3-3
LAKHRA COAL STUDY



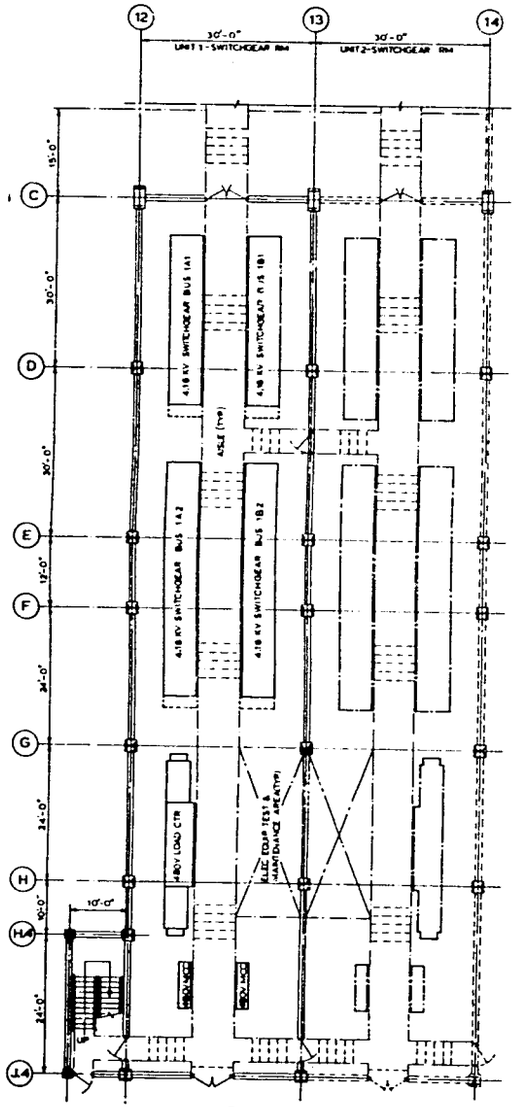
NOTES:
1. BOILER AREA ENCLOSURE OPTIONAL
2. UNIT 2 PULVERIZER MAINTENANCE AISLE TO EXIT THROUGH CHEMICAL FEED AND STORAGE AREA BY REARRANGING EQUIPMENT
3. COMPONENTS HAVE BEEN REVIEWED FOR OPERABILITY AND MAINTAINABILITY. S&W WILL PROVIDE A COMPONENT HANDLING AND MONORAIL DRAWING DEPICTING EITHER THE CLIENT'S OR S&W RECOMMENDATIONS, AS APPROPRIATE.

REFERENCE DRAWINGS:
GENL ARRGT — BOILER AREA (BURNER LEVEL) EM 2028
GENERAL ARRANGEMENT-TURBINE AREA EM 203 SERIES
GENERAL ARRANGEMENT (CONTROL BUILDING) EE-051 SERIES

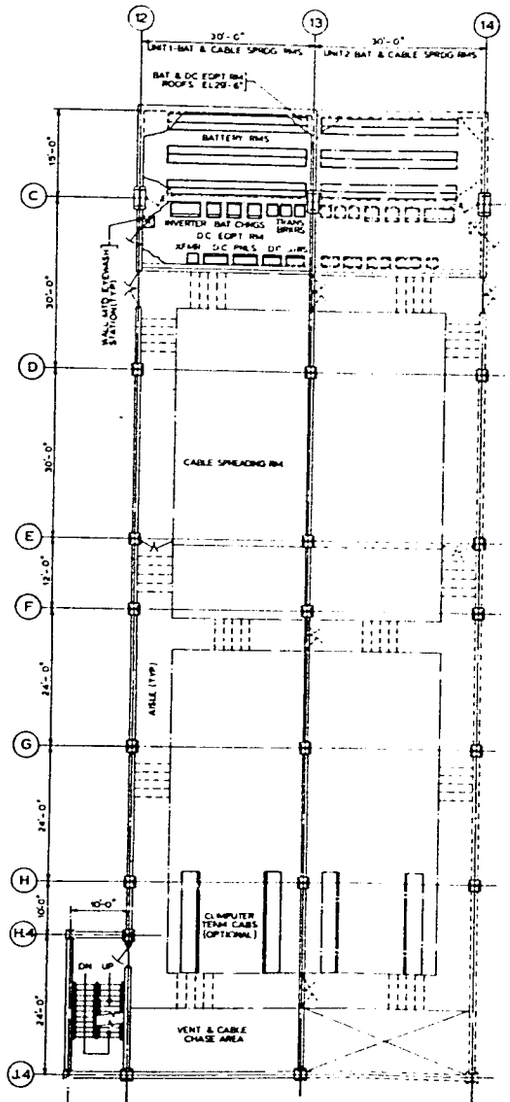
FIGURE 6.7-9
GENERAL ARRGT-BOILER ROOM
GROUND FLOOR
PLAN-EL 0'-6"
LAKHRA COAL STUDY

FIGURE 6.7-10
GENERAL ARRGT-BOILER ROOM CROSS SECTION
LAKHRA COAL STUDY

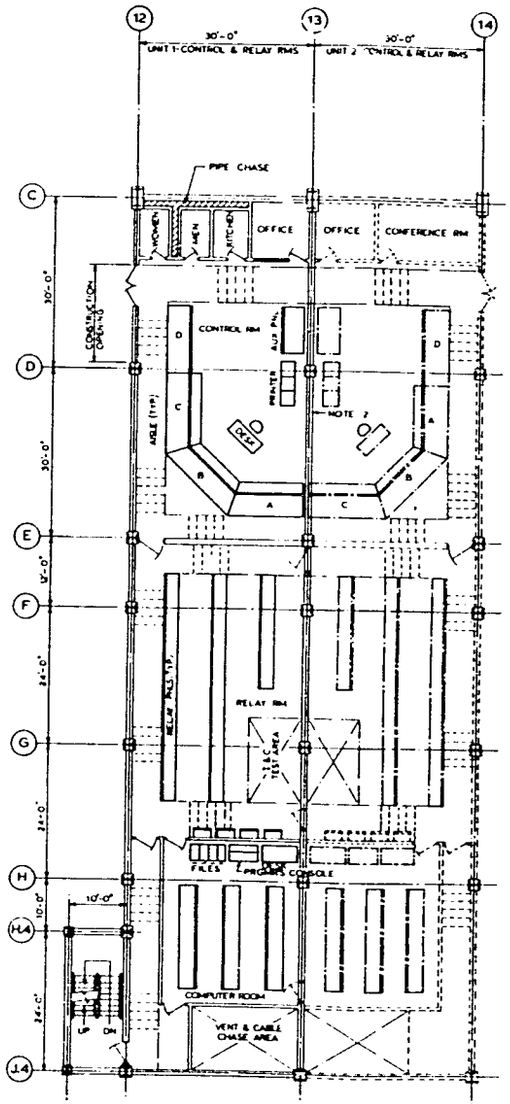
NOTES
1 GENERAL NOTES & REFERENCE DWGS EM-2024



PLAN-GROUND FLOOR
EL 0'-6"



PLAN-MEZZANINE FLOOR
EL 20'-6"



PLAN-OPERATING FLOOR
EL 38'-6"

NOTES:
1. SCALE: 1/8" = 1'-0"
2. WALL SHOWN BETWEEN CONTROL RMS REQUIRED ONLY IF SINGLE UNIT IS BUILT.
3. EQUIPMENT SHOWN FOR UNIT 2 IS SIMILAR TO UNIT 1.

FIGURE 6.7-11
GENERAL ARRANGEMENT
CONTROL BUILDING - SH. I
LAKHRA COAL STUDY

6.8 STAFFING PLAN

A functional organization chart and manning levels for the proposed Lakhra coal-fired plant are presented on Figures 6.8-1 through 6.8-4. The staffing levels of Guddu Power Station Unit 3 served as a starting point for developing the Lakhra staffing levels.

Adjustments were made to account for coal handling, fly ash and bottom ash handling, particulate removal, and ash disposal. Consequently, the Lakhra staffing of the operating, mechanical, and chemical maintenance sections were increased by a factor of 2 over the Guddu staffing. The instrument and electrical maintenance sections were increased by a factor of 1.5. Other significant changes included increases in the staffing of the inspection and test and records sections and the addition of a medical staff.

The detailed staff breakdown and annual cost of plant personnel is presented below. Salaries and labor costs are expressed in December 1982 rupees.

Position	Total Personnel	Annual Salary	Direct Labor Cost
Resident Engineer's Office			
Chief/Resident Engineer	1	54,000	54,000
Deputy Resident Engineer	1	49,000	49,000
Steno I	2	11,545	23,090
Naib Qasid	2	7,380	14,760
Subtotal	6		140,850
Administration Section			
Assistant Director of Administration	1	24,636	24,636
Labor Officer	1	13,250	13,250
Jr. Superintendent	1	12,690	12,690
Steno I	1	11,545	11,545
Assistant	4	13,174	52,696
Steno II	2	9,490	18,980
Sr. Clerk	4	10,072	40,288
Jr. Clerk	6	7,696	46,176
Daftre	1	7,453	7,453
Naib Qasid	7	7,380	51,660
Subtotal	28		279,374
Operators Section			
Assistant Resident Engineer	1	42,230	42,230
Sr. Engineer	8	42,230	337,840
Jr. Engineer	32	28,580	994,560
Foreman	16	20,720	331,520
Operator	72	24,134	1,737,648

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Position	Total Personnel	Annual Salary	Direct Labor Cost
Steno I	1	11,545	11,545
Assistant Foreman	8	19,841	158,728
Attendant	104	19,841	2,063,464
Helper	104	11,993	1,247,272
Subtotal	346		6,844,807
Maintenance Section			
Assistant Resident Engineer	1	42,230	42,230
Sr. Electrical Engineer	1	42,230	42,230
Jr. Electrical Engineer	4	28,580	114,320
Foreman	4	20,720	82,880
Attendant	3	19,841	59,523
Line Superintendent II	1	9,004	9,004
Cable Jointer	2	13,000	26,000
Fitter Gr. I	12	15,460	185,520
Electrician	27	15,068	406,836
Armature Winder	1	14,797	14,797
Line Man I	1	10,000	10,000
Line Man II	2	8,700	17,400
Assistant Line Man	2	7,756	15,512
Helper	20	11,993	239,860
Sr. Mechanical Engineer	1	42,230	42,230
Jr. Mechanical Engineer	7	28,580	200,060
Foreman	9	20,720	186,480
High Pressure Welder I	7	16,081	112,567
Low Pressure Welder I	3	15,000	45,000
Assistant Foreman	4	19,841	79,364
Attendant	16	19,841	317,456
Fitter Gr. I	56	15,460	865,760
Boiler Mason	4	12,094	48,376
Crane Operator	4	11,780	47,120
Fitter Gr. II	5	14,262	71,310
Scaffolder	4	14,262	57,048
Helper	68	11,993	815,524
Electrician	1	15,068	15,068
Miller	1	12,094	12,094
Turner	1	13,026	13,026
Driver	40	8,810	352,400
Carpenter	4	14,262	57,048
Jr. Clerk	1	7,696	7,696
Spray Painter	2	11,554	23,108
Blacksmith	2	12,000	24,000
Tinsmith	2	12,000	24,000
Pattern Maker	1	12,000	12,000
Moulder	1	12,000	12,000
Painter	1	11,554	11,554
Cooly	10	6,665	66,650
Cleaner	2	10,171	20,342
Sr. Chemist	1	29,601	29,601

Position	Total Personnel	Annual Salary	Direct Labor Cost
Jr. Chemist	2	23,450	46,900
Assistant Chemist	16	20,481	327,696
Chemical Attendant	40	14,514	580,560
Helper	16	11,993	191,888
Lime Cooly	16	6,665	106,640
Sr. Instrument Engineer	1	42,230	42,230
Jr. Instrument Engineer	3	28,580	85,740
Foreman	3	20,720	62,160
Welder	2	16,081	32,162
Test Inspector	3	15,130	45,390
Assistant Foreman	3	19,841	59,523
Lab Assistant	15	13,314	199,710
Fitter Gr. I	15	15,460	231,900
Precision Lathe Turner	2	13,026	26,052
Fitter Gr. II	4	14,262	32,552
Telephone Operator	4	8,138	32,552
Telex Operator	1	8,138	8,138
Helper	15	11,993	179,895
Sr. Stores Officer	1	32,000	32,000
Assistant Stores Officer	1	20,000	20,000
Assistant	1	13,000	13,000
Line Superintendent II	1	9,004	9,004
Steno II	1	9,490	9,490
Sr. Clerk	3	10,072	30,216
Carpenter	2	14,262	28,524
Sr. Store Keeper	4	7,828	31,312
Jr. Clerk	2	7,696	15,392
Jr. Store Keeper	3	8,610	25,830
Helper	14	11,993	167,902
Naib Qasid	2	7,380	14,760
Cooly	5	6,665	33,325
Chowkidar/Security Guard	12	8,000	96,000
Store Munshi	2	7,471	14,942
Fire Officer	1	10,900	10,900
Head Fireman	4	6,960	27,840
Fireman	32	8,228	263,296
Chowkidar/Security Guard	8	8,000	64,000
Subtotal	599		8,058,911
Inspection, Test and Records Section			
Sr. Engineer	1	42,230	42,230
Jr. Engineer	2	28,580	57,160
Steno II	2	9,490	18,980
Sr. Clerk	2	10,072	20,144
Naib Qasid	1	7,380	7,380
Subtotal	8		145,894

Position	Total Personnel	Annual Salary	Direct Labor Cost
Training Section			
Director of Training	1	49,000	49,000
Sr. Engineer	2	42,230	84,460
Sr. Chemist	1	29,601	29,601
Jr. Engineer	10	28,580	285,800
Jr. Chemist	2	23,450	46,900
Instructor Foreman	2	20,770	41,440
Foreman	20	20,720	414,400
Welder	1	16,081	16,081
Assistant Chemist	4	20,481	81,924
Operators	36	24,134	868,824
Attendant	79	19,841	1,567,439
Fitter Gr. I	43	15,460	664,780
Electrician	20	15,068	301,360
Steno I	1	11,545	11,545
Steno II	1	9,490	9,490
G/Operator	1	7,380	7,380
Naib Qasid	3	7,380	22,140
Sewer Man	2	7,453	14,906
Mate	1	7,380	7,380
Keyman	2	7,453	14,906
Trolley Man	16	7,380	118,080
Gang Man	9	7,380	66,420
Head Mali	10	7,518	75,180
Mali	36	7,260	261,360
Bull Cart Attendant	1	11,993	11,993
Imam Masjid	1	11,346	11,346
Khadim Masjid	1	5,089	5,089
Subtotal	306		5,089,224
Civil Section			
Sr. Civil Engineer	1	42,230	42,230
Jr. Engineer	3	28,580	85,740
Arboriculture Superintendent	1	13,250	13,250
Assistant Foreman	1	19,841	19,841
Civil Overseer	4	9,004	36,016
Supervisor	4	8,810	35,240
Fitter Gr. I	1	15,460	15,460
Mason	3	8,138	24,414
Caretaker	1	8,138	8,138
Fitter Gr. II	1	14,262	14,262
Carpenter	4	14,262	57,048
Jr. Clerk	3	7,696	23,088
Blacksmith	1	12,000	12,000
Pump Driver	20	7,816	156,320
Jr. Storekeeper	1	8,610	8,610
Plumber	4	6,816	27,264
Work Mistry	3	8,228	24,684
Cook	2	7,453	14,906

Position	Total Personnel	Annual Salary	Direct Labor Cost
Helpers	11	11,993	131,923
Painter	2	11,554	23,108
Cooly	56	6,665	373,240
Chowkidar/Security Guard	7	8,000	56,000
Donkey Cart Attendant	1	7,380	7,380
Sweeper	46	7,260	333,960
Bearer	3	7,393	22,179
Subtotal	184		1,566,301
Drawing Section			
Head Draftsman A	1	15,000	15,000
Draftsman B	1	13,734	13,734
Tracer	2	4,990	9,980
Naid Qasid	1	7,380	7,380
Subtotal	5		46,094
Security Section			
Chief Security Officer	1	40,000	40,000
Security Inspector	6	10,000	60,000
Jr. Clerk	1	7,696	7,696
Security Sergeant	18	8,000	144,000
Chowkidar/Security Guard	187	8,000	1,496,000
Subtotal	213		1,747,696
Medical Section			
Medical Officer In Charge	1	27,760	27,760
Lady Medical Officer	1	24,636	24,636
Steno I	1	11,545	11,545
Nurse	1	7,460	7,460
Midwife	1	7,393	7,393
Dispenser	2	7,696	15,392
Compounder	1	7,696	7,696
Job Clerk	1	7,696	7,696
Naib Qasid	1	7,380	7,380
Dresser	1	7,393	7,393
Sweeper	1	7,260	7,260
Subtotal	12		131,611
Accounting Section			
Budgets and Accounts Officer	1	21,300	21,300
Steno II	1	9,490	9,490
Accounts Assistant	2	10,900	21800
Cashier	1	8,000	8,000
Sr. Clerk	3	10,072	30,216

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Position	Total Personnel	Annual Salary	Direct Labor Cost
Jr. Clerk	3	7,696	23,088
Daftre	1	7,453	7,453
Naib Qasid	1	7,380	7,380
Subtotal	13		128,727
Contingency Staff			
Jr. Engineer	5	28,580	142,900
Others	50	14,000	700,000
Subtotal	55		842,900
TOTAL	1,775		25,022,389

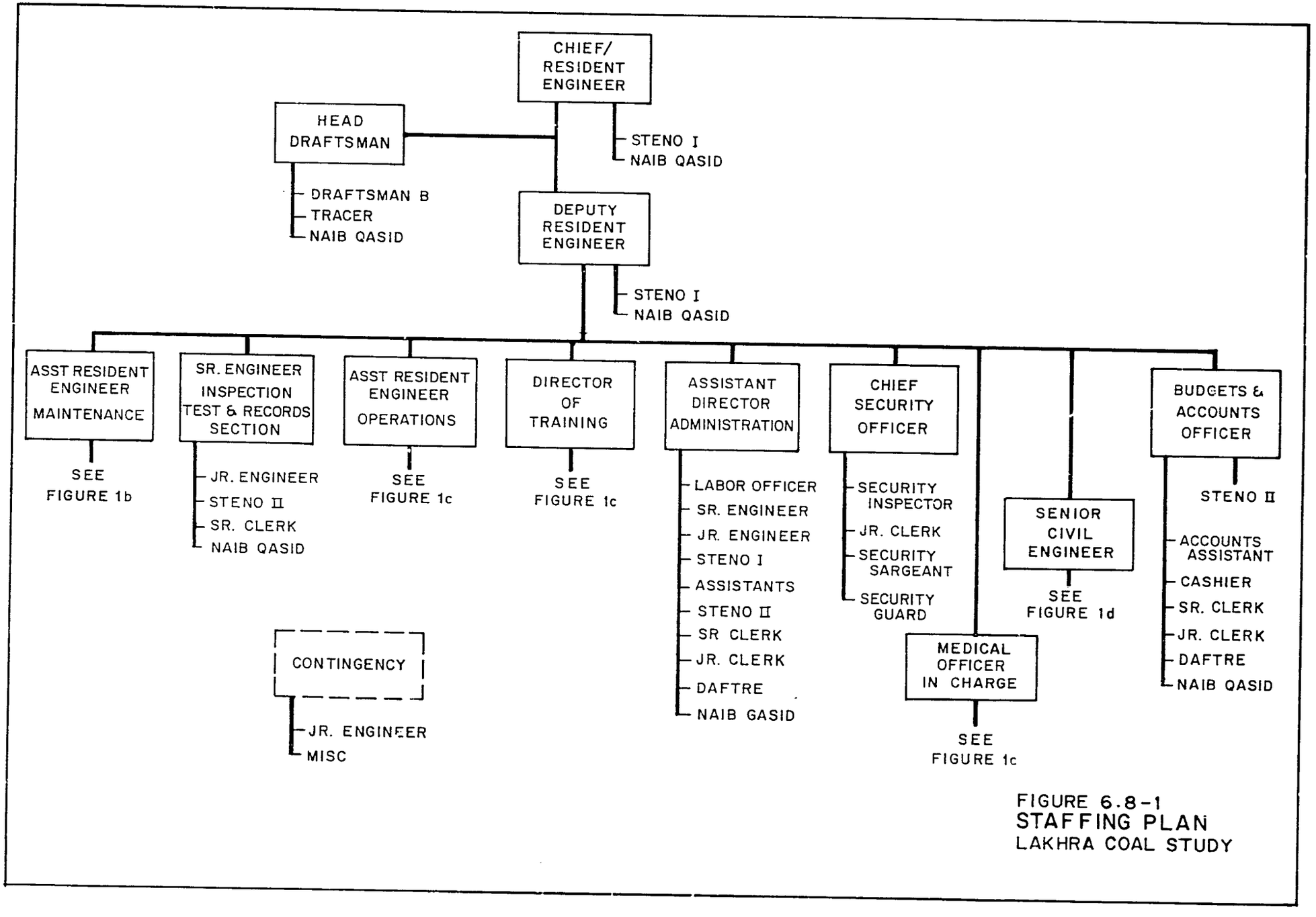


FIGURE 6.8-1
STAFFING PLAN
LAKHRA COAL STUDY

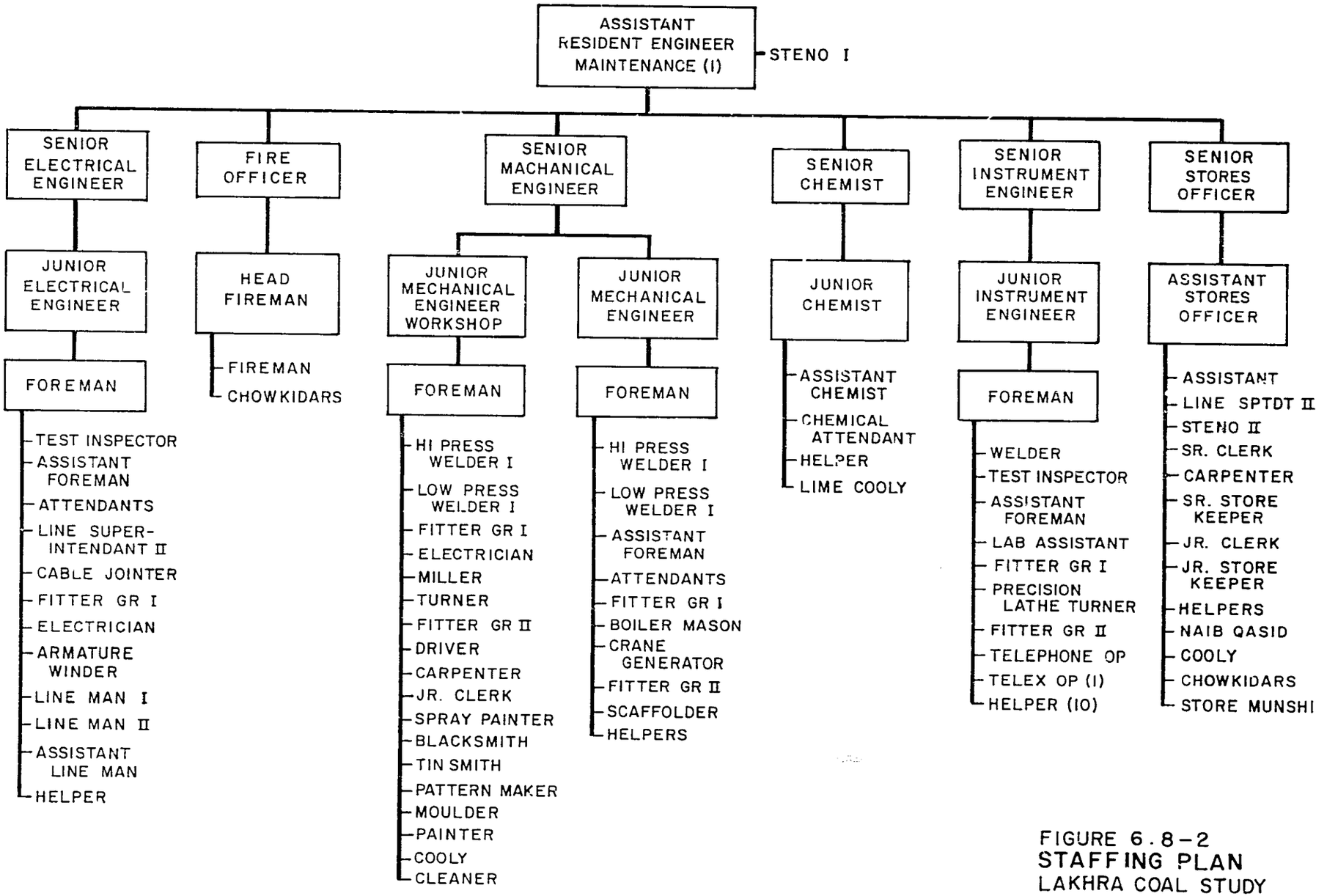


FIGURE 6.8-2
STAFFING PLAN
LAKHRA COAL STUDY

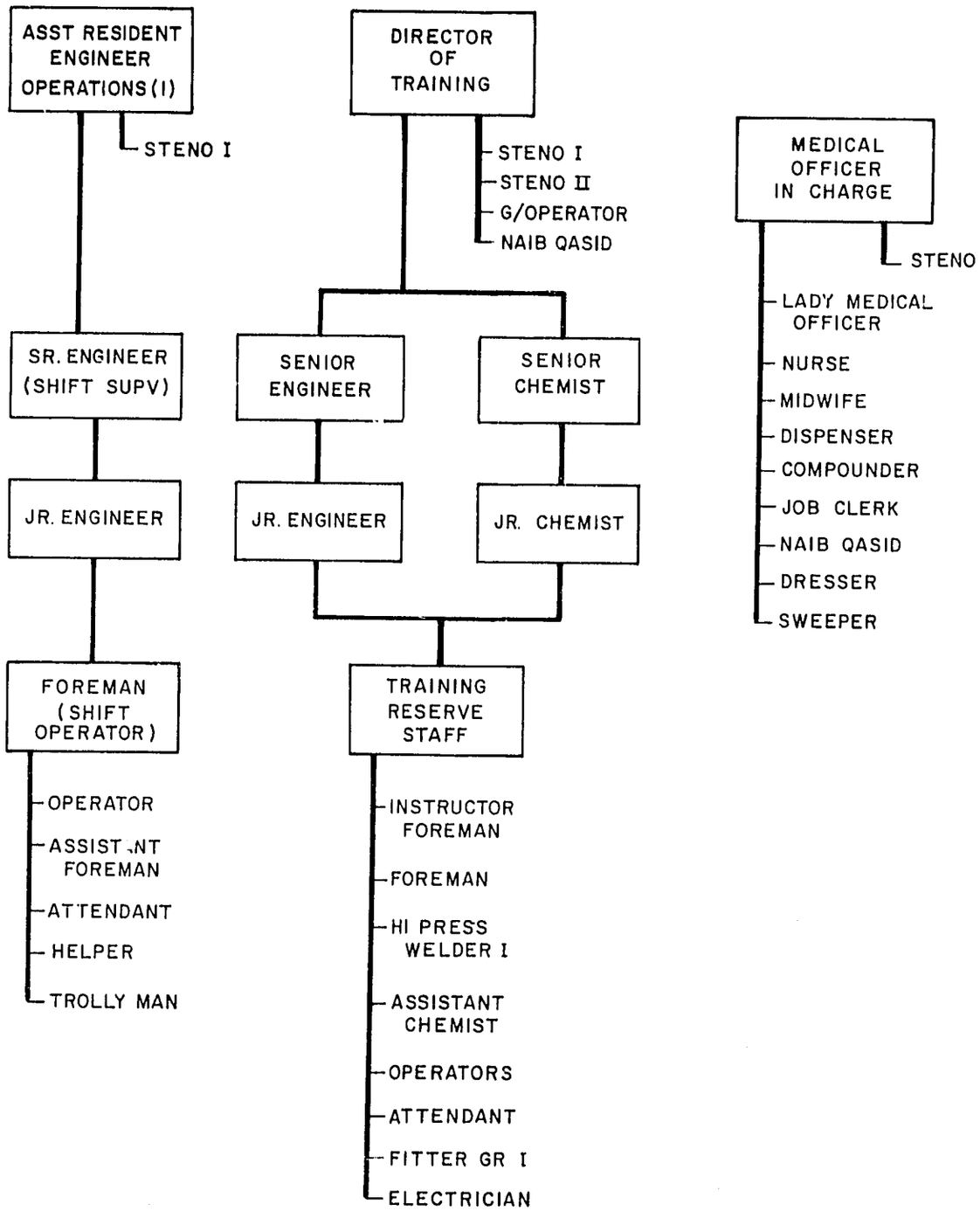


FIGURE 6.8-3
STAFFING PLAN
LAKHRA COAL STUDY

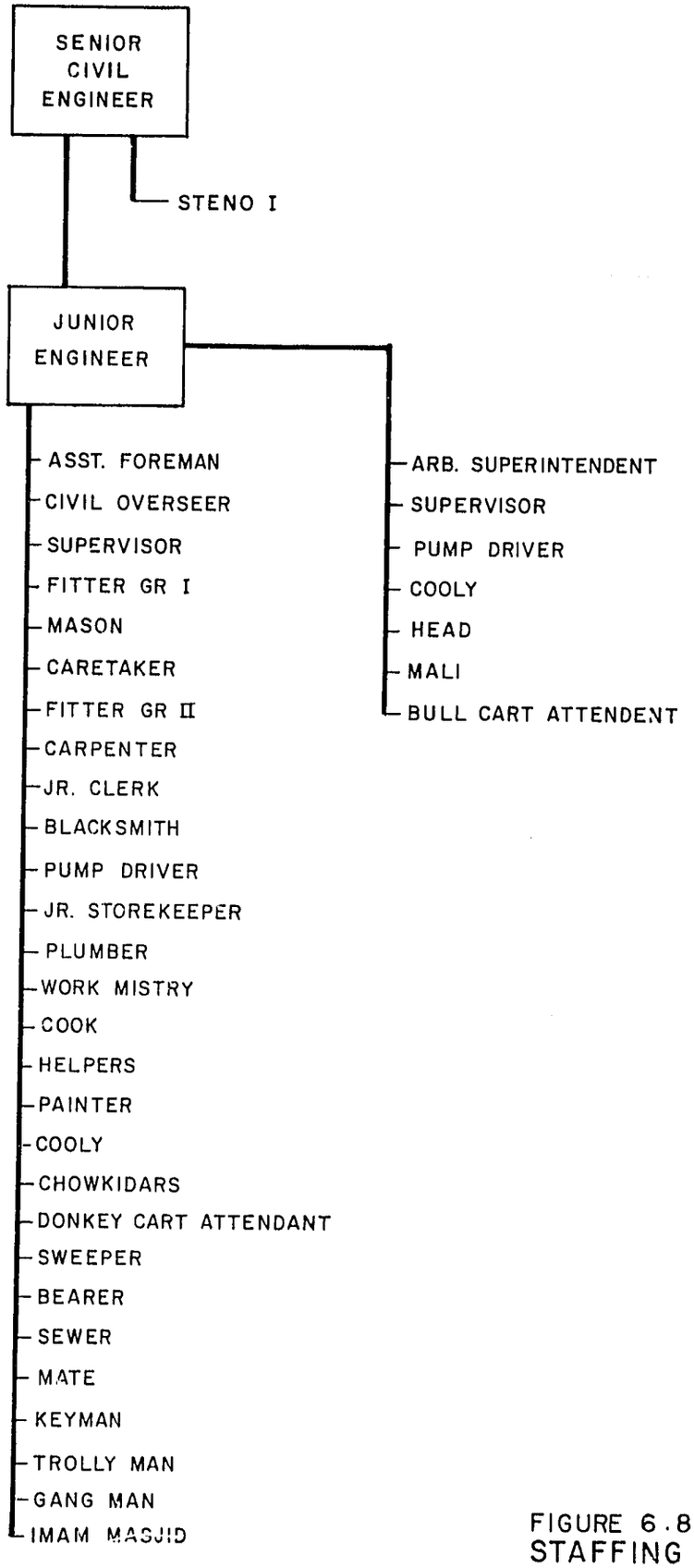


FIGURE 6.8-4
STAFFING PLAN
LAKHRA COAL STUDY

SECTION 7

IMPLEMENTATION SCHEDULES

A 54-month schedule has been established for accomplishing the engineering, design, procurement, and construction of the mines, coal preparation facilities, a railroad and station at Lakhra/Jamshoro, Pakistan. It was necessary to presume that Stone & Webster Engineering Corporation (SWEC) would be appointed as consultants and that this would occur by June 1, 1983. This schedule further assumes that SWEC, acting as agents for the Water and Power Development Authority (WAPDA), would perform the engineering, design procurement, and construction management tasks. Project summary networks, outlining major efforts and milestones, were developed and are included as Figures 7-1 through 7-4.

A July 1, 1983 project start date allows for a commercial operation start date of December 31, 1987. The critical path for achieving this is:

(i) award of a purchase order for major mine and power plant equipment items by February 28, 1983

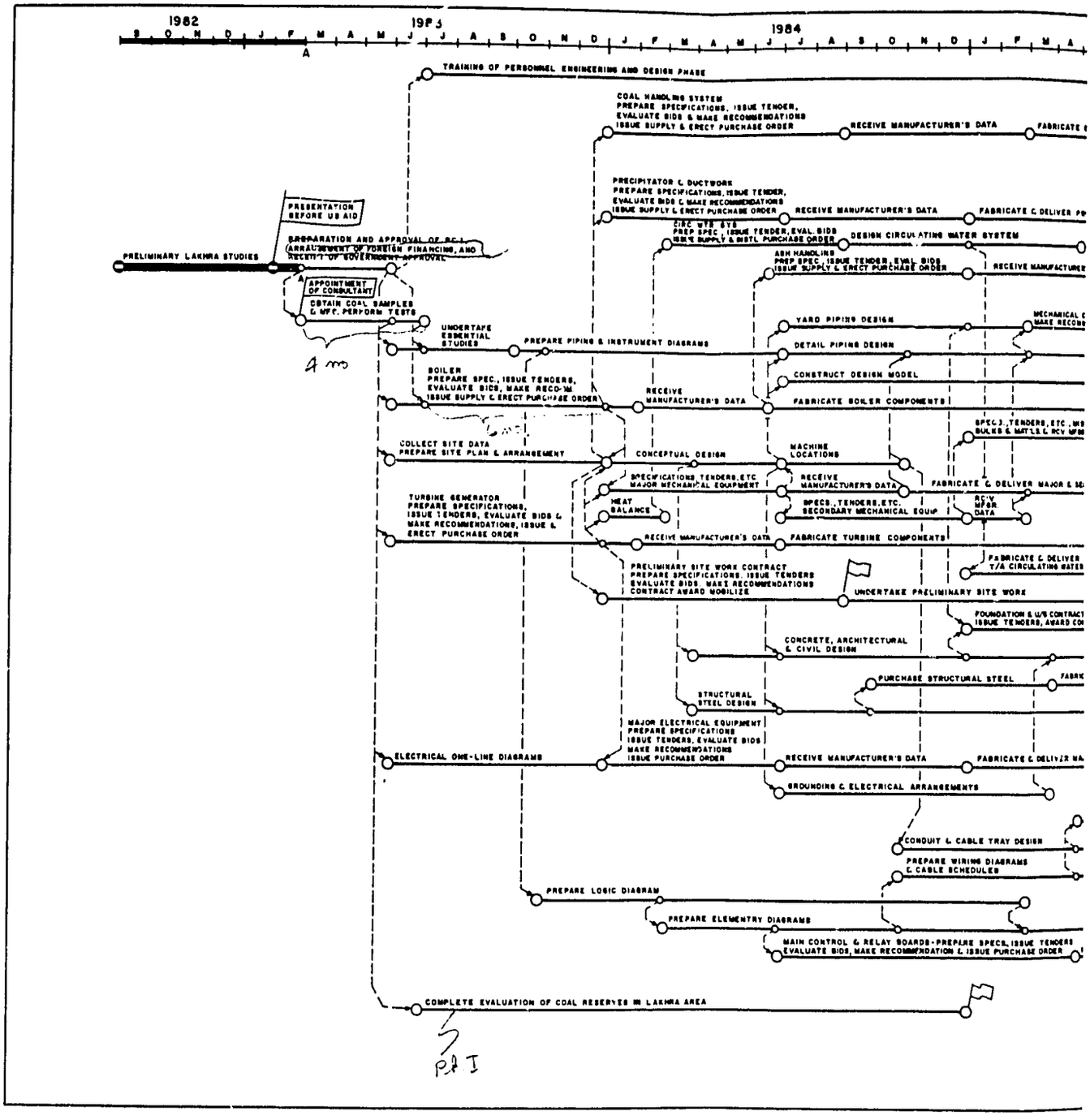
(ii) completion of the Lakhra/Jamshoro railway by October 30, 1984

(iii) initial deliveries of major mining equipment (electric shovels and large trucks) in October 1984 followed by their field erection

(iv) delivery of boiler pressure parts by May 1, 1986 and erection of the boiler by August 31, 1987

(v) completion of tests and start of commercial operation of the mines and power plant by December 31, 1987.

A first issue of the machine location drawings is required by October 30, 1984 and the completion of all significant design activities is scheduled for December 31, 1985.


1982
1983
1984
TRAINING OF PERSONNEL ENGINEERING AND DESIGN PHASE
COAL HANDLING SYSTEM
PREPARE SPECIFICATIONS, ISSUE TENDER, EVALUATE BIDS & MAKE RECOMMENDATIONS
ISSUE SUPPLY & ERECT PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
PRECIPITATOR & DUCTWORK
PREPARE SPECIFICATIONS, ISSUE TENDER, EVALUATE BIDS & MAKE RECOMMENDATIONS
ISSUE SUPPLY & ERECT PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
DESIGN CIRCULATING WATER SYSTEM
ASH HANDLING
PREP SPEC., ISSUE TENDER, EVAL. BIDS
ISSUE SUPPLY & ERECT PURCHASE ORDER
PRESENTATION BEFORE US AID
PRELIMINARY LAKHRA STUDIES
APPOINTMENT OF CONSULTANT
OBTAIN COAL SAMPLES & MFC. PERFORM TESTS
4 mo
UNDERTAKE ESSENTIAL STUDIES
PREPARE PIPING & INSTRUMENT DIAGRAMS
YARD PIPING DESIGN
DETAIL PIPING DESIGN
CONSTRUCT DESIGN MODEL
BOILER
PREPARE SPEC., ISSUE TENDERS, EVALUATE BIDS, MAKE RECOMM
ISSUE SUPPLY & ERECT PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
FABRICATE BOILER COMPONENTS
COLLECT SITE DATA
PREPARE SITE PLAN & ARRANGEMENT
CONCEPTUAL DESIGN
MACHINE LOCATIONS
SPECIFICATIONS, TENDERS, ETC. MAJOR MECHANICAL EQUIPMENT
RECEIVE MANUFACTURER'S DATA
FABRICATE & DELIVER MAJOR
HEAT BALANCE
SPECS., TENDERS, ETC. SECONDARY MECHANICAL EQUIP
TURBINE GENERATOR
PREPARE SPECIFICATIONS, ISSUE TENDERS, EVALUATE BIDS & MAKE RECOMMENDATIONS, ISSUE & ERECT PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
FABRICATE TURBINE COMPONENTS
PRELIMINARY SITE WORK CONTRACT
PREPARE SPECIFICATIONS, ISSUE TENDERS
EVALUATE BIDS, MAKE RECOMMENDATIONS
CONTRACT AWARD MOBILIZE
UNDERTAKE PRELIMINARY SITE WORK
CONCRETE, ARCHITECTURAL & CIVIL DESIGN
PURCHASE STRUCTURAL STEEL
STRUCTURAL STEEL DESIGN
MAJOR ELECTRICAL EQUIPMENT
PREPARE SPECIFICATIONS
ISSUE TENDERS, EVALUATE BIDS
MAKE RECOMMENDATIONS
ISSUE PURCHASE ORDER
ELECTRICAL ONE-LINE DIAGRAMS
RECEIVE MANUFACTURER'S DATA
GROUNDING & ELECTRICAL ARRANGEMENTS
CONDUIT & CABLE TRAY DESIGN
PREPARE WIRING DIAGRAMS & CABLE SCHEDULES
PREPARE LOGIC DIAGRAM
PREPARE ELEMENTRY DIAGRAMS
MAIN CONTROL & RELAY BOARDS - PREPARE SPECS, ISSUE TENDERS
EVALUATE BIDS, MAKE RECOMMENDATION & ISSUE PURCHASE ORDER
COMPLETE EVALUATION OF COAL RESERVES IN LAKHRA AREA
PA I

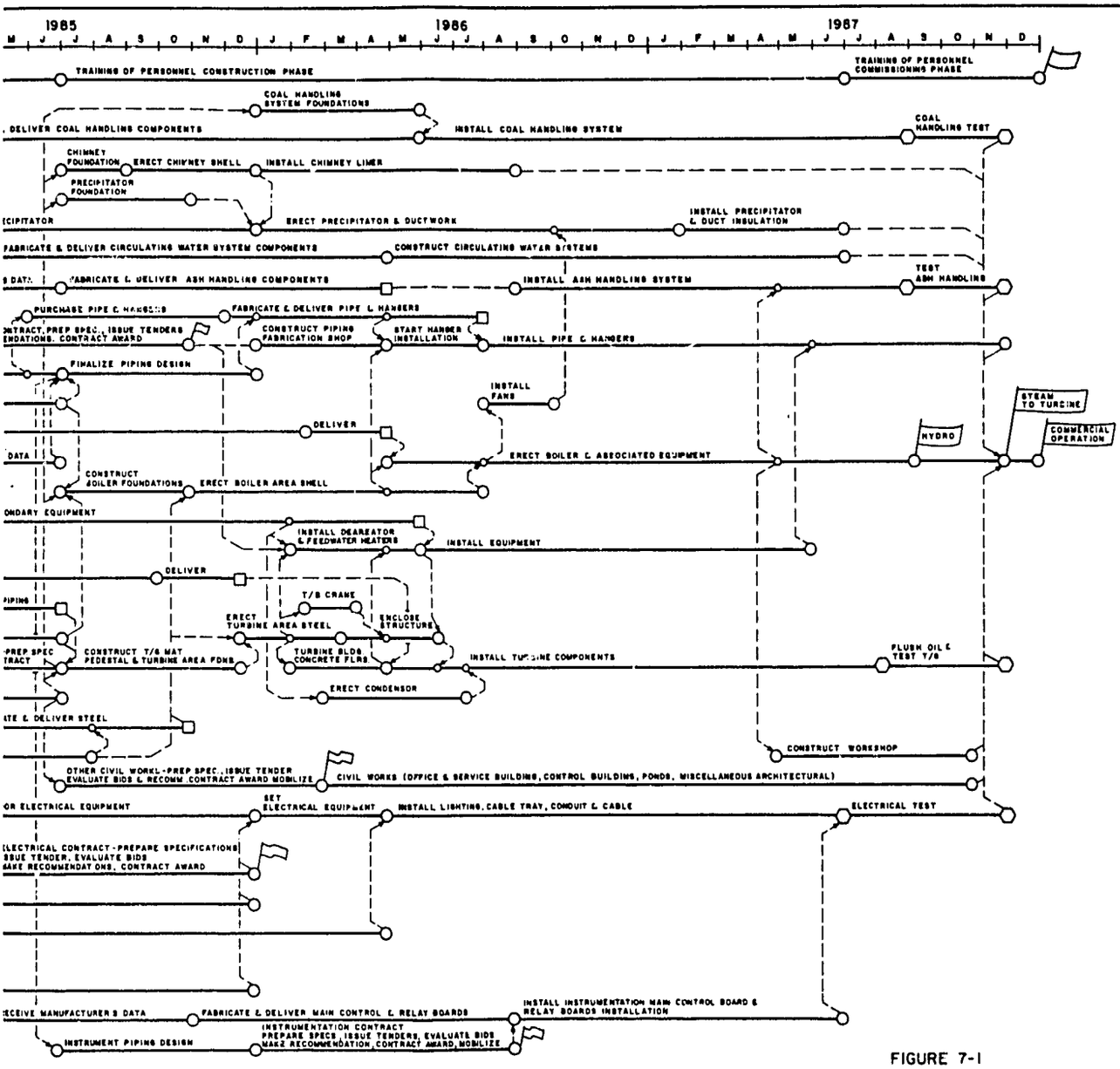


FIGURE 7-1
FIRST 300 MW POWER PLANT
PROJECT SUMMARY NETWORK
LAKHRA COAL STUDY

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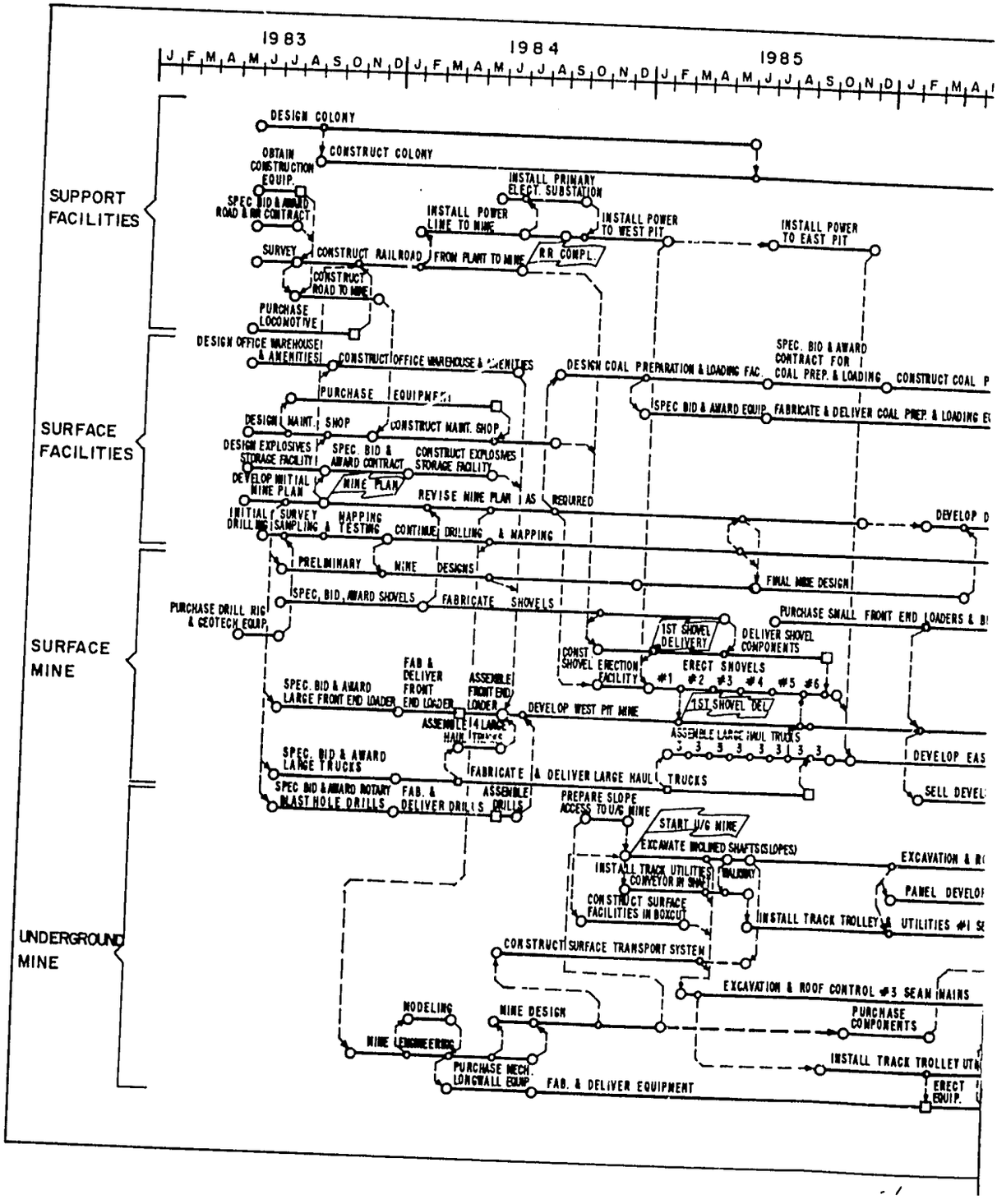
9 OF 9

FOR

FIGURE(S):

2-2


1983
1984
1985
J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A
SUPPORT FACILITIES
SURFACE FACILITIES
SURFACE MINE
UNDERGROUND MINE
DESIGN COLONY
CONSTRUCT COLONY
OBTAIN CONSTRUCTION EQUIP.
SPEC BID & AWARD ROAD & RR CONTRACT
SURVEY
CONSTRUCT RAILROAD FROM PLANT TO MINE
CONSTRUCT ROAD TO MINE
INSTALL POWER LINE TO MINE
INSTALL PRIMARY ELECT. SUBSTATION
INSTALL POWER TO WEST PIT
INSTALL POWER TO EAST PIT
RR COMPL.
PURCHASE LOCOMOTIVE
DESIGN OFFICE WAREHOUSE & AMENITIES
CONSTRUCT OFFICE WAREHOUSE & AMENITIES
DESIGN COAL PREPARATION & LOADING FAC.
SPEC. BID & AWARD CONTRACT FOR COAL PREP. & LOADING
CONSTRUCT COAL P
PURCHASE EQUIPMENT
SPEC BID & AWARD EQUIP.
FABRICATE & DELIVER COAL PREP. & LOADING E
DESIGN MAINT. SHOP
CONSTRUCT MAINT. SHOP
DESIGN EXPLOSIVES STORAGE FACILITY
SPEC. BID & AWARD CONTRACT
CONSTRUCT EXPLOSIVES STORAGE FACILITY
DEVELOP INITIAL MINE PLAN
MINE PLAN
REVISE MINE PLAN AS REQUIRED
DEVELOP D
INITIAL DRILLING
SURVEY SAMPLING & TESTING
MAPPING
CONTINUE DRILLING & MAPPING
PRELIMINARY MINE DESIGNS
FINAL MINE DESIGN
SPEC. BID, AWARD SHOVELS
FABRICATE SHOVELS
PURCHASE DRILL RIG & GEOTECH EQUIP.
PURCHASE SMALL FRONT END LOADERS & B
1ST SHOVEL DELIVERY
DELIVER SHOVEL COMPONENTS
CONST SHOVEL ERECTION FACILITY
ERECT SHOVELS
#1 #2 #3 #4 #5 #6
1ST SHOVEL DEL
SPEC. BID & AWARD LARGE FRONT END LOADER
FAB & DELIVER FRONT END LOADER
ASSEMBLE FRONT END LOADER
DEVELOP WEST PIT MINE
ASSEMBLE 4 LARGE HAUL TRUCKS
ASSEMBLE LARGE HAUL TRUCKS
3 3 3 3 3 3 3 3
DEVELOP EAS
SPEC. BID & AWARD LARGE TRUCKS
FABRICATE & DELIVER LARGE HAUL TRUCKS
SPEC BID & AWARD ROTARY BLAST HOLE DRILLS
FAB. & DELIVER DRILLS
ASSEMBLE DRILLS
PREPARE SLOPE ACCESS TO U/G MINE
SELL DEVEL
START U/G MINE
EXCAVATE INCLINED SHAFTS (SLOPES)
EXCAVATION & R
INSTALL TRACK UTILITIES & CONVEYOR IN SHAFT
TRAILWAY
PANEL DEVELO
CONSTRUCT SURFACE FACILITIES IN BOXCUT
INSTALL TRACK TROLLEY & UTILITIES #1 S
CONSTRUCT SURFACE TRANSPORT SYSTEM
EXCAVATION & ROOF CONTROL #3 SEAM MAINS
MODELING
MINE DESIGN
PURCHASE COMPONENTS
MINE ENGINEERING
INSTALL TRACK TROLLEY UT
PURCHASE MECH. LONGWALL EQUIP.
FAB. & DELIVER EQUIPMENT
ERECT EQUIP.

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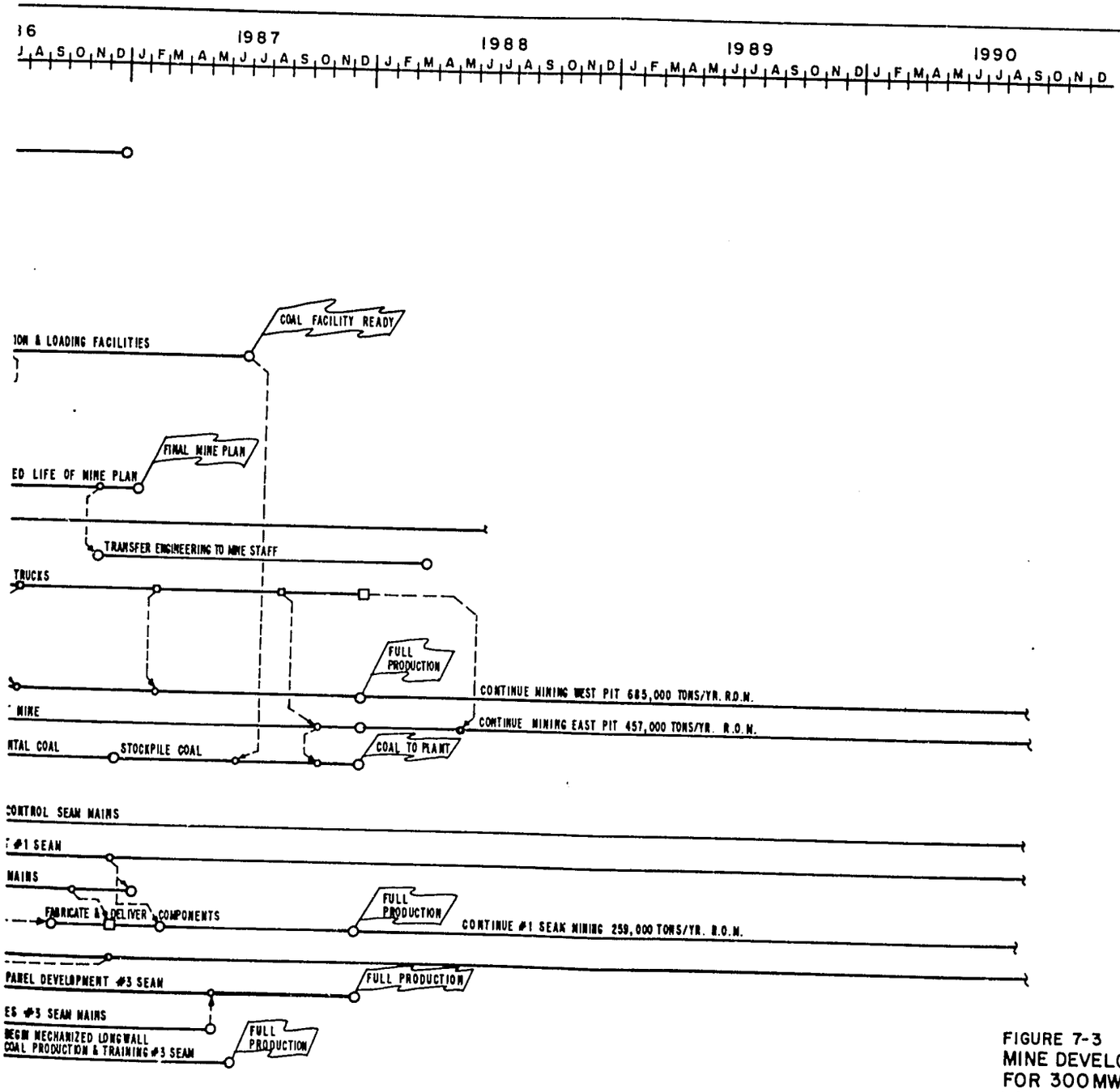
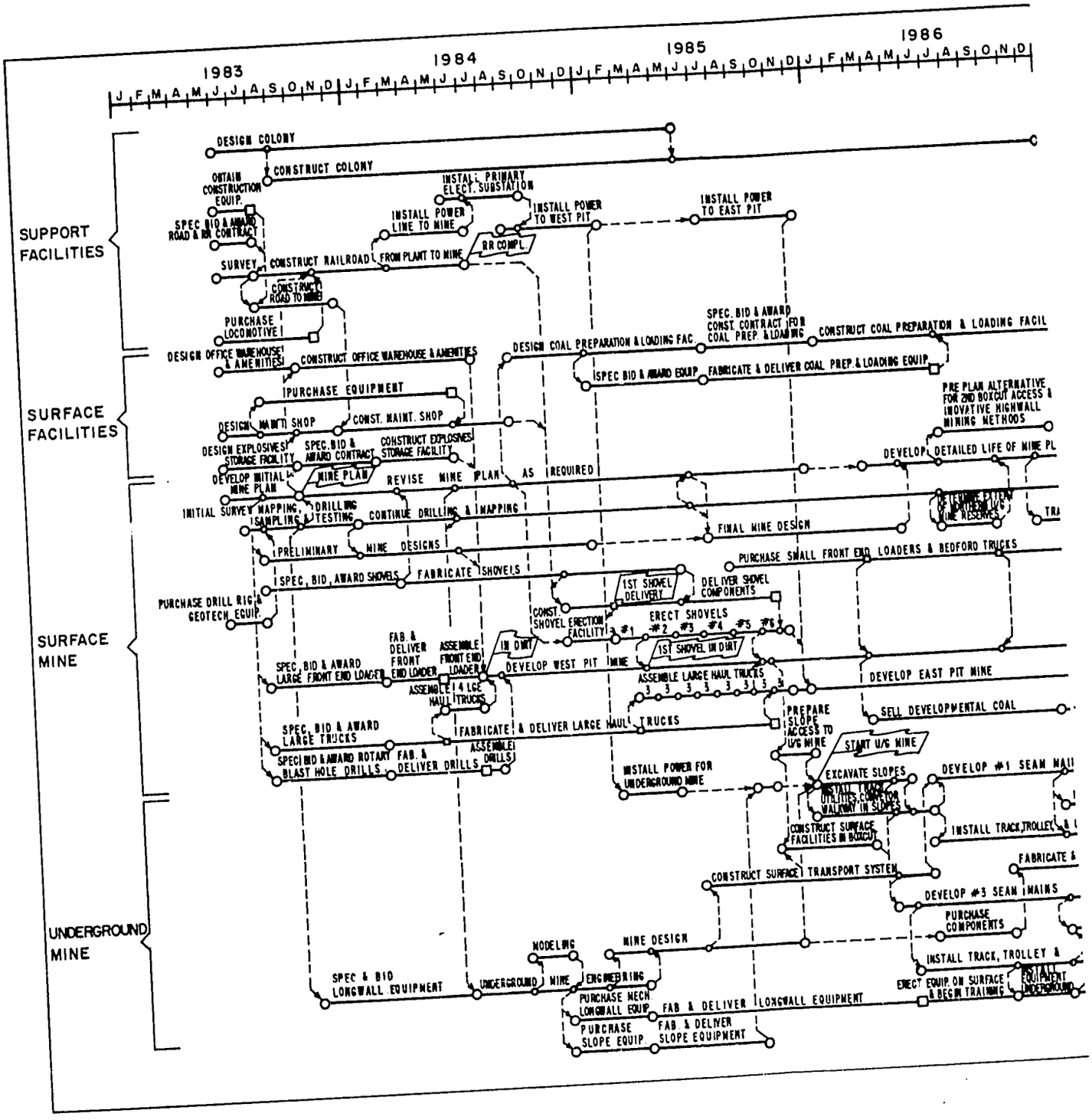
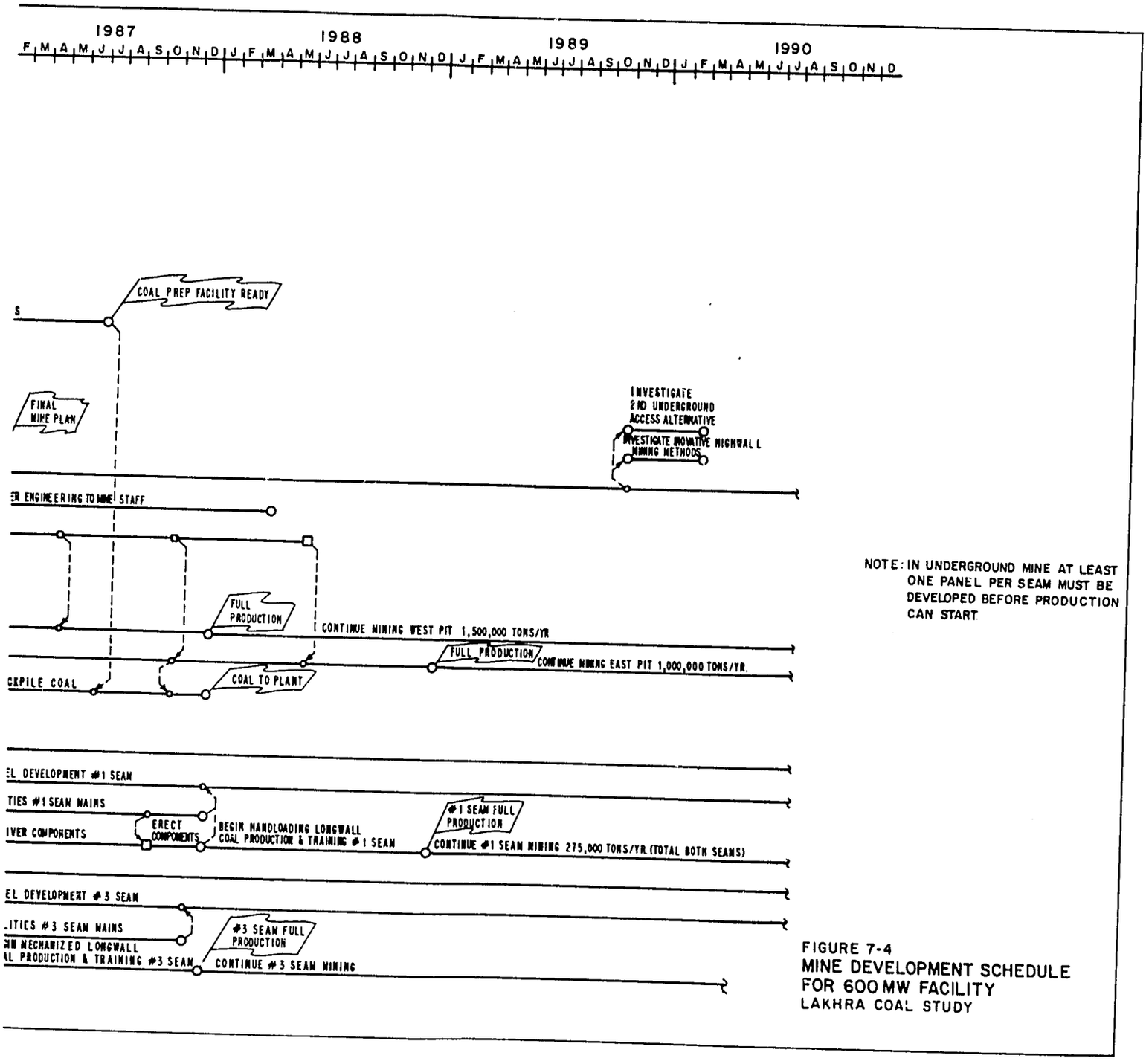


FIGURE 7-3
MINE DEVELOPMENT SCH
FOR 300MW FACILITY
LAKHRA COAL STUDY


1983
1984
1985
1986
J F M A M J J A S O N D
SUPPORT FACILITIES
SURFACE FACILITIES
SURFACE MINE
UNDERGROUND MINE
DESIGN COLONY
CONSTRUCT COLONY
OBTAIN CONSTRUCTION EQUIP.
SPEC BID & AWARD ROAD & RR CONTRACT
SURVEY
CONSTRUCT RAILROAD FROM PLANT TO MINE
CONSTRUCT ROAD TO MINE
PURCHASE LOCOMOTIVE
INSTALL PRIMARY ELECT. SUBSTATION
INSTALL POWER LINE TO MINE
INSTALL POWER TO WEST PIT
RR COMPL.
INSTALL POWER TO EAST PIT
DESIGN OFFICE WAREHOUSE & AMENITIES
CONSTRUCT OFFICE WAREHOUSE & AMENITIES
PURCHASE EQUIPMENT
DESIGN MAINT. SHOP
CONST. MAINT. SHOP
DESIGN EXPLOSIVES STORAGE FACILITY
SPEC. BID & AWARD CONTRACT
CONSTRUCT EXPLOSIVES STORAGE FACILITY
DEVELOP INITIAL MINE PLAN
MINE PLAN
REVISE MINE PLAN AS REQUIRED
INITIAL SURVEY
MAPPING, SAMPLING
DRILLING TESTING
CONTINUE DRILLING & MAPPING
PRELIMINARY MINE DESIGNS
FINAL MINE DESIGN
SPEC, BID, AWARD SHOVELS
FABRICATE SHOVELS
1ST SHOVEL DELIVERY
DELIVER SHOVEL COMPONENTS
PURCHASE DRILL RIG & GEOTECH EQUIP.
CONST. SHOVEL ERECTION FACILITY
ERECT SHOVELS #1 #2 #3 #4 #5 #6
1ST SHOVEL IN DIRT
SPEC. BID & AWARD LARGE FRONT END LOADER
FAB. & DELIVER FRONT END LOADER
ASSEMBLE FRONT END LOADER
IN DIRT
DEVELOP WEST PIT MINE
ASSEMBLE 4 LGE HAUL TRUCKS
ASSEMBLE LARGE HAUL TRUCKS
DEVELOP EAST PIT MINE
SPEC. BID & AWARD LARGE TRUCKS
FABRICATE & DELIVER LARGE HAUL TRUCKS
PREPARE SLOPE ACCESS TO U/G MINE
SELL DEVELOPMENTAL COAL
START U/G MINE
SPEC. BID & AWARD ROTARY BLAST HOLE DRILLS
FAB. & DELIVER DRILLS
ASSEMBLE DRILLS
INSTALL POWER FOR UNDERGROUND MINE
EXCAVATE SLOPES
INSTALL TRACK, UTILITIES, CONVEYOR, WALKWAY IN SLOPES
DEVELOP #1 SEAM MAINS
CONSTRUCT SURFACE FACILITIES IN BOXCUT
INSTALL TRACK, TROLLEY
CONSTRUCT SURFACE TRANSPORT SYSTEM
DEVELOP #3 SEAM MAINS
PURCHASE COMPONENTS
INSTALL TRACK, TROLLEY &
MODELING
MINE DESIGN
SPEC & BID LONGWALL EQUIPMENT
UNDERGROUND MINE ENGINEERING
PURCHASE MECH. LONGWALL EQUIP.
FAB. & DELIVER LONGWALL EQUIPMENT
ERECT EQUIP. ON SURFACE & BEGIN TRAINING
INSTALL EQUIPMENT UNDERGROUND
PURCHASE SLOPE EQUIP.
FAB. & DELIVER SLOPE EQUIPMENT
DESIGN COAL PREPARATION & LOADING FAC.
SPEC. BID & AWARD CONST. CONTRACT FOR COAL PREP. & LOADING
CONSTRUCT COAL PREPARATION & LOADING FACIL
SPEC BID & AWARD EQUIP.
FABRICATE & DELIVER COAL PREP. & LOADING EQUIP.
PRE PLAN ALTERNATIVE FOR 2ND BOXCUT ACCESS & INOVATIVE HIGHWALL MINING METHODS
DEVELOP DETAILED LIFE OF MINE PL
FINAL MINE RESERVES
PURCHASE SMALL FRONT END LOADERS & BEDFORD TRUCKS



NOTE: IN UNDERGROUND MINE AT LEAST ONE PANEL PER SEAM MUST BE DEVELOPED BEFORE PRODUCTION CAN START.

FIGURE 7-4
MINE DEVELOPMENT SCHEDULE FOR 600 MW FACILITY
LAKHRA COAL STUDY

Section 8

COST ANALYSIS

8.1 CAPITAL COST ESTIMATES AND EXPENDITURE SCHEDULES

Itemized capital cost estimates and the associated capital expenditure schedules were developed for the 300- and 600-MW* facilities with and without import duty as indicated in Tables 8.1-1 through 8.1-6. A summary of the capital cost estimates is provided in Table 8.1-7.

All capital costs were determined for a facility producing, handling, and burning Lakhra Coal (see Section 5.4 for a discussion on coal quality). To enhance the reliability of the estimate, manufacturers of major equipment were asked to quote a present day (January 1983) price for their equipment. These prices were compared to SWEC in-house cost data and modified as required to provide the best possible estimate of an actual price quoted in a competitive bidding situation. The price of material and labor provided locally were estimated in rupees. All prices on foreign materials and labor were estimated in dollars.

Indirect costs such as WAPDA and PMDC administrative costs, engineering services, housing and community related facilities for the mining and power plant labor forces, and infrastructural facilities such as telecommunications, roads, pipelines, and power lines were also included in the cost estimate. Import duty was calculated based on 40 percent of the delivered price of foreign equipment. WAPDA and PMDC provided the cost data for administrative charges, community facilities and infrastructural costs. To account for indeterminant costs, a 15 percent contingency was added to coal production capital costs while a 10 percent contingency was added to power plant capital costs.

All costs in Table 8.1-1 through 8.1-7 are expressed in January 1983 dollars. Escalation and interest during construction are not included in these tables. If the sources of funding for the Lakhra Facility were known, a "weighted" interest rate could be developed based on the quantity of capital received from each source and the associated interest rate. However, the sources of funding were not known as of April 1983. It is expected that funding for the facility will come from many sources at different interest rates. Therefore, estimating escalation and interest rates for the purposes of calculating a 1988 capital investment could give misleading results due to the uncertainty of the

*The 600 MW scheme includes a modified mine design in which the additional coal required is produced by increasing the sizes of the east and west surface mines leaving the underground mine unchanged.

estimates and would not in any case enhance the quality of the estimate. Furthermore, it is customary to leave the capital cost estimates in present day currency for feasibility studies that will subsequently be used by financial institutions to establish project feasibility and funding strategy. Normally these financial institutions conduct their own financial and economic analyses at internally-generated escalation and interest rates.

TABLE 8.1-1
CAPITAL EXPENDITURE SCHEDULE FOR THE 300-MW COAL PRODUCTION FACILITIES
(ALL COSTS ARE EXPRESSED IN THOUSANDS OF JANUARY-1983 DOLLARS.)

	Total Project			1983			1984			1985			1986			1987		
	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
East Open Pit	21,656	16,339	37,995	557	250	807	7,971	13,541	21,512	5,811	917	6,728	3,226	322	3,548	4,091	1,309	5,400
West Open Pit	25,028	16,256	41,284	557	250	807	8,178	13,324	21,502	5,382	1,129	6,511	7,007	712	7,719	3,903	841	4,744
Underground Mine	13,661	7,630	21,291	100	200	300	2,867	1,766	4,633	3,386	2,537	5,923	3,316	1,778	5,094	3,993	1,349	5,342
Coal Prep & Handling	4,988	2,072	7,060	0	0	0	0	0	0	0	0	0	2,993	1,243	4,236	1,995	829	2,824
Surface Facilities	1,816	387	2,203	549	40	589	760	347	1,107	507	0	507	0	0	0	0	0	0
Roadway Corridor	10,040	825	10,865	1,000	75	1,075	6,490	750	7,240	0	0	0	1,275	0	1,275	1,275	0	1,275
Colony	15,686	0	15,686	787	0	787	5,490	0	5,490	4,706	0	4,706	4,706	0	4,706	0	0	0
Engineering & Consulting	2,196	12,500	14,696	126	720	846	902	5,133	6,035	623	3,545	4,168	311	1,773	2,084	234	1,330	1,564
Subtotal	95,072	56,010	151,082	3,674	1,535	5,209	32,658	34,861	67,519	20,415	8,128	28,543	22,834	5,828	28,662	15,491	5,658	21,149
Contingency (15%)	14,261	8,401	22,662	551	230	781	4,899	5,229	10,128	3,062	1,219	4,281	3,425	874	4,299	2,324	849	3,172
Total Capital Cost Excluding Import Duty, 1/83	109,333	64,410	173,743	4,225	1,765	5,990	37,557	40,090	77,647	23,477	9,347	32,824	26,259	6,702	32,961	17,815	6,507	24,321
Import Duty	17,404	0	17,403	326	0	326	11,891	0	11,891	1,833	0	1,833	1,622	0	1,622	1,731	0	1,731
Total Capital Cost Including Import Duty, 1/83	126,737	64,410	191,146	4,551	1,765	6,316	49,448	40,090	89,538	25,310	9,347	34,657	27,881	6,702	34,583	19,546	6,507	26,052

NOTE:

Rs. 12.75 = $1.

TABLE 8.1-2
CAPITAL EXPENDITURE SCHEDULE FOR THE 600-MW COAL PRODUCTION FACILITIES
(ALL COSTS ARE EXPRESSED IN THOUSANDS OF JANUARY-1983 DOLLARS.)

	Total Project			1983			1984			1985			1986			1987			1888		
	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
East Open Pit	46,912	39,606	86,518	0	250	250	403	2,233	2,636	3,318	18,208	21,526	11,408	11,434	22,842	14,872	4,938	19,810	16,912	2,543	19,455
West Open Pit	51,707	37,348	89,055	1,114	250	1,364	7,561	26,497	34,058	12,607	3,176	15,783	14,933	3,252	18,185	15,492	4,173	19,665	Full Production		
Underground Mine	13,661	7,629	21,290	0	200	200	100	0	100	2,867	1,766	4,633	3,386	2,537	5,923	3,316	1,778	5,094	3,993	1,349	5,342
Coal Prep & Handling	6,236	2,591	8,827	0	0	0	0	0	0	0	0	0	3,437	1,413	4,850	2,798	1,178	3,976	0	0	0
Surface Facilities	2,270	484	2,754	549	40	589	984	444	1,428	737	0	737	0	0	0	0	0	0	0	0	0
Roadway Corridor	10,590	825	11,415	1,000	75	1,075	6,490	750	7,240	0	0	0	1,275	0	1,275	1,275	0	1,275	550	0	550
Colony	19,608	0	19,608	784	0	784	6,275	0	6,275	6,275	0	6,275	6,275	0	6,275	0	0	0	0	0	0
Engineering & Consulting	2,510	14,100	16,610	151	811	962	878	4,789	5,667	552	3,100	3,652	351	2,000	2,351	351	2,000	2,351	226	1,400	1,626
Subtotal	153,494	102,583	256,077	3,598	1,626	5,224	22,691	34,713	57,404	26,356	26,250	52,606	41,065	20,636	61,701	35,104	14,067	52,171	21,681	5,292	26,973
Contingency (15%)	23,024	15,387	38,411	540	244	784	3,404	5,207	8,611	3,953	3,938	7,891	6,160	3,095	9,255	5,716	2,110	7,826	3,252	794	4,046
Total Capital Cost Excluding Import Duty, 1/83	17,518	117,970	294,488	4,138	1,870	6,008	26,095	39,920	66,015	30,309	30,188	60,497	47,225	23,731	70,956	43,820	16,177	59,997	24,933	6,086	31,019
Import Duty, 1/83	26,183	0	26,183	326	0	326	5,920	0	5,920	8,844	0	8,844	6,635	0	6,635	3,761	0	3,761	698	0	698
Total Capital Cost Including Import Duty, 1/83	202,701	117,970	320,671	4,464	1,870	6,334	32,015	39,920	71,935	39,153	30,188	69,341	53,860	23,731	77,591	47,581	16,177	63,758	25,631	6,086	31,717

NOTE:

1. Exchange rate: Rs. 12.75 = $1.

TABLE 8.1-3

THE CAPITAL EXPENDITURE SCHEDULE FOR FIRST 300-MW POWER PLANT INCLUDING IMPORT DUTY

(ALL EXPENDITURES ARE EXPRESSED IN THOUSANDS OF JANUARY-1983 DOLLARS.)

	Total Project				1983			1984			1985			1986			1987		
	Local	Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total
Land & Site Prep.	155	0	0	455	182	0	182	136	0	136	46	0	46	0	0	0	91	0	91
Coal Handling	510	2,970	7,437	10,917	0	0	0	0	0	0	1,500	5,305	6,805	1,980	1,462	3,442	0	670	670
Ash Handling	660	4,110	10,269	15,039	0	0	0	0	300	300	600	3,610	4,210	4,170	5,439	9,609	0	920	920
Cooling System	9,660	2,540	6,356	18,556	0	0	0	0	0	0	250	2,060	2,310	3,250	3,726	6,976	8,700	570	9,270
Turbine & Aux.	715	10,700	26,754	38,169	0	0	0	0	3,070	3,070	5,700	10,120	15,820	5,070	12,164,	17,234	645	1,400	2,045
Boiler & Au.	3,160	24,320	60,817	88,297	0	0	0	0	1,660	1,660	0	24,595	24,595	24,320	32,812	57,132	3,160	1,750	4,910
Precipitator & Aux.	840	4,270	10,682	15,792	0	0	0	0	900	900	4,270	8,048	12,318	670	1,654	2,324	170	80	250
Chimney	2,553	130	323	3,006	0	0	0	0	0	0	0	323	323	2,153	0	2,153	530	0	530
Boiler & Turbine Bldg.	9,694	1,080	2,698	13,472	0	0	0	0	0	0	980	2,595	3,575	8,794	103	8,897	1,000	0	1,000
Yard & Civil Work	6,600	1,890	4,728	13,218	0	0	0	0	0	0	1,360	1,077	2,437	6,450	3,651	10,101	680	0	680
Office Bldg.	1,948	1,250	3,128	6,326	0	0	0	0	0	0	0	0	0	2,198	3,128	5,326	1,000	0	1,000
Spare Parts	60	2,670	6,690	9 420	0	0	0	0	820	820	1,500	2,654	4,154	1,230	2,946	4,176	0	270	270
Erection	17,715	0	9,438	27,153	0	0	0	530	280	810	1,240	660	1,900	8,505	4,530	13,035	7,440	3,968	11,408
Supv. & Maint. for 1 Yr.	200	0	300	500	0	0	0	0	0	0	0	0	0	0	0	0	200	300	500
Lease of Equipment	12,500	0	0	12,500	0	0	0	400	0	400	900	0	900	6,000	0	6,000	5,200	0	5,200
Colony	8,518	0	0	8,518	0	0	0	3,748	0	3,748	4,174	0	4,174	341	0	341	255	0	255
Subtotal	75,788	55,930	149,620	281,338	182	0	182	4,814	7,030	11,844	22,520	61,047	83,567	75,131	71,615	145,746	29,071	9,928	38,999
Engineering & Consult.	3,400	0	31,800	35,200	128	1,709	1,837	1,034	11,260	12,294	1,473	10,971	12,444	638	6,270	6,908	127	1,590	1,717
WAPDA Admin.	11,253	0	0	11,253	0	0	0	450	0	450	5,064	0	5,064	5,401	0	5,401	338	0	338
Contingencies	7,578	5,593	14,963	28,134	18	0	18	481	703	1,184	2,252	6,105	8,357	7,513	7,162	14,675	2,907	993	3,900
Others																			
Forward Handling & Trans.	7,000	0	0	7,000	0	0	0	350	0	350	3,080	0	3,080	3,290	0	3,290	280	0	280
Insurance During Const.	3,900	0	0	3,900	0	0	0	195	0	195	1,716	0	1,716	1,833	0	1,833	156	0	156
Subtotal	33,131	5,593	46,763	85,487	146	1,709	1,855	2,510	11,963	14,473	13,585	17,076	30,661	18,675	13,342	32,107	3,808	2,583	6,391
Total Present Day Cost, 1/83	108,919	61,523	196,383	366,825	328	1,709	2,037	7,324	18,993	26,317	36,105	78,123	114,228	93,806	85,047	178,853	32,879	12,511	45,390

NOTES:

1. Exchange rate: Rs. 12.75 = $1.
2. Import duty is based on 40% of delivered price of foreign equipment.

TABLE 8.1-4

THE CAPITAL EXPENDITURE SCHEDULE FOR FIRST 300-MW POWER PLANT EXCLUDING IMPORT DUTY

(ALL EXPENDITURES ARE EXPRESSED IN THOUSANDS OF JANUARY-1983 DOLLARS.)

	Total Project				1983			1984			1985			1986			1987		
	Local	Import Duty	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
Land & Site Prep.	455	NOT INCLUDED	0	455	182	0	182	136	0	136	46	0	46	0	0	0	91	0	91
Coal Handling	510		7,437	7,947	0	0	0	0	0	0	0	5,305	5,305	510	1,462	1,972	0	670	670
Ash Handling	660		10,269	10,929	0	0	0	0	300	300	0	3,610	3,610	660	5,439	6,099	0	920	920
Cooling System	9,660		6,356	16,016	0	0	0	0	0	0	0	2,060	2,060	960	3,726	4,686	8,700	570	9,270
Turbine & Aux.	715		26,754	27,469	0	0	0	0	3,070	3,070	0	10,120	10,120	70	12,164	12,234	645	1,400	2,045
Boiler & Aux.	3,160		60,817	63,977	0	0	0	0	1,660	1,660	0	24,595	24,595	0	32,812	32,812	3,160	1,750	4,910
Precipitator & Aux.	840		10,682	11,522	0	0	0	0	900	900	0	8,048	8,048	670	1,654	2,324	170	80	250
Chimney	2,553		323	2,876	0	0	0	0	0	0	0	323	323	2,023	0	2,023	530	0	530
Boiler & Turbine Bldg.	9,694		2,698	12,392	0	0	0	0	0	0	620	2,595	3,215	8,074	103	8,177	1,000	0	1,000
Yard & Civil Work	6,600		4,728	11,328	0	0	0	0	0	0	210	1,077	1,287	5,710	3,651	9,361	680	0	680
Office Bldg.	1,948		3,128	5,076	0	0	0	0	0	0	0	0	0	948	3,128	4,076	1,000	0	1,000
Spare Parts	60		6,690	6,750	0	0	0	0	820	820	0	2,654	2,654	60	2,946	3,006	0	270	270
Erection Charges	17,715		9,438	27,153	0	0	0	530	280	810	1,240	660	1,900	8,505	4,530	13,035	7,440	3,968	11,408
Supv. & Maint. for 1 Yr.	200		300	500	0	0	0	0	0	0	0	0	0	0	0	0	200	300	500
Lease of Equipment	12,500		0	12,500	0	0	0	400	0	400	900	0	900	6,000	0	6,000	5,200	0	5,200
Colony	8,518		0	8,518	0	0	0	3,748	0	3,748	4,174	0	4,174	341	0	341	255	0	255
Subtotal	75,788		149,620	225,408	182	0	182	4,814	7,030	11,844	7,190	61,047	68,237	34,531	71,615	106,146	29,071	9,928	38,999
Engineering & Consult.	3,400		31,800	35,200	128	1,709	1,837	1,034	11,260	12,294	1,473	10,971	12,444	638	6,270	6,908	127	1,590	1,717
WAPDA Admin.	9,016		0	9,016	0	0	0	361	0	361	4,057	0	4,057	4,328	0	4,328	270	0	270
Contingencies	7,578		14,963	22,541	18	0	18	481	703	1,184	719	6,105	6,824	3,453	7,162	10,615	2,907	993	3,900
Others																			
Forward Handling & Trans.	7,000		0	7,000	0	0	0	350	0	350	3,080	0	3,080	3,290	0	3,290	280	0	280
Insurance During Const.	3,900		0	3,900	0	0	0	195	0	195	1,716	0	1,716	1,833	0	1,833	156	0	156
Subtotal	30,894		46,763	77,657	146	1,709	1,855	2,421	11,963	14,384	11,045	17,076	28,121	13,542	13,432	26,974	3,740	2,583	6,323
Total Present Day Cost, 1/83	106,682		196,383	303,065	328	1,709	2,037	7,235	18,993	26,228	18,235	78,123	96,358	48,073	85,047	133,120	32,811	12,511	45,322

NOTE:

1. Exchange rate: Rs. 12.75 = $1.

TABLE 8.1-5

CAPITAL EXPENDITURE SCHEDULE FOR SECOND 300-MW POWER PLANT INCLUDING IMPORT DUTY
(ALL EXPENDITURES ARE EXPRESSED IN THOUSANDS OF JANUARY-1983 DOLLARS.)

	Total Project				1983			1984			1985			1986			1987			1988		
	Local	Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total
Land & Site Prep.	300	0	0	300	0	0	0	150	0	150	0	0	0	0	0	0	90	0	90	60	0	60
Coal Handling	64	103	258	425	0	0	0	0	0	0	0	0	0	52	0	52	115	258	373	0	0	0
Ash Handling	600	3,900	9,751	14,251	0	0	0	0	0	0	0	280	280	570	3,420	3,990	3,930	5,170	9,100	0	881	881
Cooling System	5,819	2,151	5,377	13,347	0	0	0	0	0	0	0	0	0	512	1,742	2,254	4,214	3,152	7,366	3,244	483	3,727
Turbine & Aux.	703	10,166	25,416	36,285	0	0	0	0	0	0	0	2,920	2,920	5,416	9,628	15,044	4,820	11,572	16,392	633	1,296	1,929
Boiler & Aux.	3,134	23,114	57,786	84,034	0	0	0	0	0	0	0	1,580	1,580	0	23,370	23,370	23,114	31,200	54,314	3,134	1,636	4,770
Precipitator & Aux.	817	4,060	10,149	15,026	0	0	0	0	0	0	0	855	855	4,360	7,646	12,006	517	1,571	2,088	0	77	77
Chimney	2,553	123	308	2,984	0	0	0	0	0	0	0	0	0	2,023	308	2,331	653	0	653	0	0	0
Boiler & Turbine Bldg.	9,690	894	2,235	12,819	0	0	0	0	0	0	620	0	620	4,298	2,150	6,448	4,666	85	4,751	1,000	0	1,000
Yard & Civil Work	3,983	1,750	4,376	10,109	0	0	0	0	0	0	100	0	100	3,065	996	4,061	2,168	3,380	5,548	400	0	400
Office Bldg.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spare Parts	52	2,334	5,835	8,221	0	0	0	0	0	0	0	715	715	1,341	2,314	3,655	1,045	2,569	3,614	0	237	237
Erection Charges	14,235	0	6,607	20,842	0	0	0	0	0	0	0	0	0	996	462	1,458	6,833	3,367	10,200	6,406	2,778	9,184
Supv. & Maint. for 1 Yr.	200	0	300	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	300	500
Lease of Equipment	9,375	0	0	9,375	0	0	0	0	0	0	300	0	300	675	0	675	4,500	0	4,500	3,900	0	3,900
Colony	4,000	0	0	4,000	0	0	0	0	0	0	1,760	0	1,760	1,960	0	1,960	160	0	160	120	0	120
Subtotal	55,525	48,595	128,398	232,518	0	0	0	150	0	150	2,780	6,350	9,130	25,268	52,036	77,304	56,825	62,324	119,149	19,097	7,688	26,785
Engineering & Consult.	850	0	7,950	8,800	25	239	264	136	1,537	1,673	182	1,571	1,753	183	1,582	1,765	103	2,385	2,488	221	636	857
WAPDA Admin.	9,300	0	0	9,300	0	0	0	186	0	186	558	0	558	3,999	0	3,999	4,092	0	4,092	465	0	465
Contingencies	5,553	4,860	12,839	23,252	0	0	0	15	0	15	278	635	913	2,527	5,203	7,730	5,683	6,232	11,915	1,910	769	2,679
Others																						
Forward Handling & Trans.	6,000	0	0	6,000	0	0	0	0	0	0	0	0	0	1,620	0	1,620	4,380	0	4,380	0	0	0
Insurance During Const.	1,300	0	0	1,300	0	0	0	0	0	0	0	0	0	351	0	351	949	0	949	0	0	0
Subtotal	23,003	4,860	20,789	48,652	25	239	264	337	1,537	1,874	1,018	2,206	3,224	8,680	6,785	15,465	15,207	8,617	23,824	2,596	1,405	4,001
Total Present Day Cost, 1/83	78,528	53,455	149,187	281,170	25	239	264	487	1,537	2,024	3,798	8,556	12,354	33,948	58,821	92,769	72,032	70,941	142,973	21,693	9,093	30,786

NOTES:

1. Exchange rate: Rs. 12.75 = $1.
2. Import duty is based on 40% of delivered price of foreign equipment

TABLE 8.1-6

CAPITAL EXPENDITURE SCHEDULE FOR SECOND 300-MW POWER PLANT EXCLUDING IMPORT DUTY
(ALL EXPENDITURES ARE EXPRESSED IN THOUSANDS OF JANUARY-1983 DOLLARS.)

	Total Project				1983			1984			1985			1986			1987			1988		
	Local	Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total	Local Incl Import Duty	Foreign	Total
		NOT INCLUDED																				
Land & Site Prep.	300		0	300	0	0	0	150	0	150	0	0	0	0	0	0	90	0	90	60	0	60
Coal Handling	64		258	322	0	0	0	0	0	0	0	0	0	0	0	0	64	258	322	0	0	0
Ash Handling	600		9,751	10,351	0	0	0	0	0	0	0	280	280	0	3,420	3,420	600	5,170	5,770	0	881	881
Cooling System	5,819		5,377	11,196	0	0	0	0	0	0	0	0	0	300	1,742	2,042	2,275	3,152	5,427	3,244	483	3,727
Turbine & Aux.	703		25,416	26,119	0	0	0	0	0	0	0	2,920	2,920	0	9,628	9,628	70	11,572	11,642	633	1,296	1,929
Boiler & Aux.	3,134		57,786	60,920	0	0	0	0	0	0	0	1,580	1,580	0	23,370	23,370	0	31,200	31,200	3,134	1,636	4,770
Precipitator & Aux.	817		10,149	10,966	0	0	0	0	0	0	0	855	855	300	7,646	7,946	517	1,571	2,088	0	77	77
Chimney	2,553		308	2,861	0	0	0	0	0	0	0	0	0	2,023	308	2,331	530	0	530	0	0	0
Boiler & Turbine Bldg.	9,690		2,235	11,925	0	0	0	0	0	0	620	0	620	4,000	2,150	6,150	4,070	85	4,155	1,000	0	1,000
Yard & Civil Work	3,983		4,376	8,359	0	0	0	0	0	0	100	0	100	2,000	996	2,996	1,483	3,380	4,863	400	0	400
Office Bldg.	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spare Parts	52		5,835	5,887	0	0	0	0	0	0	0	715	715	30	2,314	2,344	22	2,569	2,591	0	237	237
Erection Charges	14,235		6,607	20,842	0	0	0	0	0	0	0	0	0	996	462	1,458	6,833	3,367	10,200	6,406	2,778	9,184
Supv. & Maint. for 1 Yr.	200		300	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	300	500
Lease of Equipment	9,375		0	9,375	0	0	0	0	0	0	300	0	300	675	0	675	4,500	0	4,500	3,900	0	3,900
Colony	4,000		0	4,000	0	0	0	0	0	0	1,760	0	1,760	1,960	0	1,960	160	0	160	120	0	120
Subtotal	55,525		128,398	183,923	0	0	0	150	0	150	2,780	6,350	9,130	12,284	52,036	64,320	21,214	62,324	83,538	19,097	7,688	26,785
Engineering & Consult.	850		7,950	8,800	25	239	264	136	1,537	1,673	182	1,571	1,753	183	1,582	1,765	103	2,385	2,488	221	636	857
WAPDA Admin.	7,357		0	7,357	0	0	0	147	0	147	441	0	441	3,164	0	3,164	3,237	0	3,237	368	0	368
Contingencies	5,552		12,840	18,392	0	0	0	15	0	15	278	635	913	1,228	5,204	6,432	2,121	6,232	8,353	1,910	769	2,679
Others																						
Forward Handling & Trans.	6,000		0	6,000	0	0	0	0	0	0	0	0	0	1,620	0	1,620	4,380	0	4,380	0	0	0
Insurance During Const.	1,300		0	1,300	0	0	0	0	0	0	0	0	0	351	0	351	949	0	949	0	0	0
Subtotal	21,359		20,790	41,849	25	239	264	298	1,537	1,835	901	2,206	3,107	6,546	6,786	13,332	10,790	8,617	19,407	2,499	1,405	3,904
Total Present Day Cost, 1/83	76,884		149,188	225,772	25	239	264	448	1,537	1,985	3,681	8,556	12,237	18,830	58,822	77,652	32,004	70,941	102,945	21,596	9,093	30,689

NOTE:

1. Exchange rate: Rs. 12.75 = $1.

TABLE 8.1-7

SUMMARY OF CAPITAL COST ESTIMATES

Capital Cost Estimates Expressed in Millions of Dollars	Foreign Component	Local Component	Total Excluding Import Duty	Import Duty	Total Including Import Duty
o 300 MW (Net) Power Plant	196.4	108.9	305.3	61.5	366.8
o 300 MW Coal Production Facility	64.4	109.3	173.7	17.4	191.1
Total 300 MW Facility	260.8	218.2	479.0	78.9	557.9
o First 300 MW (Net) Power Plant	196.4	108.9	305.3	61.5	366.8
o Second 300 MW (Net) Power Plant	149.2	78.5	227.7	53.5	281.2
o 600 MW Coal Production Facility	118.0	176.5	294.5	26.2	320.7
Total 600 MW Facility	463.6	363.9	827.5	141.2	968.7
Capital Cost Estimates Expressed in Millions of Rupees					
o 300 MW (Net) Power Plant	2504.1	1388.5	3892.6	784.1	4676.7
o 300 MW Coal Production Facility	821.1	1393.6	2214.7	221.9	2436.6
Total 300 MW Facility	3325.2	2782.1	6107.3	1006.0	7113.3
o First 300 MW (Net) Power Plant	2504.1	1388.5	3892.6	784.1	4676.7
o Second 300 MW (Net) Power Plant	1902.3	1000.9	2903.2	682.1	3585.3
o 600 MW Coal Production Facility	1504.5	2250.4	3754.9	334.1	4089.0
Total 600 MW Facility	5910.9	4639.8	10550.7	1800.3	12351.0

NOTES:

1. Capital cost estimates include direct costs, indirect costs, and an allowance for indeterminate costs based on prices quoted for January 1983. Escalation and interest during construction are not included in these estimates. Exchange rate: Rs. 12.75 = 1.00 Dollar.

2. Coal Production Facilities include coal transportation facilities.

3. The 300 MW and 600 MW coal Production Facilities incorporate different designs. Thus, the total cost of each facility is provided separately.

4. The two 300 MW power plants employ identical designs. Thus, the incremental cost of the second 300 MW power plant is provided.

8.2 UNIT COSTS OF COAL AND ELECTRICITY

The cost per metric ton of Lakhra Coal delivered to the power station and the cost per kWH of electricity delivered to the WAPDA grid is calculated in Tables 8.2-1 and 8.2-2.

Annual costs computed in this section are based on the following data:

- Annual interest rate on foreign loans: 10%
- Annual interest rate on domestic loans: 13%
- Depreciation schedule: sinking fund
- Operating lifetime = capital recovery period: 30 years
- Equivalent full load power plant capacity factor: 70%
- Exchange rate: Rs12.75 = $1.00

Discussion

The unit cost of coal delivered to the power plant in 1983 (excluding escalation and interest during construction) is found by dividing the total annual coal production and transportation costs by the total annual coal production (see Table 8.2-1). Based on 1983 operating and replacement costs, the cost of coal delivered to the power plant in 1983 including import duty is 36.57/metric ton = Rs 466/metric ton and excluding import duty is $33.93/metric ton = Rs 433/metric ton.

The unit cost of electricity delivered to the WAPDA grid during 1983 is found by dividing the total annual power generation cost by the total net annual output (see Table 8.2-2). Based on 1983 operation and maintenance costs (see Section 6.8 for labor costs), the unit cost of electricity delivered to the WAPDA grid in 1983 including import duty is 5.5¢/kWH = 70 paisa/kWH and excluding import duty is 4.8¢/KWH = 61 paisa/kWH.

TABLE 8.2-1

ANNUAL COSTS OF COAL PRODUCTION FACILITIES

All annual costs are expressed in millions of January 1983 dollars. Escalation and interest during construction are not included.

	Excluding Import Duty	Including Import Duty
Annual Salaries and Wages	$ 2.7	$ 2.7
Annual Administration Costs	0.9	0.9
Annual Debt Service[1]	21.4	23.7
Annual Equipment Replacement	3.3	4.2
Annual Production Supplies	19.2	19.7
TOTAL Annual Cost, 1983[2]	$47.5	$51.2
Unit Cost of Coal Delivered to the Power Plant, 1983[3]	$33.93 metric ton	$36.57 metric ton

NOTES:

1 Based on sinking fund depreciation for 30 years and annual interest rates on domestic loans of 13 percent and on foreign loans of 10 percent.

2 Royalties paid the provincial government are not included in this estimate.

3 Total annual production of coal delivered to the power plant is assumed to 1.4 million tonnes.

TABLE 8.2-2

ANNUAL COSTS OF POWER GENERATION FACILITIES

All annual costs are expressed in millions of January 1983 dollars. Escalation and interest during construction are not included.

	Excluding Import Duty	Including Import Duty
Fixed Annual Debit Service (1)	$35.3	$43.6
Annual Fuel Cost	45.2	48.7
Annual Operation & Maintenance Cost	8.1	9.3
TOTAL Annual Cost, 1983	88.6	101.6
Unit Cost of Electricity Delivered to WAPDA Grid, 1983 (2)	4.8¢/kwH	5.5¢/kwH

NOTES:

1. Based on sinking fund depreciation for 30 years and annual interest rates on domestic loans of 13 percent and on foreign loans of 10 percent.

2. Total annual generation is based on 300 MWe of net output for for 6,132 hours per year (corresponds to an equivalent full load capacity factor of 70 percent.)

8.3 COMPARISON OF ALTERNATIVES

The discussion that follows compares Lakhra Coal with two possible alternative fuels: imported furnace oil (also referred to as residual oil, Bunker "C" and Number 6 oil) and imported coal. It assumes that a power plant burning either imported oil or imported coal would be located at Karachi using existing unloading facilities at Port Qasim.

Comparison of Lakhra Coal with Imported Oil

While some costs associated with power generation alternatives are quantifiable, others are not. Two benefits identified with the use of Lakhra Coal but not with imported fuel that are not quantified in this discussion are job creation and the initiation of a modern, large-scale coal industry in Pakistan.

The Lakhra coal production, preparation, and transportation facilities supplying 1.4 million metric tons of coal per year for a 300-MW power plant would employ approximately 1,900 people. The installation of the first 300-MW of coal production capacity at Lakhra would thus provide for the daily needs of approximately 1,900 Pakistani families over 30-years. With a power plant burning imported fuel, this benefit would not exist.

The mine at Lakhra required to supply the first 300-MW power plant would be about 7 times larger than the largest mine currently operating in Pakistan. The development of the coal production facilites at Lakhra would, for the first time, introduce large-scale coal technology into Pakistan. Mining coal on this scale requires a considerable amount of mechanization to ensure reasonable efficiency and productivity even with the labor-intensive designs proposed for the Lakhra facility. Thus, a wide range of coal-based technology would be transferred to Pakistan. The expertise to explore, sample, analyze, transport, and prepare for utilization would be developed preparing the way for more extensive use of coal in other energy-intensive industries such as cement and steel.

The quantifiable costs incurred by power plants burning Lakhra Coal and imported oil and coal are summarized in Table 8.3-1. Columns (1) and (2) give the annual and unit (per kilowatt-hour) generation costs for the Lakhra Coal and imported oil alternatives. Import duty, escalation, and interest during construction are excluded from the calculation. All costs are presented in millions of January 1983 dollars. The generation cost is broken down into three component costs: the annual fixed charges on the capital investment, (i.e., interest and sinking fund depreciation costs), the annual fuel cost and the annual operation and maintenance (O&M) cost. The total cost for each alternative is found by adding the three component costs. The unit generation cost is then calculated by dividing the total annual cost by the total annual power output in kWH.

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As Table 8.3-1 indicates, the capital cost of a power plant burning Lakhra Coal is approximately 30 percent higher than one designed to burn imported furnace oil. The higher costs are due primarily to the coal handling and preparation equipment, the larger steam generator required, and the ash handling and disposal equipment. The fuel cost of a power plant burning Lakhra coal, however, is about half that of one burning imported furnace oil. Lakhra's higher annual operation and maintenance (O&M) cost is due to higher labor and materials replacement requirements associated with coal.

When all costs are added up, the total annual cost of a Lakhra plant is 26.9 million dollars lower per year than imported oil at 1983 prices.

It follows that WAPDA would have to charge approximately 30 percent more for electricity generated by imported oil than electricity generated with Lakhra Coal during the first year of commercial operation. This spread increases throughout the plant lifetime since the difference in fuel costs increases each year with escalation while the difference in capital costs is constant.

One can also compute the return on the additional capital investment incurred by the Lakhra Coal alternative relative to the imported oil alternative. This additional capital investment is recovered in about 2 1/2 years by a reduction in net operating (Fuel and O&M) cost relative to the imported oil alternative. Investing in the Lakhra alternative would yield an incremental internal rate of return* of approximately 50 percent.

An additional cost associated with the imported oil alternative is the "hidden cost" of foreign exchange. As indicated in Table 8.3-1, the additional foreign exchange required each year by the imported oil alternative is 70.7 million dollars if the two alternative power plants were operating in 1983. This represents approximately 5.5 percent of Pakistan's current foreign exchange reserves.** A power plant fired by imported oil would thus be a significant drain on the country's foreign exchange.

Comparison of Lakhra Coal with Imported Coal

The qualitative discussion offered in the comparison of Lakhra Coal and imported oil concerning employment and technology transfer associated with the development of a modern coal

*Note: Escalation and interest during construction, had to be included in this calculation while import duty was not.

** Source: Prospect of Targetted Economic Growth Diminishing, the Muslim, March 5, 1983.

industry in Pakistan holds true for this comparison as well. The quantifiable costs used to compare the Lakhra Coal and imported coal alternatives are listed Columns (1) and (3) of Table 8.3-1. The capital cost of a power plant designed to burn Lakhra Coal is approximately 10 percent higher than one designed to burn the higher quality (12 percent ash, 25,000 KJ/kg) imported coal. Compared to imported coal, Lakhra Coal has higher ash, and moisture, and a lower heating value. Therefore, more Lakhra Coal must be burned per kW of electricity produced. This increases the size of the boiler and related auxiliaries which increases power plant capital cost. The delivered price of imported coal to a power plant near Karachi is estimated to be about 5 percent higher than the delivered price of Lakhra Coal. This price differential is, however, offset because a power plant burning Lakhra Coal will be slightly less efficient than one burning higher quality imported coal. Differences in O&M costs for the two plants are considered negligible.

Adding component costs indicates that the unit generation cost associated with Lakhra Coal is 6 percent higher than that associated with imported coal. Given the accuracy of the cost estimates used in this calculation the difference is small and is offset by the qualitative advantages described above. Furthermore, the avoidance of an additional 33.9 million dollars per year of foreign exchange required by an imported coal-fired plant is another benefit associated with Lakhra Coal that is not indicated in the comparison of unit costs. While this foreign exchange drain is less than the one for the imported oil alternative, it is still significant and should be considered in the overall evaluation of alternatives over the scheduled 30-year lifetime.

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TABLE 8.3-1

ECONOMIC COMPARISON OF ALTERNATIVES

All costs are expressed in millions of January, 1983 dollars. Import duty, interest during construction, and escalation are not included.

Costs	Lakhra Coal	Imported Oil	Imported Coal
1. Annual Fixed Capital Charges[1]			
Domestic	14.5	10.5	13.1
Foreign	20.8	15.0	18.7
Total:	35.3	25.5	31.8
2. Annual Fuel Cost[2,3]			
Domestic	38.4	0.0	0.0
Foreign	6.8	84.6	42.8
Total:	45.2	84.6	42.8
3. Annual Operation & Maintenance Cost			
Domestic	4.1	2.7	4.1
Foreign	4.0	2.7	4.0
Total:	8.1	5.4	8.1
4. Total Annual Generation Cost			
Domestic	57.0	13.2	17.2
Foreign	31.6	102.3	65.5
Total:	88.6	115.5	82.7
5. Unit Generation Cost[2]	4.8¢/kwH	6.3¢/kwH	4.5¢/kwH

NOTES:

1 Includes interest and sinking fund depreciation costs for a capital recovery period of 30 years. Annual interest rates used are 13 percent for domestic debt, and 10 percent for foreign debt.

2 Based on the output from a 300 MW power plant, operated in 1983 at full load for 70 percent of the year (i.e., 6,132 hours per year).

3 The 1983 fuel prices used in this comparison are:

Lakhra Coal	$2.37/10^6$ kJ ($34/metric ton)
Imported Coal	$2.46/10^6$ kJ ($70/metric ton)
Imported Oil	$4.91/10^6$ kJ ($28/bbl)

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SECTION 9

CONCLUSIONS

1. The Lakhra Facility

The initial 300-MW Lakhra Coal Facility should consist of the following:

- A three-section mine within the delineated mine area in the Lakhra coal field; the east and west sections - open pit mines; the central section - underground;
- Surface coal preparation facilities;
- A colony for miners and mine support personnel;
- A new dedicated railway for coal transport about 35 kilometers in length between Lakhra and Jamshoro;
- Coal receiving, storage and handling facilities and a 300-MW net capacity coal-fired, steam turbine power plant located at WAPDA's Jamshoro site;
- Electrical connection facilities to WAPDA's existing transmission network;
- An intake water system located at the Kotri Barrage on the Indus River and a makeup water line to the Jamshoro site of a size sufficient for evaporative cooling towers; and
- A colony at the Jamshoro site for plant construction and plant operation and maintenance personnel.

2. Technical Feasibility

The design, construction, and operation of the Lakhra Facility is technically feasible. Proven technologies and methods can be supplied in the mining, coal transport and power plant elements of the facility. Extensive experience exists in the application and use of these technologies and methods.

3. Economic Feasibility

The Lakhra Facility is economically competitive with other power generation alternatives for meeting Pakistan's growing requirements for electricity. Electricity generation costs would be significantly less with Lakhra coal than with imported oil and comparable to imported coal. Exploiting domestic Lakhra coal will save millions of dollars in foreign exchange each year, thousands of Pakistanis will be employed, and a modern coal industry will emerge.

4. Environmental Feasibility

The Lakhra project can be implemented so that its emissions will meet World Bank guidelines and have a minimum impact on the environment.

5. Institutional Organization

The institutional structure to efficiently support the implementation and operation of the Lakhra Facility does not currently exist in Pakistan. An institutional organization is required that has the authority to effectively manage the design, construction, and operation of the facility.

6. Implementation Schedule

A 54-month implementation schedule is practical to adopt. Thus, the Lakhra Facility can help satisfy Pakistan's urgent need for power generation capacity as early as 1988.

7. Technology Transfer

The implementation of the Lakhra Coal project requires a substantial amount of large-scale, coal-based technology transfer and adaptation. New related industrial activities in Pakistan, having the potential to impact significantly on national economic growth, would soon follow.

8. Pakistan Coal Industry Growth and Modernization

The demonstration by the Lakhra Facility of large scale coal field development and production, the building of a coal mining infrastructure, and the generation of a large scale demand for domestic coal can lead to:

- Development of other Pakistan coal fields;
- The availability and use of lower cost coal for other energy applications;
- Future expanded use of coal fuels for electricity generation.

Such a program provides a solid foundation on which the nation can enlist the many resources and capabilities of its private sector.

9. Second 300-MW Unit

Cost considerations clearly support the construction of a second identical coal-fired unit at the Jamshoro site. The initial operation date of a second unit should be scheduled 1 to 3 years after the initial operation date of the first Lakhra unit pending the proof of sufficient coal reserves by additional geological investigations. Achievement of the associated cost savings requires a decision to install a second unit within 12 months of project start date.

SECTION 10

RECOMMENDATIONS

WAPDA has recommended to the Government of Pakistan (GOP) that the Lakhra Coal Facility be included as a project in Pakistan's Sixth Economic Development Plan covering the period 1983-1988. The following recommendations are directed at the implementation of a project to design, construct, and commission the Lakhra Facility.

Institutional

1. Establish a Lakhra Project Implementation Organization* within the GOP. This organization should be responsible for the complete implementation and eventual operation of the Lakhra Facility. It should also be capable of planning, implementing and overseeing the operation of all future coal-fired power generation projects in Pakistan.

2. Staff the Lakhra Project Implementation Organization with highly-qualified, experienced personnel. Specialized training for the staff should be defined and carried out according to individual needs and responsibilities. Provide appropriate professional and financial incentives to assure long-term commitments by the personnel receiving the training.

3. Review manpower development, training, and other technology transfer programs underway or planned in Pakistan to determine the extent to which these programs can be used to meet the training and technology transfer requirements of the Lakhra project. Take measures to ensure that Pakistan private sector corporations have the opportunity to participate in these human resource development and technology transfer programs. Consider the appropriate components of the USAID Energy Planning and Development Project as a source for this training need.

4. Begin at the earliest practical date the coordination of the Lakhra project with other activities at the Jamshoro site.

5. Provide supplementary support for the Lakhra Project Implementation Organization to enhance its capabilities in the specialized functions listed below:

   - project management and planning
   - engineering and design
   - equipment procurement, inspeciton, expediting, and transportation

* Commonly referred to as the "Coal Cell" within the GOP.

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- construction management
- acceptance testing and start-up
- operations planning and management

Technical

The following technical activities need to be undertaken as soon as practical:

6. Obtain a representative large scale coal sample from the Lakhra Field for analysis and use in the design of the Lakhra Steam Generator.

7. Conduct detailed geological investigations required to establish the final mine area and mine design.

8. Install environmental monitoring equipment at the Jamshoro site and collect data to acquire the baseline data needed to determine subsequent requirements for plant effluent control.

9. Survey route(s) for railway, road, water and power lines to the Lakhra Mining Area.

10. Establish area contour lines and obtain preliminary soils data from the area of the Jamshoro site for use as input to foundation design and plant layout.

11. Develop equipment specifications for the steam generator, steam turbine, and electric shovels.

12. Prepare project and purchasing procedures and specifications to be used in procuring services and in purchasing the major equipment as quickly as practical.

13. Prepare schedule networks of all major project activities soon after project authorization and make the requirements for maintaining these schedules known to all management and approval authorities.

14. Decide within nine months after project authorization whether a second 30-MW power plant will be included in the project, and plan the production capacity of the mine accordingly.

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LAKHRA COAL AND POWER DEVELOPMENT PROJECT REVIEW

VOLUME II APPENDICES

APRIL 1983

PREPARED FOR:

UNITED STATES AGENCY FOR INTERNATIONAL DEVELOPMENT

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WATER AND POWER DEVELOPMENT AUTHORITY
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APPENDIX 1

U.S. COAL INDUSTRY

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PART I COAL DEPOSITS, COAL MINING, AND TRANSPORTATION

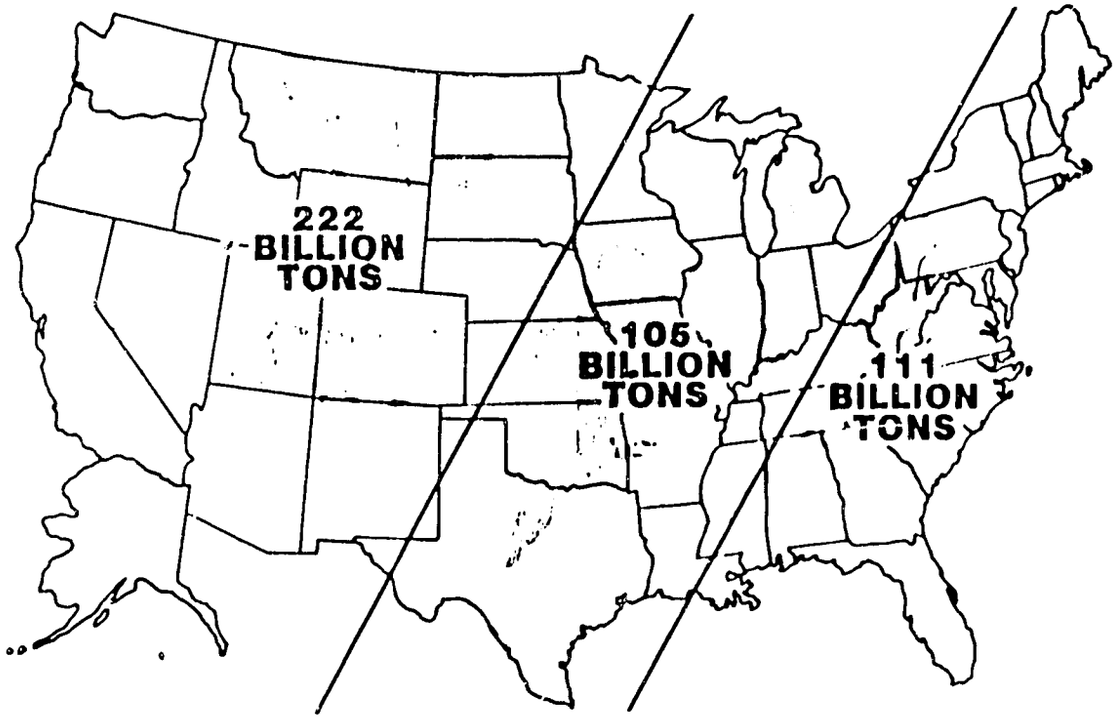
1. INTRODUCTION

1.1 The United States Geological Survey reports that there are 1.7 trillion tons of coal resources in the United States.

About 438 billion tons of coal are identified as minable with existing technology, which is sufficient to supply America's entire present energy demand for hundreds of years.

Forty-five percent of the reserves are located east of the Mississippi, and fifty-five percent to the west of this line.

Fig. 1-1.1 **COAL RESERVES IN THE UNITED STATES**



The coal deposits are spread over 30 states in three main areas associated with different geological formations:

- Appalachian Coal Basin, stretching parallel to the Appalachian Mountains from Pennsylvania in the north to Alabama in the south (1,600 km). The coal beds are confined to rocks of Pennsylvanian and Permian age, comparable to Oberkarbon and Perm in Europe.

  The quality of the coal ranges from high volatile steam coal to anthracite.

- Interior Coal Province, coal deposits underlaying the states of Ohio, Illinois, Indiana, Kentucky, Iowa, Kansas, Missouri, Oklahoma, Arkansas, and Texas. The age of the coal is about the same as in the Appalachian Coal Basin, but the geomorphic and structural setting of the coal beds and the coal quality differ greatly.

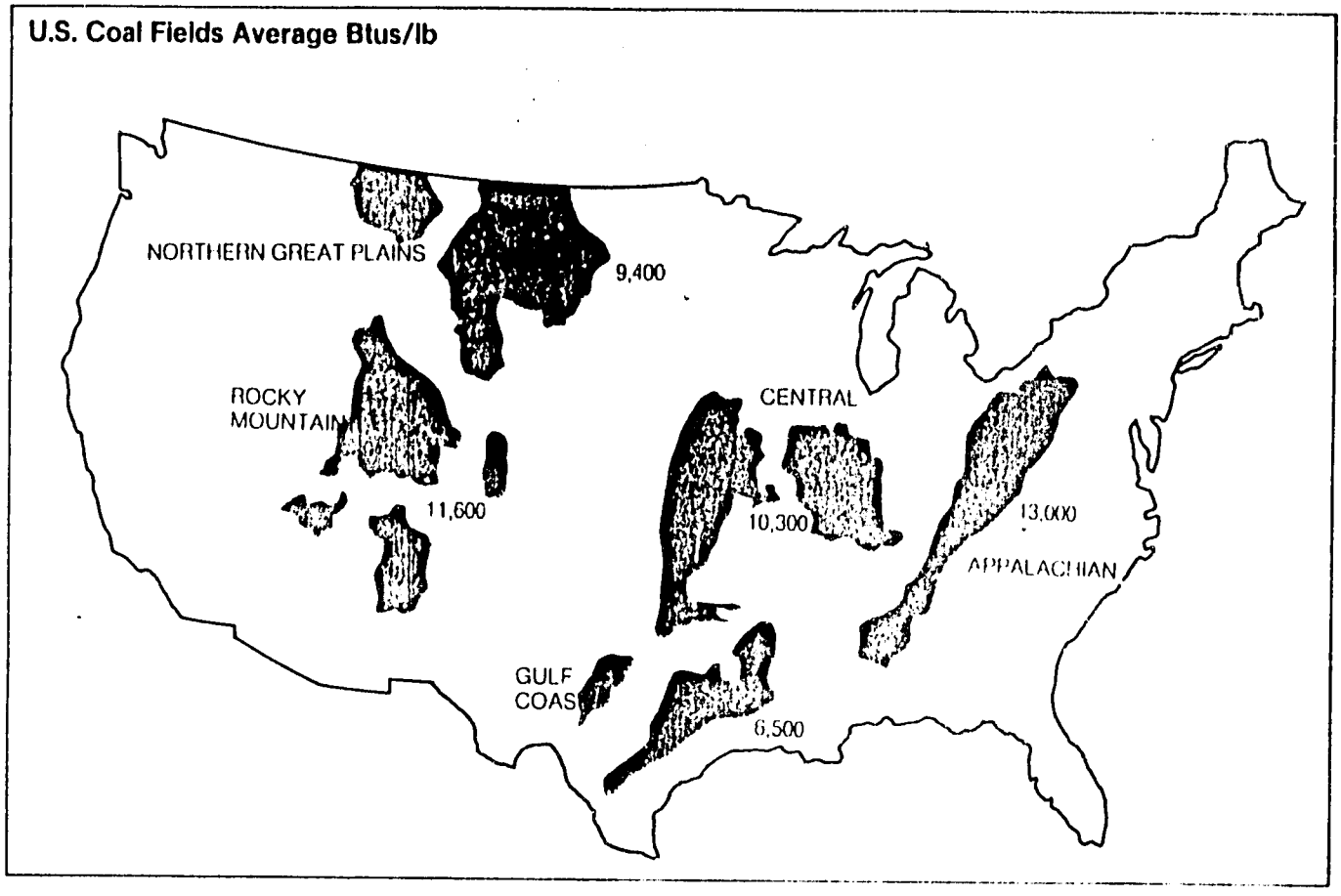
  In Texas there are, in addition, lignite resources which are close to the surface and which were deposited during the lower Eocene period.

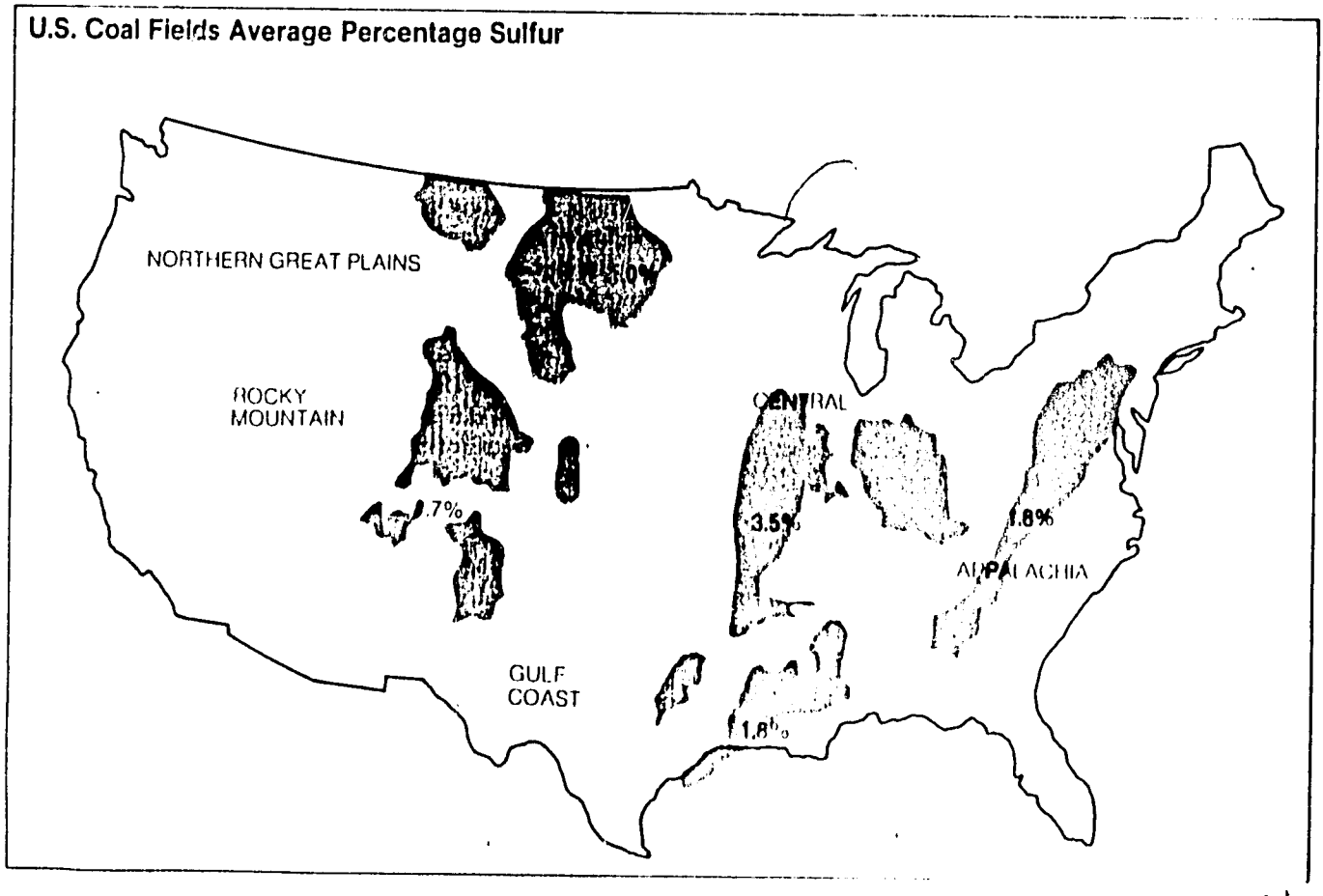
- Western Coal Province, includes the Great Plains coal area, which extends from Saskatchewan in Canada to Wyoming, and covers also parts of the states of North and South Dakota, and the Rocky Mountains area with deposits in Utah, Colorado, Arizona, and New Mexico.

  The coal in the west occurs mostly in upper Cretaceous and Eocene formations. Their genesis corresponds with the orogenesis of the Rocky Mountains. In Montana, the formation of coal basins commenced earlier, i.e., in the late Jurassic age, and lasted until the Miocene period.

  The major part of the western coal reserves are lignites and subbituminous coals, but there is also a large resource of bituminous coals in the Rocky Mountains.

Fig. 1 - 1.2 Coal Qualities in the United States





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Coal deposits of economic importance also exist in the states of Washington and Alaska.

The 438 billion tons of minable reserves are defined as demonstrated reserves, i.e., measured and indicated reserves in place, with an overburden to 3,000 ft (915 m), a seam thickness of more than 14 inch (36 cm) for bituminous coal, and 2½ ft (76 cm) for subbituminous coal and lignite.

The total reserves are divided into several coal qualities as shown in Table 1.1.

Table 1.1. Coal Reserves by Rank in the United States

	Total Minable Reserves (billion tons)	Recoverable by Underground Mining (million tons)
Bituminous Coal	229	182
Subbituminous Coal	168	108
Lignite	34	-
Anthracite	7	7

The total reported resources are four times higher than the demonstrated reserves, and subdivide:

750 billion tons bituminous coal
480 billion tons subbituminous coal
400 billion tons lignite

If mining depths to 6,000 ft are considered, another 390 billion tons are added to the estimates of minable reserves.

Table 1.2 shows the states with major estimated coal reserves:

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Table 1.2 States Having Largest Estimated Coal Reserves

State	Total Reserves (billion tons)	Coal Type
Alaska	130	mostly subbituminous
West:		
North Dakota	350	lignite
Montana	290	subbituminous and lignite
Wyoming	135	mostly subbituminous
Colorado	130	bituminous
New Mexico	60	mostly subbituminous
East:		
Illinois	145	bituminous
West Virginia	100	bituminous
Pennsylvania	60	bituminous and anthracite

1.2 Production

Reported coal production for 1980 is 832 million tons bituminous coals and lignite. The tonnage mined in underground operations was 337 million tons, surface operations produced 495 million tons. This represents an increase of 56 million tons over 1979, or 7.2 percent. About 70 percent of the coal presently mined comes from fields east of the Mississippi. The increase resulted from a higher consumption of coal by electric utilities and a high export demand for metallurgical and steam coal.

The trend in the coal industry is strongly towards increasing production, as depicted in Figure 1-2.

Coal production in 1980 was produced by 6,300 mine operations.[1] This number has remained constant since 1979. As will be shown in Section 2, approximately 85 groups of mining companies produced 72 percent of the 1980 total coal production.

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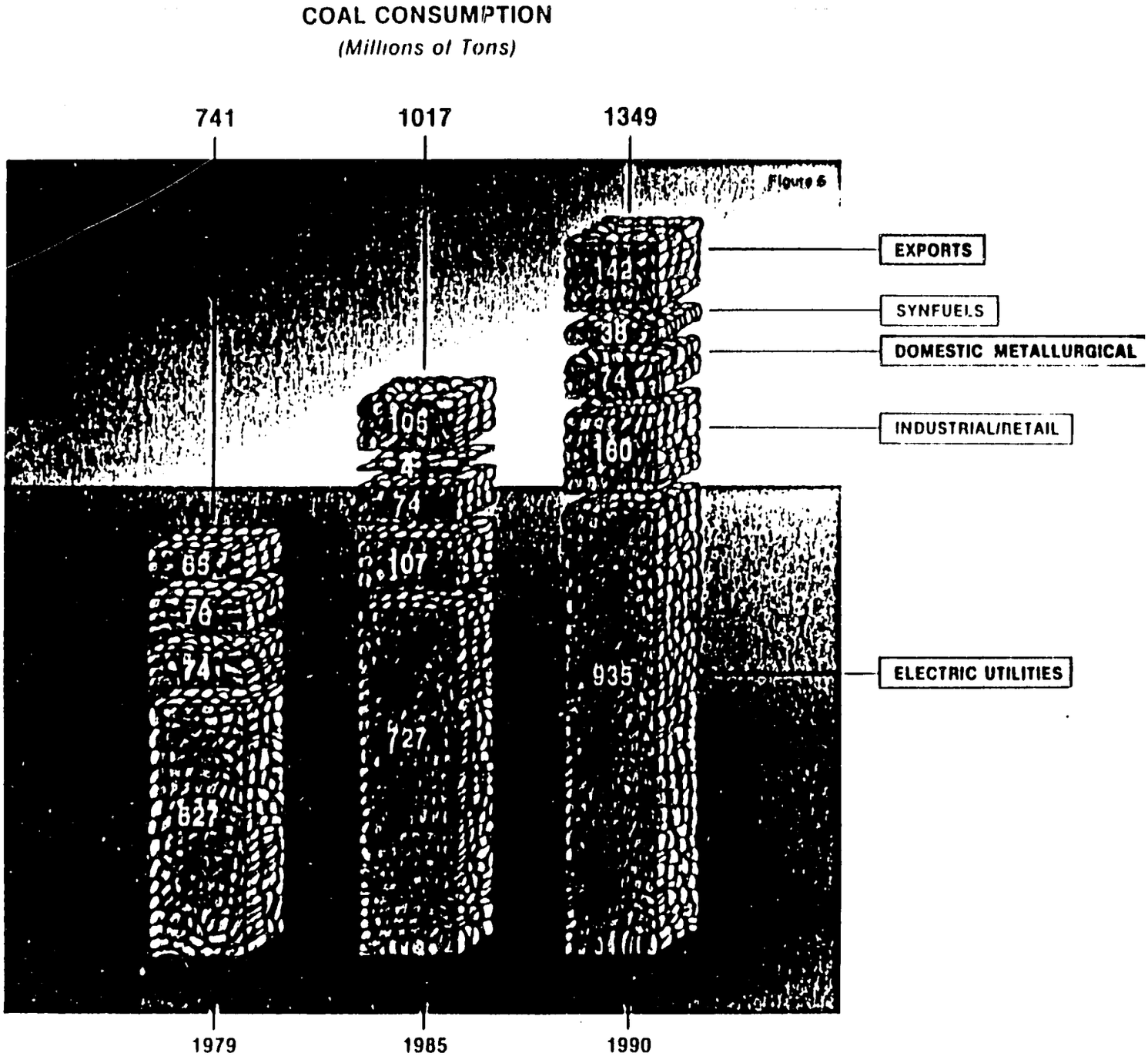
1) Source: DOE, Coal News March 23, 1981

Figure 1-2 NCA Forecast of Bituminous Coal and Lignite Consumption and Exports



The coal industry still has an overcapacity of approximately 100 million tons[2], and 20,000 miners are currently laid off or unemployed.

Productivity increased in 1980 by 1.6 tons per manday, or 11.2 percent[1] (underground from 7.9 tons to 9.0 tons, and surface from 24.8 tons to 27.75 tons, a total average from 13.5 tons to 15.09 tons). This trend reversed a declining productivity experienced during the 1970's.

1.3 Future Aspects

The National Coal Association (NCA) expects a slower growth rate of 2.3 percent in 1981, with a total production of 867 million tons. The relatively modest production growth is based on the fact that consuming industries have high inventories and it is expected that they will not be increased in 1981. The Department of Energy (DOE) estimates that an inventory of stocks at utilities, industrial plants, coke ovens, mine sites, lake docks, and export piers showed 203.8 million tons at the end of December 1980.

Higher oil prices last year spurred greater than expected domestic and foreign demands in U.S. coal which caused an increase of 7.2 percent in the 1980 production.

The demand figures for 1981 are expected to be as shown in Table 1.3.

NCA expects overseas demand for steam coal to rise, but that gain will be offset by reduced demands for metallurgical coal.

The inadequacies of the U.S. ports in handling coal exports held up overseas shipments in 1980 to some 9 million tons below potential levels, according to NCA sources. Improvements are not expected to have an effect before 1982.

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1) See footnote Page 5

2) In February 1981, a weekly production of 19.8 million tons was acheived.

Table 1.3 Projected Coal Demand in 1981

	Million Tons	Increase over 1979 Percent
Utilities	540	5.3
Industries and Retail	73	3.9
Steel Industry	68	3.0
Export	79	3.9
Total Demand	760	4.8

As Figure 1-2 shows, the coal demand within the next four years will increase to 1,017 million tons, or 258 million tons over the estimated demand of 1981, i.e., an average increase of 64 million tons or 8.4 percent per year. Until the end of the decade a demand of 1,349 million tons is anticipated, or another increase of 332 million tons over a five-year period, i.e., an unchanged linear increase of 65 millions per year. These figures include a demand for 4 million tons of coal for synfuels by 1985, which is expected to increase to 38 million tons by 1990.

It can be concluded that there is no strong interdependency between the oil and coal market. There are capacities and capabilities within the coal industry for meeting the demand. A substitution of major amounts of oil will impose enormous strains to obtain the necessary capital and to build up the engineering and construction base for a large-scale synfuels industry, which may be beyond present capabilities, even for the United States. On the other hand, the export coal market will persist in a competitive international climate because major reserves are being developed in other industrial countries like Canada, South Africa, and Australia to supply international demand.

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3. MINING TECHNIQUES IN THE U.S.A.

3.1 Surface Mining

Fifty-nine percent of total coal production is mined by surface mining methods - in 1980, this amounted to 498 million tons. In the future, the ratio surface to underground mining will continue on that level. That means, the incremental tonnage will increase more in surface mines, especially in the west.

3.1.1 Mining Methods in the East and West

The topography in the east and in the Appalachian region shows a hilly land with steep valleys. In these areas, contour mining is applicable, either by following outcrops of the seams around the hills or by chopping the crests of the hills and mining the underlaying coal. In many cases, contour mining is extended by coal augering for distances up to 300 ft length into the hillsides. The overburden has to be drilled and blasted. The overburden to coal ratio is generally limited to 1:20 by economic considerations.

The mining equipment consists of mobile drill rigs for depths up to 300 ft and diameters in the range up to 12 inches. The loosened rock is removed by draglines and shovels; the surface of the coal seams is cleaned by front-end loaders and scrapers. The coal is either blasted separately or directly loaded with similar equipment. Coal transportation is by trucks of up to 120 tons capacity. Because of incrasing fuel expenses, belt conveying is being increasingly investigated.

Plates 1 to 4 show surface mining operations in Alabama and Pennsylvania. Plate 4 shows a 36 cu.yd dragline with a 300-ft boom opening a syncline in an anthracite mine.

The reclamations require restoring the previous contours in the mined areas. Strict regulations govern lowering of groundwater levels and the discharge of contaminated mine waters into public creeks or other drainage systems.

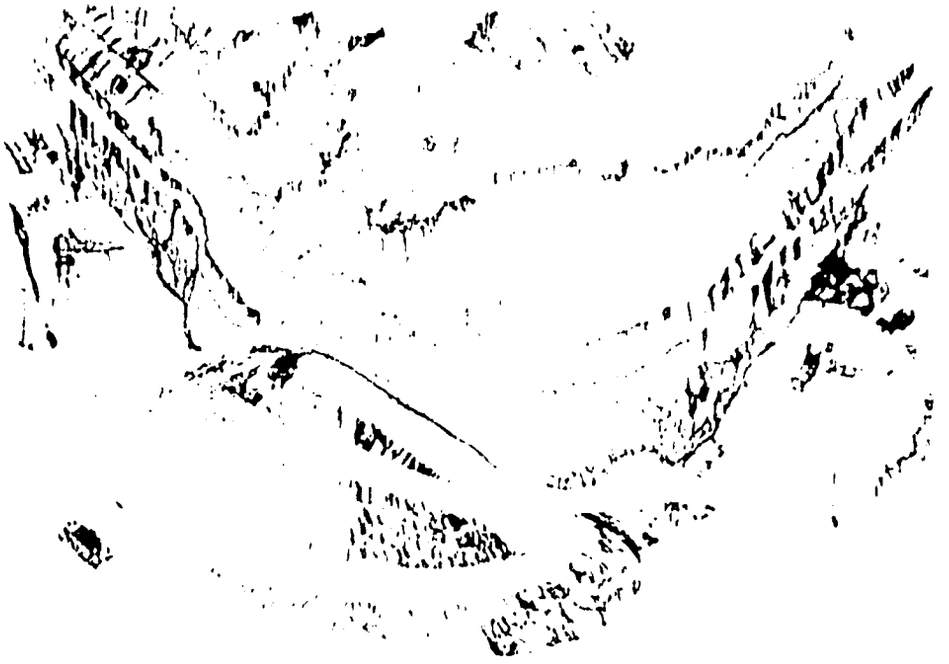

Plate 1

Artist sketch - Contour mining in the Appalachian region

Plate 2

Surface mining in Warrier coalfield in Alabama, 15 cyd dragline, front-end loader, and trucks

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Plate 3 - High wall in a surface mine in Alabama. At the bottom, two high-quality coal seams with thicknesses of 3 to 4 feet

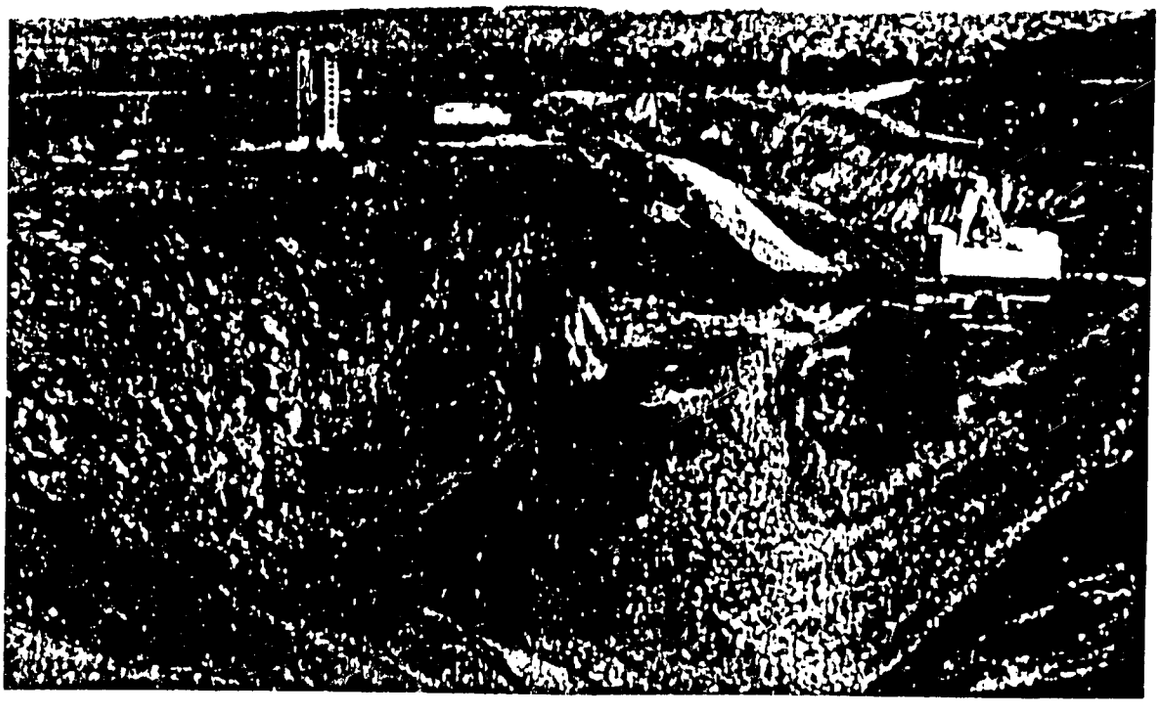


Plate 4 - Surface-mining operation at an anthracite syncline in Pennsylvania

Because of these regulations, the trend in the east is towards more underground operations.

In areas with flater topography, i.e., in the Interior Coal Basin (West Kentucky, Illinois, and Ohio) regular open-cut mining is used, employing drill rigs, draglines, and shovel excavators combined with truck fleets for transportation. The capacity of the mines is usually greater than those of the Appalachian region (up to 6 million tons a year in Ohio) and reclamation is easier.

Surface mining methods in the western United States differ from those in the traditional coal districts in the east more by size than by methods. All newer mines try to achieve "economy of scale" by applying larger equipment: draglines, shovels, and trucks. In order to achieve greater depths in surface mines (if this is desirable) or to improve reclamation results, many companies investigate use of conveyors or bucketwheel excavators. Reluctance to deviate from conventional methods, however, is great.

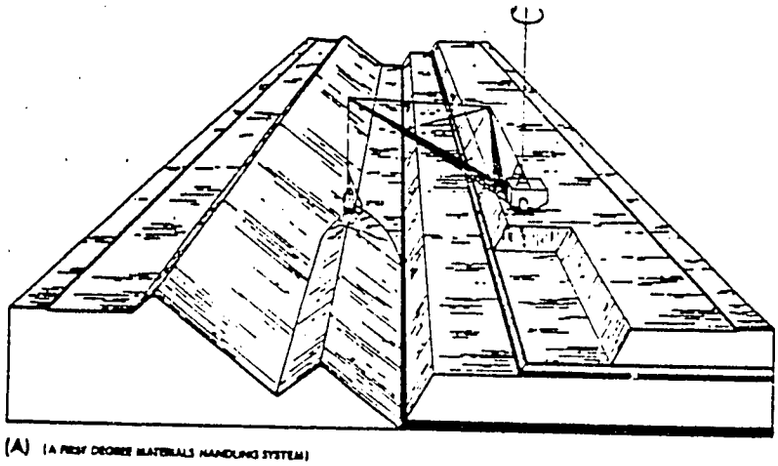
Because of excellent overburden to coal ratios from 0.5:1 to 3:1 and capacities of up to 20 million tons a year, surface mines in the west produce at lower costs. This is very necessary because of lower coal quality and greater distances to the coal consumers.

In the southern lignite belt mainly mine-mouth operations combined with power plants are economically feasible.

Plates 5 and 6 show conventional dragline operation and subsequent reclamation in the west.

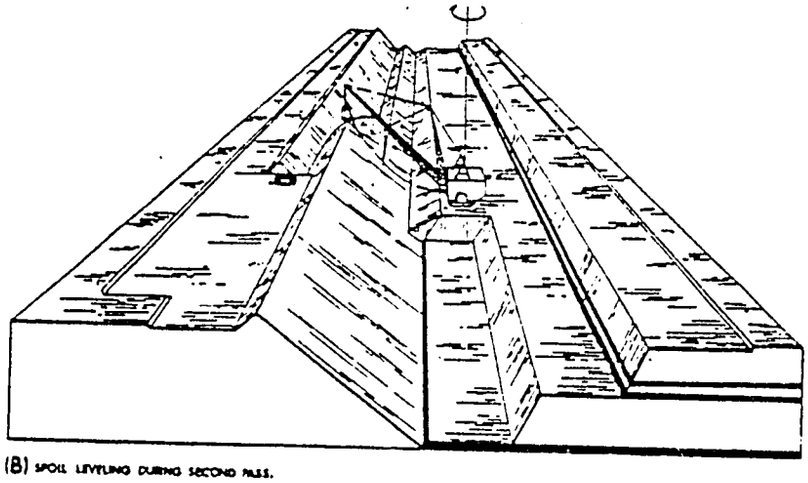
.1.2 Influence of Legislation and Licensing

To obtain a mining permit in the western United States may take as long as seven years or more. There is hesitation by states like Montana and Wyoming with small population to allow rapid development detrimental to the interests of their citizens. Also, federal ownership of mineral rights has to be taken into consideration. There is hardly any reasonably large lease available of



(A) (A FIRST DEGREE MATERIALS HANDLING SYSTEM)

CONVENTIONAL DRAGLINE STRIPPING AFTER TOPSOIL REMOVED-FIRST PASS



(B) SPOIL LEVELING DURING SECOND PASS.

CONVENTIONAL DRAGLINE STRIPPING-SECOND PASS

Plate 5

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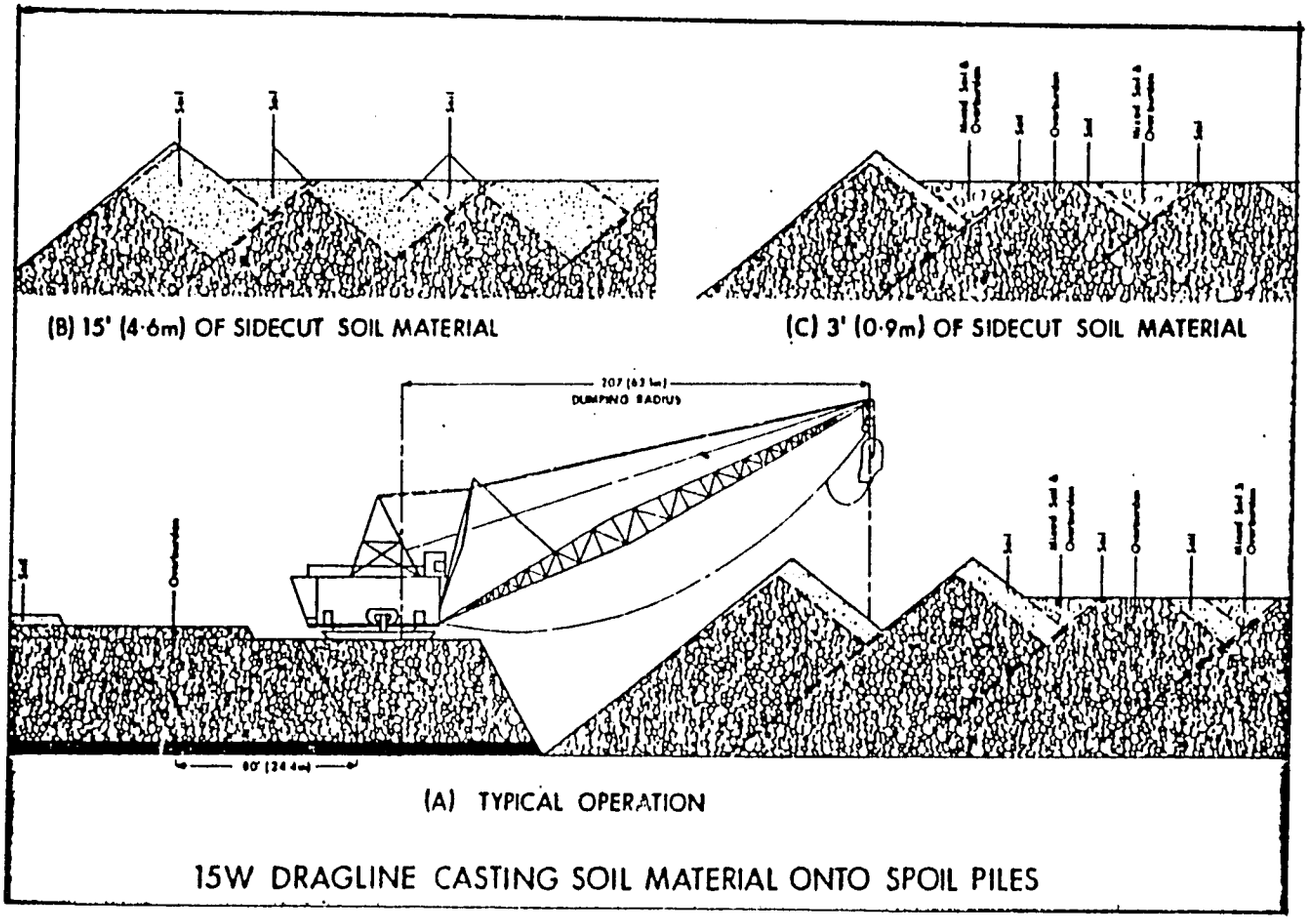

15W DRAGLINE CASTING SOIL MATERIAL ONTO SPOIL PILES

Plate 6

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which the Federal Government does not hold a section. Thus, government leasing policy is the decisive factor in Montana and Wyoming. Typically, an environmental impact statement has to be prepared first (Bureau of Land Management) after which the U.S. Geological Survey determines where mining should logically start first.

Amazing as it may sound, these two permitting activities alone usually take about four years.

Only then - and after both studies have been accepted - will the federal lease tract be offered to the highest bidding coal company which then has to submit its own mine plans for evaluation and approval.

Besides federal ownership of land and mineral rights, the railroads hold vast reserves. Historically, as an incentive for construction of railroads into the west, railroad companies were given a checkerboard of square-mile-size areas left and right of the railroad line. These included mineral rights. Later on, and after thorough exploration, the railroad companies then exchanged their properties with the aim to consolidate their mineral holdings. Though prevented from mining by law, coal companies have to deal with the railroad companies to obtain subleases (see ownership indicated on previous tables and figures.

A distinctly different situation prevails in North Dakota. North Dakota is primarily farm land, settled by so-called homesteaders in the 19th century. A homestead is a certain area of land on which the settler tried to develop a farm. Initially, homesteads included mineral rights; only at a very much later date were mineral rights separated from surface rights.

Any mining company trying to assemble enough reserves for a reasonable production therefore has to deal with stubborn farmers and shrewd railroad companies.

In the Gulf Coast states (Texas, Arkansas, Louisiana, Mississippi) private ownership prevails everywhere. In many in-

stances, however, mineral rights and surface rights are separated or it is unclear whether they are separated or not. Coal companies often complain about the insecure situation, and long-lasting litigation is the result. As compared with the states of Wyoming, Montana, and North Dakota, the chances for fast processing of mine permits are generally much better.

3.1.3 Equipment and Capacities

For overburden removal, draglines and shovels are employed with bucket sizes of 7.5 to 85 cyd. The boom length varies between 50 and 350 ft (15 to 105 m). Smaller draglines and most of the shovels are on chain tracks, larger draglines operate on a walking system. Larger shovels and dragline have loading capacities up to 10,000 tons/h (compared to bucketwheel excavators in West Germany of 25,000 tons/h.

Overlaying hard rock is mainly drilled by using rotary downhole drill rigs mounted on self-propelling chassis either on chains or on wheels. Capacities of drill rigs are up to 12-inch diameter and 350 ft (105 m) depth.

For overburden and coal transportation, trucks are used with loading capacities from 50 to 350 tons (50 to 120 tons in the Appalachian region, higher capacities in the Interior Basin and in the west).

Front-end loaders are employed for coal loading or in larger mines as auxiliary loading units.

For cleaning of coal-seam surfaces, graders and dozers are used, equipment which is also mainly employed for reclamation.

3.1.4 Reclamation

Reclamation requirements are now a firm part of any mining permit (since 1977). As so often in government policies, reaction to exploitation of mineral wealth by ruthless coal companies in the last century and during the first 50 years of this century was exaggerated and sometimes illogical.

Reference is made to the requirement that a piece of land has to be reclaimed within six months after mining or a penalty must be paid for each month elapsing until reclamation is achieved. This rule disregards greater time spans that inevitably will elapse if larger mines need a wider opening.

On the other hand, stringent legislation was urgently needed and has slowly made coal companies reclamation conscious. Nowadays, up to $5000 can be spent for reclamation of one acre of farm land.

Resettlement of villages, farms, and relocation of roads, power lines or other surface obstacles is very difficult, if it is at all possible. Speculation often leads to outrageous costs, since the coal companies are not aided by any rights of expropriation.

3.2 Underground Mining

In 1980, 40.5 percent or 337 million tons of the U.S. coal production was derived from underground mining. Most of this coal was mined in West Virginia, Kentucky, Pennsylvania, Virginia, Illinois, Utah and Alabama.

Depending on mine access, there are three basic types of mines:

- Drift mines: Where coal seams outcrop above drainage or the water table, the mine is developed from the outcrop by multiple-entry systems following the seam (Plate 7).

- Slope Mines: Coal seams below drainage but within a reasonable distance from surface are opened by inclines or slopes.

- Shaft mines: Deeper coal seams are reached by shafts.

Due to geological and topographical conditions, most U.S. mines are drift mines, slope mines or combinations of slope/shaft mines.

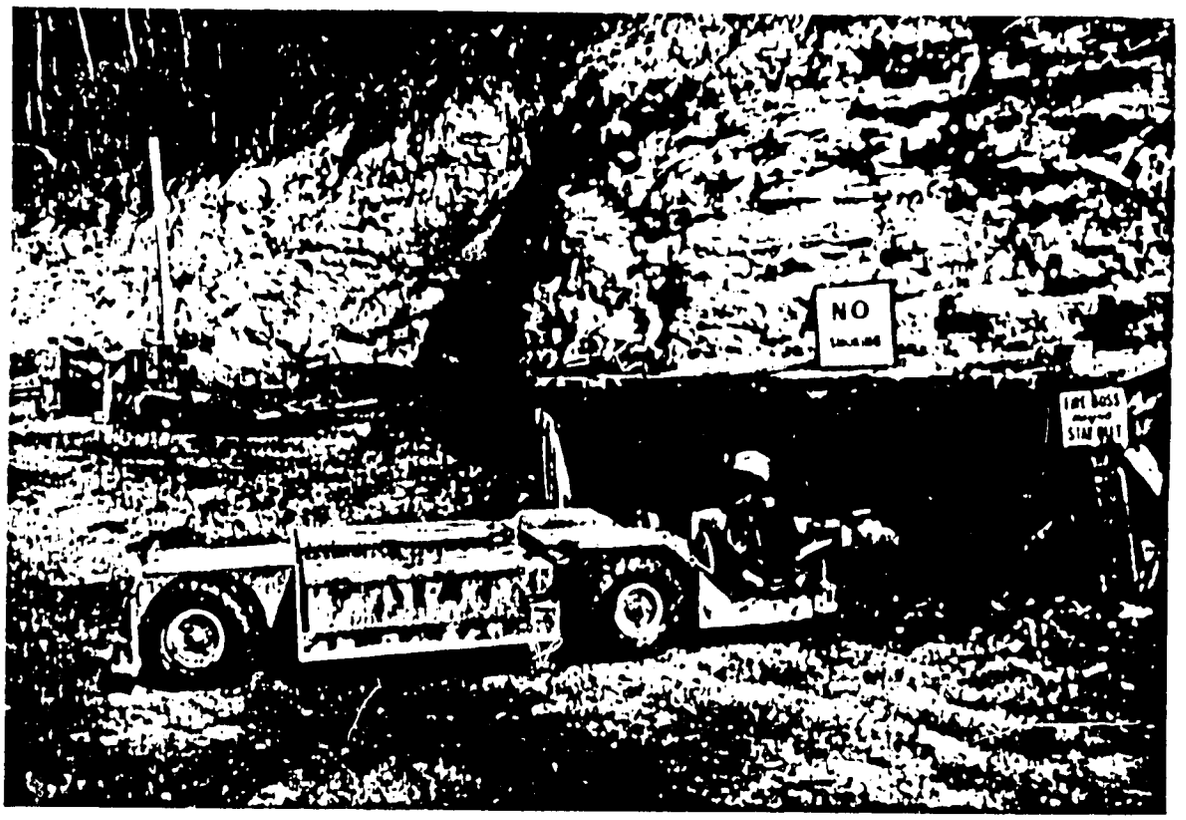


Plate 7 - Drift Mine in East Kentucky

3.2.1 Mining Methods

Room and pillar methods are predominantly used with minor variations due to mining conditions. They account for approximately 95 percent of underground production.

Depending on mine size, mines are developed by main entries or mains in sets of four to sixteen parallel entries, each interconnected every 50 to 100 ft. by crosscuts. Submains, which originate from the mains, divide the mining area into larger blocks, which, again, become subdivided into panels. Panels are penetrated by multiple-entry systems and remaining coal pillars are finally recovered as far as possible by retreat mining (Plate 8).

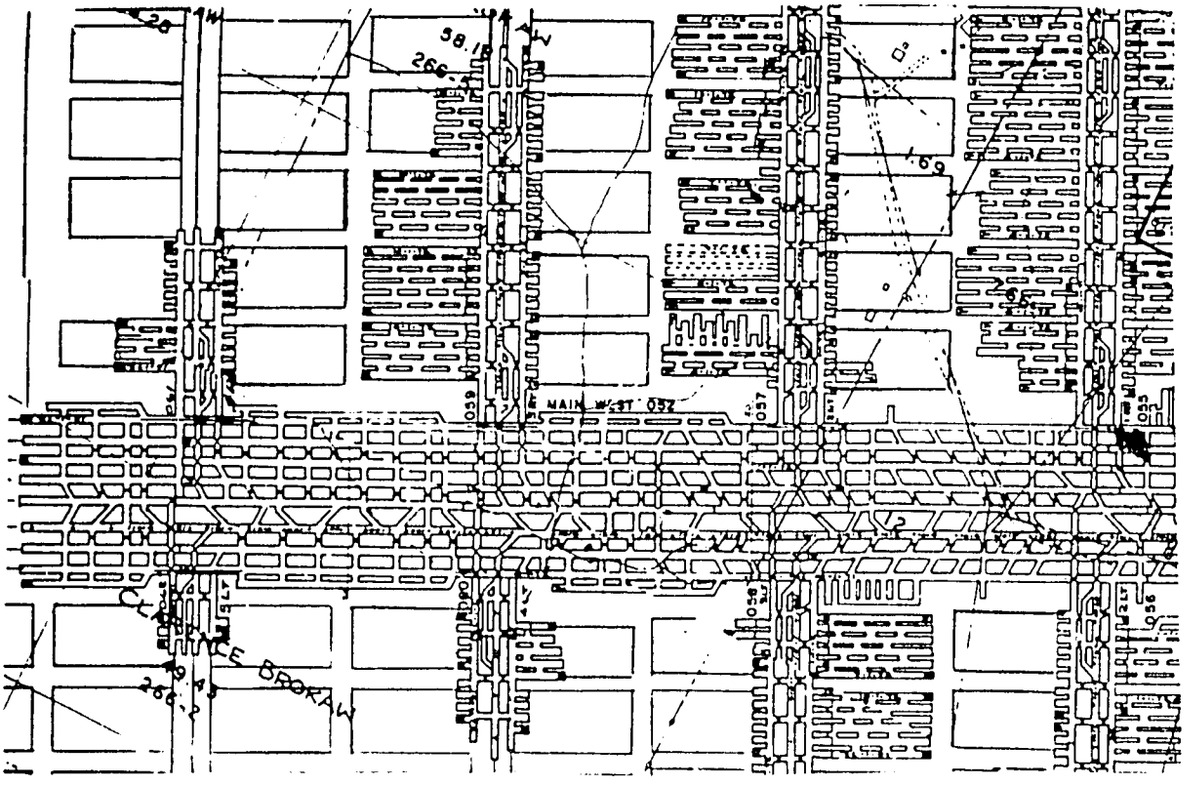


Plate 8 - Mine Layout Room and Pillar Mining

All entries remain, as far as possible, within the seam in order to avoid out-of-seam dilution and slower rates of advance. Cross-sections necessary for ventilation are achieved by driving a greater number of parallel entries. The principle of restricting entry heights to the seam thickness is applied in smaller mines down to seam heights of 30 inches. Only in larger mines, using track haulage, is the minimum height for locomotives and mine cars established in low seams by taking floor and/or roof strata. There are, however, many seams where the direct floor and roof layers are so weak that they have to be mined together with the coal.

Since roofbolting is sufficient for roof control in nearly all U.S. mines, driving of multiple-entry systems is the most economical method of mine development and simultaneous coal winning.

The individual tasks of drilling/blasting, loading or cutting/loading and roof bolting can be performed simultaneously in separate entries, resulting in a high utilization of the equipment and a nearly permanent flow of coal (see Section 3.2.2). Productivity is only higher in repillaring workings and longwall operations.

This is in sharp contrast to European single-entry headings where high overburden and rock pressure, unfavorable geological conditions, etc. render multiple-entry systems in coal seams unfeasible and dangerous (coal bumps, ventilation aspects, etc.). However, U.S. mining legislation makes multiple-entry systems mandatory and requires three to four separate entries for ventilation, escapeways and belt conveyors. Typical main entries, therefore, might have four to six entries for intake air and escapeways, four to six entries for return air, one entry (intake air) for track haulage using trolley wire, one separately ventilated entry for belt conveyors and several entries for return air from mined-out gob areas. The legislation allows overcasts (air crossings), air dividers within one entry and brick walls in crosscuts, which do not have to be explosion-proof.

In summary, multiple-entry headings and room-and-pillar methods have to be considered as very successful, flexible and productive under prevailing geological conditions of the U.S. Disadvantages are a recovery of only 55 to 90 percent of coal reserves - with 70 percent being a good average - and a lower daily production per section compared to good longwall operations.

Therefore, longwall mining is the second most important mining method in the U.S. Although approximately 100 longwall faces provide only for five percent of the underground production, the number of longwalls is increasing slowly. This is mainly

due to higher productivity, better roof control and recovery. Besides this, longwalls are becoming favored in larger mines, i.e., in mines producing between 1.5 and 3.6 million tons raw per year. Since the room-and-pillar method requires for this production operation more than 15 continuous miners, infrastructure and ventilation problems occur. They can be reduced by operating one to two longwall faces which normally yield a higher production per unit.

For legal and economical reasons, all U.S. longwall faces, except three, are retreating longwalls operated between multiple-entry systems (Plate 9 and Plate 10). Typical panel lengths are 3,500 to 5,000 feet, face lengths vary between 400 and 600 feet.

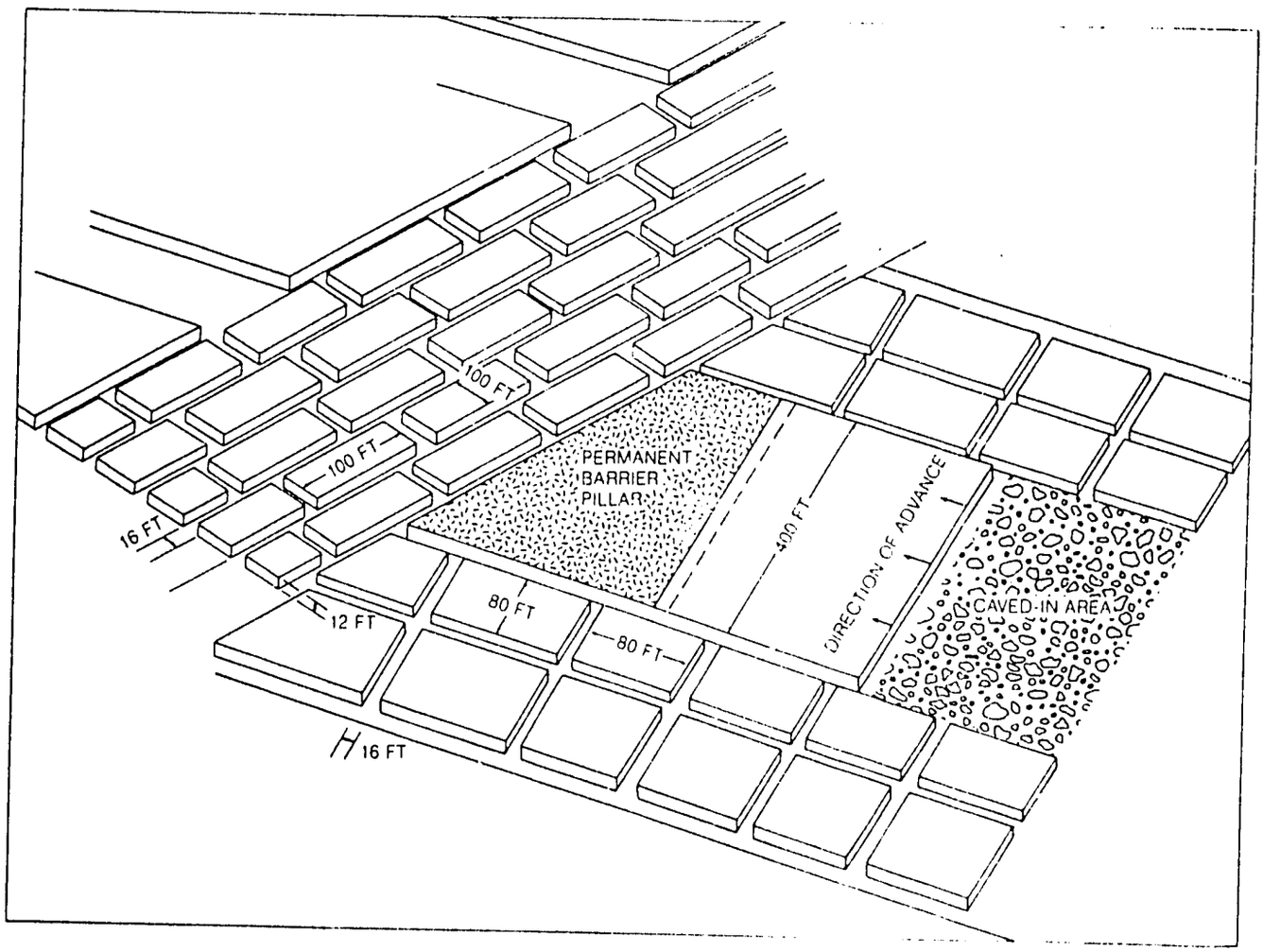


Plate 9 - Layout Longwall Panel

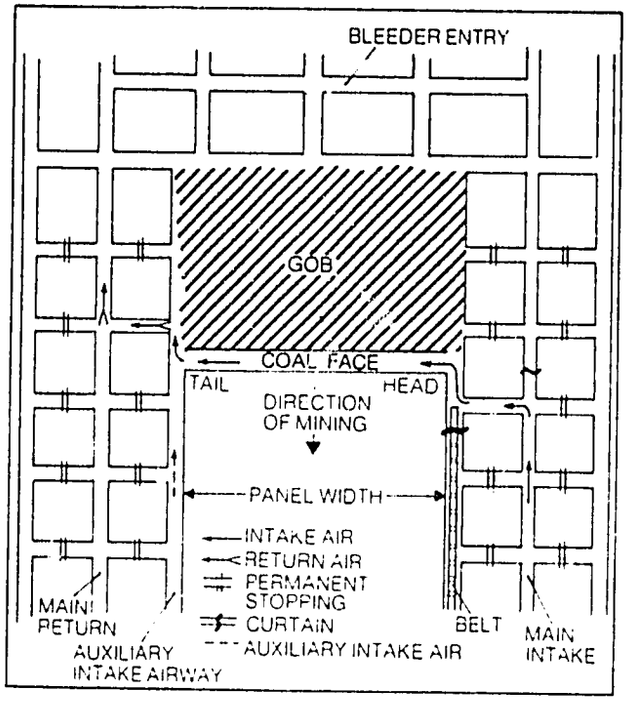


Plate 10 - Layout Longwall Panel

Several reasons explain the slow growth of longwall application:

- absence of stringent necessity as in Europe,
- less flexibility in reference to local changes in coal quality and seam height, oil and gas wells within mining properties, etc.,
- higher capital investment per unit which only larger companies are able to afford,
- subsidence unavoidable, whereas pillar recovery can be tailored to local requirements.

Although several records have been established by U.S. longwalls, the average operation shows poorer results than German counterparts.

An often publicized variation of longwall mining is shortwall mining. This method uses modified longwall roof supports together with continuous miners and shuttle cars in a shortened longwall face. Various systems have shown some advantages and success, but for several reasons shortwall mining has found only marginal application.

Finally, hydraulic mining might be another mining method feasible for some U.S. coal deposits. A strong interest is shown in Canadian and other foreign operations, but currently only studies and evaluations are being done in the U.S.A.

3.2.2 Size of Mines, Equipment and Capacities

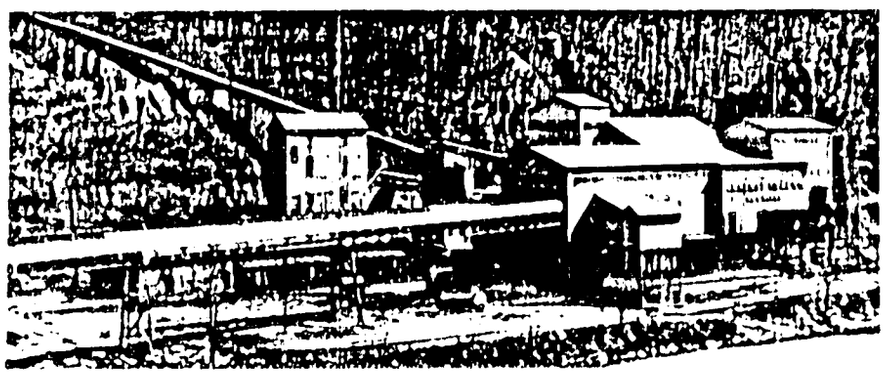
Although 50 percent of underground coal production is derived from mines with an annual capacity of more than 500,000 tons clean coal, typical U.S. mines, especially in the east, are very small compared to European standards. The majority of mines range between 10,000 and 50,000 tons per year.

This development is explained by the following:

- Geological conditions and topography enable mining operations above drainage or under locally shallow cover. This enables mine access at low costs.

- Since most seams outcrop in the neighboring valley or reach again shallow overburden, opening of new mines is necessary or more economical.

- Size of individual mining areas is restricted and narrow valleys cannot accommodate large mines and surface facilities (Plate 11).



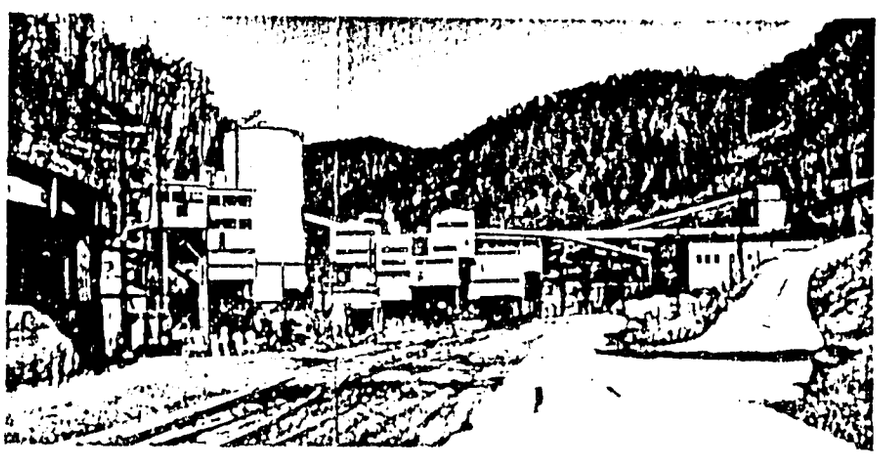


Plate II - Surface Facilities in West Virginia

These geological conditions, prevailing in the east and some parts of the west, favor smaller mines and enable several thousand small operators and contractors to run viable mining operations. Their success is based on using only an absolute minimum of equipment, partly bought second-hand and rebuilt, installing only temporary and movable surface facilities, running family-type and non-union operations, entrepreneurial spirits, etc. (Plates 7, 12, 13, 14).

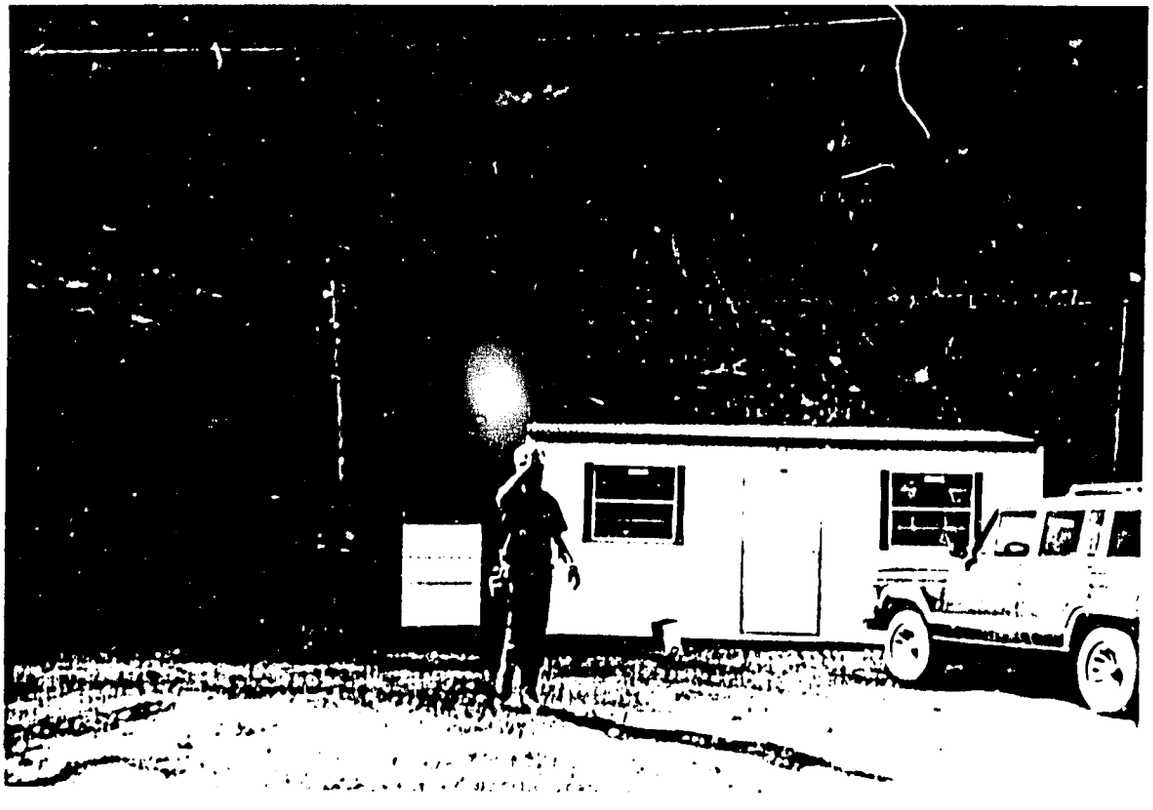


Plate 12 - Entry for a Drift Mine in East Kentucky
Lower Elkhorn Seam

Plate 13 - Coal Chute and Loading Point
Underground Slope Mine
in East Kentucky

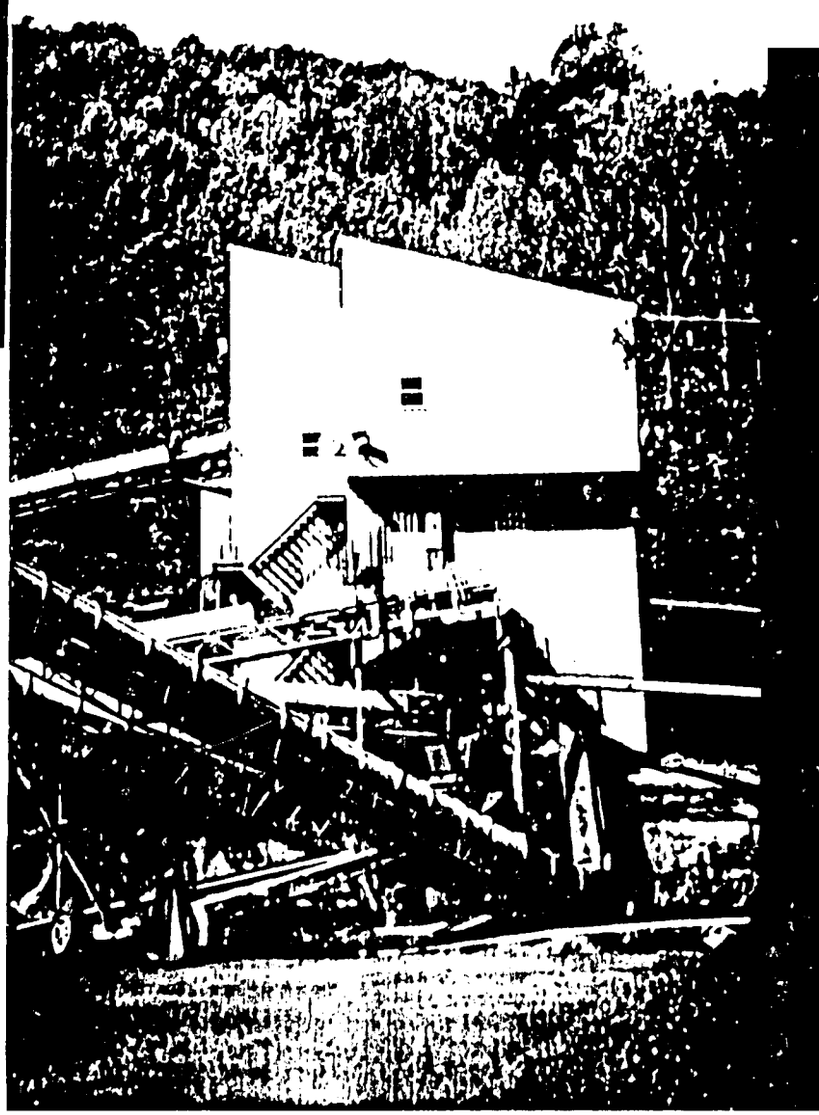


Plate 14 - Heavy Media Preparation Plant
250 tph
in West Virginia

Since small operators are very flexible, they are able to open and close their mines according to the market.

Mining under more unfavorable geological conditions, however, requires larger mines which are more prevalent in the newer projects.

In reference to mining equipment, two different methods of driving entries are used:

- Continuous mining, where drum-type or boring machines cut and load coal simultaneously (Plates 15 and 16);

- Conventional mining, where the coal is undercut, drilled and blasted, and subsequently loaded by different single-function machines.

Plate 15 - Continuous Miner

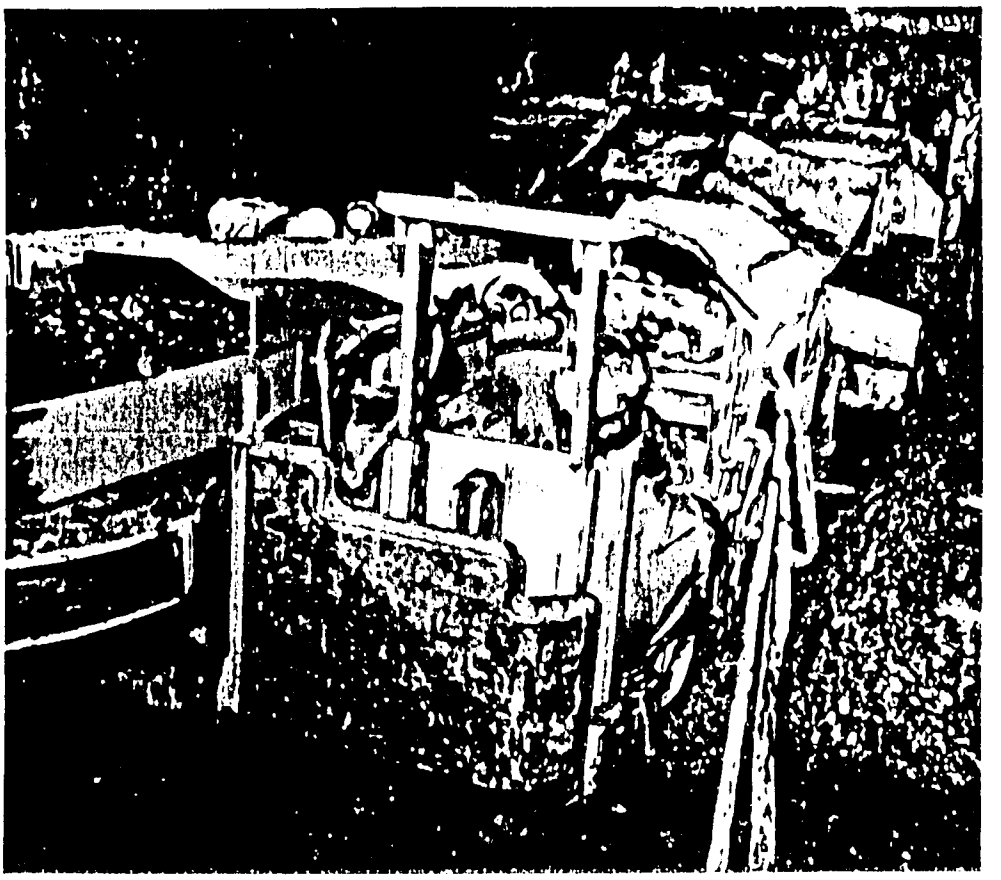


Plate 16 - Continuous Miner

For both methods coal is hauled by shuttle cars (Plate 17) to a belt conveyor or in some cases directly into mine cars. Roof bolters (Plate 18) are used for drilling holes and installing roof bolts. All units are arranged to operate simultaneously in adjacent faces.

About 3,500 continuous miners produce approximately two-thirds of the total underground production. They were first introduced in 1948 and, incorporating the undercutting, drilling, blasting and loading steps of conventional mining, they rapidly surpassed the conventional method. Continuous miners are easily maneuverable and, therefore, fit into the traditional system of moving from heading to heading.

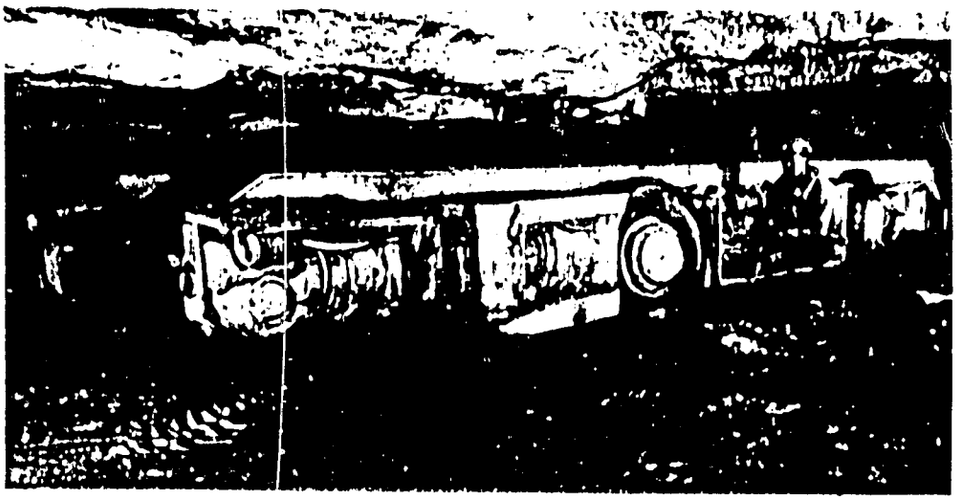


Plate 17 - Shuttle Car

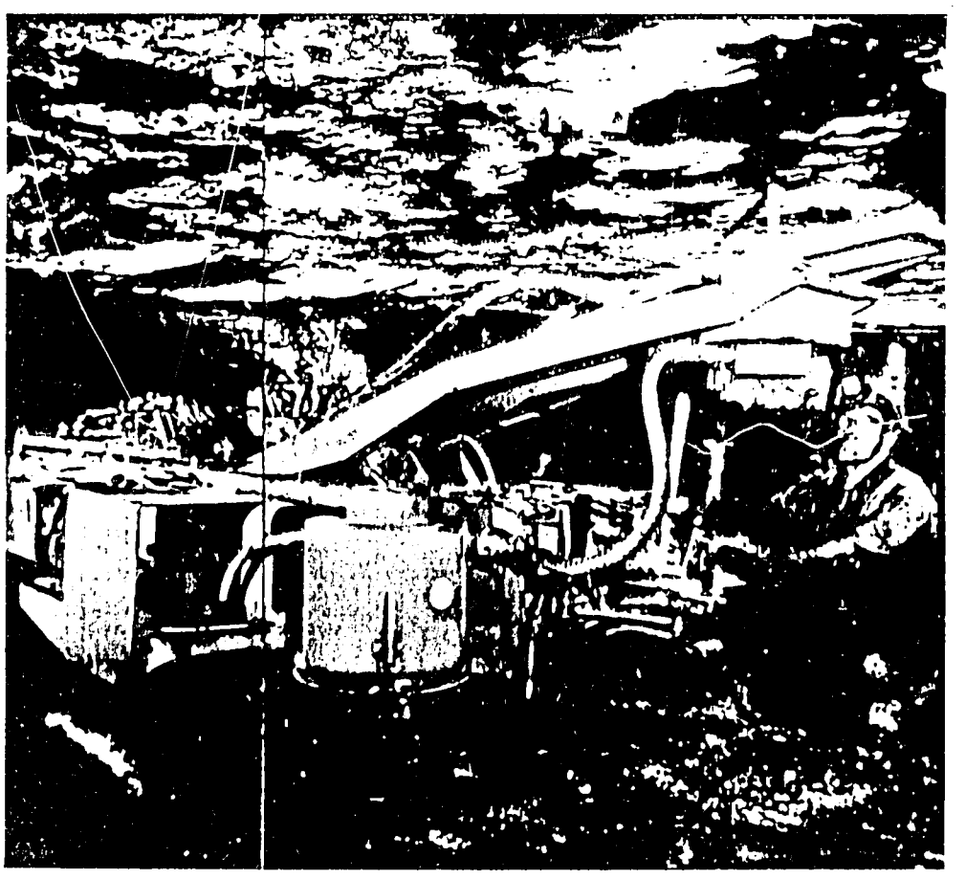


Plate 18 - Roof Bolter

Miner capacities are between 4 and 16 tons per minute, minimum/maximum heights between 28 inches and 13 feet.

Shuttle cars have capacities between 3 and 18 tons, with most of them in the range of 9 to 12 tons.

Although continuous mining has proved most successful under prevailing mining conditions, the conventinal method is expected to keep a good market share due to some specific advantages.

Equipment used in longwall operations is the same as in Europe except a higher roof support resistance is required in the United States. Drum shearers are the predominant winning machines.

Production statistics are only available for 1977. They show an average net output per unit per year as follows:

Conventional units	- 50,000 tons clean
Continuous miner units	- 64,000 tons clean
Longwall units	- 182,000 tons clean

Depending on many variables, the following output figures per unit shift can be expected:

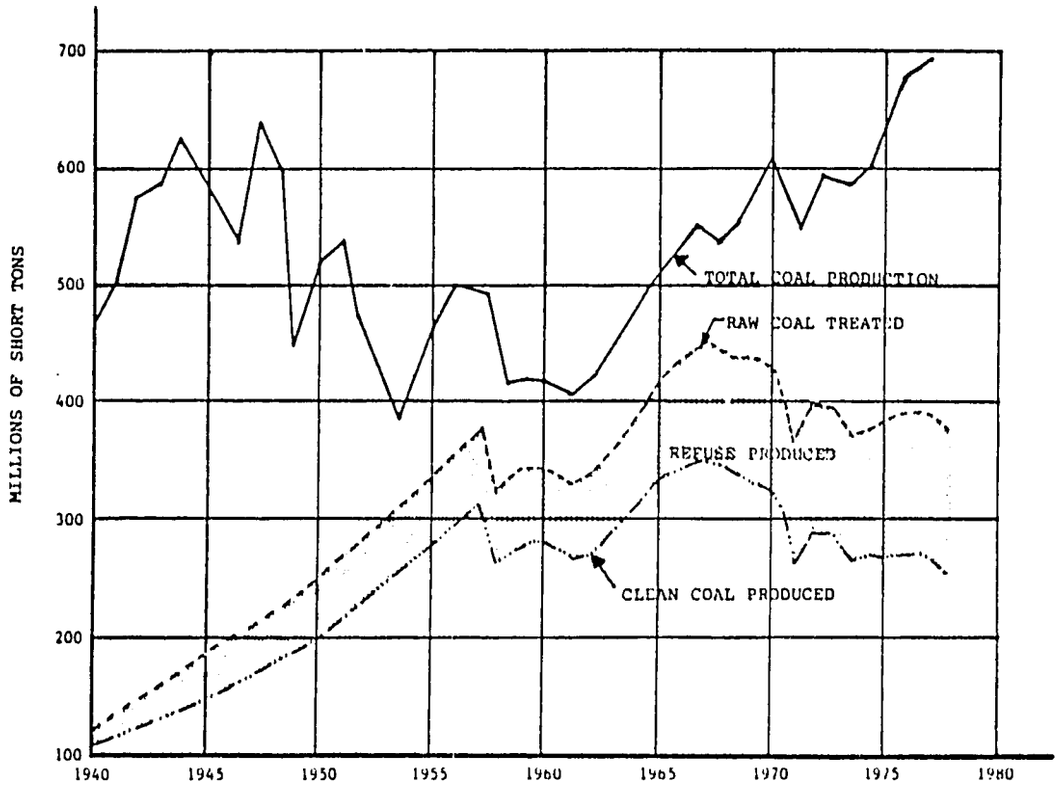
Conventional miner units	- 250 - 550 tons
Continuous miner units	- 300 - 650 tons
Longwall units	- 700 - 1500 tons

4. COAL PREPARATION AND BENEFICIATION

4.1 Range of Application in the U.S.A.

Coal cleaning in the United States is mainly a post-World War II development which achieved peak capacity in 1967. Since then it has declined substantially both as to the total tonnage of raw coal handled by treatment plants, and as to the yield of clean coal produced. The historical record is presented in Figure 14 for bituminous coals and lignites. Lignites are produced in the western states of Montana, North Dakota and Texas. While of rapidly growing importance to the national energy budget lignite production is still at comparatively low levels so that the picture presented in Figure 14 is essentially that of the bituminous industry. Not shown is anthracite; current production is about 6.5 million tons/year, which contains a very small proportion (less than 0.2 million tons/year) of coal recovered by dredging. The remainder, freshly mined, is all washed and sized for its special markets. Small though the industry may be, it has played an important part over the years in the development of efficient coal preparation systems.

The structure of the coal preparation industry is currently changing to meet the overall change in demand and market requirements faced by it. Traditionally, the industry is a mine-mouth activity preparing bituminous coals and anthracites mined by underground methods. It has not been customary to wash subbituminous coals or lignites, although this practice may change in the future and, already, one of the biggest coal preparation plants in the west is cleaning subbituminous coal. In 1977, there were approximately 5,100 mines in operation, but only 418 cleaning plants. The geographical distribution of these plants is as shown in Table 4.1. The plants are thus seen to be preponderantly in Appalachia where the mine capacities are generally smaller. The future growth of



B A S F

Fig. 14 United States Production of Bituminous Coal and Lignites

NJ-1028

NORTH AMERICAN MINING CONSULTANTS, INC.

Table 4.1 Distribution of Coal Cleaning Plants by State

State	1977
Alabama	29
Alaska	1
Arkansas	2
Colorado	4
Illinois	37
Indiana	14
Iowa	1
Kansas	2
Kentucky	64
Maryland	1
Missouri	3
New Mexico	1
Ohio	18
Oklahoma	5
Pennsylvania	66
Tennessee	2
Texas	1
Utah	6
Virginia	24
Washington	2
West Virginia	135
Wyoming	-
Other States	-
Total U.S.	418

coal cleaning is highly geared to future electric utility requirements. A 1000 MWe generating station burning bituminous coal requires about 12,600 tons/day over a five-day week while coal conversion plants producing 50,000 barrels/day of synthetic liquids could require up to 25,000 tons/day. Inspection of the sizes of cleaning plants presented in Table 4.2 shows that only 20 percent of present plant could individually support power-generating plant of this size, which are not large by present standards and less than five produce 20,000 tons/day.

Table 4.2 Distribution of Coal-Cleaning Plants by Daily Capacity

Plant Capacity tons/day	No.
> 20,000	4
12,000 - 20,000	80
10,000 - 12,000	90
5,000 - 10,000	60
- 5,000	184
Total	418

Unless a move to larger coal-cleaning plant occurs in the future, these facilities will be required to take coal supplies from a multiplicity of sources, a situation already common in the eastern states. The logistics of large central coal preparation plants handling raw coal outputs from a number of mines within their catchment areas versus a larger number of small self-contained mine-mouth plants is an important consideration in deriving future estimates of the delivered cost of clean coal.

The National Energy Plan requires that coal production increases from its present level (830 million tons in 1980) to 1.0 - 1.2 billion tons by 1985 and to 1.5 billion tons (1.1 - 1.85 range) by 1990. Estimates of future demand are shown in Table 4.3.

Table 4.3 Estimates of Future Demand for Bituminous Coal Production

		East of Mississippi	West of Mississippi	Total
1979		551,340,000	220,500,000	771,840,000
			(million tons)	
1985	Low	610	380	990
	Medium	644	472	1,116
	High	668	520	1,118
1990	Low	660	454	1,114
	Medium	758	763	1,521
	High	806	1,050	1,856

The figures imply production-rate increases of about 15 to 20 million tons/year in eastern coalfields and 25 to 60 million tons/year west of the Mississippi. Much of the increasing western production will be low sulfur subbituminous and lignite grades requiring a minimum of coal preparation. Presently, 37 percent of total production is cleaned by mechanical methods. However, if present trends of employing coal preparation for electric utility coal supplies are maintained in the future, it is expected that 70 to 75 percent of higher rank bituminous coals will require treatment so that the requirement for new plant capacity will be about 15 to 25 million tons of new capacity per year.

4.2 Preparation Methods

About 37 percent of current production is cleaned by mechanical methods. The range of cleaning options available are summarized in Figure 15. The types of mechanical cleaning systems utilized, together with their relative contributions towards the total cleaned coal are shown in Table 4.4. The trends illustrated indicate that jigs are the principal cleaning method, accounting for 45 to 50 percent of total clean coal. Dense medium systems produced 30 to 35 percent of the total, whereas the other systems commonly employed for cleaning coarse sizes viz. classifiers and launders have diminished in importance and now handle less than 3 percent of total output. Concentrating tables, which have always been more popular and more widely used in the United States than in all other countries, continue to make a substantial contribution to the total output of fine coal. Froth flotation, initially slow to be adopted, is now being more widely used and is producing around 5 percent of the total production. It may be noted that to a large degree the contribution made by froth flotation consists of fine coal formerly discarded to tailings ponds and its growth hence represents a significant improvement in recovery efficiency of the industry. Oil agglomeration, a technique

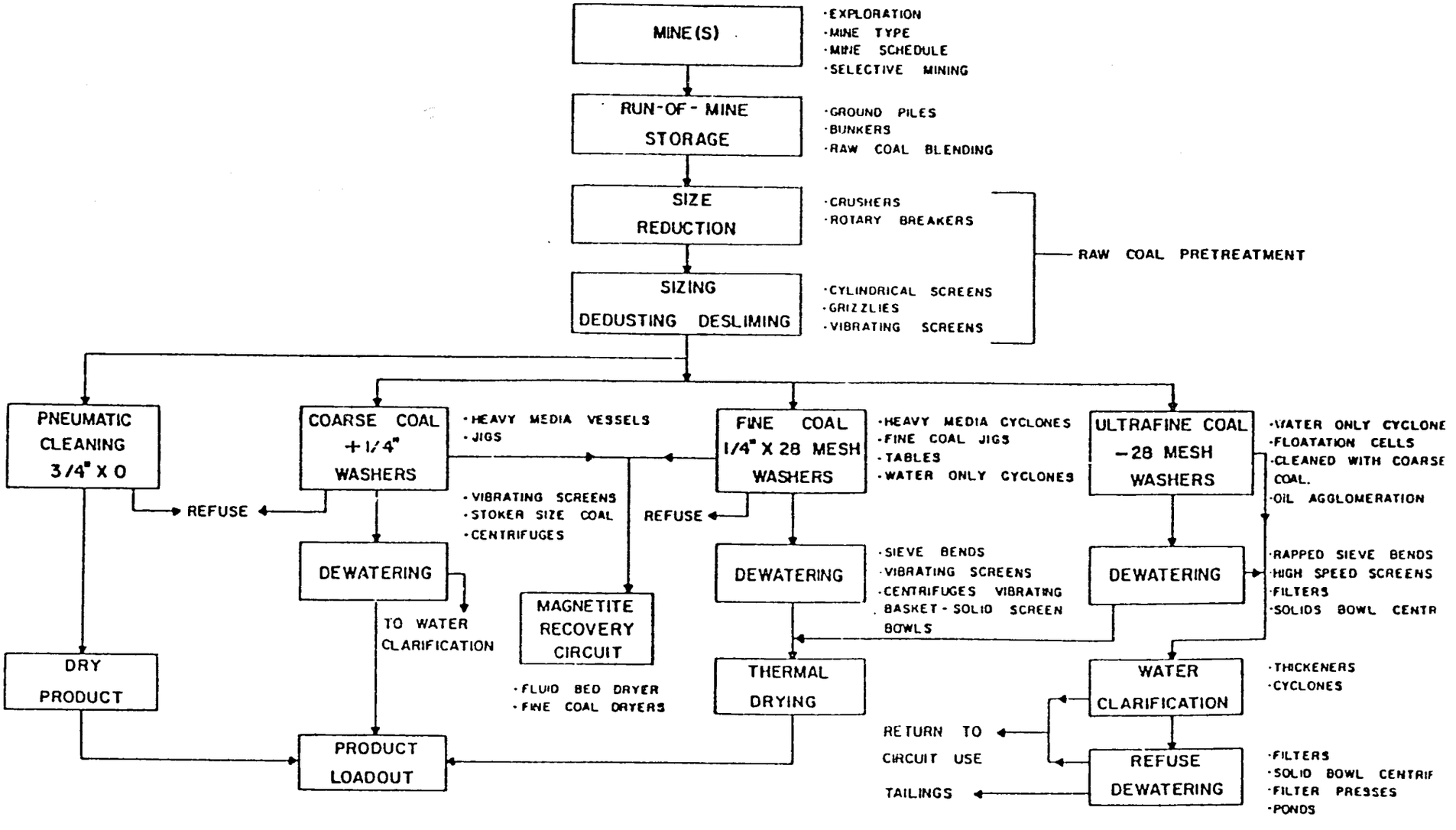


Fig. 15 GENERAL COAL PREPARATION PLANT FLOW SHEET

RANGE OF OPTIONS

Table 4.4 Mechanical Cleaning of Bituminous Coal in the United States 1960 - 1977

000's of tons

Year	BY WET METHODS							BY PNEUMATIC METHODS	TOTAL MECHANICALLY CLEANED
	Jigs	Concentrating Tables	Classifiers	Launders	Dense Media	Flotation	Total Wet		
1960	136,633	30,741	11,012	7,561	66,251	1,826	255,030	18,139	273,169
1961	133,360	30,158	9,263	6,529	65,148	2,567	247,020	17,691	264,711
1962	136,879	31,859	5,681	5,986	68,565	3,959	252,929	18,704	271,633
1963	142,540	37,492	5,558	5,221	74,177	4,539	269,527	19,935	289,462
1964	145,918	40,878	6,725	6,000	84,159	5,123	288,803	21,400	310,203
1965	151,541	43,197	5,844	4,801	94,636	6,853	306,872	25,384	332,256
1966	156,789	45,427	4,775	4,691	97,301	7,438	316,421	24,205	340,626
1967	161,302	49,529	3,902	4,627	101,043	7,732	328,135	21,268	349,402
1968	159,028	47,268	4,871	4,498	99,497	8,961	324,123	16,804	340,923
1969	155,027	45,328	3,401	4,644	97,636	9,560	315,596	19,163	334,761
1970	140,457	44,058	3,593	5,199	101,593	10,694	305,594	17,855	323,452
1971	115,407	35,656	2,071	4,896	89,764	9,098	256,892	14,506	271,401
1972	130,331	38,232	2,980	5,467	91,058	13,050	281,119	11,710	292,829
1973	132,655	34,935	3,297	5,121	88,203	14,201	278,413	10,505	288,918
1974	129,302	28,869	2,698	3,577	82,283	10,863	257,592	7,557	265,150
1975	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	260,300	6,700	267,000
1976	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	262,413	6,419	268,830
1977	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	249,447	4,469	253,917

first developed in 1914, has recently been reintroduced for recovery and cleaning of fine coals. Its use is expected to increase for certain special situations. Finally, it should be noted that the use of pneumatic cleaning has declined considerably, although recent developments in pneumatic and other dry-cleaning devices may act to reverse this trend in the future. Other changes that might be expected include the replacement of some heavy media systems by the newer generation of high efficiency jigs, and the further replacement of heavy media vessels by heavy media cyclones. Wider use of water-only cyclones, particularly of the compound type, may replace some capacity presently provided by feldspar jigs and concentrating tables.

4.3 Equipment and Capacities

The principal types of equipment employed are listed in Table 4.5 together with typical ranges of coal sizes handled and upper limits of machine capacities. All the equipment is readily available from American manufacturers.

4.4 Refuse and Tailings Disposal

The quantities of refuse and tailings requiring disposal are shown in Figure 16, current tonnages being about 76,000,000 tons/year. Federal and states environmental regulations impose strict controls on the disposal of these quantities and also upon the discharges of water from coal preparation plants, settling ponds and lagoons. The practice of total recycle, nil-discharge of waters is being increasingly applied.

The range of options for the handling and disposal of refuse and tailings is summarized in Figure 16.

Table 4.5 Cleaning Equipment and Capacities

Equipment	Effective Size Range	Effective S.G. Range	Upper Machine Capacities (tons/h)
Coarse Coal:			
Jigs	8" x 0	1.45 - 2.00	1000
H.M. Vessels	6" x 0	1.30 - 2.00	1000
H.M. Cyclones	2" x 0	1.30 - 2.00	100
Fine Coal:			
Feldspar Jigs	3/4" - 48 mesh	1.45 - 2.00	100
Batac Jigs	1/2" - 48 mesh	1.45 - 2.00	700
Spirals	4" - 200 mesh	1.30 - 1.90	120
Compound Water Cyclone	2" - 150 mesh	1.30 - 1.90	65
H.M. Cyclone	1/4" - 200 mesh	1.30 - 2.00	100
Froth Flotation	28 mesh x 0	-	120
Oil Agglomeration	100 mesh x 0	-	35

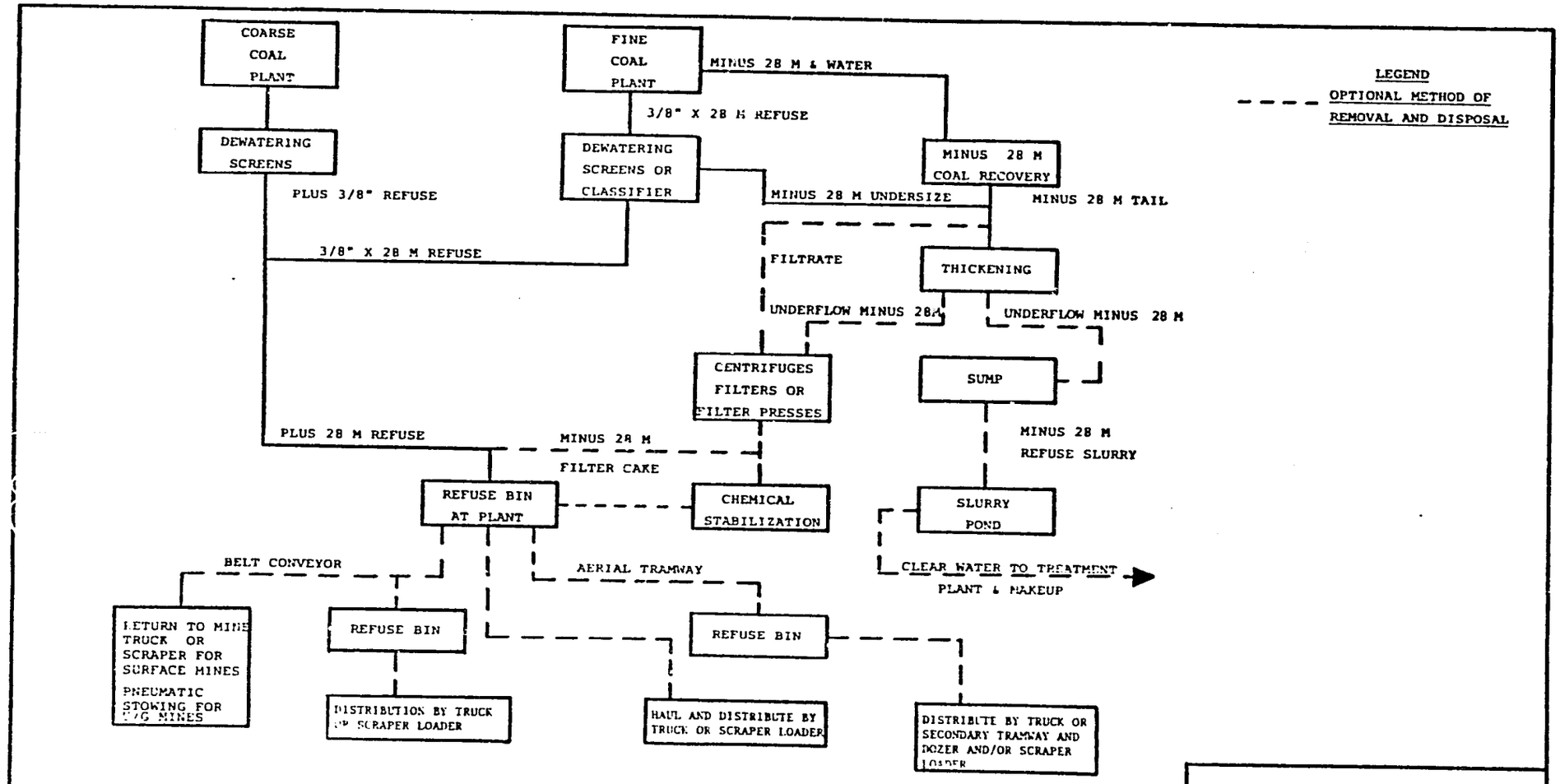


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Fig. 16 Refuse Handling and Disposal Range of Options

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5. ECONOMICS

5.1 Performance Rates

As mentioned in Section 1, the average performance rate in the United States coal industry was estimated at 15.00 tons per man per day in 1980, compared to only 13.5 tons in 1979, and showed the first upward trend after a decade of permanent decline.

5.1.1 Surface Mining

Performance rates in the east vary between 20 and 40 tons per man per day. In the west, these rates vary between 40 and 100 tons per man per day. Newly established mines range from 70 - 120 tons per man per day and even higher rates will be achieved once full production is reached. Gulf Coast lignite mines are generally lower due to greater effort required for overburden removal.

Differences between eastern and western operations are mainly caused by geological conditions and different mine sizes. Higher coal quality and shorter distances to consumers or export harbors, however, compensate lower eastern productivity.

The national average production per man per day in surface mining rose from 24.8 tons in 1979 to 27.75 in 1980 (estimate).

5.1.2 Deep Mining

Deep mining productivity suffered the biggest decrease during the past decade, during which it steadily fell from 15.61 tons per man per day in 1968 to 7.9 tons in 1979. Most significant losses occurred in the Illinois Basin followed by the Appalachian region and western states. Only Utah has been able to slightly improve productivity during this period.

300

The sharp decline of mining productivity has been attributed to more stringent regulations introduced with the Federal Coal Mine Health and Safety Act of 1969 and to unfavorable labor relations.

Since preliminary 1980 estimates of the national average now report 9.0 tons per man per day, the downward trend seems to have been reversed also in deep mining operations. An explanation may be found in improved operations and work habits but also in the fact that ailing coal markets closed down many marginal operations.

Average productivity for the major regions are 6 to 10 tons in the Appalachian region, 9 to 14 tons in the Illinois Basin, and 12 to 17 tons in western states.

5.2 Mine Production Costs

In surface mines, production costs are closely dependent on the overburden-to-coal ratio and the type of overlaying rock. Other major factors to be considered are the reclamation costs and environment protection measurements (groundwater, etc.). The price of coal in different areas is thus a good parameter on costs.

In the east, tonnage costs f.o.b. preparation plant or f.o.b. mine mouth vary betwen $15.00 and $20.00 for steam coal, some $5.00 more for metallurgical coal.

In the west, the coal prices for Wyoming range between $6.50 and $10.50 at mine mouth (March 1981). In Montana, somewhat less favored by nature than Wyoming, production cost mine mouth are between $12.00 and $15.00 per ton.

A number of studies conducted by NAMCO and discussions with leaseholders have established a certain price up to which

lignite can be profitably sold (without preparation) to utilities. At the present time, this is approximately $1.75 per million BTU. This upper price limit is almost exclusively dependent on prices charged for Power River Basin coal and its transportation by railroad. Competition from oil and gas is less influential because it is unlikely that newly built power stations will be allowed to use oil and gas.

Under favorable geological conditions, lignite in the southern lignite belt, which can be produced with a stripping ratio of 16:1 or less, can reach the above-mentioned price level.

As a result of a number of studies performed in the aforementioned states, production costs of $4.00 to $10.00 per ton of coal or lignite is to be expected. Costs are lowest in the Powder River Basin and in North Dakota, highest in the Gulf Coast States.

In underground mines, production costs are estimated to be in a range between $15.00 and $25.00 per ton raw coal or $20.00 to $35.00 on a clean coal basis. The lower rates are valid for drift mines with good roof conditions or longwalls with high performance rates. The higher rates are valid for less favorable operations or deep and gassy mines. The latter operations must produce higher quality coal.

5.3 Coal Preparation Costs

The costs of coal cleaning and preparation are determined by the depth of cleaning employed. The various levels of treatment commonly employed are summarized in Figure 17 and correspond to the range of available cleaning options shown in Table 5.1. Cleaning costs are also dependent upon the sizes of the coals treated, costs increasing sharply as the mean sizes of the particles decrease. These increased costs

Table 5.1 Levels of Coal Preparation

LEVEL & BRIEF DESIGNATION	SCOPE	YIELD WEIGHT %	RECOVERY BTU %	REDUCTION POTENTIAL ASH	REDUCTION POTENTIAL SULFUR	WORK DONE ON RAW COAL*	TYPICAL CIRCUITS & EQUIPMENT USED	REFUSE	COMMENTS
A ABSENCE	NO. PREP.	100	100	NONE		NONE-SHIP ROM COAL	NONE	NONE	NOT GENERAL PRACTICE
B BREAKING	TOP SIZE CONTROL ONLY	98-100	100	NONE TO MINOR	NONE	CRUSHING TO 3" OR LESS AT REMOVAL OF COARSE REFUSE	SCALPING SCREEN, CRUSHER, ROTARY BREAKER	DRY LUMPS & TRASH	GENERAL PRACTICE ON ALL ROM COALS
C COARSE	COARSE BENEFICIATION	75- 85	90-95	FAIR TO GOOD	NONE TO MINOR	LEVEL B FOLLOWED BY, DRY SCREEN AT 3/8" WET BENEFICIATE AT +3/8" ONLY. SHIP 3/8X0 AS IS	SAME AS LEVEL B PLUS, VIBR. SCREENS, JIGS, HEAVY MEDIA VESSELS OR CYCLONES, DEWATERING THICKNERS, FILTERS	+3/8" DRAINED -28M PONDED	USED WHERE-3/8" FRACTION FAIRLY CLEAN OR MUCH ROCK PRESENT IN +3/8" FRACTION
D DELIBERATE	FINE BENEFICIATION	60- 80	80-90	GOOD	FAIR	LEVEL B FOLLOWED BY, WET SCREEN AT 1/4" AT WET BENEFICIATE +28M DISCARD 28MX0	SAME AS LEVEL C PLUS, CONCENTRATING TABLES OR HYDROCYCLONES. SOME THERMAL DRYING.	+1/4" DRAINED +28M DEWATERED -28M PONDERED OR FILTERED	USED WITH COALS HAVING GOOD WASHABILITY CHARACTERISTICS
E ELABORATE	VERY FINE BENEFICIATION	60- 80	80-90	GOOD TO EXCELLENT	FAIR TO GOOD	LEVEL D PLUS WET BENEFICIATE 28MX0	SAME AS LEVEL D PLUS FLOTATION CIRCUITS. THERMAL DRYING PREVALENT.	SAME AS LEVEL D EXCEPT MORE FINES	USED WITH COALS HAVING EXCELLENT WASHABILITY CHARACTERISTICS
F FULL	DEEP CLEANING	60- 80	85-90	CLEAN COAL STEAM, EXCELLENT MIDDLING STEAM NONE TO FAIR		LEVEL E AFTER GREATER THAN NORMAL SIZE REDUCTION & SEPARATION INTO TWO STREAMS CLEAN COAL AND MIDDLINGS	SAME AS LEVEL E PLUS ADDITIONAL SIZE REDUCTION	SUBSTANTIALLY SAME AS LEVEL E	TWO OR MORE WASHED COAL PRODUCTS OF DIFFERENT QUALITIES ARE OBTAINED

*COAL SIZES SHOWN ARE TYPICAL BUT WILL VARY SOMEWHAT WITH EACH COAL AND PROCESS SELECTED.

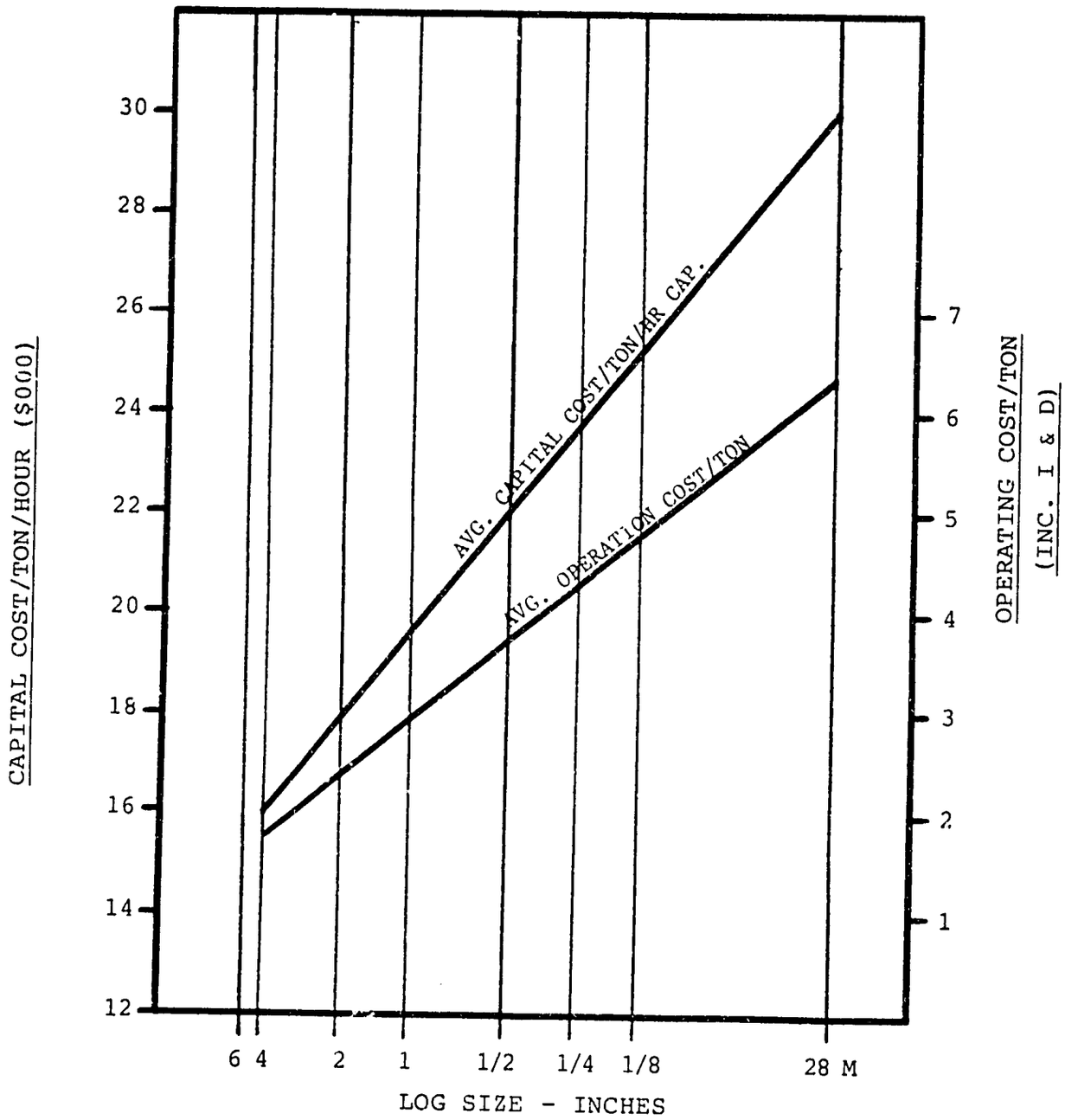

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Fig. 17 Coal Prep. Plant Capital and Operating Cost vs Percent Weight Oversize (Raw Coal Input)

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are reflected in both the installed costs of the treatment plant and the subsequent production costs. These costs are shown in Figure 17.

5.4 Capital Costs

5.4.1 Surface Mines

Capital investment for mining equipment has to be seen in direct relationship to the overburden quantity to be removed.

Investment per ton of coal produced per year ranges between $10.00 (Wyoming, North Dakota) and $50.00 (Texas) per annual ton capacity.

5.4.2 Underground Mines

Depth, mine capacity, geological conditions, general layout and mining methods determine the capital cost of new underground mines. The following capital costs per ton of annual production have to be considered for new projects of about one million tons per year:

Drift mines	-	$45 - $55
Slope mines	-	$50 - $90
Shaft mines	-	$80 - $110

These costs do not include preparation plants and general infrastructure.

5.4.3 Preparation Plants

Capital costs currently range from about $15,000 to $30,000 per ton of raw coal feed per hour, but are subject to rapid escalation at the present time. Deep cleaning, at the equivalent level E-F of Table 5.1 add $5.00 to $7.00 per ton to the production costs of clean coal.

6. TRANSPORTATION

Since mine-mouth consumption takes only a very small part of the coal produced, the transportation industry takes a decisive role in reference to the question where and at which price the mined coal can be sold.

Table 6.1 shows shipments from the mines and mode of transportation.

Table 6.1 Shipments of Coal from the Mine (1,000 Net Tons)

Year	Loaded at Mine for Shipment by Rail	Loaded at Mine for Shipment by Water	Trucked to Final Destination	Used at Mine-Mouth Generating Plants	Used at Mine 1)	Total Production
1972	394,014	69,825	65,633	61,878	4,036	595,386
1973	397,158	68,604	57,268	64,424	4,284	591,738
1974	397,161	67,754	66,382	66,635	5,474	603,406
1975	418,148	69,094	79,365	73,543	8,288	648,438
1976	431,051	69,625	89,834	79,182	8,994	678,685
1979	463,469	112,770	104,648	80,422	2)	761,309
			Percent of Total			
1972	66.2	11.7	11.0	10.4	0.7	100.0
1973	67.1	11.6	9.7	10.9	0.7	100.0
1974	65.8	11.2	11.0	11.0	0.9	100.0
1975	64.5	10.7	12.2	11.3	1.3	100.0
1976	63.5	10.3	13.2	11.7	1.3	100.0
1979	60.9	14.8	13.7	10.6	2)	100.0

1) Includes coal used at mine for power and heat, made into beehive coke at mine, used by mine employees, used for all other purposes at mine, and shipped by slurry pipeline.

2) Included in mine-mouth column.

Note: Data given here indicate the originating mode only, regardless whether transshipment occurs before coal reaches its final destinations. The 1979 data are the latest available.

Source: Department of Energy/National Coal Association.

6.1 Railroad Transportation

a) Historical Background

The railroad and coal mining industries historically have a broad range of connections and interdependence. These span from the importance of railroads in the development of the country, especially in opening the West, to the fact that railroad companies are among the largest owners of coal reserves and were once major coal consumers.

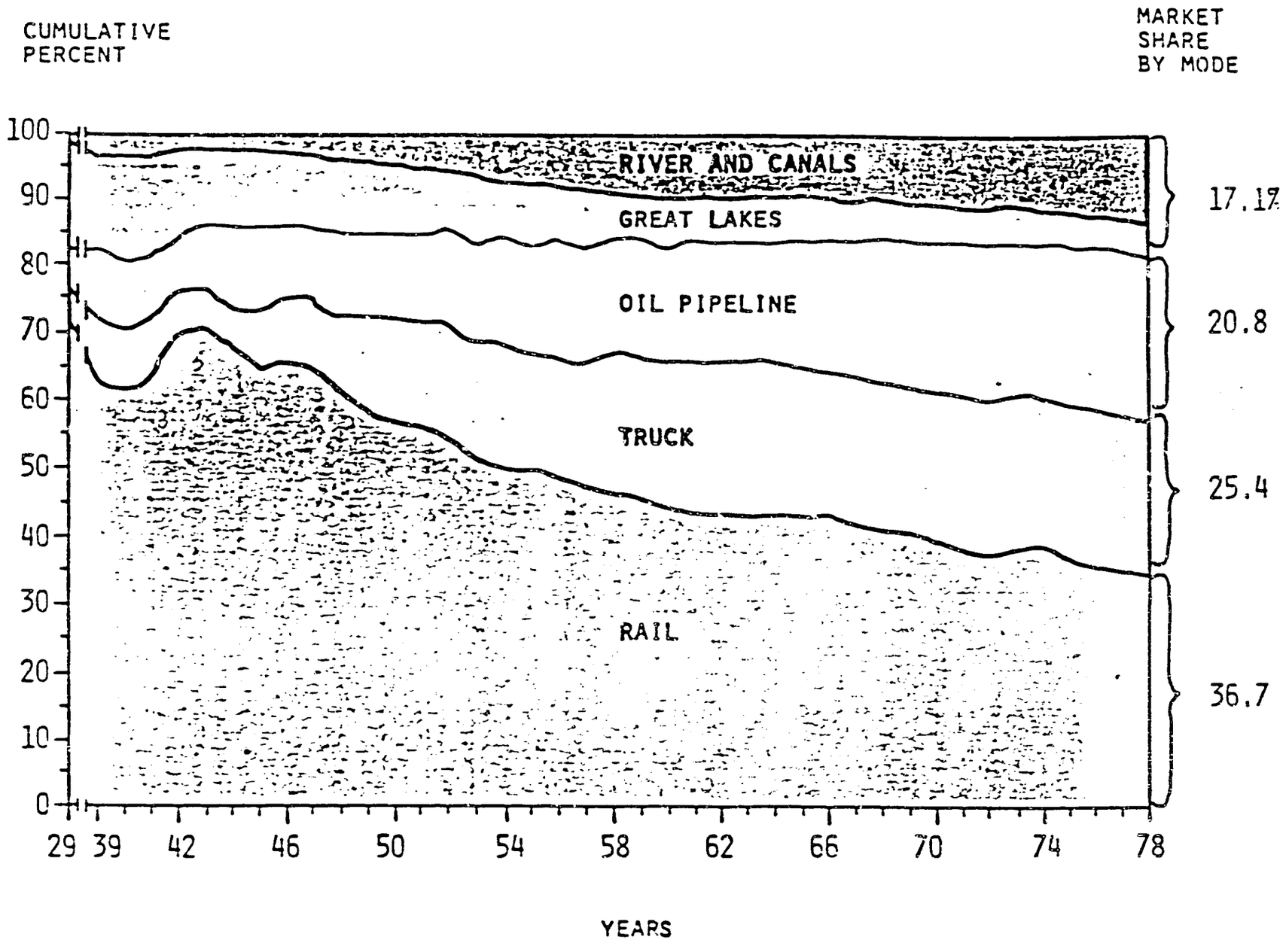
Railroads were so successful, that by the end of the 19th Century, they were the biggest of big business and the most important industry in the United States. The coal mining industry profited from this development but also was affected by the monopolistic character of the railroads and later by the rapid conversion to diesel engines.

The railroad industry reached its peak in size some time between 1900 and 1930, as shown in the following statistics:

Measure	Peak Amount	Peak Year	1978
Number of Operating Railroads	1,564	1907	336
Miles of Road Owned	254,251	1916	190,555
Passengers Carried	1,269,913,000	1920	280,961
Employment	2,076,000	1920	491,254
Locomotives in Service	69,486	1924	27,457
Freight Cars in Service	2,414,083	1925	1,652,774
Passenger Cars in Service	65,763	1926	4,326
Miles of First Main Track Operated	260,570	1929	183,055
Miles of Total Track Operated	429,883	1930	309,700

Although the railroads' freight tonnage and ton-miles continued to grow, their importance within the transportation industry has steadily diminished because of the rise of competing modes and considerable changes in the market. Figure 18 shows the railroad industry's declining market share in inter-city freight over the period 1929 to 1978 and the growth of trucking, pipeline and barge transportation.

Figure 18 SHARE OF INTERCITY FREIGHT BY MODE



Even worse than the railroad's decline in the freight market has been its decline in the inter-city passenger transportation market. Automobile, bus and air transportation became so popular and competitive that in 1976 railroads retained only 0.7 percent of the inter-city passenger market. In addition, they lost the mail and express package services, once a large source of income.

Deteriorating financial conditions, a changing economic environment, strangling regulatory constraints, growing labor problems, poor management, funding problems, the industry's own structure, etc., finally led the railroad industry in a vicious cycle. Many companies deferred maintenance of rail plant and tracks, delayed capital expenditures, used up their working capital and several of them ended in bankruptcy.

The negative impact of these developments affected the mining industry mostly in the east of the United States because southern and western railroads suffered a smaller decline due to a growing population and industrial activity. However, since most of the coal is produced in the eastern part of the country, the railroad system's deterioration has often been cited as being a big constraint for the mining industry.

b) Current Status and Prospects

Presently a good portion of the railroad industry is in a struggle for survival. Nevertheless, the industry is still playing a vital role in America's commerce. It is still a private industry and will not become nationalized as in almost all other countries. The former regulatory burden and the role of government in the transportation in general, and the railroads in particular, has been substantially modified by the Staggers Rail Act of 1980, but remains undeniably stronger compared to other private industry.

Current statistics show 473 operating railroad companies, many of which are interrelated. These companies are divided into two major categories by the Interstate Commerce Commission: line-haul railroads (324 in 1979) and switching and terminal railroads (149 in 1979). Line-haul railroads perform the basic service of hauling freight and/or passengers. Switching and terminal railroads provide only limited service functions.

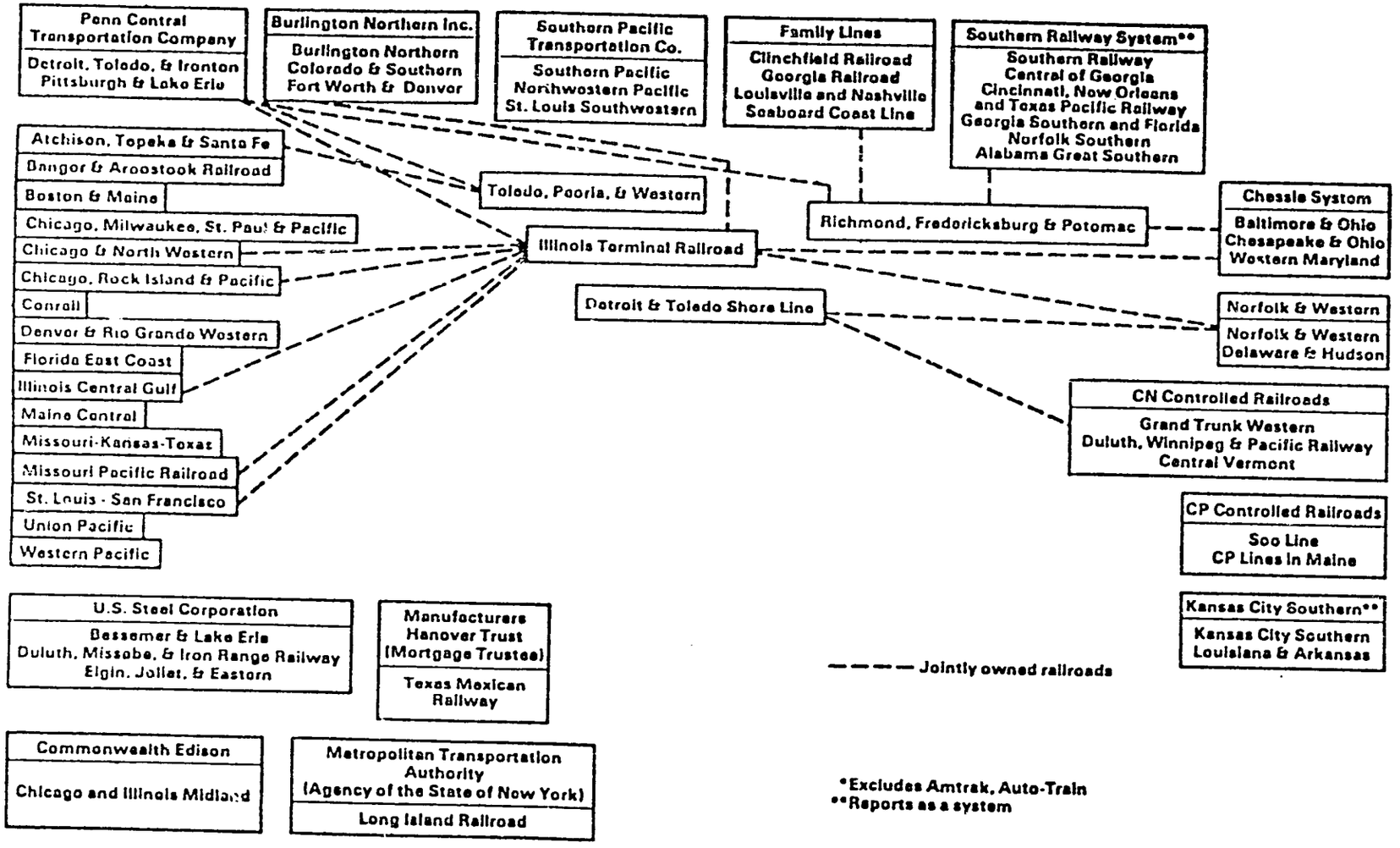
Of real importance are the Class I railroads (41 in 1979). They are defined as having annual operating revenues of $50 million or more. These railroads represent 98 percent of the industry's traffic, operate 94 percent of rail mileage, and account for 92 percent of the workers employed. Many of the Class I railroads are interrelated, as shown in Figure 19.

The web of railroad lines covering the country are shown in Figure 20; the major coal hauling companies in Table 6.2. Statistical information on these companies is provided in Table 6.3.

There have been many mergers over the industry's history. The earlier emphasis has been on expanding the capabilities and financial position of the companies. More recently, the emphasis has been on providing more effective competition against other modes of transportation.

Currently, five major mergers are in a stage of negotiations, government approval or execution. These are:

Chessie System with Family Lines (SCL/L&N, Clinc), now CSX Corp.
Norfolk Western with Southern System
Burlington Northern with St. Louis - San Francisco
Union Pacific with Western Pacific - Missouri Pacific
Southern Pacific with (Atkison-Topeka & Santa Fe).



SOURCE: Railroad ownership and control is depicted as specified in Moody's Investors Service, Inc., Moody's Transportation Manual, 1977 Edition (Moody's Investors Service, Inc., 1977).

Figure 19

U.S. Railroad Industry Organization Class I Line-Haul Railroads*
December 31, 1976
30 Affiliated Groups • 56 Class I Line-Haul Railroads • 50 Reporting Class I Railroads

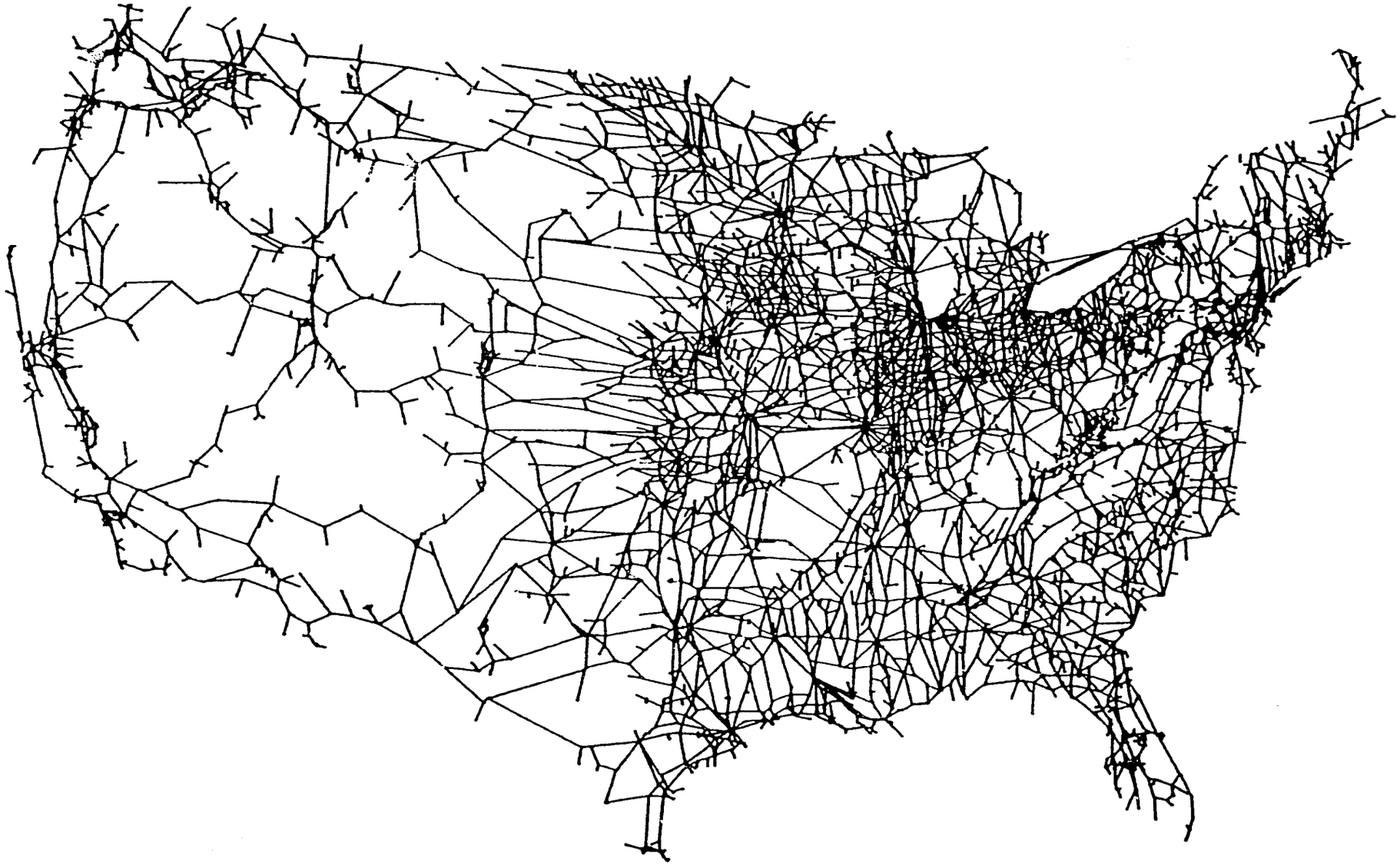


Figure 20 U.S. Rail Network

TABLE 6.2

MAJOR COAL HAULING RAILROAD COMPANIES

Railroads	Amount of Coal Hauled (1000 Tons)	Percent of Total
Chessie System	100,738	17.3
Family Lines (SCL/L&N, Clinch)	89,494	15.3
Burlington Northern	66,221	11.4
Conrail	62,882	10.8
Norfolk Western	53,949	9.2
Southern	36,412	6.2
Union Pacific	23,119	4.0
Illinois Central Gulf	21,060	3.6
Missouri Pacific	15,473	2.7
Denver & Rio Grande Southern	15,316	2.6
Others	98,549	16.9

TABLE 6.3

STATISTICAL INFORMATION

MAJOR COAL CARRYING RAILROADS 1978
(Tons Expressed in 1,000)

Railroads	Total Tons Hauled	Originated Coal Tons	Tons Rec'vd From Carrier	Total Coal Tons Hauled	Percent of Coal Hauled To Total	Average Coal Revenue Per Ton	Miles Track	Number of Cars	Number of Locomotives
B & O	67,223	21,522	17,182	38,704	57.6	$ 5.22	*	26,886	*
C & O	72,648	43,642	10,183	53,825	74.1	5.13	15,480	45,374	*
Western Maryland	12,611	5,110	3,099	8,209	65.1	2.77	1,600	5,892	113
TOTAL CHESSIE SYSTEM	152,482	70,274	30,464	100,738	66.1	4.97	17,080	78,152	2,036
Proposed merger									
Seaboard Coastline	119,546	9	17,916	17,925	15.0	2.95	13,895	3,409	1,294
Louisville-Nashville	90,188	53,651	2,934	56,585	62.7	3.97	10,616	32,287	*
Clinchfield	*	6,336	8,648	14,984	*	2.53	*	4,312	*
TOTAL WITH MERGER	362,216	130,270	59,962	190,232	52.5	4.29	49,591	118,160	3,330
N & W	85,563	47,344	6,605	53,949	63.0	6.47	17,205	52,957	1,409
Proposed Merger									
Southern System	109,703	28,253	8,159	36,412	33.2	4.25	10,215	12,787	1,395
TOTAL WITH MERGER	195,266	75,597	14,764	90,361	46.2	5.58	27,420	65,744	2,804
Burlington Northern	148,194	63,047	3,174	66,221	44.7	7.00	26,524	10,731	2,940
Proposed Merger									
St. Louis - San Fransisco	24,081	4,112	2,944	7,056	29.3	4.26	*	2,491	*
TOTAL WITH MERGER	172,275	67,159	6,118	73,277	42.5	6.74	26,624**	13,222	2,940**
Union Pacific	73,807	17,340	5,779	23,119	31.3	7.25	*	8,030	1,589
Proposed Merger									
Western Pacific	*	*	29	29	*	4.03	1,719	798	146
Missouri Pacific	73,075	9,155	6,318	15,473	21.2	4.12	*	6,531	*
TOTAL WITH MERGER	146,882	26,495	12,126	38,621	26.3**	5.99	1,719**	15,359	1,735**
Southern Pacific	128,056	1	2,869	2,870	2.2	5.17	20,671	4,118	*
Proposed Merger									
Atkinson-Topeka & Santa Fe	49,157	3,480	5,734	9,214	18.7	5.49	20,502	5,291	2,527
TOTAL WITH MERGER	177,213	3,481	8,603	12,084	6.82	5.41	41,173	9,409	2,527**
Bessemer & Lake Erie	14,786	5,240	3,943	9,183	62.1	3.52	434	7,176	66
Boston & Maine	*	1	868	869	*	3.35	*	238	*
Conrail	167,935	31,565	31,317	62,882	37.4	4.89	43,107	39,205	*
Detroit, Toledo & Ironton	*	12	1,195	1,207	*	5.14	*	87	*
Elgin, Joliet & Eastern	*	2	9,944	9,946	*	1.83	*	3,349	*
Grand Trunk Western	*	1	1,506	1,507	*	2.60	*	315	*
Long Island	*	*	38	38	*	4.61	*	0	*
Pittsburgh & Lake Erie	14,431	1,662	4,570	6,232	43.2	2.33	*	5,537	*
Illinois Central Gulf	68,014	15,039	6,021	21,060	31.0	3.30	14,532	7,708	*
Soo Line	11,016	172	277	449	4.1	4.24	2,966	1,449	233
Chicago & Northwestern	*	2,656	10,941	13,597	*	3.25	14,371	1,957	*
Chicago, Milwaukee, St. Paul & Pac.	30,494	4,969	4,856	9,825	32.2	3.46	14,888	32,287	348
Chicago, R.I. & Pacific	*	818	2,112	2,930	*	5.13	10,727	3,788	*
Denver & Rio Grande	*	13,197	2,119	15,316	*	4.29	1,850	3,341	275
Duluth, Missabe	*	540	378	918	*	1.67	*	445	*
Kansas City & Southern	*	1,409	6,163	7,572	*	3.01	2,617	412	*
Missouri-Kansas-Texas	*	898	150	1,048	*	4.12	3,226	1,167	*

* Data not available ** Data Not Complete

When all these mergers take place, the top ten will be reduced to 5 major railroad companies. Since all of them are carrying large tonnages of coal (Table 6.3), an improvement of coal transportation is expected, especially in the eastern part of the U.S. and in north-south destinations. The mergers will offer greater opportunity for runthrough trains that avoid interchange costs and advantages from combining railyard operations and improved locomotive and railcar operating use.

The railroads' share of coal traffic is shown in Table 6.1. Although the tonnages hauled increased steadily, the railroads share has dropped from 84 percent of the market in 1939 to 61 percent in 1979. Competition from barge operators and, most recently, mine-mouth power generation, have accounted for this decline.

To combat this competition, the railroad industry has instituted unit coal trains for concentrated coal moves between larger mines and consumers. Due to the lack of funds, the equipment has partly been financed by consumers or leasing companies. Other improvements referred to the development of new handling systems and operating methods, increased hopper car capacities (up to 100 tons per car) and other technological advances. These innovations have helped railroads maintain an overall competitive advantage in most of the coal market.

It is expected that rail mergers in particular will strengthen the carriers' ability to serve the mining industry with competitive transport rates. The Staggers Rail Act of 1980 will improve the carriers' financial situation. Therefore, all projections assume that railroads will keep their market share in the range of 61 to 63 percent through 1990.

6.2 Waterways

Since the early development of America closely followed its water courses, the national interest in the navigable waters is as old as the nation.

Today's inland waterway system has been developed in several steps during the last 150 years. With the exception of the Mississippi River below St. Louis, all of the natural water-courses making up the inland waterway system have required improvements in the form of widening and deepening channels, reducing bends, constructing locks and dams and modifying river banks.

The present inland waterway system of the U.S., as depicted in Figure 21, consists of 25,543 miles of navigable waterway and has 255 locks and dams. It is second only in size to the U.S.S.R.'s system. The major components of the system are:

- The Mississippi and its tributaries - 8,954 miles - 65 percent of which has a minimum channel depth of 9 feet;
- The Atlantic Intra-coastal Waterway - 7,004 miles - 60 percent of which has a minimum channel depth of 9 feet;
- The Gulf Intra-coastal Waterway - 5,429 miles - 50 percent of which has a minimum channel depth of 9 feet; and
- The Pacific Coast Waterways - 3,575 miles - 65 percent of which have a minimum channel depth of 9 feet.

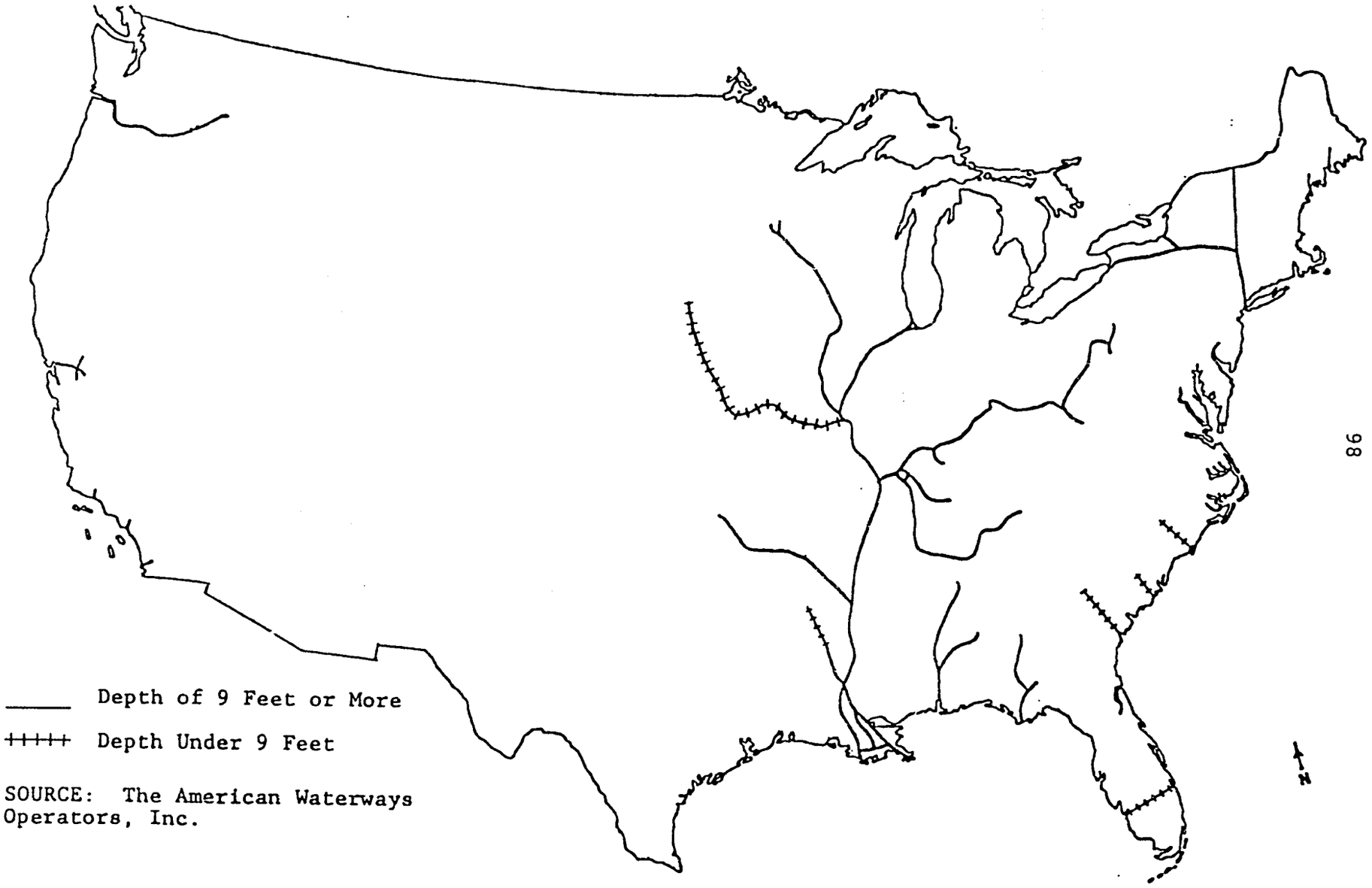


Figure 21 MAJOR INLAND WATERWAYS OF THE UNITED STATES

The 255 locks range from 138 to 1,200 feet in length, from 30 to 110 feet wide and take from 2½ to 25 minutes to fill. This series of locks and dams means that most of the inland waterway system is a system of slack water routes (i.e., no river current). The principal exceptions to this are the Mississippi River below St. Louis and the Missouri River.

The "Mid-America's" waterways comprised of the Mississippi River System, Gulf Coast Waterways and Alabama Rivers consist of approximately 15,000 miles of navigable channels with 157 locks and dams; most channels on the waterways are maintained for navigation by barges with depths up to nine feet. This system is presently carrying about one-fourth of the nation's total foreign imports and exports and domestic waterborne commerce.

The inland waterways in this area, as shown in Figure 22 consist of:

1. The Mississippi and her tributaries including the Minnesota, Missouri, Arkansas, Ouachita, Illinois Waterway, Ohio, Kaskaskia, Monongahela, Allegheny, Kanawha, Kentucky, Green, Cumberland, Tennessee Rivers and minor tributaries;
2. The Gulf Rivers including the Gulf Intracoastal waterway, Lake Charles, Calcasieu River, Sabine River, Atchafalaya River, Port Allen-Morgan City route, Pearl River and minor tributaries and outlets to the Gulf;
3. Alabama's River System including the Mobile, Tombigbee, Black Warrior, Alabama, Coosa and Chattahoochee Rivers and minor tributaries.

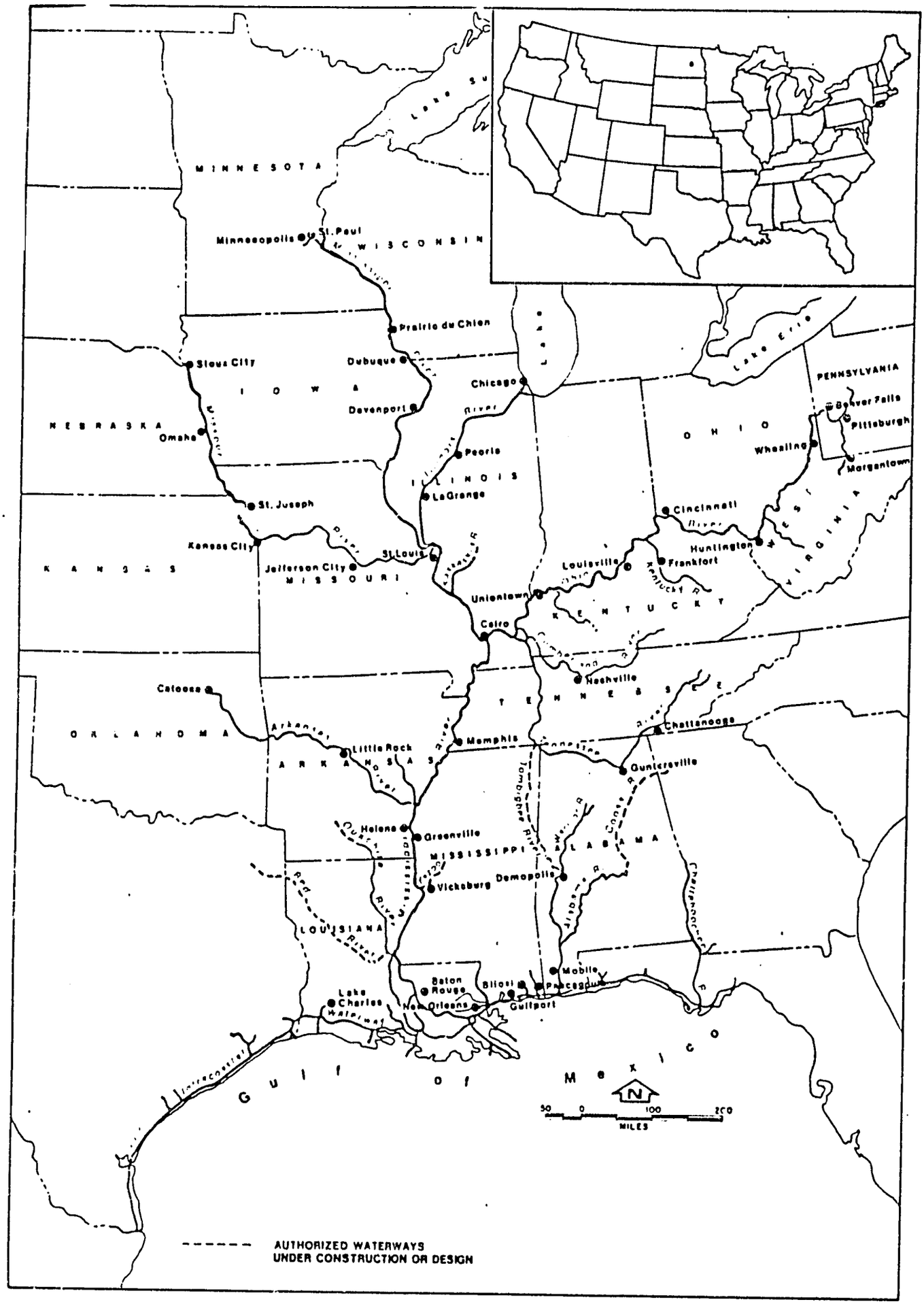


FIGURE 22 WATERWAYS OF MID-AMERICA

The Illinois Waterway permits access to the Mississippi River system from Lake Michigan. The Mississippi is linked to the Gulf of Mexico by several outlets. The Corps of Engineers has a project underway which will connect the Tennessee and Tombigbee Rivers, permitting access to the Mississippi River system through Mobile.

The Cumberland and Tennessee rivers are joined by a canal above the Barkley and Kentucky Locks, which enables vessels on the two rivers to use either lock.

Presently, there are several other Mid-America waterway projects under construction or in the stage of consideration and approval.

Another waterway, the Great Lakes - St. Lawrence Seaway System, is very different from the inland waterway system. The major reason for these differences is that the minimum depth of the Great Lakes - St. Lawrence System is 27 feet as opposed to the 6-to 12-foot depth of the inland system. This means that not only ocean-going vessels can call at Great Lakes ports, but that the type of vessel used for domestic commerce on the Great Lakes is completely different from the barges that are typically used on the inland waterway system.

A water route via the St. Lawrence to the Great Lakes has existed since shortly after the War of 1812 when Canada developed a route to compete with the Erie Canal. During the early twentieth century, a series of minor improvements were made and in 1932 the Welland Canal was opened, thereby allowing large ships to pass from the upper Lakes into Lake Ontario.

The St. Lawrence Seaway project, completed in 1959, rebuilt the Welland Canal and replaced 22 locks between Lake Ontario and Montreal, Quebec, with 7 locks. This increased the draft to 27 feet, almost tripling the size of the vessels that could be used on the Great Lakes. Shortly thereafter, the Poe Locks at Sault St. Marie were rebuilt, allowing a further increase in the size of vessels on the upper Lakes.

The Great Lakes - St. Lawrence Seaway System extends 2,342 miles from the western end of Lake Superior to the Atlantic Ocean and serves 57 public and 8 private ports. The Seaway suffers from two natural deficiencies that limit its economic usefullness -- circuitry and cold weather. It is very common for the distance by water between ports to be twice the distance by land, and no two major ports are closer by water than they are by land. In addition, the Seaway is closed for 2 to 3 months every year by ice that blocks the harbors and tributary rivers.

Traffic on the inland waterway system is carried in barges which are generally lashed together to form tows, which in turn are pushed by "towboats" or pulled by "tugboats." At the beginning of 1976, there were 4,095 towboats and tugboats and 26,522 barges used in transportation service on the inland waterway system. Towboats are diesel-powered and reach from 300 to 10,000 horsepower. The majority has 1,200 to 1,800 horsepower. The most widely used barge is a 195 foot x 35 foot barge having a 9 foot draft and a capacity of 1,500 tons.

The Great Lakes Fleet consists of 208 dry bulk freighters with a capacity of 3,196,000 long tons, 79 self unloading dry bulk freighters with a capacity of 1,469,000 long tons and 58 tankers with a capacity of 329,000 long tons. The average age of the dry bulk fleet is 45 years and only 11 new vessels were built from 1960 to 1974. The newer vessels

are much larger than the old ones, so the ships built since 1960 represent almost 35 percent of the capacity of the Great Lakes' fleet. Self unloading vessels are a comparatively recent development and tend to be smaller than the other new ships; the newest one can discharge 11,000 tons per hour.

The tendency for vessels to be built to fit just within the physical limitations of the waterway is very pronounced. Prior to the completion of the St. Lawrence Seaway, the 14 foot depth of the Welland Canal was the limiting constraint. When the depth of the canal was increased to 27 feet, the 250 foot long "canaller" of 2,500 ton capacity was immediately made obsolete by 730 foot long vessels of 25,000 ton capacity. When the Poe Lock at Sault St. Marie was completed, 1,000 foot long vessels of 60,000 ton capacity were built.

The growth in traffic on the inland waterway system has been at a rate of almost 5 percent per year over the last decade and has occurred at an even faster rate on the Mississippi River, which has increased its share from 57 percent to 68 percent of the total in the same period.

Coal movements by water in 1974 and the principal waterways of the United States are shown in one of the maps at the end of the Report.

The present major coal hauling river system consists of eight river systems:

1. Ohio River
2. Monongahela River
3. Green & Barren Rivers
4. Harrion River System (including Tombigbee)
5. Mississippi River
6. Kanawha River
7. Illinois River
8. Tennessee River

These rivers, conveniently located to important coal producing areas, were predominantly used for coal shipments. Even some of the coal produced in the western states and the northern Great Plains is brought east by rail and loaded on to barges for final destination.

Total coal shipments from mines via waterways reached 112,770 tons or 14.8 percent of total production in 1979. (Table 6.1). With coal production increasing over the next decade, projections state an even larger growth for coal shipments on waterways. Compared to other modes, barge transportation is expected to size up to a market share of 21 percent by 1990.

6.3 Slurry Pipelines

At present there are two commercial coal slurry pipelines in existence in the United States, one of which is operational: The first pipeline, which is 108 miles long and 10 inches in diameter with an annual capacity of 1.3 million tons, was built by Consolidation Coal Company, connecting southern Ohio to a power plant on Lake Erie in northern Ohio. The system operated successfully for six years, from 1957 to 1963, and delivered more than 7 million tons of coal. It produced significant savings in the cost of transportation and the resulting competition stimulated the railroad industry into improving their efficiency by introducing unit trains. In addition, the railroads reduced their rates to the point where the pipeline was no longer economical and as a consequence it was closed down.

The second commercial slurry pipeline carries about 5 million tons of coal annually from Peabody Coal Coampany's Black Mesa Mine in northeastern Arizona to the Mohave generating station in southern Nevada. The pipeline, which has been in operation since 1970, is 273 miles long, 18 inches in diameter, and has a capacity of 5 million tons per year. The pipeline has been

available for service 99 percent of the time and transportation costs have been nearly half of other modes.

The success of the Black Mesa Line has spurred considerations and proposals to build several other coal slurry pipelines in the United States and Canada.

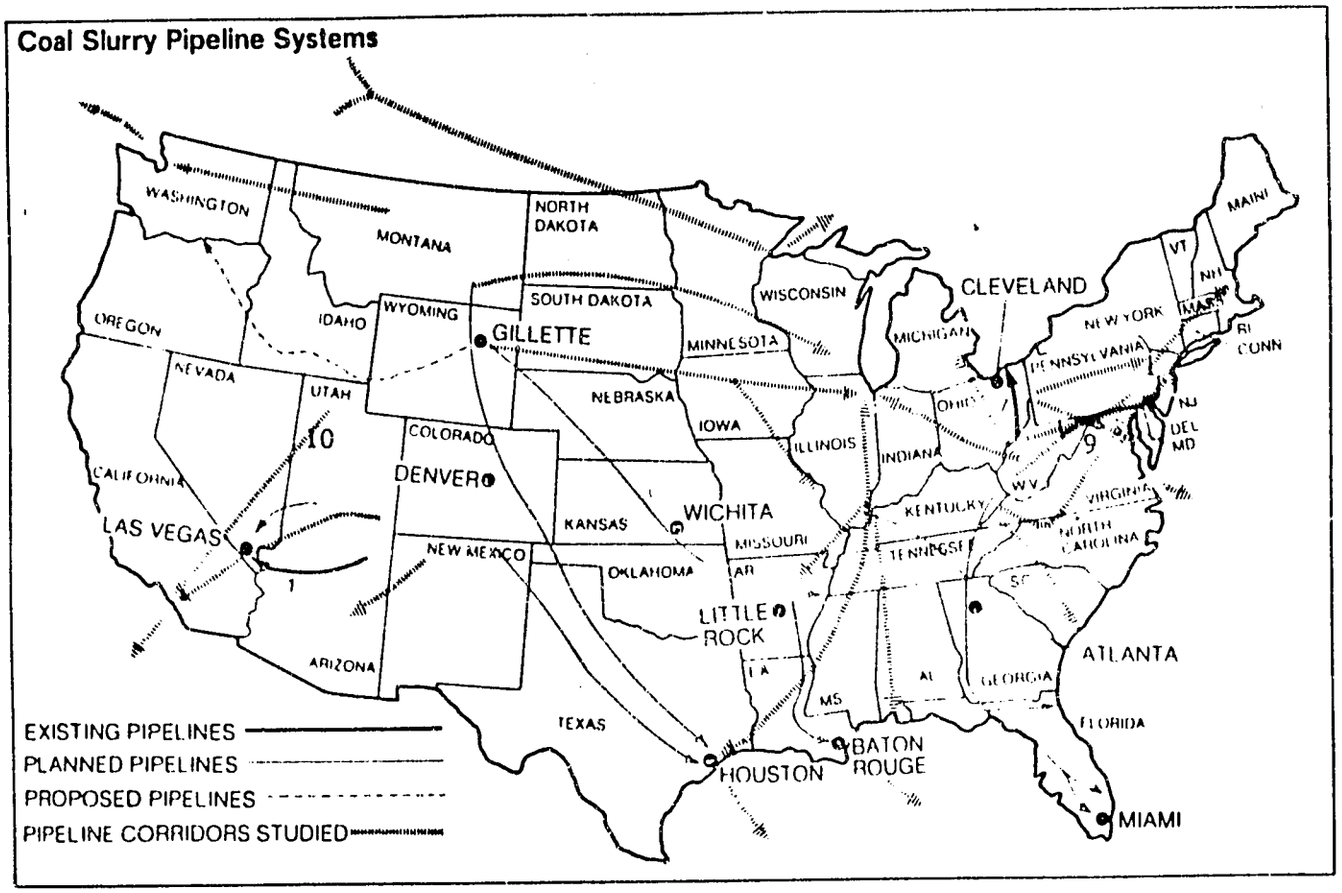
Various economical comparisons of railroad versus pipeline slurry transportation of coal favor pipelines and show considerable savings. Other sources, however, point to the unexpected high costs of installing the Alaskan Oil Pipeline, water availability problems, and spiraling future construction costs.

Existing and proposed coal slurry pipelines in the United States are shown in Figure 23. Just recently, another pipeline was proposed between Alberta/Canada and the Pacific Coast.

The future of nearly all projects is dim. Strong opposition to slurry pipelines arose from environmental concerns. The western U.S. suffers from a severe water shortage and there is fear that the huge diversion of groundwater necessary to create the coal slurry (one ton of water for each ton of coal) would increase the water shortage. The assurance of water rights is, therefore, an obstacle for many of the projects originating in western states.

An even stronger opposition originates from railroad companies, which consider the transportation of coal, especially in the west, as their biggest area of growth. Since pipelines would be a strong competitor in the most profitable market of high volume, long-term and most concentrated movements of coal, the railroads have blocked the construction of slurry pipelines, on a strictly legal basis, by refusing to allow them to cross railroad rights-of-way.

Figure 23



Source: COAL AGE

Pipeline System	Length	Annual Capacity
1. Black Mesa Pipeline	273 miles	5,000,000 tons
2. Alton Pipeline	183 miles	11,600,000 tons
3. Snake River Pipeline	1,100 miles	10,000,000 tons
4. San Marco Pipeline	900 miles	15,000,000 tons
5. Wytex Pipeline	1,260 miles	22,000,000 tons
6. ETSI Pipeline	1,378 miles	25,000,000 tons
7. Ohio Pipeline	108 miles	1,300,000 tons
8. Florida Pipeline	1,500 miles	15-45,000,000 tons
9. VEPCO Pipeline	320 miles	10,000,000 tons
10. Pacific Bulk Transportation System	645 miles	10,000,000 tons

The slurry pipeline interests have countered by seeking the right of eminent domain similar to that granted for the construction of natural gas, crude oil and petroleum product pipelines under either federal or state laws. Eminent domain provides that once construction has been approved by the relevant government agencies, property owners (including railroads) cannot refuse rights-of-way to the pipeline. The railroad industry is now vigorously opposing pending federal legislation which would grant coal slurry pipelines the right of eminent domain. Some states have already granted eminent domain, but this does little to help the proposed interstate pipelines. It is unlikely that any additional slurry pipelines will be built, other than by railroads, unless the right of eminent domain is granted since the pipelines must cross railroads many, many times.

Considering the major obstacles and vigorous opposition, it appears that final resolution of whether more slurry pipelines will be constructed is probably some years away. Also, considering the lead time required for pipeline construction, it is likely that this mode of coal transportation will remain insignificant and not begin to expand until the late 1980's or later.

6.4 Ports and Terminals for Coal Export

Present U.S. ports handling coal exports are shown on the map at the end of the text.

Most of the ports are located on the East Coast; two ports with three terminals are operating on the Gulf Coast and two on the West Coast.

1. Atlantic Coast Ports

Six facilities are presently in operation, one of which handles coke nut size coal almost exclusively and one handles domestic coal shipments almost exclusively. There are two coal piers which are presently idle. The locations of these facilities are shown on Figure 24 and detailed descriptions and capabilities are shown on Table 6.4.

The operating East Coast Ports are owned, served and operated by three railroad companies, namely, Conrail, the Chessie System and Norfolk & Western Railway Co. The railroads are controlled by the Interstate Commerce Commission and must serve all customers on an equal basis.

Curtis Bay (Baltimore), Pier No. 14 (Newport News) and Lamberts Point No. 6 (Norfolk) are the major coal exporting facilities in the country today, retaining 80 percent of export capacities.

The Atlantic Coast ports are all located in congested metropolitan areas serving the industrial heartland and there is little unused space available. The coal piers are adjacent to other cargo piers in the ports. None of the coal piers have ground storage facilities for the coal. Coal is stored in railroad cars in yards at and near the piers. All East Coast piers must contend with frozen coal problems during the winter season's cold weather which adversely affects loading capacity.

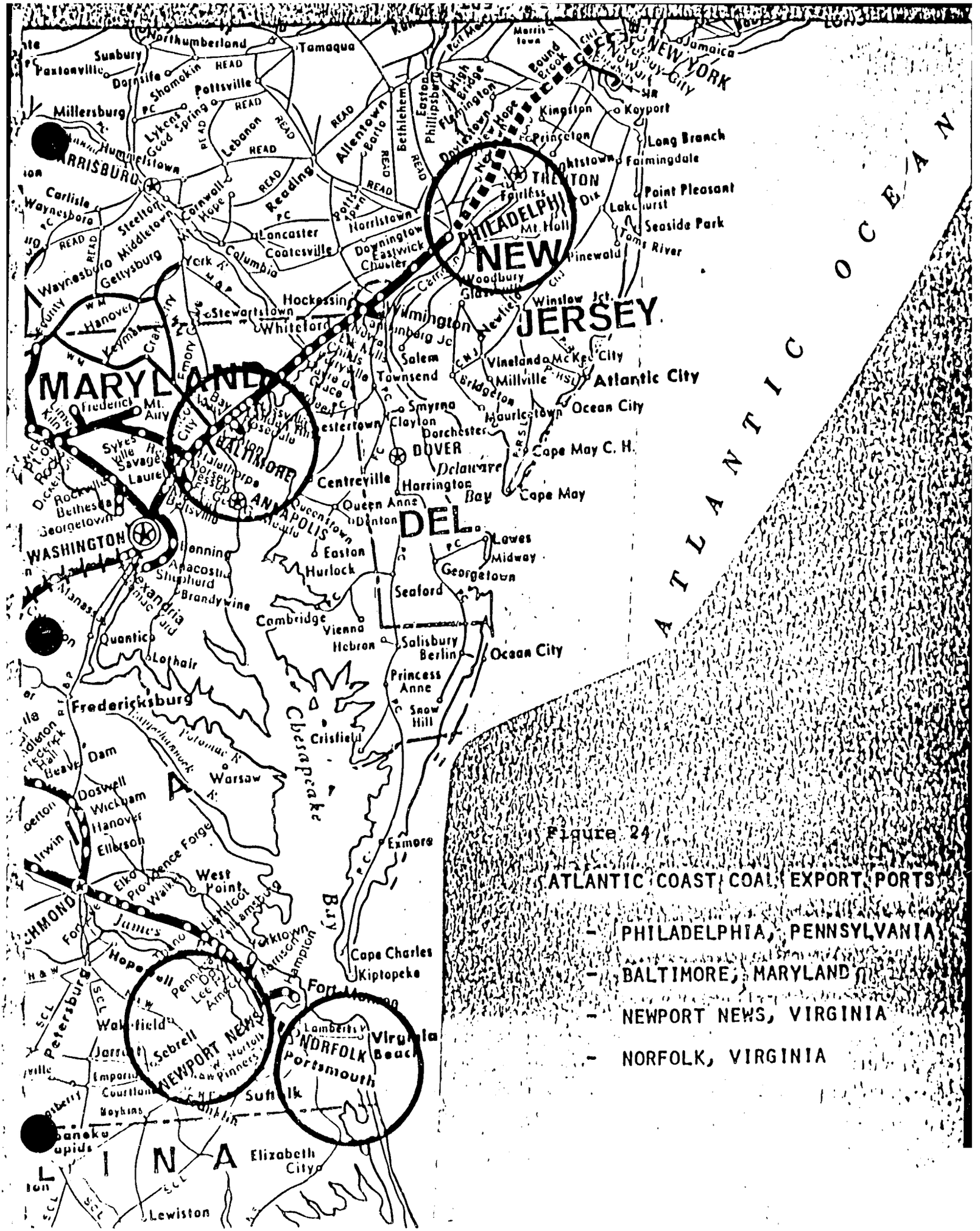


Figure 24

ATLANTIC COAST COAL EXPORT PORTS

- PHILADELPHIA, PENNSYLVANIA
- BALTIMORE, MARYLAND
- NEWPORT NEWS, VIRGINIA
- NORFOLK, VIRGINIA

The export piers were designed to serve the foreign metallurgical coal market and they have the capability of blending coals for many different customer specifications. Since the coal is stored in railroad cars, the blending can be done only as the coal is loaded into the vessel. The blending procedure reduces the capacity of the loading facilities to the extent blending is utilized. Besides this, blending requires an excellent coordination. Because of poor scheduling and coordination among the suppliers, trans-shippers, railroads and customers, the right kinds of coal are not always on hand at the port to load the awaiting ships, resulting in delayed dumping of the railroad cars and delayed loading of the ships. An occasional delay is caused at some ports when a ship is fully loaded at low tide and has to wait until high tide in order to leave the pier.

Recent foreign demand for steam coal has increased storage requirements and traffic at the ports.

The largest vessel which can be full-loaded on the Atlantic Coast is about 80,000 dwt. Details of the port facilities are compiled in Table 6.4.

East Coast terminals are long known for their deficiencies and outmoded status but, generally, they have been able to handle the usual volumes of export shipments. Only in 1980 did the sudden and unexpected surge of the export market, especially spurred by steam coal demand, cause a chaotic situation and drew public and international attention towards the port situation. Over a period of months, up to 170 vessels have waited up to 63 days at anchor for their turn to take on cargo. Delays such as these were costing millions in demurrage fees and threatened hopes for large future export contracts.

The Carter administration established a Coal Export Task Force to investigate the port conditions and to make recommendations

Table 6.4

U. S. COAST PORT FACILITIES

	PIER	STATUS	STORAGE FACILITY		SUPPLY SERVICE BY		WINTER FACILITIES	FULL LOAD MAXIMUM VESSEL SIZE	LOADING CAP.-TPH MAX./AVG.	LENGTH	RAILROAD CAR DUMPING	TYPE OF VESSEL LOADER	1,000 TONS EST. ANNUAL CAPACITY-EXPORT	DRAFT: HIGH TIDE/ LOW TIDE	NORMAL MINING DISTRICT COALS AVAILABLE FROM
			CARS	GROUND	RAILROAD	BARGE									
ATLANTIC COAST	Philadelphia, PA														
	Greenwich Coal Pier	Operating	1,200	None	Conrail	No	Thawing Facilities	35,000 Tons	1,000	1,100'	2 Rotary	1 Stationary	3,500	40' - Mean	1, 2, 3
	Port Richmond Pier	Idle	1,500	None	Conrail	No	Thawing Facilities	116' Beam & Max. 45' Ht.			1 Side Dump			35' - Mean	1, 2, 3
	Baltimore, MD														
	Canton Coal Pier	Idle		None	Conrail	No	Thawing Facilities		900	925'	1 Rotary	2 Movable		31' - Mean	1, 2, 3
	B & O Curtis Bay	Operating	1,600/ 3,000 Remote	None	B & O	No	Thaw Sheds	70,000 Tons	6,000	900'	1 Rotary Tandem	Movable	12,200 export (and 5,000 domestic)	40' - Mean	1, 2, 3
	Hampton Roads, VA														
	C & O Pier No. 14 Newport News, VA	Operating	7,000	None	C & O	No	Propane Thawing Sheds	100,000 Tons	9,000/ 8,000	1,078'	2 Rotary Tandem	2 Movable Towers w/2 Booms	18,000	45' - Low	7, 8
	C & O Pier No. 15 Newport News, VA	Operating		None	C & O	No	Electric Thawing Sheds	35,000 Tons	5,500/ 3,600	1,600'	2 Rotary	2 Stationary Towers	2,500	38' - Low	7, 8
	N & W Lamberts Point Pier No. 5, Norfolk	Limited Use	3,500	None	N & W	No	None	35,000 Tons	2,520/ 1,680	1,000'	1 Rotary	1 Low Level Lake Type	1,000	39'/36'	7, 8
	N & W Lamberts Point Pier No. 6, Norfolk	Operating	8,000	None	N & W	No	Electric Thawing Sheds	100,000 Tons	20,000/ 16,600	1,800'	2 Rotary	2 Movable	35,000	49.5/46.5	7, 8
											TOTAL ATLANTIC COAST		72,000		
GULF COAST	Mobile, AL														
	Alabama State Docks McDuffie Terminal	Operating	None	450,000 Tons	ICG L & N	Yes		70,000 Tons	3,300/ 1,800		1 Rotary		1,500 export (and 1,500 domestic)	40'	13
	Alabama State Docks Bulk Handling	Being Repaired	None	Yes	Frisco ICG, L&N Southern				600/ 400	1,600'	1 Side Dump	1 Movable		40' - Low	13
	New Orleans, LA														
	Electro-Coal	Operating	None					70,000 Tons	4,200	710'	None	1 Stationary	2,000 export (and 4,000 domestic)	40'	2, 3, 4, 6, 8, 9, 10, 11, 12, 14, 15
	Intl. Marine Terminal Plaquemines Parish Term.	Operating	None	250,000 Tons	None	Yes		70,000 Tons	3,900	875'	None	1 Stationary	3,000 (all domestic)		2, 3, 4, 6, 8, 9, 10, 11, 12, 14, 15
											TOTAL GULF COAST		3,500		
WEST COAST	Long Beach, California	Operating											± 1,000		
	Los Angeles, California	Operating						120,000 Tons					± 1,000		
											TOTAL WEST COAST		± 2,000		
											GRAND TOTAL		77,700		

380

for improvements. At the same time many proposals came into public from mining companies, coal exporters, port authorities and operators, engineering companies, etc., for port improvements and new facilities.

Several coal producers and exporters have, in the meantime, acquired sites for new storage, blending and loading facilities; others are considering similar steps, mostly in order to become less dependent on present railroad/coal pier operators and to be prepared for an increasing export market.

Although plans change from week to week, the following East Coast projects are under consideration and presented in geographic order:

- New York, N.Y.: Feasibility study ongoing;
- Philadelphia, PA: Proposed expansion and modernization of Greenwich Pier 124 for 8 to 10 million tons;
- Camden, N.J.: Proposed new terminal for 1 to 1.5 million tons;
- Wilmington, Delaware: Construction of a new coal port for 5 million tons;
- Baltimore, Maryland: Rehabilitation of Canton Pier by Consolidation Coal Co. (10 million tons);

  Improvement of B&O Curtis Bay Coal Piers by Chessie System;

  Purchase of Boston Metals Pier by Island Creek and conversion into coal pier for 15 million tons;

  Soros Engineering Co. and consortium plan coal pier for 15 million tons;
- Hampton Roads, VA: Improvement of existing facilities;

  Planned new terminal for A.T. Massey (10 million tons);

Feasibility studie Carney Island for several coal exporters;

Proposal of an offshore coal slurry terminal;

- Moorehead City or Wilmington, N.C.: Interests in terminal (8 million tons);
- Charleston, S.C.: Studies by A.T. Massey;
- Savannah, GA: Steam coal export terminal in design stage, 12 to 15 million tons.

2. Gulf Coast Ports

There are presently three coal terminals operating on the Gulf Coast, one of which handles domestic shipments exclusively. The other two ship both domestically and overseas. Export capacities are 9 million tons per year.

The Gulf Coast ports have ground storage capabilities which reduce turn-around time for barges, railroad cars and ocean vessels. This is a capability presently not enjoyed by the Atlantic Coast facilities. Also, the Gulf ports have no feezing problems, and have a freedom from congestion. However, not all of them have railroad service. In addition, the maximum 40 ft. draft of the Gulf ports limits the maximum vessel size which can be fully loaded to about 70,000 tons.

The operating terminals are:

- McDuffie Terminal in Mobile, Alabama, presently having a capacity of 4 million tons per year. An expansion program will increase this capacity to 7 million tons next year.

- Electro-Coal Transfer Terminal near New Orleans, Louisiana. Coal is received exclusively from barges and unloaded directly into ships or to ground storage.

The terminal is in the process of expanding the capacity from 6.0 to 10.0 million tons, which is expected to be completed in 1981. All of this capacity has been either committed or optioned to Tampa Electric Utility in Florida.

- International Marine Terminals, Plaquemines Parish Terminal, near New Orleans, Louisiana. Present capacity is 3 million tons per year with plans for additional 3 to 9 million tons. Coal is received from barges exclusively.

Besides these operating facilities, several terminal expansions or new projects are being considered and studied.

3. Pacific Coast Ports

There has been very little coal shipped from West Coast ports so far. Presently, the U.S. inland transportation costs make most western coals non-competitive with Australian coals in the Pacific markets. Some western "test" coal shipments and small orders are exported from West Coast ports from time to time, but the quantities have been negligible.

The Pacific Coast ports do not have rapid loading facilities and use bulk handling facilities to load the coal. This results in loading charges of $4.25 to $5.00/ton - two to three times the rate of East Coast ports.

Most of the coal has been exported from Long Beach and Los Angeles, California. Both ports are being served by the Southern Pacific, Union Pacific and AT & SR Railroads.

Expansion plans exist for the case that sufficient shipments justify the investment. Also, new facilities are considered such as San Francisco, Kalama, Washington, Portland, Oregon, and Seattle, Washington.

4. Great Lake Ports, St. Lawrence Seaway

Coal shipments to Canada are presently being handled by Great Lake Ports. Due to the congestion of Atlantic ports, several considerations have been made to use these ports and the St. Lawrence Seaway for oversea exports. However, the feasibility is still doubtful except for smaller shipments out of Quebec, which are scheduled to start in 1981.

The overall situation of U.S. export ports can be summarized as follows:

U.S. coal exports surged in 1980 when supplies from competing overseas exporters fell short because of labor instability. Output of U.S. ports increased 60 percent over 1979. Some terminals increased shipments by 80 percent and use of loading piers averaged 90 percent, the practical limit. This resulted in port congestion and vessel loading delays; it increased the cost of U.S. coal and adversely affected competitive advantages. The situation has, however, aroused considerable private and governmental attention, and many actions are being taken to respond to the partial implications of increased coal exports.

APPENDIX 2

U.S. LONGWALL CENSUS '82

Longwall Census '82

Active longwall systems total 112, with 22 companies operating faces in 11 states

by Mark W. Sprouls,*
Managing Editor

Longwall installations continue to grow in number and sophistication throughout the US. In a survey of operators and longwall equipment manufacturers, CM&P identified 112 systems capable of current operation. That figure compares to DoE's 1979 figure of 91 systems.

However, a growth rate of seven longwall faces per year does not match 1979 projections of 144 faces (DoE), to 192 faces (a manufacturer) by the end of 1985. Considering the fact that few predicted the current production overcapacity and decline in coal market growth, the DoE estimate is suprisingly accurate.

In fact, 10 new faces started up in 1982, and 6 new systems replaced old ones—creating a surprising total of 16 new systems (at $6 million to $8 million each). On the other hand, research shows that seven systems were retired and not replaced in late '81 and 1982.

Perhaps most significant is the trend for operators with multiple longwall systems (Table I) to install more. Consolidation Coal Co., the leading longwall operator with 19 installations, added three new systems in '82. Island Creek (13 installations) added two new systems, and Eastern Associated (9) added one new system and replaced one old system. Old Ben Coal (8 installations) is planning to operate 10 systems by early in 1984. Sixteen companies operate more than one longwall while only six companies operate a single face.

Eastern field is longwall haven

Table II shows that 88 longwall faces operate in the eastern coal fields, 8 operate in the Midwest and 16 in the West. West Virginia decidely outscores other states by having 44 faces, almost 40% of the US total. Pennsylvania and Virginia each have 13 faces.

It's no surprise that 30 longwalls mine the Pittsburgh #8 seam, underlying northern West Virginia, southwestern Pennsylvania and southeastern Ohio. Only the Pocahontas #3 seam approaches that level of longwall activity. It feeds 18 longwall systems in southern West Virginia and northwestern Virginia.

Equipment improves

The most sophisticated type of longwall roof supports, shields, now comprise 93 of US longwall installations. Only 13 faces use chocks, and a scant 6 installations still have frame-type roof supports.

Similarly, the most sophisticated type of cutting machines, the double-ended-ranging-drum shearer (DERS) dominates. There are 82 DERS, 5 single-ended-ranging-drum shearers (SERS), 7 single-drum fixed shearers (SDF), and 18 plows operating as part of the 112 systems. These figures do not include spare cutting machines that many companies now keep on hand to allow removing machines for rebuilding outside of the mines. The practice of purchasing spare cutting machines and face conveyors is becoming more common as more operators install multiple longwalls.

Though the survey doesn't show changes in face conveyors, comments from operators and manufacturers point out many improvements. New conveyors are more rugged in all respects and experience a fraction of the downtime that besieged older conveyors. Additionally, many conveyors now have side discharge, which uncomplicates the headgate.

The survey also shows a trend for operators to purchase stage loaders with crusher/breakers. The crushers eliminate problems with chunks of material at conveyor transfer points.

Tests are now underway that could prove longwall for a wider range of conditions, such as thick seams, steeply dipping seams, and multiple seams. Also, predominately British and German longwall manufacturers continue to build and expand their US manufacturing facilities. All in all, longwall's future in the US looks bright—especially for operators who have already acquired experience. □

*The John T. Boyd Co., Pittsburgh, PA, specifically Leo Shelledy, mining engineer for the consulting firm, provided much of the data included in the "Census."

Reprints of "Longwall Census '82" can be purchased for $2 each. Please write: Reprints, *Coal Mining & Processing*, 300 W. Adams St., Chicago, IL, 60606. Payment must accompany the order.

Table I—Top 12 longwall mining companies.

Mining company	No. of longwalls
Consolidation	19
Island Creek	13
Eastern Associated	9
Old Ben	8
US Steel Mining	7
American Elec. Power	6
Bethlehem Mines	5
Jim Walter Resources	4
Kaiser Steel	4
North American	4
Pittston	4
Utah Power & Light	4

Table II—Number of longwalls in each state.

State	Faces	Companies with faces
Alabama	5	2
Colorado	6	4
Illinois	8	1
Kentucky	4	3
New Mexico	2	1
Ohio	9	3
Pennsylvania	13	8
Utah	7	3
Virginia	13	3
West Virginia	44	10
Wyoming	1	1

	ORGANIZATION		MINING PARAMETERS				INSTALLATION			ROOF SUPPORT			CUTTING MACHINERY			FACE CONVEYOR & STAGE LOADER/CRUSHER			
	Mining Company	Mine & (County)	Seam & Height	Mined Height	Panel Width	Depth of Overburden	Initial Face	Present Face	Status & comments	Manufacturer	Type & (# Legs)	Yield Pressure	Manufacturer & Model	Type & HP	Haulage & Manufacturer	Conveyor Manufacturer	Sprocket & Chain size	Motors —HP	Loader Mfr. & Crusher
ALABAMA	Jim Walter Resources	Blue Creek #3 (Jefferson)	Blue Creek 42-78 in.	78 in.	500 ft	1300-1500 ft	1979	—		Kloeckner-Becorit	Shield (2)	352	Anderson Mavor 500	DERS 600	Rack Halbach & Braun	American Longwall	2B 26	1-800	American Longwall crusher
	Jim Walter Resources	Blue Creek #3 (Jefferson)	Blue Creek 42-78 in.	78 in.	482 ft	1500 ft	1980	—		Dowty	Shield (4)	610	Eickhoff 150-2L	DERS 477	Rack Eickhoff	American Longwall	2B 26	2-300	American Longwall crusher
	Jim Walter Resources	Blue Creek #3 (Jefferson)	Blue Creek 42-78 in.	78 in.	482 ft	1500 ft	1980	—		Dowty	Shield (4)	610	Anderson Mavor 300	DERS 300	Rack Flech.-Sut.-Wild	American Longwall	2B 26	2-800	American Longwall
	Jim Walter Resources	Blue Creek #4 (Tuscaloosa)	Blue Creek 68-128 in.	78 in.	600 ft	1500 ft	1982	—	Another identical face will start up in 1983.	Thyssen	Shield (2)	575	Anderson Mavor 500	DERS 500	Rack Halbach & Braun	American Longwall	2B 26	2-300	American Longwall
	North River Energy	North River #1 (Fayette)	Pratt 54 in.	59 to 62 in.	600 ft		1980	—		Kloeckner-Becorit	Shield (2)	352	Eickhoff 150-2L	DERS 477	Rack Huwood-Irwin	Kloeckner-Becorit	2B 26	2-250	Kloeckner-Becorit crusher
COLORADO	[illegible] Steel	Allen (Las Animas)	Allen 72 in.	72 in.	450 ft	1500-1700 ft	1974	—		Hamscheidt	Chock (4)	500	Eickhoff 170L	DERS 225	Chain Eickhoff	Halbach & Braun	1 30	2-150	Halbach & Braun
	Mid Cont. Coal & Coke	Dutch Creek #1 (Pitkin)	"B" 84 in.	84 in.	516 ft	2400 ft	1974	1982		Dowty	Shield (4)	500	Anderson Mavor 300	DERS 300	Chain Anderson Mavor	Halbach & Braun	20B 22	2-150	Halbach & Braun
	Mid Cont. Coal & Coke	Dutch Creek #1 (Pitkin)	"B" 264-258 in.	120 in. per lift	800 ft 600 ft	2400 ft	1982	—	In a DOE-sponsored project, the two systems at #1 will take two lifts of about 120 in. each.	Hamscheidt	Shield (2)	512	Eickhoff 300-LH	DERS 400	Chain Eickhoff	Halbach & Braun	2B 30	2-400	Halbach & Braun crusher
	Mid Cont. Coal & Coke	Dutch Creek #2 (Pitkin)	"B" 84 in.	84 in.	516 ft	2000 ft	1977	1981		Gullick Dobson	Shield (6)	510	Anderson Mavor 500	DERS 500	Chain Anderson Mavor	Halbach & Braun	1 26	2-200	Halbach & Braun
	Sunnyside Coal (Minerals Associates)	Thompson Creek (Pitkin)	"A" 96 in.	96 in.	450 ft	1500-2300 ft	1980	—	Roof supports are Tinika, operating in a 30° dip.	Hamscheidt	Shield (2)	380	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	Dowty			
	Western Slope Carbon	Hawks Nest (Gunnison)	"E" 72 in.	72 in.	400 ft	2200 ft	1980	—	A Dowty conveyor is available.	Dowty	Shield (2)	440	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	Halbach & Braun	20B 30	2-300	Halbach & Braun
ILLINOIS	Old Ben Coal	#21 (Franklin)	#6 101 in.	101 in.	480 ft	680 ft	1978	—	A second system will be added in 1983 or 1984.	Thyssen	Shield (2)	500	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher
	Old Ben Coal	#25 (Franklin)	#6 101 in.	100 in.	480 ft	660 ft	1981	—		Thyssen	Shield (2)	500	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher
	Old Ben Coal	#25 (Franklin)	#6 102 in.	100 in.	480 ft	550-600 ft	1980	—	Mine #24 will have one longwall installed in early 1983 and one in late 1983.	Thyssen	Shield (2)	500	Joy Mfg. 1LS-5	DERS	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher
	Old Ben Coal	#25 (Franklin)	#6 100 in.	100 in.	515 ft	600 ft	1979	—		Thyssen	Shield (2)	500	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher
	Old Ben Coal	#26 (Franklin)	#6 96 in.	96 in.	500 ft	600 ft	1979	—	Old Ben has additional longwall equipment which is rebuilt while active equipment operates.	Hamscheidt	Shield (2)	500	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 26	2-200	Halbach & Braun crusher
	Old Ben Coal	#26 (Franklin)	#6 96 in.	96 in.		600 ft	1979	—		Thyssen	Shield (2)	500	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher
	Old Ben Coal	#27 (Franklin)	#6 96 in.	96 in.	420 ft	600 ft	1979	—		Thyssen	Shield (2)	500	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher
	Old Ben Coal	#27 (Franklin)	#6 96 in.	96 in.	420 ft	600 ft	1980	—		Thyssen	Shield (2)	500	Joy Mfg. 1LS-5	DERS	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun crusher

	ORGANIZATION		MINING PARAMETERS				INSTALLATION			ROOF SUPPORT			CUTTING MACHINERY			FACE CONVEYOR & STAGE LOADER/CRUSHER			
	Mining Company	Mine & (County)	Seam & Height	Mined Height	Panel Width	Depth of Overburden	Initial Face	Present Face	Status & comments	Manufacturer	Type & (# Legs)	Yield Pressure	Manufacturer & Model	Type & HP	Haulage & Manufacturer	Conveyor Manufacturer	Sprocket & Chain size	Motors —HP	Loader Mfr. & Crusher
KENTUCKY	Bethlehem Mth. (Beth Elkhorn)	Pike #26 (Pike)	Elkhorn #2 47 in.	47 in.	455 ft	400-1100 ft	1974	1980	A second, similar system, but with an Eickhoff shearer, will be installed in 1983	Joy Mfg.	Shield	400	Anderson Mavor 270	DERS 270	Chain Anderson Mavor	Huwood-Irwin	2B 18	2-150	
	Carbon Fuel (KY Carbon)	Kencar (Pike)	Pond Creek 59 in.	59 in.	500 ft	800 ft	1974	1977		Dowty	Shield (4)	610	Anderson Mavor 300	DERS 300	Chain Anderson Mavor	Dowty	2OB 22	2-200	
	Carbon Fuel (KY Carbon)	Kencar (Pike)	Pond Creek 59 in.	59 in.	450 ft	800 ft	1977	1980		Dowty	Shield (4)	610	Anderson Mavor 300	DERS 300	Chain Anderson Mavor	Dowty	2OB 22	2-200	
	US Steel Mining (Lynch Dist.)	Lynch #37 (Harlan)	Harlan 120 in.	120 in.	500 ft	400-1800 ft	1982	—		Westfalia Lunen	Shield (4)	640	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	Westfalia Lunen	2B 30	2-300	
NEW MEXICO	Kaiser Steel	York Canyon (Colfax)	York 72-132 in.	96 in.	600 ft	600-800 ft	1972	1976		Hemscheidt	Shield (2)	353	Eickhoff 300L	DERS 403	Chain Eickhoff	Halbach & Braun	1 30	2-225	Halbach & Braun
	Kaiser Steel	York Canyon (Colfax)	York 72-132 in.	84 in.	576 ft	550-700 ft	1974	1979		Dowty	Shield (2)	375	Eickhoff 150-2L	DERG 477	Rack Eickhoff	Dowty	2B 26	2-300	
OHIO	Consolidation Coal (Midwestern Region)	Franklin (Harrison)	Pittsburgh #8 54-66 in.	54-66 in.	550 ft	100-250 ft	1982	—		Dowty	Shield (4)	610	Joy Mfg. 1LS-4	DERS 370	Rack Eickhoff	Huwood-Irwin	2B 26	2-300	Huwood-Irwin
	Consolidation Coal (Midwestern Region)	Oak Park (Harrison)	Lwr. Frept. 6A 54-66 in.	54-66 in.	600 ft	500-650 ft	1982	—		Dowty	Shield (4)	530	Joy Mfg. 1LS-4	DERS 370	Rack Eickhoff	Huwood-Irwin	2B 26	2-300	Huwood-Irwin
	North American Coal (Quarto Mining)	Powhatan #4 (Monroe)	Pittsburgh #8 57 in.	57 in.	500 ft	700 ft	1977	—	North American currently operates only one system in each mine	Hemscheidt	Shield (2)	380	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	1 30	2-200	Halbach & Braun
	North American Coal (Quarto Mining)	Powhatan #4 (Monroe)	Pittsburgh #8 57 in.	57 in.	500 ft	450-1100 ft	1979	—		Thyssen	Shield (2)	375	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	American Longwall	2B 26	2-200	
	North American Coal (Quarto Mining)	Powhatan #7 (Monroe)	Pittsburgh #8 48 in.	48 in.	500 ft	350-650 ft	1977	—		Dowty	Shield (4)	500	Anderson Mavor 300	DERS 300	Chain Anderson Mavor	Dowty	2B 26	2-200	American Longwall
	North American Coal (Quarto Mining)	Powhatan #7 (Monroe)	Pittsburgh #8 48 in.	48 in.	500 ft	350-650 ft	1979	—		Hemscheidt	Shield (2)	350	Anderson Mavor 300	DERS 300	Rack Anderson Mavor	American Longwall	2B 26	2-300	American Longwall
	American Elec. Power (Southern Ohio Coal)	Meigs #1 (Meigs)	Clarion #4A 52 in.	52 in.	500 ft	300 ft	1980	—		Dowty	Shield (1)	610	Sagem 400	DERS 400	Rack Perard	Westfalia Lunen	2B 26	3-175	
	American Elec. Power (Southern Ohio Coal)	Meigs #2 (Meigs)	Clarion #4A 57 in.	57 in.	504 ft	300 ft	1979	—		Dowty	Shield (4)	610	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	Westfalia Lunen	2B 26	3-175	
	American Elec. Power (Southern Ohio Coal)	Meigs #2 (Meigs)	Clarion #4A 57 in.	57 in.	500 ft	300 ft	1980	—		Westfalia Lunen	Shield (4)	640	Sagem 400	DERS 400	Rack Perard	Westfalia Lunen	2B 25	3-175	

	ORGANIZATION		MINING PARAMETERS				INSTALLATION			ROOF SUPPORT			CUTTING MACHINERY			FACE CONVEYOR & STAGE LOADER/CRUSHER			
	Mining Company	Mine & (County)	Seam & Height	Mined Height	Panel Width	Depth of Overburden	Initial Face	Present Face	Status & comments	Manufacturer	Type & (# Legs)	Yield Pressure	Manufacturer & Model	Type & HP	Haulage & Manufacturer	Conveyor Manufacturer	Sprocket & Chain size	Motors —HP	Loader Mfr. & Crusher
PENNSYLVANIA	Barnes & Tucker	Lancashire #24 (Cambria)	Lower Freeport 44 in.	44 in.	480 ft	350-400 ft	1967	—	Normally, only one face is in operation at #24.	Gullick Dobson	Chock (5)	275	Eickhoff 130L	SDF 175	Chain Eickhoff	Dowty	20B 18 mm	2-150	
	Barnes & Tucker	Lancashire #24 (Cambria)	Lower Freeport 44 in.	44 in.	480 ft	350-400 ft	1968	—		Gullick Dobson	Chock (5)	275	Eickhoff 130L	SDF 175	Chain Eickhoff	Dowty	20B 18 mm	2-150	
	Barnes & Tucker	Lancashire #20 (Cambria)	Lower Kittanning 54 in.	54 in.		600 ft	1968	1978		Dowty	Chock (4)	700	Anderson Mavor 300	SDF 300	Chain	Dowty	2B 26 mm	3-200	
	Bethlehem Mines (Cambria Div.)	Cabna Slp.33 (Cambria)	Lower Kittanning 48 in.	48 in.	600 ft	500-800 ft	1974	1978		Huwood-Irwin	Chock (4)	280	Anderson Mavor 300	SDF 300	Rope Anderson Mavor	Huwood-Irwin	2B 18 mm	2-150	
	Bethlehem Mines (Ellsworth-Butler Div.)	Somerset #80 (Washington)	Pittsburgh 66 in.	66 in.	600 ft	625-600 ft	1974	1978		Kloeckner-Becorit	Shield (2)	352	Eickhoff 150-2L	DERS 477	Rack Eickhoff	Halbach & Braun	1 30 mm	2-200	
	Emsey Resources	Emerald #1 (Greene)	Pittsburgh #8 72 in.				1982	—		Dowty	Shield (2)	460	Joy Mfg. 1LS-4	DERS	Rack Halbach & Braun	Halbach & Braun	1 26 mm	2-250	Halbach & Braun crusher
	Greenwich Collieries	North (Cambria)	Lower Freeport 48 in.	48 in.	600 ft	350-480 ft	1973	1977	This face includes 10, 6-leg Gullick Dobson shields.	Gullick Dobson	Chock (6)	510	Eickhoff 170L	SERS 228	Chain Eickhoff	Halbach & Braun	1 26 mm	2-125	Halbach & Braun
	Greenwich Collieries	South (Cambria)	Lower Freeport 48 in.	48 in.	600 ft	350-480 ft	1973	1981	This face includes 17, 2-leg Hemschedt shields.	Gullick Dobson	Chock (6)	510	Eickhoff 170L	SERS 228	Chain Eickhoff	Halbach & Braun	1 26 mm	2-125	Halbach & Braun
	Gateway Coal	Gateway (Greene)	Pittsburgh 70 in.	66 in.	600 ft	500-700 ft	1970	1975		Kloeckner-Becorit	Shield (2)	352	Anderson Mavor 300	DERS 300	Chain Anderson Mavor	Halbach & Braun	1 26 mm	2-125	Halbach & Braun crusher
	Inland Steel Mining	Lancashire #25 (Cambria)	Lower Freeport 42 in.	42 in.	560 ft	450 ft	1967	1980	Formerly Barnes & Tucker 25D Mine.	Dowty	Shield (6)	450	Eickhoff 130-L	SDF 175	Chain Eickhoff	Huwood-Irwin	2B 26 mm	2-200	Huwood-Irwin
	Florence Mining (North Amer. Coal)	Florence #1 (Indiana)	Lower Kittanning 60-72 in.	72 in.	450 ft	300-400 ft	1973	1979		Thyssen	Shield (2)	575	Anderson Mavor 300	DERS 300	Rack Huwood-Irwin	American Longwall	1 30 mm	3-125	American Longwall crusher
	U.S. Steel Mining (Cumberland District)	Cumberland (Greene)	Pittsburgh 78-84 in.	78-84 in.	500 ft	900 ft	1980	—		Dowty	Shield (4)	360	Eickhoff 300L	DERS 478	Rack Eickhoff	Halbach & Braun	1 30 mm	2-200	Halbach & Braun crusher
	U.S. Steel Mining (Frick District)	Maple Creek #2 (Washington)	Pittsburgh 63-66 in.	63-66 in.	500-600 ft	350 ft	1980	—		Joy Mfg.	Shield (2)	450	Joy Mfg. 1LS-1	DERS 295	Rack Eickhoff	Joy Mfg.	2B 26 mm	2-150	
UTAH	American Elec. Power (Price River Coal)	Price Riv. #3 (Carbon)	Subseam #3 60-100 in.	75 in.	504 ft	1400-1600 ft	1981	—	A second system is targeted for Price River #5.	Westfalia Lunen	Shield (4)	640	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	Anderson Mavor	1 30	2-150	Halbach & Braun
	Kaiser Steel	Sunnyside #1 (Carbon)	Lwr. Sunnyside. 76-105 in.	105 in.	500 ft	2500 ft	1975	1980		Hemschedt	Shield (2)	350	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	1 30	2-125	Halbach & Braun crusher
	Kaiser Steel	Sunnyside #3 (Carbon)	Upr. Sunnyside. 60-120 in.	90 in.	600 ft	2500 ft	1969	1982		Thyssen	Shield (2)	490	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun			
	Utah Power & Light (Emery Mining Corp.)	Deer Creek (Emery)	Blind Canyon 144 in.	108 in.	580 ft	1600 ft	1978	—		Hemschedt	Shield (2)	472	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 30	2-150	Halbach & Braun
	Utah Power & Light (Emery Mining Corp.)	Dusk Creek (Emery)	Blind Canyon 144 in.	108 in.	600 ft	1600 ft	1979	—		Hemschedt	Shield (2)	472	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 30		Halbach & Braun
	Utah Power & Light (Emery Mining Corp.)	Wilberg (Emery)	Hiawatha 144 in.	108 in.	600 ft	1600 ft	1979	—		Hemschedt	Shield (2)	472	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	2B 30		Halbach & Braun
	Utah Power & Light (Emery Mining Corp.)	Wilberg #2 (Emery)	Hiawatha 144 in.	108 in.	600 ft	1600 ft	1981	—		Hemschedt	Shield (2)	472	Eickhoff 400L	DERS 536	Rack Eickhoff	Halbach & Braun	2B 30	2-175	Halbach & Braun

	ORGANIZATION		MINING PARAMETERS				INSTALLATION			ROOF SUPPORT			CUTTING MACHINERY			FACE CONVEYOR & STAGE LOADER/CRUSHER			
	Mining Company	Mine & (County)	Seam & Height	Mined Height	Panel Width	Depth of Overburden	Initial Face	Present Face	Status & comments	Manufacturer	Type & (# Legs)	Yield Pressure	Manufacturer & Model	Type & HP	Haulage & Manufacturer	Conveyor Manufacturer	Sprocket & Chain size	Motors —HP	Loader Mfr. & Crusher
VIRGINIA	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #1 (Buchanan)	Pocahon. #3 56 in.	48 in.	580 ft	1050-2700 ft	1968	—		Westfalia Lunen	Frame (4)	560	Westfalia Lunen Hook	Plow 2-175	Chain Westfalia Lunen	Westfalia Lunen	2B 22	3-125	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #1 (Buchanan)	Pocahon. #3 56 in.	48 in.	580 ft	1050-2700 ft	1968	1978		Westfalia Lunen	Shield (4)	640	Westfalia Lunen Gleitobel	Plow 2-175	Chain Westfalia Lunen	Westfalia Lunen	2B 26	2-175	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #1 (Buchanan)	Pocahon. #3 48 in.	48 in.	580 ft	1050-2700 ft	1970	—		Westfalia Lunen	Frame (4)	560	Westfalia Lunen hook	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2B 22	3-125	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #2 (Buchanan)	Pocahon. #3 54 in.	48 in.	510 ft	1050-2700 ft	1977	—		Westfalia Lunen	Frame (4)	560	Westfalia Lunen Gleitobel	Plow 2-175	Chain Westfalia Lunen	Westfalia Lunen	2B 22	2-175	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #2 (Buchanan)	Pocahon. #3 54 in.	48 in.	510 ft	1050-2700 ft	1974	1977		Westfalia Lunen	Chock (4)	560	Westfalia Lunen Gleitobel	Plow 2-175	Chain Westfalia Lunen	Westfalia Lunen	2B 26	2-175	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #3 (Buchanan)	Pocahon. #3 60 in.	60 in.	580 ft	1050-2700 ft	1974	—		Westfalia Lunen	Frame (4)	560	Westfalia Lunen Hook	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2B 22	3-125	Halbach & Braun
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #3 (Buchanan)	Pocahon. #3 60 in.	60 in.	580 ft	1050-2700 ft	1972	1977		Hemscheidt	Shield (4)	520	Westfalia Lunen Hook	Plow 2-200	Chain Westfalia Lunen	Halbach & Braun	1 30	2-200	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #3 (Buchanan)	Pocahon. #3 60 in.	60 in.	580 ft	1050-2700 ft	1974	—		Westfalia Lunen	Frame (4)	560	Westfalia Lunen Hook	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2B 22	2-175	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #6 (Buchanan)	Pocahon. #3 70 in.	70 in.	580 ft	1050-2700 ft	1980	—		Westfalia Lunen	Shield (4)	570	Eickhoff 150-2L	DERS 477	Rack Eickhoff	Westfalia Lunen	2B 26	1-300 1-175	
	Island Creek Coal (VA Pocahon. Div.)	VA Pocahon. #6 (Buchanan)	Pocahon. #3 66 in.	60 in.	580 ft	1050-2700 ft	1982	—		Dowty	Shield (4)	620	Joy Mfg. 1LS-6	DERS	Rack Eickhoff	Halbach & Braun	2B 26	2-250	Halbach & Braun
	Island Creek Coal (Beatrice Div.)	Beatrice (Buchanan)	Pocahon. #3 60 in.	60 in.	580 ft	1050-2700 ft	1967	1979	A second, similar system is to be installed in 1983.	Westfalia Lunen	Shield (4)	640	Westfalia Lunen Gleitobel	Plow 2-175	Chain Westfalia Lunen	Westfalia Lunen	2B 26	2-175	
	Jewell Coal & Coke	Coronet #2 (Buchanan)	Red Ash 28-30 in.	30 in.	260 ft	400 ft	1981	—	This system is to be moved.	Hemtzmann	Shield (2.5)		Halbach & Braun	Plow	Chain Halbach & Braun	Halbach & Braun	1 30		Halbach & Braun
	Pittston Coal (Clinchfield Div.)	Moss #4 (Russell)	Tiller 48-60 in.	48 in.	400 ft	400 ft	1974	1981		Westfalia Lunen	Shield (4)	600	Eickhoff EW-130L	SERS 175	Chain Eickhoff	Westfalia Lunen	2B 26	3-125	Halbach & Braun crusher
WEST VIRGINIA	American Elec. Power (Southern Ohio Coal)	Martinka #1 (Marion)	Lwr. Kittanning 52 in.	52 in.	700 ft	200-500 ft	1977	1981	Will convert to roller curve in early 1983.	Gullick Dobson	Shield (4)	600	Eickhoff 340L	DERS 535	Rack Eickhoff	Westfalia Lunen	1 30	3-175	Halbach & Braun
	American Elec. Power (Southern Ohio Coal)	Martinka #1 (Marion)	Lwr. Kittanning 52 in.	52 in.	700 ft	200-500 ft	1978	1979	Roller curve.	Westfalia Lunen	Shield (4)	600	Eickhoff 340L	DERS 535	Rack Eickhoff	Westfalia Lunen	1 30	3-175	
	Amoco	Wathende #7 (Raleigh)	#2 Gas 60-100 in.	66 in.	480 ft	500-1000 ft	1974	1976		Klöckner-Becorit	Shield (2)	352	Eickhoff 170L	DERS 223	Chain Eickhoff	Halbach & Braun	1 26	2-150	Halbach & Braun
	Bethlehem Mines	#131 (Boone)	Powellton 72 in.	75 in.	560 ft		1982	—		Dowty	Shield (4)	600	Joy Mfg. 1LS-6	DERS	Chain Joy Mfg.	Huwood-Irwin	2B 26	2-300	Huwood-Irwin crusher
	Bethlehem Mines	Barbour #108 (Barbour)	Pedstone 72 in.				1982	—		Huwood-Irwin	Chock (4)	400	Anderson Mayor 270	SERS 270	Chain Anderson Mayor	Huwood-Irwin	2CS 22	3-150	Huwood-Irwin crusher

(Continued on page 56)

ORGANIZATION		MINING PARAMETERS				INSTALLATION			ROOF SUPPORT			CUTTING MACHINERY			FACE CONVEYOR & STAGE LOADER/CRUSHER			
Mining Company	Mine & (County)	Seam & Height	Mined height	Panel Width	Depth of Overburden	Initial Face	Present Face	Status & comments	Manufacturer	Type & (# Legs)	Yield Pressure	Manufacturer & Model	Type & HP	Haulage & Manufacturer	Conveyor Manufacturer	Sprocket & Chain size	Motors -HP	Loader Mfr. & Crusher
U.S. Steel Mining (Dakota District)	Morton #34 (Kanawha)	Eagle #2 60 in.	58 in.	500 ft	600-1000 ft	1968	1980	Formerly Carbon Fuel.	Dowty	Shield (4)	610	Anderson Mavor	DERS 300	Chain Anderson Mavor	Dowty	20B 26	2-200	
U.S. Steel Mining (Dakota District)	Morton #34 (Kanawha)	Eagle #2 60 in.	58 in.	426 ft	600-1000 ft	1968	1982	Formerly Carbon Fuel.	Dowty	Shield (4)	610	Anderson Mavor	SEF 300	Chain Anderson Mavor	Dowty	20B 26	2-200	
Consolidation Coal (Eastern Region)	Ireland (Marshall)	Pittsburgh #8 66 in.	66 in.	600 ft	400-800 ft	1977	—		Kloeckner-Becorit	Shield (2)	352	Eickhoff 150-2L	DERS 403	Rack Eickhoff	Halbach & Braun	21B 26	2-250	Eickhoff or Halbach & Braun
Consolidation Coal (Eastern Region)	McElroy (Marshall)	Pittsburgh #8 66 in.	66 in.	550 ft	500-600 ft	1978	—	KB shields will be installed in 1983.	Joy Mfg.	Shield (2)	400	Eickhoff 150-2L	DERS 403	Rack Eickhoff	Halbach & Braun	21B 26	2-250	Eickhoff or Halbach & Braun
Consolidation Coal (Eastern Region)	Shoemaker (Marshall)	Pittsburgh 70 in.	63 in.	600 ft	650 ft	1975	—	New KB shields will be installed in 1983.	Kloeckner-Becorit	Shield (2)	352	Joy Mfg. 1LS-4	DERS 370	Rack Eickhoff	Halbach & Braun	21B 26	2-250	Eickhoff or Halbach & Braun
Consolidation Coal (Eastern Region)	Shoemaker (Marshall)	Pittsburgh 70 in.	60 in.	600 ft	650 ft	1979	—	New KB shields will be installed in 1983.	Kloeckner-Becorit	Shield (2)	352	Joy Mfg. 1LS-4	DERS 370	Rack Eickhoff	Halbach & Braun	1 30	2-200	Kloeckner-Becorit crusher
Consolidation Coal (Northern WV Region)	Blacksville #1 (Monongalia)	Pittsburgh 92 in.	80 in.	585 ft	700-1100 ft	1974	1979		Dowty	Shield (4)	500	Eickhoff 170L	DERS 228	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Long-Airdox or Halbach & Braun
Consolidation Coal (Northern WV Region)	Blacksville #2 (Monongalia)	Pittsburgh 84 in.	80 in.	575 ft	750-1100 ft	1972	1979		Dowty	Shield (4)	500	Eickhoff 170L	DERS 228	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Long-Airdox or Halbach & Braun
Consolidation Coal (Northern WV Region)	Blacksville #2 (Monongalia)	Pittsburgh 84 in.	80 in.	575 ft	800-1150 ft	1980	—		Dowty	Shield (4)	500	Eickhoff 170L	DERS 228	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Long-Airdox or Halbach & Braun
Consolidation Coal (Northern WV Region)	Humphrey #7 (Monongalia)	Pittsburgh 84 in.	84 in.	565 ft	400-900 ft	1979	—		Kloeckner-Becorit	Shield (2)	352	Joy Mfg. 1LS-4	DERS 380	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Long-Airdox or Halbach & Braun
Consolidation Coal (Northern WV Region)	Humphrey #7 (Monongalia)	Pittsburgh 84 in.	84 in.	630 ft	400-900 ft	1982	—		Dowty	Shield (4)	500	Joy Mfg. 1LS-4	DERS 330	Rack Eickhoff	Kloeckner-Becorit	21B 26	2-250	Kloeckner-Becorit or Long-Airdox
Consolidation Coal (Northern WV Region)	Loveridge #22 (Marion)	Pittsburgh 94 in.	92 in.	500 ft	1005-1300 ft	1977	—		Kloeckner-Becorit	Shield (2)	352	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	21B 30	2-300	Halbach & Braun or Long-Airdox
Consolidation Coal (Northern WV Region)	Loveridge #22 (Marion)	Pittsburgh 94 in.	92 in.	470 ft	1000-1500 ft	1978	—		Kloeckner-Becorit	Shield (2)	352	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	21B 30	2-300	Halbach & Braun or Long-Airdox
Consolidation Coal (Northern WV Region)	O'Donnell #20 (Marion)	Pittsburgh 84 in.	82 in.	550 ft	800 ft	1978	—		Kloeckner-Becorit	Shield (2)	352	Joy Mfg. 1LS-4	DERS 330	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Eickhoff or Halbach & Braun
Consolidation Coal (Northern WV Region)	Osage #3 (Monongalia)	Pittsburgh 84 in.	84 in.	610 ft	450-850 ft	1981	—		Dowty	Shield (4)	500	Joy Mfg. 1LS-4	DERS 310	Rack Eickhoff	Kloeckner-Becorit	21B 26	2-250	Kloeckner-Becorit
Consolidation Coal (Northern WV Region)	Pursglove #15 (Monongalia)	Pittsburgh 90 in.	90 in.	605 ft	500-900 ft	1981	—		Dowty	Shield (4)	500	Eickhoff 150-2L	DERS 477	Rack Eickhoff	Kloeckner-Becorit	21B 26	2-250	Kloeckner-Becorit
Consolidation Coal (Northern WV Region)	Robinson Run #95 (Harrison)	Pittsburgh 72 in.	70 in.	550 ft	750 ft	1972	1981		Gullick Dobson	Shield (2)	500	Eickhoff 150-2L	DERS 460	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Halbach & Braun or Long-Airdox
Consolidation Coal (Northern WV Region)	Robinson Run #95 (Harrison)	Pittsburgh 75 in.	72 in.	550 ft	650 ft	1975	—		Kloeckner-Becorit	Shield (2)	352	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	21B 26	2-200	Halbach & Braun or Long-Airdox
Consolidation Coal (Southern WV Region)	Hobet #3 (Boone)	Peacham #3 43-48 in.	46 in.	450 ft	600-900 ft	1971	—		Dowty	Chock (4)	700	Anderson Mavor 300	SFD 300	Chain Anderson Mavor	Dowty	31B 18	2-150	
Eastern Associated	Federal #1 (Marion)	Pittsburgh 84 in.	78 in.	550 ft	500 ft	1970	1981		Dowty	Shield (4)	610	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	26	2-250	Halbach & Braun
Eastern Associated	Federal #2 (Marion)	Pittsburgh 96 in.	90 in.	550 ft	750 ft	1973	1977		Dowty	Chock (4)	610	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun			Halbach & Braun
Eastern Associated	Federal #2 (Marion)	Pittsburgh 96 in.	90 in.	550 ft	750 ft	1973	1982		Dowty	Shield (4)	610	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	26	2-250	Halbach & Braun
Eastern Associated	Harris #1 (Boone)	Eagle 68 in.	60 in.	500 ft	200-1200 ft	1979	—		Westfalia Lunen	Shield (4)	600	Sagem 400	DERS 400	Chain Perard	Westfalia Lunen	21B 26	3-175	Halbach & Braun

ORGANIZATION		MINING PARAMETERS				INSTALLATION			ROOF SUPPORT			CUTTING MACHINERY			FACE CONVEYOR & STAGE LOADER/CRUSHER			
Mining Company	Mine & (County)	Seam & Height	Mined Height	Panel Width	Depth of Overburden	Initial Face	Present Face	Status & comments	Manufacturer	Type & (# Legs)	Yield Pressure	Manufacturer & Model	Type & HP	Haulage & Manufacturer	Conveyor Manufacturer	Sprocket & Chain size	Motors —HP	Loader Mfr. & Crusher
Eastern Associated	Harris #2 (Boone)	Campbell Ck. 70 in.	72 in.	480 ft	600-2000 ft	1970	1977		Westfalia Lunen	Shield (2)	427	Eickhoff 170L	DERS 226	Chain Eickhoff	Halbach & Braun	2B 26	3-178	Halbach & Braun
Eastern Associated	JoAnne (Marion)	Pittsburgh 84 in.		600 ft		1982	—		Westfalia Lunen	Shield (2)	360	Eickhoff 300L	DERS 403	Rack Eickhoff	Halbach & Braun	26	2-250	Halbach & Braun
Eastern Assoc. Coal	Keystone #2 (Wyoming)	Pocahon. #3 30 in.	60 in.	400 ft	600-1200 ft	1987	—		Westfalia Lunen	Chock (4)	450	Sabein 400	DERS 400	Chain Westfalia Lunen	Westfalia Lunen	2B 26	2-175	Halbach & Braun
Eastern Assoc. Coal	Keystone #5 (Raleigh)	Pocahon. #3 40 in.	40 in.	400 ft	600 ft	1974	1979		Westfalia Lunen	Shield (4)	460	Westfalia Lunen Gleithobel	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2B 22	2-175	Halbach & Braun
Eastern Assoc. Coal	Koppenaal #1 (Wyoming)	Eagle 64 in.	60 in.	520 ft	1000-1200 ft	1988	1991	Roller crush.	Westfalia Lunen	Shield (2)	580	Westfalia Lunen Gleithobel	Plow 2-200	Chain Westfalia Lunen	Westfalia Lunen	[illegible] 30	3-125	
Island Creek Coal (Northern Div.)	North Branch (Grant)	Upr. Freeport 96 in.	96 in.	450 ft	350-800 ft	1978	—		Kloeckner-Becorit	Shield (2)	440	Eickhoff 300L	DERS 403	Rack Eickhoff	Kloeckner-Becorit	2B 30	2-300	Kloeckner-Becorit crusher
Island Creek Coal (Northern Div.)	Dobbin (Grant)	Upr. Freeport 96-120 in.	96 in.	580 ft	200-700 ft	1982	—		Kloeckner-Becorit	Shield (2)	550	Eickhoff 300L	DERS 403	Rack Eickhoff	Kloeckner-Becorit	2B 30	2-300	Kloeckner-Becorit crusher
Pittston Coal Grp. (Badger Fuel Corp.)	Grand Badger (Upshur)	Mid. Kittanning 60 in.	60 in.	300 ft	250-600 ft	1978	1981		Westfalia Lunen	Shield (2)	360	Eickhoff 150-2L	DERS 477	Chain Eickhoff	Westfalia Lunen	2B 26	3-175	
Pittston Coal Grp. (Ranger Fuel Corp.)	Beckley #2 (Wyoming)	Beckley 48 in.	48 in.	500 ft	400-800 ft	1982	—		Hemscheidt	Shield (2)	394	Halbach & Braun	Plow 2-160	Chain Westfalia Lunen	Halbach & Braun	2B 26	2-160	Halbach & Braun crusher
Pittston Coal Grp. (Ranger Fuel Corp.)	Beckley #4 (Wyoming)	Beckley 48 in.	48 in.	350 ft	800 ft	1975	—		Westfalia Lunen	Chock (4)	560	Westfalia Lunen Gleithobel	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	3B 18	2-125	Long-Airdox
[illegible] Energy	Kilt #1 (Barbour)	Dist. Kittanning 57 in.	57 in.	600 ft	[illegible]	1991	[illegible]		Kloeckner-Becorit	Shield (2)	352	Eickhoff 150-2L	DERS 403	Rack Eickhoff	Halbach & Braun			Long-Airdox
US Steel Mining (Gary District)	Gary #9 (McDowell)	Pocahon. #3 50 in.	45 in.	400 ft	200-600 ft	1970		Mine is not operating.	Westfalia Lunen	Frames (4)	500	Westfalia Lunen P-Hook	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2OB 18	2-125	
US Steel Mining (Gary District)	Gary #9 (McDowell)	Pocahon. #3 50 in.	36 in.	500 ft	200-600 ft	1974	Pending	Mine is not operating, but new system is ready to install.	Westfalia Lunen	Shield (2)	420	Westfalia Lunen Gleithobel	Plow 2-200	Chain Westfalia Lunen	Westfalia Lunen	2B 26	1-350	
US Steel Mining (Gary District)	Gary #50 (Wyoming)	Pocahon. #3 50 in.	45 in.	500 ft	350-600 ft	1978	—		Hemscheidt	Shield (2)	353	Westfalia Lunen Gleithobel	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2B 26	2-175	Long-Airdox
US Steel Mining (Gary District)	Gary #50 (Wyoming)	Pocahon. #3 50 in.	36 in.	650 ft	350-600 ft	1990	—		Kloeckner-Becorit	Shield (2)	378	Westfalia Lunen Gleithobel	Plow 2-125	Chain Westfalia Lunen	Westfalia Lunen	2B 26	2-175	Long-Airdox
Laurel Run Mining (VA Elec. Power Co.)	#1 (Grant)	Upr. Freeport 74 in.				1974	1981		Dowty	Shield (4)	500	Anderson Mavor 500	DERS 500	Rack Anderson Mavor	Dowty	26	2-200	
Carbon County Coal	CCC #1 (Carbon)	120-168 in.	126 in.	450 ft	200-600 ft	1981	—		Kloeckner-Becorit	Shield (2)	550	Eickhoff 300-LH	DERS 470	Rack Eickhoff	Halbach & Braun			

APPENDIX 3

CURRENT STATUS OF COAL CLEANING IN U.S.

CURRENT STATUS OF PHYSICAL COAL CLEANING

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Presented at Coal Expo VI
Louisville, KY.

October 1981

Current Status of Physical Coal Cleaning

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INTRODUCTION

The coal industry in the United States has entered a period of unprecedented growth. If current predictions become reality, the production of coal will grow at rates of seven to eight percent per year until the end of the century, this rate being substantially greater than will occur in the economy as a whole. Most of it will be consumed in electrical power generation.

In addition to meeting the challenge of reducing America's dependence on foreign energy sources it has become very clear, in the past year or so, that the coal resources of the United States have become increasingly attractive to many foreign nations who have no coal, or, having depleted their resources, are trying to break the grip of OPEC oil on their economies. The United States has been a successful exporter of coal for many years, mainly to the international steel industry, attributable in large part to the excellent quality, in terms of ash, sulfur and coking properties of United States' coals. Effective and efficient coal preparation has played an important role in winning this pre-eminence. In the future, however, the coal requirements of the steel industry are expected to grow at a relatively slow rate compared with the demand for coal for electrical power generation so that, like on the home front, the greatest export potential now lies in meeting the needs of foreign electric generating companies and other major steam users. Coal preparation will need to adapt to meet the quality requirements of this market in competition with Australia, South Africa, Canada, Poland and, soon, some of the Third World countries.

The early industrialization of the United States produced major centers of population at the major eastern seaports, in the Appalachian and Central coalfields and along the great natural transportation routes serving those coalfields. During, and since the 1950's as industrial activity became increasingly dependent on oil and natural gas, these early links became less important and has resulted in major sections of the population becoming established in the Southwest and in Southern states at locations far removed from the developed coalfields. The new found dependence on coal

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as the primary energy source has, therefore, had several consequences on coal production and preparation. Firstly, the development of formerly remote and isolated western coalfields has become necessary. Secondly, Western coals are very different in nature and properties than those of the central and eastern coalfields and their preparation requirements are different. Thirdly, the option of long-range transportation of low rank coals or of prior conversion before transportation, are posing difficult questions.

One other point needs to be mentioned in this context. The increased opportunities facing the industry have provided incentives for finding more efficient and cost effective methods for producing coal, while at the same time, meeting stiffer regulatory requirements for safety, health, land management and environmental control. We are seeing greatly increased scales of production, increasing mechanization and automation, and new demands that these be performed with minimum impact on our world. Like other essential activities in the chain comprising the production and use of coal, they have an important bearing on the practices of coal preparation and, hence, on physical coal cleaning.

Coal preparation includes, but is not synonymous with physical coal cleaning. Coal preparation comprises the totality of treatments which coal receives on its way from the coalface to its end use. These treatments are mainly designed to provide adequate control of size consist, proximate analyses and certain other special properties such as coking or ash fusion characteristics. The unit operations may include sorting, crushing, screening, washing, dewatering, drying, dry cleaning and blending. Of necessity it also includes other indirect operations such as water treatment, refuse treatment and disposal, dust control and, more recently, noise control.

Physical coal cleaning has, as its prime objective, control of the proximate components, ash and moisture contents, by reducing them to levels achievable with the appropriate equipment and systems used and with optimized recovery of the thermal value of the coal. For certain coals, methods used for removing mineral matter (ash) are also effective to some extent in reducing the pyritic sulfur content and are being increasingly considered for this purpose. Physical coal cleaning is not effective and cannot be effective for reducing the organic sulfur content of coals. Removal or reduction of the organic sulfur component requires chemical treatments.

At the present time chemical methods of coal cleaning are not in commercial use in the United States, or, as far as can be ascertained, in the world. Commercial cleaning of coal therefore consists, for the time being, entirely of mechanical methods which exploit differences in the physical or physico-chemical properties of coal and refuse, and comprises some, but not all, of the unit operations listed earlier. In this situation one might expect that, in step with rising coal production and preparation, physical coal cleaning would be increasing. Inspection of the industry's statistics shows otherwise. Over the last fifteen years, physical coal cleaning both in absolute and relative tonnage terms has been steadily declining. The production of mechanically cleaned coal in the United States is presently at levels similar to those obtaining in 1951.

During this same period substantial progress has been made in introducing newer, more efficient, cleaning methods, in building larger plants, in introducing cheaper 'portable' and 'package' plants, and in the cleaning and recovery of fine coal.

The recent status of physical coal cleaning, therefore, appears to be an astonishing one of decline in the face of increasing technical innovation and rapidly rising coal production. Some of this decline is more apparent than real because an increasingly large part of the incremental coal production, particularly that produced in western states, is not suitable for or results in only marginal benefits from physical coal cleaning. This aspect effectively disengages the rate of increase of coal production from any apparently corresponding increase in the application of physical coal cleaning. However the decreasing tonnage of cleaned coal in absolute terms since 1967 cannot be so easily dismissed. It implies both that the extent of coal cleaning actually decreased as an industrial activity and that the average yields obtained on cleaning may also have diminished.

This poses a serious question for the future importance of physical coal cleaning. Is, then, the real decline due to the fact that consumers are not convinced that the premium they are charged for cleaned coal is worth the percieved benefits? Physically cleaned coal offers substantially lower levels of ash content, some reduction of sulfur content (although this is far less predictable) and much smaller variability in these constituents and in moisture content. If used as steam coal, the potential benefits to users are a reduced ash disposal problem, improved control of particulates emmissions, some reduction in sulfur emmissions and improved control of heat input to the boilers. Other benefits of an

operational nature can also result, which were ably described to this conference last year by Gerald Blackmore. The case for physical coal cleaning of steam coals, for R&D in certain areas of the physical cleaning processes, for convincing demonstration on a commercial scale and, above all, for a wider education of the electric utility industry into the benefits of physical coal cleaning has been a program vigorously pursued by the Electic Power Research Institute since 1975. Just recently, the commissioning of EPRI's new demonstration pilot plant at Homer City, Pennsylvania was announced. The Environmental Protection Agency, the federal, and many states Departments of Energy also have programs and investigations in progress.

There is little question that there exists substantial technical support for physical coal cleaning. Serious misconceptions about its usefulness, however, also exist, both in support and in opposition. For example, there appears to be far too abundant a belief that physical coal cleaning is generally an effective method for substantially desulfurizing coal; and even that all the pyritic sulfur in coals can be removed by existing washing methods. Coal preparation engineers have as much a duty to explain the reality of the situation in this context as they do of countering the reluctance to believe that paying a premium for cleaned coal can be worthwhile in bottom-line economic terms.

This introduction has been lengthy but the subject is extensive and has many ramifications. The remainder of this paper will discuss specific aspects of the production of physically cleaned coal; the impact of changes in the mining industry; recent technical innovations in physical coal cleaning; some continuing problems; physical coal desulfurization; and costs aspects.

PRODUCTION OF PHYSICALLY CLEANED COAL

Table I provides a summary of cleaning plant operations for the period since 1972. Table II summarizes the distribution of coal cleaning between underground and surface mined coals. Table III indicates recent cleaning practice by types of equipment employed.

Table 1 shows that the annual production of cleaned coal dropped by about 70 million tons between 1972 and 1978, representing a real reduction in the industry of approximately 25 percent. The numbers of washplants did not reduce by anything like this proportion and the present situation is one of substantially underemployed coal cleaning capacity. The table also shows that average yields of cleaned prod-

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TABLE I: SUMMARIZED CLEANING PLANT OPERATIONS

YEAR	TOTAL COAL PRODUCED	NO. OF CLEANING PLANTS	RAW COAL MOVED TO CLEANING PLANTS	CLEAN COAL PRODUCED	PERCENT YIELD ON CLEANING	PERCENT OF TOTAL PRODUCTION
	000's TONS					
1972	595,386	408	398,678	292,829	73.4	49.2
1973	591,738	382	397,646	288,918	72.7	48.8
1974	603,406	387	363,334	265,150	73.0	43.9
1975	648,438	388	374,094	266,993	71.4	41.2
1976	678,685	417	379,236	268,830	70.9	39.6
1977	691,344	418	358,824	253,917	70.8	36.7
1978	665,127	419	320,500	224,780	70.1	33.8
1979	776,299	NA	NA	NA	-	-
1980	830,000 1/	NA	NA	NA	-	-

1/ Preliminary

Source: US DOE

TABLE II: DISTRIBUTION OF PHYSICAL CLEANING BETWEEN UNDERGROUND AND SURFACE OPERATIONS

YEAR	UNDERGROUND			SURFACE		
	TOTAL COAL	CLEAN COAL	PERCENT	TOTAL COAL	CLEAN COAL	PERCENT
		000's TONS			000's TONS	
1972	304,103	204,986	67.4	291,284	87,843	30.2
1973	299,354	205,967	68.8	292,384	82,951	28.4
1974	277,309	180,024	64.9	326,097	85,125	26.1
1975	292,826	179,379	61.3	355,612	87,614	24.6
1976	292,384	180,897	61.9	383,803	87,935	22.9
1977	265,950	165,554	62.2	425,395	88,362	20.8
1978	242,177	147,024	60.7	422,950	77,756	18.4
1979	320,321	NA	-	455,978	NA	-
1980	334,430	NA	-	495,370	NA	-

Source: US DOE

TABLE III: PHYSICAL COAL CLEANING BY TYPE OF EQUIPMENT

TYPE OF EQUIPMENT	1975	1976	1977	1978	1979
	000's TONS				
WET METHODS:					
Jigs	124,317	125,556	114,689	104,811	NA
Concentrating Tables	28,682	30,213	30,479	23,549	NA
Classifiers	6,176	5,772	6,965	6,153	NA
Launders	2,664	2,977	1,636	1,358	NA
DENSE MEDIUM PROCESSES:					
Magnetite	72,448	72,742	71,529	65,823	NA
Sand	13,533	12,673	10,238	7,765	NA
Calcium Chloride	951	902	552	924	NA
FLOTATION	11,519	11,578	13,361	10,068	NA
TOTAL, WET METHODS	260,290	262,413	249,449	220,451	NA
PNEUMATIC (DRY) METHODS	6,704	6,419	4,469	4,330	NA
GRAND TOTAL	266,994	268,832	253,918	224,781	NA

Source: US DOE

ucts have been falling significantly during this period, indicating deterioration in the quality of the raw coal sent to cleaning plants. This reduction in yield is attributable to both increasing ash contents and ultrafines contents (-28 mesh) and reflects changing mining practices, particularly in underground mines. Table II shows that more than 60 percent of all coal produced underground is physically cleaned whereas only 25 percent of surface mined coal is cleaned.

Table III shows that the principal cleaning methods, in terms of tonnage produced, are jigs, dense medium vessels and cyclones, concentrating tables and froth flotation. The other methods listed in the table are generally diminishing in importance, including dry cleaning by pneumatic methods. What the table does not reveal is a substantial redistribution within the main heads included. Thus, while dense medium processes are maintaining their share of the total production, recent years have seen the introduction of dense medium cyclone systems which have, in some cases, replaced dense medium vessels. Similarly, the pre-eminence of concentrating tables for cleaning small sizes is being challenged by the new introduction of water-only hydrocyclone systems and by newer jig systems capable of cleaning effectively to much finer sizes.

IMPACT OF MINING CHANGES

Changes in coal mining can be expected to impact on coal cleaning in two principal ways. Firstly, an increasing proportion of total coal production will consist of lignites and sub-bituminous grades produced, mostly by surface mining methods, in coalfields west of the Mississippi where the largest reserves exist. (See Table IV.) Table V shows National Coal Association forecasts of future sources of production. The existing methods of physical coal cleaning were mainly developed for anthracites and bituminous coals and are not easily applicable to lower-rank coals having different cleaning characteristics. Their principal characteristics are generally lower ash and sulfur contents and substantially higher equilibrium moisture contents. The ash contents are generally low enough to avoid the need for cleaning, and where ash contents are higher it is often due to intercalated bands of swelling clays that render the coal unsuited for cleaning by wet methods. The main problem presented by many of these coals is to provide effective methods for thermal drying and hence reduce transportation and handling costs. Effective drying is also required in utilizing these coals.

TABLE IV: STATES HAVING LARGEST ESTIMATED COAL RESERVES

STATE	TOTAL RESERVES (billion tons)	COAL TYPE
Alaska	130	mostly sub-bituminous
West of Mississippi:		
North Dakota	350	lignite
Montana	290	Sub-bituminous and lignite
Wyoming	135	mostly sub-bituminous
Colorado	130	bituminous
New Mexico	60	mostly sub-bituminous
East of Mississippi:		
Illinois	145	bituminous
West Virginia	100	bituminous
Pennsylvania	60	bituminous and anthracite

Source: USGS

TABLE V: NCA FORECAST OF SOURCES OF PRODUCTION

	ACTUAL 1979	1985 LOW	1985 MOST LIKELY	1985 HIGH	1990 LOW	1990 MOST LIKELY	1990 HIGH
Production East of the Mississippi River	555	569	665	722	677	827	925
Production West of the Mississippi River	221	309	350	409	415	518	615
Total Production	776	878	1,015	1,131	1,092	1,345	1,540

Source: National Coal Association

A second impact on coal cleaning results from changes in mining of bituminous coals, particularly in underground mines. Surface mining is already highly mechanized and employs equipment - draglines, shovels, bulldozers, scrapers, trucks, conveyor systems - that is not expected to change much in the foreseeable future. The dimensions of the problem of cleaning surface mined bituminous coals are therefore already understood, and effective cleaning methods are available. In the case of underground mining practices, conventional methods have been increasingly replaced by continuous mining and, more recently still, by longwall operations and these methods are expected to increase and eventually dominate underground production. They represent the limits of current technology and operate at high production rates. However, they are, of necessity, less selective than conventional methods, resulting in increased ash contents through rock dilution of run-of-mine coals; and their cutting action generally results in the production of finer coal. The problem of increasing ash is not too serious, except for the inconvenience of decreasing yield, since the available coal cleaning systems are sufficiently flexible to handle the increased refuse loading. The problem presented by increased fines is more serious because efficiency decreases and costs of cleaning and dewatering increase markedly as particle sizes become smaller. In some cases, increases in ultrafines content (-28 mesh) from 15 percent to 25 to 30 percent have resulted from increased mechanization. A significant part of the increased breakage is known to result from degradation in the high-capacity handling and transportation systems between the mine and washplant. This problem is being tackled at source by the introduction of new designs of conveyor transfer points, in-line surge bunkers and storage bunkers, and stacking and reclaiming equipment. Nevertheless an increased fines load can be expected and it is well recognized that efficient and cost-effective methods for cleaning, dewatering and drying fine coals remains a major problem.

PHYSICAL CLEANING - CURRENT OPTIONS

The current range of options commercially available are shown in Figure I. Most cleaning plant systems separate the raw coal feed into coarse, fine and ultrafine sizes. These are not definable with precision but may be represented as + 3/8" (10 mm), 3/8 x 28 mesh (10 mm - 0.5 mm) and -28 mesh (-0.5 mm). Many washplants today receive a raw feed crushed to 2" x 0, and containing up to 20 percent of material passing 28 mesh; with allowance for some additional in-plant degradation the loads on the ultrafine

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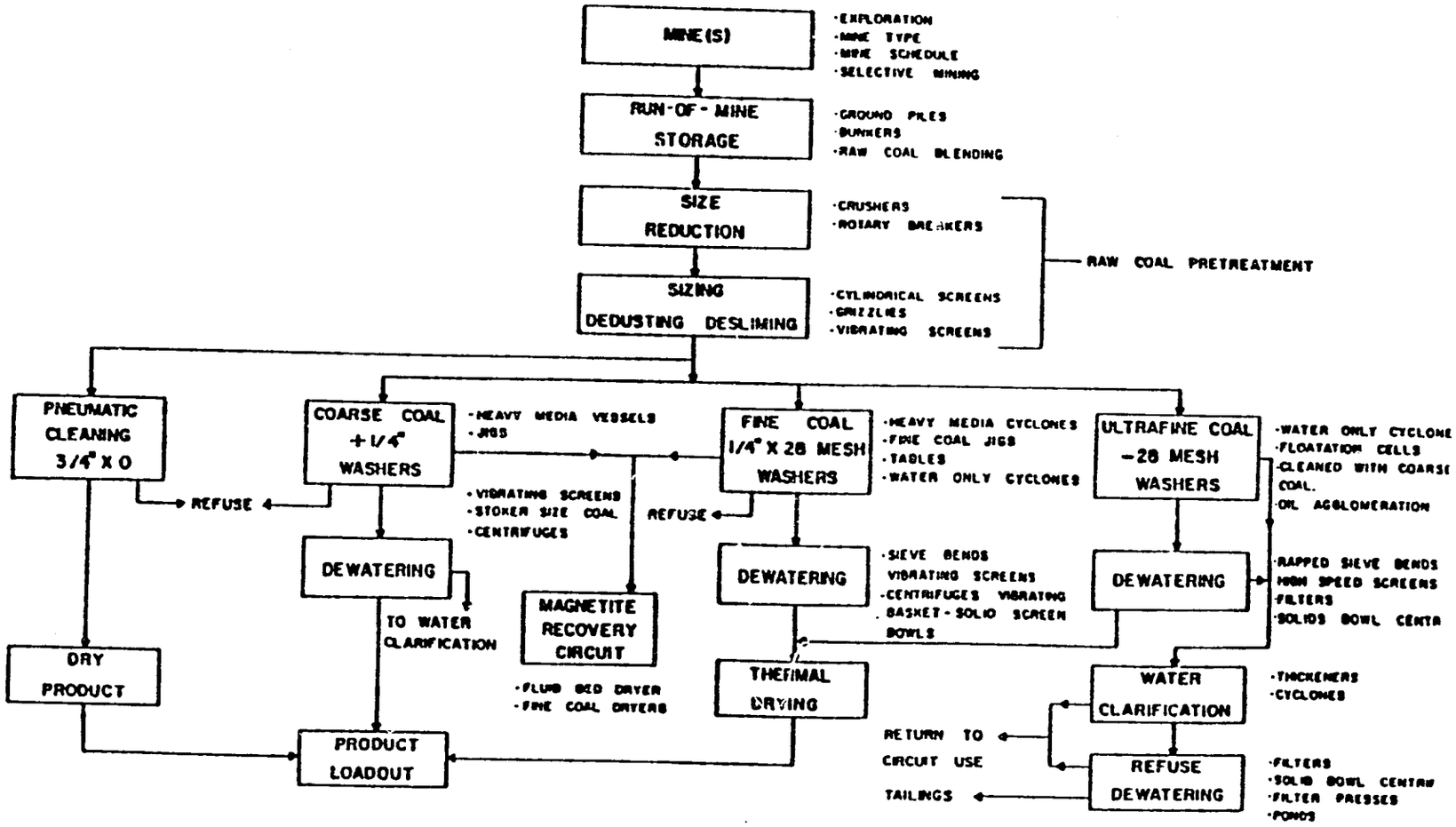


FIG. 1 PHYSICAL COAL CLEANING - RANGE OF OPTIONS

circuits can reach 25 percent of coal feed.

The wet physical cleaning processes involve a stage in which coal is separated from shales and a second stage in which the coal is recovered from the fluid and dewatered. As stated earlier, these processes become decidedly more difficult as particle sizes decrease. Typical ranges of equipment efficiency for the separatory stage are shown in Figure II. The ranges of particle sizes and resulting moisture contents for equipment employed in recovery, drying and dewatering of cleaned coal are shown in Figure III.

Figure II shows that in general the efficiency of separation is greatest for dense medium systems; and least for the interfacial (froth flotation) systems when particle sizes become smaller than 20 microns. This is a remarkably wide range of cleaning capability and the figure gives no direct indication of the substantial capability of each of these systems for handling fluctuating raw coal feed quality.

Some other significant advances are also worth noting. It has recently been demonstrated, both in the U.S.A. and other countries, that dense medium cyclone circuits are capable of cleaning coal effectively down to 100 mesh. This represents a large reduction in the load potential of interfacial units (froth flotation or oil agglomeration) and since the cleaned product, after separation from magnetite, can be dewatered by centrifuges, it also represents a substantial reduction in capital and operating costs. The new Batac Jigs are showing effective cleaning capabilities down to 65 mesh. Water-only cyclones of the compound type have been demonstrated to be effective down to 150 mesh. In these cases primary dewatering is obtainable with a sieve bend followed by centrifuging. The use of the sieve bends alone has, in many cases, resulted in the recovery of significant quantities of coal from raw slurries formerly passed to refuse impoundments, with resulting substantial improvements in financial results. The attack on the problem of cleaning and recovering coal fines has been many sided and effective.

Whereas froth flotation was formerly a process employed, if ultrafines were cleaned at all, for cleaning -28 mesh raw slurries, in the newer plants it is being applied to the smaller quantities of -100 mesh material. One improvement in the control of the process has been the introduction, initially in West Germany, of a static thickening stage for conditioning raw slurry. This allows much more precise con-

FIGURE II TYPICAL SEPARATING EFFICIENCIES WITH PARTICLE SIZE

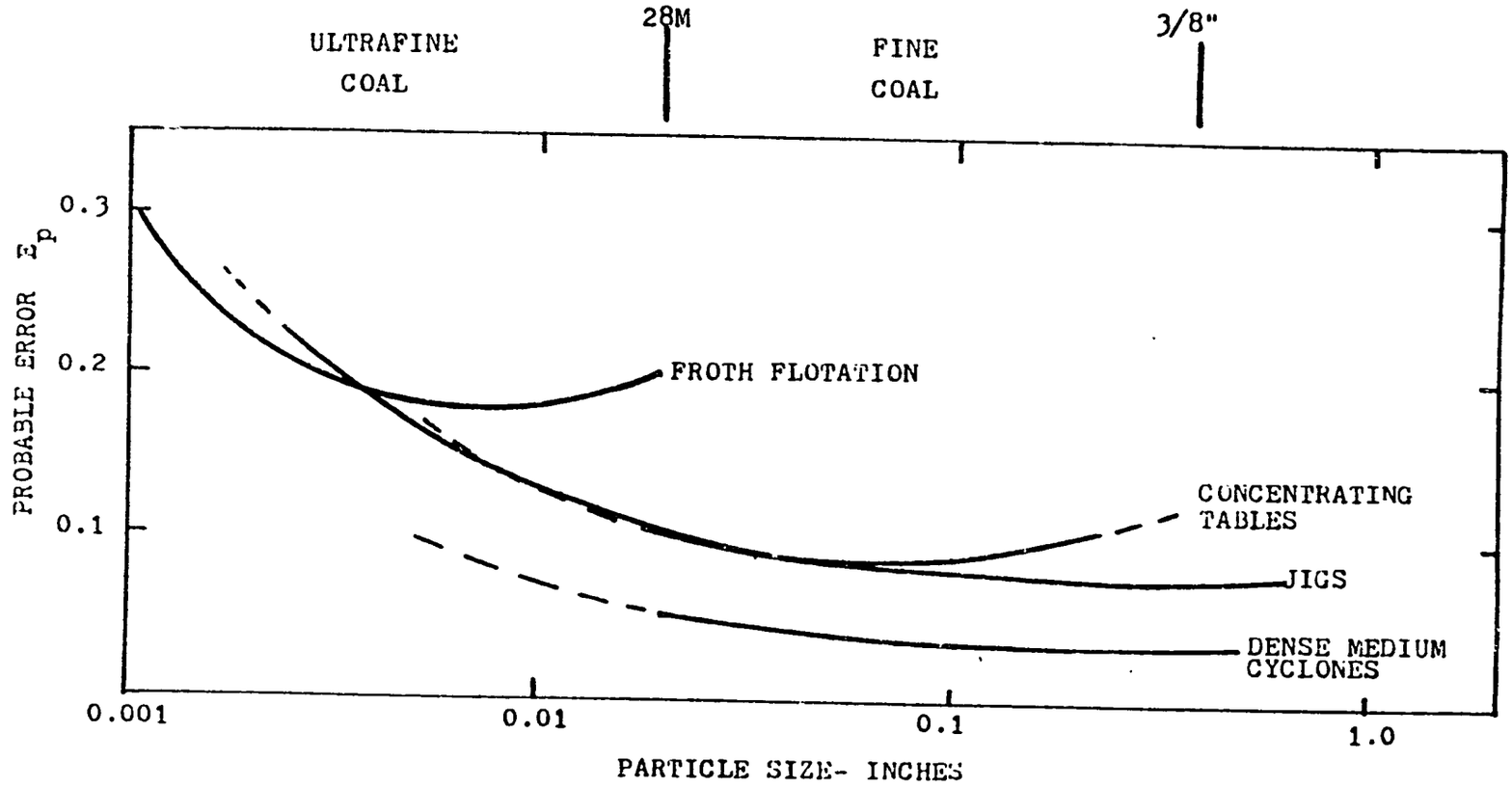
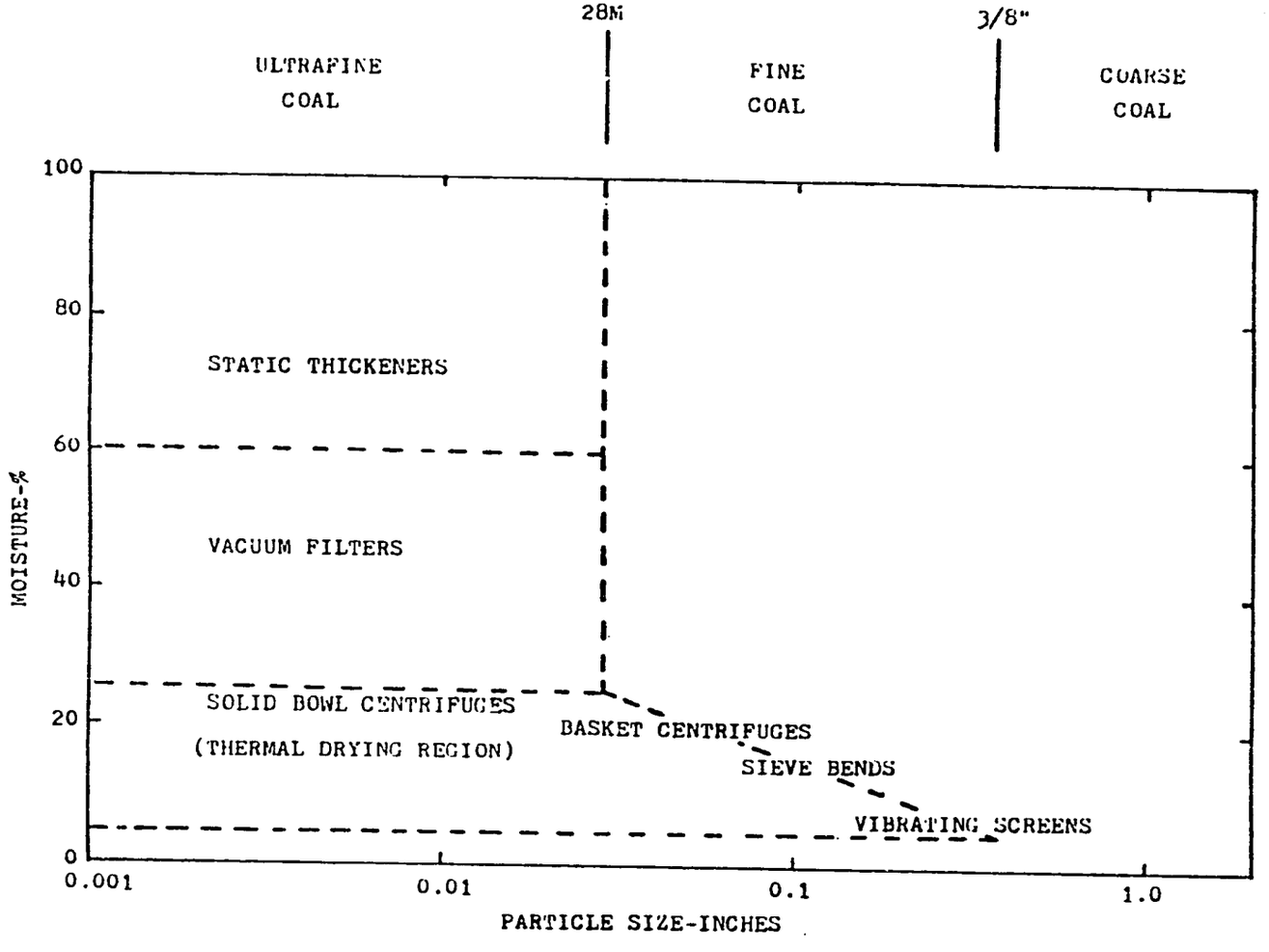


FIGURE III TYPICAL APPLICATIONS OF DEWATERING EQUIPMENT



trol of pulp concentrations and uniformity in reagent dosing; both leading to observable improvements in cleaning efficiency.

During World War I, a certain Colonel Trent, disturbed at the large quantities of fine coal lost from the existing washplants to refuse impoundments, devised a method of reclaiming this coal from the raw slurries by adding fuel oil, stirring vigorously, and recovering the coal/oil agglomerates by passing the mixture over a wire screen. The mechanism that drives this 'collector' process is similar to that which operates in froth flotation. The principal differences are that much larger quantities of oil are required, much more vigorous stirring is required, and the coal is not recovered as a froth, which is difficult to dewater, but as roughly spherical agglomerates, up to half an inch in average size, from which free water is substantially excluded. By appropriate control of process parameters - oil type, oil quantity, agitating action - it has been demonstrated that the process can selectively recover coal from high ash slurries so that oil agglomeration may be utilized as both a recovery and as a cleaning process. Its principal advantage over froth flotation is the much lower costs of dewatering the coal/oil agglomerates. Its principal dis-advantage is the high cost of the oil required; this latter being the reason why, after being developed in recent years to full scale application, it has been abandoned again in Europe. It has found limited application in Australia, Canada and the USA, and is being investigated in India and South Africa.

SOME REMAINING PROBLEMS

Except in those cases of coals having substantial amounts of 'near gravity' material, that is, having 'difficult' washing characteristics in which coal substance and gangue materials are intimately bound, even at very small particle diameters, the available methods for separating coal and refuse are highly effective, flexible and cost effective. In a very limited number of cases, oxidation renders some coal ultrafines difficult to clean by froth flotation because of its effect on the non-polar characteristics of the surfaces of the coal particles. But even this problem is succumbing to recent developments in the improvement of frother agents. However, practising washplant engineers would insist that successful cleaning continues to be an art as much as a science. And who will deny this when even today, we still lack a universally accepted method for expressing the efficiency of cleaning? As recently as June 1981, K.F. Tromp was proposing modifications of his original

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method of assessing separation efficiency, based on material distribution factors, first introduced in 1937!* And many other investigators have proposed methods in the intervening period. However, coal cleaning is not alone in being an industry in which the achievement of high technical efficiency has preceded a scientific explanation of it.

For bituminous coals, the main problems remaining, therefore, lie in the dewatering and drying of ultrafines, the dewatering and disposal of shales and slurries and, in the case of high sulfur coals, maximizing the removal of pyritic sulfur. For the sub-bituminous coals and lignites in western coalfields, the main problems are reduction of ash by removal of swelling clays intercalated in the coal seams, and reduction of very high inherent moisture contents. As Figure III shows, the methods available for dewatering ultrafines are solid bowl centrifuges and vacuum filtration. The former are bein improved, within limits, by the introduction of high "g" machines. But as these limits are increasingly due to the operation of Stokes Law and of the properties of colloids, as particle sizes decrease, the physical limits are absolute ones. Similarly, improvements in the operation of rotary drum and disc filters have encountered constraints imposed by the viscosity and surface tension of water at ambient temperatures. Improved performance can result if the filtration pulp is heated, or if the cake on the filter is heated by steam during filtration, because both the viscosity and surface tension of water decrease appreciably with temperature between ambient temperatures and the boiling point. Steam-heated hoods on rotary filters have been in effective use for many years but add to the already high operating and maintenance costs of this equipment and hence are not popular. Pressure belt filters, long used in the paper and sewage industries, are being regarded with increased interest.

Ultrafines, which after dewatering contain 20 to 25 percent residual moisture, can comprise as much as 20 to 25 percent of the product of deep cleaning. The coarse and fine coal fractions of the same product may have moisture contents averaging less than seven percent but the overall result is that in such cases, it is impossible to achieve total product moisture contents of less than 10 to 11 percent. This has its inevitable consequences in terms of increased handling difficulties caused by sticky coal, increased transportation costs and increased freezing problems in winter months. Effective methods for the thermal drying of fine

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*K.F. Tromp "Modified Methods of Assessing Separating Efficiency". Mine & Quarry, Vol. 10., No. 6 pp 49-50

and ultrafine bitumimous coals are available. They were developed mainly to meet export specifications for metallurgical coals. They include a variety of types ranging from trays and tumblers to fluidized beds. Many are fired by oil or natural gas, for convenience and ease of control of the hot flue gases used for drying. In such cases, some savings are obtainable by conversion to coal firing or, better still, by utilizing the high-ash coal wastes which still contain sufficient heat values to support autogenous combustion. In the case of fluidized combustors, this can be as low as 2500 to 3000 Btu/lb, and many coal wastes fall into this range. This presents a substantial technical challenge and some promise of economic benefits.

Drying sub-bituminous coals and lignites presents a different set of problems, and is not yet widely practised. The bulk of the moisture present is not surficial, but is more strongly 'bound' and interstitial water inherent in the structure of the coal. Because these coals are much more liable to spontaneous ignition, particularly as they dry out, milder regimes of temperature are necessary in drying than for bituminous coals. The heat inputs required per unit mass of water evaporated are higher but the temperature at which this heat is applied must be lower. Also, the dried coals show tendencies to reabsorb water, some even being appreciably hygroscopic. North American does not face the severest problems in this context since its lignites generally range 35 to 40 percent moisture. This may be compared with German brown coals which contain about 60 percent and Australian brown coals which contain as much as 75 percent moisture. In general, where process and/or transportation economics demand, methods for drying low rank coals are available but it remains an area where more R&D is required.

A particularly severe dewatering problem exists where environmental regulations limit or prohibit the discharge of liquid shales and slimes to impoundments. This requirement is becoming universal and new washplants are designed for total water recycle. Elaborate water treatment becomes necessary from which the slimes are usually available as flocculated solids exhibiting pronounced non-Newtonian characteristics. The flocs are both highly compressible and thixotropic and are mainly unsuitable for dewatering by vacuum filtration. Cloth filter presses are in use but are costly in capital, operating and maintenance terms, and the process is slow. In some cases, settling in extra-deep cones is effective. Still, further improvements are urgently required. Feeding the partially dewatered slurries to fluidized-bed combustors, both to recover residual thermal values

and simplify disposal, may provide the best solution in certain cases.

When the extraneous ash in sub-bituminous coals and lignites consists of intercalated bands of clays, which exhibit swelling characteristics, wet cleaning methods, whether hydraulic or dense medium, can result in extremely severe water treatment problems and such methods are best avoided. Some plants have already encountered great difficulties from this cause. The difficulties have led to a renewal of interest in dry cleaning methods. The coals are too wet to allow application of conventional air tables. Research and development is under way both in the USA and Canada but satisfactory commercial application of new methods is not yet in sight.

PHYSICAL COAL DESULFURIZATION

Any consideration of the physical desulfurization of a coal must start from an examination of the distribution of the total sulfur in that coal; the so-called 'forms of sulfur'. The conventional distribution is into organic sulfur, pyritic sulfur and inorganic (or sulfate) sulfur. Standard analytical methods exist for the determination of total, pyritic and sulfate sulfur contents, organic sulfur being the difference between the total and sum of the other two forms.

In the great majority of coals, sulfate sulfur is so low as to be conveniently ignored; and pyritic and organic forms comprise the bulk of the total sulfur present. Pyritic sulfur is most usually present as one or other of the crystalline modifications of iron pyrites, FeS_2.

It occurs as discrete microcrystalline entities dispersed in both the pure coal substance (macerals) and its associated shale (minerals). The sight of an apparantly isolated crystallite of pyrite embedded entirely within a vitrinite granule, a scintillating jewel in a uniform sea of grey, is a familiar sight to coal petrographers. Sometimes the pyrite occurs as more massive crystals or lenses at coal/shale interfaces. No general rules exist which determine whether the pyrite is mainly associated with the macerals or minerals, whether it is distributed in massive inclusions or lenses so that it is substantially liberated by crushing and grinding, or whether it is distributed as microcrystallites so small that crushing and grinding results in only a very limited release. This is the crux of the difficulty of separating pyrites from coal and must be determined separately for each individual coal. It may even vary for different locations within a given coal seam.

Organic sulfur is known to exist in coal as a component of heterocyclic structures (thiophen) and as mercaptan and thioether linkages of an aliphatic nature. These carbon to sulfur linkages are all recognized as chemically stable bonds and require quite vigorous chemical treatment to induce rupture and facilitate sulfur removal. This is the subject of a paper by Robert Meyers at this conference, and requires no further consideration here except to note that physical coal cleaning methods, by their nature, are unable to remove organically bound sulfur in coal.

The differences in physical properties between coal macerals, minerals (excluding pyrite) and pyrite are summarized in Table VI. The table shows the substantial differences exist in all the properties listed except that of wettability (Contact Angle). Here, coals and pyrites share an overlapping range of values and in fact many instances are known where free pyrite particles are recovered in the froth, during flotation, despite the large difference in specific gravities of coal and pyrite particles. A second flotation carried out after redispersing the primary or 'rougher' froth is usually effective in separating the coal from pyrites and underlies the occasional employment of two-stage flotation processes. Apart from these instances, most of the gravity based separatory processes - small jigs, dense medium systems, tables, water only cyclones, spirals - can be effective in separating liberated pyrite from coal. Some relevant information is summarized in Table VII.

The propensity for physical desulfurization of coals can be assessed by laboratory washability tests carried out on coal samples crushed to various top sizes. Typical sizes could be 2" x 0 and 3/8" x 0. Determination of the sulfur contents of the various size and gravity fractions obtained indicate whether measurable release of pyrite occurs and the gravity cut-point at which separation and yields can be optimized. Such methods formed the basis of the investigations into Sulfur-cleaning potentials of US coals conducted by the U.S. Bureau of Mines. (RI 8118). By taking cut-point at 1.60 specific gravity for coals crushed at 3/8" x 0 the average potential reduction, expressed in terms of lbs. SO_2/MM Btu, ranged from 16 to 43 percent for different coal regions, as shown in Table VII.

By a consideration of theoretical cut-points in this manner coupled with the separating efficiencies of commercial equipment as shown in Figure II, it is possible to calculate hypothetical desulfurization obtainable under actual operating conditions. Such an investigation has recently been completed in conjunction with observed plant results*.

* Versar Inc. NTIS PB80-210529 (May 1980)

TABLE VI: SOME PHYSICAL PROPERTIES OF RAW COAL COMPONENTS

PROPERTY	COAL MACERALS	MINERALS (excluding Pyrite)	PYRITE
Color	Black	Grey	Golden
Specific Gravity	1.15 - 1.5	2.2 - 3.9	4.8 - 5.0
Reflectance %	0.5 - 7.5	4 - 8	42 - 47
Hardness (Mohs' Scale)	2.1 2.5	2.0 - 4.5	6.0 - 6.5
Wettability (Contact Angle)^{o}	49 68	11 - 15	60 - 75
Magnetic Susceptibility (c.g.s.)	(-0.5) - (-0.6)	(-20) -(+400)	(+40) - (+65)
Dielectric Constant	2.0	4.7 - 7.8	5.2 - 8.5

TABLE VII: CLEANING EQUIPMENT EFFECTIVE FOR SEPARATING FREE PYRITES

PROCESS	EQUIPMENT	FEED	EFFECTIVE SIZE RANGE	EFFECTIVE S.G. RANGE	MACHINE CAPACITY tph
Dry	Air Table	Fine Coal	3/4" - 48 mesh	1.70 - 2.00	150
Wet	Feldspar Jig	Fine Coal	1/2" - 28 mesh	1.45 - 2.00	100
Hydraulic	Batac Jig	Fine Coal	3/4" - 100 mesh	1.45 - 2.00	700
	Compound Water Cyclone	Fine Coal	2" - 150 mesh	1.30 - 1.90	65
Heavy Media	Cyclone	Fine Coal	1/4" - 200 mesh	1.30 - 2.00	100
Interfacial	Froth Flotation	Ultrafines	28 mesh - 0	-	120
	Oil Agglomeration	Ultrafines	100 mesh - 0	-	35

A digest of the relevant results is summarized in Table VIII. Inter alia it was concluded -

> "In seven of eight coal cleaning plants, for which matched pairs of feed and product coal data were available..... The mean total sulfur content was reduced by 14 to 45 percent, the mean heating value was increased by 6 to 23 percent, and the mean lbs SO_2/MM Btu was reduced by 24 to 50 percent....."

The conclusions continue on to find that the empirical data fall within the range of calculated physical coal cleaning performance of hypothetical plants; and that the range of effectiveness of physical coal cleaning as a sulfur dioxide control technology is demonstrated by these data from operating commercial coal preparation plants.

In addition to finding the actual range of reduction in sulfur quoted above,the investigators demonstrated that physical coal cleaning was also effective in achieving a substantial reduction in the variability of sulfur contents, heating values and sulfur to heating value ratios.

And finally, the conclusions of this recent study strike an appropriate note of balance -

> "The ranges of both demonstrated and calculated effectiveness are wide, reflecting the sensitivity of coal cleaning efficiency to the washability characteristics of specific coals and to the complexity of plant design. These actual and calculated data demonstrate that no valid "typical" effectiveness can be quoted for physical coal cleaning technology".

COSTS OF PHYSICAL COAL CLEANING

Cleaning costs are determined primarily by the level of cleaning employed and the ash content and size consist of the raw coal to be cleaned.

Various ways of defining the level of cleaning are available, mainly determined by the argument to be presented and usually in terms of increasing plant complexity. In the desulfurization study referred to in the previous section, five levels of cleaning, and hence five levels of plant complexity,were defined as follows -

Level 1 - Breaker for top size control and for the removal of coarse refuse.

TABLE VIII: OBSERVED PHYSICAL DESULFURIZATION IN COMMERCIAL PLANTS

Cleaning Plant ID.			1	2	3	4	5	6	7	8
Cleaning Level			5	3	6	5	5	5	3	5
State			Ky	Il	Il	Ky	Ky	OH	WV	VA
County			Ohio	Randolph	Christian	Ohio	Muhlen-berg	Perry	Hancock	-
Seam(s)			9 & 14	6	6	9	11 & 12	6	Lower Kittaning	SW
Total Sulfur	Feed	%	4.16	4.75	5.12	4.29	4.26	3.94	1.94	0.93
	Product	%	3.19	4.10	4.39	3.37	3.22	3.01	1.07	1.17
HHV	Feed	Btu/lb	11,320	10,762	10,650	12,230	10,270	11,070	12,950	9,980
	Product	Btu/lb	13,000	12,177	12,300	12,970	12,650	12,460	14,370	14,470
lbs SO_2/MM Btu	Feed	-	7.35	8.82	9.60	7.01	8.33	7.13	3.00	1.85
	Product	-	4.90	6.73	7.13	5.18	5.09	4.83	1.49	1.61
	Reduction	%	33	24	26	26	39	32	50	13

Source: Versar Inc. "Effect of Physical Coal Cleaning on Sulfur Content and Variability". NTIS PB80-210529. May 1980

Level 2 - Coarse beneficiation - where larger fractions of coal (plus 3/8 inch) are treated. The separated and untreated minus 3/8 inch portion of the coal is combined with the cleaned coarse coal for shipment.

Level 3 - Fine and coarse size beneficiation - where all the feed is wetted. Plus 28M is beneficiated; 28M x 0 material is dewatered and either shipped with clean coal or discarded as refuse.

Level 4 - Very fine beneficiation - where all the feed is wetted and washed. Thermal drying of 1/4" x 0 fraction generally is often desired to limit moisture content.

Level 5 - Full beneficiation resulting in multiproducts - where the raw coal is crushed to much finer sizes, resulting in multistage cleaning and multiproduct operation.

The particular level chosen is clearly decided by the particular needs of the subsequent coal utilization. A plant optimized to remove both pyritic sulfur and ash would fall into Levels 4 or 5.

The ash content of the raw coal feed mainly determines the obtainable yield and has an important impact on capital costs because equipment sizes are mostly determined by raw coal throughputs.

Size consist is a primary cost determining factor because both capital and operating costs are related functions of the surface area of the coal to be treated. More costly equipment and greater energy are required to separate and dewater the finer sizes. In general it is three to five times more costly to clean ultrafines than the coarser sizes.

We have seen that, especially in the case of underground coal production, average raw coal ash contents are likely to increase in the future and size consists will become finer. Mining practices will therefore exert some upward pressure on costs. But factors such as this are, in the case of new plants at least, overwhelmed by the cost of money at the present time. The arbitrary actions of OPEC oil ministers, the theories of monetarist economists, and the printing of banknotes by governments to cover budget deficits, have produced, and are sustaining, historically high interest rates. However, we're all in this boat to-

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gether, and while determined efforts to achieve hard won gains in productivity and lower operating and maintenance costs may appear disappointing in relation to current amortization and depreciation costs, such efforts are still of equal relative value in these areas under our control.

The costs of the various levels of coal preparation defined above currently range from about $0.03 - $0.40/MM Btu, Levels 4 and 5 being towards the top-end of this range. This compares with maximum delivered costs of about $2.00/MM Btu for bituminous coals,and $6.00 for fuel oil.

For this premium,the coal users get low ash, reduced sulfur and higher thermal values; and substantially reduced variation in these operational parameters. For any given case, the coal user can be provided with data relating to the quality and cost of cleaned and uncleaned.coal with some precision and hence enabled to conduct his own costs/benefits analysis.

Coal consumption is rising rapidly because it now offers substantial economic advantages and these are perceived as continuing into the future. Why physical coal cleaning itself is not, also, increasing I have no convincing explanation to offer except to suggest that perhaps the biggest problem is effective communication of what it can offer and produce.

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Coal supplies and the economics of treatment

Interest has intensified in the value of burning clean coal in power plant boilers, yet delivered tonnage has dropped. Potential intrusion of regulations notwithstanding, the advantages of clean coal will change the life styles of utilities and coal producers as well

By R. C. RITTENHOUSE, Senior Editor

Little doubt remains that benefits can be realized from the cleaning of coals for use in power plants. The challenge is that the questions of when, where, how and why each coal should be cleaned still need more definitive answers.

Statistics alone reveal seeming anomalies. For example, coal production has been rising at a relatively rapid rate, overall, for many years. Specifically, U.S. Department of Energy figures show that raw coal production reached 665,127,000 tons in 1978 compared to 595,386,000 tons in 1972. Although the number of cleaning plants increased from 408 to 419 in that time period, production of clean coal actually dropped from 292,829,000 tons to 224,780,000 tons. There is idle cleaning capacity at these plants which are primarily located in the eastern states. Meanwhile, raw coal production is expected to realize a long-term rise with a National Energy Plan requirement of coal production to reach about 1.5 billion tons by 1990. National Coal Association figures showed 1980 production of bituminous and lignite at 823.6 million tons (add another 5 million to roughly match Department of Energy (DOE) totals which include anthracite). Bituminous and lignite production for 1981, which was expected to increase by about 50 million tons, is now pegged at a preliminary figure of 802 million tons. The drop was attributed to the strike. Projections for 1982 are now at 880 million tons.

Electric utilities are expected to be using 860 million tons of this total by 1985. Reasons for the drop in the use of clean coal are partially traceable to a greater use of low sulfur supplies. Such coals as western coals generally are not suited to physical cleaning, or the benefits of doing so may be only marginal. Examination of the deepest reasons for the decline in actual delivered tonnage of clean coals, beyond perhaps the possibility of a decline in average yields by cleaning plants, is too abstract to be discussed adequately here.

A coal cleaning industry, as such, is not separately identifiable, but, viewed as a unit for purposes of discussion, it appears that any appreciable growth in coal cleaning processes will depend largely upon future demand from power plants. Assuming that a hypothetical 1000-MW power plant requires 9000 tpd of a bituminous coal over a 7-day week, the cleaning plant would have to process about 12,600 tpd over a 5-day work week. Studies show that only about one-fifth of the cleaning plants available in 1977 could handle that volume of coal. It appears that even if demand for clean coal rises slowly near-term, it soon will absorb the idle capacity and unless new, much larger, cleaning plants are constructed, utilities will likely be faced with a scramble for contracts with multiple suppliers. The reason is that a single supplier in many cases could not handle the order alone. This could be a source of higher fuel costs for utilities if power plants are forced into a more universal coal cleaning requirement than is now considered necessary, and, if either the mines or the utilities do not move soon to fill the potential gap in coal-cleaning capability.

Why pay extra for clean coal? The benefits realized by a power plant as a result of using clean coal vs run-of-mine (ROM) coal include those related to coal and ash handling and transportation, boiler operation, and flue gas cleanup for environmental protection.

Dave Williams, Senior Vice President of Operations, American Electric Power Services Co., identified similar areas of benefits derived from coal cleaning. For example, by obtaining higher quality coal through cleaning, "AEP was able to reduce the pounds of SO_2 per million Btu as well as the amount of ash per million Btu. On the operation side, the benefits have run the gamut of improved boiler performance, lower maintenance costs, better mill performance and much more. About 75% of all coal burned at AEP is washed or cleaned in some form and this will increase over the next few years." He added that, from the environmental protection viewpoint, "it is more economical for our company to improve the quality of the coal than it is to, say, invest in extra pollution control equipment."

One report from the Environmental Protection Agency (EPA) observes that all benefits to be derived from using clean coal generally will offset the cost of that cleaning. The agency estimates that a typical case will have a $4.85/ton cost for cleaning coal, whereas the total benefits add up to $7.20/ton. This calculation includes the cost of supplemental equipment for flue gas desulfurization (FGD) for compliance, with and without the clean coal. Later figures and studies have attempted to quantify assumptions of the type that had to be used in this and other early reports from EPA. This report called for just such work and results of some research are mentioned later in this article.

Pushing for more legislation

Power plants, as a group, have shown increasing interest in the improvements offered by precombustion cleaning (PCC) of coal from the standpoint of cost savings and the technological benefits evident in boiler reliability and reduction of maintenance problems. However, a political specter hangs over the logical further development of coal cleaning technology and the use of clean coals in power plants.

Few power plant operators and small coal mine operators can be found today who are not incensed, or at least very concerned, over the possibility of having some ill-advised legislation result in regulations that dictate the cleaning of all coal burned by power plants. Some feel that we are again on the threshold of another fiasco such as that which found political and social pressures forcing a rush into the untried and unproved FGD equipment in the early 1970s. As one statesman of the utility industry put it, "We should make every effort to be sure that research precedes control in the 1980s."

Causes of this widespread concern are buried in the various proposals for

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changes in the Clean Air Act (CAA), particularly those that reflect the general outcry over perceived effects of acidic precipitation. One of the most mentioned of these bills is S. 1706, which was introduced by Sen. George J. Mitchell (See POWER ENGINEERING, April, 1982, page 40). This and the other bills do not have mandatory washing of all coals in their makeup. That is true merely because a specific mandated control technique normally would not appear in the legislative documents. At this level the control objectives are noted, but the specific method of control would normally be established at the regulatory agency or left up to the regulated industry. As Joel D. Patterson, Manager of Environmental Affairs, Middle South Services, Inc., suggests, "Coal washing is certainly a likely requirement to come out of the so-called acid rain legislation typified by the Mitchell bill. There are other methods to meet the goal of a 10-million-ton reduction of SO_2 as set down in the bill. These include conservation, shutdown of units, and other means for each power plant to gain its share of that increment of reduction.

Industry annoyance

"It is time for industry to get concerned when a group of state representatives (from 23 states), such as those who met in New York recently, speak out strongly in favor of a national near term coal washing mandate."

The annoyance that comes through from many segments of the industry seems justified when the basis for such pronouncements comes to the surface.

To put the general situation into perspective, it is worth reviewing some observations of Tom R. Howard, Senior Fuel Resources Engineer, Detroit Edison. During the past five years, notes Howard, Detroit Edison has undergone a massive fuel substitution because of environmental protection requirements. Most of the high-sulfur coal originally used has been backed out of the system. It was replaced with new coals that were purchased based upon a fuel specification tailored to the operating needs of each power plant. The sulfur limit is a given factor from the outset of each procurement of southern coal and varies depending upon the price of the coal.

The range of coals on the system is from western subbituminous coal, which is a 9500 Btu product with less than 5% ash, all the way to a fully washed 13,000 Btu low-sulfur southern coal at 7% ash, all purchased in roughly the same time frame of a few years. The economics of the southern coal are very attractive compared to the compliance alternatives that the company faced. The higher cost incurred for a higher Btu coal resulted in a significant increase in performance on the power plant units. As for the high-ash low-Btu coal, the company built a new electrostatic precipitator to accommodate its use on each of two coal-fired units and still meet the emissions requirements. The economies of the coal price were sufficient to warrant that choice. In addition, the plants are all operating units with established handling methods and disposal sites. Therefore, additional volumes of ash were not a problem.

Detroit Edison's main sources for coal in the East include northern West Virginia, its principal high sulfur coal supplier at about 4.5 million tpy. About 40% of that is coarse washed coal. The low-sulfur southern supplies come from eastern Kentucky and southern West Virginia, of which 35% is washed. Blending systems at the power plants, particularly complex at the Monroe plant, are used to arrive at the desired combination. This includes some washed and some raw coals. The emphasis over the system is on arriving at an ideal economic mix. This mix now includes western coals at some stations. For example, a special blending program of western and high and low sulfur eastern and southern coals is underway at the Monroe plant, the company's largest. The St. Clair power plant was the first to use western coals and now uses them along with some high sulfur product blended in.

Interestingly, the company's fairly elaborate evaluation programs for ranking different coal qualities are performed on purchased-coal specification, and the coal quality could be achieved by a high grade raw product or a low grade end product. The system does not look at washing in regard to cost-effectiveness and similar concerns in the manner suggested by various studies such as the Teknekron Report.

Many millions of dollars have been spent to develop the coal network of blending and selection at Detroit Edison. It and many other utilities also burn large quantities of western coals which often are at levels of ½% sulfur or less. Tom Howard's personal opinion is that, "If in spite of this success in meeting emissions limits, someone tries to make us wash coal anyway, such washing would do nothing more to protect the environment and would simply cost more money." A point here is that attempts to wash coal that has less than perhaps 3% sulfur will result in reducing that sulfur content by probably less than 10%.

Indecision prevails

The legislative and general public disagreement and confusion on what should or should not be done relative to environmental protection has served a large helping of indecision all around. The situation is further complicated by differences of opinion that prevail on the technological aspects of coal cleaning and its actual degree of need.

The tradition has been for power plants to set a coal specification to meet emissions limitations at the power plant stack and then to permit the coal supplier to meet that specification in whatever manner he can throughout the contract period. If it should happen that all coal, including the low sulfur genre, must be 100% washed, the major coal companies probably would have little trouble accommodating the need. However, even though there are some smaller sized coal cleaning facilities that can be erected, dismantled and fairly easily moved to a new location, most of the small mining operations cannot afford to provide such operations.

The feeling is that such a turn of events would force too many mines out of the market and result in less competition which, in turn, would result in potentially higher coal prices over the long term.

The crux of the problem for small mines is in obtaining financing for the cleaning plant. The consensus is that no matter how small or great the benefit might be that is realized from coal cleaning, the coal user pays the costs. Is it worth the price? The answer to that question depends not only on to whom the question is addressed, but also on an enormously complicated tangle of qualifications and potential economic benefits throughout the entire power generation process. The evaluation of clean coal's worth to a power plant rests as much upon the disadvantages and their related costs as it does on the advantages.

The first economic penalty placed upon the clean coal user, of course, is that of the cost of the process itself. Costs for each cleaning plant arrangement will vary greatly depending upon the number and type of circuits, size and type of equipment, volume flow and exactly how the plant is being operated. A comparison of costs for eight different cleaning plants is shown in Table 1 just as an example. The first four sample processes are jigs and the second four are dense medium process plants. The table is from a report by E. C. Holt, Jr. of Hoffman-Munter Corp. for the DOE and entitled "An Engineering/Economic Analysis of Coal Preparation Plant Operation and Costs." Cleaning costs for all eight plants ranged from $4.40 to $8.41 per ton of clean coal produced. One reason for the high capital cost per ton of product stems from the fact that the plants averaged about 30% in actual operating time. Aside from capital, and operating and maintenance costs, the cost of replacing the rejected tonnage of raw product must be included in the cost of cleaning. This cost can be substantial depending upon the efficiency of the cleaning plant.

A disadvantage that must be weighed as part of the overall cost evaluation is the surface moisture that is added to coal by

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Table 1. Total annual costs for eight coal preparation plants.

Plant No.*	O&M cost,[a] $/ton of cleaned coal	Capital charges,[b] $/ton of cleaned coal	Cost of Btu loss, $/ton of cleaned coal	Total cost, $/ton of cleaned coal	Total annual cost $/100 Btu recovered	$/ton of ash removed	$/ton of sulfur removed
1	2.70	0.65	2.14	5.49	0.227	9.92	1746
2	2.55	1.12	0.75	4.42	0.183	13.39	271
3	2.67	1.25	4.49	8.41	0.338	15.71	344
4	2.96	1.40	1.60	5.96	0.222	10.47	789
5[c]	3.20	0.56	1.10	4.86	0.239	27.69	244
6	3.04	1.79	2.21	7.04	0.258	30.53	187
7	2.12	1.36	1.76	5.24	0.206	9.55	1000
8	2.44	0.94[d]	1.02	4.40	0.176	52.28	421

*Process: Plants 1-4 = jig — Plants 5-8 = dense medium

aOperating and maintenance (O&M) cost includes labor, supervision, overhead, supplies, fuel, electricity, and subcontract services.

bBased on a 10-year amortization period, 9% discount rate, and 30% utilization factor, except as noted.

cCosts shown for Plant No. 5 are based on 1400 tph.

d50% utilization factor.

Table 2. Impact of improved plant availability on cost of Level C coal cleaning.

Case no.	Coal source/ Power plant location	30-Year levelized revenue requirement (mills/kWh, 1979 to 2008): Level A no cleaning %S	Mills/kWh	Net reduction (or increase) with Level C* cleaning vs improvement in availability 0%	1%	5%
1	Illinois/Illinois	3.39	61.8	(0.3)	0.1	1.7
2	West Virginia/Pennsylvania	3.38	65.9	0.3	0.7	2.2
3	West Virginia/Massachusetts	0.85	69.5	1.3	1.7	3.2
4	Alabama/Florida	1.26	66.3	2.0	2.4	3.9
5	Montana/Texas	0.60	73.4	0.0	0.4	2.0
6	Iowa/Iowa	6.90	66.6	0.0	0.4	2.0
7	Utah/Utah	0.64	61.1	0.7	1.1	2.6

*Deep cleaning.

Table 3. Percent of projected 1985 coal production able to meet emissions limits using raw coal or coal cleaning.

Region	State[a]	1985 Production (10^6 ton)	Raw coal emission limit (lb $SO_2/10^6$ Btu) 1.2	2.0	4.0	Clean coal[b] emission limit (lb $SO_2/10^6$ Btu) 1.2	2.0	4.0
1	OH	54.5	0	1	17	0	4	43
	PA	99.6	5	20	80	15	48	88
	WV-N	52.8	19	26	63	23	42	82
	Total	209.7	8	17	58	13	35	76
2	KY-E	106.2	49	85	95	58	88	97
	VA	46.4	67	87	100	67	87	100
	WV-S	88.0	75	97	99	78	97	99
	Total	249.6	61	89	97	66	90	98
3	AL	32.1	45	71	93	49	77	95
	Total	32.1	45	71	93	49	77	95
4	IL	92.6	0	7	25	1	16	42
	IN	30.6	6	11	42	10	15	52
	KY-W	58.7	0	0	8	0	0	28
	Total	181.9	1	6	22	2	11	37
5	TX	66.3	0	28	84	1	32	86
	Total	79.2	2	27	69	3	30	76
6	CO	38.0	89	100	100	95	95	100
	MT	75.0	29	100	100	81	100	100
	MN	39.2	53	72	100	54	95	100
	ND	43.8	12	67	100	66	99	100
	UT	33.6	82	99	100	82	99	100
	WY	241.9	46	97	98	54	97	98
	Total	495.6	48	93	100	65	98	100
Total U.S.		1248.1	34	62	74	43	68	82

aStates producing less than 20 million tons not listed but included in totals: MD, GA, TN, AR, IA, KS, MO, OK, AZ, WA.

bPCC estimates based on cleaning by crushing to 1½ in. top size and separating at 1.6 s.g.

COAL SUPPLIES

washing. One measure of this penalty can be found in an interagency R & D program report from the EPA and the Tennessee Valley Authority (TVA). The report (EPA-600/7-79-250; TVA-ECDP B-5) is entitled "Evaluation of Physical/Chemical Coal Cleaning and Flue Gas Desulfurization." Moisture in coal results in a loss of Btu and also adds to the cost of transportation and, to the extent that coal cleaning adds to this penalty, it increases the effects.

The study report offers an example of the loss to be expected. Under typical boiler conditions it takes about 1150 Btu to vaporize each pound of water from coal. "Consequently, if 111 lb of water is added to 1000 lb of surface dry coal having a total heating value of 12,000,000 Btu, the resulting product is 1111 lb of coal containing 10% surface moisture and a total heating value of approximately 11,877,000 Btu. In this example, 123,000 Btu is spent in the heating and vaporization of water during the burning process. In general, 10% increase in total moisture reduces the net heating value of the coal by approximately 1%," explains the report. One factor that may be overlooked in calculating the cost that water adds to coal transportation is the Btu loss associated with the extra heating needed during combustion. If moisture adds 11.1% to the weight of coal, there is a corresponding 11.1% boost in the cost of transporting the coal.

EPRI study agrees

A study for the Electric Power Research Institute arrived at the same general conclusions (after adjusting to a consistent basis) as the EPA/TVA report just men-

tioned. EPRI CS-1622 is the final report entitled "Impact of Coal Cleaning on the Cost of New Coal-Fired Power Generation" dated March 1981 and prepared by Bechtel National, Inc. The object of the project was to evaluate overall cost impacts of coal cleaning on new power plants with wet flue gas desulfurization systems. The findings show that the use of clean coal reduces total system capital cost in most cases (6 out of 7 cases in the study). The costs in coal cleaning generally are balanced by the cost benefits. Also, the capital cost of a coal cleaning plant is revealed to be consistently less than 5% of the cost of the power plant.

Study findings are considered conservative, according to Fred Karlson of EPRI and are so indicated by Bechtel. One reason is that economic benefits, such as improved power plant availability and operability, are not included in the calculations. Table 2 shows that a 1% improvement in availability would increase cost savings by at least $1.5 million/1000 MW-yr (mid-1978 dollars) or 0.4 mills/kWh (levelized over 1979 to 2008). A 5% boost in availability, according to the report, would increase cost savings by at least $7.5 million/1000 MW-yr or 1.9 mills/kWh.

The authors caution that the report, while a useful guide for utilities evaluating coal cleaning benefits, offers cost estimates that should be used only for comparison in planning. These estimates cannot safely be generalized in the case of, for example, manufacturer's current selling prices for equipment.

The lack of consideration of the availability and operating factors in this and other studies is a major point. Even though there was insufficient data available to be included in such studies at the time they were conducted, some utilities are using coal cleaning for exactly that—primarily to get better unit operation. This is true of such organizations as Southern Company Services where operating units, in many cases, have moderate to low sulfur coal as a regular supply. Dr. Charles Goodman, Manager of Air, Water and Thermal Sciences Programs, explains that while more than 50% of the coal used by operating companies of SCS is washed, he does not feel that further cleaning of such moderate to low sulfur coals changes sulfur content enough to make the effort cost-effective at this point.

Individual problems and specific needs of each power plant aside, there are a variety of other reasons why some experienced people advise against rushing into what may be unfamiliar territory. A quick-fix in making a coal-cleaning-related decision may create greater problems. Some reasons for caution are identified in an EPA project summary (EPA 600/S7-81-146, Oct. 1981) by E. H. Hall et al.

Called "barriers to expanded coal cleaning," the following factors were listed in the report in much greater detail. Factors of a technical nature include a need for better quality control in cleaning and improved techniques for separation of fine pyrite, and the need for more data on the benefits accruing from burning clean coal in a boiler. Environmental factors cited as slowing the growth of clean coal use are problems of solid waste disposal relative to leaching, fugitive dust and fire control, and concentration of trace elements in the refuse (the essence of the reality that we do not get rid of the undesirable materials, we simply transform them into some other waste product). The last factor tends to limit the scope of land use options available. Some localized transportation problems may be aggravated by increased use of coals that are cleanable, such as in the corridor from Appalachia to the middle Atlantic states.

Institutional resistance to more precombustion coal cleaning may take the form of a lack of appreciation of its benefits by potential investors, and the potential for commercial application of PCC as a sulfur removal device may not strike them as adequately demonstrated.

There is no tax consideration at the moment for coal cleaning as a pollution control investment. In addition, the traditional uncertainty surrounds many aspects of present and future potential for legislation and regulation. As the EPA suggests, there is an uncertain outlook for the enforcement of state implementation programs (SIPs), averaging periods and variances. Also in question is the permanence of the SO_2 emission standard as well as air and water pollution standards for coal cleaning plants.

A strong case against mandatory coal washing seems to be building in the statistics revealed by many ongoing studies as well as in the opinions of veteran coal mine and power plant operators. A composite of this side of the opinion says that the fuel departments of many power plants do not want to become committed to such a near term expediency simply for its public relations value. Operators say that power plants should be dedicated to meeting requirements that are related to protecting the environment. The best option, of course, is to use compliance coal that, in fact, would need no extra cleaning.

Pressures on quality coal supplies

The nearly certain boost in demand for coal over the next decade will place heavy pressures on compliance coal availability. Some of this growth is evident in the changing need of present power plants and of the 150 new coal-fired units (79,670 MW) committed to come on line through 1997, as reported by utilities and published in the April 1982 issue of POWER ENGINEERING, page 54. An additional 30 power plants (15,113 MW) are proposed for construction by the year 2000.

The potential for bringing major new sources into the fold of compliance coal is perhaps the biggest attraction that coal cleaning has for power plant operators. James D. Kilgroe, manager of the coal cleaning program for the EPA, and Heinz G. Pfeiffer, manager of technology and energy assessment for Pennsylvania Power and Light Co., provide estimates of the projected 1985 coal production which can comply with long term emission standards of 1.2, 2.0 and 4.0 lb $SO_2/10^6$ Btu using raw and physically cleaned coals (Table 3). Their paper "Coal Cleaning in Relation to the Clean Air Act" (Coal Conference & Expo VI, October 1981) offers several interesting conclusions on various coals and the possibility of meeting regulations. It is generally acknowledged that the moderate to high sulfur coals common to the Midwest and the northern tracts of Appalachia can be used to meet moderate SIP emission limits after physical cleaning. PCC has the potential for making these coals adequate as a control strategy for SO_2 emission control in bubbles and offsets. However, cleaning alone will not bring more than a few of these coals down to the 1.2 level required by the 1971 NSPS.

Western coals, as well as those from Alabama and southern Appalachia, often can meet the 1.2 limit without PCC.

Kilgroe and Pfeiffer observe that 70%-90% emission reductions required by the 1979 NSPS "eliminate the use of PCC as a sole method for complying with these regulations. However, a number of studies have shown that in many cases combinations of PCC and FGD can be more cost-effective than FGD alone." It is easier for the FGD system to meet the 90% removal requirement if potential SO_2 emissions can be reduced by a range of 20-30%+ before scrubbing when burning such high sulfur coals. The foregoing is based upon gross estimates, according to Kilgroe. Table 4 shows potential emission reductions and costs due to selective washing of Illinois coals delivered to utilities in 1979

Actually, the present methods of cleaning coal (physical methods) are not entirely adaptable for use with the largely surface-mined lower rank subbituminous and lignite coals. This is true mainly because these methods were developed for use with the anthracite and bituminous coals which for example, are more suited to wet methods of cleaning. The switch to more mechanized mining methods (especially for deep mine bitumi-

nous) and other changes have a direct impact upon the quality and cleanability of extracted coal. This, in turn, influences the effectiveness of available cleaning methods. Specifically, the increased use of continuous and longwall extraction methods naturally tends to produce more rock and other contributors to higher ash content of the raw coal. New demands and resultant expansion of new coal fields reportedly has affected the mining work force as well. Inexperienced people at the mines also contribute to the lower quality mix being sent to preparation plants. Additionally, and perhaps a greater problem, is the high degree of fines produced by such mining methods and related problems. Much of that breakage down to fines results from super-capacity handling systems operating between mine and plant. Designers and equipment manufacturers have been reworking conveyor transfer points, surge and storage bunkers and stacking and reclaiming equipment to reduce fines at that juncture at least. Logically, much of the research in coal cleaning currently is directed toward better handling of the fines.

Cleaning systems available

The current range of options in physical cleaning systems that are available commercially are shown in Figure 1. D. Glanville Williams, vice president, North American Mining Consultants, Inc., examined some of these options in his paper "Current Status of Physical Coal Cleaning" presented at the Coal Preparation and Equalization Symposium, held in Louisville, Ky., October 1981. He explains that most cleaning systems separate raw coal into three general size categories: coarse = +¾ inch, fine = ¾ x 28 mesh, and −28 mesh. Wash plants currently are being fed raw coal crushed to 2 in. x 0 and up to 20% of it passes a 28 mesh. The ultrafine circuits can receive a load of up to 25% of the coal feed. Figure 2 indicates the ranges of equipment efficiency for the separatory stages. It shows that in general the efficiency of separation is greatest for dense medium systems and least for the interfacial (froth flotation) systems when particle sizes become smaller than 20 microns. This is a remarkably wide range of cleaning capability, Williams observes.

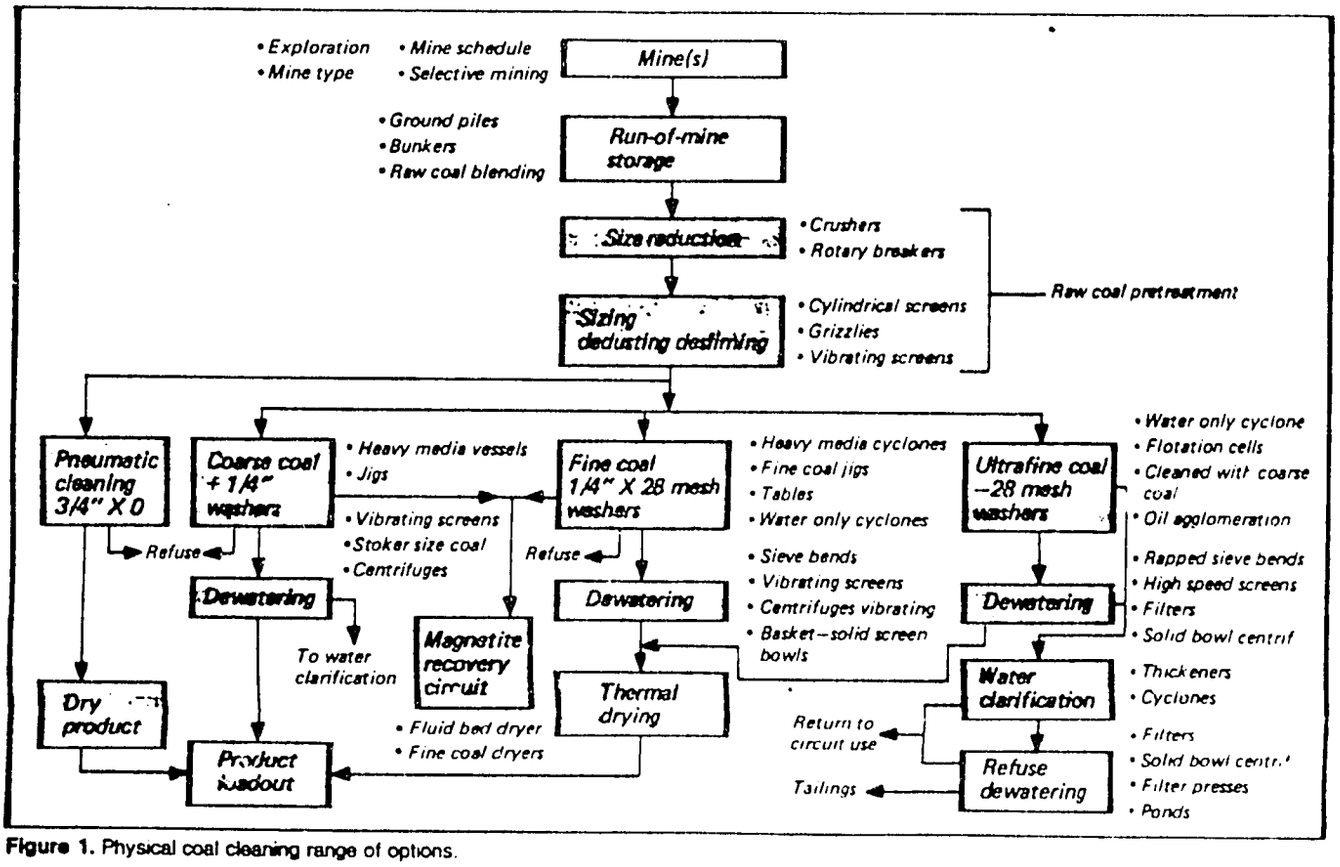


Figure 1. Physical coal cleaning range of options.

Table 4. Potential SO_2 emission reductions and costs due to selective washing of Illinois coals delivered to utilities in 1979.

Coals to be washed[a]	Quantity to be washed (10^3 tons)	Total SO_2 emissions after selective washing (10^3 tons)	SO_2 emission reduction achieved by selective washing (10^3 tons)	(%)	Levelized cost of washing (10^6 1979$)	Cost-effectiveness ($/ton SO_2)
No coals	0	819	0	0	0	–
Coals with SO_2 contents above floor of:						
7 lb/10^6 Btu	2,055	760	59	7	17	290
6 lb/10^6 Btu	5,046	715	105	13	36	340
5 lb/10^6 Btu	8,500	643	176	22	66	370
4 lb/10^6 Btu	11,444	606	214	26	85	400
All coals	15,089	585	234	29	100	430

[a] Excluding the 24,473,000 tons of

Coal cleaning is still considered to be as much of an art as it is a science. Hence, the subject details range far beyond the scope of this article. However, Williams' observations on some other significant advances in cleaning bear mention. Recent demonstrations show that dense medium cyclone circuits can clean coal effectively down to 100 mesh representing a large reduction in the load potential of interfacial units (froth flotation or oil agglomeration). This also offers a substantial reduction in capital and operating costs because the cleaned product can be dewatered by centrifuges. Another type of equipment, water-only cyclones of the compound type, have been effective down to 150 mesh in demonstrations. In these cases, primary dewatering was obtained with a sieve bend and centrifuging. In others the sieve bend alone recovered significant amounts of coal from raw slurries which previously went through to refuse impoundments; another aid to cost reduction or financial gain.

More details on advances in coal cleaning methods and systems can be found in Chapter 6 of the *Coal Handbook*. The 840-page illustrated publication from Marcel Dekker, Inc. of New York and edited by Robert A. Meyers of TRW was published in late 1981 and is priced at $75 per copy. Chapter 6, written by Glanville Williams, examines coal cleaning and worldwide preparation practices and processes, including the economics involved. In addition to cleaning, the book discusses coal structure and analysis, mining, coke making, combustion, conversion to liquid and gas, and other coal uses. It is especially written for engineers and scientists who may be expert in one area of coal technology but must have access to a broader range of knowledge on the subject.

Table 5. Annual cost savings from use of a sulfurmeter and Btu meter.

Sulfur % (± Δ)	Btu/lb (± Δ)	Blend (HSE/LSS)	Annual savings 1000 MW $ million*
—	—	66/34	0
0.20	500	69.5/30.5	1.6
0.20	175	70/30	1.9
0.10	175	75/25	4.2
0.04	175	78/22	5.8
0.04	—	77.5/22.5	5.3

*Preliminary.

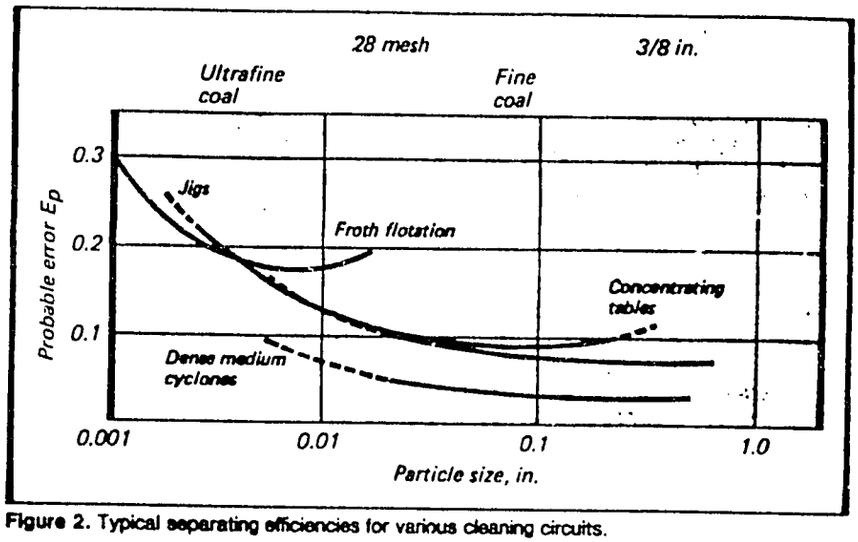


Figure 2. Typical separating efficiencies for various cleaning circuits.

Variability of sulfur

The problems created by sulfur variability in coals from a mine or from the same seam also are particular challenges for coal cleaning procedures. Sulfur variability is especially critical when air pollution control factors (SO_2) are present especially where regulations call for an averaging time of 24 hours as opposed to a 140-day time span. Actually, the average sulfur content of different areas of a mine can be plotted, but, potential sulfur emissions from that coal, when burned, will change in sequence according to the mining scheme used. The combination of procedures after mining are important controls for balancing sulfur variability at the point of use. This includes the preparation method, transportation flow, blending, combustion methods, and pollution control devices used.

Reliability is the watchword for coal users as well as producers; they need a reliable method to measure sulfur variability in mined coal and in sulfur emissions due to differences in scrubber performance and retention of sulfur in the ash. After examining EPA statistical studies of coal sulfur variability, such as the PEDCo Environmental (1977) and Warholic at al (1980), George D. Andria of Bituminous Research, Inc. made some interesting observations about them in his recent paper "Coal Sulfur Variability and Sulfur Emissions," given at the June 1981 Air Pollution Control Association meeting in Philadelphia.

The PEDCo study's major finding was that sulfur variability decreases as the size of the coal lot increases. The later 1980 study failed to support this inverse relationship leading to Warholic's statement, "This suggests that the language of many current regulations is not consistent with the state of knowledge concerning sulfur variability."

Andria notes that sulfur variability decreases, generally, as the degree of handling increases. "Based upon previous observations concerning organic and inorganic sulfur, the effectiveness of coal preparation will depend primarily on theoretical washability of a particular coal, and secondarily, on the operating efficiency of the particular coal-cleaning plant." The imprecise sampling and laboratory techniques often present accuracy problems in characterizing this variability.

Preparation plant data, as reported in other EPA studies, suggest an RSD reduction of about 50%. A decreased sulfur variability of washed coal derived by D. H. Sargent et al in their draft report EPA contract (68-02-31-36, Nov. 15, 1979) was estimated by the equation

$$RSD = 0.159 - 0.0216 \log_{10} T \text{ (washed)}$$

"which can explain about 13% of the total sulfur variability," notes Andria.

It is clear from Andria's report and the many other observations and reports extant that there is no reliable way to predict the variability of sulfur in coal. However, methods to overcome the problem are making progress. One such development involves, according to Andria, the application of geostatistical methods to the characterization of coal reserves. If this were to prove reliable and become acceptable to coal producers and users, it would bring variability estimation one step closer to acceptable accuracy.

Work is moving forward on another device that may take more of the guesswork out of sulfur variability measurement: the continuous on-line nuclear coal analyzer. Several papers have been presented by R. S. C. Rogers of Kennedy Van Saun Corp. and Bozorgmanesh, Gozani and Brown of Science Applications, Inc. and staff members at EPRI and TVA

Chemical coal cleaning

The advances in coal washing systems or methods have evolved over many years and even the most recent gains may not seem spectacular while at the same time being significant. More exotic methods, particularly chemical processes, seem likely to offer some dramatic possibilities for improvement of coal cleaning as a science. That will take some doing for two reasons. First, chemical processes for the most part still are in the research stage. Second, great strides are felt to be difficult to accomplish in an "industry" which does not even have a method of expressing cleaning efficiency that is accepted by all who function in the area of coal cleaning.

Chemical processes were compared in a paper, "Evaluation of Chemical Coal Cleaning Processes," presented during the 1980 Coal Technology symposium by H. Huettenhain et al of Bechtel National, Inc. and S. R. Taylor of the Department of Energy. The processes chosen from those existing at the time are shown in Table 6. This table provides estimates that include coal and lime handling, physical cleaning, and coal grinding. The initials PETC in the table refer to the Pittsburgh Energy Technology Center process. Others are: Ledgemont, one of several by Ledgemont; Ames Laboratory process; JPL, the Jet Propulsion Laboratory; and the Guth process, formerly known as the KVB process. Incidentally, a fixed charge rate of 27% was arrived at to annualize capital costs. Costs are stated at first-quarter 1980 levels.

Table 6. Chemical coal cleaning economic comparison.

Process	Capital cost, $ millions	Operating and maintenance costs, $ millions/yr	$/ton	$/10⁶ kJ (10⁶ Btu)	Annual production, million tpy
PETC	301	18.84	47.50	1.59 (1.68)	2.107
Ledgemont	255	18.48	40.80	1.33 (1.41)	2.141
Ames	277	21.24	41.90	1.40 (1.48)	2.292
JPL	249	18.69	39.10	1.26 (1.33)	2.200
Guth	208	32.11	35.80	1.15 (1.22)	2.469

Note: All costs are at first-quarter 1980 price level. Annual production is on a dry basis, the net quantity after process consumption. Cleaning cost for physical and chemical cleaning excludes the price of raw coal.

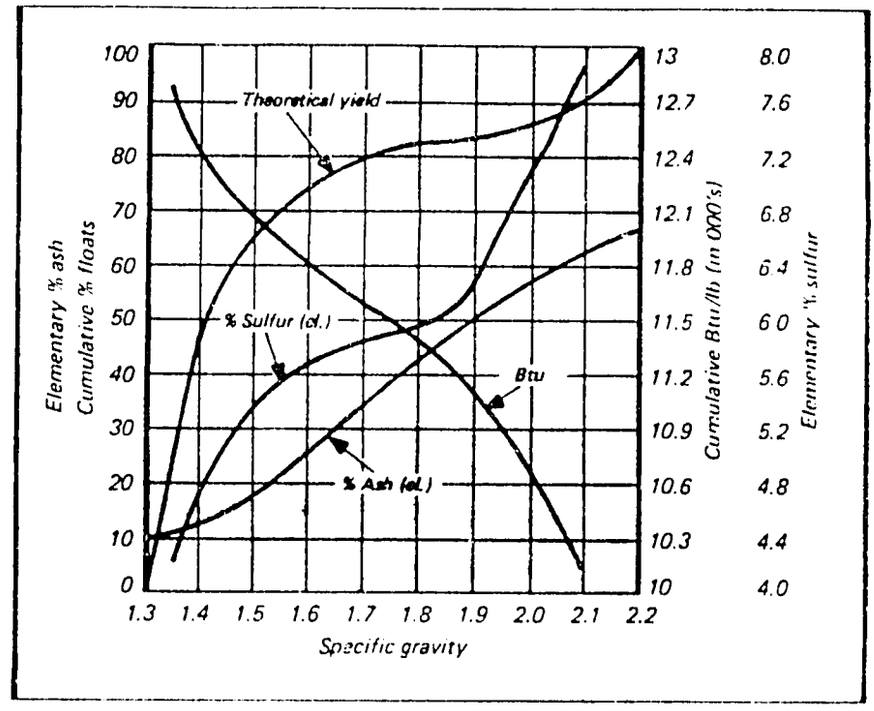


Figure 3. Washability curves for coal from an Ohio No 9 seam

The basic conclusions of the above-mentioned study of chemical coal cleaning processes indicate that all appear technically feasible. Economic feasibility, on the other hand, is less certain. This is one reason why demand by electric utility units seems unlikely. Another reason for limited interest here is current environmental regulations. Industrial power plants and applications for coal-oil mixtures offer the main potential for these processes, according to the authors. It also should be noted that chemical treatment plants have not yet been engineered and the extra handling, transportation and storage of fine coal also will add to fuel costs.

Many projects at CCTF

Research, development and demonstration of various coal cleaning processes is one of the goals at Homer City, Pa. where the coal cleaning test facility (CCTF) is located. Pinpointing the effects of coal quality on power plants is another goal of the facility which is sponsored by New York State Electric and Gas Corp., Empire State Electric Energy Research Corp. and EPRI. This demonstration scale facility has a maximum coal handling rate of 100 tph. It is able to handle various projects, being capable of simulating 50 or more commercial cleaning plant system designs. Principal among the benefits offered to coal users is the opportunity to discover how a given operation integrates with the needs of the balance of the plant. During his statement before the House Committee on Science and Technology last December, Kurt Yeager, director of the EPRI Coal Combustion Systems Division, invited all interested coal users and producers to participate. Those who participate supply a sample of about 1000 tons of ROM coal for study.

Most utilities agree that coal cleaning to remove ash and sulfur is growing in its importance. They also agree that the principal reasons for this are the substantial cost savings and potential emissions savings in power plants. Those areas most likely to gain in cost savings include lower coal transportation and handling, improvements in plant performance and lower power consumption, as well as a cut in FGD and waste disposal costs.

What strikes many as a rather significant comment for coal suppliers, as well as utilities and other users came in Yeager's testimony when he said, "Integrated planning and economic studies from coal base to busbar are essential if the coal producer is to adequately cover his capital investment in improving coal quality with a reasonable return." It would seem that at no time in the history of mining and power generation has there been a greater need for teamwork between the two industries, their suppliers and government agencies.

Other observers feel strongly that the traditional study used to determine the feasibility of a coal mine, which excludes considerations of the economics of cleaning, transportation, end-use and

basis for a long-term contract with a utility power plant.

The difficulty in all of this is that even the experts who are continually close to the subject lament the lack of enough accurate data in many areas. One such instance is in estimates of the cleanability of regional coals, in terms of ash and sulfur reduction, which use data bases developed from national coal reserve and properties data bases. Essentially, this is explained by the lack of adequate washability data now available on coal reserves (for future mining), on the specific performance of commercial coal cleaning plants and the lack of data to assess the costs involved, on the inadequate base of accountability for sulfur and ash added to coal by the mechanics of mining, and on feeling that estimates of cleanability are not tied to a realistic coal production plan in each region. There is a need to develop more detailed washability data and to perform burn tests for measuring the slagging and fouling behavior of raw and clean coals. This should reduce the unknowns and permit more accurate cost-benefit analysis of coal cleaning and its relationship to each power plant case.

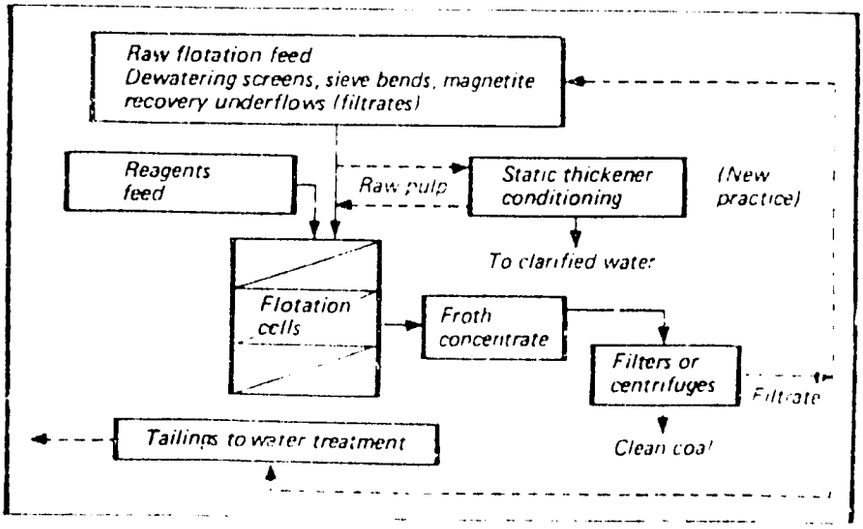
The CCTF offers one base for the needed additional research and development yet to be done. For example, work is planned for developing better techniques to get test samples from all types of coal reserves. Another major objective of the CCTF, according to EPRI, is to develop a data base that will allow conversion of reserve and washability estimates into accurate estimates of actual clean coal quality and production. Many more goals must be met, such as development of reliable techniques for cleaning and upgrading lower rank western coals, particularly in terms of reducing moisture and alkali content. One other need, as noted by key people at EPRI, is for the development of better automated cleaning process control and on-line continuous monitoring techniques. Yeager states that an estimated 5% boost in cleaning plant energy recovery can be achieved through such improved process control.

Table 7. Comparison of size efficiency related cost percentage profit changes.

Item	Heavy medium system Min. fine	Heavy medium system Max. fine	Jigs Min. fine	Jigs Max. fine
% Yield at 10750 Btu/lb	83.0%	79.4%	76.9%	71.8%
Clean coal from 3.0 million raw tons/yr (million tons)	2.49	2.38	2.31	2.15
Value/ton @ $1.25/million Btu	26.88	26.88	26.88	26.88
Total annual income ($ millions)	66.93	63.97	62.09	57.79
Plant capital cost ($ millions)(*1)	22.70	24.40	20.60	22.10
Cost per clean coal ton				
(a) Mining $ (*2)	19.28	20.15	20.81	22.33
(b) Preparation $ (*1)	3.68	4.20	3.33	3.80
Total $/ton	22.96	24.35	24.14	26.13
Total cost ($ millions)	57.17	57.95	55.76	56.28
Profit ($ millions)	9.76	6.02	6.33	1.51

Note *1—Heavy medium system = 1.05 X average cost jig = 0.95 X average cost

Note *2—Assumes common mining costs of $16.00 per ton of raw coal.



Washability curves

Gerald Blackmore, Executive Vice President-Fuel Supply, American Electric Power Service Corp., made a cogent reference to developments in coal procurement when he said, "Complete washing has been progressively adopted over recent decades for coals going to the metallurgical market. . . . at a fast increasing pace, the same quality control will be required, environmentally and economically, for deliveries to the electric utility industry."

Blackmore showed an example of a coal washability curve in one of his many presentations, "Coal Cleaning, Steam Raising and Environmental Control," given during the EPRI Integrated Environmental Control for Coal-fired Power Plants Symposium, February, 1981, Figure 3. He notes that this is a typical curve showing the relationship between quality—i.e., ash, sulfur and Btu—at various gravities. The laboratory analysis (called the elementary analysis) and the resulting curves are used often as a basis for a wash plant design and to determine whether or not the coal is marketable. But the efficacy of the approach is dependent upon whether the raw coal sample was truly representative and has met the necessary parameters to satisfy a long term contract or to cover the range of coal that must be washed economically over a wash plant's work life. (A wash plant cost ranges from about $40 to $[illegible] The size consist of the coa[illegible] stages of handling and preparation [illegible] the wash plant often is not receiving the detailed attention that it should. This is indicated as one possibility for higher than satisfactory coal losses and variations in product quality of delivered coal.

Blackmore presents some detailed data on capital and operating costs of coal preparation plants for various sizes of coals. Generally, he shows that a coarse (4 in. x ¼ in.) coal preparation system will have a capital cost per ton/hr capacity of $16,000 and the operating cost per ton product (including interest and depreciation) of $1.70. An average (¼ in.-28 mesh) will be $22,500 and $3.75, and fine (28 mesh-0) will be at $30,000 and $6.10. A specific proposed installation will vary, of course, but indications are that this is a reasonable set of figures for present day costs.

Blackmore summarized an economic review of the effects of efficiency and size distribution as presented in Table 7. He states: "The size distribution with the higher fines content has a poorer average separating efficiency, higher operating and capital cost and poorer profitability (assuming common mining costs) irrespective of whether a very efficient heavy medium or average performance jigs are employed in the separation."

for various systems at a coal producer's operation will help in arriving at a mutually agreeable contract for coal delivered to the power plant in compliance with specifications agreed upon.

As Blackmore observes, along with most who follow the black art, the area of greatest inefficiency in coal cleaning is in the 28 mesh-0 size range, hence it was common practice to throw away any smaller-sized fines. Froth flotation may change that because it has been used successfully in Europe thanks to developed cell designs and flotation oils. One problem here is that certain oils do not meet EPA standards in the United States. Figure 4 shows a typical system.

Froth flotation is new to the steam coal mining industry even though it has been used for many years in the metallurgical coal and hard rock mining industries. Unlike most other coal cleaning methods which rely upon the specific gravities of the coal for functioning, froth flotation depends upon the action of surface properties. It takes advantage of the fact that coal repels water and attracts oil while refuse generally attracts water and repels oil. In operation, such a system first treats the raw fines with an oil-based collecting agent and this slurry is fed into a cell (tank). Air is introduced into the cell by mechanical agitation and bubbles rise to the surface carrying the coal fines with them.

Most of the impurities or refuse stays in the slurry and moves out as tailings. Some utilities investigating the potential of froth flotation have expressed concern over a few points. For example, there is a feeling that not all of the cleaned fines product may be of high quality, partly because pyrite also repels water and much of it rises with the coal in the process. In addition, the disposal of fine tailings has become a problem in some areas. One key to a quality product in this process lies with accurate instrumentation and control.

American Electric Power apparently has found froth flotation a productive system (or circuit) to add to its preparation plants. All of its modern (built since 1977) plants have froth flotation circuits and they have been included because of the economics of coal fines recovery. Incidentally, the basic coal preparation plants at AEP operations include circuits for coarse coal in the form of heavy media drums, heavy media cyclones for medium fines, and froth flotation plus filter presses for dewatering, among other example, is nominally rated at 2000 tph of raw coal feed.

Washability curves may not always be the best guideline to follow in some coal selection analysis. For example, Jerry Vaninetti and C. Fred Busch of Norwest Resource Consultants, Inc., among others, point to certain bituminous coals that are very similar in their standard analysis but that perform in a very dissimilar fashion. Certain coals from one county of Colorado, central Utah and some of the northwest New Mexico coals are very close together in their standard analysis and washability performance. However, the coal from that particular seam in Utah creates an unusual problem of erosion and abrasion of equipment. It was found that washing this coal with the usual intent of reducing ash content (and in the normally accepted manner) actually produced a coal product that was more abrasive to its power plant surroundings. The reason was that the washing circuit used in preparing ROM coal bypassed ¼ x 0 material, and it happens that about half of the abrasive component in that coal is in that ¼ x 0 fraction. The abrasive level of the feed coal was raised, on a ton for ton basis, after washing. This is a good example of a case where choosing a system to solve one problem aggravated another. It also is a case demonstrating the importance of knowing what systems the supplier is using and considering the total plant performance in evaluating those systems from the viewpoint of the power plant. The most economical method to get that coal down to an acceptable ash content does not address the abrasion problem at all. Therefore, when reexamining the beneficiation cycle, the power plant operator must see that the special abrasive condition is treated also.

Such anomalies in apparently similar coals can create problems in boiler design if the design is based solely on one coal that seems to be the same as the coal intended for future use. A detailed investigation of plant availability and boiler performance of plants using that similar coal, combined with test experience with the new coal, may reveal the overall considerations.

Even small changes in washing procedures may cause operating problems. Washing western coals to lower ash content has resulted in concentrating some of the alkali components which contribute to fouling in the back passes of the boiler. Not everything that changes in coals as they progress through the mine-to-user system is directly related to what the producer may do to them. By the same token, what the supplier is actually doing to the coal can have an appreciable effect on how it performs in the power what is being done to the coal before it is delivered. The point is that unless the user is familiar with the changes and potential changes at the mine and does something about keeping tabs on them, the complaint that the mine is sending bad coal will have a hollow ring. It may not be true.

Vaninetti and Busch reported on some preliminary investigations of western coal at Utah Power & Light Co. in their paper "The Effects of Beneficiation on the Performance of Western Steam Coal" given at Coal Technology 1980. A final report on studies that have been ongoing since then at Utah Power & Light is due to be completed by the time this article is published, according to Frank Davis, vice president of engineering and construction. The company has been active in its study of coal cleaning techniques and benefits. Davis does feel that utilities are keeping a slightly more critical eye on what is happening in the area of coal cleaning and at the supplier's operation.

One last [illegible] asiveness which results [illegible] chemical and physic[illegible] Relative abrasiveness [illegible] measured by the amount of free silica (not chemically bound in the coal), or quartz, found in the product. A measure of the abrasiveness of coal, called relative quartz value (RQV), was developed about 15 years ago by Babcock & Wilcox. The RQV has been useful in showing good correlations with grinding mill component wear. However, it has been observed that RQV values may not be good indicators of how exhauster blades, coal piping and convective tubing will be affected by a cleaned coal. Further, it is noted that excessive tonnages of coal that must be handled because of a high ash content may be a more substantial contributing factor in wear than the abrasive properties [illegible] coal itself.

Wi[illegible] coal

She[illegible] that the cleaning pla[illegible] major source of the coal. This [illegible] mine mouth. To pay transportation costs to haul the waste products that are to be extracted from the raw coal by cleaning would simply compound fuel expense. Therefore, it remains to be seen whether more justification can be found for doing some cleaning at the power plant. Utilities that own coal mines, of course, have their plans in place. American Electric Power, Utah Power & Light, and others are already deeply involved.

Utilities generally can no longer afford to buy the cheapest ROM coal that might be on the market. Most power plants require a highly consistent, matched quality coal over the long te[illegible] They also must face the reality of planning that fully integrates

APPENDIX 4

AUGER MINING

APPENDIX 4

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APPENDIX 4

AUGER MINING OPERATIONS - SMALL BUT EFFECTIVE

The auger mining industry is a small division of the surface mining industry, supplying approximately 15 million tons per year, or 2 1/2 percent of the total U.S. coal production of about 600 million tons per year. The industry is located primarily in the Eastern coal mining region, and due to its size and state-of-the-art, is extremely sensitive to fluctuations in price of coal and changes in economics.

Only five of the 50 largest bituminous-coal producing companies direct engage in auger mining. A large portion of the industry carries out augering on a contractual basis, and most of the smaller independent producers combine augering with other types of mining.

Special Skills

Coal augering is a highly specialized skill dependent on the operator's sense of touch. Once the auger bit enters the highwall, the operator cannot see what is happening at the cutting face or know of deviations occurring from the cutting and conveying process. (See Figures 1 and 2.)

Before starting the cutting process, the operator makes absolutely certain the machine is aligned, because as the head enters the highwall face, a faulty alignment of the auger tends to magnify and deflections with penetration into the auger hole. At 150-foot depths, factional deflections graduate to about 2 to 4 inches below the initially established centerline. Unless a more effective auger flight system can be developed to maintain true direction over greater distances,

penetration to depths of 600 feet would produce fourfold deflections and would result in cutting of more rock and fireclay than coal.

Auger mining, however, often can recover coal that is physically or economically beyond recovery by any other means. Furthermore, augering averages more tons of coal per manday than any comparable mining method, and it produces this coal without any additional stripping of the overburden.

Some mines, especially in Kentucky, use the auger method only. The coal seams are augered from specially prepared narrow benches, some only about 20 feet wide and from a low highwall that is scarcely more than the thickness of the coal seam.

Auger equipment, however, has definite limitations: coal recovery for the resource area augered is usually less than 35 percent, and the length of the hole drilled into the mountainside is usually only about 150 feet; rarely does this length attain 200 feet. (See details of research to develop higher horsepower augers with guided heads that would penetrate 800 feet, in an earlier section of this issue.)

Augering requires much skill and alertness, and Kentucky has some exceptionally good operators, says the report, "Design of Surface Mining Systems in Eastern Kentucky." The skill of Kentucky operators became apparent about 2 years ago, states the report, when Australia chose Kentucky as the place to learn augering and to seek skilled auger operators.

Some proprietors of coal lands do not presently permit augering, since it recovers so little of the natural resource. Others offset losses by charging higher royalties for auger mining than for conventional surface

mining. Some proprietors await the development of a more efficient auger or equivalent remote-controlled mining machine or method that will recover substantially higher percentages of the coal resource.

Present Practice

Theoretically, augering should recover considerably more of the coal seam than at present. It should be possible to drill longer holes, having a diameter nearly equal to the thickness of the coal seam and drilled so that little or no coal remains unmined between holes. This theory assumes coal seams of constant thickness and regularity and without undulations, which is not usually the case.

Present augering equipment drills holes that sag gradually downward, tending to eventually drill through the bottom of the coal seam into the rock below. In actual practice, each hole is drilled about 30 percent undersize to allow for the downward leaning of the hole-sagging caused by bending from the weight of the column of auger steel as it advances into the mountainside. Holes are begun near the top of the coal seam to allow for sagging.

Current augering practice also leaves coal unmined between auger holes. Additional amounts of coal are left unmined between drill holes because holes are often not parallel. For example, when the highwall is not in a straight line, which is usually the case, there are pie-shaped blocks of the coal seam untouched by the auger holes.

Advantages of Auger Mining

Augering has many advantages:

- Provides more tons per manday than any other form of mining.

- Is low in cost as related to capital expenditures.

- Produces less environmental disturbance per acre than surface mining.

- Quality of coal produced commands a relatively high price, even though the volumes of coal produced as a result of augering are comparatively small when compared to surface or underground methodology.

- Offers relatively safe form of mining when compared to surface and underground mining.

- Can be activated quickly and used for recovery of smaller coal deposits as compared to surface or underground methods of mining, which require large reserves and substantial capital and time to develop.

Disadvantages of auger mining must be also considered:

- Provides low total coal recoveries, even though rate of production is high.

- Handicapped somewhat by the inflexibility of auger machines, the lack of versatility in auger components, the limited number of accessories available, the inadequate guidance systems, and the limited control of drill pressure and cutting speeds.

The relatively low recoveries of coal from auger mining suggest the development of alternate methods to recover those additional quantities of coal located in the pillar section between auger holes.

Recovery of lignite auger mining areas is expected to be about one-third of the in-place auger reserves. The recovered lignite is expected to be consistent with the quality of the lignite excavated by other methods.

Auger mining could increase the chances of post mining subsidence. Since all the auger reserves fall under areas that will be backfilled, this is not considered to be a serious problem.

Auger miners are easy to transport and deploy on an intermittent basis. They can be integrated into the mine plan so their work is isolated from the active work areas.

There are numerous machine options to accomplish auger mining. Machine history is based on good experience in the Eastern United States. Capital investment and operational costs are expected to be reasonably low regardless of the machinery selected from common off the shelf units.

Some augers can operate several sizes of cutter heads and conveyor flights so different seam thicknesses can be mined. The range is limited to about 1 foot with dual or triple heads and about 2 feet with single-head units.

Seam orientation and consistency are also critical factors. Flat lying seams that are uniform in thickness and do not vary radically in elevation are much easier to auger than irregular seams.

Lignite is a relatively weak material with compressive strength of about 1,000 psi. Its Hardgrove Grindability Index is about 50 so it should be easily penetrated by an auger. Lignites are generally the least friable of all types of coal with 12 to 15 percent friability. The lump and

particle sizes should not be dramatically altered during conveyance out of the hole by the conveyor flights. Lignite also has a Shore hardness number of about 10. The hardness is not expected to adversely affect augering. The abrasiveness of the lignite is quite low so the amount of fines is expected to be relatively low.

Lignite, in addition to being very weak, also slacks very readily; slacking indices generally approach 100. Slacking will not readily affect the mining of the lignite; however, the ease of slacking, weathering, and oxidation will combine with the overall compressive weakness to create pillar support problems. The integrity of the augered area is questionable regardless of the hole pattern selected. The implications of these facts will no doubt influence the layout of the auger patterns for web thickness, hole configuration, and hole patterns. The proper pattern to control subsidence can only be determined from empirical experience. It is likely that relatively wide hole spacing and single-hole configuration will be best able to provide the necessary seam support. It may also be necessary to plan some barrier webs at predetermined lengths along the highwall. These barriers probably will need to be about 10 feet wide and spaced about 100 feet apart in areas where subsidence needs to be controlled. The barriers and the webs can probably be kept smaller in the areas where lignite fracturing is limited since fracturing contributes to compressive weakness and the weathering process.

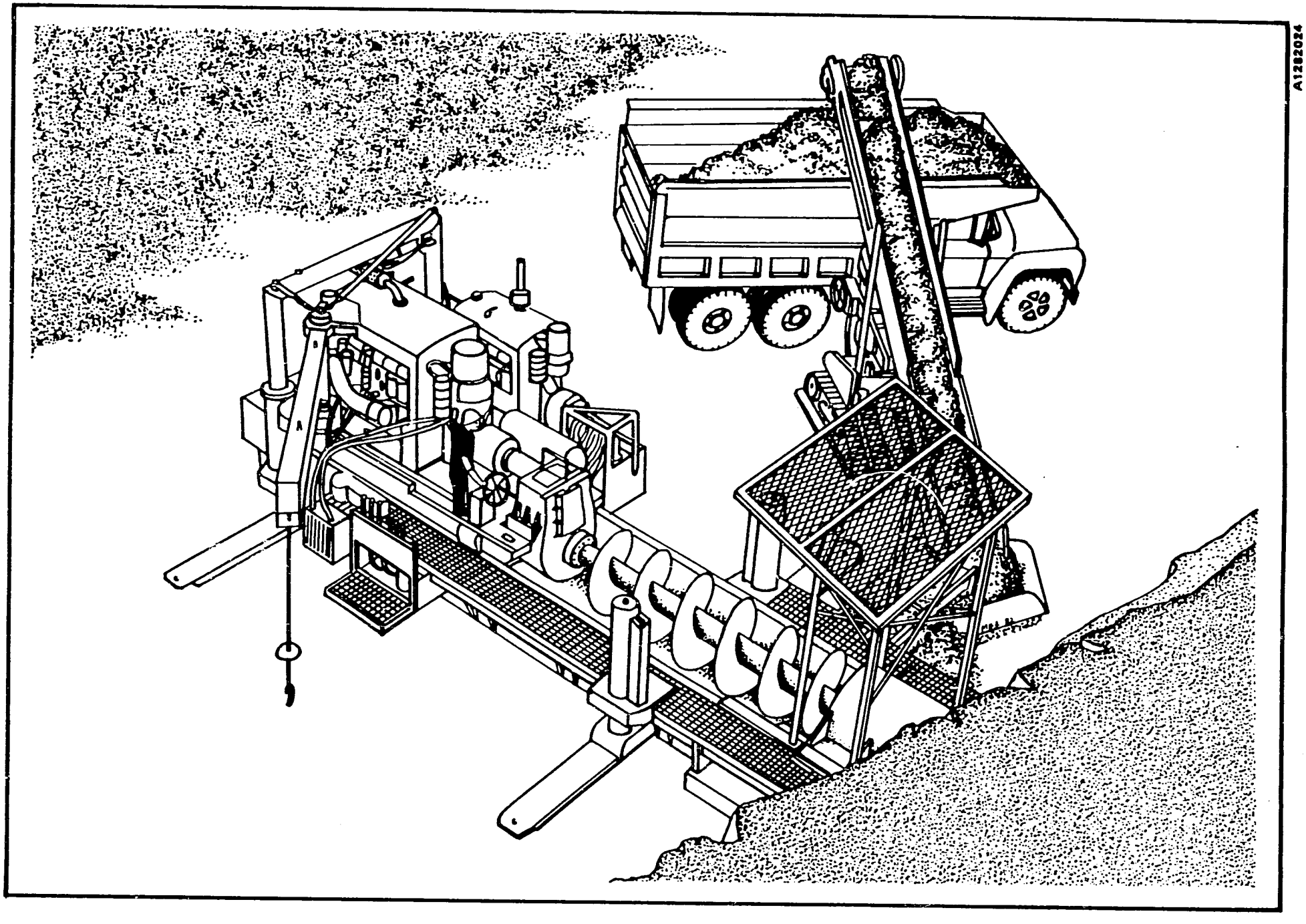
The quality of lignite from the auger is expected to be consistent with other excavation methods. Contamination can be expected to occur from the depositing of the augered lignite on the ground. There will be subsequent dilution and losses when it is picked back up for transport.

This can be eliminated or minimized by depositing the material directly into a truck from the stacking conveyor, whenever possible. This should be practical at the mine and is common practice in other parts of the country. Another means of contamination is from roof or floor materials. This usually occurs where severe seam undulations occur, where the operator is careless, or the auger is too large for the seam. The auger should usually have a diameter about 6 inches less than the seam thickness to prevent contamination. If washing is anticipated, the auger can be larger with respect to the seam thickness.

The size of the material from the auger is a function of the cutting kerf of the cutter head. It shows the relative percentage of fines of a common cutter kerf with respect to hole diameter. Since the lignite will ultimately be reduced to 2 inches x 0 inch anyway, fines are not considered a problem and the worst case situation is expected to be considerably less in fines than lignite from the bucket wheel excavators.

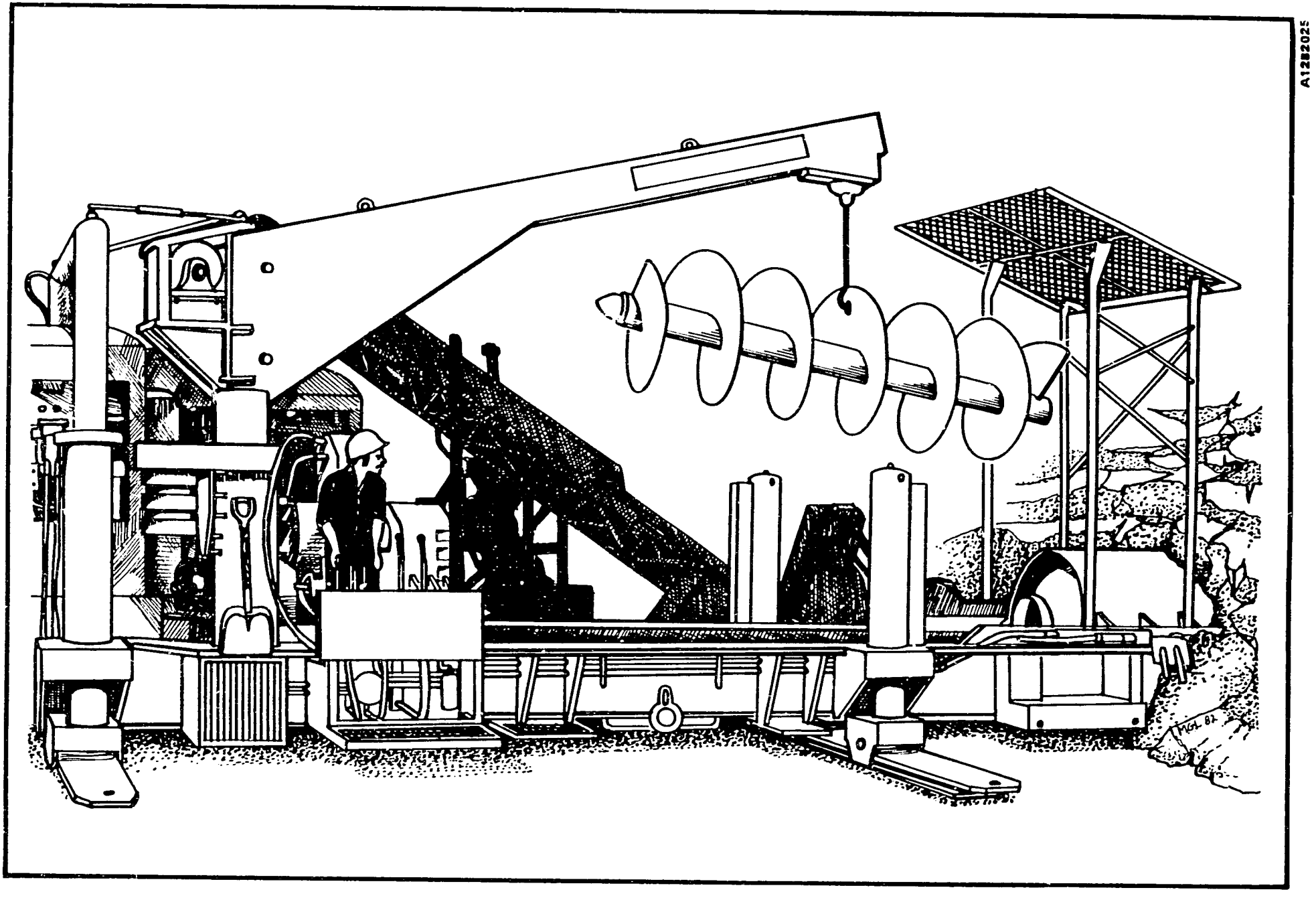
Auger miners can be employed on the sidewalls and final endwalls of virtually every surface mine excavation without serious impact on surface mine operations. In the event that natural conditions of seam thickness and roof rock are favorable, short underground drift mines can be developed. Their overall impact on scheduling of the surface mines could be significant, however. From these drift adits conventional, continuous, or modified longwall panels could be developed.

Figures 3 through 9 provides supplementary graphical data on auger mining.



COAL AUGER

FIGURE 1



COAL AUGER OPERATION

FIGURE 2

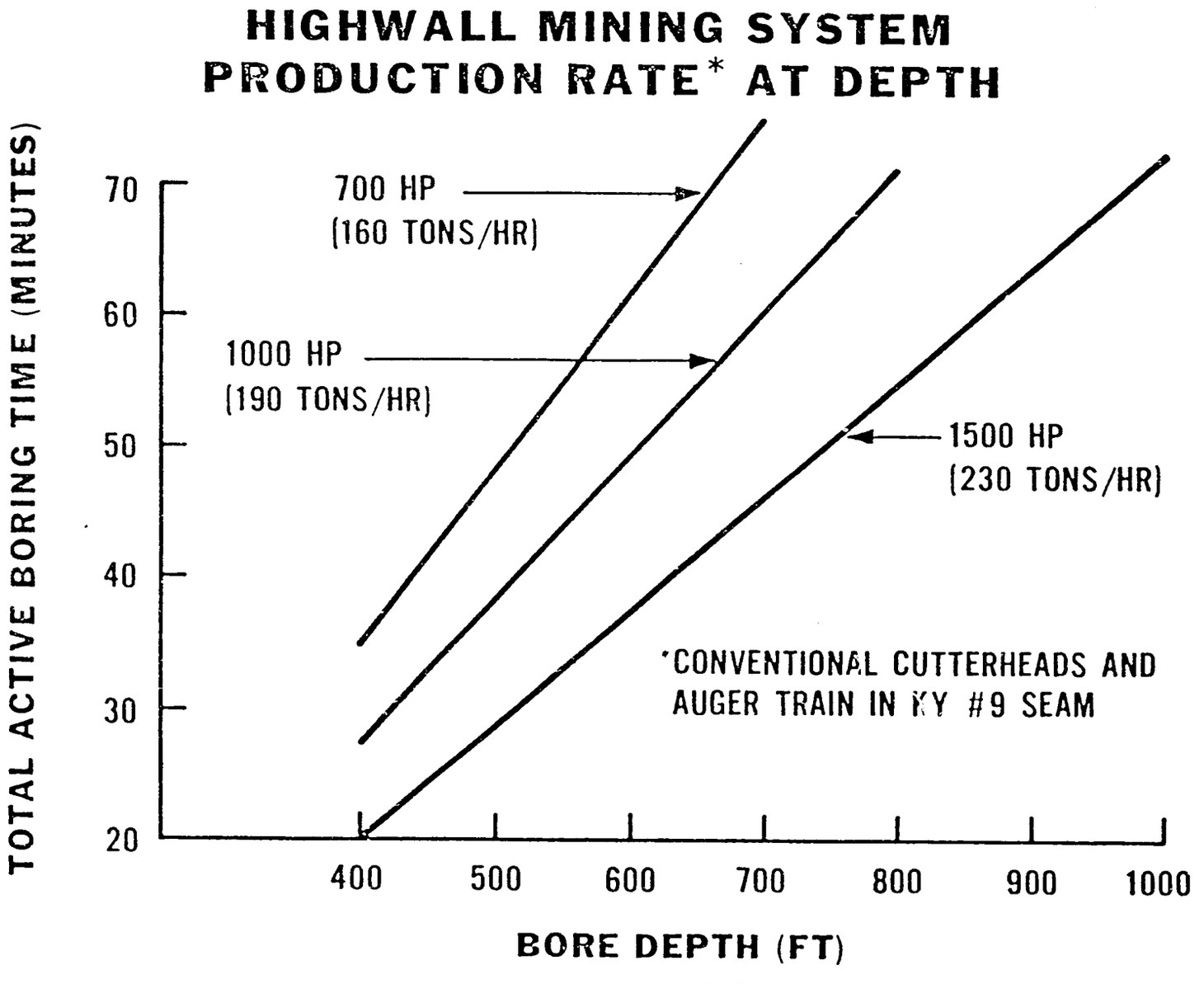


FIGURE 3

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FIGURE 4

HIGHWALL MINING SYSTEM PRODUCTION RATE* VS. BORE DEPTH

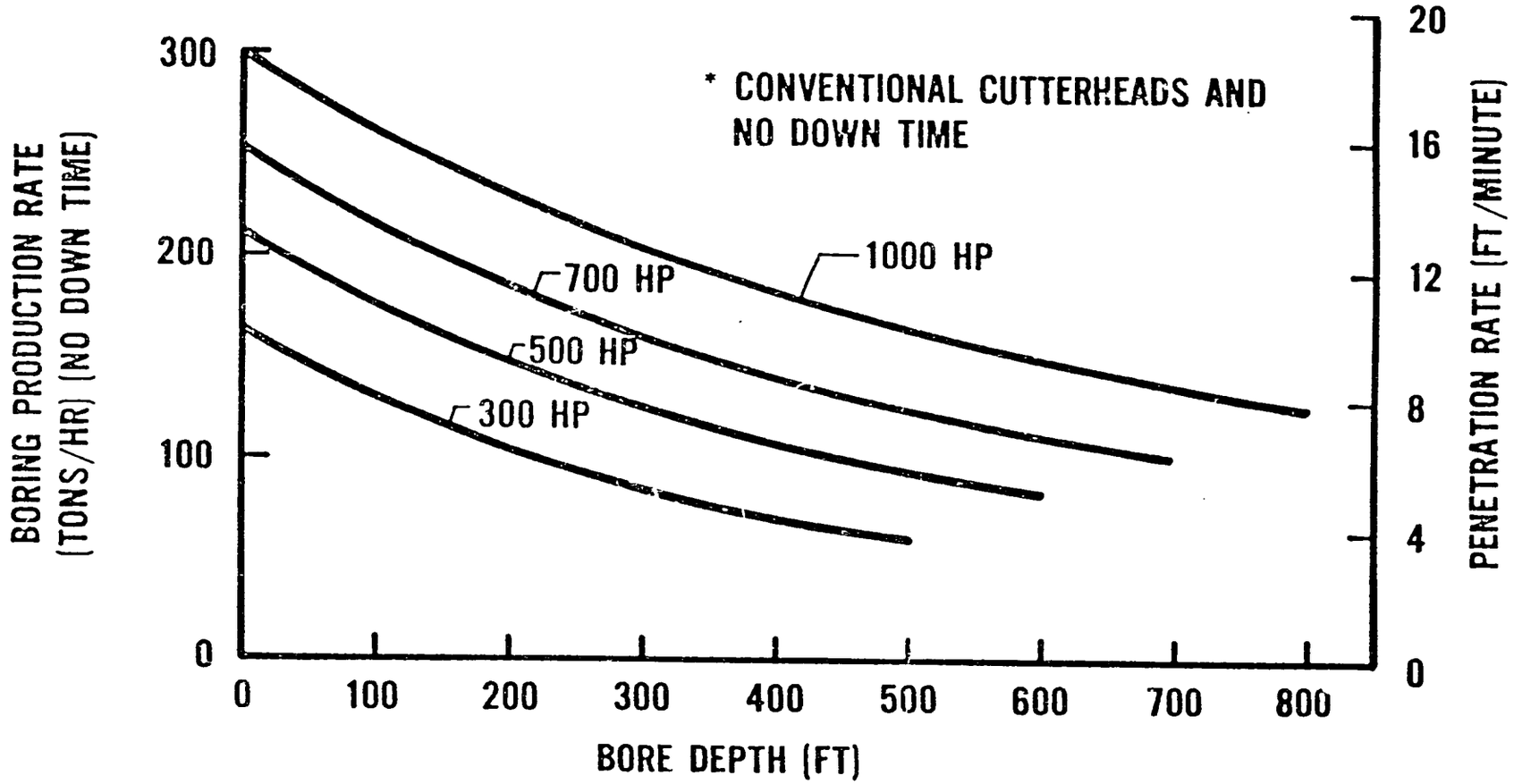

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FIGURE 5

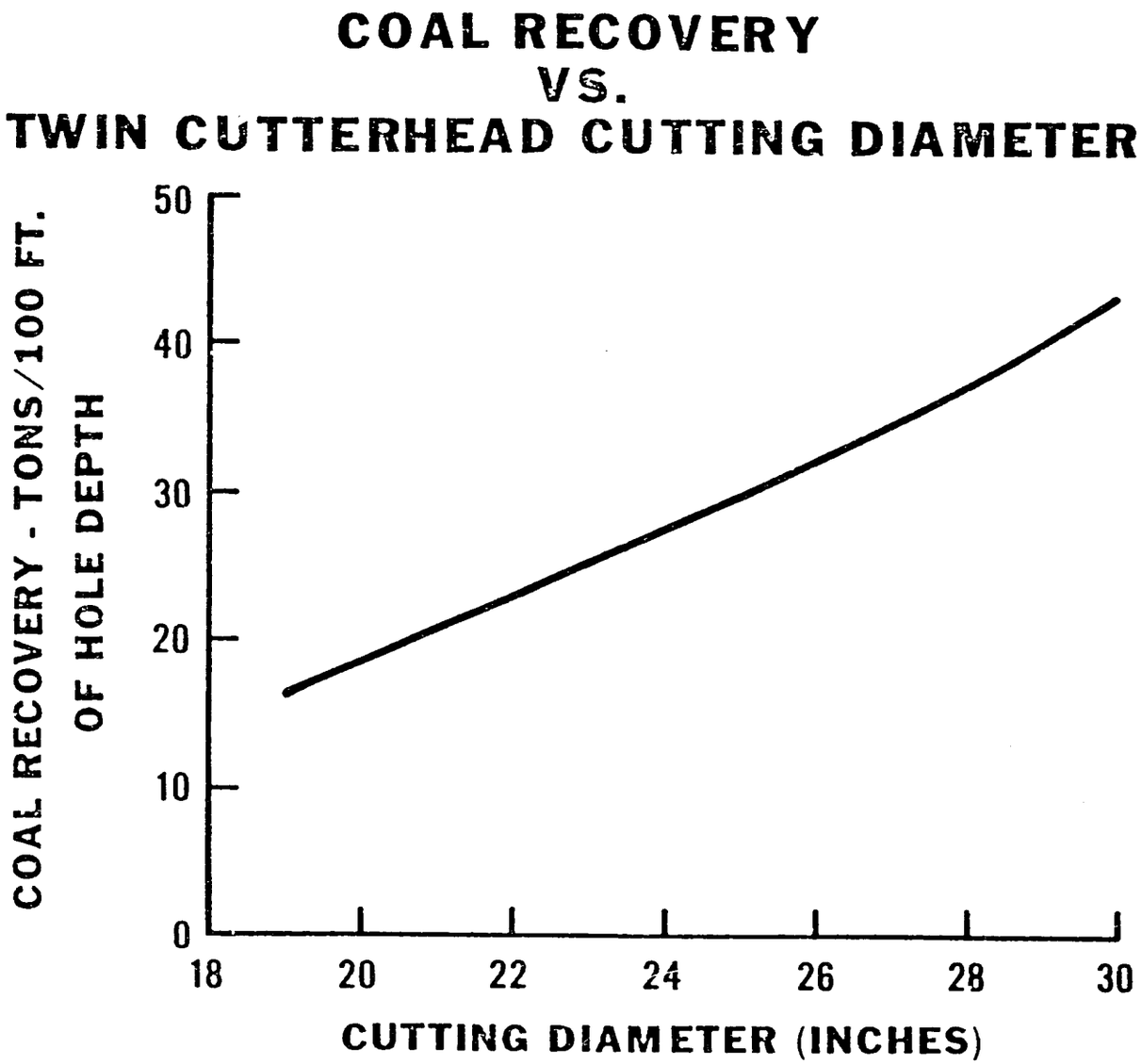

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FIGURE 6

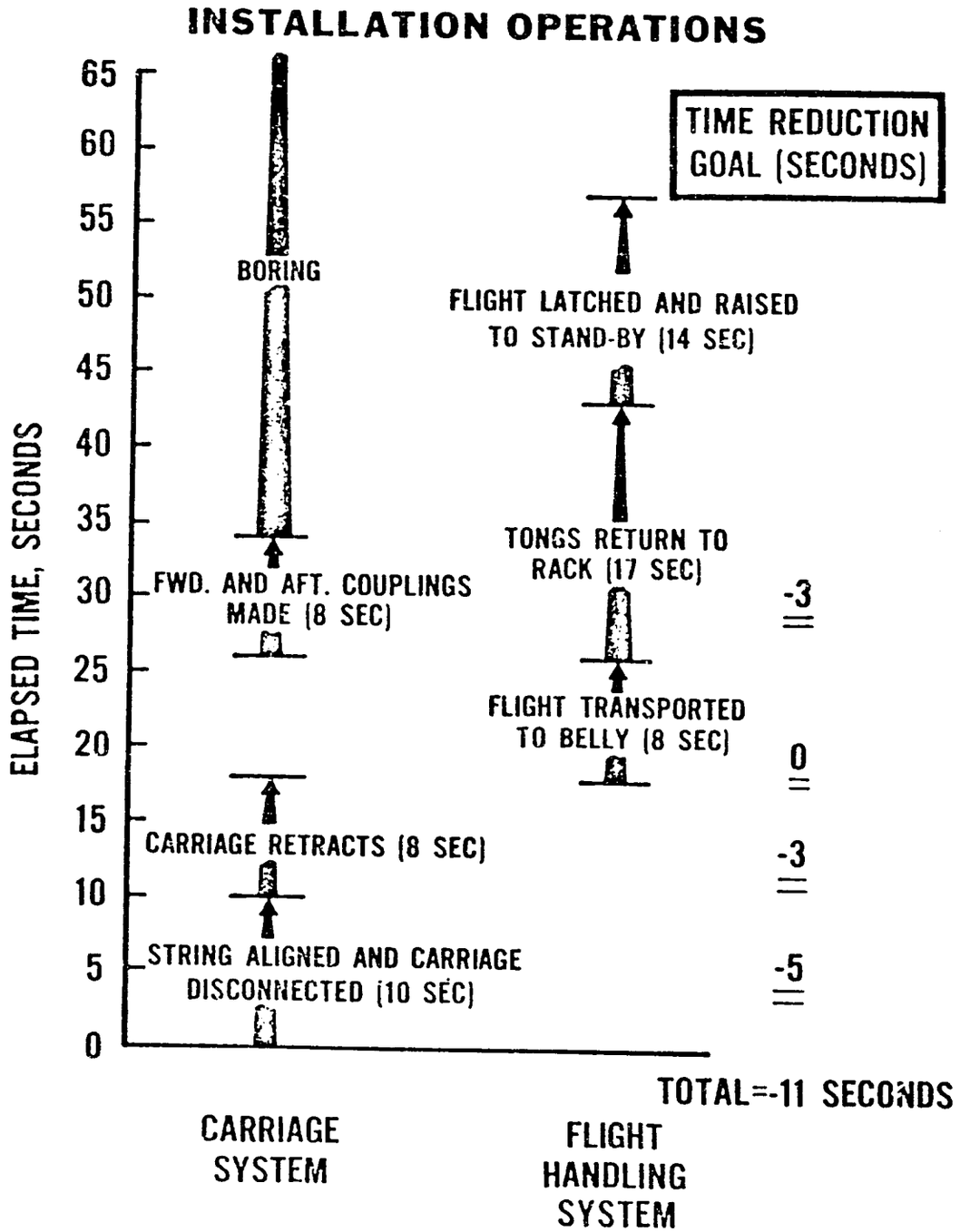

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FIGURE 7

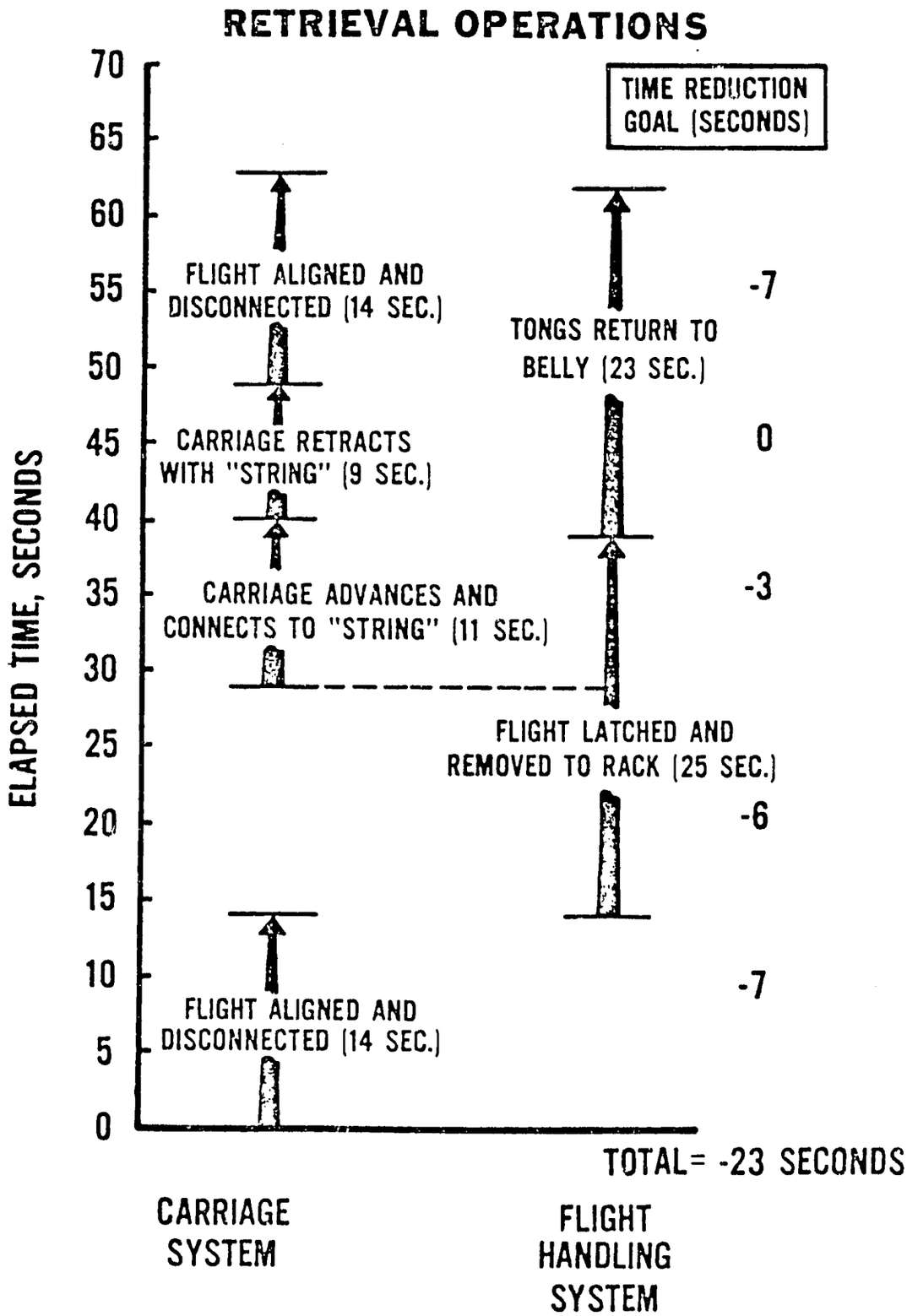
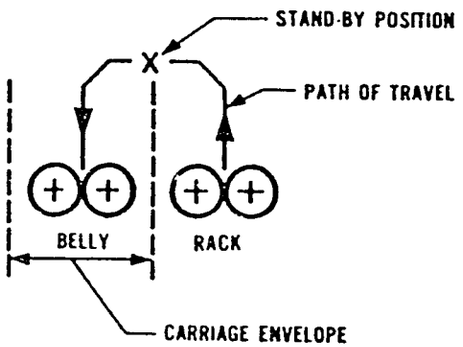

RETRIEVAL OPERATIONS
A1282019
TIME REDUCTION GOAL (SECONDS)
ELAPSED TIME, SECONDS
70
65
60
55
50
45
40
35
30
25
20
15
10
5
0
FLIGHT ALIGNED AND DISCONNECTED (14 SEC.)
CARRIAGE RETRACTS WITH "STRING" (9 SEC.)
CARRIAGE ADVANCES AND CONNECTS TO "STRING" (11 SEC.)
FLIGHT ALIGNED AND DISCONNECTED (14 SEC.)
TONGS RETURN TO BELLY (23 SEC.)
FLIGHT LATCHED AND REMOVED TO RACK (25 SEC.)
-7
0
-3
-6
-7
TOTAL= -23 SECONDS
CARRIAGE SYSTEM
FLIGHT HANDLING SYSTEM

FIGURE 8

TWO DIMENSIONAL REPRESENTATION OF FLIGHT HANDLING SYSTEM KINEMATICS (SALEM MUL-T)

A1282021

FLIGHT ADD CYCLE



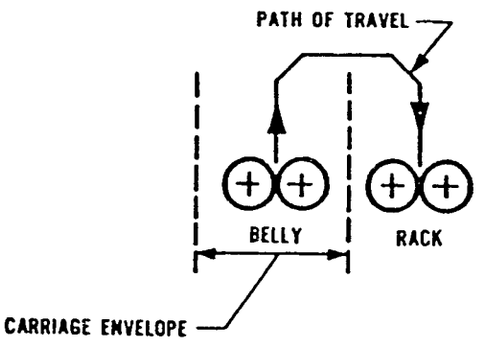
CYCLE DESCRIPTION AND TIME REQUIREMENTS:

SECURE AND RAISE FLIGHT TO STAND-BY ⇒ 13.5 SEC.

TRANSFER TO BELLY AND RELEASE ⇒ 7.5 SEC.

RETURN TO RACK FOR NEXT SECTION ⇒ 21 SEC.

FLIGHT REMOVAL CYCLE



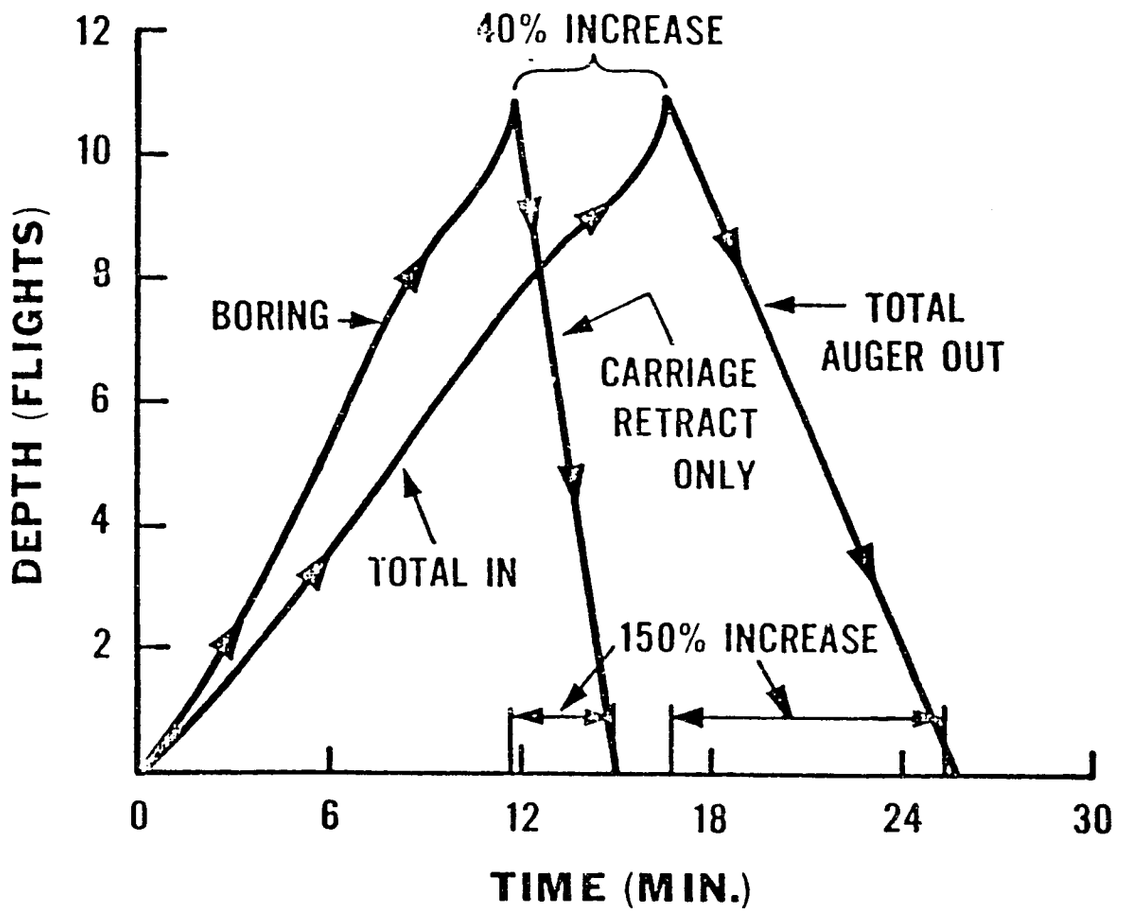
CYCLE DESCRIPTION AND REQUIREMENTS:

SECURE AND REMOVE FLIGHT TO RACK ⇒ 25.5 SEC.

RETURN TO BELLY FOR NEXT SECTION ⇒ 26 SEC.

FIGURE 9

TYPICAL OPERATING PROFILE



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APPENDIX 5

U.S. AND WORLD BANK

ENVIRONMENTAL GUIDELINES

THE WORLD BANK

OFFICE OF ENVIRONMENTAL AFFAIRS

WORLD BANK ENVIRONMENTAL GUIDELINES

MARCH 1981

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THE WORLD BANK

MARCH 1981

OFFICE OF ENVIRONMENTAL AFFAIRS

ENVIRONMENTAL GUIDELINES

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* Denotes Environmental and OH&S

a/ Not Available

THE WORLD BANK

OCTOBER 1980

OFFICE OF ENVIRONMENTAL AFFAIRS

DUST EMISSIONS

GENERAL POLLUTION GUIDELINES

Introduction

1. The following guidelines are given for two different locations: the place of work and the general environment.

2. Dust concentration figures inside industrial or agroindustrial plants are threshold limit values (TLV) for an eight hour day and a forty hour week. For this reason, the plant should be engineered to give levels well below the TLV.

3. The figures given for the environment (outside the working place) could probably be topped a few times per year without permanent adverse effects.

4. The Office of Environmental and Health Affairs (OE and HA) will revise the guidelines when additional knowledge from inside or outside the Bank Group warrants changes.

Definition and Properties of Dust

5. Dust is a particulate contaminant suspended in the atmosphere. The lower size limit for dust particulates is the transition to molecular dispersions (gases). The upper size limit is about 500 μm. When this size is exceeded, the gravitational pull removes the particle rapidly from the air. Industrial and agroindustrial processes, transport and domestic equipment, all release particles of dust into the air. The dust may or may not be mixed with other gaseous and/or liquid contaminants.

6. The five main factors in the interaction between dust and the human body are:

a) Size of dust particle.
b) Chemical composition of dust.
c) Concentration of dust.
e) Duration of the exposure.
f) Individual susceptibility.

7. Size of dust particle: Retention of dust in the lungs varies with the particle size as shown by the following table (from the US Bureau of Mines).

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Particle Diameter (micrometers)	Retention in Lungs (approximate)
> 6 - < 10	20%
5	25%
4	42%
3	50%
2	70%
1	70%
0.5	50%

The retention gets very low below 0.2 micrometers since dust particles of this size tend to act as gas molecules. This is only a general rule that varies with specific gravity and shape.

8. Chemical composition: Dust deposited in the lungs causes pneumoconiosis (pneumo = lung; koni = dust; osis = disease) that can be disabling or non-disabling depending whether the dust is physiologically active or not. Most forms of disabling pneumoconiosis are caused by crystalline SiO_2 (silica or quartz). Amorphous silica and silicates (except asbestos) do not cause disabling diseases.

9. Concentration of dust and duration of exposure: Dosage is the function of the concentration of the dust times the duration of exposure. In the TLV table given below for mineral dusts in industrial plants, the figures are in fact dosages. For instance this means that if a respirable inert dust reaches the concentration of 5 mg/m^3, the worker can stay there for eight hours, but if the concentration is 10 mg/m^3, the worker can only stay in this atmosphere for four hours per day.

10. Individual susceptibility: Genetic factors, not yet fully understood, will make some individuals more resistant than others. Environmental factors can also change this resistance. Heavy smokers or workers exposed to chemical irritants will likely develop pneumoconiosis at an earlier stage.

Sampling and Measuring Dust

11. Accurately determining dust concentration in the air remains a problem. One must remember that the total dust is much less important than the respirable dust. The sampling instrument should thus duplicate insofar as possible the retention characteristics of the human lung. A number of such instruments have been developed. The best known in the US are the British MRE (Mines Research Establishment) and the American personal sampler. Their retention characteristics is given in annex in comparison with the human lung. There is good correlation between these two instruments. The MRE collects 1.88 times more than the personal sampler. As these instruments collect only a few miligrams of dust per eight hours, an accurate and sensitive balance is necessary. The preceding shows why the name of the instrument and its characteristics should be given with the results of the analysis.

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Occupational Guidelines

12. The occupational guidelines are given in the following table itself extracted from OSHA regulations and from the booklet "TLV" 1977 published by the American Conference of Governmental Industrial Hygienists. As mentioned in the introduction, the figures are TLV and the plant should be designed and engineered to give levels well below these TLV (for instance no more than half the TLV value).

13. When the figures are given in mppcf (million particles per cubic foot), the measure is based on impinger samples counted by light field techniques.

TLVs for Dust		
Substance	mppcf	mg/m^3
Silica (SiO_2)		
Crystalline Quartz (Respirable[4])	$\frac{300}{\% SiO_2 + 10}$	$\frac{10}{\% SiO_2 + 2}$ [1]
Quartz (Total Dust)		$\frac{30}{\% SiO_2 + 2}$
Cristobalite: Use one half the value calculated for quartz.		
Thidymite: " " " " " "		" "
Silica fused: Use quartz formula.		
Tripoli (Respirable[4])		$\frac{10}{\% SiO_2 + 2}$
Amorphous (including diatomecous earth) Respirable [4]		1 (< 5 µm)
Total		3 (all sizes)
Silicates (<1% quartz)		
Asbestos (all forms) 2 fibers/cc>5 µm[3]	—	—
Graphite (Natural)	15	—
Mica	20	—
Mineral Wool Fiber	—	10
Perlite	30	—

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TLVs for Dust (Continued)		
Substance	**mppcf**	**mg/m^3**
Portland Cement	30	—
Soapstone	20	—
Talc (Non-Asbestiform)	20	—
Talc (fibrous): use asbestos		
Tremolite: use asbestos		
Coal Dust		
Bituminous		
respirable fraction(4) < 5% SiO_2		2.4
respirable fraction (4) > 5% SiO_2		$\frac{10}{\% SiO_2 + 2}$
Inert or Nuisance Dust(2)		
Respirable (4)	15	5
Total	50	15

(1) Both concentration and % SiO_2 (quartz) to be determined from the fraction passing a size selector with the following characteristics:

Aerodynamic Diameter (μm) (unit density sphere)	% Passing Selector
< 2	90
2.5	75
3.5	50
5.0	25
10	0

(2) This dust should contain less than 1% quartz; if quartz content > 1%, use formula for quartz.

(3) As determined by the membrane filter method at 400-450X magnification (4 mm objective) phase contrast illumination.

(4) Respirable dust as defined by the British Medical Research Council criteria and as sampled by a device producing equivalent results (MRE sampler).

Vegetable Dusts

14. If they contain less than 1% SiO_2, the TLV for inert dust applies. If they contain more than 1% SiO_2 in the material or mixed with it, the TLV for quartz applies. Many of these dusts produce allergic reactions through their own content of antigens or through the effects of molds and fungi that grow during storage. Vegetable dusts create three types of hazards: respiratory effects, skin and eye effect, and fires and explosions.

Environmental Guidelines

15. The US Department of Health, Education and Welfare estimates that adverse health effects begin when the dust content is higher than 80 $\mu g/m^3$, while adverse effects on materials and vegetation can begin at 60 $\mu g/m^3$. The preceding forms the basis of the following EPA guidelines issued in July, 1974:

(a) 75 $\mu g/m^3$ annual geometric mean

(b) 260 $\mu g/m^3$ maximum 24 hour concentration no more than once a year.

To make the observance of these guidelines easier, EPA (at the same time) also gave a guideline for stack discharges: 50 mg/Nm^3 (dry). As a comparison the USSR guideline is 150 $\mu g/m^3$ maximum 24 hour concentration. The preceding figures apply to total inert dust (< 1% SiO_2) containing no carcinogenic compounds. Because of the major variations from one project to another, not only in dust physical and chemical composition, but also in climate (dry or rainy) and location, it is difficult to give universal guidelines for dust control. As a rule, the following figures should be met:

Stack emission:	below 100 mg/Nm^3
Annual geometric mean:	100 $\mu g/m^3$
Maximum 24-hour concentration:	500 $\mu g/m^3$

If the same dust is affecting vegetation, the annual mean and the 24-hour concentration figures should be adjusted downwards.

Samples and Analysis

16. To be meaningful, the analysis figures should give the method of

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sampling and the method of analysis. The most reliable sample is "respirable dust". If this is not possible, the "total dust" should be evaluated. Whatever the method chosen the name of the instrument and its characteristics should be given. Weighing the sample (when this is possible) is the most accurate way for analyzing. Precautions should be taken to weigh only dry dust where all humidity has been removed. Counting the particles is less accurate but acceptable for all silicates except asbestos. Counting for asbestos should only be done for fibers longer than 5 μm.

Control

17. The appraisal mission should receive assurances that the project will meet the guidelines but should also make sure that the necessary trained personnel and equipment will be available to sample, analyze and take the corrective steps that may be necessary. The follow-up mission should check analysis results and compare them to the guidelines. If results are over the guidelines they should ask for the reasons and discuss possible corrective measures.

Legislation

18. If the existing legislation in the project country calls for standards or guidelines tougher than IBRD's guidelines, the country standards will prevail.

19. If the country's legal guidelines are more lenient, the appraisal mission should give the reasons why, by not following IBRD's guidelines, the plant personnel, the people living around the plant and the environment will still be protected.

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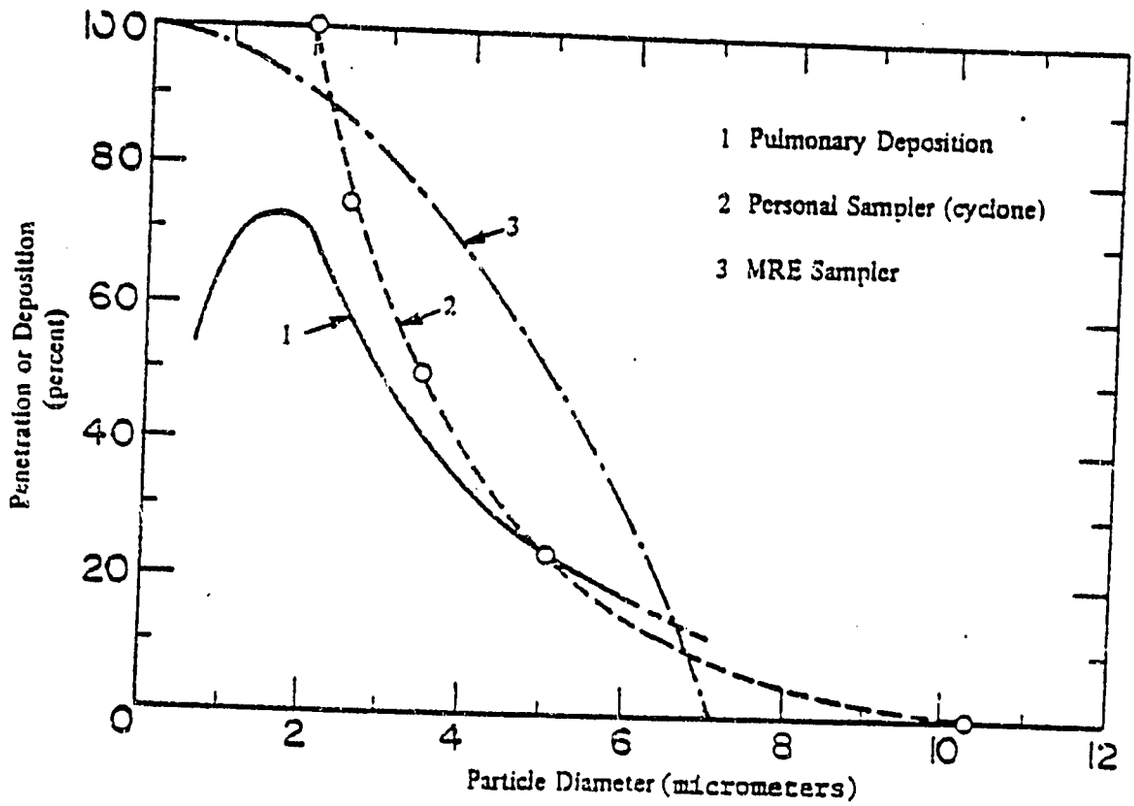

Source: U.S. Bureau of Mines. Sampling and Evaluating Respirable Coal Mine Dust: A Training Manual. U.S. Bureau of Mines, Information Circular No. 8503, February 1971, p. 3. Adapted from Figure 1.

Visual 12-4

THE WORLD BANK JANUARY 1981

OFFICE OF ENVIRONMENTAL AFFAIRS

ELECTROSTATIC PRECIPITATORS (ESP's)

GUIDELINES

1. Electrostatic Precipitators (ESP's) are one of the best ways to collect dust from gaseous effluents. Several industries use them extensively; among them, cement, mining, steel and non-ferrous metals. They act by ionizing the dust particles in the gas stream. The particle is then pulled towards an electrode by the electrostatic field then removed from the electrode and collected.

ESP Design

2. The design takes into account the following factors:

gas flow and composition
dust concentration in raw gas
dust concentration exit ESP

All other conditions being equal, the dust amount in the gas exit ESP will determine the characteristics of the precipitators (electrode total surface).

3. If, instead of a 100 mg/m^3 concentration we want 50 mg/m^3 exit ESP, we will have to practically double the electrode total surface and, at the same time, the equipment price.

4. From the preceding, it is easy to see that the most important technical guarantee is the dust concentration exit ESP. Defining ESP performance by the ratio of dust removed over total dust should be avoided as this depends on the dust concentration inlet equipment.

5. The US and West German standard is now 50 mg/Nm^3 in the stack.

World Bank Guidelines

6. The World Bank guideline will be 100 mg/m^3 in the stack. The concentration 150 mg/m^3 can be accepted if the plant is in a rural area, and if dust concentration at ground level is within World Bank guidelines inside the plant fence and 260 µg (microgram)/m^3 maximum outside the plant fence.

7. Up to 1980 the ESP for LDCs were designed usually for 300 mg/m^3. This has created problems particularly in conjunction with low level stacks. The decrease to 100 mg/m^3 will also have the added benefit of decreasing the shut down time and the maintenance cost on the extracting fan. At 300 mg/m^3 in a power station using normal coal (10% ash), the fan has to be shut down every 3 to 4 months to rebalance or replace some blades.

THE WORLD BANK

MAY 1980

OFFICE OF ENVIRONMENTAL AND HEALTH AFFAIRS

GUIDELINES

STRIP (SURFACE) MINING OPERATIONS

SEDIMENT AND EROSION CONTROL

1. Control of erosion and sedimentation has assumed a new importance in view of world-wide industrial expansion and increased energy needs. Greater reliance is being placed on coal as a major energy source. Many mineral ores and coal supplies are readily accessible through strip (or surface) mining operations. Therefore measures are necessary to protect the environment from uncontrolled soil movement and offsite damage that could result from such operations.

2. Each Bank appraisal report should include a complete and detailed proposal, with a timetable, for controlling erosion and sedimentation which could result from projects. The plan should provide for initiating land reclamation and other necessary measures in the early project stages, and in no case later than three (3) years following the start of mining operations.

3. These guidelines present basic concepts and sources of sediment pollution, principles of control, and the planning needed for effective control measures.

CONCEPTS AND SOURCES OF SEDIMENT POLLUTION

4. Surface mining, like any large-scale earth-moving operation, can generate large volumes of sediment. If the sediment can be contained within the mining site, then no problems are created. However, if the sediments are not contained but are allowed to reach adjacent waterways, as is most frequently the case, then they become pollutants.

5. As pollutants, the sediments can have a number of detrimental effects, such as:

- Reducing storage capacity in reservoirs;
- Filling lakes and ponds;
- Clogging stream channels;
- Destroying aquatic habitats;
- Degrading water quality for consumptive uses;
- Increasing water treatment costs; and
- Acting as carriers of other pollutants (such as plant nutrients, insecticides, heavy metals and disease organisms).

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6. The major sources of sediment pollution are those land-disturbing activities associated with mining, construction, agriculture, and forestry. It has been reported that active surface mining and construction operations cause the highest rates of erosion.

7. The major sources of sediment in surface mining operations are the areas being cleared, grubbed (removal of stumps and roots), and scalped (removal of vegetation cover); roadways; spoil pits; and active mining areas.

8. Soil losses from clearing, grubbing and scalping operations are caused by:

- Failing to install perimeter control measures prior to start up of operations;
- Exposing soils or steep slopes;
- Clearing too far above the unexcavated face of the overburden;
- Clearing and grubbing too far ahead of the open cut;
- Improperly placing or protecting the salvaged or stockpiled materials; and
- Creating a surface that impedes infiltration or concentrates surface runoff, such as leaving bulldozer cleat marks that run up and down a slope.

9. Roadways are often the major source of sediment, and may function as conduits for sediment washing down from other areas into the natural drainage systems. This includes the roadways within the mining area itself as well as the access roads outside the actual mine site.

10. Long access roads can adversely disrupt the natural drainage systems by intercepting, concentrating and diverting surface runoff. This will result in severe soil losses from roadway surfaces, ditches, cut slopes and safety berms.

11. Accelerated onsite and offsite erosion will occur after the mine ceases operations if steps are not taken to permanently stabilize exposed surfaces with vegetation and to otherwise lessen disruption of the normal drainage patterns.

12. In area strip mining operations, carried out in level or gently rolling topography, the spoil accumulating below the outcrop line has the greatest potential for causing offsite sediment damage. Water pumped from the pit during rainfall can also contribute significant quantities of sediment and other contaminants.

13. Contour strip mining, carried out in steep or mountainous terrain, has a much greater potential for sediment damage. Since contour mines have a narrow, linear configuration more of the spoil area tends to discharge directly into the natural drainage systems. Another contributing factor is that the receiving waterway is generally closer to the sediment source and separated by

relatively steep terrain. Additionally, the mine site receives erosive runoff from undisturbed areas above it.

14. Mountain-top removal mining has, in recent years, been an alternative to strip mining. The most critical areas at this type of operation are the spoil slopes around the perimeter, mine roadway exits, and valley fills. The fills are highly susceptible to piping (subsurface removal of soil) and to landslides. Another serious problem can be the soil losses from the face of the slope due to rainfall and runoff. Chemical and acid pollution can also cause serious problems.

15. Certain reclamation practices contribute significantly to environmental damage if not properly carried out. Configuration of the graded areas, the pattern of reestablished drainageways, revegetation measures, tillage practices, and followup maintenance will all influence the long term soil losses and offsite damages.

PRINCIPLES OF EROSION AND SEDIMENT TRANSPORT

16. As applied to mining operations the most important types of erosion are those caused by a stormwater runoff. Three basic types are of major significance:

- Sheet erosion - resulting from rain striking a bare soil surface, and displacing soil particles;
- Rill and gully erosion - removal of soil by water through small, well-defined channels; and
- Stream channel erosion - scouring of the stream channel by sediment reaching the stream from land surfaces.

17. The erosion potential of any area is determined by climate (precipitation, temperature and wind); vegetative cover; soil characteristics (structure, texture, organic matter, moisture, and permeability); and topography. While these factors must be considered separately, it is their combined effects which determine the total erosion potential.

18. Sediment transportation and deposition are influenced by the flow patterns of the water and the nature of the particles being transported. As velocity and turbulence increase, more sediment is transported. Small, light particles such as fine sand, silt and clay are easily transported. Conversely, coarser and heavier particles are more readily deposited.

CONTROL TECHNOLOGY

19. Stormwater runoff, which is the basic cause of soil erosion, can be controlled through applications of proper vegetative and structual practices, and construction measures that control the location, volume, and velocity of runoff. To this should be combined a suitable program of scheduling mining operations to minimize problems related to seasonal climatic fluctuations.

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20. Control may be accomplished through one or more of the following:

- Reduction and detention of the runoff;
- Interception and diversion of the runoff; and
- Proper handling and disposal of concentrated flow.

21. Soil stabilization is another means of preventing soil erosion. Stabilization measures may be either vegetative or non-vegetative, short term or long term, or a combination of these. Vegetative stabilization utilizes different types of vegetation to protect the soil from erosion. Non-vegetative stabilization employs a multitude of measures that depend on materials other than vegetation to prevent erosion. Frequently the two types are used together.

22. Mulching and chemical stabilization are the two major types of short term measures applied. Mulching, with organic materials such as straw, hay, wood chips, wood fiber or other products, is most often used. Chemical stabilizers serve to coat and penetrate the soil surface and bind the soil particles together. These are most effective for dry, highly permeable spoil or inplace soils subject to sheet flow.

23. Mulching and channel stabilization are most frequently used for long term stabilization. However, mulching in this case involves the use of fiber glass, plastics, or other non-biodegradable material to protect seed beds during the germination and early plant development periods. In general, structual channel stabilization involves the use of stone riprap (broken rock) or other durable material to stabilize ditches and other waterways. Stone surfacing is sometimes used to stabilize highly toxic surfaces or excessively wet seepage areas on slopes.

24. Sediment is the product of erosion and hence must be contained, and every effort should be made to control sediments at, or as close to, the source as possible. The procedures used successfully for trapping sediments include natural or installed vegetative buffers, sediment traps (such as sandbags and straw bales), settling basins and chemical coagulation.

25. All erosion control and sediment containment facilities must receive proper maintenance during their design life in order to perform effectively. They should be located in a highly visible area so as not to be overlooked. They must also be readily accessible to personnel and equipment for regular inspections, and for the performance of routine and emergency repairs.

26. Once the mining operation is finished, all sediment control structures should be disposed of in such a way as to prevent both the structures and the accumulated sediments from becoming nuisances and contributing to environmental deterioration.

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EFFLUENT LIMITATIONS

27. Runoff and drainage from surface mining operations should not exceed the following limitations prior to discharge into surface waters:

Total Suspended Solids:	30 - 100 mg/L
Total Iron	4 - 7 mg/L
pH	6 - 9
Alkalinity	Greater than acidity
Soluble Toxicants	None

CONTROL PLANNING

28. An erosion and sediment control plan serves as the basis for operating the mine and at the same time minimizing or eliminating environmental damage.

29. Preparation of a control plan requires five basic steps:

- Identification of legal and technical requirements;
- Collection and evaluation of site information;
- Development of a control strategy;
- Interdisciplinary review of the feasibility of the preliminary plan; and
- Revision and finalization of the control plan.

30. Table 1 presents a list of the major components which should be considered in formulating an erosion and sediment control master plan. This should be made an integral part of the overall mining operation.

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2. U.S. Environmental Protection Agency "Erosion and Sediment Control". (2 Vols.) Doc. EPA-625/3-76-006. Washington (October 1976).

3. "Guidelines for Reclamation and Revegetation, Surface-Mined Coal Areas in Southwest Virginia". Virginia Polytechnic Institute and State University, Extension Division. Blacksburg, Virginia (February 1973).

Table 1. Components to be Considered for Preparation of Erosion and Sediment Control Plans a/

Background information:

1. General:

Location of project
Extent of area to be affected
Type of mining operation
Evidence of compliance with State's legal requirements

2. Site inventory:

Topography
Geologic analysis
Soil analysis
Climatic analysis
Hydrologic analysis
Vegetative analysis
Land use analysis

Schedule of activities:

Site preparation:

1. Access roads:

Plan view (location)
Typical cross section
Profiles
Maintenance requirements and schedule

2. Drainage and sediment control structures:

Plan view (location)
Typical cross sections
Details (where needed)
Design computations (where needed)
Maintenance requirements and schedule

3. Clearing and grubbing:

Plan views of limits of areas to be cleared
Description of procedure
Machinery to be used
Method of disposing of timber, brush, and waste materials
Identification of critical areas requiring temporary stabilization

Mining operations:

1. Scalping:

Method of scalping topsoil material
Equipment to be used
Plan view of topsoil storage areas
Temporary vegetative stabilization of stockpile areas

Schedule of activities—*continued:*

Mining operations—*continued:*

2. Overburden handling:

Method of overburden handling
Handling of first cut
Plan view of overburden storage areas
Stormwater handling in overburden storage areas
Temporary stabilization measures
Permanent stabilization measures

Reclamation operations:

1. Handling of toxic material:

Method of handling toxic material
Equipment to be used

2. Spoil rehandling and grading:

Typical cross section of regrading
Equipment to be used
Method of spreading topsoil or upper horizon material on the regraded area, including approximate thickness of the final surfacing material
Method of drainage control for the final regraded area

3. Revegetation:

Method to be used
Surface preparation
Type of vegetation
Fertilizer application (method and rate)
Seasonal revegetation schedule and rate
Mulch application (method and rate)
Maintenance requirements and schedule

4. Mine abandonment:

Method for disposal and stabilization of drainage structures not covered above, particularly sediment basins
Method for stabilization and/or abandonment of haul road
Assignment of responsibility for any permanent structures left behind
Maintenance program and schedule for any permanent structures left behind

a/ USEPA "Erosion and Sediment Control". Doc. EPA-625/3-76-006. (October 1976).

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THE WORLD BANK FEBRUARY 1981

OFFICE OF ENVIRONMENTAL AFFAIRS

UNDERGROUND COAL MINING

EFFLUENT GUIDELINES

1. Many of the world's mineral resources are extracted from the earth through underground mining operations. The principal ones include coal, and to a lesser degree, copper, lead, zinc, molybdenum, uranium, and others. This document will be confined to the environmental effects of underground coal production and its associated operations.

MINING PROCESSES

2. Underground mining is a highly complex operation, involving basically working beneath a thick overburden, connected to the outside by shafts and passageways which are sometimes hundreds of meters long. Major problems which are not found or are of lesser importance in surface mining include roof supports, ventilation, lighting, drainage, methane release, equipment access and coal conveyance.

3. Once a main access portal has been established, parallel entries are driven into the coal deposit to provide corridors for haulage, ventilation, power and other operational needs. Cross-corridors then reach to the sides of the mine, leaving pillars in a checkerboard fashion to support the roof and overburden. The deeper the mine, the larger the pillars must be relative to the mined out areas. Where large pillars are required for support during operations it may be desirable to mine the pillars as the equipment retreats back toward the main tunnel. The roof must then be supported by other means or allowed to collapse.

4. Equipment used in underground mining ranges from relatively simple to highly automated machinery. Many small mines still rely primarily on hand labor. Coal is blasted from the face of the seam and loaded into shuttle cars, using mechanical techniques in most cases. This involves undercutting, drilling, blasting and loading. Shuttle cars, filled by portable conveyor belts, take the coal either to an underground transfer point or directly out of the mine.

5. These operations produce large amounts of dust and liberate methane trapped in the coal, requiring that exposed areas be kept essentially free of particulates or open flames to prevent coal dust or methane explosions. Machines are usually connected to a water supply to provide a spray for dust control. Frequent methane testing is required at the seam face to avoid danger to the workers.

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6. Continuous machines are employed in many locations. Basically a rotating head digs into the coal and loosens it while arms scoop it onto a conveyor belt for loading into a shuttle car.

7. Longwall mining has been used in Europe for many years and is now gaining popularity in other regions. Corridors about 100 to 200 meters apart are driven into the coal and interconnected. The longwall of the interconnection is then mined in slices. The roof is held up by steel supports while the cutter makes a pass across the face. The roof supports are advanced with the shearing machine to make a new pass, while the roof in the mined out area collapses behind the supports.

8. For most uses, the mined coal must be processed to meet consumer needs in terms of size, moisture, mineral concentrations, heat content and other properties. This may be done by either physical or chemical procedures, and usually takes place at the mine site.

9. Physical coal cleaning involves crushing, grinding, sizing, solids separation, washing and flotation in various combinations. These techniques remove portions of the sulfur and ash contents. Although the sulfur exists in the coal in both the organic and inorganic forms, physical cleaning is effective only in reducing the inorganic portion. Because of partial ash removal, the procedure also increases the per kilogram heat content.

10. Chemical coal cleaning or desulfurization involves treating coal with a reagent capable of converting the sulfur to a soluble or volatile form. Leaching solutions such as nitric acid, hydrofluoric acid, chlorine, ammonia, and organic solvents have been reported to be successful. However, this cleaning procedure is still in the experimental stage and is not currently being applied commercially.

SOURCES AND CHARACTERISTICS OF WASTES

11. Coal mining operations and equipment choices vary widely, and are generally selected on the basis of local geology and other natural conditions. The specific environmental effects will depend upon the mining techniques utilized and the existing geological or geochemical characteristics.

Air Emissions

12. Air pollutants from coal mining operations are not considered to be significant. Dusts originate from drilling and blasting procedures, but these are generally controlled by water sprays at the working face. Methane is controlled through effective ventilation with air in order to reduce the gas concentrations to levels below the flammable or toxic limits, and thus avoids the possibility of underground explosions. The methane problem increases with greater depths because the methane has less opportunity to diffuse to the surface over geologic time. It has been estimated that at mining levels methane is produced at an average rate of 5 cubic meters per ton of coal mined.

Liquid Effluents

13. The principal environmental pollutant resulting from underground coal mining operations is acid mine drainage. The acidity results when naturally occurring pyrite (FeS_2) in the coal seam and wastes is oxidized in the presence of air and water to form sulfuric acid (H_2SO_4) and iron sulfates ($FeSO_4$ and $Fe_2(SO_4)_3$. This very acidic (pH 2 to 3) effluent must be treated for pH and dissolved iron before release to water courses. At the low pH values heavy metals (such as iron, manganese, cadmium, copper, zinc, and lead) are more soluble and can create serious water pollution problems. Continuous acid discharges will seriously affect aquatic ecosystems. Acid waters containing heavy concentrations of dissolved heavy metals will support only a limited water flora, such as acid-tolerant molds and algae, and will not support fish. Acid waters are not suitable for human consumption nor for most industrial uses.

14. The amount and rate of acid formation and the quality of water discharged will depend upon the amount and type of pyrite in the overburden and in the coal, time of exposure, characteristics of the overburden, and amount of available water. It has been estimated that in the Appalachian bituminous coal mining regions of the eastern United States an average of 1200 liters of acid mine water is discharged for each metric ton of coal mined.

15. Water is supplied to coal mines primarily for suppressing dust (continuous mining and conveyor belt operation) and for equipment cooling. Rain water can enter mine areas through infiltration. Hence, continuous water removal is required to assure continuity and efficiency of the mining process.

16. In coal preparation the water is deliberately introduced into the unit process operations which include wet screening, tables, cyclones, gravity separation and heavy media separation. Water is also used for dust control, equipment cooling, and transporting coal in the washing process.

17. The parameters of principal concern in underground coal mining operations and for coal preparation plants include hydrogen ion concentrations (pH), total suspended solids (TSS), total iron, and total manganese. Average levels of these parameters found in typical underground mining and coal preparation plants are given in Table 1.

Solid Wastes

18. Solid wastes are generated both during underground mining and during the preparation process. The solid waste from underground mines (commonly referred to as "gob") results from the digging required to reach the coal seams. Normally this material is transported to the surface and dumped in piles on the land. Its composition in general corresponds to the overburden found in the mining area.

Table 1. Average Quality of Raw Effluents From Acid Mine Drainage and Coal Preparation

Parameter	Acid Drainage	Coal Preparation
Total Susp. Sol. - mg/L	158	218,000
Total Manganese - mg/L	4.9	8.4
Total Iron - mg/L	135	733
pH - Units	5.7	7.0

19. Refuse from the coal extraction and preparation, consisting of solid wastes and other impurities, is also generally disposed of by dumping on nearby land areas.

20. The waste piles are unsightly, causing degradation of local property values and destruction of esthetics. The refuse contains flammable material readily susceptible to spontaneous combustion and difficult to quench. This burning produces particulate matter and fumes high in sulfur dioxide. Acid mine drainage and siltation can also result from runoff from the piles. Siltation is influenced by the steepness, compaction, drainage control structures, and cover material of the pile.

WASTE DISCHARGE LIMITATIONS

Air Emissions

21. Dust and methane gas are the principal air pollutants of concern in underground mining. Particulates should be controlled by water sprays. Methane gases should be controlled by efficient ventilation systems bringing outside air to the working areas.

22. Coal preparation plants can be sources of discharges of particulate matter to the atmosphere. Pneumatic cleaning and thermal drying are the chief sources. Particulates should be limited to:

Ann. Geom. Mean	75 $\mu g/m^3$
Max. 24-hours	260 $\mu g/m^3$

(outside the mine fence at ground level)

Liquid Effluents

23. Liquid effluents from subsurface mining and coal preparation operations should conform to the limitations shown in Table 2.

Table 2 - Effluent Limitations for Acid Mine Drainage and Coal Preparation

Parameter	Limitation
Total Susp. Sol. - mg/L	70
Total Manganese - mg/L	4
Total Iron - mg/L	6
pH - Units	6 to 9

CONTROL AND TREATMENT OF WASTES

Air Emissions

24. Dust control in the mines is effected by continuous spraying of the working face. The methane is diluted with air to less-than-flammable limits to avoid the possibility of underground explosions. In some instances the methane can be drained from the coal seam before mining. Such an operation recovers the gas for use as a fuel and at the same time reduces the danger of mine explosions.

25. Particulate matter from coal preparation originates from crushing, pneumatic cleaning and thermal drying. These emissions can be effectively controlled by use of baghouses or other dust collection devices.

Liquid Effluents

26. The acidity in the acid mine drainage may be controlled through pH adjustment and chemical precipitation. Hydrated lime ($Ca(OH)_2$) is most commonly used for this purpose, and can be introduced as an aqueous slurry or as a dry powder. In large installations calcined lime (CaO) (also termed "unslaked" or "quick" lime) or limestone ($CaCO_3$) may be more economical to use. Caustic soda (NaOH) or soda ash (Na_2CO_3) can also be used, but are much more expensive.

27. Control of the pH will also result in a reduction of the iron and manganese levels in the effluent, by causing oxidation which converts the ferrous iron to ferric iron and thus precipitates it out of solution. The upward adjustment of the pH causes a solubility decrease and precipitation of the heavy metals in the effluent. The precipitates can then be removed by settling.

28. The effectiveness of neutralization and settling in controlling the effluent is governed by the reagents used, the influent and effluent pH, temperature, volume of flow and the presence of any side reactions, including metal chelation and mixed-metal hydroxide complexing.. (Chelation is a chemical reaction in which a central metallic ion is captured in a complex within a ring containing several atoms).

29. Oxidation of certain components common to coal mine wastewaters (such as ferrous ions) to easily removed compounds can also be accomplished by aeration, either mechanical or simple cascading flow. The resulting sludge and other solids are readily settled in settling basins.

30. Wastewater from coal preparation plants may be satisfactorily treated by settling. If the settling pond capacity is limited it may be necessary to use a coagulant. The overflow from the ponds is generally suitable for recycling through the preparation systems, resulting in little or no discharge to surface waters. Where sufficient land area is available two or more ponds are used on an intermittent basis. As a pond is filled with settled solids, it is taken out of service for removal and disposal of the sludge.

Solid Wastes

31. Refuse from the mining operation may be left underground but in most cases it is brought to the surface and dumped nearby. Refuse from the coal cleaning is generally collected and also dumped near the site.

32. Steps should be taken to assure that leachate and surface runoff from the piles does not cause harm to surface waters or groundwater supplies. Leaching, which should be monitored, can be minimized or prevented by careful composition and layering of the refuse material. Leaching water will be treated if need be.

33. Sludges from the settling ponds can be dredged and conveyed to a refuse pile and sludge lagoon. Where sufficient pond capacity is provided, the sludge may be allowed to dry in the lagoon. This will reduce the volume and facilitate removal and final disposal.

COAL SLURRY PIPELINES

34. Although it is not being widely applied at this time, coal slurry pipeline technology has already proven to be a commercially successful alternative for transportation of coal. Because use of this technology is expanding,

it is considered advisable to outline the possible environmental effects. Guidelines on use of pipelines for transportation of petroleum and its derivatives have been prepared by the Bank's Office of Environmental Affairs.

35. The major risks of environmental damage occur during the construction phases of slurry pipelines. The environmental effects and measures that can be taken to minimize these effects are shown in Table 3. Coal pipelines may extend for distances of as much as 500 to 2000 kilometers. The facilities are usually buried underground and hence cause no permanent esthetic damage.

Table 3 - Environmental Effects of Coal Pipeline Construction a/

Activity	Environmental Effects	Mitigation Measures
(1) Clearing and grading	Destroys wildlife habitat Encourages runoff and erosion Degrades esthetics	Revegetate quickly Slow runoff Leave screening vegetation
(2) Ditching	Potential runoff from spoil pile Covering top soil may produce rock rubble	Close ditch as soon as possible Separate top soil and set aside Haul to appropriate disposal site
(3) Hauling and Stringing Pipe	Increased truck traffic	Limit haul hours and route
(4) Welding Pipe	None	None
(5) Coating Pipe	Accidental spill of coating materials	Normal care in operation and availability of cleanup materials
(6) Backfill	Extra top soil or ditch "padding" soil may be needed	Use existing or properly sited borrow pits
(7) Clean-up	Erosion of right-of-way	Adequate revegetation program Restore drainage patterns Monitoring of recovery
(8) Testing System	Requires large volumes of water	Careful selection of water source and discharge

a/ From EPA Document EPA - 600/7-77-015 (See Bibliography)

36. The risk of spills from such facilities is considered to be negligible. The control and prevention of corrosion are well developed technologies because of extensive use of these underground systems to transport petroleum, natural gas, and other resources.

37. Operational impacts are affected by the coal preparation, pumping stations, and dewatering facilities. Problems are associated with preparation of the coal slurry, inter-basin transfer of large quantities of water required, and discharge or disposal of the separated water at the destination.

38. Since preparation of the slurry is generally done at the site of coal preparation, as previously discussed, the handling of wastes is genrally included in the measures otherwise taken at the site. To prevent settling and possible obstruction in the system, ponds are provided at intervals for emptying the line in case of a system breakdown or other interruption.

39. At the discharge end, the coal slurry goes into agitated tank storage, from which it is conveyed to the dewatering systems. Dewatering is done by natural settling, vacuum filtration, or by centrifuge. Additional thermal drying is required before use of the coal. The finely ground coal still remaining in the water is generally removed by chemical flocculation. The reclaimed water may be used for cooling or other purposes.

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THE WORLD BANK

OCTOBER 1980

OFFICE OF ENVIRONMENTAL AFFAIRS

NOISE

1. Bank missions will be concerned with noise and its environmental effects in various types of projects. Among these are highway and railway projects, airports, agricultural enterprises (from operation of farm machinery), and industrial installations.

BASIC CONCEPTS

2. Noise may be described as sound without agreeable musical quality, or as "unwanted sound". Generally, noise is produced when an object or surface vibrates rapidly enough to generate a pressure wave or disturbance in the surrounding medium. From the standpoint of environmental effects the medium of greatest concern is air, although sound may also be transmitted through liquids and solids.

3. Sound is transmitted by wave motion. It propagates as the result of the elastic interactions between the molecular components of the medium through which it travels. The speed of sound, therefore, depends upon the mass of molecules (density) and their elastic reactions (pressure). The human ear responds to the pressure fluctuations set up in the surrounding medium. Airborne sound travels at a speed of 344 meters per second at a temperature of 20°C. In seawater sound travels at the rate of about 1490 meters per second.

4. The decibel (dB) is used to measure the relative pressure of different sounds. The decibel is equal to 20 times the logarithm of the ratio of sound pressure to a reference pressure of 20 μPa*, or

$$\text{Sound pressure level (dB)} = \log_{10} \frac{\text{Measured Pressure}}{\text{Reference Pressure}}$$

Thus, a sound with 10 times the pressure of another is considered to be 20 dB louder, and each succeeding 10-fold increase adds another 20 dB to the sound level. Relative sound pressure levels for various degrees of "loudness" are presented in Table 1.

5. The quality of sound (or noise) is measured by flow of energy per unit area. Frequency is a measure of the number of complete vibrations occurring per second, and is measured in "hertz" (Hz). Thus, 1 Hz equals 1 cycle per second. Normally, the human ear cannot detect sounds above 15,000 Hz (ultrasound). The lower limit of human detection depends more on the quantity of sound. At 65 Hz the human ear does not normally detect sounds below 60 dB.

* 1 Pascal = 10 dyne per square centimeter.

Table 1. Relative Sound Pressure Levels for Various Sources of Noise a/.

Apparent Loudness	Examples	Relative Sound Pressude Levels		Pascals
		dB	Ratio to 0 dB	
Deafening	Jet aircraft	140	10,000,000	200
	Threshold of feeling	130	3,162,000	
Very loud	Elevated train, thunder	120	1,000,000	20
	Subway train, riveter	110	316,200	
	Noisy Ind. Plant	100	100,000	2
	Loud street noise	90	31,620	
	Noisy office	80	10,000	0.2
Loud	Av. Street noise	70	3,162	
	Av. office	60	1,000	0.02
Moderate	Mod. restaurant clatter	50	316	
	Private office	40	100	0.002
Faint	Rustling leaves	20	10	0.0002
Very faint	Normal breathing	10	3	
	Threshold audibility	0	1	0.00002

a/ From "Sound Control Construction" U. S. Gypsum Co.

MEASUREMENT OF NOISE

6. The basic goal in quantifying sound is to determine the time and location variations of noise in the environment throughout a community and to assure that the data can be used as a measure of the effects of environmental noise on people.

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7. The Sound Level Meter (SLM) is the basic instrument for measuring sound or noise. While such instruments are available from a number of manufacturers, all meters to be used for this purpose must meet the American National Standards Institute (ANSI) specification S1.4-1971, or the latest ANSI issuances. Both Type 1 (Precision) and Type 2 (General Purpose) meters are acceptable. The Type 2 meter has broader performance tolerances, and is usually less bulky, lighter, and less expensive than the Type 1.

8. A sound level meter electronically weighs the amplitude of the various frequencies in accordance with a person's hearing sensitivity and sums the resulting weighted spectrum into a single number. The typical meter contains three different response weighting networks: A, to match the response of the ear to sound of low intensity; B, to match response to sound of moderate intensity; and C, to match response to sound of high intensity. The A scale is most commonly used, since it most closely approximates the human perception of sound. The weighted sound level unit, at the A setting is commonly designated as dB (A).

9. The SLM A-setting measures the sound level at a frequency of 1,000 Hz. Where frequency readings differ from the standard of 1,000 Hz, then a correction must be made to convert "flat" response readings to the A levels. The term "flat" response designates the uniform response of an instrument over a wide frequency range, up to 20 K Hz.

Table 2. Corrections from "Flat" Response Levels to A Levels.

Octave Band Center Frequency (Hz)	Correction (dB)
31.5	- 39.5
63	- 26
125	- 16
250	- 8.5
500	- 3.0
1000	0
2000	+ 1.0
4000	+ 1.0
8000	- 1.0
16000	- 6.5

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EFFECTS OF NOISE

10. A universal effect of noise is its interference with the understanding of speech. This is one aspect of "masking" — an interaction of two acoustic stimuli whereby one of them changes the perceived quality of the other, shifts its apparent location or loudness, or makes speech completely inaudible. Various factors enter into the degree of speech interference, such as speech, age, and hearing of individuals. Children have less precise speech than do adults, while older persons are more susceptible to interference from background noise.

11. Noise can elicit a variety of physiological responses, but no clear evidence exists to indicate that continued activation of these responses leads to permanent health effects. Sounds of sufficient intensity can cause pain to the auditory nervous system. It can be presumed that noise exposure can cause general personal stress, either by itself or in combination with other stress sources. Noise exposure to moderate intensities that may be found in the environment does have some effect on the cardiovascular system, but no definite permanent effects on the circulatory systems have been demonstrated. Moderate noise levels have been known to cause vasoconstriction of the peripheral areas of the body and pupillary dilation, but there is no evidence that these effects can lead to harmful consequences over a period of time.

12. Continuous noise levels above 90 dB (A) have detrimental effects on human performance, especially in so-called "noise-sensitive" functions, such as vigilance tasks, information gathering, and analytical processes. Noise levels below 90 dB (A) can be disruptive, particularly if they have predominantly high frequency components, and are intermittent, unexpected and uncontrollable.

13. Frequencies below 16 Hz are referred to as infrasonic, and include such sources as earthquakes, wind, thunder, and distant jet aircraft. Man-made infrasound occurs at higher intensity levels than those found in nature. Effects associated with infrasound resemble mild stress reactions and bizarre auditory sensations, such as pulsating and fluttering. Ultrasonic frequencies are those above 20,000 Hz, and are produced by a variety of jet engines and industrial equipment. Above 105 dB, the effects of high intensity ultrasounds resemble those observed during stress situations.

14. Noise has the same general effects on wildlife and other animals as it does on humans. Noise of sufficient intensity can disrupt normal patterns of animal existence. Exploratory behavior can be curtailed, avoidance behavior can limit access to food and shelter, and breeding habits can be disrupted. Hearing loss and the masking of auditory signals can complicate an animal's abilities to recognize its young, detect and locate prey and evade predators. Physiological effects of noise exposure—such as changes in blood pressure and chemistry, hormone balance, and reproductivity—have been demonstrated in laboratory animals and, to some extent, in farm animals.

15. Secondary effects of noise on the health and welfare of man include three general types: sonic boom effects, noise induced vibration and sonic fatigue. Sound can also cause buildings to vibrate, and this can have a direct effect on humans. Some booms of sufficient intensity not only can break windows,

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but they can also damage building structures. However, sonic booms can be controlled to levels which are innocuous in relation to buildings and structures. Noise induced vibrations near rocket launch sites can also cause window breakage. Construction activities may have similar effects. Sonic fatigue is also a problem where material is used near intense sound sources, but such problems can be avoided by proper design and this type of fatigue does not usually cause environmental problems.

NOISE CONTROL TECHNIQUES

16. Noise control techniques fall into two general catetories: control at the source and control of the path of sound. Within the urban environment noises originate principally from aircraft and airport operations, industrial operations, construction activities and highway traffic.

17. Aircraft related noises mainly affect the populations living near airports or in the flight paths of low flying airplanes. Although many new types of jet-powered ships introduced since 1972 emit less noise than earlier models, noise continues to be the most serious constraint currently facing airport operations.

18. A number of techniques may be applied, alone or in combination, to the reduction of aircraft noises and their effects. The principal ones include:

— Operational measures designed to limit the production of noise by aircraft. This could involve special take-off and landing procedures, restrictions on the total noisy aircraft traffic, banning of night traffic, diversion of part of the traffic to other regional airports, and application of local airport noise regulations.

— Measures aimed at changing the land use in areas exposed to heavy noise. This requires close coordination of airport planning with regional and local land use policy. Such an approach is most easily implemented in the case of new airports in areas not yet intensely developed. However, even around existing airports it is possible to re-zone the heavily impacted areas over a period of time and minimize noise exposures for private dwellings, schools, hospitals and recreation areas.

— Measures aimed at reducing the impact of noise at the point of receiption. This will require sound-proofing of private residences, hotels, offices and other structures. Such measures should be taken as a last resort, since they do nothing to eliminate the source of the noise or to improve the outdoor environment.

19. Noises resulting from industrial operations are generally confined within the plant structure. Machinery and equipment are the main sources, and the effects are felt mostly by the individual workers. Controls may be accomplished through measures at the source (relocation, vibration, vibration control,

etc.); installation of acoustical shields, enclosures, or other barriers to interrupt the path of the sound; or through limiting the duration of the exposure by the receiver. The first two of these measures will help reduce the noise levels in the environment outside the plant.

20. While construction operations are not permanent, large projects are carried out over relatively long time periods, and measures are frequently required to reduce noise emissions. Construction noises can originate from such sources as crane and hoisting equipment, air compressors, concrete mixers, tractor and bulldozing equipment and materials delivery vehicles.

21. Noise control at construction sites will require an analysis of each individual situation to determine which measures should be applied. The general measures which can be effective include:

- Assurance that the manufacturer has designed, built and equipped the unit to conform with existing noise control regulations.
- Adequate operation and maintenance of equipment.
- Limiting the time of day during which equipment may be operated.
- Limiting the places or zones in which equipment may be used.

22. The effect of vehicle noise on populations is usually dependent upon traffic concentrations rather than on any one individual vehicle. Although trucks are normally fewer in number, they tend to contribute the largest share of the noise. Motorcycle traffic can also be a significant contributor. For highway vehicles, noises originate from the exhaust systems, engines, special features (such as loading machinery on solid waste carriers and other heavy duty trucks), and other individual characteristics.

23. Noise abatement measures are similar to those for construction equipment, as given in paragraph 21. Additional controls may be imposed through licensing and inspection procedures, and through driver education on operational procedures.

ACCEPTABLE NOISE LIMITATIONS

24. There are considerable variations in the recommended allowable noise levels emitted by the many individual sources existing in the environment. The limitations presented in Table 3 represent the net effect of cumulative contributions from all sources. The levels given are considered adequate for protecting the health and welfare of the general public in the specific environmental situation. The term "public health and welfare" denotes personal comfort and well-being as well as the absence of hearing damage or other clinical symptom.

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Table 3. Yearly Average Equivalent Sound Levels Required for Protection of Public Health and Welfare 1/.

	Measure 2/	Indoor Activity Interference	Indoor Hearing Loss Consideration	Indoor To Protect Against Both Effects (b)	Outdoor Activity Interference	Outdoor Hearing Loss Consideration	Outdoor To Protect Against Both Effects (b)
Residential with Outside Space and Farm Residences	L_{dn}	45		45	55		55
	$L_{eq(24)}$		70			70	
Residential with No Outside Space	L_{dn}	45		45			
	$L_{eq(24)}$		70				
Commercial	$L_{eq(24)}$	(a)	70	70(c)	(a)	70	70(c)
Inside Transportation	$L_{eq(24)}$	(a)	70	(a)			
Industrial	$L_{eq(24)}$(d)	(a)	70	70(c)	(a)	70	70(c)
Hospitals	L_{dn}	45		45	55		55
	$L_{eq(24)}$		70			70	
Educational	$L_{eq(24)}$	45		45	55		55
	$L_{eq(24)}$(d)		70			70	
Recreational Areas	$L_{eq(24)}$	(a)	70	70(c)	(a)	70	70(c)
Farm Land and General Unpopulated Land	$L_{eq(24)}$				(a)	70	70(c)

Code:

a. Since different types of activities appear to be associated with different levels, identification of a maximum level for activity interference may be difficult except in those circumstances where speech communication is a critical activity.

b. Based on lowest level.

c. Based only on hearing loss.

d. An $L_{eq(8)}$ of 75 dB may be identified in these situations so long as the exposure over the remaining 16 hours per day is low enough to result in a negligible contribution to the 24-hour average, i.e., no greater than an L_{eq} of 60 dB.

1/ From Ref. 4

2/ L_{dn} = Day-night average A - weighted equivalent sound level, with a 10-decibel weighting applied to night time levels.

L_{eq} (24) = Equivalent A-weighted sound level over 24 hours.

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THE WORLD BANK OCTOBER 1980

OFFICE OF ENVIRONMENTAL AFFAIRS

SULFUR DIOXIDE EMISSIONS

GUIDELINES

1. Man-made emissions of sulfur dioxide originate from a variety of sources discharging to the environment, but the major source is from the combustion of fossil fuels such as coal and oil. Some 90 to 95 percent of pollution-related sulfur oxide emissions are in the form of sulfur dioxide. Another source of sulfur dioxides are auto exhaust gases, although they account for a relatively small portion of such discharges to the atmosphere. This guideline will concern itself with stationary sources only, particularly those resulting from combustion of fuels containing sulfur.

2. Sulfur dioxide oxidizes in the atmosphere to form sulfates, a particulate form of sulfur compounds. These compounds may have adverse effects on human health and property, depending upon particle sizes, the particulate form of sulfur present, dispersion as affected by weather conditions, and the presence of other pollutants which may magnify the effects.

SOURCES AND EFFECTS

3. Sulfur dioxide, which has a sharp and choking odor, is considered to be one of the most dangerous gases to man. It is one of several forms in which sulfur circulates globally. The sulfur cycle also includes hydrogen sulfide gas, sulfuric acid aerosol, and several sulfate salts in aerosol form. For purposes of this discussion, an aerosol is defined as a suspension of liquid droplets or solid particles in a gas.

4. The concentration of populations into large metropolitan areas, with the resulting energy needs and industrial activity, causes the emissions to accumulate over these areas and disperse slowly. A US study, made in 1968, showed nationwide distribution of sulfur oxide emission sources to be as follows:

Fuel combustion		73.5%
Coal	60.5%	
Residual fuel oil	11.8%	
Distillate fuel oil	1.2%	
Industrial Processes		22.0%
Transportation		2.4%
Coal Refuse		1.8%
Solid Waste Disposal		0.3%

5. Electric power plants, the bulk of which utilize coal and oils as fuel, are the leading sources of sulfur dioxide emissions, as shown above. Except for transportation sources (which includes motor vehicles, vessels, and railroads), over 97% of the man-made sources are stationary. The degree of sulfur dioxide production from any individual source depends not only on the amount, but also on the type of fuel burned.

6. Sulfur, in a free or combined state, occurs in practically all fossil fuels. When freed to the atmosphere, usually by combustion, the sulfur or its compounds react with the oxygen present in the air to form the dioxide and other oxides. These can combine with moisture to form sulfurous acid, followed by formation of sulfuric acid, as follows:

$$SO_2 + H_2O \longrightarrow H_2SO_3$$

$$SO_2 + 1/2O_2 \longrightarrow SO_3$$

$$SO_3 + H_2O \longrightarrow H_2SO_4$$

7. Acids formed in the atmosphere fall with rain and affect crops and plants. Since lichens, for example, store acid in their roots and then die, they are sometimes used as indicators of sulfur dioxide fallout.

8. Sulfur dioxide emissions, through the formation of acids and other salts in the atmosphere, can cause damages to human health and property. High levels of sulfate concentrations will aggravate asthma, lung and heart disease. Sulfur dioxide in the presence of photochemical oxidants and by-products such as sulfuric acid and hydrogen sulfide has been shown to affect the respiratory tract. It is also widely believed that long term exposure to sulfates may increase the likelihood of respiratory illness such as bronchitis, emphysema and asthma. This effect is more probable when high concentrations of particulates are present.

9. Sensitive vegetation can be severely damaged by low levels of sulfur dioxide, levels even lower than those said to cause distress to pulmonary disease patients. Such effects result from the synergistic action of sulfur dioxide with low levels of ozone or nitrogen oxide which may be present. Wheat, barley, oats, white pine, cotton, alfalfa, buckwheat, sugar beets, and other crop plants have been reported killed by relatively low levels of sulfur dioxide fallout. Studies made in the USSR during the past decade showed that pine trees growing in an atmosphere having SO_2 concentrations of 500 ug/m^3 had a growth loss of 48 percent in comparison with pine trees growing in an atmosphere free of SO_2.

10. Sulfur oxides and their acid by-products will attack any exposed metal surface, including steel rail tracks. Reactions will also occur on other substances such as brick, stonework and even granite. Plastics, rubber, paper, and many other similar materials will become discolored and brittle when exposed. Buildings, bridges, steel girders, automobiles and highways are all affected by excessive emissions.

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EMISSION SAMPLING AND MEASUREMENT

11. Although several units have been used in the past to express the concentrations of sulfur dioxide in the air, the unit in most common use today is in terms of weight per unit volume of air-micrograms of SO_2 per cubic meter of air ($\mu gr/m^3$). This unit should be used by the Bank's staff in their reports dealing with this pollutant. Where analytical results are given in parts per million (ppm) of SO_2, the data can be converted to ugr/m^3 as follows:

$$1 \text{ ppm } SO_2 = 2850 \mu gr/m^3$$

It is important to note that this conversion factor applies to SO_2 only, and will not apply to any other substance having a different molecular weight.

12. Because industrial operations may involve frequent cyclic changes, the timing of testing or monitoring must be properly coordinated. Individual polluting substances should be identified and fluctuations of peak loadings determined in advance. All the variables associated with source testing should be considered so that the sampling and analytical results will be representative of the entire source process.

13. The initial step in sampling is the determination of the total volume of gas sampled during the period of sampling. A wide variety of instruments are available for this purpose, among which are: the pitot tube (most commonly used), rotating vane anemometer, swinging vane anemometer, double pitot tube heated thermometer anemometer, and the thermal anemometer.

14. Continuous sampling is preferable where potential emissions are substantial, as in power plants. Sulfur dioxide samples are best collected by chemical absorption methods. Considerations in selecting sampling sites include: zones of highest actual or potential pollutant concentrations, need for background data prior to operating new installations, areas of high population density, and data requirements for enforcement purposes. Meteorological factors, site accessibility, availability of space, power needs for sampling equipment and security must also be considered. All samples should be carefully collected, and all equipment should be carefully installed and maintained.

15. For determination of sulfur dioxide, samples may be analyzed by either chemical or physical methods. There are many variations among these. In each case, the most recent literature on laboratory methods covering SO_2 should be carefully reviewed and evaluated for application to the problem. Care should be taken to select a method which will permit comparison of results with established or accepted emission control standards.

16. An established method of sulfur dioxide determination is to collect samples of gas emissions by selective and quantitative absorption. Sulfuric acid and sulfur trioxide are absorbed by a isopropanol-water solution, and sulfur dioxide is then absorbed by a hydrogen peroxide solution. Isopropanol inhibits the oxidation of sulfur dioxide by being itself preferentially oxidized, and hydrogen peroxide oxidizes the sulfuric dioxide to sulfate. The sulfate concentration of each solution is measured titrimetrically. The complete detail of this method is available in another World Bank document.

ACCEPTABLE STANDARDS

17. Standards are generally of two types -- emission and ambient. Emission standards apply to allowable concentrations at the source, such as stacks, ventilating systems and other discharge points. Ambient standards apply to the allowable concentrations of a contaminant in the air surrounding an industrial area or community. Emission levels are necessary for identification of specific pollution sources and design of remedial works. Ambient levels are essential for determining possible environmental damages and for avoiding adverse physical, health and other effects upon the surrounding area and its inhabitants. The standards presented below represent the concentrations of SO_2 which may be permitted in the area surrounding the emission source.

18. For all Bank projects ambient air concentrations of sulfur oxides should not exceed the following for new plants.

Inside plant fence	Annual Arith. mean:	100 $\mu g/m^3$
	Max. 24-hr peak	1000 $\mu g/m^3$
Outside plant fence	Annual Arith. mean:	100 $\mu g/m^3$
	Max. 24-hr peak	500 $\mu g/m^3$

19. In special situations strict adherence to these standards may be difficult. All such cases are to be carefully documented by the Bank missions. Factors which may affect the ability to meet these standards include:

- Expansion of existing plants - Arithmetic mean resulting from new units is to be no greater than that existing prior to operation of new units. In addition, the new units by themselves should meet established standards.

- Revamping of existing plants - Every effort should be made to decrease existing pollution levels and provide measures which will minimize concentrations without placing unreasonable economic burdens on the industry.

- Inversions - Atmospheric conditions in certain locations, as in a valley surrounded by mountains, may be such that guidelines cannot be met. Unless there are major economic advantages to such a location, the site should be changed to where prevailing wind conditions will avoid inversions.

- Non-ferrous metal smelters - Substitutions of flash or electric furnaces may be necessary to meet guideline requirements.

20. For purposes of guidance and comparison, the existing US national ambient air quality standards are as follows:

- Primary - based on health effects on humans

Annual arith mean:	80 ugr/m^3
Max. 24-hr. - once yearly:	365 ugr/m^3

— Secondary - based on environmental effects

Annual arith mean:	60 ugr/m^3
Max. 24-hr. - once yearly:	260 ugr/m^3
Max. 3-hr. - Once yearly:	1300 ugr/m^3

CONTROL TECHNOLOGY

21. The technology to be applied for the control of emissions must be designed for each individual case since, in most instances, the system used must be capable of removing or reducing more than one pollutant at the same time.

22. Since SO_2 emissions are due principally to the content of sulfur and its compounds in the coal and oil used for fuel, the first measure to be considered is the substitution of low sulfur fuels or natural gas. Any increase in fuel cost should be balanced against the cost of treating the gaseous wastes.

23. Emissions may be reduced through process changes or by increasing stack heights. In-plant measures could include changing raw materials, modifying process operations, or recovering and reusing materials otherwise being wasted through the stack. Raising the point of discharge above the ground, by increasing the stack height, will reduce contaminant concentrations at ground level.

24. When measures such as those outlined above cannot be applied, then chemical or physical methods should be utilized. Gases such as sulfur dioxide may be removed by adsorption, absorption, or a chemical process such as catalytic conversion. In some of these processes the SO_2 can be removed and serve as the raw material for sulfuric acid production.

25. One of the promising methods for flue gas desulfurization utilizes the reaction of magnesium oxide with SO_2, to form magnesium sulfite. The magnesium sulfite solids are separated by centrifuging, dried to remove the moistur and then calcined to regenerate the magnesium oxide for recycling. The dried $Mg\ SO_3$ is used for sulfuric acid production.

26. Limestone scrubbers have been used successfully for desulfurization of flue gases. Injection of lime or magnesium into the fuel combustion chamber has also been effective in reducing sulfur dioxide emissions.

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INTERNATIONAL DEVELOPMENT COOPERATION AGENCY
Agency for International Development

22 CFR Part 216

Environmental Procedures

§ 216.1 Introduction.

(a) *Purpose.* In accordance with Sections 118(b) and 621 of the Foreign Assistance Act of 1961, as amended, (the FAA) the following general procedures shall be used by A.I.D. to ensure that environmental factors and values are integrated into the A.I.D. decision making process. These procedures also assign responsibility within the Agency for assessing the environmental effects of A.I.D.'s actions. These procedures are consistent with Executive Order 12114, issued January 4, 1979, entitled Environmental Effects Abroad of Major Federal Actions, and the purposes of the National Environmental Policy Act of 1970, as amended (42 U.S.C. 4371 et seq.) (NEPA). They are intended to implement the requirements of NEPA as they effect the A.I.D. program.

(b) *Environmental Policy.* In the conduct of its mandate to help upgrade the quality of life of the poor in developing countries, A.I.D. conducts a broad range of activities. These activities address such basic problems as hunger, malnutrition, overpopulation, disease, disaster, deterioration of the environment and the natural resource base, illiteracy as well as the lack of adequate housing and transportation. Pursuant to the FAA, A.I.D. provides development assistance in the form of technical advisory services, research, training, construction and commodity support. In addition, A.I.D. conducts programs under the Agricultural Trade Development and Assistance Act of 1954 (Pub. L. 480) that are designed to combat hunger, malnutrition and to facilitate economic development. Assistance programs are carried out under the foreign policy guidance of the Secretary of State and in cooperation with the governments of sovereign states. Within this framework, it is A.I.D. policy to:

(1) Ensure that the environmental consequences of A.I.D.-financed activities are identified and considered by A.I.D. and the host country prior to a final decision to proceed and that appropriate environmental safeguards are adopted;

(2) Assist developing countries to strengthen their capabilities to appreciate and effectively evaluate the potential environmental effects of proposed development strategies and projects, and to select, implement and manage effective environmental programs;

(3) Identify impacts resulting from A.I.D.'s actions upon the environment, including those aspects of the biosphere which are the common and cultural heritage of all mankind; and

(4) Define environmental limiting factors that constrain development and identify and carry out activities that assist in restoring the renewable resource base on which sustained development depends.

(c) *Definitions.*—(1) *CEQ Regulations.* Regulations promulgated by the President's Council on Environmental Quality (CEQ) (Federal Register, Volume 43, Number 230, November 29, 1978) under the authority of NEPA and Executive Order 11514, entitled Protection and Enhancement of Environmental Quality (March 5, 1970) as amended by Executive Order 11991 (May 24, 1977).

(2) *Initial Environmental Examination.* An Initial Environmental Examination is the first review of the reasonably foreseeable effects of a proposed action on the environment. Its function is to provide a brief statement of the factual basis for a Threshold Decision as to whether an Environmental Assessment or an Environmental Impact Statement will be required.

(3) *Threshold Decision.* A formal Agency decision which determines, based on an Initial Environmental Examination, whether a proposed Agency action is a major action significantly affecting the environment.

(4) *Environmental Assessment.* A detailed study of the reasonably foreseeable significant effects, both beneficial and adverse, of a proposed action on the environment of a foreign country or countries.

(5) *Environmental Impact Statement.* A detailed study of the reasonably foreseeable environmental impacts, both positive and negative, of a proposed

A.I.D. action and its reasonable alternatives on the United States, the global environment or areas outside the jurisdiction of any nation as described in § 216.7 of these procedures. It is a specific document having a definite format and content, as provided in NEPA and the CEQ Regulations. The required form and content of an Environmental Impact Statement is further described in § 216.7 infra.

(6) *Project Identification Document (PID).* An internal A.I.D. document which initially identifies and describes a proposed project.

(7) *Program Assistance Initial Proposal (PAIP).* An internal A.I.D. document used to initiate and identify proposed non-project assistance, including commodity import programs. It is analogous to the PID.

(8) *Project Paper (PP).* An internal A.I.D. document which provides a definitive description and appraisal of the project and particularly the plan or implementation.

(9) *Program Assistance Approval Document (PAAD).* An internal A.I.D. document approving non-project assistance. It is analogous to the PP.

(10) *Environment.* The term environment, as used in these procedures with respect to effects occurring outside the United States, means the natural and physical environment. With respect to effects occurring within the United States see § 216.7(b).

(11) *Significant Effect.* With respect to effects on the environment outside the United States, a proposed action has a significant effect on the environment if it does significant harm to the environment.

(12) *Minor Donor.* For purposes of these procedures, A.I.D. is a minor donor to a multidonor project when A.I.D. does not control the planning or design of the multidonor project and either (i) A.I.D.'s total contribution to the project is both less than $1,000,000 and less than 25 percent of the estimated project cost, or (ii) A.I.D.'s total contribution is more than $1,000,000 but less than 25 percent of the estimated project cost and the environmental procedures of the donor in control of the planning of design of the project are followed, but only if the A.I.D. Environmental Coordinator determines that such procedures are adequate.

§ 216.2 Applicability of procedures.

(a) *Scope.* Except as provided in § 216.2(b), these procedures apply to all new projects, programs or activities authorized or approved by A.I.D. and to substantive amendments or extensions of ongoing projects, programs, or activities.

(b) *Exemptions.* (1) Projects, programs or activities involving the following are exempt from these procedures:

(i) International disaster assistance;

(ii) Other emergency circumstances; and

(iii) Circumstances involving exceptional foreign policy sensitivities.

(2) A formal written determination, including a statement of the justification therefore, is required for each project, program or activity for which an exemption is made under paragraphs (b)(1) (ii) and (iii) of this section, but is not required for projects, programs or activities under paragraph (b)(1)(i) of this section. The determination shall be made either by the Assistant Administrator having responsibility for the program, project or activity, or by the Administrator, where authority to approve financing has been reserved by the Administrator. The determination shall be made after consultation with CEQ regarding the environmental consequences of the proposed program, project or activity.

(c) *Categorical Exclusions.* (1) The following criteria have been applied in determining the classes of actions included in § 216.2(c)(2) for which an Initial Environmental Examination, Environmental Assessment and Environmental Impact Statement generally are not required:

(i) The action does not have an effect on the natural or physicial environment;

(ii) A.I.D. does not have knowledge of or control over, and the objective of A.I.D. in furnishing assistance does not require, either prior to approval of financing or prior to implementation of specific activities, knowledge of or control over, the details of the specific activities that have an effect on the physicial and natural environment for which financing is provided by A.I.D.;

(iii) Research activities which may have an affect on the physicial and natural environment but will not have a significant effect as a result of limited scope, carefully controlled nature and effective monitoring.

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(2) The following classes of actions are not subject to the procedures set forth in § 216.3, except to the extent provided herein:

(i) Education, technical assistance, or training programs except to the extent such programs include activities directly affecting the environment (such as construction of facilities, etc.);

(ii) Controlled experimentation exclusively for the purpose of research and field evaluation which are confined to small areas and carefully monitored;

(iii) Analyses, studies, academic or research workshops and meetings;

(iv) Projects in which A.I.D. is a minor donor to a multidonor project and there is no potential significant effects upon the environment of the United States, areas outside any nation's jurisdiction or endangered or threatened species or their critical habitat;

(v) Document and information transfers;

(vi) Contributions to international, regional or national organizations by the United States which are not for the purpose of carrying out a specifically identifiable project or projects;

(vii) Institution building grants to research and educational institutions in the United States such as those provided for under Section 122(d) and Title XII of Chapter 2 of Part I of the FAA (22 USCA §§ 2151 p. (b) 2220a. (1979));

(viii) Programs involving nutrition, health care or population and family planning services except to the extent designed to include activities directly affecting the environment (such as construction of facilities, water supply systems, waste water treatment, etc.)

(ix) Assistance provided under a Commodity Import Program when, prior to approval, A.I.D. does not have knowledge of the specific commodities to be financed and when the objective in furnishing such assistance requires neither knowledge, at the time the assistance is authorized, nor control, during implementation, of the commodities or their use in the host country.

(x) Support for intermediate credit institutions when the objective is to assist in the capitalization of the institution or part thereof and when such support does not involve reservation of the right to review and approve individual loans made by the institution;

(xi) Programs of maternal or child feeding conducted under Title II of Pub. L. 480;

(xii) Food for development programs conducted by food recipient countries under Title III of Pub. L. 480, when achieving A.I.D.'s objectives in such programs does not require knowledge of or control over the details of the specific activities conducted by the foreign country under such program;

(xiii) Matching, general support and institutional support grants provided to private voluntary organizations (PVOs) to assist in financing programs where A.I.D.'s objective in providing such financing does not require knowledge of or control over the details of the specific activities conducted by the PVO;

(xiv) Studies, projects or programs intended to develop the capability of recipient countries to engage in development planning, except to the extent designed to result in activities directly affecting the environment (such as construction of facilities, etc.); and

(xv) Activities which involve the application of design criteria or standards developed and approved by A.I.D.

(3) The originator of a project, program or activity shall determine the extent to which it is within the classes of actions described in paragraph (c)(2) of this section. This determination shall be made in writing and be submitted with the PID, PAIP or comparable document. This determination, which must include a brief statement supporting application of the exclusion shall be reviewed by the Bureau Environmental Officer in the same manner as a Threshold Decision under § 216.3(a)(2) of these procedures. Notwithstanding paragraph (c)(2) of this section, the procedures set forth in § 216.3 shall apply to any project, program or activity included in the classes of actions listed in paragraph (c)(2) of this section, or any aspect or component thereof, if at any time in the design, review or approval of the activity it is determined that the project, program or activity, or aspect or component thereof, is subject to the control of A.I.D. and may have a significant effect on the environment.

(d) *Classes of Actions Normally Having a Significant Effect on the Environment.* (1) The following classes of actions have been determined generally to have a significant effect on the environment and an Environmental Assessment or Environmental Impact Statement, as appropriate, will be required:

(i) Programs of river basin development;

(ii) Irrigation or water management projects, including dams and impoundments;

(iii) Agricultural land leveling;

(iv) Drainage projects;

(v) Large scale agricultural mechanization;

(vi) New lands development;

(vii) Resettlement projects;

(viii) Penetration road building or road improvement projects;

(ix) Powerplants;

(x) Industrial plants;

(xi) Potable water and sewerage projects other than those that are small-scale.

(2) An Initial Environmental Examination normally will not be necessary for activities within the classes described in § 216.2(d), except when the originator of the project believes that the project will not have a significant effect on the environment. In such cases, the activity may be subjected to the procedures set forth in § 216.3.

(e) *Pesticides.* The exemptions of § 216.2(b)(1) and the categorical exclusions of § 216.2(c)(2) are not applicable to assistance for the procurement or use of pesticides.

§ 216.3 Procedures.

(a) *General Procedures*—(1) *Preparation of the Initial Environmental Examination.* Except as otherwise provided, an Initial Environmental Examination is not required for activities identified in § 216.2(b)(1), (c)(2), and (d). For all other A.I.D. activities described in § 216.2(a) an Initial Environmental Examination will be prepared by the originator of an action. Except as indicated in this section, it should be prepared with the PID or PAIP. For projects including the procurement or use of pesticides, the procedures set forth in § 216.3(b) will be followed, in addition to the procedures in this paragraph. Activities which cannot be identified in sufficient detail to permit the completion of an Initial Environmental Examination with the PID or PAIP, shall be described by including with the PID or PAIP: (i) an explanation indicating why the Initial Environmental Examination cannot be completed; (ii) an estimate of the amount of time required to complete the Initial Environmental Examination; and (iii) a recommendation that a Threshold Decision be deferred until the Initial Environmental Examination is completed. The responsible Assistant Administrator will act on the request for deferral concurrently with action on the PID or PAIP and will designate a time for completion of the Initial Environmental Examination. In all instances, except as provided in § 216.3(a)(7), this completion date will be in sufficient time to allow for the completion of an Environmental Assessment or Environmental Impact Statement, if required, before a final decision is made to provide A.I.D. funding for the action.

(2) *Threshold decision.* (i) The Initial Environmental Examination will include a Threshold Decision made by the officer in the originating office who signs the PID or PAIP. If the Initial Environmental Examination is completed prior to or at the same time as the PID or PAIP, the Threshold Decision will be reviewed by the Bureau Environmental Officer concurrently with approval of the PID or PAIP. The Bureau Environmental Officer will either concur in the Threshold Decision or request reconsideration by the officer who made the Threshold Decision, stating the reasons for the request. Differences of opinion between these officers shall be submitted for resolution to the Assistant Administrator at the same time that the PID is submitted for approval.

(ii) An Initial Environmental Examination, completed subsequent to approval of the PID or PAIP, will be forwarded immediately together with the Threshold Determination to the Bureau Environmental Officer for action as described above.

(iii) A Positive Threshold Decision shall result from a finding that the proposed action will have a significant effect on the environment. An Environmental Impact Statement shall be prepared if required pursuant to

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§ 216.7. If an impact statement is not required, an Environmental Assessment will be prepared in accordance with § 216.6. The cognizant Bureau or Office will record a Negative Determination if the proposed action will not have a significant effect on the environment.

(3) *Negative Declaration.* The Assistant Administrator, or the Administrator in actions for which the approval of the Administrator is required for the authorization of financing, may make a Negative Declaration, in writing, that the Agency will not develop an Environmental Assessment or an Environmental Impact Statement regarding an action found to have a significant effect on the environment when (i) a substantial number of Environmental Assessments or Environmental Impact Statements relating to similar activities have been prepared in the past, if relevant to the proposed action, (ii) the Agency has previously prepared a programmatic Statement or Assessment covering the activity in question which has been considered in the development of such activity, or (iii) the Agency has developed design criteria for such an action which, if applied in the design of the action, will avoid a significant effect on the environment.

(4) *Scope of Environmental Assessment or Impact Statement*—(i) *Procedure and Content.* After a Positive Threshold Decision has been made, or a determination is made under the presticide procedures set forth in § 216.3(b) that an Environmental Assessment or Environmental Impact Statement is required, the originator of the action shall commence the process of identifying the significant issues relating to the proposed action and of determining the scope of the issues to be addressed in the Environmental Assessment or Environmental Impact Statement. The originator of an action within the classes of actions described in § 216.2(d) shall commence this scoping process as soon as practicable. Persons having expertise relevant to the environmental aspects of the proposed action shall also participate in this scoping process. (Participants may include but are not limited to representatives of host governments, public and private institutions, the A.I.D. Mission staff and contractors.) This process shall result in a written statement which shall include the following matters:

(*a*) A determination of the scope and significance of issues to be analyzed in the Environmental Assessment or Impact Statement, including direct and indirect effects of the project on the environment.

(*b*) Identification and elimination from detailed study of the issues that are not significant or have been covered by earlier environmental review, or approved design considerations, narrowing the discussion of these issues to a brief presentation of why they will not have a significant effect on the environment.

(*c*) A description of (*1*) the timing of the preparation of environmental analyses, including phasing if appropriate, (*2*) variations required in the format of the Environmental Assessment, and (*3*) the tentative planning and decision making schedule; and

(*d*) A description of how the analysis will be conducted and the disciplines that will participate in the analysis.

(ii) These written statements shall be reviewed and approved by the Bureau Environmental Officer.

(iii) *Circulation of Scoping Statement.* To assist in the preparation of an Environmental Assessment, the Bureau Environmental Office may circulate copies of the written statement, together with a request for written comments, within thirty days, to selected federal agencies if that Officer believes comments by such federal agencies will be useful in the preparation of an Environmental Assessment. Comments received from reviewing federal agencies will be considered in the preparation of the Environmental Assessment and in the formulation of the design and implementation of the project, and will, together with the scoping statement, will be included in the project file.

(iv) *Change in Threshold Decision.* If it becomes evident that the action will not have a significant effect on the environment (i.e., will not cause significant harm to the environment), the Positive Threshold Decision may be withdrawn with the concurrence of the Bureau Environmental Officer. In the case of an action included in § 216.2(d)(2), the request for withdrawal shall be made to the Bureau Environmental Officer.

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(5) *Preparation of Environmental Assessments and Environmental Impact Statement.* If the PID or PAIP is approved, and the Threshold Decision is positive, or the action is included in § 216.2(d), the originator of the action will be responsible for the preparation of an Environmental Assessment or Environmental Impact Statement as required. Draft Environmental Impact Statements will be circulated for review and comment as part of the review of Project Papers and as outlined further in § 216.7 of those procedures. Except as provided in § 216.3(a)(7), final approval of the PP or PAAD and the method of implementation will include consideration of the Environmental Assessment of final Environmental Impact Statement.

(6) *Processing and Review Within A.I.D.* (i) Initial Environmental Examinations, Environmental Assessments and final Environmental Impact Statements will be processed pursuant to standard A.I.D. procedures for project approval documents. Except as provided in § 216.3(a)(7), Environmental Assessments and final Environmental Impact Statements will be reviewed as an integral part of the Project Paper or equivalent document. In addition to these procedures, Environmental Assessments will be reviewed and cleared by the Bureau Environmental Officer. They may also be reviewed by the Agency's Environmental Coordinator who will monitor the Environmental Assessment process.

(ii) When project approval authority is delegated to field posts, Environmental Assessments shall be reviewed and cleared by the Bureau Environmental Officer prior to the approval of such actions.

(iii) Draft and final Environmental Impact Statements will be reviewed and cleared by the Environmental Coordinator and the Office of the General Counsel.

(7) *Environmental Review After Authorization of Financing.* (i) Environmental review may be performed after authorization of a project, program or activity only with respect to subprojects or significant aspects of the project, program or activity that are unidentified at the time of authorization. Environmental review shall be completed prior to authorization for all subprojects and aspects of a project, program or activity that are identified.

(ii) Environmental review should occur at the earliest time in design or implementation at which a meaningful review can be undertaken, but in no event later than when previously unidentified subprojects or aspects of projects, programs or activities are identified and planned. To the extent possible, adequate information to undertake deferred environmental review should be obtained before funds are obligated for unidentified subprojects or aspects of projects, programs or activities. (Funds may be obligated for the other aspects for which environmental review has been completed.) To avoid an irreversible commitment of resources prior to the conclusion of environmental review, the obligation of funds can be made incrementally as subprojects or aspects of projects, programs or activities are identified; or if necessary while planning continues, including environmental review, the agreement or other document obligating funds may contain appropriate convenants or conditions precedent to disbursement for unidentified subprojects or aspects of projects, programs or activities.

(iii) When environmetal review must be deferred beyond the time some of the funds are to be disbursed (e.g. long lead times for the delivery of goods or services), the project agreement or other document obligating funds shall contain a covenant or covenants requiring environmental review, including an Environmental Assessment or Environmental Impact Statement, when appropriate, to be completed and taken into account prior to implementation of those subprojects or aspects of the project, program or activity for which environmental review is deferred. Such convenants shall ensure that implementation plans will be modified in accordance with environmental review if the parties decide that modifications are necessary.

(iv) When environmental review will not be completed for an entire project, program or activity prior to authorization, the Initial Environmental Examination and Threshold Decision required under § 216.3(a)(1) and (2) shall identify those aspects of the project, program or activity for which

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environmental review will be completed prior to the time financing is authorized. It shall also include those subprojects or aspects for which environmental review will be deferred, stating the reasons for deferral and the time when environmental review will be completed. Further, it shall state how an irreversible commitment of funds will be avoided until environmental review is completed. The A.I.D. officer responsible for making environmental decisions for such projects, programs or activities shall also be identified (the same officer who has decision making authority for the other aspects of implementation). This deferral shall be reviewed and approved by the officer making the Threshold Decision and the officer who authorizes the project, program or activity. Such approval may be made only after consultation with the Office of General Counsel for the purpose of establishing the manner in which conditions precedent to disbursement or covenants in project and other agreements will avoid an irreversible commitment of resources before environmental review is completed.

(8) *Monitoring.* To the extent feasible and relevant, projects and programs for which Environmental Impact Statements or Environmental Assessments have been prepared should be designed to include measurement of any changes in environmental quality, positive or negative, during their implementation. This will require recording of baseline data at the start. To the extent that available data permit, originating offices of A.I.D. will formulate systems in collaboration with recipient nations, to monitor such impacts during the life of A.I.D.'s involvement. Monitoring implementation of projects, programs and activities shall take into account environmental impacts to the same extent as other aspects of such projects, programs and activities. If during implementation of any project, program or activity, whether or not an Environmental Assessment or Environmental Impact Statement was originally required, it appears to the Mission Director, or officer responsible for the project, program or activity, that it is having or will have a significant effect on the environment that was not previously studied in an Environmental Assessment or Environmental Impact Statement, the procedures contained in this part shall be followed including, as appropriate, a Threshold Decision, Scoping and an Environmental Assessment or Environmental Impact Statement.

(9) *Revisions.* If, after a Threshold Decision is made resulting in a Negative Determination, a project is revised or new information becomes available which indicates that a proposed action might be "major" and its effects "significant", the Negative Determination will be reviewed and revised by the cognizant Bureau and an Environmental Assessment or Environmental Impact Statement will be prepared, if appropriate. Environmental Assessments and Environmental Impact Statements will be amended and processed appropriately if there are major changes in the project or program, or if significant new information becomes available which relates to the impact of the project, program or activity on the environment that was not considered at the time the Environmental Assessment or Environmental Impact Statement was approved. When on-going programs are revised to incorporate a change in scope or nature, a determination will be made as to whether such change may have an environmental impact not previously assessed. If so, the procedures outlined in this part will be followed.

(10) *Other Approval Documents.* These procedures refer to certain A.I.D. documents such as PIDs, PAIPs, PPs and PAADs as the A.I.D. internal instruments for approval of projects, programs or activities. From time to time, certain special procedures, such as those in § 216.4, may not require the use of the aforementioned documents. In these situations, these environmental procedures shall apply to those special approval procedures, unless otherwise exempt, at approval times and levels comparable to projects, programs and activities in which the aforementioned documents are used.

(b) *Pesticide Procedures*—(1) *Project Assistance.* Except as provided in § 216.3(b)(2), all proposed projects involving assistance for the procurement or use, or both, of pesticides shall be subject to the procedures prescribed in

§ 216.3(b)(1) (i) through (v) below. These procedures shall also apply, to the extent permitted by agreements entered into by A.I.D. before the effective date of these pesticide procedures, to such projects that have been authorized but for which pesticides have not been procured as of the effective date of these pesticide procedures.

(i) When a project includes assistance for procurement or use, or both, of pesticides registered for the same or similar uses by USEPA without restriction, the Initial Environmental Examination for the project shall include a separate section evaluating the economic, social and environmental risks and benefits of the planned pesticide use to determine whether the use may result in significant environmental impact. Factors to be considered in such an evaluation shall include, but not be limited to the following:

(a) The USEPA registration status of the requested pesticide;

(b) The basis for selection of the requested pesticide;

(c) The extent to which the proposed pesticide use is part of an integrated pest management program;

(d) The proposed method or methods of application, including availability of appropriate application and safety equipment;

(e) Any acute and long-term toxicological hazards, either human or environmental, associated with the proposed use and measures available to minimize such hazards;

(f) The effectiveness of the requested pesticide for the proposed use;

(g) Compatibility of the proposed pesticide with target and nontarget ecosystems;

(h) The conditions under which the pesticide is to be used, including climate, flora, fauna, geography, hydrology, and soils;

(i) The availability and effectiveness of other pesticides or nonchemical control methods;

(j) The requesting country's ability to regulate or control the distribution, storage, use and disposal of the requested pesticide;

(k) The provisions made for training of users and applicators; and

(l) The provisions made for monitoring the use and effectiveness of the pesticide.

In those cases where the evaluation of the proposed pesticide use in the Initial Environmental Examination indicates that the use will significantly effect the human environment, the Threshold Decision will include a recommendation for the preparation of an Environmental Assessment or Environmental Impact Statement, as appropriate. In the event a decision is made to approve the planned pesticide use, the Project Paper shall include to the extent practicable, provisions designed to mitigate potential adverse effects of the pesticide. When the pesticide evaluation section of the Initial Environmental Examination does not indicate a potentially unreasonable risk arising from the pesticide use, an Environmental Assessment or Environmental Impact Statement shall nevertheless be prepared if the environmental effects of the project otherwise require further assessment.

(ii) When a project includes assistance for the procurement or use, or both, of any pesticide registered for the same or similar uses in the United States but the proposed use is restricted by the USEPA on the basis of user hazard, the procedures set forth in § 216.3(b)(1)(i) above will be followed. In addition, the Initial Environmental Examination will include an evaluation of the user hazards associated with the proposed USEPA restricted uses to ensure that the implementation plan which is contained in the Project Paper incorporates provisions for making the recipient government aware of these risks and providing, if necessary, such technical assistance as may be required to mitigate these risks. If the proposed pesticide use is also restricted on a basis other than user hazard, the procedures in § 216.3(b)(1)(iii) shall be followed in lieu of the procedures in this section.

(iii) If the project includes assistance for the procurement or use, or both of:

(a) Any pesticide other than one registered for the same or similar uses by USEPA without restriction or for restricted use on the basis of user hazard; or

(b) Any pesticide for which a notice of rebuttable presumption against reregistration, notice of intent to cancel, or notice of intent to suspend has been issued by USEPA,

The Threshold Decision will provide for the preparation of an Environmental Assessment or Environmental Impact Statement, as appropriate (§ 216.6(a)). The EA or EIS shall include, but not be limited to, an analysis of the factors identified in § 216.3(b)(1)(i) above.

(iv) Notwithstanding the provisions of §§ 216.3(b)(1) (i) through (iii) above, if the project includes assistance for the procurement or use, or both, of a pesticide against which USEPA has initiated a regulatory action for cause, or for which it has issued a notice of rebuttable presumption against reregistration, the nature of the action or notice, including the relevant techni-

cal and scientific factors will be discussed with the requesting government and considered in the IEE and, if prepared, in the EA or EIS. If USEPA initiates any of the regulatory actions above against a pesticide subsequent to its evaluation in an IEE, EA or EIS, the nature of the action will be discussed with the recipient government and considered in an amended IEE or amended EA or EIS, as appropriate.

(v) If the project includes assistance for the procurement or use, or both of pesticides but the specific pesticides to be procured or used cannot be identified at the time the IEE is prepared, the procedures outlined in §§ 216.3(b)(i) through (iv) will be followed when the specific pesticides are identified and before procurement or use is authorized. Where identification of the pesticides to be procured or used does not occur until after Project Paper approval, neither the procurement nor the use of the pesticides shall be undertaken unless approved, in writing, by the Assistant Administrator (or in the case of projects authorized at the Mission level, the Mission Director) who approved the Project Paper.

(2) *Exceptions to Pesticide Procedures.* The procedures set forth in § 216.3(b)(1) above shall not apply to the following projects including assistance for the procurement or use, or both, of pesticides.

(i) Projects under emergency conditions.

Emergency conditions shall be deemed to exist when it is determined by the Administrator, A.I.D., in writing that:

(*a*) A pest outbreak has occurred or is imminent; and

(*b*) Significant health problems (either human or animal) or significant economic problems will occur without the prompt use of the proposed pesticide; and

(*c*) Insufficient time is available before the pesticide must be used to evaluate the proposed use in accordance with the provisions of this regulation.

(ii) Projects where A.I.D. is a minor donor, as defined in § 216.1(c)(12) above, to a multi-donor project.

(iii) Projects including assistance for procurement or use, or both, of pesticides for research or limited field evaluation purposes by or under the supervision of project personnel. In such instances, however, A.I.D. will ensure that the manufacturers of the pesticides provide toxicological and environmental data necessary to safeguard the health or research personnel and the quality of the local environment in which the pesticides will be used. Furthermore, treated crops will not be used for human or animal consumption unless appropriate tolerances have been established by EPA or recommended by FAO/WHO, and the rates and frequency of application, together with the prescribed preharvest intervals, do not result in residues exceeding such tolerances. This prohibition does not apply to the feeding of such crops to animals for research purposes.

(3) *Non-Project Assistance.* In a very few limited number of circumstances A.I.D. may provide non-project assistance for the procurement and use of pesticides. Assistance in such cases shall be provided if the A.I.D. Administrator determines in writing that (i) emergency conditions, as defined in § 216.3(b)(2)(i) above exists; or (ii) that compelling circumstances exist such that failure to provide the proposed assistance would seriously impede the attainment of U.S. foreign policy objectives or the objectives of the foreign assistance program. In the latter case, a decision to provide the assistance will be based to the maximum extent practicable, upon a consideration of the factors set forth in § 216.3(b)(1)(i) and, to the extent available, the history of efficacy and safety covering the past use of the pesticide the in recipient country.

§ 216.4 Private applicants.

Programs, projects or activities for which financing from A.I.D. is sought by private applicants, such as PVOs and educational and research institutions, are subject to these procedures. Except as provided in §§ 216.2 (b), (c) or (d), preliminary proposals for financing submitted by private applicants shall be accompanied by an Initial Environmental Examination or adequate information to permit preparation of an Initial Environmental Examination. The Threshold Decision shall be made by the Mission Director for the country to which the proposal relates, if the preliminary proposal is submitted to the A.I.D. Mission, or shall be made by the officer in A.I.D. who approves the preliminary proposal. In either case, the concurrence of the Bureau Environmental Officer is required in the same manner as in § 216.3(a)(2), except for PVO projects approved in A.I.D. Missions with total life of project costs

less than $500,000. Thereafter, the same procedures set forth in § 216.3 including as appropriate scoping and Environmental Assessments or Environmental Impact Statements, shall be applicable to programs, projects or activities submitted by private applicants. The final proposal submitted for financing shall be treated, for purposes of these procedures, as a Project Paper. The Bureau Environmental Officer shall advise private applicants of studies or other information foreseeably required for action by A.I.D.

§ 216.5 Endangered species.

It is A.I.D. policy to conduct its assistance programs in a manner that is sensitive to the protection of endangered or threatened species and their critical habitats. The Initial Environmental Examination for each project, program or activity having an effect on the environment shall specifically determine whether the project, program or activity will have an effect on an endangered or threatened species, or critical habitat. If the proposed project, program or activity will have the effect of jeopardizing an endangered or threatened species or of adversely modifying its critical habitat, the Threshold Decision shall be a Positive Determination and an Environmental Assessment or Environmental Impact Statement completed as appropriate, which shall discuss alternatives or modifications to avoid or mitigate such impact on the species or its habitat.

§ 216.6 Environmental assessments.

(a) *General Purpose.* The purpose of the Environmental Assessment is to provide Agency and host country decision makers with a full discussion of significant environmental effects of a proposed action. It includes alternatives which would avoid or minimize adverse effects or enhance the quality of the environment so that the expected benefits of development objectives can be weighed against any adverse impacts upon the human environment or any irreversible or irretrievable commitment of resources.

(b) *Collaboration with Affected Nation on Preparation.* Collaboration in obtaining data, conducting analyses and considering alternatives will help build an awareness of development associated environmental problems in less developed countries as well as assist in building an indigenous institutional capability to deal nationally with such problems. Missions, Bureaus and Offices will collaborate with affected countries to the maximum extent possible, in the development of any Environmental Assessments and consideration of environmental consequences as set forth therein.

(c) *Content and Form.* The Environmental Assessment shall be based upon the scoping statement and shall address the following elements, as appropriate:

(1) *Summary.* The summary shall stress the major conclusions, areas of controversy, if any, and the issues to be resolved.

(2) *Purpose.* The Environmental Assessment shall briefly specify the underlying purpose and need to which the Agency is responding in proposing the alternatives including the proposed action.

(3) *Alternatives Including the Proposed Action.* This section should present the environmental impacts of the proposal and its alternatives in comparative form, thereby sharpening the issues and providing a clear basis for choice among options by the decision maker. This section should explore and evaluate reasonable alternatives and briefly discuss the reasons for eliminating those alternatives which were not included in the detailed study; devote substantial treatment to each alternative considered in detail including the proposed action so that reviewers may evaluate their comparative merits; include the alternative of no action; identify the Agency's preferred alternative or alternatives, if one or more exists; include appropriate mitigation measures not already included in the proposed action or alternatives.

(4) *Affected Environment.* The Environmental Assessment shall succinctly describe the environment of the area(s) to be affected or created by the alternatives under consideration. The descriptions shall be no longer than is necessary to understand the effects of the alternatives. Data and analyses in the Environmental Assessment shall be commensurate with the significance of the impact with less important material

summarized, consolidated or simply referenced.

(5) *Environmental Consequences.* This section forms the analytic basis for the comparisons under paragraph (c)(3) of this section. It will include the environmental impacts of the alternatives including the proposed action; any adverse effects that cannot be avoided should the proposed action be implemented; the relationship between short-term uses of the environment and the maintenance and enhancement of long-term productivity; and any irreversible or irretrievable commitments of resources which would be involved in the proposal should it be implemented. It should not duplicate discussions in paragraph (c)(3) of this section. This section of the Environmental Assessment should include discussions of direct effects and their significance; indirect effects and their significance; possible conflicts between the proposed action and land use plans, policies and controls for the areas concerned; energy requirements and conservation potential of various alternatives and mitigation measures; natural or depletable resource requirements and conservation potential of various requirements and mitigation measures; urban quality; historic and cultural resources and the design of the built environment, including the reuse and conservation potential of various alternatives and mitigation measures; and means to mitigate adverse environmental impacts.

(6) *List of Preparers.* The Environmental Assessment shall list the names and qualifications (expertise, experience, professional discipline) of the persons primarily responsible for preparing the Environmental Assessment or significant background papers.

(7) *Appendix.* An Appendix may be prepared.

(d) *Program Assessment.* Program Assessments may be appropriate in order to assess the environmental effects of a number of individual actions and their cumulative environmental impact in a given country or geographic area, or the environmental impacts that are generic or common to a class of agency actions, or other activities which are not country-specific. In these cases, a single, programmatic assessment will be prepared in A.I.D./Washington and circulated to appropriate overseas Missions, host governments, and to interested parties within the United States. To the extent practicable, the form and content of the programmatic Environmental Assessment will be the same as for project Assessments. Subsequent Environmental Assessments on major individual actions will only be necessary where such follow-on or subsequent activities may have significant environmental impacts on specific countries where such impacts have not been adequately evaluated in the programmatic Environmental Assessment. Other programmatic evaluations of classes of actions may be conducted in an effort to establish additional categorical exclusions or design standards or criteria for such classes that will eliminate or minimize adverse effects of such actions, enhance the environmental effect of such action or reduce the amount of paperwork or time involved in these procedures. Programmatic evaluations conducted for the purpose of establishing additional categorical exclusions under § 216.2(c) or design considerations that will eliminate significant effects for classes of actions shall be made available for public comment before the categorical exclusions or design standards or criteria are adopted by A.I.D. Notice of the availability of such document shall be published in the **Federal Register.** Additional categorical exclusions shall be adopted by A.I.D. upon the approval of the Administrator, and design consideration in accordance with usual agency procedures.

(e) *Consultation and Review.* (1) When Environmental Assessments are prepared on activities carried out within or focused on specific developing countries, consultation will be held between A.I.D. staff and the host government both in the early stages of preparation and on the results and significance of the completed Assessment before the project is authorized.

(2) Missions will encourage the host government to make the Environmental Assessment available to the general public of the recipient country. If Environmental Assessments are prepared on activities which are not country-specific, the Assessment will be circulated by the Environmental Coordinator to A.I.D.'s Overseas Missions and interested governments for information, guidance and comment and will be made available in the U.S. to

interested parties.

(f) *Effect in Other Countries.* In a situation where an analysis indicates that potential effects may extend beyond the national boundaries of a recipient country and adjacent foreign nations may be affected, A.I.D. will urge the recipient country to consult with such countries in advance of project approval and to negotiate mutually acceptable accommodations.

(g) *Classified Material.* Environmental Assessments will not normally include classified or administratively controlled material. However, there may be situations where environmental aspects cannot be adequately discussed without the inclusion of such material. The handling and disclosure of classified or administratively controlled material shall be governed by 22 CFR Part 9. Those portions of an Environmental Assessment which are not classified or administratively controlled will be made available to persons outside the Agency as provided for in 22 CFR Part 212.

§ 216.7 Environmental impact statements.

(a) *Applicability.* An Environmental Impact Statement shall be prepared when agency actions significantly affect:

(1) The global environment or areas outside the jurisdiction of any nation (e.g., the oceans);

(2) The environment of the United States; or

(3) Other aspects of the environment at the discretion of the Administrator.

(b) *Effects on the United States: Content and Form.* An Environmental Impact Statement relating to paragraph (a)(2) of this section shall comply with the CEQ Regulations. With respect to effects on the United States, the terms environment and significant effect wherever used in these procedures have the same meaning as in the CEQ Regulations rather than as defined in § 216.1(c) (12) and (13) of these procedures.

(c) *Other Effects: Content and Form.* An Environmental Impact Statement relating to paragraphs (a)(1) and (a)(3) of this section will generally follow the CEQ Regulations, but will take into account the special considerations and concerns of A.I.D. Circulation of such Environmental Impact Statements in draft form will precede approval of a Project Paper or equivalent and comments from such circulation will be considered before final project authorization as outlined in § 216.3 of these procedures. The draft Environmental Impact Statement will also be circulated by the Missions to affected foreign governments for information and comment. Draft Environmental Impact Statements generally will be made available for comment to Federal agencies with jurisdiction by law or special expertise with respect to any environmental impact involved, and to public and private organizations and individuals for not less than forty-five (45) days. Notice of availability of the draft Environmental Impact Statements will be published in the Federal Register. Cognizant Bureaus and Offices will submit these drafts for circulation through the Environmental Coordinator who will have the responsibility for coordinating all such communications with persons outside A.I.D. Any comments received by the Environmental Coordinator will be forwarded to the originating Bureau or Office for consideration in final policy decisions and the preparation of a final Environmental Impact Statement. All such comments will be attached to the final Statement, and those relevant comments not adequately discussed in the draft Environmental Impact Statement will be appropriately dealt with in the final Environmental Impact Statement. Copies of the final Environmental Impact Statement, with comments attached, will be sent by the Environmental Coordinator to CEQ and to all other Federal, state, and local agencies and private organizations that made substantive comments on the draft, including affected foreign governments. Where emergency circumstances or considerations of foreign policy make it necessary to take an action without observing the provisions of § 1506.10 of the CEQ Regulations, or when there are overriding considerations of expense to the United States or foreign governments, the originating Office will advise the Environmental Coordinator who will consult with Department of State and CEQ concerning appropriate modification of review procedures.

§ 216.8 Public hearings.

(a) In most instances AID will be able to gain the benefit of public par-

ticipation in the impact statement process through circulation of draft statements and notice of public availability in CEQ publications. However, in some cases the Administrator may wish to hold public hearings on draft Environmental Impact Statements. In deciding whether or not a public hearing is appropriate, Bureaus in conjunction with the Environmental Coordinator should consider:

(1) The magnitude of the proposal in terms of economic costs, the geographic area involved, and the uniqueness or size of commitment of the resources involved;

(2) The degree of interest in the proposal as evidenced by requests from the public and from Federal, state and local authorities, and private organizations and individuals, that a hearing be held;

(3) The complexity of the issue and likelihood that information will be presented at the hearing which will be of assistance to the Agency; and

(4) The extent to which public involvement already has been achieved through other means, such as earlier public hearings, meetings with citizen representatives, and/or written comments on the proposed action.

(b) If public hearings are held, draft Environmental Impact Statements to be discussed should be made available to the public at least fifteen (15) days prior to the time of the public hearings, and a notice will be placed in the FEDERAL REGISTER giving the subject, time and place of the proposed hearings.

§ 216.9 Bilateral and multilateral studies and concise reviews of environmental issues.

Notwithstanding anything to the contrary in these procedures, the Administrator may approve the use of either of the following documents as a substitute for an Environmental Assessment (but not a substitute for an Environmental Impact Statement) required under these procedures:

(a) Bilateral or multilateral environmental studies, relevant or related to the proposed action, prepared by the United States and one or more foreign countries or by an international body or organization in which the United States is a member or participant; or

(b) Concise reviews of the environmental issues involved including summary environmental analyses or other appropriate documents.

§ 216.10 Records and reports.

Each Agency Bureau will maintain a current list of activities for which Environmental Assessments and Environmental Impact Statements are being prepared and for which Negative Determinations and Declarations have been made. Copies of final Initial Environmental Examinations, scoping statements, Assessments and Impact Statements will be available to interested Federal agencies upon request. The cognizant Bureau will maintain a permanent file (which may be part of its normal project files) of Environmental Impact Statements, Environmental Assessments, final Initial Environmental Examinations, scoping statements, Determinations and Declarations which will be available to the public under the Freedom of Information Act. Interested persons can obtain information or status reports regarding Environmental Assessments and Environmental Impact Statements through the A.I.D. Environmental Coordinator.

(22 U.S.C. 2381; 42 U.S.C. 4332)

Dated October 9, 1980.

Joseph C. Wheeler,

Acting Administrator.

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APPENDIX 6

STEAM GENERATOR DESIGN

APPENDIX 6

STEAM GENERATOR DESIGN

The general trend in the U.S. during the 70s was toward 500-700 MW drum-type units, and the need to improve availability of the units assumed higher priority. Throughout the 70s, the utility industry tended toward a more conservative design to be able to handle a wider variation in low grade coals, including those with severe slagging and fouling characteristics. This design also tends to reduce NOx emissions.

Today, most of the major boiler manufacturers in the U.S. are offering conservative designs with emphasis on high availability and minimum use of oil for ignition and flame stabilization. The general perception throughout the industry is that the higher capital cost associated with the more conservative design will be recovered many times over by even a small increase in availability. This is the philosophy that would now be generally used in the U.S. to design a steam generator fired by Lakhra coal.

VARIATIONS IN COMBUSTION DESIGN

There are four fundamentally different methods of feeding and combusting coal for the purpose of generating steam:

- Stoker
- Cyclone furnace
- Fluidized bed
- Pulverized coal

Stoker type boilers are available from the smallest sizes up to approximately 650,000 lb/hr steam generation rate or larger. Practical

considerations, however, generally limit their application to sizes up to 300,000 to 400,000 lb/hr. Therefore, they were not considered for Lakhra.

The cyclone boiler includes large horizontal cylinders ranging from 6 to 10 ft in diameter into which the fuel/air mixture is fired followed by a primary, and possibly a secondary, furnace in direction of gas flow. The combustion of coal is completely contained inside the furnace. Primary, secondary and sometimes tertiary air is blown in tangentially and/or axially to promote turbulence, therein enhancing the combustion process. Gas temperatures exceed 3,000°F, which is high enough to melt the coal ash into liquid slag. Tangential firing produces centrifugal forces that throw the ash toward the cylinder walls. The ash melts and forms a thin layer of slag along the cylinder wall. Slag continuously drains to the bottom of the cylinder and away from the burner end out through a slag tap and into a slag tank filled with water. A major portion of the ash is collected in this manner.

While the cyclone boiler drew considerable attention in the 50s and 60s, high NOx emissions generated by the cyclone furnace due to high cyclone temperatures significantly reduced its applicability when NOx emission limits were instituted in the U.S., Europe, and Japan in the 70s.

The cyclone boiler is also limited to a rather narrow range of coals. Volatile matter should exceed 15 percent on a dry basis to obtain the required high combustion rate. Ash content must be between 6 and 25 percent on a dry basis. Sulfur content in the coal and the iron/iron pyrites content in the ash cannot exceed moderate limits or severe

corrosion will occur. Slag viscosity must be less than 250 poises at 2600°F and, in general, ash fusion temperatures should be low.

Atmospheric Fluidized Bed Combustion (AFBC) boilers are typically available in a fire-tube design up to 40,000 to 50,000 lb/hr steam generation rate and water-tube design from 20,000 to 300,000 lb/hr and larger, with 300,000 lb/hr being the largest Atmospheric Fluidized Bed (AFB) boiler sold commercially to date.

A first-generation AFB is composed of solid granular particles supported on a perforated grid plate through which a stream of air is passed to lift the particles and keep them in a fluidized state. The air velocity is high enough (4 to 14 fps) to counteract gravitational forces on the particles without transporting the entire bed out with air stream. The pressure above the bed is atmospheric.* Under these conditions, the bed behaves like a turbulently boiling fluid.

In the typical AFB boiler, the bed consists of a small percentage of crushed fuel plus additional particulate material in the form of ash, inerts such as sand, and possibly a limestone sorbent for sulfur removal. Fuel and sorbent are typically fed either pneumatically under bed or by spreader-stoker above bed. Steam generation occurs in tubes submerged within the bed, in waterwall tubes, and in a convection section in the flue gas path. Superheating occurs in the convection section and/or in the bed.

The AFB has the following principal advantages when compared to conventional technologies:

*Pressurized fluidized bed combustion steam generators are not commercially available but are under development.

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- High sulfur fuels may be cleanly burned without need for Flue Gas Desulfurization system.

- Reduced combustion temperature (approximately from 1,500°F to 3,000°F) yields reduced NOx emissions and reduced slagging and bonded ash deposits. Soot blowing requirements will be less.

- Ability to burn low-grade fuels, particularly those containing high sulphur and high ash.

- Dry granular waste product.

The Fluidized Bed System could perhaps be ideal for the Lakhra coal which contains high sulphur and high ash. But in view of the fact that only small boilers of 20-25 MW range have so far become commercial, this technology is not being considered for the project in question. As larger AFBC systems become commercially available, and many of the practical problems are resolved, WAPDA may wish to consider AFBC. (See Appendix 12 for a more complete discussion of fluidized bed combustion).

Pulverized coal (PC) type boilers are generally available from approximately 100,000 lb/hr up to large utility sizes. The most common type of PC boiler today is the balanced draft, direct fired type. In this system, raw coal is fed through a feeder to a pulverizer where it is finely ground and dried with a stream of hot air (primary air) which has been heated in an air heater and represents 15 to 20 percent of the total air. The primary air then transports the pulverized and partially dried coal to the burner where it is mixed with the remaining 80 to 85 percent of total air (secondary air) and burned in a turbulent suspension.

VARIATIONS IN CIRCUITRY DESIGN

There are two fundamental types of steam generator circuitry designs: the "drum-type" design and the "once-through" design. The drum-type design is well-known in Pakistan and needs no description here.

The once-through design, which is drumless, does not provide a surface at which steam separates from water before entering the superheater. Instead, heat converts the water flowing through the tubes into steam which gets superheated to the desired temperature at the outlet. In this arrangement, the economizer and the superheater are connected with each other with the help of numerous small tubes to provide effective heat transfer without any drum coming in between.

The move toward larger, more efficient power plants in the 60s led to the design of 3,500 psig and even 4,500 psig supercritical steam generators. Water at pressures in excess of 3,208 psia will not boil. Thus, heating water at pressures in excess of 3,208 psia does not result in two-phase flow (water and steam) as happens in the boilers of lower pressures. Instead, as water flowing through the furnace of a supercritical boiler is heated, the thermodynamic properties of a single fluid are gradually converted from those of water to those of steam within the 850 to 1,050 Btu/lb enthalpy range. Consequently, since water is "instantaneously" converted into steam, a surface to separate water from steam is not required for supercritical operation; all supercritical boilers are therefore drumless or the "once-through" type.

The once-through design, (both subcritical and supercritical) requires very high quality feedwater. In the drum-type design, most of the undissolved solids collected in the steam drum are routinely removed

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through "boiler blowdown." However, since the once-through design does not include a drum, any undesirable solids in the feedwater cannot be removed. Consequently, only the best feedwater treatment is acceptable for once-through steam generators, otherwise the impurities are carried over to the superheater and ultimately to the turbine resulting in deposit.

While subcritical drum-type and supercritical steam generators are offered by manufacturers throughout the U.S., Europe, and Japan, the subcritical, once-through design is primarily a European design.

NATURAL VS FORCED CIRCULATION

Natural circulation relies on the difference in steam and water densities to drive furnace water against the force of gravity from the bottom of the boiler to the drum. As pressures approach the critical pressure of water (3208 psia), the "natural driving potential reduces with the difference in steam and water densities." Hence at high pressures, pump-assisted circulation is sometimes provided. Both "natural" and "forced" circulation are available and give satisfactory results.

PRESSURIZED VS BALANCED DRAFT

There are two fan arrangements which have been employed in the U.S.

1. Forced Draft (FD) fan(s) located at front-end of boiler resulting in a "pressurized" steam generator.

2. Induced Draft (ID) fan(s) located at back-end of boiler and an FD fan(s) at front-end, resulting in a "balanced draft" steam generator.

Because of maintenance problems associated with furnace gas leaks and other miscellaneous problems, the pressurized design has been discarded in the U.S.

Technical Paper

High temperature gas side corrosion in coal-fired boilers

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BR-1157

Babcock & Wilcox
a McDermott company

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PGTP 79-79

Abstract

As summarized by Reid[1], much work has been done on high temperature corrosion resulting from burning high S coal. Little work has been published on corrosion with low S bituminous, subbituminous, and lignite coals that now have wider use. In 1974, Babcock & Wilcox initiated a development program to determine, qualitatively, if these coals are as corrosive as the higher S coals. To determine the corrosivity of various coals under actual operating conditions, samples of alloys were welded to the superheater tubes of units burning various coals. The program also included a survey of nine utilities, which collected data on their coal ash corrosion experience with 51 boilers designed for 566C (1050F), or higher steam temperature. The data and information from this program suggests that all coals are not equally corrosive.

Introduction

Serious external wastage of high temperature superheater tubes in coal-fired utility boilers was first encountered in the United States during the 1950's[2,3]. The corrosion, which resulted in tube failures due to excessive thinning, was concentrated on the upstream side of the tubes with the greatest metal loss at the 10 and 2 o'clock positions of the tube. This is shown in Figures 1 and 2. Significantly, these boilers were among the first to be designed for 566C (1050F) main and reheat steam temperatures and they burned high S, high alkali coals from central and southern Illinois. Since that time, there was

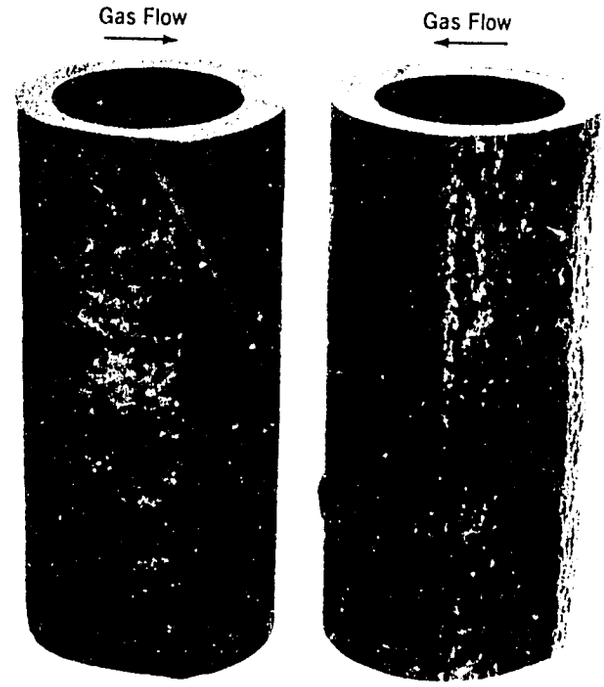


Fig. 1 Typical coal ash corroded tube.

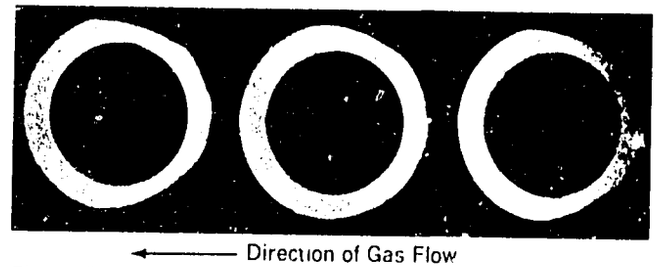


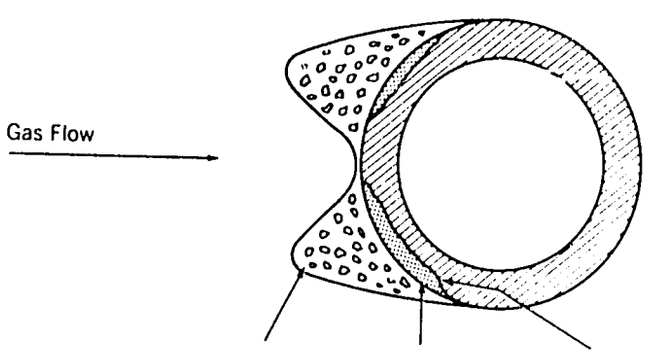
Fig. 2 Transverse sections of corroded tube.

much research devoted to high temperature corrosion resulting from burning the high S coal, which was a popular fuel for power plants prior to the 1967 Clean Air Act. Little work has been done on high temperature corrosion experienced while burning the low S bituminous, subbituminous, and lignite type coals that have increased in use today. In 1974, Babcock & Wilcox initiated a development program to determine, qualitatively, if these coals are as corrosive as the higher S coals.

Researchers have not as yet agreed on the basic mechanism of high temperature coal ash corrosion, but have attempted to define the limits and the elements involved in the corrosion process[4]. It is generally accepted that a liquid phase is necessary for severe corrosion to occur, and that S may be a key element in the corrosion process. Though S may be the key element, it is also accepted that K, Na, Fe, and Al are involved in the formation of the corrosive deposits.

Corrosion is rarely, if ever, found in superheaters or reheaters having only dusty deposits; it is associated with the sintered, or slag type, deposits that are strongly bonded to the tubes. These corrosive ash deposits, as shown in Figure 3, consist of at least three distinct layers:

1. A hard, brittle, and porous outer layer which is the bulk of the deposit and has a composition similar to the boiler fly ash.
2. A white, intermediate layer. When the white layer has a chalky consistency, corrosion is found to be mild or nonexistent. When it is fused and semi-glossy, corrosion is found to be severe. Identifying the compounds of this layer is difficult because its constituents are not well crystallized. The usual sulfates are normally absent, but complex alkali sulfates are detected irregularly by X-ray diffraction. Although other complex sulfates are thought to be present, the most common compounds found are $Na_3Fe(SO_4)_3$ and $K_3Fe(SO_4)_3$.
3. A black, glossy inner layer, composed primarily of corrosion products; i.e., oxides, sulfides, and sulfates of Fe.



	Outer Layer % by wt.	Intermediate Layer % by wt.	Inner Layer % by wt.
SiO_2	23.5	23.3	7.6
Al_2O_3	14.0	11.5	1.7
Fe_2O_3	36.0	11.0	70.5
TiO_2	0.9	<0.1	<0.1
CaO	1.3	<0.1	<0.1
MgO	1.3	1.1	<0.1
Na_2O	0.3	1.7	0.15
K_2O	2.9	13.5	1.3
NiO	<0.1	<0.1	0.3
Cr_2O_3	<0.1	<0.1	7.0
SO_3	7.3	27.5	10.0
Cl	0.02	<0.01	<0.01
Water Soluble—%	9.0	45.4	9.0
pH	3.0	2.2	4.3
Excess SO_3—%	0.5	11.2	11.8

Fig. 3 Analysis of typical corrosive ash deposit from 18Cr-8Ni superheater tube.

The normal alkali sulfates Na_2SO_4 and K_2SO_4, and the alkali pyrosulfates $Na_2S_2O_7$ and $K_2S_2O_7$, apparently are not involved in the problem. The sodium and the potassium sulfates, having 884C (1623F) and 1069C (1956F) melting points respectively, become molten at temperatures considerably higher than superheater metal temperatures. Sodium pyrosulfate, having a 401C (754F) melting point, and potassium pyrosulfate, having a 300C (572F) melting point, also are not problems, as they are unstable at the higher superheater metal temperatures.

The complex iron and aluminum alkali sulfates, detected in the white deposit, are the only known compounds encountered in this system that are molten, stable, and corrosive at superheater metal temperatures.

Formation of the corrosive complex alkali sulfates requires extremely high amounts of SO_3. Anderson and Goddard[5] determined that the equilibrium SO_3 partial pressure, required to form and maintain the white layers, at 634C (1175F), is approximately 1.0-1.5 x 10^{-3} atmospheres, equivalent to 1000-1500 ppm of SO_3. As this SO_3 concentration is approximately 50 times greater than the amount normally found in boiler flue gas, the researchers concluded that the SO_3 was obtained from the catalytic oxidation of SO_2, which allegedly takes place within the tube deposit. The high SO_3 value very nearly corresponds to the equilibrium conversion of SO_2 from a coal containing 3.5% sulfer burned in 10% excess air (over that required for stoichometric combustion). This value suggests that all coals are not equally corrosive, because the reaction involves S, an element whose concentration varies in the dif-

ferent coals. The lower the S in the coal, the lower the SO_2 (and SO_3) concentrations. This results in lower equilibrium SO_3 partial pressures, increasing the temperature for the molten phase of the ash. This suggests that possibly at some S level, a coal will not provide the SO_2 concentrations necessary to form the molten phase of the complex alkali sulfates at superheater metal temperatures.

Borio, et al.[6], in their study for the Office of Coal Research to correlate corrosion rates with the chemical and physical properties of coal, reported that Ca as CaO, and Mg as MgO, in the ash, have an inhibiting effect on the formation of the corrosive, complex alkali sulfates. They explained that Mg and Ca have the ability to tie up Na and K in the form of harmless double salts, of the $K_2SO_4 \cdot 2CaSO_4$ type, and render them unavailable as reactants to form complex $K_3Fe(SO_4)_3$ and $Na_3Fe(SO_4)_3$. If this reaction is true, it suggests that the lignite-type ash, which are high in CaO and MgO, are not corrosive.

Development program

Coal ash corrosion, as a utility boiler operating problem, has been kept at a tolerable level for the past 15 years. This success has been (or is) attributed to the utility industry's retreat to 538C (1000F) steam temperatures and the design changes based on the coal ash corrosion experience with Illinois coal. Shortly after these important changes were made, the Clean Air Act of the late 1960's and the 1973 oil embargo made low S coals attractive as power plant fuel.

The primary objective of this program was to determine the extent to which low S coal might alleviate the corrosion problem. The program included a survey of the experience of 9 utilities, the exposure of test specimens in 10 operating boilers, and laboratory evaluation of selected test samples removed after 12- and 27-month exposures.

Survey

This portion of the development program included a survey of nine utilities on their coal ash experience with 51 boilers that were designed for 565C (1050F) or higher steam temperatures, and to burn high S coals. See Table 1. The survey attempted to determine the extent that coal ash corrosion is a problem, and the changes the utilities had made that may have alleviated the problem.

From the survey:

26 of the 51 boilers are not experiencing high temperature gas side corrosion. Of these units:

- 12 are burning low S coal and continue to operate at (the high) design steam temperature
- 5 continue to burn high S coal but are operating at reduced steam temperature
- 2 are burning low S coal and have reduced steam temperatures (for problems other than coal ash corrosion)
- 2 continue to burn high S coal and operate at design temperature
- 5 have been converted and are burning low S oil

25 of the 51 boilers are experiencing high temperature gas side corrosion. Of these units:

- 14 are operating at design steam temperature and continue to burn high S coal
- 11 are operating at reduced steam temperature and continue to burn high S coal

The significant information from the survey is that of the 14 boilers that are burning low S coal, none are experiencing coal ash corrosion problems and 12 of these continue to operate at the original design temperature. The survey also suggests that the high S coals are not equally corrosive. Two of the boilers burn high S coal at design temperature without coal ash corrosion, while 11 units continue to have corrosion problems even though they are operating at reduced steam temperature.

Field test program

The field test portion involved welding test tabs to the superheater tubes of ten operating boilers burning a variety of coals. See Table 2. Unit 7, a cyclone-fired unit burning high S bituminous coal, with known coal ash corrosion problems, was included as a control or base unit for comparison.

Test tabs of 2¼Cr-1Mo and TP304 stainless alloy, as shown in Figure 4, were welded parallel to the gas flow on the leading edge tubes, and perpendicular to the gas flow on the trailing edge tubes, of the superheater bank. See Figure 5. Welding of the test tabs to the superheater tubes had the advantage of exposing the material to actual operating conditions and providing a temperature gradient across the test tab that ranged from the tube skin temperature through the critical temperature for aggressive corrosion to occur. It had been reported by Koopman[7] and generally accepted that the rate of coal ash corrosion is a nonlinear function of the metal temperature. As shown in Figure 6, the corrosion rate curve has a bell shape; corrosion begins at approximately 551C (1025F), increases sharply between 583C (1100F) and 704C (1300F), then drops quickly above 704C.

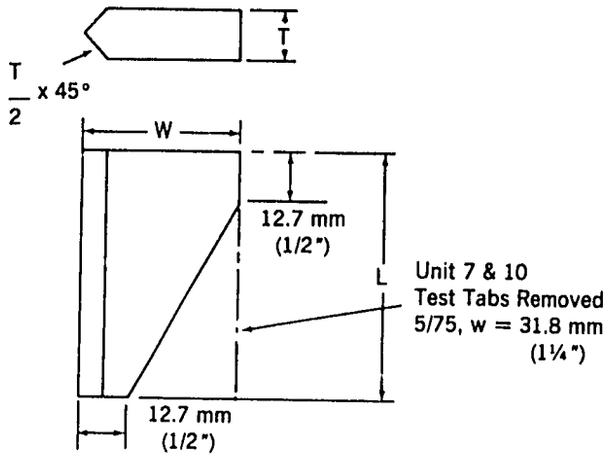
Table 1
Coal Ash Corrosion Survey

	As Designed				Corrective Action			
Unit #	Type of Firing	Temperature °C	Corrosion Yes	Corrosion No	Reduce Stm. Temp.	Change Fuel	Corrosion Yes	Corrosion No
1	Cyc	565/565/565	•		Yes			•
2	PC	565/565/565			No	2% S Coal		•
3	Cyc	538/551/565		•	No			•
4	PC	538/551/565			No	2% S Coal		•
5	PC	538/551/565			No	2% S Coal		•
6	Cyc	565/538	•		Yes		•	
7	Cyc	565/538	•		Yes		•	
8	PC	565/565		•	Yes			•
9	PC	565/565		•	Yes			•
10	PC	538/551/565		•	No			•
11	Cyc	565/538	•		Yes		•	
12	Cyc	565/538	•		Yes		•	
13	Cyc	565/538	•		Yes		•	
14	PC	565/538			No	2% S Coal		•
15	PC	565/538			No	2% S Coal		•
16	PC	565/565			No	2% S Coal		•
17	PC	565/565	•		Yes	2% S Coal		•
18	PC	565/565			No	2% S Coal		•
19	PC	565/565			No	2% S Coal		•
20	PC	565/565	•		No		•	
21	PC	565/565	•		No		•	
22	PC	565/565	•		No		•	
23	PC	565/565	•		No		•	
24	PC	565/565	•		No		•	
25	PC	565/565	•		No		•	
26	PC	565/565	•		Yes		•	
27	PC	565/565	•		Yes		•	
28	PC	565/565	•		Yes		•	
29	PC	565/565	•		Yes		•	
30	PC	565/565	•		Yes		•	
31	PC	565/540	•		No	2% S Coal		•
32	Cyc	565/538	•		No		•	
33	Cyc	565/538	•		No		•	
34	Cyc	565/538			No	Low S Oil		•
35	PC	570/538			No	2% S Coal		•
36	PC	570/538			No	2% S Coal		•
37	Cyc	568/538			Yes			•
38	PC	565/538			No	2% S Coal		•
39	Cyc	568/540			Yes			•
40	PC	570/582			Yes	2% S Coal		•
41	Cyc	565/538			No	Low S Oil		•
42	Cyc	567/567	•		No		•	
43	Cyc	567/567	•		No		•	
44	Cyc	567/567	•		No		•	
45	PC	565/538	•		No	Low S Oil		•
46	PC	565/538	•		Yes		•	
47	PC	565/538	•		No		•	
48	PC	565/538	•		No		•	
49	PC	568	•		No	Low S Oil		•
50	PC	568/565	•		No		•	
51	PC	565	•		No	Low S Oil		•

Table 2
Field Test Program

Unit	Design Temp. °C(F)	Coal	Samples Installed	Gas Tube °C(F)	Tube T_{OD} °C(F)	Sample Location Orientation to Gas Flow	Visual Inspect	Remarks
1	513C(955)	North Dakota Lignite	5/76	1270(2319) 1122(2054) 1097(1015)	504(940) 557(1036) 546(1015)	Parallel and Perpendicular Parallel Parallel and Perpendicular	5/77	Heavy Deposits—No Visual Corrosion
2	540/540 (1005/1005)	Low S Subbituminous	4/76	1082(1982) 1033(1893)	551(1025) 523(915)	Perpendicular Parallel	10/76	Light Deposits—No Apparent Corrosion
3	540/540 (1005/1005)	High Na Lignite	5/76	1201(2197) 1038(1903) 872(1604)	546(1016) 518(965) 465(870)	Parallel Parallel Parallel		
4	538/538 (1000/1000)	High Na Lignite	3/76	1100(2015) 1074(1967) 990(1816)	562(1045) 607(1125) 521(971)	Perpendicular* Parallel* Parallel	10/78	No Apparent Corrosion Samples Removed For Lab Analysis 10/78
5	540/540 (1005/1005)	Low S Subbituminous	6/76	1119(2048) 1072(1963) 869(1597) 748(1380)	571(1060) 482(900) 398(750) 498(930)	Parallel Parallel Parallel Parallel	3/77	No Apparent Corrosion
6	540/540/540 (1005/1005/1005)	Low S Bituminous	7/76	1276(2332) 1192(2180) 1003(1839)	593(1100) 500(930) 510(950)	Parallel Parallel Parallel	11/77-8/78	No Apparent Corrosion
7	540/540 (1005/1005)	High S Bituminous	4/74	1251(2286) 1217(2224) 1144(2093)	553(1028) 607(1125) 539(1003)	Parallel* Parallel* Parallel	5/75, 4/76 7/77, 7/78	Base Unit For Corrosion Severe Corrosion, Samples Removed For Laboratory Analysis 5/75, 7/78
8	542/542 (1008/1008)	Low S Subbituminous	5/76	1215(2222) 1084(1986) 1078(1972) 987(1811)	570(1059) 551(1025) 593(1100) 515(960)	Parallel and Perpendicular Perpendicular Parallel Parallel	4/77-11/78	No Apparent Corrosion
9	539/539 (1003/1003)	High S Bituminous	4/76	1355(2473) 1146(2097) 978(1795)	509(950) 577(1072) 509(950)	Parallel Perpendicular Parallel	10/78	No Apparent Corrosion
10	538/538 (1002/1002)	Low S Bituminous	4/74	1266(2313) 1123(2055) 1005(1842)	603/587(1118/1090) 603(1120) 518(965)	Parallel Parallel* Parallel	5/75	No Apparent Corrosion—Samples Removed For Laboratory Analysis 5/75

*SAMPLES REMOVED FOR LABORATORY EVALUATION



Material	L	T	W
2¼ Cr 1 Mo	70.0 mm (2¾")	12.7 mm (½")	31.8 mm (1¼")
TP 304 Stainless	76.2 mm (3")	9.5 mm (⅜")	41.2 mm (1⅝")

Fig. 4 Typical test tabs.

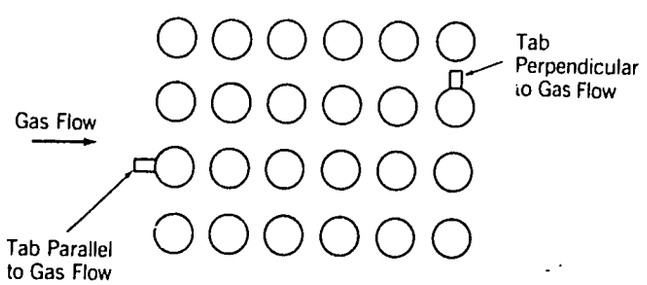


Fig. 5 Test tab orientation in superheater bank.

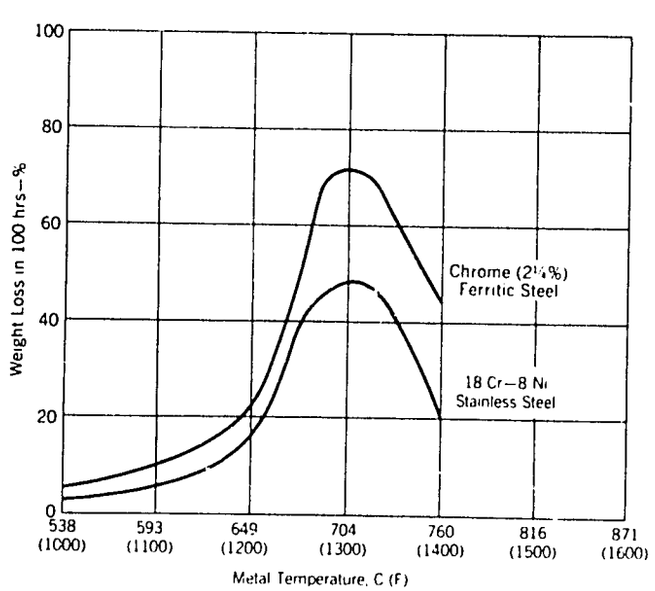


Fig. 6 Effect of temperature on corrosion rate.

The field test portion included visual examination of test specimens, as permitted by boiler outages. Except for specimens in Unit 7, where coal ash corrosion was apparent, the specimens (including Unit 9 burning high S coal) were not affected by coal ash corrosion after as long as 30 months. Selected test specimens, which visually represented all those exposed in the ten boilers, were removed after about 1- and 2½-year exposures, for laboratory analysis.

Laboratory analysis

After 12 months of exposure, test specimens were removed from Unit 7, a cyclone-fired boiler burning high S bituminous coal, and from Unit 10, a PC (pulverized coal) fired boiler burning low S bituminous coals. After 27 months of exposure, additional test specimens were removed from Unit 7 and Unit 4. Unit 4 is also cyclone-fired, but burns North Dakota lignite.

12-month exposure: Test tabs were removed from Units 7 and 10 after 12 months of exposure to the following design conditions:

Unit 7 -	Gas temperature	1217C (2224F)
	Tube T_{OD}	607C (1125F)
	(Temperature at tube OD surface)	
Unit 10 -	Gas temperature	1123C (2055F)
	Tube T_{OD}	604C (1120F)

Test tabs of TP304 stainless steel material (with an Inconel 182 weld bead on the face of the specimen), were welded parallel to the gas flow and to the leading edge tube of the superheater bank of both units. Figure 7 shows the external surface ap-

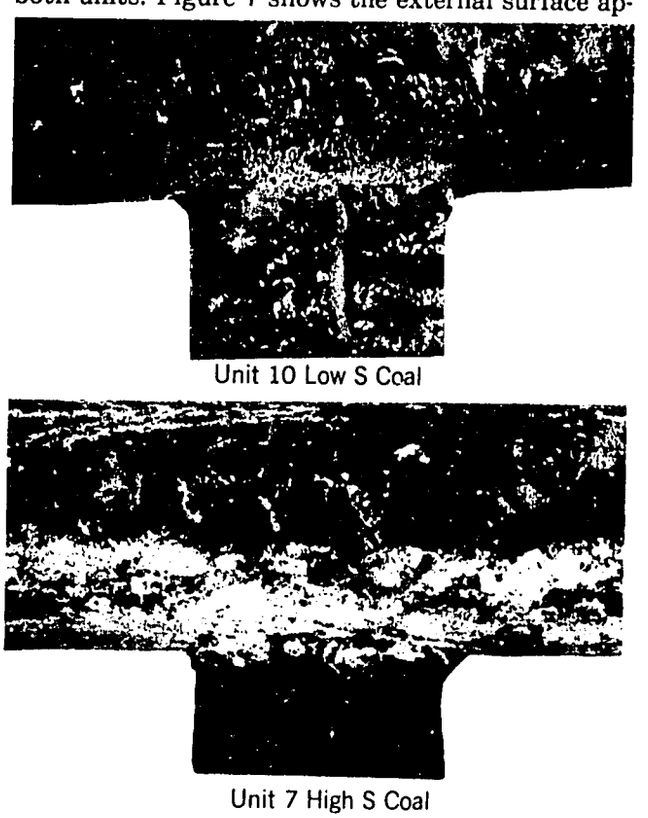
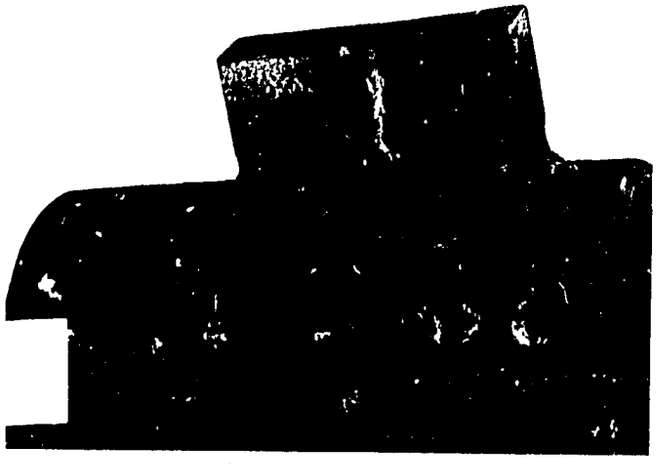
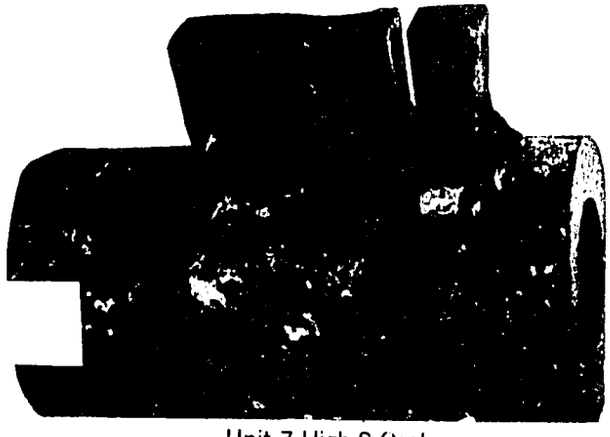


Fig. 7 As-received test tabs, 12 months exposure.

pearance of the test samples in the as-received condition, and Figure 8 shows the general condition of the samples after being wire brushed and chemically cleaned. The TP304 stainless steel test tab (and Inconel 182 weld bead) removed from Unit 7 was visually distressed, while the similar sample removed from Unit 10 appeared to be in excellent condition.



Unit 10 Low S Coal



Unit 7 High S Coal

Fig. 8 Surface appearance after cleaning, 12 months exposure.

A transverse ring segment was cut from each tube, through the test tab, approximately 12.7 mm (½ in) from one end. The ring segments were polished and photographed, and the specimen thicknesses were measured. As shown in Figure 9, a transverse view of the test specimen, there is obvious metal loss in the sample removed from Unit 7 and no apparent wastage on the sample removed from Unit 10.

Metallographic examination and photomicrographs of the test specimens were made at the bottom of the tabs (near the weld to the tube), the middle, and the top which was the hottest portion of the test tabs. Photomicrographs shown in Figures 10 and 11 indicate that both specimens experienced

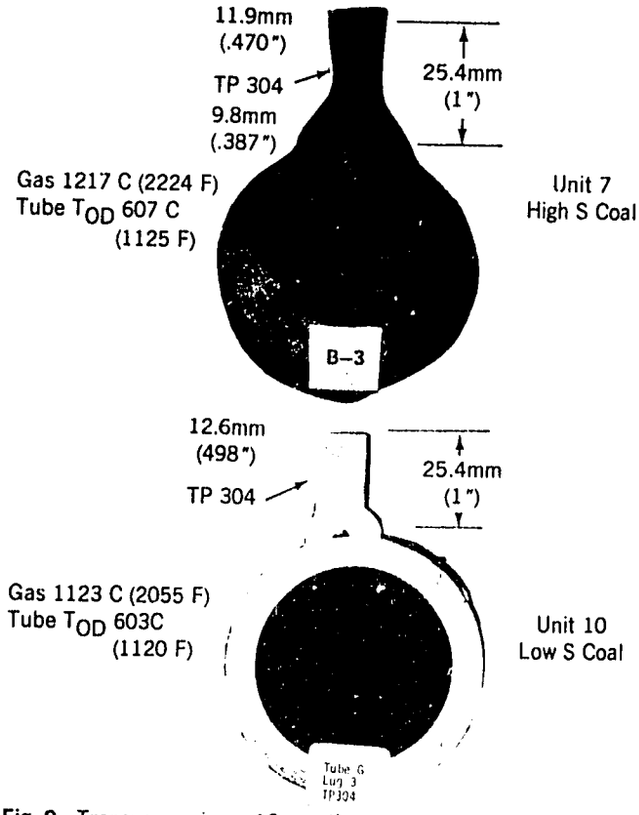


Fig. 9 Transverse views, 12 months exposure.

high temperature oxidation at the top, the hottest portion of the specimen. The cooler middle and lower portions of the specimen removed from Unit 7 display general metal attack, preceeded by grain-boundary oxidation. The specimen removed from Unit 10 had only experienced high temperature oxidation.

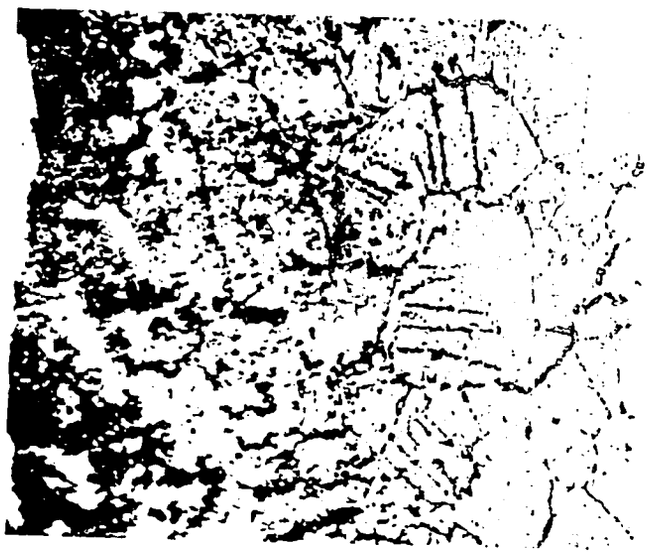
27-month exposure: Test tabs were removed from Unit 7 after 27 months of exposure, and from Unit 4 after 30 months of exposure. These test samples were exposed to the following design conditions:

Unit 7 -	Gas temperature	1251C (2286F)
	Tube T_{OD}	553C (1028F)
Unit 4 - Set #1	Gas Temperature	1100C (2015F)
	Tube T_{OD}	562C (1045F)
Unit 4 - Set #2	Gas Temperature	1074C (1967F)
	Tube T_{OD}	607C (1125F)

Test tabs of 2¼Cr-1Mo steel and TP304 stainless steel (with an Inconel 182 weld bead on the face) had been welded, parallel to the gas flow, to the leading edge tube of the superheater bank of Unit 7. Figures 12 and 13 show the external surface appearance, and a transverse view, of the test specimens in the as-received condition. Visual examination of the specimens indicated that both were severely distressed, including the Inconel weld bead.

For metallography, the test specimens were sectioned perpendicular to the tube, approximately 6.4 mm (¼ in) from the top of the sample. The transverse view, shown in Figures 12 and 13, and the photomicrographs in Figure 14, show that both the 2¼Cr-1Mo and TP304 stainless steel sample had experienced severe metal wastage due to coal ash corrosion. The 2¼Cr-1Mo sample also experienced high temperature oxidation, while the TP304 sample experienced coal ash corrosion in the cooler temperature zone of the specimen and only high temperature oxidation at the hottest zone of the sample.

Bottom (Weld) 500X Middle 500X

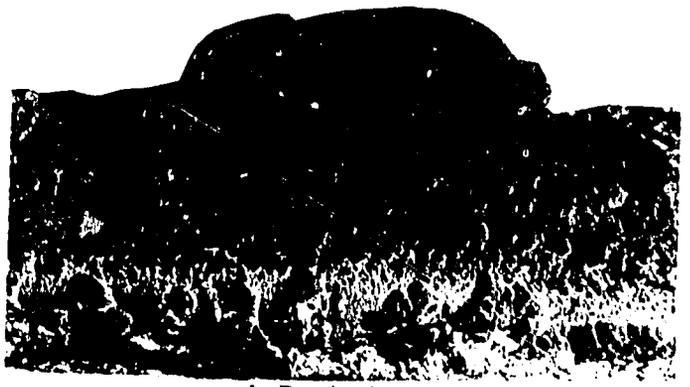


Top 500X

Fig. 10 Photomicrographs Unit 7, 12 months exposure.

Middle 500X Top 500X Bottom (Weld) 500X

Fig. 11 Photomicrographs Unit 10, 12 months exposure.



As Received

27 Month Exposure
High S Coal

Gas Temperature 1251 C (2286 F)
Tube T_{OD} 553 C (1028 F)

Transverse View

Fig. 12 Unit 7, 2¼Cr-1Mo test tabs.

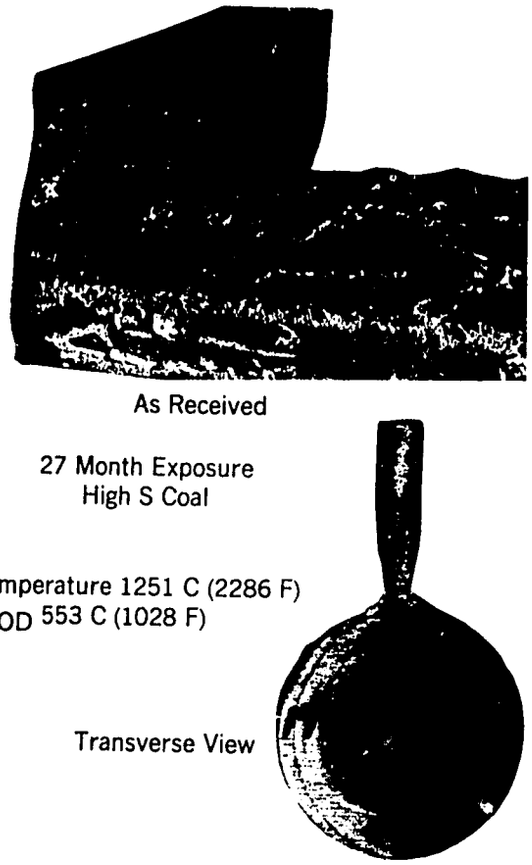


Fig. 13 Unit 7, TP304 stainless steel test tabs.

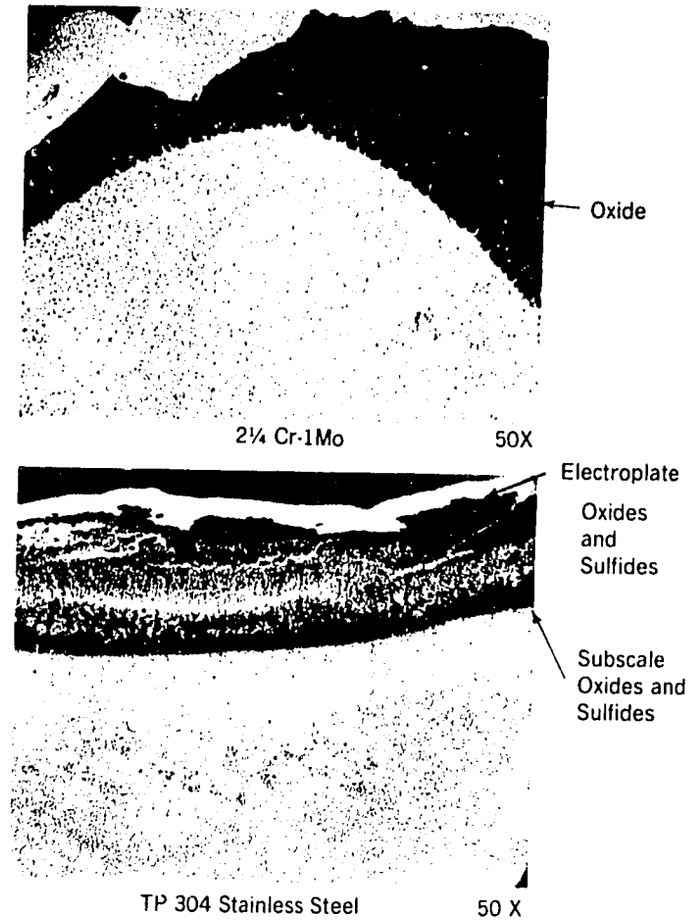


Fig. 14 Unit 7, photomicrographs.

Two sets of samples were removed from Unit 4. The first set included 2¼Cr-1Mo and TP304 stainless steel specimens. They were welded, perpendicular to the gas flow, to superheater tubes with a T_{OD} of 562C (slightly higher than the tube T_{OD} of 553C for the sample removed from Unit 7). The second set, which included the TP304 stainless steel specimen, was welded parallel to the gas flow to a tube with a T_{OD} of 607C (1125F).

Figures 15, 16, and 17 show the external surface appearance, and a transverse view, of the test samples in the as-received condition. The test specimens from Unit 4, Set #1, were covered with a hard, white-to-tan deposit, which was up to 12.7 mm (½ in) thick. Chemical composition of the deposit was predominantly $CaSO_4$, while the scale covering the 2¼Cr-1Mo sample was Fe_3O_4 with some Fe_2O_3.

For metallography, the specimens from both sets were transversely sectioned approximately 6.4 mm (¼ in) from the top of each sample. The photomicrographs, shown in Figure 18, display no evidence of coal ash corrosion. Metallographic examination of the test specimens show the scale morphologies that are normally associated with high temperature oxidation, but not coal ash corrosion.

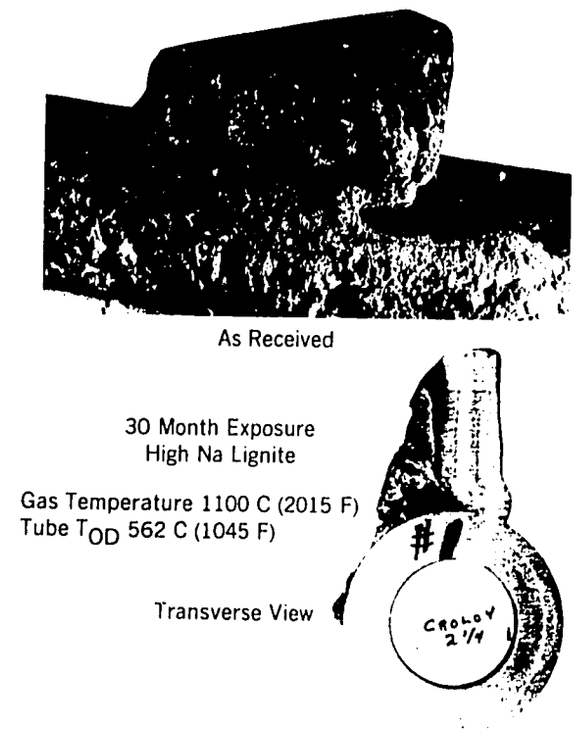


Fig. 15 Unit 4, Set 1, 2¼Cr-1Mo test tabs.

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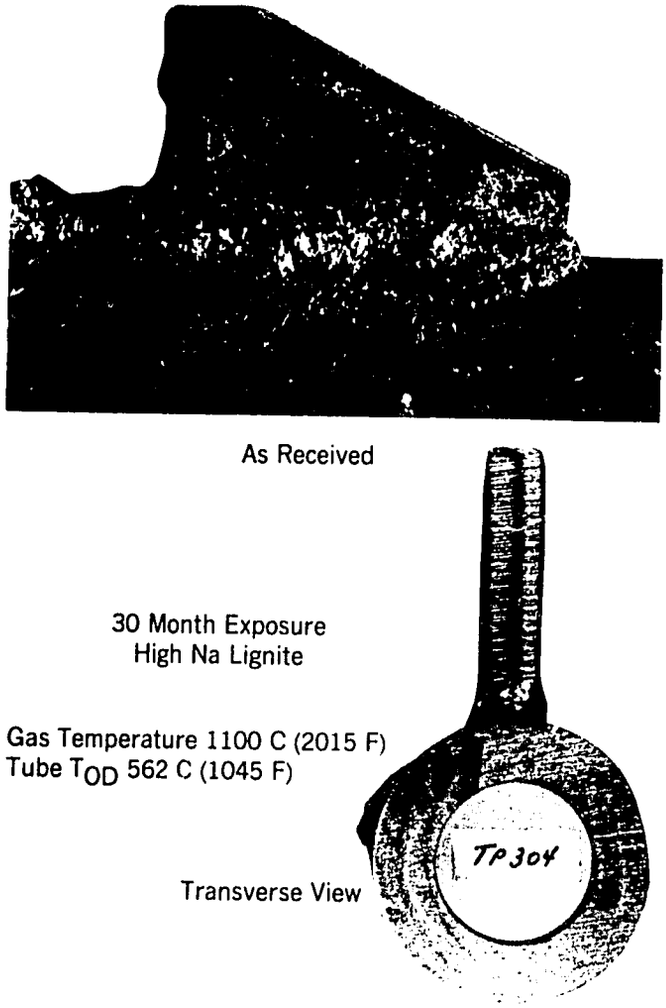

Fig. 16 Unit 4, Set 1, TP304 stainless steel test tabs.

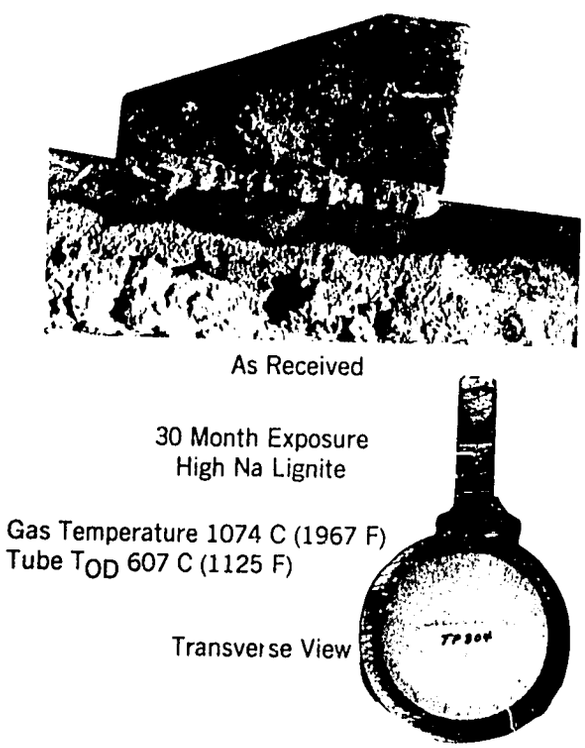

Fig. 17 Unit 4, Set 2, TP304 stainless steel test tabs.

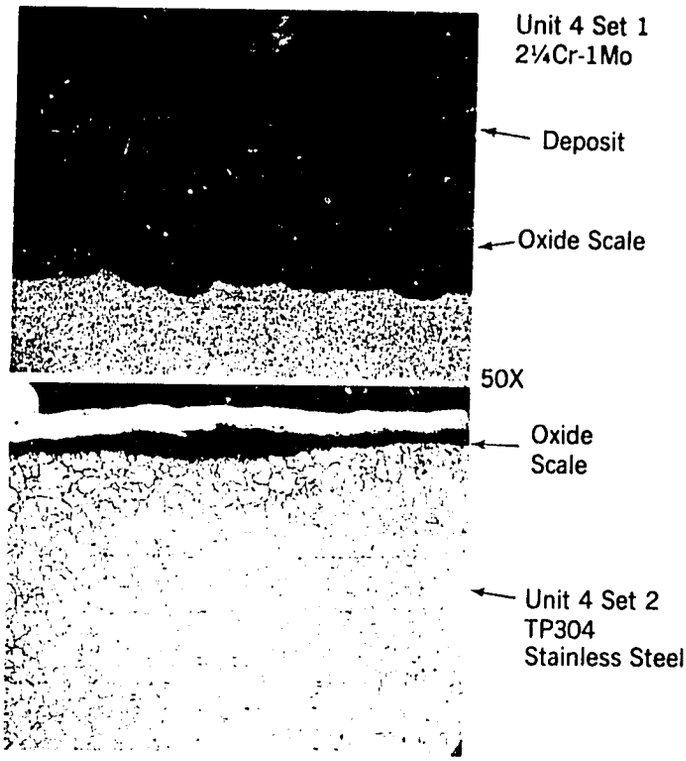

Fig. 18 Photomicrograph Unit 4, 30 months exposure.

Observations

The data and information from the development program indicate that all coals are not equally corrosive. There was no visual or reported coal ash corrosion in the 22 boilers that are burning less than 2% S coal, 12 of which are operating at 565C (1050F) or higher steam temperature. Laboratory analysis and metallographic examinations confirmed the absence of accelerated attack or scale morphologies that are normally associated with coal ash corrosion. Also, there was no visual or reported corrosion in three units burning high S coal, with two of the units operating at 565C (1050F) steam temperature.

Acknowledgements

The authors wish to thank P. L. Daniel, R. H. Emanuelson, and J. W. Seifert of the Babcock & Wilcox Alliance Research Center, for general assistance and metallographic interpretations.

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IMPACT OF COAL CHARACTERISTICS ON BOILER DESIGN

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Presented at:

COAL TECHNOLOGY '82
5th INTERNATIONAL COAL UTILIZATION
EXHIBITION & CONFERENCE

December 7-9, 1982
Houston, Texas

POWER SYSTEMS

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IMPACT OF COAL CHARACTERISTICS ON BOILER DESIGN

INTRODUCTION

One hundred percent of the utility, and most large industrial, fossil-fueled steam generators purchased since 1975 have been designed to burn coal. The trend is expected to continue past the end of this century. This paper reviews the various coal characteristics that influence the design of boilers and auxiliary equipment with emphasis on identifying potentially troublesome coal and ash properties.

COAL

Table I gives examples of the basic types of United States coal presently being used. The most important design consideration for a steam generator is the fuel to be burned. Fuel preparation and burning equipment, furnace size, heating surface quantity and placement, heat recovery equipment, ash handling/disposal, and air pollution control devices are fuel dependent and vary considerably.

The major differences between coal burning and oil and natural gas burning steam generators are a result of the solid form of coal prior to burning and the ash contained in the products of combustion. The products of combustion from burning oil contain relatively small amounts of ash and natural gas produces no ash. Coal has to be pulverized before being introduced into the furnace, whereas oil and gas, by comparison, require very little preparation. Coal burning steam generators, because of the slower burning rate and the ash produced, must have larger furnaces than

TABLE I
TYPICAL COAL ANALYSES

	Eastern Bituminous	Midwestern Bituminous	Sub-bituminous C	Texas Lignite	North Dakota Lignite
Total moisture, %	5.0	15.4	30.0	31.0	39.6
Ash, %	10.3	15.0	5.8	10.4	6.3
Volatile matter, %	31.6	33.1	32.6	31.7	27.5
Fixed carbon, %	53.1	36.5	31.6	26.9	26.6
Total, %	100.0	100.0	100.0	100.0	100.0
Btu/lb, as fired	13,240	10,500	8,125	7,590	6,523
Btu/lb, moisture & ash free	15,640	15,100	12,650	12,940	12,050
Fusion (reducing), F					
ID	2,170	1,990	2,200	2,075	2,027
ST	2,250	2,120	2,250	2,200	2,089
FT	2,440	2,290	2,290	2,310	2,203
Ash analysis, %					
SiO_2	40.0	46.4	29.5	46.1	23.1
Al_2O_3	24.0	16.2	16.0	15.2	11.3
Fe_2O_3	16.8	20.0	4.1	3.7	8.5
CaO	5.8	7.1	26.5	16.6	23.8
MgO	2.0	0.8	4.2	3.2	5.9
Na_2O	0.8	0.7	1.4	0.4	7.4
K_2O	2.4	1.5	0.5	0.6	0.7
TiO_2	1.3	1.0	1.3	1.2	0.5
P_2O_5	0.1	0.1	1.1	0.1	–
SO_3	5.3	6.0	14.8	12.7	17.7
Not accounted for	1.5	0.2	0.6	0.2	1.1
Sulfur, %	1.8	3.2	0.34	0.6	0.75
Lb moisture/million Btu	3.8	14.7	36.9	40.8	60.7
Lb ash/million Btu	7.8	14.3	7.1	13.7	9.7
Lb sulfur/million Btu	1.36	3.05	.42	.79	1.15
B/A ratio	.426	.473	.784	.392	1.33
Hardgrove grindability	55	56	43	48	25*

*With 39.6% moisture at pulverizer inlet, range is 20-50.

oil and gas burning steam generators for a given output. Velocities of the products of combustion as they pass through the steam generator heating surfaces must be lower for coal burning steam generators because of the ash. Also, tubes must be spaced farther apart because of the ash. Coal burning steam generators require ash handling and stack gas cleanup equipment, which is not generally required with oil and gas. From fuel preparation to stack gas cleanup, coal substantially affects the design of the steam generator.

COAL PREPARATION

Before any considerations are given to the furnace size, combustion, deposits and ash handling, it is essential that certain properties of coals be considered for their influence on handling, storage and pulverizing operations. These properties are coal size, moisture content, heating value, grindability and abrasion potential. An examination of coal from all parts of the country (Table II) indicates the wide variation in heating values, moisture content and, consequently, the pounds of fuel that must be fired to generate a given output. Heating values (for this example) range from 12,000 Btu/lb for an Eastern bituminous coal to 6800 Btu/lb for Northern Plains lignite. To illustrate the effect of heating value and moisture content on pre-firing, handling and preparation, coal requirements for a 600-MW (Fig. 1) unit can vary from 225 to 397 tons of coal per hour, or 90 to 160 railway carloads per day, depending on the kind of coal being burned. To burn these amounts, the coal must be transferred from the cars to the pulverizers by way of conveyors, bins, and flow-control mechanisms (feeders). Additionally, the moisture content ranges from 6 percent for Eastern bituminous through 37 percent for Dakota lignite. The corresponding moisture per million Btu's for the range varies from 5 through 54 pounds, again representing a significant difference in handling requirements.

If the delivered coal has a top size greater than 2 inches, crushers must be provided to reduce the oversize to a 1-1/2 to 2 inch limit in order that it move smoothly through the bunker and the feeder that regulates coal delivery to the pulverizers. An excess of surface moisture coupled with a large percentage of fines impedes coal flow in the conveyor systems, bins and coal feeders. In addition, excessive moisture could limit pulverizer throughput by exceeding the capability of the hot air used for drying in the pulverizer. Also, the moisture reduces the as-fired heating value of the pulverized fuel, placing an additional load on pulverizer capacity, possibly to the extent that the milling system cannot deliver enough coal to maintain full load.

Pulverizer capacity is influenced by the combined properties of moisture (and its related hot air requirements for drying), fuel heating value and grindability. Grindability is a relative measure of the coal's response to pulverizing operations. An index number is established by a standard laboratory procedure that rates the percentage of fines produced by grinding. Mill capacities are established by each manufacturer for his equipment by relating the grindability index to mill experience established in field operations. Table I indicates typical Hardgrove grindability indices for U.S. coals. Note that the general tendency for decreasing grindability coupled with lower heating values as we move from East to West, requires a marked increase in pulverizer capacity. This requirement also affects the sizing of the air heater and other heat recovery sections of the steam generator.

COAL PROPERTIES AFFECTING COMBUSTION

Good performance of a unit requires the ability to maintain load over extended time intervals with a minimum of carbon loss and with control of slag and deposit build-up. Properties of coal that influence the design and permit continuing efficient combustion are rank classification, particle size of the pulverized fuel, moisture, heating value and the ash characteristics. While steam generating units have been fired successfully with all ranks of coal from anthracite to lignite, specific unit design and auxiliary equipment will vary according to the chemical and physical properties of the fuel. Rank classifications are based on varying combinations of moisture, heating value, volatile

TABLE II

PULVERIZER REQUIREMENTS ON A 600-MW UNIT FIRING U. S. COALS

Type Coal	Eastern Bituminous	Midwestern Bituminous	Sub-bituminous C	Texas Lignite	Northern Plains Lignite
HHV, Btu/lb	12,000	10,000	8,400	7,300	6,800
Moisture, %	6	12	27	32	37
Lb $H_2O/10^6$ Btu	5	12	32	44	54
Fuel fired, lb/hr*	450,000	540,000	643,000	740,000	794,000
Air temperature for drying, F	500	650	700	725	725

*Based on Qf = 5,400 x 10^6 Btu/hr

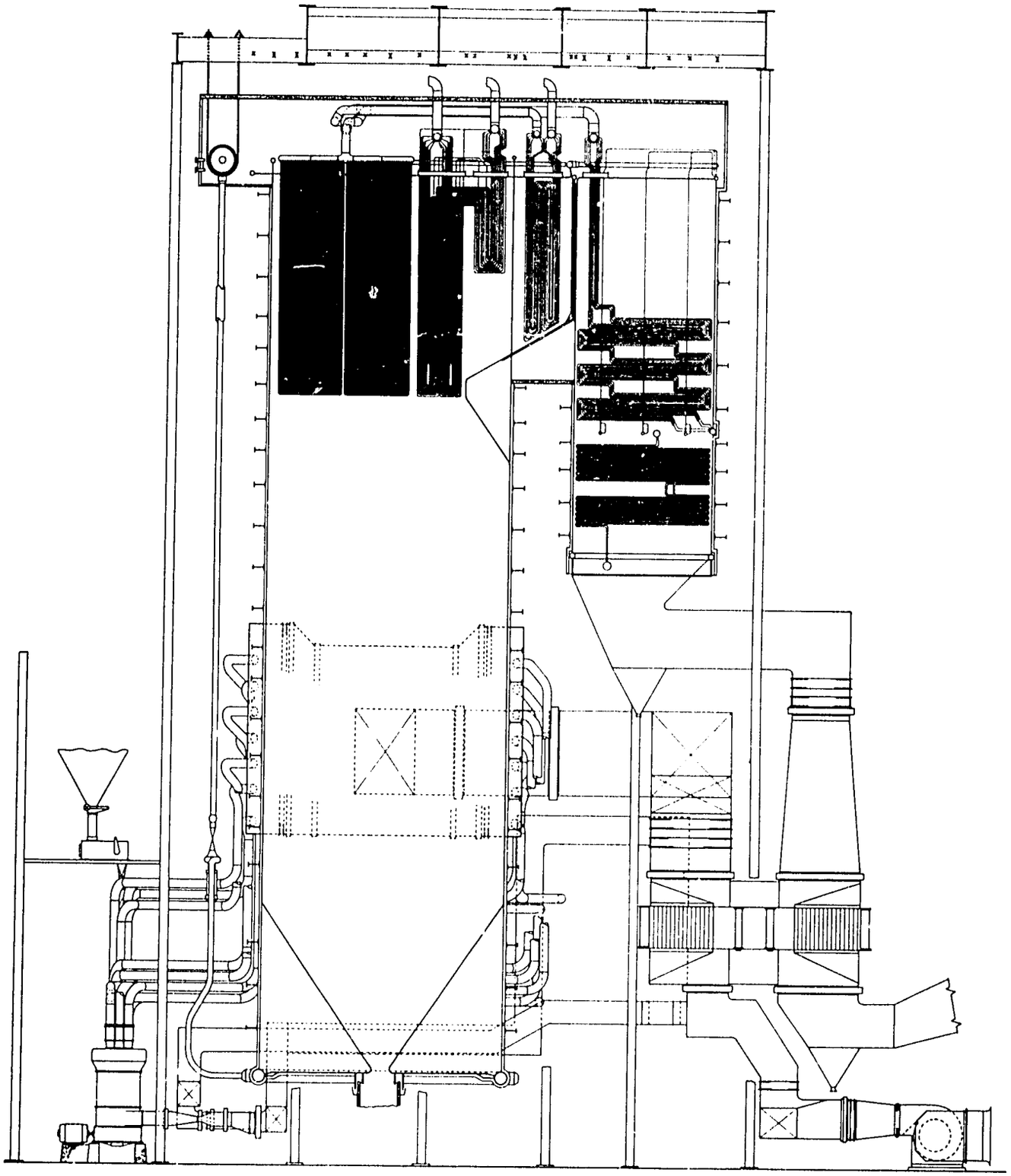

Fig. 1: Typical 600-MW coal-fired steam generator

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matter, and agglomerating properties. A reasonably accurate graphic representation of heating value and bed moisture versus coal rank is illustrated in Fig. 2.

Once rank classifications have been used to separate coals into specific groups, other properties will show some degree of correlation. To illustrate these, typical combustion properties are shown in Table III. Values listed are typical of coal seam moisture and do not include surface moisture. Actual moisture levels can be either greater or less than these values depending on the degree of exposure to drying or wetting after mining.

Two basic properties of coal that have a direct influence on combustion rate and carbon burnout are the agglomerating properties and particle reactivity, usually indicated by the amount of coal oxygen.

Agglomerating coals are interpreted as those that soften or melt when heated to the extent that they are transformed into a molten mass. The influence of agglomeration on surface area can be observed in a photomicrograph of pulverized coal particles after they have been exposed to temperatures of 970 F in a laboratory flammability apparatus. Examination of some bituminous coals reveals that within the short interval that the particles are heated, some have melted sufficiently to become swollen and spherical in shape. This property is characteristic of many bituminous coals. Examination of subbituminous coal does not reflect the agglomerating phenomenon; the particles retain their angular and block configurations. Thus, sub-

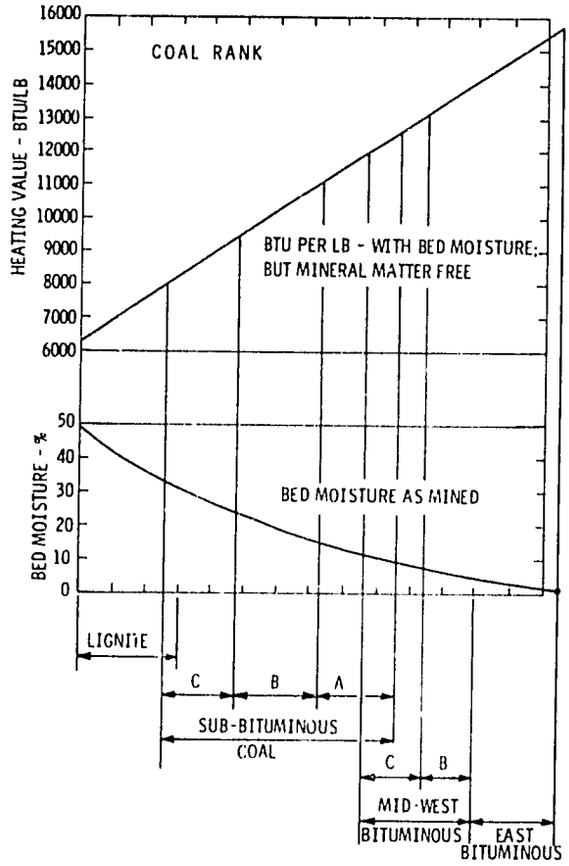

Fig. 2: Graphic determination of coal rank

TABLE III

COMBUSTION PROPERTIES OF TYPICAL U. S. COALS

Rank Classification	Bituminous					Subbituminous			Lignite
	Low	Medium	High Volatile						
Group	Volatile	Volatile	A	B	C	A	B	C	
Agglomerating character	Agg.	Agg.	Agg.	Agg.	Agg.	Non Agg.	Non Agg.	Non Agg.	Non Agg.
Moisture (Seam), %	2.0	3.0	4.0	7.0	10.0	14.0	19.0	23.0	40.0
Volatile matter (as fired), %	15.7	25.0	38.4	39.0	36.3	34.9	31.5	30.5	26.7
High heating value, Btu/lb									
As fired	11450	12450	13410	11960	10700	10200	8530	8175	6380
Moisture-ash free	15060	15040	14920	14340	13380	13300	12320	12180	11770
Ultimate Analysis (MAF), %:									
Hydrogen	5.1	5.1	5.6	5.9	5.5	5.7	4.1	4.5	4.3
Carbon	85.0	82.7	82.5	80.0	74.3	73.8	72.7	72.4	69.6
Sulfur	2.6	3.1	2.5	0.0	4.0	0.6	0.8	0.8	1.4
Nitrogen	1.5	1.6	1.5	1.4	1.4	1.5	2.3	1.7	1.0
Oxygen	4.8	7.5	7.9	11.9	14.8	18.2	20.1	20.6	23.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Flammability index, F	1010	1030	950	1030	990	970	960	990	840

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bituminous coals and lignite are nonagglomerating. Since the particles do not go through a melting stage, they retain a larger surface area per unit mass and, consequently, do not require as fine pulverization to assure burnout.

Also important in assessing coal reacitivity is the fuel oxygen content. Experience has confirmed that subbituminous coals and lignites are much more reactive than bituminous coals. This reactivity, as reflected by the ease and stability of ignition, burnout rate, etc., seems to be directly related to the coal-contained oxygen levels. Data in Table III indicates that subbituminous coals and lignite contain oxygen percentages from 18 to 25 percent, while the less reactive bituminous coals range from 5 to 15 percent. In the combustion process, the high inherent oxygen results in more rapid ignition and complete combustion of the coal particles and, therefore, a lesser degree of fineness of the pulverizer product is required to insure complete carbon burnout.

While this high inherent oxygen content is an advantage when fired in the furnace, low-rank coals have a greater potential for fires in transportation and storage. The rate of oxidation is usually high and, as a result, subbituminous coals and lignite are more prone to spontaneous ignition. Also, the high seam moisture of low-rank coals is conducive to size degradation and the fines produced contribute to excessive dust in handling, which further increases the potential for spontaneous ignition in transportation and storage.

The ignition and carbon burnout characteristics of most U.S. coals is well known and, with the possible exception of some low volatile matter Eastern bituminous coals and, of course, anthracite, there is no need for extensive laboratory investigations into combustion characteristics. However, when the designer encounters an unfamiliar coal whose bench scale tests for volatile and oxygen content indicate there may be some difficulty with ignition stability or high unburned carbon in the residue, he has available to him several additional laboratory tests for gaining insight into the coal's combustion characteristics. Among these, C-E has found the following to be most useful:

- Flammability Index (Fig. 3). The flammability index is a relative ignition temperature obtained by running tests under a given set of conditions in a specific apparatus. Briefly, testing involves firing 0.2 gram of pulverized coal (typically 100 percent through 200 mesh) in an oxygen atmosphere through a preheated furnace. The temperature of the furnace is increased incrementally until a point is reached at which the fuel ignites. This temperature is called the Flammability Index. The value of the Flammability Index compared to other fuels indicates the ignition temperature/stability on a relative basis. (See Table III.)

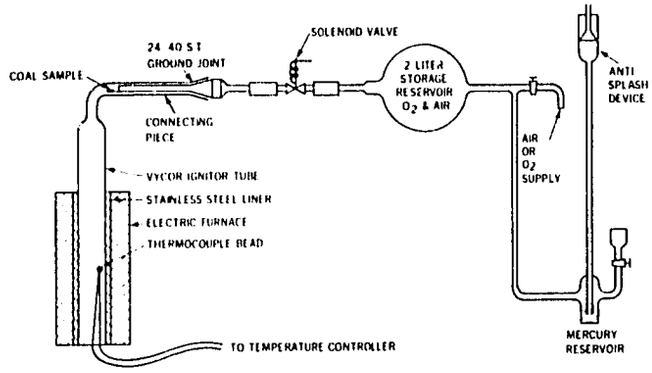

Fig. 3: Schematic of flammability apparatus

- Thermo-Gravimetric Analysis. The model TGS-2 Thermo-Gravimetric System made by Perkin Elmer Corp. is used to determine char reactivities under isothermal conditions by accurately recording the rate of weight change of a sample as it is subjected to a precisely controlled temperature environment. To make a thermo-gravimetric reactivity analysis, a char from the fuel is prepared according to the ASTM D-271 volatile matter determination method. It is then sized to 100 percent through 200 mesh. A 4-6 mg sample is placed in the TGS-2 system and heated in the presence of nitrogen at 20 C/min to 700 C. After stabilization at this temperature, air is introduced to burn off the fixed carbon. Percent weight of the unburned char and rate of weight loss are recorded on a strip chart as a function of time. These thermograms are subsequently used to determine the char's burn-off (combustion efficiency) history. A comparison to thermograms of known fuels gives a good indication of how the unfamiliar fuel will behave in a large furnace.

- Specific Surface Area Measurement. The principal of physical adsorption of gases is used to determine the specific surface areas of char samples prepared according to ASTM volatile matter determination method and sized to 100% through 200 mesh. Nitrogen adsorption and desorption measurements at specific temperatures are used to determine the sample's surface area as well as pore size and size distribution. Some typical values for U.S. coals, expressed in m^2/gram, are: Pennsylvania anthracite - 19.5, Kentucky bituminous - 36.9, Wyoming subbituminous - 99.8 and Texas lignite - 269.

- Drop Tube Furnace System (Fig. 4). The unit consists of a feed system, two temperature-controlled (up to 2800 F)

furnaces - one for air preheat and another for studying combustion/gasification, a solid/gas sampling system and a gas analysis system. The principle of operation is as follows: (i) feed pulverized char particles into the furnace reaction zone at a known rate (0.05-5 g/min), (ii) raise the temperature of these particles as rapidly as possible (at approximately 10^4 C/sec) to the predetermined combustion medium temperature, (iii), allow the combustion of these particles to occur isothermally at this temperature for a specified time, (iv) quench the combustion reactions as rapidly as possible (at approximately 10^4C/sec), and (v) separate the solid from the gaseous products. The gas is sent to on line analysis for CO, CO_2, O_2, and NO_x. The solids are subsequently analyzed to determine combustion efficiencies. Temperature is measured on line with a mini-suction pyrometer. By determining combustion efficiencies as a function of time under known oxygen concentrations and temperatures it is possible to predict burnout rates in the field.

FURNACE AND CONVECTION PASS

Both the amount and the specific nature of mineral matter in coal are significant to performance of furnace and convection pass heat transfer surface. The ash produced requires handling and disposal, has a potential for generating accumulations for the slagging and fouling of boiler surfaces, can accelerate metal loss by either corrosion or erosion mechanisms, and requires special consideration in regard to stack particulate emissions. Rather than relate the ash to a weight percentage, it is more realistic to define it in terms of energy input, usually expressed as pounds of ash per million Btu fired.

Ash compositions listed in Table I represent coals across the U.S. from both Eastern and Western deposits. In general, coal ash will have certain properties that are typical to a broad geographical location. Most coals from the Appalachian, Eastern, and Midwest Interior deposits have ash with an iron content (Fe_2O_3) higher than the combined

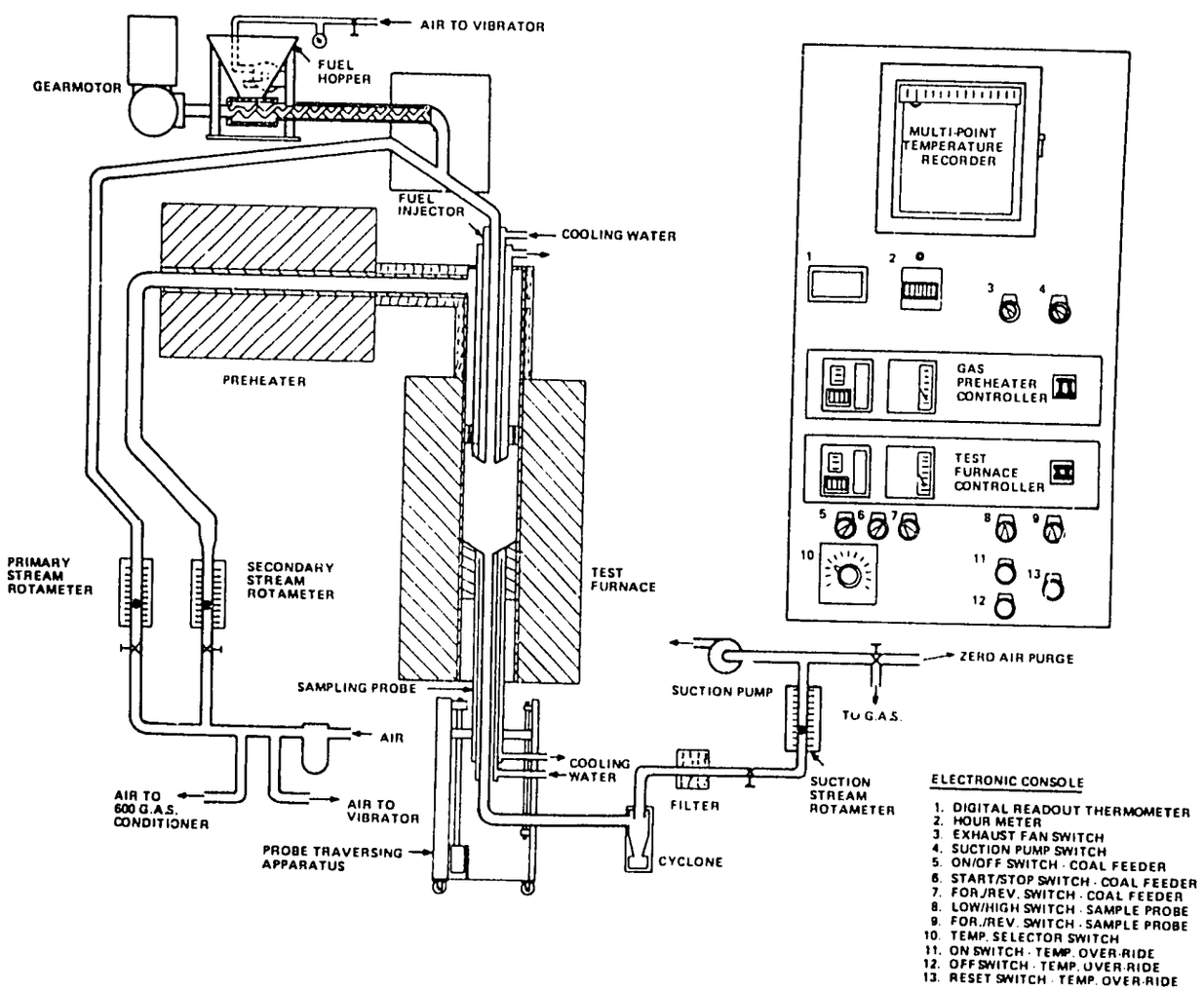

Fig. 4: Schematic of the drop tube furnace system

alkaline earth-alkali oxides (CaO, MgO, Na_2O, and K_2O). Coals west of the Mississippi including both the Rocky Mountain area and the North Dakota plains, contain ash having a higher alkaline (CaO, MgO, Na_2O, and K_2O) content than the iron oxide percentage.

The following fuel ash properties are considered important to the design and performance:

- Ash fusibility temperatures.
- Iron content and type.
- Active alkalai content.
- Ratio of basic to acidic ash constituents.
- Iron/calcium ratio.
- Fuel ash content in terms of lbs of ash/million Btu.

Ash Fusibility Temperatures

Ash fusibility has long been recognized as a tool for measuring the deposit buildup and slagging performance of coals. It is perhaps the most basic single means for predicting coal ash performance. The differential between initial deformation and the fluid point temperatures of the ash is also important. The lower the differential, the less the opportunity, at a given particle residence time, to cool the ash particles by heat transfer to boiler surfaces and avoid excessive slag buildup and running slag. Fusibility temperatures are related to ash performance in the steam generating unit as described below.

If ash arrives at the heat-absorbing surface at a temperature near its softening temperature, the resulting deposit is apt to be porous in structure. Depending on the strength of the bond, this may fall off from its own weight or may be removed by sootblowing. It ash particles arrive at the heat-absorbing surfaces at temperatures less than the softening temperature, they are apt to form no bonded structure and will settle out as dust. However, if ash particles have been subjected to temperatures higher than the softening temperature for sufficient time to become plastic or liquid, the resulting deposit is apt to be a fused mass condensed on the cooler metal surface, with the re-solidified material being tightly bonded and difficult to remove. As this material builds up on itself, its insulating properties further increase the surface temperature, until the ash fluid temperature is reached with resulting runoff.

Fusibility temperatures measured in the laboratory reflect the chemical makeup of the total ash and will vary with the ash composition. However, as the result of selective deposition of ash components, furnace performance is more apt to reflect low-melting components that will alter deposit behavior if present in sufficient quantities.

Iron Content and Type

In predicting the behavior of mineral matter during combustion, it is important to analyze coal in the size range at which it is being used because segregation of mineral matter is a function of particle size. As each particle is different, it would be ideal to analyze and quantify individual particles; however, this would prove to be difficult and costly. As a practical alternative to analyzing individual particles, a gravity fractionation technique has been applied.

The procedure developed in Combustion Engineering's Kreisinger Development Laboratory requires that the coal be pulverized to the same fineness as that during firing; the coal particles then are separated by density, using various mixtures of organic liquids having specific gravities of 1.3, 1.5, 1.7, 1.9, 2.1, 2.5, and 2.9 as illustrated in Fig. 5. Fewer separations might be adequate, but as the procedure was being developed a finer resolution of gravity fractions was found desirable. After separation, the eight fractions are air-dried at 250 F and submitted for the following analyses: percent ash, ash composition, ash fusibility, and, optionally, X-ray diffraction. Compositional differences among the gravity fractions represent the most important data obtained, since fusibility temperatures of ash contained in the gravity fractions are determined by composition. Results compare composition and behavior of the ash deposit.

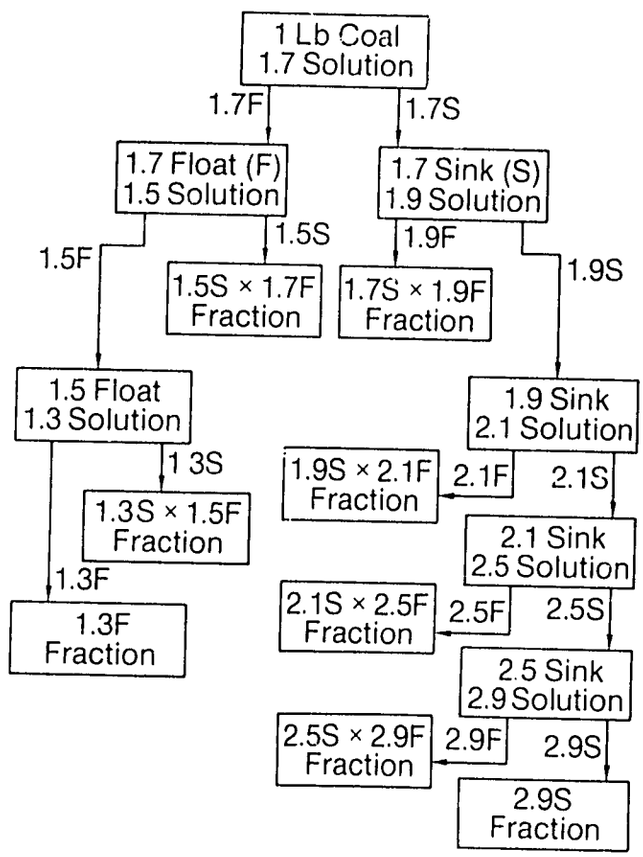

Fig. 5: Gravity separation procedure

The role of iron is one of the more important factors in assessing slagging potential. Investigators frequently use the total iron concentration in a coal ash to assess the slagging potential; however, this iron value could be misleading as it does not account for the distribution of iron compounds in the coal matrix. In addition to the importance of the distribution of mineral matter within the coal matrix, the type of minerals also plays a role in the ash deposition process. For example, iron is frequently present as pyrites (FeS_2) and carbonates ($FeCO_3$) and/or as an impurity in calcite and dolomite. Pyrites will more likely exist as discrete particles within the heavier gravity coal fractions, whereas carbonates are more likely to be disseminated throughout the coal matrix and not show a concentration with gravity fractionation. The occurrence of these and other iron-containing minerals and their degree of segregation in the coal matrix are functions of "coalification," i.e. the coal formation process.

Iron compounds in the "2.9 sink" are given special emphasis as they often contain mostly pyrites, which can cause slagging. Iron compounds that are not uniformly distributed throughout the coal matrix have high potential for slagging. This concept correlates well with field results.

Active Alkali

While ash deposit formation is a complex phenomenon depending on many variables, it is recognized that alkali metals play important roles in ash deposition. The mechanism for alkali-induced deposition in boiler convection sections is believed to be the vaporization and subsequent condensation of the alkalies. Alkalies also act as strong fluxing agents, reducing the melting temperatures of most mixtures of ash constituents They form the glue that causes ash particles to stick to the tubes and to each other in the convection sections.

Unfortunately, the total concentrations of the alkalies, which is what is measured by conventional ash analyses, are not always accurate indices of potential fouling. In the combustion process, the fouling reactions are influenced as much by the nature of the alkali as by the total amount of the alkali. It is, therefore, desirable to separate the total alkalies into meaningful categories that may be related to fouling behavior. Alkali may be separated into two general categories as follows:

1. "Active alkalies" are alkalies that readily vaporize during combustion and are, therefore, available to react chemically and physically downstream in the boiler. These active alkalies are readily extracted from coal by leaching in a weak solution of acetic acid.

2. "Inactive alkalies" are more stable forms, contained in mineral impurities, which remain relatively inert during the combustion process and are less influential in ash deposition. The inactive alkalies are not extracted from coal by leaching in a weak solution of acetic acid.

Out of all the alkali and alkaline earth metals (sodium, potassium, calcium, magnesium, etc.) that are leachable by a weak acetic acid solution, the active sodium has been found by C-E to correlate well with the degree of fouling in utility boilers. Coals containing large amounts of active sodium generally do result in a high degree of fouling in the convective surfaces of the boilers.

Results of acetic acid soluble alkali tests are presented in Table IV. Included are nine coals: eight from the U.S. and one from Australia. They are ranked in terms of fouling potential with coals having the highest fouling potential on the left, and coal having the lowest fouling potential on the right. Fouling potential has been confirmed by both field observations and pilot scale tests.

In general, potassium is not very significant as a fouling indicator for these fuels. Its content in each of the coal ashes is low (below 2 percent), and its soluble or active content is very low (below 0.5 percent). The sodium content for the nine fuels varies considerably. In general, the high sodium coals (Beulah North Dakota lignite, Decker) exhibit very high fouling potentials, while the low sodium coals (Kittaning, Wilcox Texas lignite burned at Big Brown) exhibit low fouling potentials.

A number of anomalies exist, however. The Hiawatha (Utah) coal has a sodium content (expressed as Na_2O on an ash basis) of 3.8 percent, yet it only has a moderate fouling potential. Two Texas lignites, both from the same seam (Wilcox), have similar sodium contents (0.7 and 0.9 percent), yet one exhibits a low fouling potential, while the other exhibits a moderate fouling potential.

These anomalies can be attributed to the different soluble sodium content of these coals. Although the Utah coal has 3.8 percent sodium, less than half is soluble sodium. The Wilcox lignites have essentially the same sodium content, but the one with the moderate fouling potential has 0.71 percent soluble sodium, while the other with the low fouling potential has 0.16 percent soluble sodium.

The soluble sodium content of the fuels correlates well with fouling potential (much better than total sodium content) and is generally believed to represent "active sodium." This sodium, being loosely held in the coal, vaporizes during combustion and condenses as a glue-like material in the convective sections causing fouling.* This loosely bound sodium may exist as simple inorganic constituents (sodium chloride for example) or it may be organically bound to the coal in an ion exchange fashion (Fig. 6). It is, therefore, leachable by a weak acid such as acetic acid.

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* In Table IV, some of the coals are shown as having soluble sodium contents higher than their total sodium. This is because total sodium is determined on ASTM ash, and some of the volatile sodium may be vaporized and lost during the ashing process.

TABLE IV

ACTIVE ALKALI CONTENT VS. FOULING POTENTIAL FOR U. S. AND AUSTRALIAN COAL

Coal	Beulah	Decker	Oxbow	Yegua	Wilcox (Martin Lake)	Hiawatha	Kittaning	Wilcox (Big Brown)	Ramrod Creek
Rank	Lignite	Sub B	Lignite	Lignite	Lignite	HvBb	HvAb	Lignite	HvBb
Region	N. Dakota	Montana	Louisiana	Texas	Texas	Utah	Penn	Texas	Australia (New So. Wales)
Fouling potential	Severe	Severe/High	Severe/High	High	Moderate	Moderate	Low	Low	Low
Ash, % dry coal basis	9.6	5.6	10.0	33.5	19.5	10.1	22.6	29.0	24.2
Acetic acid soluble, ppm dry coal basis									
Sodium, Na	3980	2680	4300	9650	1030	1120	250	340	131
Potassium, K	–	–	85	1230	85	85	–	110	–
Total alkali, % ash basis									
Na_2O	5.0	5.8	6.1	3.6	0.9	3.8	0.4	0.7	0.2
K_2O	0.5	1.6	0.7	1.9	1.2	0.9	1.7	0.8	–
Soluble alkali, % ash basis									
Na_2O	5.58	6.45	5.8	3.88	0.71	1.49	0.15	0.16	0.07
K_2O	–	–	0.2	0.44	0.04	0.08	–	0.05	–
Relative soluble alkali, %									
Na_2O	112%	111%	96%	108%	79%	39%	38%	23%	35%
K_2O	–	–	29%	–	3%	9%	–	6%	–

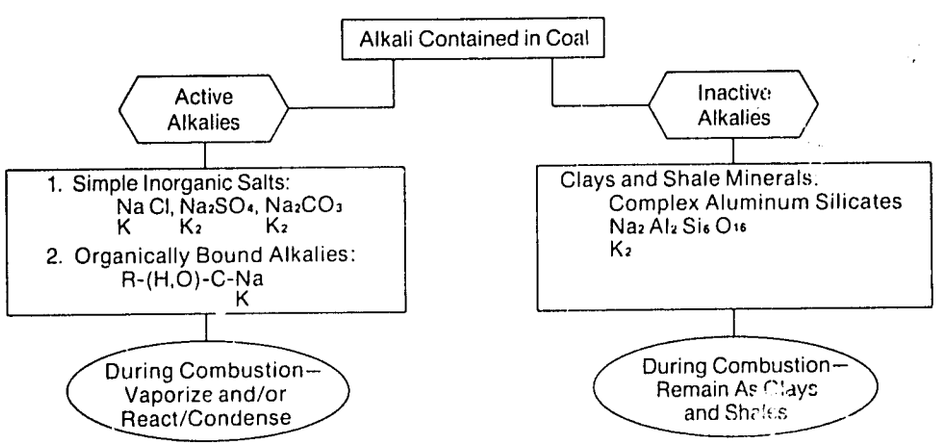

Fig. 6: Manner in which alkalies are contained in coal

Base/Acid Ratio

The base/acid ratio,

$$\frac{Fe_2O_3 + CaO + MgO + Na_2O + K_2O}{SiO_2 + Al_2O_3 + TiO_2}$$

which is reflected in ash fusibility temperatures, is a good tool for understanding ash performance in the furnace. It relates opposing chemical properties to each other, showing the potential for interaction between them. Acid oxides are generally considered to produce high melting ash temperatures and will be lowered proportionally by the relative amounts of basic oxides available for reaction. Generally, ratios below 0.25 indicate such an excess of acidic elements that fusibility temperatures are relatively high. Most Western U.S. coals contain ash having a high total percentage of calcium, magnesium, sodium, and

potassium. Deposit buildup in units burning high calcium/low iron coals is both rapid and more extensive than that experienced with units burning Eastern coal. Typical deposits from such Western coals, however, are a light weight, loosely self-bonded material that provides a soft bond to tube surfaces and responds readily to removal by sootblowing. Because buildup is rapid, transverse tube spacings are maintained on wide centers to minimize bridging. As the active sodium content increases, both the rate and density of the buildup increases.

Expressing base/acid ratios simply as total weight-percentage relationships does not take stoichiometric relationships into account nor does it differentiate between levels of chemical reactivity. Therefore, ash compositions may have the same base/acid ratio and reflect different melting characteristics and furnace behavior phenomena. Certain subordinate indices are used to further amplify the base/acid ratio. One of these is the iron/calcium ratio.

Iron/Calcium Ratio (Fe_2O_3/CaO)

While both compounds are considered to give basic reactions, there is a complex interrelationship between the two that may produce an eutectic with a lower melting temperature than that produced by either acting alone. Effects of lowered fusibility temperatures are evident between ratios of 3 and 0.3. Typical Western ash will have ratios less than one and will show lower ash fusibility temperatures as the ratio approaches one.

Fuel Ash Content

The amount of ash per million Btu fired can affect the furnace ash buildup and slagging rate; the fouling of superheater, reheater, and air heater surfaces; the unburned carbon loss; the amount of particulate emission discharged in the flue gas; and the quantity of bottom ash for disposal.

CONCLUSION

With the above information in hand, the experienced designer can design a steam generator that will perform as predicted and have the reliability demanded by utility and industrial purchasers. The word "experienced" is emphasized because without an extensive data base of operating experience with coal-fired steam generators, all of the information developed in the laboratory has only superficial value. Successful designs result from open-minded application of accurate representative laboratory data coupled with operating histories from similar equipment. Both ingredients are essential.

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SLAGGING AND FOULING PROPERTIES OF COAL ASH DEPOSITS AS DETERMINED IN A LABORATORY TEST FACILITY

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WINDSOR, CONNECTICUT

PRESENTED AT

THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
WINTER ANNUAL MEETING

NOVEMBER 28 - DECEMBER 3, 1977
ATLANTA, GEORGIA

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SLAGGING AND FOULING PROPERTIES OF COAL ASH DEPOSITS AS DETERMINED IN A LABORATORY TEST FACILITY

INTRODUCTION

A major problem in the design and operation of furnaces of coal-fired boilers is the management of the ash produced when coal is burned. Ash deposits introduce several problems. The mineral matter may form tenacious deposits on waterwall surfaces, thus insulating the heat transfer portions of the furnace. Also, the presence of ash introduces mechanical problems associated with the operation of slag and ash removal equipment from radiant and convective heat transfer surfaces. The knowledge of the behavior of ash in coal-fired units is a basic requirement to their performance and availability in operation. This paper will report the experimental studies of coal ash characteristics and relate the results to ash and slag formation in coal burning units.

Ash deposit problems can affect the safe and effective operation of boilers. Pluggage of heat transfer surface may prevent the boiler from meeting system power demands. It may not be feasible to operate continuously at the maximum continuous rating for which the boiler was designed. Heavy furnace ash deposits may require an excessive amount of desuperheat spray water to maintain the required outlet steam temperature without overheating the superheater and reheater surfaces. In extreme cases, it may be necessary to drop boiler load where heavy slag accumulation cannot be prevented by the use of sootblowers. Large slag drops from the top of the furnace may force the unit off the line. This experience has led boiler designers to design large furnaces with more conservative heat release rates in an effort to maintain reliable operation. It is evident that coal ash characteristics must receive a critical analysis before completing a design of boilers for utility service.

Combustion Engineering has had a continuing program of investigation of ash characteristics of a wide variety of coals being burned in utility and industrial boilers. This work includes the bench scale analysis of coal, the evaluation of coal ash deposits in laboratory furnaces, and the effect of ash deposits on performance of units in the field. The data generated by the three types of analyses has provided valuable design information when it is used to complement each other.

Characterization of ash deposits by quantitative methods is necessary in the development of a consistent data base for correlation of coal properties and ash characteristics for design purposes. The coals used in developing the data base are those currently being burned in C-E's utility boilers. Data obtained from field performance tests are used to calibrate the data generated in laboratory furnaces. This data can be used by the designer with confidence when planning a unit for a new fuel source.

The pilot scale evaluation of coal ash deposits is a critical segment of the program, and it will be addressed in detail in our presentation The pilot scale Solid Fuel Burning Test Facility is used to develop a standardized test procedure for the quantitative analysis of coal ash deposits formed in the combustion of pulverized coal. In this paper we will also illustrate how the data from the pilot scale measurements can be used to rank coals as to their slagging and fouling behavior.

RESEARCH FACILITIES

The Solid Fuel Burning Test Facility (Fig. 1) at C-E's Kreisinger Development Laboratory, consists of coal preparation equipment, an air preheater, and the solid fuel burning test furnace (SFBTF) with its simulated lower and upper furnace heat transfer surfaces. Crushed coal (1½ inch top size) is fed from a 5-ton capacity outside storage hopper to a C-E Model 271 bowl mill where it is pulverized to approximately 75 percent minus 200 mesh. The small, deep-bowl, single-journal (roller) mill is equipped with a direct gas-fired air heater to provide mill drying air. The pulverized coal is pneumatically transported to a cyclone collector where most of the coal is dropped into a 3-ton capacity storage hopper. Fines in the cyclone effluent are collected in a bag filter and returned to the storage hopper. Pulverized coal is fed by a belt-type gravimetric feeder from the hopper into a vibrating trough, from which it is pneumatically transported into the furnace by an air operated aspirator.

Secondary air can be heated to 800 F in an indirect gas-fired preheater. Secondary air is introduced into the SFBTF (Fig. 2) at the burner through the annulus surrounding the coal/air feed pipe. At the exit of the annulus are adjustable vanes, which can be controlled to promote a swirling-type flame, which promotes good mixing between the primary air/fuel and secondary air streams.

The furnace itself consists of a refractory-lined 30 inch I.D. cylinder, 13.7 feet in height. A two-inch thick refractory lining helps to reduce potentially high heat losses caused by a large surface-to-volume ratio, 1.6 ft^2/ft^3. Furnace cooling is provided primarily by air passing through a 1½ inch annulus surrounding the refractory lining and, to a lesser extent, by a refractory-lined, water-cooled roof.

Flue gases leave the furnace through a horizontal water-cooled superheater duct having a one square foot cross sectional area. The duct section of the furnace is designed to simulate the superheater/reheater section of a commercial boiler, and consists of five sections totaling 13 feet in length. Four banks of eight-inch long, 1½ inch diameter air-cooled probes are used to simulate superheater tubes. Each bank contains two rows of probes. The probes are inserted vertically into the duct

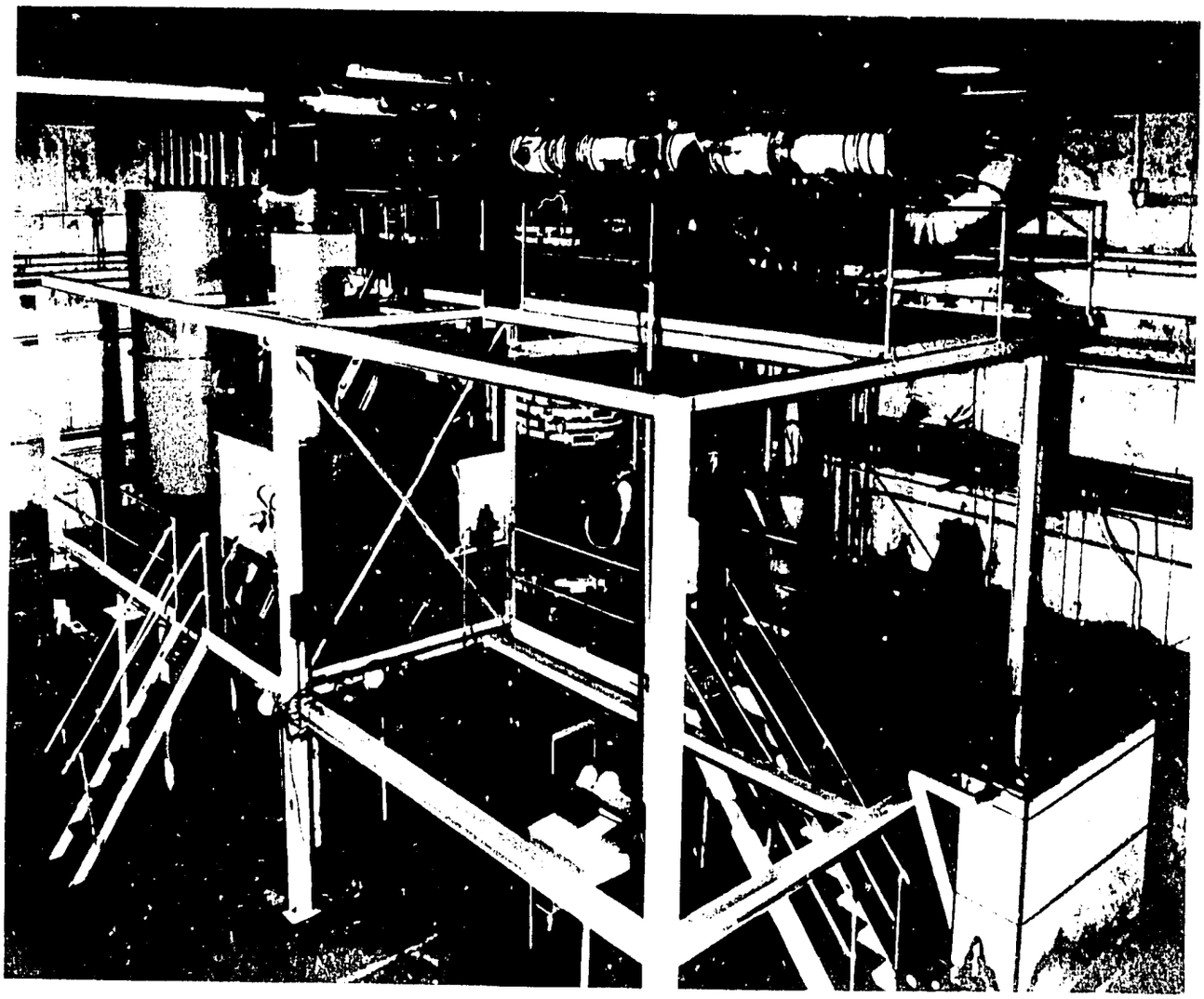

Fig. 1a: The solid fuel burning test facility (SFBTF)

and are located between 18 and 40 inches downstream from the furnace outlet (Fig. 3).

The furnace is equipped with a waterwall test panel to study lower furnace ash deposition. The test panel, designed to simulate the conditions in the lower furnace of a commercial boiler, is located approximately three feet above the burner and has 1.5 ft^2 of surface area. Therminol 66, a high boiling organic liquid, flows in a closed loop through the panel. Panel surface temperature is controlled by the Therminol temperature and mass flow rate. Heat flux through the panel is monitored by the Therminol flow rate and its inlet and outlet temperature.

Effective thermal conductivity measurements are performed in situ on the waterwall panel deposit. A water-cooled tube passes through the flame and establishes the alignment of panel thermocouples for measurements of deposit temperature and thickness (Fig. 4). The tube is supported by two rotating rings contained in a mechanical jig allowing easy alignment. The tube rotates on the same radius as the panel curvature to reduce the probability of deposit thickness measurement errors due to misalignment.

The conductive heat transfer characteristics of lower furnace deposits are determined in situ. Radiation interference from the flame and from the refractory lining makes it very difficult to use an in situ method to deposit radiative heat transfer characteristics. Consequently, a bench scale apparatus has been established for determining the emissivities (from which absorptivities can be calculated) of furnace ash deposits.

Deposits for emissivity measurement are collected on a platinum-rhodium disk which is mounted on a probe that is inserted into the SFBTF. The deposit-laden disks are then transferred to the bench scale emissivity apparatus (Fig. 5). The disk is mounted on a ceramic sample holder and heated from below by a gas/oxygen flame. Radiation from the sample travels up a water-cooled collimating jacket, reflects off two mirrors and passes into a monochromator and detector, which measure the radiation emanating from the sample at a given wavelength. Scans can be performed at a wide

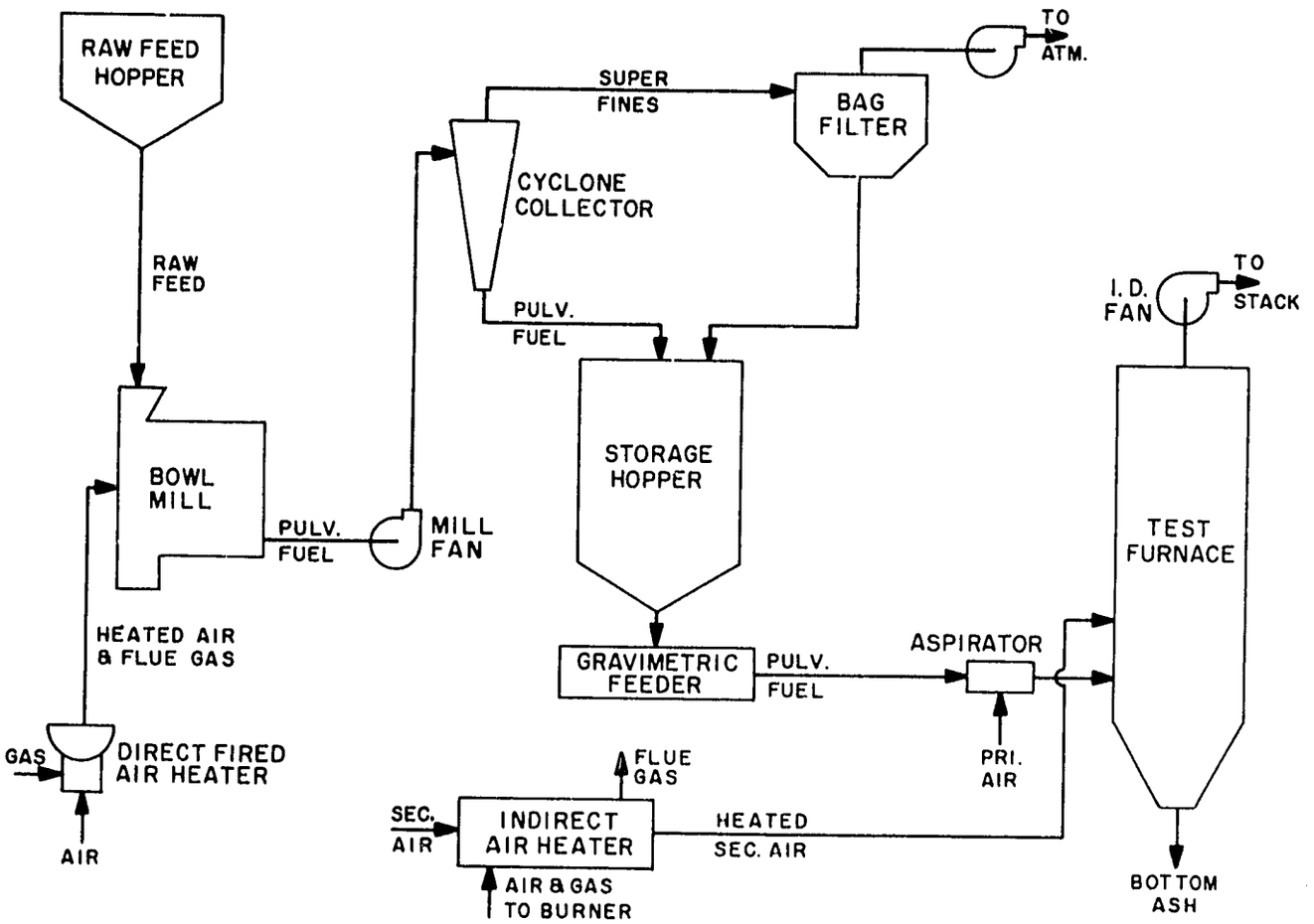

Fig. 1b: Schematic of SFBTF

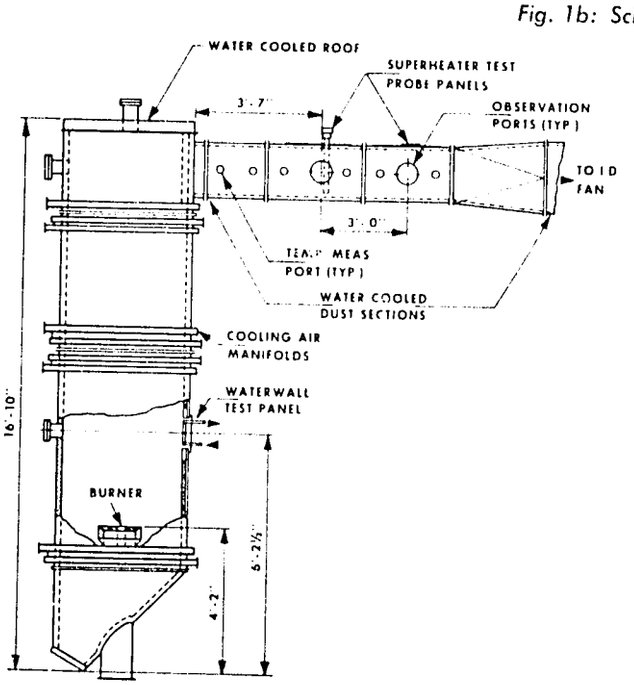

Fig. 2: Schematic of solid fuel burning test furnace

range of wavelengths. The signal is sent on to a readout control unit and recorder. The emissivity apparatus is calibrated by measuring the radiation from a black body furnace which contains a temperature controlled refractory spherical enclosure. Spectral emissivities are determined by comparing sample radiation with black body radiation.

TEST PROGRAM PROCEDURE

Standardized SFBTF tests have been developed to permit a comprehensive study of the influence of furnace operating parameters on ash deposition. The comparison of results from several coals tested under these standard conditions allows the evaluation of relative ash deposit characteristics as a function of fuel properties.

Each standardized ash deposit characterization test consists of a series of three individual trials conducted at firing rates of 2.25, 3.0, and 3.75×10^6 Btu/hr, respectively. The test sequence that is carried out at each firing rate is shown in Fig. 6. The total time span for each test is sixty hours, including more than forty hours of continuous coal firing.

A test sequence begins with a furnace warm-up period followed by a transition to coal. Once on coal, a three hour period is allowed for thermal stabilization at test conditions. All superheater probe deposits are removed at this time, and the first phase of the pressure drop tests (Pressure Drop Test I) is started.

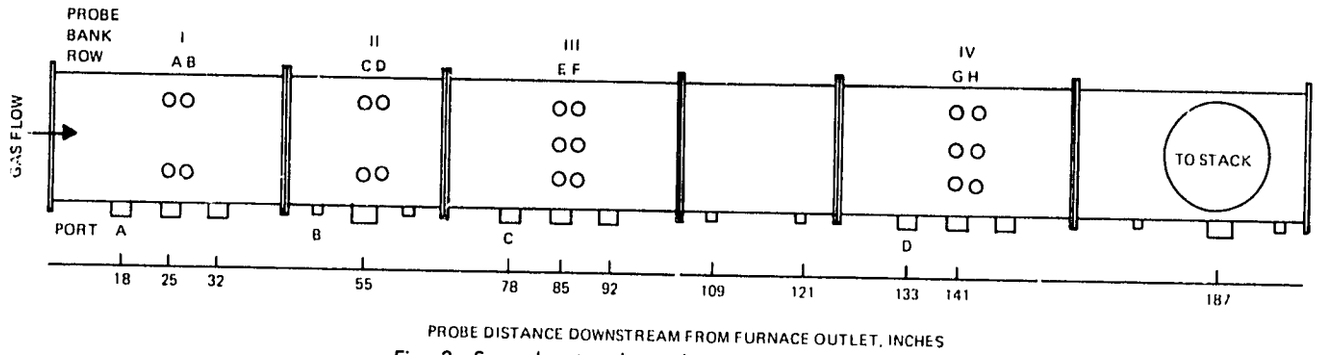

Fig. 3: Superheater ducts showing probe locations

During the pressure drop tests, the time required for deposits to build up to a standard resistance is recorded. Pressure Drop Test I is conducted with the first probe bank (Probe Bank I) removed. Upon completion of this 20 hour segment of the test, Probe Bank I is installed, on line, in the higher temperature gas stream preceding the other probe banks. A three hour interval is allowed for Probe Bank I to reach equilibrium, then all probe deposits are removed and the second phase of the pressure drop tests (Pressure Drop Test II) is conducted. The purpose of Pressure Drop Test II is to evaluate the effect of higher gas temperatures and probe location on ash deposition.

Following Pressure Drop Test II, the superheater probes are thoroughly cleaned, and the Deposit Buildup Test is begun. During this test, the mass of deposits accumulated on the probes during a standard time period is quantified. After the eight-hour buildup test, the furnace is shut down.

Lower furnace waterwall panel data are collected simultaneously during the entire test sequence. Waterwall panel coolant flow rate along with inlet and outlet temperatures are recorded continuously during the entire test sequence. Furnace operating data is logged hourly. Observations concerning deposit characteristics are carefully noted and superheater probe deposit growth is documented with photographs.

During the shutdown period (10 hours), deposit accumulation is collected and weighed. Samples of deposits are collected from each row of the superheater probes and from the waterwall panel. Samples are carefully separated into individual layers for later analysis. Analyses are also obtained on a composite sample of pulverized coal feed. Analytical data includes ash composition, fusibility temperatures, deposit density, and water and acid soluble alkalies.

Upper Furnace Deposit Characterization

The test facility has been designed and a standardized test procedure developed that allows separate characterization of coal ash deposits forming in the radiant (lower furnace) and convection (upper furnace) sections. For the upper furnace, superheater probe deposits are characterized as a function of firing rate, gas temperature and probe location. Deposits are evaluated in terms of buildup rate, bonding strength, physical properties (physical state, appearance, density, etc.), and chemical properties. Superheater deposition is studied by two methods:

1. Pressure drop tests
2. Deposit buildup tests

One method of quantifying deposit buildup is to establish the frequency of soot blowing in the SFBTF. Frequency of soot blowing is determined by the increase in pressure drop across the leading probe bank. Ash deposit growth is monitored both visually and measured by the pressure differential across the probe bank. When deposit buildup produces a specified resistance (standard ΔP), the deposits are removed with an air lance. The time required to reach the standard pressure drop indicates the frequency of soot blowing in the SFBTF.

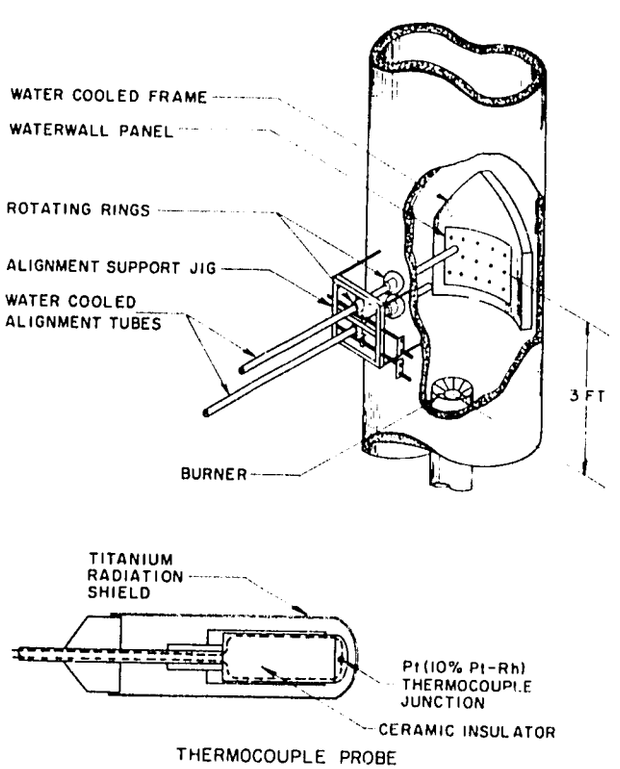

Fig. 4: Waterwall panel and test hardware

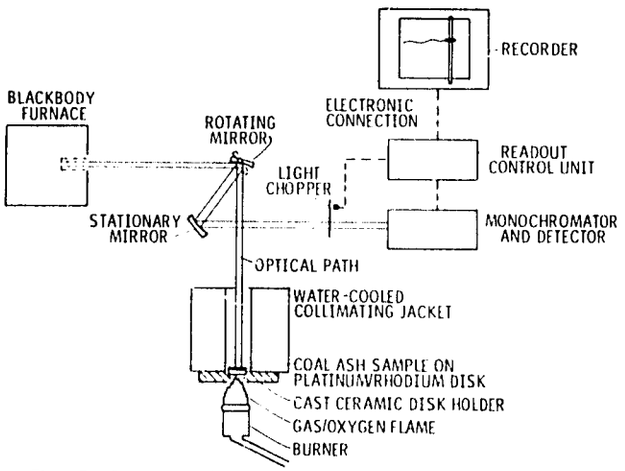

Fig. 5: Bench-scale apparatus for determining ash deposit thermal properties

The pressure drop tests establish time required for superheater probe deposits to accumulate causing a given resistance to gas flow. The deposit buildup tests establish the mass of deposit accumulated during a given period. The final eight hours of the test sequence is allotted for collection of superheater probe deposits. At the conclusion of this sequence, the ash deposits accumulated on each probe bank are collected and weighed. The weights of these deposits indicate the relative quantity of ash deposition from the test coal at the given conditions in the SFBTF.

The tenacity of the bond between the deposit and the heat transfer surface is the primary factor in determining the cleanability (degree of difficulty in removing deposits by soot blowing) of the ash deposits. A technique was developed to obtain a quantitative measure of the relative bonding strength of superheater probe deposits. A surface penetrometer was adapted to measure the force required to push the deposit off the probe surface. (The penetrometer measures the deflection of a calibrated spring and is commonly used during the soil compression evaluations.)

Bonding measurements are performed in situ during the repeat cycles of the pressure drop tests. Evaluations are made at a time when the pressure drop across the probe bank has reached a standard value. Measurements of bonding strength are made with the direction of the force applied perpendicular to the bond and tangent to the probe surface (Fig. 7).

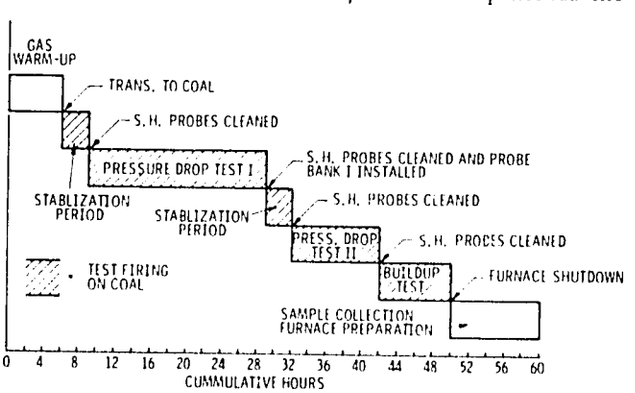

Fig. 6: Coal ash deposit characterization SFBTF test sequence

Lower Furnace Deposit Characterization

Lower ash deposition is studied primarily with the aid of a heat transfer panel simulating a waterwall surface. Panel coolant flow rate and the coolant temperature increase through the panel are continuously recorded providing a history of the heat flux through the panel during the test period. The temperature differential is directly measured by detecting the voltage differential between two calibrated thermocouples to increase the precision.

The extent to which ash deposits impede heat transfer is reflected by the panel heat flux. Variations of heat flux are attributed to the combined effect of the quantity of deposits and the thermal properties of these deposits (thermal conductivity, absorptivity, emissivity). In order to help characterize waterwall deposition, three indices

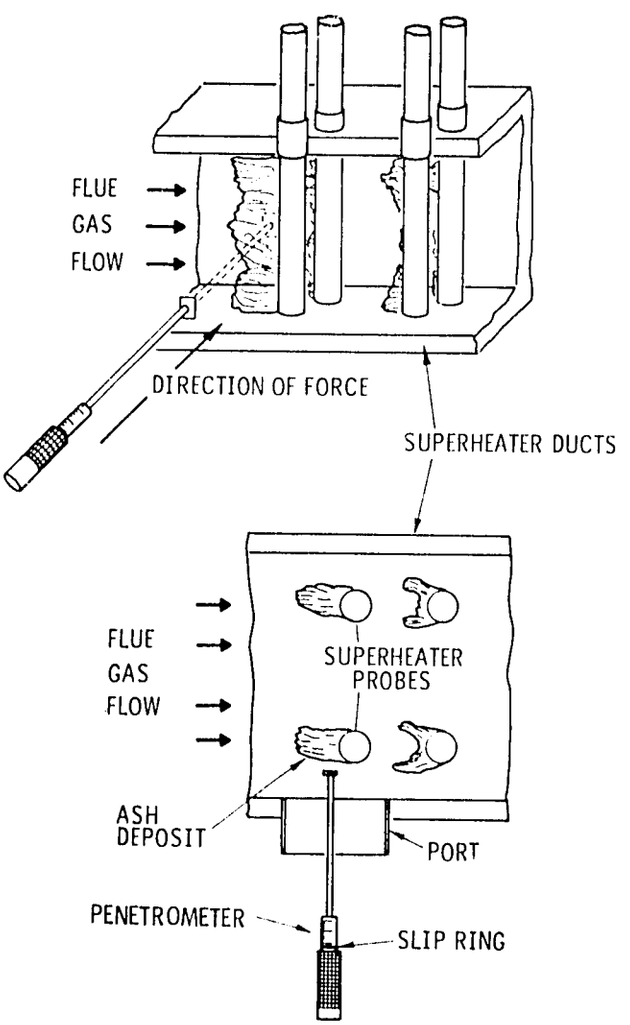

Fig. 7: Superheater deposit bonding strength measurement

were derived based on the panel heat flux curves (heat vs time).

- The average heat flux/total heat input is an index that reflects the average effects of ash deposition on heat transfer. Dividing by the total furnace heat input helps to normalize the index for minor variations in firing rate (flame temperature).
- The average cycle time is the period during which the deposits build up and slough off. This index is influenced by the rate of deposit buildup and the deposit bonding strength. Cycle time used in conjunction with average heat flux provides an indication of the range of deposit thermal resistance.
- The ratio of the average heat flux over the final twelve hours of the test to the heat flux of the clean panel is an index developed to reflect long term nature of the deposit. Well bonded deposits of high thermal resistance would yield a low ratio. As the effect of ash deposition on heat transfer decreases, the ratio would approach unity.

In Situ Measurement of Effective Thermal Conductivity of Waterwall Ash Deposits

The thermal conductivity of a deposit can be determined by measuring the rate of heat flow through a known thickness of deposit at a known thermal gradient.

$$q/A = k\Delta T/\Delta X$$

where,

q/A = Heat flux through the deposit
k = Thermal conductivity of the deposit
ΔT = Temperature gradient across the deposit
ΔX = Deposit thickness

The determination of q/A, heat flux, has already been discussed. The heat flux is calculated from the total heat absorbed by the panel and is, therefore, an average value. The temperature gradient is calculated from the surface temperature of the deposit and the metal temperature of the panel. Deposit thickness is determined by measuring the change in distance from a stationary reference to the clean panel surface to the deposit surface. Deposit thickness measurements and deposit surface temperature measurements are taken at ten locations across the panel. At each of these locations, iron constantan thermocouples are embedded in the panel metal. Deposit surface temperature is measured with a platinum 10% platinum-rhodium thermocouple.

DISCUSSION OF RESULTS

Although the program is still in progress, a number of generalized observations have been noted. A consistent difference has been observed between ash deposit characteristics of high rank Eastern coals and low rank Western coals.

With high rank Eastern coals, the predominant constituent in the ash relative to ash deposition is iron. With low rank Western coals, the key constituents are alkalies and alkaline earths. The iron in Eastern coals is generally present in more segregated form than the alkalies and alkaline earths in Western coals. The result is that where an ash deposition problem exists with high rank Eastern coals, it generally involves selective deposition of iron containing materials in the lower furnace. Extreme cases of selective deposition of iron compounds can result in well bonded deposits ranging from highly sintered to molten depending in part on the thickness of the deposit. Deposits in the convection passes are usually of secondary importance with Eastern coals: the most severe conditions generally occur on the lower furnace waterwall tubes.

Low rank Western coals, if they are to pose an ash deposition problem, will generally result in deposits (fouling) on convection tube surfaces. Western coals have typically shown low iron contents and relatively little segregation of mineral matter within the coal matrix. Vaporization of alkali compounds during combustion with subsequent condensation on convection tube surfaces is thought to be the initiating mechanism for deposition to occur. Deposits in convection passes are typified by their high rate of buildup giving the potential for voluminous, low density deposits. Deposits must be blown frequently to prevent them from becoming "keyed" in place by bridging between tubes; such bridging usually occurring from front to back, rather than from side to side.

Ash deposits from Western coals tested to date have accumulated on superheater probes in two distinct layers as opposed to Eastern coals which have formed three layers. (See Fig. 8 for a sketch of typical superheater probe deposits.) The initial layer has ranged from a fine, dry powder to a hard, fused scale. Outer layers have typically been sintered, crystalline deposits. The inner layers formed by Eastern coals have generally been

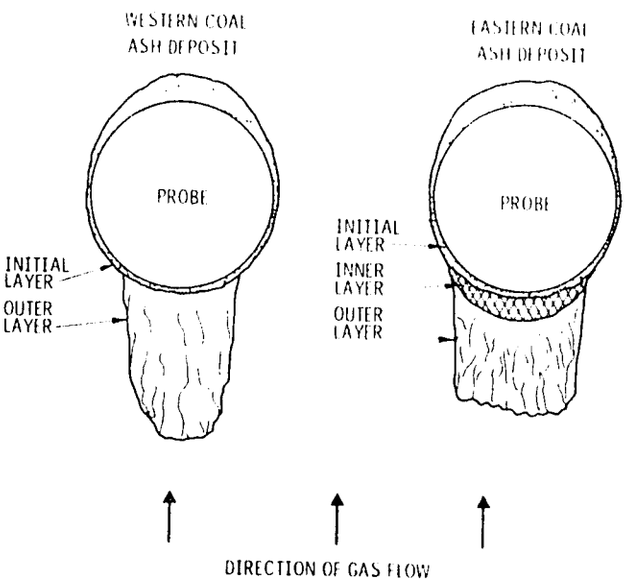

Fig. 8: Comparison of typical superheater probe deposits

a very dense material containing high amounts of iron. Providing the thickness of the deposit is not so great that the outer layer has reached a molten or semi-molten state, it is usually the inner layer that most strongly resists removal.

More specific information on a given coal is supplied by individual SFBTF tests. The program provides a matrix from which ash deposition can be evaluated over a range of parameters.

Upper Furnace Deposition

Superheater deposit growth is quantified during both the pressure drop tests and the deposit buildup test. Typical results of deposit buildup tests are summarized in Table I. Analytical data on the test coals (designated A, B, and C) is given in Table II. This data reflects the strong dependency of superheater probe deposition on firing rate. The strong influence of firing rate is the result of the combined effect of the variation of such parameters as gas temperature, lower furnace residence time, etc. The effect of particular parameters can be evaluated by comparing different probe banks at otherwise similar conditions. Preliminary results indicate the most influential parameters are gas temperature and particulate loading. Gas temperature appears to be the most predominant factor. For example when examining results from the high firing rate test with Coal A (Table I), the effect of gas temperature is reflected by a comparison of the quantities of ash deposits collected on Probe Banks I to IV as the gas temperature decreased from 2270 to 1640 F.

The plots in Fig. 9 illustrate the relationship between deposit accumulation and gas temperature. The weights of deposits collected during the buildup tests were divided by the total ash input and by the collection area of the test probes to help normalize for the changes in particulate loading and probe geometry. Superheater probe deposit growths for each of the three test coals show an exponential relationship with gas temperature. Correlation coefficients ranging from 0.77 to 0.95 were

TABLE I

SUPERHEATER DEPOSIT BUILDUP TEST

Coal	Heat Input	Probe Bank	Deposit Collected (Grams)	Gas Temp. (F)	Ash Input (lb/hr)	Weight Normalized** (gm/(lb/hr)ft²)
A	Low	I	4046	1940	22.6	270
		II	389	1735		25.9
		III	754	1660		33.5
		IV	883	1415		39.2
A	Medium	I	7512	2030	30.0	377
		II	3013	1835		151
		III	347	1720		11.6
		IV	341	1505		11.4
A	High	I	9547*	2270	39.8	—
		II	2023*	2070		—
		III	287*	1970		—
		IV	33*	1640		—
B	Low	I	168	1880	8.9	28.4
		II	169	1780		28.7
		III	174	1680		19.7
		IV	124	1560		14.3
B	Medium	I	2956	2290	10.8	413
		II	2450	2170		342
		III	1117	2110		104
		IV	230	1820		21.4
B	High	I	4587	2360	14.7	470
		II	3719	2210		382
		III	2811	2100		192
		IV	316	1870		21.6
C	Low	I	650	1960	17.9	54.8
		II	500	1750		7.0
		III	45	1630		2.5
		IV	40	1390		2.2
C	Medium	I	3540	2200	21.3	251
		II	110	2060		7.8
		III	125	1920		5.9
		IV	50	1690		2.4
C	High	I	18710	2240	27.0	1045
		II	5700	2080		318
		III	850	1930		31.6
		IV	—	1710		—

* Collected over a 25 hr. period

** Weight Normalized — Total deposit collected divided by the ash input (8-hr period) and the collection area of probe surface.

calculated with an exponential regression program. (Coefficients having a value of unity are indicative of an exact correlation, whereas a value of zero is indicative of points which do not correlate.)

Each curve in Fig. 9 illustrates a critical gas temperature range for the given coal above which deposit growth accelerates rapidly. Changes in the slope of the curves reflect the change of ash deposition rates. The amplitude of a curve at a particular temperature is an indication of the fouling severity at that temperature. For example, the plots in Fig. 9 indicate Coal A would exhibit the highest fouling potential. Below 2200 F, Coal B shows the second highest fouling potential.

TABLE II
AS-FIRED PULVERIZED COAL ANALYSES

Test Coal	A	B	C
Rank	Sub B	Sub B	hvBb
Region	Western	Western	Western
PROXIMATE, WT %			
Moisture	10.3	12.1	2.2
Volatile matter	34.3	37.1	41.0
Fixed carbon	43.4	45.6	46.9
Ash	11.9	5.2	9.9
Total	100.0	100.0	100.0
HHV, Btu/lb	9890	10,660	12,590
ULTIMATE, WT %			
Moisture	10.3	12.1	2.2
Hydrogen	3.5	5.6	5.2
Carbon	58.2	62.0	70.2
Sulfur	0.6	.5	0.7
Nitrogen	1.4	1.0	1.2
Oxygen (diff.)	14.1	13.6	10.6
Ash	11.9	5.2	9.9
Total	100.0	100.0	100.0
SCREEN ANALYSIS			
Mesh, % retained			
50	0.4	0.4	1.4
100	4.8	6.8	5.0
200	16.6	21.2	18.4
-200	78.2	70.0	75.2
Total	100.0	100.0	100.0
ASH FUSIBILITY, F			
I.D.T.	2150	1980	2190
S.T.	2200	2020	2270
H.T.	2240	2060	2390
F.T.	2440	2170	2620
ASH COMPOSITION, WT %			
SiO_2	50.2	33.8	52.5
Al_2O_3	16.9	11.2	18.9
Fe_2O_3	5.9	10.7	1.1
CaO	11.5	20.9	13.2
MgO	3.5	2.7	1.3
Na_2O	0.6	3.9	3.8
K_2O	1.7	1.6	0.9
TiO_2	0.8	0.7	1.2
SO_3	7.3	12.0	6.2
Total	98.4	97.5	99.1
Water Soluble Na, ppm*	270	1470	350
Water soluble K, ppm*	130	120	40
Acid soluble Na, ppm*	320	2450	1550
Acid soluble K, ppm*	700	285	450
Base/acid ratio	0.34	0.87	0.28
Fe_2O_3/CaO	0.51	0.51	0.08

The physical state of deposits is also illustrated by the plots in Fig. 9. A solid line represents highly fused molten deposits, whereas the dotted and dashed lines represent friable, sintered deposits and dry, powdered deposits, respectively. These characteristics refer to the outermost layer of deposit. The physical properties such as structure and strength of deposits for a given coal are generally related directly to gas temperature. The friability of deposits normally decreases with increased gas temperature as deposits become more fused and increase in density.

Results of the pressure drop tests for Coals A and B are summarized in Table III. Ash deposit buildup rates vary with time. (Deposition increases significantly as deposits accumulate due to the higher collection (deposit) surface temperature and due to the increased collection area.) Determining the time period required for deposits to build up to the same resistance, negates the effects of non-linear deposit buildup rates.

Also in Table III, the strong influence of firing rate (gas temperature and particulate loading) is illustrated. The effect of gas temperature is illustrated by comparing Probe Banks I and II at the same firing rate. For a given coal at a particular firing rate, soot blowing frequency increases as the gas temperature increases.

The data obtained during the pressure drop tests show good correlation with the results of the deposit buildup tests. (See Fig. 9). One-to-one correspondence between tests is not necessarily expected since, in the pressure drop tests, deposit resistance is measured, whereas in the deposit buildup test, mass of the deposit is measured; each of these is not necessarily interdependent.

Preliminary results of the measurement of the bond between ash deposits and superheater probes are shown for two coals (Coal A and Coal B) in Fig. 10 and Table IV. For Coal A, bonding strength measurements were obtained at two ranges of deposit thickness (1" to 2 inches and 3 to 4 inches). Plots in Fig. 10 were obtained using a linear regression program. Each of the relationships

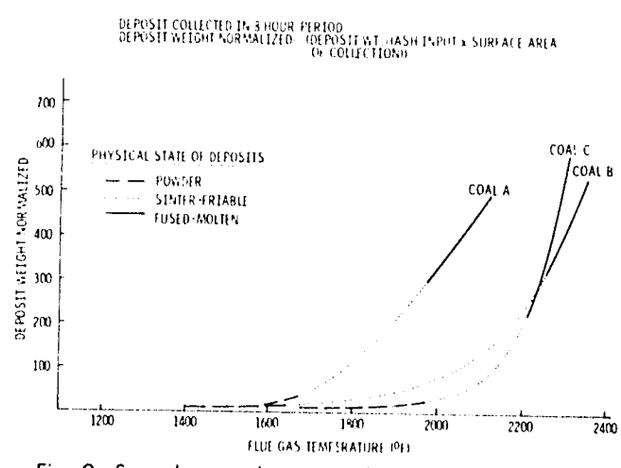

Fig. 9: Superheater deposit buildup vs flue gas temperature

TABLE III

PRESSURE DROP TESTS

Superheater Probe Deposit Soot Blowing Frequency

Coal	Heat Input (Btu/hr)	Leading Probe Bank	Pressure Drop Increase (In. H^2O) Standard	Measured	Time (Hrs)	Gas Temp. (F)	Ash Input (lb/hr)
A	Low	II	0.10	*	>20	1780	22.6
		I	0.10	*	>10	1840	22.6
A	Medium	II	0.135	0.11	9.6	2000	30.0
		I	0.135	0.135	4.5	2330	30.0
A	High	II	0.40	0.40	3.5	2180	39.8
		I	0.40	0.40	2.0	2450	39.8
B	Low	II	0.10	0.0	>20	1880	8.9
		I	0.10	0.03	>10	1880	8.9
B	Medium	II	0.135	0.19	14	2160	10.8
		I	0.135	0.10	7.5	2290	10.8
B	High	II	0.40	0.40	10	2300	14.7
		I	0.40	0.20	4.5	2410	14.7

had correlation coefficients between 0.73 and 0.89.

Results indicate that for a given coal, bonding strength increases with gas temperature. Bonding strength increases by a factor of between three and six (Fig. 10) as gas temperature increases from 1800-2400 F.

Ash deposit removal is aided by the downward force exerted by the weight of the deposit. Coal ash deposits having a thickness of 3 to 4 inches consistently exhibited lower bonding strengths than ash deposits 1½ to 2½ inches thick from the same coals.

Lower Furnace Deposition

Characterization of lower furnace deposits is primarily accomplished by monitoring the heat absorbed by the waterwall panel. Changes in the heat absorption rate of the panel illustrate the effect of ash deposition on heat transfer. Variations in the heat flux through the panel reflect the combined influence of the quantity of deposits and the thermal properties of these deposits.

Plots of the heat flux through the panel versus time are shown for Coals A, B, and C in Fig. 11. Comparison of the plot for Coal B (top plot) and the plot for Coal A (bottom plot) illustrates the two extreme cases. The magnitudes of the heat flux obtained when firing Coal B are indicative of a relatively clean coal, whereas the magnitudes obtained when firing Coal A indicate a severe slagging potential. Note the steady drop in heat flux with time during the testing of Coal A. Panel heat flux when testing Coal B remained high throughout the test as sharp increases in absorption occurred whenever the heat flux dropped to roughly 30,000 Btu/hr ft². Sharp increases are indicative of deposits sloughing off the panel when reaching a particular thickness.

Three indices (based on the heat flux plots) established to aid in the characterization of the thermal properties of waterwall deposits are summarized below:

Coal	Avg. Heat Flux Total Heat Input (1/ft²)	Avg. Cycle Time (Hrs.)	Heat Flux Avg. Last 12 Hrs. Heat Flux Clean Panel
A	6.91×10^{-1}	None	0.09
B	12.27×10^{-1}	None	0.61
C	6.82×10^{-1}	None	0.36

TABLE IV

SUPERHEATER PROBE DEPOSIT

Bonding Strength Measurements

Coal	Deposit Thickness (in.)	Temperature (F)	Relative Bonding Strength
Coal A	3.5	1830	0.65
	3.5	1910	1.5
	4	2080	0.75
	4	2330	2.2
	1.5	1950	2.25
	1.5	2050	1.0
	2.5	2140	2.75
	2.0	2330	3.75
Coal B	1.5	1930	1.12
		2180	1.55
		2310	2.87

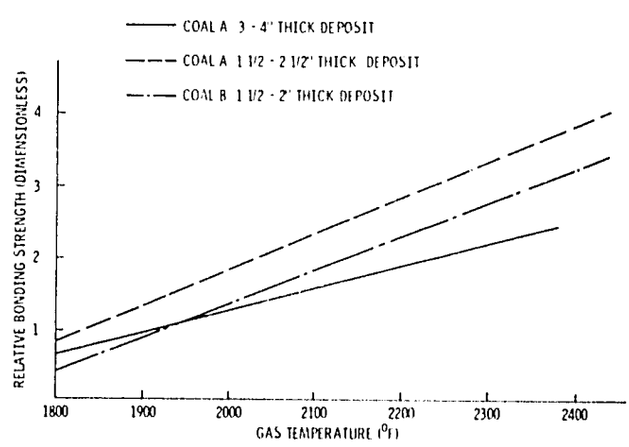

Fig. 10: Bonding strength of ash deposits

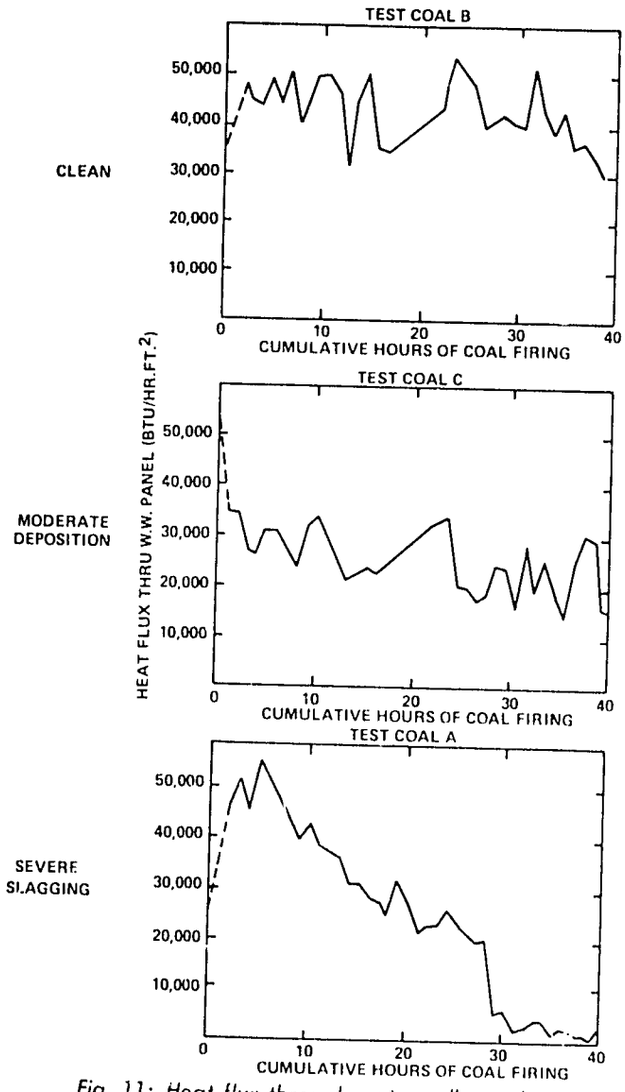

Fig. 11: Heat flux through waterwall panel

Comparing the ratios of average heat flux through the panel/total heat input, the high ratio for Coal C reflects the minimal overall thermal effects of deposits accumulated during this test. Deposits from Coal A did not exhibit any significant sloughing. This characteristic is reflected by the cycle time (Coal A >40 hours). Sloughing did occur when testing Coal B and C, although the frequency of sloughing was inconsistent and therefore no cycle time could be established. Comparing the heat flux ratios (average heat flux over the final 12 hours of the test/the heat flux of a clean panel) for the coals, the differences in the long term nature of respective waterwall deposits are reflected. The very low ratio for Coal A is indicative of the good insulating properties of the very thick, well bonded deposits produced near the end of the test. The relatively high heat flux ratio for Coal B, reflects the minimal effect of the deposits on heat transfer.

By comparing the three indices listed in Table V, it is possible to quickly determine the relative slagging potential, and to estimate the nature of the deposits. By studying the plots of heat flux through the panel vs time, more detailed information concerning the nature of waterwall deposits, and their effect on heat transfer can be determined.

Relative Coal Slagging/Fouling Potential

The previous discussion of example SFBTF test results provides an understanding of some of the data obtained during testing. The key indices used in rating the relative slagging potential (lower furnace) of the coal tested are summarized in Table V. The relative ranking of the slagging potential of example coals is also given. Considerable judgment must be used when weighing the effects of the different indices on slagging and fouling performance. Coal A was ranked as the most severe slagger due to the indicated high bonding strength (no cycling) and the thick, molten deposits generated near the end of the test (low relative heat flux during final 12 hours). Coal B was ranked as the cleanest

TABLE V
LOWER DEPOSIT CHARACTERIZATION
SLAGGING POTENTIAL

Coal	Avg. Heat Flux / Total Heat Input	Cycle Time	Heat Flux Avg. Final 12 Hrs. / Heat Flux Clean Panel	Physical State
A	6.9×10^{-3}	None	0.09	Molten
B	12.3×10^{-3}	—	0.61	Molten
C	6.8×10^{-3}	—	0.36	Sintered

RANKING
COAL

Increasing Severity ↑

A
C
B

TABLE VI
UPPER FURNACE DEPOSIT CHARACTERIZATION
FOULING POTENTIAL

Coal	Critical Gas Temp. (F)	Bonding* Strength	Min. Gas Temp. To Achieve Physical State		Deposit Accumulation (gm)†		
			Sinter	Molten	High	Med.	Low
A	1700	1.0 - 3.75	1670 F	1980 F	9550‡	7512	4046
B	2000	1.1 - 2.9	1650 F	2250 F	4590	2960	170
C	2100	- (weak)	1970 F	2220 F	18710	3540	650

RANKING
COAL

Increasing Severity ↑

A
B
C

* Penetrometer measurements taken on 1½ to 2½ inches thick superheater probe deposit
† Represents deposit accumulation on Bank I only during 8 hr buildup tests
‡ Mass of deposit collected in 2.5 hrs.

coal. Although very thin, molten deposits formed testing this coal, the effect of these deposits on heat transfer was slight.

The key indices used in rating the fouling potential (upper furnace) of the coals tested are summarized in Table VI. The relative ranking of fouling potential of the example coals is also shown. Based on the indices presented, Coal A clearly exhibits the highest fouling potential. Coal C was ranked as having the lowest fouling potential because of the weakly bonded, friable deposits generated at temperatures below 2150 F.

CONCLUSIONS

1. The Solid Fuel Burning Test Facility (SFBTF) generates ash deposits on simulated radiative and convective tube surfaces, under closely controlled reproducible conditions, consistent with those produced in an operating unit.
2. A standardized test procedure has been developed that permits highly quantitative chemical, physical, and thermal property measurements to be determined on ash deposits as a function of firing rate. An accurate relative assessment of coal's slagging and fouling behavior can thus be made.
3. Results from individual SFBTF tests provide the designer with information concerning relative ash deposition rates, critical gas temperatures, relative deposit bonding strengths, and relative waterwall heat absorption rates.
4. The combined results of a cross section of coals tested under standardized conditions will ultimately provide a consistent data base from which correlations between ash deposit characteristics and coal properties can be developed.

FUTURE WORK

Future work will entail test-firing of additional coals currently used in commercial C-E boilers until a total of approximately 20 coals have been analyzed under our standardized testing procedure. This will provide an ample statistical data base from which meaningful correlations can be developed between the coal properties (as determined by bench scale testing) and their ash deposit characteristics. Equally important will be our analysis and interpretation of field performance data collected on the same twenty coals as fired in the SFBTF. This will allow "calibration" of our laboratory-generated data so that absolute design specifications can be predicted wherever possible.

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APPENDIX 7

COAL HANDLING SYSTEMS

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COAL HANDLING SYSTEMS

The coal handling system arrangement for a utility power station is developed to best suit the particular coal site. This will take into account the method of coal delivery from the mine, location and size of storage piles, method of stock-out and reclaim, crushing, and delivery to and distribution within the station.

Sizing and cost of equipment will vary, depending on the coal. For poorer quality coals, higher conveying rates or longer periods of operation are required and, also, larger storage capacity. With higher conveying rates, sizing of coal handling equipment and power requirements will be greater. With longer periods of operation, human resources and maintenance costs will increase.

Delivery

The seven basic methods of delivering coal to the power plant are railroad, truck, belt conveyor (for mine-mouth plant), river or oceangoing barges, ocean vessel, self-unloading vessel, and pipeline slurry.

Coal delivered by railroad may be unloaded from cars using one of several methods.

At the new and larger stations, coal for the most part is delivered by "dedicated unit trains." These trains travel between mine and plant and require fast turnaround. In order to accomplish this, the complete train is unloaded without uncoupling cars or locomotives.

In warm climates and at places where freezing of coal in cars is minimal, it is possible to unload with the train in continuous motion. In this case, the train can be run across an overhead trestle or an underground track hopper without stopping, while bottom doors are opened and closed automatically. Using this method, a 100-car train can be unloaded in less than 30 minutes from the trestle and in approximately 3 hours when dumping to a hopper.

Where severe freezing of coal in cars is anticipated, it is more suitable to use a rotary car dumper with an automatic car positioner. With this arrangement, trains are indexed through the unloader one car length at a time. Coal unloaded from the rotated cars is dumped to an underground hopper. With the rotary dumper, a 100-car train can be unloaded in approximately 3 to 4 hours.

For smaller stations or where coal is to be delivered in random sized cars, cars may be unloaded on an individual basis. This can be done either with a rotary car dumper or through bottom doors into an underground hopper. Again, where frozen coal may be a problem, the rotary dumper would be more suitable for getting coal out of cars.

Truck and belt conveyor delivery of coal is most often associated with mine-mouth power plants.

With belt conveyor delivery, coal is conveyed overland from the mine to the power plant, where it is introduced into the stock-out and storage portion of the station coal handling system.

Trucks used for delivering coal are either bottom-dump or rear-dump type. Bottom dump trucks range in size from 50 tons to 200 tons and are

unloaded by driving over the underground receiving hopper. Rear dump trucks are smaller, having a capacity of up to 35 tons. These trucks are unloaded by backing up to the receiving hopper and raising the chute-type body.

Coal delivered by water at Lakhra or Jamshoro appears irrelevant; therefore, it is not being discussed in detail.

Storage

Stockpiling of coal is generally done with two purposes in mind. Live or active storage provides a short-term, readily available supply. The permanent storage pile contains 60 to 90 days' supply and protects the station against any long-term delays in coal delivery.

The permanent storage pile may be very large, depending on the size of the station, and may be as high as 100 feet. The storage site should be graded, on solid ground, and be provided with proper drainage to avoid runoff. The site should be cleared of trees, vegetation, and any other types of organic matter.

Spontaneous Combustion

Spontaneous combustion is a real and ever-present danger in stockpiling of coal. It is the result of oxidation of coal under conditions in which the rate of heat generated exceeds the rate of heat dissipated. Elements contributing to rapid oxidation are oxygen, high content of moisture, and volatile matter. Lignites or subbituminous coals are generally higher in these elements and, therefore, require more precautions during stockpiling. In all cases, when building a stockpile, incoming coal should be spread in even layers, no more than

1 foot thick for lignitic subbituminous coals. In spreading the layers, coal should be compacted by tracked or wheeled bulldozers to eliminate all air pockets. This compacted coal will have a density of approximately 70 pounds per cubic feet. Sides of the pile should have an approximate 2 to 1 slope. This slope will permit compaction and a sealing layer to be applied. When stockpiling is completed, the pile should be graded so that no pockets or depressions exist for water to collect. Water allowed to flow through the pile will wash away fines, thus creating air pockets, which, in turn, will encourage the process of oxidation. The sealing layer for the pile may be a light coating of asphalt or a 6-inch layer of finer coal anchored by a carefully placed layer of a coarser coal to offset wind erosion.

Temperature of the stored coal should be continually monitored by inserting thermocouples at strategic places in the pile. If hotspots are found, coal should be dug out and used immediately or wetted and repiled.

The live or active storage pile is actually an extension of in-plant storage. It will provide at least enough coal for overnight operation and more than likely enough for weekend operation. If a stacker-reclaimer or traveling wing stacker is used for stock-out, then the active pile can be greatly increased over weekend storage, limited only by the length of equipment travel. Cleanup by bulldozer or payloader, around the active pile, will be necessary in preventing the possibility of fire.

Silos

Concrete silos are becoming more popular as a means of storing coal at power plants. So far, they have been used almost exclusively at mine-mouth plants. They have been used to isolate high quality low sulfur coals from the rest of the storage area, and provide indoor active storage where air quality regulations are very stringent. Some of these silos are as large as 70 feet diameter x 200 feet high and provide for up to 15,000-ton storage.

Stock-out

Stock-out is the term used to describe the method of delivering coal to the storage area. The more popular equipment used for this purpose is the stationary fixed boom stacker (conical pile), the stationary swiveling boom stacker (kidney-shaped pile), traveling single wing or double wing stacker, and the traveling bucket wheel stacker-reclaimer.

The fixed boom stacker is only able to develop a conical shape of a maximum size of about 15,000 tons. The swivel boom stacker can be rotated so that coal can be discharged to the ground in the form of a kidney-shaped pile. The size of this pile is limited only by the arc through which the boom can rotate. For both types of equipment, the column of falling coal can be contained and the dust minimized either by a telescoping chute or by raising and lowering of the boom itself. In either case, the chute or the boom would be raised incrementally as the height of the coal pile increases. In addition to the telescoping chute and raising and lowering boom, a third method to be used with the fixed stacker would be a lowering well. The lowering well is a cylindrical tube which acts as support for the discharge end of the stacker boom and

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a discharge chute. The well is provided with outlets throughout its height. As coal in the well reaches these outlets, it spills out onto the pile until the coal in the well reaches the level of the boom.

The traveling wing stacker is a large tripper, traveling along the yard conveyor, discharging coal from the conveyor to its wing conveyors. These wing conveyors are mounted on the same traveling structure as the tripper and discharge coal, perpendicular to the yard conveyor, forming long triangular-shaped piles on one or both sides. As with the stationary stackers, dust is controlled either with a telescoping chute or by raising and lowering the wing conveyors.

The bucket wheel stacker-reclaimer is similar to the wing stacker in that it consists of a tripper traveling along the yard conveyor. In place of fixed wing conveyors, it is equipped with a swiveling boom conveyor that can rotate to either side, so that this single conveyor can build long triangular piles on both sides of the yard conveyor. The boom is provided with a bucket wheel, and the boom conveyor is reversible so that the machine can be used for returning coal from storage back onto the yard conveyor. The boom of the stacker-reclaimer may be raised and lowered to control dust when stocking-out and to dig into the pile when recovering coal from storage.

Reclaim

Reclaim describes the method of recovering the coal from storage for transport to the station. The two primary means for reclaiming are by gravity (to an underground tunnel), and aboveground reclaiming (using a traveling bucket wheel stacker-reclaimer).

For gravity reclaiming, a tunnel is located below the active or live storage pile with a series of drawdown hoppers located in the tunnel roof. A feeder is provided at the outlet of each of these hoppers to control material flow through the hopper onto a reclaim belt conveyor. This belt conveyor will then carry the coal aboveground and to the station. The more common feeder equipment used in this type of reclaim is vibratory, belt conveyor, and reciprocating plate feeders.

A second type of underground reclaim employs the traveling rotary plow feeder. With this arrangement, the tunnel is designed for coal to lay on ledges along either side. As the plow travels the length of the tunnel, it will sweep this coal from the ledges onto the reclaim belt conveyor for transport to the station. As coal is swept from the ledges, it is replaced by gravity from the overhead storage pile.

For all gravity reclaim systems, a certain amount of bulldozing is required. Active piles, depending on size, shape, and method of reclaim, have a live to dead storage ratio of from one-eighth to one-third. That is, only about one-eighth to one-third of the pile is recoverable by gravity. In order to recover the remainder of the pile, it is necessary to bulldoze to the reclaim hoppers.

In the reclaim mode of the stacker-reclaim machine previously described the bucket wheel located at the end of the boom conveyor digs coal from the active pile and deposits it on the boom conveyor. This conveyor is reversible so that when reclaiming, it will return coal to the yard conveyor for transport to the station.

Crushing

Crushing is done at a power plant to reduce coal size to a maximum that can be handled on conveyors and by the station pulverizer feeders.

At a mine-mouth plant, two stages of crushing are required. The first, or primary crushing, is done to reduce the as-mined coal to a product size that can be safely handled on belt conveyors. Preferably, the size would be less than 6 inches. The second stage, or secondary crushing, further reduces the coal to less than 1 1/4 inch so that it can pass over the pulverizer feeders without plugging.

At power plants remote from the mine, coal is generally delivered already crushed to less than 2 or 3 inches product size. Therefore, only one stage of crushing is required. This single stage will produce the less than 1 1/4-inch product necessary to pass over the pulverizer feeders.

The normal location for final crushing is in the reclaim system when coal is sent to the station. This location provides a means for breaking up any large lumps that may have formed in stock-out, before they reach the station. This is particularly important in cold climates where freezing can occur.

In extremely cold climates, where coal is delivered by rail or truck, it may be necessary to install special crushers in the unloading system for breaking up very large frozen lumps.

In-plant Coaling

Coal delivered to the station is distributed to the in-plant storage by one of three methods. Traveling tripper, cascading or grasshopper conveyors, or mass flow or drag chain conveyors.

Traveling trippers are the most popular method of filling silos and bunkers. They are practically maintenance free and provide more flexibility in operation than the other two methods. They can be operated either manually or in an automatic mode and can be moved to any filling position where coal might be needed in a hurry.

Cascading conveyors and mass flow conveyors lend themselves very well to automation with silos being filled sequentially.

Because of the multiple transfers required with cascading conveyors, increased maintenance is encountered and, also, more dust is generated in the gallery above the silos.

Mass flow conveyors also require more maintenance. This is due to abrasion and wear on chains, flights, and conveyor casing. However, because the mass flow conveyor casing is dust tight, there will be no dust in the gallery above the silos.

In-plant Silos

In modern power plants, the trend is toward the use of cylindrical steel vertical silos for in-plant coal storage. These silos enhance the use of automation in control of the coal handling system and, because of their shape, improve the flow of coal to the pulverizer feeders. Silos are sized to fit the boiler house with an attempt to provide at least a

12 hour capacity, and are arranged so that one is located above each pulverizer. For small plants, the pulverizers are usually located in a single bay across the front of the boiler. For large plants, the pulverizers may be located along both sides of the boiler.

Each silo is mounted on load cells to provide an indication of the level of material in the silo and for providing a low level signal.

Sampling

Coal is sampled at a power plant in order to obtain an analysis to determine such characteristics as Btu content, ash content, moisture content, and sulfur content. These results are used in determining contract prices, plant operating efficiencies, and compliance with environmental standards.

The design of the majority of coal sampling systems is based on standards developed by the American Society for Testing and Materials. These standards establish the overall requirements for the collection and analysis of coal samples. The object of these standards is to develop a system for collecting a portion of sample which is truly representative of the whole shipment or consignment.

The sampling system for coal "As-Received" is located in the coal handling system prior to stock-out. This prevents biasing of the sample from exposure to the atmosphere. The results of this sample will be used by the utility and the coal supplier in determining contract prices.

The sampling system for coal "As-Fired" is located in the reclaim system after coal is recovered from storage. This sample is used for

determining operating efficiencies and compliance with enviornmental regulations.

Weighing

Coal is usually weighed at two locations in a power plant coal handling system. The first is in the receiving system and will most likely be done over a continuous belt scale, although, with rail or truck delivery, this scale could be replaced by a track scale or a platform-type truck scale. The purpose of this as-received weighing system is to verify the quantity of coal delivered by the supplier. The second location for weighing will be in the reclaim system where continuous belt scales will record the quantity of coal sent to the in-plant silos.

Magnetic Separation

Magnetic separation is installed in the coal handling system at various locations to protect belts and crushers from ferrous metal which may find its way into the coal. Separation should be located in the receiving system as close to the unloading point as is conveniently possible, and in the reclaim system at the first conveyor transfer beyond the storage pile.

Dust Collection

All chutes and hoppers are covered to control dust. Loading skirts are provided with sealing strips and rubber curtains at conveyor head and skirt outlets to minimize spillage at conveyor transfers. Dust concentrations at conveyor transfers and at the crusher house are controlled by dust collection units, with collected material being

returned to the materials handling system. All surge and storage bins in the coal handling system, as well as the in-plant storage silos, are also provided with dust collecting equipment.

Dust Suppression

Wet type dust suppression is usually included in the receiving systems at the unloader and at each conveyor transfer through stock-out. This provides sufficient addition of surface moisture on the coal to prevent dusting during the unloading and stocking-out operations.

Ventilation

Ventilation is furnished wherever there is a possibility of methane gas collecting. This includes all pits and tunnels, transfer houses, all surge and storage bins, and the in-plant silos. Methane detection equipment may also be included to provide an alarm or automatic start of ventilation when methane reaches a dangerous level of concentration.

Fire Protection

With the danger of fire always present, fire protection is furnished throughout a great portion of the coal handling system. In particular, a water spray system is included in all pits and tunnels, along the conveyors going from the yard to the station, in the tripper gallery above the in-plant silos, and in the crusher and all transfer houses. Hydrants are located around the coal storage piles.

Car Thawing

The freezing of coal presents a difficult problem for emptying rail cars during the winter. Infrared rail car thawing equipment has been helpful in overcoming this problem.

The thawing elements are arranged in a shed located ahead of the unloading operation. The length of the thawing area and thaw shed is dependent on the amount of thawing required for each car and the rate of unloading. In addition to a heating section in the thaw shed, there is also a soaking section. This section provides a protected area where the heat applied to the sides and bottom of the car can have time to penetrate the mass of frozen coal in the car. This problem will not occur at Lakhra but may occur at some cold places like upper Baluchistan.

Costs

The coal handling system for a power plant is site related. Therefore, it is difficult to attach to it an accurate cost in dollars per kilowatt. Normally, the cost will be in the range of $15 to $20 per kilowatt, but may go as high as $30.00. This cost comprises everything associated with a coal handling system, including all equipment, transfer houses, structural steel, concrete work, electrical and controls.

Typical, approximate erected costs for major equipment are:

Ladder type vessel unloader - $3,500,000 to $4,500,000

Grab bucket type vessel unloader - $3,750,000

Rotary car dumper with positioner - $2,500,000

Belt conveyor system - $10,000,000 to $30,000,000

Bulldozer or Coaldozer - $150,000 to $800,000

Stacker-reclaimer - $4,000,000 to $5,000,000

Rail car thawing - $600,000

Coal pile costs will vary depending on station location, calorific value of coal, number of days storage, and operating load factor of the power plant.

APPENDIX 8

ASH HANDLING SYSTEMS

APPENDIX 8

LIST OF FIGURES

Figure	Title
1	Sluice & Negative Pressure Pneumatic Conveyor (Bottom Ash & Fly Ash)
2	Sluice Conveyor (Bottom Ash)
3	Recirculating Sluice Conveyor - Jet Pump Transfer (Bottom Ash)
4	Recirculating Sluice Conveyor - Combination Jet Pump & Mechanical Pump (Bottom Ash)
5	Closed Loop Cooling
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8	Sluice & Negative Pressure Pneumatic Conveyor (Bottom Ash & Fly Ash)
9	Negative Pressure Pneumatic Conveyor with Mechanical Exhauster (Fly Ash)
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APPENDIX 8

ASH HANDLING SYSTEMS

Ash is the noncombustible material in coal. This impurity in coal could range from 6 percent to 25 percent and more, and it will add to the cost of shipping and handling coal, leading to more expense for ash-handling equipment and its operation. Ash-handling system selections are closely related to boiler design, coal properties, ash content, method of coal burning and type, and amount of ash collected. Ash content in coal is of utmost importance because it largely determines the type and size of the ash-handling system. It is recommended, if properties of future coal supplies are uncertain, to err in favor of higher ash content. This will assure an ash removal system large enough to deal with extreme conditions.

Types of Ash Handling Systems

Generally speaking, there are three types of ash handling systems available today for application in the modern, pulverized coal-fired power plants: pneumatic, hydraulic, and mechanical. Ashes to be handled by these systems are as follows:

a. Bottom ash or slag; the heavier ash that falls or flows to the bottom of the main furnace in either the dry or wet state

b. Fly ash; the fine particles collected by dust collectors, precipitators, or baghouses

c. Economizer and air heater ash; the coarser particles dropped out of flue gases in the ductwork

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d. Mill rejects, or pyrites, which may consist of a variety of coarse materials

The following disucssion will cover the mechanical, hydraulic, and pneumatic methods of ash handling, and will be limited to systems applicable to coal-fired units in central generating stations.

Jet Pump Bottom Ash Sluicing System and Fly Ash Water Exhauster Vacuum System

This system utilizes water-impounded bottom ash hoppers where bottom ash and slag from the furnace are quenched in water and collected for periodic removal through a hydraulic jet pump and pipeline sluice conveyor. For pulverized coal-fired units, the majority of ash is fly ash (up to 80 percent), a water-operated vacuum system may be used to slurry the fly ash and discharge it through the same pipeline that was used for the bottom ash. Today, this arrangement still has application where ash quantities are not great, water is plentiful, and run-off from the ash pond area is acceptable environmentally.

Figure 1 illustrates a modification to the system described. Here the fly ash is stored in a bin and hauled away by truck instead of discharging to the ash pond. With this arrangement fly ash can also be made to bypass the silo and be sluiced to the ash pond.

Bottom Ash Sluicing to Dewatering Bins

An additional method for handling bottom ash is shown on Figure 2. The ash is pumped to dewatering bins where it is stored, normally for 24-hours or longer. After draining the water off through suitable decanting elements, the ash is trucked away to the disposal site. With

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this arrangement, an alternate method of disposal may be sluicing to an ash pond. In either case, decanted water will be drained to the ash pond or to a settling pond.

Recirculating Bottom Ash Sluice System

In locations where water is scarce or environmental conditions dictate, a completely closed loop system has been successfully used. As illustrated on Figure 3, the ash hopper at lower left receives the ashes from the furnace. Ash is discharged through clinker grinders to hydraulic ejectors (jet pump) and then the ash slurry is pumped to dewatering bins. From here the water flows into a settling tank where the majority of the fines are settled out. Overflow from the settling tank goes to a surge tank which provides makeup water for the recirculating system. To complete the loop, the water flows from the surge tank through the recirculating pump which supplies water to the jet pumps at the bottom ash hopper, as well as to hopper flushing nozzles, refractory cooling and seal through flushing nozzles and seal water.

The ash fines settling to the bottom of the settling and surge tanks are periodically purged and discharged back to the dewatering bin.

Many variations are possible to the system described above. Contaminated wastewater can be discharged to suitable clarifying basins with overflow being pumped back to the plant site for recycling.

Referring back to Figure 4, this pumping method utilizes jet pumps located at the bottom ash hopper outlets to pump the ash slurry to the dewatering bins. This is a simple method; however, wear on the water

recirculating pump increases with the pressure requirement of the water supply to the jet pump because of solids in the recycled water.

A second method, illustrated on Figure 4, utilizes the jet pump for removal of the ash slurry from the hopper, discharging it into a transfer tank and using a centrifugal pump to pump the slurry to the dewatering bin. In this way, the water quantity and pressure demand on the jet pumps will be reduced and the centrifugal pumps will be required to deliver the recirculated water at relatively low pressure compared to jet pump requirements. With this method, ash can be sluiced considerable distances at minimized hp requirements.

Bottom Ash Submerged Drag Chain Conveyor System

As an alternative to a bottom ash sluice system, a submerged drag chain conveyor system may be used. The submerged drag chain has been operated successfully in Europe for more than 20 years. Its acceptance in North America is growing with several units now in operation and several others in various stages of manufacture and installation.

Figure 5 illustrates a conveyor system with closed loop cooling. With this arrangement, ash is collected below the boiler in the submerged drag chain conveyor, conveyed out of the water and up an inclined section where dewatering occurs. Ash is then discharged to a grizzly where undersize particles are passed directly to a belt conveyor while oversize particles are diverted through a crusher for size reduction and then to the belt conveyor. The belt conveyor delivers the ash to a storage bin for loading to trucks for final disposal.

The closed loop cooling system consists of a surge tank, recirculating pumps, and heat exchanger. A gravity settler at the conveyor overflow will reduce the solids in the sluice water for protection of the pumps and heat exchangers.

Water drained from the ash storage bin will be recirculated back to the submerged conveyor.

Furnace seal plates will extend down into the water within the submerged drag chain conveyor, providing a seal between boiler and atmosphere.

Economizer and preheater ash, as well as pyrites, can be discharged into the submerged chain conveyor, simplifing their disposal.

Where water availability and disposal do not present problems, an open loop cooling system, as shown on Figure 6, may be installed. With this arrangement heat exchangers are not required, thus reducing some maintenance costs.

Mill Rejects Handling System

Pulverized rejects (pyrites) from coal pulverizer mills are most conveniently handled hydraulically if they are in large quantities, otherwise manually. The rejects are stored in small hoppers which are mounted below each mill discharge spout, with rejects continuously and sequentially removed in slurry from each hopper to a central transfer tank by the use of jet pumps.

The arrangement on Figure 7 illustrates the reject hoppers and a transfer tank which normally provide for 8 hours storage of rejects accumulation and can be discharged either through its own or the bottom

ash sluice lines to a fill area, collection tank, or to dewatering bins.

Fly Ash Handling

The collection and transportation of fly ash at utility power plants is critical in densely populated areas due to the large quantities of ash and the potential for air pollution due to fugitive dust emissions. The following examples will cover the types of conventional systems generally used for handling the fly ash and reducing dust emissions:

a. Pneumatic vacuum conveying through a hydraulic vacuum producer (water exhauster) with slurry flowing by gravity to a fill area with bottom ash or separately (see Figure 8)

b. Pneumatic conveying to a dry storage silo with vacuum created by means of a hydraulic or mechanical vacuum producer (see Figures 1 and 9)

c. Conveying pneumatically by pressure to dry storage silo (see Figure 10)

Conveying Fly Ash by Vacuum

Figure 9 outlines a conveying system using a mechanical exhauster for handling fly ash to a storage bin. The ash is discharged from each precipitator hopper sequentially into the moving air stream created by the mechanical exhauster. The fly ash is separated from the air stream by three stages of separating equipment and dropped into the fly ash storage silo. Figure 1 shows a similar arrangement except that only two

stages of separation are required at the silo and the motive force is created by a water exhauster.

These systems are relatively simple and trouble free, but are limited in length. The distance material can be conveyed depends on configuration of the system and plant altitude above sea level.

Conveying Fly Ash by Pressure

The pressure systems are applied where length of the system is too great for vacuum conveying or where plant altitude limits the vacuum that can be developed. In comparison with the vacuum system, the pressure conveying offers greater capacity, more efficient operation, and a blower handling clean air.

Figure 10 outlines a pressure system where the ash is fed simultaneously from all the hoppers in one precipitator row, in contrast to the vacuum system which serves one hopper at a time. Air lock feeders are used to transfer fly ash from alternate hoppers at one pressure to a conveying line at a higher pressure.

Silo storage is similar to the vacuum system except that separators are not required at the silo. A self-cleaning vent bag filter is required to exhaust the air displaced by incoming dust as well as the conveying air. As an alternative, exhausted air may be returned to the inlet duct at the precipitator.

Economizer Ash Handling

The coarser fly ash particles collected from economizers and air heaters amounts to less than 10 percent of the total ash produced and can be

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handled in the systems previously described for fly ash. Also, this ash may, under suitable conditions, be deposited continuously in water filled tanks and then pumped to a fill area or to bottom ash dewatering bins.

If a submerged drag chain conveyor is used for handling bottom ash, both economizer and air preheaters may be collected in dry type, mechanical drag chain conveyors and discharged by gravity to the bottom ash conveyor.

With a sluicing system, furnace bottom ash is stored in water impounded hoppers and can be discharged by remote or automatic control. Jet pumps, mechanical pumps, or combination of both are used for pumping the ash to the dewatering bins or to a fill area. Discharge pipe lines of the following sizes are usually used:

6-inch ID	20-40 TPH
8-inch ID	50-90 TPH
10-inch ID and larger	100-150 TPH

With a submerged drag chain conveyor system, bottom ash is removed continuously and conveyed to a storage bin by belt conveyor. Belt conveyor sizing is as follows:

18-inch	Up to 75 TPH
24-inch	Over 75 TPH

When comparing the sluicing system with the submerged drag chain system, the following points should be considered:

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1. Although the drag chain system has been used extensively in Europe, there is very little operating experience in North America. The sluicing system, on the other hand, has been operated successfully at hundreds of large power plants.

2. The water impounded hoppers used with the sluice system provide up to 12 hour storage, whereas the drag chain can only store up to 2 or 3 hours of ash.

3. Installed horsepower requirements are considerably less with the submerged drag chain system, but due to its continuous operation as compared to intermittent operation of the sluicing system, the actual energy consumption would probably be only slightly less.

4. Due to both ash system designs and easy access to the submerged drag chain, forced outages or load reductions with either system are considered to be quite remote.

5. With use of the submerged drag chain, the overall boiler height may be lowered as much as 10 to 20 ft below that required for a sluicing system hopper.

6. Handling of pyrites, economizer ash, and preheater ash may be greatly simplified with the submerged drag chain.

7. In a closed loop water system, water losses will be approximately the same for both the sluicing system and submerged drag chain system. In an open loop system, the use of water during the conveying cycles (3 to 5 hours per day) for

the sluicing system will exceed the use of water by the drag chain system by as much as 2,000 gpm.

When it is necessary to conserve water or environmental conditions dictate, the water used in both the sluicing system and submerged drag chain system can be clarified and recycled.

Pyrites are stored in small hoppers and sequentially removed hydraulically by jet pumps to a storage and transfer tank for ultimate removal to the dewatering bin or fill area, or to the submerged drag chain if used for bottom ash removal.

Fly ash can be conveyed pneumatically by vacuum or pressure systems to storage silos.

Fly ash is normally deposited in trucks or railroad cars through wet ash conditioning unloaders or through dry unloading spouts if the ash must be kept dry. An important consideration for commercial utilization of fly ash is as an additive for a bulk concrete. Also, a mixture of fly ash, lime, and soil produces load carrying base for road building, paving parking lots, and other similar applications.

Fly ash from western coals in the U.S. have a greater tendency to build up in the pipeline and sets up faster than ash from other coals. Abrasive bottom ash discharged through a common line will aid in retarding this build-up condition. Wetted fly ash may be difficult to unload from a carrier if it is not unloaded in a short time.

Economizer and air heater ash is best handled through continuous removal from the hot gas stream and discharged through either water-filled vessels, mechanical drag chains, or dry pneumatic systems.

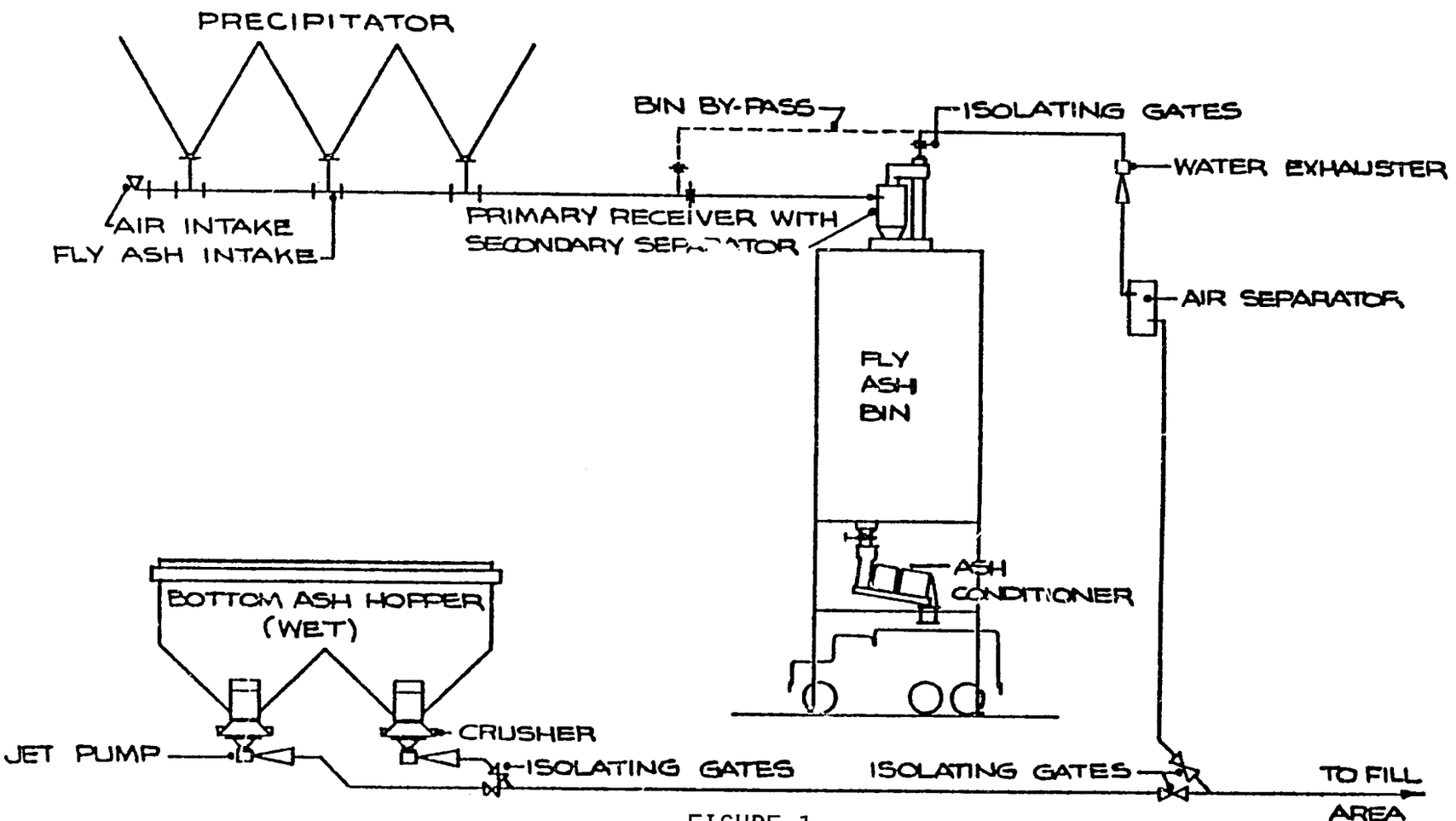

FIGURE 1

SLUICE & NEGATIVE PRESSURE PNEUMATIC CONVEYOR
WITH OPTION FOR DRY FLY ASH STORAGE
(BOTTOM ASH & FLY ASH)

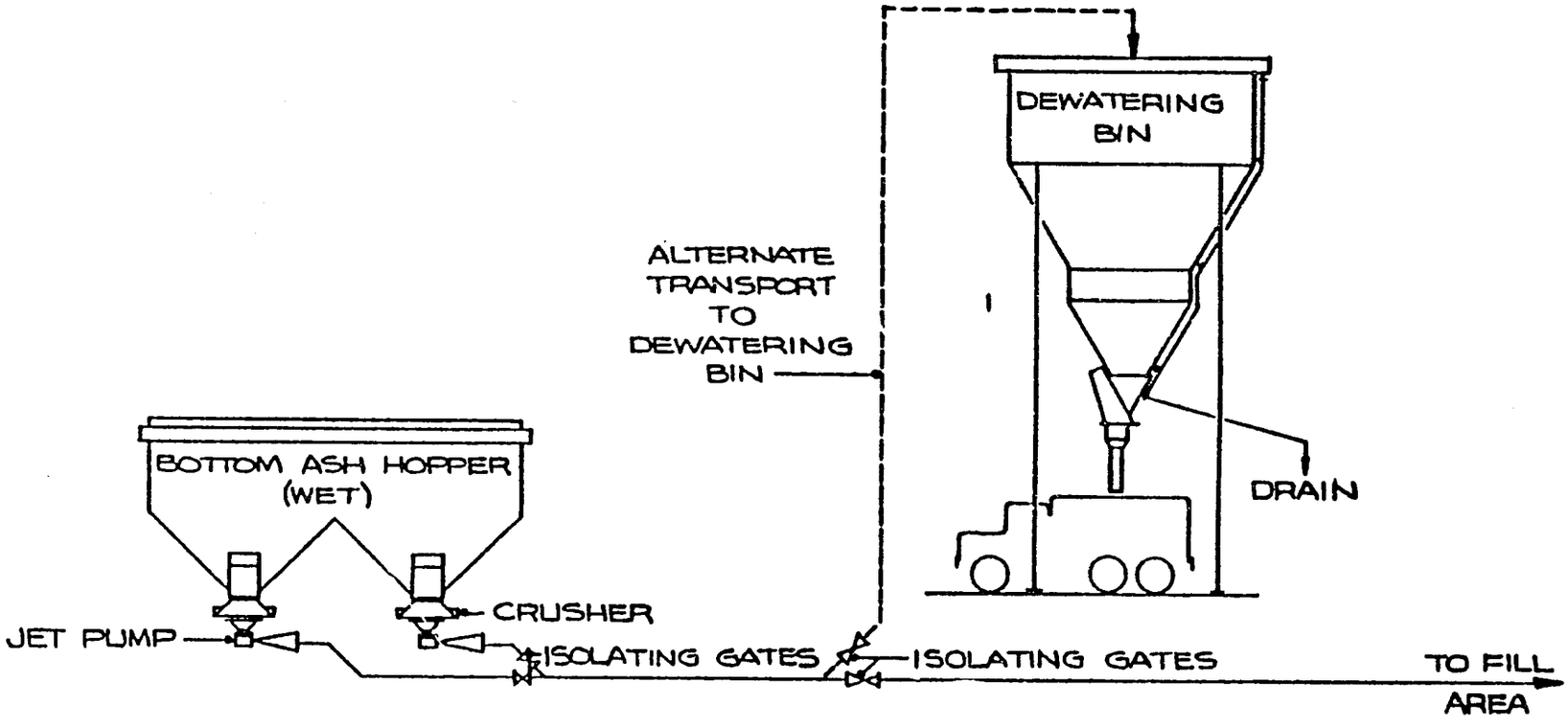

FIGURE 2

SLUICE CONVEYOR

(BOTTOM ASH)

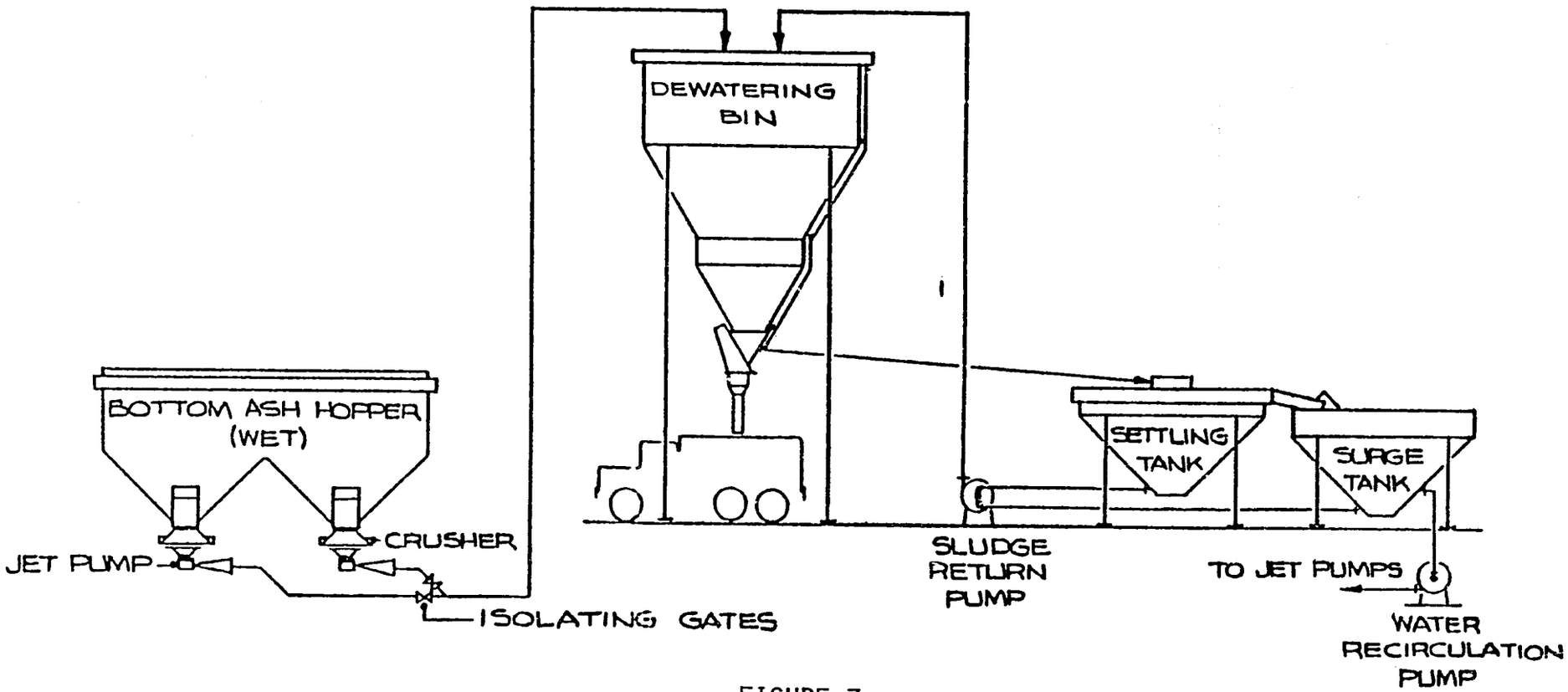

FIGURE 3

RECIRCULATING SLUICE CONVEYOR

JET PUMP TRANSFER
(BOTTOM ASH)

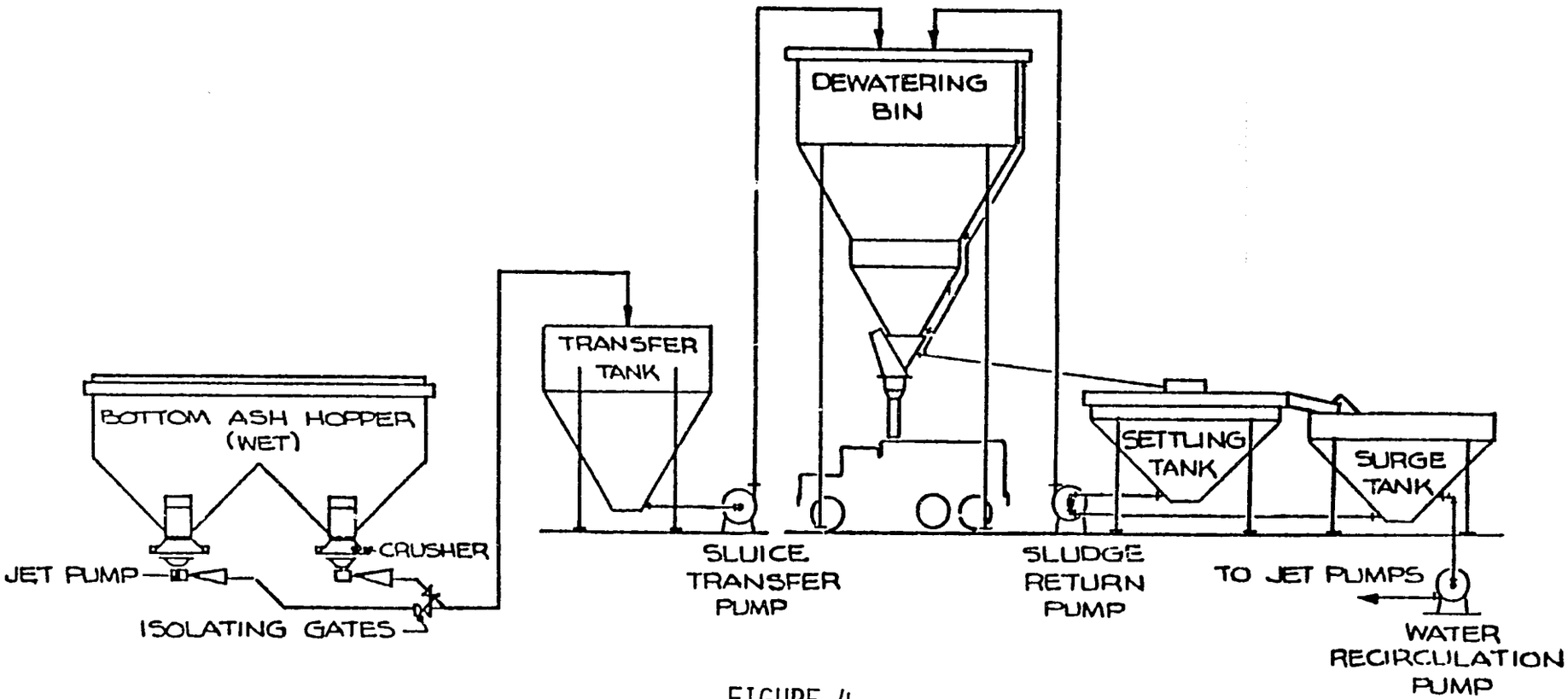

FIGURE 4

RECIRCULATING SLUICE CONVEYOR

COMBINATION JET PUMP & MECHANICAL PUMP
(BOTTOM ASH)

Closed loop cooling

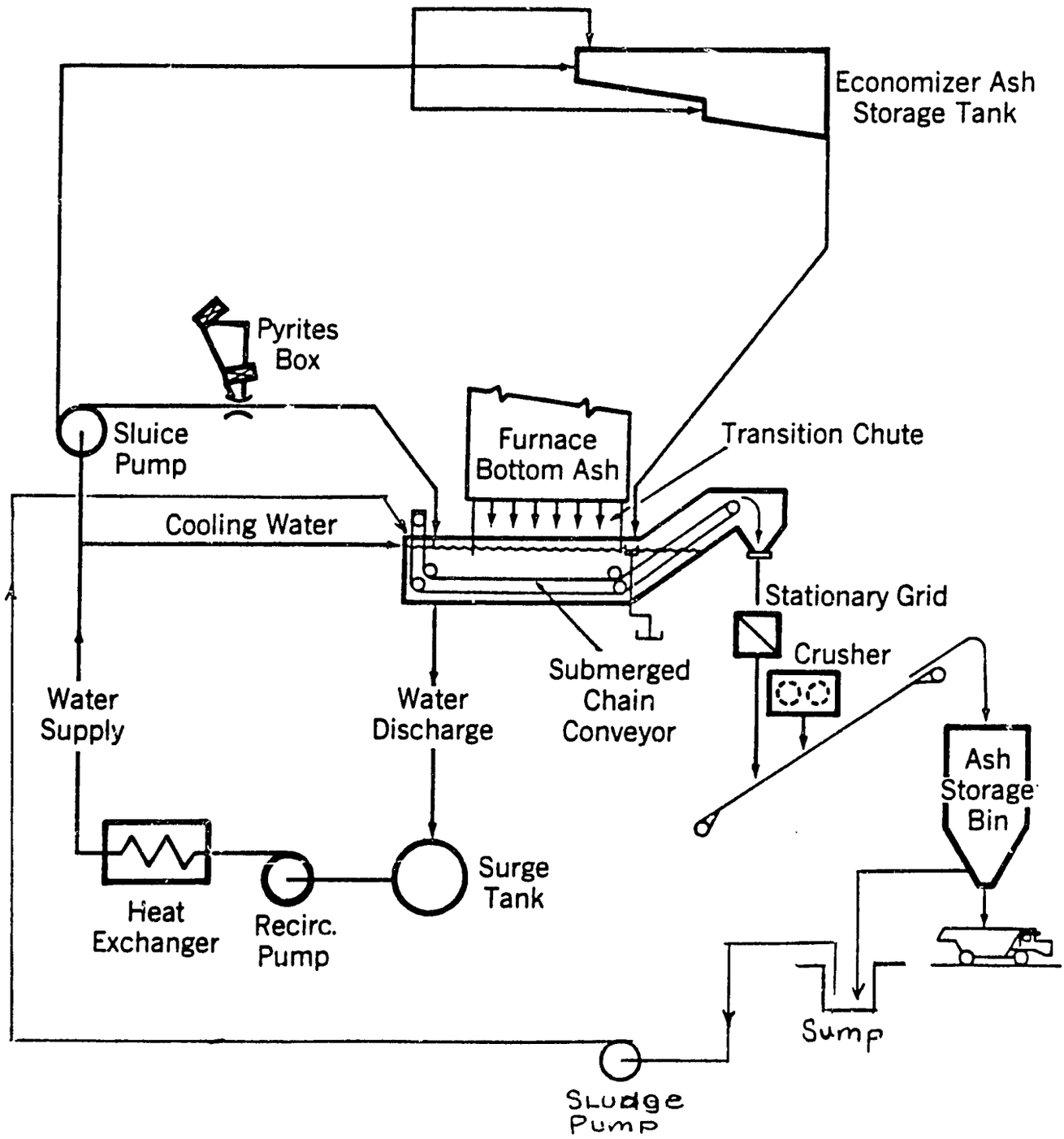

FIGURE 5

Open loop cooling

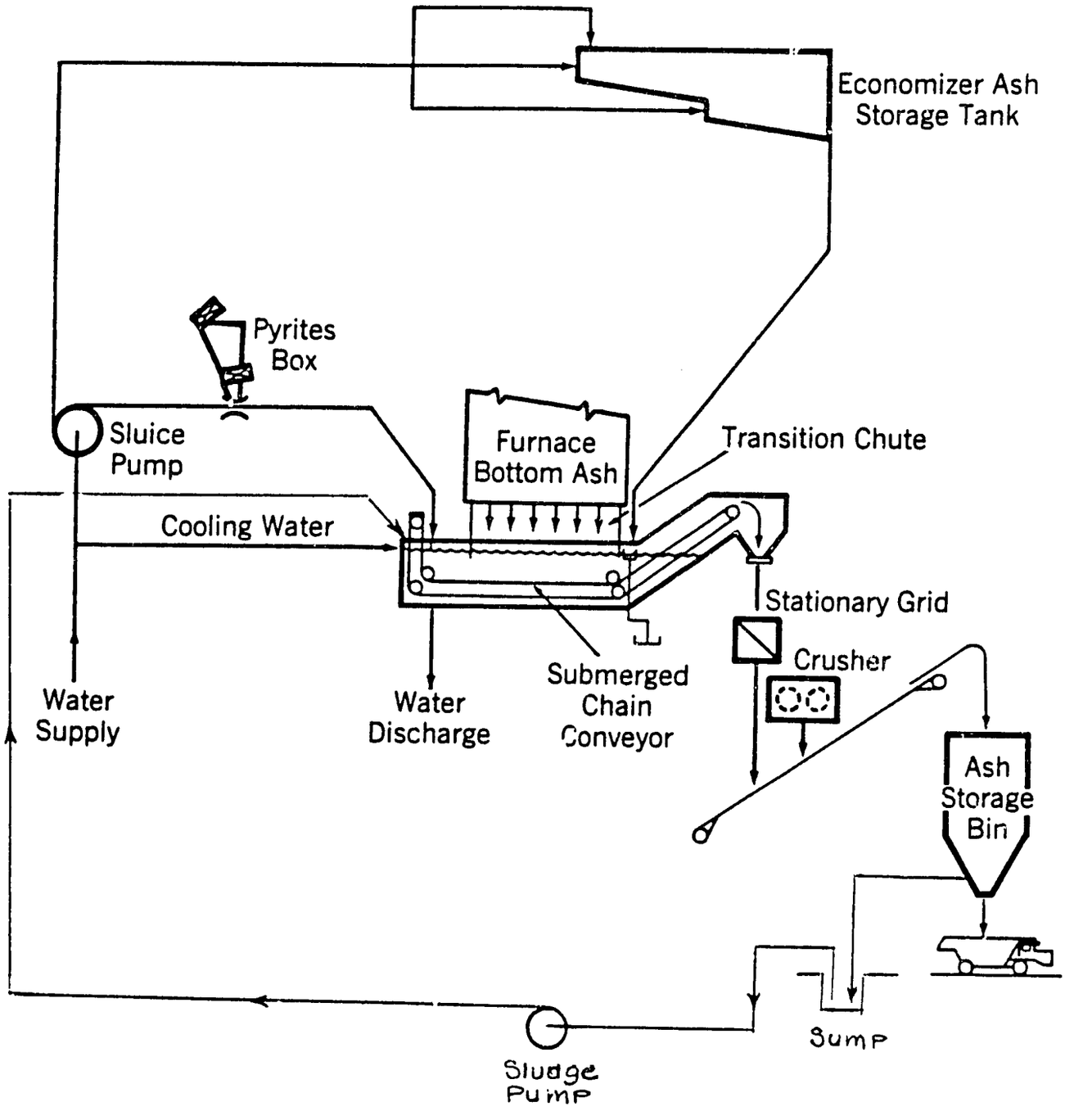

FIGURE 6

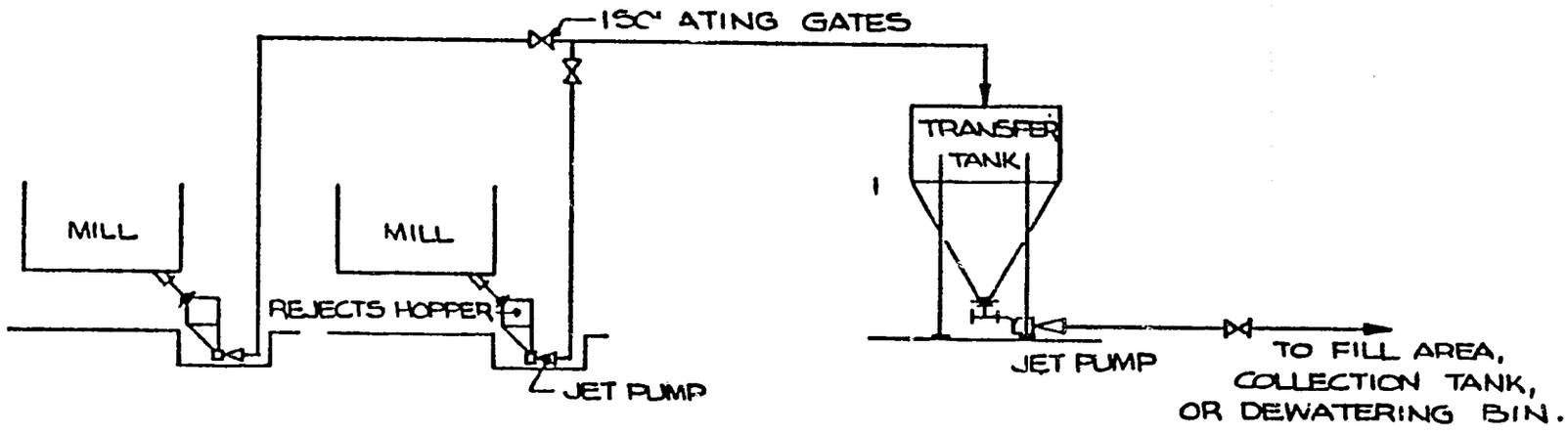

FIGURE 7

MILL REJECTS SLUICE CONVEYOR

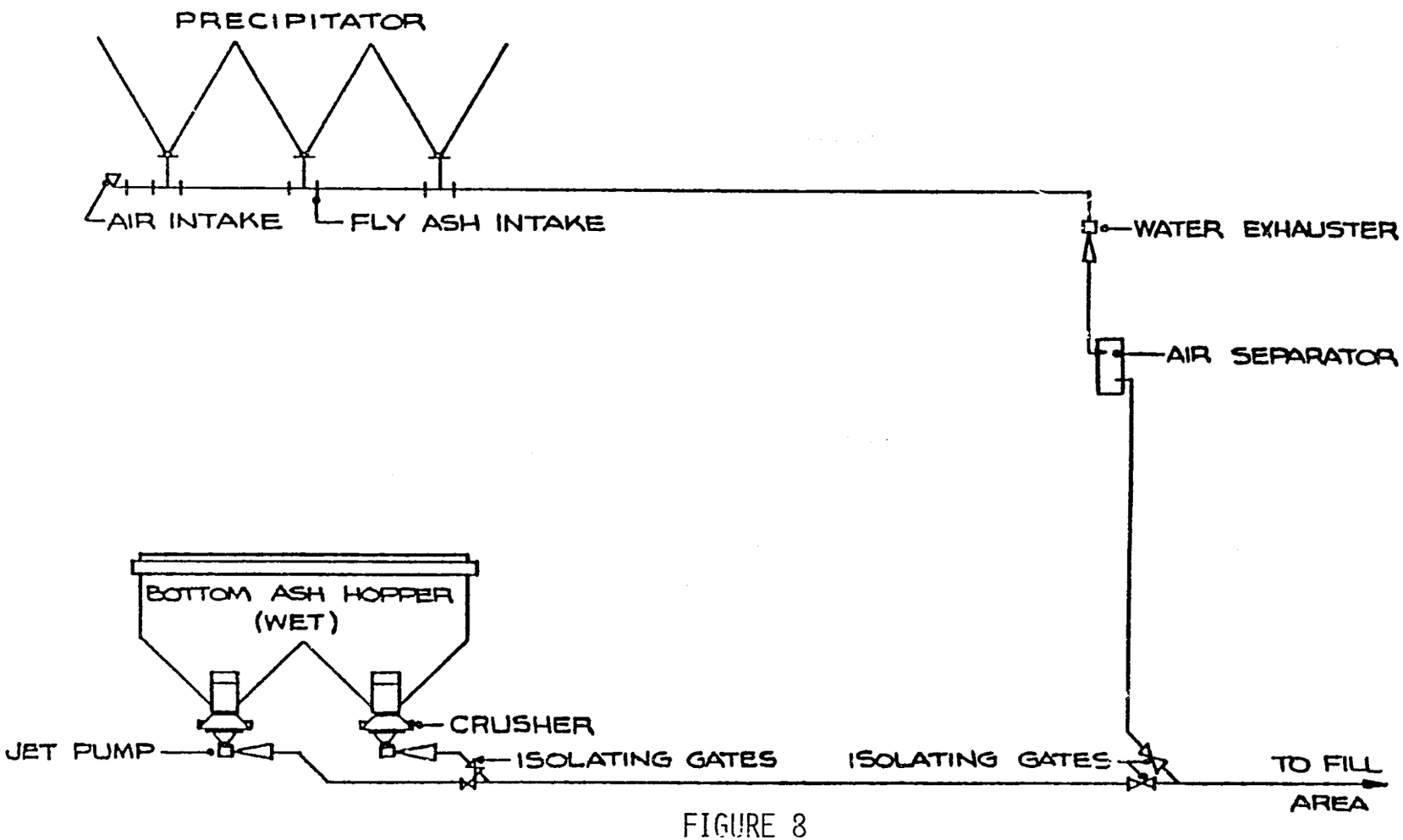

FIGURE 8

SLUICE & NEGATIVE PRESSURE PNEUMATIC CONVEYOR

(BOTTOM ASH • FLY ASH)

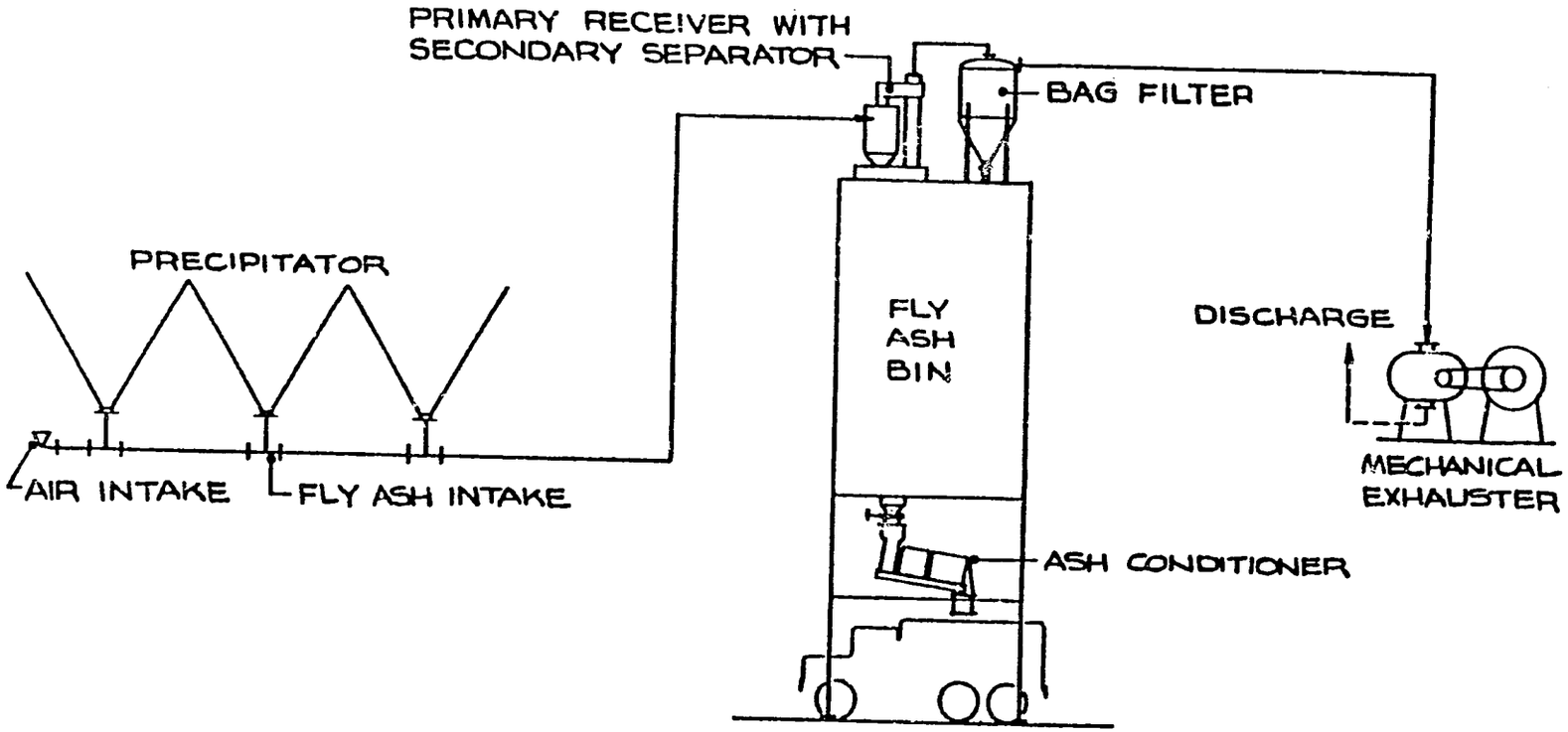

FIGURE 9

NEGATIVE PRESSURE PNEUMATIC CONVEYOR
WITH MECHANICAL EXHAUSTER
(FLY ASH)

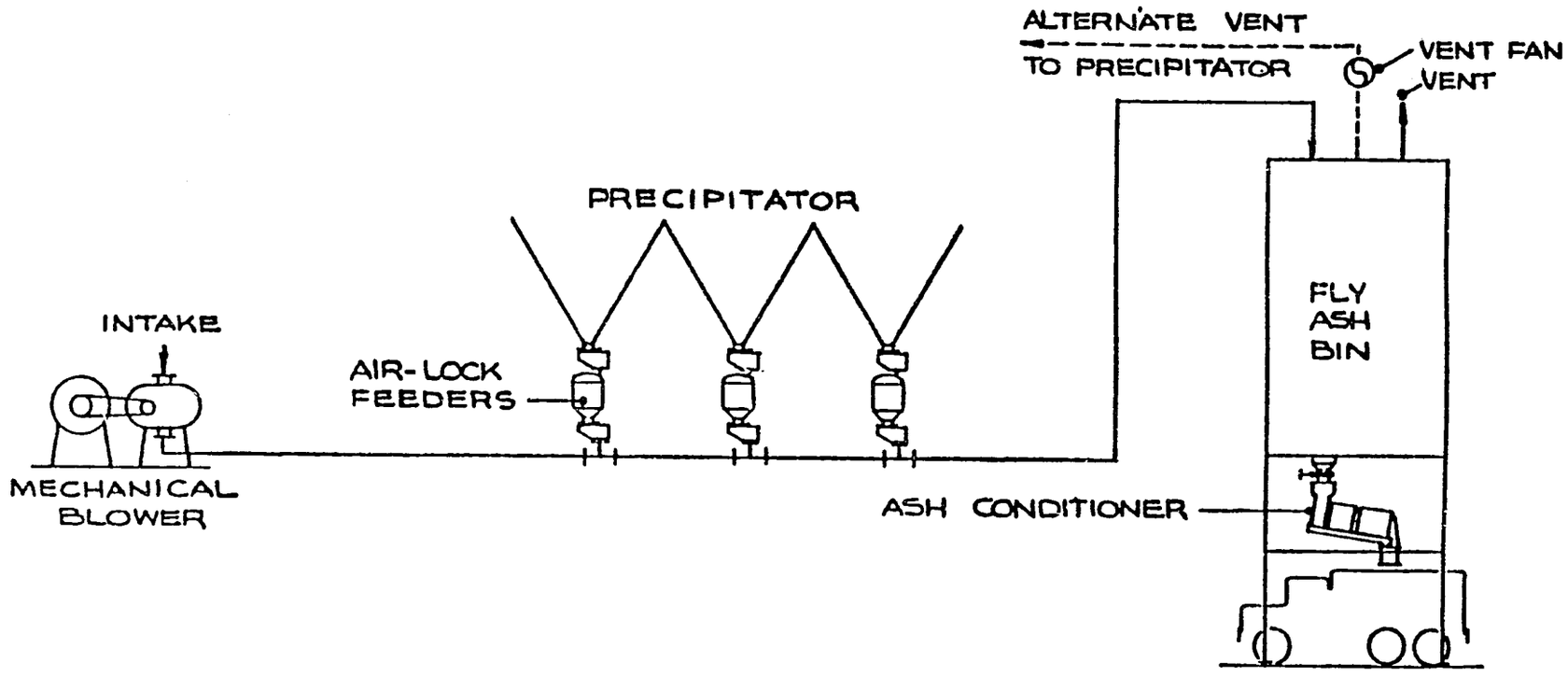

FIGURE 10

POSITIVE PRESSURE PNEUMATIC CONVEYOR

(FLY ASH)

APPENDIX 9

PARTICULATE REMOVAL SYSTEM

APPENDIX 9

PARTICULATE REMOVAL SYSTEMS

The types of fly ash collection methods discussed are: cold precipitators downstream of the air heater, hot precipitator upstream of the air heaters, and a fabric filter system downstream of the air heater.

Criteria for Fly Ash Collection System Selection

The fly ash collection methods given major consideration in this report generally satisfy the following technical requirements:

a. Have long-term commercial experience on utility or industrial applications of at least 100 MW or equivalent size.

b. Have at least 90 percent operating availability relative to the anticipated operating hours per year of the plant.

c. Be able to remove approximately 99 plus percent of the particulate from the inlet flue gas stream on a weight basis.

d. Be able to operate in a remote area under extreme weather conditions, i.e., high temperature in summer and low temperature in winter.

Precipitators

Hot and cold precipitators are constant pressure drop, constant efficiency devices with emission levels directly proportioned to inlet loading as long as all of the elements of the precipitator are

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functioning. Spare precipitator units are usually included in the design.

Since precipitators remove a fixed percentage of fly ash, the upper limit of ash in the expected range of coals would have to be known in order to be confident that the required emission limits would not be exceeded.

A precipitator's effectiveness is based on fly ash resistivity. Total fly ash resistivity includes the contributing effects of both surface resistivity and mass resistivity. Total resistivity is the measure of the ability of an ash particle to become electrically charged when subjected to a strong electrical field imposed by the high voltage discharge, and to change its direction of travel and be attracted to an electrically charged collection plate. In general, the lower the sulfur content in the fuel, the harder it will be to electrically charge the ash. The resistance to induced charging, the conductivity of the surface area, is mainly effected by surface adsorbtion of sulfur compounds, and is called surface resistivity. It is influenced by all of the ash constituents, but sulfur is the predominant item. Mass resistivity is the resistance of an ash particle to become charged as a result of the mass conduction of the particle itself. It is a temperature sensitive parameter because at higher temperatures the effect of surface resistivity, or surface conductions, decreases to the point where the mass conduction is dominant.

As ash resistivity increases and particle size decreases, the physical size, the amount of electrical equipment, etc, increases. This causes the cost of the precipitator to increase. Coals with greater than

2 percent sulfur have a significantly lower resistivity than coals with less than 2 percent. Therefore, higher sulphur content in Lakhra coal will be helpful in the process of electrostatic precipitation.

In general, as either the sulfur content decreases or the demand for collection efficiency increases, the number of precipitator electrical fields increases. Since the gas flow through a precipitator is through the fields in series, the ability to collect ash is improved with each additional field and the unit becomes longer.

Each field is electrically isolated and contains a discreet number of corona discharge electrode wires. The wires may be furnished as flexible wires, weighted at the bottom, referred to as the American flexible wire design or weighted wire design. These wires are vibrated to remove any ash buildup on them. Wires are also furnished as rigid shapes supported in a rigid frame referred to as the European rigid frame design. Since this design is fairly rigid and massive, the entire wire frame may be rapped with rapping hammers to remove any ash build up.

The ability to collect ash is also affected by the design of the precipitator inlet and outlet ducts and duct transition section. Both the pressure drop across each precipitator unit and the fly ash loading per square foot of entrance area must be the same for all of the units. Additionally, the fly ash loading should be uniform over the inlet area of each unit. A precipitator is capable of removing only a fixed percentage of the fly ash. Any overloading caused by a pressure imbalance, or poor gas distribution, will result in too much ash in one chamber, or a portion of a chamber. The overloaded section is not

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capable of removing the additional ash and it will be passed through the unit, and precipitator overall efficiency will not be achieved. To help prevent this condition from occurring, each inlet is furnished with at least one distribution device. The device creates a slight back pressure which evenly distributes the gas flow over the entire face of the plate. Fixed pressure drop differences, if not corrected with dampers or prevented by proper duct design, can be corrected by adding plates as required. Model tests are performed to verify the effectiveness of the distribution devices and entrance ductwork design.

The ash hoppers also require some special considerations. Hopper valley angles must be set steep enough to prevent dry ash from adhering to the sides. If sufficient ash adheres to the sides of the hopper, it will bridge across and plug the hopper. Since valley angles are set to accommodate dry ash, any condition which causes the ash to become moist should be avoided or accounted for by the hopper heaters. During cold weather or partial load operation there may be insufficient heat available in the hoppers to maintain the desired hopper metal temperature. The hopper heaters must furnish the balance of the heat required to maintain temperature or the acid dew point will be reached and the ash will become moist. Moist ash tends to plug hoppers very quickly and the hopper rappers may not be able to induce ash sliding.

In general, oil ash will be "stickier" than coal fly ash. If some plant operation on oil is anticipated, the precipitator specification should advise the manufacturer so that the hoppers and other areas can be designed accordingly. Since the inlet grain loading is very low when firing oil, emission requirements should not be exceeded when switching from coal to oil fuel.

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Cold Precipitators

A cold precipitator is located downstream of the air heater. Flue gas temperatures at the outlet of the air heater range between 250 and 400°F. The most common arrangements of cold precipitators include the single precipitator unit located at ground level and the multiple precipitator unit which usually consists of two identical single precipitator units. The multiple units may be arranged adjacent to each other at ground level, one on top of the other, called "stacked," or adjacent to each other but turned such that they partially face each other, called "chevron."

The arrangement best suited for a particular site is a function of available land area, pressure drop and gas distribution requirements for each technical design, and the cost of ductwork, dampers, supporting steel, insulation, ash removal equipment, etc. Regulatory requirements in industrialized countries have been forcing precipitators to increase in size in order to keep up with the collection requirements. As the size increased, the multiple precipitator unit became wider than the station unit it served. By arranging the two precipitator units in the chevron arrangement, it is possible to keep many of the required sizes within a reasonable area. As each precipitator unit becomes very large, the units must be stacked in order to keep the precipitator units reasonably behind the station unit and to keep the length, and number of turns and elbows of ductwork to a practical amount.

Regardless of the overall arrangement selected for a specific site and station unit, each precipitator unit will be designed as a multichamber, multifield device. Each precipitator unit is usually divided lengthwise

to form two separate chambers. Along each chamber are electrically separate sections, called fields. There is usually an ash hopper located below each field. The hoppers will be about 20 to 25 ft high plus about 10 ft between the outlet flange and the floor for the positive pressure ash handling valve.

Hot Precipitators

Hot precipitators are effective in collecting ash from relatively lower sulfur fuel because of the reduced surface resistivity of the ash at temperatures between 500°F and 800°F before the air preheater.

The addition of a hot precipitator and its associated ductwork between the boiler outlet and the air heater causes a heat loss that results in about a 14°F loss in flue gas temperature at the air heater. This loss results in a penalty to the overall plant thermal efficiency. For this reason and reasons associated with maintenance and performances, their use is very infrequent today.

Fabric Filters

Fabric filters are variable pressure drop, variable efficiency devices with the level of emission usually referred to as constant, though it is not actually constant. The emission level will vary with inlet loading, but not directly, because the filter bags will continue to entrap most particles above a certain size, regardless of the amount that enters the filter. This inherent feature of a fabric filter is advantageous because, should a section of the filter become inoperative, the balance of the filter continues to remove enough fly ash to meet emission requirements.

Fabric filters have been in use for many years. The earliest patents for the industrial application of filters date back to the last quarter of the 19th century. Recent advances in the collecting elements, usually referred to as a bag or sock, include:

1. The ability to operate at temperatures up to 550°F, and

2. The felted cloth made from the new synthetic materials.

If the expected fuels are extremely low in sulfur and/or sodium, a precipitator may not be able to remove sufficient ash because of the very high resistivity. Since a fabric filter's efficiency is not dependent on ash resistivity, that is, the collection ability is not dependent on the percent of sulfur, the fabric filter is an alternate collection method available to meet emission limits on low sulfur, low sodium coal applications.

A fabric filter unit is arranged internally such that the flue gas passes through a parallel arrangement of compartments. Each compartment or cell contains a number of bags which could be as long as 36 ft. To remove the collected ash from the bags, a compartment is isolated from the gas stream and a reverse direction, clean gas flow is impressed on the bags. One reverse flow gas fan per filter unit is usually provided. This short duration reverse flow loosens the dust cake and shakes the filter material. The ash then falls down into the ash hopper.

The compartment isolation method of ash removal keeps one compartment per filter unit off-line at all times, assuming continuous ash removal. The balance of the unit is exposed to the gas stream and performs the

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required filtration. The extra compartment is not really extra because it does not remove any fly ash during ash removal.

If a compartment becomes inoperative, station unit load does not have to be reduced in order to continue to meet emission requirements. The remaining compartments will handle the increased flow per compartment and remove essentially the same amount of ash as would be removed with the bad compartment in service. The pressure drop across the filter unit will increase when a compartment is inoperative and isolated. The increase in pressure drop is felt across every operating element and a slight decrease in efficiency may occur because some of the finer dust is forced through the filter but, essentially, the overall efficiency is maintained. If a number of compartments become inoperative, and the pressure drop is increased dramatically, the unit should be removed from service. The remaining filter compartment will handle the increased flow per unit but the increased pressure drop will probably be large enough to run the induced draft fans back on their curve, thereby forcing a station unit load reduction. Adequate maintenance and dry fly ash conditions should prevent a major filter outage. Adequately sized hopper heaters will help prevent ash from becoming moist in the hoppers and causing hopper plugging.

A slight increase in pressure drop is experienced between new, clean bags and normally ash caked bags, and is beneficial. This moderate increase in pressure compresses the filter cake and causes the cake to act as an efficient filter medium. The amount of additional filtration is dependent upon many variables and is difficult to determine, even with extensive testing. However, the phenomena are present and are very

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dependent upon ash properties, some of which are not considered or analyzed for any other reason.

Oil ash presents a special problem and any anticipated station firing of oil should be included in the fabric filter specification. Oil ash is "sticky" compared to coal fly ash and will tend to plug the filter bag material. The bags must be not only precoated with fly ash, or some other suitable material, to enable a fabric filter to handle oil ash, but for any extended period of time a continuous particulate injection system would also be required.

A fabric filter must be located downstream of the air heater. Flue gas temperatures at the outlet of the air heater range between 250°F and 400°F. Locating fabric filters at a higher temperature is not presently possible because the filter bag material cannot withstand higher temperatures. The most common arrangements of fabric filters include the single unit located at ground level and the multiple unit which usually consists of two identical single units, either stacked one on top of the other, or adjacent to each other.

As the required collection efficiency increases, there is very little that can be done to a fabric filter to improve its efficiency. The filter bag properties, with respect to fly ash collection, have already been maximized. No change in fabric filter unit size is incurred when considering emission requirements.

The physical size is basically a function of the flue gas flow or station unit size and the surface area of the filter bags. It is usually expressed as the ratio of cubic feet of gas to square feet of filter cloth - the air to cloth ratio.

Each fabric filter unit acts as its own pressure and flow distribution device. The filter bags create a back pressure which causes an even distribution of flow over the entire inlet of each unit. Therefore, breeching distribution plates are not required. Inlet ductwork, though, should be analyzed to ensure that the ash is evenly divided among the compartments and that no one compartment is going to be constantly overloaded. Uneven loading should not cause loss of overall unit efficiency but will cause excessive ash cake buildup, perhaps bag plugging, and subsequent overloading of the other compartments. If the condition were allowed to persist, the eventual high pressure drop would force a station load reduction. Entrance ductwork should be analyzed to ensure its ash distribution effectiveness.

Operation and Maintenance

Precipitators

The on-line operation of a hot or a cold precipitator is designed to be entirely automatic. Except for the ash handling system, the only moving parts are the penthouse pressurizing fans, the rappers, and the electro-mechanical controls for the electrodes and rappers.

The cleaning cycle, the rapping of wires, plates, and hoppers, is a sequential operation. This method raps sufficient plate area and wires at one time to keep the precipitator performing adequately. Sequential rapping prevents dislodging so much ash at one time that the unit becomes overloaded and fails to collect the ash. A failure in the control system would disrupt the sequence and result in either excessive or insufficient rapping. In either case, the net result is the loss of ash removal efficiency and emission requirements would be exceeded.

Periodic inspection, adjustment, cleaning, and replacement of worn parts of controls and rappers is required to maintain the unit at peak efficiency.

Efficiency is also impaired by the loss of an electrical field in any one of the chambers. The individual field in a chamber, called a cell, can be electrically isolated and the unit kept in service. The loss of a cell is usually caused by the failure of an electrode wire. The failed wire will swing around in the gas stream and strike the collector plate. This causes intermittent shorts. Should the wire weld itself to the plate, the continuous short caused is sensed by the automatic voltage control (AVC) system. The AVC will automatically isolate the cell. To prevent the loss of collecting ability of the unit when a wire breaks, the units are usually purchased with a spare field or cell. Units purchased with a spare field may perform slightly better when all fields are energized but will meet emission requirements when a cell is inoperative. To repair the broken wire, the entire precipitator unit must be physically and electrically isolated because repairs are performed inside of the unit. To prevent the remaining operating units from becoming overloaded during repairs, the station unit load must be proportionally reduced so that emission requirements will not be exceeded.

General maintenance should be performed to prevent normal conditions from becoming severe enough to effect unit performance. The penthouse bus insulators and heaters should be kept clean and dry to prevent arcing and failure. The penthouse pressurizing fans should be kept operational to prevent loss of availability and subsequent ability to keep the penthouse clean by pressurizing it. A dirty penthouse will

make it nearly impossible to keep the insulators clean. The ash hopper heating system, though simple, must be kept operational to prevent cold spots. A cold hopper will cause condensation. The ash will become sticky and bridge the hopper. This condition will cause pluggage and, eventually, loss of precipitator efficiency.

Fabric Filter

The on-line operation of a fabric filter is designed to be entirely automatic. In the filter cleaning system and the ash handling system there are moving parts required to function during normal, automatic operation. These include the reverse air fans, compartment isolation valves and their operators, and the electromechanical controls for the operation of the valves during the cleaning cycle.

The cleaning cycle is a sequential operation. Each compartment is isolated in turn, and the gas flow across the filter bags is reversed. At any given time, about 5 percent of the filter unit is being cleaned. This method cleans a sufficient number of bags at one time to prevent too thick an ash cake on the bags and a subsequent excessive pressure buildup. Sequential cleaning keeps all of the compartments, except the one being cleaned, operational and functional. The compartments not being cleaned are capable of maintaining unit efficiency and pressure drop. The surface area of the bags in the active compartment is called the net collection area. The area of all of the bags in the unit is called the gross collection area and is the area calculated using the air-to-cloth ratio.

To clean a compartment, it must be isolated. The controls automatically isolate a compartment by closing the compartment isolation valves at the

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compartment connections to the unit inlet and outlet ducts along the length of the inside of the unit. Reverse gas flow is furnished by the reverse air fan which takes suction from the clean gas flow. A compartment reverse air inlet valve is opened automatically and the gas blows the ash cake off of the bag collection surface. Reverse gas flow tends to collapse the bag, therefore the bags are reinforced to prevent their total collapse. The tendency to collapse sets up a fluttering action along the length of the bag and helps shake the ash cake loose. The ash falls into the hopper where the gas separates and returns to the unit intake duct. After about a minute of reverse gas flow, the compartment is returned to service and another compartment is isolated for cleaning. A malfunction in any of the isolation valves prevents the compartment from being cleaned and the compartment should be isolated and removed from service. The effect of removing the compartment from service is to increase the flow across the remaining compartments. With 22 compartments, the increase in pressure drop is only about 5 percent. As mentioned earlier, if a number of compartments become inoperative, the unit should be removed from service and station load reduced accordingly. Loss of the reverse air fan will also force removal of the unit from service and an appropriate station load reduction.

The filter elements, or bags, are susceptable to failure and a visual inspection should be made during every outage. One type of failure is caused by physical abrasion of the bag material against itself. The other type of failure is an acid attack condition caused by moisture getting at the bag and the adhering dust. Neither type of failure is severe with today's present designs and fabric materials, although some is to be expected. Bag failure is detected by monitoring the stack

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emission. If the emission suddenly decreases when a compartment is being cleaned, it may be assumed that a bag has failed and that compartment should be isolated. If only a couple of bags have failed, they can be capped off and the compartment returned to service. The bags can be replaced during a scheduled maintenance period.

The balance of the filter unit requires normal maintenance and cleaning for the type of equipment involved. The fans, valves, and controls should be maintained on a scheduled, periodic basis.

Operating Experience

Precipitators have been in use in the power industry since 1923, when the first full scale unit was installed in Detroit, Michigan. By the 1960s, precipitators were installed on the majority of all coal-fired boilers. By the 1970s, almost all coal-fired units were so equipped.

The Clean Air Act Amendments of 1971 established the first strict requirements for both particulate and gaseous emissions. Fabric filters became an economic alternative to the precipitator because of the strict requirements of the Amendments. The first power industry fabric filter was installed on an oil-fired plant for controlling gaseous emissions by collecting absorbing particles introduced into the gas stream upstream of the fabric filter. All subsequent fabric filters have been installed for fly ash particulate collection. The first installation was in 1973 at Pennsylvania Power & Light Company, Sunbury Station. Since then, a number of units have been installed, the largest in operation being at Texas Utilities Company, Monticello Station.

Since the implementation of strict emission requirements and their enforcement, precipitators and fabric filters have both had sufficient domestic power industry operating experience to prove they are acceptable methods of removing fly ash. They are used world wide in a variety of dust removal applications and both are satisfactory methods of dust collection.

Redundant (standby) isolatable precipitator chambers are necessary to ensure compliance with emission requirements. If redundant chambers are not provided, some reduced load operation must be expected because of the inability to enter a chamber during operation.

APPENDIX 1C

FLUE GAS DESULFURIZATION SYSTEMS

APPENDIX 10

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APPENDIX 10

FLUE GAS DESULFURIZATION SYSTEMS

GENERAL

Flue gas desulfurization (FGD) processes are categorized by two distinct characteristics: the final state of the SO_2 absorbent (wet or dry) and the ability to regenerate the SO_2 absorbent for reuse.

An FGD process in which the flue gas is cooled and saturated, and the waste is in liquid form, is classified "wet". A process in which the flue gas is not saturated, and the waste produced is in dry form, is classified "dry."

FGD processes that produce sulfur products in the form of SO_2, sulfuric acid, or elemental sulfur and that reclaim and reuse the absorbent are termed regenerable. Processes which combine the absorbent with the SO_2 to produce a product for disposal are termed nonregenerable or throwaway. Table 1 classifies the FGD processes covered in this study.

Table 2 indicates the preference of the United States utility industry for limestone over other FGD systems. Limestone systems constitute approximately 56 percent of the current calcium-based capacity in service and under construction, and 54 percent of planned systems (MW basis). These figures indicate the continuing commitment to limestone processes. Process economics appear to be the primary reason for this trend. Table 3 lists the operational FGD systems at utilities in the United States.

The FGD by-product treatment process, installed or planned, for each system is also listed. Of the systems listed, 23 perform some kind of

mixing between fly ash and unoxidized FGD sludge to produce a "fixed" or stabilized product. Five systems produce an oxidized product, either commercial or disposable grade gypsum. Future United States FGD systems are shown in Table 4.

The FGD systems given major consideration in this study satisfy the following technical requirements:

- Commercial experience on utility applications of 100 MW equivalent size or greater
- At least a 90-percent operating reliability index, defined as hours the FGD system was operated, divided by the hours the FGD system was called upon to operate
- Capable of removing at least 90 percent of the SO_2 from the inlet flue gas stream on a weight basis
- Capable of continuous boiler load following to an ultimate of 8:1 turndown ratio in capacity based on the nameplate rating of the boiler. The system must be capable of following the boiler during partial or complete boiler cycling. The unit also must be capable of operating at a capacity equal to the test block ID fan capacity

To ensure high reliability, the particulate content of the flue gas is assumed to be reduced to a normal level of 0.03 lb/10^6 Btu and a maximum level of 0.3 lb/10^6 Btu before entering the FGD system. These levels are in accordance with New Source Performance Standards (NSPS).

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Generic Design Considerations

All FGD systems discussed have many similarities with respect to the absorption process, reagent solution preparation and circulation, waste processing and disposal, operation, and maintenance. These common characteristics will be summarized in this section. Characteristics particular to an individual FGD system will be detailed in the section for that system. Drawings related to each system are referenced in these subsequent sections.

1. Process Description

The absorption portions of the FGD systems are similar for each "wet" process.

Boiler flue gas is distributed to the absorber modules for desulfurization. The flue gas enters the first SO_2 removal section of the absorber module, the quencher, where it is cooled to saturation temperature with the reagent solution before entering the bottom of the absorber tower. The quencher provides additional fly ash removal, augmenting the removal accomplished upstream by an electrostatic precipitator or baghouse, to protect the rest of the absorber tower from short term fly ash excursions. In the absorber tower, the flue gas is contacted (normally countercurrently) with sprayed reagent solution from levels of spray nozzles. The principal chemical reactions, removing the SO_2 from the flue gas, take place in the absorber and the recycle tanks.

The flue gas then passes through a mist elimination system before exiting the tower. The mist eliminator removes entrained slurry droplets, entrained solids, and is water-washed for cleaning. The

solids removal efficiency of the mist eliminator must be sufficiently great to meet strict particulate emission regulations. The SO_2 stripped flue gas is then reheated and exits to the stack.

The chemical reagent storage, preparation, and circulation portions of the FGD systems are similar. However, an important difference does exist between the regenerable and the nonregenerable systems with respect to the spent reagent solution. Normally, the reagent chemical is delivered and stored in dry, solid form. It is combined with water to make a reagent solution which is circulated to the absorber module spray nozzles for SO_2 removal.

In the no regenerable FGD systems, the waste stream is directed to a thickener in which the solids are allowed to settle and the thickener underflow is pumped to the sludge treatment system. Reclaimed water is taken from the top of the thickener for reuse.

In the regenerable FGD systems, the spent reagent solution leaving the absorber modules is regenerated to produce reagent solution, some solid waste, and SO_2. The SO_2 is processed into sulfuric acid or elemental sulfur.

2. Waste Processing/Disposal

The major distinction between regenerable and nonregenerable FGD systems is the type of end product produced. Regenerable systems separate the SO_2 from the used reagent solution, which then is reused. Only a relatively small amount of solid waste is produced. However, very large quantities of sulfuric acid or sulfur are produced and a reliable market

must exist to accept them. If sale is not possible, disposal of these materials is a severe problem.

Nonregenerable systems do not reuse the reagent solution and, therefore, produce large quantities of waste. These systems require significant reagent storage facilities onsite and large disposal areas either onsite or off site. Various methods of waste disposal are available, depending upon the type of FGD system. The two most common means of waste disposal in the United States are sludge ponding and sludge stabilization.

If governmental regulations permit the use of a sludge pond, the FGD sludge slurry, fly ash slurry, and bottom ash slurry can be pumped to the pond where the solids settle and the reclaimed water is returned to the FGD system. An advantage of sludge ponding is that this is a relatively simple process. Sludge ponding disadvantages include the construction of a lined pond, thixotropic pond sludge, decreasing viscosity with increasing piping area, and an increased possibility of groundwater contamination.

An FGD sludge stabilization system is diagrammed on Figure 1. The FGD waste slurry is normally dewatered by vacuum filters or centrifuges to approximately 50 to 60 percent by weight hydrated solids. The filtrate is returned to the FGD system. The dewatered FGD waste is mixed with fly ash, bottom ash (if desired), and lime to produce a stabilized sludge suitable for landfill. The FGD sludge stabilization system should be designed to handle a range of weight ratios (dewatered sludge/fly ash). If the utility wants to sell boiler fly ash to local cement industries, the FGD sludge stabilization system can be designed

to produce stabilized sludge using a fraction of the available fly ash if the weight ratio of dewatered sludge/fly ash is within the range of 1 to 3. Low sulfur coal and high sulfur coal result in low and high weight ratios, respectively.

An advantage of sludge stabilization is that it produces a chemically and physically stable landfill material with low trace element leach rates and ultimate load bearing strengths of at least 3 tons per square foot. Normally, stabilized sludge is disposed of as landfill. Several utilities have investigated commercial uses of stabilized sludge for road bed material, lake front fill material, fertilizer, dam fill material, and others. Utilities should investigate legal liabilities before committing themselves to a commercial contract involving their FGD waste.

Another means of FGD sludge disposal is forced oxidation. In this process, air is bubbled through the FGD waste slurry to produce gypsum which can be dewatered and disposed of as landfill or used commercially. The production of gypsum allows the possibility of selling or giving away boiler fly ash and bottom ash to local cement industries. Gypsum may have a commercial value if it has desirable properties, such as proper water content, size distribution, crystal structure, color, chemical purity, and mechanical properties. Potential commercial gypsum consumers are cement industries, wall board industries, and fertilizer industries. Only during special situations will FGD gypsum have commercial value, but the commercial value may help defray the utility's cost of transporting the gypsum to the consumer.

The ultimate disposal of FGD waste is a serious problem. Dewatered FGD waste from the "throwaway" systems can be used as landfill. A brief description of the handling/disposal of stabilized FGD sludge follows.

Dewatered FGD waste is mixed with fly ash and lime and conveyed outside of the sludge stabilization building to a radial stacker that delivers the sludge to a 3- to 7-day surge pile. The fresh material from the radial stacker is normally too wet to work immediately; it is normally allowed to stand for 3- to 7-days to partially set up, in a manner similar to cement, before being moved. After 3 to 7 days, it is similar to clay and is manageable with the proper earth moving and handling equipment. If the material is left for more than 10 days the pile may become quite hard and break apart in very large boulders. This hampers the movement and placement of the fixated material. Experience has shown that rubber-tired equipment has poor traction on the initially placed stabilized sludge. This surface condition is due to the fine-grained nature of the material and the "bleeding" of the surface pore water from the stabilized sludge when compressed during its early setting period. The film created by the bleeding effect causes the surface to be slick prior to final set. Tracked equipment, normally used in earth moving operations, can move the stabilized sludge adequately.

The stabilized sludge of the radial stacker surge pile can be conveyed or front-end loaded into a transportation means and transported to a disposal area. The type of stabilized sludge transportation employed depends on economics. For example, the use of an onsite landfill disposal area within a few miles of the sludge stabilization building usually dictates the use of truck or conveyor transportation. The use

of an offsite landfill disposal area located a great distance from the sludge stabilization building normally results in the use of railcar or truck. The use of barges to haul stabilized sludge has been proposed by several utilities in the United States but currently no utility or industry employs barges.

Onsite landfill disposal can be performed using oversized hauler trucks (greater than 20 ton loads) because restrictive governmental regulations concerning loads greater than 20 tons normally do not apply to onsite hauling (i.e., stabilized sludge could be hauled in 50 ton haulers similar to 50 ton coal haulers). Offsite landfill disposal by truck usually means the utility is forced to drive on public roads (unless the utility constructs its own road), hauler loads are kept to less than 20 tons, and the utility maintains the public road in proportion to their use of the road. Offsite disposal by truck on public roads can result in massive convoys, especially if hauling is restricted to daylight hours, loads are restricted to 20 tons, and the coal fired plant has a high burn rate of high sulfur coal.

Each transportation means (truck, rail, conveyor, or barge) must be specially designed to handle/haul stabilized sludge. Of great importance are the physical-chemical properties of the stabilized sludge such as bulk density, angle of slide, angle of repose, preconsolidation strength, permeability, curing time, adhesion properties, bridging properties, and other properties.

The ultimate disposal of stabilized sludge can occur in a variety of places. Usually the stabilized sludge is employed as landfill and is used to levelize terrain. In some instances, no terrain gradients

initially exist and the stabilized sludge is shaped into a massive plateau. Another method is mine disposal, where the stabilized sludge is used as landfill in the plant's coal stripping/mining or limestone quarry area. Some utilities in the United States have proposed ocean or lake front landfill using stabilized sludge. This proposal is pending governmental regulations.

In a typical landfill operation, the stabilized sludge from the radial stacker pile is front-end loaded into haulers, which are driven to the disposal area and dumped. After the truck has pulled away, a grader layers (usually 2 feet thick) and a roller compacts the stabilized sludge. The compacted stabilized sludge may have a preconsolidation stress of 3 tons per square foot or more. The final chemical-physical properties of the landfill depend on the FGD system employed, fuel used, method of curing, and compaction employed. When the stabilized sludge becomes wet due to normal rain or snow, it usually behaves as earth and does not become thixotropic. Compacted stabilized sludge usually has low permeabilities (10^{-6} to 10^{-7} cm/second) which means special water run-off considerations are given in the design of a landfill area. Usually, utilities grow vegetation (i.e., grass or trees) on top of the stabilized sludge landfill area after the filling operation has terminated.

Operation and Maintenance

1. Operation and Maintenance Personnel

FGD systems are large scale chemical plants that have mechanical and chemical process equipment in which complex chemical reactions occur. The large number of components and subsystems, and the fact that FGD

systems cannot be completely automated, necessitates a significant number of operating and maintenance personnel. In order to ensure reliable operation, maintenance personnel are required to perform preventive maintenance and repairs. Utilities and industries in the United States which have highly reliable FGD systems usually have achieved this by a properly trained staff with adequate funding, managed by dedicated supervisors.

The throwaway systems produce very large quantities of waste, the truck handling of which requires a significant number of personnel. The regenerable systems include a complete regeneration plant and sulfuric acid plant which also require significant numbers of personnel for proper operation and maintenance.

2. Generic Operating and Maintenance Problems

The limestone, wet lime, double alkali, and Wellman-Lord FGD systems have many similar operation and maintenance (O&M) problems such as mechanical and electrical component failures, wear, stress, shear, corrosion, erosion, and plugging. These problems can be minimized by proper design, operation, and maintenance. These problems can cause the shutdown of a portion or all of the FGD system with subsequent derating or shutdown of the boiler, if sulfur dioxide emission variances are not granted.

The following list includes the most common modes of failure in an FGD system:

1. Mechanical failure of rotating equipment

2. Electrical failure of controls and instrumentation

3. Corrosion and erosion inside components which handle liquids and/or flue gas

4. Plugging and sealing inside components which process or hold slurries

3. Coal Type and Its Effect on Flue Gas Desulfurization Systems Operation and Maintenance

The type of coal that is burned at the power plant influences the design, maintenance, and operation of the FGD system. If the use of a wide range of coals is anticipated, the FGD system must be designed to meet SO_2 emission regulations while burning any of the selected coals. The FGD system can be designed to meet NSPS when inlet flue gas SO_2 concentrations are as low as 50 ppm volume (low sulfur coal) and when they are as high as 4,000 ppm volume (high sulfur coal). FGD systems can be designed to accommodate varying flue gas flow rates which result from burning different coals. In addition, FGD systems can be designed to withstand high equilibrium chloride concentrations which result from the use of high cloride coal and/or high chloride makeup water. The FGD waste handling system must be designed to process the maximum amount of waste produced by the FGD system. Maximum FGD waste usually is produced at full load operation burning highest sulfur coal. If a sludge stabilization system is employed, it must be designed to produce an environmentally acceptable stabilized waste even during conditions of varying ash to dewatered sludge ratios.

Generally, the number of FGD system maintenance and operation personnel increases as coal sulfur, ash, and chloride contents increase. The use of high sulfur coals usually results in larger and more complex reagent

handling, storage and preparation systems, higher liquid to gas ratios (L/G), larger reaction tanks, and larger sludge handling, dewatering, and disposal facilities. The use of high ash coals usually results in larger and more complex sludge stabilization systems and larger stabilized sludge disposal areas.

4. Control and Instrumentation

FGD systems require accurate control and monitoring to ensure reliable operation. The two primary means of controlling the sulfur dioxide removal performance of an FGD system are SO_2 mass flow or SO_2 absorber reagent slurry pH. During the SO_2 mass flow control method, the fresh reagent is fed to the absorber recycle tank at a rate determined by, and proportional to, the SO_2 mass flow entering the absorber tower. During the SO_2 absorber reagent slurry pH control method, the fresh reagent is fed to the absorber recycle tank at a rate determined by, and proportional to, the pH differential between setpoint minus actual absorber reagent pH readings.

If the SO_2 mass flow control method is employed, pH of absorber reagent is only monitored and recorded. If the pH of absorber reagent slurry control method is employed, the SO_2 mass flow entering the absorber tower is only monitored and recorded.

FGD systems usually monitor and record the following process information:

- Flue gas flow
- SO_2 concentrations

- Temperatures
- Pressures (liquid and gas)
- Slurry solids concentrations by density
- Slurry pH
- Slurry and water flows
- Consumption of electricity, steam, water, and chemical reagent and production of waste products

Control monitoring and recording of critical FGD process parameters usually is accomplished using an FGD control panel located in the FGD power and control building. Less important parameters are indicated at local instrument/indicator racks. Solid state electronic equipment utilizing integrated circuits generally are employed.

FGD systems must be designed so they will not cause a trip of the boiler. Where regulations permit, a flue gas bypass around the FGD system can be employed with either no bypass dampers, constantly open bypass dampers, or partially/completely closed bypass dampers with quick opening pneumatic drives. If a total bypass around the FGD system is not permitted by governmental regulations, the use of a partial bypass around the FGD system or individual scrubber module bypasses should be employed.

Control valves in slurry lines usually are avoided to minimize maintenance.

Flue Gas Desulfurization Equipment Philosophy

1. Stack Gas Reheater

Stack gas reheat is used to provide added gas buoyancy, prevent acid condensation, and to minimize visible plume formation. Excessive reheat may result in higher flue gas buoyancy but will result in increased reheater steam usage. An indirect type reheater sized for total volume stack gas is preferable to an inline reheater. The latter would be located in the flue gas stream where it would be subject to corrosion problems. The indirect type reheater is located external to the gas stream. A blower passes ambient air over a heat exchanger through which low pressure steam or hot water passes, and the resulting hot air is mixed with the scrubber offgas before the stack.

When regulations allow, reheating with bypassed flue gas is recommended to avoid or minimize the mechanical problems inherent to reheaters and the high cost of steam or hot water.

2. Spare Equipment

A full-size spare scrubber module is recommended for high system reliability and is included in the economic analysis. In this report, all FGD systems have three scrubber modules (two operating modules and one spare module, each sized for 50 percent of full flow.

All pump services should include one operational spare pump which is identical in design and operation to the other pumps. This operational spare pump should be capable of being operated as frequently as the other pumps.

The ducting should permit bypassing of the entire FGD system if regulations permit.

3. Generic Equipment

Some equipment is generic to the major FGD systems presented in this report. Mechanical equipment such as scrubber modules, pumps, fans, ductwork, mist eliminators, reheaters, sample sinks, valves, conveyors, material handling equipment, tanks, agitators, piping, filters, hoists, HVAC, and other equipment are present in all of the FGD systems. Generic instrumentation and control equipment include control panels, logic cabinets, thermocouples, visual indicators, power-control-instrument cable, transmitters, analyzers, primary elements, sensors, power supplies, and instrumentation and controls for process parameters indicated in Section 2.3.4. Electrical equipment generic to all FGD systems are motors, switchgear, load centers, supervisory control system, control boards, relay panels, station batteries and chargers, lighting, transformers, fixtures, outlets, switches, lamps, power cable, conduit, cable trays, wire plugs, grounding system, intraplant communication, and other equipment. The different FGD systems share generic structural/civil/architectural concepts such as foundations, FGD system power and control building, pumphouses, waste handling building, trestles, trenches, structural steel, concrete, reinforcing steel, embedded iron, inserts, dowels, anchor bolts, excavation, dewatering, backfill, finish grading, platforms, ladders, stairways, enclosures, tanks, silos, basins, sumps, brackets, pads, pedestals, painting, roofing, insulation, tile work, sanitary facilities, and other structures. FGD systems have many common erection procedures such as labor, supervision, unloading, storing, protection, cranes, trucks,

cable, hoisting, rigging, scaffolding, welding, NDT, grouting, tools, and other erection aspects.

In general, different FGD systems share many common design, engineering, erection, and operation and maintenance concepts while differing in detailed chemical process flow schemes.

4. Flue Gas Desulfurization System Bypass

In this report, the major FGD systems such as lime, limestone, double alkali, and Wellman-Lord are recommended to have FGD system bypass. The use of a bypass is recommended for the following reasons:

1. Simplify plant startup and shutdown procedures especially during initial plant operation when control systems are being tuned.

2. Increase plant availability by permitting power generation during FGD system outages, assuming SO_2 emission variances are granted.

3. Protect FGD system from high flue gas temperatures during emergency conditions such as air preheater failure.

4. Allow treatment of only a portion of the flue gas when FGD is used in conjunction with other means of sulfur removal, i.e., coal cleaning or use of very low sulfur coal.

5. Permit the utility to reduce the plant's coal burn rate during emergency coal storages (i.e., coal mining/handling strikes) by partially or totally bypassing the FGD system, assuming SO_2 variances are granted.

5. FGD System Terminal Points

FGD systems require utility and chemical reagent terminal point supplies as presented in Table 5.

Terminal points within the FGD system scope have been established as follows:

- Flue gas outlet of ID main fans
- Flue gas exit at entry flange to the stack
- Utilities have single points of supply at the unit battery limit
- FGD chemical reagents are assumed delivered at the plant gate
- FGD stabilized sludge and ash are disposed of onsite. Sulfuric acid and sulfate cake are sold to local chemical companies.

6. Effect of Flue Gas Desulfurization System on Coal Fired Plant Availability

The limestone, lime, double alkali, or Wellman-Lord FGD systems have a reasonable expectation of operating greater than 90 percent of the anticipated plant operating hours per year without affecting plant electrical output. This 90 percent value is based on data from the few highly reliable FGD systems currently operating in the United States. During 10 percent of the anticipated plant operating hours, the FGD system may partially or completely shutdown, resulting in a forced derating or forced shutdown of the plant. The high cost of forced

derating or forced shutdown of the plant represents an incentive for having a highly reliable FGD system.

LIMESTONE UNOXIDIZED FLUE GAS DESULFURIZATION SYSTEM

General

The limestone system described in this section is of the unoxidized type (i.e., forced oxidation is not used) and produces a by-product that is primarily calcium sulfite, with some calcium sulfate occuring through natural oxidation.

Two types of limestone FGD systems are available, single loop and double loop. The double loop flow scheme is shown on Figure 2.

The double loop system differs from the single loop in the absorber portion of the process. The single loop system utilizes a design in which recycled reagent slurry is sprayed into the absorber modules where it reacts with the flue gas to remove SO_2. The spent slurry is then sent to the thickeners for waste processing.

In the double loop system, the reagent slurry is used twice for SO_2 removal from the flue gas. Partially spent reagent is sprayed into the absorber modules early in the gas flow path where the SO_2 concentration is high. Fresh reagent is sprayed into the upper part of the absorber modules where the SO_2 concentration is reduced.

A potential advantage of the double loop system is a more efficient utilization of the reagent, thereby lowering reagent operating cost. A potential disadvantage of the double loop system is a slightly higher capital cost as a result of an increased use of pumps. Competitive

bidding between a double loop limestone system and a single loop limestone system will determine which type of system is more economical for a specific application.

Limestone FGD Process Description

The absorption portion of the single loop limestone FGD system is described in Section 1.

In a double loop limestone FGD system the flue gas enters the module where it is quenched and SO_2 is removed in the lower loop. The flue gas is then contacted countercurrently in the upper loop to remove the remaining required SO_2. The SO_2 stripped flue gas then passes through a two-stage mist elimination system and is reheated indirectly before exiting to the stack.

The limestone reagent storage, preparation, and circulation portions of the limestone FGD system are described generally in Section 1 and are described in detail below.

Bulk limestone (normally 3/4 inch x 0 inch and containing greater than 90 percent reactive $CaCO_3$) is delivered to the site by truck, rail, or barge and is transported to the pile by belt conveyor. The limestone pile should be sufficient for 90-day operation at annual average load and annual average sulfur content. Dolomitic limestone (normally 40 percent magnesium carbonate, 50 percent calcium carbonate, and 10 percent inerts by weight) usually is not adequate for use in an FGD system.

From the limestone pile, the limestone is reclaimed into conveyors that transport the limestone to a surge silo with a 1-day limestone capacity.

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With the surge silo discharge valve open, the limestone is weigh-fed to wet ball mills, where pulverized limestone slurry is prepared with a normal composition of less than 100 mesh and greater than 40 percent by weight solids. This slurry is then sent to the reagent feed tanks, each of which has a minimum of 8-hour storage capacity at design conditions. A wet cyclone separates oversized limestone particles before the slurry enters the reagent feed tank and returns them to the inlet of the ball mill. The slurry is then fed to the recycle tank at a rate proportional to the SO_2 mass flow entering the absorber tower. Flue gas flow rate, SO_2 concentrations, temperatures, and pressures are monitored.

From the recycle tank, the slurry (normally approximately 10 to 15 percent by weight solids) is recirculated to the spray section of each tower. Slurry density, pH, and flow are monitored. A slip stream from the scrubber is discharged to thickeners where part of the water is reclaimed and thickener underflow is fed to the sludge stabilization system.

The calcium sulfate/sulfite underflow slurry from the FGD thickeners usually contains 20 to 35 percent by weight suspended solids, including water of hydration. The underflow slurry has a temperature of approximately 110°F, a pH of 5.5 normally, and a specific gravity of approximately 1.3.

1. Chemistry

The principle reactions in the absorber are between SO_2 in the flue gas and water (H_2O) in the absorbing solution. The reactions involving the limestone are completed in the recycle tanks.

Absorber reactions:

$SO_2 + H_2O \quad H_2SO_3$

$H_2SO_3 \quad HSO_3^- + H^+$

$HSO_3^- \quad H^+ + SO_3^{-2}$

$CaCO_3 \quad Ca^{+2} + CO_3^{-2}$

$CO_3^{-2} + 2SO_2 + H_2O \quad 2HSO_3^- + CO_2$

Recycle tank reactions:

$CaCO_3 \quad Ca^{+2} + CO_3^{-2}$

$Ca^{+2} + CO_3^{-2} + H^+ \quad CaHCO_3^+$

$CaHCO_3^+ \quad Ca^{+2} + HCO_3^-$

$Ca^{+2} + SO_3^{-2} \quad CaSO_3$

$CO_3^{-2} + 2HSO_3^- \quad 2SO_3^{-2} + CO_2 + H_2O$

$CaSO_3 + 1/2\ O_2 \quad CaSO_4$

The insoluble waste calcium products are actually hydrated as $CaSO_3 \cdot 1/2\ H_2O$ and $CaSO_4 \cdot 2H_2O$.

2. Waste Processing and Disposal

The FGD waste from the thickeners can be disposed of by sludge ponding or sludge stabilization followed by burial. These methods are described in Section 1.0 of this Appendix.

When sludge ponding is not employed, an emergency dump pond is provided for waste from the thickeners, in the event that the sludge stabilization system is out of service. This emergency dump pond is sized for 10 days operation at full load, maximum sulfur coal.

3. Scaling Problems

In limestone FGD systems, the reagent solution is in slurry form and severe scaling and plugging problems can occur. These problems can lead to shutdown. The deposition of solids on scrubber surfaces interferes with gas flow and can plug piping. The scale formed on surfaces is often so adherent that removal is difficult and must be done manually. Scaling and plugging can be minimized by accurate pH control, water wash of surfaces, water flush of piping, and design features which minimize scale buildup.

Scaling normally occurs in the following limestone FGD system areas:

- Wet/dry interface of flue gas duct work entering quencher section
- Spray nozzles
- Absorber internal structures such as "packings" or support steel
- Mist eliminators
- Inline reheater steam coils if indirect reheaters are not employed
- Instruments

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Scaling at the wet/dry interface can be minimized by a design which prevents back splashing of absorber slurry back into the flue gas inlet duct work.

Scaling in spray nozzles, absorber internals, and mist eliminators can be minimized by proper control of slurry pH. Generally, pH is maintained within a narrow range (i.e., 4.5 to 5.0 or 5.0 to 5.5). If the pH rises above the maximum desirable value, chemical reactions occur which result in massive precipitation and scale buildup of $CaCO_3$, $CaSO_3$, and $CaSO_4$ hydrate on surfaces. If the pH falls below the desirable minimum value, SO_2 removal efficiency may decrease and materials of construction may suffer as a result of acid attack. Slurry pH control is normally accomplished with limestone being added automatically if the pH falls below the desirable minimum value. If pH is above the desired maximum value, the rate of limestone slurry addition to the recycle tank is decreased. As indicated in Section 1.0 of this Appendix, fresh limestone slurry addition can also be controlled by using SO_2 mass flow method instead of pH of slurry method. Both methods can be made to work adequately, with the result being minimum scaling.

Scale buildup on mist eliminators can be minimized by water wash of mist eliminator surfaces. Two-stage mist eliminators usually have their first stage water washed on top and bottom using continuous fresh water (an adequate flow rate per square foot of mist eliminator blade surface area is required). The second stage of the mist eliminator is normally fresh water washed automatically on a periodic basis or on high gas pressure drop. The effects of scale buildup on mist eliminators can be minimized by a proper design which incorporates adequate spacing between the blades. Adequate spacing between mist eliminator blades results in

minimum scale bridging between the blades. Mist eliminators inherently have close spacings between the blades; therefore, prevention of scale buildup by pH control and fresh water wash are considered the most effective means of scale control.

Scale buildup inside spray nozzles can be minimized by proper spray nozzle flow design which incorporates large cross sectional areas for flow, wide angle bends, and elimination of areas where static slurry can accumulate.

Scale buildup on absorber internal structures can be minimized by proper design which incorporates low pressure drop internal structures and elimination of areas where static slurry can accumulate.

Scale buildup on inline heaters results from $CaCO_3$, $CaSO_3$, $CaSO_4$ hydrates that exit the mist eliminators and deposit and "bake on" the hot reheater coils. This reheater coil scale causes a decrease in the overall heat transfer rate between the steam and scrubbed flue gas and often results in an unacceptably low amount of flue gas reheat. Scale buildup on inline reheaters may be minimized by extra washing of mist eliminators, more efficient mist eliminators, and periodic water wash of the inline reheater coils. The effects of inline reheater coil scale buildup may also be minimized by a design with extra heat transfer area. Indirect reheaters are often employed to accomplish flue gas reheat without inline reheater scale buildup and/or acid corrosion.

Scale buildup can occur on instrument sensor surface areas often resulting in erroneous instrument readings. For example, $CaSO_4/CaSO_3$ hydrate scale can deposit on glass pH probes and form an electrical/physical barrier between the liquid and the probe. The

results are erroneous pH readings and subsequent operator loss of confidence in the pH probe readings. Since slurry pH control is of great importance, pH probe scale must be minimized. Probe scale buildup can be minimized by maintaining proper pH in the slurry, periodic fresh water wash of probe surface, and continuous ultrasonic cleaning.

In limestone FGD systems, plugging can occur as a result of massive scale buildup and/or settled slurry solids. Plugs stop gas and/or liquid flow and can lead to FGD system shutdown. Plugs are often so massive that removal is difficult and must be done manually. Plugs can occur in pipes and instruments that handle or come in contact with slurry. Plugs can be minimized by accurate pH control, water wash of surfaces, and automatic or manual water flush of piping. In addition, plugs can be minimized by proper pipe and instrument design and layout which includes wide angle bends, vertical gradients less than 20 degrees, high linear velocity (usually greater than 8 ft/sec), integrated water flush system, quick disconnect couplings, short pipe section lengths (approximately 20 ft from flange to flange), no areas where solids can settle out, and other design features.

Scale buildup and plugging can be determined by visual inspection, increased gas pressure drop, increased liquid pressure drop, erroneous instrument readings, and loss of gas or liquid flow. If scale buildup continues after the aforementioned corrective action is taken, alternative measures must be taken to correct the situation. For example, the absorber module can be shutdown, isolated, and manually cleaned by skilled and unskilled maintenance personnel. The required cleaning tools include high pressure hoses, hammers, chisels, shovels, cutting tools, and other manual tools. If instruments or pipes scale or

plug, they are usually water flushed or disassembled and manually cleaned.

LIMESTONE GYPSUM FLUE GAS DESOLFURIZATION

Gypsum is produced in limestone FGD systems by forced oxidation. There are two approaches commonly used to oxidize calcium sulfite to calcium sulfate (gypsum), as follows: (1) in-situ oxidation within the absorber module or (2) bleed stream oxidation in a separate tank, which is more frequently practiced in Japan. The oxidation process itself is simple, requiring the sparging of air from compressors through the liquid in the tank. In addition to the extra oxidation tank required in bleed stream oxidation, equipment for chemical addition to control pH is usually required. At low pH levels, the oxidation of the sulfite ion is more easily accomplished. For this purpose, magnesium oxide (MgO) or sulfuric acid (H_2SO_4) have been used in the past. For in-situ oxidation, the double loop scheme is particularly well-suited; the lower loop can be operated at low pH to promote oxidation, without the additional equipment required for bleed stream oxidation. Therefore the double loop arrangement is preferred for the gypsum producing systems. The flow scheme for the FGD system is shown on Figure 3.

The degree of oxidation, relative to the percent gypsum in the final product, depends upon oxygen stoichiometry. As a result, the only difference in the FGD system between producing a disposable grade gypsum and a commercial grade gypsum is the size of the oxidation compressors, as measured by horsepower. Disposable grade gypsum is assumed to contain 80 percent calcium sulfate dihydrate ($CaSO_4 \cdot 2H_2O$) on a dry weight basis. This value is the minimum percent gypsum required to

achieve the high degree of dewatering, by vacuum filters, necessary for a handleable gypsum product (without further treatment). Commercial grade gypsum is assumed to contain a minimum of 94 percent calcium sulfate dihydrate on a dry weight basis, in accordance with the specification of National Gypsum for FGD by-product gypsum. Limestone purity and FGD system operating stoichiometry are very important in determining if a gypsum of commercial grade quality can be produced.

1. Process Description

As in the unoxidized double loop system, flue gas enters the quencher section first, where the gas is saturated and SO_2 removed. Within the quencher section, air from the oxidation compressors is sparged through the liquid at the base of the absorber module. The flue gas (with oxidation air) passes to the upper loop where the remaining SO_2 is removed. The SO_2 stripped flue gas then passes through a two-stage mist eliminator system and then to an indirect reheat section before exiting to the stack.

Limestone storage, handling, and preparation are the same as described in Section 2.0 of this Appendix for the unoxidized system.

From the recycle tank, the gypsum slurry, which normally contains approximately 15 percent by weight solids, is recirculated to the spray section of each tower. Slurry density, pH, and flow are monitored. A slip stream from the absorber is discharged to a bank of hydroclones, which concentrate the solids in overflow streams containing 35 to 50 percent suspended solids, including water of hydration.

2. Chemistry

The principal reactions in the absorber and recycle tank for the forced oxidation FGD system are the same as for the unoxidized system, as described in Section 2.0 of this Appendix. The oxidation reaction from sulfite to sulfate does, however, proceed to a different equilibrium, favoring the latter species. This condition is reflected in the precipitation of a solid product, which is primarily $CaSO_4 \cdot 2H_2O$. As stated previously, the actual percentage gypsum depends upon whether the system is operating to produce disposable or commercial grade by product.

3. Disposable Grade Gypsum

Disposable grade gypsum in slurry form is pumped from hydroclones to rotary drum vacuum filters, where it is dewatered to approximately 80 percent by weight hydrated solids. From the vacuum filters, the cake is moved by belt conveyor outside of the building. The gypsum is discharged for transport to a landfill disposal site. It is likely that some type of lined landfill (e.g., clay) would be necessary for gypsum disposal. An emergency radial stacker is also provided to construct a temporary storage pile in the event that transportation to the landfill is disrupted. Since gypsum does not cure as stabilized sludge does, temporary storage is not necessary to improve handling properties. The 80 percent solids by-product can be readily conveyed and handled by conventional equipment.

Gypsum (calcium sulfate) has superior characteristics, with respect to dewatering and structural properties, compared to unstabilized FGD sludge (primarily calcium sulfite), because of the crystal structure of

gypsum. With time, gypsum demonstrates relatively strong cementitious properties, although less than stabilized sludge. The "cemented" permeability is approximately 10^{-4} cm/sec, considerably higher (and less desirable) than stabilized sludge.

An alternative to dewatering disposable grade gypsum is "stacking" the by-product as received directly from hydroclones (35 to 50 percent solids), and then pumping reclaim water from the stacking area back to the FGD system. Such an approach is not considered environmentally acceptable, due to the very wet nature of the stack and the potential for contamination of the local environment by scrubber liquor.

An emergency sludge pond is provided for waste in the event that dewatering equipment is out of service or for blowdown from an absorber module.

4. Commercial Grade Gypsum

Commercial grade gypsum is pumped from hydroclones to rotary drum vacuum filters and dewatered to approximately 90 percent by weight hydrated solids. The higher gypsum content allows greater dewatering than is possible with disposable grade by-product. From the vacuum filters, the filter cake is either transported to the landfill disposal site or conveyed to an emergency radial stacker, in the same fashion as disposable gypsum. The radial stacker can be used to load a truck if the gypsum is to be sold or to construct a temporary storage pile under emergency conditions.

5. Scaling Problems

By maintaining a gypsum slurry at approximately 15 weight percent solids, the degree of sulfate supersaturation in solution is decreased. Gypsum does not precipitate on vessel walls and in piping, but precipitates instead on existing crystals. This process of gypsum crystal growth reduces the possibility of sulfate scaling, which is a recurring problem in unoxidized systems. Also, in the case of commercial grade gypsum, almost complete conversion of sulfite to sulfate decreases the likelihood of sulfite scaling. However, scaling at wet/dry interfaces is still a danger and is minimized by proper design.

Plugging, due to solids deposition at locations throughout the system can occur, as previously discussed in the limestone unoxidized case (Section 2 of this Appendix).

6. Chloride Problems

The burning of a specific coal in a boiler followed by a gypsum FGD system produces very different chloride concentrations compared to an unoxidized FGD system. Because of the higher degree of rotary drum vacuum filter dewatering possible in an oxidized system, more water is removed from the filter cake. To maintain a system water balance, less fresh makeup water is added. The concentration of chloride ions in the scrubbing solutions is not diluted as greatly and therefore reaches significantly higher values. Therefore, it is necessary to operate a chloride purge stream to protect metallic components and reduce adverse effects upon process chemistry. For certain coals, such a bleed stream is large in volume, particularly in FGD systems producing commercial

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grade gypsum, and cannot be discharged in the plant or to the surrounding environment. The purge stream, usually taken from the filtrate of the vacuum filter, must be sent to a water treatment system for pH adjustment, precipitation of heavy metals (as necessary), and removal of suspended solids. The treated stream could not be reused within the power plant without additional treatment for chloride removal. Dilution in waste basins would not be sufficient for this purpose. Three methods for handling the chloride stream are evaporation, reverse osmosis, and deep well injection. Evaporation and reverse osmosis appear to be very expensive, and the latter method produces a reject stream which, in itself, would present a disposal problem. Deep well injection requires a large surface treatment facility plus associated environmental studies, all of which would be very costly. Further study is required to determine the economic and technical feasibility of chloride disposal.

7. Commercial Grade Gypsum Quality

To produce high quality (purity) gypsum, restrictions upon operation and maintenance are necessary. Fly ash is tolerable only in very small quantities; proper operation of upstream precipitators is essential to making a saleable by-product gypsum. Also, limestone impurities enter into the gypsum product, requiring that the purchase of limestone be monitored and quality control be checked upon receipt. Finally, chloride levels in excess of 800 ppm in the by-product are not allowable (in accordance with National Gypsum Specification), requiring that the filter cake be washed to maintain chlorides at low concentrations.

WET LIME FLUE GAS DESULFURIZATION SYSTEM

1. Process Description

Refer to Figure 4 for the wet lime FGD system flow scheme.

The absorption portion of the wet lime FGD system is as described in Section 1.0 of this appendix.

The chemical reagent storage, preparation, and circulation portions of the wet lime FGD system, generally described in Section 1.0 of this Appendix, are further detailed below.

Generally, wet lime FGD systems employ pulverized quicklime or special limes such as "Thiosorbic" lime. Pulverized quicklime usually contains greater than 90 percent reactive calcium oxide and is less than 20 mesh. Special lime may be burned lime that contains greater than 90 percent calcium oxide and 5 to 6 percent magnesium oxide. Both quicklime and special lime perform adequately in FGD systems. Some utilities have employed special limes in an effort to maximize sulfur dioxide removal efficiencies and minimize potential scaling problems.

Lime is transported either in enclosed trucks, enclosed railroad cars, or enclosed barges and is unloaded into pneumatic or belt conveyors. Lime must be protected against moisture. Bulk lime storage silos should be sufficient for 90-day operation at annual average load and annual average coal sulfur content. The silos must be watertight since lime tends to absorb moisture readily, forming an adherent soft cake which can cause arching or bridging. The lime from the storage silos is pneumatically conveyed to a lime surge silo with a one day capacity. From the surge silo, the lime is weigh-fed to lime slakers where a

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concentrated slurry is prepared by addition of water and sent to lime slurry transfer tanks. This slaking reaction between quick lime and water generates a considerable amount of energy which makes the resultant concentrated lime slurry hot (120° to 180°F). The lime slurry is then transferred to the lime slurry tank which has an 8-hour storage capacity at design conditions. From the lime slurry tank, the lime slurry is pumped to the recycle tank at a rate proportional to the SO_2 mass flow entering the absorber tower or proportional to lime slurry pH. Flue gas flow rate, SO_2 concentrations, temperatures, and pressures are monitored.

From the recycle tank, the slurry is recirculated to the spray headers of each tower. The absorber slurry flow, density, and pH are monitored. A slipstream from the absorber loop is discharged to thickeners where thickener overflow is reclaimed and underflow is fed to the sludge stabilization system.

The calcium sulfite/sulfate underflow slurry from the FGD thickeners to the FGD waste disposal system usually contains 20 to 35 percent by weight suspended solids including water of hydration. The underflow slurry has a temperature of approximately 110°F, a pH of 5.8 normally, and a specific gravity of approximately 1.3.

2. Chemistry

The principle reactions in the absorber are between SO_2 in the flue gas and water in the absorbing solution. The reactions involving the lime are completed in the recycle tanks.

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Absorber reactions:

$SO_2 + H_2O$ H_2SO_3

H_2SO_3 $HSO_3^- + H^+$

HSO_3^- $H^+ + SO_3^{-2}$

$Ca(OH)_2$ $Ca^{+2} + 2OH^-$

Absorber and recycle tank reactions:

$Ca(OH)_2$ $Ca^{+2} + 2OH^-$

$Ca^{+2} + SO_3^{-2}$ $CaSO_3$

$CaSO_3 + 1/2\ O_2$ $CaSO_4$

The insoluble waste calcium products are actually hydrated as $CaSO_3 \cdot 1/2\ H_2O$ and $CaSO_4 \cdot 2H_2O$.

3. Waste Processing and Disposal

The FGD waste from the thickeners can be disposed of by sludge ponding or sludge stabilization. The slurry can also be force oxidized to produce gypsum. These methods are described in Section 1.0 of this Appendix.

When sludge ponding is not employed, an emergency dump pond is provided for waste from the thickeners, in the event that the sludge stabilization system is out of service. This emergency dump pond is sized for 10 days operation at full load, maximum sulfur coal.

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4. Operation and Maintenance

The wet lime FGD system is similar to the limestone system in design, operation, and maintenance. However, scaling and plugging is potentially less of a problem in the wet lime system because lime is more soluble than limestone.

DOUBLE ALKALI FLUE GAS DESULFURIZATION SYSTEM

Refer to Figure 5 for the double alkali FGD system flow scheme.

In the double alkali process, the sodium based reagent is chemically regenerated for reuse. The reagent is regenerated in a chemical reaction which requires the addition of about as much lime as the lime FGD system utilizes, resulting in a large amount of waste. The chemical reaction produces a sodium based solution, which is reused as reagent, and large quantities of calcium sulfite/sulfate which must be disposed of. For this reason, the double alkali process is classified as a throwaway process.

SO_2 removal efficiency may be higher than for the lime or limestone systems due to the higher reactivity of soda ash.

1. Process Description

The absorption portion of the double alkali FGD system is as described in Section 1.0 of this Appendix.

The chemical reagent storage, preparation, and circulation portions of the double alkali FGD system, generally described in Section 1.0 of this Appendix, are further detailed below.

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Pulverized soda ash (generally containing greater than 90 percent sodium carbonate) is delivered in dry form by truck or rail and is pneumatically unloaded directly into soda ash storage tanks where it is mixed with water to form a slurry. Direct recirculation of soda ash solution to wet the dry soda ash as it is blown into the storage tank is usually performed. In the storage tank, the soda ash crystals fall to the bottom and the saturated solution is drawn off in a floating pump suction line. The soda ash storage tanks hold 90-day operation at annual average load and annual average coal sulfur content. This solution is pumped to the dissolving tank to replace the sodium lost.

The lime (generally pulverized quicklime) is delivered in dry form by truck, rail, or barge and is unloaded into dry lime storage silos sufficient for 90-day operation at annual average load and annual average coal sulfur content. The lime from the storage silos is pneumatically conveyed to a lime surge silo with one-day lime capacity. With the surge silo discharge valve open, the lime is weigh-fed to lime slakers and a concentrated slurry is prepared by addition of water. The lime slurry flows to lime slurry feed tanks, each of which has an 8-hour storage capacity at design conditions. From the lime slurry tanks, the lime slurry is pumped to the lime reaction tank.

The sodium based solution in the dissolving tank is fed to the recycle tank at a rate normally determined by the pH of the recirculating scrubber solution. The recirculating solution is continuously purged to remove sulfites and sulfates that result from chemical reaction in the absorber. Reclaimed water is added to the absorber tower feed tank, as well as soda ash solution, to maintain minimum level. Flue gas flow rate, SO_2 concentrations, temperatures, and pressures are monitored.

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The purge stream containing soluble sulfite and sulfate is fed to a lime reactor tank where insoluble calcium sulfite and sulfate are precipitated out in a chemical reaction. The sodium based solution is regenerated to a sodium sulfite solution in the lime reaction tank for reuse in the absorber. The calcium sulfite/sulfate slurry is transferred to a thickener where water is reclaimed and thickener underflow is fed to the sludge stabilization system.

The calcium sulfite/sulfate underflow slurry from the FGD thickener contains usually 20 to 35 percent by weight suspended solids including water of hydration. The underflow slurry has a temperature of approximately 110°F, pH of 6 normally, and a specific gravity of 1.3.

The use of low sulfur coal instead of high sulfur coal may result in more sodium sulfate and calcium sulfate being produced per pound mole of sulfur dioxide removed (thus more soda ash required) due to the higher oxygen content in low sulfur coal flue gas.

2. Chemistry

The principal reactions in the absorber are between SO_2, soda ash, and water.

$$Na_2CO_3 + SO_2 \qquad Na_2SO_3 + CO_2$$

$$Na_2SO_3 + SO_2 + H_2O \qquad 2NaHSO_3$$

$$2Na_2SO_3 + O_2 \qquad 2Na_2SO_4 \quad \text{(by-product)}$$

The purge stream from the recycle tank is fed to a lime reactor tank where insoluble calcium sulphite and sulphate are precipitated by the following reactions:

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$$Na_2SO_3 + Ca(OH)_2 \quad 2NaOH + CaSO_3$$

$$Na_2SO_4 + Ca(OH)_2 \quad 2NaOH + CaSO_4$$

The insoluble waste calcium products are actually hydrated as $CaSO_3 \cdot 1/2\ H_2O$ and $CaSO_4 \cdot 2H_2O$.

3. Waste Processing and Disposal

Thickener underflow waste can be dewatered to form sludge cake which may be suitable as landfill without further stabilization. If desired, sludge stabilization can be employed to make the dewatered waste more structurally and environmentally stable before landfill. Forced oxidation of the waste to produce gypsum can also be done. These methods are described in Section 1.0 of this Appendix.

An emergency dump pond is provided for waste from the thickeners, in the event that the dewatering equipment and/or the sludge stabilization system is out of service. This emergency dump pond is sized for 10 days operation at full load, maximum sulfur coal.

4. Operation and Maintenance

In the double alkali FGD system, the reagent solution is a clear liquor instead of a slurry. As a result, plugging and scaling in the absorber modules is reduced. However, the lime preparation section, lime reactor tank area, and thickener area do handle slurries which can cause plugging and scaling problems as presented in earlier sections of this report.

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In general, the double alkali system is similar in design and operation/maintenance requirements to the wet lime and limestone FGD systems.

WELLMAN-LORD FLUE GAS DESULFURIZATION SYSTEM

Refer to Figure 6 for the Wellman-Lord FGD system flow scheme.

The Wellman-Lord system is a "wet" process which utilizes a clear liquor as the reagent solution. Soda ash is the reagent material used. The system is "regenerable" since the spent reagent is thermally decomposed in an evaporator/crystallizer, producing reagent chemical, SO_2, and some waste by-products. The SO_2 is transformed into sulfuric acid or elemental sulfur for commercial sale and the waste by-products are discarded.

The advantage derived from the production of a saleable product may, however, be offset by the higher capital cost due to the greater complexity of this system. The Wellman-Lord system may require large quantities of process steam, resulting in derating the power plant more than other FGD systems. This potential greater derating of the power plant must be recognized early in the plant design and considerations should be given to purchasing a larger power plant to supply this steam and process the resulting increased flue gas.

1. Process Description

The absorption portion of the Wellman-Lord system differs from that described in Section 1.0 of this Appendix in that the quencher is replaced by a prescrubber and demister.

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From the booster fans, the flue gas flows to a venturi-type prescrubber for saturation, cooling, and particulate removal. A slip stream is purged to maintain the scrubbing solution suspended solids at below 5 weit percent and/or chloride concentration below the required level. The saturated gas flows through the absorber inlet gas mist eliminator for removal of entrained liquid before entering the absorber. The remaining portion of the gas flow path (through the absorber module, mist eliminator, reheater, and to the stack) is as described in Section 1.0 of this Appendix.

The chemical reagent storage, preparation, and circulation portions of the Wellman-Lord FGD system, generally described in Section 1.0 of this Appendix are further detailed below.

The reagent liquor is stored in the absorber feed tank. From here it is pumped to the absorber modules for SO_2 removal. The spent reagent liquor is pumped to double-effect evaporators for SO_2 recovery. A slip stream is fed to the purge crystallizer for removal of sodium sulfate by-product.

In the purge crystallizer, the solution is heated by a steam shell and tube heat exchanger. The slurry leaving the crystallizer is fed to a centrifuge to separate crystals from the liquor.

The wet cake from the centrifuge is fed to a rotary type dryer for further treatment. The dryer product is conveyed to the sulfate purge bin for storage. Vent gases from the dryer, as well as from all tanks, are passed through a vent gas scrubber to remove SO_2 before discharging to the atmosphere.

In the double-effect evaporators, the spent reagent liquor is heated in shell-and-tube heat exchangers releasing SO_2 and H_2O vapor and precipitating sodium sulfite crystals. In the first-effect evaporator, low pressure steam is used as the heating medium. In the second-effect evaporator, the solution is heated by condensing overhead vapors from the first-effect evaporator and the purge crystallizer. This condensate is sent to a condensate stripper to remove dissolved SO_2. The uncondensed vapor from the heat exchanger and the vapor from the second-effect evaporator is sent to a primary condenser. The condensate formed in the primary condenser is fed to the condensate stripper. The SO_2 gas leaving the primary condenser joins the SO_2 gas leaving the condensate stripper for final condensing in the secondary condenser. The SO_2 is further processed into sulfuric acid or elemental sulfur.

The slurry product from each evaporator is discharged to the dissolving tank for recycle back to the absorber as feed.

2. Reagent Preparation Area

The soda ash storage tank stores soda ash in slurry form. Unloading of dry soda ash to the storage tank is accomplished pneumatically. The soda ash is mixed with makeup water in the storage tank. The soda ash crystals fall to the bottom and the saturated solution is pumped to the dissolving tank. The regenerated solution from the dissolving tank is pumped to the absorber feed tank for storage.

3. Chemistry

The principal reactions in the absorber are between SO_2, soda ash, and water.

$$Na_2CO_3 + SO_2 \qquad Na_2SO_3 + CO_2$$

$$SO_2 + Na_2SO_3 + H_2O \qquad 2NaHSO_3$$

Some oxidation of the sodium sulphite occurs in the absorber as follows:

$$Na_2SO_3 + 1/2\ O_2 \qquad Na_2SO_4$$

The following reaction may occur in the absorber if sulphur trioxide (SO_3) is present in the flue gas:

$$2Na_2SO_3 + SO_3 \qquad Na_2SO_4 + Na_2S_2O_5$$

Sodium sulphate (Na_2SO_4) is removed from the absorbing solution in the purge crystallization area.

4. Regenerated SO_2 Processing and Waste Disposal

The recovered SO_2 (usually 95 percent SO_2 and 5 percent H_2O by weight, 110°F, and 15 psia) must be processed into sulfuric acid or elemental sulfur. This is accomplished by a downstream chemical facility purchased by the utility. Although these plants are a proven technology in the chemical industry, they present unique and significant operating and maintenance problems for a utility. A reliable market for the sulfuric acid product must exist. Elemental sulfur can be disposed of as a solid if no reliable sulfur market exists. Both sulfuric acid and molten elemental sulfur can be shipped as liquid by railroad tank car, tank truck, or barge.

Sulfuric acid (usually 77.7 to 93.2 percent by weight H_2SO_4) is normally produced using the direct contact method which passes sulfur dioxide with air over a catalyst (usually V_2O_5) to form sulfur trioxide, the

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sulfur trioxide is absorbed in dilute sulfuric acid to form oleum ($H_2S_2O_7$), and the oleum is split with water to form the sulfuric acid (H_2SO_4). The resulting sulfuric acid is stored in a tank form designed for 90-day operation at annual average plant load factor and annual average sulfur content in coal.

Sulfur (normally very pure and molten) is usually produced by either the Allied Process or the Claus Process. In the Allied Process the Wellman-Lord FGD system sulfur dioxide is heated with natural gas (CH_4) to form CO_2, H_2O, H_2S, and S; the H_2S and SO_2 are reacted in a Claus unit to form the final sulfur. In the Claus process, the sulfur dioxide is reacted with hydrogen sulfide (H_2S) to form the desired sulfur. The disadvantage of producing sulfur instead of sulfuric acid is that valuable natural gas or rarely available hydrogen sulfide is required. Hydrogen sulfide usually exists at sour gas refinery industries.

The sulfate purge (usually contains 20 to 40 percent Na_2SO_3, 57 to 77 percent Na_2SO_4, 1.5 percent H_2O), is in dry pellet form, is soluble in water, and should not be stored in unprotected piles. It can not be disposed of as landfill since it will leach into the ground. However, it is useful as a raw material for the paper industry.

The use of low sulfur coal instead of high sulfur coal may result in more sodium sulfate being produced per pound mole of sulfur dioxide removed (thus more soda ash makeup required) due to the higher oxygen content in low sulfur flue gas.

The fly ash purge (usually 120°F and pH = 1 to 3) from the quencher section will contain less than 5 percent suspended solids by weight, is normally neutralized, and sent to settling ponds with the supernatant

liquid returned to the FGD system to minimize makeup water requirements. The fly ash purge solids may settle to approximately 75 lb dry solids per cubic foot of settled mass in the pond.

5. Operation and Maintenance

The major problem area associated with the Wellman-Lord system is the handling, storage, and distribution of the by-products produced. This has been discussed earlier in the section.

Scaling and plugging in the absorber area is less of a problem than for most throwaway systems (those utilizing a reagent in slurry form) since the Wellman-Lord system uses a clear liquor. The reagent preparation area and the crystallizer/centrifuge represent potential problem areas.

TABLE 1

CHARACTERISTICS OF FLUE GAS DESULFURIZATION PROCESSES

Process	Primary Removal Agent	Operational Mode	Regenerable	Form of Principal Waste Product
Limestone	Limestone	Wet	No	$H_2O/CaSO_3/CaSO_4$ or $H_2O/CaSO_4$
Wet Lime	Lime	Wet	No	$H_2O/CaSO_3/CaSO_4$
Double Alkali	Sodium Carbonate/Lime	Wet	No	$H_2O/CaSO_3/CaSO_4$
Wellman-Lord	Sodium Carbonate	Wet	Yes	SO_2/Sulfate Cake/Fly Ash Purge Stream

TABLE 2

DISTRIBUTION OF FLUE GAS DESULFURIZATION SYSTEMS BY CHEMICAL PROCESS IN THE UNITED STATES (MW)

Process Type	Operational	Under Construction	Planned[3]	Total
Limestone[1]	14,191	8,851	7,335	30,397
Lime[2]	11,691	3,045	6,260	20,996
Lime/Spray Drying	110	1,551	0	1,661
Sodium Carbonate	925	330	1,900	3,155
Sodium Carbonate/ Spray Drying	440	100	0	540
Magnesium Oxide	0	724	0	724
Wellman-Lord	1,540	534	0	2,074
Double Alkali	1,181	421	0	1,602
Others	80	331	0	391
Total	30,158	15,887	15,495	61,540

Notes

(1) Includes alkaline fly ash/limestone and limestone wet slurry process design configurations.

(2) Includes alkaline fly ash/lime and lime wet slurry process design configurations.

(3) Includes only systems for which process has been selected.

TABLE 3

OPERATIONAL FGD SYSTEMS AT UTILITIES IN USA

Plant	State	Total Capacity (Min)	FGD Process	By-product	
				Type	Disposal
Tombigbee 2-3	Alabama	510	Limestone	-	Pond
Apache 3-2	Arizona	390	Limestone	-	Pond
Cholla 1-2-4	Arizona	779	Limestone	-	Pond
Four Corners 1-2-3	New Mexico	615	Lime/Alkaline Fly Ash	-	-
Laramie River 1-2	Wyoming	1140	Limestone	Forced Oxidation	Landfill
Green 1-2	Kentucky	484	Lime	Fixation	Landfill
Duck Creek 1	Illinois	416	Limestone	-	Pond
Newton 1	Illinois	617	Double Alkali	Fixation	Landfill
East Bend 2	Kentucky	650	Lime	Fixation	Landfill
Craig 1-2	Colorado	910	Limestone	-	Pond
Conesville 5-6	Ohio	810	Lime	Fixation	Landfill
Powerton 51	Illinois	450	Limestone	Fixation	Pond
Coal Creek 1-2	North Dakota	1100	Lime/Alkaline Fly Ash	Fixation	Pond
Elrama 1-4	Pennsylvania	510	Lime	Fixation	Landfill
Phillips 1-6	Pennsylvania	408	Lime	Fixation	Landfill
Petersburg 3	Indiana	532	Limestone	Fixation	Landfill
Hawthorn 3-4	Missouri	180	Lime	Stabilization	Pond
LaCygne 1	Kansas	874	Limestone	-	Pond
Jeffrey 1-2	Kansas	1440	Limestone	Stabilization	Pond
Lawrence 4-5	Kansas	545	Limestone	Forced Oxidation	Pond
Green River 1-3	Kentucky	64	Lime	-	Pond
Cane Run 4-5-6	Kentucky	687	Lime	Fixation	Landfill
Mill Creek 1-2-3-4	Kentucky	1630	Lime	Fixation	Landfill

TABLE 3 (CONT)

Plant	State	Total Capacity (Min)	FGD Process	By-product Type	By-product Disposal
Delaware City 1-2-3	Delaware	180	Wellman-Lord	Sulphuric Acid	Self consume
Coyote 1	North Dakota	440	Sodium Carbonate/spray	-	-
Reid Gardner 1-2-3	Nevada	375	Sodium Carbonate	-	Pond
Paddy's Run 6	Kentucky	72	Lime	Fixation	Pond
Clay Boswell 4	Minnesota	554	Lime/Alkaline Fly Ash	-	Pond
Milton R. Young 2	North Dakota	440	Lime/Alkaline Fly Ash	-	Landfill
Pleasants 1-2	West Virginia	1252	Lime	Fixation	Pond
Colstrip 1-2	Montana	720	Lime/Alkaline Fly Ash	-	Pond
Riverside 6-7	Minneapolis	110	Lime/Spray Drying	-	Landfill
Sherburne 1-2	Minnesota	1500	Limestone/Alkaline Fly Ash	Forced Oxidation	Pond
Bruce Mansfield 1-2-3	Pennsylvania	2751	Lime	Fixation	Pond
Coronado 1-2	Arizona	800	Limestone	-	Pond
Winyah 2-3-4	South Carolina	840	Limestone	-	Pond
R.D. Morrow, Sr. 1-2	Mississippi	400	Limestone	Stabilization	Landfill
Marion 4	Illinois	184	Limestone	Stabilization	Landfill
A.B. Brown 1	Indiana	265	Double Alkali	-	Landfill
Southwest 1	Missouri	194	Limestone	Stabilization	Landfill
Dallman 3	Illinois	205	Limestone	Forced Oxidation	Landfill
Shawnee 10A-10B	Kentucky	20	Lime/Limestone	-	Landfill
Widows Creek 8	Alabama	1125	Limestone	-	Pond
Sandow 4	Texas	545	Limestone	Forced Oxidation	Pond
Martin Lake 1-2-3	Texas	2379	Limestone	Stabilization	Landfill
Monticello 3	Texas	800	Limestone	Stabilization	Landfill
Hunter 1-2	Utah	840	Lime	Stabilization	Landfill

TABLE 3 (CONT)

Plant	State	Total Capacity (Min)	FGD Process	By-product	
				Type	Disposal
Huntington 1	Utah	432	Lime	Stabilization	Landfill
Charles R. Huntley 66	New York	100	Aqueous Carbonate/ Spray Drying	Elemental Sulphur	-
Jim Bridger 2A	Wyoming	550	Lime/Sodium Carbonate	-	-
Jim Bridger 4	Wyoming	550	Sodium Carbonate	-	-
Eddystone 1	Philadelphia	240	Magnesium Oxide	-	-
San Juan 1-2-3-4	New Mexico	1779	Wellman-Lord	Elemental Sulphur	Marketed
G.F. Wheaton 1	Pennsylvania	60	Citrate	Elemental Sulphur	-
Naughton 3	Utah	330	Sodium Carbonate	-	-
San Miguel 1	Texas	400	Limestone	Stabilization	Landfill
A.B. Brown	Indiana	265	Double Alkali	Unstabilized	Landfill

TABLE 4

FUTURE UNITED STATES FLUE GAS DESULFURIZATION SYSTEMS

Plant	State	Start-up Date	Total Capacity (MW)	FGD Process
Thomas Hill 3	Missouri	01/82	730	Limestone
Antelope Valley 1	North Dakota	04/83	440	Lime/Spray Drying
Laramine River 3	Wyoming	10/82	570	Lime/Spray Drying
D.B. Wilson 1	Kentucky	07/84	440	Limestone
Craig 3	Colorado	04/83	447	Lime/Spray Drying
Bonanza 1	Utah	09/84	410	Limestone
Spurlock 2	Kentucky	00/82	500	Lime
J.B. Sims 3	Michigan	06/83	65	Lime
Merom 1-2	Indiana	05/82,09/81	980	Limestone
Petersburg 4	Indiana	10/84	530	Limestone
McIntosh 3	Florida	00/82	364	Limestone
Shiras 3	Michigan	10/82	44	Lime/Spray Drying
Project 1	Michigan	06/82	55	Limestone
Colstrip 3-4	Montana	10/83,00/84	1400	Lime/Alkaline Fly Ash
Muscatine 9	Iowa	09/82	166	Limestone
Schahfer 17-18	Indiana	06/83,06/85	421	Double Alkali
Gibson 5	Indiana	00/82	650	Limestone
Cross 2	South Carolina	01/84	500	Limestone
Paradise 1-2	Kentucky	03/82,06/82	1408	Limestone
Gibbons Creek 1	Texas	03/82	443	Limestone
Stanton 1A	North Dakota	06/82	60	Lime/Spray Drying
Hunter 3	Utah	06/83,00/85	400	Limestone
Mitchell 33	Pennsylvania	03/82	300	Lime

TABLE 4 (CONT)

Plant	State	Start-up Date	Total Capacity (MW)	FGD Process
Four Corners 4-5	New Mexico	00/82	1510	Lime
Antelope Valley 2	North Dakota	10/85	440	Lime/Spray Drying
D.B. Wilson 2	Kentucky	01/86	440	Limestone
Limestone 1-2	Texas	12/86,00/87	1500	Limestone
Plains Escalante 1	New Mexico	12/83	233	Limestone
Rawhide 1	Colorado	12/83	279	Lime/Spray Drying
Seminole 1-2	Florida	03/83,01/85	1240	Limestone
Cross 1	South Carolina	05/88	500	Limestone
Dolet Hills 1	Louisiana	03/86	720	Limestone
Henry W. Pirkey 1	Texas	12/84	720	Limestone
Holcomb 1	Kansas	08/83	347	Lime/Spray Drying
Big Bend 4	Florida	03/85	475	Limestone
Twin Oaks 1-2	Texas	08/88,00/87	1500	Limestone
Martin Lake 4	Texas	00/87	750	Limestone
Springerville 1-2	Arizona	03/87	140	Lime/Spray Drying
J.K. Smith 1	Kentucky	01/85,00/87	650	Lime
Guthrie Co. 1	Iowa	11/87	720	Limestone
Arkansas Lignite 5-6	Arkansas	00/90,00/92 00/93	1780	Limestone
Wilton 1-2	Louisiana	00/88,00/91	390	Limestone
Somerset 1	New York	06/84	625	Limestone
W. A. Parish 8	Texas	05/83	600	Limestone
Reid Gardner 4	Nevada	00/84	250	Sodium Carbonate
Cromby 1	Philadelphia	05/83	150	Magnesium Oxide
Eddystone 2	Philadelphia	12/82	334	Magnesium Oxide
Valmy 2	Nevada	10/84	276	Lime/Spray Drying

TABLE 4 (CONT)

Plant	State	Start-up Date	Total Capacity (MW)	FGD Process
Oklaunion 1-2	Texas	12/86, 0/90	1440	Limestone
GRDA 2	Oklahoma	08/85	575	Lime/Spray Drying
Hancock 1-2	Kentucky	0/88, 0/94	1300	Limestone
Intermountain 1,2,3,4	California	07/86, 07/87, 07/88, 07/89	3280	Limestone

TABLE 5

FLUE GAS DESULFURIZATION SYSTEM TERMINAL POINT SUPPLIES

Type	Lime-stone	Wet Lime	Double Alkali	Wellman-Lord
Utilities				
Reheat Steam or Hot Water	Yes	Yes	Yes	Yes
Process Steam	No	No	No	Yes
Electricity (6,900 V)	Yes	Yes	Yes	Yes
Emergency Electricity (480 V)	Yes	Yes	Yes	Yes
Makeup/Seal Water	Yes	Yes	Yes	Yes
Cooling Water	No	No	No	Yes
Service Air	Yes	Yes	Yes	Yes
Instrument Air	Yes	Yes	Yes	Yes
Potable Water	Yes	Yes	Yes	Yes
Chemical Reagents				
Limestone (90% $CaCO_3$)	Yes	No	No	No
Lime (90% CaO)	Yes	Yes	Yes	No
Soda Ash (90% Na_2CO_3)	No	No	Yes	Yes
Drainage				
Yard Drainage	Yes	Yes	Yes	Yes
Sewage Drainage	Yes	Yes	Yes	Yes
By-produce Disposal				
Transport Equipment	Yes	Yes	Yes	Yes

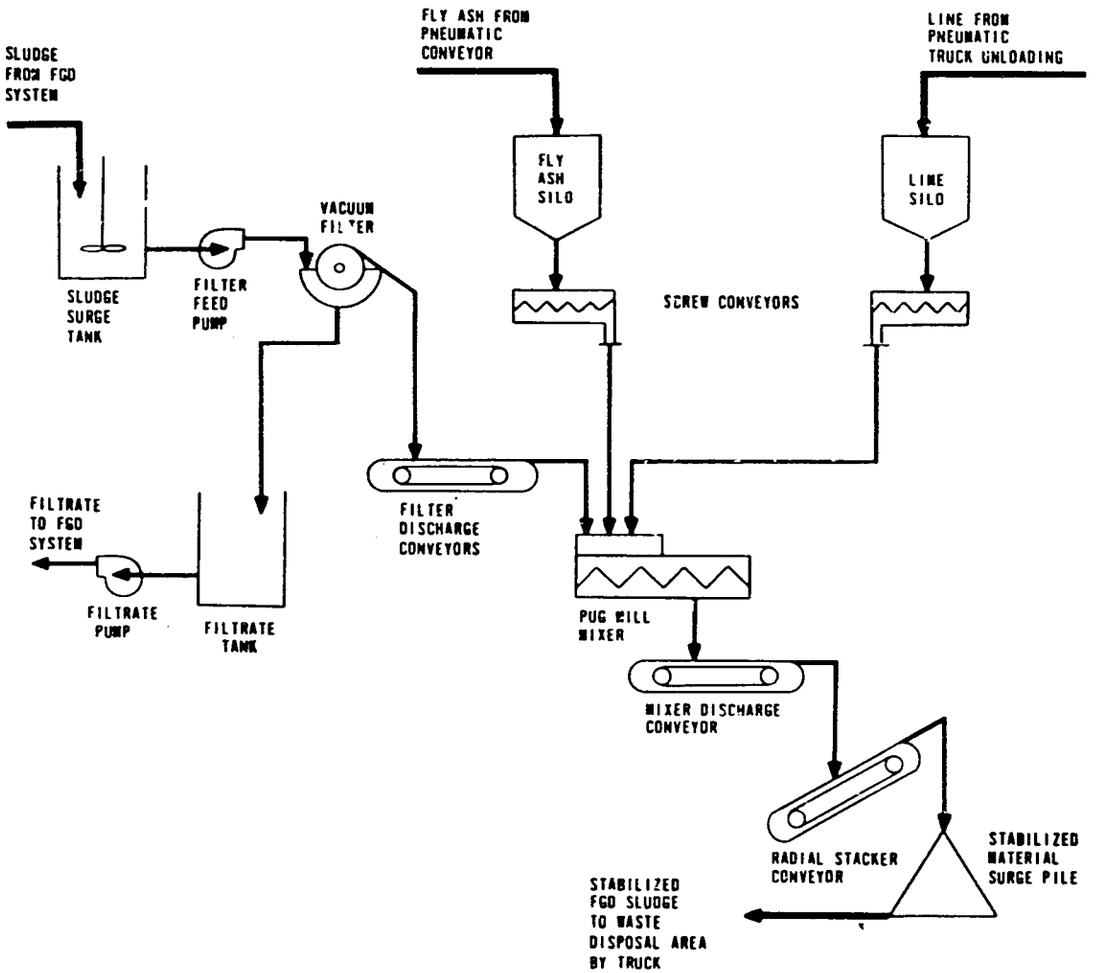

FIGURE 1
PROCESS FLOW DIAGRAM
FGD SLUDGE STABILIZATION SYSTEM

LAKHRA PROJECT - JAMSHORO SITE - 300 MW UNIT
PAKISTAN WATER & POWER DEVELOPMENT AUTHORITY
J.O. NO. 14003.04

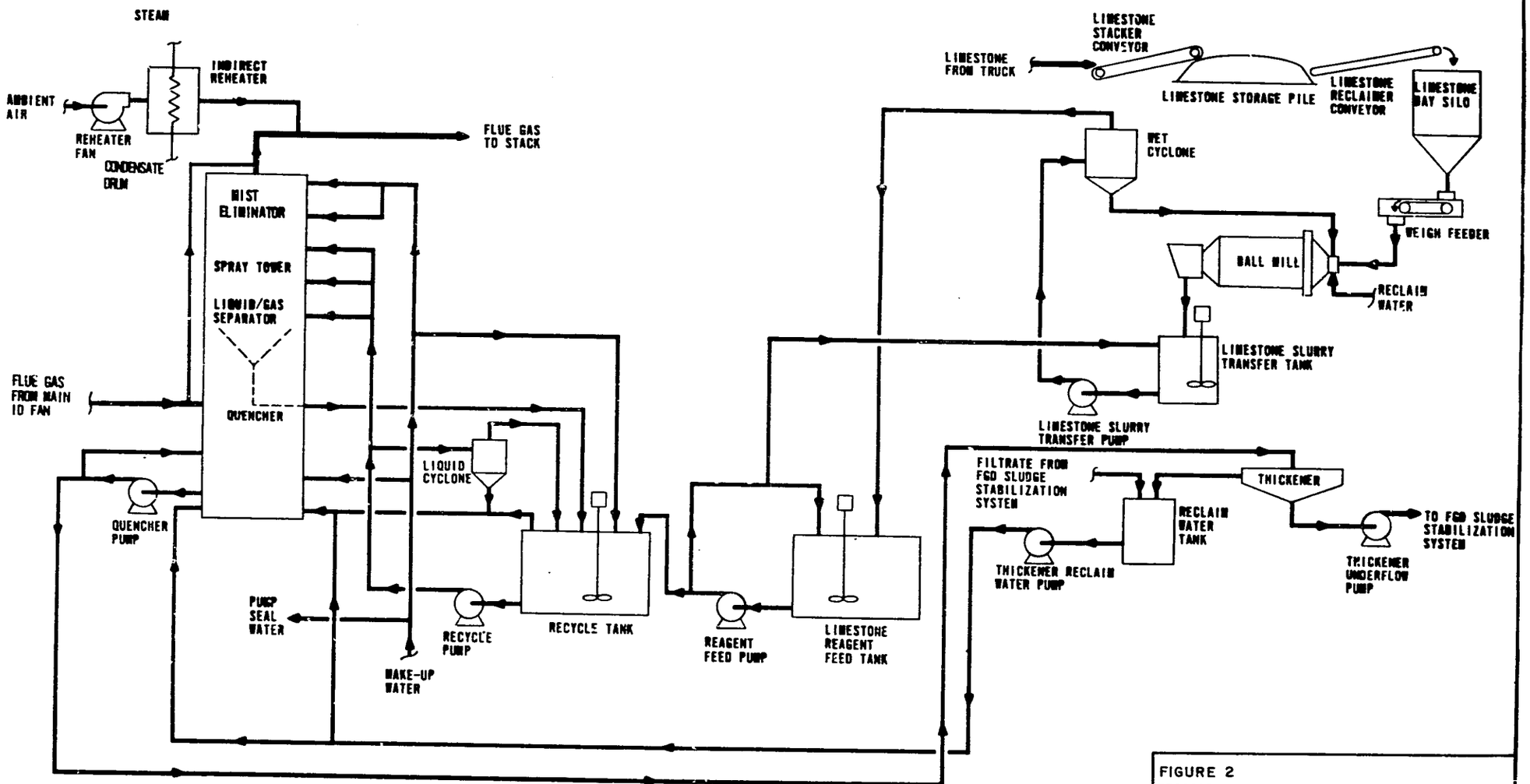

FIGURE 2
PROCESS FLOW DIAGRAM
LIMESTONE FGD SYSTEM - DOUBLE LOOP

LAKHRA PROJECT - JAMSHORO SITE - 300 MW UNIT
PAKISTAN WATER & POWER DEVELOPMENT AUTHORITY
J.O. NO. 14003.04

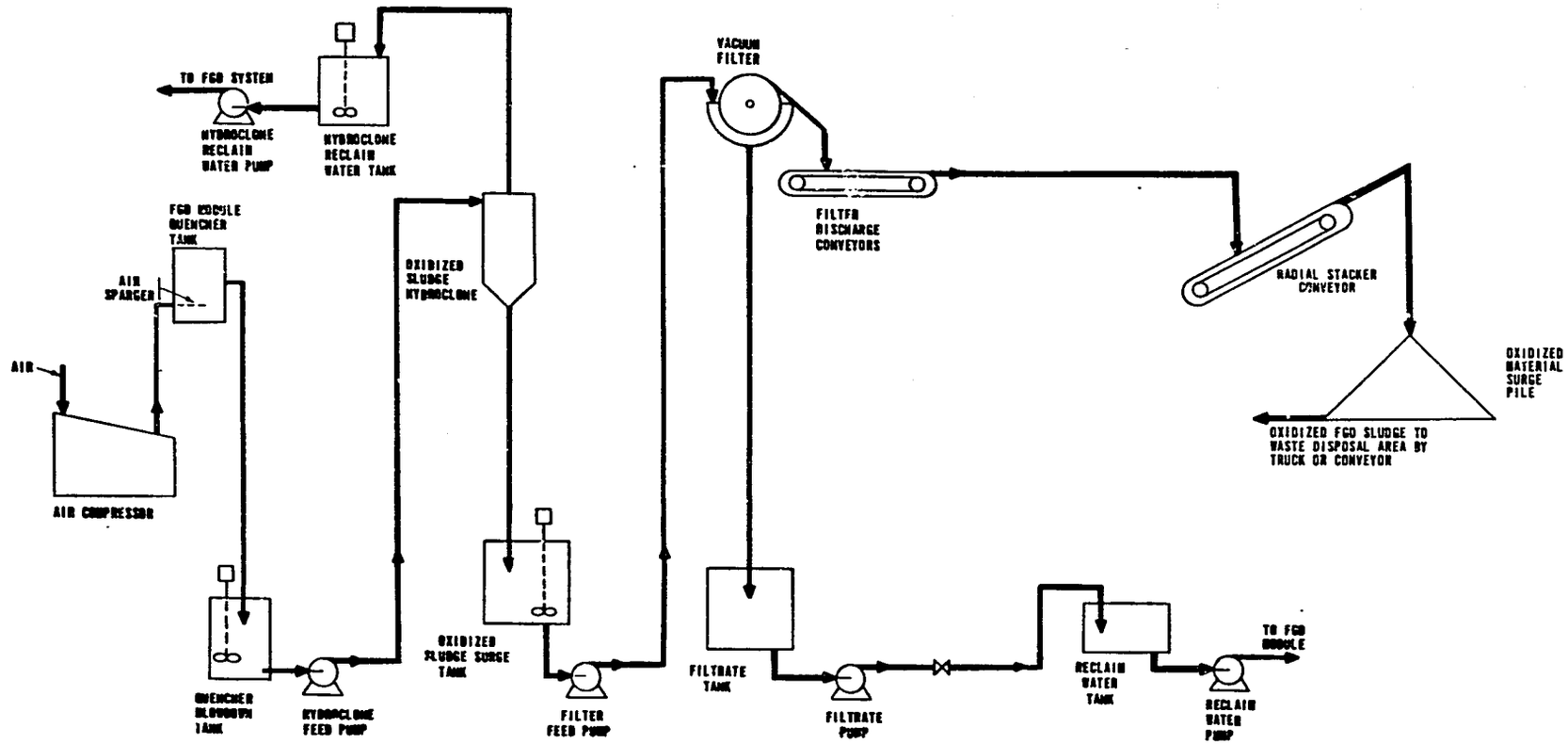

FIGURE 3
PROCESS FLOW DIAGRAM
LIMESTONE FORCED OXIDATION FGD SYSTEM

LAKHRA PROJECT - JAMSHORO SITE - 300 MW UNIT
PAKISTAN WATER & POWER DEVELOPMENT AUTHORITY
J.O. NO. 14803.04

A 90010

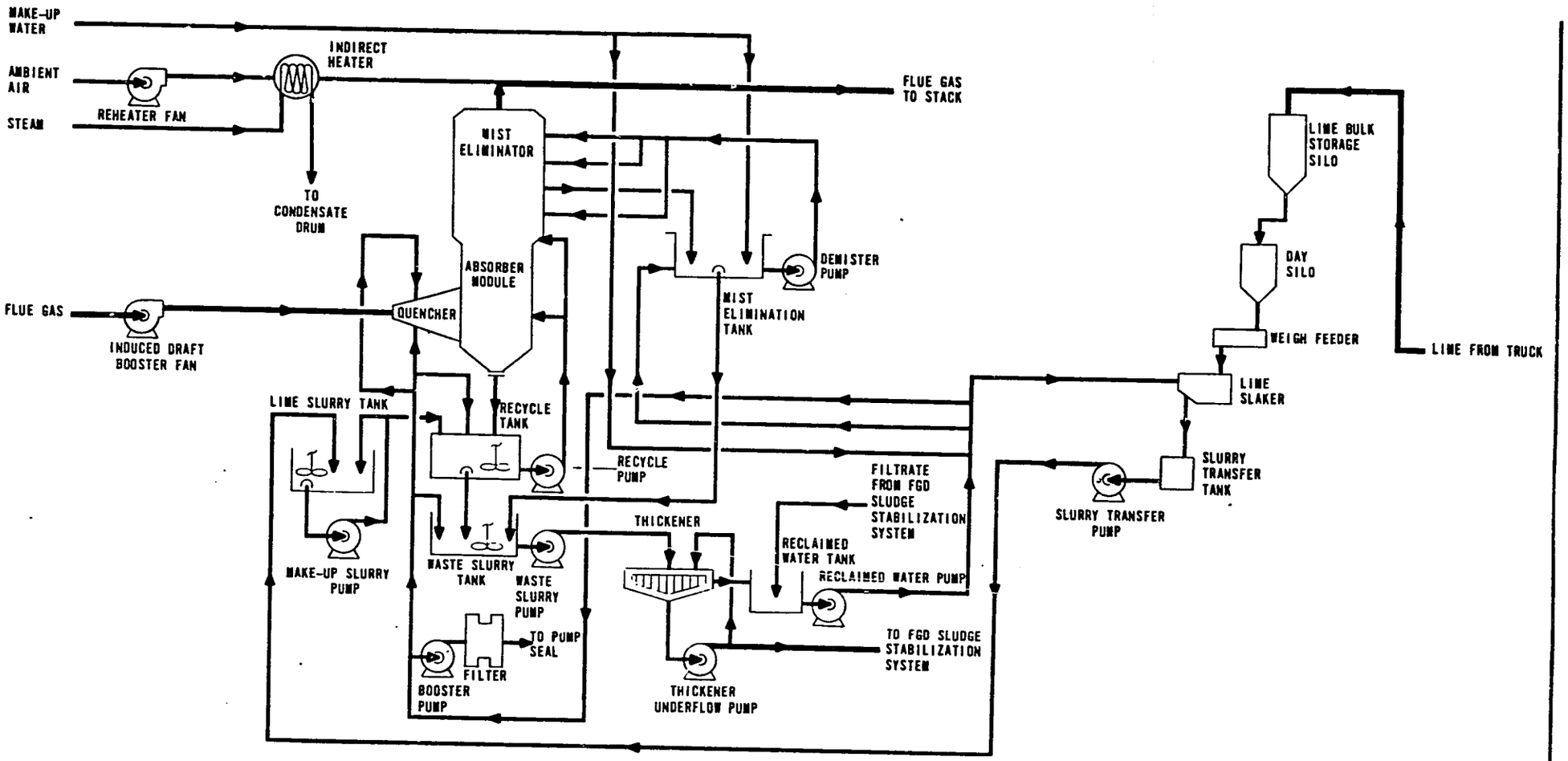

FIGURE 4 . .
PROCESS FLOW DIAGRAM
LIME FGD SYSTEM

LAKHRA PROJECT - JAMSHORO SITE - 300 MW UNIT
PAKISTAN WATER & POWER DEVELOPMENT AUTHORITY .
J.O. NO. 14003.04

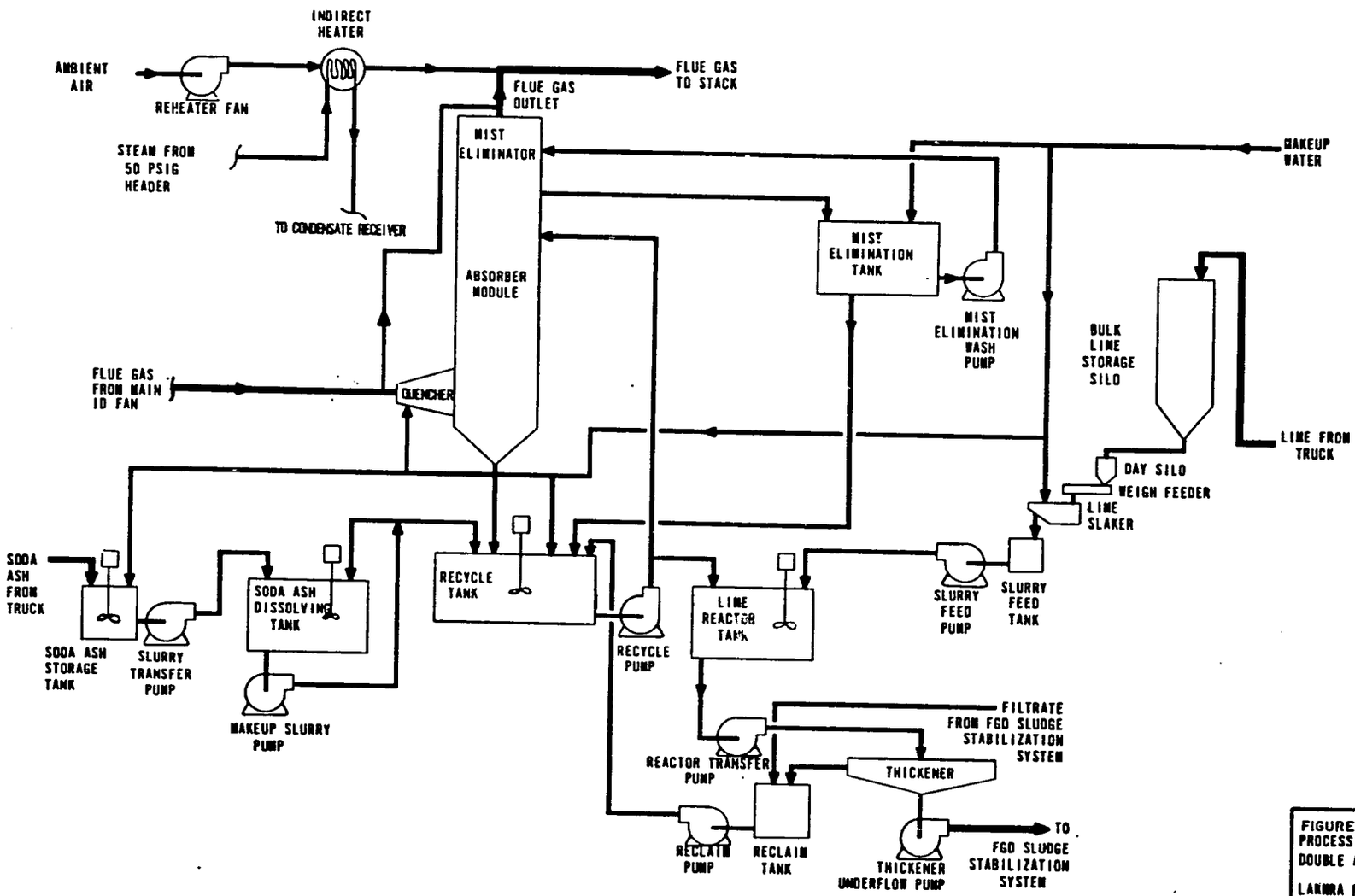

FIGURE 5
PROCESS FLOW DIAGRAM
DOUBLE ALKALI FGD SYSTEM

LAKHRA PROJECT - JAMSHORO SITE - 300 MW UNIT
PAKISTAN WATER & POWER DEVELOPMENT AUTHORITY
J.O. NO. 14003.04

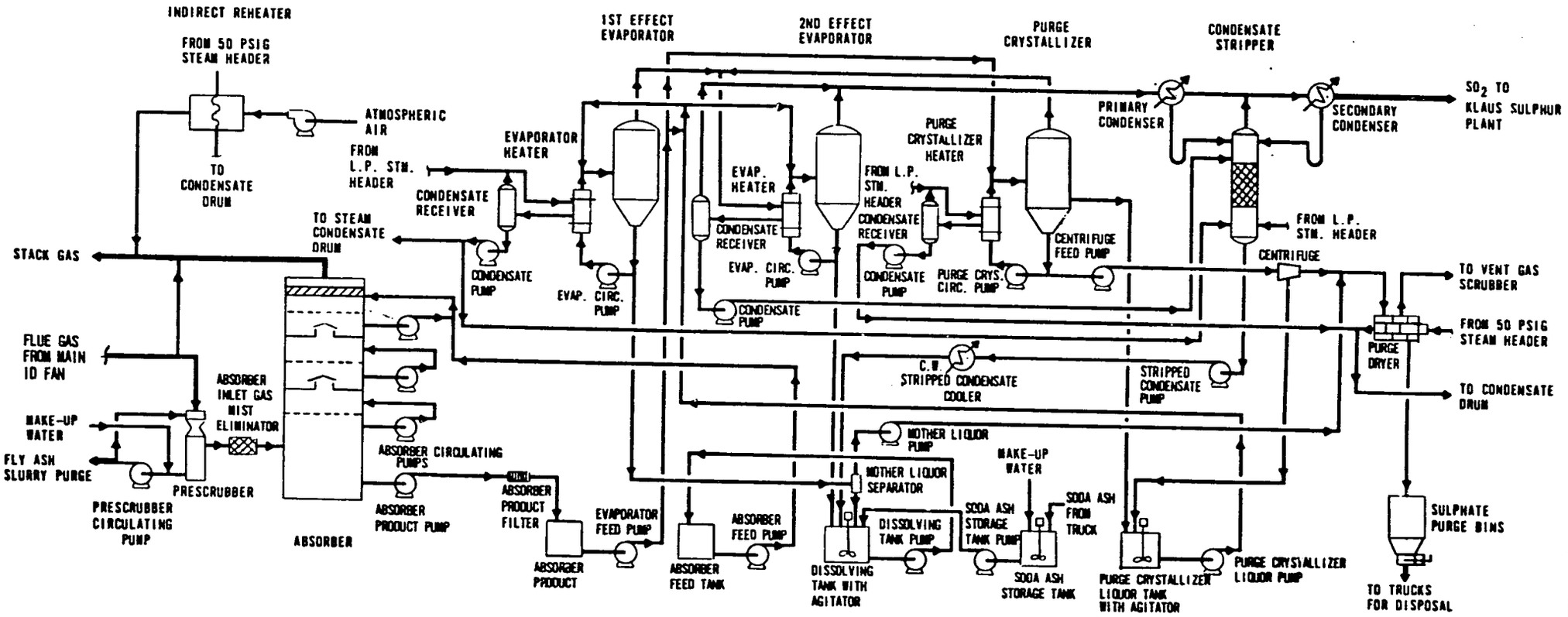

FIGURE 6 .
WELLMAN - LORD FGD SYSTEM
PURGE CRYSTALLIZATION

LAKHRA PROJECT - JAMSHORO SITE - 300 MW UNIT
PAKISTAN WATER & POWER DEVELOPMENT AUTHORITY
J.O. NO. 14003.04

THE IMPACT OF A FLUE GAS DESULFURIZATION SYSTEM ON A COAL-FIRED ELECTRIC GENERATING STATION

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S. A. Smith
B. L. McSweeney

ABSTRACT

This paper presents the technical and economic impact of a limestone flue gas desulfurization system (FGD) and a FGD sludge stabilization system on a coal-fired electric generating station. A typical 535 MW (net) station operating at an annual capacity factor of 65 percent and burning 2.85 percent sulfur, 10 percent ash, 10,430 Btu/lb coal, and with a 90 percent efficient FGD system, will remove 78,500 tons of sulfur dioxide per year. A FGD system with a 98 percent reliability will cause forced station outages equal to 6.4 x 10^7 kWh annually.

A typical limestone FGD system with a sludge stabilization system will require annually: 81 operation and maintenance personnel, 162,000 tons limestone, 10,400 tons lime for sludge stabilization, 2.6 x 10^8 gallons makeup water, 32,000 gallons of fuel for disposal trucks, 7.7 x 10^7 kWh electricity, 7.6 x 10^8 pounds of reheat steam, and 16.2 acres of real estate for equipment and maintenance. The systems will produce 528,000 tons of stabilized sludge per year requiring 303 acres of disposal land at 35 feet deep during a 35-year life. The use of the FGD system will increase the heat rate of the station by approximately 3.5 percent and result in the need to burn 51,000 tons of extra coal per year.

The cost of this highly reliable limestone FGD system with sludge stabilization will be approximately \$200 x 10^6 (1987) installed capital and \$25 x 10^6 per year (levelized) for the aforementioned operation and maintenance parameters. Typically, this amounts to a total cost of 19.1 mills/kWh or \$740 per ton of removed sulfur dioxide expressed in 1987 levelized dollars.

PURPOSE AND SCOPE

The purpose of this paper is to present the technical and economic impact of a limestone FGD system and a FGD sludge stabilization system on a coal-fired electric generating station burning coal as presented in Table 1.1.

Table 1.1

Coal and Flue Gas Data

Coal Analysis	Maximum	Average
Sulfur Content, % by wt.	4.5	2.85
Chlorine Content,% by wt.	0.1	0.05
Ash Content, % by wt.	15	10
Higher Heating Value, Btu/lb	10,430	10,430
Heat Input to Boiler from Coal at Full Load	6.0×10^9 Btu/hr	5.59×10^9
Flue Gas Data		
Flue Gas Entering FGD System at Full Load, lb/hr	7.3×10^6	6.6×10^6
Flue Gas Temp., ^oF	700 (short duration)	270
Flue Gas Particulate Content Entering FGD System, lb/10^6 Btu	0.3	0.03

ECONOMIC PREMISES

GENERAL

The following basic economic assumptions are used in this paper for the impact evaluation of a limestone FGD system. The assumptions, while in line with typical utility conditions, are made without reference to a particular utility's situation. Further, the economic values and results of this paper may appear to the reader to be higher than usually found in literature. This is because this paper presents economic parameters and results in terms of levelized and/or capitalized values. Capital costs are expressed in terms of total installed capital cost 1987 dollars. In addition, this paper includes all costs of a FGD system.

Financial Assumptions

Discount rate is 11.5 percent, levelized fixed charge rate is 16.67 percent, commercial operation date is June 1987, economic life is 35 years.

Investment Cost Assumptions

a. Investment costs are based on present day (mid 1981) direct cost estimates.

b. Capital investment cost (1987 dollars) can be obtained by multiplication of the present day direct cost (a) estimate by 2.01. This factor includes indirects, distributables, allowance for indeterminates, escalation based on a 42-month construction schedule, and interest during construction.

Plant Operational Assumptions

Electrical output is 535,000 kW (e) (net), the levelized capacity factor is 65 percent, and the plant heat rate equals 10,450 Btu/kWh (includes FGD system).

Operating Cost Assumptions

The levelized factor takes into account the effect of price escalation during the life of the power plant. Levelized factor is 2.54 to convert a price in 1981 dollars to a levelized price. This levelized factor is consistent with escalation assumptions of 7 percent per year between 1981 and 1991 and 5 percent per year between 1992 and 2022.

LIMESTONE FLUE GAS DESULFURIZATION SYSTEM

GENERAL

Two types of limestone FGD systems are available: single loop and double loop. The overall technical and economic impact of a single loop and double loop limestone FGD system on a station are essentially equivalent. The double loop flow scheme is shown on Drawing 3.1.1. The use of a double loop limestone FGD system in this paper was an arbitrary choice made by the authors of this paper and does not represent a preference for this technology.

Limestone FGD systems require high calcium limestone. High calcium limestone is available in New Jersey, Pennsylvania, and New York in sufficient quality and quantity to meet the limestone requirements presented in this paper. If numerous limestone FGD systems are employed in the State of New York, new limestone quarries may have to be opened. Utilities should have several sources of limestone in order to ensure reasonable quantity and price.

PROCESS DESCRIPTION

In a double loop limestone FGD system the flue gas enters the module where it is quenched and SO_2 is removed in the lower loop. The flue gas then is contacted countercurrently in the upper loop to remove the remaining required SO_2. The SO_2 stripped flue gas then passes through a two-stage mist eliminator system and is reheated indirectly before exiting to the stack.

Bulk limestone (normally 3/4 in x 0 in and containing greater than 90 percent reactive $CaCO_3$) is delivered to the site by truck, rail, or barge and is transported to the pile by belt conveyor. The power plant should be designed for at least two modes of limestone delivery. The limestone pile should be sufficient for 90-day operation at annual average load and annual average sulfur content. Dolomitic limestone usually is not adequate for use in an FGD system.

From the limestone pile, the limestone is reclaimed into conveyors that transport the limestone to surge silos, each with a one-day limestone capacity. With the surge silo discharge valve open, the limestone is weigh-fed to wet ball mills, where pulverized limestone slurry is prepared with a normal composition of less than 100 mesh and greater than 40 percent by weight solids. This slurry then is sent to the reagent feed tanks, each of which has a minimum of eight-hour storage capacity at design conditions. A wet cyclone separates oversized limestone particles (greater than 100 mesh) before the slurry enters the reagent feed tank and returns them to the inlet of the ball mill. The slurry then is fed to the recycle tank at a rate proportional to the SO_2 mass flow entering the absorber tower. Flue gas flow rate, SO_2 concentrations, temperatures, and pressure are monitored.

From the recycle tank, the slurry, which normally contains 10 to 15 percent by weight solids, is recirculated to the spray section of each tower. Slurry density, pH, and flow are monitored. A slip stream from the scrubber is discharged to thickeners where part of the water is reclaimed and thickener underflow is fed to the sludge stabilization system.

The calcium sulfate/sulfite underflow slurry from the FGD thickener usually contains 20 to 35 percent by weight suspended solids, including water of hydration. The underflow slurry has a temperature of approximately 110°F, a pH of 5.5 normally, and a specific gravity of approximately 1.3.

CHEMISTRY

The principal reactions in the absorber are between SO_2 in the flue gas and water in the absorbing solution. The reactions involving the limestone are completed in the recycle tanks. The resultant insoluble waste calcium products are actually hydrated as $CaSO_3 \cdot 1/2\ H_2O$ and $CaSO_4 \cdot 2H_2O$.

WASTE PROCESSING AND DISPOSAL

This paper's analysis is based on a FGD sludge stabilization system. An FGD sludge stabilization system is diagrammed on Drawing 3.4.1.

The FGD waste slurry normally is dewatered by vacuum filters to 50 to 60 percent by weight hydrated solids. The filtrate is returned to the FGD system. The dewatered FGD waste is mixed with fly ash, bottom ash (if desired), and lime and conveyed outside of the sludge stabilization building to a radial stacker which delivers the sludge to

a surge pile. The fresh material from the radial stacker is sometimes too wet to work immediately (due to lack of fly ash); it can stand for three to seven days to partially set up, in a manner similar to cement, before being moved. At some utility installations, the fresh material from the radial stacker is too dry, due to excess fly ash, and causes a dusting problem. Usually the fresh material from the radial stacker is neither too wet nor too dry and can be transported immediately.

An emergency dump pond is provided for waste from the thickeners and surge tanks, in the event that the sludge stabilization system is out of service. This emergency dump pond is sized for 10-day operation at full load, maximum sulfur coal.

This paper presents the economics of stabilized sludge truck transport (four mile round trip) using 20 ton trucks on a public road. In a typical landfill operation, the stabilized sludge from the radial stacker pile is front-end loaded into haulers, which are driven to the disposal area and dumped by elevating the truck bed to the angle of slide of the sludge. After the truck has pulled away, a grader layers (usually one to two feet thick) and a roller compacts the stabilized sludge. The final chemical-physical properties of the landfill depend on the FGD system employed, coal used, method of curing, and compaction employed. When the stabilized sludge becomes wet due to normal rain or snow, it usually behaves as earth and does not become thixotropic. Compacted stabilized sludge usually has low permeabilities (10^{-6} to 10^{-7} cm/sec) which means special water run-off considerations are given in the design of a landfill area. Utilities grow vegetation (i.e., grass or trees) on top of the stabilized sludge landfill area after the filling operation has terminated.

An advantage of sludge stabilization is that it produces a chemically and physically stable landfill material with low trace element leach rates and ultimate load bearing strengths of at least 3 tons per square foot. A disadvantage of stabilized sludge is that it solidifies to a low grade concrete which is not easily removed from rail cars or barges.

OPERATION AND MAINTENANCE

Scaling and Plugging Problems

In limestone FGD systems the reagent solution is in slurry form and severe scaling and plugging problems can occur. Scaling and plugging problems can lead to shutdown. The deposition of solids on scrubber surfaces interferes with gas flow and can plug piping. Scale buildup and plugging can be determined by visual inspection, increased gas pressure drop, increased liquid pressure drop, erroneous instrument readings, and loss of gas or liquid flow. Scaling and plugging can be minimized by accurate pH control, water wash of surfaces, water flush of piping, and design features minimizing scale buildup.

The scale formed on surfaces often is so adherent that removal is difficult and must be done by hand. For example, the absorber module can be shut down, isolated, and manually cleaned by any maintenance

personnel. The required cleaning tools include high-pressure hoses, hammers, chisels, shovels, cutting tools, and other manual tools. If instruments or pipes scale or plug, they usually are water flushed or disassembled and cleaned manually.

Other Problems

Numerous other operation and maintenance problems can occur in a FGD system; for example, limestone silos can plug, coal can be carried to the limestone silo, piping can erode, pumps and pipes can plug, condensate can freeze, instruments corrode, motors burn out, isolation dampers fail to seal properly, SO_2 monitors fail, ductwork corrode, tank and duct liners fail, in-line reheaters scale, stack liners fail, piping break, dust collectors become plugged, thickener rake mechanisms fail, vacuum filter cloth plug or tear, radial stackers fail, isolation valves fail to isolate, slurry pumps use excessive seal water, scrubber module material or construction corrode and erode, wet ID fans corrode and erode, pumps erode, or FGD sludge become either too dry or too wet. These aforementioned problems can be eliminated or minimized by proper design, engineering, construction, operation, and maintenance of the FGD system and sludge stabilization system.

FGD SYSTEM TERMINAL POINTS

Terminal points for this paper have been established as follows: flue gas outlet of ID main fans, flue gas exit at entry flange to the stack, utilities have single points of supply at the unit battery limit, FGD chemical reagents are assumed delivered at the plant gate, and FGD stabilized sludge is truck transported on public roads to a utility-owned disposal landfill site.

LIMESTONE FGD SYSTEM REAL ESTATE REQUIREMENTS

The real estate requirements of a FGD system, FGD waste system, and FGD waste disposal area have a major influence on the selection and layout of a new site for a coal-fired electric generating station. Table 3.7.1 presents estimated real estate requirements for a limestone FGD system and a FGD sludge stabilization system for a single new 535 MW (net) coal-fired generating station. These real estate areas correspond to simple plot plan drawing 3.7.1.

Table 3.7.1

Limestone FGD Systems' Real Estate Requirements

Plant Areas	Acres
Limestone Storage Pile	2.9
Absorber Section	2.3
Sludge Stabilization Area	11.0
Stabilized Sludge Disposal Area	303.0
Total Real Estate Area, Acres	319.2

The use of a retrofit FGD system at an existing power station can present unique problems such as lack of adequate real estate, boiler outage while the FGD system is being connected, movement or removal of existing equipment, construction of a new stack since existing stacks usually are not designed to withstand the humid acidic properties of the reheated FGD system flue gas, and other unique problems.

EFFECT OF FGD SYSTEM ON COAL-FIRED PLANT AVAILABILITY

A highly reliable limestone FGD system with a FGD sludge stabilization system has a reasonable expectation of operating at greater than 98 percent of the anticipated plant operating hours per year without affecting plant electrical output. This 98 percent value is based on data from the few highly reliable FGD systems which currently are operating in the USA.

ECONOMIC IMPACT

LIMESTONE FGD SYSTEM ECONOMICS

The economic impact of a FGD system on a electric generating station is substantial. Tables 4.1.1 and 4.1.2 present a summary of the economic impact of the limestone FGD system for a new 535 (net) MW coal-fired plant burning high-sulfur coal. A new power plant was chosen for analysis in this paper because most utilities in the State of New York planning to convert existing plants from oil to coal firing will be burning low sulfur coal and may not require flue gas sulfur dioxide control.

Table 4.1.1

Limestone FGD System With Sludge Stabilization System Capital Cost Estimate (Millions of Dollars)

Component	Cost
Limestone Storage/Handling Section	$ 3.0
Absorber Section/Limestone Slurry Preparation Building/Control Building	65.2
Sludge Stabilization Section/ Thickener/Emergency Sludge Pond	11.2
Stabilized Sludge Transport and Disposal Vehicles and Vehicle Maintenance Building	10.1
Initial Spare Parts	0.9
Initial 90 Day Supply of Reagents	0.8
Total Direct Cost (1981 Dollars) (1)	$91.2

Indirect and Distributables	21.9
Indeterminates	11.3
Escalation	39.3
Interest During Construction	19.6
FGD Capital Investment (1987 Dollars) (2)	$183.3
FGD Electrical Incremental Power Plant Cost ($750/kW)	10.0
FGD Reheat Steam Incremental Power Plant Cost ($50/lb/hr steam)	6.7
Total Capital Investment (1987 Dollars)	$200.0

Notes

(1) Direct cost figures include provision for: site preparation, excavation, piles, foundations, structural steel, buildings, piping, process equipment, valves, instrumentation, controls, electrical layout, winterized plant design (-20°F), disposal vehicles, plus all that which is required for a completely operational system.

(2) Capital costs are based on a new electric generating station and do not include the 10 to 30 percent increase in capital cost usually associated with a retrofit FGD system and sludge stabilization system.

Table 4.1.2
Limestone FGD System and Sludge Stabilization System
Total Capitalized Investments
(Thousands of 1987 Dollars)

Manpower	Cost
FGD Absorber (28 O&M personnel)	$ 2,352
FGD Sludge Stabilization Area (10 O&M personnel)	840
Limestone Handling Area (6 O&M personnel)	504
FGD Stabilized Sludge Disposal Crew (37 O&M personnel)	3,108
Subtotal (81 personnel) ($84,000/person)	$ 6,804
Utilities	
Electricity (7.7×10^7 kWh/yr) ($0.0477/kWh)	3,673
Reheat Steam (7.6×10^8 lb/yr) ($0.00318/lb)	2,417
Makeup Water (2.6×10^8 gal/yr)($0.76/1000 gal)	198
Subtotal	$ 6,228

	Cost
Reagents and Fuel	
Limestone (162,000 ton/yr) ($34/ton)	5,508
Lime (10,400 ton/yr) ($200/ton)	2,080
Fuel (32,000 gal/yr) ($5/gal)	160
Subtotal	$ 7,748
Repairs Allowance	
Routine Repair Parts Material	2,000
Routine Plant Support Maintenance Personnel	1,000
Scheduled Shutdown Maintenance Manpower and Material	1,000
Subtotal	$ 4,000
Total Levelized Annual Operating Cost (Dollars per year)	$ 24,840
Capitalized Levelized Annual Operating Cost (at a levelized fixed charge rate of 16.67%)	$149,000
Total Capital Investment (from Table 4.1.1)	$200,000
Total Capitalized Investment (sum of capitalized levelized annual operating cost and total capital investment)	$349,000

Table 4.1.1 direct capital costs may appear greater than those normally presented in literature references. This is because this paper's FGD system consists of 90-day storage of limestone, four scrubber modules (three operating and one spare), quencher constructed of IN 625 alloy, absorber section constructed of 904L, isolation dampers constructed of IN 625, scrubber outlet ductwork of 904L and IN 625, spare pumps in every service, spare ball mill, spare vacuum dewatering filter, Marconaflo emergency pond, and other design features to ensure 98 percent FGD system reliability.

The Table 4.1.1 limestone FGD system total direct cost includes approximately 500,000 man-hours of construction labor. These FGD construction labor crafts are the same as those used in other areas of the power plant.

Table 4.1.2 presents the typical operational and maintenance personnel for the entire FGD system during the year. These personnel would not be needed if FGD was not required. The large number of personnel required reflects the high degree of manual operation and maintenance required for reliable service. A large fraction of the total personnel employed in a throwaway FGD system can be associated with the transport and disposal of the FGD waste.

Table 4.1.2 presents FGD system utility requirements for the limestone FGD system. An approximation of the normal full load hourly utility demands (except peak makeup water) can be made by dividing Table 4.1.2 values by 5,700 hr. Peak utility demands may be 120 percent of the normal full load hourly utility demand (except peak makeup water). Because peak makeup water demands are very high (during intermittent mist eliminator wash periods or chloride purge periods), a makeup water surge tank normally is provided to supply peak makeup water requirements.

Table 4.1.2 indicates the annual average reagent and fuel consumption of the limestone FGD system. Throwaway FGD systems consume a massive amount of reagent annually. The well-scheduled delivery of FGD reagent to the power plant is of great importance. Alternative reagent delivery methods to this paper's eight-hour shift truck delivery method should be investigated. In this paper, reagent is delivered using 20 ton trucks during an eight-hour shift on weekdays only. This means that for this average coal case, a truck arrives at this single power plant with 20 tons of limestone every 15 minutes. Peak hourly reagent demands could be 170 percent of the normal full load hourly reagent demands. Peak reagent demands correspond to high stoichiometric ratio and high sulfur coal.

The amount of stabilized sludge produced from the limestone FGD system for this high sulfur case is substantial; the value of 528,000 ton/yr corresponds to approximately 300 acres, one foot deep, every year. This stabilized sludge includes 371,600 ton/yr of dewatered FGD sludge and lime. This 371,600 ton/yr of waste would not exist if a FGD system was not employed. The well-scheduled disposal of stabilized sludge is of great importance. In this paper, stabilized sludge is disposed using 20 ton trucks during an eight-hour shift per day. This means that, for this average ash and sulfur coal case, a 20 ton truck arrives at the stabilized sludge landfill area every six minutes. Peak hourly waste production could be 150 percent of the normal full load hourly waste production. Peak waste production corresponds to high ash, high sulfur, and high stoichiometric ratio.

The large electrical and steam requirements of FGD systems must be taken into consideration early in the conceptual design phase of a specific project.

Based on Table 4.1.2 electricity and steam usages, the limestone FGD system with a sludge stabilization system will increase the normal power plant heat rate by approximately 350 Btu/kWh. This represents a 3.5 percent increase in the heat rate of the station and results in the need to burn 51,000 tons of extra coal per year. This extra 51,000 tons/yr of coal represents approximately 1,000 extra 50-ton rail cars which must arrive at the power plant site per year because of the FGD system.

The total capitalized investments of Table 4.1.2 can be expressed as levelized mills per net kWh. For example, the levelized extra cost of one killowatt hour of electricity due to sulfur dioxide removal and stabilized FGD sludge production, transport, and disposal is

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approximately 19.1 mills/kWh. This value of 19.1 mills/kWh does not include the cost of replacement power due to power plant forced outages or deratings caused by an unavailable FGD system. For this paper's situation, 57 percent of the 19.1 mills/kWh value is for paying back the capital investment. This extra 19.1 mills/kWh is a substantial amount of money when compared to this paper's assumed levelized cost of auxiliary electricity at 47.7 mills/kWh. (This 47.4 mills/kWh includes only fuel charges.)

Values found in Table 4.1.2 can be used to develop other meaningful parameters. For example, the total levelized cost of removing one ton of sulfur from the flue gas of high sulfur coal is $1,480 for the limestone FGD system. One should expect to be able to purchase one ton of raw sulfur for a levelized cost of less than $350.

CONCLUSIONS

Federal, New York State, and New York City air quality regulations limit sulfur oxide emissions from new coal-fired boilers with firing rates in excess of 250 million Btu/hr. To meet these governmental requirements at a new conventional pulverized coal-fired electrical generating station, a FGD system is required.

The major impacts of a FGD system and a sludge stabilization system on a power station are the following: minimize sulfur dioxide emissions; forced station outages due to system unreliability; requirement for numerous operation and maintenance personnel; requirement for large quantities of limestone, lime, water, fuel for disposal trucks, electricity, reheat steam, and real estate; production of massive amounts of FGD waste; increase in the overall noise levels of the station; increase in traffic on delivery routes to and from the power station; unavoidable fugitive dust emission from the material handling operation; negative affect on stack plume dispersion since the reheated FGD system flue gas is cooler compared to unscrubbed flue gas; and increased heat rate of the power station.

FGD systems and FGD waste systems are expensive. For this paper's 535 MW (net) electric generating station, the limestone FGD system and FGD sludge stabilization system are estimated to cost $200 x 10^6 installed capital (1987 dollars) and $24.8 x 10^6 per year (levelized) for operation and maintenance. This amounts to a total capital investment of $370/kW (net) and a 19.1 mills/kWh increase in electricity rates expressed in 1987 levelized dollars.

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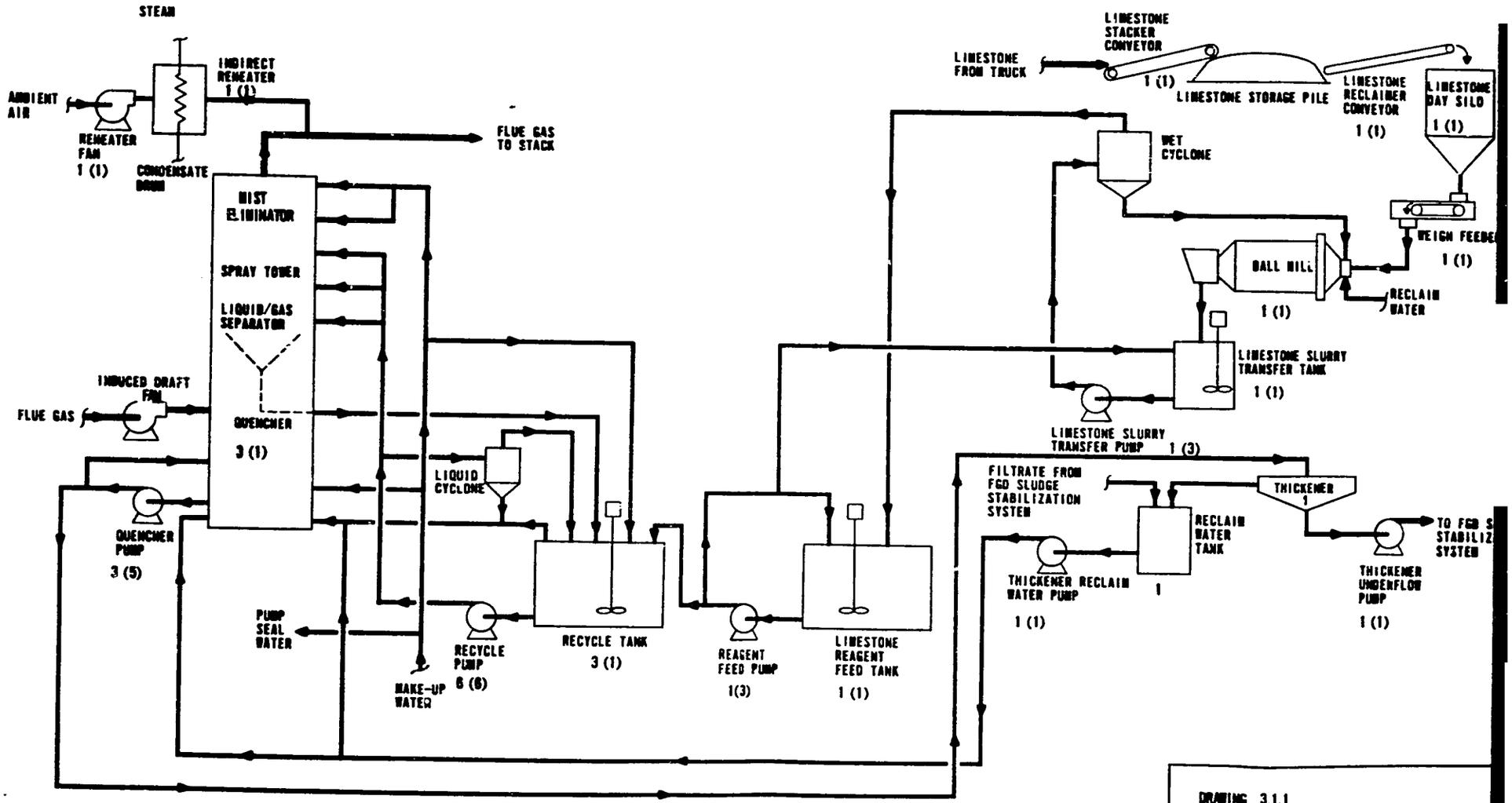
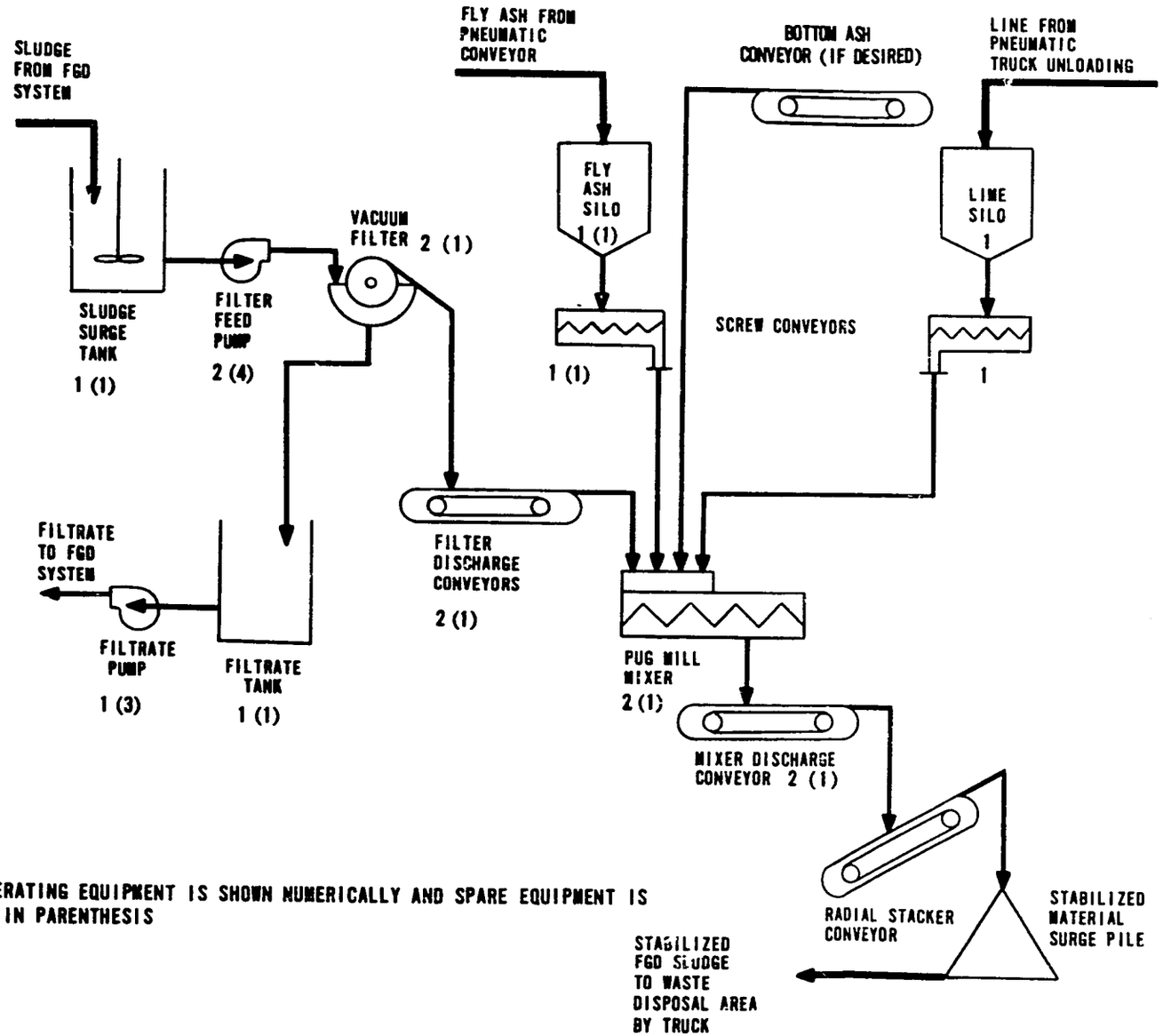


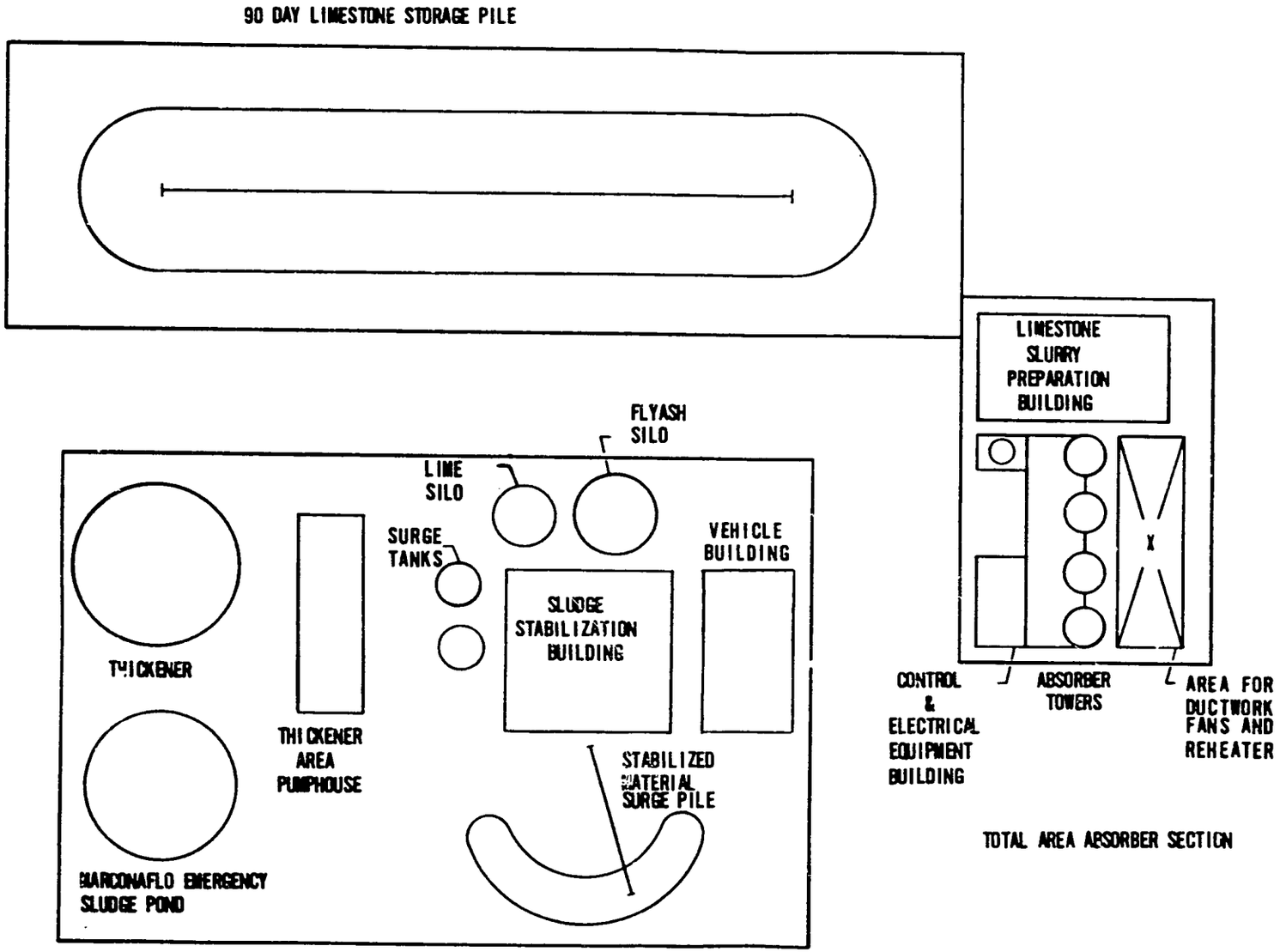
NOTE: NORMAL OPERATING EQUIPMENT IS SHOWN NUMERICALLY AND SPARE EQUIPMENT IS PRESENTED IN PARENTHESIS

DRAWING 3.1.1
PROCESS FLOW DIAGRAM
LIMESTONE FGD SYSTEM
DOUBLE LOOP



RMAL OPERATING EQUIPMENT IS SHOWN NUMERICALLY AND SPARE EQUIPMENT IS
ESENTED IN PARENTHESIS

DRAWING 3.4.1
PROCESS FLOW DIAGRAM
FGD SLUDGE STABILIZATION SYSTE



DRAWING IS NOT DRAWN TO SCALE AND DOES NOT INCLUDE THE STABILIZED SLUDGE DISPOSAL AREA.

DRAWING 3.7.1
PLOT PLAN
LIMESTONE FGD SYSTEM

APPENDIX 11

SWEC COST AND SCHEDULE CONTROL SYSTEM

APPENDIX 11

LIST OF FIGURES

Figure	Title
1	Engineering Work Breakdown Structure - Lignite Power Plant
2	Description of Services
3	Sample Work Package Network
4	Engineering and Purchase Schedule
5	Drawing Schedule and Progress Chart
6	Construction Work Breakdown Structure - Lignite Power Plant
7	Construction Work Package Scope of Work
8	Performance Report
9	Work Package Manhour Report
10	Cumulative Progress Index Report
11	Activity Analysis Report "A"
12	Detail WBS Account Report by Work Package
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APPENDIX 11

STONE AND WEBSTER ENGINEERING CORPORATION (SWEC)
COST AND SCHEDULING CONTROL SYSTEM

COST AND SCHEDULING CONTROL

Over the past years, it has become increasingly important to plan, organize, staff, direct, and control projects of greater complexity in less time and with better control of costs. The individual assigned the responsibility and authority to achieve project success is the Project Manager. As the company representative, the Project Manager is accountable for the schedule, hours, cost, and overall project performance, and is repsonsible for maintaining a close contact with the Client. To accomplish these objectives, a Project Manager must have the best tools available to properly plan and manage all aspects of the project. The Project Manager must have accurate and timely data in a format which can be easily analyzed so that proper decisions can be made.

To aid the Project Manager in meeting the objectives of the project within schedule and estimated budget, SWEC has developed and can apply an effective integrated (tied together) system to control the engineering effort and construction activities.

a. The Engineering Management System (EMS) is used to assist in managing the services of the engineering effort.

b. The Construction Management System (CMS) is used to assist in the management and building of all construction activities.

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The principal elements within both the Engineering and Construction Management Systems are a work breakdown structure and work packages (a specific grouping of like products).

Definition of a Work Breakdown Structure

A Work Breakdown Structure (WBS) divides the scope of a project into small, definable, and accountable (people performing the work) groupings of work. It is a logical method of organizing, defining, and graphically displaying the scope of services and products provided for a Lignite Power Plant.

A WBS is divided into successively smaller subgroupings of related products (such as design drawings and specifications). The manageable group is called a Work Package (WP). The WP is the key element within a WBS. It represents the lowest level, where the scope of services is best managed, in terms of schedule control, hour control, material monitoring, and where responsibility can be assigned.

A WBS is expected to accomplish the following objectives:

a. Define the scope of services for engineering or construction task, and assign responsibiltiy for performance in a logical framework.

b. Provide the basis for estimating the hours and quantity of material required for a project and relate them directly to their schedules.

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c. Provide the basis for a management reporting system and summarize information which provides both product and organization visibility.

d. Identify the construction groups performing the work.

e. Document the scope of work that will be performed and serve as the basis for identifying changes.

Developing an Engineering Work Breakdown Structure

An Engineering Work Breakdown Structure (EWBS) is developed to organize and define the complete engineering effort for a Lignite Power Plant and is developed along System-related products approach.

SWEC has found, over the years of operating and improving on the concepts of managing projects, that the system approach has greatly improved the working relationship between the engineering groups (such as mechanical, structural, and electrical engineers). This has resulted in the assignment of a specific person, known as a Work Package Engineer, who is responsible for managing the total engineering effort of a system or building. This makes it easier to plan, progress, and control the work, rather than trying to monitor the different activities of each engineering group.

In developing a WBS, all the systems and products (drawing/specification) that will have to be produced for a project are defined. Once this is accomplished, all similar and related tasks are grouped together into a WP (like all the steel drawings for the turbine building).

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Planning when activities should be done, assigning dates to these activities, estimating the hours to perform the work, and reporting progress are accomplished at the Activity Level (Level 7), and summarized to the Total Project Level, which is Level 1.

Figure 1 is an overview of a Lignite Power Plant engineering WBS.

Level 5 - Work Packages

A Work Package (WP) is a grouping of all related products to a system or a building. A Fluid System WP includes all its related products, such as flow diagrams, logic and elementary diagrams, system description, calculations, design drawings, and specifications leading to the complete design of that system (such as feedwater or service water systems). A Building System WP includes such products as structure design criteria, concrete, steel, and architectural design drawings, calculations, and specifications required for the design of a building or structure (such as the turbine or control building).

The size (number of drawings and hours required to produce those drawings) of a WP should be small so that it can be managed effectively by a Work Package Engineer. This person is responsible for the management of products, hour estimate, and schedule performance. Usually, the Work Package Engineer is a structural, mechanical, or other discipline engineer who has the majority of the engineering and design activities in a WP. He is responsible for directing the efforts of other engineers' groups to meet their schedule in support of his assigned tasks.

Summarizing Work Packages

Once all the products are defined and grouped into WPs (Level 5), the balance of the WBS can be constructed. The WBS is built from the "Bottom Up" to provide the Project Team and Client with the best information to properly manage the effort. The levels above the WP are designed to provide a logical summary of information and reports that would be meaningful to the user. All levels are summarized until Level 1 is reached. This is the total summary of all the products and services performed by the engineering team to fully design a Lignite Power Plant at SWEC. Each project within SWEC is given a unique five-digit job number (Example: 12000) for identification and accounting purposes.

Description of Services for a Lignite Project

A detailed description of the engineering services and design efforts required for every WP on a Lignite Project is described in a book called the "Description of Services" (DOS). The Description of Services lists the scope of work of all WPs and the specific products such as specifications, system descriptions, engineering diagrams, design drawings, and engineering studies. Figure 2 is an example of a description of an engineering WP and its products.

Planning and Scheduling

The Project Management will maintain continued and close watch of the project, using data from network-based project plans and schedules. Engineering, design, and procurement activities will be scheduled in considerable detail and interfaced with significant construction,

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installation, and testing activities on project network diagrams. These activities are evaluated monthly for progress.

Project Summary Network

The project Summary Network will be a manually prepared time-scaled network that displays, in summary form, key engineering, design, procurement, and construction project milestone events and their schedule from authorization to project completion. It is used for management reporting and is updated monthly, based on the progress shown on the work package networks.

Engineering Work Package Networks

Individual WP networks are detailed plans and schedules (dates) showing all activities necessary to complete the work for a work package. A typical work package network representing the activities that are required for a system is shown in Figure 3. Construction field required dates are also shown on these networks to establish the end date for the engineering activities. These networks are input computerized and are man-loaded to form the basis of engineering hour and performance reports. The networks are updated, progressed, and analyzed monthly. Output reports are available in list or bar chart format. SWEC has developed work package networks for a Lignite Power Plant that can be used on this project.

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Specification Schedules

A computerized specification schedule is the listing and scheduling of each step in the procurement cycle for materials and equipment to be purchased by engineering. It will be used by project groups in identifying, scheduling, monitoring, and status reporting of events related to engineering/procurement and preparation of construction specifications. This is accomplished through user-oriented (by engineering group) reports which are grouped and sorted to provide maximum visibility of the project. An example of this report is shown in Figure 4.

Detailed Drawing Schedules

A detailed drawing schedule is the tool for planning the start, issue, and completion of individual design drawings at the sheet level. The schedule lists the drawing number and title for identification purposes, the WP, and the job site area where the drawing is applicable. The percent of completion of the drawing is also shown for monitoring the progress of the effort. The schedule dates are derived directly from the overall plan on the WP networks. Some of the most important information on the drawing schedule is the scheduled, planned, predicted, and actual dates for start, out of design, issued, and completion. A typical format for these reports is shown in Figure 5.

Developing a Construction Work Breakdown Structure

A Construction Work Breakdown Structure (CWBS) is developed to organize and define all the construction work that will be planned and controlled by field management. The CWBS summarizes all construction labor and

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material costs to be accumulated and in a manner compatible with the construction operations. It is the basis foundation upon which all scope of services, schedules, and field human resources are planned and controlled in the construction effort. The person directly responsible for the coordination, erection, and performance of all field construction activities is the Superintendent of Construction. To aid the Superintendent of Construction with his job, SWEC has developed and will operate a Construction Management System. This system utilizes a CWBS similar in format to the one used in the engineering effort.

A CWBS is developed early in the preconstruction phase by starting at the total project level and dividing the construction effort into successively smaller subdivisions of work products within a area or building. Figure 6 is a CWBS for a Lignite Power Plant. It illustrates the relationship between all construction levels.

Level 1 - Total Construction Effort

This level includes the total summary of all construction activities based on the labor and quantity of material installed.

Level 2 - Account Groups

The total construction effort (Level 1) is initially subdivided into two distinct account groups, Direct Accounts and Indirect Accounts.

- Direct Accounts are the construction activities that have tangible material quantity (such as rebar, concrete, pipe, etc.) which require installation during the construction effort.

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- Indirect and Distributable Accounts are construction activities that do not have tangible quantities which require installation, such as hours expended for maintenance and repair of equipment assembly and disassembly of temporary structures, and craft support.

Level 3 - Building/Area

The next level of the WBS is the basic building block in the development of a CWBS. Construction projects are managed on an "Area" basis. This means that a Lignite Power Plant is physically divided into specific construction areas or buildings of work that have definable boundaries for better planning and control.

Level 4 - Category of Work

The work in each building/area (Level 3) is then broken down into the five basic Categories of Work. These basic construction categories are: Structural, Piping and Mechanical, Electrical, Building Service, and Miscellaneous Power Plant work items.

Levels 5 and 6 - Work Block and Subwork Block

At Level 5, each Category of Work is broken down into the major classes of work known as Work Blocks. A Work Block includes Substructure, Superstructure, Structural Steel, and Miscellaneous Structural Work (iron).

Level 7 - Work Package

Each Work Block or Subwork Block is then broken down into WPs, which is the lowest level of the CWBS. The WP, shown on Figure 7, is the key element of the CWBS. It contains manageable construction activities within a Work Block, such as concrete placement between two elevations of a particular building. The percent complete for a WP is a summary of the physical percent complete for each element of work within a WP such as erecting steel or pouring concrete. The responsiblity for the completion of a WP is assigned to a Construction Supervisor, and its duration extends over a relatively short period of time, usually 2 to 3 months.

Construction Networks

Building/area construction networks are time-scaled networks that will be developed to plan the construction activities for both subcontracted and force account work. They are in greater detail than that shown on the Project Summary Network and in sufficient detail to establish the initial sequencing of engineering and the interface of various subcontractors, and to define the field required dates for drawings, material, and equipment. These manual time-scaled networks shall be utilized to establish engineering and procurement field required dates.

The Relationship Between Engineering and Construction Work Packages

The relationship between the engineering and construction work packages is accomplished at the activity level. Engineering WP networks are developed, showing in detail the plans and schedules of all activities necessry to complete the work for a WP Construction field required dates

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are also shown on those WP networks to establish the end date for the engineering activities. Construction networks are developed by building or area, showing the sequence of construction activities for both subcontracted and force account work. The construction networks establish the criteria for interfacing the activities within the engineering WP networks to WP construction activities.

Since engineering WPs are established along "System" lines, engineering activities will usually interface with one or more construction WPs. All engineering and construction network activities are integrated (tied together) into one total Project Network File. By producing a total Project Network File, any schedule changes by either engineering or construction can be easily montitored and the impact analyzed as it relates to one another. Alternative solutions to problems can be formulated enabling management to make realistic and timely decisions. Once decisions are made, the appropriate solutions are incorporated into the project plan at the WP level. This procedure keeps the engineering and construction mangement system up to date and allows summarizing of information at all levels.

During the progress of the work, supervision at the working level can evaluate the work by WP and compare actual progress and expenditures to planned progress and expenditures. Schedule and cost reports identify deviations from the approved plan and permit early attention to their resolution.

Information on the overall scope of work, cost, and schedule performance is made available to management, using the summarizing feature of the

WBS. Exception reports show deviations from the approved plan which can be detected promptly and traced accurately to the affected WP.

Reports

Reports covering the schedule or man-hour and cost performance aspects of a project are available from the engineering and construction management systems. Each system is capable of producing progress and exception reports at a detail level for use by the working engineers and construction supervisors. Also, these reports can be summarized for use by project management and Client personnel. Some of the basic working reports from the engineering and construction systems are as follows:

Engineering Management System Work Package Performance Report compares the actual man-hours expended to the work accomplished both for the current period and cumulative to date. This report also presents the total estimated budget for a WP as well as an estimated forecast at the completion. Figure 8 is an example of this report. This report is used by the Project Engineer and Project Manager to monitor the performance of all engineering WPs.

Work Package Man-hour Report provides budgets, actual man-hours expended, and forecasts for each performing engineering group by accounting period. This enables the Work Package Engineer to analyze and detect any deviation from the estimated man-hour budget and the future work to be performed. Figure 9 is an example of this report.

Cumulative Progress Report provides project with a concise summary of the project status on one piece of paper. The report compares

planned progress, actual progress, and actual man-hours on a cumulative basis. This report is used by the Client, Senior Management, Project Manager, Project Engineer, and Project Cost Engineer. Figure 10 is an example of this report.

Construction Management System

Activity Analysis Report shows scope of work and progress to date and provides schedule status, completion dates, and work to be accomplished for each construction activity. This is a weekly report that provides construction supervisors and construction management with the visibility of current and cumulative performance of various construction WPs at the activity level. Figure 11 is a sample of this type of report.

Work Package Report is a detail breakdown of all tasks in a WP with estimated data and actual data for each construction element of work. A physical percent complete for each element of work is found by a direct comparison of the quantities installed to the estimated (planned) quantities. This report gives the visibility of the progress of the construction job by WP. Figure 12 is a sample of a Work Package Report.

Selected Building Report shows the overall percent complete and performance for each building or area being constructed. This report gives the Client and Project Manager a summary status of the job, as well as a projected view of the future progress of the construction effort. Figure 13 is a sample of a selected building report.

Major Benefits of a Management System

The major benefits that SWEC and its Clients have experienced from using engineering and construction WPs and WBS can be summarized in the following areas:

1. The definition of the scope of work is more complete because it is prepared using a system/building approach instead of by discipline. This makes it easier for the engineer to visualize the total effort of each system vs the overall grand total of the project all at once.

2. SWEC has discovered that the use of WPs ensures a clear-cut assignment of responsibility when it is integrated into the organizational structure of the project.

3. A good management system has proven to its Clients that, whenever networks and schedules are developed by WP, the probability of accomplishing the project milestones increases.

4. Clients have observed that, when engineering and construction estimates have been developed by using a WBS format, they are more complete and accurate.

5. Collecting actual man-hour and quantity data at the lowest level of a WBS results in an accurate evaluation of the percent complete of each product, system, building, and project with a greater confidence factor.

6. Developing the scope of work for a project by using a WBS and a WP creates a better basis for documenting scope changes.

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Documenting all the scope changes within a Management System results in a permanent record of the transaction between the Client and SWEC.

7. Developing a WBS and WP from other Lignite projects provides the basis for exchanging engineering and construction information between similar projects.

8. Using a WBS for summarizing planning man-hour and cost information allows the means for producing reports for each level of supervision and management on the project.

9. The requirements for successfully using WBSs and WPs in a Management System result in many specific managerial and technical requirements. The most important criterion for success is a total commitment of a company, personnel assigned to a project, and their day-to-day operational support of a Management System. This commitment requires project personnel, involved in the working details of the system, to conform to one formal method of operation for performing their individual tasks.

ENGINEERING WORK BREAKDOWN STRUCTURE

LIGNITE POWER PLANT

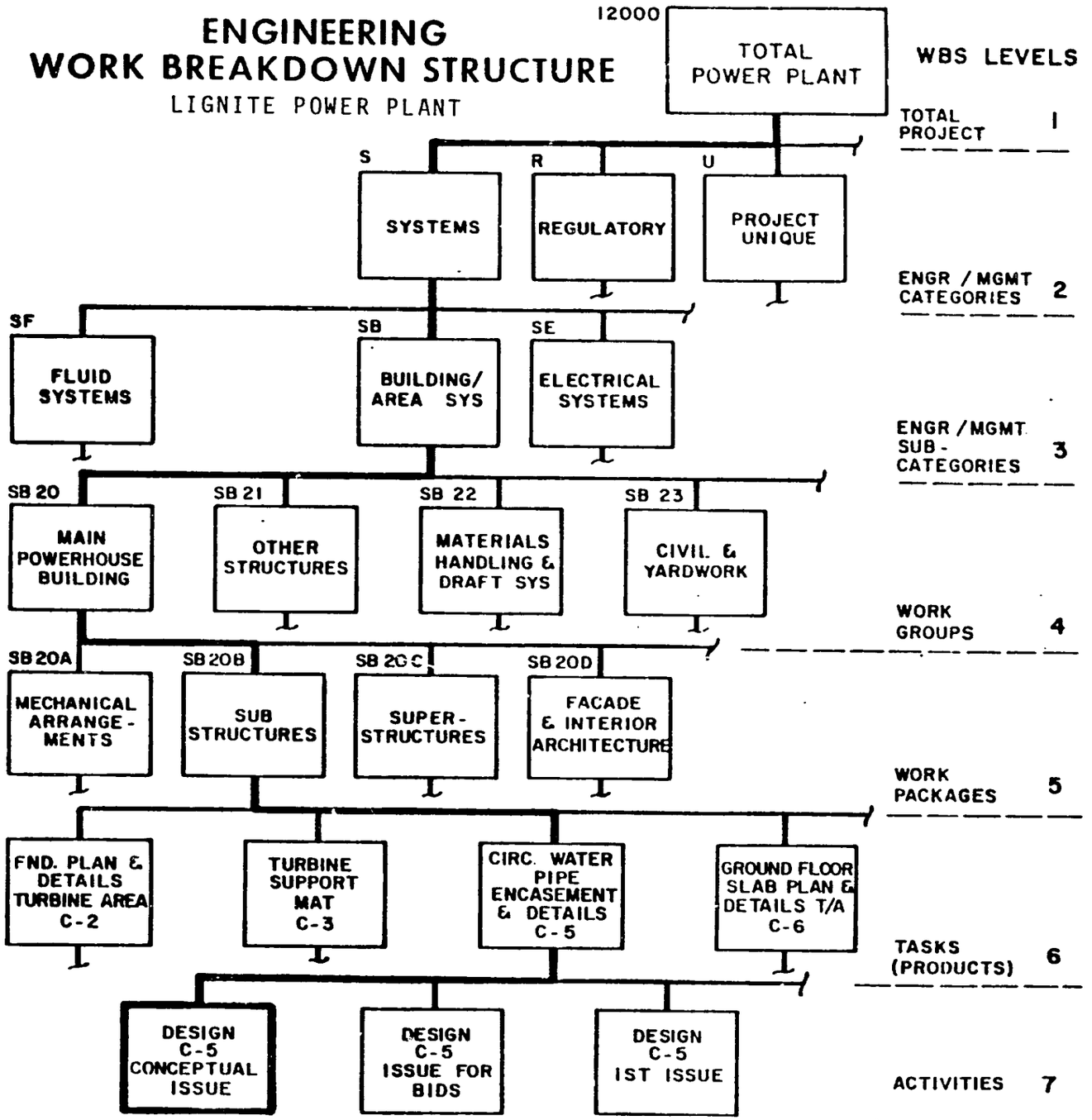


FIGURE 1

20B. Substructures

I. Description of Scope

The scope of this WP is the engineering and design effort required for the development of the substructure for the main powerhouse building. Included within this effort are the design of reinforced concrete foundations, grade beams, and ground floor slab along with associated equipment foundations.

The engineering effort for procurement of materials and construction services is included in Work Group 24 - Structural Group Procurement.

II. Work Package Products

The specific analyses, procurement packages, system descriptions, engineering diagrams, and design drawings to be generated in this WP are presented below:

Procurement Packages

None

System Descriptions

None

Engineering Diagrams

None

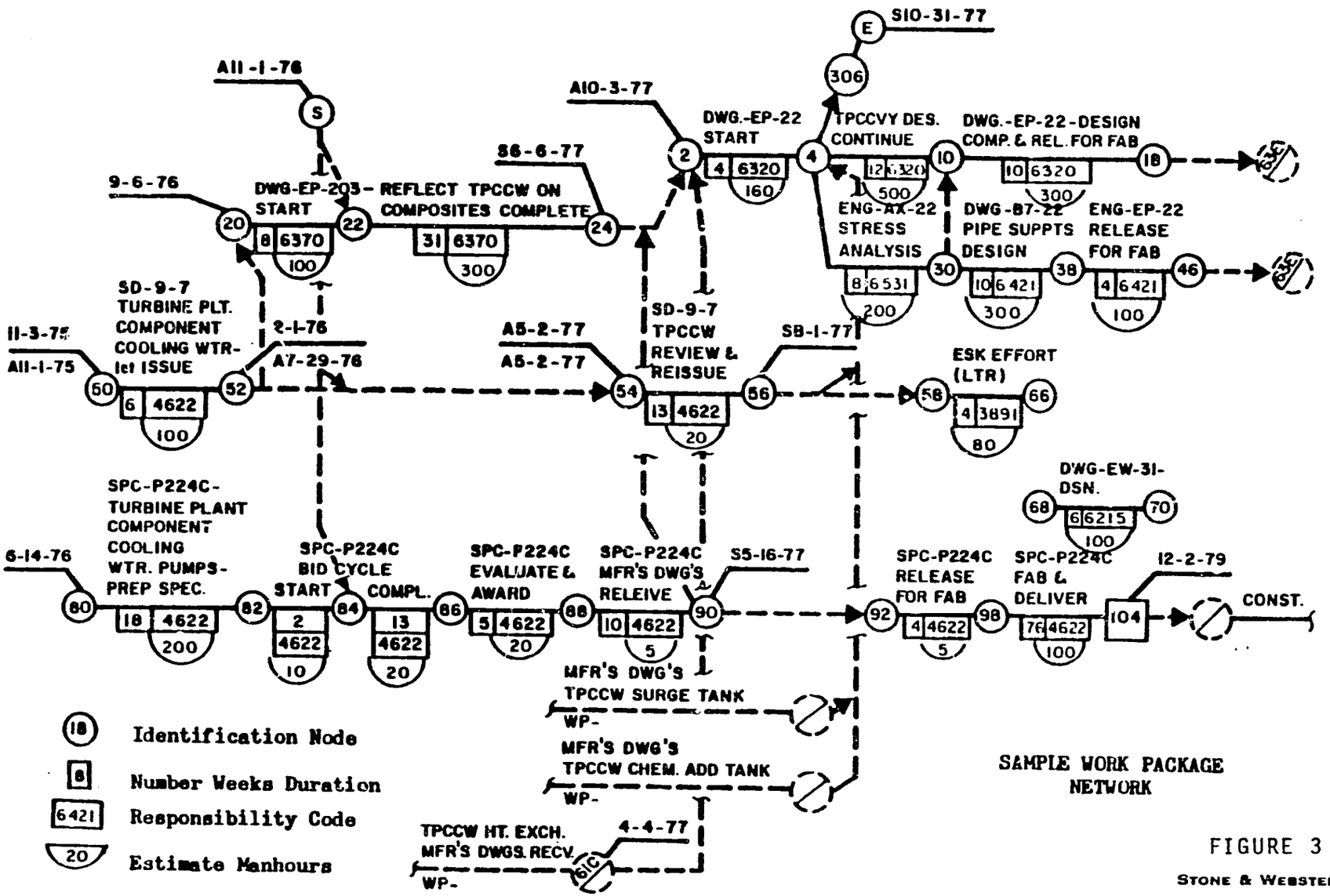
Design Drawings

C-2	Foundation Plan & Details - Turbine Area
C-3	Turbine Support Mat
C-5	Circulating Water Pipe Encasement and Details
C-6	Ground Floor Slab Plan & Details - Turbine Area
C-8	Major Equipment Foundations - Turbine Area
C-11	Foundation Plan & Details - Boiler Area
C-12	Ground Floor Slab - Plan & Details - Boiler Area
C-14	Major Equipment Foundations - Boiler Area

Other Products

Structural Design Criteria

WP-06D
TURBINE PLANT COMPONENT COOLING WATER SYSTEM



SAMPLE WORK PACKAGE NETWORK

FIGURE 3

STONE & WEBSTER

JOB NO.
CLIENT NAME

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS
ENGINEERING AND PURCHASE SCHEDULE
SORTED BY RESP DEPT

REPORT RUN DATE 05SEP78
STATUS AS OF 02JAN78
PROJECT PLAN DATE 02JAN78

C-5 CONTRACT NO.	W P. - DESCRIPTION	RESP DEPT.	START SPEC	TRANSMIT. TO CLIENT	PREP FOR BIDS	OUT FOR BIDS	BIDS RECEIVED.	RECOM. TO CLIENT	PLACE PURCHASE ORDER	RECIEVE. MFGR.'S PRINTS	REMARKS
N051C.	15B PREP FIELD FAB&ERECT TANKS.		30JAN78.	13MAR78.	10APR78.	08MAY78.	19JUN78.	14AUG78.	11SEP78.	04DEC78.	
		46	30JAN78.	13MAR78.	10APR78.	08MAY78.	19JUN78.	14AUG78.	11SEP78.	04DEC78.	
N051D.	15B PREP SHOP FAB VESSELS&TANK.		30JAN78.	13MAR78.	10APR78.	08MAY78.	19JUN78.	14AUG78.	11SEP78.	04DEC78.	
		46	30JAN78.	13MAR78.	10APR78.	08MAY78.	19JUN78.	14AUG78.	11SEP78.	04DEC78.	
P201A.	01A PREP BOILER PURCHASE SPEC		30JAN78.	27MAR78.	24APR78.	22MAY78.	31JUL78.	25SEP78.	23OCT78.	15JAN79.	
		46	30JAN78.	27MAR78.	24APR78.	22MAY78.	31JUL78.	25SEP78.	23OCT78.	15JAN79.	
P201C.	01A PREP BOILER ERECTION SPEC		23OCT78.	18DEC78.	15JAN79.	12FEB79.	09APR79.	21MAY79.	18JUN79.	N/R	
		46	23OCT78.	18DEC78.	15JAN79.	12FEB79.	09APR79.	21MAY79.	18JUN79.	N/R	
P202K.	01A PREP SOOT BLOW COMPRESSOR		15JAN79.	26FEB79.	26MAR79.	23APR79.	04JUN79.	30JUL79.	27AUG79.	19NOV79.	
		46	15JAN79.	26FEB79.	26MAR79.	23APR79.	04JUN79.	30JUL79.	27AUG79.	19NOV79.	
P212C.	01B PREP CENTRIFUGAL FD&ID FAN.		02JAN78.	13FEB78.	13MAR78.	10APR78.	22MAY78.	17JUL78.	14AUG78.	06NOV78.	
		46	A02JAN78.	13FEB78.	13MAR78.	10APR78.	22MAY78.	17JUL78.	14AUG78.	06NOV78.	
P213A.	01B PREP COMBUSTION AIR PREHTR.		06NOV78.	18DEC78.	15JAN79.	12FEB79.	26MAR79.	21MAY79.	18JUN79.	10SEP79.	
		46	06NOV78.	18DEC78.	15JAN79.	12FEB79.	26MAR79.	21MAY79.	18JUN79.	10SEP79.	
P214K.	01B PREP PRECIPITATOR PURCHASE.		02JAN78.	13FEB78.	20MAR78.	08MAY78.	17JUL78.	11SEP78.	06NOV78.	29JAN79.	
		46	A02JAN78.	13FEB78.	20MAR78.	08MAY78.	17JUL78.	11SEP78.	06NOV78.	29JAN79.	
P214M.	01B PREPARE PRECIPITATOR ERECT.		06NOV78.	18DEC78.	15JAN79.	26FEB79.	09APR79.	04JUN79.	02JUL79.	N/R	
		46	06NOV78.	18DEC78.	15JAN79.	26FEB79.	09APR79.	04JUN79.	02JUL79.	N/R	
P231B.	06A PREP PURCH&ERECT COAL HAND.		02JAN78.	13MAR78.	04SEP78.	02OCT78.	25DEC78.	19FEB79.	19MAR79.	11JUN79.	
		46	A02JAN78.	13MAR78.	04SEP78.	02OCT78.	25DEC78.	19FEB79.	19MAR79.	11JUN79.	

FIGURE 4

STONE & WEBSTER

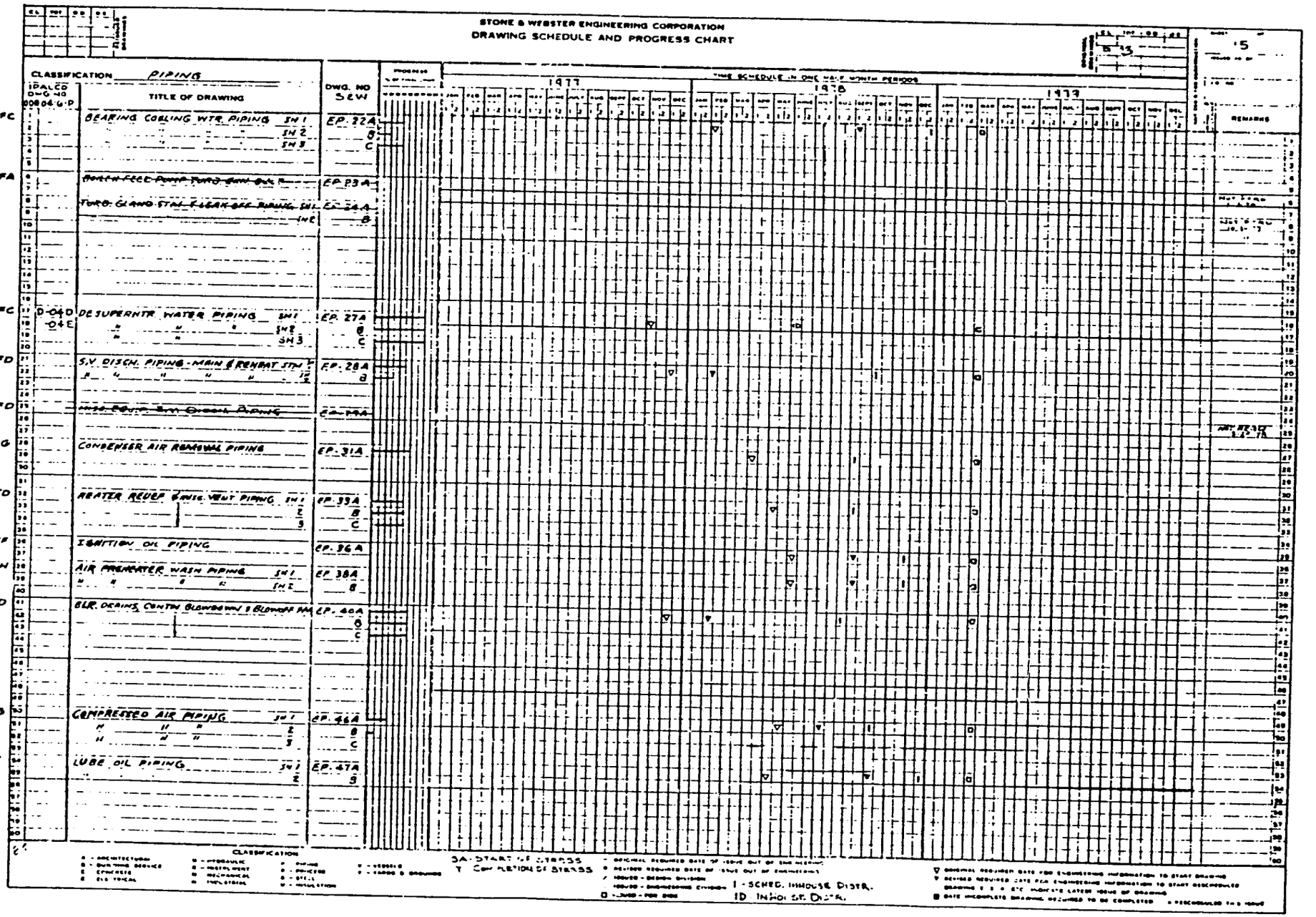

STONE & WEBSTER ENGINEERING CORPORATION
DRAWING SCHEDULE AND PROGRESS CHART
CLASSIFICATION PIPING
TITLE OF DRAWING
DWG. NO
1977
1978
1979
REMARKS
BEARING COOLING WTR. PIPING
DESUPERHTR WATER PIPING
S.V. DISCH. PIPING - MAIN & REHEAT STM
CONDENSER AIR REMOVAL PIPING
HEATER RELIEF & MISC. VENT PIPING
IGNITION OIL PIPING
AIR PREHEATER WASH PIPING
BLR. DRAINS, CONTIN BLOWDOWN & BLOWOFF
COMPRESSED AIR PIPING
LUBE OIL PIPING
CLASSIFICATION
S - START OF STRESS
T - COMPLETION OF STRESS
I - SCHED. INHOUSE DISTR.
ID - INHOUSE DISTR.

FIGURE 5

CONSTRUCTION WORK BREAKDOWN STRUCTURE

LIGNITE POWER PLANT

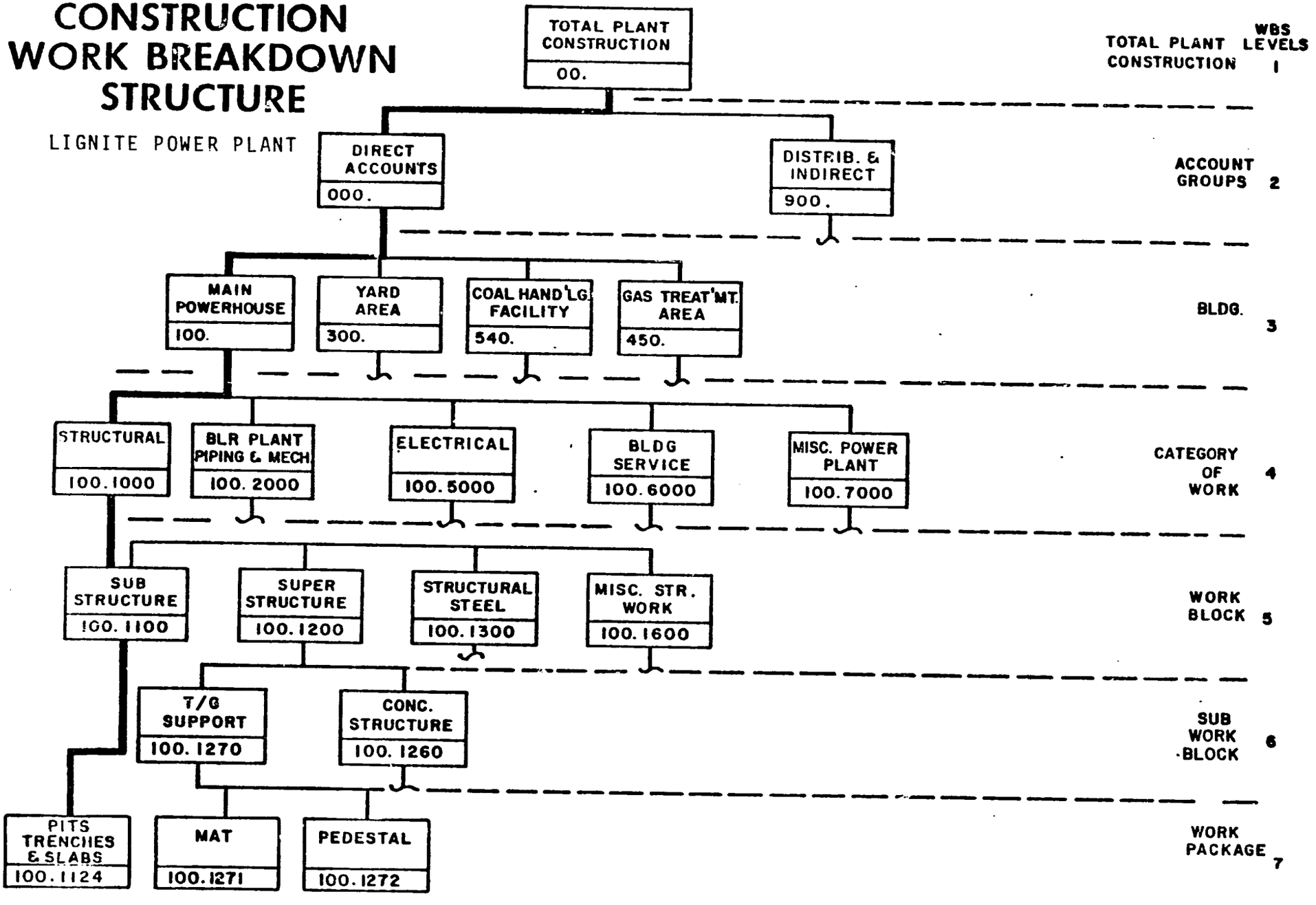


FIGURE 6

CONSTRUCTION WP SCOPE OF WORK

W.P. 100.1124 PITS, TRENCHES AND SLABS (TURBINE AREA)

THE SCOPE OF THIS WORK PACKAGE INCLUDES ALL WORK REQUIRED FOR THE COMPLETE CONSTRUCTION OF ALL CONCRETE GROUND ELEVATION FLOOR SLABS, AND ALL PITS, TUNNELS AND TRENCHES IN THE TURBINE AREA. INCLUDES EXCAVATION AND SELECT BACKFILL UNDER THE ITEMS.

STONE & WEBSTER ENGINEERING CORPORATION - ESTIMATE FILE REPORT DETAIL WBSC1 PAGE 5
CLIENT- S&W ENG. CORP.
WORK DESCRIPTION-REFERENCE FOSSIL POWER PLANT DATE-11/15/1979

WP REPORT

CODES WP	WBS	ML	DESCRIPTION	QUAN-TITY	UNITS	MATL $/UNIT	LABOR HR/UNIT	LABOR $/HR	MATERIAL $	LABOR $	LABOR MHRS
			PITS&TRENCHES, SLABS								
100.1124	1402	AE	REINF-SLAB ON EARTH	55	TN	.00	20.000	29.18		32,098	1,100
100.1124	1402	2-	REINF-SLAB ON EARTH	55	TN	500.00	.000	.00	27,500		
100.1124	1403	AE	REINF-COND.P&WW SUMP	15	TN	.00	25.000	29.61		11,104	375
100.1124	1403	2-	REINF-COND.P&WW SUMP	15	TN	500.00	.000	.00	7,500		
100.1124	1405	AE	REINF-WALLS	2	TN	.00	25.000	28.76		1,438	50
100.1124	1405	2-	REINF-WALLS	2	TN	500.00	.000	.00	1,000		
100.1124	1422	AE	FORMWORK-SLAB ON EARTH	1485	SF	.70	.500	22.67	1,039	16,832	742
100.1124	1423	AE	FORMWORK	2755	SF	.70	.500	22.67	1,928	31,228	1,377
100.1124	1443	AE	CONCRETE	170	CY	.00	1.500	21.37		5,449	255
100.1124	1443	2-	CONCRETE	170	CY	40.00	.000	.00	6,800		
100.1124	1445	AE	CONCRETE WALLS	20	CY	.00	2.500	22.25		1,112	50
100.1124	1445	2-	CONCRETE WALLS	20	CY	40.00	.000	.00	800		
100.1124	1501	AE	EMBEDDED IRON	8855	LB	.00	.100	26.80		23,731	885
100.1124	1501	2-	EMBEDDED IRON	8855	LB	.70	.000	.00	6,198		
100.1124	TOTAL WORK PACKAGE								83,216	164,119	6,688

FIGURE 7

STONE & WEBSTER ENGINEERING CORPORATION

PERFORMANCE REPORT
SORTED BY: TOT. PROJ., WORK PKG.

PROJECT TITLE:

STATUS AS OF: 01DEC82 | REPORT DATED: 18DEC82

TOTAL PROJECT

VH WBS=5, OAT=1, N085A,86A&99H
BUDGET PERIOD 23SEP80-01MAY87
CURRENT PERIOD IS 01NOV82 TO 30NOV82

** DATA **
EXCLUDED

WORK PKG. NO.	CURRENT PERIOD ACTUAL MANHRS (ACWP)	CURRENT PERIOD ACTUAL PROG (BCWP)	CURRENT PERIOD PCNT MANHR EXPND	CURRENT PERIOD PCNT PROG COMP	CUMULATIVE TO DATE ACTUAL MANHOURS (ACWP)	CUMULATIVE TO DATE ACTUAL PROGRESS (BCWP)	CUMULATIVE TO DATE PCNT MANHR EXPND	CUMULATIVE TO DATE PCNT PROG COMP	AT COMPLETION BUDGET MANHOURS	AT COMPLETION FORECAST MANHOURS (EAC)	AT COMPLETION (OVER)/ UNDER BUD-FOR	NGTD PCNT	NGTD PROG COMP	PERF. INDEX (CPI)
	SWITCHGEAR													
35D	6	111	.7	13.5	433	489	52.5	59.3	825	769	56	.10	.06	1.13
	DISTRIBUTIONS PANELS													
35E	0	0	.0	.0	0	0	.0	.0	231	231	0	.03	.00	-
	CABLE TRAY - STATION													
35F	39	59	13.2	19.9	79	90	26.7	30.4	296	285	11	.04	.01	1.14
	CONTROL CABLE - STATION													
35G	0	20	.0	6.4	56	90	18.0	28.9	311	277	34	.04	.01	1.61
	POWER CABLE - STATION													
35H	26	22	4.2	3.5	236	338	37.9	54.3	622	520	102	.08	.04	1.43
	INSTRUMENT CABLE - STATION													
35J	0	32	.0	5.8	1	159	.2	28.9	551	393	158	.07	.02	159.00
	NON-SEGREGATED BUS DUCT													
35K	63	33	7.2	3.8	512	750	58.6	85.8	874	636	238	.11	.09	1.46
	MAIN POWER TRANSFORMER													
35L	103	168	8.6	14.0	720	756	60.2	63.2	1,197	1,161	36	.15	.09	1.05
	LIGHTING TRANSFORMER													
35M	28	0	-	-	28	0	-	-	0	28	(28)	.00	-	.00
	PLANT COMMUNICATION SYSTEMS													
35N	113	245	2.7	5.9	427	723	10.3	17.5	4,137	3,841	296	.50	.09	1.69
	GENERATOR LEADS/BUS DUCT													
35P	3	2	.4	.3	590	598	77.8	78.9	758	750	8	.09	.07	1.01
	AUXILIARY STANDBY POWER TRANSFORMER													
35Q	69	9	8.2	1.2	555	660	71.2	84.7	779	674	105	.09	.08	1.19
	AUXILIARY POWER TRANSFORMER													
35R	40	11	4.9	1.3	470	607	57.6	74.4	816	679	137	.10	.07	1.29
	EMERGENCY DIESEL GENERATOR													
35S	47	23	5.7	2.8	430	167	52.1	20.2	826	1,089	(263)	.10	.02	.39
	STATION BATTERY													
35T	17	47	6.6	18.4	132	157	51.6	61.3	256	231	25	.03	.02	1.19
	STATION BATTERY CHARGER													
35U	15	50	5.4	18.1	108	161	39.1	58.3	276	223	53	.03	.02	1.49
	HEAT TRACING													
35V	0	0	.0	.0	1	0	.3	.0	346	347	(1)	.04	.00	.00
	CATHODIC PROTECTIONS													
35W	40	28	5.3	3.7	134	281	17.7	37.1	758	611	147	.09	.03	2.10

FIGURE 8

WORK PKG MANHOUR REPORT EMS-K11

BY WORK PKG, PERIOD, PERF DEPT

PROJECT TITLE	CLIENT	JOB ORDER NO.	STATUS AS OF: 01NOV82	REPORT DATED: 10NOV82
HALAKOFF EGS	HL&P	13800	CURRENT PERIOD IS 01OCT82 TO 31OCT82	
LEVEL/WORK PKG TITLE: 6/PLANT COMPUTER			CURRENT. 01OCT-31OCT82 NO 05A 06A 99II BUDGET PERIOD 23SEP80 THRU 01MAY88	

IDENTIFICATION				MANHOURS				
ACCOUNTING PERIOD	H.P. MGR	PERF DEPT	J.O.NO.-H.P.NO.	ACTUAL	BUDGET	FORECAST TO COMPLETION	(OVER)/UNDER BUDGET - FORECAST	REMARKS
	GOLDBE		13800-SC30C					
CUM THRU 30SEP82		3820		38	141	38	103	
		3891		0	1	0	1	
		3920		0	5	0	5	
TOTAL				38	147	38	109	
01OCT82 - 31OCT82		3820		73	98	73	25	
		3920		0	3	0	3	
TOTAL				73	101	73	28	
01NOV82 - 30NOV82		3820		0	161	161	0	
		3920		0	6	6	0	
TOTAL				0	167	167	0	
01DEC82 - 31DEC82		3820		0	140	140	0	
		3920		0	6	6	0	
TOTAL				0	146	146	0	
01JAN83 - 31JAN83		3820		0	226	226	0	
TOTAL				0	226	226	0	
01FEB83 - 28FEB83		3820		0	437	437	0	
		3920		0	0	0	0	
		4520		0	0	0	0	
TOTAL				0	437	437	0	
01MAR83 - 31MAR83		3820		0	450	450	0	
		3920		0	0	0	0	
		4520		0	0	0	0	
TOTAL				0	450	450	0	

FIGURE 9

STONE & WEBSTER ENGINEERING CORPORATION

CUMULATIVE PROGRESS INDEX REPORT
SORTED BY: TOT. PROJ., MAJOR AREA
REPORT VIII

PROJECT TITLE: | CLIENT: | STATUS AS OF: 01DEC82 | REPORT DATED: 10DEC82

TOTAL PROJECT

BUDGET PERIOD 23SEP80-01MAY88

** DATA **
EXCLUDED

	MAJOR AREA DESCRIPTION	MANHOURS						% COMPLETE		INDICES		
			CUM TO DATE					UNWEIGHTED		CUM TO DATE		
	TITLE	BUDGET MANHOURS	PLANNED MH'S & PROGRESS (BCWS)	ACTUAL MANHOURS (ACWP)	ACTUAL PROGRESS (BCWP)	FORECAST AT COMPLTN (EAC)	WGT	PLN'D	ACT	PROG (SPI)	M.H.	PERF (CPI)
D	DISCREPANCIES TO BE RECONCILED	0	0	1,621	0	1,621	.00	-	-	-	-	.00
J	PROJECT SERVICES	109,045	65,491	67,233	65,491	110,787	.13	60.06	60.06	1.00	1.03	.97
H	PROJECT MANAGEMENT & ADMINISTRA	90,881	53,314	57,658	53,314	95,225	.11	58.66	58.66	1.00	1.08	.92
P	PROJECT VARIABLE	46,339	23,113	20,432	23,113	43,650	.06	49.88	49.88	1.00	.88	1.13
R	REGULATORY & ENVIRONMENTAL	5,334	4,709	4,956	4,709	5,501	.01	88.28	88.28	1.00	1.05	.95
S	SYSTEMS	570,375	246,803	287,445	246,786	611,034	.69	43.27	43.27	1.00	1.16	.86
	TOTAL *	821,974	393,430	439,345	393,413	867,906	1.00			1.00	1.12	.90

$$\text{PROGRESS INDEX (SPI)} = \frac{\text{ACTUAL PROGRESS}}{\text{PLN'D PROGRESS}} = 1.00$$

$$\text{MANHOUR INDEX} = \frac{\text{ACTUAL MANHOURS}}{\text{PLANNED MANHOURS}} = 1.12$$

$$\text{PERFORMANCE INDEX TO DATE (CPI)} = \frac{\text{ACTUAL PROGRESS}}{\text{ACTUAL MANHOURS}} = .90$$

ACTUAL CUMULATIVE PERCENTAGES

$$\text{PROGRESS} = \frac{\text{ACTUAL PROGRESS}}{\text{BUDGET MANHOURS}} = 47.86$$

$$\text{MANHOURS} = \frac{\text{ACTUAL MANHOURS}}{\text{BUDGET MANHOURS}} = 53.45$$

FIGURE 10

ACTIVITY ANALYSIS REPORT "A"
(WEEKLY UPDATE)

STONE & WEBSTER ENGINEERING CORPORATION-ACTIVITY ANALYSIS REPORT A

CLIENT
WORK DESCRIPTION
ACTIVITY DESCRIPTION

J.O. NO.
REPORTING DATE 04 JAN 81
REPORT RUN DATE

CHARGE NUMBER	CHARGE DESCRIPTION	E. START / A. START	E. FINISH	PRED	SUCC.	SLACK	L. FIN.	LATEST ESTIMATE QUAN-UN	LATEST ESTIMATE MHRS	LATEST ESTIMATE MH RATE	CURR. PERIOD QUAN	CURR. PERIOD MHRS	CURR. PERIOD MH RATE	CURR. PERIOD MHR RATE RATIO	TOTAL TO DATE QUAN-UN	TOTAL TO DATE MHRS	TOTAL TO DATE MHRATE	TOTAL TO DATE MHR RATE RATIO
100.1271	INSTALL TURB. MAT	28 DEC 80	01 MAR 81	SC-115	TO SC-120	25.0	23 AUG 81											
100.1271.1120	AE T/G FDN-EXCA.	28 DEC 80						522 CY	111	.213	261	56	.214	1.00	261	56	.214	1.00+
100.1271.1130	AE T/G FDN.-BACK.	00	00					290 CY	126	.435			.000	.00			.000	.00
100.1271.1404	AE T/G REINF.	28 DEC 80						128 TN	2640	20.625	19	198	10.421	.50	19	198	10.421	.50+
100.1271.1424	AE T/G FDNS FORMS	00	00					3712 SF	4054	1.092			.000	.00			.000	.00
100.1271.1444	AE T/G FDNS. CONCRE	00	00					1740 CY	1281	.736			.000	.00			.000	.00
100.1271.1467	AE T/G MISC. CONCRE	28 DEC 80						100 UN	244	2.440	5	12	2.440	.98	5	12	2.440	.98+
100.1271.1501	AE T/G FDNS. EMBED	28 DEC 80						1740 LB	200	.115	261	61	.233	2.02	261	61	.233	2.02+
ACTIVITY TOTAL									8656			327				327		

DATA SOURCE	COLUMN 1	COL 2	COL 3	COL 4	COL 5	COL 6	COL 7	COL 8	COL 9	COL 10	COL 11	COL 12	COL 13
	PROJECT ESTIMATE	FIRST QTY. RPTD.	X-REF. FILE	COL 5 X COL 3	COST FILE	FQ-2 INPUT RPT.	PROJ ACCT.	COL 7 ÷ COL 6	COL 8 ÷ COL 5	SUM OF COL 6 TO DATE	PROJ ACCT.	COL 11 ÷ COL 10	COL 12 ÷ COL 5

FIGURE 11

STONE & WEBSTER

CHS-FR-2
JOB NUMBER
CLIENT
PROJECT
410.1121 AUX BLDG MAT FOUNDATIONS SECT1

STONE & WEBSTER ENGINEERING CORPORATION
DETAIL WBS ACCOUNT REPORT BY WORK PACKAGE
(2A) USER SELECTED PERCENT 20 ESTIMATED DATA FROM MOD-01

RUN DATE 07/07/80
AS OF DATE 07/06/80

(1) DESCRIPTION / WBS ACCOUNT NO. (2)			DATA EXCEPT CODE	REPORTING SECTION QUANTITY	UM	UNIT RATE	MAN-HOURS	RATE RATIO	PERCENT COMPLETE	BCWP	ANALYSIS SECTION PROJECTED MAN-HOURS	UNDER(OVER) MAN--HOURS
BKFL-NORM CAT 2/3	AUX BLD	1 EST DATA	B	215	CY	1.000	215				215	0
410.1121.1131-1		CUM ACT DATA		0		.000	0	.00	0	(8) 0	215	0
		CUR ACT DATA		0		.000	0	.00				
MISC STRUCTURAL	AUX BLD	EST DATA (3)		100	UN	13.000 (5A)	1,300 (6A)				(7A) 650	(10A) 650
410.1121.1300-1		CUM ACT DATA (4)		97		6.299 (5B)	611 (6B)	.48	97 (7)	1,261	(9B) 630	(10B) 670
		CUR ACT DATA		0		.000	0	.00 (6C)				
REIN-FDNS&SUBSTR	AUX BLD	4 EST DATA		252	TN	29.504	7,435				7,435	0
410.1121.1401-1		CUM ACT DATA		252		29.504	7,435	1.00	100	7,435	7,435	0
		CUR ACT DATA		0		.000	0	.00				
FORM-FDN & SUBSTR	AUX BLD	4 EST DATA		4,270	SF	1.315	5,615				5,617	(2)
410.1121.1421-1		CUM ACT DATA		4,270		1.315	5,617	1.00	100	5,615	5,617	(2)
		CUR ACT DATA		0		.000	0	.00				
CONC-FDN & SUBSTR	AUX BLD	4 EST DATA		1,884	CY	3.302	6,221				6,221	0
410.1121.1441-1		CUM ACT DATA		1,884		3.302	6,221	1.00	100	6,221	6,221	0
		CUR ACT DATA		0		.000	0	.00				
CONC-POROUS	AUX BLD	4 EST DATA		1,341	CY	.442	593				594	(1)
410.1121.1465-1		CUM ACT DATA		1,341		.443	594	1.00	100	593	594	(1)
		CUR ACT DATA		0		.000	0	.00				
CONC-RUB FIN HRDN	AUX BLD	1 EST DATA	B	12,320	SF	.047	579				579	0
410.1121.1470-1		CUM ACT DATA		0		.000	0	.00	0	0	579	0
		CUR ACT DATA		0		.000	0	.00				
CONC-MTRPRF MEMBRN	AUX BLD	1 EST DATA		14,050	SF	.080	1,188				1,216	(28)
410.1121.1472FM		CUM ACT DATA		7,324		.084	614	1.05	49	586	1,246	(58)
		CUR ACT DATA		0		.000	0	.00				
CONC-WEEPS&DRAINS	AUX BLD	1 EST DATA		582	LF	.235	137				163	(26)
410.1121.1474-1		CUM ACT DATA		294		.323	95	1.37	51	69	188	(51)
		CUR ACT DATA		0		.000	0	.00				
EMBEDDED IRON	AUX BLD	4 EST DATA		6,890	LB	.214	1,474				1,479	(5)
410.1121.1501-1		CUM ACT DATA		6,890		.215	1,479	1.00	100	1,474	1,479	(5)
		CUR ACT DATA		0		.000	0	.00				
SLEEVES	AUX BLD	1 EST DATA	B	10	EA	12.000	120				120	0
410.1121.1510-1		CUM ACT DATA		0		.000	0	.00	0	0	120	0
		CUR ACT DATA		0		.000	0	.00				
WORK PACKAGE SUBTOTAL 410.1121*******		EST DATA					24,877				24,289	588
		ACTUAL DATA					22,666	.97	93 (11)	23,254	24,324	553
REWORK SUBTOTAL (12) 410.1121*******		NO REWORK HOURS FOR THIS WORK PACKAGE										

FIGURE 12

CMS-FR-2

CLIENT
PROJECT

SELECTED BUILDINGS REPORT

STONE & WEBSTER ENGINEERING CORPORATION

SELECTED BUILDINGS REPORT
USER SELECTED PERCENT 20
JOB NUMBER

RUN DATE
AS OF DATE

		MANHOURS	PERCENT COMPLETE	BCWP	PROJECTED MANHOURS SUMMARIED	UNDER (OVER) MANHOURS
STEMS- 100 DESC- MAIN STRUCTURE	ESTIMATE DATA	1,980,000			1,978,855	1,145
	ACTUAL DATA	265,855	13	267,000	1,978,475	1,525
STEMS- 323 DESC- COOLING TOWER	ESTIMATE DATA	57,000			57,151	(151)
	ACTUAL DATA	2,651	4	2,500	57,160	(160)
STEMS- 330 DESC- WASTE TREATMENT AREA	ESTIMATE DATA	110,000			109,944	56
	ACTUAL DATA	2,794	2	2,850	109,912	88
STEMS- 370 DESC- SWITCHYARD	ESTIMATE DATA	10,500			10,500	0
	ACTUAL DATA	0	0	0	10,900	0
STEMS- 390 DESC- YARD WORK	ESTIMATE DATA	59,800			59,976	(176)
	ACTUAL DATA	22,176	36	22,000	60,238	(438)
STEMS- 451 452 453 DESC- GAS TREATMENT AREA	ESTIMATE DATA	848,200			849,486	(1286)
	ACTUAL DATA	91,786	10	90,500	849,593	(1393)
STEMS- 540 DESC- COAL HANDLING	ESTIMATE DATA	285,000			285,051	(51)
	ACTUAL DATA	4,851	2	4,600	285,238	(238)
STEMS- 932 DESC- DISTRIBUTABLES	ESTIMATE DATA	28,000			28,171	(171)
	ACTUAL DATA	2,671	9	2,500	28,190	(190)
BUILDING GRAND TOTALS	ESTIMATE DATA	3,378,500			3,379,134	(634)
	ACTUAL DATA	392,784	12	392,150	3,379,306	(806)

FIGURE 13

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APPENDIX 12

FLUIDIZED BED COMBUSTION

APPENDIX 12

FLUIDIZED BED COMUBSTION

Atmospheric Fluidized Bed Combustion

Introduction

Atmospheric fluidized bed combustion (AFBC) is a technology to burn high sulfur coal cleanly without need for a flue gas desulfurization system (scrubber). It also provides a wide range of fuel flexibility including the capability to burn many low grade or waste fuels. AFBC is commercially available in industrial sizes up to approximately 600,000 lb/hr steam generation rate with several boiler manufacturers offering commercial guarantees. Additional development and testing in demonstration size units will be required prior to commercial availability of large electric utility AFB boilers. The reluctance of large numbers of users and suppliers to pursue this alternate is demonstrative of the fact that AFB is not a fully mature and widely demonstrated technology. The numbers of questions for which there are only qualitative answers demonstrates the need for continued development and results of projects to date indicate potential for benefits which justify continued development. However, the fact that several commercial orders have been placed indicates industry's willingness to assume a degree of risk in pursuit of these benefits.

In fluidized bed combustion, fuel and inert material (which may consist of ash, sand, alumina, etc) are suspended by an upflow of air in a combustion chamber such that the mass behaves like a fluid. Air is distributed beneath the bed via a perforated plate or nozzle system. The resultant enhanced mixing and turbulence allow combustion to take

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place at relatively low temperatures (1500-1600°F) thereby minimizing ash slagging and fusion, volitilization of alkali, and NOx generation. A sorbent such as limestone may be added to the bed to absorb sulfur from the fuel. In this reaction, limestone is first calcined to form calcium oxide (CaO) which then combines with sulfur dioxide (SO_2) to form calcium sulfate ($CaSO_4$). The amount of calcium required to meet effluent requirements is generally expressed as a molar ratio to the sulfur in the fuel. All waste products are dry and relatively inert.

Technological Approaches

The technological variations in approach to AFB are primarily related to the following:

- Boiler configuration
- In-bed heat absorbing medium
- Fuel/sorbent feed methodology
- Fuel/Sorbent utilization

Boiler Configuration

The following two basic approaches are currently being used:

- Firetube
- Watertube

Firetube

Firetube AFB boilers are offered commercially for low pressure steam applications up to approximately 50,000 lb/hr steam generation rate. In a firetube AFB boiler, steam is normally generated in three areas:

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- In tubes immersed in the bed
- In tubes placed in the freeboard zone above the bed
- In the shell via firetube surface immersed in the water

Their application is normally institutional and small industrial where superheated steam is not required.

Watertube

Watertube AFB boilers are offered commercially up to approximately 600,000 lb/hr steam generation rate, 2400 psig, and 1050°F. In a watertube AFB boiler, steam is normally generated in three areas:

- In tubes immersed in the bed
- In tubes placed in the freeboard above the bed
- In the watertube membrane wall surface enclosing the boiler

Their application is normally larger institutional, industrial, or utility or where superheated steam is required.

In-bed Heat Absorbing Medium

The primary heat absorbing medium for steam and electric power generation is water/steam. Air may also be used and a few AFB units are now in operation using in-bed air cooled tubes. These units have the capability of being coupled with a gas turbine expander for power generation and some designs can generate steam as well, thereby increasing overall plant efficiency.

Fuel/Sorbent Feed Methodology

Fuel/Sorbent feed systems being considered/evaluated are:

- Gravity
- Spreader-stoker
- Pneumatic injection
- Screw feed

Gravity Feed

Gravity feed was used at the Monongahela Power Company Rivesville facility (Foster-Wheeler boiler). It has been found to require extensive height to overcome bed pressure and control backflow of gases and effective splitting is difficult without long vertical runs. Also, gravity feed's inherent low velocity may result in reducing zones at feed points.

Spreader Stoker

The Georgetown University AFB (Foster-Wheeler boiler) is equipped with spreader stokers. This approach permits one feed point for each 100-150 sq ft of bed area which when extrapolated to the 500-600 MW size results in only 60 feed points.

The potential for excessive unburned carbon loss and lower calcium utilization represents the major drawback to this feed methodology. Higher recycle rates are expected to alleviate these problems to some extent.

Pneumatic overbed spreaders have also been used successfully and are installed at the Northern States Power Company French Island Power Plant (Energy Products of Idaho FBC design) for firing wood waste.

Pneumatic Underbed Feed

Three types of pneumatic underbed feed are currently prevalent. With all types, coal must normally be dried to prevent clogging feed lines and erosion is a potential problem.

The first is a simple pneumatic feed system consisting of a blower, a rotary feed valve and a downstream splitter.

The second uses a Fuller-Kinyon (F-K) type system consisting of a blower and screw type solids pump with an integral check valve and a symetrical pneumatic splitter.

The third uses a modified pulverizer to crush and dry the coal with splitting accomplished on the head of the pulverizer, similiar to normal pulverized coal distribuion to multiple burners.

In all cases, feed point spacing has been limited to 36 sq ft/feed point with most experience limited to 9-18 sq ft/feed point.

The simple pneumatic feed system is being used at the Great Lakes Naval Training Center facility.

The F-K type system is currently being used at the Babcock & Wilcox Alliance 6X6 facility, and was used at the Monongahela Power Company Rivesville facility. It is also being used initially at the Tennessee Valley Authority 20 MW pilot plant facility.

The modified pulverizer approach is being utilized at Babcock Power Ltd's Renfrew test facility.

In all cases, care must be exercised to ensure that the transport air is not a significant fraction of the main fluidization air and thus affect uniform bed fluidization.

lok2

Fuel/Sorbent Utilization

High gas velocity in the combustor (called superficial velocity) tends to reduce fuel and sorbent utilization due to low residence time within the bed and the freeboard zone between the bed and the convective surface. This may result in high levels of carbon monoxide and unburned hydrocarbons in the flue gas. The majority of designers currently design the boiler for 1.5 to 2.0 sec residence time in the freeboard zone.

A second reason for reduced sorbent utilization is the $CaSO_4$ barrier which forms on the surface of the CaO particle. This barrier closes the pores and prevents further calcium-sulfur dioxide reaction under the $CaSO_4$ barrier.

Recycle of particulates from the flue gas to the combustion zone is now the favored means for enhancing both carbon and sorbent utilization. With recycle, the boiler gas outlet is equipped with a cyclone separator to capture the elutriated carbon and sorbent.

The material captured in the boiler outlet is reinjected into the bed from which it was discharged (elutriated). The philosophy being that repeated passes through the combustion zone will result in high carbon and sorbent utilization.

Babcock & Wilcox testing with high recycle rates at the Alliance 6X6 ft AFB have resulted in combustion efficiencies in excess of 99 percent and calcium to sulfur ratios of approximately 2 to 1.

While the recycle approach appears to have a lower capital and operating cost, the convection surface erosion with the high (100 gr/acf) dust

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loading at the high gas velocities typical in convection passes has not been fully evaluated.

Current AFB Projects

United States

There are approximately 47 operating AFB boiler plants in the United States with several others on order or under construction. The plants range in size from 7,000-150,000 lb/hr steam generation rate and include both fire tube- and water tube-type boilers. Applications include research, demonstration, institutional, industrial, and electric utility power generation. Several of the units are relatively small wood-fired units installed for lumber/paper industry applications. The following list describes a selected few of these installations:

B&W Alliance Facility

With assistance of Electric Power Research Institute (EPRI) funding, Babcock and Wilcox (B&W) have constructed a 6 x 6 ft bed size (20,000 lb/hr) AFB at the B&W Alliance, Ohio Research Center. Much of the recent AFB research data has been developed at the Alliance 6 x 6 facility.

US DOE/CE Great Lakes Naval Training Station

Under US Department of Energy (DOE) and state of Illinois sponsorship, Combustion Engineering (CE) has installed a 50,000 lb/hr AFB boiler at the Great Lakes Naval Training Station in Illinois. The facility was commissioned in 1981.

US DOE/FW Georgetown University AFB

Under US Department of Energy (DOE) sponsorship, Pope Evans and Robbins (PER) and Foster Wheeler (FW) installed a 100,000 lb/hr FW AFB equipped with two spreader stokers. Operation commenced in 1979.

TVA/B&W 20 MW AFB Pilot Plant

A 20 MWe equivalent (120,000 lb/hr) AFB pilot plant was constructed by Babcock & Wilcox (B&W) and SWEC for the Tennessee Valley Authority (TVA) using a B&W boiler and balance of plant by SWEC. This plant is designed to be the forerunner of a 150-200 MW demonstration plant. Commercial operation began in 1982.

Ohio Psychiatric Hospital

Babcock Contractors has retrofit a 60,000 lb/hr stoker fired boiler at the Ohio Psychiatric Hospital with an AFB. FBC design is by Babcock Power Ltd. and boiler parts by Riley Stoker. Startup of the project has been delayed pending additional funding.

Northern States Power Company Wood Burning Retrofit Project

Northern States Power Company commissioned this 10 MWe (150,000 lb/hr) retrofit of a stoker boiler at its French Island Power Station at LaCrosse, Wisconsin, during 1981. The AFB was provided by Energy Products of Idaho and balance of plant by S&W.

U.S. DOE Shamokin Anthracite Culm Demonstration Plant

Under U.S. Department of Energy sponsorship, a 20,000 lb/hr industrial AFB boiler demonstration plant was constructed in Shamokin, Pennsylvania. The plant is demonstrating the feasibility

of combusting anthracite waste (culm) in an AFB boiler to produce process steam for industrial use. Operation commenced in 1981. The AFB was provided by Dorr-Oliver and balance of plant by S&W.

Iowa Beef Processors, Inc.

Wormser Engineering provided a 70,000 lb/hr multi-stage AFB boiler for Iowa Beef, Inc.'s Amarillo, Texas beef processing plant. This unit was started up during 1982.

Kentucky Agricultural Corporation

Foster Wheeler provided two 60,000 lb/hr AFB boilers for Kentucky Agricultural Corporation's alcohol plant at Franklin, Ky. The first unit was started and achieved full load during 1982 and the second unit will be started in early 1983.

Central Soya Company

Johnston Boiler Company provided a 40,000 lb/hr firetube AFB boiler for Central Soya Company's Marion, Ohio soybean processing plant. The unit was started up during 1979.

Peoples Republic of China (PRC)

It is reported that there are in excess of 2,000 AFB facilities in the PRC. These units, installed since 1965, are mostly very small although they range in size up to 300,000 lb/hr. Most burn low grade coals with up to 70% ash. Several boilers of approximately 100,000 lb/hr have been operating in excess of 40,000 hours.

United Kingdom

Under National Coal Board Association, several AFB installations have been commissioned primarily for specialized industrial application. Babcock Power Ltd's (BPL) 40,000 lb/hr boiler at Renfrew, Scotland has been operating since 1975. There are in excess of 30 AFB boilers operating in the U.K. with sizes up to approximately 80,000 lb/hr.

Summary of International AFB Experience

The following countries have approximately the number of AFB boilers indicated in operation, small bench scale unit are not included. These units have been put in service since 1965 and range in size up to approximately 350,000 lb/hr. Many other new units are currently under construction or on order worldwide.

Country	Number of Operating Units
Australia	1
Brazil	1
Canada	2
China	2,000
Czechoslovakia	7
Denmark	1
Finland	7*
India	3
Israel	1
Japan	3
Netherlands	3
Phillipines	1

Country	Number of Operating Units
Sweden	7*
Switzerland	1
United Kingdom	30
United States	47
West Germany	6

*Some units have circulating beds

Problem Areas

Fuel/Sorbent Feed

As noted previously (Fuel/Sorbent Utilization), all fuel/sorbent feed systems available have potential drawbacks.

Recycle/Carbon Burnup

Single pass combustion efficiencies and calcium utilization are in most cases sufficiently low as to necessitate, in view of increasing fuel costs, a recycle system or a separate combustion zone. The recycle option has been generally accepted and is being utilized in most current industrial-size AFB units.

Corrosion/Erosion

These subjects are covered in great detail in the literature; however, except for excluding high nickel materials, the data is insufficient to permit confident forecast of the corrosion/erosion life of boiler materials. The Georgetown unit experienced in-bed tube failure during 1981 after less than 2 years of operation and is now testing an improved design. Extensive work has been done on this subject in the People's

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Republic of China which reports significantly increased erosion life due to design improvements. The experience is being evaluated.

Load Following

Due to the thermal inertia of the bed and the limited turndown while maintaining the bed in a fluidized state, there is question regarding the suitability of the AFB boiler as a load following device. Segmental fluidization using a divided air plenum beneath the bed and use of separate combustion cells are methods which have been used to isolate or slump portions of the total bed area and thus attain turndown. These methods are somewhat cumbersome and turndown is limited to 2 or 3 to 1 by practical considerations. Normally turndown is in steps and response is generally slow.

Velocity reduction is another method which has been used over rather limited ranges of turndown to improve response. With this approach a 50 percent load swing has been demonstrated at a rate of approximately 12 percent per minute. Based on work done at Babcock and Wilcox'sAlliance 6X6 facility, it appears that 3 to 1 turndown may be achievable with suitable in-bed tube bundle redesign.

Pressurized Fluidized Bed Combustion

Introduction

Pressurized fluidized bed combustion (PFBC) is an extrapolation of the AFB and combined cycle technologies wherein the fluidized bed combustor operates at up to 16 atm in combined cycle with a gas turbine. PFB's primary intended application is utility power generation. PFB has most AFB advantages plus the following incentives for application:

- Higher combustion efficiency (99+ percent)

- Better sorbent utilization (approximately 1.7 to 1 Ca/S ratio)
- Reduced size and higher power density
- Potential for shop fabrication and barge shipment of utility size modules
- Higher overall combined cycle efficiency (36-42 percent)
- Low heat rate (approximately 8500 Btu/KWhr)
- Lower busbar power costs than conventional or other developing coal technologies predicted

The technology is not yet commercially available and lags AFB by approximately 2-4 years.

Technological Approaches

The two principal approaches to PFB include air-cooled and steam/water cooled combined cycles. Also a turbocharged PFB program is being initiated by EPRI to reduce risks and speed PFB commercialization.

Air-Cooled Cycle

In the air-cooled cycle combustion heat is removed from the combustion zone exclusively by air. The air is either as excess air or freeboard and/or in-bed air-cooled tube bundles. The heated air/gas is then delivered to a gas turbine expander which drives a generator and compressor for combustion air. The gases from the expander are passed through a waste heat boiler to produce steam for a condensing turbine cycle.

The ratio of electrical production between the expander and the steam cycle is approximately 2:1. This high ratio will permit substantially

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higher efficiencies when turbine technology development permits increased turbine inlet temperatures.

This cycle maximizes the gas flow and, when air-cooled tubes are used, minimizes the specific dust loading to the turbine by diluting the cleaned gas stream with clean hot air.

Steam/Water Cooled Cycle

In the steam/water cycle combustion heat is removed using a water wall enclosure around the combustion zone, and in-bed steam/water cooled tube bundles.

The combustor flue gas is directed to a gas turbine expander and waste heat boiler in series; however, the ratio of electric power betweeen the expander and the steam cycle is 1:2 with currently acceptable turbine inlet temperatures.

Turbocharged Cycle

The Electric Power Research Institute (EPRI) has initiated a program to develop a turbocharged PFB cycle wherein the turbine operates in a self-sustaining mode and does not drive a generator. It is felt that this cycle will minimize technical risks associated with the more complex PFB cycles and permit more rapid commercialization since the cycle would utilize more conventional technology.

In this cycle the flue gas is cooled to the point at which the turbine is self-sustaining (approximately 770°F turbine inlet vs 1550°F for other cycles).

The lower temperature offers several advantages including:

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- Turbine corrosion minimized since all alkali eutectics are solid phase at 770°F

- Turbine erosion minimized since lower gas temperature may permit use of high efficiency hot gas filters which will clean the flue gas prior to entering the turbine

- Gas turbine overspeed protection might be eliminated since the danger of loss of load has been virtually eliminated with the deletion of the gas turbine driven generator

- Reduced plant capital cost due to simplicity of cycle and fact that lower gas temperatures and attendant increased gas densitities permit smaller and less exotic hot gas systems.

- Low busbar cost of electricity comparable to that expected with more complex cycles should be achievable due to the relatively high 39 percent gross thermal efficiency expected plus reduced plant capital costs

Selected Current PFB Projects

American Electric Power, Stal-Laval, Deutshe Babcock Component Test Facility (AEP/S-L/DB CTF)

American Electric Power (AEP), Stal-Laval of Sweden (SL) and Deutsche Babcock (DB) of Germany have constructed a 15 MWe PFB Component Test Facility at Malmo, Sweden. The unit will verify the integrated system prior to construction of a 170 MW demonstration unit at AEP's Tidd Station in Ohio.

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Coal Utilization Research Lab (CURL)

CURL, under sponsorship of the National Coal Board (NCB), is operating a 0.2 MWt and a 6 MWt PFB test rig at Leatherhead, England. The facility has evaluated alternate feed systems and gas cleanup systems and has conducted corrosion and erosion tests. PFB combustion of coal slurries and large chunks of untreated (run of mine type) coal is currently being studied.

Curtiss-Wright Small Gas Turbine Rig (C/W-SGT)

C/W, with U.S. Department of Energy (DOE) funding, has operated a 2.3 MWt PFB combustor at Wood-Ridge, New Jersey in order to test PFB effects on gas turbine technology. A slipstream expander and alternate gas cleanup devices have been tested.

Curtiss-Wright Pilot Plant

Based on the successful results of the SGT facility, C/W and S&W with DOE funding have designed a 40 MWt (13MWe) PFB pilot plant. Construction of this facility is currently being completed by C/W.

General Electric Long Term Material Test Facility (GE-LTMT)

GE, with funding by DOE and the New York State Energy Research and Development Association, is operating a 0.45 MWt PFB materials testing facility at Malta, New York. The facility will expand upon materials testing done by Exxon, NCB/CURL, and C/W including the testing of protective coatings and claddings.

International Energy Agency (IEA)-Grimethorpe

Based on the results at the Curl Leatherhead, England facility, the International Energy Agency contracted with National Coal

Board/International Energy Agency (NCB/IEA) Services Ltd. to install at 85 MWt (25MWe equivalent) combustion test facility at the NCB Grimethorpe Station in England. The facility funding is equally shared by the Federal Republic of Germany (FRG), U.S. and U.K. departments of energy. The Grimethorpe facility has operated successfully as a combustion research facility and a gas turbine has now been proposed as an addition to the facility.

Warsaw Technical University (WTU)

WTU is operating a 3 MWt PFB test unit at Warsaw, Poland.

Problem Areas

The major problem areas associated with the commercialization of the PFB are erosion, corrosion, and fouling of the gas turbine. A hot gas intercept valve must also be developed and high pressure material handling systems should be improved.

Erosion

Combustion of coal in a fluid bed creates a high dust loading in the effluent stream. Gas turbines are extremely sensitive to even relatively low dust loadings. This necessitated the development of highly efficient dust collectors which must operate at 1,600°F. The inlet dust loading specification varies from gas turbine vendor to vendor; however, in all cases currently under development three stages of cyclones are being used.

Recent testing at both the Curtiss-Wright and Leatherhead facilities indicate that using three stages of cyclones approaches the gas turbine inlet solids loading limits. Exxon has tested metallic fabric filters and charged and uncharged gravel bed filters with varying success.

Corrosion

Vaporized alkalai salts are produced at combustion temperatures in excess of 1,200°F. With the 1,500°F combustion temperature used in fluid beds to capture sulfur, the potential for gas turbine corrosion is currently being evaluated.

Improved blade materials, blade cladding and blade cooling are being investigated to alleviate this problem.

Fouling

Gas turbine blade fouling was the principal cause of failure in early coal-fired gas turbine attempts. Although most PFB related deposition has been soft and readily removeable, long term tests with commercial size turbines are needed to prove various fuels, operating transient effects, and cleaning techniques.

High Temperature Gas Trip Valve

In order to prevent gas turbine overspeed, a reliable full scale hot gas intercept valve must be developed which will isolate the turbine in event of loss of load. This valve must close rapidly (approximately 1 second).

High Pressure Material Handling Systems

Solids introduction to and removal from the high pressure portion of the PFB system are areas which should be improved. This includes coal, sorbent and ash handling systems. Most current systems are based on use of lock hoppers, which provide a workable system, but are cumbersome and expensive. Lock hoppers require complex instrumentation and controls, are space intensive, and prone to clogging and failure due to high

solids moisture or incorrect size consist. Possible alternatives which should be investigated further include extruders, screw feeders and slurry feed systems.

Circulating Fluidized Bed Combustion

Introduction

Circulating Fluidized Bed Combustion (CFB) is a second-generation AFB technology in which the hot bed material is transported outside the combustion zone, through a heat removal zone, and back to the bed. This decoupling of the combustion and heat removal zones of the boiler permits elimination of tubes in the combustion bed.

Advantages

The CFB has all of the advantages of AFB as compared to conventional technologies as listed in Section 4.01, plus the following additional advantages over AFB:

- Higher processing capacity and smaller vessel diameter due to higher gas velocity
- Improved gas/solids contact resulting in better carbon burnup and sorbent utilization and lower excess air requirements
- Reduced NOx emissions due to lower excess air and capability for staged combustion
- Potentially better load follow capability than AFB and simplified fuel feed system due to decoupled combustion and heat removal zones

- Capability of retrofit by utilizing existing boiler as waste heat boiler

Technological Approaches

CFB units are still under development but are currently offered in the industrial size range by:

- Lurgi (licensed to Combustion Engineering (CE) in the U.S. and Deutsche Babcock in Europe)

- Battelle (licensed to Riley Stoker Corporation for industrial water tube boilers and utility boilers in North, Central, and South America, exclusive of enhanced oil recovery; to Struthers for enhanced oil recovery worldwide, and to Foster Wheeler, U.K., for industrial boilers in Europe, Asia, and Africa)

- Ahlstrom (offered in U.S. by Pyropower Corporation, a joint venture by Ahlstrom and General Atomic, and in Europe by Ahlstrom, Helsinki)

- Stone & Webster (licensed to Foster Wheeler Boiler Corporation in the U.S., Canada and Venezuela and to Babcock Power Ltd worldwide exclusive of Japan)

Lurgi/Combustion Engineering

The Lurgi unit utilizes a bed of ash and limestone and includes a waterwall lined combustor section operating at 20-30 fps gas velocity. The combustor discharges flue gas and entrained bed material at approximately 1,550°F to a hot primary cyclone which recirculates the captured solids either directly back to the combustor bed or to an external fluidized dense bed cooler where additional heat is removed via

in-bed tubes. The cooled solids exiting the cooler are then either returned to the combustor bed or sent to waste. Flue gas exiting the primary cyclone at 1,550°F then passes through a secondary hot cyclone to a waste heat boiler where it is cooled to approximately 570°F, passed through a hot electrostatic precipitator, further cooled in an air heater, and discharged to atmosphere. Combustor bed inventory is maintained either by draining hot bed material through an ash cooler to waste or purging the fluidized bed cooler discharge to waste.

Battelle/Struthers

The Battelle unit utilizes a bed of ash, limestone, and inert high specific gravity material and includes a waterwall lined combustor section which superimposes an entrained bed operating at 14-33 fps gas velocity over a fluidized dense bed fueled by up to 1 1/2-in coal. The combustor includes a secondary air input above the dense bed and discharges flue gas and entrained bed material at approximately 1,550°F to a hot primary cyclone which recirculates the captured solids through an external fluidized dense bed cooler where heat is removed via in-bed tubes. The solids exit the fluidized bed cooler at approximately 1,100°F and return through an "L" valve to the combustor bed. Flue gas exiting the primary cyclone at 1,550°F then passes through a waste heat boiler where it is cooled to 400°F, thence through a secondary cyclone and baghouse prior to release to atmosphere. Waste material is purged from the secondary cyclone and baghouse.

Ahlstrom/General Atomic (Pyropower)

The Ahlstrom unit utilizes a bed of ash, limestone, and sand and includes a water-wall lined combustor section which superimposes an entrained bed operating at approximately 12 fps gas velocity over a

dense fluidized bed fueled by up to 1-in-size coal. Secondary air is introduced at various levels. Flue gas and entrained bed material are discharged at approximately 1,550°F to a hot cyclone which recirculates captured solids through a nonmechanical seal back to the combustor bed. Flue gas exiting the cyclone at 1,550°F then passes through a waste heat boiler, air heater, and baghouse prior to release to atmosphere. Waste material is purged from the bed at 1,550°F, and the baghouse at approximately 330°F.

Stone & Webster/Foster Wheeler/Babcock Power Ltd

SWEC has devoted approximately four years, including two years of joint participation with CONOCO, to the development of a circulating bed fluidized bed boiler, known as the Solids Circulation Boiler (SCB), through the pilot plant phase. SWEC is now actively pursuing the commercialization of the technology and, as part of that effort, the construction of a 50,000-100,000-lb/hr steam plant firing coal and/or petroleum coke.

The heart of the SCB system is the recirculating fluidized bed shown schematically in Exhibit 1.

An inert solid is fluidized at about 7 ft/sec in a dense phase mode. Solids are withdrawn from the bed, pass through a solids control valve, and are lifted in dilute phase through a riser using about 15 percent of the stoichiometric air. The solids are returned to the bed via a downflow channel and "ski slope" which imparts a horizontal velocity casting them across the surface of the bed. In this fashion, the bed is continuously circulated at up to 100 times the typical coal feed rate, imparting important lateral mixing of solids. There are no tubes in the bed and this, combined with the high recirculation, results in an extremely well-mixed, agitated bed. Coal and limestone are introduced into the bed where they are rapidly distributed throughout the bed by the swirling action of the solids. Combustion occurs in the bed at approximately 1500-1650°F.

Steam is generated by passing hot solids from the combustion zone through the water wall riser and downflow channels using secondary air as the lifting medium. Steam production is maintained at the desired rate by controlling the quantity of solids circulated through the channel.

Fine-sized limestone is fed into the boiler and is ultimately sulfated and carried overhead and collected in the baghouse with fly ash. The limestone is finer than has been used in first generation systems; there is a greater area per unit volume and the stone tends to have a greater capacity for the absorption of SO_2. Limestone, which has been sulfated, and coal ash, which has been ground fine by the bed action are carried overhead with the flue gas through the convection section where they are partially cooled.

The cooled flue gas and entrained solids pass through a cyclone separator where the coarser, partially sulfated material is separated

from the flue gas and fines. The captured solids are returned to the combustion bed at up to 5 times the coal feed rate. No inert bed material is elutriated due to the size and density of the inert particles and the load to the cyclone consists only of limestone and coal-derived material. Normally, additional evaporator surface or superheater tubes, or both, are located in the convection section along with the economizer section of the system. As a result, the gases leaving the cyclones are only approximately 700°F.

The solids entrained in the gas increase heat transfer rates in the convection section thereby maintaining surface requirements roughly equivalent to that of conventional boilers even at the lower operating temperatures of this sytem.

The SCB system can have excellent turn-down response, because the steam generating heat transfer is dependent upon a stream of solids which can be switched off almost instantaneously. At the same time, the large heat capacity of the dense-phase fluid-bed limits temperature surges while the feed rate of coal is adjusted. The extreme mixing action of the bed eases feed problems, and the use of fine limestone with a high rate of recycle gives improved utilization of limestone. This feature lends itself also to process heating applications where good control and rapid response is required.

Multi Stage Combustion Fluidized Bed

Introduction

Considerable work has been done recently in the U.S. and Japan in developing multi-stage FBC with the primary impetus being reduced NOx generation as compared to single stage FBC. Higher combustion

efficiency and lower CO are other potential advantages. The concept has not been demonstrated on a large scale.

Technological Approaches

Three concepts are being developed:

- Single cell with overfire air
- Single cell with multi-stacked beds
- Multi-cells

Potential problems requiring further development include:

- For the single cell multi-stacked bed concept, the distributor plates between the beds are subject to clogging by ash laden flue gas and the reducing environment in the first stage combustion bed could contribute to in-bed tube corrosion.
- For the multi-cell concept in which cells are connected by transport pipes, the transfer of high temperature solids between cells is a concern.

Wormser Grate

Wormser Engineering has developed, under U.S. Department of Energy (DOE) sponsorship, a high temperature, staged FBC system. The system uses the single cell multi-stacked bed approach. It is perhaps the most developed U.S. concept since a 70,000 lb/hr industrial unit was started up during 1982 for Iowa Beef Company at Amarillo, Texas. Although definitive test data is not available at this writing, preliminary reports have been favorable.

The Wormser Grate is primarily a retrofit type combustor offered in the smaller industrial size range up to approximately 100,000-lb/hr steam

generation rate. The Wormser combustor would normally generate approximately 60 percent of the total steam demand, with the balance being generated in an external (normally pre-existing) boiler. Its primary application would appear to be the conversion of existing oil- or gas-fired boilers to coal while retaining the oil- or gas-fired capability as a backup.

The Wormser Grate consists of three relatively shallow (6-12 in deep) vertically oriented fluidized beds: a storage bed (lower bed); a combustion bed (middle bed); and an upper desulfurizing bed.

The combustion bed consists of sand and ash and operates at 1,700°F-1,800°F. Similar to a first-generation AFB, it is cooled by in-bed steam tubes and receives combustion air from below bed via bubble-cap nozzles. Coal is single screen stoker coal which is dried, crushed, screened, and pneumatically fed into the bed. Flue gas and entrained ash passes out of the combustion bed and enters the desulfurizing bed above via bubble-cap, underbed nozzles.

The desulfurizing bed consists of crushed limestone and operates at 1,550°F. Flue gas and entrained ash and fine limestone passes out of the desulfurizing bed through an external waste heat boiler, where it is cooled, and thence through a baghouse prior to release to atmosphere. Spent limestone is removed from above the desulfurizing bed. Ash and other fines are removed in the baghouse. Fresh limestone is fed pneumatically above bed.

The storage bed is located beneath the combustion bed; sand may be shuttled between the two beds, as required, with pneumatic transport lines. Use of the storage bed allows sand to be removed from the

vicinity of the combustion bed's steam tubes when low amounts of heat are required.

APPENDIX 13

AIR-COOLED CONDENSER

GER-3264

EXPERIENCE WITH THE WYODAK STEAM TURBINE DESIGNED FOR USE WITH DRY COOLING TOWERS

F.D. Ryan and D.C. Sturges

Large Steam Turbine-Generator Department
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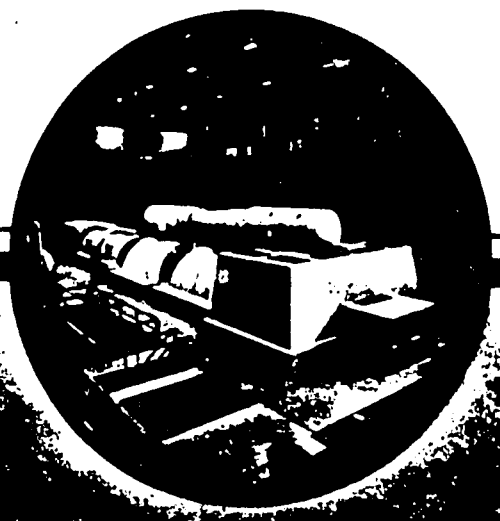

EXPERIENCE WITH THE WYODAK STEAM TURBINE DESIGNED FOR USE WITH DRY COOLING TOWERS

F.D. Ryan and D.C. Sturges

INTRODUCTION

The opportunity to supply the 330 MW steam turbine for application with the air-cooled condenser of the Wyodak Steam-Electric Plant presented the turbine manufacturer with a number of design challenges. Variations in the condenser's effectiveness with seasonal variations in the cooling air temperature led to a range of turbine exhaust pressures that significantly exceeded the normal operating range with units of this size.

The Wyodak Plant[1], built jointly by Pacific Power and Light Company and Black Hills Power and Light Company, represents a unique solution to the problem of efficiently utilizing an abundant low-sulfur coal supply which is located in a region essentially lacking the quantities of water normally required to support a large steam-electric plant. The prototype air-cooled condenser of this design minimizes the plant site requirement for make up cooling water to a level which can be supplied from available local resources.

The air cooled condenser also presented the turbine designers with higher exhaust temperatures which affect the latter-stage buckets, bearing support structures, and exhaust hoods and casings. In addition, the expected wide range of exhaust pressures affects flow distributions in the exhaust stages and exhaust hoods and increases the dynamic stimulus of the latter turbine stages.

TURBINE DESIGN OBJECTIVES

The turbine manufacturer's design objective for Wyodak was to develop a turbine optimized for operation over a range of 2 inches HgA (6.8 kPa) to 15 inches HgA (50.8 kPa) exhaust pressure associated with the seasonal variations in condenser performance. This flexibility in operating conditions had to be incorporated in a turbine which maintained maximum efficiency, demonstrated good operating characteristics, and sustained the high reliability and availability of more conventional turbines built by the authors' company.

To achieve these objectives required a design which carefully balanced the application of existing component designs of proven reliability and performance with new component designs developed to meet the specific requirements of this unique application.

DESIGN CHALLENGES

Throughout the high- and intermediate-pressure sections of the steam path, where the thermodynamic conditions were relatively unaffected by exhaust variations, conventional steam turbine design technologies were well suited to meet the design objectives. The ancillary components such as valves, bearings, controls, and lubricating oil systems were also designed with existing component technologies which have proven histories of performance and excellent reliability.

In the low-pressure turbine section, the higher than usual average exhaust pressure, coupled with the wide

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[1] For additional details on plant design and operation, see:

1) "Design and Initial Operation of the Wyodak Plant" by Gray, Brauer, Leland; presented at American Power Conference, Chicago, Ill., April 23-25, 1979.

2) "Operating Experience and Performance Testing of the World's Largest Air-Cooled Condenser" by G. J. Kosten, J. I. Morgan, J. M. Burns, and P. L. Curlett; presented at the American Power Conference, Chicago, Ill., April 27-29, 1981.

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variation of this pressure about this average, presented a range of operating conditions well outside conventional experience. The design of components required by these operating conditions was achieved through careful extension of existing technologies with verification of the designs by detailed development testing, where applicable, to ensure compliance with the design objectives.

The influence of these exhaust pressure conditions on some of the major components and the design challenges these conditions imposed are discussed individually.

Latter-Stage Buckets

During periods of operation at exhaust pressures other than this unit's nominal design condition of 6 inches HgA (20.3 kPa), the last stage operates far from its aerodynamic design point. The changed-stage pressure drop which results causes a larger deviation in the angle of the flow entering the bucket from that of the nominal design condition. This results in increased potential for aerodynamic "buffeting" and for stall flutter. Both of these phenomena result in dynamic response of the last-stage bucket which could lead to fatigue damage. The design of the Wyodak last-stage bucket therefore required adequate strength to accommodate the dynamic stresses which accompany buffeting during off angle (higher exhaust pressure) operation. At the same time, the bucket was required to be insensitive to stall flutter throughout the expected operating range.

In addition to the aerodynamic effects, variable exhaust pressure results in changes in the thermodynamic state of the steam at the last stage. Variations will be encountered in the steam density, ranging from those typical of conventional last-stage designs (274.9 ft^3/lbM, 17.2 m^3/Kg) up to six times conventional last-stage density (51.1 ft^3/lbM, 3.19 m^3/Kg). This variation in density affects last stage bucket loading and steam stimulus. Higher than usual temperatures accompany the higher exhaust pressures and, under certain operating conditions, extreme temperatures could be achieved at both the last stage and the next-to-last stage (L-1). This created further challenges in the design process since the bucket stress design needed to consider the effect of the higher possible temperatures on material strength. The thermal expansion of components needed to be studied so that adequate clearances would be maintained for all operating conditions.

Stationary Parts

These unique operating conditions also created some unusual challenges in the structural and aerodynamic design of the low-pressure turbine casings. The primary structural concern was the higher temperature of the exhaust steam corresponding to the higher back pressure, a temperature which was expected to be about 150 F (66 C) compared to about 95 F (35 C) for a conventional unit. This higher temperature causes increased thermal expansion of supports, and could result in excessive changes in bearing elevation and shaft packing clearances which would jeopardize the operation of the unit.

The larger variations in exhaust pressure affect the bucket exhaust angle and could adversely affect the turbine's thermodynamic performance if conventional exhaust designs were used. To maintain highest thermal efficiency over the operating range required innovations in the aerodynamic design of the flow passage from the last stage to the condenser. In addition, possible structural problems inherent in any new design, such as fatigue due to structural resonance, had to be anticipated and prevented.

Solutions to the design challenges were developed in parallel with the design process and incorporated into the final design.

TURBINE DESIGN

The Wyodak turbine, shown in Figure 1, is a two-casing machine consisting of an opposed-flow, six-stage, high-pres-

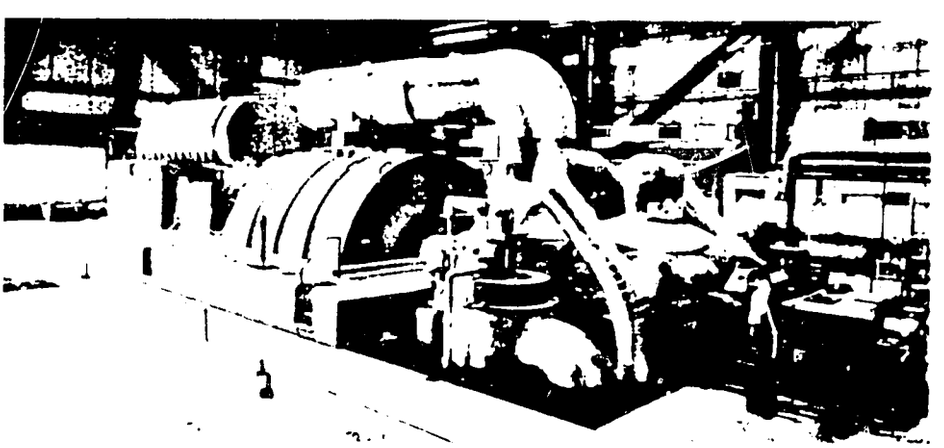

Figure 1. Turbine as installed in Wyodak Station

sure and five-stage reheat section in tandem with a double-flow, five-stage, low-pressure section. The turbine is rated at 330 MW at 6 inches HgA (20.3 kPa) exhaust pressure with rated steam conditions of 1800 psi (34.2 N/m^2) 1000 F/1000 F (538 C/538 C).

The construction of all turbine stages is of the "wheel and diaphragm" type. This construction has consistently demonstrated the ability to achieve high levels of thermal performance and turbine operating characteristics, such as starting and loading performance.

The construction of the double-shell, high-pressure reheat casing, turbine stop, control, and combined reheat intercept valves, and other auxiliaries represents direct application to the Wyodak design of conventional turbine components with demonstrated performance and reliability. The four control valves are of balanced design and are supported underneath the turbine deck along with the two stop valves at the high-pressure end of the turbine. Two combined reheat stop valves, for overspeed protection, are mounted on spring supports on the foundation and welded to the lower half high-pressure shell reheat inlet elbows. In addition, conventional designs of bearings, lube oil systems and turbine control and monitoring systems became part of the overall turbine design.

As noted earlier, major technical challenges presented by the Wyodak application were in the design of the low-pressure section of the turbine. The most significant of the new components incorporated into this section are:

Last-Stage Bucket

L-1 Bucket

Separate LP Bearing Housings

Exhaust Hood and Diffuser

L-1 Stage Temperature Monitor.

Last Stage Bucket

The thermodynamic design of the Wyodak last stage required a bucket of 20-inch (0.508 m) active length at a pitch diameter of 75 inches (1.905 m). This bucket is shown in Figure 2. The bucket tip velocity for this geometry is subsonic, thus the performance sensitivity of supersonic flow passages to off-angle operation is not a factor.

The aerodynamic requirements of this stage defined a vane section which was a derivative of the subsonic vane section of an existing, longer last-stage bucket. The pinned-finger dovetail of this existing design was used directly and, with the reduced centrifugal loading of the shorter vane,

Figure 2. 20 inch last-stage bucket

provides more than adequate strength margins to accommodate the higher expected operating temperatures of the Wyodak application.

The geometry of the 20-inch (0.508 m) last-stage bucket produced a stiff, rugged bucket design. A loose tie wire above the pitch diameter was added to the design of the row to provide coupling of the buckets needed for control of vibratory modes and to provide added damping to the structure.

Damping and structural rigidity are two major parameters affecting the potential for buffeting and flutter. Extensive tests in the manufacturer's low-pressure test facility led to an improved understanding of the relationship of these design parameters to the flutter and buffeting phenomena. Analyses, coupled with this laboratory

experience, provided confidence that the rigid, strong last-stage bucket design, enhanced by the added stiffness and damping of the tie wire coupling, provides assurance against trouble caused by these phenomena.

While the tie-wire design was instrumental in reducing the buffeting and flutter potential for the last-stage bucket, the final design and configuration of the tie wire was determined by control of the dynamic mode frequencies of the buckets. The protection of turbine buckets from fatigue damage requires the maintenance of controlled separation (margins) between the frequencies of dynamic stimuli and the lower natural frequencies of the structure. Advanced, state-of-the-art calculation methods were used to predict the natural frequencies and mode shapes of the bucket and the bucket structure dynamic response to identified stimuli for a variety of structural configurations. From this study emerged the tie-wire design which was finally employed. Prior to accepting this design however, a prototype row of buckets was manufactured and testing was conducted at speed to verify the dynamic design calculations. A partially assembled and instrumented test wheel, typically used for such testing, is shown in Figure 3.

Protection against moisture erosion of the leading edge of the last-stage bucket in many turbines is provided by a hardened material region near the tip section of the bucket. The hardened region is achieved either through addition of a hard, erosion-resistant material, such as stellite, to the bucket structure or through thermal hardening of the bucket material itself. Extensive studies of erosion and the erosion phenomena at the manufacturer's facilities indicate that under many circumstances the tough, high-strength steel of last-stage buckets built by General Electric Company exhibit erosion resistance comparable to that achieved with conventional erosion protection. For the operating conditions of the Wyodak last-stage bucket the natural erosion resistance of the bucket steel itself provides adequate protection for all anticipated operating conditions. Thus, no added erosion protection is required.

L-1 Bucket Design

The L-1 bucket for the Wyodak application was a derivative of an existing bucket design. Development tests of the existing design formed the basis for the extrapolation of the dynamic characteristics needed to minimize the potential for fatigue damage in the new design. A primary concern in the design of this bucket arose from the possibility of extreme temperature transients under certain operating conditions. The design criteria for this bucket were such that the structural integrity of the bucket could be assured at the higher temperatures anticipated. The possibility existed, however, that thermal expansion could reduce the clearances between the rotating bucket structure and stationary components to a point at which rubbing would occur. To avoid this potential problem, the stage clearances were conservatively specified to accommodate thermal expansion of the bucket structure up to at least 400 F (204 C). Because of uncertainty about the maximum temperature which could be encountered during operation, monitoring of the L-1 temperature was considered an essential precaution. Alarm and trip settings were also specified to avoid an over temperature condition which could result in damage to either the rotating or the stationary components.

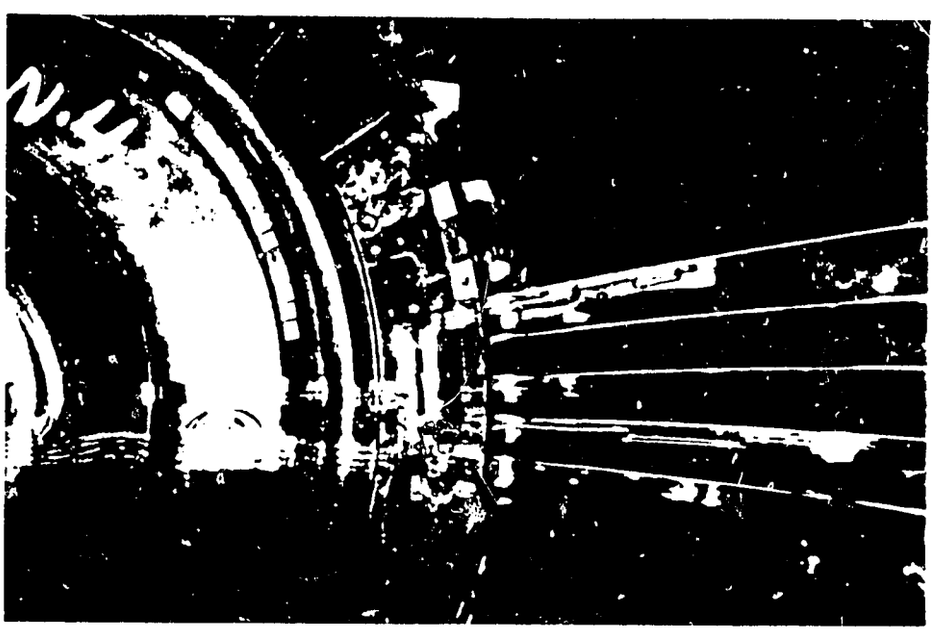

Figure 3. Typical wheel box test assembly of last-stage buckets with attached strain gages

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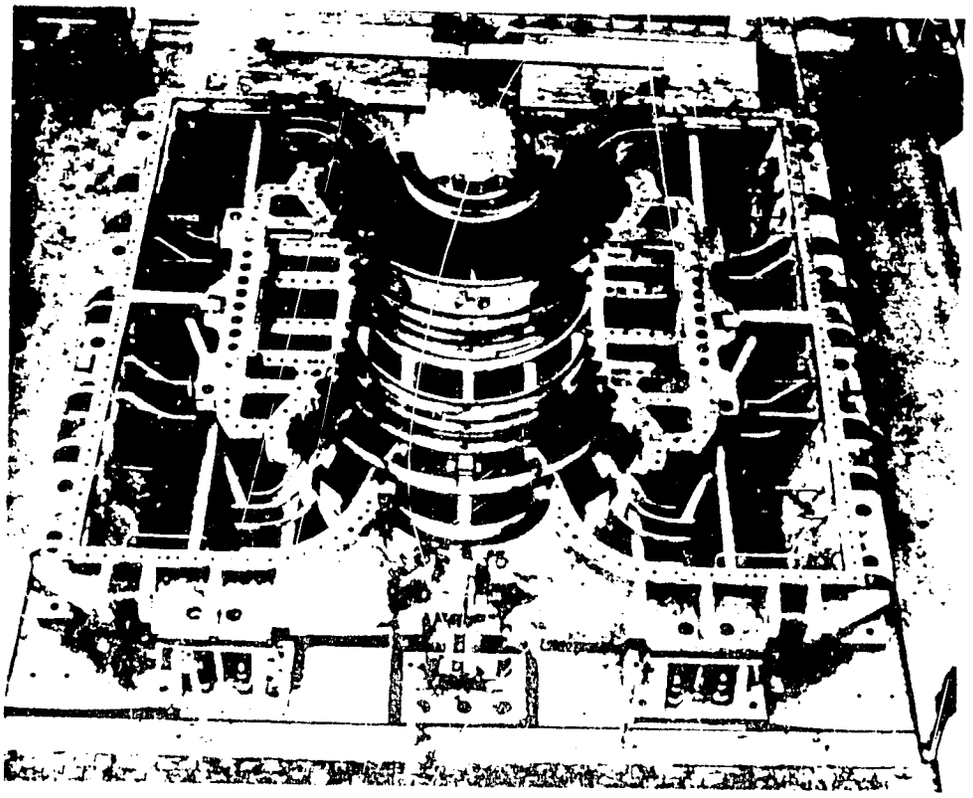

Figure 4. Lower half low pressure inner casing and exhaust hood, showing separate exhaust hood support pedestals and exhaust hood diffuser section

Low Pressure Casings

The low pressure steam path is conventionally enclosed in a fabricated inner casing. The inner casing supports the stationary nozzles and contains the LP steam flow until it exhausts at the last stage. This casing is in turn supported and contained in the fabricated exhaust hood, through which the exhaust flow is passed to the condenser.

Conventional exhaust hoods produced by the manufacturer contain a journal bearing at each end to support the rotor. The location of these bearings within the hood structure reduces rotor span while providing sufficient distance between the last-stage bucket and the hood endwall for efficient passage of exhaust flow. For the high exhaust-pressure design, however, bearing alignment with such a design would be very sensitive to the hood temperature variations resulting from the wide ranges in exhaust pressure. Therefore, the bearings were located in separate housings outside the hood. Rotor span was not a problem on this unit since the low-pressure design has one less stage than conventional units and because the distance required between the hood endwall and last-stage bucket for exhaust steam flow was reduced by the application of the special diffuser flow passage.

The comparatively high exhaust hood temperature on this unit required another design innovation. This was the use of separate exhaust hood pedestals to minimize variations in alignment with operating back pressure. These can be seen in Figure 4. This beneficial step, however, would have been negated if radiation from the hood walls caused the foundations themselves to expand more than normal, as this could also cause alignment problems. Accordingly, the lower hood outer walls, which are relatively inaccessible, were insulated with a moisture resistant lagging. The upper hood was covered with conventional block insulation to protect personnel from contact with the hot metal.

The higher than usual exhaust hood temperature also influenced the design of the low pressure turbine shaft seals. In turbines with conventional condensers, some of the cooling of the seal steam is achieved by exposing the seal-steam piping to the exhaust hood conditions. This would not be reliable for the design of the high exhaust-pressure unit since the exhaust hood conditions would

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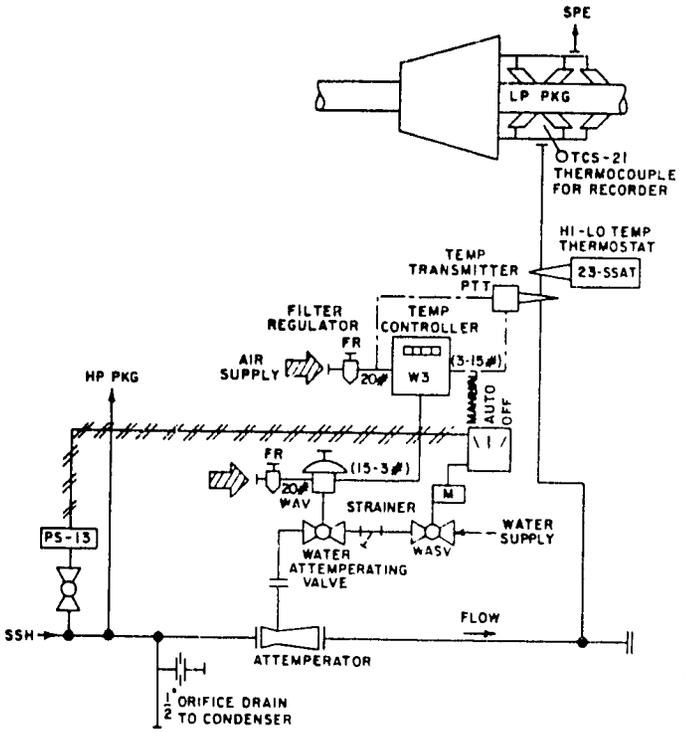

Figure 5. Steam seal attemperator diagram

vary substantially in operation. Therefore, external cooling of the seal steam was provided by a venturi type attemperator. The air-operated control system for the attemperator (see Figure 5) maintains the seal steam at 300 F (149 C). The control system is designed to be fail safe in that loss of air supply or control signal causes the water valve to open.

Perhaps the most significant design innovation for the low-pressure section was the annular diffusing flow passage at the exhaust of the last-stage buckets. The design of these fabricated turning vanes (see Figure 4) resulted from aerodynamic calculations and laboratory tests. These tests were conducted with the objective of maintaining high efficiency over the wide range of exhaust pressure while simultaneously reducing the axial distance between the last-stage bucket and hood endwall.

To maximize efficiency of the diffuser/hood assembly, the number of flow obstructions in the hood, such as struts and support gussets, were minimized. This posed a new challenge in the structural design of the diffuser, since the potential for fatigue damage of the diffuser structure with this minimum number of supports was significantly increased. Accurate dynamic design of this complex structure was required to preclude resonances near low multiples of running speed (60 or 120 Hz) which could cause rapid fatigue damage in service. Dynamic computer models of the structure were constructed and analyzed. These led to optimal placement of the supporting struts. The response of the structure to possible flow stimuli and static pressure loads was also considered. These analyses were subsequently confirmed by factory tests during and after construction of the turning vanes, and by a field test during operation with dynamic sensors.

With the turning vanes of the diffuser in place, however, it is not possible to inspect the last-stage buckets from inside the hood. Therefore, provisions were made during the design of the diffuser to rotate one quadrant of the vanes out of the way to permit access to the last-stage buckets without removing the upper hood. Special equipment needed to accomplish this and facilitate this access was also designed and supplied with the unit.

During design of the latter-stage buckets there was concern for the effect of the extreme temperatures which could occur under certain operating conditions. On conventional units with exhaust pressures of 5 inches Hg. (16.9 kPa) or less, unusual temperature variations are of concern primarily at the last stage, which can be cooled by the exhaust hood water sprays. On the high exhaust-pressure unit, however, the next longest stage (L-1) could also heat up excessively under some conditions. This led to the need for monitoring of the stage temperatures and, as stated previously, to set an upper limit for operation. The design of the hood, inner casing, and L-1 diaphragms was required to accommodate the temperature monitoring equipment needed to sense L-1 stage temperature. Three thermostats and one dual-element thermocouple were installed. Although additional margin for high-temperature operation had been provided during the stage design, the lack of operating experience at these conditions resulted in an initial setting of the thermostats to provide an alarm at 350 F (177 C) and to trip the turbine (after a five minute delay) at 400 F (204 C).

OPERATIONAL EXPERIENCE

The start-up of the Wyodak unit was smooth, with only a few minor rubs experienced and the unit was synchronized on June 8, 1978. Peak-to-peak vibration levels at all bearings were under two mils (.05 mm). At full load the unit has been operating in the exhaust pressure range of 6 inches - 12 inches HgA (20.3-40.6 kPa). Although the air cooled condenser is capable of lower exhaust pressure during the cold months, the lower operating value of 6 inches HgA (152.4 mm HgA) avoids icing problems in the condenser. The effectiveness of the condenser results in full-flow operation at or below 12 inches HgA (40.6 kPa) even with 105 F (41 C) ambient air.

The gross generation with valves wide open at 6 inches HgA (20.3 kPa) is roughly 365 MW, decreasing to 330 MW at 12 inches HgA (40.6 kPa). The turbine manifests no noticeable change in behavior with changes in load or back pressure. It is remarkably quiet, even in the basement levels, where the only unusual noise is from the steam flow in the exhaust duct to the condenser.

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Accelerometers, thermocouples, pressure probes, and proximity indicators were among the instrumentation installed to monitor the operation and performance of the turbine components. Many pressure gauges were installed in the hood for its first year of operation in order to monitor the diffuser's efficiency. The data taken confirm the excellence of the design. The diffuser was free of vibration while effectively directing the exhaust steam to the condenser duct. Relative movements of bearings, shafts, and casings were measured and found to be within expected ranges. The absence of significant rubs on the start-up also confirmed that alignment of the major components was maintained.

The first turbine inspection was conducted approximately one year after initial synchronization. The unit was found to be in excellent condition. The steam path was clean and free of deposits, packing clearances were within operating tolerances (effects of a few minor rubs in the low pressure section were observed), and the rotor was also in excellent condition. Two last-stage, pressure-probe pipes, which were part of the special instrumentation, had broken off on the left side of the exhaust hood at the inner surface. No subsequent damage resulted from the fracture of these pipes. These were replaced and the supporting structure was reinforced.

At this inspection, single cracks were discovered in four covers on the turbine-end row of the L-1 buckets and one bucket in the same row was found with a single cracked tenon. The affected bucket and covers were replaced. Fractographic analysis of the cracks indicated the cause of the cracking to be high cycle fatigue. Steps were taken, therefore, to tune this row of L-1 buckets to minimize the potential for recurrence of this problem. All other buckets on the HP-IP and LP rotor, including the last-stage buckets, were found to be trouble free and in excellent condition.

CONCLUSION

The opportunity to participate in the development of the Wyodak Steam-Electric plant presented General Electric Company with unique design challenges. Innovation and extension of design technologies to limits far exceeding conventional experience were required, while the characteristics of reliability and maximum thermal efficiency of more conventional turbines needed to be maintained.

The satisfactory performance of the Wyodak turbine to date confirms that the design objectives were attained. It is noteworthy that such a unique prototype has performed so well. The success of this unit underscores the flexibility of General Electric Company turbine design technologies to respond to the changing needs of the utility industries.

The Wyodak plant is another milestone in the progress of the electric utility industry, and General Electric Company is pleased to be a part of this successful innovation.

OPERATING EXPERIENCE AND PERFORMANCE TESTING OF THE WORLD'S LARGEST AIR-COOLED CONDENSER

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Presented at
AMERICAN POWER CONFERENCE
Chicago, Illinois
April 27-29, 1981

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INTRODUCTION

The world's largest air-cooled steam condenser has been in service at the 330 MW Wyodak power station near Gillette, Wyoming, since 1978 (Figure 1). The Wyodak station, operated by Pacific Power & Light Company (PP&L) and Black Hills Power & Light Company (BHP&L), is located in an arid, coal-rich area. The use of an air-cooled condenser enabled siting of the plant without concern for a large plant water supply and allowed its construction essentially on top of a 70-foot to 90-foot seam of low-sulfur coal. Station water consumption, about 200 GPM, is principally for boiler feedwater makeup. The water used at Wyodak is reclaimed from the Gillette city sewage system by means of mechanical filtration, absorption, mixed bed demineralization, and reverse osmosis.

Since planning began more than a decade ago, the air-cooled condenser has been a pivotal point in the Wyodak plant design. The physical size of the condenser, the large number of fans, and the extreme summer and winter operating conditions called for special consideration during all phases of planning, engineering, construction, testing, and operation. Intensive coordination was required, therefore, between the operators, PP&L and BHP&L, the architect-engineer, Stone & Webster Engineering Corporation (SWEC), the supplier of the air-cooled condenser, GEA, and the turbine manufacturer, General Electric Company.

After the plant's commissioning in June 1978, the need for a condenser performance test procedure became apparent. Existing performance test codes for indirect (wet) cooling systems do not fulfill the requirements for an air-cooled condenser. The test plan, procedure, and instrumentation were established before a recognized air-cooled condenser test code was available. Since that time the AIChE has published "Air-Cooled Heat Exchangers, A Guide to Performance Evaluation." Additionally, the ASME PTC 30 committee on "Air-Cooled Heat Exchangers" has drafted a similar code in part. A review of the AIChE code indicated that the instructions are not specific enough to allow a definitive test of a large power station condenser. The contents of the final draft of the ASME PTC 30 code probably will not be known for some time.

In the interim, it is suggested that the procedure presented herein can be used effectively to test large electric utility air-cooled condensers, as was done at the Wyodak station. Furthermore, it is hoped that the ASME PTC 30 committee will take note of this procedure and review the techniques when writing sections of its proposed code related to air-cooled condensers.

Since its initial startup, the Wyodak station has completed nearly three years of operation, including three winter cycles. The data collected during this period, as well as the successful performance test, have demonstrated positive technical, economic, and environmental justification for air-cooled condensers in large power stations.

SELECTION OF CONDENSING SYSTEM

A thorough survey of the reliability and economics of state of the art indirect and direct dry cooling systems preceded the selection of a mechanical draft, direct-air-cooled condenser. As illustrated in Figure 2, the air-cooled condenser differs from the indirect dry-cooled system in that no intermediate cooling water system (which would have included circulating pumps and a surface condenser) is required. Selection of an air-cooled rather than a water-cooled system, therefore, reduces the number of components prone to failure, and thus reduces maintenance. It also improves reliability during severe winter operation because no vent system, water drain system, or air control louvers are required.

The temperature diagrams in Figure 3 illustrate the difference between isothermal condensation of steam versus air and nonisothermal cooling of water versus air. The exhaust steam temperature of 141°F corresponds to six inch-HgA back-pressure. The air-cooled condenser operates at approximately 5°F lower saturation temperature owing to pressure loss in the steam duct and condensing elements. The water cooler is designed to a terminal temperature difference (TTD) of 5°F corresponding to the HEI standard for surface condensers.

For the same amount and temperature of the cooling air, the logarithmic mean temperature difference for the air-cooled condenser is 1.35 times higher than that of the water cooler. The heat exchanger surface and plot area requirement of the air-cooled condenser, therefore, is only three-fourths that of the water cooler, which is the prime indicator of the reduced investment of a direct-air-cooled condenser. In addition, reduction of auxiliary power requirements is achieved because circulating cooling water pumps are eliminated.

The 330 MW Wyodak condenser consists of 22 standard condensing groups, each group comprising three modules. A module is an A-frame structure covered by six cooling elements, each eight feet by 20 feet, and served by one 21-foot axial flow fan, in a forced draft mode, mounted in the base of the module.

Each cooling element contains several rows of galvanized steel finned tubes, inside of which the steam is condensed. Three prototype modules with longer finned tubes of greater cross section, are located at the southwest end of the condenser bank, and are served by 33-foot diameter fans. These prototype modules are part of the 330 MW condensing system, and are aimed at both reducing the number of fans and simplifying winter operation of large power stations up to 1000 MW.

Figure 4 schematically shows one condenser group. The two outer modules of one group are the so-called K-modules, or condenser modules. Steam passes through the cooling elements co-current with the condensate being formed on its way down. Approximately 75 percent of the steam is condensed in the K-module. The balance of the condensation is accomplished in the so-called D-module, or dephlegmatoric (reflux) condenser, located in the center of the group. The D-module ensures positive steam flow leaving

the K-modules at any load condition, thereby precluding condensate from being subcooled. Within the D-module subcooling is prevented by countercurrent flow of steam and condensate. At the same time, noncondensibles are stripped effectively from the condensate and are evacuated at the top of the cooling elements by means of standard vacuum ejectors.

One unit, comprised of two K-modules and one D-module, is called a K-D group. Modules of this concept have been in operation in the U.S. since 1969 in the 20 MW Neil Simpson plant adjacent to the Wyodak station. In addition, the 85 MW combined cycle station of Massachusetts Electric Light Department at Braintree and the 65 MW combined cycle power plant of Chugach Electric Company at Beluga, Alaska, use the same type of module. These modules have proved to be a reliable and economical way of condensing steam by air.

STATION DESIGN PARAMETERS

The major Wyodak station design parameters are presented in Table 1. The steam generating system is a coal-fired, balanced draft steam generator with a single reheat cycle. The system is designed for a maximum steam flow of 2,622,000 lb/hr at 1990 psig and 1005°F at the superheater outlet, 2,319,000 lb/hr of which is reheated to the same temperature. Control requirements for NO_x limit each burner heat input to 130 million Btu/hr. Approximately 1.5 to 2 million tons of low-sulfur subbituminous coal are burned annually.

The turbine generator is rated for 330 MW with 2,373,400 lb/hr life steam at 1800 psi/1000°F and a turbine exhaust flow of 1,725,500 lb/hr at six inches HgA. With maximum steam flow, however, 365 MW or better gross generation can be obtained within the four to eight-inch HgA back-pressure range (see Figure 5). The limit of eight inches is exceeded only for ambient temperatures over 80°F, but this condition typically occurs not more than five percent of the year. The steam turbine is custom designed for a maximum back-pressure of 15 inches HgA, which requires 20-inch last-stage buckets in the turbine and provisions to accommodate exhaust temperatures up to 180°F.

The air-cooled condenser is rated for 1,885,000 lb/hr steam flow or 365 MW gross generation, which corresponds to valves wide open and five percent overpressure at the turbine. Rated conditions are obtained at an ambient temperature of 66°F and a back-pressure of six inches HgA. The condenser bank measures 360 feet by 165 feet, and is supported by a steel structure with a fan deck elevation of 72 feet to provide access for cooling air (Figure 6). Exhaust steam flows from the bottom exhaust of the turbine via one 18-foot and two 13.5-foot diameter ducts into 12 risers that feed into the distribution manifolds, located at an elevation of 85 feet at the top of the A-frames. An all-welded construction of cooling elements and steam ducts is used to ensure that the entire system is vacuum tight.

The air-cooled condenser achieves its condensing capability solely through convective transfer of latent heat of steam contained in finned tubes to the cooling air flowing across these tubes. The condensing capability, temperature, and pressure depend directly on the initial temperature difference (ITD) between the saturated steam and the cold air.

CONTROL OF CONDENSER CAPABILITY

At the design turbine back-pressure of six inches HgA and design cooling air temperature of 66°F, the ITD (141°F minus 66°F) is 75°F. With ambient temperatures varying from 100°F to -40°F, the steam saturation temperature would vary accordingly from 175°F to 35°F, corresponding to back-pressures of approximately 13 to 0.2 inches HgA.

For economical and practical reasons, the preferred back-pressure range is between four and eight inches HgA. The cooling air flow is the only controllable variable that can be used to achieve this objective. Eighteen combinations of fan speed between full speed, half speed, and zero speed provide sufficient flexibility to meet most of the load and ambient temperature conditions. For instance, turbine rated flow can be maintained at 32°F and a back-pressure of six inches HgA with all fans running at half speed (see Figure 7). This operating mode requires less than 25 percent of the full-speed fan power.

Dropping the ambient temperature even further or reducing the load below 100 percent with the fans running reduces the back-pressure, whereas operation at constant back-pressure requires that air delivery by the fans be reduced. At temperatures below 0°F, fans must be switched off progressively to maintain the back-pressure above the turbine full-load choke point of 3.8 inches HgA. For prolonged operation under these conditions, condenser groups with fans switched off are interchanged with operating groups at regular time intervals. This ensures that the cooling elements remain purged with steam, preventing accumulation of noncondensibles and "rime-ice."

For extremely low loads and extremely low ambient temperatures, isolation valves in the steam distribution system facilitate additional control of the condensing capability through reduction of heat transfer surface. Moreover, the system is designed to receive steam through a turbine bypass if station load falls below 10 percent during severe freezing weather. Fan modulation for economical and winter operation is accomplished by means of a programmable computer. For each ambient temperature, a fan switching mode is selected that provides the optimum combination of station gross generation and fan power consumption. Other auxiliary power consumers within the station further reduce the gross generation to net station output, which is shown in Figure 8 as a function of ambient temperature.

An uncontrollable variable in the performance of an air-cooled condenser is the effect of cross winds. Cross winds could aggravate air circulation and influence the air delivery by the fans. To minimize such effects, panels were installed around the condenser, as shown in Figure 1, and a margin was designed into the condenser performance based on model experiments described later.

OPERATING EXPERIENCE

The Wyodak station has completed more than 20,000 hours of operation in three years time. The principal operating statistics are summarized in Table 2. The station has experienced more than 100 start-ups, and thus far the condenser has not caused a forced outage.

LOW-TEMPERATURE OPERATION

The environmental conditions experienced by the air-cooled condenser are listed in Table 3. The most severe winter conditions occurred in the first year of its operation. A prolonged period with temperatures as low as -48°F caused difficulties in the station's coal-handling facilities and auxiliary systems, resulting in low loads of the turbine generator. At that time construction was not completed and the steam bypass was not operational. Therefore, condenser steam loads as low as five percent were encountered. Clear skies, very low temperatures, and the total absence of wind caused natural convection of the same magnitude on sections with fans switched off, as would have been experienced with fans operating at half speed.

As a result of these conditions, condensate freezing occurred in several finned tubes. Upon thawing, however, none of the tubes had developed a leak. Their resistance to leaks is attributed to an elliptical design that allows for deformation. Even though the deformed tubes could have withstood a number of additional freeze/thaw cycles, it was decided to replace them during the scheduled overhaul in the spring of 1979. The prototype modules did not freeze and operated trouble-free throughout the cold period with minimal operator attention, thereby demonstrating their ability to withstand the most severe operating conditions.

CROSS-WIND PERFORMANCE

During the planning phase, model experiments were conducted to provide predictions of condenser performance for the anticipated wind conditions at Wyodak. Figure 9 shows the results of model measurements related to the selected air condenser layout. For the main wind directions (SW to SE and N to NW) and a wind speed of 22.3 ft/sec, the capacity drop, compared with calm conditions, is less than five percent. In an unfavorable case (wind from the NE), the capacity drop for the same wind speed is, at most, 12 percent.

Although it is difficult to qualify or quantify the effect of cross winds on a condenser of this size, an attempt was made to learn more about the condenser behavior under cross winds by full-scale experiments at Wyodak and other stations. As indicated in Figure 10, the wind direction and speed are highly variable around the station at a given elevation. For example, between the condenser and the water cooler, polystyrene beakers were blown in circles of approximately 30 feet in diameter. It was virtually impossible to make sufficient observations to determine if this condition resulted from cross winds or from the enormous volume of air being displaced by the condenser.

Figure 11 shows air flow through the use of smoke traces at an elevation approximately midway between grade level and the fan deck. The air flow is directed in part outward instead of toward the fans. Such phenomena are localized and may be considered microeffects, as compared with the giant migration of air toward the condenser bank at other locations, but they demonstrate the complexity of measuring air flow under cross-wind conditions.

Experiments conducted on models and at other full-scale installations indicated that air flow recirculation could be expected (see Figure 12). "Gusty" temperature fluctuations also were noticeable at grade level under the down-wind half of the condenser. An attempt was made, therefore, to make air recirculation visible with smoke traces. It was impossible to identify a steady recirculation pattern. It is apparent that the air recirculation depends largely on wind direction and speed at any given time.

In spite of the difficulty in characterizing wind effects, it may be concluded from the performance measurements that the design margin is adequate to compensate for the effects of wind and air recirculation on the condenser.

BOILER FEEDWATER CHEMISTRY

There has been some concern about the way iron and oxygen contents are controlled in air-cooled condensers operating under vacuum with the steam and condensate exposed to the large internal steam ducting and tube surface.

The pH is controlled by means of ammonia injection, and the iron content in normal operation is 10 ppb at the condensate pump discharge. After prolonged shutdown of the unit, initial iron content is high. Upon startup, however, the condensate is blended with demineralized water to limit the iron in the feedwater to 50 ppb. After 10 to 12 hours active use of the entire condenser, the iron content returns to normal.

Normal oxygen content of the condensate returning from the condenser is approximately 20 ppb. Hydrazine is injected at the condensate pump discharge to scavenge the free oxygen. No special precautions are required upon shutdown, and no special problems are experienced at startup. The 20 ppb oxygen content is achieved within four to eight hours after the entire condenser is in active use.

OPERATION AND MAINTENANCE

Preparing the condenser for startup takes 30 minutes, mainly for evacuating the internal volume of the air-cooled condenser, the turbine, the exhaust steam duct, and the low-pressure heaters and condensate receiver tank down to 10 inches HgA with startup hogging ejectors. At startup the operational ejectors take over. These are standard two-stage, twin steam ejectors and ejector-condenser sets, dimensioned in accordance with the HEI standards.

Under normal operating conditions, the air-cooled condenser does not require any particular attention. Selection of the fan switching mode for optimum setting normally is done by computer but can be done manually if preferred.

Maintenance of the condenser consists of routine inspection, approximately 25 minutes per eight-hour shift, for the 69 fans, gears, and motor drive trains. Additionally, once-a-year scheduled maintenance during the station overhaul requires a total of approximately 800 man-hours for changing gear box lubricant, checking the torque of the fan blade hold-down clamps, and cleaning the finned tubes externally with the high-pressure fire water system, as detailed in Table 4. Over the three-year period of operation, two out of 69 gear boxes and six electric motor drive bearings needed replacement.

TEST PROCEDURE

TEST PRINCIPLE

Unlike water cooler performance, which is simply defined as the product of measurable water flow rate and temperature drop across the cooler, the air-cooled condenser performance is the product of steam flow rate and enthalpy drop due to the phase change and internal losses in the subatmospheric steam system. This presents two problems:

- It is virtually impossible to obtain a representative steam flow measurement in an 18-foot diameter steam duct.
- The enthalpy drop cannot be measured directly, and the moisture content of the exhaust steam is unknown.

From the steam cycle diagram in Figure 13, it can be seen that measuring the condensate flow from the condenser, instead of the steam flow to the condenser, introduces still another problem. Drains and flash steam of unknown quantity and quality from low-pressure heaters, boiler feed pump seals, miscellaneous drains, and boiler feedwater make-up are included in the flow leaving the condensate receiver tank. Individual measurement of all the heater drain flows seems impractical and increases the inaccuracy of the test. The heater drain flows, therefore, are determined through a heat balance computation, based on temperatures and pressures measured in the individual turbine extraction points, heater drains, and intermediate condensate heating stages. Other drains and bleeds are closed to minimize the uncertainty of the test, and the following prerequisites apply as part of the procedure:

- The generator will be within five percent of its full load gross capacity of 365 MW(e).
- The condenser heat load will be within 10 percent of design heat load.
- Ambient temperature and turbine exhaust pressure will be within the envelope of the guaranteed performance, which is indicated in Figure 7.

- Full-load fan power will be within 15 percent of design power.
- All fans preferably will be in full-speed service; but in no case will more than six fans be out of service, including not more than one fan per K-D group.
- If a dephlegmator fan is down, that whole group will be taken out of service.
- The boiler feedwater make-up will be closed off, or the make-up storage tank volume change registered.
- The drain valve between the exhaust duct drain/flash tank and the condensate receiver tank will be closed.
- The drains from the combustion air heaters, building heaters, etc., will be closed.
- The emergency feedwater heater drains will be closed.
- The boiler blowdown will be shut off.
- Calibrated test instruments with valid certificates will be used.

The only drain that will be disregarded is the air ejector condenser rain. Its flow is less than 1/4 percent of the total condensate flow, and ts effect on the heat balance is negligible.

EAT BALANCE PROCEDURE

The low-pressure heater cycle in Figure 14 identifies the measurements hat are required for the heat balance computation. In addition, the mbient air temperature, the barometric pressure, and the turbine exhaust ressure must be measured to permit comparison of the measured performance ith the guaranteed performance. Details of the measuring equipment and ocations are given in Appendix A.

The individual steam flow rates from the turbine extraction points, R_3, SR_4, and SR_5, are defined by the following equations:

$$SR_3 = \frac{W_{flw} \times Cp \times (Tw_4 - Tw_3)}{(Hs_3 - Hc_3)}$$

$$SR_4 = \frac{W_{flw} \times Cp \times (Tw_3 - Tw_2) - SR_3 \times (Hc_3 - Hc_4)}{(Hs_4 - Hc_4)}$$

$$SR_5 = \frac{W_{flw} \times Cp \times (Tw_2 - Tw_1)}{(Hs_5 - Hc_5)}$$

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The flow rate measured with the flow nozzle, W_{flw}, includes the sum of the above heater drains, W_{htr}, and the drains from boiler feedwater pump seals and turbine seals. The amount of drains, W_{bfp}, is determined by measuring the volume increase of the exhaust duct drain/flash tank over a one-hour period. The accumulated volume changes of the condensate receiver tank over a one-hour period, W_{crt}, can be positive or negative, and the measured condensate flow is corrected for this amount.

The summation of the above mass flow rates yields the net condensate flow rate. The test turbine exhaust steam flow, W_{exh}, is equal to the net condensate flow rate:

$$W_{exh} = W_{flw} - W_{htr} - W_{bfp} \pm W_{crt}$$

Using the Mollier diagram for steam, the exhaust steam enthalpy, H_{exh}, can be found by extrapolation of the turbine expansion line over the pressure/temperature conditions of the three turbine extraction points up to the line of measured turbine exhaust pressure. The enthalpy of the condensate, H_{crt}, simply follows from the measured temperature of the condensate leaving the condensate receiver tank, T_{crt}, and the specific heat of the condensate, Cp. The test condenser heat load, Q_{test}, can now be computed,

$$Q_{test} = W_{exh} \times (H_{exh} - H_{crt})$$

$$\text{and } H_{crt} = Cp \times (T_{crt} - 32)$$

GUARANTEED HEAT FLOW RATE

The guaranteed heat flow rate, Q_{guar}, for the guaranteed steam flow rate, W_{guar}, and the latent heat for saturated steam, H_{fg}, at the measured turbine exhaust pressure is

$$Q_{guar} = W_{guar} \times H_{fg}$$

The guaranteed steam flow rate, W_{guar}, is the performance heat flow rate, W_{perf}, obtained from the performance diagram (Figure 7) for the test ambient temperature and the test exhaust pressure, corrected for the following two factors:

$$W_{guar} = W_{perf} \times c_{bar} \times c_{fan}$$

The factor c_{bar} compensates for differing steam condensing capability due to differing cooling air delivery by the fans resulting from a barometric pressure P_{bar} differing from the design value, P_{des}:

$$c_{bar} = 1 + p \times \frac{(P_{bar} - P_{des})}{P_{des}}$$

The factor p depends on the make of condenser, but is typically in the range of 0.5 to 0.7. The factor c_{fan} compensates for the number of inoperative fans, N_{off}, out of a total number of fans, N_{tot}:

$$C_{fan} = 1 - \frac{N_{off} \times (1 - q)}{N_{tot}}$$

The factor q is the fraction of full-speed performance of one module with an inoperative fan. Depending on the location of the fan, the steam temperature, the ambient temperature, and the wind speed and direction, this value must be determined on a case-to-case basis. It will typically be between ± 15 percent.

Now the condenser performance factor, P_f, can be determined as the ratio of tested heat flow rate and guaranteed heat flow rate:

$$P_f = \frac{Q_{test}}{Q_{guar}}$$

If the ratio is ≧ 1, the condenser meets the guaranteed performance without tolerance. If the measured fan power, HP_{test}, differs from the guaranteed value, HP_{guar}, the influence on the condenser performance factor may be expressed as follows:

$$P_t = P_f \times \left(\frac{HP_{guar}}{HP_{test}}\right)^r$$

where P_t is the composite performance of the condenser including the fan power requirement. The influence factor, r, depends on the make of the condenser, but is typically in the range of 0.2 to 0.3. Obviously, the fan power must be corrected to guaranteed conditions for ambient temperature and barometric pressure before applying the above correction factor.

PERFORMANCE TEST

TEST RESULTS

On September 24, 1979, the Wyodak condenser was tested in accordance with the described procedure. After a one-hour run-in test to check out proper functioning of the instrumentation, two formal test runs of one hour each were made.

During the first test run, two fans were off. During the second run, all fans were on full speed. The limit heat load value, 110 percent of design load, was exceeded by only 0.2 percent during the first run, but owing to slightly higher enthalpy, the steam load was within the guaranteed diagram, as is indicated in Figure 7. The ambient temperature just reached the limit value of 80°F during the second test.

The heat balance data of run 1 are presented in Table 5. The corresponding extrapolation of the turbine expansion line is presented in Figure 15. It can be seen that the expansion line intersects with the measured turbine exhaust pressure line of 4.28 psia at an enthalpy of 1106 Btu/lb and a moisture content of 2.2 percent. The fourth point extraction deviated slightly from the line, which is also found in run 2. It is unlikely that the third point is incorrect, since the expansion line would slope negatively in that case. It is also unlikely that the fifth point is incorrect, because it would bring the exhaust point near 0 percent moisture content. It is suggested, therefore, that the pressure measurement taken at the heater should be corrected for the line pressure drop between the extraction point and the remotely located heater. The exhaust temperature measurement in the steam duct showed close agreement with the saturated steam temperature at exhaust pressure.

Some degree of subcooling is to be expected as a result of pressure drop in the steam duct, steam distribution manifolds, and condensing elements. The subcooling experienced, average 1°F, is certainly well within expectations for a condenser of this size.

The test data for runs 1 and 2 are presented in Table 6. Even with the high ambient temperatures, a gross generation of over 350 MW(e) is reached at eight inches HgA. The condenser performance factors for runs 1 and 2 are 1.060 and 1.040, respectively, with a mean value of 1.050. The fan power was measured during a separate test with a slightly different ambient temperature, but the relative fan power requirement factor can be used to determine the mean composite performance of the condenser. In this instance the lower fan power consumption improved the condenser performance to a composite performance of 1.085.

UNCERTAINTY OF TEST RESULTS

One measure of the accuracy of the instrumentation and test procedure is the "uncertainty" of the test results. This subject is receiving increased attention and emphasis by industry. All ASME PTC Committees with work in progress, for example, are now required to provide guidance on data inaccuracy within their codes.

In this test uncertainty analysis, the measurement of inaccuracy adopted generally was that recommended by the 1969 ASME PTC-6 report entitled "Guidance for Evaluation of Measurement Uncertainty in the Performance Tests of Steam Turbines." An exception was the turbine exhaust pressure measurement. The uncertainty construed in the report relates presumably to low-pressure turbine exhausts. Under many conditions, particularly near wall pressure taps, the extremely nonuniform flow contains velocity levels approaching Mach 1. As a result, the readings can be very inaccurate. The Wyodak turbine exhaust, operating at higher back-pressures, will experience lower steam velocities and relatively tranquil flow patterns. Therefore, a higher accuracy value was adopted. It is also interesting that the condensate flow was identified as a major source of error within this test.

The accuracy of the measured heat rejected to the condenser was not verified by alternative means. At a typical power station, with a water-cooled condenser, this can be performed by measuring the water flow and temperature levels across the condenser. In the present case, however, determining the aggregate air flow of 69 fans and the weighted temperature rise of that air accurately is impractical. Nonetheless, the fact that the Wyodak power station exhibits excellent performance and low turbine exhaust pressures confirms that the condenser design objectives have been met.

The uncertainty of the overall performance of this test was estimated as ± 6.5 percent. If one follows accepted practice, it is reasonable to expect that the results of only one out of 20 similar tests would fall 6.5 percent above or 6.5 percent below the average performance measured in runs 1 and 2. Hence, with due consideration of the test inaccuracy, it may be concluded with confidence that the air-cooled condenser at Wyodak meets its guarantee.

CONCLUSION

Direct dry cooling in U.S. power plants has already proven to be an economically feasible option in water-short areas. Its application is rapidly extending as competition for available water increases and the cost of obtaining, treating, and transporting water escalates.

In some instances, the choice of air-cooled condensation has reduced the need for lengthy legislative procedures and environmental approvals to obtain the rights for water usage and thereby has reduced the capital outlay during planning and construction phases. Even though water may be available today, it is essential to base decisions on long-term water availability over the life of the plant.

Operating experience at Wyodak has demonstrated the technical and economic feasibility of using dry-cooled condensers at a modern fossil-fired power plant in a water-scarce area. In early 1980, PP&L and BHP&L announced their intention to construct a duplicate unit at the Wyodak site. Both companies stated that this decision was based on favorable operating experience with the first unit. The experience at Wyodak should encourage other utilities to proceed with confidence in construction of air-cooled condenser plants in areas where obtaining adequate cooling water could become a serious problem.

APPENDIX A
MEASURING STATIONS AND EQUIPMENT

The physical size of the condenser and the spread of the measuring station necessitated thorough planning of the required number of test engineers (Figure 16). For instance, the 16 ambient temperature measurements are spread over a 1000-foot distance, which creates a problem when taking readings every five minutes for a duration of three hours. Measuring stations, therefore, were assigned to obtain the minimum time frequency and the distance over which each test engineer was required to obtain readings. In this way, the number of test engineers could be limited to 10.

Condensate Flow Rate

Permanently installed 16-inch laboratory-calibrated (ASME) flow nozzle. Differential measurements are made with a single-column mercury-over-condensate manometer, range 60 inches, scale division 0.01 inch.

Condensate Temperatures

Discharge of condensate receiver tank pumps and in between feedwater heaters and condensate drain flow from the feedwater heaters. Mercury in glass thermometers in thermowells with silicon oil for heat conductivity. Where required, 32° to 212°F or 32° to 400°F with scale division of 0.35° and 0.9°F, respectively, and certified inaccuracy of 0.09° and 0.5°F, respectively.

Condensate Receiver Tank Level

Corrections on condensate flow are made for changes in condensate receiver tank level. The changes are measured with an inch scale at the gauge glasses and converted by means of calculated capacity curves.

Turbine Exhaust Pressure

A mercury manometer, range 0 to 32 inches vacuum, with 0.01 inch Hg scale division, is connected to eight pressure tappings around the circumference of the exhaust duct to measure the mean exhaust pressure.

Turbine Exhaust Temperature

Mercury in glass thermometer, 32° to 212°F, scale division 0.35°F, with certified accuracy of 0.09°F, two each, located opposite each other in the turbine exhaust duct.

Barometric Pressure

A mercury barometer installed near the vacuum meter, scale 0 to 32 inches.

Pressure Fifth Point Extraction

Mercury + condensate U-tube manometer with ± 0.1 inch Hg accuracy.

Pressure Fourth/Third Point Extraction

Calibrated precision pressure gauge, range 0 to 30 psig/0 to 100 psig, scale divisions 0.05 psig/0.1 psig.

Extraction Point Temperatures

The temperatures of the extraction points should be measured as near to the turbine as possible. However, inaccessibility and high temperatures required remote reading though the plant data acquisition system linked to permanently installed and calibrated precision thermocouples.

Ambient and Room Temperatures

Mercury in glass thermometers, range 0 to 120°F, scale divisions 0.2°F.

Ambient temperatures are recorded at 16 locations, equally spaced around the periphery of the condenser, five feet above grade level. The meters are fixed to a pole. The bulb and lower part are protected from solar radiation by an inverted polystyrene cup, as shown in Figure 16. The "room" temperatures are measured near each manometer for the purpose of meter corrections.

Cross-Wind Speed

Owing to continuously varying wind speed and direction in time and with location, the survey was made around the power station and plotted as shown in Figure 10. A time-integrating anemometer was used to eliminate the effect of wind gusting as much as possible.

Fan Power

Individual current readings at fan blade setting and watt-hour meter readings as well as individual watt-meter readings during the test.

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TABLE 1
WYODAK STATION DESIGN CONDITIONS

Steam Generator	
Type	Open chamber, natural circulation
Reheat	Single
Design steam flow	2,622,000 lb/hr
Normal/maximum steam pressure	1800/1990 psi
Normal/maximum steam temp.	1000°/1005°F
Reheat steam flow	2,319,000 lb/hr
Auxiliary steam flow	150,000 lb/hr
Furnace size	46 ft wide x 45 ft deep
Burner input, maximum per burner	130 MMBtu/hr
Coal	
Type	Subbituminous "C"
Heating value	8000 Btu/lb
Moisture	32 percent
Ash content	6 percent
Sulfur content	< 0.5 percent
Turbine Generator	
Power rating, normal/max.VWO at 6 in HgA	330 MW/365 MW
Steam conditions	1800 psi/1000°F/1000°F
Rated turbine flow	2,373,400 lb/hr
Exhaust pressure	2-15 in HgA
Exhaust enthalpy at rated condition	1089.56 Btu/lb
Last stage blade, length	20 in
Air-Cooled Condenser	
Condenser design heat load	1871 MMBtu/hr
Condenser design steam flow	1,884,800 lb/hr
Steam quality	0.968 lb/hr
Design ambient temp.	66°F
Atmospheric pressure	25.3 in HgA
Initial temp. differential	75°F
Number of fans	69
Fan diameter	21 ft*
Fan RPM, full speed/half speed	180/90
Fan power, full speed/half speed	75/18 kW
Specific fan power	1.6 percent of generation
Condenser dimensions	164 ft wide x 360 ft long x 72 ft high
Plot plan area	59,000 ft^2
Specific plot plan area	175 ft^2/MW
Condensate receiver tank surge capacity	20,000 gal

*Three test modules have 33-foot fan diameter.

TABLE 2
WYODAK STATION OPERATING STATISTICS

Year	1978*	1979	1980	1981**
Number operating hours	3,750	7,324	8,087	1,414
Availability factor (%)	76	84	92.1	99.9
Power generated (MW/hr)	994,040	2,396,837	2,720,919	493,607
Average annual output (MW)	265	327	336	349

*June through December only.

**January and February only.

TABLE 3
WYODAK STATION EXTREME ENVIRONMENTAL CONDITIONS

Year	1978	1979	1980
Lowest temperature (°F)	-48	-21	-12
Highest temperature (°F)	+101	+100	+106
Wind velocity, max. (mph)	44	32	37

TABLE 4
CONDENSER OPERATIONS AND MAINTENANCE MAN-HOURS

Routine Operation and Maintenance on a Shift Basis	
Operations	40 man-hours/week
Maintenance	8 man-hours/week
Scheduled Maintenance (once per year)	
Lubricating gear boxes	350 man-hours
Inspecting drive trains/fans	250 man-hours
Cleaning finned tubes	200 man-hours

TABLE 5
HEAT BALANCE DATA - RUN 1

	3rd Heater	4th Heater	5th Heater
Ts (°F)	659.7	456.3	305.3
Ps (psia)	93.5	32.4	15.6
Hs (Btu/lb)	1359.1	1264.6	1195.0
Tc (°F)	308.8	252.0	215.4
Hc (Btu/lb)	278.7	220.5	183.6
$Tw_4/Tw_3/Tw_2$ (°F)	260.0	223.7	215.6

W_{flw}: 2,472,112 lb/hr

Tw_1: 162.5°F

TABLE 6
CONDENSER PERFORMANCE

	Run 1		Run 2
Test Conditions			
Fan mode	67 full speed/2 off*		69 full speed
Gross generation (MW)	353		355
Net steam flow rate (lb/hr)	2,106,400		2,028,643
Exhaust pressure (in HgA)	8.66		8.3
Ambient temperature (°F)	77.7		80.0
Barometric pressure (in HgA)	25.8		25.8
Cross-wind speed (ft/sec)	10-18		10-18
Condenser Performance			
Condensate subcooling (°F)	1.22		0.75
Tested heat flow rate (MMBtu/hr)	2,086.7		2,009.0
Guaranteed heat flow rate (MMBtu/hr)	1,948.3		1,921.3
Performance factor	1,060		1,040
Average performance factor		1.055	
Fan Power Evaluation			
Tested fan power (hp)		7,347	
Guaranteed power (hp)		8,405	
Power requirement factor		0.875	
Evaluated Performance			
Composite performance factor		1.085	

*One 21-foot K-module fan off, and one 33-foot K-module fan off equivalent to two 21-foot fans off.

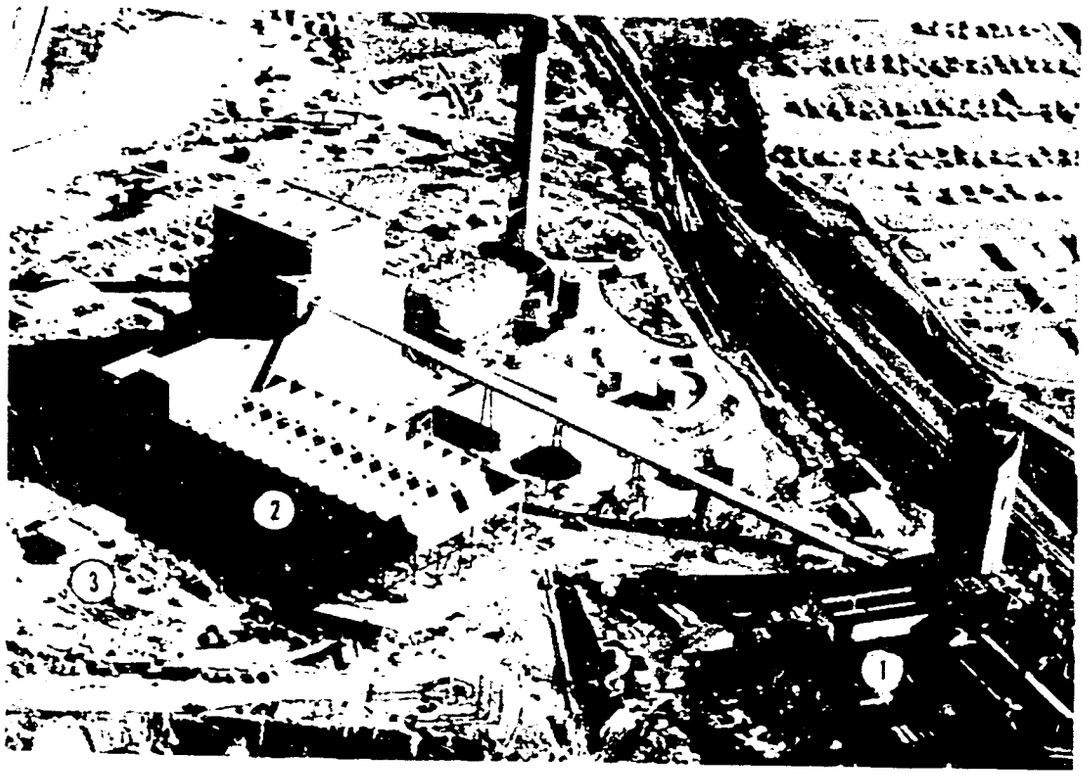

FIGURE 1
WYODAK STATION

STONE & WEBSTER

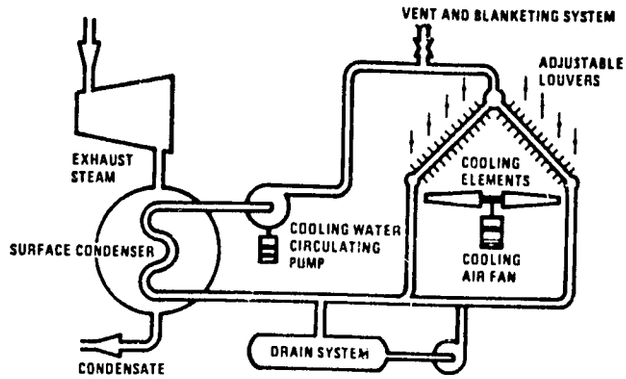

FIGURE 2A
INDIRECT AIR-COOLED CONDENSING SYSTEM

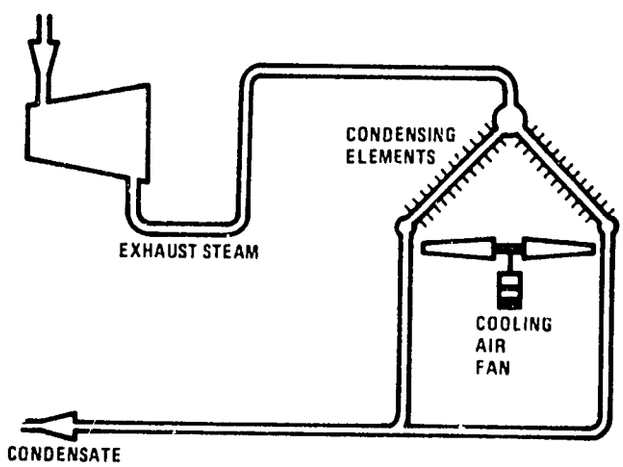

FIGURE 2B
DIRECT AIR-COOLED CONDENSING SYSTEM

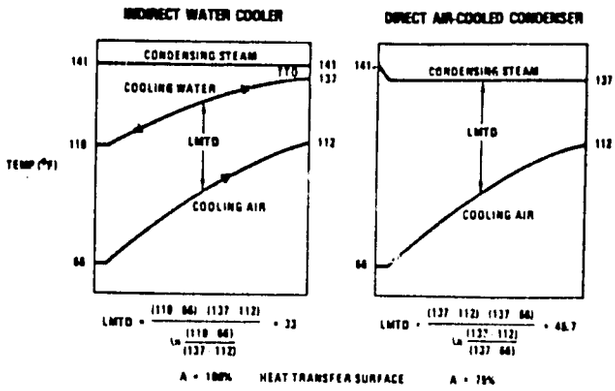

FIGURE 3
COMPARISON OF HEAT TRANSFER SURFACE WITH INDIRECT WATER COOLER AND DIRECT AIR-COOLED CONDENSER

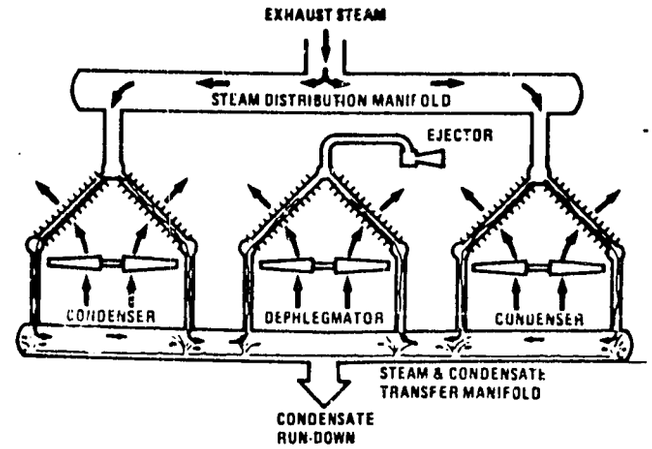

FIGURE 4
CONDENSER DEPHLEGMATOR ARRANGEMENT

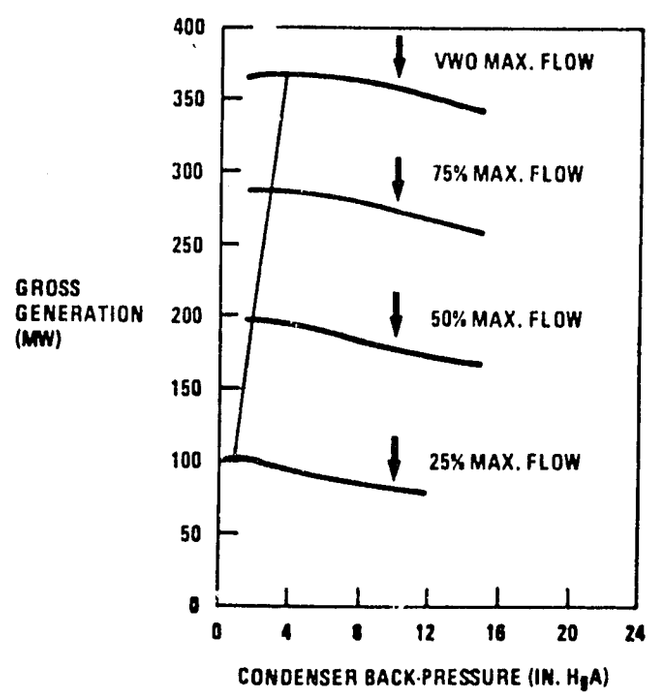

FIGURE 5
TURBINE GENERATOR BACK-PRESSURE CHARACTERISTICS

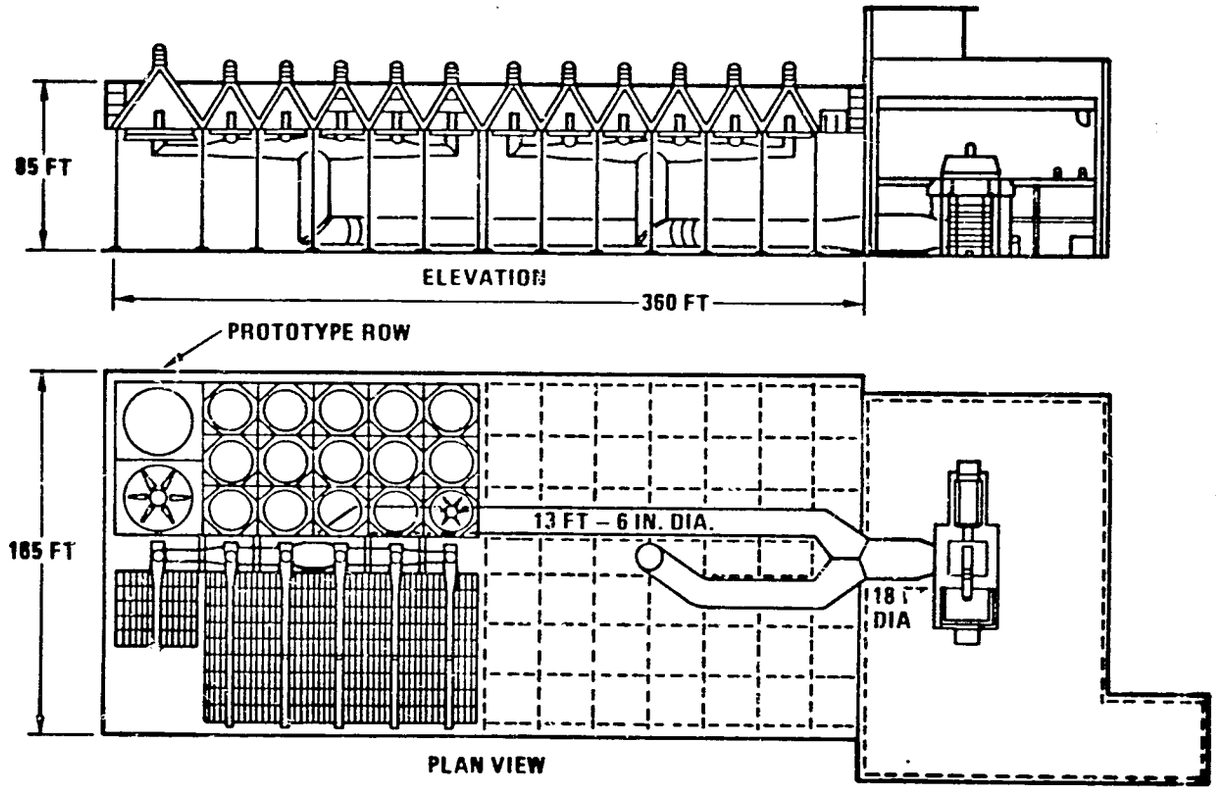

FIGURE 6

WYODAK AIR-COOLED CONDENSER ARRANGEMENT

STONE & WEBSTER

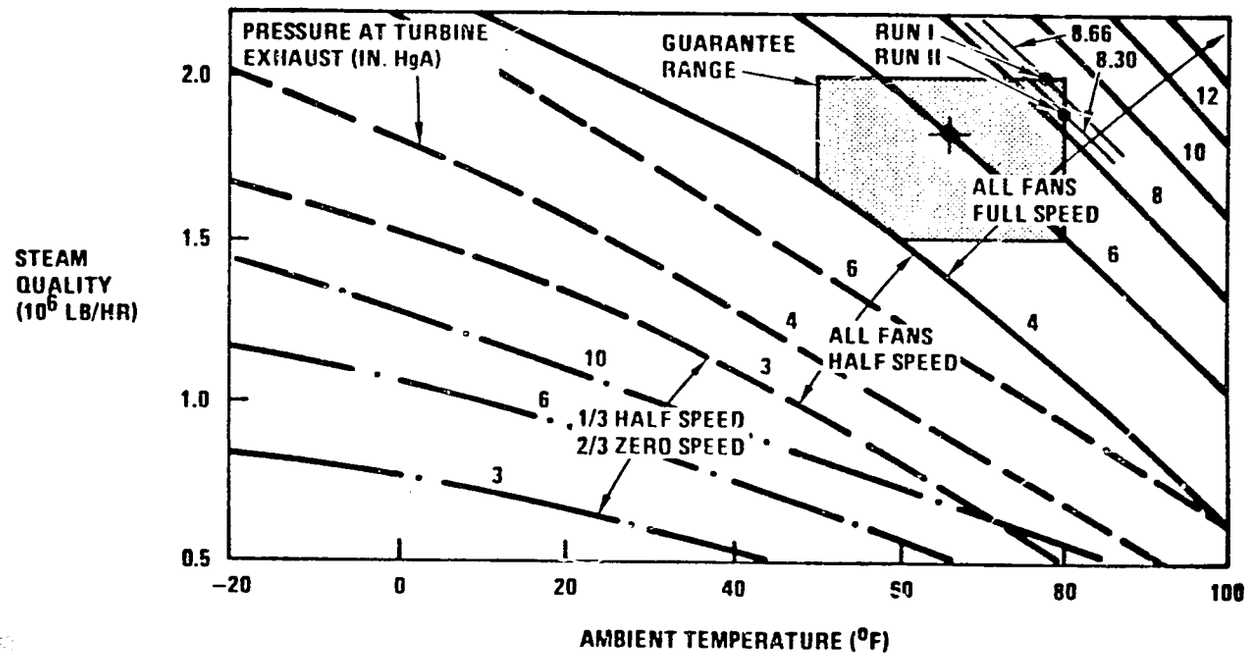

FIGURE 7

PLOT OF AIR COOLED CONDENSER PERFORMANCE

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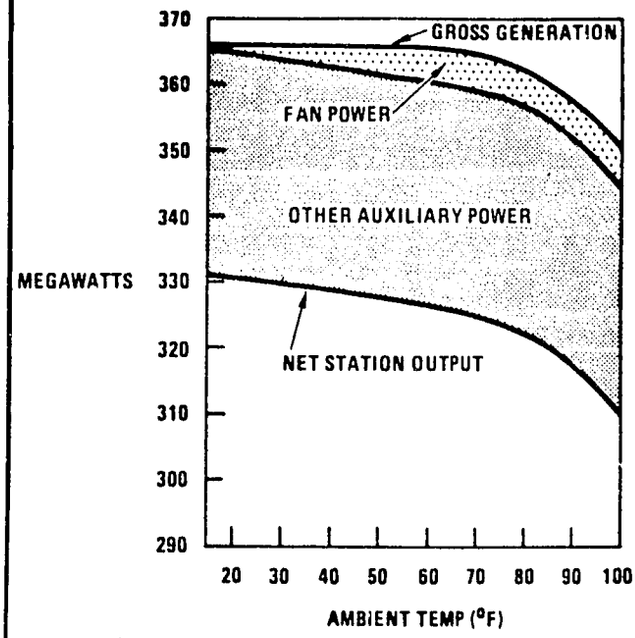


FIGURE 8
STATION OUTPUT VARIATION WITH AMBIENT TEMPERATURE

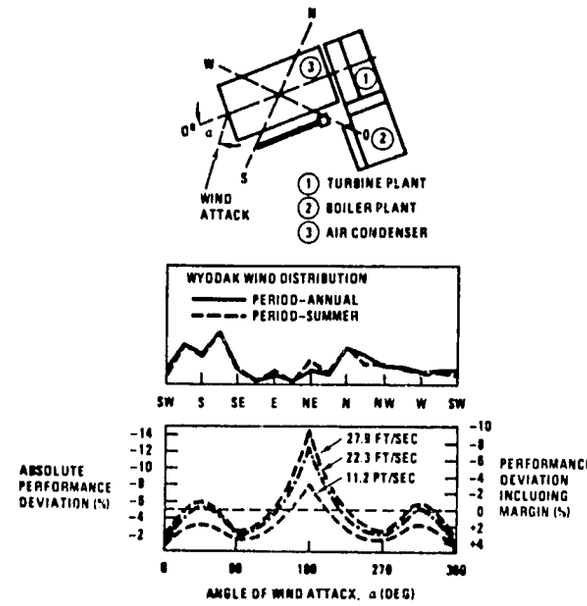
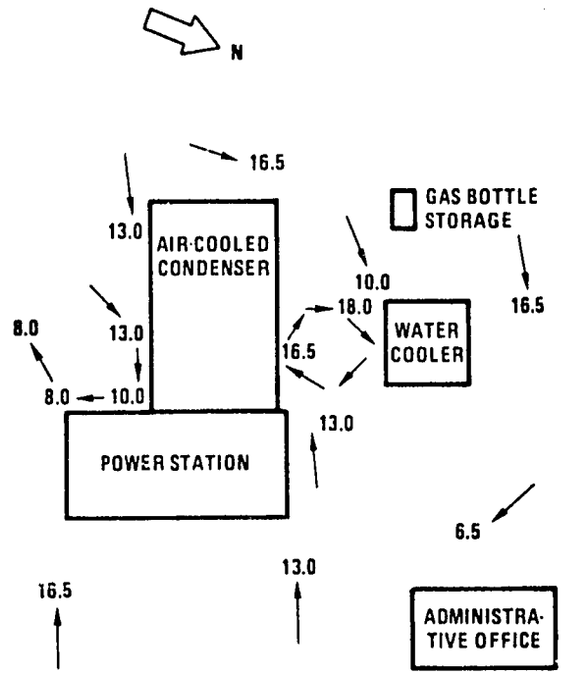


FIGURE 9
WIND INFLUENCE ON MODEL CONDENSER



NOTES:

VELOCITIES MEASURED AT 6 FT ELEVATION
VELOCITIES IN FT/SEC
MEASUREMENTS MADE SEQUENTIALLY

FIGURE 10
MEASURED WIND VELOCITY AND DIRECTION AT WYODAK

STONE & WEBSTER

FIGURE 11
OUTWARD AIR FLOW, UNDERNEATH CONDENSER
(LOCAL VORTICES)

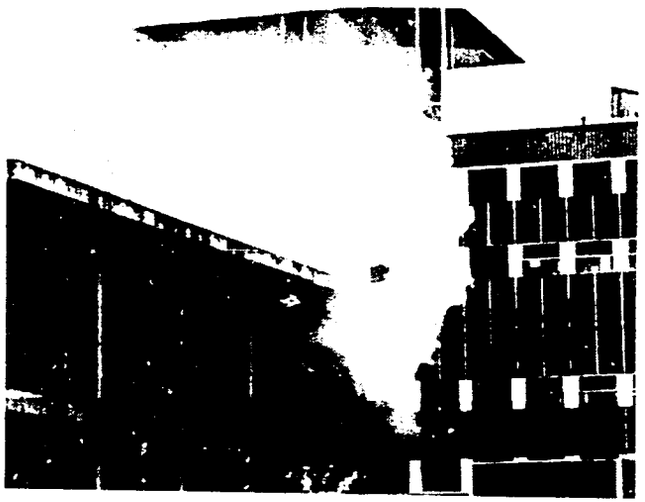


FIGURE 12
FULL SCALE AIR RECIRCULATION
EXPERIMENTS ON 120 M.W.
POWER STATION AIR-COOLED CONDENSER
(STRONG CROSS WINDS)

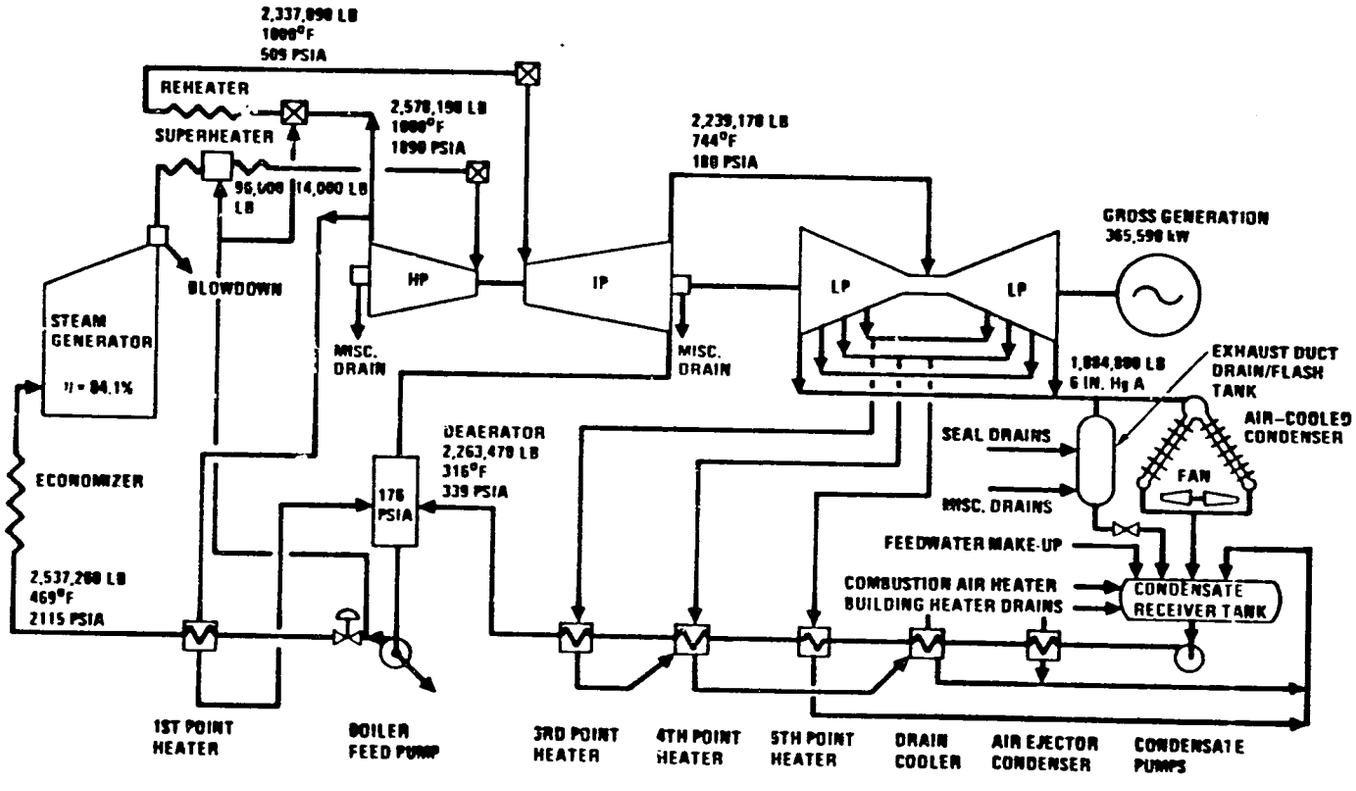


FIGURE 13

STEAM CYCLE DIAGRAM FOR TURBINE GUARANTEE
(VALVES WIDE OPEN AND 5% OVERPRESSURE)

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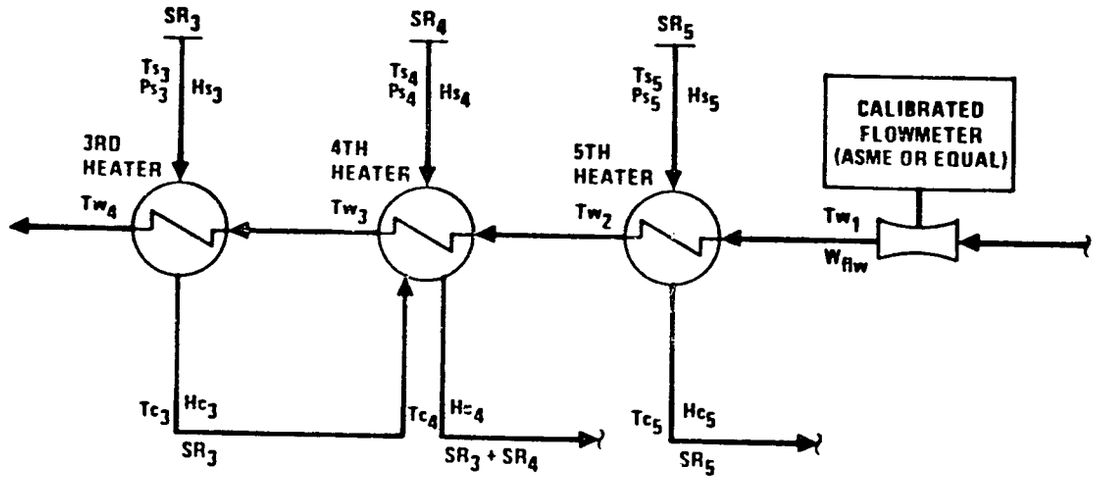

SR = STEAM RATE FROM EXTRACTION POINTS (LB/HR)
Hs = ENTHALPY OF EXTRACTION STEAM (BTU/LB)
Hc = ENTHALPY OF HEATER DRAINS (BTU/LB)
Tw = CONDENSATE TEMPERATURE (°F)

Ts = EXTRACTION STEAM TEMPERATURE (°F)
Tc = HEATER DRAINS TEMPERATURE (°F)
Ps = EXTRACTION STEAM PRESSURE (PSIA)
W_{flw} = CONDENSATE FLOW RATE (LB/HR)

FIGURE 14
HEAT BALANCE OF LOW-PRESSURE HEATER CYCLE DURING TEST

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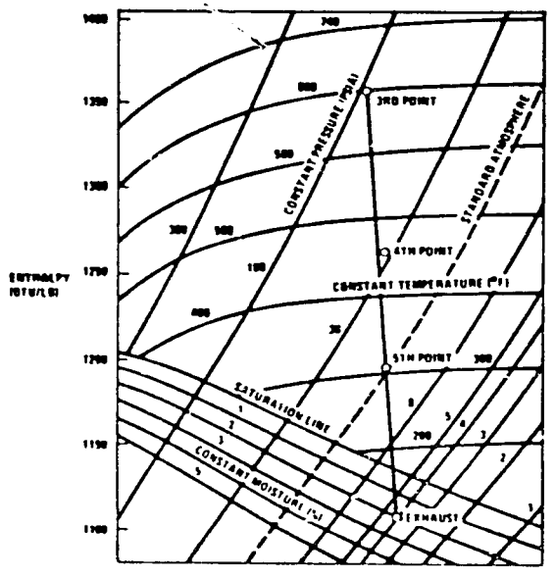

FIGURE 15
EXTRAPOLATION OF TURBINE EXPANSION
IN MOLLIER DIAGRAM FOR STEAM

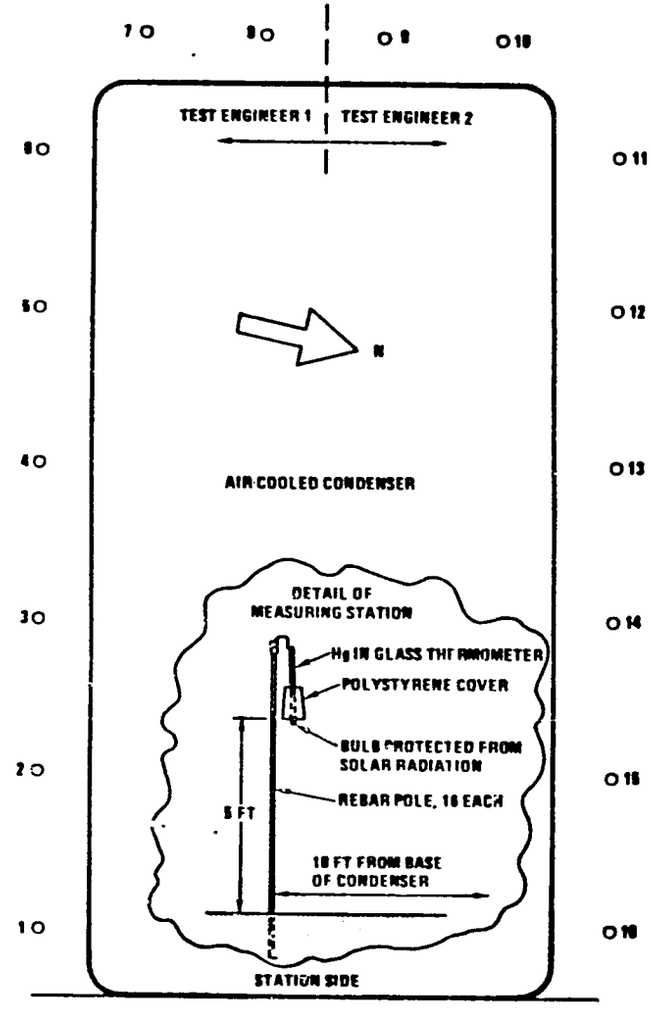

FIGURE 16
PLAN OF AMBIENT TEMPERATURE STATIONS

APPENDIX 14

RESULTS OF TESTS CONDUCTED ON RAW LAKHRA COAL SAMPLE

REPORT OF RESULTS
of the
RAW COAL SAMPLE
Submitted by
STONE & WEBSTER ENGINEERING CORP.
for the
Pakistan Project

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TABLE OF CONTENTS

Introduction & Procedure . . . . . I - II

Screen Analysis & Curve . . . . . 1 - 2
Raw Coal Analysis . . . . . 3 - 5
1.60 Float Fraction 6
1.60 Sink Fraction 7

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REPORT OF RESULTS
OF THE
RAW COAL SAMPLE
Submitted By
STONE & WEBSTER ENGINEERING CORP.
For The
Pakistan Project

Introduction

Commercial Testing & Engineering Company (CT&E Co.) was requested by Mr. D. Glanville Williams of Stone & Webster Company to perform various analyses on one raw coal sample submitted from the Pakistan project. The sample arrived at our Denver laboratory on December 6, 1982, and instructions were finalized on December 7, 1982.

Procedures

The procecures used to analyze the raw coal sample are outlined below.

The sample was first analyzed for size consist. All material greater than 2" was jaw crushed with the jaw opening set at 1 1/2". The total raw coal sample was screened over the following screen sizes:

Round Holes: 1 1/2", 1 1/4", 1", 3/4", 1/2", 3/8"
Tyler Mesh Series: 4, 8, 14, 28, 48, 100, 200

Thus, producing the following thirteen screen sized fractions:

1 1/2" x 1 1/4"	4 x 8
1 1/4" x 1"	8 x 14
1" x 3/4"	14 x 28
3/4" x 1/2"	28 x 48
1/2" x 3/8"	48 x 100
3/8" x 4	100 x 200
	200 x 0

The above size fractions were then recombined to produce the raw coal head sample. A representative portion of the head sample was properly prepared and a representative split was submitted to the laboratory for Proximate, Ultimate, Sulfur Forms, Ash Fusion (reducing and oxidizing atmospheres), Hardgrove Grindability Index, Mineral Analysis of the Ash, Equilibrium Moisture, and Trace Element (including Mercury and Fluorine).

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Upon determination of the % ash (as received) the remaining portion of the raw head sample (approximately 50%) was subjected to separation on organic liquids at the 1.60 specific gravity. Each of the sized gravity fractions was properly prepared with representative splits submitted to the laboratory. The 1.60 float fraction received a Proximate, Ultimate and Ash Fusion (reducing and oxidizing atmospheres). The 1.60 sink fraction received a Short Proximate analysis.

All pertinent data and analytical results developed by the above outlined procedures are hereby respectfully submitted and are part of this report.

Respectfully Submitted,

COMMERCIAL TESTING & ENGINEERING COMPANY

James L. Kendrick

James L. Kendrick
Manager, Denver Division

JLK/lm

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GAIL D. PALMER
DIRECTOR
WESTERN REGION

PLEASE ADDRESS ALL CORRESPONDENCE TO:
10775 EAST 51st AVE., DENVER, CO 80239
OFFICE TEL. (303) 373-4772

STONE & WEBSTER ENGINEERING CORP.
Greenwood Plaza
P.O. Box 5406
Denver, Colorado 80217

January 4, 1983

Sample identification by

Kind of sample reported to us: Coal

Stone & Webster Engineering Corp.

Sample taken at: Lakhra Project

Sample No. 20-10-82
Raw Coal Head Sample

Sample taken by: Stone & Webster Engineering Corp.

Date sampled: xxxxx

Date received: 12-6-82

Analysis report no. 72-125143 Page 1

SCREEN ANALYSIS

	PERCENT	ACCUMULATIVE PERCENT
RETAINED ON 1 1/2" ROUND, PASSING 2" ROUND	18.7	18.7
RETAINED ON 1 1/4" ROUND, PASSING 1 1/2" ROUND	15.8	34.5
RETAINED ON 1" ROUND, PASSING 1 1/4" ROUND	12.7	47.2
RETAINED ON 3/4" ROUND, PASSING 1" ROUND	10.6	57.8
RETAINED ON 1/2" ROUND, PASSING 3/4" ROUND	12.1	69.9
RETAINED ON 3/8" ROUND, PASSING 1/2" ROUND	7.0	76.9
RETAINED ON 4 MESH, PASSING 3/8" ROUND	7.5	84.4
RETAINED ON 8 MESH, PASSING 4 MESH	6.5	90.9
RETAINED ON 14 MESH, PASSING 8 MESH	3.5	94.4
RETAINED ON 28 MESH, PASSING 14 MESH	2.0	96.4
RETAINED ON 48 MESH, PASSING 28 MESH	1.4	97.8
RETAINED ON 100 MESH, PASSING 48 MESH	0.9	98.7
RETAINED ON 200 MESH, PASSING 100 MESH	0.9	99.6
RETAINED ON - - -, PASSING 200 MESH	0.4	100.0

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

James L. Kendrick

Manager, Denver Laboratory

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Charter Member

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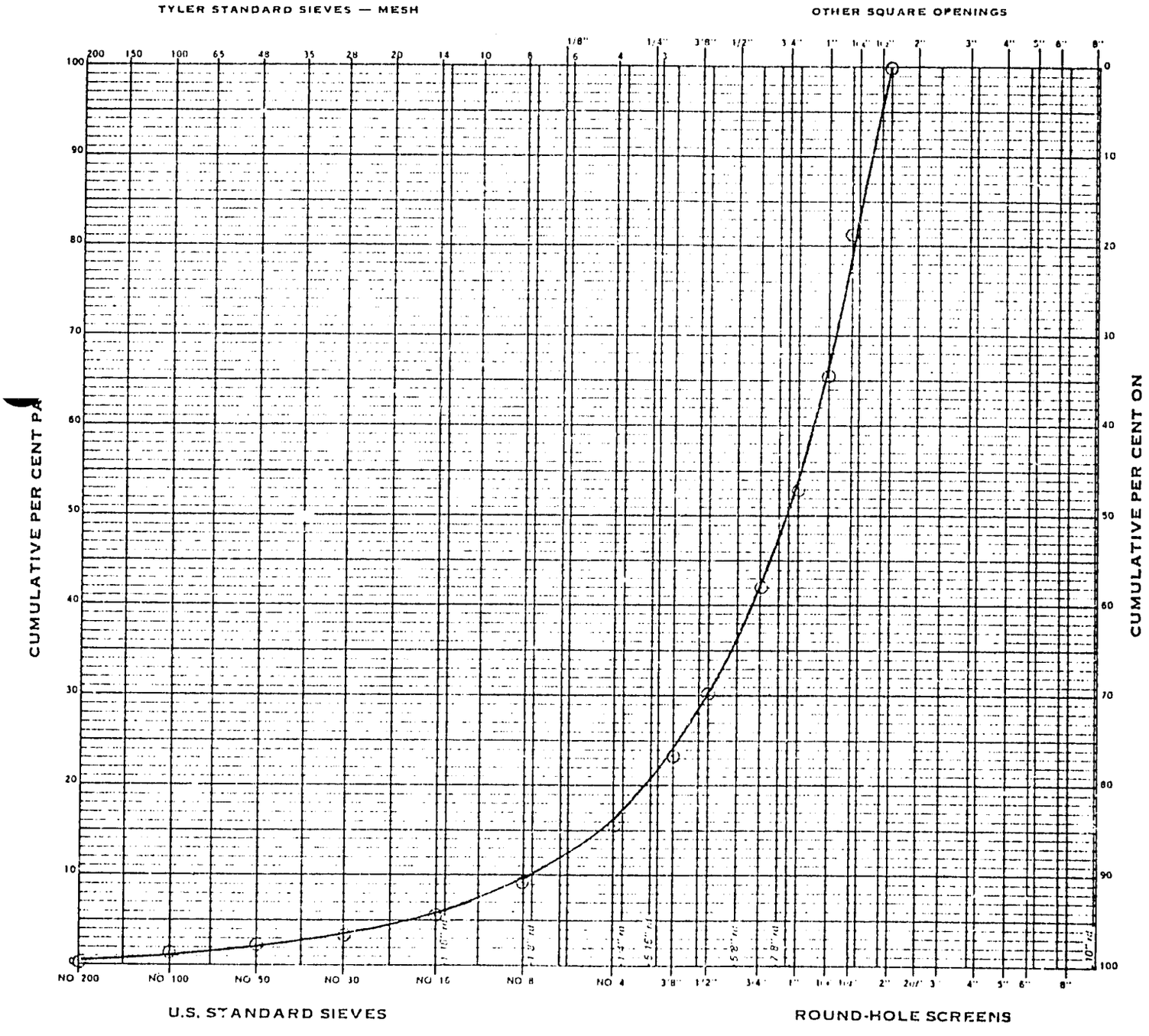
LAB NO. 72-125143 Page 2

IDENTIFICATION Sample No. 20-10-82
Raw Coal Head Sample

TOTAL WEIGHT OF SAMPLE 72 lbs.

SCREEN ANALYSIS CURVE



NOTE. SCREEN OPENINGS ON LOGARITHMIC SCALE WITH $\frac{\text{IN. RD.}}{\text{IN. SQ.}} = 1.25$

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STONE & WEBSTER ENGINEERING CORP.
Greenwood Plaza
P.O. Box 5406
Denver, Colorado 80217

January 4, 1983

Sample identification by

Kind of sample reported to us Coal

Stone & Webster Engineering Corp.

Sample taken at Lakhra Project

Sample No. 20-10-82
Raw Coal Head Sample

Sample taken by Stone & Webster Engineering Corp.

Date sampled xxxxx

Date received 12-6-82

Analysis report no. 72-125143 Page 3 Revised

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	24.03	xxxxx
% Ash	34.33	45.19
% Volatile	24.96	32.86
% Fixed Carbon	16.68	21.95
	100.00	100.00
Btu/lb.	4581	6030
% Sulfur	3.72	4.90

Moisture, Ash-free Btu = 11002

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	24.03	xxxxx
% Carbon	27.01	35.55
% Hydrogen	2.21	2.91
% Nitrogen	0.64	0.84
% Chlorine	0.29	0.38
% Sulfur	3.72	4.90
% Ash	34.33	45.19
% Oxygen (diff)	7.77	10.23
	100.00	100.00

SULFUR FORMS

	As Received	Dry Basis
% Pyritic Sulfur	2.34	3.08
% Sulfate Sulfur	0.30	0.40
% Organic Sulfur (Diff)	1.08	1.42
% Total Sulfur	3.72	4.90

FUSION TEMPERATURE OF ASH

	Reducing	Oxidizing
Initial Deformation	2670 °F	+2700 °F
Softening (H=W)	+2700 °F	+2700 °F
Softening (H=½W)	+2700 °F	+2700 °F
Fluid	+2700 °F	+2700 °F

HARDGROVE GRINDABILITY INDEX = 86.2 at 2.73 % Moisture

EQUILIBRIUM MOISTURE = 24.4

FREE SWELLING INDEX = xxxx

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Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

James I. Kendrick

Manager, Denver Laboratory

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Greenwood, Plaza
P.O. Box 5406
Denver, Colorado 80217

January 4, 1983

Sample identification by

Stone & Webster Engineering Corp.

Sample No. 20-10-82
Raw Coal Head Sample

Kind of sample reported to us: Coal

Sample taken at: Lakhra Project

Sample taken by: Stone & Webster Engineering Corp.

Date sampled: xxxxx

Date received: 12-6-82

Analysis report no. 72-125143 Page 4 Revised

MINERAL ANALYSIS OF ASH	Percent Weight Ignited Basis
Silica, SiO_2	48.45
Alumina, Al_2O_3	27.11
Titania, TiO_2	2.50
Ferric oxide, Fe_2O_3	11.93
Lime, CaO	1.49
Magnesia, MgO	1.24
Potassium oxide, K_2O	0.73
Sodium oxide, Na_2O	1.04
Sulfur trioxide, SO_3	2.91
Phos. pentoxide, P_2O_5	0.09
Strontium Oxide, SrO	0.04
Barium Oxide, BaO	0.00
Manganese Oxide, Mn_3O_4	0.02
Undetermined	2.45
	100.00

Alkalies as Na_2O, Dry Coal Basis = 0.69
Silica Value = 76.77
Base: Acid Ratio = 0.21

Fouling Index = 0.2
Slagging Index = 0.1

ESTIMATED VISCOSITY at critical viscosity Temperature of >2900 °F = <75 Poises
T_{250} Temperature = 2697 °F

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

James I. Kendrick
Manager, Denver Laboratory

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WESTERN DIVISION MANAGER
[redacted]
GAIL D. PALMER

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STONE & WEBSTER ENGINEERING CORP.
Greenwood, Plaza
P.O. Box 5406
Denver, Colorado 80217

January 4, 1983

Sample identification by

Stone & Webster Engineering Corp.

Sample No. 20-10-82
Raw Coal Head Sample

Kind of sample reported to us	Coal
Sample taken at	Lakhra Project
Sample taken by	Stone & Webster Engineering Corp.
Date sampled	xxxxx
Date received	12-6-82

Analysis report no. 72-125143 Page 5 Revised

TRACE ELEMENTS

ELEMENT	CONC. PPM WT.	ELEMENT	CONC. PPM WT.	ELEMENT	CONC. PPM WT.
Uranium	3	Gadolinium	2	Yttrium	39
Thorium	8	Europium	0.8	Strontium	280
Bismuth		Samarium	4	Rubidium	15
Lead	6	Neodymium	20	Bromine	12
Thallium		Prsaeodymium	7	Selenium	10
Mercury*	0.13	Cerium	46	Arsenic	4
Gold		Lanthanum	73	Germanium	4
Platinum		Barium	190	Gallium	47
Iridium		Cesium	2	Zinc	26
Osmium		Iodine	0.8	Copper	120
Rhenium		Tellurium	1	Nickel	7
Tungsten	1	Antimony	0.3	Cobalt	13
Tantalum	4	Tin	6	Manganese	60
Hafnium	2	Cadmium	<0.6	Chromium	200
Lutetium	0.2	Silver	<0.2	Vanadium	890
Ytterbium	1	Palladium		Scandium	26
Thulium	0.1	Rhodium		Fluorine**	86
Erbium	1	Ruthenium		Boron	66
Holmium	2	Molybdenum	4	Beryllium	0.3
Dysprosium	3	Niobium	91	Lithium	11
Terbium	0.3	Zirconium	230		

- elements not reported <0.2 ppm weight
- Flameless Atomic Absorption
- *Specific Ion Electrode

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

James I. Kendrick

G. D. PALMER, Manager, Denver Laboratory

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Greenwood, Plaza
P.O. Box 5406
Denver, Colorado 80217

January 4, 1983

Sample identification by

Kind of sample reported to us Coal

Sample taken at Lakhra Project

Sample taken by Stone & Webster Engineering Corp.

Date sampled xxxxx

Date received 12-6-82

Stone & Webster Engineering Corp.

Sample No. 20-10-82

1.60 Float = 54.7 % (by weight)
*Total Moisture Taken From The Raw Coal Analysis
**Raw Coal Chlorine Analysis Used Due To Separation On Organic Liquids

Analysis report no. 72-125143-A Page 6

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture *	24.03	xxxxx
% Ash	13.79	18.15
% Volatile	30.86	40.62
% Fixed Carbon	31.32	41.23
	100.00	100.00
Btu/lb.	7911	10413
% Sulfur	3.76	4.95

Moisture, Ash-free Btu = 12722

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	* 24.03	xxxxx
% Carbon	44.44	58.50
% Hydrogen	3.27	4.31
% Nitrogen	0.92	1.21
% Chlorine	0.29	0.38 **
% Sulfur	3.76	4.95
% Ash	13.79	18.15
% Oxygen (diff)	9.50	12.50
	100.00	100.00

SULFUR FORMS

	As Received	Dry Basis
% Pyritic Sulfur	xxxx	xxxx
% Sulfate Sulfur	xxxx	xxxx
% Organic Sulfur (Diff)	xxxx	xxxx
% Total Sulfur	xxxx	xxxx

FUSION TEMPERATURE OF ASH

	Reducing	Oxidizing
Initial Deformation	2080 °F	2370 °F
Softening (H=W)	2130 °F	2430 °F
Softening (H=½W)	2170 °F	2500 °F
Fluid	2360 °F	2600 °F

HARDGROVE GRINDABILITY INDEX = xxxx at xxxx % Moisture

EQUILIBRIUM MOISTURE = xxxx

FREE SWELLING INDEX = xxxx

JLK/ap /lm

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COMMERCIAL TESTING & ENGINEERING CO.

James I. Kendrick

Manager, Denver Laboratory

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STONE & WEBSTER CORP.
Greenwood, Plaza
P.O. Box 5406
Denver, Colorado 80217

January 4, 1983

Sample identification by

Kind of sample reported to us: Coal

Sample taken at: Lakhra Project

Sample taken by: Stone & Webster Engineering Corp.

Date sampled: xxxxx

Date received: 12-6-82

Stone & Webster Engineering Corp.

Sample No. 20-10-82

1.60 Sink = 45.3 % (by weight)
*Total Moisture Taken From The Raw Coal Analysis

Analysis report no. 72-125143-B Page 7

SHORT PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	* 24.03	xxxxx
% Ash	56.37	74.20
Btu/lb	1598	2103
% Sulfur	4.19	5.52

Moisture, Ash-free Btu =	8151
Pounds of SO2 per 10^6 Btu =	52.50
Moist, Mineral matter free Btu * = (Based on as rec'd moisture)*	3771
Pounds of Sulfur per 10^6 Btu =	26.25

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Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

James I. Kendrick
Manager, Denver Laboratory

Charter Member

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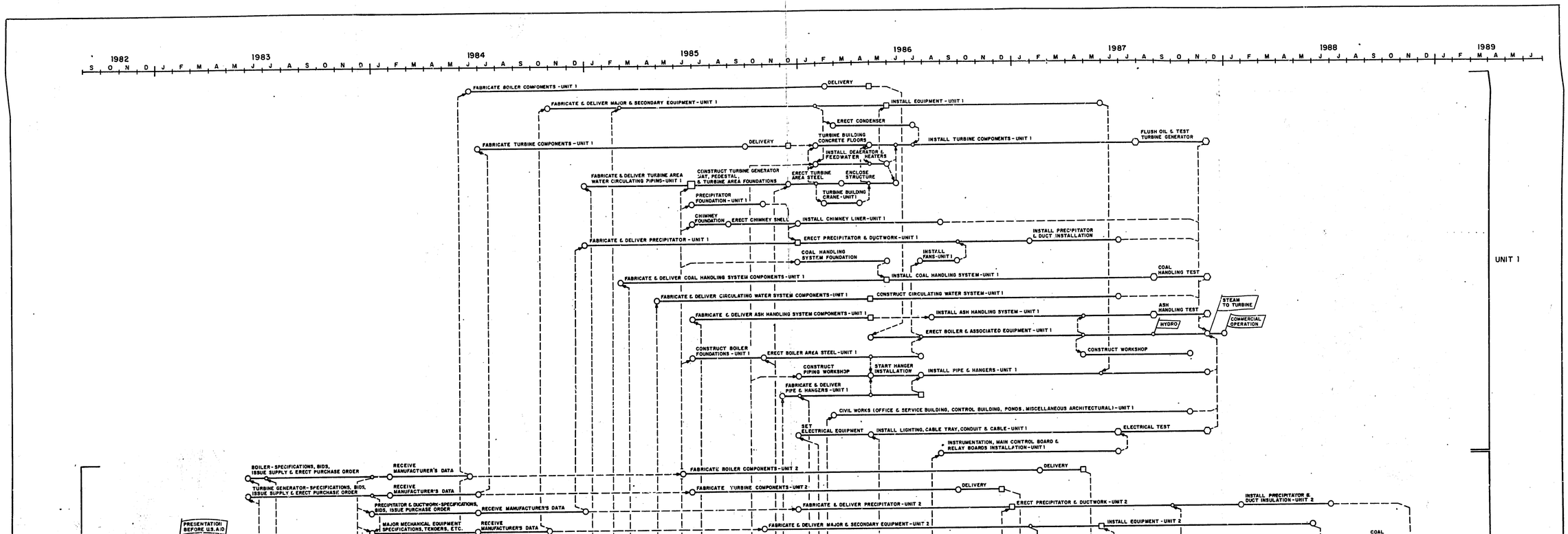
1982
1983
1984
1985
1986
1987
1988
1989
S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J
UNIT 1
FABRICATE BOILER COMPONENTS - UNIT 1
DELIVERY
FABRICATE & DELIVER MAJOR & SECONDARY EQUIPMENT - UNIT 1
INSTALL EQUIPMENT - UNIT 1
ERECT CONDENSER
TURBINE BUILDING CONCRETE FLOORS
FABRICATE TURBINE COMPONENTS - UNIT 1
DELIVERY
INSTALL TURBINE COMPONENTS - UNIT 1
FLUSH OIL & TEST TURBINE GENERATOR
INSTALL DEAERATOR & FEEDWATER HEATERS
FABRICATE & DELIVER TURBINE AREA WATER CIRCULATING PIPING - UNIT 1
CONSTRUCT TURBINE GENERATOR MAT, PEDESTAL, & TURBINE AREA FOUNDATIONS
ERECT TURBINE AREA STEEL
ENCLOSE STRUCTURE
TURBINE BUILDING CRANE - UNIT 1
PRECIPITATOR FOUNDATION - UNIT 1
CHIMNEY FOUNDATION
ERECT CHIMNEY SHELL
INSTALL CHIMNEY LINER - UNIT 1
FABRICATE & DELIVER PRECIPITATOR - UNIT 1
ERECT PRECIPITATOR & DUCTWORK - UNIT 1
INSTALL PRECIPITATOR & DUCT INSTALLATION
COAL HANDLING SYSTEM FOUNDATION
INSTALL FANS - UNIT 1
FABRICATE & DELIVER COAL HANDLING SYSTEM COMPONENTS - UNIT 1
INSTALL COAL HANDLING SYSTEM - UNIT 1
COAL HANDLING TEST
FABRICATE & DELIVER CIRCULATING WATER SYSTEM COMPONENTS - UNIT 1
CONSTRUCT CIRCULATING WATER SYSTEM - UNIT 1
FABRICATE & DELIVER ASH HANDLING SYSTEM COMPONENTS - UNIT 1
INSTALL ASH HANDLING SYSTEM - UNIT 1
ASH HANDLING TEST
STEAM TO TURBINE
HYDRO
COMMERCIAL OPERATION
ERECT BOILER & ASSOCIATED EQUIPMENT - UNIT 1
CONSTRUCT BOILER FOUNDATIONS - UNIT 1
ERECT BOILER AREA STEEL - UNIT 1
CONSTRUCT WORKSHOP
CONSTRUCT PIPING WORKSHOP
START HANGER INSTALLATION
INSTALL PIPE & HANGERS - UNIT 1
FABRICATE & DELIVER PIPE & HANGERS - UNIT 1
CIVIL WORKS (OFFICE & SERVICE BUILDING, CONTROL BUILDING, PONDS, MISCELLANEOUS ARCHITECTURAL) - UNIT 1
SET ELECTRICAL EQUIPMENT
INSTALL LIGHTING, CABLE TRAY, CONDUIT & CABLE - UNIT 1
ELECTRICAL TEST
INSTRUMENTATION, MAIN CONTROL BOARD & RELAY BOARDS INSTALLATION - UNIT 1
BOILER - SPECIFICATIONS, BIDS, ISSUE SUPPLY & ERECT PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
FABRICATE BOILER COMPONENTS - UNIT 2
DELIVERY
TURBINE GENERATOR - SPECIFICATIONS, BIDS, ISSUE SUPPLY & ERECT PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
FABRICATE TURBINE COMPONENTS - UNIT 2
DELIVERY
PRECIPITATOR & DUCTWORK - SPECIFICATIONS, BIDS, ISSUE PURCHASE ORDER
RECEIVE MANUFACTURER'S DATA
FABRICATE & DELIVER PRECIPITATOR - UNIT 2
ERECT PRECIPITATOR & DUCTWORK - UNIT 2
INSTALL PRECIPITATOR & DUCT INSULATION - UNIT 2
PRESENTATION BEFORE U.S. AID
MAJOR MECHANICAL EQUIPMENT SPECIFICATIONS, TENDERS, ETC.
RECEIVE MANUFACTURER'S DATA
FABRICATE & DELIVER MAJOR & SECONDARY EQUIPMENT - UNIT 2
INSTALL EQUIPMENT - UNIT 2
COAL

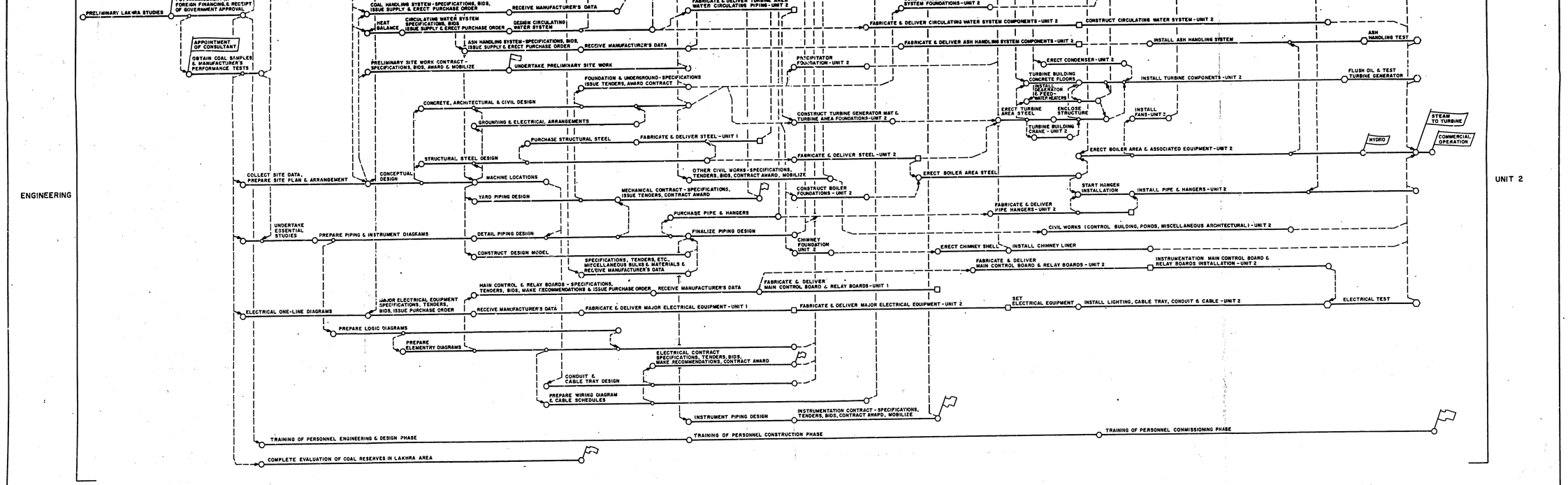

FIGURE 7-2
FIRST AND SECOND 300 MW POWER PLANTS
PROJECT SUMMARY NETWORK
LAKHRA COAL STUDY

PD-AAT-155
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