BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

Integ-Ebasco - Hat Creek Project - Air Quality Control Study -
October 1979

ENVIRONMENTAL IMPACT STATEMENT REFERENCE NUMBER: 29

B.C. Hydro & Power Authority

Hat Creek Project
Air Quality Control Study

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AIR QUALITY CONTROL STUDY

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A. SUMMARY

The purpose of this study is to identify and cost alternative methods of controlling particulate and sulphur dioxide emissions for the four 500 MW unit Hat Creek power plant. The levels to be met in the study are the upper and lower emission levels defined in the recently revised objectives of the Pollution Control Board (PCB) of British Columbia.

The study is required to be based on coal defined as "worst quality blended" of as-fired higher calorific value 12.21 MJ/kg (5250 BTU/lb) and 29% ash with 25% moisture.

The study concludes that electrostatic precipitators and wet flue gas desulphurization systems are the only methods of particulate and SO_2 emission control considered at present to be proven. These, and other methods considered close to this status, are listed in the following table which gives the associated differential of the capital costs, the capitalized operating and maintenance costs and the owning and operating costs. All differentials are relative to the base scheme utilizing electrostatic precipitators of 99.49% efficiency. Also listed in the table are combinations of particulate and SO_2 emission control equipment which the study indicates could meet the combined upper limits and the combined lower limits given in the PCB objectives.

Retrofitting a flue gas desulphurization system to units already equipped with suitable particulate control equipment raises the capital cost of the combined air quality control system by the order of 3 - 8% dependent on the selected combination.

B. DISCUSSION

The costs estimated in this study reflect the quality of coal used as a design basis and also the inclusion of spare flue gas desulphurization modules.

The coal quality used as a basis for calculations was specified by B.C. Hydro.

In conformance with normal industry practice a spare scrubber module is included in the flue gas desulphurization systems to permit full load operation during an outage of one module while maintaining conformance with the specified SO_2 emission levels.

Should SO_2 emission control equipment be retrofitted then the increased electrical auxiliary consumption would result in a reduction in the total net output of the power plant. For comparison purposes the retrofit alternatives considered in this study assume the power plant gross output (and therefore differential capital cost) is increased to maintain a constant total net output of 2000 MW.

It is also emphasized that only wet flue gas desulphurization systems can practically be retrofitted to a plant already utilizing electrostatic precipitators. If fabric filters are initially installed for particulate control with suitable provisions, then either wet or dry flue gas desulphurizations systems can feasibly be retrofitted.

	BASE	PARTICULATE CONTROL			SO_2 EMISSION CONTROL				COMBINED PARTICULATE & SO_2 EMISSION CONTROL				
		UPPER LIMIT	LOWER LIMIT		UPPER LIMIT		LOWER LIMIT		UPPER LIMITS			LOWER LIMITS	
PCB Objectives (lb/MBTU) Particulates Emission SO_2 Emissions	 - -	 0.09 -	 0.02 -	 0.02 -	 - 0.8	 - 0.8	 - 0.2	 - 0.2	 0.09 0.8	 0.09 0.8	 0.09 0.8	 0.02 0.2	 0.02 0.2
AQCS Equipment	ESP	ESP	ESP	FF	ESP + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Dry FGD	ESP + Partial Wet FGD	FF + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Wet FGD
Emissions (lb/MBTU) Particulates *Sulphur Dioxide*	 0.225 1.34	 0.09 -	 0.02 -	 0.02 -	 0.225 0.8	 0.035 0.8	 0.225 0.2	 0.05 0.2	 0.09 0.8	 <0.02 0.08	 0.035 0.8	 0.02 0.2	 <0.02 0.2
Differential Capital Cost (Including Incremental Capability) $ x 10^6 $/kW	 Base Base	 18 9	 40 20	 -(13) - (6)	 189 95	 126 63	 283 142	 199 100	 207 104	 176 89	 126 63	 323 162	 270 135
Differential Capitalized Operating & Maintenance Cost - $ x 10^6	Base	2	3	16	60	52	103	98	62	44	52	106	119
Differential Owning & Operating Cost Capitalized ($ x 10^6)	Base	20	43	3	249	178	386	297	269	252	178	429	389
Differential Mill Rate (mills/kWhr)	Base	0.2	0.5	0.03	2.7	1.9	4.2	3.0	2.9	2.73	1.9	4.7	4.23

NOTES:
- ESP = Cold Side Electrostatic Precipitators, FF = Fabric Filters
- FGD = Flue Gas Desulphurization
- Capital costs for the four unit plant are in October 1978 dollars excluding corporate overhead and interest during construction.
- Costs are based on originally fitted equipment - i.e. not retrofitted.

AIR QUALITY CONTROL STUDY

LIST OF EXHIBITS

HAT CREEK PROJECT

AIR QUALITY CONTROL STUDY

1.0 INTRODUCTION

In March 1979, revised draft pollution control objectives were issued by the POLLUTION CONTROL BOARD (PCB) of British Columbia. Subsequently, the B.C. HYDRO & POWER AUTHORITY requested INTEG-EBASCO to investigate air quality control system (AQCS) alternatives which meet these objectives, applied to the Hat Creek Project conditions.

During the course of preliminary engineering, the Hat Creek AQCS design has proceeded on the basis of the available PCB Objectives for other industries or on the basis of assumed levels. To date, the Project Base Scheme power plant incorporates cold side electrostatic precipitators (ESP) for control of particulate emissions, and space allowance for the future retrofitting of flue gas desulphurization (FGD) equipment should it become necessary for control of SO_2 emissions.

For coal fired plants the revised PCB Objectives prescribe very stringent ranges of emissions for particulates and SO_2. Exhibit 1-1 illustrates these ranges, the approximate AQCS removal efficiencies required to meet the upper and lower limits of the ranges referenced to worst quality blended coal, and the present Base Scheme powerplant emission levels.

This Report briefly reviews the major AQCS technology applicable to the Utility Industry, identifies a number of primary AQCS alternatives suitable for the combustion of "worst quality blended coal" in the four 500 MW unit Hat Creek power plant, and includes capital and operating costs for each. The alternatives are designated Group A or Group B. Group A applies to AQCS plant which would be installed with each power plant unit development, while Group B applies to the initial installation of particulate control equipment with later retrofitting of FGD equipment.

Within the constraints of the Study, the alternatives have been developed consistent with the Base Scheme design philosophies and costing structures. The Base Scheme component plant costs are used where possible and the cost contingency allowances are retained for consistency with the Base Scheme, notwithstanding a lower level of confidence and lesser degree of detailed definition. Other component costs have been derived from a number of sources, including in-house information related to vendor proposals received from recent investigations, or active projects. Vendors' proposals have also been received in response to specific ESP enquiries which include costs and opinions concerning problems and possible limitations associated with the revised Objectives.

The Report concludes with an assessment of flue gas conditioning (FGC); this is reviewed as a mechanism which could assist to improve the effectiveness of particulate precipitation and lead to an overall reduction of ESP system costs. An ESP-FGC combination has been included separate from the primary AQCS cases, since gas conditioning has mainly been used as a means to upgrade the performance of ESP equipment previously installed, rather than as an accepted method to be adopted at the outset of the AQC plant conceptual design.

Appendices to this report enumerate the US utility industry's and Ebasco Service Inc's experience with the air quality control systems and US installations of bag houses (fabric filters).

1.1 PCB OBJECTIVES

This Study is concerned with evaluating only the impact of the PCB emission levels on the Hat Creek Project with specific reference to particulates and sulphur dioxide emissions. The report does not study the significance of the opacity requirements of the Objectives.

For reference, the revised PCB Objectives from Table III - Gases and Particulate Emissions for Specific Processes, Coal Fired Boilers - are as follows:

PARAMETER	UNITS	RANGE	
Total Particulate	mg/kJ fuel	0.01	0.04
	$lb/10^6$ BTU fuel	0.02	0.09
Sulphur Dioxide	mg/kJ fuel	0.09	0.34
	$lb/10^6$ BTU fuel	0.2	0.8

The emission values are illustrated graphically in Exhibit 1-1 which also includes the Base Scheme having a particulate emission of 0.225 lb/MBTU and uncontrolled sulphur dioxide emission.

1.2 REFERENCES

1) B.C. Hydro & Power Authority letter to Integ Ebasco dated 15 May 1979 subject Hat Creek Project, Power Plant Air Quality.

2) Recommendations for the Design of an Electrostatic Precipitator - First and Final Report, Southern Research Institute, 2000 9th Avenue, Birmingham, Ala. 35205, SORIEAS77668 3923I & F.

3) Precipitator Study for the Test Burn of Hat Creek Coal at Alberta Power Ltd., Forestburg, Western Research and Development, Job 3462, Nov 77.

4) PilotScale Combustion Tests B.C. Hydro & Power Authority, Canmet Joint Program, Canadian Combustion Research Laboratory (CCRL), Energy Research Laboratories. Reports ERP/ER1 76/79, 101103, 105136, 138140, 142144, 146148, 150152, 154156, 158160, 162164, 166168, 170171, 77/1, 77/7.

5) PilotScale Combustion Tests with Hat Creek Coal, B.C. Hydro Canmet Joint Research Project, Canadian Combustion Research Laboratory Report ERL 7796 (TR), October 1977.

6) Flue Gas Desulfurization Study, Ebasco Services Incorporated, May 1977.

7) Integ-Ebasco S.D.M. Section 72.1-a Rev. 3 - Financial Criteria.

8) Integ-Ebasco S.D.M. Section 74.1-a Rev. 1 - Boiler Coal Consumption Rate, Ash and Emission Rates.

9) Integ-Ebasco S.D.M. Section 20.1-a Rev. 0 - Design Criteria for Cold Side Electrostatic Precipitator (without Flue Gas Conditioning).

10) Integ-Ebasco S.D.M. Section 5.92-a, Rev. 0 - Chimney Sizing.

11) Integ-Ebasco S.D.M. Section 5.92-b, Rev. 0 - Chimney Design and Construction.

12) Integ-Ebasco S.D.M. Section 8.5-c, Rev. 1 - F.D., I.D. and PA Fan Horsepower.

13) Integ-Ebasco S.S.D.M. Section 20.1-a Rev. 0 - Review of Technical Information Provided by Manufacturers of Cold Side Electrostatic Precipitators.

14) Integ-Ebasco S.S.D.M. Section 20.1-c Rev. 0 - Review of Technical Information Provided by Manufacturers of Fabric Filters.

15) Integ-Ebasco S.S.D.M. Section 20.2-a, Rev. 0 - Review of Technical Information on subject of Trace Element Removal by Wet Scrubbers Provided by Manufacturers.

16) Alternative "B" - Ash Disposal Study - Integ-Ebasco Study dated November 1978.

17) Integ-Ebasco S.D.M. Section 74.1-c, Rev. 1 - Boiler Particulate, SO_2 and NO_x Emission.

18) Air Quality and Climatic Effects of the proposed Hat Creek Project, Document P-5074-F, prepared by Environmental Research & Technology, Inc., April 1978.

1.3 SPECIFIC ASSUMPTIONS:

1) Coal Quality: Worst Blended -

HHV (as received)	12.21 MJ/kg (5250 BTU/lb)
Ash content	29% (as received)
Moisture content	25%

2) Flue Gas Flow corresponding to 105% Load (Turbine Valves Wide Open).

3) Inlet particulate loading: 80% total ash as fly ash.

4) Inlet SO_2 FGD loading: 0.6 mg/kJ (1.34 $lb/10^6 Btu$) based on 95% total S in coal (i.e. 5% S assumed removed with mill rejects and bottom ash).

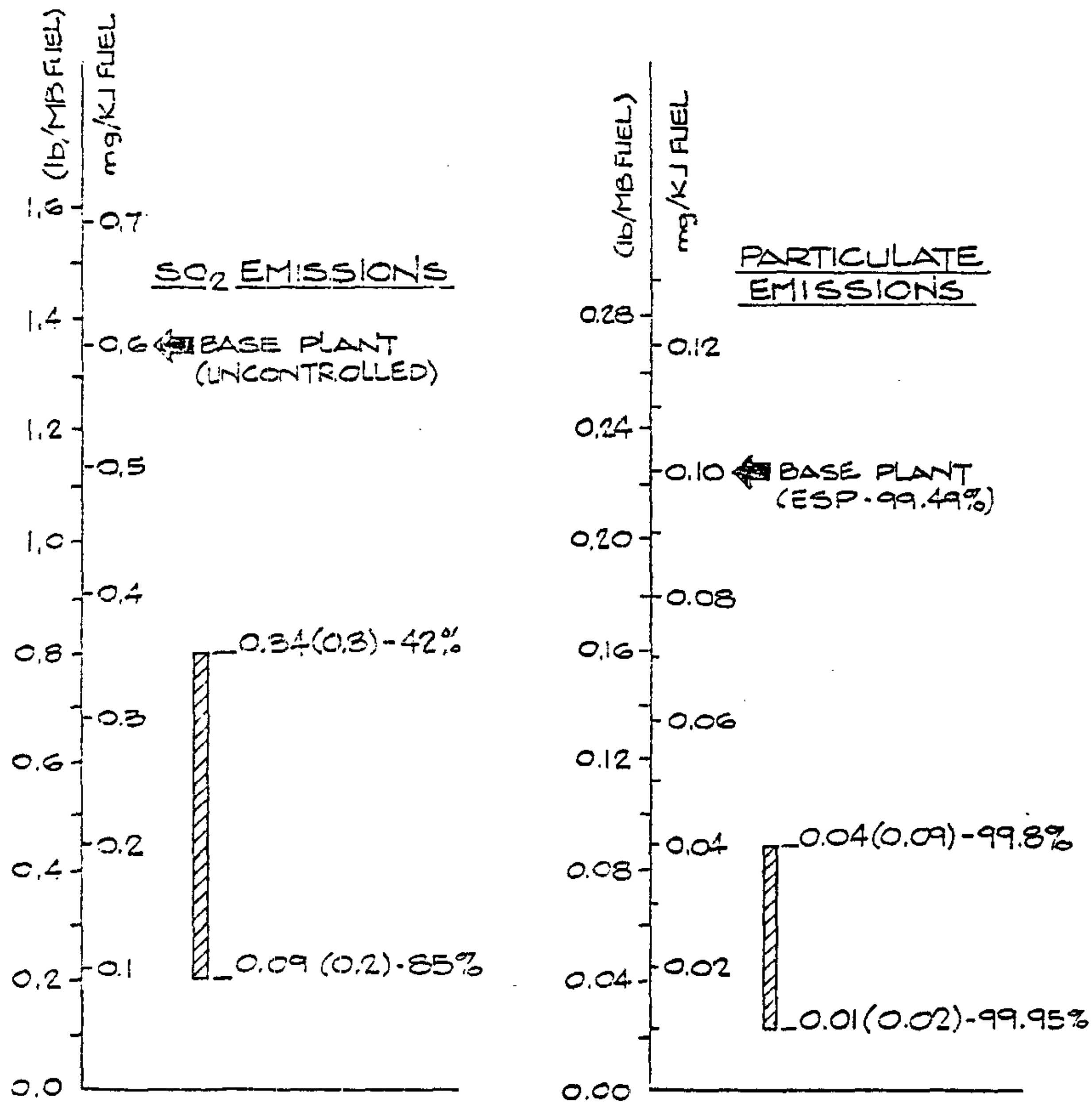
5) Base Scheme Precipitator Efficiency: 99.49%.

6) Base Scheme Precipitator Emission: 0.1 mg/kJ (0.225 $lb/10^6 Btu$ fuel).

EXHIBITS 1.0

Exhibit	
1-1	PROPOSED PCB OBJECTIVES EMISSION RANGES

HAT CREEK PROJECT
AIR QUALITY CONTROL SYSTEMS
(WORST BLENDED COAL)



PROPOSED PCB OBJECTIVES EMISSION RANGES

EXHIBIT 1-1

2.0 AIR QUALITY CONTROL REVIEW OF TECHNOLOGY

By mutual consent of B.C. Hydro & Integ-Ebasco, this study addresses means of meeting the PCB Objectives with, among others, ESP's and wet calcium based flue gas desulfurization (being the predominant technology in the industry) and also fabric filters and dry lime scrubbing (which would appear to offer economic advantages for low sulphur coal applications).

2.1 PARTICULATE CONTROL

A number of particulate control devices are employed by the Electrical Utility Industry for regulation of flyash emissions including mechanical dust collectors (MDC) of the multicyclone type, electrostatic precipitators, wet venturi scrubbers (WVS), and fabric filters (FF) i.e. baghouses.

Mechanical Dust Collectors

Mechanical dust collectors, which remove flyash by inertial impaction in multiple small cyclones, exhibit removal efficiencies of typically 60 to 85 percent at system pressure drops of about 1.0 kPa (4 in. Wg.). A MDC would normally be installed upstream of wet venturi scrubbers to collect part of the ash in dry form to simplify ultimate waste disposal.

Collection efficiency is sensitive to particle size of the inlet flyash and sequential stages of collection do not significantly improve the overall collection performance. Because of its inherently low efficiency, the mechanical collector alone cannot be employed to meet the current low levels of emission now commonly required by regulatory agencies.

Combination MDC and Particulate Removal Plant

In the 1950's and 1960's the industry used mechanical dust collectors as a pre-cleaning device installed ahead of the electrostatic precipitator to achieve overall removal efficiencies of up to 95 percent. The performance of both the MDC and the ESP is particle size dependent. Multiclone type mechanical dust collectors show low collection efficiencies of less than about 30 percent for particulates below 2 microns, and moderate efficiencies of 40 percent to 85 percent for intermediate particle sizes of 2 to 10 microns. The ESP exhibits a similar performance relationship of lower efficiency for the smaller particles and higher efficiency for larger particles.

The current permitted emission levels, calling for very high particulate removal efficiencies of 99 percent and greater, has necessitated a substantial increase in the size of precipitators to provide adequate removal of particulates 1 micron and below. The mechanical dust collector as a precleaning device would reduce large particle input to the ESP but would not appreciably reduce the input of small particles which is now the governing design criterion. Therefore no appreciable size reduction or significant cost savings for ESP plant could be anticipated. The use of MDC-ESP combinations has essentially disappeared and INTEG-EBASCO is not aware of any major utility which has incorporated this combination within the last 5 to 8 years.

The mechanical collector in combination with fabric filters is discussed in sub-section 3.2.2 of this Report where, for a high collection efficiency and high dust inlet loading, the mechanical collector would contribute to improve performance.

Wet Venturi Scrubbers

Wet venturi scrubbers remove flyash by high velocity impaction with water droplets, and have been applied in the Electric Utility Industry in combination with wet FGD systems. The inherent disadvantages of this technology include the need for alkaline reagent addition for chemistry control, extensive dewatering equipment if ash is to be used for land fill, and high fan horsepower to overcome the large nonrecoverable pressure drop required at the venturi throat.

For the typical range of removal efficiencies of 99.0-99.5 percent, pressure drops in the order of 3.23 to 6.22 kPa (13 to 25 in. Wg.) are to be expected. Although there is no generally accepted model for predicting scrubber performance, it is expected that substantially higher pressure drops would be required for efficiencies greater than 99.5 percent. This would greatly increase the potential for furnace implosion.

Wet scrubbing for particulate control represents a complex technology which is more difficult to successfully apply than alternative dry collection techniques. With the advent of lower regulatory emission limits in North America, it is expected that venturi scrubbers will be precluded from extensive further application within the industry.

Electrostatic Precipitators

Electrostatic precipitators have been the common method employed for the higher flyash removal efficiencies within the last decade; it is estimated that approximately 90 percent of all installations committed during this period employ precipitators.

The electrostatic precipitator enjoys wide acceptance in the industry and is considered to be a feasible method for meeting the upper FCB particulate emission Objectives. Meeting the lower emission objectives will require an extension to proven precipitator technology but Integ-Ebasco believe this will be achieved in the near future.

Fabric Filters

Fabric filter installations have been used by the utility industry for small units of less than 40 MW over the last 5 years. As a result of development work on fabric materials, many of these installations now show acceptable performance with respect to fabric life duration at low grain loadings. Collection efficiencies for this technology are typically in the range of 99.8 to 99.9 percent and, for certain flyashes which are difficult to collect by electrostatic precipitation, fabric filters can offer economic advantages over ESP's.

Fabric filters are viewed as an emerging technology which is possibly a technically feasible alternative to ESP's for the Hat Creek project and is accepted for this study as such. However, it is felt that a more definitive determination of feasibility would require an assessment of the initial operation of the larger fabric filter installations expected online in the 1979 to 1981 period in conjunction with bench or pilotscale tests of fabrics on the Hat Creek flyash to define the operating characteristics.

Others

In addition to the technology previously described, a number of other types have been applied in specific instances, or are being developed. These include such applications as wet electrostatic precipitators, electrical augmentation of venturi scrubbers, low energy foam scrubbers, mobile bed scrubbers, chemical conditioning of ash for ESP's, and high energy pre-ionization or pulsed ionization for ESP's. Although some of these processes have merit, they would generally require further technical development or pilot work specific to the Hat Creek coal before a sound assessment could be made. Also, suitable economic and operational reliability data is generally lacking.

Chemical conditioning of fly ash and ESP's are reported in section 5 of this study.

2.2 SULPHUR DIOXIDE CONTROL

Control of sulphur dioxide (SO_2) emissions by flue gas desulfurization (FGD) is more complex and project specific than flyash control and historically many more types of process or variants have been applied to control emissions. However, probably over 90 percent of all recent utility applications include some form of calcium-based wet absorption system in which the gas comes into direct contact with a lime or limestone slurry in an open spray tower absorber. SO_2 in the flue gas is absorbed by the slurry and forms calcium sulfite/sulfate salts. These calcium waste products are disposed of by ponding or by dewatering with subsequent landfill.

An alternative dry FGD system technology is being actively developed in which a lime slurry spray is introduced to remove SO_2 from the flue gas.

Although additional FGD processes and reagents have been proposed, tested, or are in the course of development, the two more common calcium-based technologies mentioned are selected for the purposes of assessing the impact of the revised PCB Objectives.

Wet FGD System

The wet FGD calcium absorption system is capable of providing SO_2 removal efficiencies typically in the range of 70 to 90 percent. Higher efficiencies have been obtained in specific cases. The technology has evolved to a greater degree than competing processes, but is subject to high cost, plant complexity, and operational difficulties. At present it represents the system with the greatest experience level and is therefore an acceptable candidate for controlling the SO_2 emissions of the Hat Creek plant.

Dry FGD System

With dry FGD systems, the flue gas contacts the lime slurry in a spraydryer type of down-flow vessel. The water content of the slurry is less than that necessary to achieve saturation, and the resultant calcium reaction products appear as a powder which is suitable for collection in a dry type particulate collection device such as a fabric filter. This system consequently results in a higher particulate inlet loading on the downstream particulate collection device, a factor detrimental in cases which are required to comply with very low particulate emission.

This process has yet to be fully assessed in operation on large utility units, but several large facilities are expected to be operational in 1980 and 1981. This process is considered to be an emerging technology in the Western United States as it gives indications of being economically more attractive than wet scrubbing, and the waste products are suited to dry disposal. Thus, although the technology has yet to be fully established for unit sizes comparable to the Hat Creek plant, the dry process is considered to be a suitable candidate for SO_2 removal and offers an alternative to the wet calcium scrubbing system.

3.0 AIR QUALITY CONTROL SYSTEM ALTERNATIVES

Certain air quality control technologies identified in Section 2.0 are considered to be suitable methods for the Hat Creek Project to control particulate and SO_2 emissions. These technologies include the use of electrostatic precipitators and fabric filters, and the dry and wet FGD processes. They are selected having regard for the present state of development and compatibility with the Hat Creek design. With the fabric filter and dry FGD systems, these emerging technologies have been selected in the expectation that favourable operating experience will shortly be available on a scale appropriate to the Hat Creek size of unit.

The particulate control and/or FGD processes have been arranged in various combinations of plant to produce eight primary alternatives or cases. The emissions correspond with the PCB Objectives upper or lower emission limits for SO_2 and particulates. The exceptions are Case 1, and Cases 7 and 8; Case 1 appies to the present Base Scheme particulate emissions (SO_2 uncontrolled), while the particulate emissions of Cases 7 and 8 are restricted when combined with fabric filters and result in values somewhat above the lower PCB emission limit. The emission data for the eight cases are presented in Exhibit 3-1.

Design and cost optimizations for the Power Plant - AQCS system combinations have not been performed. For example, an optimization of AQCS - Chimney combinations might produce ultimate design improvements and cost savings over the present four flue, single chimney design concept.

Design margins have been incorporated in the sizing of the main AQCS components e.g. ESP's, fabric filters, wet and dry scrubber modules. In addition FGD systems incorporate redundant modules to permit full load operation while maintenance is being performed.

The role of low sulphur coal and the necessity of the above margins and redundancies would require review when the power plant emissions specifically applicable to this project are established. Such a review should also consider the technical experience available at that time.

3.1 DEFINITION OF ALTERNATIVES

Two groups of AQCS alternatives are identified; the performance levels and block diagram plant arrangements are illustrated in Exhibits 3-1 and 3-2 respectively.

Group A Cases - Integrated Systems

The "A" group set of 8 cases presume that the particulate and SO_2 regulatory requirements would be in effect at the project commencement/approval stage, and that equipment would be installed concurrent with the power plant in an integrated mode. Cases 1A to 4A identify particulate control systems only, with SO_2 emissions uncontrolled. Cases 5A to 8A provide particulate and SO_2 control. Cases 1A (Base Scheme) to 3A incorporate electro-static precipitators; Case 4A includes fabric filters in combination with multi-cyclone mechanical dust collectors to reduce the inlet dust loading. Cases 5A and 6A identify partial and full gas wet scrubbing FGD options, each in combination with the Base Scheme 99.49% (Case 1A) electrostatic precipitator. Cases 7A and 8A identify partial and full gas dry scrubbing FGD options, each with the fabric filter - dust collector combination similar to Case 4A. Thus the "A" group of AQCS alternatives are complete and stand alone to provide various levels of particulate and/or SO_2 emission control.

Group B - Retrofit Systems

The "B" group set refers to AQCS plant adapted for the retrofitting of either wet or dry FGD options. The emission performance levels for the "B" group are the same as given for the "A" group except that the FGD options, Cases 5B to 8B, exclude particulate control systems. Thus the FGD options are "add-on" systems and must be combined with one of the particulate control cases, 1B to 4B.

Installing a total AQCS system in two stages (particulate control initially and FGD retrofitted) results in some technical changes & cost increases which are described in Section 4.2.

Other AQCS Alternatives

Further to the eight cases introduced under Group A with emission performance levels identified in Exhibit 3-1, other AQCS alternatives can be developed involving additional combinations of particulate and SO_2 emissions. The Base Scheme ESP in Case 5A or 6A, or the fabric filters in Case 7A or 8A, can be replaced with any one of the ESP's or the fabric filters respectively of Cases 1A to 4A. To a first order of accuracy, the costs of these new AQCS alternatives can be developed by adding the cost of the new particulate control system to - and deducting the original particulate system cost from - the appropriate Case, 5A through 8A. The costs of certain new alternatives involving ESP's and fabric filters, in combination with the wet scrubber cases only, are included in Section 4.0, Exhibit 4-8 and 4-9. The costs are presented in bar-chart form.

Likewise for the retrofit Group B cases where a particulate control system, Case 1B through 4B, can be added to an FGD system case, 5B through 8B, to produce other alternatives. The costs of these combinations have not been specifically included but the particulate and FGD component system costs of Exhibit 4-4 and 4-6 can be used in their determination.

Technical Summary of Alternatives

Design and performance parameters of the primary AQCS alternatives selected are presented in Exhibit 3-3.

3.2 DISCUSSION OF AQCS PLANT

This Section discusses specific operating and design considerations for the primary plant components incorporated in the AQCS alternatives. Since in most material respects the principal plant components in the "A" and "B" groups of alternatives are similar, references to cases are abbreviated to number indentification only except where specific distinctions are necessary.

3.2.1 Electrostatic Precipitators (Cases 1 to 3)

The present engineering for the Hat Creek project incorporates electrostatic precipitators which receive flue gas from the boiler air heater outlets. The precipitators discharge to induced draft fans and from there to an individual flue of a four flue common chimney. This chimney arrangement is maintained for all AQCS alternatives considered in this study.

This Base Scheme cold side precipitator design (Case 1) is based on receiving flue gas in accordance with the criteria specified in SDM 20.1 - a, Rev. 0. For this Study the criteria are modified by the relevant assumptions identified in Section 1.3 of this report. The precipitator design, based on the average of seven vendors' proposals, has a specific collection area (SCA) of 112.4 m^2/m^3/sec. (571 $ft.^2$/ 1000 acfm) for an expected particulate collection efficiency of 99.49% when firing worst quality blended coal.

To achieve higher precipitator collection efficiencies necessary for the lower emission levels of the PCB Objectives, higher SCA's are required. The design conditions for the case 2 and 3 particulate emission levels were presented to a number of vendors with requests for costs and opinions concerning possible problem areas which might be anticipated from the combination of higher efficiency precipitator performance requirements and the use of low-sulphur Hat Creek coals. The following reviews the vendors' responses.

For the Case 2 conditions, the required ESP performance efficiency of 99.8 percent was considered to be readily achievable, in combination with current good design practices to cater for the high inlet dust loadings. An extra field in the direction of gas flow was the general recommendation, although one proposal advocated a precipitator design of increased width and plate height.

For the Case 3 conditions, the required performance efficiency of 99.95 percent was received with reservations particularly concerning the difficulties and costliness of meeting the performance and maintaining this level during operation; however, the performance was generally considered to be technically achievable. One manufacturer (WHEELABRATOR CORPORATION) stated that the outlet dust loading is about the minimum level which can be guaranteed. It claims to have a number of major utility installations (e.g. American Electric Power) in the United States achieving lower outlet loadings but in combination with significantly lower inlet loadings.

JOY MANUFACTURING COMPANY has attempted to correlate the Hat Creek requirements with operational experience gained in Australia using coal of apparently similar precipitating characteristics. Its advice is that, although the performance is achievable with cold side precipitators, rapping losses or other causes of re-entrainment would result in non-compliance. From previous investigations for the Hat Creek project, JOY indicated at that time that the performance of a cold side ESP unit of 99.52% efficiency would be variable; from this it may be concluded that JOY would have significantly greater reservations with regard to the Case 3 conditions.

American Air Filter advise that the design of cold side electrostatic precipitators unassisted by flue gas conditioning (FGC) are uneconomic. Research Cottrell concur and believe that FGC should be utilized in the design of the precipitators for the case 3 alternative.

The vendors' information does not give good correlation concerning the number of additional fields required for the Case 3 conditions; quotations vary between one and four extra fields, in combination with variations in the heights and widths of collection plate designs to achieve the required collection areas. The width of precipitator will in practice be restricted to some degree by the proximity of neighbouring plant. Thus the length of the precipitators can be expected to increase accordingly.

For Cases 2 and 3, the average of three vendors' quotations for specific collection areas are tabulated, together with that for Case 1. For comparison, SCA values have also been estimated and included, based on SOUTHERN RESEARCH INSTITUTE (SRI) cold side precipitator design parameters.

CASE	EFFICIENCY	PRECIPITATOR SCA DATA m^2/m^3sec (ft^2/1000 acfm) ADJUSTED SRI	VENDORS' AVERAGE
1	99.49	91.9 (467)	112.4 (571)
2	99.8	126 (640)	158.8 (807)
3	99.95	198.8 (1010)	212.5 (1080)

The estimated SCA's, based on SRI design parameters, are minima and exclude a design margin allowance of 20 percent indicated by SRI in previous Hat Creek precipitator investigatory work. The average of Vendors' data has been used in this study.

Summarising, it is expected that the range of particulate emissions identified in the PCB Objectives can be met using electrostatic precipitators given that careful attention is paid to design and operation factors. The physical size, in combination with space restraints for the Case 3 units, has not been fully resolved. More detailed investigations of this aspect could lead to the exposure of additional plant complexity and costs which have not been allowed for beyond the cost contingency allowance of 15 percent incorporated in the AQCS equipment capital costs.

For the Cases involving ESP and wet FGD systems in combination, no allowance has been made for further particulate removal in the scrubbing process.

3.2.2 Fabric Filters (Case 4)

For Case 4 the arrangement of the plant elements is similar to that for the ESP cases except that fabric filters replace the ESP's. Due to the high inlet ash loading, it is provisionally considered that mechanical dust collectors would be required in order to pre-clean the gas and reduce the inlet dust loading to the fabric filters. This would reduce the inlet particulate concentrations to values which are regarded to be within the present experience of Industry, and at the same time would reduce the fall-out of coarser particulates in the horizontal inlet ductwork, reduce abrasion on inlet dampers, and lower the frequency of bag cleaning.

There is evidence, although by no means conclusive, that the collection efficiency of fabric filters is not strongly dependent upon particle size, and that pre-cleaning of the flue gas will lead to a reduced outlet loading from the filters. Typical efficiencies for fabric filters are in the range of 99.8 to 99.9 percent, therefore pre-cleaning appears to be essential for meeting the overall 99.95 percent performance level dictated by the PCB Objective lower particulate limit.

The effectiveness of pre-cleaning is accepted for this study as a valid approach for meeting the lower limit, with the understanding that confirmation from the results of pilot and/or bench scale tests on Hat Creek flyash will be necessary. Such tests should be conducted in the course of establishing the design criteria for filter efficiency and pressure loss.

The mechanical dust collector - fabric filter combination is substantially longer than the Base Scheme precipitator, thus the ID fans and chimney require to be moved further out. The system would incur an increased pressure drop in the order of 2.25 kPa (9 in. Wg) greater than the comparable ESP installation. The corresponding increase in ID fan power is taken into account in the operating and maintenance costs.

The above comments apply equally where the fabric filter particulate system is combined with one of the FGD processes. However, in the case of the fabric filter in combination with the spray dryer system (dry FGD) the mechanical collector would be located upstream of the spray dryers as noted in Exhibit 3-2, Sheet 4, Plant Arrangement Block Diagram.

3.2.3 FGD Systems - Wet Scrubbing (Cases 5 and 6)

The wet scrubbing system alternatives are essentially similar (Cases 5 and 6) differing mainly in the size of plant necessary to provide partial or full flue gas scrubbing. Flue gas leaves the particulate control system and passes to the FGD absorber modules for SO_2 removal with subsequent discharge to the chimney.

Reagent is delivered to the FGD modules in slurry form with preparation in a sub-system consisting primarily of dry storage silos, wet ball mills, slurry storage tanks and transfer pumps. Blowdown waste slurry is dewatered in gravity thickeners and vacuum filters, and is then blended with flyash and a small quantity of lime to produce an essentially dry product which can be handled by the dry ash conveying system incorporated in the project base plant design.

For Case 5 - partial wet scrubbing - 50 percent of the flue gas passes through the FGD absorber modules (2 operating plus 1 spare) having an 85 percent SO_2 removal efficiency, giving an overall efficiency of 42 percent relative to total gas flow. One half of the total gas flow bypasses the FGD modules at all times and re-combines with the treated flue gas at the downstream mixing chamber. For this case reheating of the flue gas is not required.

For Case 6 - full wet scrubbing - all the flue gas passes through the FGD absorber modules (3 operating plus 1 spare) to remove 85 percent of the SO_2. Hot air is injected into the treated flue gas in a downstream mixing chamber to raise the mix temperature above saturation and prevent water fall-out within the plant area. The FGD module facility is equipped with a full flow bypass for utilization during startup, shutdown or upset conditions; this bypass is not used under normal operating conditions.

With retrofitting (Cases 5B and 6B) the FGD absorber modules could be planned for locating beyond the chimney resulting in no major rearrangement of plant. As original or new plant, however, the modules would be placed ahead of the chimney for reasons of economy and convenience of layout.

The reagent handling and waste disposal facilities are common for all units and can be located remote from the scrubber modules.

3.2.4 FGD Systems - Dry Scrubbing (Cases 7 and 8)

The dry scrubbing process is capable of achieving an 85 to 90 percent SO_2 removal efficiency related to the portion of the flue gas treated. It is more commonly employed in combination with fabric filters.

For combinations of ESP and dry FGD systems, specific information has not been solicited from ESP vendors concerning the effect that this would have on the ESP design criteria or performance. With dry scrubbers installed upstream of the precipitators, the flue gas to the ESP will have experienced changes in temperature, moisture content, particle size distribution, ash resistivity, dust loading and volumetric flow rate. One manufacturer, BABCOCK & WILCOX, is known to be pursuing the ESP - dry FGD combination and, from pilot tests undertaken at Basin Electtric Utility, is indicating that precipitator sizing remains the same. This apparently fortuitous combination of changes in gas conditions as to cause no modifications to ESP performance requires further verification.

Whereas the approximate costs for this combination can be inferred from the tables (Exhibits 4.0) Integ-Ebasco consider that full scale operational experience and additional investigation into the precipitator design aspects to be necessary. Until such factors are satisfied the combination cannot be treated with the same degree of technical confidence as the dry scrubber - fabric filter combination.

The dry scrubber system is located upstream of the particulate control device. For combination with fabric filters typified by Cases 7A and 8A, the spray dryer vessels would be located between the mechanical collectors and filters.

The mechanical collectors remove an estimated 85 percent of the particulates. The lime slurry injected in the spray dryers reacts with the SO_2 to produce calcium sulphite and sulphate in a dry powder form; the reaction is considered to occur during or shortly after evaporation of the injected slurry water. The fabric filters receive the flue gas leaving the spray dryers to remove the calcium salts and further fly ash quantities.

The waste material from fabric filter hoppers is in dry form and can be pneumatically conveyed to a central location for disposal via belt conveyors, which is consistent with the Base Plant dry ash disposal scheme.

The combined system of mechanical dust collectors, spray dryers, and fabric filters is substantially larger than the Base Scheme plant, requiring relocation of the chimney.

For Case 7 approximately 50 percent of the flue gas must be treated to achieve the upper PCB emission limit for SO_2 of 0.34 mg/kJ (0.8 lb/MB). The remaining 50 percent is bypassed and re-mixed with the spray dryer exit gas prior to the fabric filters. The mixed gas temperature would be approximately 110°C (230°F). With a constant fabric filter design criteria air-to-cloth ratio of 0.01 $m^3/sec/m^2$ (2 $acfm/ft^2$), the effect of the lower gas inlet temperature is to reduce the filter size required by approximately 5 percent compared with the Case 4 fabric filter (particulate control only).

For Case 8 all flue gas must be treated in order to achieve the lower PCB limit for SO_2 of 0.09 mg/kJ (0.2 lb/MB). The spray dryer facility is equipped with a by-pass for start up, shutdown and upset conditions but is not used during normal operation. The filter inlet gas temperature would be approximately 77°C (170°F) resulting in a filter some 10 percent smaller than for the Case 4 condition.

The generation of calcium salts in the fly ash increases the dust loading to the filters which has an adverse effect on the efficiency of particulate removal. For both Case 7 and 8 it is expected that this will prevent the lower PCB particulate limit from being attained. The predicted particulate emissions corresponding to Case 7 and 8 (with fabric filters) are 0.015 mg/kJ (0.035 lb/MB) and 0.02 mg/kJ (0.05 lb/MB) respectively.

Dry FGD Lime Utilisation

The inputs of lime and water to the spray dryers must be separately adjusted to provide correct stoichiometry and temperature. Both lime utilisation and SO_2 removal effectiveness are improved at lower temperatures so that the water content is increased beyond slurry composition requirements in order to achieve this condition. The expected gas operating temperature in the spray dryers is 77°C (170°F) or about 17°C (30°F) above the water dew point. This temperature is low enough to achieve better utilisation of lime but high enough to avoid possible dew point problems in the downstream fabric filters.

Dry FGD systems have demonstrated high lime use during pilot testing with stoichiometric ratios of 2 or greater being realised for the higher removal efficiency levels of 85 to 90 percent. Recycling of unreacted lime reagent from the fabric filter hoppers back to the spray dryers has been proposed as one method of reducing lime consumption. Although this increases the complexity of the overall process, Cases 7 and 8 have incorporated this probable near-term process development feature; improvements in stoichiometry to the 1.1 to 1.4 level, based on inlet SO_2, are expected.

For recycling of unreacted reagent, a portion of the fabric filter hopper contents is pneumatically conveyed to the reagent preparation area and blended with the lime slurry in mixing tanks at the slaker discharges. The use of mechanical dust collectors provides an additional advantage by reducing the burden of inert fly ash (due to low calcium content) which must be recycled through the spray dryers along with the unreacted lime.

3.3 OTHER FGD RELATED FACTORS

This Section discusses other factors related to the incorporation of FGD systems, including: reagent properties, availability and cost; FGD sludge as a by-product; and chimney design considerations.

3.3.1 Reagents

FGD systems consume substantial quantities of reagents in the process of removing SO_2. Depending on the particular process these reagents chemically combine with SO_2 and reappear as either a dry or wet waste product. Further treatment of the wet FGD scrubber waste product (sludge) makes it suitable for dry disposal, using the Base Scheme dry ash disposal system.

In view of the large quantities of reagents required for the Hat Creek Project, the respective sources of reagent, costs, availability and quality are important factors. The following reports briefly on the pricipal findings of investigations into these factors which are tabulated in Exhibit 3-4.

The three more common chemical reagents used with desulphurization processes are soda ash (sodium carbonate), limestone and lime. Either soda ash or lime can be used for SO_2 adsorption in the dry FGD process (Cases 7 and 8). Lime could also be used for SO_2 absorption with wet FGD systems but this application has generally been limited to high sulphur coals. Lime is also used as an additive for waste stabilization with wet limestone FGD systems.

The primary commercial source of soda ash in North America is Green River, Wyoming, and the lowest quoted delivered bulk price to Vancouver is approximately \$143/tonne (\$130/ton);

with final transportation to site, the price of soda ash is estimated to be about $150/tonne ($136/ ton).

The ready availability of lime from the Pavilion Lake lime plant close to the Hat Creek site, will depend on the quantity required which is, in turn, dependant upon the FGD alternative ultimately selected. It is understood with present supply commitments, that additional kiln facilities will be required to meet the demand for lime arising with Cases 6, 7 or 8. Up to 2 years advanced notice may therefore be necessary. For lime the delivered price F.O.B. site is approximately $53/tonne ($48/ton).

The significant price difference between soda ash and lime effectively limits the use of sodium reagents to Wyoming and adjacent States.

Limestone for the wet FGD process is available in sufficient quantities from the Pavilion Lake plant. The delivered price is approximately $10/tonne ($9.15/ton) for a product size of 9 mm (3/8 in) minus, or $16/tonne ($14.60/ton) for a product 50 mm x 9 mm (2 in. x 3/8 in). The 9 mm minus size is suitable for the SO_2 removal process. Particle size reduction with 70 percent of particles passing through a No. 200 Mesh provides good reactant surface area and scrubber performance and grinding at the power plant is considered likely to be the most economical choice.

Reagent Quality

The following typical compositions of lime and limestone have been reported applicable to the Pavilion Lake Lime Plant:

Limestone (%)		Lime (%)	
CaO	54.5	Total CaO	95.0
MgO	0.2	MgO	0.5
Silica	0.4	SiO_2	0.3
R_2O_3	0.2	R_2O_3	0.8
L.O.I.	42.7	L.O.I.	0.9
Others	2.0	Others	2.5
	100.0		100.0

(L.O.I. - Loss on Ignition)

These are typical high calcium products which are generally acceptable for wet scrubbing processes. The major requirement for limestone is a low dolomite ($CaCO_3 \cdot MgCO_3$) content as this is non-reactive for SO_2 removal. Other constituents may require checking for their effect on the FGD process.

The costs used in this study are those for reagent supply from the Pavilion Lake Lime Plant, which are assumed to be suitable for the FGD process alternatives.

3.3.2 FGD Waste By-Product Utilisation

There are several possible uses for the anhydrous calcium sulphate produced by full wet FGD scrubbing at an approximate rate for the plant of 160,000 Mg/year (176,000 Tons/year).

The possibilities are very site specific and this study does not address their feasibility or potential. Cost credits for the product have therefore not been applied.

3.3.3 Chimney Design Considerations

The chimney design incorporates a single concrete shell with four independent mild steel liners which is considered to be satisfactory for all but the wet scrubber cases. Mild steel liners are common within the Industry and provide adequate protection against acid corrosion when the flue gas is above, or not substantially below, the acid dew point. These conditions normally exist with dry particulate collection and also with semi-dry FGD processes. The acceptance of mild steel for the latter case is evidenced by the exclusive use of mild steel construction for components such as spray dryer vessels, and fabric filter casing and tube sheets, which are in direct contact with the gas stream.

With the wet FGD process, not only SO_2 is removed but also about 50 percent of the SO_3 in the treated gas stream is believed to be removed. A reduction in SO_3 lowers the sulphuric acid dew point, which is typically 121 to 149°C (250°F to 300°F) in the FGD inlet gas, by 14 to 28°C (25°F to 50°F). Since it is not generally economically feasible to reheat flue gas after the wet process to the level of 107 to 135°C (225°F to 275°F) in order to avoid acid condensation, operation below the acid dew point is accepted and steps must be taken to protect the chimney liner from corrosion.

Most of the early attempts at corrosion protection involved the application of thin film (30 to 60 mills) coatings of flake glass-filled epoxy or vinyl esters. Many of these applications have failed due to poor quality control during coating or from chemical attack at gas temperatures above the water dew point [about 55°C (130°F)] but below the sulphuric acid dew point. Organic coatings containing flake glass are no longer recommended by the major chimney manufacturers for corrosion control and these products are not generally guaranteed by the coating manufacturer for this application. The use of a new type of thin film coating, a fluoro-elastomer by PULLMAN-KELLOGG, shows superior chemical resistance and has received limited attention in the United States. However, the cost of this coating is about 377 to 430 $\$/m^2$ (35 to 40 $\$/ft.^2$), which is comparable to the entire chimney cost and would therefore appear to be limited to "last resort" retrofit applications.

The current recommendation by the major chimney manufacturers is to use acid-resistant brick and mortar construction with a pressurized annulus to prevent exfiltration of gas through mortar cracks. The manufacturers indicate that this type of design is representative of 90 percent of the chimneys sold in the last several years for use with wet FGD systems.

For these reasons, a brick lined chimney has been selected for the wet scrubbing systems, Cases 5 and 6.

Brick liners cost about 10 percent more than mild steel liners, however they would be about 5 percent less than mild steel using a lower cost casing.

Although the brick liner offers good acid attack resistance it should not be considered the "universal" liner material suitable for all applications. Acid resistant mortars do not perform well under alkaline conditions in the presence of sodium, and are not recommended for use after dry scrubbing systems employing a sodium reagent. This factor dictates that a decision regarding the use of a sodium reagent for dry scrubbing must be confirmed prior to commitment to a specific liner material.

Chimney costs relating to liner, external shell, and foundation, have not been adjusted for the effects of reduced gas flow volume and plume buoyancy resulting from FGD system operation.

EXHIBITS 3.0

HAT CREEK PROJECT

SUMMARY OF AQCS ALTERNATIVES - A GROUP

PLANT EMISSIONS AND ARRANGEMENT DATA

(Worst Quality Blended Coal)

	SO_2 CONTROL		PARTICULATE CONTROL		BLOCK[1] PLANT ARRGT.
	mg/kJ (lb/MB)	%	mg/kJ (lb/MB)	%	
<u>PARTICULATE REGULATION</u>					
(SO_2 emission uncontrolled)					
Case 1A - (Base Scheme) Electrostatic Precipitor	0.58 (1.34)	-	0.1 (0.225)	99.49	Sheet 1
Case 2A - Electrostatic Precipitor	0.58 (1.34)	-	0.04 (0.09)	99.8	Sheet 1
Case 3A - Electrostatic Precipitator	0.58 (1.34)	-	0.01 (0.02)	99.95	Sheet 1
Case 4A - Fabric Filter + Mechanical Collector	0.58 (1.34)	-	< 0.01 (0.02)	99.97	Sheet 2
<u>PARTICULATE (BASE ESP) + SO_2 REGULATION (WET FGD)</u>					
Case 5A - Partial Gas Treatment	0.34 (0.8)	42	0.1 (0.225)	99.49	Sheet 1 & 3
Case 6A - Full Gas Treatment	0.09 (0.2)	85	0.1 (0.225)	99.49	Sheet 1 & 3
<u>PARTICULATE + SO_2 REGULATION (DRY FGD F/FILTER)</u>					
Case 7A - Partial Gas Treatment	0.34 (0.8)	42	0.015 (0.035)	99.9[2]	Sheet 2 & 4
Case 8A - Full Gas Treatment	0.09 (0.2)	85	0.02 (0.05)	99.85[2]	Sheet 2 & 4

<u>Notes:</u> [1]For combinations of AQCS Block Plant Arrangement, refer to Exhibit 3-2 and the sheet numbers identified in column.

[2]The F/Filter 'sees' a higher inlet dust loading due to calcium salts additions from spray dryers (SD) The efficiency quoted for reference applies to system overall i.e., is based on inlet load to SD and outlet load from F/Filter.

HAT CREEK PROJECT

SUMMARY OF AQCS ALTERNATIVES - B GROUP (RETROFIT)

PLANT EMISSIONS AND ARRANGEMENT DATA

(Worst Quality Blended Coal)

	SO_2 CONTROL		PARTICULATE CONTROL		BLOCK[4] PLANT ARRGT.
	mg/kJ (lb/MB)	%	mg/kJ (lb/MB)	%	
PARTICULATE REGULATION					
(SO_2 emission uncontrolled)					
Case 1B - (Base Scheme) Electrostatic Precipitor	0.58 (1.34)	-	0.1 (0.225)	99.49	Sheet 1
Case 2B - Electrostatic Precipitator	0.58 (1.34)	-	0.04 (0.09)	99.8	Sheet 1
Case 3B - Electrostatic Precipitator	0.58 (1.34)	-	0.01 (0.02)	99.95	Sheet 1
Case 4B - Fabric Filter + Mechanical Collector[2]	0.58 (1.34)	-	< 0.01 (0.02)	99.97	Sheet 2
SO_2 REGULATION (WET FGD)					
Case 5B - Partial Gas Treatment	0.34 (0.8)	41	not incl.[1]	-	Sheet 3
Case 6B - Full Gas Treatment	0.09 (0.2)	85	not incl.	-	Sheet 3
SO_2 REGULATION (DRY FGD F/FILTER)					
Case 7B - Partial Gas Treatment[3]	0.34 (0.8)	41	not incl.	-	Sheet 4
Case 8B - Full Gas Treatment[3]	0.09 (0.2)	85	not incl.	-	Sheet 4

Notes:

(1) Cases 5B to 8B, FGD systems, require to be added to any one of Cases 1B to 4B to achieve combined SO_2 and particulate control.

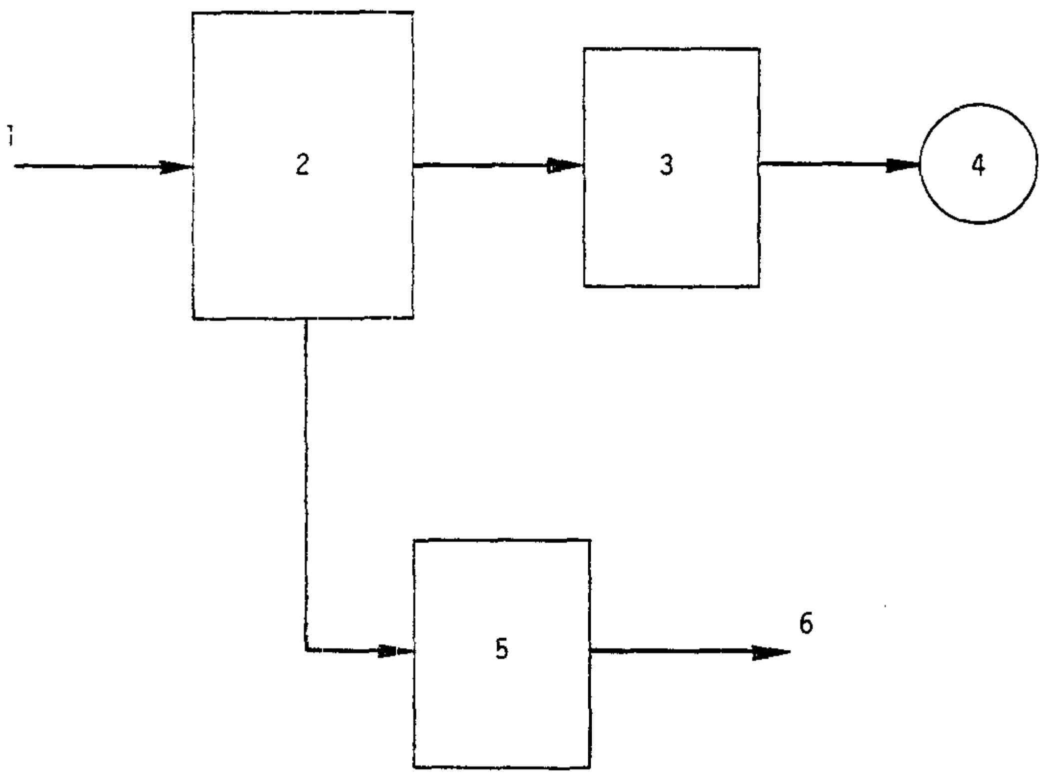
(2) The combination of Case 4B (particulate control) with either Case 7B or 8B results in an increase in particulate emissions to 0.015 (0.035) - 99.9% - and 0.02 (0.05) - 99.85% - respectively.

(3) The combination of Case 7B or 8B with electrostatic precipitor Cases 1B to 3B is assumed not to affect the particulate control performance.

(4) For combinations of AQCS Block Plant arrangement, refer to Exhibit 3-2 and sheet numbers identified in column.

PLANT ARRANGEMENT BLOCK DIAGRAMS

ELECTROSTATIC PRECIPITATORS

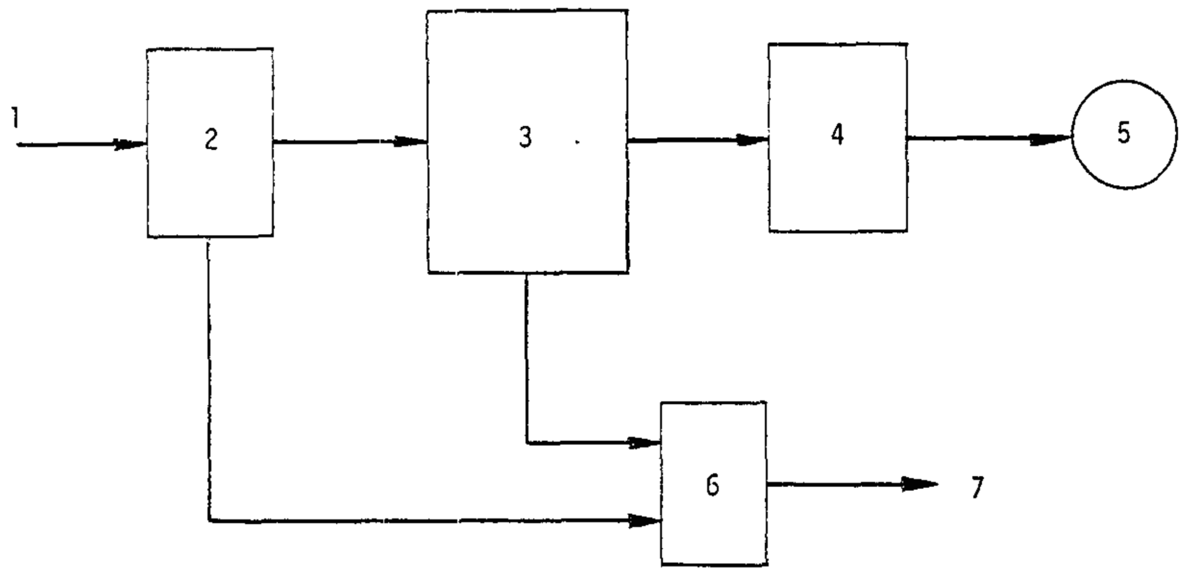


1. Flue Gas from Air Heater Exits or Dry FGD System
2. Electrostatic Precipitator
3. Induced Draft Fans
4. Chimney
5. Pneumatic Ash Handling
6. Fly Ash to Disposal Via Conveyor

EXHIBIT 3-2 (SHEET 1 OF 4)

PLANT ARRANGEMENT BLOCK DIAGRAMS

FABRIC FILTER

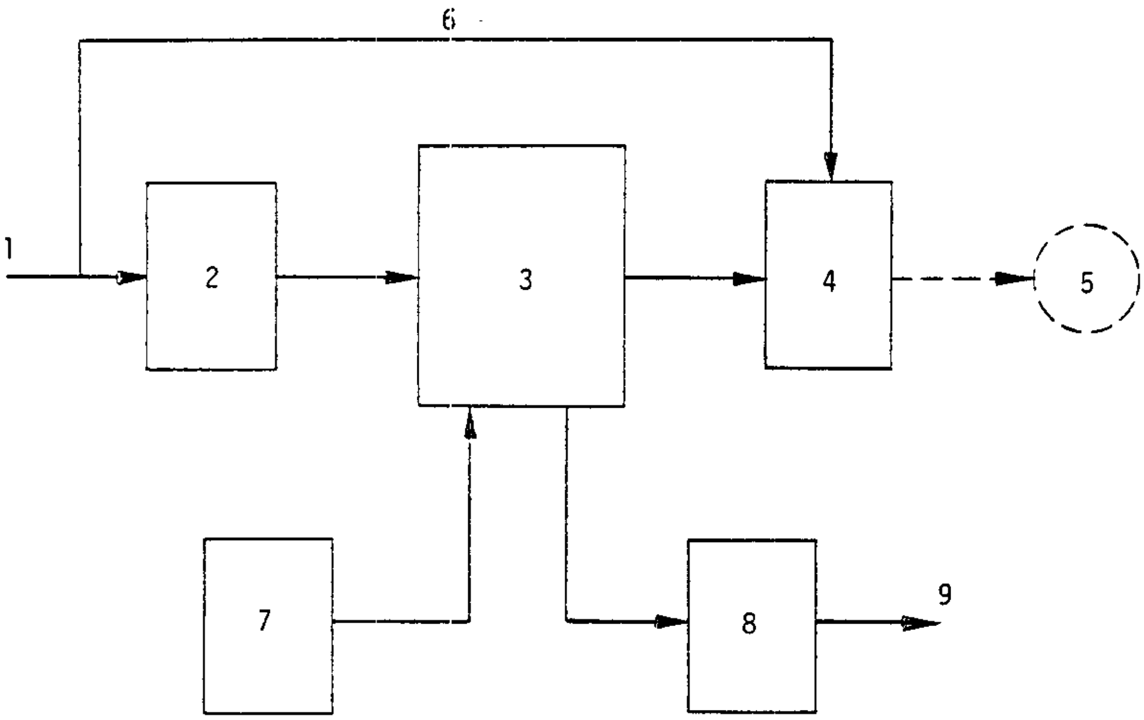


1. Flue Gas from Air Heater Exits
2. Mechanical Dust Collectors
3. Fabric Filters
4. Induced Draft Fans
5. Chimney
6. Pneumatic Ash Handling
7. Fly Ash to Disposal Via Conveyor

EXHIBIT 3-2 (SHEET 2 OF 4)

PLANT ARRANGEMENT BLOCK DIAGRAMS

WET SCRUBBING FGD

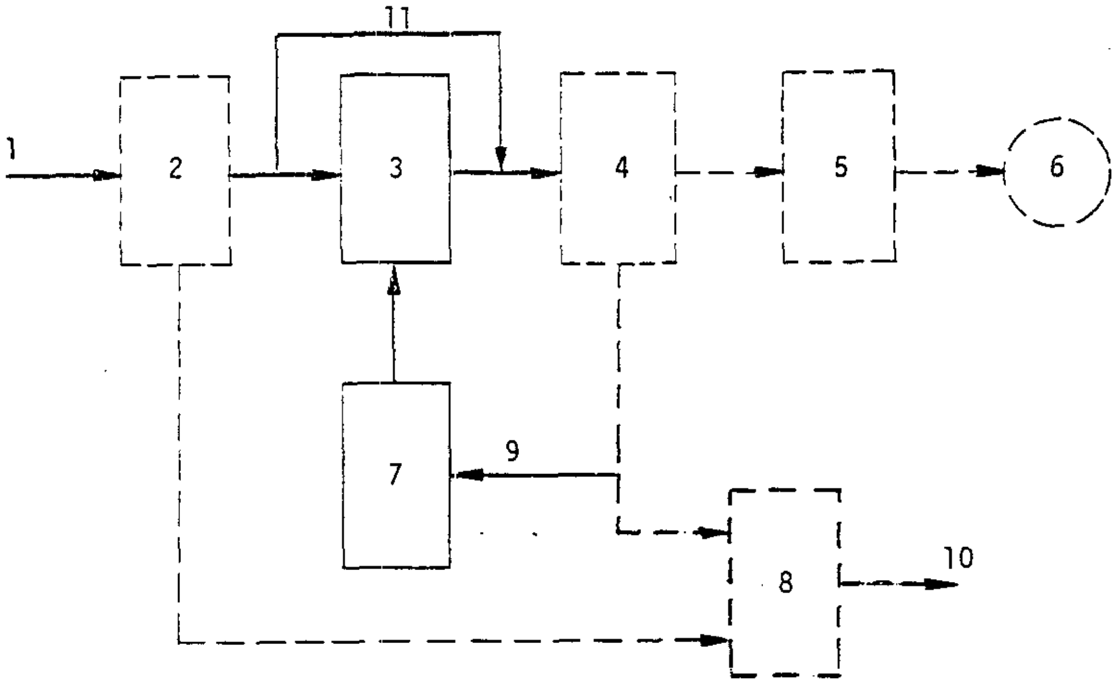


1. Flue Gas from Particulate Control/ID Fans
2. Booster Fans
3. SO_2 Absorbers
4. Gas Reheat
5. Chimney
6. Bypass (used for partial scrubbing cases only)
7. Reagent Preparation
8. Sludge Dewatering/Stabilization
9. Waste to Disposal Via Conveyor

EXHIBIT 3-2 (SHEET 3 OF 4)

PLANT ARRANGEMENT BLOCK DIAGRAMS

DRY SCRUBBING



1. Flue Gas from Air Heater Exits
2. Mechanical Dust Collectors (Only with Fabric Filters)
3. Spray Dryers
4. Fabric Filter or Electrostatic Precipitator
5. Induced Draft Fans
6. Chimney
7. Reagent Preparation
8. Pneumatic Ash Handling
9. Partial Product Recycle
10. Waste to Disposal Via Conveyor
11. Bypass (for Partial Treatment Cases Only)

EXHIBIT 3-2 (SHEET 4 OF 4)

AIR QUALITY CONTROL STUDY

TECHNICAL SUMMARY OF ALTERNATIVES

(SI UNITS)

CASE:	1A & 1B	2A & 2B	3A & 3B	4A & 4B	5A & (1B + 5B)	6A & (1B + 6B)	7A & (4B + 7B)	8A & (4B + 8B)
Brief Description Type of System	ESP (Base Alternative)	ESP	ESP	MDC + FF	ESP (Base Alternative) + Wet Limestone FGD (50% Scrubbing)	ESP (Base Alternative) + Wet Limestone FGD (100% Scrubbing)	MDC + Lime Spray Drier (50% Scrubbing) + FF	MDC + Lime Spray Drier (100% Scrubbing) + FF
Emission Rate (mg/kJ)								
Particulate	0.0967 (2)	0.0387	0.0086	0.0086	0.0967 (2)	0.0967 (2)	0.01505	0.0215
SO_2	0.576	0.576	0.576	0.576	0.344	0.086	0.344	0.086
Major Equipment Design Sizing	2 x 50% ESP	2 x 50% ESP	2 x 50% ESP	4 x 25% MDC + 2 x 50% FF (14 compartments each, reverse air cleaning)	2 x 50% ESP + 3 x 25% FGD	2 x 50% ESP + 4 x 33% FGD	4 x 25% MDC + 4 x 16% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)	4 x 25% MDC + 6 x 20% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)
ESP S.C.A. ($m^2/m^3/sec$)	112.4	130.5	214.5	-	112.4	112.4	-	-
ESP Area (m^2)	133,502	155,520	255,669	-	133,502	133,502	-	-
FF Air to Cloth Ratio (m/s)	-	-	-	0.0102	-	-	0.0102	0.0102
FF Cloth Area (m^2)	-	-	-	133.6	-	-	127.2 (133.6)	119.8 (133.6)
MDC Pressure Drop (kPa)	-	-	-	0.622	-	-	0.622	0.622
Spray Dryer Modules	-	-	-	-	-	-	3 operating + 1 spare	5 operating + 1 spare
FGD Reheat (°C)	-	-	-	-	{Partial Bypass {Reheat to 104°C	{Hot Air Injection {Reheat to 68°C	-	-
FGD Modules	-	-	-	-	2 operating + 1 spare	3 operating + 1 spare	-	-
FGD Booster Fans (No. - MW)	-	-	-	-	2 - 1.5	2 - 3.0	-	-
I.D. Fans (No. - MW)	2 - 3.7(4.1)	2 - 3.7(4.1)	2 - 3.7(4.1)	4 - 3.7(4.1)	2 - 3.7(4.1)	2 - 3.7(4.1)	4 - 4.1	4 - 4.1
AQCS Pressure Drop (kPa)	0.5	0.5	0.5	2.75	3.0 + 0.5	3.0 + 0.5	2.75 + 1	2.75 + 1
Reagent Consumption (tonnes/yr)	None	None	None	None	Limestone 14,515	Limestone 29,937	Lime 9979	Lime 19958
Water Consumption (1000 m^3/year)	None	None	None	None	340	680	250	510
Waste Products (tonnes per year)	Flyash 635,036 - -	Flyash 635,036 - -	Flyash 635,036 - -	Flyash 635,036 - -	Flyash 635,036 Sludge Dry Basis 23,587 Water 0.76 l/s	Flyash 635,036 Sludge Dry Basis 47,174 Water 1.51 l/s	Flyash 635,036 - - SO_2 Products 19,958	Flyash 635,036 - - SO_2 Products 39,917
Chimney Liner Type	Mild Steel	Mild Steel	Mild Steel	Mild Steel	Brick	Brick	Mild Steel	Mild Steel
SO_2 Emission Maximum (kg/sec)	0.979	0.979	0.979	0.979	0.556	0.139	0.556	0.139
Particulate Emission Maximum (kg/sec)	0.164	0.066	0.015	0.015	0.164	0.164	0.026	0.037
Total Gas Flow (kg/sec)	833.39	833.39	833.39	833.39	850	950	845	858
Exit Temperature (°C)	146	146	146	146	102	65	104	68
Exit Velocity (m/s)	27.4	27.4	27.4	27.4	24.4	25.3	25.0	23.2

NOTE: 1) Values are on a per Generating Unit basis.

2) 0.0967 mg/kJ ≡ 0.1 gr/scf (dry basis).

3) Values in brackets apply to Group B retrofit alternatives where such values differ from the A Group values.

EXHIBIT 3-3 (SHEET 1 of 2)

AIR QUALITY CONTROL STUDY

TECHNICAL SUMMARY OF ALTERNATIVES

(NORTH AMERICAN UNITS)

CASE	1A & 1B	2A & 2B	3A & 3B	4A & 4B	5A & (1B + 5B)	6A & (1B + 6B)	7A & (4B + 7B)	8A & (4B + 8B)
Brief Description Type of System	ESP (Base Alternative)	ESP	ESP	MDC + FF	ESP (Base Alternative) + Wet Limestone FGD (50% Scrubbing)	ESP (Base Alternative) + Wet Limestone FGD (100% Scrubbing)	MDC + Lime Spray Drier (50% Scrubbing) + FF	MDC + Lime Spray Drier (100% Scrubbing) + FF
Emission Rate (lbs./million BTU) Particulate SO_2	 0.225(2) 1.34	 0.09 1.34	 0.02 1.34	 0.02 1.34	 0.225(2) 0.8	 0.225(2) 0.2	 0.035 0.8	 0.05 0.2
Major Equipment Design Sizing	2 x 50% ESP	2 x 50% ESP	2 x 50% ESP	4 x 25% MDC + 2 x 50% FF (14 compartments each, reverse air cleaning)	2 x 50% ESP + 3 x 25% FGD	2 x 50% ESP + 4 x 33% FGD	4 x 25% MDC + 4 x 16% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)	4 x 25% MDC + 6 x 20% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)
ESP S.C.A. (ft²/1000 acfm)	571	663	1,090	-	571	571	-	-
ESP Area (ft²)	1,437,000	1,674,000	2,752,000	-	1,437,000	1,437,000	-	-
FF Air to Cloth Ratio (ft/min)	-	-	-	2.0	-	-	2.0	2.0
FF Cloth Area (1,000 ft²)	-	-	-	1438	-	-	1370 (1438)	1290 (1438)
FF Pressure Drop (in. Wg.)	-	-	-	2.5	-	-	2.5	2.5
Spray Dryer Modules	-	-	-	-	-	-	3 operating + 1 spare	5 operating + 1 spare
FGD Reheat (°F)	-	-	-	-	{Partial Bypass {Reheat to 220°F	{Hot Air Injection {Reheat to 155°F	-	-
FGD Modules	-	-	-	-	2 operating + 1 spare	3 operating + 1 spare	-	-
FGD Booster Fans (No. - hp x 10³)	-	-	-	-	2 - 2	2 - 3.5	-	-
I.D. Fans (No. - hp x 10³)	2 - 5(5.5)	2 - 5(5.5)	2 - 5(5.5)	4 - 5(5.5)	2 - 5(5.5)	2 - 5(5.5)	4 - 5.5	4 - 5.5
AQCS Pressure Drop (in. Wg.)	2	2	2	11	12 + 2	12 + 2	11 + 4	11 + 4
Reagent Consumption (T.P.Y.)	None	None	None	None	Limestone 16000	Limestone 33000	Lime 11000	Lime 22000
Water Consumption (10^6 U.S. gal./year)	None	None	None	None	90	180	67	135
Waste Products (T.P.Y.)	Flyash 700,000 - -	Flyash 700,000 - -	Flyash 700,000 - -	Flyash 700,000 - -	Flyash 700,000 Sludge Dry Basis 26,000 Water 12 USgpm	Flyash 700,000 Sludge Dry Basis 52,000 Water 24 USgpm	Flyash 700,000 - - SO_2 Products 22,000	Flyash 700,000 - - SO_2 Products 44,000
Chimney Liner Type	Mild Steel	Mild Steel	Mild Steel	Mild Steel	Brick	Brick	Mild Steel	Mild Steel
SO_2 Emission Maximum (lbs./hr.)	7766	7766	7766	7766	4410	1103	4410	1103
Particulate Emission Maximum (lbs./hr.)	1304	522	116	116	1304	1304	203	290
Total Gas Flow (lbs./hr.)	6.614×10^6	6.614×10^6	6.614×10^6	6.614×10^6	6.75×10^6	7.54×10^6	6.71×10^6	6.81×10^6
Exit Temperature (°F)	295	295	295	295	215	150	220	155
Exit Velocity (f.p.s.)	90	90	90	90	80	83	82	76

NOTE:
1) Values are on a per Generating Unit basis.
2) 0.225 lb./MB ≡ 0.1 gr/scf (dry basis).
3) Values in brackets apply to Group B retrofit alternatives where such values differ from the A Group values.

EXHIBIT 3-3 (SHEET 2 OF 2)

AIR QUALITY CONTROL SYSTEMS STUDY

FGD REAGENTS

CHEMICAL	CASE	QUANTITY (TONS/YEAR)	VENDOR	ENQUIRY DATE	RESPONSE DATE	PRICE ($)	DELIVERY METHOD	PRICE ESCALATION	AVAILABILITY
Limestone	Case 5	60,000 to 73,800	Canadian Industries Limited	NOT INCLUDED	NOT INCLUDED	Unable to Quote Price on This Item.	Not Advised	Not Advised	Not Advised
	Case 6	130,000 to 159,900							
	Case 5	60,000 to 73,800	Steel Brothers Canada Ltd.	NOT INCLUDED	NOT INCLUDED	2" x 3/8" $8.50/ton at Pavilion Lake Plant	By Others, eg. CP Transport @ $6.15/Ton in 25 Ton Trucks	8% or 9% Per Annum is Not Unlikely	Could be possible over 35 year period.
	Case 6	130,000 to 159,900				3/8" Minus $3.00/ton at Pavilion Lake Plant			

NOTES: 1) Cases 5 and 6 use limestone for SO_2 absorption. Lime is used for sludge stabilization.

EXHIBIT 3-4 (SHEET 1 OF 2)

AIR QUALITY CONTROL SYSTEM

FGD REAGENTS

CHEMICAL	CASE	QUANTITY (TONS/YEAR)	VENDOR	ENQUIRY DATE	RESPONSE DATE	PRICE ($)	DELIVERY METHOD	PRICE ESCALATION	AVAILABILITY
Lime	Case 5	8,000 to 9,840	Canadian Industries Limited	NOT INCLUDED	NOT INCLUDED	$53.00/Ton, F.O.B. Kananaskis, Alta. plus $22.00/Ton to Ashcroft	Truck Load Lots 45,000 lbs.	Not Advised	Not Advised
	Case 6	18,000 to 22,140							
	Case 7	35,000 to 43,050							
	Case 8	89,000 to 109,470							
	Case 5	8,000 to 9,840	Steel Brothers Canada Ltd.	NOT INCLUDED	NOT INCLUDED	$42.50/Ton at Pavilion Lake Plant, Cache Creek, B.C.	35 Ton Train Units Case 5 - $5.00/Ton Case 6 - $4.50/Ton Case 7 - $4.38/Ton Case 8 - $4.15/Ton Trimac Transportation System CP - $5.00/Ton All Cases	8% or 9% per annum is not unlikely	Case 5 - is presently possible. Case 6 - expanding markets could create concern in 3, 4 or 5 years time. Case 7 and 8 - would require another kiln with a minimum two years notice being required.
	Case 6	18,000 to 22,140							
	Case 7	35,000 to 43,050							
	Case 8	89,000 to 109,470							

NOTES: 1) Cases 5 and 6 use lime only for sludge stabilization.

2) Cases 7 and 8 use lime for SO_2 absorption.

EXHIBIT 3-4 (SHEET 2 OF 2)

4.0 AQCS COSTS

This section presents capital costs and detailed cost breakdown; levelized and unlevelized owning and operating (O & O) costs; AQCS capital cost cash flows; and AQCS consumption quantities for power, reagents, water and so forth.

The economic factors used in the evaluations are tabulated in Exhibit 4-1 and include reagent, labour, energy, and other costs.

The estimated quantities of power, energy, and materials consumed by the AQCS plants are tabulated in Exhibit 4-2.

Cost evaluations are presented in Exhibits 4-3 and 4-4, applicable to Group A and Group B primary alternatives, and include both capital costs (total $ and Unit $/kW) and the owning and operating costs (mills/kWh) unlevelized. Differential costs of the alternatives relative to the Base Scheme Case 1 AQCS system are shown. The capital costs include an incremental capability cost as described in 4.1 of this report.

Levelized owning and operating costs for Group A and Group B are illustrated in Exhibit 4-5 and 4-6 respectively. These Exhibits include capitalized values of the levelized O & O costs, and also differentials relative to the Base Case.

Engineering and Construction expenditure cash flows, expressed as percentages of the total capital cost for a 4-unit development, are presented in Exhibit 4-7. The total capital costs are to be found in either Exhibit 4-3 or 4-4 for the particular AQC system and Group chosen. It must be recognised, that these costs exclude IDC, and corporate overhead, escalation-during-construction (EDC). To determine actual cash flows, these factors should be accounted for, using the given cash flow percentages as the basis.

Each FGD system of Case 5A to 8A could be combined with an alternative particulate control device (of different efficiency, type) to the particulate device specified in the Cases. Thus, for example, the 99.49% ESP of Case 5A can be substituted by the 99.95% ESP of Case 3A to give rise to a new AQCS alternative, designated Case 5/3A. This new alternative will meet the bottom of the particulate emission range and the top of the SO_2 range of the PCB Objectives . Other new AQCS alternatives can be obtained in similar fashion and their costs would be developed by deducting and adding the appropriate values for the particulate control costs given.

Costs for various of these other AQCS alternatives, together with the Group A alternatives, are presented in bar-chart form in Exhibit 4-8 and 4-9. Not all possible alternatives have been included; some combinations of dry FGD and ESP systems are not shown, because of the high level of uncertainty regarding their overall performance. Exhibit 4-8 illustrates the respective unit capital costs, with the capitalized O & O cost added, for the AQCS A Group of alternatives. Exhibit 4-9 shows levelized O & O costs and differentials in mills/kWh.

In Exhibit 4-10, detailed capital cost estimates for the A Group of alternatives, Cases 1 to 8, are tabulated.

Embedded spare FGD module costs are shown in Exhibit 4-11. The FGD systems incorporate redundancy in the form of spare modules to allow for module outages. To assess the impact of designed plant redundancy, the embedded capital costs for spare modules, expressed in total dollars and $/kW, are included for reference purposes.

4.1 AQCS EXTENT OF PLANT & BASIS OF COSTS

The AQCS primary alternatives of the A Group, and Cases 1B to 4B of the B Group, include the total "back-end" plant extending from the boiler air heater outlet to the chimney inclusive. All of these alternatives are complete and stand alone. The remaining Cases 5B through 8B identify FGD systems only, which insert between the boiler and chimney; each requires to be combined with one of the Cases 1B through 4B to produce the total AQCS (particulate plus SO_2 control).

The capital and operating costs for all A and B alternatives are developed accordingly. Regarding the Base Scheme capital cost (Case 1A) as detailed in Exhibit 4-10, the total cost exceeds the amount included in Account 20 of the Hat Creek Power Plant Project Estimate since that Account does not include for all equipment such as ID fans, breeching, structural steel and chimney. Amounts for these items have been abstracted from the appropriate detailed categories and are included to provide the Case 1 capital cost: similarly for the other cases as appropriate.

To determine the impact of a particular AQCS alternative on the overall Project cost, the total cost (e.g. capital, O & O, mills/kWh etc.) of the Base Scheme (Case 1A) is deducted from that of the particular AQCS alternative and this differential added to the Base Scheme Power Plant cost. These differential amounts in various forms are included in Exhibits 4-3, 4-4, 4-5 and 4-6 for the primary cases.

Capital Costs

The capital costs for the various alternatives include the following plant as applicable:

- AQCS Equipment: precipitator, mechanical dust collector and fabric filter, flyash removal system, FGD system.
- Flue gas ductwork and support: boiler house to AQCS equipment, between AQCS equipment, from AQCS equipment to chimney.
- ID fans, ID booster fans and chimney.

- Site improvement, earthwork, piling, concrete, structural steel, building, piping, insulation, instrumentation, electrical and painting for the above.
- Incremental cost for the waste transportation and disposal system from Power Plant to Mid Medicine Creek Valley.

Note with regard to the last item, the dry ash disposal scheme (Alternative "B") for the Project has been assumed. Incremental costs are included for each Case to cater for the effect of increased quantities of waste products generated.

Separately calculated and tabulated is the incremental capability cost. This represents the cost of adjusting the power plant gross output to satisfy the requirements of the electrical auxiliaries and power consumption for the AQC system applied while preserving the net station output at 2000 MW.

Capital costs for precipitator and fabric filter cases were obtained from vendors' quotations supplemented with INTEG-EBASCO in-house data. Costs for the wet FGD scrubber systems are based on the EBASCO FGD study[6] for the Hat Creek Project, adjusted to suit worst quality blended coal, the dry ash disposal scheme, and the specific emission limits of the PCB Objectives. Costs for the dry FGD scrubbing cases were derived from INTEG-EBASCO estimates for other projects, in-house vendor quotations, and published data.

All costs are in 1978 canadian dollars; US prices and costs have been converted at the exchange rate:

$1.00 US = $0.85 Canadian

The indirect construction cost factor of 28 percent which includes indirect (5%), cost contingency (15%), and engineering (6%), has been applied to the direct costs. The cost contingency value is consistant with the Project allowance (14.4%) for the Base AQCS system, and has been maintained for other alternatives, notwithstanding the greater uncertainty of the costs for these alternatives.

Annual Costs

The annual owning and operating costs are incremental values, applying only to AQCS plant operation and not the total power plant. O & O costs consist of fixed charges plus operation and maintenance (O & M) costs. The fixed charge rate (unlevelized) of 12.33 percent used excludes the fixed O & M component. The O & M costs are separately derived based on the consumption data and costs of Exhibit 4-1 and 4-2, and are illustrated in Exhibit 4-3, to 4-6.

4.2 RETROFIT OF FGD SYSTEMS

For cases 1B to 3B, (ESP particulate control), in order to achieve the flexibility of retrofitting either wet or dry FGD systems, an ultimate plant arrangement is assumed which makes it necessary for the ESP's and downstream plant to be located a further 52 metres (170 feet) from the boiler back end. This shift of plant is required to provide space upstream in order to retain the option of retrofitting dry scrubber systems. Therefore Cases 1B to 3B incur increased inlet ductwork and additional electrical cable/raceway lengths for extending the ESP and ID fans. Additional costs are included for these features together with an allowance for an increased waste disposal system, larger ID fans to accommodate future FGD system losses, and alternative chimney liners suited to the corrosive effects of low temperature flue gas with wet FGD systems.

The capital cost increases, amounting to about 6 or 7 percent of which about three quarters is assigned to ductwork, are applied to the ESP particulate system costs. They represent a shift of costs to the particulate systems although the costs are actually due to FGD retrofitting.

For Case 4B, (Fabric filters with dust collectors), this also requires a shift in the location of the ID fans and chimney, but the quantity of additional ductwork is less. The estimated cost increase to incorporate allowances for FGD retrofitting for this case is approximately 6 percent.

With Cases 5B and 6B, (Partial and full wet scrubbing FGD systems only), the total costs are increased in the order of 2 percent to cover additional ductwork tie-in sections, electrical system modifications, and premium time for tieing in during the retrofit, but exclude amounts already included for in the particulate Group B cases for the chimney liner and ID fan sizing.

For the total AQCS plant - incorporating suitable particulate control plus retrofitted wet FGD systems - the cost is in the order of 3 to 5 percent greater than for the comparable system installed with the power plant.

The Cases 7B and 8B (Partial and full dry scrubbing FGD systems) incorporate spray dryers and reagent handling only, with no particulate control. In combination with fabric filters, the total AQCS costs with retrofitting would be in the order of 8 percent higher than the comparable system designed for installation integral with the power plant development. An important component of the extra retrofit system costs arises from the need to initially install a fabric filter which is 5 to 10 percent larger than would otherwise be necessary with integrated plant development. The lower gas temperature, and hence volume flow through the filters, is not achieved until the FGD systems are retrofitted.

EXHIBITS 4.0

AIR QUALITY CONTROL STUDY

ECONOMIC FACTORS

- Net Unit Rating	4 x 500 MW
- Capacity Factor (Lifetime Average)	65%
- Annual Net Generation	11,388 GWh
- Base Date for Costs	October 1978
- Indirect Construction Cost (Indirect + Contingency + Engineering as % of Direct Cost)	28%
- Levelizing Factor (5.75% inflation rate, 10% interest rate, 38 year life)	1.98
- Fixed Charge Rate (Not including O&M Costs)	12.33%
- Levelized Fixed Charge Rate (Not including O&M Costs)	14.25%
- Coal Cost (1978 Dollars)	$0.679/GJ ($0.717/MB)
- Limestone Cost (1978 Dollars)	$10.08/tonne
- Lime Cost (1978 Dollars)	$52.30/tonne
- F.F. Bag Cost (1978 Dollars)	$60.00/ea.
- Labour Cost (1978 Dollars)	$18.3/hour
- Incremental Energy Cost (1978 Dollars)	9.55 Mills/kWh
- Water Cost (1978 Dollars)	$0.56/m^3
- Levelized Water Cost (1978 Dollars)	$0.71/m^3
- Cost of Steam (1978 Dollars)	$0.36/MB
- Incremental Capacity Cost (1978 Dollars)	$450/kW

EXHIBIT 4-1

AIR QUALITY CONTROL STUDY

CONSUMPTION DATA FOR AQCS CASES

(PER UNIT BASIS)

CASE NO.	PARTICULATE CONTROL 1A	2A	3A	4A	COMBINED PART. & SO_2 CONTROL 5A	6A	7A	8A
EQUIPMENT	ESP (99.5)	ESP (99.8)	ESP (99.95)	FF (99.97)	ESP (99.5) + Part. Wet FGD	ESP (99.5) + Full Wet FGD	FF + Part. Dry FGD	FF + Full Dry FGD
Capability								
Power - kW	3,700	4,200	4,800	6,000	9,200	14,100	7,000	8,300
Steam - GJ/hr	-	-	-	-	-	42	-	-
Operation								
Energy - 10^6 kWhr/yr (1)	21	24	27	34	52	80	40	47
Steam - GJ/yr	-	-	-	-	-	243,000	-	-
Water - m^3/yr	-	-	-	-	340,000	680,000	250,000	510,000
Limestone - Tonne/yr	-	-	-	-	14,500	29,900	-	-
Lime - Tonne/yr	-	-	-	-	2,000	4,100	10,000	20,000
Labour - man hr/yr	1,400	1,400	1,400	1,400	25,400	31,400	8,000	10,000
Maintenance (Mat. & Labor)								
Bag Replacement - no/yr (2)	-	-	-	5,000	-	-	4,750	4,500
Other - % Cap. Cost/yr (3)	0.5	0.5	0.5	0.5	1.5	1.5	1.0	1.0

(1) Includes Differential Power/Energy consumed by ID Fans.

(2) Bag Replacement Labor - 1 man hr per bag.

(3) 1.5% for Wet FGD system, 1.0% for Dry FGD System and 0.5% for other equipment.

Notes: a) Quantities for Cases 1B to 4B are similar to the above for Cases 1A to 4A respectively,

b) Quantities for Case 5B to 6B may be obtained dy deducting Case 1A values from those of Case 5A or 6A above

c) Quantities for Case 7B or 8B may be obtained by deducting Case 4A values from those of Case 7A or 8A above

EXHIBIT 4-2

AIR QUALITY CONTROL STUDY

COST EVALUATION (UNLEVELIZED O&O) - GROUP A

(per 4 units, $1000, 1978 price level, not levelized, capital costs exclusive of corporate overhead and IDC)

CASE NO.	PARTICULATE CONTROL (without provision for Dry FGD retrofit)				COMBINED PART. & SO_2 CONTROL (integrated installation)			
	1A	2A	3A	4A	5A	6A	7A	8A
EQUIPMENT	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	ESP (99.49%) + PARTIAL WET FGD	ESP (99.49%) + FULL WET FGD	FF + PARTIAL DRY FGD	FF + FULL DRY FGD
AQCS Capital Cost	202,000	220,000	240,000	185,000	382,000	467,000	323,000	393,000
Incremental Capability Cost	7,000	7,000	9,000	11,000	16,000	25,000	12,000	15,000
Total Capital Cost	209,000	227,000	249,000	196,000	398,000	492,000	335,000	408,000
($/kW)	(104)	(114)	(125)	(98)	(199)	(246)	(168)	(204)
Differential Capital Cost	Base	18,000	40,000	-(13,000)	189,000	283,000	126,000	199,000
($/kW)	(Base)	(9)	(20)	-(6)	(95)	(142)	(63)	(100)
Annual Fixed Charges (@ 12.33%)	25,800	28,000	30,700	24,200	49,100	60,700	41,300	50,300
Annual Operation & Maintenance								
- Energy	800	920	1,030	1,300	1,990	3,060	1,530	1,800
- Steam	-	-	-	-	-	660	-	-
- Water	-	-	-	-	660	1,420	470	1,040
- Limestone	-	-	-	-	580	1,210	-	-
- Lime	-	-	-	-	420	860	2,090	4,180
- Operating Labour	100	100	100	100	1,860	2,300	590	730
- Bag Replacement								
Material	-	-	-	1,200	-	-	1,140	1,080
Labour	-	-	-	370	-	-	350	330
- Waste Disposal	-	-	-	-	60	140	50	120
- Other O & M	1,010	1,100	1,200	930	3,700	4,980	2,140	2,840
Total O & M	1,910	2,120	2,330	3,900	9,270	14,630	8,360	12,120
Total Annual Owning & Operating	27,710	30,120	33,030	28,100	58,370	75,330	49,660	62,420
(Mill/kWh)	(2.43)	(2.6)	(2.9)	(2.5)	(5.1)	(6.6)	(4.4)	(5.5)
Differential Annual Owning & Operating	Base	2,410	5,320	390	30,660	47,620	21,950	34,710
(Mill/kWh)	(Base)	(0.2)	(0.5)	(0.03)	(2.7)	(4.2)	(1.9)	(3.0)

EXHIBIT 4-3

AIR QUALITY CONTROL STUDY

COST EVALUATION (UNLEVELIZED O&O) - GROUP B

(per 4 units, $1000, 1978 price level, not levelized capital costs exclusive of corporate overhead and IDC)

	PARTICULATE CONTROL (with provision for Dry FGD retrofit)				SO_2 CONTROL (RETROFIT)			
CASE NO.	1B	2B	3B	4B	5B	6B	7B	8B
EQUIPMENT	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	PARTIAL WET FGD	FULL WET FGD	PARTIAL DRY FGD	FULL DRY FGD
AQCS Capital Cost	216,000	234,000	255,000	196,000	187,000	271,000	138,000	210,000
Incremental Capability Cost	7,000	7,000	8,000	11,000	10,000	19,000	2,000	5,000
Total Capital Cost	223,000	241,000	263,000	207,000	197,000	290,000	140,000	215,000
($/kW)	(112)	(120)	(131)	(103)	(98)	(145)	(70)	(107)
Differential Capital Cost	Base	18,000	40,000	-(16,000)				
($/kW)	(Base)	(9)	(20)	-(8)				
Annual Fixed Charges (@ 12.33%)	27,500	29,800	32,500	25,500	24,300	35,700	17,300	26,500
Annual Operating & Maintenance								
- Energy	800	920	1,030	1,300	1,190	2,260	230	500
- Steam	-	-	-	-	-	660	-	-
- Water	-	-	-	-	660	1,420	470	1,040
- Limestone	-	-	-	-	580	1,210	-	-
- Lime	-	-	-	-	420	860	2,090	4,180
- Operating Labour	100	100	100	100	1,760	2,200	490	630
- Bag Replacement								
Material	-	-	-	1,200	-	-	-	-
Labour	-	-	-	370	-	-	-	-
- Waste Disposal	-	-	-	-	60	140	50	120
- Other O & M	1,080	1,170	1,270	980	2,810	4,070	1,380	2,100
Total O & M	1,980	2,190	2,400	3,950	7,480	12,820	4,710	8,570
Total Annual Owning & Operating	29,480	31,990	34,900	29,450	31,780	48,520	22,010	35,070
(Mill/kWh)	(2.6)	(2.8)	(3.1)	(2.6)	(2.8)	(4.3)	(1.9)	(3.1)
Differential Annual Owning & Operating	Base	2,510	5,420	-(30)				
(Mill/kWh)	(Base)	(0.2)	(0.5)	(0.0)				

NOTE: For comparison purposes, the Capital and Energy Costs for Retrofit SO_2 Control Cases include Capability and Energy Costs at the same rate ($450/kW and 9.55 mills/kWh) as Group A Cases.

EXHIBIT 4-4

AIR QUALITY CONTROL STUDY

LEVELIZED OWNING AND OPERATING COSTS - GROUP A

(Per 4 Units, $1000, 1978 price level. Capital costs exclusive of corporate overhead and IDC.)

	PARTICULATE CONTROL (Without provision for dry FGD retrofit)				COMBINED PART. & SO_2 CONTROL (Integrated Installation)			
CASE NO.	1A	2A	3A	4A	5A	6A	7A	8A
BRIEF DESCRIPTION	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	ESP (99.49%) + Part. Wet	ESP (99.49%) + Full Wet	FF + Part. Dry	FF + Full Dry
Levelized Annual Fixed Charges (@ 14.25%)	29,800	32,300	35,500	27,900	56,700	70,100	47,700	58,100
Levelized Annual O&M Costs								
- Energy	1,550	1,800	2,000	2,500	3,850	5,920	2,960	3,500
- Steam	-	-	-	-	-	1,310	-	-
- Water	-	-	-	-	830	1,810	590	1,320
- Limestone	-	-	-	-	1,160	2,390	-	-
- Lime	-	-	-	-	830	1,700	4,140	8,280
- Operating Labour	200	200	200	200	3,980	4,550	1,160	1,450
- Bag Replacement								
Material	-	-	-	2,380	-	-	2,260	2,140
Labour	-	-	-	720	-	-	690	650
- Waste Disposal	-	-	-	-	120	280	100	240
- Other O&M	2,000	2,170	2,380	1,840	7,330	9,860	4,240	5,650
Total O&M	3,750	4,170	4,580	7,640	18,100	27,820	16,140	23,230
Total Levelized Annual Owning & Operating (Mill/kWh)	33,550 (2.9)	36,470 (3.2)	40,080 (3.5)	35,540 (3.1)	74,800 (6.6)	97,920 (8.6)	63,840 (5.6)	81,330 (7.1)
Total Owning & Operating (Levelized & Capitalized) ($/kW)	235,000 (118)	256,000 (128)	281,000 (141)	249,000 (125)	525,000 (262)	687,000 (343)	448,000 (224)	571,000 (285)
Differential Cost to Case 1A								
Levelized Annual Owning & Operating (Mill/kWh)	Base (Base)	2,920 (0.3)	6,530 (0.6)	1,990 (0.2)	41,250 (3.6)	64,370 (5.7)	30,290 (2.7)	47,780 (4.2)
Total Owning & Operating (Levelized & Capitalized) ($/kW)	Base (Base)	21,000 (11)	46,000 (23)	14,000 (7)	290,000 (145)	452,000 (226)	213,000 (106)	336,000 (168)

EXHIBIT 4-5

AIR QUALITY CONTROL STUDY

LEVELIZED OWNING AND OPERATING COSTS - GROUP B

(Per 4 units, $1000, 1978 price level. Capital costs exclusive of corporate overhead and IDC.)

	PARTICULATE CONTROL (with retrofit provision for dry FGD)				SO_2 CONTROL (RETROFIT)			
CASE NO.	1B	2B	3B	4B	5B	6B	7B	8B
EQUIPMENT	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	Partial Wet	Full Wet	Partial Wet	Full Dry
Levelized Annual Fixed Charges (@ 14.25%)	31,800	34,300	37,500	29,500	28,100	41,300	19,900	30,600
Levelized Annual O&M Costs								
- Energy	1,500	1,800	2,000	2,500	2,340	4,460	460	1,000
- Steam	-	-	-	-	-	1,310	-	-
- Water	-	-	-	-	830	1,810	590	1,320
- Limestone	-	-	-	-	1,160	2,390	-	-
- Lime	-	-	-	-	830	1,700	4,140	8,280
- Operating Labour	200	200	200	200	3,780	4,350	960	1,250
- Bag Replacement								
Material	-	-	-	2,380	-	-	-	-
Labour	-	-	-	720	-	-	-	-
- Waste Disposal	-	-	-	-	120	280	100	240
- Other O&M	2,140	2,320	2,520	1,940	5,550	8,040	2,740	4,170
Total O&M	3,890	4,320	4,720	7,740	14,610	24,390	8,990	16,260
Total Levelized Annual Owning & Operating (Mill/kWh)	35,690 (3.1)	38,620 (3.4)	42,220 (3.7)	37,240 (3.3)	42,710 (3.8)	65,690 (5.8)	28,890 (2.5)	46,860 (4.1)
Total Owning & Operating (Levelized & Capitalized) ($/kW)	250,000 (125)	271,000 (135)	296,000 (148)	261,000 (130)				
Differential Cost to Case 1B								
Levelized Annual Owning & Operating (Mill/kWh)	Base (Base)	2,930 (0.3)	6,530 (0.6)	1,550 (0.15)	42,710 (3.8)	65,690 (5.8)	28,890 (2.5)	46,860 (4.1)
Total Owning & Operating (Levelized & Capitalized) ($/kW)	Base (Base)	21,000 (10)	46,000 (23)	11,000 (5)	300,000 (150)	461,000 (230)	203,000 (101)	329,000 (164)

NOTE: For comparison purposes, the Levelized Annual Fixed Charges and the Energy Cost for Retrofit SO_2 Control Cases include Capability and Energy Costs at the same rate as Group A cases.

AIR QUALITY CONTROL STUDY

4-UNIT CASH FLOWS (PERCENTAGE)

(Total capital cost of 4 units exclusive of corporate overhead and IDC = 100%; "*" indicates AQCS initial operation on January 1 of year indicated.)

CASH FLOW #1 (For all Particulate Control Cases 1A to 4A and 1B to 4B)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.6	-	-	-	4.6
2	11.1	5.6	-	-	16.5
3	8.0	10.0	5.8	-	23.8
4	5.4*	4.5	9.8	5.9	25.6
5	0.4	3.1*	4.5	9.7	17.7
6	-	0.3	3.1*	4.4	7.8
7	-	-	0.3	3.0*	3.3
8	-	-	-	0.5	0.5
	29.5	23.5	23.5	23.5	100.0

CASH FLOW #2 (For Combined Cases 5A and 6A, ESP 99.5% + Partial or Full Wet FGD)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.3	-	-	-	4.3
2	10.9	4.7	-	-	15.6
3	8.8	10.0	4.9	-	23.7
4	3.7*	6.6	9.9	5.0	25.5
5	0.3	2.5*	6.6	9.8	19.2
6	-	0.2	2.4*	6.5	9.1
7	-	-	0.2	2.3*	2.5
8	-	-	-	0.4	0.4
	28.0	24.0	24.0	24.0	100.0

AIR QUALITY CONTROL STUDY

4-UNIT CASH FLOWS (PERCENTAGE)

CASH FLOW #3 (For Combined Cases 7A and 8A, FF + Partial or Full Dry Scrubbing)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.1	-	-	-	4.1
2	11.0	3.5	-	-	14.5
3	10.0	10.2	3.7	-	23.9
4	2.7*	8.2	10.1	3.8	24.8
5	0.2	2.0*	8.2	10.1	20.5
6	-	0.1	1.9*	8.9	10.0
7	-	-	0.1	1.9*	2.0
8	-	-	-	0.2	0.2
	28.0	24.0	24.0	24.0	100.0

CASH FLOW #4 (For Retrofit SO_2 Control Cases 5B to 8B)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.0	3.7	-	-	7.7
2	10.8	9.8	3.9	3.9	28.4
3	9.8	9.0	9.9	10.0	38.7
4	1.7*	1.9*	8.9	8.8	21.3
5	0.2	0.1	1.7*	1.6*	3.6
6	-	-	0.1	0.2	0.3
	26.5	24.5	24.5	24.5	100.0

AIR QUALITY CONTROL STUDY

BAR CHART COMPARISON OF AQCS CAPITALISED COSTS ($/kW) (GROUP A CASES & COMBINATIONS)

COMBINED CASE	PARTICULATE CONTROL EQUIP.	PARTICULATE CONTROL EMISSION (#/MB)	SO_2 CONTROL PROCESS	SO_2 CONTROL EMISSION (#/MB)
1A	ESP	0.225	None	1.34
2A	ESP	0.09	None	1.34
3A	ESP	0.02	None	1.34
4A	FF	0.02	None	1.34
5A	ESP	0.225	Part. Wet	0.8
5/2A	ESP	0.09	Part. Wet	0.8
5/3A	ESP	0.02	Part. Wet	0.8
5/4A	FF	0.02	Part. Wet	0.8
6A	ESP	0.225	Full Wet	0.2
6/2A	ESP	0.09	Full Wet	0.2
6/3A	ESP	0.02	Full Wet	0.2
6/4A	FF	0.02	Full Wet	0.2
7A	FF	0.035	Part. Dry	0.8
8A	FF	0.05	Full Dry	0.2

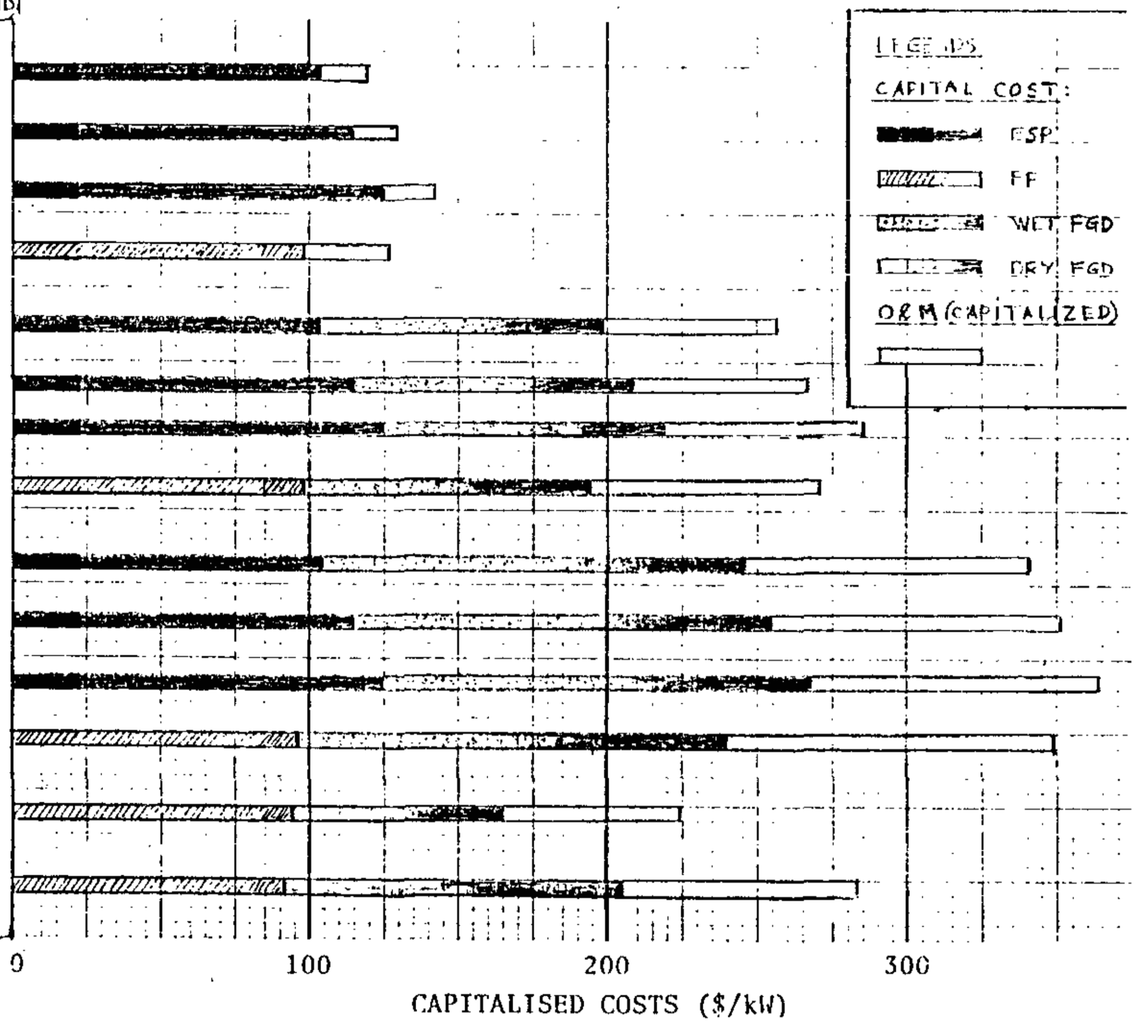


EXHIBIT 4-8

Notes:- 1) The AQC Systems extend between the boiler air heater outlet to the chimney inclusive.

For other than the Base Scheme, Case 1A, incremental costs are included for additional supporting services.

AIR QUALITY CONTROL STUDY

BAR CHART COMPARISON OF AQCS LEVELISED O & O COSTS (mills/kWh) (GROUP A CASES & COMBINATIONS)

COMBINED CASE	PARTICUALTE CONTROL EQUIP	PARTICUALTE CONTROL EMISSION (#/MB)	SO_2 CONTROL PROCESS	SO_2 CONTROL EMISSION (#/MB)
1A	ESP	0.225	None	1.34
2A	ESP	0.09	None	1.34
3A	ESP	0.02	None	1.34
4A	FF	0.02	None	1.34
5A	ESP	0.225	Part. Wet	0.8
5/2A	ESP	0.09	Part. Wet	0.8
5/3A	ESP	0.02	Part. Wet	0.8
5/4A	FF	0.02	Part. Wet	0.8
6A	ESP	0.225	Full Wet	0.2
6/2A	ESP	0.09	Full Wet	0.2
6/3A	ESP	0.02	Full Wet	0.2
6/4A	FF	0.02	Full Wet	0.2
7A	FF	0.035	Part. Dry	0.8
8A	FF	0.05	Full Dry	0.2

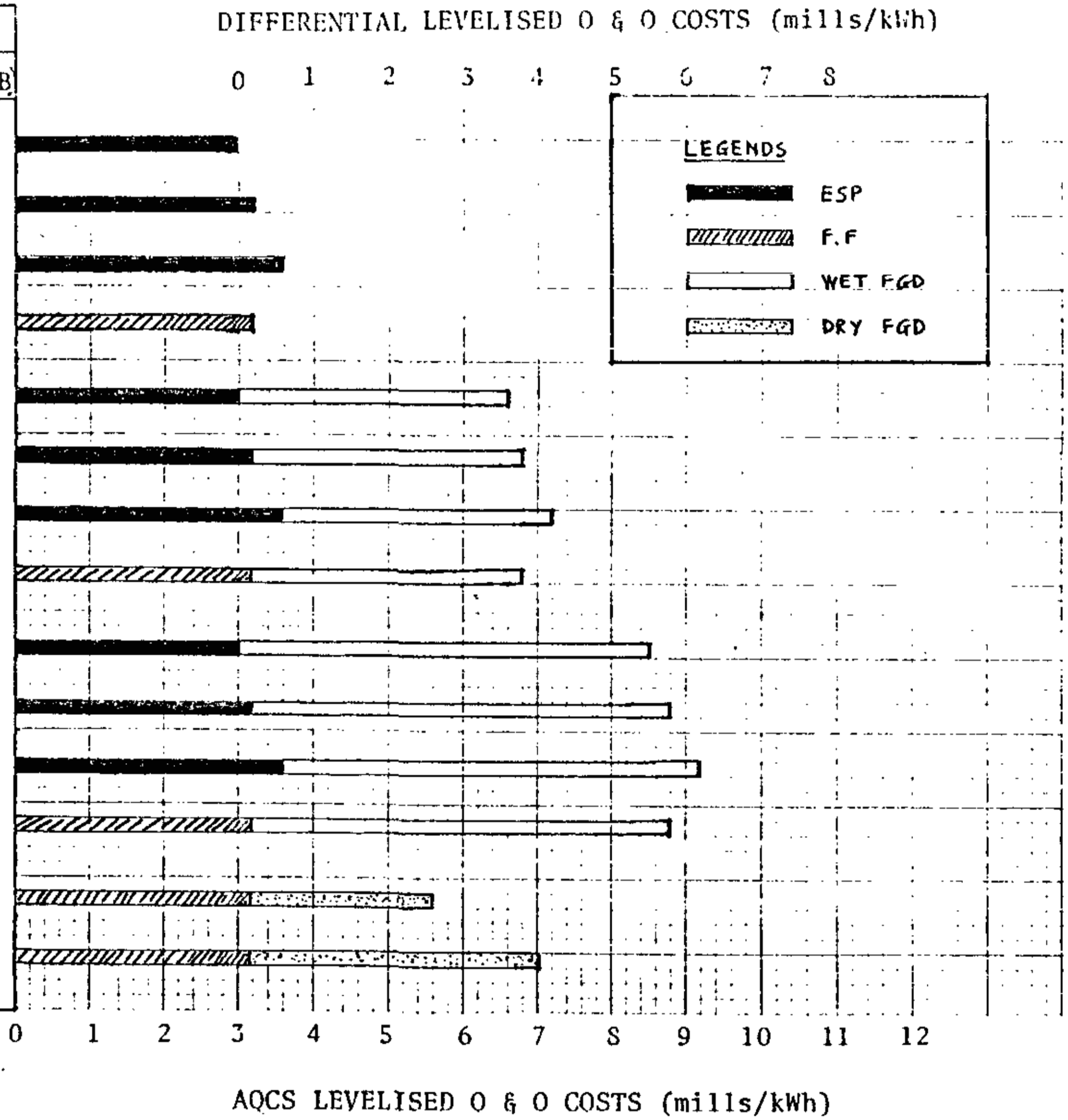


EXHIBIT 4-9

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

($1000, 1978 price level)

1) Case 1A (Base Scheme)

- Precipitator	15,520
- Flyash Handling	3,720
- ID Fans	2,400
- Chimney and Chimney Foundation	2,350
- Structural Steel Including Ductwork	5,720
- Insulation	3,340
- Electrical	3,310
- Others	3,130
Total Direct Cost	39,490
Indirect Cost (28%)	11,060
Total Cost	50,550
Total for 4 Units	202,200

(Others include: improvement to site, earthwork and piling, concrete, buildings, piping, painting.)

2) Case 2A (ESP 99.8%)

- Precipitator	17,550
- Flyash Handling	4,100
- ID Fans	2,400
- Chimney and Chimney Foundation	2,350
- Structural Steel Including Ductwork	5,780
- Insulation	3,530
- Electrical	3,740
- Others	3,450
Total Direct Cost	42,900
Indirect Cost (28%)	12,010
Total Cost	54,910
Total for 4 Units	219,640

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

3) Case 3A (ESP 99.95%)

- Precipitator	19,880
- Flyash Handling	4,530
- ID Fans	2,400
- Chimney and Chimney Foundation	2,350
- Structural Steel Including Ductwork	5,850
- Insulation	3,720
- Electrical	4,230
- Others	4,000
Total Direct	46,960
Indirect Cost (28%)	13,150
Total Cost	60,110
Total for 4 Units	240,440

4) Case 4A (Mech. Collector + Fabric Filter)

- Fabric Filter	9,880
- Mechanical Collectors	1,400
- Flyash Handling	4,210
- ID Fans	3,990
- Chimney and Chimney Foundation	2,350
- Structural Steel Including Ductwork	6,750
- Insulation	3,080
- Electrical	1,590
- Others	2,970
Total Direct Cost	36,220
Indirect Cost (28%)	10,140
Total Cost	46,360
Total for 4 Units	185,440

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

5) Case 5A (ESP + Partial Wet FGD)

- Base Scheme Cost (ESP)	39,490
- Wet FGD System (Including Ductwork to Chimney)	35,960
- Incremental Chimney Cost	300
- Incremental Waste Transportation and Disposal System Cost	100
- Adjustment to Base Scheme Cost (Delete Ductwork from ID Fans to Chimney)	-(1,300)
Total Direct Cost	74,550
Indirect Cost (28%)	20,870
Total Cost	95,420
Total for 4 Units	381,680

6) Case 6A (ESP + Full Wet FGD)

- Base Scheme Cost (ESP)	39,490
- Wet FGD System (Including Ductwork to Chimney)	52,510
- Incremental Chimney Cost	300
- Incremental Waste Transportation and Disposal System Cost	200
- Adjustment to Base Scheme Cost (Delete Ductwork from ID Fans to Chimney)	-(1,300)
Total Direct Cost	91,200
Indirect Cost (28%)	25,540
Total Cost	116,740
Total for 4 Units	466,960

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

7) Case 7A (FF + Partial Dry Scrubbing)

- Case 4 Cost		36,220
- Dry FGD System		27,510
- Incremental Waste Transportation and Disposal System Cost		100
- Adjustment to Case 4 Fabric Filter Cost (Reduce Size)		-(800)
	Total Direct Cost	63,030
	Indirect Cost (28%)	17,650
	Total Cost	80,680
	Total for 4 Units	322,720

8) Case 8A (FF + Full Dry Scrubbing)

- Case 4 Cost		36,220
- Dry FGD System		42,020
- Incremental Waste Transportation and Disposal System Cost		200
- Adjustment to Case 4 Fabric Filter Cost (Reduce Size)		-(1,650)
	Total Direct Cost	76,790
	Indirect Cost (28%)	21,500
	Total Cost	98,290
	Total for 4 Units	393,160

AIR QUALITY CONTROL STUDY

FGD PLANT REDUNDANCY

EMBEDDED CAPITAL COSTS

	SPARE MODULE		
		CAPITAL COST[2]	
CASE[1]	SIZE (MW)	UNIT ($/KW)	TOTAL ($ x 10^6)
5A	144	26.6	53.2
6A	192	30.7	61.4
7A	96	13.7	27.4
8A	115	15.5	31.0

NOTES: [1]To a first order of accuracy the costs can be applied to the Group B Cases.

[2]Capital costs are in $ 1978, and are inclusive of direct and indirect construction costs but exclude corporate overhead, IDC and EDC. These costs are embedded in the capital costs given in Exhibit 4-3 and 4-4.

5.0 PRECIPITATION WITH FLUE GAS CONDITIONING

As a measure of the developing confidence in the part that flue gas conditioning (FGC) can play in precipitator design and performance, FGC-ESP technology is now being promoted as a serious contender for new utility precipitator applications. In that a properly selected FGC system can sometimes contribute to significant reductions in such factors as precipitator size, cost, and possibly power demand; higher availability of FGC equipment is now being observed with retrofitted installations in the United States; and one or two Utilities are known to be operating with or installing FGC-ESP combinations as original equipment; it is considered appropriate to review flue gas conditioning as an AQCS alternative for Hat Creek.

FGC is regarded as an emerging technology certainly for new precipitator applications but does not rank at the present time with the other AQCS alternatives concerning its stage of development or probable application for the Hat Creek Plant. It is therefore reviewed apart from the other alternatives considered here.

The investigation of FGC technology included an assessment of the current state of development in the United States and, based on vendors' recommendations, has identified sulphur trioxide (SO_3) as a suitable gas conditioning reagent for the low sulphur Hat Creek coals. This section summarises the principal considerations, the FGC mechanisms acting to improve collection efficiency, an outline of a typical SO_3 gas conditioning system, and concludes with order-of-magnitude costs for a FGC-ESP (coldside) design combination of 99.95 per cent efficiency, corresponding to the lower PCB particulate limit.

5.1 FLUE GAS CONDITIONING

Flue gas conditioning as an aid to improving the collection efficiency of electrostatic precipitators has been known about since the

1920's. More recently, FGC systems have been fitted-not always successfully-to existing plant in order to upgrade the performance of precipitator installations, either as a result of the original units being unable to meet their guarantees, or in attempts to comply with more stringent air pollution regulations. The body of knowledge is continuing to grow as the results from pilot experimentation and data on full scale installations become available. One vendor of FGC systems has supplied more than 90 retrofitted systems, and two systems as original equipment, one of which is now in operation and the other is in the course of construction.

Conditioning involves the injection of reagents, moisture and/or chemicals, to the flue gas causing a modification of the flyash particulate and bulk flue gas conditions in a way which can improve the collection and/or precipitation of the entrained flyash. The causal mechanisms are not necessarily fully understood, nor are their effects always predictable. The composition of the flue gas and the constituents of the flyash all play a part in a complex and interrelated fashion so that predictions of improvements in performance with FGC are by no means secure, and should ultimately be confirmed by pilot scale testing under conditions representative of the full scale operation.

Flyash resistivity is a principal factor affecting precipitator performance. For example, the high resistivity flyash typical of low sulphur coals is normally difficult to precipitate and requires costly precipitators with high specific collection areas (SCA). FGC can lower flyash resistivity; the ash particle surfaces adsorb a polar substance, e.g. moisture, which results is an improvement in dust deposition and precipitator performance. Alternatively, utilizing FGC, a precipitator design of smaller SCA can be provided to achieve a given collection efficiency.

The presence of SO_3 also contributes significantly to the controlling of resistivity. Free SO_3 raises the acid dewpoint of the flue gas enabling the flyash particulates to adsorb more water, thereby reducing resistivity. Conditioning, to lower the ash resistivity, is also achieved by the injection of other additives such as sodium compounds, H_2SO_4, ammonia, and certain proprietory chemical formulations. Ammonia is understood to improve collection efficiency by increasing the cohesiveness of the flyash minimizing re-entrainment. Other mechanisms assisting collection include modification of particle size, and of the electrical space charge, which in turn raises the precipitator operating voltage.

5.1.1 WAHLCO Sulphur Trioxide Gas Conditioning System

A typical configuration of the WAHLCO SO_3 gas conditioning plant is illustrated in Exhibit 5-1. SO_3 conditioning at cold-side precipitator temperatures involves the catalytic conversion of vapourized SO_2 into SO_3 and its injection into the flue gas upstream of the precipitator. Vanadium pentoxide is the catalyst used, and the reaction is exothermic; the outlet temperature from the converter would range between 540-595°C (1000-1100°F), well above the acid dew point of 260°C (500°F).

Due to the cost of commercially available liquid SO_2 and the difficulty of storing it, a system incorporating a sulfur burner to make SO_2 has been patented. This burner resembles the front end of a small sulfuric acid plant. Much of the heat needed for the SO_2 to SO_3 convertion can be provided by the heat of combustion of the sulfur. Since one ton of sulfur costs about a third to a quarter as much as a ton of SO_2, and produces two tons SO_2, the investment costs of a sulfur burner could be offset by lower operating costs.

Careful attention needs to be given to the injection temperature of SO_3. It must be as far from the acid dew point as possible. The design and location of the injection system is important for even SO_3 distribution. Sufficient retention time is needed for the interaction of the SO_3 and the flue gas.

5.2 FGC-ESP HAT CREEK ALTERNATIVE

For comparison with cold-side precipitator applications designed without gas conditioning, a FGC-ESP combination has been investigated applicable to the Hat Creek project. The particulate emission for this AQCS is 0.01 mg/kJ (0.02 lb/MB), corresponding to the 99.95 per cent collection efficiency of Case 3.

Enquiries were issued to various vendors identifying the flyash and other design conditions, which included requests for comments on the suitability of gas conditioning to aid precipitation. These vendors include WAHLCO, RESEARCH COTTRELL (RC), and AMERICAN AIR FILTER (AAF): in addition, APOLLO CHEMICAL CORPORATION, a vendor for proprietory FGC chemical additives, was contacted. The quotations from AAF and RC, as precipitator manufacturers, included the FGC-ESP plant combination whereas, WAHLCO quoted only for the FGC system. AAF advised that it relies on the experience of WAHLCO and others for the gas conditioning component. The majority of FGC systems quoted identified SO_3 gas conditioning for the application.

To date, WAHLCO is understood to have engineered over 90 retrofitted FGC installations, all employing SO_3 conditioning (e.g. Iowa Public Service, Commonwealth Edison). Utility precipitator installations designed specifically with SO_3 conditioning by WAHLCO include one for the Public Service Company, Colorado (Arapahoe Unit No. 1, in operation since 1976) and Wisconsin Electric Power (unit currently under construction).

WAHLCO/AAF predicted a SCA of between 84-89 m^2/m^3/sec (425-450 ft^2/1000 acfm) with 50 p.p.m. SO_3 injection. These values compare with 212.5 m^2/m^3/sec (1080 ft^2/1000 acfm) for the ESP Case 3 conditions given in sub-section 3.2.1.

5.2.1 Costs

The costs in 1978 dollars for this alternative have been developed on a similar basis to other AQC systems (refer to Section 4.0); the capital costs include a 15 percent contingency factor and exclude corporate overhead. The estimated capital cost for the FGC-ESP system installed as original equipment, is $182,400,000 for the 4-units, or $91 /kW.

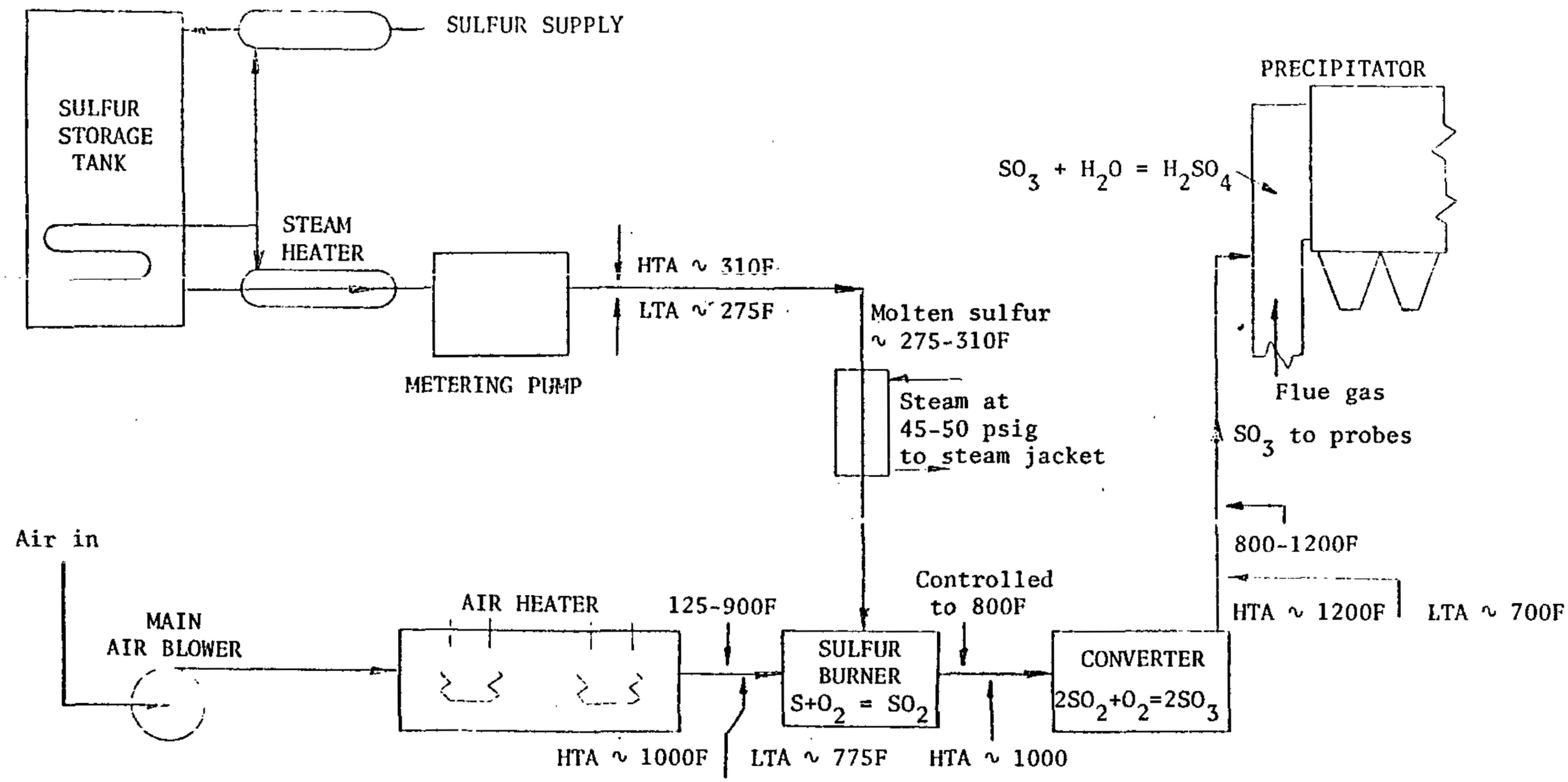
The estimated total annual and owning cost (unlevelized) is $25,000,000 for the 4-units, or 2.2 mills/kWh.

Relative to Case 3A, the estimated savings in capital cost for 4-units is $58,000,000 or 0.7 mills/kWh in owning and operating costs although a FGC-ESP combination designed for the 99.49 percent base conditions would expectedly produce much smaller savings. The costs of the 99.95 percent FGC-ESP combination compare very closely to the mechanical collector-fabric filter combination of Case 4A which is of comparable efficiency.

EXHIBITS 5.0

AIR QUALITY CONTROL STUDY

SO_3 PREPARATION & GAS CONDITIONING SCHEMATIC



HTA - High Temperature Alarm

LTA - Low Temperature Alarm

EXHIBIT 5-1

AQCS PROCESS STATUS
IN U S ELECTRIC UTILITY INDUSTRY

The following is a brief summary of the extent of application of the several AQCS processes which are under consideration for the Hat Creek project of B C Hydro.

A. FGD Wet Scrubbing

The master document for FGD status in the United States is the "PEDCo Report" (EPA Utility FGD Survey EPA-600/7-79-022c, May 1979) which is maintained by PEDCo Environmental Company under contract to the EPA. The following information is extracted from the latest annual report which is current through January, 1979.

	No. of Units/Total MW (1/79)	
	Total FGD	Wet Calcium Based Scrubbing
Operational	46/15 795	39/14 474
Under Construction	45/16 976	38/14 576
Contract Awarded	21/11 051	16/ 8 843
Planned 1/	46/26 382	10/ 6 388
TOTAL	158/70 204	103/44 281

1/ 75 percent of planned units listed as "Process not Selected"

Calcium based wet scrubbing (lime or limestone) has been the predominant method of SO_2 removal in the U S for the last decade and this trend would be expected to continue for at least another 10 years or longer.

Ebasco has served as the architect/engineer on 4 wet FGD type systems which are currently (or near) operational. These include:

- Kansas City Power/Kansas Gas & Electric LaCygne Unit No. 1 840 net MW 6.0 percent sulfur Kansas Coal Limestone wet scrubbing Initial Operation in 1972
- Pacific Power & Light Company Dave Johnstone Unit No. 4 330 net MW 0.5 percent sulfur Wyoming Coal Lime/alkaline fly ash wet scrubbing Initial Operation in 1971

- Arizona Public Service Company Cholla Unit No. 2
  250 net MW 0.9 percent sulfur New Mexico Coal Limestone
  wet scrubbing Initial Operation in 1978

- Minnesota Power & Light Company Clay Boswell Unit No. 4
  500 net MW 3.3 percent sulfur Montana Coal Lime/alkaline
  fly ash wet scrubbing Initial Operation expected late 1979

The attached document "Ebasco Services Incorporated Air Quality Control Systems Experience 1970-1978" provides greater detail on the Ebasco extent of involvement with these 4 systems and also lists work in progress on future systems. It is anticipated that current work for Houston Light and Power, Jacksonville Electric Authority and General Public Utilities (including Pennelec) will result in an additional 3000 MW of operational FGD by the late 1980's.

B. FGD Dry Scrubbing

PEDCo lists the following dry scrubbing systems which have been committed:

- Otter Tail Power Coyote Unit No. 1 440 MW gross
  0.9 percent sulfur Dakota lignite spray dryer/fabric
  filter by Wheelabrator Frye/Atomics International
  sodium carbonate reagent Initial Operation expected mid-1981

- Basin Electric Power Coop Antelope Valley Unit No. 1
  440 MW gross 0.7 percent sulfur Dakota lignite
  spray dryer/fabric filter by Joy/Niro lime reagent
  Initial operation expected late 1981 (Replicate Unit
  No. 2, 1983, has not yet been committed to dry
  scrubbing process)

- Basin Electric Power Coop Laramie River Unit No. 3
  600 MW gross 0.5 percent sulfur subbituminous coal
  spray dryer/ESP by B&W lime reagent Initial operation
  expected early 1982

In addition, 2 lime dry scrubbing industrial units (Celanese Corp, 25 MW equivalent and Strathmore Paper Co, 11 MW equivalent) are expected to be operational in late 1979. Several substantial pilot plant dry scrubbers are anticipated at the Jim Bridger (Wyoming) station of Pacific Power and Light Company.

Ebasco's involvement with the dry scrubbing process has been limited to study work only with no formal inquiries issued and no operational systems anticipated prior to 1986.

C. Fabric Filter Particulate Removal

Reference is made to the attached Exhibit No. 15 of the Ebasco "East Kootenay Thermal Project, 300 MW Units No. 1 & 2, Particulate Removal Equipment Study" June 1978. This Exhibit lists 24 electric utility applications totaling over 5000 MW. Eight coal fired stations totaling over 1000 MW are currently in operation with fabric filters.

Ebasco will be issuing formal inquiries for fabric filters (and also ESP's) for 2 x 750 MW lignite units for Houston Light and Power in late 1979. These units are expected to be operational in 1985/86.

D. ESP Particulate Removal

This has been the predominant method for particulate removal for the U S electric utility industry with probably greater than 90 percent of all units after 1970 so equipped.

Operational (or near operational) systems by Ebasco on coal fired units include the following:

- Carolina Power & Light Co 14 ESP retrofits to existing units approximately 3000 MW 1973
- Iowa Public Service Co Geo Neal Units 3 & 4 1100 MW total 1977 & 1979
- Arizona Public Service Co Cholla Units 3 & 4 650 MW total 1980 & 1982 expected

- Dayton Power and Light Co — Killen Units 1 & 2
  1200 MW total — 1981 & 1982 expected
- Pacific Power and Light — Dave Johnston Units 1, 2 & 3
  440 MW total — 1977 retrofit
- General Public Utilities — Homer City Unit No. 3
  630 MW — 1977

APPENDIX B

EBASCO SERVICES INCORPORATED AIR QUALITY CONTROL SYSTEMS EXPERIENCE 1970-1978

Ebasco Services Incorporated
Two Rector Street
New York, N Y

March 1978

Since the Air Quality Act of 1967, which authorized EPA to establish safe levels of air pollutants and apply the controls necessary to achieve these levels, Ebasco Services Inc has been involved in helping the Electric Utility Industry to apply new technology to air pollution problems and adapt these control measures to be consistent with the historical industry requirement of high flexibility and reliability. Since air and water quality provisions often represent over one third of new plant investment, it is logical that the architect-engineer function is a major aspect of successful control equipment application. The complexity and cost of current control schemes require careful integration with the balance of plant not only to minimize the impact on the basic power generation function but also to facilitate dealing with the "new" products of a power plant - solid and liquid wastes.

The following discussion summarizes the salient features of six specific air quality control systems which illustrate Ebasco's involvement from conceptual design through preparation of specifications and engineering of system auxiliaries. La Cygne Unit 1 and Dave Johnston Unit 4 are operational systems designed for particulate and SO_2 removal. The remaining units, Cholla 2, Homer City 3, Killen 1 & 2, and Boswell 4 are in various stages of planning and engineering. All of these systems are based on wet chemical technology although, as is often the case with air quality control equipment, not all will proceed to completion in accordance with the original conceptual design.

These units were selected for discussion here because they are believed to be good examples of the more complex type of systems which Ebasco and the Electric Utility Industry are currently applying to large new coal-fired units. A brief summary of Ebasco's related experience and study work on other units is also included.

A - LA CYGNE UNIT 1

1. System Description

La Cygne Unit 1 (840 MW net) of Kansas City Power and Light and Kansas Gas and Electric Company has a B&W cyclone fired balanced draft boiler rated at 6 200 000 lb steam per hour. The unit was the first installation at a new mine mouth plant at La Cygne, Kansas using bituminous coal of low quality:

9 000-10 000 Btu/lb, 20-30% ash, and up to 6.0% sulfur

The B&W-designed air quality control system consists of seven scrubber-absorber modules (subsequently increased to eight) with each module containing a variable throat rectangular venturi for particulate removal, a tray type absorber superficially similar to the UOP turbulent contact absorber for SO_2 removal, chevron demisters and an in-line bare tube steam reheater. The boiler and AQCS are drafted by six parallel induced draft fans located downstream of the AQCS and discharging to a 700 ft chimney. Locally mined limestone is milled to an aqueous slurry in two wet ball mills. Spent slurry of flyash and calcium products is pumped to a 160 acre settling pond with clear liquor returned to the AQCS.

2. <u>System Responsibility</u>

Ebasco, with responsibility for overall plant design and construction, also was involved in the AQCS. Study work associated with the AQCS included:

1. Review of state-of-the-art of alternative systems and their investment and operating costs.
2. Suitability of alternate systems for the La Cygne Unit and their impact on over-all plant performance and schedule.
3. Determination of ambient SO_2 concentrations as a function of stack height with recommendation on required height.
4. Review of state-of-the-art and cost of continuous emission monitoring equipment components and systems.
5. Determination of adequacy of supply of locally available limestone.
6. Determination of technical and economic feasibility of on-site calcining of limestone in rotary kilns.
7. Preparation of system specifications and evaluation of proposals.

Additional effort was expended on the Montrose Pilot Test. In 1970, pilot tests of a Chemico two-stage venturi scrubber were conducted at the Montrose Station on a 1500 cfm slip stream taken ahead of the electrostatic precipitators. The objective was to determine the effect of operating parameters such as ΔP, L/G, stoichiometic ratio and furnace injection on particulate and SO_2 removal as a guide to system design at La Cygne. Ebasco functioned as a test observer, including review of technical results and conclusions. Program results were incorporated into evaluation of eventual proposed systems for La Cygne Unit 1.

Ebasco-designed system auxiliaries included:

1. Limestone storage and handling, including general equipment arrangement within the millhouse.
2. AQCS support steel (partial) plus all foundations.
3. Piping and valves (partial) within AQCS battery limits.
4. Pumps and piping for slurry blowdown to settling pond and clear water return.

3. Operational Experience

Ebasco's Plant Operations Department was responsible for startup and shakedown of the entire plant, including the AQCS (in conjunction with B&W). Initial operation of the AQCS was in late 1972, although only one module was equipped with absorber internals and recirculation pumps, and not all instrumentation had been installed. Some initial operating problems included:

1. I D fan vibration
2. Venturi spray nozzle plugging and erosion
3. Pump inlet screen plugging
4. Slurry control valve failure
5. Demister plugging
6. Reheater corrosion
7. Instrument sensor pluggage
8. Loss of balls from limestone mills
9. Pluggage of area drainage sump pumps
10. Damper scaling

During Ebasco's one year shakedown period at the site, some of the changes made were:

1. Steam tube reheaters were supplemented with hot air diverted from the air heater. This minimized wet deposits adhering to the fans causing imbalance, and reduced damper and reheater scaling.

2. Hydroclones were installed in the venturi recycle loops to remove large (50 mesh) particles and minimize nozzle and screen pluggage and reduce valve and nozzle erosion.

3. Limestone mill outlet geometry was altered to prevent ball loss.

4. Sump pumps were converted to jet pulsion type to improve removal of slurry spills.

5. Underspray demister washers were replaced with overspray washers to improve performance.

The La Cygne system has been shown to be capable of achieving 0.1 lb per mB particulate emission with 80 percent SO_2 removal. High availability and reliable performance can be achieved provided careful attention is paid to cleaning and established preventative maintenance programs.

B - DAVE JOHNSTON UNIT 4

1. System Description

Dave Johnston No. 4 (330 MW net) of Pacific Power & Light Company has a CE tangentially fired balance draft boiler rated at 2 450 000 lb steam per hour. The unit is an extension at the Dave Johnston Station at Glenrock, Wyoming, and uses local sub-bituminous coal:

7 500 Btu/lb, 12% ash, 0.5% sulfur

The Chemico-designed air quality control system consists of three scrubber trains or modules with each train consisting of a variable throat cylindrical venturi for particulate removal, chevron demisters, and a wet operation induced draft fan. The ID fans discharge to a 250 ft low velocity wet chimney. Dilute flyash slurry is blown down from the scrubbers to an ash settling pond with clear liquor returned to the scrubbers.

2. Division of Responsibility

Although balance of plant design and construction were within Ebasco's scope, the AQCS, including venturi scrubbers, ID fans and chimney were within the scope of Chemico. Ebasco study work related to the AQCS included:

1. Review of state-of-the-art of precipitators and venturi scrubbers for investment costs and suitability for Dave Johnston 4.
2. Determination of ambient concentrations as a function of stack height with recommendation on required height.
3. Inspections of similar Chemico installations at Holtwood and Four Corners to determine relevance of operating experience.
4. Design of overall plant water balance and ash ponds.
5. Preparation of ID fan specifications.
6. Determination of performance testing procedures.

3. Operational Experience

Ebasco's Plant Operations Department cooperated with Chemico during startup and shakedown of the AQCS. Initial operation was in the fall of 1971, and operating problems included:

1. Ash deposits on non-irrigated internal portions of the scrubbers.
2. Scaling of discharge lines to ash ponds.
3. Pluggage of pump suctions with hard scale.
4. Excessive ID fan vibration.
5. Leaky ductwork expansion joints.

The following are some of the changes which were made during the first three years of operation:

1. Fan wash nozzle system was replaced with upstream "fogging" nozzles and closer control was maintained over wash water quality (cooling tower blowdown) in order to prevent deposits from adhering to the fan rotors.
2. Discharge pump piping was resized to prevent deposition of solids and scale.

3. Recycle pump suction nozzles were raised to prevent large pieces from plugging lines.

4. Venturi inlet geometry was revised to minimize buildup of deposits at wet/dry interface.

5. Tests were conducted with lime addition for pH control to minimize erratic performance when burning coal from two different seams with substantially different CaO contents in the flyash.

6. Tests were conducted with chemical additives to select compounds which would influence scale characteristics.

The Dave Johnston System has been shown to be capable of achieving 0.1 lb per mB particulate emission rate and 30 percent of SO_2 removal relying solely on high flyash alkalinity. High availability has been achieved for extended periods provided proper attention is paid to periodic flushing and manual cleaning of the scrubbers.

C - CHOLLA UNITS 2 & 3

1. System Description

Cholla 2 & 3 (250 MW net each) of Arizona Public Service Co have CE tangentially fired balanced draft boilers rated at 2 000 000 lb steam per hour. The units are extensions at the existing plant at Holbrook, Arizona, and will use bituminous New Mexico coal of fairly good quality:

9 000 - 10 800 Btu/lb, 9-18% ash and 0.4-0.9 sulfur

The Research Cottrell designed air quality control system for Unit 2 consists of two mechanical dust collectors, two ID fans, four variable throat flooded disc venturis for particulate removal, four packed bed SO_2 absorbers with integral demisters and bare tube steam reheaters, two booster ID fans and a 550 ft chimney (common to Units 2 & 3) with two free standing steel liners. The reagent system consists of two wet ball mills sized to provide limestone slurry to Units 1 & 2 and a future Unit 4.

The AQC system for Cholla 3 consists of two UOP-designed hot precipitators, two ID fans and the shared chimney with Unit 2. Compliance with Arizona State SO_2 emission regulations is achieved by averaging the emissions between Unit 2 and 3. Although the flue gas streams from the two units are not physically blended together, provision has been made for future addition of a gas mixing chamber upstream of the chimney if such an arrangement is required.

The waste disposal system is common to the entire plant. Dry flyash from mechanical dust collectors and precipitators is pneumatically conveyed to tanks and mixed with venturi/absorber blowdown. The mixed product is pumped four miles by three parallel plunger pumps to a pond located on the site. The air quality control system takes all of its makeup requirement from cooling tower blowdown and any excess cooling tower blowdown is mixed with the waste sludge and pumped to the disposal pond. Solar evaporation rates are sufficiently high that all water which is sent to the pond (and this represents the total plant waste water generation) is evaporated with no water returned from the pond or blown down.

The original RC-designed AQC system for Unit 1 (115 MW), which is basically the same as the Unit 2 system, was modified to incorporate water balance, reagent supply and waste disposal arrangements consistent with overall plant design philosophy.

2. System Responsibility

Overall plant design are within Ebasco's scope and study work related to the AQCS included:

1. Review of state-of-the-art of SO_2/particulate removal systems with feasibility and cost for the Cholla application.
2. Determination of ambient concentrations as a function of stack height for various alternative systems with a recommendation on stack height.
3. Determination of suitability of axial flow fans for abrasive/corrosive environments associated with AQCS.
4. Conceptual design of overall plant water balance and waste disposal schemes.

5. Recommendations on sound control provisions.
6. Preparation of Environmental Impact Statement and presentation of testimony at public hearings.
7. Examination of coal handling system to provide for allocation between units based on coal sulfur content.
8. Review of alternative flue gas reheat schemes including gas mixing between units and oil firing.
9. Study of costs and provisions to be made for segregation and classification of flyash for possible future use in cement manufacture.
10. Preparation of specifications and evaluations of proposals for mechanical dust collectors, ID fans, booster ID fans, venturi/absorber system, limestone handling equipment, and electrostatic precipitators.

Excluding the venturi/absorbers and limestone milling equipment, which were designed by Research Cottrell, and the hot electrostatic precipitators, which were designed by UOP, Ebasco specified or designed AQCS auxiliaries included:

1. Mechanical dust collectors
2. ID and booster ID fans
3. Chimney
4. Waste disposal system-pumps, piping, tanks, agitators
5. Pond dike including clay sealing
6. Dry limestone handling equipment
7. Interconnecting ductwork and bypass
8. Electrical auxiliaries and foundations
9. AQCS control system (partial)

3. System Status

Scheduled trial operation dates for Units 2 and 3 are 1st quarter, 1978 and 1st quarter, 1979, respectively. The Unit 2 AQCS is essentially complete and gas and slurry flows are expected to be established in March of 1978.

D - HOMER CITY 3

1. System Description

Homer City Unit 3 (630 MW) of New York State Electric & Gas Corporation and Pennsylvania Electric Co. has a B&W pulverized coal (with CE Raymond Mills), balance draft steam generator rated at 4 280 000 lb steam per hour. The unit is an extension of an existing mine mouth plant at Homer City, Pennsylvania, which has historically utilized the following coal:

10 900-12 700 Btu/lb, 12-23% ash, 1.4-2.8% sulfur

The AQCS, as defined in the original conceptual design and developed to the contract stage with equipment Vendor, was to consist of hot electrostatic precipitators, ID fans, mobile bed SO_2 absorbers utilizing lime reagent, in-line steam tube reheaters and downstream booster ID fans exiting to a 1200 ft chimney. Auxiliary equipment was to include conveyors, silos and slakers for reagent preparation and thickeners, vacuum filters and truck loading facilities for waste disposal.

However, in view of State requirements for emission reductions on the existing Homer City Units 1 & 2, an approach was developed by NYSE&G and Pennelec as an alternative to the AQCS just described. This was based upon a two stage coal washing process which reduced maximum coal sulfur from 2.8 wt% to 1.7 wt% and then segregated the coal into two streams of 2.1 wt% sulfur and 0.6 wt% sulfur. These two streams would meet emission requirements of both the existing units and also Unit 3 without the use of flue gas desulfurization. The planned Unit 3 AQCS was thus modified to consist of hot precipitators (supplied by Research Cottrell), ID fans, a 1200 ft chimney and provision for addition of an SO_2 removal system if it were to be required in the future.

2. System Responsibility

Overall plant design and construction are within Ebasco's scope and study work related to the AQCS includes:

1. Determination of ambient concentrations as a function of stack height, including a review of extensive ambient SO_2 monitoring data from the Homer City/Keystone/Conemaugh area, with a recommendation on stack height.

2. Cost comparison of increased stack height vs increased flue gas reheat as a means of increasing plume height.

3. Review of status of coal mill pyrite rejection as a partial sulfur removal technique.

4. Visits to all operating FGD systems within the industry prior to development of conceptual design of system.

5. Conceptual design of water balance and waste disposal schemes, but excluding ultimate disposal which was intended to be off-site by trucking.

6. Preparation of specifications and evaluations of proposals for hot electrostatic precipitators, ID fans, SO_2 absorbers, lime handling equipment, chimney and waste disposal equipment, including vacuum filters.

3. System Status

Homer City 3 commenced operation in late 1977 utilizing high sulfur run-of-mine coal which had been previously stockpiled. The first stage of the wash plant is complete and has supplied some coal for Units 1 & 2. Operation of the wash plant and construction activity on the second wash stage have been suspended for the duration of the UMW strike.

E - KILLEN 1 & 2

1. System Description

Killen Units 1 & 2 (600 MW net each) of Dayton Power & Light Company and Cincinnati Gas & Electric Company have B&W balanced draft boilers rated at 4 545 000 lb steam/hr. The units are the first installations at a new site near Manchester, Ohio. System design has been based on a high ash coal with both high and low sulfur coal, 10 500-12 000 Btu/lb, 10-23% ash, although the actual source and quality have not been finalized.

For initial operation on low sulfur coal, the AQCS will consist of hot side precipitators (supplied by UOP) for particulate removal only. A conceptual design was developed for expansion of the AQCS to include SO_2 removal if conversion to high sulfur coal is required. The conceptual design consists of hot electrostatic precipitators, axial flow ID fans, SO_2 absorbers utilizing limestone reagent, booster ID fans, steam tube reheaters and a common 950 ft chimney with independent steel liners. Absorber water makeup would be taken from cooling tower blowdown with both absorber sludge and flyash blown down to on-site clay lined ponds with recycle of water. The reagent system would consist of three wet ball mills for limestone slurry with limestone delivered to the plant by barge.

2. System Responsibility

Overall plant design is within Ebasco's scope and study work related to the AQCS included:

1. Determination of breakeven coal cost as a function of sulfur content for various absorber alternatives.
2. Determination of ambient concentrations as a function of stack height with recommendations on stack height.
3. Study of investment and operating cost comparison between wet and dry chimney operation.
4. Conceptual design of overall plant water balance and waste disposal schemes.
5. Preparation of Environmental Impact Statement and information for permit applications.

3. System Status

Scheduled trail operation dates for the Killen Units, originally 1979 and 1980 have been postponed to 1981 and 1982. Excluding the hot precipitators, no specifications for major AQCS components have been prepared pending resolution of coal supply.

F - CLAY BOSWELL 4

1. System Description

Clay Boswell Unit 4 (500 MW) of Minnesota Power & Light Co has a Combustion Engineering tangentially fired balanced draft boiler. The unit is an extension to an existing plant at Cohasset, Minnesota, and will be fired with sub-bituminous Montana coal with the following characteristics:

7 500 - 10 400 Btu/lb, 2-20% ash and 0.5 - 3.8% sulfur

The final design for the AQC system will include a four train arrangement with each train consisting of a variable-throat venturi for particulate, an open spray tower utilizing lime for SO_2 removal, bypass gas injection for reheat, and a downstream high alloy fan to draft both the boiler and AQCS. Hot gas for reheat (representing about 5 percent of total flow) is withdrawn upstream of the Ljungstrom air heaters and cleaned of particulates in a hot electrostatic precipitator prior to injection into the absorber exit gas. ID fans are equipped with wash sprays and the 600 ft chimney liner is large diameter, low velocity so that operation without reheat is also possible. The flyash/absorber sludge is pumped to a permanent settling pond with recycle of water back to the AQCS in a closed loop mode.

This all wet system was designed to maximize the utilization of natural alkalinity in the flyash, which is quite high, and minimizes the makeup lime requirement.

2. System Responsibility

Ebasco's scope of work related to the AQCS includes the following:

1. Conceptual design of the overall AQC system.
2. Preparation of specifications and evaluation of proposals for venturi scrubbers/SO_2 absorbers, small hot electrostatic precipitators, and related auxiliary equipment.
3. Stack height optimization study.

4. Review of pilot test results as related to final system design.

5. Water management program, including three existing units.

In addition, Ebasco is in the process of specifying or designing the following components of the AQC system.

1. ID fans
2. Chimney
3. Waste disposal system (ponds, piping, pumps)
4. Limestone handling and storage equipment
5. Electrical auxiliaries
6. Foundations and enclosures

3. System Status

Scheduled trial operation date is February 1980. Purchase Orders for major components have been placed including a venturi/absorber system with Peabody and a small hot esp with Joy-Western.

G - OTHER AQCS - RELATED EXPERIENCE

1. Recently Initiated Work (1977/1978-In Progress)

Ebasco will be or is in the process of conducting AQCS related study efforts, and engineering/design/procurement activities for the following recently acquired projects:

- Houston Power & Light - 2 x 750 MW lignite units (1982,1983)
- General Public Utilities - 1 x 650 MW coal unit (1983)
- Jacksonville Electric Authority - 1 x 600 MW coal unit

2. W R Grace Co (1978 - In Progress)

Ebasco will develop conceptual arrangements and investment estimates for alternative regenerable AQC systems to be used on the coal-fired steam supply system for an ammonia from coal gas plant. Pending approval by ERDA, of results of preliminary phases, project would proceed to operation of a demonstration plant by 1982. In this event, Ebasco would also provide engineering/design/procurement services for the AQCS.

3. British Columbia Hydro (1977 - In Progress)

A joint venture of Ebasco and Intercontinental Engineering has determined the technical and economic feasibility of alternative particulate and SO_2 removal systems for 4 x 500 MW coal-fired units where blending of coal was also an option.

4. New York Power Pool (1976/1977)

Ebasco developed investment estimates for air quality control systems for 800 MW class coal-fired units in conjunction with preparation of testimony for public hearings on generic cost differences between fossil/nuclear power generation.

5. Central Hudson Gas and Electric Co. (1977)

Ebasco determined the technical and economic feasibility of air quality control systems for existing units under consideration by FEA for coal conversion orders.

6. Washington Public Power Supply System (1976)

Ebasco developed site-related AQCS investment cost correction factors for CONCEPT site selection program for broad screening of alternative sites for coal-fired units.

7. Niagara Mohawk Power Corporation - (1975 - In Progress)
Lake Erie Generating Station Units 1 & 2

Ebasco prepared an Environmental Impact Statement for two 850 MW coal-fired units including conceptual design and cost estimates for alternative Air Quality Control systems for low, medium and high sulfur coals.

8. Federal Energy Administration (FEA) - (1974)

A Fuel Conversion Study was performed by Ebasco in 1974 for the Federal Energy Administration entitled "Practicality and Reliability Assessment Study" FEA Contract No. C-05-50095-00. The purpose of this study was to provide guidelines for identifying the potential candidates for conversion of existing units to direct firing of coals and to determine the equipment required, approximate range of investment involved for the conversion, construction time and unit outage time required for conversion. Investment and operating cost curves were developed for particulate and SO_2 control equipment as a function of unit size and remaining life.

9. Pacific Power & Light Co - (1974)
<u>Dave Johnston Units 1, 2, & 3 (440 MW Total)</u>

Ebasco determined the technical and economic feasibility of retrofitting venturi scrubbers or electrostatic precipitators to existing units at this station. Design/engineering/procurement services were provided for the selected precipitator alternative which became operational in 1977.

10. <u>Houston Lighting and Power Co - (1973)</u>

Ebasco prepared a state-of-the-art review of particulate control technolog for oil-fired units.

11. <u>Iowa Public Service Co - (1972 - 1975)</u>

George Neal Unit 1 - Preparation of specifications and analysis of proposals for hot electrostatic precipitator for retrofit application.

George Neal Unit 2 - Initiation of field test on gas conditioning to upgrade precipitator performance.

George Neal Unit 3 - Preparation of specifications and analysis of proposals for cold electrostatic precipitator including supervision of testing on Unit 2 to obtain design parameters for Unit 3.

George Neal Unit 4 - Preparation of specifications and analysis of proposals for hot electrostatic precipitators.

12. <u>Carolina Power & Light Co - (1973)</u>

Roxboro Units 1, 2 & 3; Cape Fear Units 5 & 6; H F Lee Units 1, 2 & 3; Ashville Units 1 & 2; H B Robinson Unit 1; W H Weatherspoon Unit 1, 2 & 3; L V Sutton Unit 1 & 2; (3340 MW total). Ebasco determined technical feasibility and prepared investment estimates for retrofitting electrostatic precipitators to existing units.

13. Allegheny Power Service Corp - (1972)

Unnamed Units 1 & 2 (600 MW each). Ebasco estimated ambient SO_2 concentrations for alternative air quality control systems, including coal washing, for two potential sites. An AQCS engineering backup report was prepared for the construction permit application.

14. Columbus & Southern Ohio Electric Co - (1971)

E M Poston Station Units 1, 2, 3 & 4 (220 MW total). Ebasco determined technical and economic feasibility of retrofitting particulate/SO_2 removal equipment to existing units.

15. Associated Electric Corp - (1972)

New Madrid Unit 2 - Ebasco prepared an Environmental Impact Statement including conceptual AQCS design.

US UTILITY BAG HOUSE INSTALLATIONS

No.	Utility	Station	Size	Coal	Bag House Supplier	Comment
1	Pennsylvania Power & Light	Sunbury No. 1 & No. 2 (four boilers)	176 MW	Anthracite 30% ash 0.8% sulfur	Western Precipitation Div, Joy Mfg Co	Retrofit installed 1973. First filter on coal-fired unit in US
2	Pennsylvania Power & Light	Holtwood No. 17	73 MW	Anthracite silt 35% ash 0.7% sulfur	Wheelabrator-Frye	Retrofit installed 1975. Runs in parallel with wet scrubber. Another filter will replace scrubber to eliminate opacity problem.
3	Pennsylvania Power & Light	Brunner Island No. 1	350 MW	2.0-3.5% sulfur 12-18% ash	Carborundum	Retrofit intended to be in service by 1980.
4	Colorado Ute Electric Assn	Nucla 1, 2, 3	39 MW	Colorado bituminous 12% ash 0.7% sulfur	Wheelabrator-Frye	Installed 1973. Retrofit on stoker-fired boilers. First US installation on bituminous coal.
5	Colorado Ute Electric Assn	Bullock	12 MW (two boilers)	Colorado bituminous	Industrial Clean Air Div, Ecolaire Inc	Retrofit started up Dec 1977.
6	Crisp County Power Commission Cordele, GA	Crisp	10 MW	Bituminous 10% ash 1.0% sulfur	Zurn	Installed 1975.
7	Nebraska Public Power District	Kramer (four boilers)	125 MW	Wyoming subbituminous 3-4% ash 0.75% sulfur	ICA - Ecolaire	Retrofit, started up March 1977.
8	Southwestern Public Service	Harrington No. 2	350 MW	Wyoming subbituminous 5-6% ash 1% sulfur	Wheelabrator-Frye	Installation on a new unit slated to start operating in 1978.
9	Southwestern Public Service	Harrington No. 3	350 MW	Wyoming subbituminous 5-6% ash 1% sulfur	Wheelabrator-Frye	Scheduled to start up in 1980. New unit.
10	Texas Utilities	Monticello No. 1 & 2	575 MW each	Lignite 8.1% ash to 21% ash 0.6% sulfur	Wheelabrator-Frye	Start-up in 1978 - retrofit.

US UTILITY BAG HOUSE INSTALLATIONS (Cont'd)

No.	Utility	Station	Size	Coal	Bag House Supplier	Comment
11	Public Service of Colorado	Cameo No. 1	22 MW	Colorado bituminous 0.3-0.7% sulfur 4.18% ash 4.17% water	Carborundum	1978 - retrofit.
12	Public Service of Colorado	Arapahoe No. 3	44 MW	Colorado bituminous	Western Precipitation	1980 - retrofit.
13	City of Colorado Springs	Drake No. 6	85 MW	15% ash 0.3% sulfur	Buell-Envirotech	1978 - retrofit. Will replace cold-side precipitator.
14	City of Colorado Spring	Nixon	200 MW		Western Precipitator	1980 - new unit.
15	United Power Association	Elk River (three boilers)	64 MW	4.2-20% ash 0.7% sulfur	Research-Cottrell	1978 - retrofit on three existing boilers - two stokers.
16	City of Fremont, Nebraska	Wright No. 6	16.5 MW	1.5% sulfur (max) 20% ash (max) 5-20% water	Carborundum	1978 - retrofit.
17	City of Fremont, Nebraska	Wright No. 7	22 MW	Same as above	Carborundum	1978 - retrofit.
18	City of Rochester, Minnesota	North Broadway	115 MW	0.5-2.5% sulfur 5-10% ash 5-28% water	Carborundum	1978 - retrofit
19	Minnesota Power & Light	Clay Boswell No. 1 & 2	64 MW each	NA	Watern Precipitation	1978.
20	City of Columbia, Missouri	Columbia	38.5 MW	1.5-3.6% sulfur 11.9-16% ash 42% water	Carborundum	1979 - retrofit.
21	Board of Public Utilities, Kansas City, Kansas	Kansas City	88 MW	West bituminous	ICA - Ecolaire	1979.

US UTILITY BAG HOUSE INSTALLATIONS (Cont'd)

No.	Utility	Station	Size	Coal	Bag House Supplier	Comment
22	Otter Tail Power Co	Coyote	410 MW	North Dakota lignite	Wheelabrator-Fryo/ Atomics Intl	Filter to be used in combination with new, dry sulfur scrubber - 1981 start up.
23	Sierra Pacific	Valmy No. 1	250 MW	Utah bituminous 0.3-1.5% sulfur 3-20% ash 3-32% water	Carborundum	1981 - new unit.
24	Tennessee Valley Authority	Shawnee No. 1-10	1750 MW	Various low sulfur western coal types	Buell-Envirotech	Retrofit - completion in 1981 - largest order to date.

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14	City of Colorado Spring	Nixon	200 MW		Western Precipitator	1980 - new unit.
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24	Tennessee Valley Authority	Shawnee No. 1-10	1750 MW	Various low sulfur western coal types	Buell-Envirotech	Retrofit - completion in 1981 - largest order to date.

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integ - ebasco

Joint Venture

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FILE 604H-200.0
THERMAL DIV.
OCT 17 1979
ROUTE
DIV. MGR.
3 PROJ. CONTROL
POWER PLANT
MINING
CONSTRUCTION
1 Project Engineer
2 Staff Eng'r
AC

17 October, 1979
File: 0064.006
.150
IE-79-82

4 Copies Report:
1 - PCCD File
1 - AC
2 - Thermal Engs
19/10/79

Mr. M.A. Favell
Manager, Engineering Services
B.C. Hydro & Power Authority
Box 12121
555 West Hastings Street
Vancouver, B.C. V6B 4T6

Dear Mr. Favell:

Re: Hat Creek Project
Air Quality Control Study

We have pleasure in attaching four copies of our air quality control study. This is in response to your letters dated 15 May and 27 July, 1979 and our letter IE-79-49 dated 19 June, 1979.

Throughout the progress of the study and the report preparation we have kept you informed of our results by means of draft copies and informal meetings. Your comments emanating from these have been addressed and incorporated where appropriate.

We believe the table in the front of the report also presents our results in the form you require.

As agreed with you the study relates solely to the Pollution Control Board emission levels and we have not considered the effects of ambient levels. Likewise opacity considerations have been excluded from the report.

We propose that the abstract comprising summary, discussion and table of results be made into a Supplementary SDM with a reference to the

SDM

.../2

complete report. We shall be pleased to do this on receipt of your clearance.

Very truly yours,

INTEG-EBASCO

P.R. Gurney
Project Engineer

PRG/di

Att.

	BASE	PARTICULATE CONTROL			SO_2 EMISSION CONTROL				COMBINED PARTICULATE & SO_2 EMISSION CONTROL				
		UPPER LIMIT	LOWER LIMIT		UPPER LIMIT		LOWER LIMIT		UPPER LIMITS			LOWER LIMITS	
PCB Objectives (lb/MBTU)													
Particulates Emission	-	0.09	0.02	0.02	-	-	-	-	0.09	0.09	0.09	0.02	0.02
SO_2 Emissions	-	-	-	-	0.8	0.8	0.2	0.2	0.8	0.8	0.8	0.2	0.2
AQCS Equipment	ESP	ESP	ESP	FF	ESP + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Dry FGD	ESP + Partial Wet FGD	FF + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Wet FGD
Emissions (lb/MBTU)													
Particulates	0.225	0.09	0.02	0.02	0.225	0.035	0.225	0.05	0.09	<0.02	0.035	0.02	<0.02
Sulphur Dioxide	1.34	-	-	-	0.8	0.8	0.2	0.2	0.8	0.08	0.8	0.2	0.2
Differential Capital Cost (Including Incremental Capability) %			3	-(1)	15	10	22	16	16	14	10	25	21
$ x 10^6 1280 ←	Base	18	40	-(13)	189	126	283	199	207	176	126	323	270
$/kW 640 ←	Base	9	20	- (6)	95	63	142	100	104	89	63	162	135
~~Differential~~ Capitalized Operating & Maintenance Cost - $ x 10^6 %		0.4	0.4	2	8	7	13	13	8	6	7	14	15
776 ←	Base	2	3	16	60	52	103	98	62	44	52	106	119
~~Differential~~ Owning & Operating Cost Capitalized ($ x 10^6) %		1	2	0.1	12	9	19	14	13	12	9	21	19
2056 ←	Base	20	43	3	249	178	386	297	269	252	178	429	399
~~Differential~~ Mill Rate (mills/kWhr) % 22.26 ←	Base	0.2 1	0.5 2	0.03 0.1	2.7 12	1.9 9	4.2 19	3.0 14	2.9 13	2.73 12	1.9 9	4.7 21	4.23 19

NOTES:
- ESP = Cold Side Electrostatic Precipitators, FF = Fabric Filters
- FGD = Flue Gas Desulphurization
- Capital costs for the four unit plant are in October 1978 dollars excluding corporate overhead and interest during construction.
- Costs are based on originally fitted equipment - i.e. not retrofitted.

HAT CREEK PROJECT

AQCS ALTERNATIVES

	BASE	PARTICULATE CONTROL			SO_2 EMISSION CONTROL				COMBINED PARTICULATE & SO_2 EMISSION CONTROL				
		UPPER LIMIT	LOWER LIMIT		UPPER LIMIT		LOWER LIMIT		UPPER LIMITS			LOWER LIMITS	
PCB Objectives (lb/MBTU) Particulates Emission SO_2 Emissions		0.09 -	0.02 -	0.02 -	- 0.8	- 0.8	- 0.2	- 0.2	0.09 0.8	0.09 0.8	0.09 0.8	0.02 0.2	0.02 0.2
AQCS Equipment	ESP	ESP	ESP	FF	ESP + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Dry FGD	ESP + Partial Wet FGD	FF + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Wet FGD
Emissions (lb/MBTU) Particulates Sulphur Dioxide	0.225 1.36	0.09 -	0.02 -	0.02 -	0.225 0.8	0.035 0.8	0.225 0.2	0.05 0.2	0.09 0.8	<0.02 0.08	0.035 0.8	0.02 0.2	<0.02 0.2
Differential Capital Cost (Including Incremental Capability) $ x 10^6 $/kW	1,280 640	18 9	40 20	-(13) - (6)	189 95	126 63	283 142	199 100	207 104	176 89	126 63	323 162	270 135
Percentage (%)	–	1.4	3.1	- 1.0	14.7	9.8	22.1	15.5	16.2	13.6	9.8	25.2	21.1
Differential Capitalized Operating & Maintenance Cost - $ x 10^6	776	2	3	16	60	52	103	98	62	44	52	106	119
Percentage (%)	–	0.4	0.4	2	8	7	13	13	8	6	7	14	15
Differential Owning & Operating Cost Capitalized ($ x 10^6)	2056	20	43	3	249	178	386	297	269	252	178	429	389
Percentage (%)	–	1	2	0.1	12	9	19	14	13	12	9	21	19
Differential Mill Rate (mills/kWhr)	22.26	0.2	0.5	0.03	2.7	1.9	4.2	3.0	2.9	2.73	1.9	4.7	4.23
Percentage (%)	–	1	2	0.1	12	9	19	14	13	12	9	21	19

NOTES:
- ESP = Cold Side Electrostatic Precipitators, FF = Fabric Filters
- FGD = Flue Gas Desulphurization
- Capital costs for the four unit plant are in October 1978 dollars excluding corporate overhead and interest during construction.
- Costs are based on originally fitted equipment - i.e. not retrofitted.
- To convert to October 1979 dollars × 1.08

HAT CREEK PROJECT

AQCS ALTERNATIVES

	BASE	PARTICULATE CONTROL			SO_2 EMISSION CONTROL				COMBINED PARTICULATE & SO_2 EMISSION CONTROL				
		UPPER LIMIT	LOWER LIMIT		UPPER LIMIT		LOWER LIMIT		UPPER LIMITS			LOWER LIMITS	
PCB Objectives (lb/MBTU)													
Particulates Emission		0.09	0.02	0.02	-	-	-	-	0.09	0.09	0.09	0.02	0.02
SO_2 Emissions		-	-	-	0.8	0.8	0.2	0.2	0.8	0.8	0.8	0.2	0.2
AQCS Equipment	ESP	ESP	ESP	FF	ESP + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Dry FGD	ESP + Partial Wet FGD	FF + Partial Wet FGD	FF + Partial Dry FGD	ESP + Full Wet FGD	FF + Full Wet FGD
Emissions (lb/MBTU)													
Particulates	0.225	0.09	0.02	0.02	0.225	0.035	0.225	0.05	0.09	<0.02	0.035	0.02	<0.02
Sulphur Dioxide	1.36	-	-	-	0.8	0.8	0.2	0.2	0.8	0.08	0.8	0.2	0.2
Differential Capital Cost (Including Incremental Capability)													
$ x 10^6	1,280	18	40	-(13)	189	126	283	199	207	176	126	323	270
$/kW	640	9	20	- (6)	95	63	142	100	104	89	63	162	135
Percentage (%)	—	1.4	3.1	- 1.0	14.7	9.8	22.1	15.5	16.2	13.6	9.8	25.2	21.1
Differential Capitalized Operating & Maintenance Cost - $ x 10^6		2	3	16	60	52	103	98	62	44	52	106	119
Percentage (%)	—												
Differential Owning & Operating Cost Capitalized ($ x 10^6)		20	43	3	249	178	386	297	269	252	178	429	389
Percentage (%)	—												
Differential Mill Rate (mills/kWhr)		0.2	0.5	0.03	2.7	1.9	4.2	3.0	2.9	2.73	1.9	4.7	4.23
Percentage (%)	—												

NOTES:

- ESP = Cold Side Electrostatic Precipitators, FF = Fabric Filters
- FGD = Flue Gas Desulphurization
- Capital costs for the four unit plant are in October 1978 dollars excluding corporate overhead and interest during construction.
- Costs are based on originally fitted equipment - i.e. not retrofitted.
- To convert to October 1979 dollars × 1.08

metric flow rate. One manufacturer, BABCOCK & WILCOX, is known to be pursuing the ESP - dry FGD combination and, from pilot tests undertaken at Basin Electtric Utility, is indicating that precipitator sizing remains the same. This apparently fortuitous combination of changes in gas conditions as to cause no modifications to ESP performance requires further verification.

Whereas the approximate costs for this combination can be inferred from the tables (Exhibits 4.0) Integ-Ebasco consider that full scale operational experience and additional investigation into the precipitator design aspects to be necessary. Until such factors are satisfied the combination cannot be treated with the same degree of technical confidence as the dry scrubber - fabric filter combination.

The dry scrubber system is located upstream of the particulate control device. For combination with fabric filters typified by Cases 7A and 8A, the spray dryer vessels would be located between the mechanical collectors and filters.

The mechanical collectors remove an estimated 85 percent of the particulates. The lime slurry injected in the spray dryers reacts with the SO_2 to produce calcium sulphite and sulphate in a dry powder form; the reaction is considered to occur during or shortly after evaporation of the injected slurry water. The fabric filters receive the flue gas leaving the spray dryers to remove the calcium salts and further fly ash quantities.

The waste material from fabric filter hoppers is in dry form and can be pneumatically conveyed to a central location for disposal via belt conveyors, which is consistent with the Base Plant dry ash disposal scheme.

The combined system of mechanical dust collectors, spray dryers, and fabric filters is substantially larger than the Base Scheme plant, requiring relocation of the chimney.

For Case 7 approximately 50 percent of the flue gas must be treated to achieve the upper PCB emission limit for SO_2 of 0.34 mg/kJ (0.8 lb/MB). The remaining 50 percent is bypassed and re-mixed with the spray dryer exit gas prior to the fabric filters. The mixed gas temperature would be approximately 110°C (230°F). With a constant fabric filter design criteria air-to-cloth ratio of 0.01 $m^3/sec/m^2$ (2 $acfm/ft^2$), the effect of the lower gas inlet temperature is to reduce the filter size required by approximately 5 percent compared with the Case 4 fabric filter (particulate control only).

For Case 8 all flue gas must be treated in order to achieve the lower PCB limit for SO_2 of 0.09 mg/kJ (0.2 lb/MB). The spray dryer facility is equipped with a by-pass for start up, shutdown and upset conditions but is not used during normal operation. The filter inlet gas temperature would be approximately 77°C (170°F) resulting in a filter some 10 percent smaller than for the Case 4 condition.

The generation of calcium salts in the fly ash increases the dust loading to the filters which has an adverse effect on the efficiency of particulate removal. For both Case 7 and 8 it is expected that this will prevent the lower PCB particulate limit from being attained. The predicted particulate emissions corresponding to Case 7 and 8 (with fabric filters) are 0.015 mg/kJ (0.035 lb/MB) and 0.02 mg/kJ (0.05 lb/MB) respectively.

Dry FGD Lime Utilisation

The inputs of lime and water to the spray dryers must be separately adjusted to provide correct stoichiometry and temperature. Both lime utilisation and SO_2 removal effectiveness are improved at lower temperatures so that the water content is increased beyond slurry composition requirements in order to achieve this condition. The expected gas operating temperature in the spray dryers is 77°C (170°F) or about 17°C (30°F) above the water dew point. This temperature is low enough to achieve better utilisation of lime but high enough to avoid possible dew point problems in the downstream fabric filters.

Dry FGD systems have demonstrated high lime use during pilot testing with stoichiometric ratios of 2 or greater being realised for the higher removal efficiency levels of 85 to 90 percent. Recycling of unreacted lime reagent from the fabric filter hoppers back to the spray dryers has been proposed as one method of reducing lime consumption. Although this increases the complexity of the overall process, Cases 7 and 8 have incorporated this probable near-term process development feature; improvements in stoichiometry to the 1.1 to 1.4 level, based on inlet SO_2, are expected.

For recycling of unreacted reagent, a portion of the fabric filter hopper contents is pneumatically conveyed to the reagent preparation area and blended with the lime slurry in mixing tanks at the slaker discharges. The use of mechanical dust collectors provides an additional advantage by reducing the burden of inert fly ash (due to low calcium content) which must be recycled through the spray dryers along with the unreacted lime.

3.3 OTHER FGD RELATED FACTORS

This Section discusses other factors related to the incorporation of FGD systems, including: reagent properties, availability and cost; FGD sludge as a by-product; and chimney design considerations.

3.3.1 Reagents

FGD systems consume substantial quantities of reagents in the process of removing SO_2. Depending on the particular process these reagents chemically combine with SO_2 and reappear as either a dry or wet waste product. Further treatment of the wet FGD scrubber waste product (sludge) makes it suitable for dry disposal, using the Base Scheme dry ash disposal system.

In view of the large quantities of reagents required for the Hat Creek Project, the respective sources of reagent, costs, availability and quality are important factors. The following reports briefly on the pricipal findings of investigations into these factors which are tabulated in Exhibit 3-4.

The three more common chemical reagents used with desulphurization processes are soda ash (sodium carbonate), limestone and lime. Either soda ash or lime can be used for SO_2 adsorption in the dry FGD process (Cases 7 and 8). Lime could also be used for SO_2 absorption with wet FGD systems but this application has generally been limited to high sulphur coals. Lime is also used as an additive for waste stabilization with wet limestone FGD systems.

The primary commercial source of soda ash in North America is Green River, Wyoming, and the lowest quoted delivered bulk price to Vancouver is approximately \$143/tonne (\$130/ton);

with final transportation to site, the price of soda ash is estimated to be about $150/tonne ($136/ ton).

The ready availability of lime from the Pavilion Lake lime plant close to the Hat Creek site, will depend on the quantity required which is, in turn, dependant upon the FGD alternative ultimately selected. It is understood with present supply commitments, that additional kiln facilities will be required to meet the demand for lime arising with Cases 6, 7 or 8. Up to 2 years advanced notice may therefore be necessary. For lime the delivered price F.O.B. site is approximately $53/tonne ($48/ton).

The significant price difference between soda ash and lime effectively limits the use of sodium reagents to Wyoming and adjacent States.

Limestone for the wet FGD process is available in sufficient quantities from the Pavilion Lake plant. The delivered price is approximately $10/tonne ($9.15/ton) for a product size of 9 mm (3/8 in) minus, or $16/tonne ($14.60/ton) for a product 50 mm x 9 mm (2 in. x 3/8 in). The 9 mm minus size is suitable for the SO_2 removal process. Particle size reduction with 70 percent of particles passing through a No. 200 Mesh provides good reactant surface area and scrubber performance and grinding at the power plant is considered likely to be the most economical choice.

Reagent Quality

The following typical compositions of lime and limestone have been reported applicable to the Pavilion Lake Lime Plant:

Limestone (%)		Lime (%)	
CaO	54.5	Total CaO	95.0
MgO	0.2	MgO	0.5
Silica	0.4	SiO_2	0.3
R_2O_3	0.2	R_2O_3	0.8
L.O.I.	42.7	L.O.I.	0.9
Others	2.0	Others	2.5
	100.0		100.0

(L.O.I. - Loss on Ignition)

These are typical high calcium products which are generally acceptable for wet scrubbing processes. The major requirement for limestone is a low dolomite ($CaCO_3 \cdot MgCO_3$) content as this is non-reactive for SO_2 removal. Other constituents may require checking for their effect on the FGD process.

The costs used in this study are those for reagent supply from the Pavilion Lake Lime Plant, which are assumed to be suitable for the FGD process alternatives.

3.3.2 FGD Waste By-Product Utilisation

There are several possible uses for the anhydrous calcium sulphate produced by full wet FGD scrubbing at an approximate rate for the plant of 160,000 Mg/year (176,000 Tons/year).

The possibilities are very site specific and this study does not address their feasibility or potential. Cost credits for the product have therefore not been applied.

3.3.3 Chimney Design Considerations

The chimney design incorporates a single concrete shell with four independent mild steel liners which is considered to be satisfactory for all but the wet scrubber cases. Mild steel liners are common within the Industry and provide adequate protection against acid corrosion when the flue gas is above, or not substantially below, the acid dew point. These conditions normally exist with dry particulate collection and also with semi-dry FGD processes. The acceptance of mild steel for the latter case is evidenced by the exclusive use of mild steel construction for components such as spray dryer vessels, and fabric filter casing and tube sheets, which are in direct contact with the gas stream.

With the wet FGD process, not only SO_2 is removed but also about 50 percent of the SO_3 in the treated gas stream is believed to be removed. A reduction in SO_3 lowers the sulphuric acid dew point, which is typically 121 to 149°C (250°F to 300°F) in the FGD inlet gas, by 14 to 28°C (25°F to 50°F). Since it is not generally economically feasible to reheat flue gas after the wet process to the level of 107 to 135°C (225°F to 275°F) in order to avoid acid condensation, operation below the acid dew point is accepted and steps must be taken to protect the chimney liner from corrosion.

Most of the early attempts at corrosion protection involved the application of thin film (30 to 60 mills) coatings of flake glass-filled epoxy or vinyl esters. Many of these applications have failed due to poor quality control during coating or from chemical attack at gas temperatures above the water dew point [about 55°C (130°F)] but below the sulphuric acid dew point. Organic coatings containing flake glass are no longer recommended by the major chimney manufacturers for corrosion control and these products are not generally guaranteed by the coating manufacturer for this application. The use of a new type of thin film coating, a fluoro-elastomer by PULLMAN-KELLOGG, shows superior chemical resistance and has received limited attention in the United States. However, the cost of this coating is about 377 to 430 $\$/m^2$ (35 to 40 $\$/ft.^2$), which is comparable to the entire chimney cost and would therefore appear to be limited to "last resort" retrofit applications.

The current recommendation by the major chimney manufacturers is to use acid-resistant brick and mortar construction with a pressurized annulus to prevent exfiltration of gas through mortar cracks. The manufacturers indicate that this type of design is representative of 90 percent of the chimneys sold in the last several years for use with wet FGD systems.

For these reasons, a brick lined chimney has been selected for the wet scrubbing systems, Cases 5 and 6.

Brick liners cost about 10 percent more than mild steel liners, however they would be about 5 percent less than mild steel using a lower cost casing.

Although the brick liner offers good acid attack resistance it should not be considered the "universal" liner material suitable for all applications. Acid resistant mortars do not perform well under alkaline conditions in the presence of sodium, and are not recommended for use after dry scrubbing systems employing a sodium reagent. This factor dictates that a decision regarding the use of a sodium reagent for dry scrubbing must be confirmed prior to commitment to a specific liner material.

Chimney costs relating to liner, external shell, and foundation, have not been adjusted for the effects of reduced gas flow volume and plume buoyancy resulting from FGD system operation.

EXHIBITS 3.0

HAT CREEK PROJECT

SUMMARY OF AQCS ALTERNATIVES - A GROUP

PLANT EMISSIONS AND ARRANGEMENT DATA

(Worst Quality Blended Coal)

	SO_2 CONTROL		PARTICULATE CONTROL		BLOCK[1] PLANT ARRGT.
	mg/kJ (lb/MB)	%	mg/kJ (lb/MB)	%	
PARTICULATE REGULATION					
(SO_2 emission uncontrolled)					
Case 1A - (Base Scheme) Electrostatic Precipitor	0.58 (1.34)	-	0.1 (0.225)	99.49	Sheet 1
Case 2A - Electrostatic Precipitor	0.58 (1.34)	-	0.04 (0.09)	99.8	Sheet 1
Case 3A - Electrostatic Precipitator	0.58 (1.34)	-	0.01 (0.02)	99.95	Sheet 1
Case 4A - Fabric Filter + Mechanical Collector	0.58 (1.34)	-	< 0.01 (0.02)	99.97	Sheet 2
PARTICULATE (BASE ESP) + SO_2 REGULATION (WET FGD)					
Case 5A - Partial Gas Treatment	0.34 (0.8)	42	0.1 (0.225)	99.49	Sheet 1 & 3
Case 6A - Full Gas Treatment	0.09 (0.2)	85	0.1 (0.225)	99.49	Sheet 1 & 3
PARTICULATE + SO_2 REGULATION (DRY FGD F/FILTER)					
Case 7A - Partial Gas Treatment	0.34 (0.8)	42	0.015 (0.035)	99.9[2]	Sheet 2 & 4
Case 8A - Full Gas Treatment	0.09 (0.2)	85	0.02 (0.05)	99.85[2]	Sheet 2 & 4

Notes: [1] For combinations of AQCS Block Plant Arrangement, refer to Exhibit 3-2 and the sheet numbers identified in column.

[2] The F/Filter 'sees' a higher inlet dust loading due to calcium salts additions from spray dryers (SD) The efficiency quoted for reference applies to system overall i.e., is based on inlet load to SD and outlet load from F/Filter.

EXHIBIT 3-1 (SHEET 1 OF 2)

HAT CREEK PROJECT

SUMMARY OF AQCS ALTERNATIVES - B GROUP (RETROFIT)

PLANT EMISSIONS AND ARRANGEMENT DATA

(Worst Quality Blended Coal)

	SO_2 CONTROL		PARTICULATE CONTROL		BLOCK[4] PLANT ARRGT.
	mg/kJ (lb/MB)	%	mg/kJ (lb/MB)	%	
PARTICULATE REGULATION					
(SO_2 emission uncontrolled)					
Case 1B - (Base Scheme) Electrostatic Precipitor	0.58 (1.34)	-	0.1 (0.225)	99.49	Sheet 1
Case 2B - Electrostatic Precipitator	0.58 (1.34)	-	0.04 (0.09)	99.8	Sheet 1
Case 3B - Electrostatic Precipitator	0.58 (1.34)	-	0.01 (0.02)	99.95	Sheet 1
Case 4B - Fabric Filter + Mechanical Collector[2]	0.58 (1.34)	-	< 0.01 (0.02)	99.97	Sheet 2
SO_2 REGULATION (WET FGD)					
Case 5B - Partial Gas Treatment	0.34 (0.8)	41	not incl.[1]	-	Sheet 3
Case 6B - Full Gas Treatment	0.09 (0.2)	85	not incl.	-	Sheet 3
SO_2 REGULATION (DRY FGD F/FILTER)					
Case 7B - Partial Gas Treatment[3]	0.34 (0.8)	41	not incl.	-	Sheet 4
Case 8B - Full Gas Treatment[3]	0.09 (0.2)	85	not incl.	-	Sheet 4

Notes:

(1) Cases 5B to 8B, FGD systems, require to be added to any one of Cases 1B to 4B to achieve combined SO_2 and particulate control.

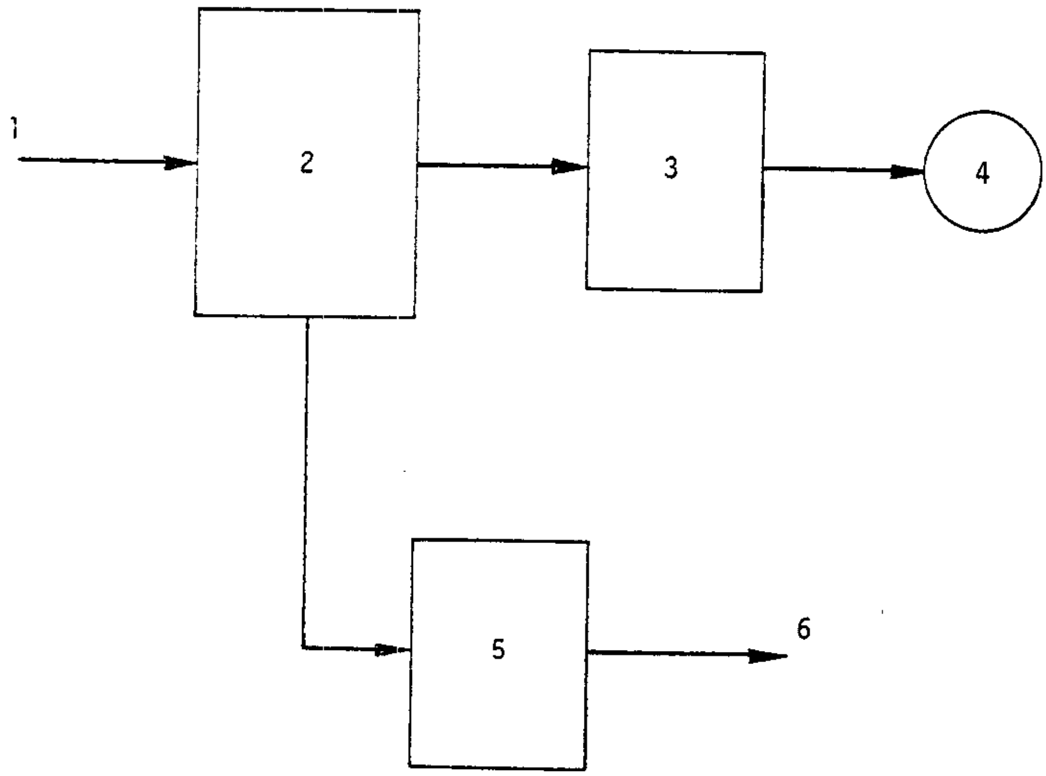
(2) The combination of Case 4B (particulate control) with either Case 7B or 8B results in an increase in particulate emissions to 0.015 (0.035) - 99.9% - and 0.02 (0.05) - 99.85% - respectively.

(3) The combination of Case 7B or 8B with electrostatic precipitor Cases 1B to 3B is assumed not to affect the particulate control performance.

(4) For combinations of AQCS Block Plant arrangement, refer to Exhibit 3-2 and sheet numbers identified in column.

PLANT ARRANGEMENT BLOCK DIAGRAMS

ELECTROSTATIC PRECIPITATORS

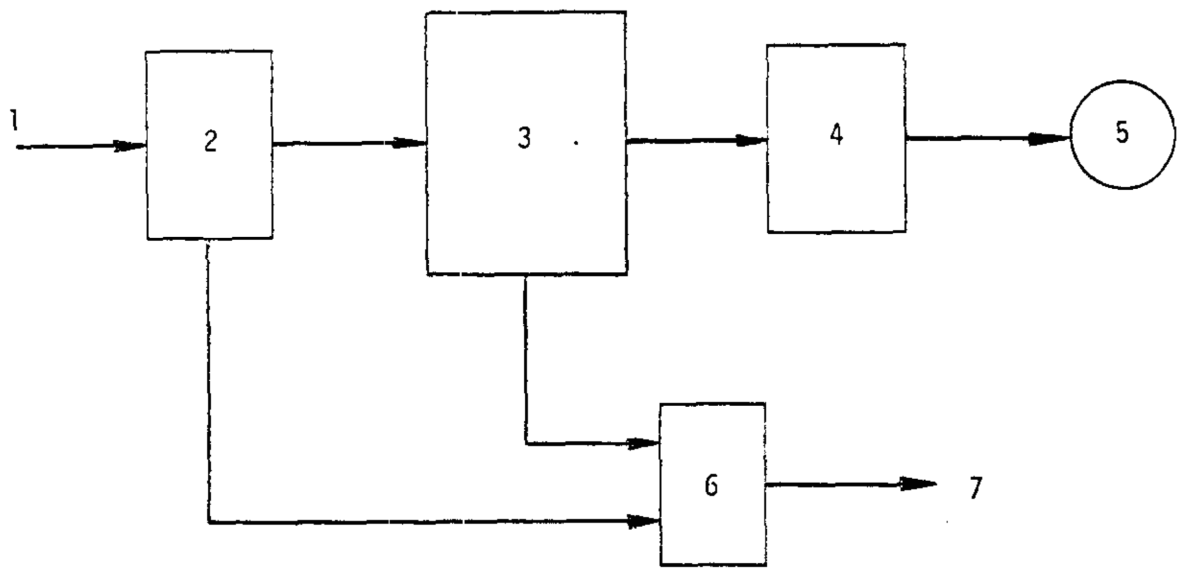


1. Flue Gas from Air Heater Exits or Dry FGD System
2. Electrostatic Precipitator
3. Induced Draft Fans
4. Chimney
5. Pneumatic Ash Handling
6. Fly Ash to Disposal Via Conveyor

EXHIBIT 3-2 (SHEET 1 OF 4)

PLANT ARRANGEMENT BLOCK DIAGRAMS

FABRIC FILTER

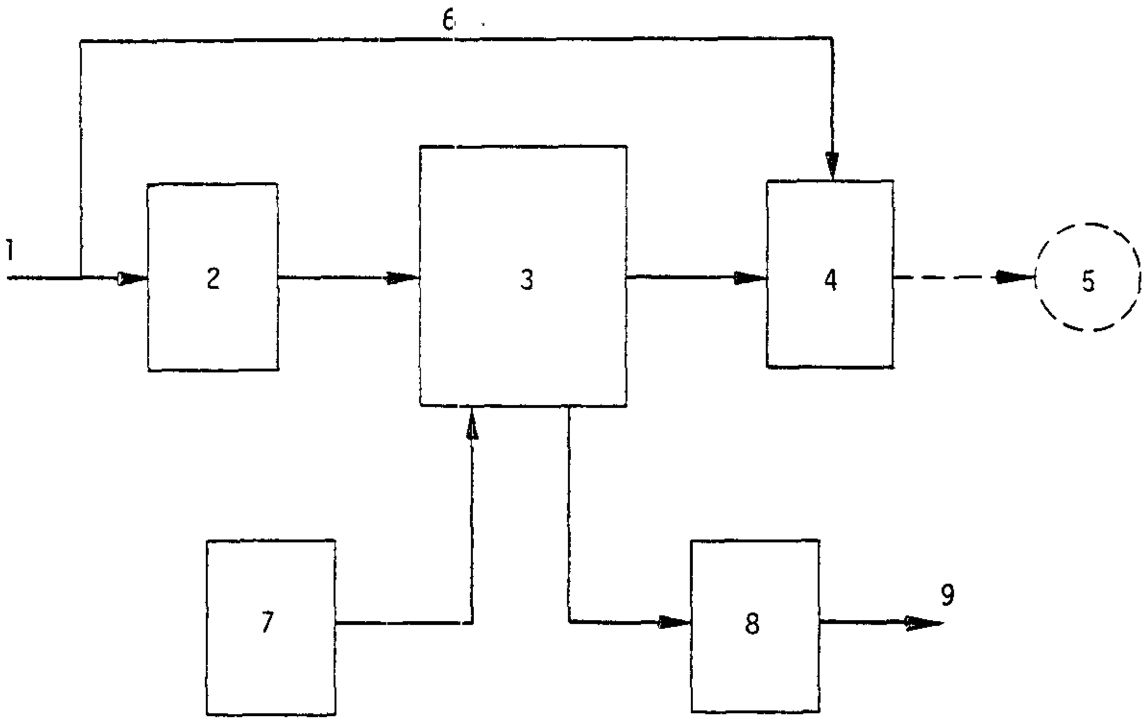


1. Flue Gas from Air Heater Exits
2. Mechanical Dust Collectors
3. Fabric Filters
4. Induced Draft Fans
5. Chimney
6. Pneumatic Ash Handling
7. Fly Ash to Disposal Via Conveyor

EXHIBIT 3-2 (SHEET 2 OF 4)

PLANT ARRANGEMENT BLOCK DIAGRAMS

WET SCRUBBING FGD

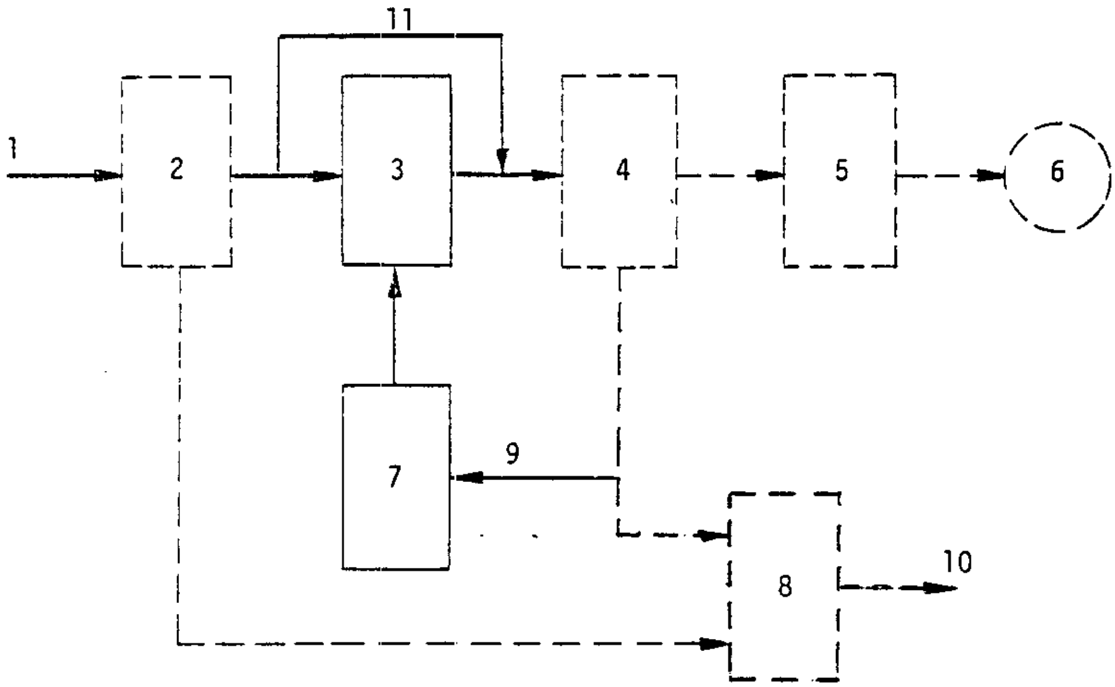


1. Flue Gas from Particulate Control/ID Fans
2. Booster Fans
3. SO_2 Absorbers
4. Gas Reheat
5. Chimney
6. Bypass (used for partial scrubbing cases only)
7. Reagent Preparation
8. Sludge Dewatering/Stabilization
9. Waste to Disposal Via Conveyor

EXHIBIT 3-2 (SHEET 3 OF 4)

PLANT ARRANGEMENT BLOCK DIAGRAMS

DRY SCRUBBING



1. Flue Gas from Air Heater Exits
2. Mechanical Dust Collectors (Only with Fabric Filters)
3. Spray Dryers
4. Fabric Filter or Electrostatic Precipitator
5. Induced Draft Fans
6. Chimney
7. Reagent Preparation
8. Pneumatic Ash Handling
9. Partial Product Recycle
10. Waste to Disposal Via Conveyor
11. Bypass (for Partial Treatment Cases Only)

EXHIBIT 3-2 (SHEET 4 OF 4)

AIR QUALITY CONTROL STUDY

TECHNICAL SUMMARY OF ALTERNATIVES

(SI UNITS)

CASE	1A & 1B	2A & 2B	3A & 3B	4A & 4B	5A & (1B + 5B)	6A & (1B + 6B)	7A & (4B + 7B)	8A & (4B + 8B)
Brief Description Type of System	ESP (Base Alternative)	ESP	ESP	MDC + FF	ESP (Base Alternative) + Wet Limestone FGD (50% Scrubbing)	ESP (Base Alternative) + Wet Limestone FGD (100% Scrubbing)	MDC + Lime Spray Drier (50% Scrubbing) + FF	MDC + Lime Spray Drier (100% Scrubbing) + FF
Emission Rate (mg/kJ)								
Particulate	0.0967(2)	0.0387	0.0086	0.0086	0.0967(2)	0.0967(2)	0.01505	0.0215
SO_2	0.576	0.576	0.576	0.576	0.344	0.086	0.344	0.086
Major Equipment Design Sizing	2 x 50% ESP	2 x 50% ESP	2 x 50% ESP	4 x 25% MDC + 2 x 50% FF (14 compartments each, reverse air cleaning)	2 x 50% ESP + 3 x 25% FGD	2 x 50% ESP + 4 x 33% FGD	4 x 25% MDC + 4 x 16% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)	4 x 25% MDC + 6 x 20% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)
ESP S.C.A. (m^2/m^3/sec)	112.4	130.5	214.5	-	112.4	112.4	-	-
ESP Area (m^2)	133,502	155,520	255,669	-	133,502	133,502	-	-
FF Air to Cloth Ratio (m/s)	-	-	-	0.0102	-	-	0.0102	0.0102
FF Cloth Area (m^2)	-	-	-	133.6	-	-	127.2 (133.6)	119.8 (133.6)
MDC Pressure Drop (kPa)	-	-	-	0.622	-	-	0.622	0.622
Spray Dryer Modules	-	-	-	-	-	-	3 operating + 1 spare	5 operating + 1 spare
FGD Reheat (°C)	-	-	-	-	Partial Bypass Reheat to 104°C	Hot Air Injection Reheat to 68°C	-	-
FGD Modules	-	-	-	-	2 operating + 1 spare	3 operating + 1 spare	-	-
FGD Booster Fans (No. - MW)	-	-	-	-	2 - 1.5	2 - 3.0	-	-
I.D. Fans (No. - MW)	2 - 3.7(4.1)	2 - 3.7(4.1)	2 - 3.7(4.1)	4 - 3.7(4.1)	2 - 3.7(4.1)	2 - 3.7(4.1)	4 - 4.1	4 - 4.1
AQCS Pressure Drop (kPa)	0.5	0.5	0.5	2.75	3.0 + 0.5	3.0 + 0.5	2.75 + 1	2.75 + 1
Reagent Consumption (tonnes/yr)	None	None	None	None	Limestone 14,515	Limestone 29,937	Lime 9979	Lime 19958
Water Consumption (1000 m^3/year)	*None*	*None*	*None*	*None*	340	680	250	510
Waste Products (tonnes per year)	Flyash 635,036 - -	Flyash 535,036 - -	Flyash 635,036 - -	Flyash 635,036 - -	Flyash 635,036 Sludge Dry Basis 23,587 Water 0.76 l/s	Flyash 635,036 Sludge Dry Basis 47,174 Water 1.51 l/s	Flyash 635,036 - - SO_2 Products 19,958	Flyash 635,036 - - SO_2 Products 39,917
Chimney Liner Type	Mild Steel	Mild Steel	Mild Steel	Mild Steel	Brick	Brick	Mild Steel	Mild Steel
SO_2 Emission Maximum (kg/sec)	0.979	0.979	0.979	0.979	0.556	0.139	0.556	0.139
Particulate Emission Maximum (kg/sec)	0.164	0.066	0.015	0.015	0.164	0.164	0.026	0.037
Total Gas Flow (kg/sec)	833.39	833.39	833.39	833.39	850	950	845	858
Exit Temperature (°C)	146	146	146	146	102	65	104	68
Exit Velocity (m/s)	27.4	27.4	27.4	27.4	24.4	25.3	25.0	23.2

NOTE: 1) Values are on a per Generating Unit basis.

2) 0.0967 mg/kJ ≡ 0.1 gr/scf (dry basis).

3) Values in brackets apply to Group B retrofit alternatives where such values differ from the A Group values.

EXHIBIT 3-5 (SHEET 1 of 2)

AIR QUALITY CONTROL STUDY

TECHNICAL SUMMARY OF ALTERNATIVES

(NORTH AMERICAN UNITS)

CASE	1A & 1B	2A & 2B	3A & 3B	4A & 4B	5A & (1B + 5B)	6A & (1B + 6B)	7A & (4B + 7B)	8A & (4B + 8B)
Brief Description Type of System	ESP (Base Alternative)	ESP	ESP	MDC + FF	ESP (Base Alternative) + Wet Limestone FGD (50% Scrubbing)	ESP (Base Alternative) + Wet Limestone FGD (100% Scrubbing)	MDC + Lime Spray Drier (50% Scrubbing) + FF	MDC + Lime Spray Drier (100% Scrubbing) + FF
Emission Rate (lbs./million BTU) Particulate SO_2	 0.225(2) 1.34	 0.09 1.34	 0.02 1.34	 0.02 1.34	 0.225(2) 0.8	 0.225(2) 0.2	 0.035 0.8	 0.05 0.2
Major Equipment Design Sizing	2 x 50% ESP	2 x 50% ESP	2 x 50% ESP	4 x 25% MDC + 2 x 50% FF (14 compartments each, reverse air cleaning)	2 x 50% ESP + 3 x 25% FGD	2 x 50% ESP + 4 x 33% FGD	4 x 25% MDC + 4 x 16% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)	4 x 25% MDC + 6 x 20% SD + 2 x 50% FF (14 compartments each, reverse air cleaning)
ESP S.C.A. (ft^2/1000 acfm)	571	663	1,090	-	571	571	-	-
ESP Area (ft^2)	1,437,000	1,674,000	2,752,000	-	1,437,000	1,437,000	-	-
FF Air to Cloth Ratio (ft./min)	-	-	-	2.0	-	-	2.0	2.0
FF Cloth Area (1,000 ft^2)	-	-	-	1438	-	-	1370 (1438)	1290 (1438)
MDC Pressure Drop (in. Wg.)	-	-	-	2.5	-	-	2.5	2.5
Spray Dryer Modules	-	-	-	-	-	-	3 operating + 1 spare	5 operating + 1 spare
FGD Reheat (°F)	-	-	-	-	(Partial Bypass (Reheat to 220°F	(Hot Air Injection (Reheat to 155°F	-	-
FGD Modules	-	-	-	-	2 operating + 1 spare	3 operating + 1 spare	-	-
FGD Booster Fans (No. - hp x 10^3)	-	-	-	-	2 - 2	2 - 3.5	-	-
I.D. Fans (No. - hp x 10^3)	2 - 5(5.5)	2 - 5(5.5)	2 - 5(5.5)	4 - 5(5.5)	2 - 5(5.5)	2 - 5(5.5)	4 - 5.5	4 - 5.5
AQCS Pressure Drop (in. Wg.)	2	2	2	11	12 + 2	12 + 2	11 + 4	11 + 4
Reagent Consumption (T.P.Y.)	None	None	None	None	Limestone 16000	Limestone 33000	Lime 11000	Lime 22000
Water Consumption (10^6 U.S. gal./year)	None	None	None	None	90	180	67	135
Waste Products (T.P.Y.)	Flyash 700,000 - -	Flyash 700,000 - -	Flyash 700,000 - -	Flyash 700,000 - -	Flyash 700,000 Sludge Dry Basis 26,000 Water 12 USgpm	Flyash 700,000 Sludge Dry Basis 52,000 Water 24 USgpm	Flyash 700,000 - - SO_2 Products 22,000	Flyash 700,000 - - SO_2 Products 44,000
Chimney Liner Type	Mild Steel	Mild Steel	Mild Steel	Mild Steel	Brick	Brick	Mild Steel	Mild Steel
SO_2 Emission Maximum (lbs./hr.)	7766	7766	7766	7766	4410	1103	4410	1103
Particulate Emission Maximum (lbs./hr.)	1304	522	116	116	1304	1304	203	290
Total Gas Flow (lbs./hr.)	6.614×10^6	6.614×10^6	6.614×10^6	6.614×10^6	6.75×10^6	7.54×10^6	6.71×10^6	6.81×10^6
Exit Temperature (°F)	295	295	295	295	215	150	220	155
Exit Velocity (f.p.s.)	90	90	90	90	80	83	82	76

NOTE. 1) Values are on a per Generating Unit basis.

2) 0.225 lb./MB ≡ 0.1 gr/scf (dry basis).

3) Values in brackets apply to Group B retrofit alternatives where such values differ from the A Group values.

EXHIBIT 3-3 (SHEET 2 OF 2)

AIR QUALITY CONTROL SYSTEMS STUDY

FGD REAGENTS

CHEMICAL	CASE	QUANTITY (TONS/YEAR)	VENDOR	ENQUIRY DATE	RESPONSE DATE	PRICE ($)	DELIVERY METHOD	PRICE ESCALATION	AVAILABILITY
Limestone	Case 5	60,000 to 73,800	Canadian Industries Limited	NOT INCLUDED	NOT INCLUDED	Unable to Quote Price on This Item.	Not Advised	Not Advised	Not Advised
	Case 6	130,000 to 159,900							
	Case 5	60,000 to 73,800	Steel Brothers Canada Ltd.	NOT INCLUDED	NOT INCLUDED	2" x 3/8" $8.50/ton at Pavilion Lake Plant	By Others, eg. CP Transport @ $6.15/Ton in 25 Ton Trucks	8% or 9% Per Annum is Not Unlikely	Could be possible over 35 year period.
	Case 6	130,000 to 159,900				3/8" Minus $3.00/ton at Pavilion Lake Plant			

NOTES: 1) Cases 5 and 6 use limestone for SO_2 absorption. Lime is used for sludge stabilization.

EXHIBIT 3-4 (SHEET 1 OF 2)

AIR QUALITY CONTROL SYSTEM

FGD REAGENTS

CHEMICAL	CASE	QUANTITY (TONS/YEAR)	VENDOR	ENQUIRY DATE	RESPONSE DATE	PRICE ($)	DELIVERY METHOD	PRICE ESCALATION	AVAILABILITY
Lime	Case 5	8,000 to 9,840	Canadian Industries Limited	NOT INCLUDED	NOT INCLUDED	$53.00/Ton, F.O.B. Kananaskis, Alta. plus $22.00/Ton to Ashcroft	Truck Load Lots 45,000 lbs.	Not Advised	Not Advised
	Case 6	18,000 to 22,140							
	Case 7	35,000 to 43,050							
	Case 8	89,000 to 109,470							
	Case 5	8,000 to 9,840	Steel Brothers Canada Ltd.	NOT INCLUDED	NOT INCLUDED	$42.50/Ton at Pavilion Lake Plant, Cache Creek, B.C.	35 Ton Train Units Case 5 - $5.00/Ton Case 6 - $4.50/Ton Case 7 - $4.38/Ton Case 8 - $4.15/Ton Trimac Transportation System CP - $5.00/Ton All Cases	8% or 9% per annum is not unlikely	Case 5 - is presently possible. Case 6 - expanding markets could create concern in 3, 4 or 5 years time. Case 7 and 8 - would require another kiln with a minimum two years notice being required.
	Case 6	18,000 to 22,140							
	Case 7	35,000 to 43,050							
	Case 8	89,000 to 109,470							

NOTES: 1) Cases 5 and 6 use lime only for sludge stabilization.

2) Cases 7 and 8 use lime for SO_2 absorption.

EXHIBIT 3-4 (SHEET 2 OF 2)

4.0 AQCS COSTS

This section presents capital costs and detailed cost breakdown; levelized and unlevelized owning and operating (O & O) costs; AQCS capital cost cash flows; and AQCS consumption quantities for power, reagents, water and so forth.

The economic factors used in the evaluations are tabulated in Exhibit 4-1 and include reagent, labour, energy, and other costs.

The estimated quantities of power, energy, and materials consumed by the AQCS plants are tabulated in Exhibit 4-2.

Cost evaluations are presented in Exhibits 4-3 and 4-4, applicable to Group A and Group B primary alternatives, and include both capital costs (total $ and Unit $/kW) and the owning and operating costs (mills/kWh) unlevelized. Differential costs of the alternatives relative to the Base Scheme Case 1 AQCS system are shown. The capital costs include an incremental capability cost as described in 4.1 of this report.

Levelized owning and operating costs for Group A and Group B are illustrated in Exhibit 4-5 and 4-6 respectively. These Exhibits include capitalized values of the levelized O & O costs, and also differentials relative to the Base Case.

Engineering and Construction expenditure cash flows, expressed as percentages of the total capital cost for a 4-unit development, are presented in Exhibit 4-7. The total capital costs are to be found in either Exhibit 4-3 or 4-4 for the particular AQC system and Group chosen. It must be recognised, that these costs exclude IDC, and corporate overhead, escalation-during-construction (EDC). To determine actual cash flows, these factors should be accounted for, using the given cash flow percentages as the basis.

Each FGD system of Case 5A to 8A could be combined with an alternative particulate control device (of different efficiency, type) to the particulate device specified in the Cases. Thus, for example, the 99.49% ESP of Case 5A can be substituted by the 99.95% ESP of Case 3A to give rise to a new AQCS alternative, designated Case 5/3A. This new alternative will meet the bottom of the particulate emission range and the top of the SO_2 range of the PCB Objectives . Other new AQCS alternatives can be obtained in similar fashion and their costs would be developed by deducting and adding the appropriate values for the particulate control costs given.

Costs for various of these other AQCS alternatives, together with the Group A alternatives, are presented in bar-chart form in Exhibit 4-8 and 4-9. Not all possible alternatives have been included; some combinations of dry FGD and ESP systems are not shown, because of the high level of uncertainty regarding their overall performance. Exhibit 4-8 illustrates the respective unit capital costs, with the capitalized O & O cost added, for the AQCS A Group of alternatives. Exhibit 4-9 shows levelized O & O costs and differentials in mills/kWh.

In Exhibit 4-10, detailed capital cost estimates for the A Group of alternatives, Cases 1 to 8, are tabulated.

Embedded spare FGD module costs are shown in Exhibit 4-11. The FGD systems incorporate redundancy in the form of spare modules to allow for module outages. To assess the impact of designed plant redundancy, the embedded capital costs for spare modules, expressed in total dollars and $/kW, are included for reference purposes.

4.1 AQCS EXTENT OF PLANT & BASIS OF COSTS

The AQCS primary alternatives of the A Group, and Cases 1B to 4B of the B Group, include the total "back-end" plant extending from the boiler air heater outlet to the chimney inclusive. All of these alternatives are complete and stand alone. The remaining Cases 5B through 8B identify FGD systems only, which insert between the boiler and chimney; each requires to be combined with one of the Cases 1B through 4B to produce the total AQCS (particulate plus SO_2 control).

The capital and operating costs for all A and B alternatives are developed accordingly. Regarding the Base Scheme capital cost (Case 1A) as detailed in Exhibit 4-10, the total cost exceeds the amount included in Account 20 of the Hat Creek Power Plant Project Estimate since that Account does not include for all equipment such as ID fans, breeching, structural steel and chimney. Amounts for these items have been abstracted from the appropriate detailed categories and are included to provide the Case 1 capital cost: similarly for the other cases as appropriate.

To determine the impact of a particular AQCS alternative on the overall Project cost, the total cost (e.g. capital, O & O, mills/kWh etc.) of the Base Scheme (Case 1A) is deducted from that of the particular AQCS alternative and this differential added to the Base Scheme Power Plant cost. These differential amounts in various forms are included in Exhibits 4-3, 4-4, 4-5 and 4-6 for the primary cases.

Capital Costs

The capital costs for the various alternatives include the following plant as applicable:

- AQCS Equipment: precipitator, mechanical dust collector and fabric filter, flyash removal system, FGD system.
- Flue gas ductwork and support: boiler house to AQCS equipment, between AQCS equipment, from AQCS equipment to chimney.
- ID fans, ID booster fans and chimney.

- Site improvement, earthwork, piling, concrete, structural steel, building, piping, insulation, instrumentation, electrical and painting for the above.
- Incremental cost for the waste transportation and disposal system from Power Plant to Mid Medicine Creek Valley.

Note with regard to the last item, the dry ash disposal scheme (Alternative "B") for the Project has been assumed. Incremental costs are included for each Case to cater for the effect of increased quantities of waste products generated.

Separately calculated and tabulated is the incremental capability cost. This represents the cost of adjusting the power plant gross output to satisfy the requirements of the electrical auxiliaries and power consumption for the AQC system applied while preserving the net station output at 2000 MW.

Capital costs for precipitator and fabric filter cases were obtained from vendors' quotations supplemented with INTEG-EBASCO in-house data. Costs for the wet FGD scrubber systems are based on the EBASCO FGD study[6] for the Hat Creek Project, adjusted to suit worst quality blended coal, the dry ash disposal scheme, and the specific emission limits of the PCB Objectives. Costs for the dry FGD scrubbing cases were derived from INTEG-EBASCO estimates for other projects, in-house vendor quotations, and published data.

All costs are in 1978 canadian dollars; US prices and costs have been converted at the exchange rate:

$1.00 US = $0.85 Canadian

The indirect construction cost factor of 28 percent which includes indirect (5%), cost contingency (15%), and engineering (6%), has been applied to the direct costs. The cost contingency value is consistant with the Project allowance (14.4%) for the Base AQCS system, and has been maintained for other alternatives, notwithstanding the greater uncertainty of the costs for these alternatives.

Annual Costs

The annual owning and operating costs are incremental values, applying only to AQCS plant operation and not the total power plant. O & O costs consist of fixed charges plus operation and maintenance (O & M) costs. The fixed charge rate (unlevelized) of 12.33 percent used excludes the fixed O & M component. The O & M costs are separately derived based on the consumption data and costs of Exhibit 4-1 and 4-2, and are illustrated in Exhibit 4-3, to 4-6.

4.2 RETROFIT OF FGD SYSTEMS

For cases 1B to 3B, (ESP particulate control), in order to achieve the flexibility of retrofitting either wet or dry FGD systems, an ultimate plant arrangement is assumed which makes it necessary for the ESP's and downstream plant to be located a further 52 metres (170 feet) from the boiler back end. This shift of plant is required to provide space upstream in order to retain the option of retrofitting dry scrubber systems. Therefore Cases 1B to 3B incur increased inlet ductwork and additional electrical cable/raceway lengths for extending the ESP and ID fans. Additional costs are included for these features together with an allowance for an increased waste disposal system, larger ID fans to accommodate future FGD system losses, and alternative chimney liners suited to the corrosive effects of low temperature flue gas with wet FGD systems.

The capital cost increases, amounting to about 6 or 7 percent of which about three quarters is assigned to ductwork, are applied to the ESP particulate system costs. They represent a shift of costs to the particulate systems although the costs are actually due to FGD retrofitting.

For Case 4B, (Fabric filters with dust collectors), this also requires a shift in the location of the ID fans and chimney. but the quantity of additional ductwork is less. The estimated cost increase to incorporate allowances for FGD retrofitting for this case is approximately 6 percent.

With Cases 5B and 6B, (Partial and full wet scrubbing FGD systems only), the total costs are increased in the order of 2 percent to cover additional ductwork tie-in sections, electrical system modifications, and premium time for tieing in during the retrofit, but exclude amounts already included for in the particulate Group B cases for the chimney liner and ID fan sizing.

For the total AQCS plant - incorporating suitable particulate control plus retrofitted wet FGD systems - the cost is in the order of 3 to 5 percent greater than for the comparable system installed with the power plant.

The Cases 7B and 8B (Partial and full dry scrubbing FGD systems) incorporate spray dryers and reagent handling only, with no particulate control. In combination with fabric filters, the total AQCS costs with retrofitting would be in the order of 8 percent higher than the comparable system designed for installation integral with the power plant development. An important component of the extra retrofit system costs arises from the need to initially install a fabric filter which is 5 to 10 percent larger than would otherwise be necessary with integrated plant development. The lower gas temperature, and hence volume flow through the filters, is not achieved until the FGD systems are retrofitted.

EXHIBITS 4.0

AIR QUALITY CONTROL STUDY
ECONOMIC FACTORS

- Net Unit Rating	4 x 500 MW
- Capacity Factor (Lifetime Average)	65%
- Annual Net Generation	11,388 GWh
- Base Date for Costs	October 1978
- Indirect Construction Cost (Indirect + Contingency + Engineering as % of Direct Cost)	28%
- Levelizing Factor (5.75% inflation rate, 10% interest rate, 38 year life)	1.98
- Fixed Charge Rate (Not including O&M Costs)	12.33%
- Levelized Fixed Charge Rate (Not including O&M Costs)	14.25%
- Coal Cost (1978 Dollars)	$0.679/GJ ($0.717/MB)
- Limestone Cost (1978 Dollars)	$10.08/tonne
- Lime Cost (1978 Dollars)	$52.30/tonne
- F.F. Bag Cost (1978 Dollars)	$60.00/ea.
- Labour Cost (1978 Dollars)	$18.3/hour
- Incremental Energy Cost (1978 Dollars)	9.55 Mills/kWh
- Water Cost (1978 Dollars)	$0.56/m^3
- Levelized Water Cost (1978 Dollars)	$0.71/m^3
- Cost of Steam (1978 Dollars)	$0.36/MB
- Incremental Capacity Cost (1978 Dollars)	$450/kW

EXHIBIT 4-1

AIR QUALITY CONTROL STUDY

CONSUMPTION DATA FOR AQCS CASES

(PER UNIT BASIS)

	PARTICULATE CONTROL				COMBINED PART. & SO_2 CONTROL			
CASE NO.	1A	2A	3A	4A	5A	6A	7A	8A
EQUIPMENT	ESP (99.5)	ESP (99.8)	ESP (99.95)	FF (99.97)	ESP (99.5) + Part. Wet FGD	ESP (99.5) + Full Wet FGD	FF + Part. Dry FGD	FF + Full Dry FGD
Capability								
Power - kW	3,700	4,200	4,800	6,000	9,200	14,100	7,000	8,300
Steam - GJ/hr	-	-	-	-	-	42	-	-
Operation								
Energy - 10^6 kWhr/yr (1)	21	24	27	34	52	80	40	47
Steam - GJ/yr	-	-	-	-	-	243,000	-	-
Water - m^3/yr	-	-	-	-	340,000	680,000	250,000	510,000
Limestone - Tonne/yr	-	-	-	-	14,500	29,900	-	-
Lime - Tonne/yr	-	-	-	-	2,000	4,100	10,000	20,000
Labour - man hr/yr	1,400	1,400	1,400	1,400	25,400	31,400	8,000	10,000
Maintenance (Mat. & Labor)								
Bag Replacement - no/yr (2)	-	-	-	5,000	-	-	4,750	4,500
Other - % Cap. Cost/yr (3)	0.5	0.5	0.5	0.5	1.5	1.5	1.0	1.0

(1) Includes Differential Power/Energy consumed by ID Fans.

(2) Bag Replacement Labor - 1 man hr per bag.

(3) 1.5% for Wet FGD system, 1.0% for Dry FGD System and 0.5% for other equipment.

Notes: a) Quantities for Cases 1B to 4B are similar to the above for Cases 1A to 4A respectively,

b) Quantities for Case 5B to 6B may be obtained dy deducting Case 1A values from those of Case 5A or 6A above

c) Quantities for Case 7B or 8B may be obtained by deducting Case 4A values from those of Case 7A or 8A above

EXHIBIT 4-2

AIR QUALITY CONTROL STUDY

COST EVALUATION (UNLEVELIZED O&O) - GROUP A

(per 4 units, $1000, 1978 price level, not levelized, capital costs exclusive of corporate overhead and IDC)

CASE NO.	PARTICULATE CONTROL (without provision for Dry FGD retrofit)				COMBINED PART. & SO_2 CONTROL (integrated installation)			
	1A	2A	3A	4A	5A	6A	7A	8A
EQUIPMENT	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	ESP (99.49%) + PARTIAL WET FGD	ESP (99.49%) + FULL WET FGD	FF + PARTIAL DRY FGD	FF + FULL DRY FGD
AQCS Capital Cost	202,000	220,000	240,000	185,000	382,000	467,000	323,000	393,000
Incremental Capability Cost	7,000	7,000	9,000	11,000	16,000	25,000	12,000	15,000
Total Capital Cost	209,000	227,000	249,000	196,000	398,000	492,000	335,000	408,000
($/kW)	(104)	(114)	(125)	(98)	(199)	(246)	(168)	(204)
Differential Capital Cost	Base	18,000	40,000	-(13,000)	189,000	283,000	126,000	199,000
($/kW)	(Base)	(9)	(20)	-(6)	(95)	(142)	(63)	(100)
Annual Fixed Charges (@ 12.33%)	25,800	28,000	30,700	24,200	49,100	60,700	41,300	50,300
Annual Operation & Maintenance								
- Energy	800	920	1,030	1,300	1,990	3,060	1,530	1,800
- Steam	-	-	-	-	-	660	-	-
- Water	-	-	-	-	660	1,420	470	1,040
- Limestone	-	-	-	-	580	1,210	-	-
- Lime	-	-	-	-	420	860	2,090	4,180
- Operating Labour	100	100	100	100	1,860	2,300	590	730
- Bag Replacement								
Material	-	-	-	1,200	-	-	1,140	1,080
Labour	-	-	-	370	-	-	350	330
- Waste Disposal	-	-	-	-	60	140	50	120
- Other O & M	1,010	1,100	1,200	930	3,700	4,980	2,140	2,840
Total O & M	1,910	2,120	2,330	3,900	9,270	14,630	8,360	12,120
Total Annual Owning & Operating	27,710	30,120	33,030	28,100	58,370	75,330	49,660	62,420
(Mill/kWh)	(2.43)	(2.6)	(2.9)	(2.5)	(5.1)	(6.6)	(4.4)	(5.5)
Differential Annual Owning & Operating	Base	2,410	5,320	390	30,660	47,620	21,950	34,710
(Mill/kWh)	(Base)	(0.2)	(0.5)	(0.03)	(2.7)	(4.2)	(1.9)	(3.0)

EXHIBIT 4-5

AIR QUALITY CONTROL STUDY

COST EVALUATION (UNLEVELIZED O&O) - GROUP B

(per 4 units, $1000, 1978 price level, not levelized capital costs exclusive of corporate overhead and IDC)

	PARTICULATE CONTROL (with provision for Dry FGD retrofit)				SO_2 CONTROL (RETROFIT)			
CASE NO.	1B	2B	3B	4B	5B	6B	7B	8B
EQUIPMENT	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	PARTIAL WET FGD	FULL WET FGD	PARTIAL DRY FGD	FULL DRY FGD
AQCS Capital Cost	216,000	234,000	255,000	196,000	187,000	271,000	138,000	210,000
Incremental Capability Cost	7,000	7,000	8,000	11,000	10,000	19,000	2,000	5,000
Total Capital Cost	223,000	241,000	263,000	207,000	197,000	290,000	140,000	215,000
($/kW)	(112)	(120)	(131)	(103)	(98)	(145)	(70)	(107)
Differential Capital Cost	Base	18,000	40,000	-(16,000)				
($/kW)	(Base)	(9)	(20)	-(8)				
Annual Fixed Charges (@ 12.33%)	27,500	29,800	32,500	25,500	24,300	35,700	17,300	26,500
Annual Operating & Maintenance								
- Energy	800	920	1,030	1,300	1,190	2,260	230	500
- Steam	-	-	-	-	-	660	-	-
- Water	-	-	-	-	660	1,420	470	1,040
- Limestone	-	-	-	-	580	1,210	-	-
- Lime	-	-	-	-	420	860	2,090	4,180
- Operating Labour	100	100	100	100	1,760	2,200	490	630
- Bag Replacement								
Material	-	-	-	1,200	-	-	-	-
Labour	-	-	-	370	-	-	-	-
- Waste Disposal	-	-	-	-	60	140	50	120
- Other O & M	1,080	1,170	1,270	980	2,810	4,070	1,380	2,100
Total O & M	1,980	2,190	2,400	3,950	7,480	12,820	4,710	8,570
Total Annual Owning & Operating	29,480	31,990	34,900	29,450	31,780	48,520	22,010	35,070
(Mill/kWh)	(2.6)	(2.8)	(3.1)	(2.6)	(2.8)	(4.3)	(1.9)	(3.1)
Differential Annual Owning & Operating	Base	2,510	5,420	-(30)				
(Mill/kWh)	(Base)	(0.2)	(0.5)	(0.0)				

NOTE: For comparison purposes, the Capital and Energy Costs for Retrofit SO_2 Control Cases include Capability and Energy Costs at the same rate ($450/kW and 9.55 mills/kWh) as Group A Cases.

EXHIBIT 4-4

AIR QUALITY CONTROL STUDY

LEVELIZED OWNING AND OPERATING COSTS - GROUP A

(Per 4 Units, $1000, 1978 price level. Capital costs exclusive of corporate overhead and IDC.)

	PARTICULATE CONTROL (Without provision for dry FGD retrofit)				COMBINED PART. & SO CONTROL (Integrated Installation)			
CASE NO.	1A	2A	3A	4A	5A	6A	7A	8A
BRIEF DESCRIPTION	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	ESP (99.49%) + Part. Wet	ESP (99.49%) + Full Wet	FF + Part. Dry	FF + Full Dry
Levelized Annual Fixed Charges (@ 14.25%)	29,800	32,300	35,500	27,900	56,700	70,100	47,700	58,100
Levelized Annual O&M Costs								
- Energy	1,550	1,800	2,000	2,500	3,850	5,920	2,960	3,500
- Steam	-	-	-	-	-	1,310	-	-
- Water	-	-	-	-	830	1,810	590	1,320
- Limestone	-	-	-	-	1,160	2,390	-	-
- Lime	-	-	-	-	830	1,700	4,140	8,280
- Operating Labour	200	200	200	200	3,980	4,550	1,160	1,450
- Bag Replacement								
Material	-	-	-	2,380	-	-	2,260	2,140
Labour	-	-	-	720	-	-	690	650
- Waste Disposal	-	-	-	-	120	280	100	240
- Other O&M	2,000	2,170	2,380	1,840	7,330	9,860	4,240	5,650
Total O&M	3,750	4,170	4,580	7,640	18,100	27,820	16,140	23,230
Total Levelized Annual Owning & Operating	33,550	36,470	40,080	35,540	74,800	97,920	63,840	81,330
(Mill/kWh)	(2.9)	(3.2)	(3.5)	(3.1)	(6.6)	(8.6)	(5.6)	(7.1)
Total Owning & Operating (Levelized & Capitalized)	235,000	256,000	281,000	249,000	525,000	687,000	448,000	571,000
($/kW)	(118)	(128)	(141)	(125)	(262)	(343)	(224)	(285)
Differential Cost to Case 1A								
Levelized Annual Owning & Operating	Base	2,920	6,530	1,990	41,250	64,370	30,290	47,780
(Mill/kWh)	(Base)	(0.3)	(0.6)	(0.2)	(3.6)	(5.7)	(2.7)	(4.2)
Total Owning & Operating (Levelized & Capitalized)	Base	21,000	46,000	14,000	290,000	452,000	213,000	336,000
($/kW)	(Base)	(11)	(23)	(7)	(145)	(226)	(106)	(168)

AIR QUALITY CONTROL STUDY

LEVELIZED OWNING AND OPERATING COSTS - GROUP B

(Per 4 units, $1000, 1978 price level. Capital costs exclusive of corporate overhead and IDC.)

	PARTICULATE CONTROL (with retrofit provision for dry FGD)				SO_2 CONTROL (RETROFIT)			
CASE NO.	1B	2B	3B	4B	5B	6B	7B	8B
EQUIPMENT	ESP (99.49%)	ESP (99.8%)	ESP (99.95%)	FF (99.97%)	Partial Wet	Full Wet	Partial Wet	Full Dry
Levelized Annual Fixed Charges (@ 14.25%)	31,800	34,300	37,500	29,500	28,100	41,300	19,900	30,600
Levelized Annual O&M Costs								
- Energy	1,500	1,800	2,000	2,500	2,340	4,460	460	1,000
- Steam	-	-	-	-	-	1,310	-	-
- Water	-	-	-	-	830	1,810	590	1,320
- Limestone	-	-	-	-	1,160	2,390	-	-
- Lime	-	-	-	-	830	1,700	4,140	8,280
- Operating Labour	200	200	200	200	3,780	4,350	960	1,250
- Bag Replacement								
Material	-	-	-	2,380	-	-	-	-
Labour	-	-	-	720	-	-	-	-
- Waste Disposal	-	-	-	-	120	280	100	240
- Other O&M	2,140	2,320	2,520	1,940	5,550	8,040	2,740	4,170
Total O&M	3,890	4,320	4,720	7,740	14,610	24,390	8,990	16,260
Total Levelized Annual Owning & Operating (Mill/kWh)	35,690 (3.1)	38,620 (3.4)	42,220 (3.7)	37,240 (3.3)	42,710 (3.8)	65,690 (5.8)	28,890 (2.5)	46,860 (4.1)
Total Owning & Operating (Levelized & Capitalized) ($/kW)	250,000 (125)	271,000 (135)	296,000 (148)	261,000 (130)				
Differential Cost to Case 1B								
Levelized Annual Owning & Operating (Mill/kWh)	Base (Base)	2,930 (0.3)	6,530 (0.6)	1,550 (0.15)	42,710 (3.8)	65,690 (5.8)	28,890 (2.5)	46,860 (4.1)
Total Owning & Operating (Levelized & Capitalized) ($/kW)	Base (Base)	21,000 (10)	46,000 (23)	11,000 (5)	300,000 (150)	461,000 (230)	203,000 (101)	329,000 (164)

NOTE: For comparison purposes, the Levelized Annual Fixed Charges and the Energy Cost for Retrofit SO_2 Control Cases include Capability and Energy Costs at the same rate as Group A cases.

[illegible] 9-1

AIR QUALITY CONTROL STUDY

4-UNIT CASH FLOWS (PERCENTAGE)

(Total capital cost of 4 units exclusive of corporate overhead and IDC = 100%; "*" indicates AQCS initial operation on January 1 of year indicated.)

CASH FLOW #1 (For all Particulate Control Cases 1A to 4A and 1B to 4B)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.6	-	-	-	4.6
2	11.1	5.6	-	-	16.5
3	8.0	10.0	5.8	-	23.8
4	5.4*	4.5	9.8	5.9	25.6
5	0.4	3.1*	4.5	9.7	17.7
6	-	0.3	3.1*	4.4	7.8
7	-	-	0.3	3.0*	3.3
8	-	-	-	0.5	0.5
	29.5	23.5	23.5	23.5	100.0

CASH FLOW #2 (For Combined Cases 5A and 6A, ESP 99.5% + Partial or Full Wet FGD)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.3	-	-	-	4.3
2	10.9	4.7	-	-	15.6
3	8.8	10.0	4.9	-	23.7
4	3.7*	6.6	9.9	5.0	25.5
5	0.3	2.5*	6.6	9.8	19.2
6	-	0.2	2.4*	6.5	9.1
7	-	-	0.2	2.3*	2.5
8	-	-	-	0.4	0.4
	28.0	24.0	24.0	24.0	100.0

AIR QUALITY CONTROL STUDY
4-UNIT CASH FLOWS (PERCENTAGE)

CASH FLOW #3 (For Combined Cases 7A and 8A, FF + Partial or Full Dry Scrubbing)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.1	-	-	-	4.1
2	11.0	3.5	-	-	14.5
3	10.0	10.2	3.7	-	23.9
4	2.7*	8.2	10.1	3.8	24.8
5	0.2	2.0*	8.2	10.1	20.5
6	-	0.1	1.9*	8.9	10.0
7	-	-	0.1	1.9*	2.0
8	-	-	-	0.2	0.2
	28.0	24.0	24.0	24.0	100.0

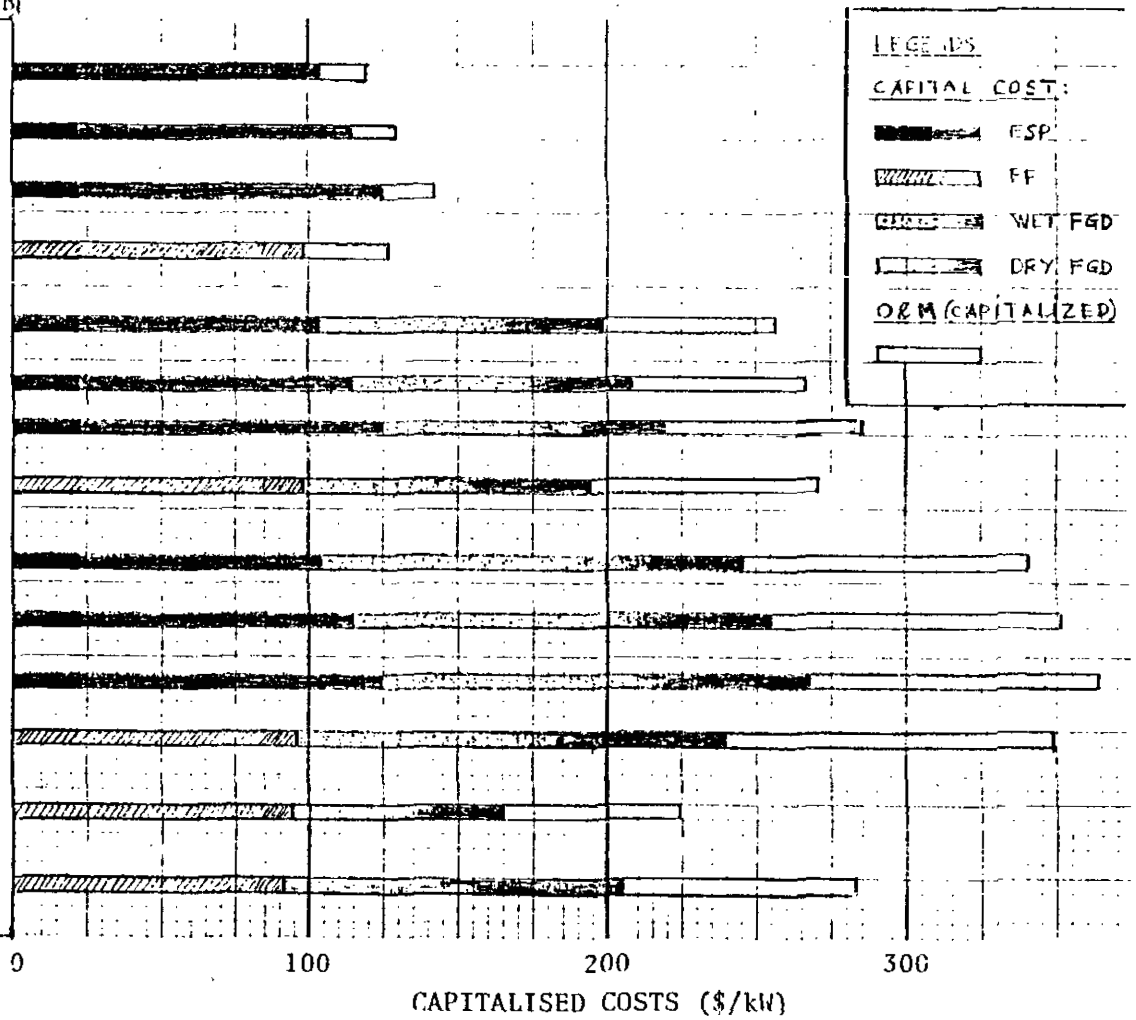
CASH FLOW #4 (For Retrofit SO_2 Control Cases 5B to 8B)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Fiscal Year 1	4.0	3.7	-	-	7.7
2	10.8	9.8	3.9	3.9	28.4
3	9.8	9.0	9.9	10.0	38.7
4	1.7*	1.9*	8.9	8.8	21.3
5	0.2	0.1	1.7*	1.6*	3.6
6	-	-	0.1	0.2	0.3
	26.5	24.5	24.5	24.5	100.0

AIR QUALITY CONTROL STUDY

BAR CHART COMPARISON OF AQCS CAPITALISED COSTS ($/kW) (GROUP A CASES & COMBINATIONS)

COMBINED CASE	PARTICULATE CONTROL EQUIP.	PARTICULATE CONTROL EMISSION (#/MB)	SO_2 CONTROL PROCESS	SO_2 CONTROL EMISSION (#/MB)
1A	ESP	0.225	None	1.34
2A	ESP	0.09	None	1.34
3A	ESP	0.02	None	1.34
4A	FF	0.02	None	1.34
5A	ESP	0.225	Part. Wet	0.8
5/2A	ESP	0.09	Part. Wet	0.8
5/3A	ESP	0.02	Part. Wet	0.8
5/4A	FF	0.02	Part. Wet	0.8
6A	ESP	0.225	Full Wet	0.2
6/2A	ESP	0.09	Full Wet	0.2
6/3A	ESP	0.02	Full Wet	0.2
6/4A	FF	0.02	Full Wet	0.2
7A	FF	0.035	Part. Dry	0.8
8A	FF	0.05	Full Dry	0.2



Notes:- 1) The AQC Systems extend between the boiler air heater outlet to the chimney inclusive.

For other than the Base Scheme, Case 1A, incremental costs are included for additional supporting services.

EXHIBIT 4-8

AIR QUALITY CONTROL STUDY

BAR CHART COMPARISON OF AQCS LEVELISED O & O COSTS (mills/kWh) (GROUP A CASES & COMBINATIONS)

COMBINED CASE	PARTICUALTE CONTROL		SO_2 CONTROL	
	EQUIP	EMISSION (#/MB)	PROCESS	EMISSION (#/MB)
1A	ESP	0.225	None	1.34
2A	ESP	0.09	None	1.34
3A	ESP	0.02	None	1.34
4A	FF	0.02	None	1.34
5A	ESP	0.225	Part. Wet	0.8
5/2A	ESP	0.09	Part. Wet	0.8
5/3A	ESP	0.02	Part. Wet	0.8
5/4A	FF	0.02	Part. Wet	0.8
6A	ESP	0.225	Full Wet	0.2
6/2A	ESP	0.09	Full Wet	0.2
6/3A	ESP	0.02	Full Wet	0.2
6/4A	FF	0.02	Full Wet	0.2
7A	FF	0.035	Part, Dry	0.8
8A	FF	0.05	Full Dry	0.2

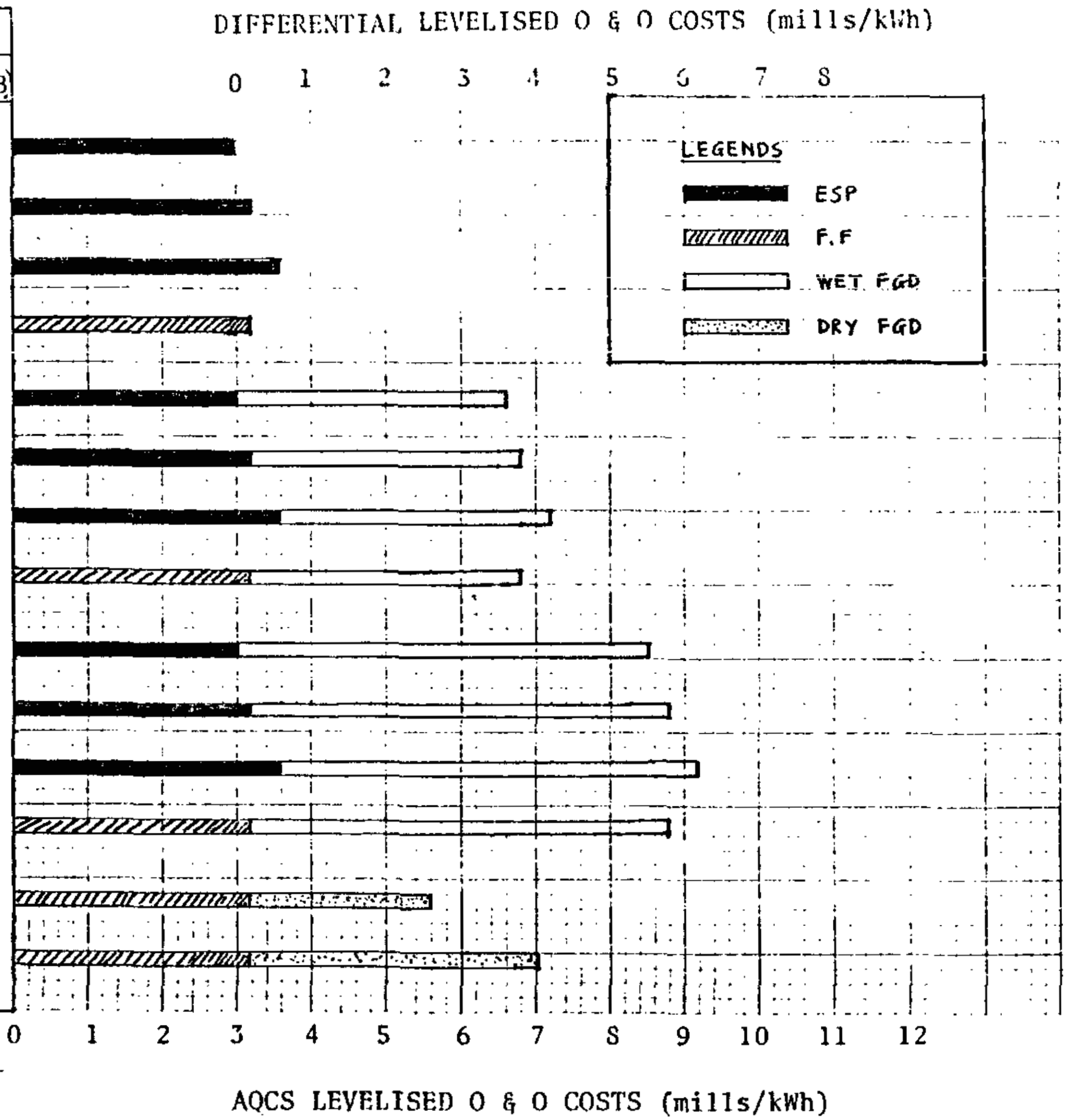


EXHIBIT 4-9

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

($1000, 1978 price level)

1) Case 1A (Base Scheme)

- Precipitator		15,520
- Flyash Handling		3,720
- ID Fans		2,400
- Chimney and Chimney Foundation		2,350
- Structural Steel Including Ductwork		5,720
- Insulation		3,340
- Electrical		3,310
- Others		3,130
	Total Direct Cost	39,490
	Indirect Cost (28%)	11,060
	Total Cost	50,550
	Total for 4 Units	202,200

(Others include: improvement to site, earthwork and piling, concrete, buildings, piping, painting.)

2) Case 2A (ESP 99.8%)

- Precipitator		17,550
- Flyash Handling		4,100
- ID Fans		2,400
- Chimney and Chimney Foundation		2,350
- Structural Steel Including Ductwork		5,780
- Insulation		3,530
- Electrical		3,740
- Others		3,450
	Total Direct Cost	42,900
	Indirect Cost (28%)	12,010
	Total Cost	54,910
	Total for 4 Units	219,640

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

3) Case 3A (ESP 99.95%)

- Precipitator		19,880
- Flyash Handling		4,530
- ID Fans		2,400
- Chimney and Chimney Foundation		2,350
- Structural Steel Including Ductwork		5,850
- Insulation		3,720
- Electrical		4,230
- Others		4,000
	Total Direct	46,960
	Indirect Cost (28%)	13,150
	Total Cost	60,110
	Total for 4 Units	240,440

4) Case 4A (Mech. Collector + Fabric Filter)

- Fabric Filter		9,880
- Mechanical Collectors		1,400
- Flyash Handling		4,210
- ID Fans		3,990
- Chimney and Chimney Foundation		2,350
- Structural Steel Including Ductwork		6,750
- Insulation		3,080
- Electrical		1,590
- Others		2,970
	Total Direct Cost	36,220
	Indirect Cost (28%)	10,140
	Total Cost	46,360
	Total for 4 Units	185,440

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

5) Case 5A (ESP + Partial Wet FGD)

- Base Scheme Cost (ESP)		39,490
- Wet FGD System (Including Ductwork to Chimney)		35,960
- Incremental Chimney Cost		300
- Incremental Waste Transportation and Disposal System Cost		100
- Adjustment to Base Scheme Cost (Delete Ductwork from ID Fans to Chimney)		-(1,300)
	Total Direct Cost	74,550
	Indirect Cost (28%)	20,870
	Total Cost	95,420
	Total for 4 Units	381,680

6) Case 6A (ESP + Full Wet FGD)

- Base Scheme Cost (ESP)		39,490
- Wet FGD System (Including Ductwork to Chimney)		52,510
- Incremental Chimney Cost		300
- Incremental Waste Transportation and Disposal System Cost		200
- Adjustment to Base Scheme Cost (Delete Ductwork from ID Fans to Chimney)		-(1,300)
	Total Direct Cost	91,200
	Indirect Cost (28%)	25,540
	Total Cost	116,740
	Total for 4 Units	466,960

AIR QUALITY CONTROL STUDY

DETAILED CAPITAL COST ESTIMATES (GROUP A)

7) Case 7A (FF + Partial Dry Scrubbing)

- Case 4 Cost		36,220
- Dry FGD System		27,510
- Incremental Waste Transportation and Disposal System Cost		100
- Adjustment to Case 4 Fabric Filter Cost (Reduce Size)		-(800)
	Total Direct Cost	63,030
	Indirect Cost (28%)	17,650
	Total Cost	80,680
	Total for 4 Units	322,720

8) Case 8A (FF + Full Dry Scrubbing)

- Case 4 Cost		36,220
- Dry FGD System		42,020
- Incremental Waste Transportation and Disposal System Cost		200
- Adjustment to Case 4 Fabric Filter Cost (Reduce Size)		-(1,650)
	Total Direct Cost	76,790
	Indirect Cost (28%)	21,500
	Total Cost	98,290
	Total for 4 Units	393,160

AIR QUALITY CONTROL STUDY

FGD PLANT REDUNDANCY

EMBEDDED CAPITAL COSTS

	SPARE MODULE		
		CAPITAL COST (2)	
CASE (1)	SIZE (MW)	UNIT ($/KW)	TOTAL ($ x 10^6)
5A	144	26.6	53.2
6A	192	30.7	61.4
7A	96	13.7	27.4
8A	115	15.5	31.0

NOTES: (1) To a first order of accuracy the costs can be applied to the Group B Cases.

(2) Capital costs are in $ 1978, and are inclusive of direct and indirect construction costs but exclude corporate overhead, IDC and EDC. These costs are embedded in the capital costs given in Exhibit 4-3 and 4-4.

EXHIBIT 4-11

5.0 PRECIPITATION WITH FLUE GAS CONDITIONING

As a measure of the developing confidence in the part that flue gas conditioning (FGC) can play in precipitator design and performance, FGC-ESP technology is now being promoted as a serious contender for new utility precipitator applications. In that a properly selected FGC system can sometimes contribute to significant reductions in such factors as precipitator size, cost, and possibly power demand; higher availability of FGC equipment is now being observed with retrofitted installations in the United States; and one or two Utilities are known to be operating with or installing FGC-ESP combinations as original equipment; it is considered appropriate to review flue gas conditioning as an AQCS alternative for Hat Creek.

FGC is regarded as an emerging technology certainly for new precipitator applications but does not rank at the present time with the other AQCS alternatives concerning its stage of development or probable application for the Hat Creek Plant. It is therefore reviewed apart from the other alternatives considered here.

The investigation of FGC technology included an assessment of the current state of development in the United States and, based on vendors' recommendations, has identified sulphur trioxide (SO_3) as a suitable gas conditioning reagent for the low sulphur Hat Creek coals. This section summarises the principal considerations, the FGC mechanisms acting to improve collection efficiency, an outline of a typical SO_3 gas conditioning system, and concludes with order-of-magnitude costs for a FGC-ESP (coldside) design combination of 99.95 per cent efficiency, corresponding to the lower PCB particulate limit.

5.1 FLUE GAS CONDITIONING

Flue gas conditioning as an aid to improving the collection efficiency of electrostatic precipitators has been known about since the

1920's. More recently, FGC systems have been fitted-not always successfully-to existing plant in order to upgrade the performance of precipitator installations, either as a result of the original units being unable to meet their guarantees, or in attempts to comply with more stringent air pollution regulations. The body of knowledge is continuing to grow as the results from pilot experimentation and data on full scale installations become available. One vendor of FGC systems has supplied more than 90 retrofitted systems, and two systems as original equipment, one of which is now in operation and the other is in the course of construction.

Conditioning involves the injection of reagents, moisture and/or chemicals, to the flue gas causing a modification of the flyash particulate and bulk flue gas conditions in a way which can improve the collection and/or precipitation of the entrained flyash. The causal mechanisms are not necessarily fully understood, nor are their effects always predictable. The composition of the flue gas and the constituents of the flyash all play a part in a complex and interrelated fashion so that predictions of improvements in performance with FGC are by no means secure, and should ultimately be confirmed by pilot scale testing under conditions representative of the full scale operation.

Flyash resistivity is a principal factor affecting precipitator performance. For example, the high resistivity flyash typical of low sulphur coals is normally difficult to precipitate and requires costly precipitators with high specific collection areas (SCA). FGC can lower flyash resistivity; the ash particle surfaces adsorb a polar substance, e.g. moisture, which results is an improvement in dust deposition and precipitator performance. Alternatively, utilizing FGC, a precipitator design of smaller SCA can be provided to achieve a given collection efficiency.

The presence of SO_3 also contributes significantly to the controlling of resistivity. Free SO_3 raises the acid dewpoint of the flue gas enabling the flyash particulates to adsorb more water, thereby reducing resistivity. Conditioning, to lower the ash resistivity, is also achieved by the injection of other additives such as sodium compounds, H_2SO_4, ammonia, and certain proprietory chemical formulations. Ammonia is understood to improve collection efficiency by increasing the cohesiveness of the flyash minimizing re-entrainment. Other mechanisms assisting collection include modification of particle size, and of the electrical space charge, which in turn raises the precipitator operating voltage.

5.1.1 WAHLCO Sulphur Trioxide Gas Conditioning System

A typical configuration of the WAHLCO SO_3 gas conditioning plant is illustrated in Exhibit 5-1. SO_3 conditioning at cold-side precipitator temperatures involves the catalytic conversion of vapourized SO_2 into SO_3 and its injection into the flue gas upstream of the precipitator. Vanadium pentoxide is the catalyst used, and the reaction is exothermic; the outlet temperature from the converter would range between 540-595°C (1000-1100°F), well above the acid dew point of 260°C (500°F).

Due to the cost of commercially available liquid SO_2 and the difficulty of storing it, a system incorporating a sulfur burner to make SO_2 has been patented. This burner resembles the front end of a small sulfuric acid plant. Much of the heat needed for the SO_2 to SO_3 convertion can be provided by the heat of combustion of the sulfur. Since one ton of sulfur costs about a third to a quarter as much as a ton of SO_2, and produces two tons SO_2, the investment costs of a sulfur burner could be offset by lower operating costs.

Careful attention needs to be given to the injection temperature of SO_3. It must be as far from the acid dew point as possible. The design and location of the injection system is important for even SO_3 distribution. Sufficient retention time is needed for the interaction of the SO_3 and the flue gas.

5.2 FGC-ESP HAT CREEK ALTERNATIVE

For comparison with cold-side precipitator applications designed without gas conditioning, a FGC-ESP combination has been investigated applicable to the Hat Creek project. The particulate emission for this AQCS is 0.01 mg/kJ (0.02 lb/MB), corresponding to the 99.95 per cent collection efficiency of Case 3.

Enquiries were issued to various vendors identifying the flyash and other design conditions, which included requests for comments on the suitability of gas conditioning to aid precipitation. These vendors include WAHLCO, RESEARCH COTTRELL (RC), and AMERICAN AIR FILTER (AAF): in addition, APOLLO CHEMICAL CORPORATION, a vendor for proprietory FGC chemical additives, was contacted. The quotations from AAF and RC, as precipitator manufacturers, included the FGC-ESP plant combination whereas, WAHLCO quoted only for the FGC system. AAF advised that it relies on the experience of WAHLCO and others for the gas conditioning component. The majority of FGC systems quoted identified SO_3 gas conditioning for the application.

To date, WAHLCO is understood to have engineered over 90 retrofitted FGC installations, all employing SO_3 conditioning (e.g. Iowa Public Service, Commonwealth Edison). Utility precipitator installations designed specifically with SO_3 conditioning by WAHLCO include one for the Public Service Company, Colorado (Arapahoe Unit No. 1, in operation since 1976) and Wisconsin Electric Power (unit currently under construction).

WAHLCO/AAF predicted a SCA of between 84-89 m^2/m^3/sec (425-450 ft^2/1000 acfm) with 50 p.p.m. SO_3 injection. These values compare with 212.5 m^2/m^3/sec (1080 ft^2/1000 acfm) for the ESP Case 3 conditions given in sub-section 3.2.1.

5.2.1 Costs

The costs in 1978 dollars for this alternative have been developed on a similar basis to other AQC systems (refer to Section 4.0); the capital costs include a 15 percent contingency factor and exclude corporate overhead. The estimated capital cost for the FGC-ESP system installed as original equipment, is $182,400,000 for the 4-units, or $91 /kW.

The estimated total annual and owning cost (unlevelized) is $25,000,000 for the 4-units, or 2.2 mills/kWh.

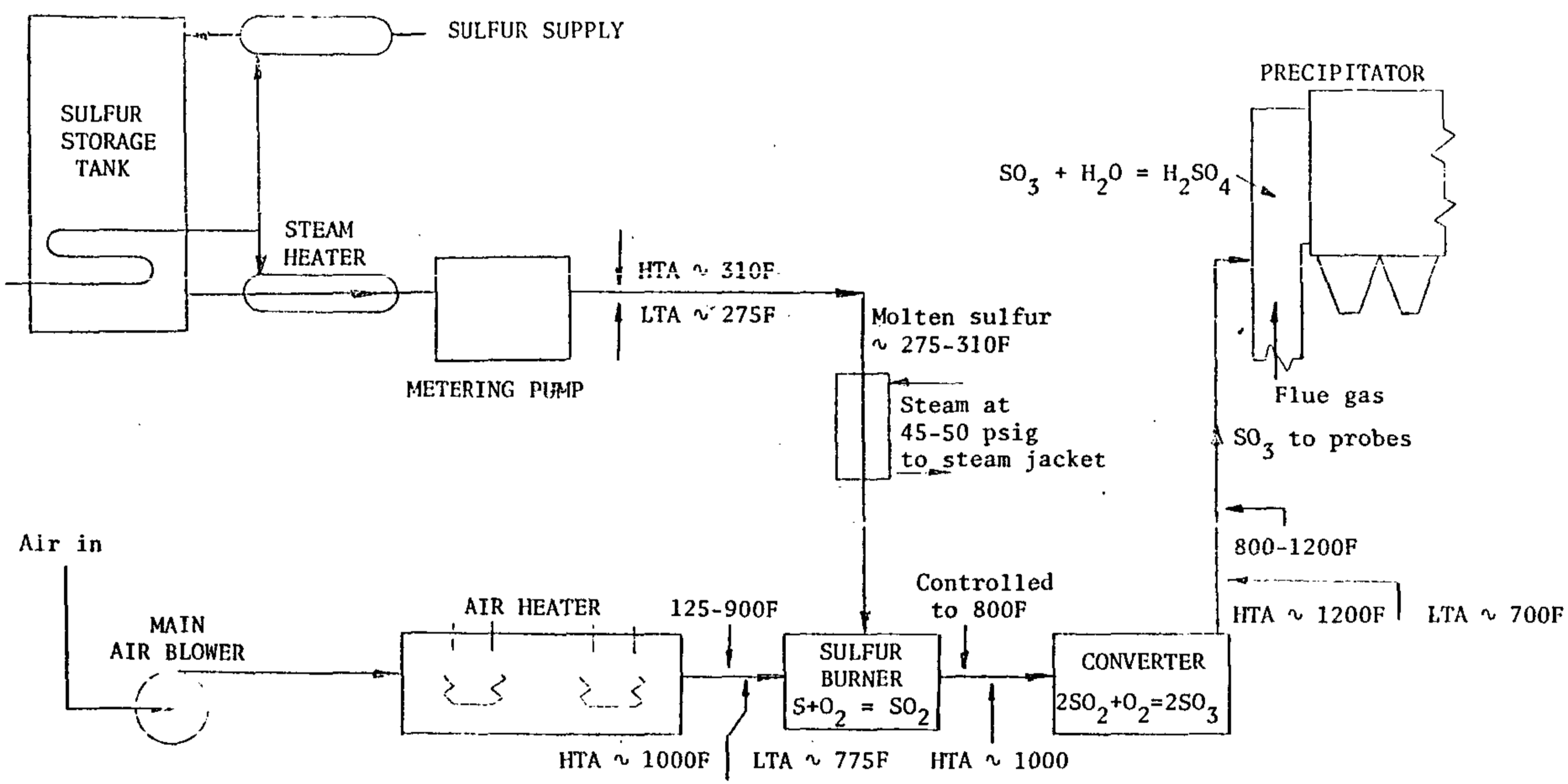
Relative to Case 3A, the estimated savings in capital cost for 4-units is $58,000,000 or 0.7 mills/kWh in owning and operating costs although a FGC-ESP combination designed for the 99.49 percent base conditions would expectedly produce much smaller savings. The costs of the 99.95 percent FGC-ESP combination compare very closely to the mechanical collector-fabric filter combination of Case 4A which is of comparable efficiency.

EXHIBITS 5.0

Exhibit	
5-1	SO_3 PREPARATION & GAS CONDITIONING SCHEMATIC

AIR QUALITY CONTROL STUDY

SO_3 PREPARATION & GAS CONDITIONING SCHEMATIC



HTA - High Temperature Alarm

LTA - Low Temperature Alarm

EXHIBIT 5-1

AQCS PROCESS STATUS IN U S ELECTRIC UTILITY INDUSTRY

The following is a brief summary of the extent of application of the several AQCS processes which are under consideration for the Hat Creek project of B C Hydro.

A. FGD Wet Scrubbing

The master document for FGD status in the United States is the "PEDCo Report" (EPA Utility FGD Survey EPA-600/7-79-022c, May 1979) which is maintained by PEDCo Environmental Company under contract to the EPA. The following information is extracted from the latest annual report which is current through January, 1979.

	No. of Units/Total MW (1/79)	
	Total FGD	Wet Calcium Based Scrubbing
Operational	46/15 795	39/14 474
Under Construction	45/16 976	38/14 576
Contract Awarded	21/11 051	16/ 8 843
Planned 1/	46/26 382	10/ 6 388
TOTAL	158/70 204	103/44 281

1/ 75 percent of planned units listed as "Process not Selected"

Calcium based wet scrubbing (lime or limestone) has been the predominant method of SO_2 removal in the U S for the last decade and this trend would be expected to continue for at least another 10 years or longer.

Ebasco has served as the architect/engineer on 4 wet FGD type systems which are currently (or near) operational. These include:

- Kansas City Power/Kansas Gas & Electric LaCygne Unit No. 1 840 net MW 6.0 percent sulfur Kansas Coal Limestone wet scrubbing Initial Operation in 1972
- Pacific Power & Light Company Dave Johnstone Unit No. 4 330 net MW 0.5 percent sulfur Wyoming Coal Lime/alkaline fly ash wet scrubbing Initial Operation in 1971

- Arizona Public Service Company Cholla Unit No. 2
  250 net MW 0.9 percent sulfur New Mexico Coal Limestone
  wet scrubbing Initial Operation in 1978

- Minnesota Power & Light Company Clay Boswell Unit No. 4
  500 net MW 3.8 percent sulfur Montana Coal Lime/alkaline
  fly ash wet scrubbing Initial Operation expected late 1979

The attached document "Ebasco Services Incorporated Air Quality Control Systems Experience 1970-1978" provides greater detail on the Ebasco extent of involvement with these 4 systems and also lists work in progress on future systems. It is anticipated that current work for Houston Light and Power, Jacksonville Electric Authority and General Public Utilities (including Pennelec) will result in an additional 3000 MW of operational FGD by the late 1980's.

B. <u>FGD Dry Scrubbing</u>

PEDCo lists the following dry scrubbing systems which have been committed:

- Otter Tail Power Coyote Unit No. 1 440 MW gross
  0.9 percent sulfur Dakota lignite spray dryer/fabric
  filter by Wheelabrator Frye/Atomics International
  sodium carbonate reagent Initial Operation expected mid-1981

- Basin Electric Power Coop Antelope Valley Unit No. 1
  440 MW gross 0.7 percent sulfur Dakota lignite
  spray dryer/fabric filter by Joy/Niro lime reagent
  Initial operation expected late 1981 (Replicate Unit
  No. 2, 1983, has not yet been committed to dry
  scrubbing process)

- Basin Electric Power Coop Laramie River Unit No. 3
  600 MW gross 0.5 percent sulfur subbituminous coal
  spray dryer/ESP by B&W lime reagent Initial operation
  expected early 1982

In addition, 2 lime dry scrubbing industrial units (Celanese Corp, 25 MW equivalent and Strathmore Paper Co, 11 MW equivalent) are expected to be operational in late 1979. Several substantial pilot plant dry scrubbers are anticipated at the Jim Bridger (Wyoming) station of Pacific Power and Light Company.

Ebasco's involvement with the dry scrubbing process has been limited to study work only with no formal inquiries issued and no operational systems anticipated prior to 1986.

C. Fabric Filter Particulate Removal

Reference is made to the attached Exhibit No. 15 of the Ebasco "East Kootenay Thermal Project, 300 MW Units No. 1 & 2, Particulate Removal Equipment Study" June 1978. This Exhibit lists 24 electric utility applications totaling over 5000 MW. Eight coal fired stations totaling over 1000 MW are currently in operation with fabric filters.

Ebasco will be issuing formal inquiries for fabric filters (and also ESP's) for 2 x 750 MW lignite units for Houston Light and Power in late 1979. These units are expected to be operational in 1985/86.

D. ESP Particulate Removal

This has been the predominant method for particulate removal for the U S electric utility industry with probably greater than 90 percent of all units after 1970 so equipped.

Operational (or near operational) systems by Ebasco on coal fired units include the following:

- Carolina Power & Light Co 14 ESP retrofits to existing units approximately 3000 MW 1973
- Iowa Public Service Co Geo Neal Units 3 & 4 1100 MW total 1977 & 1979
- Arizona Public Service Co Cholla Units 3 & 4 650 MW total 1980 & 1982 expected

- Dayton Power and Light Co — Killen Units 1 & 2
  1200 MW total — 1981 & 1982 expected
- Pacific Power and Light — Dave Johnston Units 1, 2 & 3
  440 MW total — 1977 retrofit
- General Public Utilities — Homer City Unit No. 3
  630 MW 1977

HAT CREEK A.Q.C.S. OPTIONS

OCT. 79.
I/E STUDY.

		BASE	PARTICULATES			SO_2			
OBJECTIVE	LB/10^6 Btu		0.09	0.02		0.8		0.2	
	I/E COL.	1A	2A	3A	4A	5A	7A	6A	8A
AQCS.		ESP 99.55% No SCRUBBERS	ESP 99.8 No SCRUB.	ESP 99.95 No SCRUB	F.F. ~~ESP~~ 99.97 No SCRUB	ESP 99.55 PARTIAL SCRUB (WET)	~~EF~~ FF PARTIAL SCRUB (DRY)	ESP 99.55 FULL SCRUB (WET)	FF FULL SCRUB (DRY)
SO_2 EMISS. @ MCR	LB/10^6 Btu	1.36	1.36	1.36	1.36	0.8	0.8	0.2	0.2
	kg/day	308,000	308,000	308,000	308,000	186,340	186,340	46,600	46,600
PARTICULATE EMISSION @ MCR.	LB/10^6 Btu	0.15	0.09	0.02	0.02	0.15	{0.09} A	0.15	{0.09} A
	kg/day	35,000	21,000	4,700	4,700	35,000	{21,000} WORST	35,000	{21,000} WORST
CAPITAL COST DIFFERENCE	$ x 10^6	BASE	+ 18	+ 40	− 13	+ 189	+ 126	+ 283	+ 199
	%	(1300)	+ 1.38%	+ 3.1%	− 1%	+ 14.5%	+ 9.7%	+ 21.8%	+ 15.3%
OWNING & OP. COST DIFF. (ANNUAL) @ 65% C.F.	$ x 10^6								
	mils/kWh	BASE	+ 0.2	+ 0.5	+ 0.03	+ 2.7	+ 1.9	+ 4.2	+ 3.0
	%	(25.3)	+ 0.8%			+ 10.7%	+ 7.5%	+ 16.6%	+ 11.9%
CAPITALISED OWNING & OPER. COSTS @ % C.F.	$ x 10^6	2,093							