BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

British Columbia Hydro and Power Authority - A Brief on Coal-fired Powerplants - submitted to the Pollution Control Branch for presentation at the Public Inquiry to Review Pollution Control Objectives for the Mining, Mine-Milling and Smelting Industries of British Columbia - September 1977

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A BRIEF ON
COAL-FIRED POWER PLANTS

Submitted to the

POLLUTION CONTROL BRANCH

for presentation at the

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for the

MINING, MINE-MILLING AND SMELTING INDUSTRIES

of

BRITISH COLUMBIA

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

Introduction

British Columbia is endowed with a vast coal resource. Much of this resource is of "thermal" as opposed to "metallurgical" grade. Ready availability of hydro-electric power has deferred development of the thermal coal resource but as the economic hydro-electric resources are harnessed to meet new load demands, the economics of using thermal coal for electric power generation become increasingly attractive.

In anticipation of this development, B.C. Hydro welcomes the opportunity to participate in an inquiry to be held by the Pollution Control Branch which includes coal-fired power plants.

Currently, all proposed coal development in the Province follows a procedure in accordance with "Guidelines for Coal Development" issued in March 1976 by the Environment and Land Use Committee, pursuant to the Environment and Land Use Act. In these guidelines, the Pollution Control Act is cited as one of the statutory requirements applicable to coal mine development and the Pollution Control Objectives for Mining, Mine-milling and Smelting Industries of British Columbia are identified as the pertinent objectives.

The extension of the inquiry to review Objectives for the Mining, Mine-milling and Smelting Industries provides a suitable forum for B.C. Hydro to present this brief which includes recommendations on appropriate objectives for large-scale coal-fired power plants which are frequently adjacent to the mine which supplies them.

B.C. Hydro considers that the approach to the administration of the Pollution Control Act, (through the establishment of objectives and guidelines followed by the assessment of each new or existing plant on a site-specific basis) is environmentally effective, cost effective, and more flexible than the rigid "standards" philosophy of some other jurisdictions.

General Comments

The economic viability of new developments may in some cases be dependent upon the type and extent of ancillary equipment required for pollution control. Certain socio-economic and environmental trade-offs may be justified for large-scale coal-fired power plants operating in the public interest and it is intended that these may be implied from the technical material and recommendations presented in this brief.

In developing its recommendations for coal-fired power plants, B. C. Hydro has examined the existing Pollution Control Objectives for the Mining, Mine-milling and Smelting Industries and is satisfied that they are generally suitable for coal-fired power plants.

Coal Resources

The potential coal resource in the Province is vast; it has been estimated that if less than ten percent of this resource were to be economic as a source of power plant fuel, it would be sufficient to provide in excess of 200,000 million kwh per year over the next century. The current annual energy demand on the B. C. Hydro system is approximately 30,000 million kwh per year.

Thermal coals occur in five specific regions in the Province and these are described in the brief.

In most cases, the economics of a coal-fired power plant would favour a location close to the mine itself in order to minimize transportation costs. However, other factors such as the characteristics of the air shed, the availability of cooling water and the location of the demand for the power may require that the plant be sited elsewhere and that the cost of coal transportation is justified. The brief includes a review of the economics and environmental aspects of coal transportation.

Operation of Thermal Plants

Coal, as fuel for the thermal power plant, provides energy to raise steam in the boiler and this steam is expanded through a turbine to provide the motive power to drive an electric generator. The steam leaving the turbine is condensed and recycled to the boiler. The condenser absorbs residual heat that cannot be utilized by the turbine and this waste heat is dissipated to an extensive quantity of cooling water.

In the combustion process, coal, as fuel, and the by-products of its combustion are more difficult to handle than is the case for oil or natural gas. The combustion process results not only in heat being released from the coal but also wastes in the form of particulates, gaseous emissions, and ash. The brief discusses practical methods of managing and processing these wastes to maintain environmental impacts within acceptable levels.

Environmental Impacts

It is recognized by B.C. Hydro that the nature of a large-scale coal-fired power plant is such that it has the potential to alter or impair the usefulness of the surrounding land, water or air resources.

Present concern appears to be directed to the air resource which is a critical determinant in the siting and economic feasibility of such a plant. For this reason B.C. Hydro has concentrated the thrust of its brief on air related matters. Liquid and solid waste disposal from thermal plants also require close attention.

As one of the outcomes of the current inquiry it should be recognized that the objectives established for ambient air quality and emissions may determine whether large-scale coal developments will become a reality in the Province.

Pollution Control Technology

B.C. Hydro recognizes that two approaches can be adopted in Pollution Control Objectives for air. In addition, a combination of the two is also possible.

Essentially these approaches are:

(a) Controlling all contaminants at their source of emission.

(b) Maintaining acceptable ambient air quality within the air shed surrounding the source of emission.

By recommending the ambient air quality approach as the critical consideration, B.C. Hydro recognizes that air must be maintained at a quality that is not injurious or damaging to health, safety or comfort of a person, plant or other form of life, and that the quality may not significantly interfere with property or the normal conduct of business.

B.C. Hydro recognizes that source emission levels are more readily regulated than ambient air quality objectives; however, B.C. Hydro contends that the adoption of air quality as the critical parameter will provide satisfactory environmental protection.

Ambient air quality may be controlled by a Meteorological Control System (MCS) by which measures are taken to reduce source emissions during short-term adverse meteorological conditions. The critical contaminant for large-scale power plants will likely be sulphur dioxide and a means of ensuring control over this contaminant would be to stockpile low-sulphur coal at the thermal plant for use during such adverse conditions. The power output of a thermal plant could also be reduced to control sulphur dioxide emissions. B.C. Hydro's power system, by virtue of being predominantly hydroelectric, is more suited to this approach than predominantly thermal systems.

An MCS is dependent upon reliable forecasting of adverse meteorological conditions as well as a monitoring network of continuous ambient sensors. For a large-scale thermal plant operating continuously in a typical region of elevated terrain it is proposed that the shortest period over which sulphur dioxide levels are averaged should be three hours.

A three-hour sulphur dioxide guideline, like the existing one-hour guideline, is solely related to economic protection rather than health considerations, for which the guidelines for periods of 24 hours and greater have been developed. B.C. Hydro examines this matter at some length in the brief as it is an area where a modification to the existing objectives is recommended for coal-fired power plants.

A discussion on technology available to achieve pollution control is provided in the brief and includes the cost, effectiveness, problems and reliability of equipment such as electrostatic precipitators and flue gas scrubbers.

Future Coal Conversion Technology

Prospective developments in combustion technology such as fluidized bed combustion are described. This technology is currently not available on the scale necessary for coal-fired power plants but does have the potential for significant reduction in sulphur dioxide emissions at their source.

A means of making a clean fuel from coal is to gasify it. This approach would result in benefits with respect to air quality but would create new problems in terms of the treatment of liquid effluents.

Recommendations

(1) The Pollution Control Objectives for the Mining, Mine-milling and Smelting Industries of British Columbia should be amended to include coal-fired power plants.

(2) Environmental monitoring programs should be initiated prior to the commencement of operations in order to provide baseline data for impact assessment. After plant start-up, the monitoring programs should be reviewed, assessed, and modified where necessary, to ensure that all significant contaminants are being adequately monitored during plant operation.

(3) The ambient air quality should be the overriding constraint in establishing the acceptability of emission controls as applied to coal-fired power plants.

(4) In the area of trace element concentrations, B.C. Hydro is concerned at the lack of available data on which to base province-wide recommendations and has therefore recommended that baseline studies of the major coal deposits in the Province be undertaken for presentation and review at the next inquiry.

No recommendation with respect with trace elements levels is made at this time.

(5) The one-hour averaging period for sulphur dioxide levels should be waived for coal-fired thermal plants and a three-hour averaging period established with a maximum average concentration of 0.25 ppm.

(6) The objectives for gaseous and particulate emissions of the existing Pollution Control Objectives appear reasonable and applicable to coal-fired power plants provided that a further option be added under sulphur dioxide emissions, which, for coal-fired power plants, specifically excludes the 80% sulphur removal criterion as long as the proposed ambient air quality levels are met.

(7) The existing Guidelines for Solid-waste Management practices appear reasonable and applicable to coal-fired power plants.

(8) The existing Objectives for Effluent Discharges, and Objectives for Toxicity for Effluent Concentrations are generally acceptable for thermal power plants, with the exception of discharges from recirculating condenser cooling water systems. These should be evaluated on a site-specific basis as recirculation of cooling water (the major water use in a power plant) can concentrate, due to evaporation losses, the chemicals naturally found in the water supply source.

(9) A waste heat discharge limitation, such as a maximum allowable temperature increase, should be established on a site-specific basis, having regard for the relationship of the project to its environment.

1. INTRODUCTION

In response to the letter from the Pollution Control Branch, dated July 15, 1977, British Columbia Hydro and Power Authority, herein called B.C. Hydro, welcomes the opportunity to participate in the inquiry to review the Pollution Control Objectives, as issued December 1973, for the Mining, Mine-milling and Smelting Industries, and to present this brief on the Pollution Control Objectives for Coal-fired Power Plants.

In so doing, it must be emphasized that this brief is intended to complement the presentation related to the mining aspects of the inquiry. Our representation on that aspect is in support of, and through, the submission presented by the British Columbia Mining Association.

B. C. Hydro supports and endorses the environmental management philosophy expressed by the Pollution Control Branch in Section 1.11 of the Pollution Control Objectives.

Currently considerable attention is being focussed on long-range air contaminant transport. This concern may also extend to contaminant transport in lakes, rivers and marine waters. It is believed that such interprovincial and international matters may be beyond the scope of this inquiry. Such long-range effects would originate from specific projects and therefore should properly be dealt with during the application and licensing process for the project in question. Accordingly, no discussion is presented, or recommendations made, on this subject.

1.1 Purpose

It is the purpose of this brief to present technical information and recommendations on pollution control objectives for coal-fired power plants in the Province of British Columbia.

1.2 Report Organization

In developing B. C. Hydro's position the existing industrial pollution control objectives and guidelines are cited and the Guidelines for Coal Development are reviewed. The particular climate and topography that are characteristic of British Columbia and the Province's power supply alternatives, are also described.

In respect of these power supply alternatives, consideration is given to an overview of thermal coal resources of British Columbia, their regional distribution and quality.

Factors related to site selection, design and operation of coal-fired power plants are discussed, with particular emphasis on the impact of fuel quality on design and operation of the large-scale modern plant.

The potential impacts of thermal plant construction and operations on the air, water and land components of the environment are reviewed considering the nature of the emissions, protection of health, protection of socio-economic interests, and the capacity of the environment to assimilate the resultant burden without undue adverse effect.

A review is presented of the available technology to mitigate the potential adverse effects on the environment that may result from emissions inherent in coal-fired power plant operation.

Possible future technology for power production with cleaner emission characteristics is discussed briefly.

Recommended additions and/or changes to specific objectives and guidelines are proposed for contaminants in emissions from large scale coal-fired power plants. Some general recommendations are also presented. It is believed that these recommendations are consistent with Pollution Control Branch policies for the effective protection of the environment.

2. GENERAL CONSIDERATIONS

Of special relevance to the study of pollution control objectives for coal-fired thermal power plants are:

- The current objectives and guidelines applicable to the Mining, Mine-milling and Smelting industries of British Columbia.
- The particular features of British Columbia's climate and topography.
- The power alternatives available to meet British Columbia's requirements.

In 1975 a Federal Government Task Force was formed to establish National Emission Guidelines for Thermal Plants in Canada. The Canadian Electrical Association and representatives from Canadian Provincial Utilities as well as Provincial Government representatives studied aspects of the appropriate levels for emissions from thermal plants. It is expected that National Emission Guidelines will be published in the Canada Gazette by early 1978. Emission guidelines for coal-fired power plants have been considered for sulphur-dioxide (SO_2), nitrogen oxides (NO_x) and particulates. Trace elements were not considered in the Task Force studies of emission guidelines.

2.1 Current Objectives

Currently, there are five Pollution Control Objectives published for the guidance of industries in British Columbia. These Objectives are listed below in order of publication:

Objectives	Issued	Revised By Inquiry
The Forest Products Industry	September 1971	1976
The Mining, Mine-milling, and Smelting Industries	December 1973	1978
The Chemical and Petroleum Industries	March 1974	
The Food-processing, Agriculturally Oriented, and Other Miscellaneous Industries	January 1975	
The Municipal Type Waste Discharges	September 1975	

These booklets contain the objectives for source emissions and waste management that should be used in the design of any project.

2.2 Guidelines for Coal Development

In March 1976 the Province of British Columbia issued "Guidelines for Coal Development" under the authority of the Environment and Land Use Committee pursuant to the Environment and Land Use Act.

These guidelines reflect the wide diversity of interest amongst various Departments, Branches and Service sections of the Provincial Government, and the concerns of the public, on matters related to coal development and all interrelated activities. The guidelines are intended to provide the necessary procedure for "the developer, Government, and the public to assess and manage all major impacts".

Pursuant to the Pollution Control Act, the Director issues a permit or approval for each discharge of effluent, or refuse, or emission of air contaminants. Objectives have been formulated for various industries in order that the technical considerations and measures of each application will meet the requirements of the Pollution Control Act.

At the present time there are no objectives published that are applicable specifically to large-scale coal-fired power plants. In most cases power plants are located in close proximity or adjacent to the mine. Therefore coal-fired plants are considered to be a 'related development' to the utilization of British Columbia's thermal coal resources.

The Guidelines for Coal Development cite the Pollution Control Act as an applicable statute and state the pertinent objectives for coal-mining and related developments are the Pollution Control Objectives for Mining, Mine-milling, and Smelting Industries of British Columbia.

Accordingly, B. C. Hydro agrees that this inquiry to review the Pollution Control Objectives for Mining, Mine-milling and Smelting Industries is the appropriate forum at which objectives for coal-fired power plants should be discussed.

It is proposed that, arising from these deliberations, objectives for large-scale coal-fired power plants will be included in the Pollution Control Objectives for Mining, Mine-milling, and Smelting Industries.

2.3 Climate and Terrain of British Columbia

In British Columbia, climate and terrain are significant factors to be considered in power plant site selection and environmental protection.

Generally, for economic reasons, it is preferable in mountainous terrain to locate a coal-fired power plant near the mine rather than transport the coal. As coal quality decreases (decreasing heat content and/or increasing ash content) coal transport becomes less economic and more energy-consumptive.

With respect to environmental protection, particularly ambient air quality, the following constraints make British Columbia one of the more restrictive and costly regions in Canada for the development of major industrial facilities such as coal-fired power plants:

- mountainous terrain,
- deep valleys and coastal inlets,
- large lakes in interior valleys, and
- frequent meteorological conditions limiting the local assimilative capacity of the atmosphere.

2.4 British Columbia Power Alternatives

Currently, the Province of British Columbia is fortunate in being able to meet its future demand from several alternative energy sources. Development of hydro-electric sites or conventional plants burning fossil fuels are currently considered as viable alternatives.

Oil and natural gas reserves in British Columbia appear to be limited and their use for large-scale power generation projects is unlikely. However, the province is endowed with large undeveloped reserves of 'thermal' coals that are usually characterized by a high ash content, high moisture content, sulphur content below one percent, and often by low heating value.

B.C. Hydro is continually evaluating the costs and problems associated with the development of these alternative power resources so that electrical energy can be delivered in the future to its customers at the lowest possible cost consistent with safety to its employees and the public, good quality of service to its customers, and subject to the social, economic and environmental policies of the Government.

In 1975, the B. C. Hydro Task Force on Future Generation and Transmission Requirements (1) reported that:

> "Hydroelectric projects in undeveloped river basins could provide 125,000 million kwh per year. If less than 10 percent of the potential coal resources of the Province were proven to be economic as sources of thermal coal, they would be sufficient to provide in excess of 200,000 million kwh per year for a 100-year period."

3. THERMAL COAL RESOURCES

3.1 Resources of the Province of British Columbia

In this section the thermal coal resources of British Columbia are examined by region. The Province has been subdivided into the following five regions based on the spatial distribution of coal (Figure 3-1).

- Coastal,
- Southern Rocky Mountain,
- Northern Rocky Mountain,
- Southern Interior,
- Northern Interior.

Figure 3-1 also illustrates the location of coalfields within each district (2). The Coastal region contains two coalfields and several deposits. Nanaimo and Cumberland coalfields are within the Nanaimo group of Late Cretaceous age. Graham Island coal deposits on the Queen Charlotte Islands are for the most part in the Queen Charlotte group of Upper Cretaceous age, however there are some deposits of lignite of Tertiary age in the Skokum Formation.

The Southern Rocky Mountain region contains the Elk, Crowsnest and Flathead coalfields. All of these fields lie in the Lower Cretaceous Kootenay formation. They extend from the United States to the Alberta border in the main ranges of the Rocky Mountains.

The Northern Rocky Mountain region is comprised of the Saxon area, Belcourt East area, Belcourt West area, Wapiti area, Quintette coalfield, Sukunka coalfield, Pine River coalfield, Peace River coalfield, Carbon Creek area, Butler Ridge coalfield, Halfway River area and extensions of the coal bearing formation to the north. This region extends to the northwest from the Alberta border and it is centered about 120 km (75

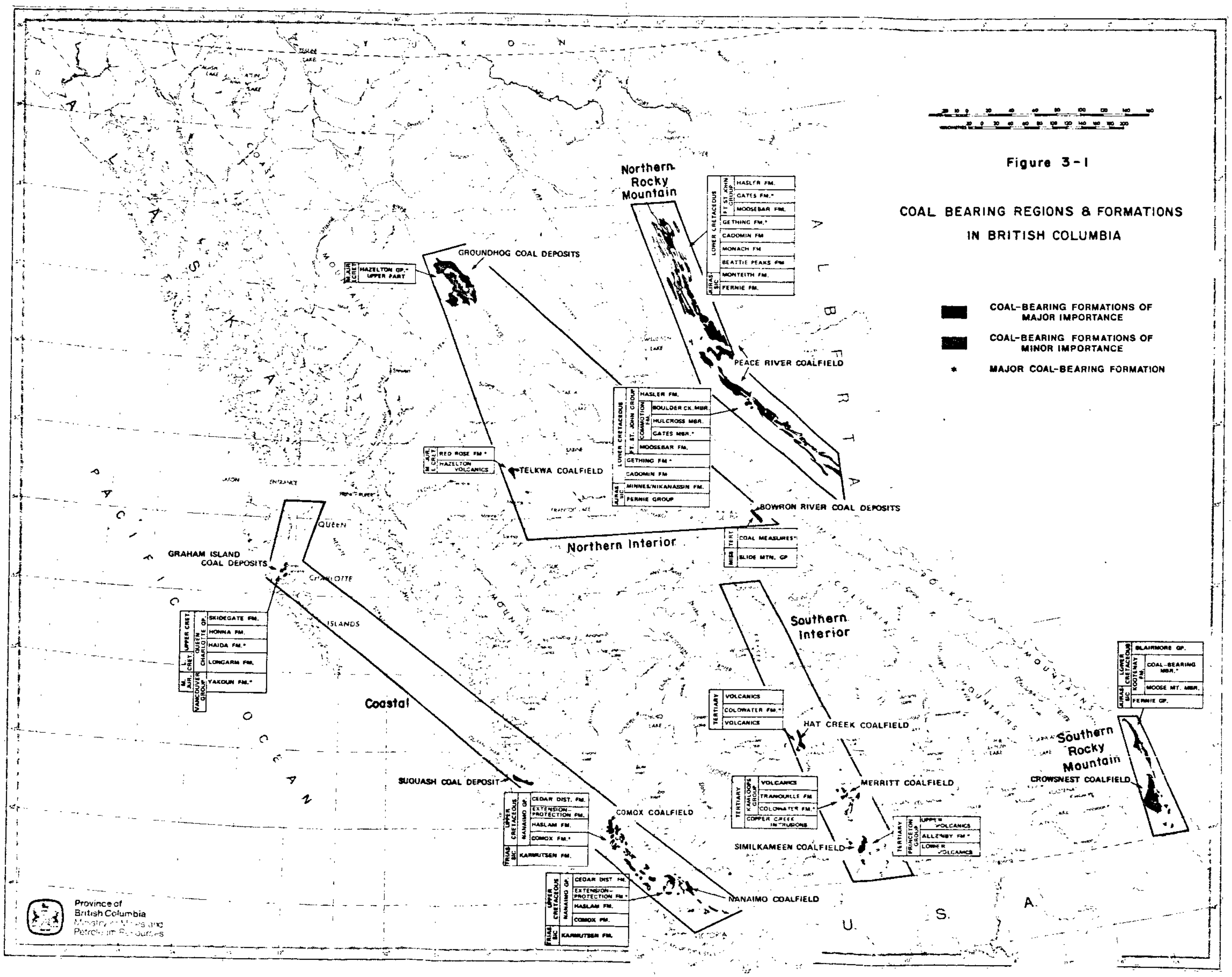

Figure 3-1

COAL BEARING REGIONS & FORMATIONS IN BRITISH COLUMBIA miles) southwest of Fort St. John. The coal measures are in the Gates member of the Commotion formation, and in the Gething formation; both intervals are of Early Cretaceous age.

The Southern interior coalfields and deposits extend in a line from Princeton to Quesnel. This region contains the Similkameen, Merritt and Hat Creek coalfields in addition to the Cariboo deposits south of Quesnel near the Fraser River. The Similkameen deposits near Princeton lie in the Princeton group. The deposits at Merritt and Hat Creek are in the Kamloops group. These coalfields, together with the Cariboo deposits are of Eocene age.

The Northern Interior Coalfields consist of the Bowron River coalfield, the Telkwa coalfield, the Zymoetz River deposits, the Groundhog coalfield, and the Sustut River deposits. The Bowron River coalfield, east of Prince George, and the Sustut River occurrences are in rocks of Paleocene age although part of the latter occurrences are of Mid to Late Cretaceous age. The Sustut field lies on the southeastern margin of the Groundhog coalfield 200 km (125 miles) north of Hazelton. The Telkwa coalfield and Zymoetz River deposits, near Smithers, are in the Skeena group of Mid-Cretaceous age. The Groundhog coalfield is in the Bowser Assemblage and ranges from Mid-Jurassic to Early Cretaceous age.

3.2 Regional Reserves and Quality

3.2.1 Classification of Resources

In assessing the thermal coal resources of the province a number of problems arise.

First, most of the work in the assessment of the Rocky Mountain coalfields has defined coking coal resources. A general rule-of-thumb has been applied, that 10 percent of the coal outlined in these fields is thermal coal resulting from oxidation downward from surface exposures, and from deeper burial, which has increased the rank of the coal. It is believed that this 10 percent figure is conservative.

Oxidized zones tend to penetrate significantly deeper along fracture zones which accounts for some of the deposits of exclusively thermal coal. Some of the oxidized coal can be blended with the higher-quality coking coals to produce an acceptable coking product; therefore not all oxidized coal is available for thermal use.

The second problem arises from variations in the extent of exploration among coalfields and individual deposits. As a result of these variations in exploration five categories of reserves and resources have been defined:

1. Proven reserves: The quantity of coal has been computed from closely spaced data points (ie. drill holes, adits or exposures).

2. Probable reserves: The quantity of coal has been computed partly from measurements and partly from projections.

3. Possible reserves: The quantity of coal has been computed from a thorough knowledge of the deposits and a few measurements.

4. Indicated resource: The quantity of coal is based on a few widely spaced data points and some knowledge of the geology of the deposit.

5. Inferred resource: The quantity of coal is based totally on geological projections.

Because of the nature of the data base, quantities listed as indicated and inferred resources are speculative. Although there may be appreciable tonnages, the actual amounts of coal are probably somewhat less than the projections due to faults, washouts and irregularities on the original depositional surface.

A third problem in assessing the coal resources is the reliability of the analytical data. Some of the analyses are from grab samples on surface outcrops whereas others are from sampling associated with extensive drilling programs. In addition some analyses are from washed coals whereas others are from raw coals.

Trace element considerations are becoming important aspects of any environmental study on the use of coals for power generation. Trace element composition is site-specific and indeed could be variable vertically and latterally within the deposit.

As yet, trace element studies have only been undertaken for the Hat Creek No. 1 deposit. Preliminary examinations have only been completed for the Hat Creek No. 2 deposit and part of the Crowsnest coalfield. The Geological Survey of Canada is beginning research into trace elements in Western Canadian coals which will serve as a useful guide for other trace element studies.

3.2.2 Reserves of Thermal Coal

Distribution of British Columbia's thermal coal reserves and resources by region are shown in Table 3-1. The Southern Interior is the dominant region containing about 2,000 million metric tons (2,200 million tons) or 50 percent of thermal coal reserves. It also contains the largest indicated thermal coal resources.

A detailed description of these reserves by region is contained in Appendix I.

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TABLE 3-1

INSITU THERMAL COAL RESERVES AND RESOURCES OF BRITISH COLUMBIA
IN MILLIONS OF METRIC TONS (SHORT TONS)

REGIONS	RESERVES				RESOURCES	
	PROVEN	PROBABLE	POSSIBLE	TOTAL	INDICATED	INFERRED
Coastal(1)	159 (175)	241 (265)	500 (550)	900 (990) 1970	14 (15)	410 (450)
Southern Rocky Mountain		310 (340)	400 (440)	710 (780) 7866	- -	5,720 (6,300)
Northern Rocky Mountain		46 (51) 556		46 (51)	910 (1,000)	2,730 (3,000)
Southern Interior	384 (422)	636 (700) 3990	1,000 (1,100) 6270	2,020 (2,222)	13,700 (15,070)	273 (300) 1710
Northern Interior	7 (8)	46 (51)	74 (81)	127 (140) 1549	332 (365) 4026	3,640 (4,000) 44,120

(1) Reserve figures were supplied by the company holding the coal rights.

16,450 t
index.

14050 t

14,400

770
710
51
2222
140
4183

RESERVES

= 7875

MW 3,902 10,679 16,029 30621

3.2.3 Quality of Thermal Coal

Quality of thermal coal reserves by region is shown in Table 3-2. The southern interior coals range in rank from lignite to subituminous B. A heating value (dry basis) of 18,269 kJ/kg (7875 Btu/lb), an ash content of 33 percent, and 0.5 percent sulphur are typical of the largest of these deposits.

3.2.4 Reserves of Refuse Coal

The existing mines of the southern Rocky Mountain region are producing refuse coals that could be significant sources of fuel for power generation. Reserves, indicated production rates and qualities are presented in Table 3-3.

3.3 Coal Transportation

3.3.1 Site Location

Transportation of coal and transmission of power are important factors in determining the location of a coal-fired power plant. Coal must be moved from a mine site to the plant, and power must be transmitted from the plant to the load centres.

Normally, the most efficient means of transporting electrical energy over long distances is by high voltage transmission lines. Therefore, from the point of view of reducing total energy transportation cost, coal-fired power plants are usually located as close to the coal source as possible, after taking into consideration non-transportation site-related factors.

TABLE 3-2

COAL QUALITY

REGION	HEATING[1] VALUE	ASH %	VOLATILES %	FIXED CARBON %	SULPHUR %	MOISTURE[2] %	RANK
Coastal	22,620 (9,752)	35.7	25.1	37.9	1.4	1.3	High Vol. B Bituminous to anthracite
Southern Rocky Mountain	28,540 (12,300)	15.9	19.6	63.7	0.4	1.0	Medium Vol. A Bituminous
Northern Rocky Mountain	30,620 (13,200)	8.0	22.0	67.0	0.7	1.0	Low to medium Vol. A Bituminous
Southern[3,4] Interior	18,269 (7,875)	33.0	32.3	34.7	0.5	0.0	Lignite to Subituminous B[2]
	27,000 (11,640)	15.0	33.3	47.5	0.5	5.9	
Northern Interior	30,800 (13,300)	8.7	13.2	73.48	0.7	1.8	High Vol. A Bituminous to semi-anthracite

1. Heating values are in kJ/kg with Btu/lb. listed in brackets.
2. Hat Creek values have been considered on a dry basis; the second analysis from the Southern Interior is on an "as received" basis. The remaining analyses are on an air-dried basis.
3. A range of 1.0 to 5.0 percent moisture is quoted in the "Coal Resources of British Columbia".
4. The range has been listed in the table because of the variable nature of the deposits.

TABLE 3-3

RESERVES AND ANNUAL PRODUCTION OF REFUSE COAL

		Weight[1]	Heating Value[2]	Ash[3] %	Volatile %	Fixed Carbon %	Sulphur %	Moisture %		
	Coarse Refuse:									
46	reserve	5.7	19,490	48.7	17.0	34.3		5		722
		(6.3)	(8,400)							
	production	1.4	19,490	48.7	17.0	34.3		5		722
		(1.5)	(8,400)							
	Fine Refuse:									
36	reserve	5.0	22,280	33.2	18.0	48.8		25		
		(5.5)	(9,600)						7.0	6.51
	production	1.3	22,280	33.2	18.0	48.8		25		
		(1.4)	(9,600)							

1. The weight is in millions of metric tons with short ton equivalents in brackets.
2. The heating value is in kJ/kg with Btu/lb in brackets.
3. Proximate analyses are on a moisture-free basis.

3.3.2 Route and Transportation Options

Routes connecting a coal mine with a power plant are selected on the basis of local topography and the compatibility of different modes of transportation to this terrain. The basic objective is to minimize distance, however, factors such as topography, geology, hydrology, and availability of existing transport corridors, plus social and environmental considerations may modify this objective.

Due to the relative abundance, limited marketability and resultant low price of thermal coal, only large-scale, efficient transportation alternatives are considered. Over land the practicable alternatives for bulk thermal coal transport are railways, trucks, conveyor belts, and slurry pipelines. Over water conventional ships, special bulk carriers or tug-barge systems are practicable alternatives. For the foreseeable future there appears to be no major technical changes which will provide competitive alternatives.

Each method of transportation is subject to a minimum throughput volume below which the required capital investment cannot be justified. These are normally competitive only over a limited range of distances. Consequently, such factors as variations in annual tonnage and in source of supply, over time, can have an important bearing on the selection of the optimum coal transport mode.

3.3.3 Brief Description of Alternative Transport Options

Railways are one of the most efficient and versatile methods of bulk commodity transportation. They may be single-purpose private systems, large common carrier systems, or a combination of both.

Private single-purpose railways can be highly specialized with automated operations and unique equipment specific to a project. Such features are more common on short distance hauling; longer railways are usually conventional systems dedicated to a single commodity and operating between fixed terminals.

Large common carrier railway systems, such as national and provincial lines, are among the most effective means of transporting low-valued dry bulk commodities such as thermal coal over long distances. These systems can carry small volumes in conventional mixed trains or large volumes in unit trains. Unit trains are complete train sets dedicated to a particular service cycling regularly between a loading point, such as a coal mine, and an unloading point, such as a power plant.

In general, unit trains operating on existing rail networks with reserve capacity are the most likely means for the medium to long distance haulage of thermal coal.

Truck systems are used to haul coal over reasonably level terrain for short to medium distances. They have the advantage of being able to adjust quickly to route and volume changes but suffer the disadvantage of poor utilization of energy and labour. Efficiency can be improved by the use of large 100 to 200 tonne capacity off-highway vehicles.

Conveyor belts have the advantage of not being labour intensive but suffer the disadvantage of being capital intensive and inflexible in operation. That is, they are designed for a particular commodity and throughput volume to be moved from one origin to one destination. Changes to any of these design parameters are not easily accommodated.

This alternative is attractive in the transportation of large volumes of thermal coal over short distances of steep and irregular terrain. Frequently a considerable saving in overall route length can be obtained.

Generalized coal transportation unit costs for 1977 are presented in the following Table 3-4.

TABLE 3-4

GENERALIZED COAL TRANSPORTATION UNIT COSTS

Mode	Practicable Minimum Throughput Volume (Million Tonnes/Yr)	Practicable Distance (km**)	Practicable Distance (mi)	Unit Cost* (¢/Tonne km)**	Unit Cost* (¢/Ton mile)
Modern Bulk Marine Carriers	1	800	500	.07 to .7	.1 to 1
Tug-Barge Combinations	.5	40-1600	25-1000	.3 to 4	.5 to 5
Unit Trains	.5	80	50	.7 to 1.4	1 to 2
Conventional Trains	.01	40	25	1.4 to 4	2 to 5
Heavy Trucks	.01	160	100	4 to 10	5 to 15
Slurry Pipeline	3	40	25	.3 to 2	.5 to 2.5
Conveyor Belt	.5	40	25	20 to 40	25 to 50
Ropeway	.1	40	25	30 to 60	40 to 80

* Based on 1977 costs in U.S. Dollars. Costs shown are approximate.

** Metric conversions are rounded off.

At certain mines where stip-mining or open pit mining is used, and depending on the distance involved, truck systems, conveyor belts or a combination may be more appropriate. An industrial ropeway is a series of buckets attached to a cable which is pulled along a system of supporting towers. Industrial ropeway systems are not considered to be economic for the transportation of thermal coal.

A slurry pipeline system is used to pump finely ground coal suspended in water through a pipeline from a plant which prepares the coal, to a dewatering facility at the destination. This system may be competitive where large steady volumes of thermal coal require transportation over medium to long distances.

Slurry pipelines have the advantage of being extremely reliable, and may operate at very high utilization factors. Disadvantages are the large water supplies necessary, and the problem of removing coal fines and dissolved chemicals from the water before recirculation or disposal. Like conveyor belts, slurry pipelines are capital intensive and are inflexible to changes in operation.

There are only limited applications of this mode in North America. It would seem to have good potential as a competitor to unit trains for the supply of fuel to coal-fired power plants.

3.3.4 Bulk Commodity Transportation Economics

The economic comparison of alternative coal transportation systems connecting a mine site with a power plant requires the evaluation of all capital and operating costs likely to be incurred over the project life. The present-worth of these alternative system costs are then compared to select the most economic alternatives.

3.3.5 Environmental and Social Impact

The impact of coal transportation on the environment and society is dependent on the many factors related to the specific aspects of a project. However, the following general comments can be made on the alternative options:

- Waterborne transport of bulk coal has a minor impact except for the possibility of dust emission at terminals.

- Adding coal unit trains to existing rail lines increases the traffic and therefore does not change conditions substantially other than possibly introducing additional noise, dust, and vehicle emissions. The construction of new lines requires the alienation of considerable amounts of land for right-of-way purposes.

- Trucks may add to road traffic, noise, dust and vehicle emissions. The construction of new haul roads requires the use of additional lands, but such corridors may be put to multiple use.

- Slurry pipelines usually have little in the way of above ground structures. Therefore they have minimal impact on physical conditions and aesthetics of the surrounding area except during the construction phase. However, water supply and removal of fines and dissolved chemicals from this water do present special problems.

- Conveyor belts are continuous structures and therefore require passageways over or under them to reduce the barrier effect. Noise and dust emissions can be reduced by covering this equipment.

Dec. 19th / re MAF memo / cc to all PCB members

I-101

B.A.C.T.

"Best Available Control Technology" is a term mostly heard or read re current projects in the USA and E.P.A's regulations.

There seem to be wide differences of opinion on what is BACT between many operators of plants and EPA, especially in the reduction of SO_2 emissions.

When a device or process is "sufficiently proven on a commercial scale" seems to be the bone of contention. If a device which is theoretically the "BACT" turns out to be inadequate in practice the end results for the environment as well as for power production may <u>be worse</u> than before the device was used.

<u>B.C.Hydro</u> feels that each proposed plant and each coal and each contaminant must be assessed specifically. Then the <u>best</u> technology for the specifi application should be used after evaluation of all factors including environmental impact. The latter would be assessed in detail vis-a-vis the current Objectives for coal-fired power plants.

~~DAb~~ Dec. 19th. re MAF memo cc ~~to th~~ all PCB members.

Recommendation #6:- (p7 and p 9-3 & 10-2 of brief)

In our brief we have tried to relate the existing text and tables to coal-fired power plants with a minimum of specific changes or addenda.
Neither of the Options I+II presently described in Clause 2.2 and Table II could be applied without modification to large coal-fired boilers.

Option II however, which we understand to relate to plants, such as smelters, which recover sulphur in their processes, could be expanded with minimal change to the text and tables.

We therefore propose an Option III in our brief by which the emission objective for coal-fired power plants would, as now under ~~Option II~~, be that which provides Level B ~~ambient~~ levels. There would be no sulphur recovery in a power plant and therefore we are recommending the removal of that provision.

Our brief proposes a stricter 3-hour ambient guideline for coal-fired power plants of 655 $\mu g/m^3$ (0·25 ppm) compared to the present Level B guideline of 799 $\mu g/m^3$ (0·30 ppm)

4. CONVENTIONAL COAL-FIRED POWER PLANTS

4.1 Introduction

Canada has some 19,000 MW of fossil fuel power plant now in service of which two-thirds is coal-fired. Most new fossil units will use coal and the role of this abundant fuel, especially in the west, will be a significant component of Canada's energy policy (15).

For the B.C. Hydro system, the smallest single unit size would probably be 150 MW, while for larger plants, units could be in the 500 MW to 750 MW range. The largest single coal-fired units in the world are currently 1300 MW. A typical new coal-fired plant might contain up to four single units.

4.2 Principal Components

4.2.1 Basic Coal-fired Power Plant Description

Figure 4-1 shows the basic cycles in a typical coal-fired power plant.

The coal is burned in pulverized form in large water-tube type boilers to produce high pressure steam. Reference (2) page 45 summarizes combustion basics in coal-fired power plants.

Boilers for low-rank coals have unusually large dimensions, particularly due to the higher quantity of coal of low heating value which must be burned for a given output and the need to use low gas velocities in the convection surfaces to avoid erosion from fly ash.

An extensive system of sootblowers, including deslaggers or "wall blowers" for the furnace walls, and "retractables" for the convection surfaces is required.

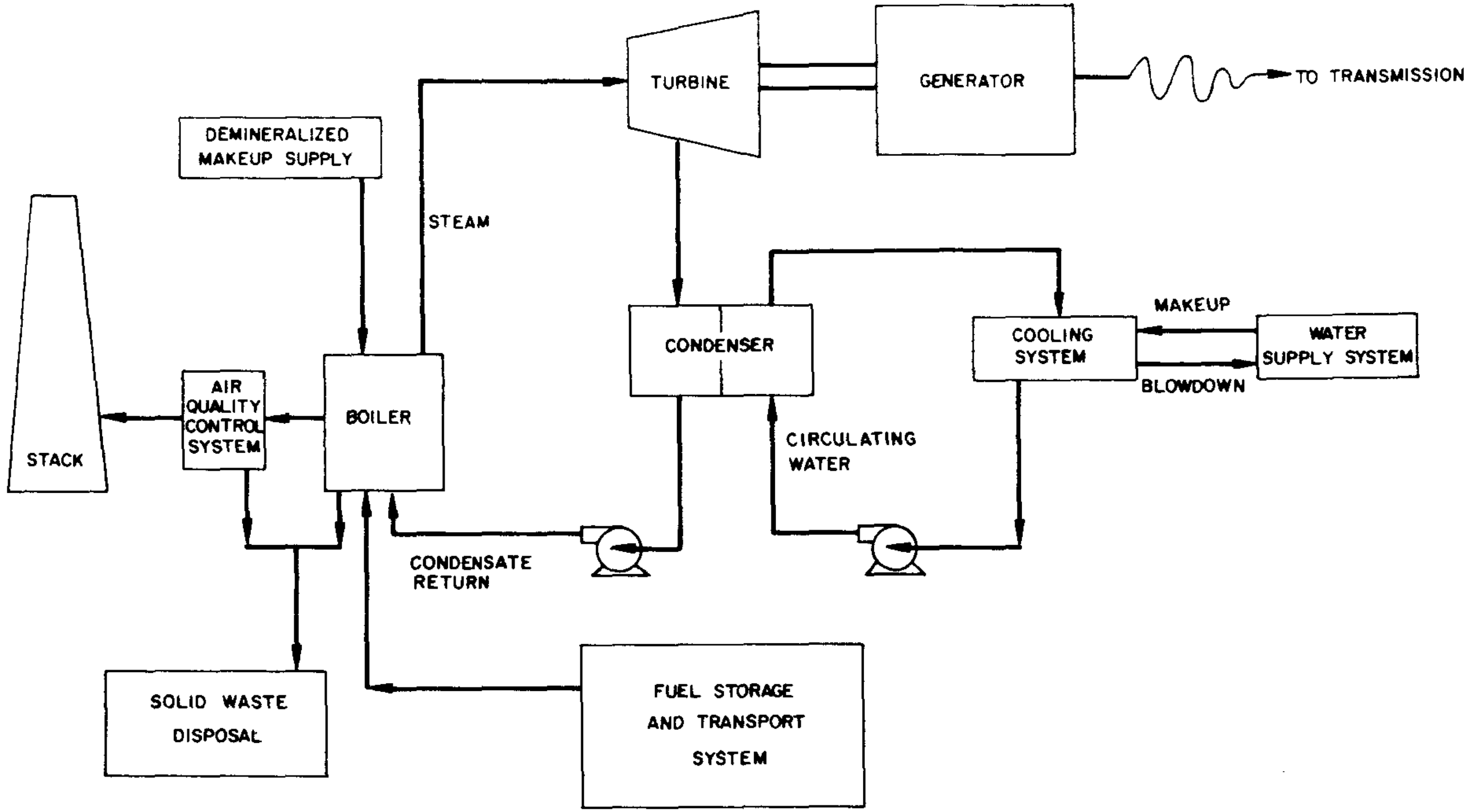


Figure 4-1

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

SITE EVALUATION STUDY

GENERIC FEATURES OF A
FOSSIL FUELED POWER PLANT

integ - ebasco

High pressure steam from the boiler is delivered to the turbine generator which converts the heat energy in the steam to mechanical energy for rotation of the turbine.

The turbine drives an electrical generator that produces electricity; voltage is stepped up for efficient transmission to the load centres.

After the steam has done its work in the turbine, and has been reduced from its high inlet pressure to a very low pressure at the exhaust end, the exhaust steam is condensed in a condenser below the turbine. The condensate is then pumped back to the boiler to be "recharged" with heat energy from coal combustion to make steam and perform the cycle again.

To condense the low pressure steam, a supply of cooling water is necessary for the condensers. Where large volumes of water from the ocean, large lakes or rivers are available, once-through cooling is possible. It is drawn from the source, passed through the condenser, and discharged back into the source at a higher temperature (8 to 14°C rise) (15 to 25°F). Sometimes tempering of discharge water with cold water from the intake is used.

Where power plants have to be located away from large sources of water, cooling towers are often used. The towers effect cooling by evaporating part of the cooling water flow. This cooled water can be returned to the condensers to condense steam. The evaporated portion is emitted by the cooling towers to the atmosphere as water vapour and is a water loss from the system. This loss has to be made up from a suitable source, usually an adjacent lake or river.

The quantity of water for tower make-up is only a fraction of that required for once-through cooling. For instance, a 2000 MW plant would require about 2300 m^3/minute (500,000 Igpm) for once-through cooling but only about 76 m^3/minute (17,000 Igpm) for tower make-up and general service. The tower makeup is a consumptive use, whereas the once-through cooling is not.

In some locations it is possible to effect cooling on a natural or man-made lake or "cooling pond". Warm water from the condensers gives up heat by evaporation at the pond surface after being discharged furthest from the plant. Cold water is drawn from the near end and pumped to condensers. The area required for cooling ponds is typically a minimum of 0.6 hectares (1-1/2 acres) per MW of plant capacity. The loss of water by evaporation must be made up by precipitation or diversion of water from other streams or sources.

Sometimes the cooling pond performance can be augmented by passing the warm water through a spray system en route to the pond.

The main advantages of cooling ponds are their simplicity, reasonable construction cost, flexibility in operation (they can run for prolonged periods without make-up), and benefits to the public for recreation.

The main disadvantages are the inundation of large land area (if man-made), need for ~~suitable~~ [illegible] soil ~~permeability~~, and possible fogging.

Cooling towers of various types are available ranging from those in which fans are used to move air to those which use natural draft in a tall hyperbolic concrete tower.

Each project requires a complex evaluation of tower cost and performance against turbine and condenser cost and performance under specific climate conditions on a year-round production basis.

In some arid locations "dry" cooling towers, for which no significant make-up water is required, have been used. Air is used indirectly to cool the condenser cooling water (or sometimes the condensate of the main cycle) for recycling. Dry towers have severe limitations in warm climate conditions, need large land areas, cannot achieve the same efficient vacuum of conventional cooling systems, and so far have not been applied to units in North America larger than 330 MW.

Dry towers have the advantages of no make-up, no thermal impact on water sources and no fogging. However, they are most costly.

Cooling tower types are described in Reference (31).

4.2.2 Coal Handling at Power Plants

Coals for power plants might be delivered by several different methods including railway, slurry pipeline, trucks, conveyors (from adjacent mines), barges or ships as previously discussed.

On arrival at a power plant, the coal would be delivered direct to the silos in the boiler house or to a storage area usually divided into 'live' and 'dead' storage areas. Facilities for unloading, storing, conveying, crushing and reclaiming coal are known as the coal handling plant.

Such a plant would typically include unloading hoppers, crushers to break up frozen coal, stacker-reclaimers, bulldozers, carrier scrapers, and numerous conveyor belts, transfer points and sampling points.

Where a varying coal has to be accepted or where coals from various mines or sources are to be burned, provision must be made, either at the plant or at the sources, for proper blending of coal types to ensure a reasonably uniform fuel delivered to the boilers.

Coal is finally discharged in as uniform a condition and quality as possible to the silos above the pulverizers. The silos are kept full by an automatic system. Power plant operation requires an assured reliability and consistency of fuel supply.

Typically, coal for six to eight hours of operation would be stored in the silos.

The pulverizers are a vital feature of the plant, especially where coals are of low quality. Pulverized coal-firing system characteristics are different from those for industrial scale coal-burning where travelling grate stokers, or spreader-type stokers, are often used. With pulverized coal-firing, large water-tube boilers react immediately to changes in incoming fuel quantity and quality. The coal feeding system from silo to pulverizer is also critical to consistent and safe operation.

4.2.3 Bottom Ash System

Many coals are of high ash and/or moisture content resulting in a fairly low heating value. When coal is pulverized and burned in the furnace of large water-tube boilers, about 20% of the ash in the coal falls to the bottom of the furnace into a water-containing hopper. This "bottom ash" is sluiced from the hopper in a water/ash slurry pipeline.

The bottom ash can be delivered to dewatering bins that discharge the dewatered ash into trucks or on to conveyors for transport to disposal areas. The water would be returned to the sluicing system for reuse.

Bottom ash is usually disposed of in ponds that are ultimately drained, reclaimed and converted to their former land use, or an alternative use. Bottom ash does not present problems in handling. Potential uses of bottom ash include road surfacing, earth dam drainage, filters and general fill material.

4.2.4 Fly Ash System

The other 80% or so of the ash produced is carried out of the furnace in the flue gases. Almost all this fly ash is then captured in a gas-cleaning device, often an electrostatic precipitator, and from the bottom of that device it is transported dry by a pneumatic system.

Fly ash is often drawn first to a storage silo if there are customers for its use requiring loading of trucks. The quantities produced at a large coal-fired power plant are usually considerably more than actual or potential markets can absorb and, therefore, fly ash disposal areas are also necessary.

When transported to the disposal areas by trucks or conveyors, fly ash is usually watered for dust control. If the distance is not too far, it can be carried pneumatically to the disposal areas in dry form.

Often the final disposal areas for fly ash are wet ponds that can be ultimately drained and reclaimed for future use. Some plants now use "dry ash disposal" systems where bottom ash and/or fly ash is used in "land-fill" rows which are sequentially sealed, covered and landscaped.

Fly ash from coal-fired power plants is being sold for many purposes including augmenting cement in major concrete dams, soil stabilizing, asphalt paving filler, lightweight aggregate, concrete blocks, pozzolan cement, oil-well cementing and structural land fill. Studies of potential alumina extraction from fly ash are being made.

4.2.5 Stacks

Power plant stack design parameters are important for ensuring adequate plume emission characteristics. Current practice is frequently to connect more than one large unit to a single stack shell in order to emit the hot gases from one point and improve plume buoyancy. A concrete shell houses up to four individual steel flues, each serving one large unit. Stack heights for large plants can exceed 500 ft. Each power plant site has to be evaluated according to the fuel, operating characteristics, adjacent terrain and the diffusion capability of the atmosphere.

4.2.6 Other Features

New coal-fired power plants would be designed in accordance with well-proven Canadian and North American practice. There are many plant systems involved beyond the areas briefly described above.

The Nanticoke Generating Station of Ontario Hydro burns primarily United States bituminous coals although recently low-rank coals from Western Canada have also been used although they were not considered in the design of the plant Reference (6).

The large Boundary Dam lignite-fired power plant of Saskatchewan Power, the Wabamun and Sundance plants of Calgary Power, the Battle River plant of Alberta Power and the Centralia plant of Pacific Power & Light (and other sponsoring utilities) are typical existing plants burning low-grade western coals with similarities to coals of this Province.

4.2.7 Operation

Large thermal power plants for electrical power generation in this Province would probably be operated under base-load conditions for a major portion of their working lives. They would also be expected, at certain times, to be two-shifted (i.e. shut down at night) and, in their later working lives, to be operated to some degree as cycling or peaking units. The plants would be supplying electricity to the integrated provincial transmission grid and their output and load changes would be closely related to the satisfactory operation of the electric system.

Base-load operation would be continuous 24 hours/day, 365 days/year, with one planned outage of each large coal-fired unit for about four weeks each year. Normal operation would be automatic control of each generating unit with extensive use of computers and data logging.

4.2.8 Construction/Scheduling

A coal-fired power plant of typical utility size requires 4-1/2 to 5-1/2 years for design and construction excluding pre-approval periods. The latter periods vary considerably and include time for engineering, environmental and economic feasibility studies, obtaining permits and other related matters.

A construction work force peaking at around 2,000 men would be required for a 2000 MW coal-fired plant (excluding mine and coal preparation plant) and major field construction would last upwards of three years depending upon the number of units involved and their timing.

Extensive civil works including site clearing, excavation, concrete foundations, structural steel frames and building enclosures would be followed by installation of heavy machinery, (boilers, turbines and generators, etc.).

Inter-connecting piping, cabling, and control systems and numerous auxiliary component systems would form the main work in the later stages of construction.

4.2.9 Emission/Discharges

A coal-fired thermal power plant includes a complex series of material and energy cycles. The basic coal and ash systems have been briefly described above. Table 4-1 shows some typical data for a 2000 MW coal-fired power plant, using low-rank fuel and cooling towers,which relates to its emissions and discharges, and power output.

TABLE 4-1

TYPICAL COAL-FIRED PLANT DATA

Plant	
Output	2000 MW (net) 2240 MW (gross)(inc. mine power)
Station Heat Rate	11,000 kJ/kW hr sent out (10,400 Btu)
No. of Units	4
Capacity each	560 MW (gross)
Coal	
HHV as fired	14,653 kJ/Cal. (6,300 Btu/lb)
Moisture	20%
Ash	26%
Consumption/hr (plant)	1,513 tonnes (1,668 tons)(at full load)
Consumption/hr (1 unit)	378 tonnes (417 tons)(at full load)
Consumption/day (plant)	36,312 tonnes (40,000 tons)(at full load)
Consumption/day (1 unit)	9,078 tonnes (10,000 tons)(at full load)
Consumption/yr (plant)	9.3 x 10^6 tonnes (10.3 x 10^6 tons) (at 70% cap. f.)
Consumption 35 yr lifetime (plant)	326 x 10^6 tonnes (361 x 10^6 tons) (at 70% cap. f.)
Ash	
Produced/day (plant)	9,441 tonnes (10,400 tons)(at full load)
Produced/yr (plant)	2.4 x 10^6 tonnes (2.7 x 10^6 tons) (at 70% cap. f.)
Boilers	
Capacity each	486 kg/sec (3,850,000 lb/hr)
Steam Conditions	16.6 MPa/538°C/538°C
(at turbine)	2400 psig/1000°F/1000°F
No. of pulverizers	8 per boiler
Cooling Towers	
Number	4 (1 per unit)
Type	Rectangular mechanical draft
Total Plant Make-up	76 m^3/minute (20,000 U.S. gpm) max.
Precipitators	
Each Unit	68,000 a.m^3/minute (2.4 x 10^6 acfm)
Efficiency	99.5% +
Gas temperature	149 °C (300°F)

4.3 Power Plant Project Study Considerations

Reference (1) reviews potential fossil fuel development for power in British Columbia. Coal-fired plants often include one or two units as the initial stage and then add units as load growth requires them. Often the later units are of larger size.

Potential combined power and steam production in association with adjacent industries, or with a district heating system, are always reviewed, but in British Columbia, there are few possibilities for projects of this nature. District Heating is discussed in Reference (14).

4.3.1 Site Selection

Selecting a site for a coal-fired thermal power plant is a complex exercise involving many considerations, once the detailed coal and ash characteristics are known.

These include: -

- air dispersion of emissions;
- water supply and waste disposal;
- transportation of coal and materials;
- transmission of power to the grid;
- location of population and industry.

All factors must be evaluated on the basis of engineering, economic and environmental considerations and the best compromise determined.

In some cases for instance air dispersion considerations may limit the size of the plant or even rule out valley sites with restricted dispersion characteristics.

The water supply is always a vital consideration. Availability of a once-through supply alongside the plant would normally mean lowest capital cost for cooling water. If cooling towers have to be used and make-up water brought a considerable distance or pumped a considerable height to the site, cost is high. Suitable waste disposal areas must be available near the plant.

Coal transportation has been discussed previously. The consideration of electrical transmission is primarily one of economics, land use and location of major power consumption areas. Figure 4-2 shows the electric transmission system of B. C. Hydro.

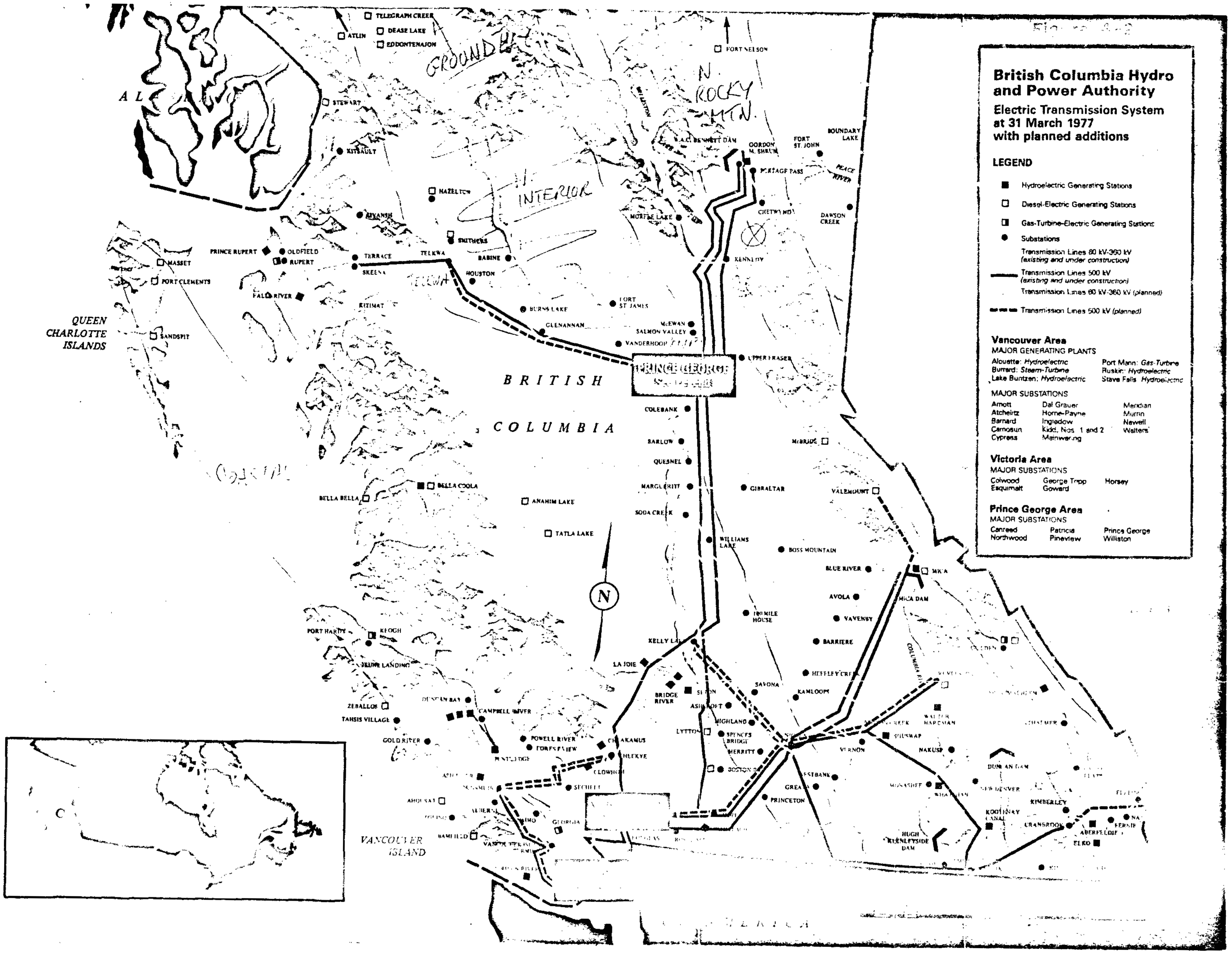
The population and industry considerations are numerous. They include suitable living locations for plant staff, area economic development, technical training establishments, and ensuring that the proposed power plant planning is in harmony with all other developments in the area.

4.3.2 Fuel Requirements and Quality

Evaluation of coal deposits prior to use is most important and, in many cases, most complex. Future power plants might use coal from several sources in the Province, and, also, consideration may be given to augmenting coal-burning with other fuels such as hog fuel or municipal refuse. Oil and gas are considered to be premium fuels, and as such are unlikely to be used as prime fuels for large thermal power plants.

Hog fuel on its own is unlikely to be a major fuel for power generation in the B. C. Hydro system. This is because of the difficulty in developing an assured and adequate supply at an economic price in a central location. B.C. Hydro is presently participating in joint studies with the B.C. Energy Commission and the Council of Forest Industries which will examine the problem of surplus wood fuel in the industry.

Figure 4-2



British Columbia Hydro and Power Authority

Electric Transmission System at 31 March 1977 with planned additions

In large metropolitan areas such as the St. Louis area in the U.S. or the Toronto area in Canada, municipal refuse may be available in sufficient quantities to justify its use in augmenting power plant coal fuel. Up to 10% or so of the heat input to a large coal-fired utility boiler (300-500 MW) could come from refuse. In most cases, and particularly in British Columbia, it is unlikely that a coal-fired thermal power plant would be located near enough to reasonably large sources of refuse to make combined firing worthwhile. The potential of Vancouver would be about 30 MW of refuse firing. The GVRD has reported that combustion of refuse could not compete with relatively low cost landfill alternatives.

Some power plants have "wet-bottom" furnaces on their coal-fired units. In these most ash is made molten in the combustion zone and removed in quenched form as bottom ash. Ash fusion characteristics must be correct and consistent for this type of boiler. Recent problems with high NO_x emissions due to the high heat release rate in the furnace have resulted in a decline in use of "wet-bottom" furnaces. For British Columbia fuels conventional coal-firing would predominate.

Should a fuel be of high ash and/or high moisture content the resultant low heating value means higher quantities of fuel are required to produce a given output. The generally low sulphur content of western coals means lower SO_2 emission. The higher ash content means much larger gas cleaning devices to remove particulate matter as well as additional operating problems due to erosion of pulverizers, and boiler and economizer surfaces.

4.3.3 Ash Production and Quality

With high ash in the coals, and large units envisaged, the quantity of bottom ash and fly ash produced in thermal power plants would be large. In a 2000 MW plant burning low quality coal of heating value 14,000 kJ/kg (6000 Btu/lb.) and ash content up to 30%, the quantity of ash produced per day at full load could be about 9100 tonnes (10,000 tons), of which about 20 percent would be bottom ash and 80 percent fly ash. Careful attention would be given to ash hopper capacities, ash moving system design parameters, and ash disposal area capacity.

Should coal washing be used to reduce ash, the disposal problem is substituted in part by an effluent disposal problem from the preparation plant.

4.3.4 Other Considerations

4.3.4.1 Operating Constraints

When reviewing possible thermal power plants in the Province, many factors must be considered, especially relating to the expected operating characteristics of the plant.

Coal-fired units of the size likely to be considered would be major additions to the generating capacity of the provincial electrical system, and would be planned to ensure maximum availability and suitability for the electrical system of which they are part, while converting coal energy efficiently and cleanly.

Any constraints on operating practices must allow reasonable time for change and must be attainable within safe and reasonable operating adjustments of large coal-fired units.

Many constraints not directly related to emissions are already in effect for the plant operators, for example, rates of loading and unloading large turbine generators, and matching boiler and turbine temperatures.

During periods when large units are being brought on line, operating conditions and hence the emissions may be different from steady, steady-state operation. For example, auxiliary fuel may augment coal for short periods.

4.3.4.2 Costs/Economics

Typically a four-unit 2000 MW plant without scrubbers would cost (1977 dollars) about 1 to 1.25 billion dollars.

The operating costs of such a plant would be determined primarily by the fixed charges on the investment and by the cost of the coal.

Studies of possible coal-fired plants in B. C. must stress accurate coal cost assessment and plant cost estimates and include all other normal evaluation factors such as number and size of units and cycle conditions. Objectives for pollution control are a critical consideration in such studies.

5. ENVIRONMENTAL IMPACTS

Section 4 presented the basic design, construction and operation of coal-fired power plants and some important considerations when evaluating new projects of this type. This section discusses potential environmental impacts arising from the construction and operation of such plants.

5.1 Air

5.1.1 Emissions and Ambient Air Quality

"Emissions" refer to the mass discharge rate of material from a source, such as the flue gas from an industrial stack. "Ambient air quality" describes the concentrations of specific substances in the air we breathe and thus relates to the composition of the air at ground level at some distance from the source.

The Pollution Control Act defines an air "contaminant" as:

> "...any substance, . . .
>
> (a) that is foreign to or in excess of the natural constituents of the air; or
>
> (b) that affects the natural, physical, chemical, or biological quality of the air;
>
> and that is, or may be, injurious to health or safety or comfort of a person or injurious or damaging to property or to plant and animal life, or that may interfere with visibility or the normal conduct of transport or business or is obnoxious to the public..."

Air "pollution" is described in the Act as:

> "...discharging or emitting into the air such substances or contaminants of such character as to substantially alter or impair the usefulness of the land, water, or air..."

It is the responsibility of industries within the Province to cortrol the discharge of contaminants to avoid pollution. An assessment of the air quality impact of any existing or proposed source must examine the criteria for achieving this objective in terms of the many constraints imposed by socio-economic and design requirements in the site specific context. For a thermal generating station, the principal considerations to be addressed in the assessment include:

. plant location and physical layout (determined principally by the type and source of fuels) the water, and location of the load centre;

. topography and airshed meteorology (as related to the frequency of conditions producing high ambient air quality levels);

. stack gas emission rates and the concentrations of contaminants;

. stack dimensions and plume properties (that is stack gas temperature and flow rate and their impact on plume rise and its dispersion);

. airshed air quality (i.e., contributions attributable to other nearby installations, existing and future); and

. proposed plant operating regime.

It cannot be overstressed that the constraints imposed by such considerations are <u>unique for every installation</u> and that determination of an acceptable program for air quality maintenance involves detailed examination on a case-by-case basis.

5.1.2 Protection of Public Health

The following section presents a basic discussion on the impact of typical gaseous emissions from coal-fired power plants. This is a condensation of a more extensive review of public health effects, which is presented in Appendix II.

Establishment of ambient guideline levels has always had as its primary objective the protection of human health. Historically most regulatory bodies, in attempting to set guidelines aimed at eliminating adverse effects on human health, have postulated that for each contaminant there is a threshold concentration, below which deleterious health impacts are not observed. Such a threshold is desirable as a regulatory tool, as it allows the establishment of a definitive value and consequent ease of enforcement.

In practice, this threshold concept has suffered from several major drawbacks. As clinical diagnostic methods have improved, it has been possible to detect more subtle changes in health indicators. However, the significance of such changes in terms of actual health status has often remained unclear or unknown.

The refinement of measurement techniques makes it possible to evaluate low exposure levels more accurately. The increased sensitivity of detecting changes in health indicators, and in monitoring contaminants, necessitates re-evaluation of no-effects thresholds. In general, this has lead to revision of ambient guideline levels.

The assumption of a unique relationship between a single contaminant and a specific health effect is usually not demonstrable. Limitations of existing statistical techniques make it difficult to isolate such relationships. Thus there is often a likelihood that observed health effects are influenced by contaminants other than the one of immediate concern.

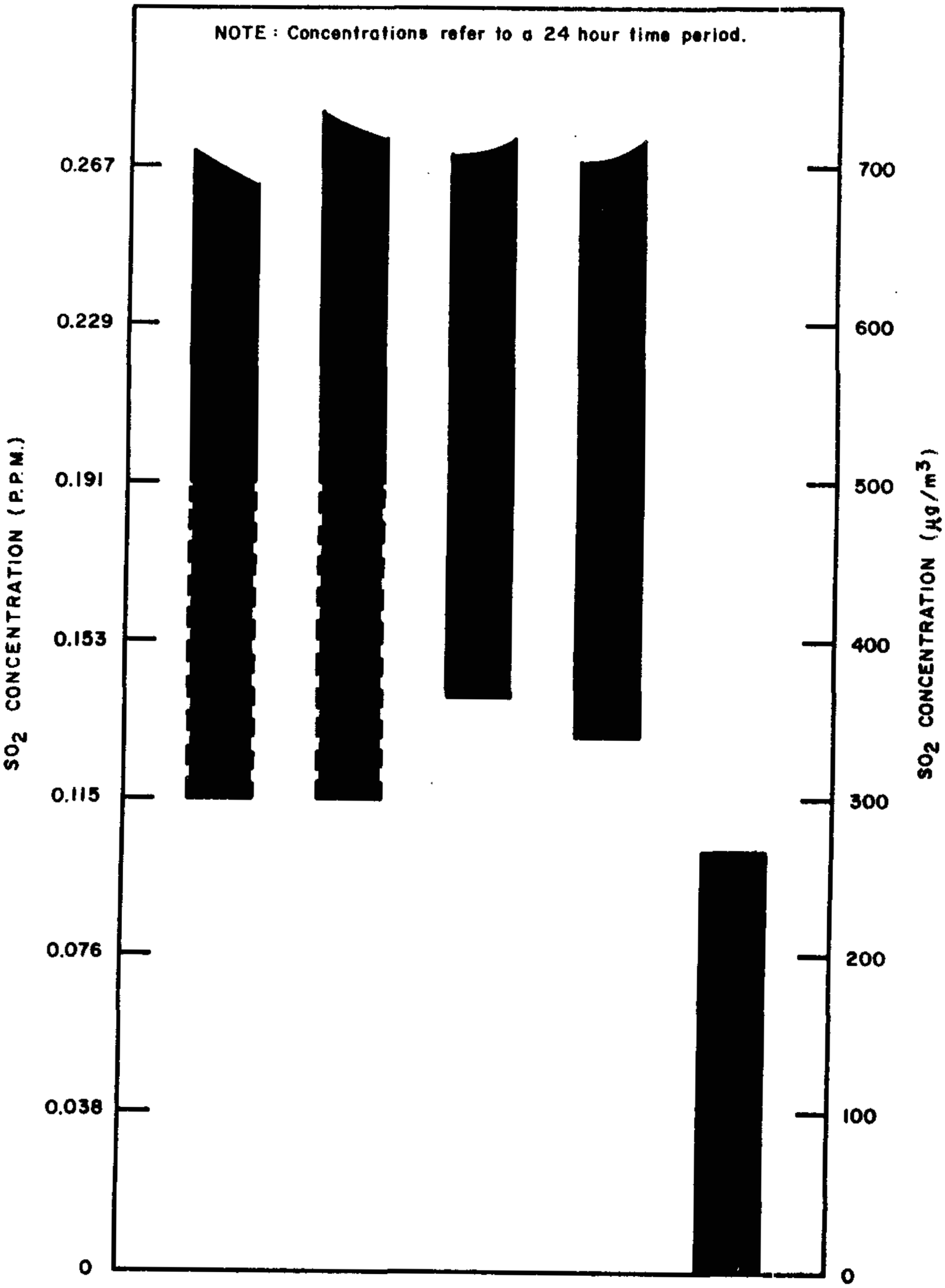
Often contaminants are present in complex mixtures for which quantitative analyses are not available. At low levels, apparent health effects are similar for many contaminants. In most situations, variations in the concentrations of contaminants occur simultaneously.

In general, attempts to identify the threshold for various contaminants as a basis for defensible ambient guidelines have met with considerable difficulty. This does not mean that clearly defined effects are not visible and attributable to specific substances at high concentrations, but rather, as one moves toward lower concentrations, the ability to isolate clear cause-effect relationships becomes extremely tenuous.

For these reasons it is sometimes useful to examine a range of contaminant concentrations that may lead to adverse human health effects. Figure 5-1 presents sulphur dioxide concentration ranges for a specific averaging time (24 hours) which has been identified in recent studies in association with adverse health effects. Known effects associated with annual average concentrations are indicated in Figure 5-2. The current understanding regarding nitrogen dioxide effects is illustrated in Appendix II, Figure II-1.

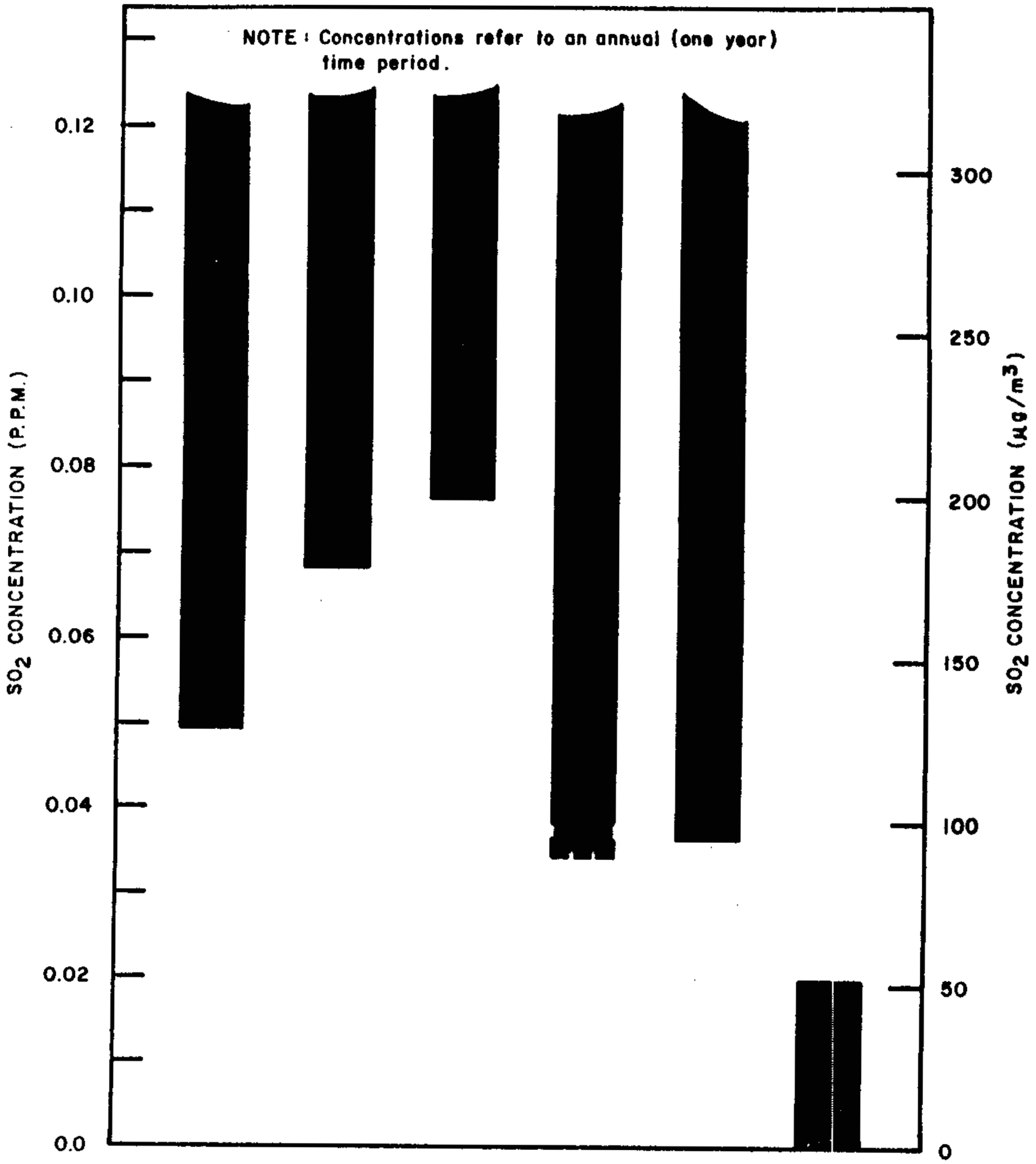
Evaluation of health aspects of air quality levels must reflect consideration of sensitive members of the community (i.e., the chronically ill, the young, the elderly) as well as the general public as a whole. To be meaningful, health criteria for all contaminants should be related to ambient air quality values, and not source emission levels.

RECENT SCIENTIFIC STUDIES RELATING TO THE ADVERSE HEALTH EFFECTS OF SULPHUR DIOXIDE (SO_2)



Based on Table II-1

RECENT SCIENTIFIC STUDIES RELATING TO THE ADVERSE HEALTH EFFECTS OF SULPHUR DIOXIDE (SO_2)



Based on Table II-I

For sulphur dioxide and particulates, it is also noteworthy that the shortest meaningful averaging time associated with documented health impacts is 24 hours. No important reactions to exposures for one or three hour periods have been reported for coal-fired power plant gaseous contaminants, such as sulphur dioxide, at moderate to low concentrations.

5.1.2.1 Sulphur Dioxide Guidelines

Health guidelines for sulphur dioxide should be based on the examination of the available technical data with primary emphasis on human exposure information relative to both mortality and morbidity. A 24 hour and an annual average guideline can be justified by existing health data. These data are shown in Figure 5-1 and Figure 5-2 taken from Table II-1 in Appendix II.

Morbidity Data - 24 Hour

Review of the available epidemiological data relative to the adverse health effects of sulphur dioxide for 24 hour exposures indicates a range of response between 120 and 500 ug/m^3 with the strongest evidence suggesting a range approaching 300-400 ug/m^3. Some more recent results indicate that deleterious health effects occurred from sulphur dioxide at concentrations below 300 ug/m^3, but it was the best judgement of the researchers conducting the studies that this effect was due to sulphates, alleged to arise from the interaction of sulphur dioxide and particulate matter in the atmosphere, and not sulphur dioxide alone (43). Reanalysis of the data show that the effects were not confirmed for asthma and particulates of sulphates (44).

Mortality Data - 24 Hour

There exist epidemiological data that are alleged to relate excess mortality to increases in ambient sulphur dioxide concentrations. However, examination of these data reveals a consistent simultaneous presence of high smoke or particulate concentrations of 500 ug/m^3 or higher, during mortality episodes. This is compared to lower particulate concentrations, e.g. 300 ug/m^3 smoke, when describing morbidity. The observance of such differences has led researchers to ascribe these effects to the joint interaction of particulates and sulphur dioxide. This has led to the speculation that sulphates are the causative agent behind some adverse human health effects (43).

It has been concluded that mortality is an insensitive indicator of pollution health effects for all but the most extreme deviations in pollutant levels (45). Also, mortality data deriving from epidemiological studies can neither support nor preclude a 24-hour sulphur dioxide guideline in the range of 300 to 400 ug/m^3, or below, because these findings are compounded by the contribution of factors other than sulphur-dioxide.

The existing 24-hour guideline of 266 ug/m^3 (0.1 ppm) appears to provide adequate protection for human health and is reasonable until further studies can provide more adequate data.

Morbidity Data - Annual

Health information gathered thus far indicates that no significant increase in morbidity results from long-term exposures to sulphur dioxide at concentrations below an annual average of 90 ug/m^3. In fact, with respect to several key parameters such as increased prevalence of chronic bronchitis in adults and increased acute lower respiratory disease in children, adverse effects are first observed at concentrations in the annual average range of 90 to 200 ug/m^3.

Mortality Data - Annual

Attempts to link excess mortality data with increased sulphur dioxide levels as stated previously, are equivocal. Most studies have focused on increased mortality during episodic conditions of severe inversion that are not consistent with long-term exposures. Further, all study results have been obscured by other subtle effects that are not contaminant-specific enough to factor out sulphur dioxide, or natural phenomena.

The existing annual average guideline of 53 mg/m^3 (0.02 ppm) appears to provide adequate protection for human health and is reasonable until further studies can provide more adequate data.

5.1.2.2 *Sulphur Oxides and Total Suspended Particulates*

As mentioned earlier and in Appendix II, it has been alleged that low concentrations of suspended particulates, especially sulphates, exacerbate asthma and other conditions (43). A recent report clarifies this issue (44).

A careful statistical re-evaluation of these data collected originally in New York in 1970-71 does not support the hypothesis of the Community Health Environment Surveillance Studies (CHESS) (42) that a positive association exists between the incidence of asthma attacks and levels of suspended particulate or suspended ambient sulphate levels (43, 44). Also, serious questions have been raised about the validity of the data (44). When adjustment is made for the statistical design factors significantly associated with the asthma attack rate, there is no evidence of a positive association between sulphur oxides and asthma attack. Further, there is no conclusive evidence about any association between total suspended particulate levels and incidence of asthma attacks. (44)

5.1.2.3 Other Contaminants

The basis for review of ambient air guidelines for suspended particulate, oxides of nitrogen as nitrogen dioxide, fluoride, and mercury is presented in Appendix II. Dustfall has been excluded from Appendix II because it is considered to be a nuisance rather than a health hazard.

5.1.3 Protection of Economic Interests

In addition to human health considerations, ambient air guidelines must be set in accordance with available information regarding potential aesthetic and economic effects related to air quality. Examples of so-called nuisance impacts include visibility reduction, objectionable odour and dustfall. Such effects cannot, however, be considered entirely independent from economic impacts. Conditions generally considered aesthetically undesirable might also be expected to reduce property values, contribute to corrosion of paint and structures, damage agricultural crops, or cause harm to wildlife and recreational facilities.

To avoid problems of this type, modern coal-fired power plants are routinely equipped with control equipment capable of removing nearly all flyash, effectively eliminating concerns regarding visibility and dust fallout. As well, odour thresholds for stack gas contaminants are well above ground-level concentrations expected to result from tall-stack power plant emissions.

In a series of studies commissioned by Ontario Hydro (50) the incremental social costs of coal-fired electric power generation for export were examined in detail for both urban and rural settings. A total cost of "between 0 and 0.77 mills per kwh and probably well into the lower portion of this range" was estimated for a power plant located near Toronto. No adverse impacts on plants or animals in Ontario due to power generation were identified.

Costs associated with deterioration of building materials (zinc, paint, copper, nickel, concrete, aluminum, brick, tin, stone and glass) including repair and additional cleaning costs were estimated at 0.03 to 0.17 mills per kwh in an urban area and 0.002 to 0.008 mills per kwh near a rural plant. These values represent potential costs for remedial action rather than actual expenditures.

Damage to clothing and incremental cleaning costs attributable to power plant emissions were found to be extremely small in comparision with other soiling factors in Toronto and virtually zero for the rural area investigated. No relationship between property values and air quality levels was found.

Studies have attempted to identify specific effects of air contaminants upon individual species of plants and animals. In all literature currently available, few impacts identifiable with a particular point source have been found. Severe damage to vegetation and aquatic ecosystems have been related to the smelter in Sudbury, Ontario. However, this is the largest stack source in the world, responsible for about 3% of the world's anthropogenic SO_2 emissions (37)(38). Effects of gaseous emissions on vegetation in the vicinity of the smelter at Trail have been observed. There is now strong evidence of vegetation recovery following the introduction of abatement procedures in the early 1940's. A meteorological control system was introduced in 1941 to reduce plant emissions during adverse meteorological conditions and extended periods of air stagnation. No similar impacts associated with thermal generating plants have been thus far identified.

5.1.4 Acid Rain

Recent investigations in Scandinavia and eastern North America have focused attention on long-range transport of emissions from tall stacks. Most noteworthy among impacts associated with long range transport is the observed acidification of precipitation in regions generally downwind from major industrial centres.

While much controversy exists regarding the nature of mechanisms affecting the pH in precipitation, it is generally believed that suphuric acid and nitric acid (formed in the atmosphere over large travel distances) are the chemical constituents chiefly responsible for increasing acidity. Since these acids result from atmospheric conversion of sulphur dioxide and oxides of nitrogen produced by combustion processes, concern has been voiced regarding the effects of increased coal use to meet future energy demands.

While Beamish (48) stated that no published studies exist for long-range transport of acid precipitation in Canada, a survey of acid precipitation is being conducted by Environment Canada (49). The pH values of rain were found to be generally lowest in Ontario especially in the vicinity of Sudbury. The least acid rain was found in west central Canada in the region of eastern British Columbia, Alberta, Saskatchewan and Manitoba.

Currently a literature survey of acid precipitation is being undertaken by an inter-agency Federal-Provincial committee. This survey should be available in early 1978. B. C. Hydro has conducted snow sampling experiments in the Cornwall Hills near Cache Creek and in the mountains of Wells Gray Park. Sampling to date indicates snow pH in the range from 5.0 to 6.0; this is near the 'natural' pH (value expected for precipitation achieving equilibrium with atmospheric carbon dioxide). Analysis of water samples taken from mountain streams carrying the spring runoff from these snow packs reflects substantial buffering of the melted snow, apparently accomplished by interaction with alkaline materials in the soil. pH values near 8.0 were found in the streams. Estimates of expected changes of pH due to incremental increases in atmospheric contaminants indicate that small pH reductions in the precipitation itself may occur.

5.1.5 Climate

As noted in section 2.3 the elevated terrain of British Columbia and its effects upon climate (in particular wind patterns) may impose constraints regarding the selection of acceptable sites for future coal-fired power plants. For this reason, a thorough and site-specific assessment of local climatology (with specific regard for the dispersive capability of the atmosphere) is essential to determine potential impacts arising from this type of development. Measurements of on-site windspeed, wind direction, temperature, vertical temperature gradient and relative humidity, for a period of at least one year are some of the parameters used as input to evaluate the atmospheric dispersion air quality arising from a proposed project.

For certain locations within British Columbia, once-through cooling for thermal plants may be considered unacceptable. Where cooling systems such as holding ponds, spray canals and cooling towers are considered for a coal-fired power plant, the selection of the system should be made with the goal of minimizing potential environmental impacts, such as icing and fogging at the ground, chemical drift deposition, obscured visibility, incremental clouding, and precipitation effects.

5.1.6 Three-Hour Ambient Air-Quality Guideline for Sulphur Dioxide

Protection of health has always been the primary basis for the establishment of acceptable ambient air quality levels. As discussed in Section 5.1.2 no health data exist to support ambient sulphur dioxide guidelines for averaging times of less than 24 hours. Guidelines for shorter exposure periods have not been recommended on the basis of correlations between sulphur dioxide concentrations and specific human health effects. This is due to both the lack of evidence of such effects for fractions of a day, and the difficulties in extrapolating data for longer exposure conditions.

In the past, one-hour and three-hour sulphur dioxide guidelines have been enacted by regulatory agencies in Canada and the U.S.A. On the basis of available evidence related to corrosion of materials, damage to vegetation, and effects on animals, it appears that both the ambient air guidelines and the averaging periods themselves have been chosen somewhat arbitrarily, although certainly the intent has been to provide a margin of safety against adverse health effects and other impacts.

Discernible damage to vegetation over short exposure periods has been reported, but only when the sulphur dioxide concentrations involved were much higher than those expected to occur as a result of emissions from modern power plants (47). In short, there appears to be little scientific justification for choosing a period as short as one hour rather than three hours as a minimum averaging time for ambient sulphur dioxide guidelines.

The climate and terrain of British Columbia place much greater constraints upon the ability of major emitting sources to operate within short-term guidelines than would be the case in regions characterized by relatively flat topography. Practical site selection criteria of:

- water supply
- coal transport
- space (land) requirements, and
- personnel access

would often dictate that coal-fired power plants be located in regions of the Province where the effective plume release height is insufficient to preclude occasional impingement of stack emissions on elevated terrain surrounding the plant.

The likelihood of plume interaction with terrain may also be increased as a consequence of local air circulation patterns directly associated with rugged topographic features. When the synoptic (large-scale) wind flow is light, transport of airborne contaminants can be dominated for short periods by such circulations especially in mountain valleys or coastal inlets. Such effects can result in localized high ground-level concentrations for short time periods. When the wind speed at plume height is strong, the contribution of such flows is secondary, and atmospheric dispersion conditions are improved.

Obviously, variability in wind direction (and consequently plume trajectory) over a three hour period is normally much greater than that expected during a single hour. A three-hour sulphur dioxide guideline of 0.25 ppm should therefore be more reasonable for large coal-fired power plants than a 0.30 ppm value for one hour. As noted above, no quantitative evidence exists that would justify the considerable incremental expenditures that may be required to maintain the one-hour rather than the proposed three-hour guideline.

5.1.7 Air Quality Impact Assessment for Major Facilities

In order to estimate the air quality effects of proposed coal-fired power plants, a comprehensive impact assessment study would be performed and submitted in support of the Air Pollution Permit Application. Such a study could include the following components:

- An accurate assessment of the fuel characteristics, the design of the plant, and the proposed operating regime.

- Background air quality data.

- Baseline surface and upper air meteorological measurements to provide input for air quality modeling studies and to identify site-specific wind circulation patterns of potential importance with regard to maintaining acceptable ambient air quality levels.

- Additional field studies such as constant-level balloon trajectory experiments and gas tracer releases to simulate the behaviour of stack gases. Vertical profiles of wind speed and temperature should be measured to provide information on the dispersive characteristics of the atmosphere. Such studies can provide important information to assist in development and validation of diffusion modeling techniques for site-specific applications.

- Diffusion modeling studies to determine expected maximum ambient contaminant concentrations from the proposed project and the frequency of occurrence of values above specific guideline thresholds for various averaging times. Modeling can also be used to determine acceptable stack heights and compliance limitations for the thermal plant.

- In some instances physical modeling (i.e wind tunnel experiments) can be used to study airflow in regions of unusual terrain or sharp structures and to investigate the effects of such flows on contaminant dispersion. It should be recognized that such techniques are useful for evaluating mechanical turbulence behaviour but generally can provide little information regarding complex flows due to differential heating of mountain slopes or other thermally-induced phenomena.

- Mathematical modeling to assess impacts due to cooling towers or other closed-cycle cooling systems. Such studies should include evaluation of seasonal and annual cooling tower drift deposition patterns, frequencies of incremental fogging and icing and visible plume lengths as a function of distance and direction from cooling towers.

- Trace element studies to assess the kind and amount of trace substances present in the coal, to determine their fate in the various phases of the combustion process, and to evaluate the potential impacts upon land, air, water and biological species when they re-enter the environment.

5.1.8 Airshed Ambient Air Quality

The existence of a number of large coal deposits within the Province must be considered in formulating energy policy and possible industrial use in the future. As there are no specific ambient guidelines nor emission objectives for the control of air pollution due to thermal plants, problems could arise if the use of coal for electrical generation in the Province is to be developed. The following comments reflect particular concerns of B. C. Hydro regarding the establishment of air quality control criteria for such developments.

- When granting air pollution permits consideration be given to individual plants on the basis of site-specific information, local dispersive capability, background air quality and adjacent land use activities.

- Procedures for amending Permits to allow plant expansion, to reflect operating experience, or to incorporate new information regarding specific impacts associated with air contaminants, are important elements in effective pollution control.

- Ambient air quality guidelines are a basis for the establishment of entire airshed regions such that public health and economic interests are considered in assessing cumulative effects due to local expansion of industrial and non-industrial developments.

5.2 Water

Water resources may be affected both during construction and operation of a coal-fired power plant. Figure 5-3 illustrates the water balance in a modern coal-fired thermal plant.

5.2.1 Construction

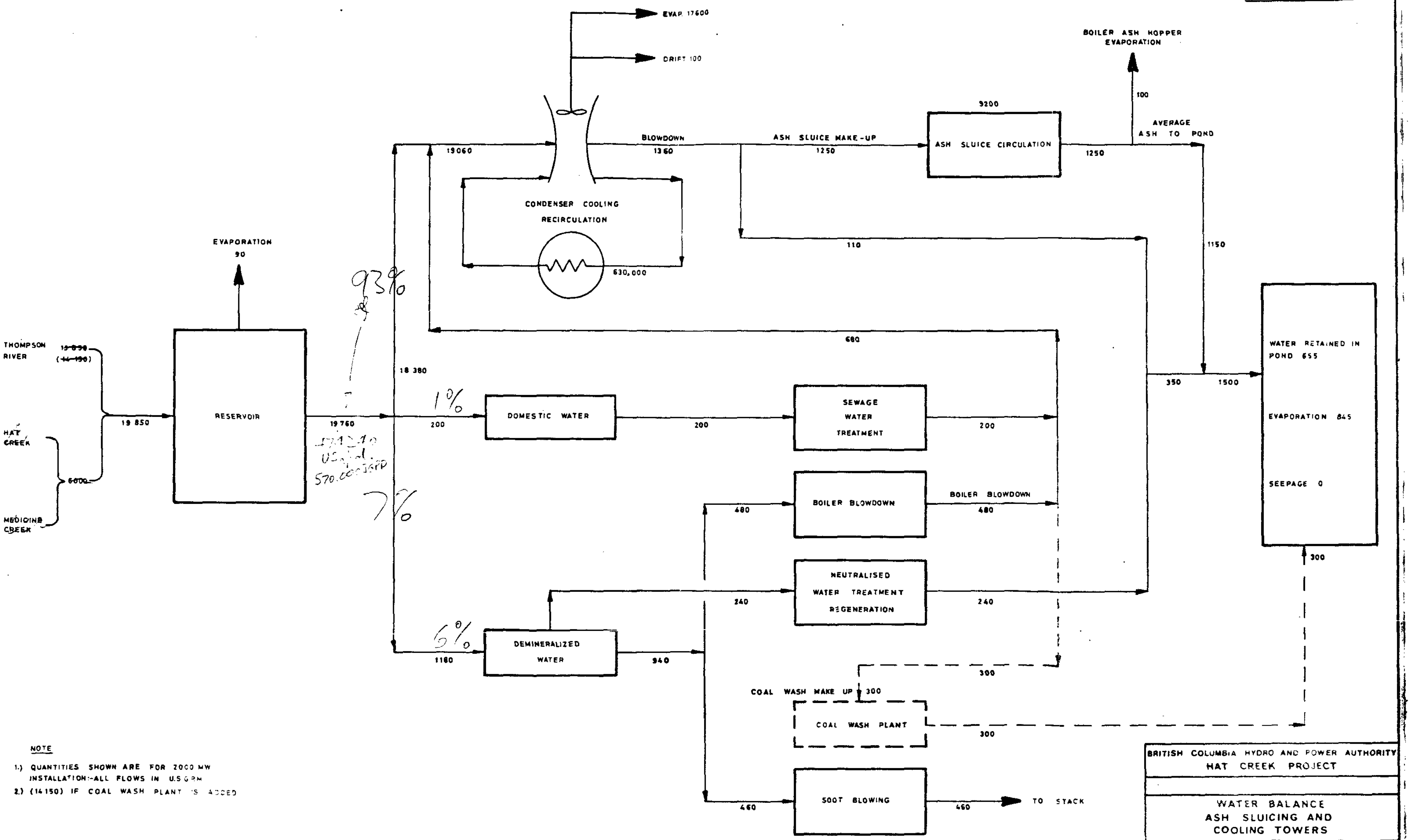
Construction of coal-fired power plants is briefly described in Section 4.

Both land and water impacts may occur. A major concern is erosion resulting in the silting of water courses and lakes. Runoff volume and thereby suspended solid concentrations may be controlled by suitably located embankments and settling ponds. Dredging operations may affect biological communities both by direct disruptions and indirectly via downstream siltation.

5.2.2 Operation

The operation of a coal-fired power plant involves the withdrawal of water for plant use and the potential contamination of water through the disposal of plant wastes.

Figure 5-3



NOTE

1.) QUANTITIES SHOWN ARE FOR 2000 MW INSTALLATION:-ALL FLOWS IN U.S.G.P.M.
2.) (14 150) IF COAL WASH PLANT IS ADDED

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
HAT CREEK PROJECT

WATER BALANCE
ASH SLUICING AND
COOLING TOWERS

integ-ebasco

5.2.2.1 Water Withdrawal

Water is used primarily for condenser cooling and to a considerably lesser extent to make up process losses such as boiler blow-down and plant service requirements. The quantity of water required may vary significantly depending on the type of condenser cooling system (once through or recirculating) adopted and, therefore the system selected is greatly influenced by site-dependent factors such as the availability and the quality of the water source.

Water Intakes may cause the entrapment, entrainment and/or impingement of aquatic organisms. Impingement of large aquatic organisms is a function of the hydraulic forces in the region of the screens. Careful intake design and flow patterns are employed to minimize this effect. Smaller organisms, e.g. plankton and larvae which pass through the screens, may be subject to physical impact, thermal shock or biocide antifouling agents in the plant water system.

The effect of water withdrawal on the water body is a function of the quantity of water withdrawn and any attendant reduction in the quantity of water in the waterbody. Flow reductions in streams may affect downstream ecology and/or the quantity of water available for downstream users.

5.2.2.2. Effluent Discharges

The disposal of solid and liquid power plant wastes may potentially affect the water quality of surface sources, streams and groundwater aquifers.

Groundwater Resources

Effects of power plant liquid and/or solid waste disposal (eg. coal pile runoff, flue gas desulphurization waste water etc.) upon groundwater quality is a function of the climate, geologic and hydrogeologic characteristics and morphology of the disposal site. In particular the permeability of the soil/rock, the location of aquifers, surface water drainage patterns and the ratio of precipitation to evaporation all affect the potential for leachate material to enter and contaminate groundwater systems. Other factors which influence the concentration of dissolved materials are natural purification mechanisms via dispersion, filtration, retention and ion exchange. These latter factors may have either a positive or a negative effect on groundwater quality.

Surface waters may be affected indirectly via contaminated groundwater or directly by the discharge of plant liquid wastes in the form of added dissolved and/or suspended solid loadings, or, in the case of once - through cooling, by thermal loadings. In any case the ability of the receiving waterbody to successfully assimilate the discharges without adverse effects may be expected to be site-specific.

Chemistry, in addition to the concentration, is of significance when assessing dissolved and suspended solid discharges. Effects on aquatic organisms may result from changes in water quality and thereby in aquatic habitat, though the impact may be expected to vary between species.

The potential for adverse environmental impact due to the discharge of waste heat is in general proportional to the degree of temperature rise and the volume of water discharged. The extent of any impact thus induced can be enhanced or ameliorated depending on the mixing characteristics of the receiving water body and the response of the aquatic community. Discharge plumes can create a partial or total "thermal blockage" which can slow or bar passage to migrating organisms. Increased water temperatures can locally change the character of resident aquatic communities by favouring the increase of certain species over others, or lengthening productive growing seasons.

5.3 Land

Coal-fired power plants, like all major projects, have construction and operation impacts on the terrestrial environment. The impacts can be reduced by compromising siting and design options with environmental constraints such as land use priorities, wildlife considerations etc. The major potential impact arising from the disposal of solid waste would be via the contamination of ground and/or surface water (see 5.2.2.2.). Ultimately, solid waste disposal sites could be returned to effective use by suitable reclamation.

6. CURRENT TECHNOLOGY FOR POLLUTION CONTROL

6.1 Air

6.1.1 Pollution Control at Source

Coal-fired boilers have been used in industry and in the production of electricity for over a century. This extensive operational experience has led to the development of many proven types of equipment and technology to control the emissions of contaminants at the source.

The following sections are brief discussions on the applicable technology for controlling the emission of the major contaminants in boiler flue gas particulates, sulphur oxides, and oxides of nitrogen.

6.1.1.1 Particulate Control Technology

Particulate emissions from coal-fired boilers are primarily a function of the amount of ash in the coal, the firing rate, and the firing method used, boiler type, type and efficiency of particulate control equipment boiler control and operation, burner design and chemical conditioning of fuels or flue gases.

Particulates are most commonly removed from power plant flue gas by electrostatic precipitation and cyclones, a form of mechanical dust collector. Fabric filtration and wet scrubbers have been used to a lesser extent. High efficiency electrostatic precipitators appear to the most economical and practical devices for particulate removal at a new plant. Their use on bituminous fuel has been proven by reliable performance when conservatively designed and well maintained. Successful application of electrostatic precipitation on coals having high ash and low sulphur content is more difficult and is dependent on a thorough design and field testing program to evaluate ash resistivity and precipitator power input levels.

Although fabric filtration baghouses and flue gas scrubbers have not as yet been used in Canada on power plants, with their successful application in the United States they are an alternative to the high efficiency electrostatic precipitor. A capital cost comparison for the three types of particulate control equipment is given in Table 6-1 (32). Precipitators have the most substantial data base. They were expected to fall into the cost range of $10.00-$20.00/kw in the mid 1970's. Costs for other systems are less reliable because of the limited number of installations.

Table .6-1

Capital Cost Comparison for New Units (500-1000 MW)*

Particulate Control Method	$/kw
Precipitators	10-20
Venturi Scrubbers	20-40
Bag Filters	15-25

*Capital costs for precipitators and fabric filters include the precipitator or filter connected flange to flange, insulation, support steel and erection. Venturi scrubbers include vessel costs and holding ponds. Fan and motor costs are not included.

34×10^6 ES
(680.000 m
21×10^6 B
(300 000 m/h

say 52 ESP
32 BH.
= 26/kw ESP
16/kw BH

6.1.1.2 Oxides of Nitrogen

Oxides of nitrogen (NO_x) are formed by oxidation of atmospheric nitrogen at high temperatures in power plant furnaces and by partial combustion of the nitrogenous compounds contained in the fuel. In coal combustion approximately 95% of the NO_x formed is NO and the remainder is in the form of NO_2 as it leaves the stack. In general the formation of NO_x increases with increased excess air, higher flame temperature and longer residence time, regardless of fuel type.

NO_x emissions can be reduced by several techniques related to boiler design and operation. The design of the furnace, combustion air system and burner design are especially important. Today, any new coal-fired boiler may be specified such that the emissions would meet the proposed objectives.

6.1.1.3 Sulphur Oxides

Sulphur oxides in stack emissions from coal-fired power plants are directly proportional to the sulphur content of the fuel. Typically coals can have sulphur contents ranging from .25% to more than 5%, however British Columbia coals are lower in sulphur and typically contain sulphur in the range of .25% to 2% by weight. Sulphur oxides produced from combustion of coal are typically 90-95% SO_2, 1-3% SO_3, with the remainder of the oxides being absorbed by the fly ash.

The formation of SO_3 is normally minimal in a coal-fired power plant.

Sulphur dioxide is formed when sulphur in the coal combines with oxygen in the furnace. Combustion of a typical Hat Creek coal would produce a flue gas with about 600 parts per million by volume of sulphur dioxide.

Control of sulphur dioxide at the source can be achieved by flue gas desulphurization (FGD). Numerous processes are available including lime or limestone scrubbing, both non-regenerative processes. Magnesia and sodium scrubbing and catalytic oxidation are regenerative processes where the sulphur is recovered in the form of elemental sulphur or sulphuric acid. These processes are discussed further in a later section on flue gas desulphurization.

6.1.1.4 Trace Elements

Trace quantities of elements contained in the fuel may be transmitted to the atmosphere by the combustion process. Trace elements become significant if their presence in receptors is greater than normal concentrations, and if they are identified as being potentially toxic to humans or other forms of life.

The potential impact that may arise from the use of new coal reserves can be assessed by trace element emission evaluation carried out during a test burn program. Trace elements associated with fly ash emissions can be controlled using particulate control devices; however, elements that exist in the gaseous form after combustion are emitted to the atmosphere.

6.1.2 Meteorological Control

A meteorological control system (MCS) is a systematic plan of defined procedures for the reduction of contaminant emissions to the atmosphere in response to anticipated or observed meteorological conditions associated with high ground-level ambient concentrations. Unlike continuous control strategies, such as flue gas desulphurization, MCS programs involve procedures for selective emission curtailment as required to prevent the occurrence of concentrations above specified threshold values.

For a given thermal generating facility, the principal factors that govern the design of a meteorological control program are: (1) the contaminant species to be controlled; (2) the type(s) and quality of available fuel supplies; (3) the plant load demand schedule, and (4) operating flexibility, this being governed by the type, size and number of units at the plant.

In general, an MCS is most effective when applied to a plant that is the dominant source of emissions within its zone of air quality influence and is located in a region having predictable atmospheric dispersion characteristics. The first criterion is important to ensure that control measures will produce the necessary air quality improvement, while the second condition stems from the need to minimize the frequency of required control actions and to reduce the inherent uncertainties involved in the prediction of meteorological events occurring.

To be successful MCS control must have: a source that can effect necessary load reduction as required; an ability to forecast poor dispersion conditions well in advance; a verified air quality prediction model; and a monitoring network to collect and process ambient air quality data. A schematic representation of an operational MCS is presented in Figure 6-1.

Meteorological control has been used primarily to maintain desirable sulphur dioxide levels; however, MCS procedures designed to control other contaminants might be practical as well.

A fuel-switching MCS (designed for SO_2 control) involves stockpiling low-sulphur fuel for use during periods of poor air dispersion characteristics when emissions from the source might otherwise produce ambient concentrations above acceptable thresholds. Straightforward load reduction procedures can be used to reduce emissions in some instances. The practicability of this type of MCS for an electric generating plant depends on the role of the plant with respect to other generating facilities. In general, load switching is feasible only for a capacity surplus energy deficient system such as exists in British Columbia at the present time.

SCHEMATIC REPRESENTATION OF METEOROLOGICAL CONTROL SYSTEM WITH COMPONENT INTERACTION FOR THERMAL GENERATING PLANT

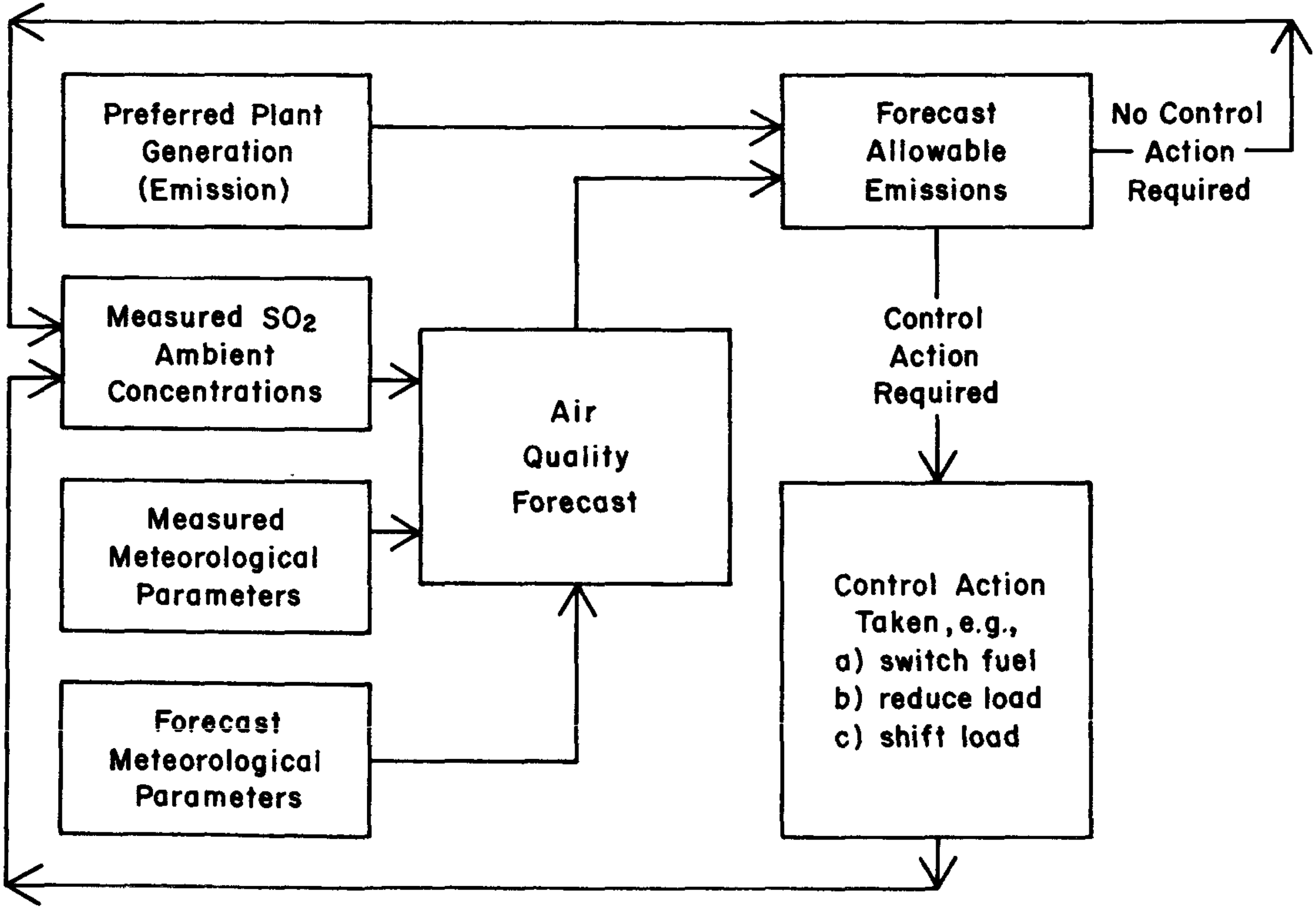


Figure 6-1

The 80% sulphur removal criterion presently required under subsection 2.2 of the Objectives for Mining, Mine-milling and Smelting Industries with the operation of an MCS or "sulphur dioxide control regime" would not necessarily be required for a coal-fired power plant to meet the proposed three-hour, twenty-four hour and annual ambient air levels. Local topography and meteorology, background air quality and adjacent land use activities should also be considered for each individual case.

For a coal-fired thermal plant operating in mountainous terrain in the Province, the time lag associated with the components of an MCS (e.g. distance between plant and sensor, time to achieve load reduction or fuel switching) is such that an MCS is not practical unless the shortest averaging time for sulphur dioxide concentrations is at least three hours.

As described in Section 5.1.6, the adoption of a three-hour averaging period, at a slightly more stringent level than currently applicable for the one-hour guideline, is reasonable for large coal-fired plants.

The use of MCS provides for environmental protection in an economic manner, and, with current improvements in monitoring techniques and data processing, facilitates both compliance by an operator and enforcement by a regulatory agency.

6.1.3 Cooling Towers

Factors affecting the potential environmental impact of both natural and mechanical draft towers include tower shape, plume release height and multiple tower location relative to each other.

Natural and mechanical draft towers differ substantially in their environmental impacts. During periods of moderate to strong winds, the potential for plume downwash and recirculation is greatest for rectangular mechanical towers. The severity of downwash depends upon the angle of the wind relative to the tower. Greatest potential for ground-level impact is expected when the wind is perpendicular to the line of cells; conversely, maximum plume rise and the least potential ground-level impact should occur with winds parallel to the tower's long dimension.

In contrast, round mechanical draft or natural draft towers present less of an obstacle to the local air flow and this reduces the frequency of downwash occurrences. In addition, the pattern of the plume is independent of wind direction. Due to the low release height of round mechanical draft towers (approximately 65 feet), ground-level impact potential under conditions of high wind speeds must still be considered.

Natural draft towers typically discharge their effluents from heights of 300 to 500 feet above grade. In general, observations in the vicinity of such towers indicate that visible plumes do not extend to the ground, where icing and fogging impacts are of concern, especially at the plant switchyard, transmission lines, access roads, etc.

It is also possible that even elevated plumes will impact upon high terrain downwind of the cooling towers.

All the cooling tower designs will lead to extended visible plumes during situations of light winds and cool temperatures.

Drift is a small carry over of water droplets entrained in the exhaust air, and is independent of the water lost by evaporation.

The amount of drift deposition from cooling towers is also a function of the type of cooling towers and their relative placement. The low release height and susceptibility to downwash which characterize the mechanical draft towers, tend to produce patterns of drift deposition that are chiefly concentrated in the area near the tower structure. In contrast, drift from the hyperbolic (natural draft) design is dispersed over a larger area resulting in less concentrated deposition patterns. Deployment of multiple-tower cooling systems is important because drift from individual towers can overlap, creating substantially higher deposition rates near the towers.

6.1.4 Fugitive Emissions

Fugitive emissions from power plant operations occur from wind-blown particulate originating with coal and fly ash handling operations. Water spraying is an effective control method to reduce fugitive emissions from coal conveying and coal stockpiling operations. Fly ash storage in slurry form will prevent emissions of particulate from this source.

6.2 Water

Primary water uses and wastewater flows in a typical coal-fired thermal generating station are presented in Table 6-2.

In the following sections, the wastewater streams and pollution control technologies are discussed in detail.

6.2.1 Construction Phase

The major material preparation system utilized during the construction of a power plant is a concrete batch system. Wastes from these operations are produced by mixer, truck and other associated equipment

TABLE 6-2

PRIMARY WATER USES AND WASTEWATER FLOWS IN A COAL-FIRED THERMAL GENERATING STATION

PROCESS PHENOMENON	IMPACT ON PLANT-CONTROL	IMPACT ON ENVIRONMENT-USE INCREMENT	WASTEWATER STREAM	CURRENT TECHNOLOGY FOR POLLUTION CONTROL
Construction				
1. Construction Activity	Drainage System	Suspended Solids (SS)	Construction Runoff	Clarification
2. Potable Water Supply	Treatment for SS Removal and Chlorination	Organics (BOD), Bacteria, SS, Nutrients	Sanitary Wastes	Biological Waste Treatment Processes, Clarification, Chlorination
Operation				
1. Condenser Cooling Water System	Treatment by Chemical Addition & SS Removal	Heat, Chlorine, Corrosion Inhibitors, Sulfates	Cooling System Blowdown	Cooling Towers for Heat Dissipation, Dechlorination if required, Reuse.
2. Plant Equipment Cooling Water	Treatment by Chemical Addition and Suspended Solids Removal	Heat, Chlorine, Corrosion, Inhibitors, Oil/Grease	Cooling System Blowdown	Oil/Water Separation, Dechlorination if required. Reuse.
3. Boiler Makeup	Treatment by Demineralization and Chemical Addition	Metals, Chemicals, Total Dissolved Solids (TDS), Sulfates, Sodium	Boiler Blowdown and Demineralization Regeneration Wastes	Reuse, Equalization, Neutralization
4. Bottom Ash/Fly Ash Transport	---	Metals, TDS, SS	Ash Sluicing Supernatant	Clarification and if required Chemical Precipitation of Metals and Filtration for SS Removal, Reuse.
5. Flue Gas Desulfurization (if applicable)	Chemical Addition	TDS, Metals, SS, pH	Scrubber Waste Supernatant	Aeration, Neutralization, Metal Precipitation, Clarification, Filtration
6. Floor and Equipment Washdown	Drainage System	Oil/Grease and SS	Drainage Wastes	Oil/Water Separation, Clarification, Reuse.
7. Potable Water Supply	Treatment	Organics (BOD), Bacteria, SS, Nutrients	Sanitary Wastes	Biological Waste Treatment Processes, Clarification, Chlorination, Reuse.
8. Runoff Coal Pile	Drainage System	Sulfates, Metals, TDS, SS, pH	Coal Pile Runoff	Clarification and if necessary Aeration, Neutralization, Metal Precipitation and Filtration, Reuse.
9. Metal Cleaning Processes	Chemical Addition	Metals, TDS, SS, pH	Metal Cleaning Wastewaters	Incineration or Neutralization, Metal Precipitation and Clarification, Reuse.

washdown, floor washdown, aggregate washing, as well as rainfall runoff from the materials storage area and entire batch plant area.

Operation-related waste water is usually diverted into retention ponds where it is clarified for reuse. Discharge, if required, would be appropriately treated before discharge.

6.2.2 Controlling Intake Effects

Once-through intakes (and outfalls) must remain in continuous service while the power plant is running. That is, they cannot be shut down temporarily to accommodate fish runs, clean out silt, or lessen some other seasonal environmental impact.

Recirculating cooling water systems with make-up requirements of much lower capacity often include a storage reservoir near the cooling towers and intake of water from the source can be interrupted without affecting power plant operation. Design problems to protect the source and the aquatic environment are accordingly less severe than for once-through systems.

6.2.3 Potable Water

Waste streams are transported to the sewerage treatment facility, the effluent from which, if discharged into a receiving water body would comply with the Pollution Control Branch Objectives of Municipal type waste discharges; where this is discharged onto land it should comply with the appropriate regulations of the Department of Health.

6.2.4 Site Preparation

Current technology to prevent the silting of water courses during site preparation and construction includes storm water control structures, sedimentation ponds and soil stabilization (re-vegetation) practices.

Dredging effects can be minimized by proper design, use of appropriate equipment, the choice of season, and the use of coffer dams and sediment traps.

6.2.5 Cooling Tower Blowdown

Blowdown from recirculating cooling systems is essentially make-up water concentrated a specific number of times. Slime and corrosion control procedures may require the addition of very small quantities of suitable inhibitors depending on site specific conditions. Where chlorine is used for microbiological control in the cooling system, the blowdown may have to be treated to eliminate residual chlorine.

6.2.6 Boiler Blowdown and Demineralizer Regeneration Wastes

Boiler blowdown is characteristically alkaline in nature with the pH ranging from 8.8 to 10.0. Total disolved solids concentrations are generally low, and are mainly phosphates which are used as a buffering system (5-50 mg/L). Most commonly, the blowdown will be discharged to other plant water users, e.g. ash sluicing, for reuse.

Demineralizer regeneration is usually accomplished by the application of sulphuric acid and sodium hydroxide solutions to the demineralizer beds which liberates the cations and anions originally removed from the process water. Often the wastewater from regeneration exhibits a non-neutral character, and is neutralized before discharge or reuse. Subsequently, these wastes are usually equalized and neutralized before discharge.

6.2.7 Ash Sluicing Wastewater

In both bottom ash and fly ash hydraulic disposal, on-site ponding and sluicing system operation can occur in three general modes: a once-through system, an open loop system and a closed loop system. These techniques refer to various degrees of ash pond supernatant reuse. In a once-through system, water is withdrawn from the makeup supply source as needed for sluicing, discharged with the ash to a pond and the subsequent supernatant is then allowed to overflow from the pond to the receiving water body without any reuse.

In an open-loop system, pond supernatant is reused for sluicing in various degrees depending upon supernatant water quality. This type of operation incorporates a makeup to offset system losses such as pond evaporation, seepage and water lost to the solids, i.e. water bound in the void volume of the ash and unable to be recycled. Blowdown to maintain recirculating water quality is also used.

In a closed loop operation, where maximum recirculation of sluicing water is used substantial chemical treatment of sluicewater may be employed as an alternative to intermittent blowdown. Makeup, however, is still required to offset system losses.

6.2.8 Flue Gas Desulphurization Wastewater

Any liquor discharge to plant effluent from lime or limestone flue gas scrubbers requires aeration to oxidize the calcium sulphite. It also requires soda ash addition for neutralization and precipitation of metals leached from fly ash that are carried to the scrubber or from the lime or limestone. After reaction, sedimentation and filtration, the effluent may be reused.

6.2.9 Floor Drainage

Central vacuum-cleaning systems are used in coal-fired plants together with a floor drainage system that receives plant washdown.

The main contaminants that can be expected in floor drainage are suspended solids, oil and grease. These waters are usually treated by a gravity oil/water separation unit In some cases chemical treatment of emulsified oil is required.

6.2.10 Coal Pile Runoff

Runoff from coal piles can be collected and diverted to storage basins, where the coal fines settle out. The settled water is then withdrawn at a steady rate to empty the basin and the coal fines are periodically removed to the coal storage pile. Where the runoff is acid and dissolved metals are present, the pond is aerated, neutralized (which also precipitates dissolved metals), settled in a clarifier, filtered and then discharged to the receiving waters. Alternatively, the coal pile runoff may be added directly to the ash sluice system.

6.2.11 Metal Cleaning Wastes

Metal cleaning wastes are generated at longer intervals. The nature of the cleaning solvents used is important in the selection of the methods of treatment. Some may be disposed of by incineration.

To discharge these wastes, the cleaning solutions are usually neutralized and then precipitated metal oxides are removed by sedimentation. Effluent produced in some types of clarifier requires additional filtration before discharge to the outfall.

In some plants the boiler cleaning wastes may be discharged slowly to the ash pond, particularly if an alkaline ash is produced and the precipitated solids are allowed to settle out in the pond. The pond effluent will usually require further clarification by filtration before discharge.

6.2.12 Total Dissolved Solids Removal

If a receiving water body cannot accommodate a discharge which is high in dissolved solids within a mixing zone area, e.g. cooling tower blowdown, ash pond supernatant or the combined plant wastewater discharge, then more sophisticated and costly treatment methods must be implemented. Chemical precipitation methods may be used to reduce the concentration of dissolved solids, but other components of the wastewater may require more specialized techniques for removal.

Processes for the removal of dissolved solids which are in current use include membrane devices such as reverse osmosis and electrodialysis units, evaporators including mechanical evaporators, flash evaporators and vapor compression evaporators and ion exchange demineralizers. All of these units are similar in that they produce high quality reusable water and relatively low volume highly concentrated waste solutions. The waste solutions are usually disposed of through solar evaporation ponds or solidification techniques.

6.3 Land

The land requirement for a typical large coal-fired thermal station might range from 150 to 600 acres depending on the site specific features.

The most significant items would be the water reservoir and ash disposal area. Whether a reservoir is needed is governed by the type and location of the water supply. The size of the ash storage area is dependent on the properties of the fuel and the characteristics of the mine. For example, in a strip mine it is possible to return the ash to the mine.

In previous sections the uses of ash and the discharges from ash ponds have been discussed.

There are a number of alternatives which can minimize the size and impact of an ash disposal area.

Ideally, an ash pond would be located in a natural depression or gully that may not be usable for the present land activity (eg. agriculture). The soil should be impervious, however, if it is not, an impervious clay or plastic liner might be necessary.

Should a pond be unacceptable for some site specific reason, it is possible to dump the ash dry (wetted for dust control). In such cases it is necessary to cover the ash quickly to prevent fugitive emissions.

Once filled with ash, a disposal area would be covered with topsoil and reclaimed.

7. ADVANCES IN EXISTING TECHNOLOGY

7.1 Fabric Filters (Bag Houses)

A few large power plant units in the United States have recently been fitted with fabric filter baghouses for particulate removal.

These are assemblies of fabric filter bags or sleeves which catch the fly ash and allow clean gases to proceed. The fly ash is dropped into storage hoppers below the bag chamber. Bag cleaning can be effected by shaking or reversing the gas flow.

Large assemblies of bags would be required for power plant units using British Columbia coals with high ash. One serious operational problem is the temperature limit of the fabric (about 550^{0}F). If an air heater rotor stops, gas temperature can exceed this temporarily.

The use of oil as ignition and warm-up fuel on large coal-fired boilers can also lead to problems of fires in baghouses.

7.2 Sulphur Reduction by Coal Washing

Where coal washing is used to raise the heating value and remove ash prior to use in power plants, some sulphur reduction takes place.

The three forms of sulphur that occur in coals are organic, sulphate and pyritic. Organic sulphur predominates and, as it cannot be physically removed, it is the major source of sulphur that combines with oxygen in the furnace to form sulphur dioxide.

Sulphate sulphur is usually present in insignificant amounts.

Pyritic sulphur is often present as about 25 percent or more of the total sulphur. It can be removed by common coal preparation methods of size reduction and gravimetric separation. Thus, where only a modest reduction of sulphur content is required, removal of pyritic sulphur can be an economical and successful method, especially where a coal preparation plant is already available.

Results of sulphur reduction wash tests on US coals are given in Reference (4).

With bentonitic clay in coal, the subsequent disposal of wash plant effluents can become a difficult disposal problem due to thixotropic characteristics of the sludge.

7.3 Methods of Reducing SO_2 Emissions in Operations

If a coal-fired power plant without gas-cleaning equipment has to reduce SO_2 emissions during periods of adverse meteorological conditions that can affect plume dispersion, several methods are available to plant operators.

These include:

- Burning low sulphur coal from a ready pile.
- Reducing plant output.
- Using high heating value coal (reducing amount of sulphur per unit of heat).
- Using alternative fuels (eg. low sulphur oil, natural gas).

7.4 Electrostatic Precipitators

Almost all new boilers using pulverized coal firing would have electrostatic precipitators for removing particulate matter from the flue gas. They are well-proven devices and are now in service on units up to 1300 MW capacity.

A few plants that require SO_2 scrubbing as well as particulate removal are using combined fly ash/SO_2 scrubbers. In some cases highly alkaline fly ash can partly replace lime as the reagent for neutralizing SO_2 in these combined scrubbers.

Fly-ash particles are electrically charged, and then are directed through an electrical field to remove them from the gas stream on collecting electrodes. The fly-ash is dislodged from the collecting electrodes, and falls into storage hoppers. High voltages are required and the power requirement is typically up to 0.3% of unit output.

7.5 Scrubbers and Flue Gas Desulphurization

Scrubbers are mechanical devices installed to remove contaminants from boiler flue gas. In the simplest form liquid is sprayed into a large vessel to 'wash' or 'scrub' the gas. In the more complex system, the flue gas flows through trayed or packed towers for intimate contact with a liquid solution. Scrubbing devices of various types have been applied to the flue gas effluent for many years, with or without the addition of chemical compounds of some type into the boiler combustion space, or into the ducting prior to the scrubbers.

In the original limestone process, lime was injected directly into the combustion space where the residence time was long enough to calcine the limestone to calcium oxide or to have reaction between the sulphur dioxide and the limestone.

These reaction products were collected in a wet scrubber where additional sulphur dioxide was removed from the flue gas stream by conversion to calcium sulphite and calcium sulphate. Operation problems of boiler tube plugging and demister plugging led to major modifications, with either abandonment of the process or conversion to a full limestone flue gas desulphurization system without limestone injection to the furnace.

Now, flue gas desulphurization is the term used to designate a carefully designed gas process in which each component has a specific function *under process conditions that must be precisely controlled. Such systems* have high capital cost and require technology and operating skills that historically are not well developed within the industry.

7.5.1 Flue Gas Desulphurization Today

There are no specific flue gas desulphurization (FGD) requirements under any jurisdiction in Canada and it is believed that there are no FGD systems in operation or under construction at any operational site; certainly not at any coal-fired power plant. Ontario Hydro has operated a limestone slurry FGD system pilot plant and has participated financially in other projects.

Development of specific processes to limit sulphur dioxide emissions from coal-fired thermal power plants in the United States was spurred by the Environment Protection Agency (EPA) "New Source Performance Standards" issued on 23 December 1971. These standards required all new or modified coal-fired boilers to limit SO_2 emissons to 1.2 pounds per million Btu. This standard could be met by installing flue gas desulphurization scrubbers or by burning low sulphur coal.

Wherever possible most consumers of high sulphur coal switched to low sulphur coal to meet the new standard. Meanwhile, costly full scale and some pilot scale studies commenced on flue gas desulphurization (FGD) systems; usually with extensive funding by EPA.

The adverse economic impact of this standard was severe in states having large reserves of high sulphur coal. For example, coal produced and consumed in Iowa in recent years was only 600,000 tons annually as compared to an annual consumption of seven million tons of imported low sulphur coals from Wyoming and Montana by Iowa utilities. The adverse impact was aggravated by high taxation on coal production imposed by those producing states.(53)

7.5.2 Flue Gas Desulphurization Systems

A detailed presentation on the state of the art of flue gas desulphurization technology is presented in Appendix IV. A brief description of the processes and comments on their applicability follows in this and other sections. Systems for removal of sulphur oxides from flue gas are classified as nonregenerative and regenerative processes.

In general, nonregenerative processes as applied to FGD systems produce a calcium sulphite/sulphate sludge from the continuous contact of the flue gas with limestone or lime slurries. Chemical scaling, corrosion and sludge disposal are the major adverse factors related to nonregenerative systems with the latter being very important, environmentally and economically.

The sludge of calcium sulphite/sulphate usually settles to a slurry containing about 60 percent water by weight as a thixotropic mixture so that disposal and containment require sound engineering involving soil and geotechnical expertise. Also groundwater contamination is a potential problem, water makeup volumes to the system are high, water disposal and treatment to control water purged from the system, in order to maintain low total solids, present significant operating problems. Technology for sludge fixation has been developed but this may not be effective and applicable in some regions of British Columbia that experience severe winter conditions. Finally, nonregenerative processes have a high energy consumption.

If a 2000 MW (2240 MW gross) coal-fired plant were fired with 6300 Btu/lb. coal, with 0.5 percent sulphur, 26 percent ash and 20 percent moisture (as received), it would consume at full output, 40,000 tons of coal per day and produce 10,400 tons of ash per day. At a 65 percent capacity factor, the annual coal consumption would total 9.5 million tons and produce 2.5 million tons of ash.

If a lime slurry FGD system was applied to remove 80 percent of the sulphur, sludge would be produced at the rate of about 1500 tons per day (40 percent solids by weight). Daily sludge disposal costs may approach $20,000 and require a disposal volume of 40,000 cubic feet per day.

7.5.3 Applicability of FGD Technology

Generally, the sulphur content of British Columbia coal does not warrant application of FGD processes. In some areas of the Province this technology could prove essential to meet ambient air quality criteria, given the meteorological, topographic or limited air-shed capacity to absorb the emission load from a proposed plant. Otherwise, the economics of FGD systems are not attractive compared to alternative methods of emission control. Recent published data (51) to the end of 1976 indicate that 24 installations totalling 6000 MW were operative with FGD processes. Of the 8 new plants designed with an integral FGD system, 97 percent of the MW capacity was of the nonregenerative type compared to 83 percent of the capacity on retrofit installations.

For the 33 systems under construction, totalling nearly 14,000 MW with 28 new and 5 retrofit units, 92 percent of the new MW capacity was of nonregenerative type as compared to 72 percent for the retrofit. Of the 18 systems of 9000 MW for which contracts have been granted 91 percent of the MW capacity was nonregenerative types.

These data reflect the fact that nonregenerative FGD system technology which commended development in 1968 only became proven technology in 1975.

The reliability and availability of FGD systems have been a major question as well. Mechanical problems have faced many of the units in operation. These have included plugging of boiler tubes and demister pads, corrosion of stack liners due to the cold, wet flue gas that results, plugging of reheat systems, and operational problems at partial load. Several plants in the United States have been operating with greater than 80% availability which is an improvement over performance in previous periods.

Regenerative systems are still not classed as proven technology.

High costs, operating and maintenance problems, limited availability for service, and waste disposal problems associated with FGD systems, have precluded their installation on Canadian coal-fired power plants. Instead, other methods of reducing or controlling SO_2 emissions have been used.

7.5.4 FGD Systems Economics

Figures 7-1 and 7-2 show the effects of unit size and sulphur content of coal on the investment for installations on new units (52). In comparing these rankings it should be noted that the lime slurry process does not provide facilities for calcining limestone and includes a minimum of facilities for storage of the calcined material. These figures show generalized costs only and the final costs could be affected significantly by specific applications. Table 7-1 presents a summary of the total capital investment requirements derived from U.S. experience for various FGD systems, based on mid 1974 cost data.

TABLE 7-1

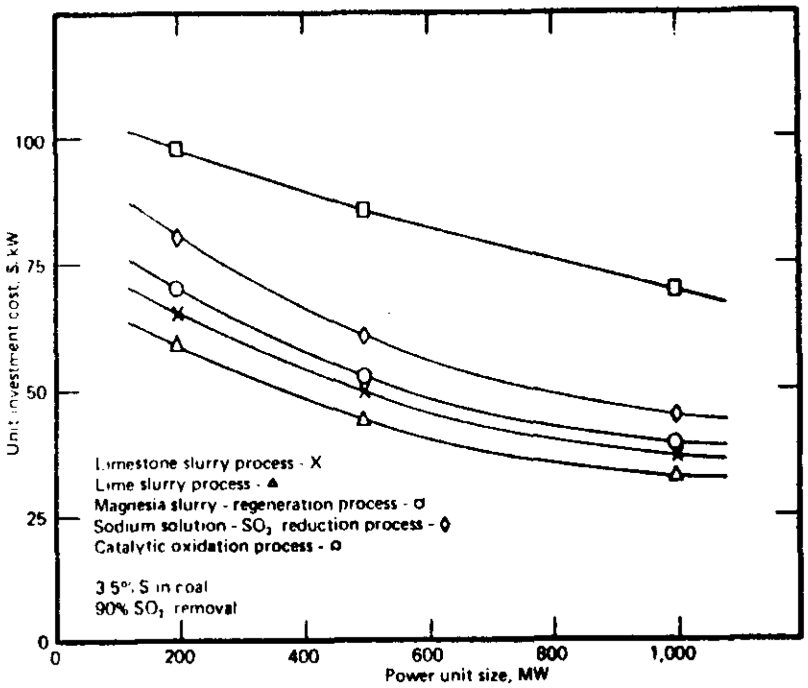
SUMMARY OF TOTAL CAPITAL INVESTMENT REQUIREMENTS FOR F.G.D. SYSTEMS ON COAL-FIRED THERMAL PLANTS[a]

Case	Years Life	Nonregenerable Processes				Regenerable Processes					
		Limestone Process		Lime Process		Magnesia Process		Sodium Process		Cat-Ox Process[b]	
		($)	($/kW)	($)	($/kW)	($)	($/kW)	($)	($/kW)	($)	($/kW)
Coal-fired power unit											
90% SO^2 removal; on-site solids disposal											
200 MW new, 3.5% sulphur	30	13,031,000	65.2	11,749,000	58.7	14,139,000	70.7	16,198,000	81.0	19,537,000	97.7
200 MW existing, 3.5% sulphur	20	11,344,000	56.7	13,036,000	65.2	14,372,000	71.9	17,149,000	85.7	17,735,000	88.7
500 MW existing, 3.5% sulphur	25	23,088,000	46.2	26,027,000	52.1	26,026,000	52.1	31,208,000	62.4	37,907,000	75.8
500 MW new, 2.0% sulphur	30	22,600,000	45.2	20,232,000	40.5	22,958,000	45.9	26,706,000	53.4	42,520,000	85.0
500 MW new, 3.5% sulphur	30	25,163,000	50.3	22,422,000	44.8	26,406,000	52.8	30,491,000	61.0	42,736,000	85.5
500 MW new, 5.0% sulphur	30	27,343,000	54.7	24,272,000	48.5	29,355,000	58.7	33,709,000	67.4	42,928,000	85.9
1000 MW existing, 3.5 sulphur	25	35,133,000	35.1	38,133,000	38.1	38,717,000	38.7	47,721,000	47.7	62,913,000	62.9
1000 MW new, 3.5% sulphur	30	37,725,000	37.7	32,765,000	32.8	38,865,000	38.9	45,932,000	45.8	69,889,000	69.9
80% SO^2 removal; on-site solids disposal											
500 MW new, 3.5% sulphur	30	24,267,000	48.5	21,586,000	43.2	25,568,000	51.1	29,127,000	58.3	-	-
90% SO^2 removal; off-site solids disposal											
500 MW new, 3.5% sulphur	30	20,532,000	41.1	18,323,000	36.6	-	-	-	-	-	-
90% SO^2 removal; on-site solids disposal (existing unit without existing particulate collection facilities)											
500 MW existing, 3.5% sulphur	25	29,996,000	60.0	26,090,000	52.2	32,213,000	64.4	37,957,000	75.9	43,816,000	87.6

[a] Midwest plant location represents project beginning mid-1972, ending mid-1975. Average cost basis for scaling, mid-1974. Minimum in process storage; only pumps are spared. Investment requirements for disposal of fly ash excluded. Construction labour shortages with accompanying overtime pay incentive not considered.

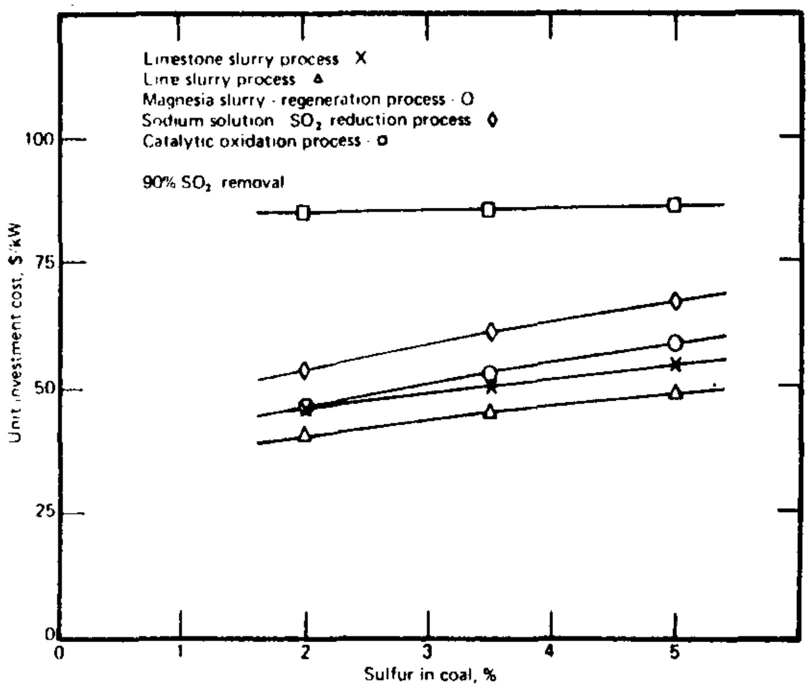
[b] All Cat-Ox installations require particulate removal to 0.005 gr/scf prior to entering converter. Because existing units are assumed to have already met EPA standards (0.1 lb particulate/mm Btu of heat input). Only incremental additional precipitator is required.

Figure 7-1



New coal-fired units--the effect of power unit size on unit investment cost, dollars per kilowatt.

Figure 7-2



500-MW new coal-fired units—effect of sulfur content of coal on unit investment cost.

More recent data (53) on actual systems with all costs adjusted to January 1975 show a range for all systems from $50/kw to $205/kw with the mean value $91/kw. For the lime and limestone slurry systems the range was from $50/kw to $88/kw with a mean value of $70/kw.

Operating cost data (53), show the maintenance costs including labour and materials were estimated at 3 percent of the capital cost. Energy requirements ranged from 1 to 9 percent of unit rating and, if applicable, another 1 to 2 percent for flue gas reheat.

The high cost and known difficulties of operation of scrubbers have precluded any Canadian utility from embarking upon their installation so far. Other methods of reducing, or controlling SO_2 emissions have been found satisfactory in ensuring that coal energy is converted to electricity on a reliable continuous basis, with acceptable environmental impacts.

The state-of-the-art for FGD systems today can be summarized as follows:

- FGD system energy consumption ranges from 2 to 3% of unit output.
- Capital cost and operating costs for FGD systems have a significant impact on the direct cost of power to the consumer.
- It is technically feasible to design systems to reduce sulphur emissions to 1.2 lb. per million Btu.
- Only nonregenerative systems may be classed as proven technology; and while SO_2 emissions are reduced the pollution problem now becomes one of major solids waste and waste water disposal.
- Capital investment in new and retrofit systems in the United States is escalating at a high rate; "the cumulative MW-years of experience will double every 18 months from now through 1980".*

* Quoted in reference (53), referring to a paper by R. L. Andrews presented at American Power Conference, April 1977, "Current Assessment of Flue Gas Desulphurization Technology".

8. FUTURE TECHNOLOGY FOR POLLUTION CONTROL

8.1 Fluidized Bed Combustors

In fluidized bed combustion the coal is burnt in an inert bed, usually coal ash, which is fluidized by blowing combustion air through it. For this process the coal need only be crushed to a small size (less than 1/8"). The advantages of fluidized bed combustion are that the combustion temperatures are low (800 - 900°C) hence reducing the NO_x formed, and that the high fuel residence time in the bed allows for the combustion of low quality fuel and absorption of sulphur directly in the bed.

8.1.1 Atmospheric Fluidized Combustion

Fluidized bed combustion has been under development since the early 1960's. The largest atmospheric unit is a 40,000 lbs/hr. (equivalent to 4 MW) boiler at Renfrew, Scotland. No development of large thermal station atmospheric fluidized bed boilers has taken place principally because there is no economic advantage to force a change from the established pulverized fuel combustion system. The capital costs are about the same and the efficiency of the fluidized bed is slightly lower due to the lower combustion temperatures.

8.1.2 Limestone Addition

Current interest in fluidized bed combustion is related to its capability to reduce emissions. Since the coal is not pulverized there is less particulate carryover in the gases from the furnace. The reduction in NO_x has already been mentioned. The most significant factor however is the possibility of injecting limestone or dolomite into the fluidized bed for absorption of sulphur. The limestone on heating forms calcium oxide which reacts with the sulphur in the coal to form calcium sulphite or calcium sulphate. This requires no special modifications to the to form calcium sulphite or calcium sulphate. This requires no special modifications to the combustion, only a system to add the limestone to the fuel is necessary. The amount of limestone required would vary with the type of limestone and also the amount of calcium inherent in the ash. Generally about twice the theoretical amount to convert the sulphur would be required.

8.1.3 Pressurized Fluidized Bed Combustion

Most of the present fluidized bed development is directed to pressurized fluidized bed combustion. This system provides the environmental advantages of atmospheric fluidized bed combustion with the promise of reduced capital costs and higher efficiency.

The reduced capital costs would be realized by the reduction in boiler/combustor size to the point where shop assembly would be possible. The increase in efficiency would be realized by using a combined gas turbine and steam cycle system.

Pressurized fluidized bed combustors are at the pilot plant development stage and they have not been operated with gas turbines. One of the critical features is the quality of gas stream produced and its effect on the gas turbine.

Pressurized fluidized bed combustion could be demonstrated by the mid 1980's in which case commercial units could be in service by the end of the 1980's or early 1990's. B.C. Hydro is currently engaged in a joint study program with the Federal Department of Energy, Mines and Resources which includes the feasibility of constructing a demonstration pressurized fluidized bed plant in British Columbia.

8.2 Gasification for Power Generation

Coal gasification by various processes has been commercial since the late 1880's. Some of the earlier processes simply heated the coal to drive off the volatile matter leaving a coke or char residue. The gasification processes considered for development today convert all the hydrocarbon matter to gas. Generally two products are considered, either a pipeline quality gas (substitute natural gas) or a lower Btu fuel gas.

The pipeline quality gas is expensive but is a product virtually indistinguishable from natural gas and can be transported and used in the same manner. The technology is commercially proven but no large scale plant is in operation although a number are close to construction commitment.

As a pollution control measure it is not necessary to produce a high Btu gas and so the gasification process can be simpler and less costly. The low Btu gas produced by air blown gasification consisting mainly of hydrogen and carbon monoxide can be cleaned using established gas cleaning methods (the sulphur is as hydrogen sulphide). The gas can be utilized in a conventional boiler or a combined cycle system. A 170 MW coal gasification combined cycle demonstration unit is currently operational in Germany. Development work is continuing and a commitment to a larger unit has been delayed. The earliest in service date for the first commercial unit is the late 1980's.

8.3 Flue Gas Desulphurization

Several advanced FGD process systems are under test at the pilot plant stage or are under demonstration at small thermal plants. All are of the regenerative type, tending to show some promise for reduced operating and capital cost. None may be classed as proven technology.

The advanced processes currently at a pilot or demonstration stage are: the molten carbonate process that has been piloted on 10 MW scale; a 20 MW pilot scale of the Foster-Wheeler/Bergbau-Forschung absorption process; the "Consol" FGD 10 MW pilot of the modified format process; the Shell copper oxide process, a pilot plant of 37 MW; and the U.S. Bureau of Mines citrate process, a pilot plant at a lead smelter, and more recently on a small coal-fired boiler of about 1 MW.

9. RECOMMENDATIONS

9.1 General

It is recommended that:

- The Pollution Control Objectives for the Mining, Mine-milling and Smelting Industries of British Columbia be amended to include coal-fired power plants.

- Objectives and Guidelines be considered as a realistic basis for initial project evaluation and design, not a standard, so that each permit application for a proposed project would be evaluated on a site-specific basis.

- Environmental monitoring programs be initiated prior to the commencement of operations in order to provide baseline data for impact assessment. After plant start-up, the monitoring programs should be reviewed, assessed, and modified where necessary, to ensure that all significant contaminants are being adequately monitored during plant operation.

- A baseline trace element study of major coal deposit regions be conducted by an appropriate British Columbia Government Agency, and that a brief be submitted to the next inquiry stating the results and recommended trace element ambient guidelines and emission objectives. B.C. Hydro has extensively evaluated, and is continuing to evaluate, the baseline levels of trace elements in the land, air, water, flora, and fauna with respect to one particular coal deposit. The studies to date do not indicate a variance with respect to trace element criteria in the existing Mining, Mine-milling, and Smelting Objectives. Trace element guidelines and objectives should be established on a province-wide basis considering all coal deposits, the baseline trace element levels in the coal, air, land, water, flora and fauna in the area of each coal deposit and their significance. No recommendation with respect to trace element levels is made at this time.

9.2 Air

The ambient air quality should be the overriding constraint in establishing the acceptability of gaseous emission controls as applied to coal-fired power plants. Since ambient air quality guidelines are designed to protect both public health and the environment, it would seem reasonable that some variance should be permitted from ambient air guidelines in unpopulated elevated terrain.

Where it is necessary to implement control measures in order to meet the ambient air quality guidelines with respect to sulphur dioxide, meteorological control should be accepted as one practical and satisfactory control measure. The details of any meteorological control system, which would generally be along the lines indicated in this brief, should be evaluated as part of the permit approval process on a site specific basis.

The levels of ambient air quality listed in Appendix I, Table I, of the Pollution Control Objectives appear satisfactory for coal-fired thermal power plants except for sulphur dioxide levels, and the qualification with respect to trace elements in 9.1 above.

It is recommended that the 1-hour averaging period for sulphur dioxide levels be waived for coal-fired thermal plants and a 3-hour averaging period established with a maximum average concentration of 0.25 ppm.

Since emissions are only one of a series of factors considered in the protection of ambient air quality, emission levels should be established on a site-specific basis.

The objectives for gaseous and particulate emissions listed in Appendix I, Table II of the Pollution Control Objectives appear reasonable and applicable to coal-fired power plants provided that an Option III be added under sulphur dioxide emissions similar to Option II, but which for coal-fired power plants specifically excludes the 80% sulphur removal criterion and which additionally makes applicable the proposed ambient air quality levels for coal-fired power plants recommended above. The previous qualification with respect to trace elements in 9.1 above would also apply.

Table III in Appendix I of the Pollution Control Objectives which tabulates the control objectives for gaseous and particulate emissions for specific processes should be amended to include the criteria for coal-fired power plants listed in Table 9-1. These additions to Table III are intended to ensure that the ambient air quality objectives for sulphur dioxide proposed for addition as Option III in Table II, are met.

9.3 Land

The Guidelines for Solid-waste Management practices which are presented in Section 3 appear reasonable and acceptable for coal-fired power plants.

TABLE 9-1

PROPOSED ADDITIONS TO TABLE III APPENDIX I OF POLLUTION CONTROL OBJECTIVES

Contaminant	Objective Levels A	Monitoring
A. Emission Control Objectives		
6. Coal-fired thermal power plants		
(a) Sulphur dioxide.....ppm	800	Continuous
(b) Oxides of Nitrogen as NO_2 ....ppm	600	Continuous
(c) Particulate.........gr/SCF	0.10	PCB Criteria
B. Ambient Air Control Objectives		
3. Coal-fired power plants		
(a) Sulphur dioxide 3 hr. conc................ppm	0.25	Continuous

9.4 Water

With respect to liquid effluents it is recommended that the Objectives in Tables IV, V and VI in the Mining, Mine-milling and Smelting Industries be accepted with the following two exceptions and with the qualifications that information resulting from studies of baseline environmental data in the vicinity of power plant sites may require that the applicability of the Objectives be re-evaluated.

It is recommended that discharges from recirculating condenser cooling water should be evaluated on a site-specific basis. This recommendation is made since the environmental effects of such systems are affected by such site-specific factors as the quality and availability of cooling water, the extent of re-use of the water, intake and discharge effects on aquatic biota and make-up water requirements.

It is further recommended that a waste heat discharge limitation such as a maximum allowable temperature increase be evaluated on a site-specific basis having regard for the relationship of the project to its environment.

10. SUMMARY STATEMENT

The vast thermal coal reserves of British Columbia are an important potential future energy source for the Province. Fifty percent of these reserves are found in the Southern Interior Region.

Coal-fired power plants to generate electricity may generally be operated within the Pollution Control Objectives established for the Mining, Mine-milling, and Smelting Industries. While other environmental factors related to water and land are important, it is believed that air emissions and air quality are the most important.

The climate and terrain of much of the Province are of such a nature that an amendment must be made to the existing air quality guidelines, for coal-fired power plants. An operating framework must be provided within a three-hour sulphur dioxide guideline, while at the same time maintaining air quality at levels that are not injurious or damaging to human health, plant or other life forms, nor interfere or detract from the social and economic interests of the people, having regard to the overall benefit-cost relationship that may exist.

With the advances that have taken place in air quality analytical techniques for meteorological parameter monitoring, rapid data processing and computer modelling, meteorological control systems offer an effective means to reduce source emissions during short-term adverse meteorological conditions.

It has therefore been proposed that a three-hour time averaging guideline be established for sulphur dioxide concentrations in ambient air quality.

Technology does exist for the control of particulate emission from stack effluent of coal-fired power plants. However, the same cannot be said for the removal of low concentration sulphur dioxide (less than 1000 ppm) from the stack effluent. Only the non-regenerative flue-gas desulphurization (FGD) processes using lime or limestone slurries may be classed as proven technology. And here a trade-off must be made from an air emission problem to two water pollution control problems: solid waste disposal of a thixotropic sludge that may contain 40 to 60 percent water; and a water treatment and disposal problem arising from water used in the FGD system, and that drained from the sludge. The capital and operating costs for FGD systems can add as much as 30 percent to the unit energy cost of coal-fired power plants.

Future technology holds promise to obviate these problems through the development of regenerative processes for flue-gas desulphurization, and improvements in combustion technology using fluidized beds. Coal gasification also holds considerable promise for the future. But again it must be emphasized that none of these developments is proven technology.

It is recommended that in adopting the existing objectives for gaseous and particulate emissions for the Mining, Mine-milling and Smelting Industries that:

(1) a three-hour time averaging period be adopted at the 0.25 ppm level for sulphur dioxide,

(2) meteorological control systems be recognized as an effective means of reducing sulphur dioxide emissions during short-term periods of unfavourable meteorological conditions, while at the same time maintaining acceptable ambient air quality, and

(3) that an exclusion be provided to the 80 percent sulphur removal criterion presently applicable to the smelting industry.

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11.2 Glossary of Terms

Application Efficiency - The ratio of the desired water application to the amount of water delivered by sprinklers to account for the desired application, deep percolation (due to distribution pattern monuniformity) and spray losses. (Application efficiencies are available from the Engineering Branch - B. C. Department of Agriculture).

Approved - Approval - Approved (or approval given) under the Pollution Control Act, 1967.

Average (avg.) Dry-Weather Flow (DWF) - A flow derived from averaging the total flow over a significant dry weather period, including all sanitary waste, industrial waste and infiltration.

Biological Resource Inventory - An annotated list of biological stocks, having actual or potential recreational, ecological or commercial value, sufficient to document whether their present or future use is liable to be impaired by a discharge.

Blowdown - Waste liquid discharge from process vessels.

BOD_5 - Five day biochemical oxygen demand at 20°C.

Cell - Compacted solid wastes that are completely enclosed by natural soil or cover material in a landfill.

Characteristics, contaminants, parameters - Those characteristics, contaminants, or parameters which are listed and defined in the most recent edition(s) of A Laboratory Manual for Chemical Analysis of Emissions, Ambient Air and Plant Tissues, A Laboratory Manual for the Chemical Analysis of Waters, Wastewaters and Biological Tissues, issued by the Environmental Laboratory, Water Resources Service, or of an alternate manual approved by the Director.

Coliforms - All of the aerobic and faculative anaerobic, gram-negative, non-spore-forming, rod shaped bacteria which ferment lactose with gas formation within 48 hrs. at 35°C.

Confinement - The pushing of loosely dumped refuse into the working face of the landfill.

Controlled Air Incinerator - An incinerator having a primary burning chamber in which combustion temperatures are maintained at a low level through fuel and air control and in which turbulence is minimized. Complete combustion and odour control are achieved in an afterburner.

Cubic metre - Volume of dry gas occupying 1 cubic metre at a temperature of 20°C and a pressure of 760 mm mercury.

Dechlorination - Means the reduction of chlorine residuals.

Digested Sludge - Solids arising from sewage treatment which have been held in a properly designed and operated biological sewage treatment system for a period of time sufficient to achieve at least 45 per cent reduction in total volatile residue.

Disinfection - Microorganism kill achieved by a dosage of chlorine to a specified limit followed by adequate mixing with not less than one hour contact at average flow rates. Alternatives to chlorination are encompassed where shown to be equally effective.

Dustfall - The deposition of solid particles, usually greater than one micron in diameter which have been released to the atmosphere by mechanical processes such as crushing, grinding and drilling.

DWF - Dry-weather flow (see Average Dry-Weather Flow).

Embayed - In general, the end of an outfall shall be considered embayed if located on the shore side of a line up to four miles long drawn between any two points on a continuous coastline, or located so that the maximum width of sea access by any route is under one mile wide, but may be taken to include other waters if flushing action is considered to be inadequate. Exceptions may be made where adequate flushing of an "embayed" area is documented. "Coastline" and "sea access" refer to the mean low tide alignment.

Estuary - That portion of a receiving water lying below the farthest upstream point of detectable changes in water movement or chemistry due to tidal action. The lower limit cannot satisfactorily be defined to meet all conditions.

Excess Moisture - Average annual difference between precipitation and evapotranspiration. (ie. a theorectical figure deduced from tables indicating on average what proportion of the rain and snow fall in an area seeps through to ground water or runs off as opposed to evaporation and plant take-up).

Excess Solids - Solids arising from wastage of those held in suspension in the aeration tank of activated-sludge type treatment plants.

Extraordinary Measures - The ripping, burning or blasting of soil which because it is frozen cannot be excavated with conventional mechanical devices such as a bull-dozer, front end loader or backhoe.

Fecal Coliforms - Those coliforms which ferment EC medium with gas formation within 24 hrs. at 44.5°C.

Fill Area - That portion of a landfill site which has been or will be filled with refuse.

Flood Plain - Any land liable to be inundated by a flood having the probability of being equalled or exceeded once in a defined period; for the purpose of these objectives this defined period is 20 years.

Flooding - The situation where ground or surface waters temporarily rise to the point where such waters may enter a landfill.

Free Water - Includes any standing or moving surface water but does not include short-term puddles or ponds formed due to precipitation.

Fresh Water - Includes lakes, rivers, or streams.

Gallon - Imperial gallon.

Growing Season - That portion of the year when the predicted daily minimum temperature (in an average year) falls above freezing or as otherwise agreed by the Department of Agriculture.

(I) gpd - Imperial gallons per day.

Hazardous Waste - Refuse which because of its inherent nature and quantity requires special disposal techniques to avoid creating health hazards, nuisances or environmental pollution. Hazardous wastes are toxins or poisons, corrosives, irritants, strong sensitizers, flammables, explosives, infectious wastes, condemned foods, etc. Flammable wastes exclude plastics, paper, paper products and the like.

Hybrid System - A two-sewer system in which surface water runnoff is collected in an upper pipe with limited capacity connections to a lower pipe carrying sanitary and/or industrial wastes.

Incinerator - A combustion device specifically designed for volume reduction by controlled high temperature burning of solid, semi-solid, liquid or gaseous combustible wastes and from which the solid residues contain little or no combustible material.

Industrial Refuse - The discarded solids arising from an industrial process excluding liquid-carried solids in sewage or process liquors and air-borne contaminants in gaseous emissions.

Inert Refuse - Refuse containing no putrescible wastes and which will not leach to any significant extent. It excludes inert waste materials such as overburden from mining operations.

Initial Dilution Zone - That zone around a waste discharge in a receiving water that is not subject to receiving water objectives. It is physically defined as follows:

a) For point discharges in lakes, estuaries, and marine waters, the zone may extend up to 300 feet horizontally in all directions, but shall not exceed 25% of the width of the water body.

b) For point discharges in rivers and streams the zone may extend up to 300 feet downstream of the discharge point, but shall not exceed 25% of the width of the river or stream.

c) For multiple point discharges, such as multiport outfalls, the zone may extend up to 300 feet horizontally from all points of discharge but shall not exceed 25% of the width of the water body.

The initial Dilution Zone extends from the bed of the receiving water to the surface. The zone may not intrude on shellfish beds, restricted routes known to be followed by migrating salmon and trout or other significant biological resource or recreational areas.

Intermediate and Final Cover Materials - Earth exhibiting good workability and compaction characteristics and having a low organic content which is used to cover a compacted refuse. Its purposes are to reduce odours and blowing debris, to control fires, to eliminate animal nuisances, to improve aesthetic conditions and to control infiltration of surface waters into the refuse.

Laboratory Manual of the Water Resources Service - "A Laboratory Manual for the Chemical Analysis of Waters, Wastewaters and Biological Tissues" current Edition, published by the Environmental Laboratory of the Water Resources Service.

Lake - A standing body of fresh water with an average retention time of at least one year.

Leachate - Liquid flowing from a landfill which has extracted dissolved or suspended material from the landfill.

Lift - The depth of landfill between soil covers.

Marine Water - Includes estuarine and coastal water, where estuarine means a semienclosed coastal body of water having free connection to the sea and having a measurable quantity of sea-salt (for example, in excess of 1,000 mg./l. chlorine ion).

Mgd. - Million gallons per day.

MPN - Most Probable Number of coliform group organisms as determined by the Most Probable Number multiple tube fermentation method in "Standard Methods".

Municipal Refuse - Includes, but is not necessarily limited to food wastes, market wastes, combustibles such as paper, cardboard, plastics, leather, yard trimmings; noncombustibles such as metal cans, glass containers, crockery, dirt, ashes from fireplaces and on-site incinerators, street sweepings; bulky wastes such as pipe, concrete, lumber, plastic and wire; all arising from domestic, commercial, institutional or municipal activities. Refuse resulting from industrial operations is not included.

New Operations - Are those operations for which detailed construction plans of the operation have not been prepared prior to the implementation of these objectives.

Opacity - The degree to which an emission obscures the view of an observer expressed numerically from 0% (transparent) to 100% (opaque).

Open Burning - Uncontrolled combustion of refuse where gaseous combustion products and other contaminants are discharged directly to the open air.

Particulate Matter - Any material, other than uncombined water, which exists in a finely divided form as a liquid or solid measured according to the latest edition of the Pollution Control Branch's "Source Testing Manual for the Determination of Discharges to the Atmosphere".

Point of Impingement - Point of maximum concentration at ground-level.

Potential Evapotranspiration - The maximum quantity of water capable of being lost as water vapour, in a given climate, by a continuous stretch of vegetation, covering the whole ground and well supplied with water.

Processed Refuse - Refuse which has undergone a physical volume reduction process such as pulverizing or high pressure baling but does not include refuse compacted by a packer truck or by landfill equipment.

Receiving Water - Any body of surface water into which a discharge of leachate or effluent may flow. Receiving waters wholly contained within a permittee's property are not included in this definition, provided that pollutants in such waters cannot be transported outside the property.

Required - Required under the Pollution Control Act, 1967.

Ringelmann Number - The opacity of grey or black smoke expressed on a 0 (transparent) to 5 (opaque) scale.

Salvaging - The controlled separation and recovery of resources from refuse by authorized persons.

Scavenging - Retrieval of material other than by salvaging as above.

Screening - Provision of screens which are self-cleaning or mechanically raked. Alternative means of preventing aesthetic nuisance are encompassed where shown to be equally effective.

Semi-solid Wastes - Sludges, slurries and septic tank pumpings.

Shellfish Waters - Waters which are inhabitied by edible species of shellfish (bivalve molluscs) and from which shellfish for human consumption are taken either commercially or privately.

Sludge - Material which has settled from liquid wastes carrying solids in suspension.

Solid Waste - Is interchangeable with "Refuse".

Special Wastes - Special wastes include, but are not necessarily limited to over-sized wastes; industrial wastes which are corrosive, volatile, toxic or explosive; wastes such as food processing, synthetic textile, leather or plastic wastes; commercial wastes such as waste oils and cleaning fluids; dead animals and hospital wastes (excluding normal cafeteria and food preparation wastes).

SS (Suspended Solids) - Suspended Solids (identical to non-filterable residue as referred to in "Standard Methods").

SCF (Standard Cubic Foot) - That volume of dry gas corrected to 12% by volume CO_2, occupying one cubic foot at 68°F (20°C) and a pressure of 14.7 pounds per square inch absolute.

Standard Methods - "Standard Methods for the Examination of Water nad Wastewater" current Edition, published by the American Public Health Association.

TL_m - Median tolerance limit. That dilution of an effluent by volume in which 50% of the test fish survive for a specified time (usually 96 hrs.).

Vector - Any living organism or animal which may carry a disease-causing organism or which may transmit disease to humans or other animals.

Working Face - That area of landfill operation at which placing, confining or compacting of refuse is actively taking place.

APPENDIX I

THERMAL COAL RESERVES AND RESOURCES OF BRITISH COLUMBIA

Thermal coal reserves and resources are described herein for the regions of British Columbia.

1. COASTAL COALFIELDS

The coastal coal resources consist of deposits at Wilson Creek, Falls Creek, Slatechuck Creek and Skokum Point on the Queen Charlotte Islands and Quinsam, Anderson Lake, Cumberland, T'Sable River and Nanaimo districts on Vancouver Island (Figure 3-1, main text).

The distribution of coal among the various categories is listed in Table 3-1 of the main text. Exploration in the Cumberland coalfield, which contains most of the Vancouver Island coal districts, is in progress in an effort to confirm sufficient proven reserves to provide a viable coal mine or mines for Vancouver Island. The reserves of coal in the Cumberland coalfield are estimated as 900 million metric tons (990 million short tons). It is estimated that less than 10% of the coal reserves are mineable by openpit methods. The indicated and inferred resources are 424 million metric tons (465 million short tons) to a depth of 610 meters (2,000 feet). Although the possible reserves and resources are large the field is divided into many faulted blocks making it necessary to develop several mines to provide a secure supply of coal for a thermal plant.

The number and quality of coal seams from the coastal districts are variable. The Tertiary deposits at Skokum Point on Graham Island are composed of 9 to 13 lignite seams with an aggregate thickness of 6.1 meters (20 feet) in 67.8 meters (230 feet) of a shaly sequence; these deposits may not be significant. The deposits at Wilson Creek, Falls Creek and Slatechuck Creek range from 27% ash, 26% volatiles, 45% fixed carbon and 0.7% sulphur at 1.1% moisture to 16% ash, 5.3% volatiles, 73.6% fixed carbon and 0.6% sulphur at 5.1% moisture. The rank varies from high volatile B bituminous to anthracite. These deposits are restricted to a single seam in each location. Seam thicknesses range from 0.9 meters (3.0 feet) to 5.2 meters (17.0 feet) and are probably discontinuous over the area. Because most of the reserves from the coastal deposits lie in the Cumberland coalfield the proximate analysis listed for Coastal desposits in Table 3-2 is for run-of-mine coal from this coalfield without appreciable selective mining. There are from one to four significant seams in the district. Seam thicknesses range from 0.8 meters (2.5 feet) to 4.6 meters (15 feet) with coal zones ranging to 7.6 meters (25 feet) thick. The coal rank is high volatile A to B bituminous.

Although some of the coal in the Vancouver Island fields is of coking quality, the amount is small and widely dispersed.

2. SOUTHERN ROCKY MOUNTAIN COALFIELDS

The Southern Rocky Mountain coal resources consist of deposits at Tobermory Ridge, Weary Ridge, Greenhills, Burnt Ridge, Burnt Ridge Extension, Natal Ridge, Sparwood Ridge, Michel South, Sparwood Ridge South, Hosmer Wheeler, Hosmer Ridge West, Fernie Ridge, Morrissey Ridge, Blairmore North, Blairmore South, Leach Creek South, Leach Creek, East, McGillivray, Tent Mountain, Marten Ridge, Marten Creek, Taylor East, Taylor South, Flathead McLatchie, Flathead North, Flathead West, Fording River, Line Creek - Horseshoe Ridge - Ewin Pass, Sage Creek, Corbin, Northern Dominion Coal Block and Southern Dominion Coal Block.

Between 10 and 22 mineable seams are present at any single locality within the district. These seams range in thickness from 1.5 meters (5 feet) to 15.2 meters (50 feet); they are locally thickened by folding or overthrusting. The thickness of coal in the coal member varies from 30.3 meters (100 feet) to 115.3 meters (380 feet) in 455 meters (1,500 feet) to 667 meters (2,200 feet) of section.

It is estimated that 710 million metric tons (780 million short tons) of thermal coal have been at least partly explored in the Southern Rocky Mountain region (Table 3-1). Of these reserves an estimated 180 million metric tons (200 million short tons) are mineable by surface methods. Inferred resources of thermal coal in this region, within 914 meters (3,000 feet) of surface total 5,720 million metric tons (6,300 million short tons). Subsequent exploration and geological mapping could increase this figure.

The Southern Rocky Mountain coalfield contains high quality, oxidized, thermal coal in addition to coking coal (Table 3-2). The mean heating value is 28,540 kJ/kg (12,300 Btu/lb.) with 0.4% sulphur. The rank is medium volatile A bituminous.

The producing mines in the Southern Rocky Mountains are Kaiser's Natal Ridge and Sparwood Ridge operations, Fording's Fording River mines, Coleman Collieries mine at Tent Mountain and Byron Creek Collieries at Corbin. These mines are producing coarse and fine refuse in addition to thermal and coking coal. This refuse could provide additional feed to an East Kootenay thermal plant (Table 3-3). Reserves of coarse refuse are approximately 5.7 million metric tons (6.3 million short tons) at 19,490 kJ/kg (8,400 Btu/lb.). Production is currently 1.4 million metric tons (1.5 million short tons) per year with increases expected from new mines coming on line that are in advanced stages of evaluation. Reserves of fine rejects are about 5.0 million metric tons (5.5 million short tons) with production of mixed fine and coarse refuse of 1.3 million metric tons (1.4 million short tons) per year. The heating value is approximately 22,280 kJ/kg (9,600 Btu/lb.). Deposits in advanced stages of development are Kaiser's Hosmer Wheeler, Fording's Hydraulic

Mine, Crows Nest Industries' Line Creek, Elco's Weary Ridge, and Rio Algom's Sage Creek. A number of these well explored deposits could provide additional thermal coal and refuse when production begins. In addition substantial exploration has been completed on a number of other coal properties in the Southern Rocky Mountain district.

3. NORTHERN ROCKY MOUNTAIN COALFIELDS

The Northern Rocky Mountain coal resources consist of deposits at Babcock Mountain, Wolverine, Roman Mountain, Sukunka, Carbon Creek, Cinnabar Peak, Hasler Creek, Willow Creek, Noman Creek, Bullmoose Mountain, Pine Pass, Master Creek, Peace River Canyon, Mount Spieker, Belcourt Creek, Wapiti River, Saxon and Butler Ridge. The coal measures continue north of Butler Ridge providing potential for additional deposits.

The Northern Rocky Mountain coalfields contain approximately 46.0 million metric tons (51 million short tons) of reserves and resources of 3,640 million metric tons (4,000 million short tons) of thermal coal within 914 meters (3,000 feet) of surface (Table 3-1). Reserves and resources of thermal coal have been estimated by assuming that 10 percent of the coking coal reserves are oxidized and have inferior coking qualities. Based on the high free swelling indices reported for Northern Rocky Mountain coking coals it is believed a high percentage of this inferior quality coal would be used for blending. As a result the estimate represents potential thermal coal, much of which may not be available to a thermal plant.

The number of seams in any locality ranges from 2 to 12 with an aggregate thickness at a single site of as much as 12.1 meters (40 feet) to 15.2 meters (50 feet).

The coal quality is excellent with the coking coal having heating values of 30,620 kJ/kg (13,200 Btu/lb.) and 0.7% sulphur (Table 3-2). The rank of the coal is low to medium volatile A bituminous.

There is no current production from these deposits however several deposits are in advanced stages of development.

4. SOUTHERN INTERIOR COALFIELDS

The Southern Interior region consists of three principal coalfields, Hat Creek, Merritt and Similkameen and several small showings in the Cariboo coalfield near Quesnel. The coalfields are of Eocene age and, unlike the previous coalfields described, they are of continental origin.

The distribution of coal among the various categories is listed in Table 3-1. Most of the reserves of 2,020 million metric tons (2,222 million short tons) and indicated resources of 13,700 million metric tons (15,070 million short tons) are from the Hat Creek coalfield. Potentially mineable thermal coal is present in the other coalfields. The Hat Creek reserves are based on significant drilling in the No. 1 and No. 2 deposits. The indicated resource figures are based on five thick coal intersections outside of these deposits and a gravity survey over the Upper Hat Creek Valley.

The seam thicknesses and continuities are variable among the deposits. The Hat Creek coalfield is much larger than the two other coalfields and is unique in that it cannot be subdivided readily into discrete seams, but it contains a coal measure, which is principally coal, and is in excess of 455 meters (1,500 feet) thick. The Merritt coalfield contains between 2 and 6 seams in excess of 1.5 meters (5 feet) thick; the thickest coal interval is 22 meters (73 feet) in 234 meters (770 feet) of stratigraphic section. The Similkameen coalfield is divided into the Princeton and Tulameen basins. The Tulameen basin contains a coal zone 21.2 meters (70 feet) thick. At Princeton the basin consists of 4 seams between 1.5 meters (5 feet) and 9.1 meters (30 feet) thick; the total coal thickness is 17.1 meters (56 feet) over an interval of 523 meters (1714 feet).

The coal quality covers a significant range from 18,269 kJ/kg (7,875 Btu/lb.) at Hat Creek to 27,000 kJ/kg (11,640 Btu/lb.) at Merritt. The sulphur contents range from 0.3% at Tulameen to 0.75% at Princeton. The rank of coal varies from lignite to high volatile C bituminous.

5. NORTHERN INTERIOR COALFIELDS

The Northern Interior coalfields consist of the Bowron River coalfield, Telkwa coalfield, Zymoetz River deposits, Sustut River deposits and the Groundhog Coalfield (Figure 3-1).

Reserves of 127 million metric tons (140 million short tons) of thermal coal have been outlined in the Groundhog and Bowron River coalfields (Table 3-1). There are additional indicated resources of 332 million metric tons (365 million short tons) and inferred resources of 3,640 million metric tons (4,000 million short tons) of thermal coal. Some of these coal reserves in the Groundhog and Telkwa deposits may be mined by openpit methods; the remainder is accessible by underground methods. Of these resources the Groundhog coalfield contains the largest potential coal resources, but the geology is complex and considerable exploration is needed to outline a substantial reserve.

The number and quality of seams among coalfields in the Northern Interior is variable. The Groundhog coalfield contains an undetermined number of seams greater than 1.2 meters (4 feet) thick; there appears to be between 5 and 10 such seams in 455.0 (1,500) to 758.3 meters (2,500 feet) of coal measures. In the Sustut field there are at least 2 seams 0.9 meters (3 feet) thick; additional work is needed to define the stratigraphic section. The Telkwa and Zymoetz River areas contain 3 seams more than 1.5 meters (5 feet) thick with one seam being 4.3 to 4.9 meters (14 to 16 feet) thick. The Bowron River deposits contain lenticular seams 1.5 to 3.0 meters (5 to 10 feet) thick with a total thickness of 4.6 to 12.1 meters (15 to 40 feet).

The coal quality averages about 30,800 kJ/kg (13,300 Btu/lb.) although some of the coal must be washed to attain this heating value (Table 3-2). The sulphur content averages 0.7%. The coal rank ranges between high volatile A bituminous and semi-anthracite. The coal is principally of thermal quality.

APPENDIX II

PUBLIC HEALTH

Sulphur Dioxide

A discussion and graph supporting proposed guidelines for sulphur dioxide is provided in the text of this brief. Table II-1 is included here, with appropriate references, which are the basis for the text.

Suspended Particulate Matter Guidelines

The aim of this section is to examine the technical basis of health guidelines for suspended particulate with primary emphasis on human exposure information relative to mortality and morbidity. The data are summarized in Table II-2.

Morbidity Data - 24 Hour

Review of the available epidemiological data relative to the adverse health effects of suspended particulate matter indicates a range of response between 75 and 375 ug/m^3 with the strongest evidence suggesting a range of 150-300 ug/m^3. While more recent results from studies indicate that deleterious health effects occurred at particulate matter concentrations below this range, in the best judgement of the researchers conducting the studies these adverse health effects were due to sulphates rather than particulate matter per se (1).

A recent report of statistical reanalysis of CHESS data from New York 1970-71 (1) found no conclusive evidence about any association between total suspended particulates and incidence of asthma attacks. (2) Further, there was no evidence of a positive association between sulphur oxides and asthma when appropriate data adjustments were made. (2)

TABLE II-1

RECENT SCIENTIFIC EVIDENCE RELATING TO THE ADVERSE HEALTH EFFECTS OF SULFUR DIOXIDE

Adverse Health Effect	Concentration $\mu g/m^3$	Averaging Time	References
1. Increased mortality	300-500	24-hour	3, 4, 14, 17, 20, 22
2. Aggravation of symptoms in elderly	365	24-hour	1, 7, 14
3. Acute irritation symptoms	340	24-hour	1, 7, 11, 12
4. Aggravation of asthma	180-250	24-hour	1, 3, 4, 5, 6, 14
5. Increased hospital admissions with respiratory illness	300-500	24-hour	3, 14
6. Increased frequency and severity of respiratory illness	130	annual mean	1, 9, 14, 16, 18, 19, 21
7. Increased specific mortality	180	annual mean	14
8. Decreased lung function in children	200	annual mean	1, 3, 13, 14
9. Increased acute lower respiratory disease in families	90-100	annual mean	1, 3, 14
10 Increased prevalence of chronic bronchitis	95	annual mean	1, 3, 8, 10, 14, 19, 20, 26

TABLE II-2

RECENT SCIENTIFIC EVIDENCE RELATING TO THE ADVERSE HEALTH EFFECTS OF TTAL SUSPENDED PARTICULATE MATTER

Adverse Health Effect	Concentration ug/m^3	Averaging Time	References
1. Increased mortality	750 or a rise of 200	24-48 hours	15, 25, 26
2. Increased infant mortality and cancer deaths	200	3 days	14, 24
3. Increased upper respiratory infection and cardiac morbidity	375	24 hours	15, 22, 23
4. Excess bronchitis mortality	200	24 hours	15, 20
5. Acute worsening of symptoms in bronchitis patients	300	daily	15, 26
6. Increased cough, chest discomfort and restricted activity	100-269	24 hours	1, 3, 12
7. Aggravation of cardiorespiratory symptoms in healthy persons, and in elderly patients with heart and lung disease; increased asthma attacks in people with asthma	80-100	24 hours	1, 3, 7, 2
8. Aggravation of cardiorespiratory disease symptoms in elderly patients with heart or chronic lung disease	76-260	24 hours	1, 3, 7
9. Increased mortality from chronic respiratory disease and all causes	100	2 years	15, 17

TABLE II-2 continued

RECENT SCIENTIFIC EVIDENCE RELATING TO THE ADVERSE HEALTH EFFECTS OF TOTAL SUSPENDED PARTICULATE MATTER

Adverse Health Effect	Concentration ug/m^3	Averaging Time	References
10. Increased chronic respiratory disease prevalence in adults; increased upper and lower respiratory tract disease and diminished pulmonary function in children	100-200	annual	15, 18, 19
11. Decreased pulmonary function in school-children	110	annual	1, 3, 13
12. Increased frequency and severity of acute lower respiratory disease in school-children	100	annual	1, 3, 11
13. Increased chronic respiratory disease symptom prevalence in adults	100	annual	1, 10

Mortality Data - 24 Hour

There exist epidemiological data which have attempted to relate increases in mortality to increases in ambient particulate concentration. These data suggest an adverse effect range between 200 and 750 ug/m^3 and as with sulphur oxides the mortality range overlaps the morbidity threshold.

Excess mortality is not a very sensitive parameter. These data are of little help in establishing a 24 hour suspended particulate matter guideline.

The range of 150-300 ug/m^3 is supportable on the basis of available data. However, the question of whether specific particulate-borne contaminants are producing adverse health responses below these concentrations is an issue yet to be resolved. Thus it is concluded that the proposed guideline of 150 ug/m^3 (24 hours) is reasonable.

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Morbidity Data - Annual

Information relative to adverse health effects of long-term exposures to particulate indicates that increases in morbidity result from long-term exposure to particulate matter in the concentration range of 60-220 ug/m^3 annual average.

Mortality Data - Annual

As with the 24 hour suspended particulate matter guideline, the mortality data allow no defensible guideline range to be established.

The proposed guideline of 60 ug/m^3 annual average is supportable on the basis of available data; however it must be stated once again that a possibility exists that specific particulate-borne contaminants may be producing effects below this range.

Nitrogen Oxides Guidelines

The aim of this section is to examine the technical basis of health guidelines for nitrogen oxides (as NO_2) with primary emphasis on human exposure information relative to mortality and morbidity. The data are shown in Figure II-1, and in Table II-3.

Morbidity Data Short-Term Averages (1-2 hours)

There exists only very limited data on response of humans to short-term nitrogen oxide exposure and these data suggest an adverse response range of 2000-3000 ug/m^3.

Mortality Data Short-Term Averages (1-2 Hours)

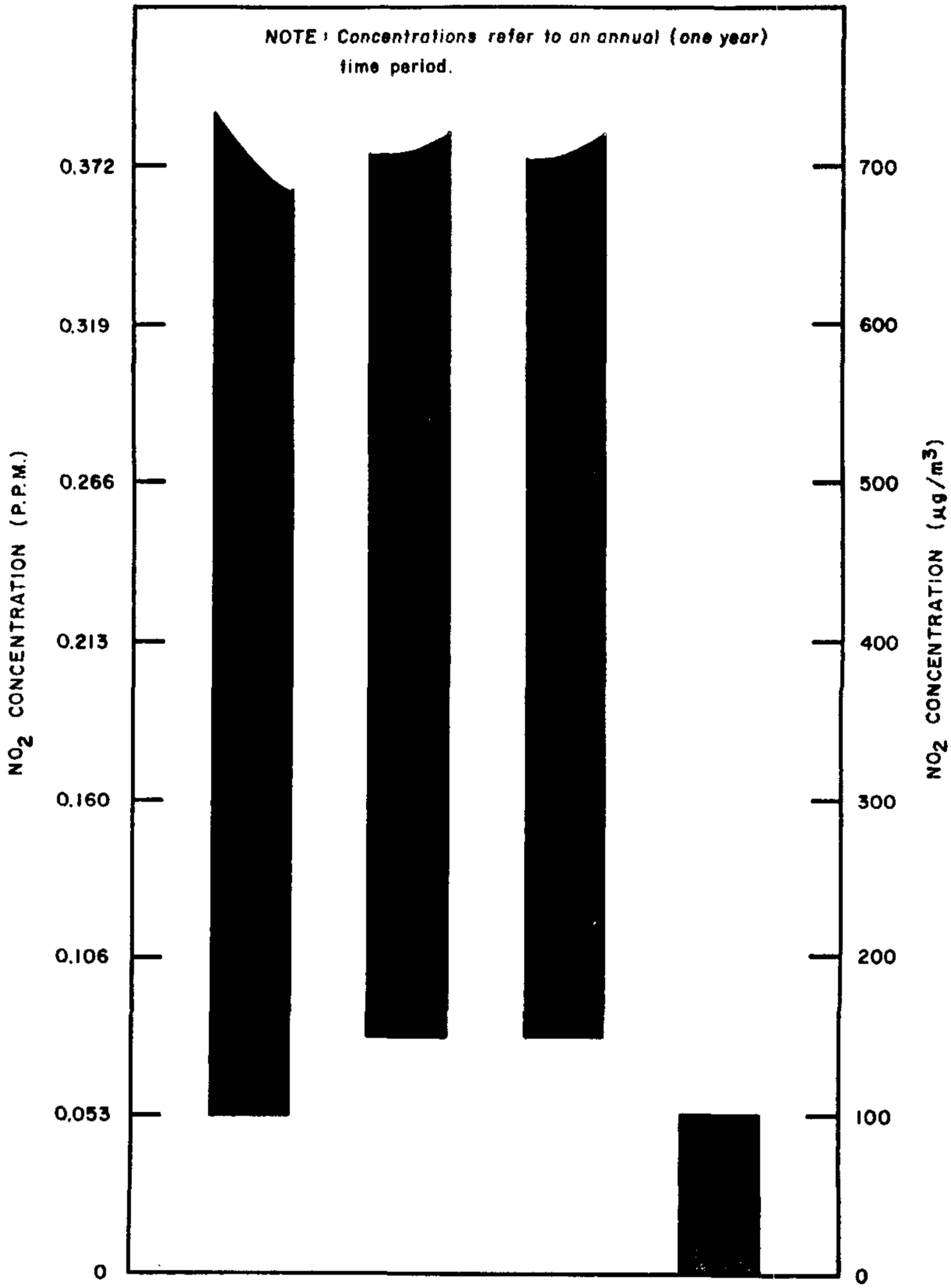
There exist no short-term studies of human mortality in response to nitrogen oxide.

Therefore, based on the limited morbidity data a concentration range of 2000-3000 ug/m^3 would be a reasonable short-term guideline. However, because these data are so scanty it would be better to postpone establishment of a short-term nitrogen oxide guideline until more data are available. The same would be true of attempts to establish 24-hour guidelines as well.

Morbidity Data - Annual

There exists only limited data relative to the response of humans to long-term nitrogen oxide exposures and these data suggest that effects are adverse in the range of 100-600 ug/m^3 annual average.

RECENT SCIENTIFIC STUDIES RELATING TO THE ADVERSE HEALTH EFFECTS OF NITROGEN OXIDES



Based on Table II - 3

TABLE II-3

RECENT SCIENTIFIC EVIDENCE RELATING TO THE ADVERSE HEALTH EFFECTS OF NITROGEN OXIDES (as NO_2)

Adverse Health Effect	Concentration $\mu g/m^3$	Averaging Time	References
1. Susceptibility to acute respiratory infection	2800	2 hours	4, 39, 40
2. Diminished lung function	3800	1 hour	4, 34, 41
3. Structural changes in lungs of experimental animals. Changes include changes in lung chemistries, damage to cilia.	564-940 940 750	6 months 1 month 7 days	4, 30, 35, 36
4. Diminished lung function of humans experimentally exposed to NO_2	3000	10-15 min.	39, 41
5. Increased prevalence of chronic respiratory disease in humans possibly attributable to NO_2	100-540	1 + year	4, 29, 31, 32
6. Association of hypertensive heart disease mortality with NO_2 exposure	unknown	unknown	24
7. Increased susceptibility to acute respiratory infection in families	150-560	1 year	39, 40
8. Increased frequency of lower respiratory disease in children	150-450	1 year	37
9. Increased mortality of animals exposed to NO_2 and challenged with infectious aerosols	940	5 hrs/day x 3 months	4, 44

TABLE II-3 continued

RECENT SCIENTIFIC EVIDENCE RELATING TO THE ADVERSE HEALTH EFFECTS OF NITROGEN OXIDES (as NO_2)

Adverse Health Effect	Concentration ug/m^3	Averaging Time	References
10. Structural and biochemical changes in	940	4 hrs/day x 5 days	4, 42, 43, 44
lungs of experimental animals.	940	6 hrs/day x 3 months	45, 46, 47, 48
Changes include alteration in structure of lung collagen, rupture of mast cells, peroxidation of lung lipids, decreased cilia on bronchiolar epithelium	1900-3800	1 year	

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Mortality Data - Annual

Only animal exposure data are available on excess in mortality attributed to nitrogen oxide exposures. However, it is considered that these data have direct input into human health guidelines.

An ambient air guideline of 400 ug/m^3 (1 hour) would be supported by the data. However, NO_x ambient levels are not specifically tied to power plants, and B. C. Hydro has not included this contamin~~e~~ant in its recommendations for ambient control objectives.

What other contaminants

Dustfall

Dustfall is considered a nuisance rather than a health hazard and is therefore not discussed.

Fluorine (F)

Acute exposure to hydrogen fluoride gas causes burns on the skin and intense irritation, in a few cases fatal, in the lungs (49). Chronic exposure to extremely high concentrations of atmospheric fluoride is known from occupational medicine to cause crippling fluorosis (debilitating bone disease). Osteosclerosis (absolute reduction in bone mass) is a much more common adverse health effect caused by occupational fluoride exposure. Accumulation of approximately 6000 ppm fluoride in bone is associated with osteosclerosis. It is generally thought that concentrations of 2.5 ug/m^3 fluoride in occupational exposures will not cause osteosclerosis in workers (50). Under normal conditions, inhaled fluoride constitutes a very small portion of the body's total fluoride intake. However, in a few instances, community health effects have been cited in people living near fluoride-emitting industry. Symptoms of hematological changes and general health effects were described. These symptoms are not unique to fluoride exposure, nor are they common in occupational fluoride exposure (51).

As with some other elements, atmospheric standards for fluorides are difficult to set. The amounts taken into the body by ingestion and inhalation are variable and difficult to estimate. The Government of Ontario regulates atmospheric fluorides, allowing up to 1.72 ug/^{3} per 24 hours and 0.69 ug/m^3 per 30 days of both gaseous and particulate flouride between April 15 and October 15. Between October 16 and April 14, 3.44 ug/m^3 is allowed over 24 hours and 1.38 ug/m^3 over 30 days (52). These regulations are promulgated to reduce ambient fluoride during the growing season since fluoride can demonstrate acute damage to vegetation.

Mercury

Mercury vapor is efficiently absorbed by man, 75-85% being absorbed from 50 to 350 ug/m^3 and more at lower concentrations (53). The effects of inhalation of acute doses of elemental mercury are most commonly manifested in the respiratory tract by pneumonitis, bronchitis, chest pains, dyspnea (shortness of breath), and coughing. Acute poisoning is cited as being caused by Hg levels of 1.2 to 8.5 ug/m^3 (54). Chronic exposure to lower doses, characteristically named "mercurialism", produces the insidious onset of long-term symptoms caused by the accumulation and retention of Hg in the brain, testes and thyroid. These long-term symptoms have been shown to be only partially reversible. Classic symptoms of "mercurialism" include gingivitis (gum inflammation), stomatitis (inflamation of the oral mucosae), erethism (abnormal physiological and psychologic distrubances) and tremor. General disturbance of the gastrointestinal system is frequently seen. Renal toxicity is also a classical finding in mercury toxicity (55, 56). Humans are exposed to mercury in food, water and air. Thus, with multiple exposure routes and the easy accumulation of mercury in the body it is difficult to cite the actual amounts of mercury which cause chronic toxicity.

Both inorganic mercury and the organic mercury secondarily formed in the environment demonstrate teratogenic properties in experimental animals. Organic mercury crosses the placenta more easily, making it more dangerous to the fetus (55). Animal experiments also suggest that mercury causes decreased reproductive performance. Cell culture experiments have shown that inorganic mercury causes chromosomal mutation (53).

The United States Environmental Protection Agency has promulgated a National Emission Standard for Hazardous Air Pollutants for mercury at 1.0 ug/m^3 for 24 hours (57). The Government of Ontario maintains a 24-hour standard of 2.0 ug/m^3 (52). A panel of six public health experts has derived a safe ambient standard for mercury of 0.8 ug/m^3 for a 24-hour period (58).

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APPENDIX III

WATER QUALITY REGULATIONS

1. Federal Legislation

1.1 Canadian Drinking Water Standards

In 1968, Health and Welfare Canada published Canadian Drinking Water Standards and Objectives, 1968. These standards and objectives were prepared by the Joint Committee on Drinking Water Standards of The Advisory Committee on Public Health Engineering and The Canadian Public Health Association. The Joint Committee recommended three types of limits, namely Objective, Acceptable and Maximum Permissible. These are defined as follows:

Objective: These limits should be interpreted as the long-term quality goal to be reached. It is implied that water supplies, which meet these requirements, are of very good and safe quality from health, aesthetic, and other viewpoints.

Acceptable Limits: These limits should not be exceeded whenever more suitable supplies are, or can be made, available within the technological and economic resources of the community. Substances in this category, when present in concentrations above the indicated limits, are either objectionable to a significant number of people or capable of producing deleterious health or other effects. When periodic evaluations of the quality confirm that the water as supplied falls between the objective and acceptable limits, a more frequent and comprehensive surveillance programm should be instituted. Any water supply, when exceeding the acceptable limits in one or more of the quality characteristics, should be assessed on its individual merits as to its suitability and safety from health, aesthetic, and other viewpoints.

Maximum Permissible Limits: These limits are standards. The term standard is used for limits on certain substances that are known or suspected to be linked with human health (e.g. toxic chemicals, radioactive substances, pathogenic organisms). The limits, in each case, if exceeded, shall be sufficient grounds for the rejection of the water supply unless effective remedial treatment is applied to either totally remove the particular substance or to bring it to a concentration below the tabulated limit. Substances in this category, when present in concentrations above the indicated values, have been associated with adverse effects on human health. Lesser concentrations, therefore, are desirable and no water supply should be permitted to carry these chemicals at the indicated levels continuously. When the quality falls between the acceptable and maximum permissible limits, careful surveillance must be maintained with active considerations of what steps would be taken when the maximum permissible limits are exceeded.

These limits have been generated for various physical, microbiological, chemical and radiological water quality characteristics. Table III-1 presents these recommended limits.

1.2 Fisheries Act

The Fisheries Act (R.S.C. 1970, c. F-14) as amended by R.S.C. 1970, c. 17 (1st Supp.); Statutes of Canada 1974-1975 c. 48, presents general pollution oriented guidelines for the protection of "Canadian Fisheries waters". This latter term encompasses all waters in the fishing zones of Canada, all waters in the territorial sea of Canada and all internal waters of Canada. Regarding pollution of waters, the Act states:

> "31.(2) . . . no person shall deposit or permit the deposit of a deleterious substance of any type in water frequented by fish or in any place under any conditions where such deleterious substance or any other deleterious substance that results from the deposit of such deleterious substance may enter any such water."

This regulation is amended by permitting waste deposition "under conditions authorized by regulations made by the Governor in Council under any other Act in any waters with respect to which these regulations are applicable . . . "

2.0 Provincial Regulations

The Pollution Control Act (c. 34, s. 1) specifies that "no person shall, directly or indirectly, discharge or cause or permit the discharge of sewage or other waste material on, in or under any land or into any water" without an authorized permit or approval. A permit for or an approval of a waste discharge must be obtained from the Director of Pollution Control serving the Provincial Pollution Control Board.

2.1 Industrial Regulations

Since 1973 and pursuant to the Pollution Control Act, the Pollution Control Board of British Columbia has promulgated recommended guidelines and objectives for waste discharges to land and water for various specific industries operating in the Province of British Columbia. During the same period the Pollution Control Board also issued receiving water quality guidelines in order to preserve and enhance the quality of provincial water consistent with their intended use. The effluent guidelines and objectives set forth three levels of compliance which are indicative of the attainment of high, intermediate and low order discharge quality and are termed Level A, Level B and Level C, respectively. The guidelines recommend that generally all new or proposed discharges meet Level A objectives.

TABLE III-1

CANADIAN DRINKING WATER STANDARDS AND OBJECTIVES*

PARAMETER	OBJECTIVE	ACCEPTABLE	MAXIMUM PERMISSIBLE
Physical			
Colour - TCU	<5	15	
Odour - T.O.N.	0	4	
Taste	Inoffensive	Inoffensive	
Turbidity - JTU	<1	5	
Temperature - °C	<10	15	
pH - Units	-	6.5 - 8.3	
Microbiological			
Total Coliform (MPN Method) (a)	No coliforms	At least 95% of the samples in any consecutive 30-day period should be "negative" for total coliform organisms.	At least 90% of the samples in any consecutive 30-day period should be "negative" for total coliform organisms.
(b)	No coliforms	None of the samples "positive" for total coliform organisms should have an MPN index greater than 4 per 100 ml.	None of the samples "positive" for total coliform organisms should have an MPN index greater than 10 per 100 ml.
Total Coliform (MF Method) (a)	No coliforms	At least 95% of the samples in any consecutive 30-day period should be "negative" for total coliform organisms.	At least 90% of the samples in any consecutive 30-day period should be "negative" for total coliform organisms.
(b)	No coliforms	None of the samples "positive" for total coliform organisms should have an MF Count greater than 4 per 200 ml or 10 per 500 ml portions.	None of the samples "positive" for total coliform organisms should have an MF Count greater than 6 per 200 ml or 15 per 500 ml portions.
Faecal Coliform(3) (a)	At least 95% of the samples in any consecutive 30-day period should have a faecal coliform density of less than 10 per 100 ml.	At least 90% of the samples in any consecutive 30-day period should have a faecal coliform density of less than 100 per 100 ml.	At least 90% of the samples in any consecutive 30-day period should have a faecal coliform density of less than 1,000 per 100 ml.
(b)	Treatment by chlorination is required.	Complete or partial treatment including chlorination may be required.	Complete water treatment is required.
Total Coliform(3) (a)	At least 95% of the samples in any consecutive 30-day period should have a total coliform density of less than 100 per 100 ml.	At least 90% of the samples in any consecutive 30-day period should have a total coliform density of less than 1,000 per 100 ml.	At least 90% of the samples in any consecutive 30-day period should have a total coliform density of less than 5,000 per 100 ml.
(b)	Treatment by chlorination is required.	Complete or partial treatment including chlorination is required.	Complete water treatment is required.
Chlorine, Free Residual	0.5	-	-
Viruses	No specific limit	No specific limit	No specific limit

* Bracketed Numbers refer to Appendix to Table 1 which follows.

TABLE III-1 (Cont'd)

PARAMETER	OBJECTIVE	ACCEPTABLE	MAXIMUM PERMISSIBLE
Toxic Chemicals			
Arsenic as As	Not Detectable	0.01	0.05
Barium as Ba	Not Detectable	<1.0	1.0
Boron as B	-	<5.0	5.0
Cadmium as Cd	Not Detectable	<0.01	0.01
Chromium as Cr^{+6}	Not Detectable	<0.05	0.05
Cyanide as CN	Not Detectable	0.01	0.20
Lead as Pb	Not Detectable	<0.05	0.05
Nitrate + Nitrate as N	<10.0	<10.0	10.0
Selenium as Se	Not Detectable	<0.01	0.01
Silver as Ag	-	-	0.05
Biocides(4)			
Aldrin	Not Detectable	Not Detectable	0.017
Chlordane	Not Detectable	Not Detectable	0.003
DDT	Not Detectable	Not Detectable	0.042
Dieldrin	Not Detectable	Not Detectable	0.017
Endrin	Not Detectable	Not Detectable	0.001
Heptachlor	Not Detectable	Not Detectable	0.018
Heptachlor Epoxide	Not Detectable	Not Detectable	0.018
Lindane	Not Detectable	Not Detectable	0.056
Methoxychlor	Not Detectable	Not Detectable	0.035
Organic Phosphates + Carbamates	Not Detectable	Not Detectable	0.100
Toxaphene	Not Detectable	Not Detectable	0.005
Herbicides (e.g. 2,4-D, 2,4-T, 2,4,5-T, 2,4,5-TP)	Not Detectable	Not Detectable	0.100
Other Chemicals			
Alkalinity(5)	-	30 - 500	
Ammonia as N	0.01	0.05	
Calcium as Ca	<75	200	
Chloride as Cl	<250	250	
Copper as Cu	<0.01	1.0	
Corrosion and Incrustation(6)	-	-	
Iron (dissolved) as Fe	<0.05	0.3	
Magnesium as Mg	<50	150	
Manganese as Mn	<0.01	.05	
Methylene Blue Active Substances	<0.2	0.5	
Phenolic Substances as Phenol	Not Detectable	0.002	
Phosphates as PO_4 (inorganic)	<0.2	0.2	
Total Dissolved Solids	<500	1000	
Total Hardness as $CaCO_3$ (7)	<120		
Organics as CCE + CAE	<0.05	0.2	
Sulphate as SO_4	<250	500	
Sulphide as H_2S	Not Detectable	0.3	
Uranyl Ion as UO_2	<1.0	5.0	
Zinc as Zn	F1.0	5.0	
Radiological(4)	1/10 of the ICRP (MPC)w(8) for 168-hour week.	1/3 of the ICRP (MCP)w(9) for 168-hour week.	The ICRP (MCP)w for 168-hour week.

EXPLANATORY NOTES TO TABLE III-1

1. All standards and objectives specified in mg/1 unless otherwise noted.

2. To be examined according to the latest edition of Standard Methods for the examination of Water and Wastewater (American Public Health Association, American Water Works Association, and Water Pollution Control Federation), or other acceptable methods as approved by the control agency.

3. Raw Water Standards.

4. Raw and Drinking Water Standards.

5. Alkalinity in the range of 30-500 mg/1 as $CaCO_3$ is generally acceptable, but does not guarantee that problems due to this characteristic, in this range, will not occur. It is necessary that each water be evaluated on its own merit.

6. It is recommended by the A.W.W.A. Task Force on Water Quality Goals (1968) that the 90-day incrustation rate on stainless steel, using "coupon insertions", should not exceed 0.05 mg/sq cm, and the 90-day loss by corrosion on galvanized iron should not exceed 5.00 mg/sq cm.

7. Total of Carbon Chloroform and Carbon Alcohol Extractibles.

8. ICRP - International Commission on Radiological Protection.

9. (MPC)w - Maximum Permissible Concentration in Water.

APPENDIX IV

A STUDY ON THE STATE OF THE ART OF FLUE GAS DESULPHURIZATION TO JUNE, 1977

1. INTRODUCTION

Flue gas desulphurization (FGD) processes are designed to remove sulphur dioxide from the flue gases produced by coal-fired power plants. Such systems are usually applied to flue gases containing from 500 to 5000 ppm of sulphur dioxide with removal efficiencies of up to 95 percent. They may also be designed to remove considerable quantities of flyash to produce a final effluent that meets both sulphur dioxide and particulate emission standards. This dual function for flue gas scrubbers has been a major cause of excessive operational problems and expense associated with FGD systems.

Three general classifications are used to define FGD technology. These are the nonregenerative, regenerative and advanced processes. Those that remove sulphur dioxide from the flue gas and convert it to a non-marketable product that must be disposed of as landfill material are classed as nonregenerative processes. Regenerative processes are those that remove the sulphur dioxide and produce marketable forms of sulphur such as elemental sulphur, pure sulphur dioxide or sulphuric acid. Advanced processes are those in the preliminary or conceptual design stage, or that may be undergoing detailed bench or pilot testing. Advanced processes are of the regenerative type.

While the application of FGD technology in the United States has been restricted to coal-fired utility power plants, in Japan most of the FGD systems have been applied to low ash, high sulphur, oil-fired industrial and commercial boilers, or to industrial emission sources such as Claus plants, sintering plants, and sulphuric acid plants.

The size and cost of FGD systems are usually expressed in terms of megawatts (MW) of installed boiler capacity and dollars per kilowatt (kw) of capacity. To convert other emission sources to a MW equivalent, or vice versa, a general rule is to use the emission volume to MW ratio of 1900 standard cubic feet per minute (SCFM) flue gas per MW. For example, a 1000 LTD Claus plant with 65 percent hydrogen sulphide in the feed gas emits about 100,000 SCFM, the equivalent of 50 MW.

2. HISTORICAL DEVELOPMENT

Flue gas streams with sulphur dioxide concentrations in excess of 5000 ppm and normally around 10,000 ppm have been successfully desulphurized for several years. These concentrations are typical of copper smelter operations and by the use of precipitators, followed by sulphuric acid plants or lime slurry scrubber systems, emissions from these sources have been effectively controlled. However, these same processes have not been successfully applied for desulphurization of high volume gas streams containing low sulphur dioxide concentrations and residual flyash.

Nearly all of the major full scale demonstration efforts of FGD technology have taken place in the last nine years on installations in the U.S.A. and Japan (1, 2, 3, 4, 5, 6, 7, 8, 9). Others have generally limited their effort to pilot plant projects and are still developing the basic technology for their process. One of the major developers of FGD technology in Canada is Ontario Hydro, having piloted a limestone slurry FGD system and participated financially in a second effort (10).

The major air pollution control equipment suppliers have been, and still are, the principal developers of the nonregenerative and regenerative processes. In many cases they are also suppliers of combustion boilers or other equipment associated with larger utility boilers. Major incentives for such development have been government regulations requiring emission controls, significant federal cost sharing in the form of demonstration grants, and a commitment by the equipment suppliers to continue and expand their business in the electrical utility and related fields.

2.1 Early Development

Water scrubbing of flue gases was experimented with as early as 1900 (8) although the most significant work was conducted around 1930 by London Power Co. in England (8, 11). This led to a large gas-washing installation at the Battersea Power Station and later at Bankside. Both used a chalk slurry as a scrubbing fluid and, after pH adjustment, the effluent was discharged into the River Thames. These plants were shut down during World War Two and have not been restarted.

The next installation was at Swansea, Wales, where the ICI-Howden system again used a chalk slurry, but the effluent was filtered to remove solids, and then reused. Major operating problems arising from high ash concentrations resulted in the scrubber being abandoned.

The next significant effort was the full scale installation by Combustion Engineering in 1968 (1) of two limestone injection, followed by lime-scrubbing, FGD systems. One was applied to a 140 MW boiler for Union Electric Co. in St. Louis, Mo. and the other on a 125 MW boiler unit for Kansas Power & Light Co. in Lawrence, Kansas. After several years of operation or partial operation, and many modifications, the Union Electric Co. system was shut down and abandoned (12). The other unit at Lawrence, Kansas underwent many similar changes and in addition was converted to a tail-end limestone scrubbing system (1). It is still operating today, nine years later.

2.2 Current Status

Since these installations in 1968, the development and implementation of FGD systems have progressed steadily and to date approximately 24 systems totalling 6000 MW have been installed and are operating in the United States (1, 7, 9). As of early 1977 construction was proceeding on five retrofit jobs and 28 new systems (9). Sixteen of these have been retrofit. Approximately five systems have been shut down.

The actual implementation schedule for these systems, including both nonregenerative and regenerative units is depicted in Figure IV-1. The total scrubbing capacity (MW) is plotted against calendar year since 1968. A 1974 summary of operational and planned installations by Ponder (1) of the United States Environmental Protection Agency (EPA) is also plotted. It appears that implementation is 1-1/2 years behind the 1974 projections.

In Japan, more than 50 FGD systems were in operation as of January 1975, and more than 80 were projected to be installed by the end of 1976 (1). The systems include a mix of both nonregenerative and regenerative processes and have been applied not only to oil and coal-fired utility boilers but also to flue gases from smelters, sintering plants, industrial boilers, Claus plants and sulphuric acid plants. Few are operating on coal-fired boiler exhausts. Figure IV-2 shows the installed and operating capacity of FGD systems in Japan. It is apparent from Figures IV-1 and IV-2 that parallel development of FGD systems took place in the United States and in Japan.

Rapid development of FGD technology in the United States was in part the direct result of EPA participation in the technology development program. Considerable information has been generated and made available to the general public through totally funded research programs and demonstration

Figure IV - 1

INSTALLED and OPERATING
FGD CAPACITY EXPRESSED IN MEGAWATTS
UNITED STATES

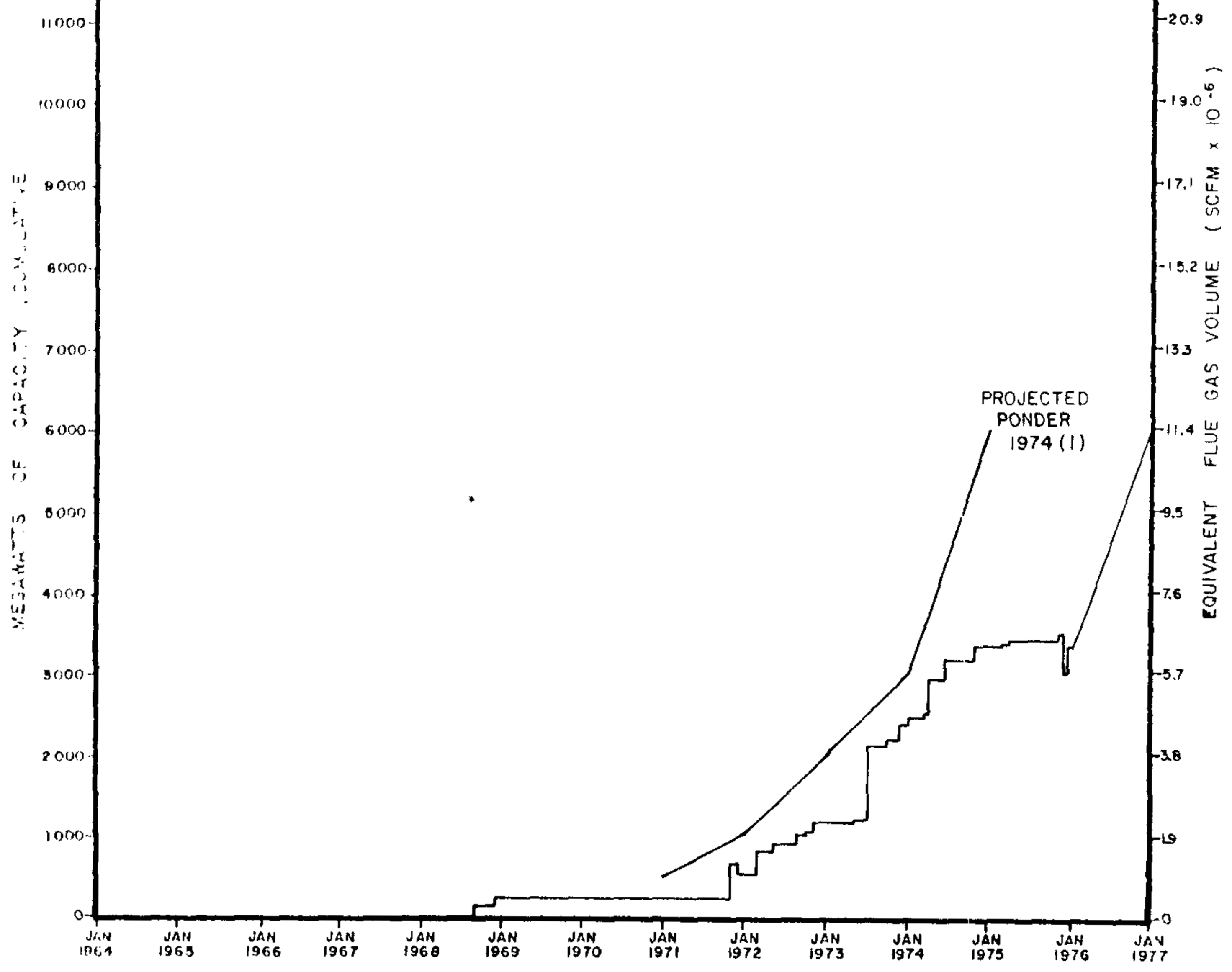


Figure IV - 2

INSTALLED and OPERATING
FGD CAPACITY EXPRESSED IN MEGAWATTS
JAPAN

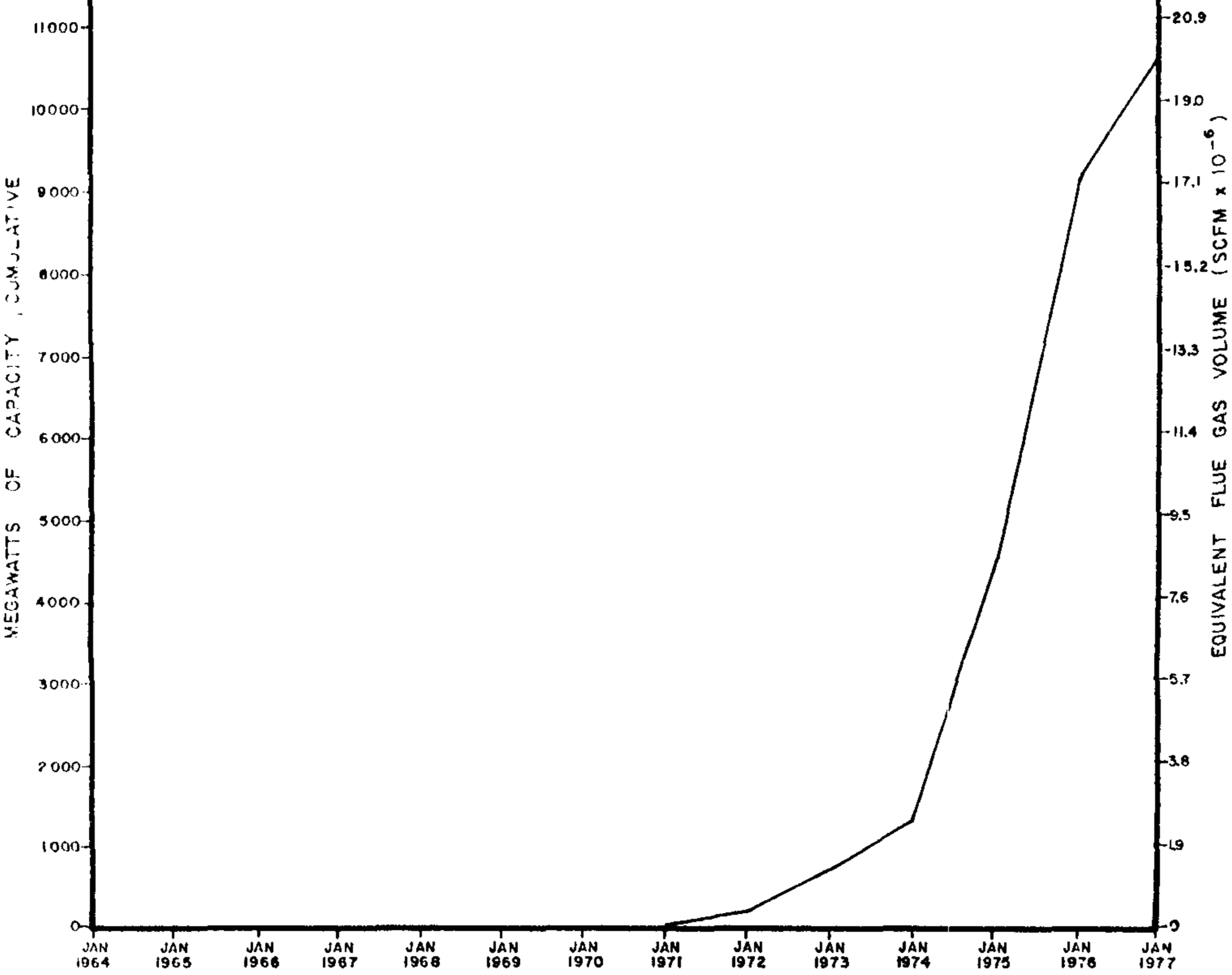


Figure IV - 3

FLUE GAS DESULPHURIZATION
CAPACITY USING LIMESTONE
IN USA and JAPAN

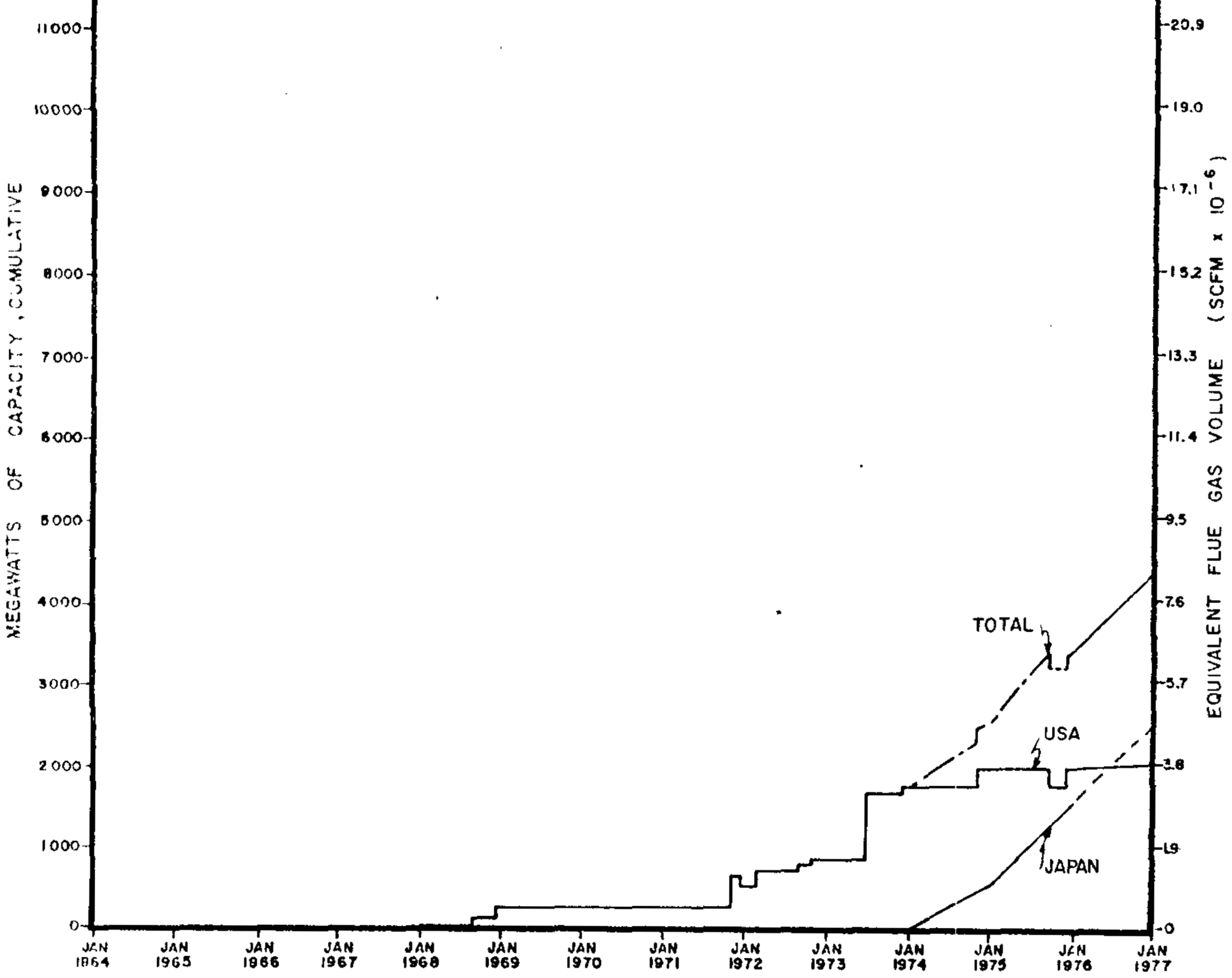


Figure IV - 4

FLUE GAS DESULPHURIZATION CAPACITY USING LIME IN USA and JAPAN

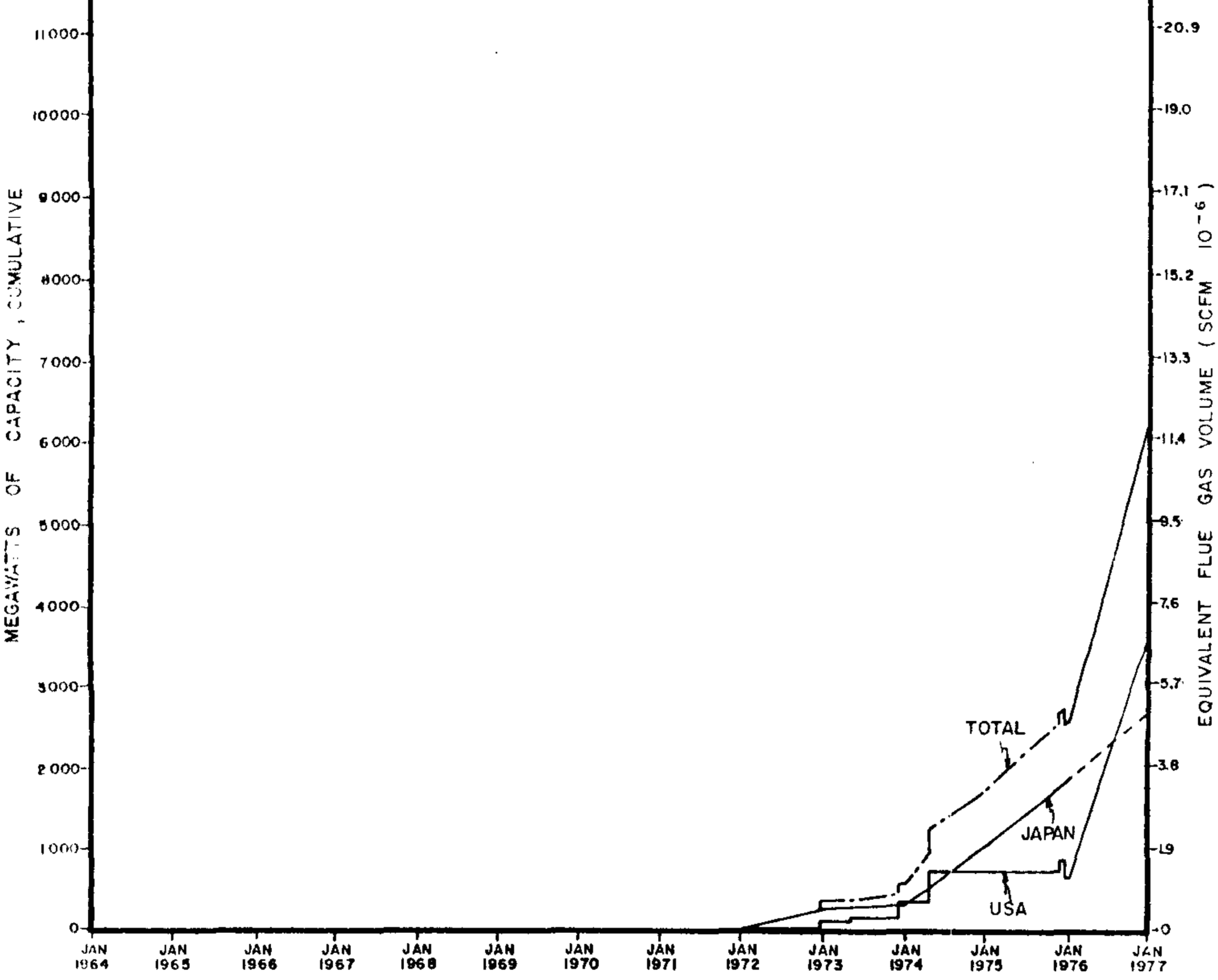
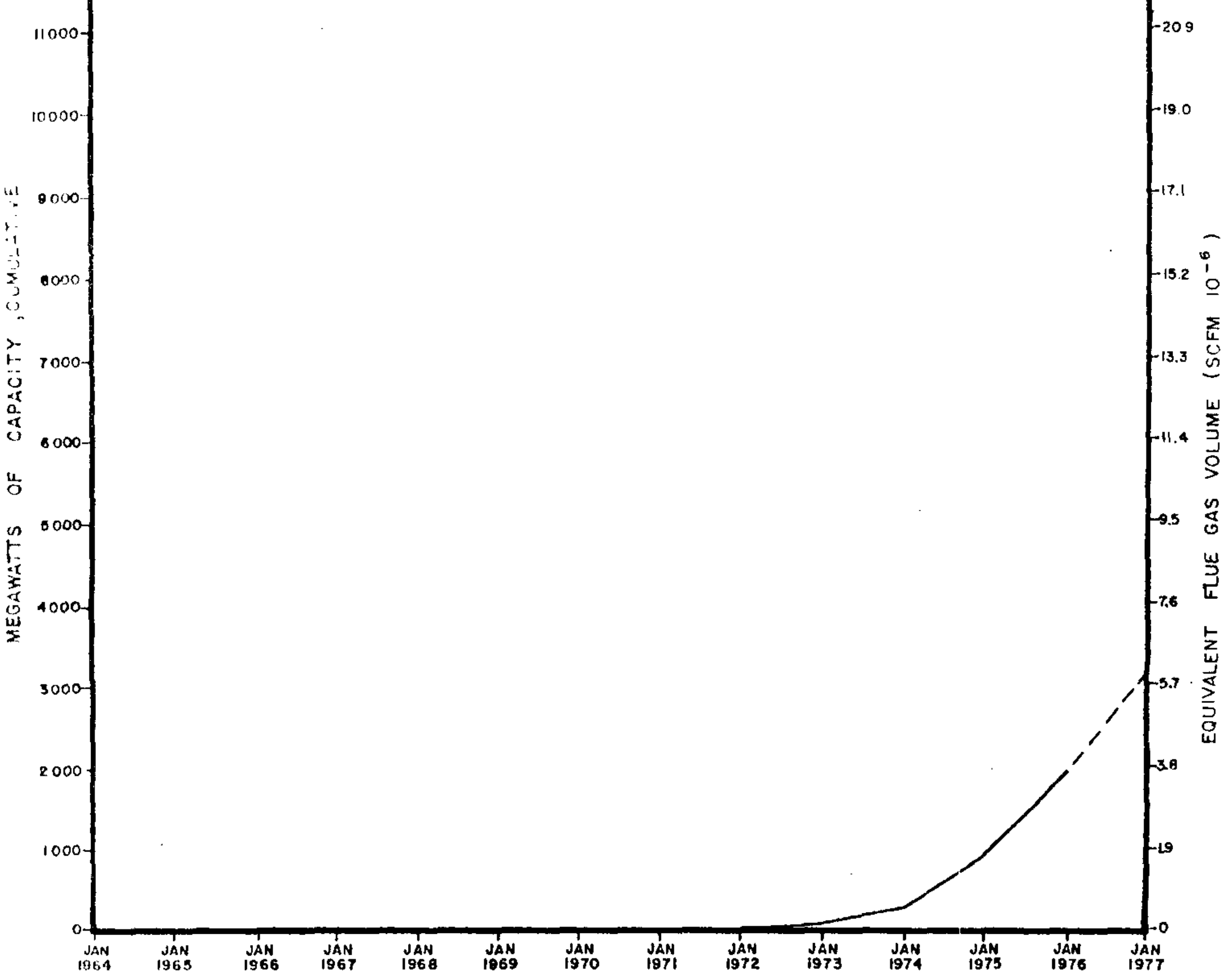


Figure IV - 5

CAPACITY USING THE DOUBLE ALKALI PROCESS JAPAN



grants for first-of-a-kind full scale installations. While up to now, EPA assistance has been primarily directed towards the nonregenerative processes, it is now being redirected towards the regenerative and advanced processes.

2.3 Proven or Practicable Technology

FGD technology has still not been officially judged to be a proven or practicable technology by the National Academy of Engineering in the United States. It has set the following (paraphrased) criteria for proven technology with respect to FGD.

A FGD process must operate satisfactorily on a 100 MW or larger commercial electricity generating station for more than one year. Sufficient operating and economic data must be generated so as to fairly judge the performance and economics of the system.

In early 1975, Research Cottrell Inc. (12) claimed to be the first to meet the criteria with their system on the Cholla No. 1 boiler of Arizona Public Service (14). This boiler generates 115 MW and burns coal containing 0.5 percent sulphur. The flue gases contain 250 to 650 ppm of sulphur dioxide. This low level of sulphur dioxide results in a less severe test of a system when compared with a scrubbing process designed to handle 3000 to 5000 ppm of sulphur dioxide. Therefore, Research Cottrell limited the application of their process to flue gases containing less than 2000 ppm sulphur dioxide until more operating experience was gained.

No other claims have been made with respect to proven technology but a fair assessment of many lime and limestone systems would classify them as proven technology as of January 1976. It would also appear that many of the systems operating in Japan on particulate-free flue gas have demonstrated proven technology as of January 1976.

A United States Commerce Technical Advisory Board Panel on Sulphur Oxide Emission Control Technology in its final report submitted on September 10, 1975, concluded that continuous SOx emissions control technology was commercially available (15). Lime and limestone FGD processes were judged to be proven technologically capable of removing as much as 90 percent of the SOx in the flue gases.

3. PARTICULATE REMOVAL

The attitude towards particulate removal has varied considerably during the development of FGD technology. In the late 1960's, almost no consideration was given to ash removal before the FGD system, and as a result some very serious problems developed in the start up and early operation stages of the FGD systems. Even the more recent systems have had to solve substantial problems associated with flyash in their start up and early operational phases.

3.1 Desulphurization without Flyash Removal

If FGD is to be accomplished without removing the flyash first, then the choice of systems is essentially limited to one of the nonregenerative processes. The prime reason is that flyash will reach the desulphurization system and contaminate the scrubber and/or scrubbing fluid. None of the regenerative processes can deal with significant quantities of ash.

Several Chemico systems such as the two Duquesne Light (16) systems and the Pennsylvania Power, Bruce Mansfield system were designed to remove flyash and sulphur dioxide independently. Each consisted of two venturi scrubbers in series so that the flyash could be removed first and then the sulphur dioxide could be removed from particulate-free gas. However, when the Duquesne Light system started up, substantial sulphur dioxide was removed in the first stage and it experienced severe acid attack.

This system now operates with a lime slurry recirculated through both scrubbers and simultaneous flyash and sulphur dioxide removal is accomplished.

This experience pointed out the difficulties encountered in attempting wet methods of flyash removal prior to FGD but suggests that properly designed FGD systems using lime or limestone can be successful. This position is held by many systems suppliers.

3.2 Desulphurization after Flyash Removal

Flyash removal with an electrostatic precipitator prior to the FGD systems, has two significant points in its favor. Firstly, even without the flue gas scrubber in operation, the utility can meet the particulate emission standard. Secondly, the choice of applicable flue gas systems is increased. This decreases the chance of having operational problems associated with flyash. A flue gas bypass option around the flue gas scrubber is normally included in this design. By adopting this design philosophy, the electrical utility ensures that its prime responsibility of producing electricity can be met, while seriously attempting to meet the sulphur dioxide emission standard. Some regulatory agencies do not approve of the bypass option.

In the United States there is no clear preference for either philosophy. However, several retrofit installations at sites where flyash removal does not meet the codes, have chosen combined flyash and sulphur dioxide removal systems. This is also the choice for many new plants in the west that burn low sulphur coal. In the east, new plants burning higher sulphur coal tend to favor high efficiency electrostatic precipitators followed by a FGD system.

4. NONREGENERATIVE PROCESSES

Nonregenerative processes remove the sulphur dioxide from the flue gases and in most cases produce a calcium sulphite/sulphate sludge. The sludge has little or no commercial value in the United States and must be disposed of in a landfill operation. In Japan, some processes have been designed so that all the sulphite is oxidized to sulphate and commercial quality gypsum is produced.

4.1 Flue Gas Desulphurization using Limestone

Limestone processes were originally designed to allow limestone injection directly into the boilers. This provided sufficient time for it to either react with the sulphur dioxide or to be calcined to calcium oxide. The reacted limestone and the calcium oxide produced were subsequently collected in a wet scrubber where additional sulphur dioxide was removed from the flue gas stream and converted to calcium sulphite and calcium sulphate. This configuration resulted in significant buildups in some of the boilers (Meremac No. 2 and Hawthorne No. 4) (1, 17) and major modifications were required. In fact, the Meremac scrubber system was later abandoned and Hawthorne No. 4 was converted to limestone scrubbing without furnace injection. The limestone injection type of system is no longer offered (18).

The most common configuration for limestone scrubbing now includes a quench chamber for flue gas conditioning, a gas-liquid contact tower and a demister section. A flue gas reheat section may also be included. The limestone slurry contains 10 to 15 percent solids by weight and is recycled through the quencher and the scrubber at rates of 40 to 80 gallons per minute per 1000 cubic feet per minute of flue gas. Pulverized limestone is added according to slurry pH, and a slurry bleed stream is taken from the recycle tank in order to maintain tank level and the solids content of the slurry. The bleed stream passes to a thickener or to a settling pond and after sufficient time the solids settle to a concentration of 40 to 60 percent by weight solids.

Many limestone processes are designed to remove both flyash and sulphur dioxide, so the sludge is a mix of flyash, calcium sulphite, calcium sulphate, and calcium carbonate. The percentage of each is dependent on the ash and sulphur content of the coal and on the degree of sulphur dioxide removal. Little can be done with this sludge and it must be disposed of in a landfill.

In the Japanese processes that produce gypsum, the boilers usually burn low ash oil, or precollectors are used to remove the ash. The product of the scrubber must be oxidized and the calcium carbonate concentration controlled by effectively maintaining the proper ratio between the limestone added and the sulphur dioxide removed.

The combined history of the United States and Japanese limestone slurry scrubbing processes is shown in Figure IV-3. New construction and retrofit will increase the indicated limestone slurry capacity in the United States by a factor of three by 1979 (9). United States installations are all on coal-fired boilers while the majority of the Japanese installations are on oil-fired industrial or utility boilers. It can be seen that 1972 and 1974 were the first years of steady growth in limestone processes in the United States and Japan respectively.

In the limestone process, the limestone is pulverized and fed on demand to the scrubber recycle tank. The limestone is carried in the scrubbing liquid as a solid and requires time and slightly acidic conditions (pH 5.5 to 6.5) in order to dissolve. The dissolved limestone is then able to react with the sulphur dioxide that has been removed from the flue gas. The normally slow dissolution rate of limestone is the rate-controlling step and this can lead to operational problems, such as scaling and/or to limited sulphur dioxide removal efficiencies.

4.2 Flue Gas Desulphurization with Lime Slurry

Flue gas desulphurization using a lime slurry is very similar to limestone scrubbing in both equipment configuration and design. However, there are several major differences in operation and these are related to the reagent.

In the lime slurry process, lime is slaked outside the scrubber slurry system and is fed to the scrubber as a saturated calcium hydroxide slurry. In this way the rate-controlling step associated with dissolution is avoided and the ability to remove and neutralize the sulphur dioxide is controlled only by mass transfer and liquid phase chemistry. Lime scrubbers usually operate at pH 6 to 7.5.

The resultant sludge is again composed of flyash, calcium sulphite, calcium sulphate, lime, and calcium carbonate. However, the amount of carbonate is related to the amount of carbon dioxide scrubbed out of the flue gas and not to the amount of unreacted reagent. With good quality lime the free lime concentrations in the sludge should be less than one percent of the solids.

Developments by Dravo Lime Corp. (18) in 1973 and 1974 resulted in production of a Thiosorbic$^{(R)}$ lime for the FGD industry. This lime includes a small percentage of magnesium oxide that enhances the alkalinity of the scrubbing liquor by the build-up of magnesium sulphite and magnesium bisulphite. In this way, the possibility of rate-limiting liquid phase reactions was eliminated and the scrubber became a gas/liquid mass transfer limited operation.

FGD using the lime slurry reagent has grown steadily since 1972 in both Japan and the United States. The installed capacity for lime scrubbers is shown in Figure 4. Installed capacity in the United States by 1979 should double the indicated 1977 value. (9)

4.3 Flue Gas Desulphurization using Double Alkali

Double alkali FGD technology is being developed by several companies and was reviewed by Kaplan (20) in 1974. This system uses a highly soluble alkaline solution, usually sodium hydroxide, to scrub the sulphur dioxide from the flue gas and thus the process is only limited by gas/liquid mass transfer. The spent scrubbing fluid is then transferred to a regeneration section where the pH is raised by the addition of either lime, calcium hydroxide, or limestone. This causes calcium sulphate and calcium sulphite to form and precipitate. The solids are physically removed and the clear sodium hydroxide solution is returned to the scrubber recycle tank.

Several variations of the basic process have been developed by the various vendors but essentially all use a sodium-based alkali in the scrubber and a calcium-based alkali in the regeneration stage. The product is a calcium sulphite/sulphate sludge, containing flyash and 2 to 5 percent sodium hydroxide. The inability to completely wash the sodium hydroxide out of the sludge is a significant problem in the double alkali process.

A few processes use an ammonium-based alkali instead of a sodium-based one, but this may result in a visible ammonium salt plume. Another version is the Monsanto 'Calsox' process that uses an aqueous organic base instead of sodium hydroxide. Both are in the development stage.

Virtually all the installed and operating double alkali processes are in Japan. In fact only two small systems totalling 50 MW operate in the United States. Construction is scheduled to be completed in July 1978 on a 575 MW unit, at the end of 1978 on a 277 MW retrofit, and April 1979 on another new 250 MW unit. Installed capacity of double alkali processes in Japan is shown in Figure IV-5.

4.4 Problem Areas for Nonregenerative Processes

The application of FGD technology has presented the electrical utility industry and FGD system vendors with complex problems that were new not only to them, the buyers and the suppliers of this technology, but to all industries. Consequently, the problems had to be solved by inexperienced people through crash research and development programs. These programs were, in many cases, conducted on full scale installations and the consequence was the expenditure of great sums of money and expensive downtime for the utility boilers. Problems related to chemical scaling and sludge disposal were perhaps the most significant trouble areas.

4.4.1 Chemical Scaling

The chemical scaling problem occurred on the very first FGD installation at Union Electric's Meremac station in 1968 and 1969. Limestone injected into the boilers caused calcium sulphate to form and deposit on the tubes in the boiler. Eventually the tube banks were completely plugged and boiler shutdown was required.

Chemical scaling next occurred in the scrubber and to date this is still a problem with some scrubber systems. In the lime and limestone slurry systems, the slurry is a complex mixture of solids and ions in solution. Sulphur dioxide that has collected in the slurry becomes a sulphite ion; as the pH of the slurry changes the solution becomes more or less saturated with respect to the main reaction product, calcium sulphite, which accordingly may precipitate out or go back into solution.

Depending on the degree of oxidation, calcium sulphate may also be formed and again the solution may be more or less saturated for this product, depending on pH fluctuations.

With at least these two chemical equilibria to satisfy, the slurry is recirculated continuously through the scrubber and may be subject to wide fluctuations in sulphur dioxide composition, depending on boiler load and coal composition. A sudden low input of sulphur dioxide results in a high pH and more product precipitation. If this happens in the scrubber rather than the recycle tank, scaling will probably result. Lower pH's due to increases in sulphur dioxide concentration can also result in temporary increases in sulphate ion concentration and subsequent calcium sulphate scaling.

The problem of scaling in the scrubber is now more fully understood and operating conditions can be specified to minimize the problem. However, this has taken many years of experimentation, including the development of a computer model to study the chemistry of the lime and limestone scrubber systems.

The double alkali system also suffers from chemical scaling. The problem starts with the lime addition to the sodium bisulphite-rich slurry. Calcium sulphite precipitates and sodium hydroxide and sodium sulphite are recovered. However, oxidation causes sulphate to form and chemical scaling due to gypsum formation can occur in the reaction tank, the process lines, and the scrubber. Development work on this problem is still in progress.

Chemical scaling due to gypsum formation also occured in the mist eliminators and required considerable experimentation with equipment design and with methods of washing or flushing the mist eliminator. The problem develops as the fine mist from the scrubber is carried up and collected by the eliminator. If a droplet becomes saturated with gypsum as a result of evaporation, sulphite oxidation or additional sulphur dioxide collection, precipitation occurs and scaling may result.

Chemical scaling is the most serious cause of FGD system unreliability and is reflected in high maintenance costs and low system availability. One particular limestone scrubber system consists of seven scrubber modules and handles the total gas volume from an 820 MW low sulphur coal-fired boiler without bypass. The system costs $48.5 million and requires a staff of 50 operators and maintenance men. One module was shut down each night for cleaning to remove scale formations (9). This effectively limited the plant capacity to 700 MW. The eighth module is now being installed to give full load utilization at 820 MW. With the completion of a new settling pond this plant's cost will be about $58 million (9).

4.4.2 Sludge Disposal

The disposal of sludge from the nonregenerative processes presents problems with regard to material handling and confinement. This represents an expenditure to the electric utility of from $2 to $10 per wet ton of sludge produced.

A typical 500 MW coal-fired boiler consumes about 440,000 lb/hr of coal with a heat value of 11,000-13,000 Btu/lb and results in a flue gas volume of 1,300,000 ACFM at 270^0 F. For 3.5 percent sulphur in the coal, the concentration of sulphur dioxide in the flue gas is about 2800 ppm. If a FGD system is applied with 90 percent removal efficiency, then sludge will be produced at a rate of 1 wet ton per minute (40 percent of solids by weight). This is greater than the normal flyash production rate of about 0.4 ton per minute (10 percent ash, dry collection). Daily sludge disposal costs will approach $15,000 and a disposal volume of 35,000 cubic feet will be required.

The sludge produced is a mixture of calcium sulphite ($CaSO_3 \cdot 1/2\, H_2O$), calcium sulphate ($CaSO_4 \cdot 2H_2O$), calcium carbonate ($CaCO_3$) and flyash that is usually a thixotropic fluid. It is extremely difficult to settle to concentrations above 40 percent or thicken above 55 percent by weight solids. Water associated with the sludge is saturated with calcium, sulphite, and sulphate ions and reported pH's range from 4 to 10. Also, the sludge may contain several thousand ppm of chloride ion due to chloride in the coal. It may also contain leachable heavy metals (22).

These problems required development of sludge fixation technology. Several studies are currently under way in the United States to study disposal methods and migration of soluble components from the confined sludge. Companies that have developed fixation technology include Dravo Corp, IU Conversion Systems and Chemfix, Div. of Environmental Sciences Inc. (22). Most of the fixation techniques produce a high pH (greater than 10), load-bearing material with a permeability of 10^{-6} cm s^{-1} or less. IUCS has also manufactured synthetic aggregate from the sludge that has properties suitable for road-base material.

4.5 Application of Nonregenerative FGD Systems

Nonregenerative FGD technology now exists and can be applied to a wide variety of plant emissions containing sulphur dioxide. However, before their application, consideration must be given to the need, consequences, and costs.

The need for desulphurization systems is directly related to plant design and operating conditions, meteorological conditions, and health requirements of plants, animals, and humans.

The consequences of applying nonregenerative FGD systems include:

(a) Favorable reduction in the sulphur dioxide emissions;

(b) Unfavorable increase in disposal area requirements.

(c) Sludge produced would require the development of suitable sludge fixation technology that is to date unavailable for areas which may experience severe winter conditions, otherwise, the sludge would remain a thixotropic mixture in the unfrozen state;

(d) Contamination of groundwater is a potential problem due to the soluble salts and/or leachable heavy metals contained in the sludge;

(e) Unfavorable plume buoyancy may require consideration of methods of flue gas reheat;

(f) The water balance for the scrubber system will require detailed evaluation so that the overall water balance is not adversely affected;

(g) Total energy consumption significantly reduces the available power from the thermal plant.

5. REGENERATIVE PROCESSES

Regenerative FGD processes are designed to remove sulphur dioxide from the flue gas and produce a saleable form of sulphur such as elemental sulphur, sulphuric acid, or pure sulphur dioxide. Installed operating capacity in the United States to the end of 1975 was less than 300 MW indicating that there had been substantially less development than for the nonregenerative processes. Japan, on the other hand, had installed a substantial number of regenerative processes and leads the way in demonstrated technology. In excess of 660 MW were in operation by the end of 1976 (9). An additional 1500 MW may be in operation by the end of 1979.

5.1 Flue Gas Desulphurization Using Magnesia

The Mag-Ox process (1, 23) utilizes a recirculating aqueous slurry (pH 7.5 - 8.5) of magnesia and reacted magnesium-sulphur salts for the removal of sulphur dioxide from flue gas. Makeup magnesia is slaked and added to the process to compensate for the magnesia losses due to sulphate formation. A bleed stream of the recirculating slurry is dewatered and the resultant sludge cake is dried and calcined to release sulphur dioxide in a concentrated form. The sulphur dioxide is reduced to elemental sulphur or converted to sulphuric acid. The magnesia produced in the calcination stage is returned to the scrubber system.

A two-year demonstration of this process was completed at the Boston Edison Mystic Station in 1974 and the unit was shutdown (7). In the United States, a 95 MW capacity unit is currently in operation and a 120 MW unit is in the start up phase.

In Japan (1) three units are now in operation and serve the following processes:

(a) Sulphuric acid plant, 48,000 SCFM (equivalent to 25 MW) installed 1971;

(b) Copper smelter, 53,000 SCFM (equivalent to 28 MW) installed 1972;

(c) Claus plant and boiler, 300,000 SCFM (equivalent to 160 MW) installed 1974.

Except for the copper smelter application, none of the Japanese installations has to deal with particulate matter and large volumes of flue gas simultaneously.

5.2 Flue Gas Desulphurization Using Sodium

The regenerative FGD process using a sodium sulphite/bisulphite liquor and producing either sulphuric acid or liquid sulphur dioxide, developed by Wellman Lord, has been installed on several oil-fired boilers in Japan. However, the first operating unit was installed on a sulphuric acid plant tail gas stream in the United States (5, 8). Since that time at least 14 installations have been made in Japan (1). The oldest unit is the one installed in 1971 on Japan Synthetic Rubber's 70 MW boiler.

The first major installation for this process on a coal-fired boiler will be in the United States at Northern Indiana Public Service Co.'s Mitchell Station on the 115 MW No. 11 boiler. Davy Powergas Inc. will supply the Wellman Lord sulphur dioxide recovery system and produce an 85 percent sulphur dioxide gas stream that will go to an Allied Chemical sulphur dioxide reduction unit (24, 25, 26). The project is 50 percent funded by a United States EPA demonstration grant. It was scheduled for start up in 1976 but latest data still indicate that currently no units are operating; 375 MW of new construction and 455 MW of retrofit capacity should be on line by 1979 (9).

The Wellman Lord Process uses a sodium sulphite rich stream to contact the flue gas in a scrubber and sodium bisulphite forms as sulphur dioxide is collected. A bleed stream of the bisulphite-rich slurry is withdrawn from the absorber system and processed in a steam-heated evaporator. This regenerates the sulphite and produces a sulphur dioxide-rich stream.

At this point several options may be exercised with respect to final product form. The sulphur dioxide can be liquefied as final product or used to make sulphuric acid. A third alternative is to reduce the sulphur dioxide to elemental sulphur using a carbon-based fuel such as coke or methane.

The Wellman Lord process can be designed to treat flue gases that contain sulphur dioxide in concentrations up to three percent or so, and yield a final effluent containing .02 percent (200 ppm) or less. The major changes required to handle these high concentrations are associated with the capacity of the regeneration system. In 1971, the Wellman Lord process was installed at Toa Nenryo Ltd., Japan and handles the tail gas from two 150 LTD Claus plants (25).

5.3 Flue Gas Desulphurization Using Dilute Sulphuric Acid

The dilute acid approach to scrubbing flue gas has been developed by Chiyoda and referred to as the Chiyoda Thoroughbred 101 FGD process (27). It is usually applied after a high efficiency electrostatic precipitator and the process unit consists of a prescrubber and an absorber. An integral part of the absorber is the oxidation section where air is used to oxidize the collected sulphur dioxide to sulphur trioxide. Ferric sulphate is added to the absorber to catalyze the oxidation reaction.

The Chiyoda process produces a dilute sulphuric acid product that could by upgraded should market conditions warrant. However, essentially all of the systems include gypsum production facilities and use lime or limestone to produce good quality gypsum.

Since the first Chiyoda systems were installed in 1972 on oil-fired boilers in Japan (1) over 1100 MW of capacity have been installed and are operating. Its application in the United States at the Sholtz Power Station of Gulf Power, marks both its first installation on the continent and on a coal-fired boiler (28). This plant will handle 53,000 SCFM (equivalent of about 23 MW), and produce about 32 tons per day of gypsum.

Because dilute sulphuric acid has a limited capacity to absorb sulphur dioxide, exceptionally high liquid flow rates are required. Typical lime, limestone or sodium-based systems use liquid to gas ratios of 50 to 100 gallon per 1000 cubic feet, while the Chiyoda process uses a ratio in excess of 300. This results in high operating costs for absorbent recirculation.

The Chiyoda process has also been successfully applied to Claus plant tail gas (1,26); a final discharge containing less than 500 ppm can be achieved for tail gases containing not more than 15,000 ppm sulphur dioxide. As with the Wellman Lord process the major process changes required to handle concentrations of sulphur dioxide greater than 5000 ppm are associated with the absorbent regeneration capacity.

A major drawback to the Chiyoda process is that only the gypsum product route has been demonstrated and the market for additional gypsum in North America does not exist.

One of the applicants for an Alberta oil sands permit had intended to use the Chiyoda process to desulphurize the coke boiler flue gases.

5.4 Flue Gas Desulphurization Using Cat-Ox

The Monsanto Cat-Ox system was first installed on the 110 MW coal-fired Wood River No. 4 boiler of Illinois Power in 1972 (29). After operating for sometime it was shut down for modifications in 1974 and has only operated intermittently since then. It is currently shutdown and may not operate again (1,7).

In the Cat-Ox process the sulphur dioxide is catalytically oxidized to sulphur trioxide at 850°F, after which the sulphur trioxide is condensed by reducing the flue gas temperature. The acid mist is then filtered out using a Brink$^{(R)}$ mist eliminator. A high efficiency electrostatic precipitor must be used because the process catalyst is very sensitive to fly ash contamination.

Based on its poor Wood River performance the process has not attracted any interest. Accordingly, it cannot be considered to be proven technology.

5.5 Problem Areas for Regenerative Processes

Problems with regenerative processes are related to marketing of the product and to regeneration of absorbent.

5.5.1 Marketing of Product

A major factor favoring regenerative processes is the potentially marketable forms of the produced sulphur. Generally, however, in both Canada and the United States, a significant market does not exist for gypsum, sulphur, sulphur dioxide, or sulphuric acid over and above that currently supplied by conventional suppliers. There is a market potential on a local basis if the demand exists and the quality and price are competitive.

The early successful applications of regenerable processes in Japan was attributable to the high quality gypsum product. In 1975 the total gypsum production from FGD processes in Japan was less than 5000 tons per day (1) and this production was absorbed by the market. It is believed that in the future, fewer gypsum-producing systems will be installed due to market saturation.

In the northeastern United States, 280 million tons of coal were consumed in 1974 and the annual consumption is expected to increase by between 100 and 200 million tons by 1980 (15). By 1980 over 100,000 MW of capacity will need continuous FGD control (15). If gypsum-producing processes were used, about 150,000 TPD of gypsum would be produced. Current production of gypsum wallboard in the United States is about 100,000 TPD.

5.5.2 Absorbent Regeneration

In the magnesia and sodium scrubbing processes and the Cat-Ox system, sulphate formation is a major source of operating problems. In the Mag-Ox process this results in the formation of non-regenerable magnesium sulphate and thus costly magnesia makeup is required. Major efforts have been made to minimize oxidation of sulphur dioxide.

Similarly, oxidation of sulphur dioxide in the sodium sulphite/bisulphite process results in sodium sulphate formation. The sodium sulphate must be continuously purged from the system and again major efforts have been made to minimize the need for this purge.

In the Cat-Ox process sulphate formation and particulate collection in the catalyst bed cause blinding and reduced catalyst life. The catalyst requires frequent catalyst regeneration if both of these effects are not minimized.

5.6 Applicabilities of Regenerable Processes

The possible application of regenerable processes may be reviewed quickly by consideration of the inherent advantages and disadvantages of the system.

Advantages of regenerative FGD systems are:

a) favorable reductions in sulphur dioxide emissions;
b) favorable conversion of sulphur dioxide to a saleable sulphur form, thus conserving a resource; and

c) minimum storage problems with the sulphur product forms where suitable markets exist.

The disadvantages are:

a) no proven technology for large scale plants;
b) the significant increase in energy consumption for the system; and
c) uncertain economics.

6. ADVANCED PROCESSES

Several advanced FGD processes have been proposed or developed through pilot studies, but none has been demonstrated on full-scale coal-fired boilers. At least five years would be required to demonstrate that any of these processes may be classed as proven technology. Few of these processes are expected to contribute significantly to FGD capacity before the mid 1980's (15).

The more prominent of these processes are described briefly in the following sections.

6.1 Molten Carbonate Process

The molten carbonate process is being developed by Atomics International (30) and has been piloted on a 10 MW scale. It uses a eutectic mix of sodium, lithium, and potassium carbonates as an absorbent for the sulphur dioxide in the flue gas. Since the flue gas must be at 800°F hot precipitators are used to move the particulate matter. Spent molten carbonate liquor is regenerated by reducing the sulphite and sulphate, using hydrogen and carbon monoxide at 1100°F, to release hydrogen sulphide. The carbonates are regenerated by the reaction of molten salt with carbon dioxide at 800°F.

6.2 FW-BF Process

The Foster Wheeler/Bergbau Forschung process (31) is a dry absorption process that produces elemental sulphur. It is currently being piloted at the Gulf Power Co., 20 MW Sholtz Station (32). The prototype absorber section consists of vertical columns of parallel louver beds loaded with char that absorbs sulphur dioxide in the flue gas. Oxidation to sulphur trioxide and subsequent formation of sulphuric acid takes place in the pores of the char.

Char continuously moves through the absorber and it is transferred to the regeneration section. Hot sand at 1500°F is used to heat spent char up to 1200°F in an inert atmosphere for regeneration. This dissociates the sulphuric acid and leads to the reduction of the sulphur trioxide to sulphur dioxide. The resultant release of oxygen consumes some of the char to produce carbon dioxide.

The sulphur dioxide rich stream is then piped to the RESOX$^{(R)}$ section of the system where coal is used to reduce the sulphur dioxide to elemental sulphur. This operation is conducted at 1200 to 1500°F.

6.3 Formate Process

The "Consol" FGD process was developed by Conoco Coal Development Co. (10) and is a modified form of the potassium formate process described by Yavorsky et al. (33) in 1970. Pilot work on a 10 MW prototype has resulted in significant improvements in the process chemistry.

A venturi scrubber is used as the first process step to quench the flue gas for the removal of particulates and sulphur trioxide. The conditioned flue gas then flows to a packed tower scrubber where it is contacted with an aqueous solution of potassium hydrogen sulphide, potassium sulphide (K_2S_x), potassium bicarbonate, potassium carbonate and potassium formate. As sulphur dioxide is absorbed potassium bisulphite is produced and this is ultimately converted to potassium thiosulphate.

In the spent slurry regeneration system, a carbon monoxide-rich gas is introduced and hydrogen sulphide and carbon dioxide are formed. The off-gas from the regenerator is scrubbed with a polar organic solvent to selectively remove the hydrogen sulphide with the resultant hydrogen sulphide rich stream being directed to a Claus plant where elemental sulphur is produced.

(R) Registered trade name - Foster Wheeler.

The estimated cost for a plant on a 100 MW coal-fired power station burning 3.5 percent sulphur coal for start up in 1977 is $70 per kilowatt and the cost to operate is 4.1 mills per kilowatt hour (10). In 1970 the estimated capital cost based on bench scale studies was only $14 per kilowatt (33).

6.4 Copper Oxide Process

Shell (34) developed a FGD process that consisted of two reactors in swing operation for the removal of sulphur dioxide and regeneration of the acceptor. Copper oxide, as the acceptor, forms sulphate at 400°C with sulphur dioxide and oxygen in the flue gas. Sulphur dioxide is released during the regeneration cycle by means of a reducing gas. The liberated sulphur dioxide is converted to elemental sulphur in a Claus plant.

One Shell copper oxide system was installed in Japan in 1974 on a 37 MW oil-fired industrial boiler (1).

6.5 Citrate Process

The citrate process, developed by the US Bureau of Mines (35,36), was piloted at a lead smelter at Kellogg, Idaho in a 1000 SCFM size plant that yielded 1/3 LTD of sulphur. A second, 2000 SCFM pilot plant is in operation in Indiana and it handles flue gas from a coal-fired boiler containing 0.1 to 0.2 percent sulphur dioxide.

This process requires that the flue gas be quenched to free it of sulphur trioxide mist and particulates. Gas off the quencher is then contacted with a sodium citrate, citric acid, and sodium thiosulphate slurry to remove sulphur dioxide. The sulphur dioxide-rich slurry is regenerated by the addition of hydrogen sulphide and carbon dioxide in a sulphur precipitation reactor. Fine powderlike crystals of elemental sulphur are formed and these are separated from the solution in an oil-flotation cell. Once collected, the sulphur is melted and transferred to storage. Hydrogen sulphide for regeneration is produced by burning some of the collected sulphur with methane and steam.

The costs for a plant to treat flue gas from a 1000 MW coal-fired power plant was estimated at $36 per kilowatt and the operating costs were set at 1.98 mills per kilowatt hour (34) (no credit for sulphur product taken).

6.6 Application of Advanced Processes

All of the advanced processes are being developed because they show promise that the capital and operating costs are less than or equal to those of other processes and, in addition, they conserve a natural resource, sulphur, in a usable form.

However, all of the processes must go through additional development and demonstration stages to substantiate the claim that they are viable FGD processes.

In summary, the advantages of advanced FGD processes are:

a) favorable reduction of sulphur dioxide emissions;
b) favorable conservation of a natural resource by conversion of sulphur to a saleable form;
c) potential for economic advantage over regenerative and nonregenerative processes;
d) potential for selected processes to produce a form of sulphur in process units remote from the absorber and regenerator components of the process system; and
e) potential to avoid flue gas reheat with some processes.

The disadvantages are:

a) no proven technology exists on the scale required;
b) increase in energy consumption;
c) uncertainty of economics involved; and
d) lack of large scale operating experience.

7. ECONOMICS OF FLUE GAS DESULPHURIZATION

The cost of FGD systems has continued to climb since they were first introduced in 1968. This has, in part, been due to inflation, but it also arises from the necessary improvements in equipment design, construction materials and operational factors. In short, the FGD system is becoming a sophisticated chemical process that is subject to many conditions that can upset routine operation.

FGD systems were initially installed with projected cost of $8/kw of installed capacity and an expected operating cost of 0.4 mills/kwh (8, 37). By 1974 this had increased to the $50 - $70/kw range and the operating costs were up to 3-3.5 mills/kwh (15, 38, 39). The capital costs for 1975 designs for 1977 startup were estimated $60-$120/kw.

Based on 43 FGD systems, capital cost including sludge disposal, ranged from \$50/kw to \$205/kw, with a mean value of \$91/kw, all costs adjusted to a January 1975 base. For lime/limestone systems the range was \$50/kw to \$88/kw with a mean value of \$70/kw. Annual operating costs for sludge disposal alone ranged from an estimated \$5 to \$15/ton, or about 0.4 to 1 mill/kwh (9). This capital cost history is shown in Figure IV-6.

Available operating cost data is less precise because of the sensitivity of operating costs to the amount of sulphur to be removed. Reported values range from 1.0 mills/kwh to more than 3.81 mills/kwh for nonregenerative processes (9).

In other words, in 10 years or less both the capital and operating costs have increased by an order of magnitude. In the same period the cost of the basic power plant has only increased two to three-fold.

The cost of applying nonregenerative systems to emissions other than those of electric utility boilers can be estimated by considering the gas volume to be handled and the sulphur dioxide concentration. A 100 MW power plant discharges about 250,000 ACFM at 270°F and typically the sulphur dioxide concentration will be 500 to 5000 ppm depending on the sulphur content. High sulphur dioxide concentration emissions are more difficult to deal with than the low to medium concentrations. Above 5000 ppm other methods of sulphur dioxide control would be preferred.

Capital costs for all FGD processes are still uncertain but some levelling out should be expected for the nonregenerative systems after 1977. Stabilization of capital costs for nonregenerative systems should result from the clearer definitions of the design requirements, improved equipment specification and operating experience.

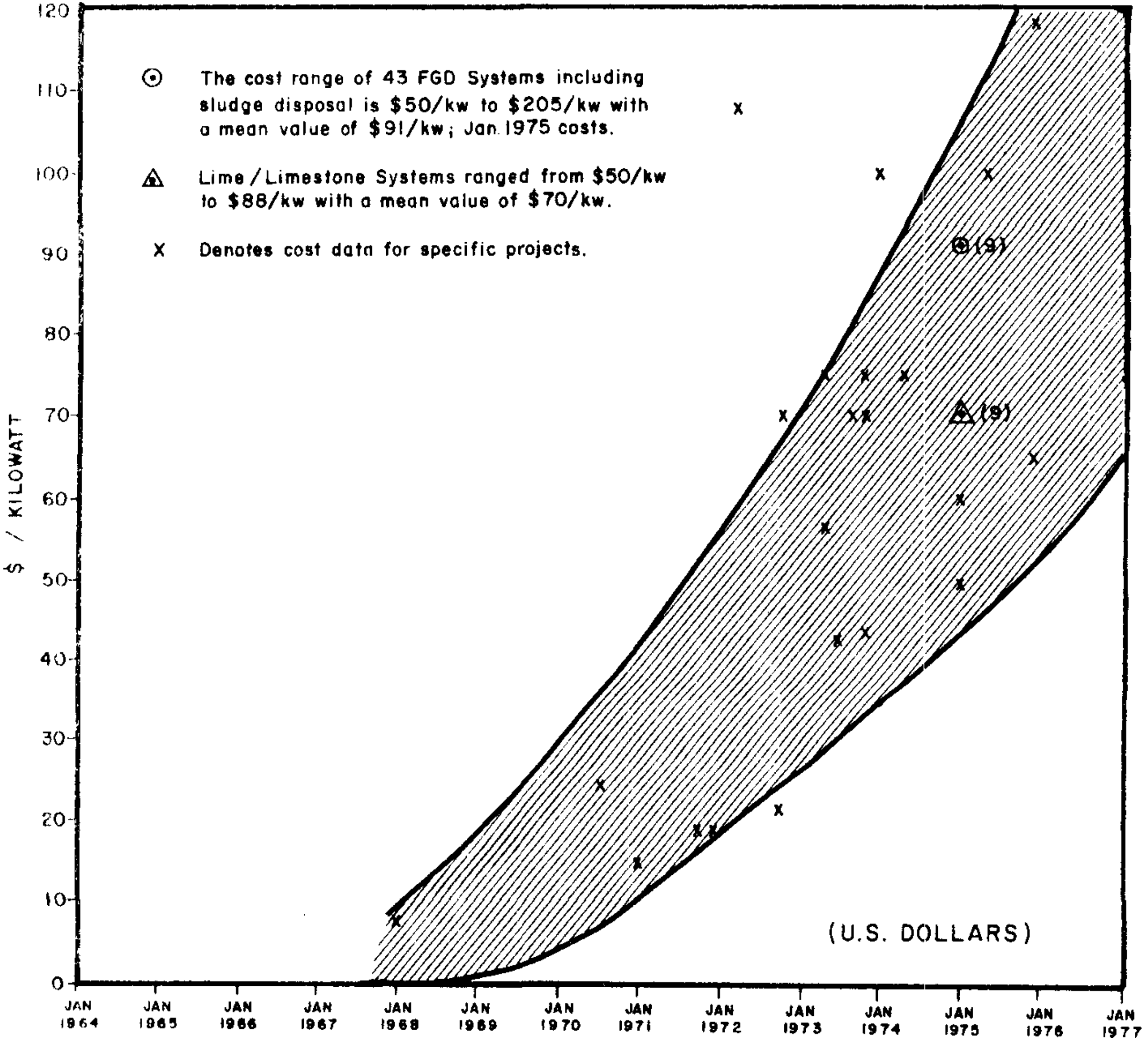
Figure IV-6

CAPITAL COST

vs

KILOWATT

SOURCES 1, 4, 5, 6, 7, 9, 13, 15, 16



8. SUMMARY

Nonregenerative FGD processes are technically applicable to a wide range of sulphur dioxide emissions. For certain flue gas conditions, in some cases low sulphur dioxide concentrations and in others particulate free gas, practicable technology has been available since 1975.

Several large scale nonregenerative systems are currently in operation in USA and Japan and are comparable in scale to thermal power installations that may be required in the future.

Capital and operating costs for nonregenerative systems are available and these could be projected for a wide range of emission applications.

Nonregenerative processes will increase any existing solid waste disposal problems.

A potential for groundwater contamination may exist.

Any adverse water supply problems will be seriously aggravated by their application.

Nonregnerative processes may require reheat of exhaust gases to ensure plume buoyancy and to minimize low level fog formation.

Significant increases in energy consumption are associated with their application.

Regenerative FGD processes are technically applicable to a wide range of sulphur dioxide emissions, but practicable technology was not available as of early 1976.

Application of regenerative processes will require the installation of electrostatic precipitators or fabric filters to remove particulates;

A few regenerative processes comparable in size to those required on thermal power plant emissions are in operation in USA or Japan but are still not classed as proven technology.

Regenerative processes will require additional consumption of fuels to produce elemental sulphur;

Regenerative process products will require storage areas and new market development programs.

Capital and operating costs for regenerative processes cannot be defined with the same degree of confidence as can those for nonregenerative processes.

Regenerative processes may require reheat of exhaust gases to ensure plume buoyancy and to minimize low level fog formation.

Advanced FGD processes are technically applicable to a wide range of sulphur dioxide emissions but practicable technology has not been demonstrated. Most processes are still in the design or development stages.

Although the economics are not established for advanced processes, they do show promise for reduced capital cost.

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