BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

HAT CREEK PROJECT

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BENEFIT-COST ANALYSIS: AIR QUALITY CONTROL SYSTEMS

FINAL DRAFT REPORT

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Environmental Consultants

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BENEFIT-COST ANALYSIS
AIR QUALITY CONTROL SYSTEMS

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SECTION 1.0 - SUMMARY

1.1 PURPOSE OF STUDY

The purpose of this study is to evaluate alternative air quality control systems for the Hat Creek powerplant on the basis of their comparative benefits and costs. The air quality control systems evaluated are intended to reduce sulphur dioxide and particulate emissions which would ensure acceptable air quality conditions if the Hat Creek Project were built. There are no devices specifically designed to control trace elements, but sulphur dioxide and particulate control methods have varying effects on trace elements and consequently are discussed within relevant sections of the report. Emission of NO_x (Oxides of Nitrogen) will be controlled by appropriate design and operation of the boilers and auxiliaries and, thus, this contaminant is not discussed in the report.

The benefit-cost evaluation provides a mechanism for the selection of those control systems offering the greatest achievable environmental benefits consistent with an efficient use of energy and capital. Specific criteria used in the benefit-cost evaluation of the feasible alternative strategies include engineering efficiencies, auxiliary power requirements, environmental considerations and economics. Also to be kept in mind are the constraints imposed by the unique characteristics of the Hat Creek coal deposit.

This study includes a review of the costs and benefits of pollution control equipment designed to meet:

a) the levels assumed for the preliminary design of the powerplant; and

b) the levels issued by the Pollution Control Board in its Objectives for Mining, Smelting and Related Industries of British Columbia in 1979.

1.2 SULPHUR DIOXIDE CONTROL

Coal beneficiation, meteorological control (MCS), and flue gas desulphurization (FGD) alternatives have been compared. Coal beneficiation provides benefits in the form of powerplant capital and operating cost savings; FGD and MCS do not provide powerplant benefits. All three SO_2 control methods offer environmental benefits through reduced emissions thereby lessening the potential for ground level concentrations to exceed acceptable levels.

Table 1-1 summarizes the benefits and costs in quantitative and qualitative terms for the various SO_2 control configurations. Meteorological control with a 244m chimney would be the most cost effective method. Coal washing is estimated to be over twice as expensive as meteorological control but still considerably cheaper than any flue gas desulphurization system. The FGD system is the most expensive SO_2 control option. The net environmental benefits associated with resource value savings are not sufficiently large to support the installation of any control system for SO_2 on benefit-cost grounds. However, to avoid exceeding ground level concentrations considered necessary to protect the environment some control measure is necessary for the powerplant. Meteorological control is the best method to control SO_2 from an overall benefit-cost viewpoint.

For the "base scheme" powerplant, a single chimney with four separate flues has been proposed in order to enhance the thermal lift of the plume. The comparative economics of the tall chimneys of 244m and 366m in height are in favour of the 244m stack. The 366m/MCS alternative would cost an additional \$10.5 million. However, a 244m/MCS system would be associated with more predicted generation losses than a 366m/MCS system. If it is assumed that all predicted generation losses would have to be replaced by

TABLE 1-1

COMPARATIVE BENEFITS AND COSTS
BASE SCHEME AOCS ALTERNATIVES

CONTAMINANT	ALTERNATIVE	POWERPLANT BENEFITS-COSTS (B-C) (Millions of 1979 $)	ENVIRONMENTAL BENEFITS AND COSTS
Sulphur Dioxide	Partial Coal Washing	-76	• unmeasured resource injury and damage reduction • reduction of potentially harmful trace elements • Btu losses • effect on ESP performance • environmental effects of tailings or effluents
	Full Coal Washing	-191	
	244m/MCS	-22	• low or insignificant impact on air quality/meteorology, epidemiology, wildlife, water resources, and beef industry
	366m/MCS	-33	• synergistic effect of SO_2 and NO_2 on irrigated land for alfalfa production - 16 ha for 244m/MCS and - 13 ha for 366m/MCS • predicted forestry damages of $12,557/a and $11,655/a for 244m/MCS and 366m/MCS respectively with probable fluoride emissions level • measurable potential injury to certain natural vegetation species • predicted forestry damages of $2,800/a and $1,898/a due to SO_2 for 244/mMCS and 366m/MCS respectively
	366m/FGD	-300	• low or insignificant impact on air quality/meteorology, epidemiology, wildlife, water resources, agriculture and natural vegetation • predicted forestry damages of $99/a due to SO_2 • predicted forestry damages of $9,856/a with probable fluoride emission level • reduction of potentially harmful trace elements
Particulates	Hot-side ESP	-104	• satisfies assumed PCB objectives • insignificant or low environmental impact of 24 hr. and annual ground level concentrations
	Cold-side ESP	-92	• expected to provide sufficient mitigation from the effects of trace elements • cold-side ESP is preferable to hot-side ESP based on energy, technical, and performance factors for a Hat Creek application

TABLE 1-1
(continued)

CONTAMINANT	ALTERNATIVE	POWERPLANT BENEFITS-COSTS(B-C) (Millions of 1979 $)	ENVIRONMENTAL BENEFITS AND COSTS
	Fabric Filter	-93	• can achieve generally higher particulate collection efficiencies than ESP • potential to collect more trace elements than ESP • could achieve assumed PCB objectives • insignificant or low environmental impact from 24 hr. and annual concentrations would be expected

Source: Ebasco Services of Canada Ltd. Environmental Consultants, 1979.

alternative energy sources such as hydro reserves, thermal plants, or imported power, the 244m/MCS alternative is still estimated to be at least $3.9 million cheaper than the 366m/MCS alternative. The cost differential in favour of the 244m chimney should be further reduced by the value of additional environmental resource losses associated with the 244m chimney over the 366m chimney. However, forestry losses are the only major environmental resources that could be measured in dollar terms. The additional forestry damages of the 244m/MCS option over the 366m/MCS option are estimated to be slightly less than $1000/a in constant 1979 dollars over the 30-year operating life of the powerplant. It is evident, therefore, that the 244m chimney is preferable to the 366m chimney in terms of minimizing total capital, energy and environmental costs.

1.3 PARTICULATE CONTROL

Electrostatic precipitators (ESP) and fabric filters (FF) or baghouses were compared as alternative control systems. Table 1-1 summarizes the benefits and costs for these alternatives. The net powerplant benefits and costs are negative for ESPs and the FF with the cold-side ESP having a slight advantage over the FF. From an environmental perspective, all systems could achieve 0.1 grains/SCF. The resultant TSP ground level concentrations were assessed by ERT to have low or insignificant environmental impacts. Although ERT did not evaluate the impact from TSP emissions from a fabric filter, it would be reasonable to conclude from the literature that a fabric filter in operation could achieve at least the environmental benefits obtained with an ESP. Fabric filters are not proposed for Hat Creek for technical reasons. The technology is still being developed and has not been demonstrated on many large generating stations using coals with characteristics similar to Hat Creek coal.

Trace elements are not expected to cause adverse health risks or impacts on the local or regional biological communities, and, therefore the

SECTION 2.0 - INTRODUCTION

The terms of reference for this study require that alternative Air Quality Control Systems (AQCS) for the Hat Creek project be evaluated through a benefit-cost analysis. This study evaluates various air quality control devices for sulphur dioxide and particulates. Trace element considerations are discussed as part of the particulate control system evaluation section. The major sulphur dioxide control alternatives include several combinations of chimney height, flue gas desulphurization and meteorological control. Electrostatic precipitators and fabric filters (baghouses) are the primary alternative systems evaluated to control particulate emissions. Oxides of Nitrogen (NO_x) control will be by appropriate design and operation of the boilers and auxiliary equipment. Benefit/Cost Analysis of NO_x control alternatives is therefore not included.

The evaluations of the various AQCS systems took into consideration the 1975 "Pollution Control Objectives for Food-Processing, Agriculturally Oriented, and Other Miscellaneous Industries of British Columbia"[1], the 1973 "Pollution Control Objectives for the Mining, Mine-Milling and Smelting Industries of British Columbia"[2], and the suggested guidelines for coal-fired powerplants presented by B.C. Hydro and Power Authority in a 1978 brief submitted to the Pollution Control Branch[3]. The 1979 "Pollution Control Objectives for the Mining, Smelting and Related Industries of British Columbia"[4] included, for the first time, objectives specifically for coal-fired powerplants. They were issued after the "base scheme" proposed for the Hat Creek project had been finalized. These pollution control objectives reflect two philosophies or approaches to protect the environment from airborne contaminants: (1) emission control of all contaminants at the source and (2) ambient air quality control. Because emissions are not the only determining variable of ambient air quality, it could be argued that emission levels should be set on a project or site specific basis. In rural areas with unpopulated elevated terrain, some variance from the ambient air quality guidelines would seem reasonable if impacts are judged to be consistent with protection of public health and the environment.

In the 1978 brief, B.C. Hydro recommended an ambient air quality approach as opposed to emission control at the source for satisfactory protection of the environment. B.C. Hydro also suggested that an one-hour averaging period for ambient sulphur dioxide levels was not practicable for coal-fired powerplants but a three-hour averaging period with a maximum average concentration of 655 $\mu g/m^3$ (0.25ppm) was appropriate and practicable. 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 of 24 hours and greater have been developed. Also, B.C. Hydro considered that the 1973 Pollution Control Objectives for gaseous and particulate emissions (Appendix I, Table II) are suitable for coal-fired powerplants but that an exclusion to the 80% sulphur removal criterion be given for coal-fired powerplants provided the proposed ambient air quality levels are met.

Since the submission of B.C. Hydro's brief to the Pollution Control Branch, new objectives for coal-fired powerplants in British Columbia were adopted by the Pollution Control Board. Compliance with the 1979 "Pollution Control Objectives for Mining, Smelting and Related Industries of British Columbia" is examined in Appendix A. The introductory section of these recent Pollution Control Objectives states that:

> The aim of these Objectives is to protect the quality of British Columbia's environment for the benefit of present and future citizens of this Province and Canada. The Objectives provide, firstly, for use of the environment's assimilative capacity within limits which do not lead to unacceptable conditions, and, secondly, for adopting realistic cost-benefit pollution control strategies.[4]

The aim of the 1979 Objectives appears to be consistent with the intent of the ambient air quality approach to setting objectives presented in B.C. Hydro's brief. Table 2-1 provides a comparison of the various ambient air quality guidelines discussed in this section.

This study is an application of benefit-cost analysis to evaluate air quality control systems as well as to measure the net benefits or costs of achieving stricter levels of air quality control for the Hat Creek project. Engineering judgement including constraints imposed by the unique properties of Hat Creek coal were also considerations in evaluating alternatives.

TABLE 2 -1

COMPARISON OF PROVINCIAL AMBIENT AIR QUALITY GUIDELINES
FOR SULPHUR DIOXIDE AND TOTAL SUSPENDED PARTICULATES

Contaminant	Averaging Period	Food Processing, Agricultrually Orientated & Misc. Industries of British Columbia[a] (µg/m³)	Mining, Mine-Milling, Smelting & Assoc. Industries[b] (µg/m³)	PCB Brief[c] (µg/m³)	Mining, Smelting and Related Industries[d] Range (µg/m³)
Sulphur Dioxide	1 hour	450	799	-	450-900
	3 hours	-	-	655	375-665
	24 hours	160	266	266	160-260
	1 year	25	53	53	25- 50
Total Suspended Particulates	24 hours	150	150	150	150-200
	1 year[e]	60	60	60	60- 70

Sources:

a - Level A Guidelines From Table 3 of "Pollution Control Objectives for Food Processing, Agriculturally Oriented, and Other Miscellaneous Industries of British Columbia", 1975.

b - Level A Values From Appendix I of "Pollution Control Objectives for The Mining, Mine-Milling, and Smelting Industries of British Columbia", 1973.

c - Brief submitted by B.C. Hydro to the Pollution Control Branch Public to Review "Pollution Control Objectives for the Mining, Mine-Milling, and Smelting Industries of British Columbia", January, 1978.

d - "Pollution Control Objectives for the Mining, Smelting and Related Industries of British Columbia, 1979.

e - Annual Geometric Mean.

SECTION 3.0 - BENEFIT-COST METHODOLOGY AND EVALUATION CRITERIA

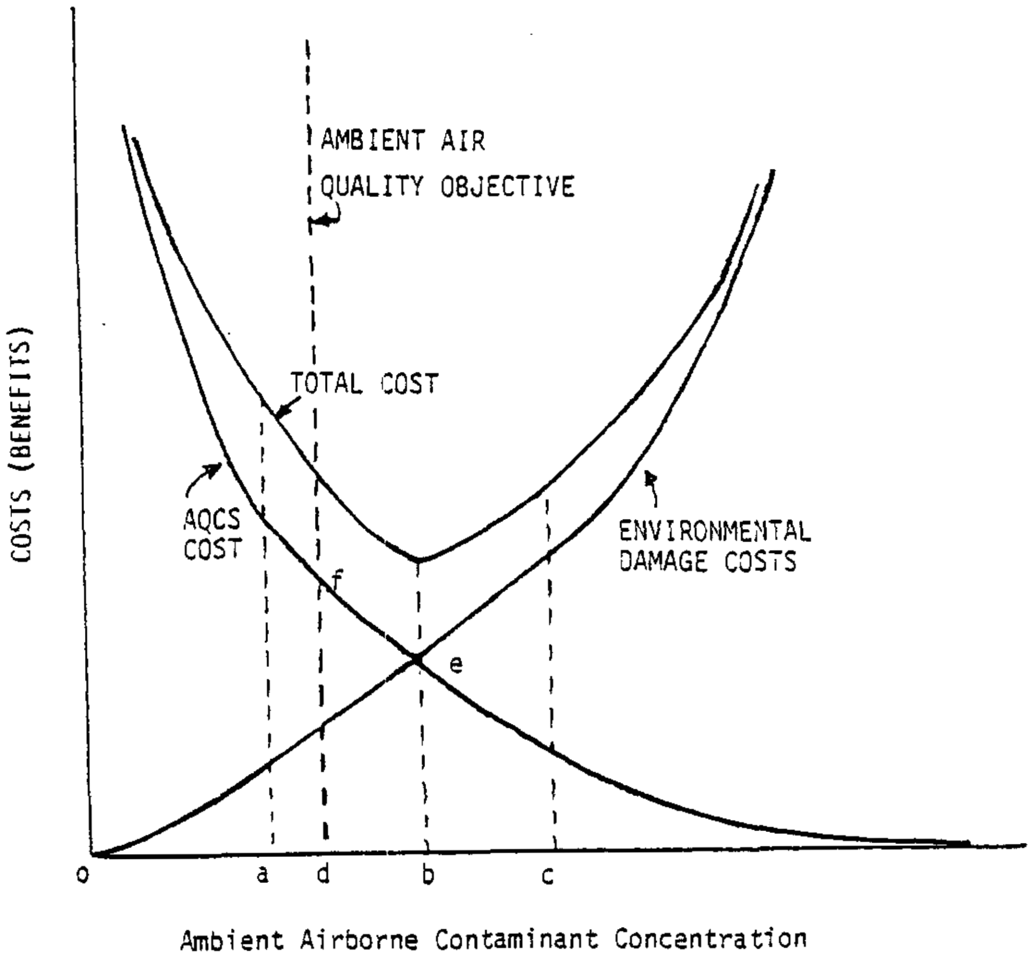
Benefit-cost methodology requires that all present and future social costs and benefits associated with a proposed action or set of alternative actions be compared and appropriately discounted. The methodology is applied in this study to assess the most appropriate air quality control technologies consistent with protection of the environment. The benefit-cost evaluation has to be combined with other considerations such as engineering, financial and public acceptability before a final selection is made.

Any AQCS alternative must be capable of achieving acceptable ambient air quality levels. The energy requirements and economic impacts of air quality control systems are determined and compared to identify the environmental, energy and economic tradeoffs associated with the various pollution control systems. The benefit-cost evaluation provides a mechanism for the assessment of those systems offering the greatest achievable environmental benefits consistent with an efficient use of energy and capital. Specific criteria integrated into the benefit-cost evaluation of the feasible alternative strategies include engineering efficiencies, auxiliary power requirements, environmental considerations and economics. In addition to looking at systems for achieving acceptable ambient air quality, the economic impacts of attaining the more stringent 1979 PCB emission objectives are also evaluated.

The conceptual framework underlying this benefit-cost study is illustrated in figure 3-1. The ambient air contaminant concentration is measured along the horizontal axis and the associated cost (benefits) along the vertical axis,

FIGURE 3-1

AIR QUALITY CONTROL
AND COST-BENEFIT
RELATIONSHIPS



Source: Ebasco Services of Canada Ltd. Environmental Consultants, 1979.

without the specific units of measurement being identified. In general, the environmental resource values lost or damage costs would tend to be positively related to the ambient pollutant concentration as denoted in figure 3-1.

On the other hand, the cost of removing or reducing the airborne contaminant in the ambient air would tend to be inversely related to the ambient pollutant concentration. The air pollution problem can be viewed as economic in nature because increased air quality control costs must be weighed against the benefits of increased resource values saved and vice versa. On the assumption that all social costs (benefits) have been appropriately accounted for, the total cost to society of maintaining a given level of ambient pollutant concentration would be the sum of the control costs and damage costs at that level. The optimum level of ambient contaminant concentration would be at "b" as denoted in figure 3-1 where total costs are minimized. If the ambient level of the contaminant was at "a", the control costs would exceed the damage costs denoting an inefficient allocation of society's scarce resources. As the ambient level increased from "a" to "b", the benefits of reduced control costs exceed the costs of increased environmental damage. Analogously, if the ambient level was at "c", there would be an inefficient allocation of resources with damage costs exceeding control costs at that level. In this case, reducing the ambient level from "c" to "b" would denote at the margin that the benefits of resource values saved would exceed the costs of increased control. Therefore, only at "e" where control costs equal damage costs would total social costs be minimized and the optimum pollution control expenditure be attained.

The potential effect of pollution control objectives on air quality control costs is also illustrated in figure 3-1. If for a given project, in particular a rural development, the real control and damage cost relationships are accurately represented by the curves in figure 3-1 the appropriate air quality control expenditure would be measured by the line segment $\overline{be}$. An assumed ambient air quality objective for the province is shown on figure 3-1. If the objective must be achieved irrespective of the costs-benefits of this specific project, control costs measured by the distance $\overline{df}$ might be required and an inefficient allocation of resources would result. In this simple example the effect of meeting the assumed ambient objective has resulted in control expenditures greater than the optimal amount.

SECTION 4.0 - BENEFIT-COST EVALUATION OF ALTERNATIVE AIR QUALITY CONTROL SYSTEMS

The benefit-cost evaluations for the sulphur dioxide and particulate control systems for the "base scheme" powerplant are presented in sections 4.1 and 4.2, respectively. In each section, the systems to be evaluated are described briefly and then the benefits and costs are presented for each system in relation to the applicable air quality objectives. The comparison of the benefits and costs of various technologies provides an economic basis for the selection of the preferred air quality control system as well as to measure the net benefits or costs of various air quality objectives.

There are two specific evaluations of importance that are made in conjunction with the primary evaluations outlined above: (1) determination of the appropriate stack height; and (2) the control of trace elements. The stack or chimney height evaluation is presented in sub-section 4.1 (b) (ii), and trace element concerns are covered in sub-section 4.2 (d).

4.1 - SULPHUR DIOXIDE CONTROL SYSTEMS

Sulphur dioxide emissions can be controlled by removal of sulphur from the coal prior to combustion (coal beneficiation), conversion of sulphur dioxide in the boiler, meteorological control systems (MCS), or by removal of sulphur dioxide from the flue gases (FGD). Coal beneficiation is evaluated in sub-section 4.1 (a); meteorological control, an intermittent control measure, in 4.1 (b); and flue gas desulphurization, a technology to remove SO_2 from the flue gases is assessed in sub-section 4.1 (c). Fluidized bed combustion and other coal conversion technologies not considered suitable for a Hat Creek application are presented in Appendix B. *The financial criteria used for economic evaluations are listed in* Appendix C.

(a) Coal Beneficiation

The fundamental purpose of beneficiation would be to improve the quality of coal. This can be achieved by means of a number of alternative methods which would variously reduce the ash content, minimize the moisture percentage, and decrease the sulphur content.

(i) Benefits of Coal Beneficiation

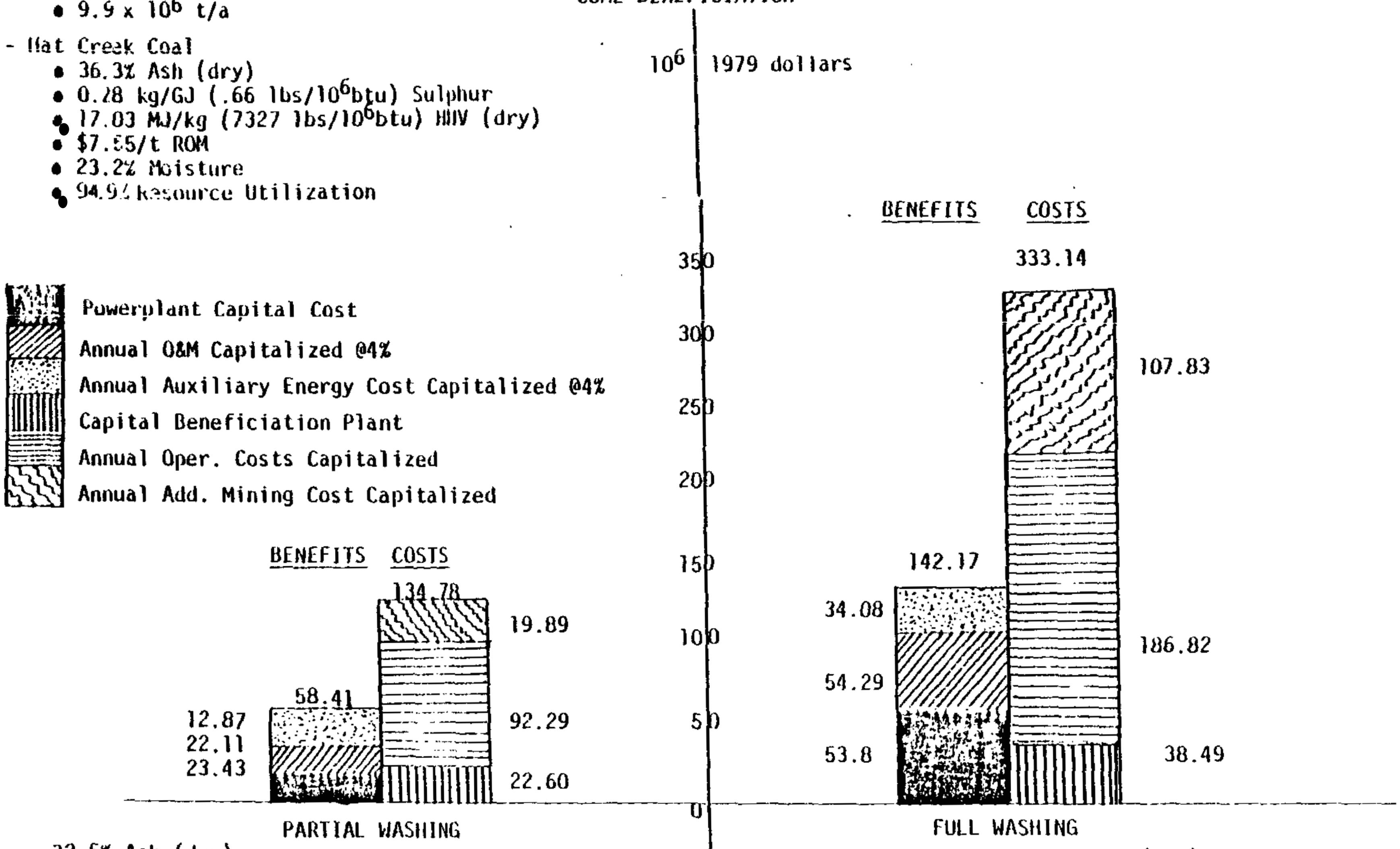
The benefits of coal beneficiation are the capital and operating cost savings to the powerplant and the reduction in emission of some contaminants. The removal of some trace elements, e.g. fluorine concentrated in clay matter might also result in environmental benefits.[5] Beneficiation would reduce the total capital and operating costs of the powerplant by increasing powerplant efficiency; lessening ash handling and disposal problems; decreasing the size of required boilers and coal handling facilities; and easing operation and maintenance problems. The estimated monetary values of these potential powerplant savings are illustrated in figure 4-1. Powerplant costs would be reduced by $58.41 million if the coal was upgraded from 17.03 MJ/kg to 18.03 MJ/kg and $142.17 million if the coal was upgraded to 21.02 MJ/kg. These values are based on 1977 dollar estimates escalated by 9% and then 8% to arrive at 1979 dollar amounts. The calculations assumed a 35 year life for the 2000 MW powerplant. "Availability" differences with varying coal quality have been allowed for in the evaluation by appropriate values of capital and operating costs. Also, because the Hat Creek project is a mine-mouth development, "transport" benefits are not relevant. The benefits to be obtained from the effect of coal washing on particulate control cost savings have been taken into account in the computation of powerplant benefits.

The major environmental benefits that should be obtained from beneficiation would be the savings in environmental resource values that might result from the reduction of fly ash and sulphur dioxide emissions. It is denoted on figure 4-1 that washing would reduce the ash content from 36.3 percent for blended raw coal to 32.5 and 24.5 percent for partial and full washing respectively. Therefore, a given level of particulate emission can be attained with washed coal and a lower efficiency electrostatic precipitator than with raw blended coal. Also, beneficiation has the potential of reducing the sulphur content

FIGURE 4-1

BENEFIT-COSTS OF COAL BENEFICIATION

- 2000 MW Powerplant
  - 65% Capacity Factor
  - 10,215 kJ/kWh
  - 9.9 x 10^6 t/a
- Hat Creek Coal
  - 36.3% Ash (dry)
  - 0.28 kg/GJ (.66 lbs/10^6btu) Sulphur
  - 17.03 MJ/kg (7327 lbs/10^6btu) HHV (dry)
  - $7.55/t ROM
  - 23.2% Moisture
  - 94.9% Resource Utilization



Partial washing:
- 32.5% Ash (dry)
- 0.26 kg/GJ (.61 lbs/10^6Btu) Sulphur
- 18.3 MJ/kg (7882 lb/10^6Btu) HHV (dry)
- 23.5% Moisture
- 92.68% Resource Utilization

Full washing:
- 24.5% Ash (dry)
- 0.22 kg/GJ (.50 lbs/10^6Btu) Sulphur
- 21.02 MJ/kg (9043 lbs/10^6Btu) HHV(dry
- 24.1% Moisture
- 86.6% Resource Utilization

SOURCE: INTEG-EBASCO: COMINCO-MONENCO JOINT VENTURE, MINING FEASIBILITY REPORT, 1978 by 3 to 20 percent as denoted in figure 4-1. The sulphur dioxide emission rates corresponding to the partially and fully washed coals would be about 1.2 lb /10^6 Btu and 1 lb/10^6 Btu respectively compared to the raw coal SO^2 emission of about 1.3 lb/10^6 Btu (assuming all sulphur in the coal goes to SO_2).[6]

A recent Canmet study[7] concluded, on the basis of washing a bulk sample of about 82 tons, that Hat Creek coal containing 6500-6600 Btu/lb and 41-42% ash, dry basis, could be upgraded to at least 8125 Btu/lb with a Btu recovery of at least 90%. The upgraded Btu content of the coal was associated with improved coal quality and a significant reduction in variability of all constituents. Also, an average reduction of 25% in sulphur content with this test sample was achieved, from 1.67 to 1.26 lb/10^6 Btu.

(ii) Costs of Coal Beneficiation

The capital and operating costs of the beneficiation plant for partial and full washing are denoted in figure 4-1. The total capitalized costs of upgrading the coal to 18.30 MJ/kg would be about $135 million and $333 million to upgrade the coal to 21.02 MJ/kg.

The beneficiation process would produce tailings or effluents which might cause environmental damage if they are not handled, treated or disposed of in an appropriate manner. Because coal washing would result in Btu losses as a consequence of reduced coal resource utilization, greater quantities of coal would be required to offset process losses. As noted in figure 4-1, resource utilization decreases from 94.9% for the blended raw coal to 92.68% and 86.6% for the partial and fully washed coal respectively.

Although beneficiation to reduce sulphur content in the coal has potential environmental benefits associated with it, some problems in operation , e.g.: a) the concentration of sodium which can cause fouling is increased; and b) the performance of the proposed electrostatic precipitators could be adversely affected by sulphur reduction in the coal.[8]

(iii) Conclusions

The benefit-cost elements that have been measured in dollar amounts are illustrated in figure 4-1. The benefit-cost criteria are listed below:

		Coal Beneficiation	
Benefit-Cost Criterion		Partial	Total
Benefits/Costs	(B/C)	0.43	0.43
Net Benefits	(B-C)	-\$76.39x10^6	-\$190.97x10^6

The environmental benefits of coal beneficiation have not been quantified. Nevertheless, the net benefits would have to be worth at least \$76.39 million on a capitalized basis to justify partial washing and commensurately greater in worth to justify total washing. Thus, even if coal washing appeared technically feasible to reduce SO_2 emissions, it would not be a cost-effective method and therefore cannot be recommended for incorporation into the "base scheme" for the Hat Creek project.

(b) Meteorological Control Systems

(i) Introduction

Under normal climatic conditions, the base scheme proposed is expected to provide acceptable ambient SO_2 levels. A meteorological control system (MCS) is a systematic plan of procedures for reducing contaminant emission to the atmosphere in response to predicted or observed adverse meteorological conditions that are conducive to high ground-level ambient concentrations. MCS is not intended to provide protection from long-range transport effects. Load reduction and fuel switching during episodes of adverse meteorological conditions have been selected for evaluation.

Closely related to the assessment of an MCS system would be the determination of stack or chimney height. In the "base scheme" for the powerplant, a single chimney with four separate flues is proposed in order to enhance the thermal life of the plume. The costs and benefits of a 244m (800 ft.) versus a 366m (1200 ft.) chimney is undertaken in sub-section 4-1 (b) (ii).

There are two operational possibilities for reacting to unfavourable dispersion conditions: The first involves fuel switching from the primary coal to a secondary fuel with lower sulphur content which could be stockpiled for use during periods of adverse dispersion potential. Fuel switching would probably be the preferred action, in the winter months (November through February). During the other months of the year, load reduction of generating units would probably be the preferred control method.[9] Table 4-1 provides the MCS parameters utilized by Environmental Research and Technology, Inc. (ERT) and "new-performance" coal[10] characteristics determined in 1979. The heating value has worsened to 5,955 Btu/lb and the mean S% has fallen from 0.45% to 0.39%. It is estimated that the daily emission, assuming all S goes to SO_2, would be less than ERT's value by about 9% under normal conditions. Also, ERT assumed the ambient SO_2 guidelines proposed in the then current 1978 B.C. Hydro brief.

(ii) Cost of Meteorological Control

Table 4-2 provides cost data developed by Integ-Ebasco[11] for the various chimney, meteorological and flue gas desulphurization systems. The amounts are stated in 1979 dollars and are based on the financial criteria found in Appendix C. Table 4-2 shows that the 244m/MCS configuration would have a total capitalized cost of almost $22 million, and the 366m/MCS configuration would have a comparative cost of about $32.5 million. These figures would suggest that the 244m/MCS configuration would be preferred. When MCS operation is included, the evaluation must include the costs associated with reduced powerplant output operation due to MCS constraints. The following analysis attempts to estimate the cost of generation losses as a result of fuel switching and load shedding for the two chimney heights.

<u>Estimation of Annual Generation Losses Due to MCS</u>

The Hat Creek powerplant is proposed as a significant addition to an extensive hydro-electric system. The powerplant would be

TABLE 4-1

METEOROLOGICAL CONTROL SYSTEM PARAMETERS

Primary Fuel ("as received" basis)	Original Fuel Characteristics (1)	New Performance Fuel Characteristics (2)
Fuel type	coal	coal
Sulphur content - %	0.45	0.39
Heating Value - MJ/kg (Btu/lb)	14.7 (6,300)	13.85 (5,955)
Ash - %	26	25.6
H_2O - %	20	23.5
Secondary Fuel ("as received" basis)		
Fuel type	coal	"D" coal
Sulphur content - %	0.21	0.23
Heating Value - MJ/kg (Btu/lb)	17.61 (7,560)	16.08 (6,915)
Ash - %		
H_2O - %	20	24.5
Ambient SO_2 Control Criteria		
3 - hour averaging time - $\mu g/m^3$	665	
24 - hour averaging time - $\mu g/m^3$	260	

Source:

(1) Environmental Research and Technology, Inc., "Air Quality and Climatic Effects of the Proposed Hat Creek Project, Santa Barbara, Ca., April 1978, P5074F.

(2) Paul Weir Co., 1979, Report Forthcoming

TABLE 4-2

CHIMNEYS AND EMISSION CONTROL SYSTEMS COST ESTIMATES
(1979 $)

		(244m) Chimney	(366m) Chimney	FGD (100%)	FGD (53%)	MCS[1]
Capital Cost[2] = A		12,117,098	20,927,552	292,098,800	203,623,340	4,329,838
Annual Cost	Operating and Maintenance Annual Cost = B	363,513	627,802	21,641,130	10,839,109	474,106
Annual Cost	Fixed Charge Rate (15.2%) C = A x 0.152	1,841,800	3,180,988	44,399,020	30,950,748	658,135
Annual Cost	Total Annual Owning and Operating Cost D = B + C	2,205,314	3,808,790	66,640,150	41,789,857	1,132,241
Capitalized Value of Total Owning and Operating Cost E = D ÷ 0.152		14,508,641	25,057,828	434,474,670	274,933,270	7,448,951

[1] MCS costs exclude costs due to reduced Hat Creek output operation due to MCS restraints.

[2] Capital cost/prices/include escalation, direct and indirect construction, contingencies and engineering costs.

[3] Operating and maintenance costs for 100% FGD include a consumption of 200 USgpm per unit for makeup water at a cost of $3.70 per 1000 USgal.

[4] Operating and maintenance costs for 53% FGD include a consumption of 100 USgpm per unit for makeup water at a cost of $3.70 per 1000 USgal.

Source: Integ-Ebasco, 1977; ESCLEC, 1979.

essentially a base load plant. In addition, the powerplant would sometimes operate on a two-shift and, later, on a cycling basis.

The MCS system may call for fuel switching from the primary coal to low sulphur coal during the months of November through February. ERT[9] predicts that, if the four-unit plant is required to operate at full load continuously, switching may be required for about 195 hours from November through February with a 244m chimney. With a 366m chimney, switching may only be required for a few periods in November. During the remaining eight months, reducing plant generating capacity to 80 percent load for about 80 hours and to 60 percent load for about 5 hours may be required with a 244 m chimney. Load reduction with a 366m chimney are expected to be nil. These figures are presented in Table 4-3.

In order to supply customer loads, alternative generating sources would be required, e.g. thermal, hydro-electric, or imported electrical energy. It is assumed that the appropriate mill rates for thermal and imported electrical energy are 20 and 25 mills/kWh. For hydro-electric energy, a case can be made for a zero mill rate and/or for analytical reasons, a mill rate of 15 mills/kWh.

If it is assumed that the system is capacity critical, the hydro reserve system would normally be selected as an alternative

TABLE 4-3

HAT CREEK

MCS COSTS OF FUEL SWITCHING AND LOAD SHEDDING

Fuel Switching			Load Shedding							
							Annual Energy Replacement Cost ($)			
							Hydro-electric		Thermal	Imported
Alternative	Hours[1]	Coal Consumption[2]	@ 80% Load (h)	@ 60% Load (h)	Generating Capacity Loss @ 80% (MWh)	Generating Capacity Loss @ 60% (MWh)	(0Mills/kwh)	(15Mills/kwh)	(20Mills/kwh)	(25Mills/kwh)
244 m/MCS	195	308 685	80	5	35 840	4580	0	606,300	808,400	1,010,500
366 m/MCS	75	110 725	0	0	0	0	0	0	0	0

1 Computed at 80% of ambient control criteria and 50% safety factor for switch hours.

2 Coal consumption per 4 units of 1583 Tph.

Source: Ebasco Services of Canada Ltd. Environmental Consultant, 1979.

to offset a reduction in load by the proposed Hat Creek power-plant. The incremental cost might be zero if the reserve capacity is drawn upon. The reason for this is that the Hat Creek power-plant might, subsequent to the removal of meteorological constraints, operate at a higher load, or for a longer period, permitting hydro-electric generation to be reduced an equivalent amount until water levels in the reservoirs are restored. Although there may appear to be no additional cost in drawing upon reserve capacity, it is appropriate to attach an "opportunity cost" to such an operation. The hydro-reserves used might have been sold for export energy at 15 mills/kWh.

The estimated costs of replacing the predicted annual load shed at Hat Creek are shown in Table 4-3. The total annual generating capacity loss for the 244m/MCS configuration is 40,420 MWH and 0 for the 366m/MCS alternative. The capitalized energy replacement costs are about $4.0 million for the hydro-electric source at the "opportunity cost" rate of 15 mills/kWh; $5.3 million for the thermal generation alternative and $6.6 million for the imported energy alternative.

Table 4-3 shows that fuel switching with 244m/MCS configuration is estimated to occur for an additional 120 hours and to consume an additional 190,000 tons for low sulphur coal than the 366m/MCS alternative. It is expected that the additional coal consumption associated with the 244m/MCS alternative should not result in any additional cost penalty because the cost per Btu would remain constant (assuming a constant heat rate).

The comparative costs of the MCS configurations are summarized in Table 4-4.

TABLE 4-4

SUMMARY OF METEOROLOGICAL
CONTROL SYSTEMS COSTS

CAPITALIZED COST COMPONENTS	ALTERNATIVE MCS COSTS (1979 $)	
	244m/MCS	366m/MCS
MCS Owning & Operating Plus Hydro Replacement of Energy (0 Mills/kWh)	21,957,592	32,506,779
MCS Owning & Operating Plus Hydro Replacement of Energy (15 Mills/kWh)	25,946,408	32,506,779
MCS Owning & Operating Plus Thermal Replacement of Energy (20 Mills/kWh)	27,276,013	32,506,779
MCS Owning & Operating Plus Import Replacement of Energy (25 Mills/kWh)	28,605,618	32,506,779

Source: Ebasco Services of Canada, Ltd., Environmental Consultants, 1979.

Based on the data contained in Table 4-4, the 244m chimney would be preferred to the 366 chimney with MCS at the Hat Creek powerplant.

(iii) Benefits of Meteorological Control

The benefits which might accrue from use of sulphur dioxide abatement equipment would be the savings value to the province of any damage which might otherwise accrue to all environmental resources, whether public or private owned.

A. *Air Quality Effects*

The assumed (original ERT study) base load emission rates for various contaminants with an uncontrolled Hat Creek generating station are presented in Table 4-5. The ERT report[9] predicted that some form of intermittent control during brief adverse weather conditions may be necessary to ensure full compliance with the 3-hour and 24-hour ambient guidelines; e.g., meteorological control or flue gas desulphurization. Table 4-6 contains the maximum ground level concentrations, within 25km of the site, of selected pollutants for various MCS and flue gas desulphurization configurations.

Significance of Annual SO_2 Concentrations

Table 4-7 provides a summary impact assessment matrix indicating the predicted impact of the proposed powerplant on the air resource as a result of sulphur dioxide emissions.

TABLE 4-5

ESTIMATED BASE-LOAD EMISSION PARAMETERS FOR THE PROPOSED HAT CREEK GENERATING PLANT

Contaminant	Symbol	Emission Rate (kg per day)		
		Particulate	Gaseous	Total
Sulphur Dioxide	SO_2		324 768	324 768
Nitrogen Oxide	NO		82 489[1]	82 489[1]
Nitrogen Dioxide	NO_2		124 759[1]	124 759[1]
Total Particulates	TSP	40 000[2]		40 000[2]
Carbon Monoxide	CO		18 043[3]	18 043[3]
Total Hydrocarbons	HC		5 413[4]	5 413[4]
Arsenic	As	7.13[4]	11.9[4]	19.0[4]
Beryllium	Be	0.55[4]	0.11[4]	0.66[4]
Cadmium	Cd	0.195[4]		0.195[4]
Chromium	Cr	2.29[4]		2.29[4]
Copper	Cu	0.094[4]		0.094[4]
Fluorine	F	25.7[5]	265[5]	290.7[5]
Lead	Pb	2.59[5]	4.95[5]	7.54[5]
Manganese	Mn	4.4[5]		4.4[5]
Mercury	Hg	2.28[5]	3.67[5]	5.95[5]
Nickel	Ni	3.14[5]		3.14[5]
Selenium	Se	0.0337[5]	0.132	0.1657
Uranium	U		no emission	
Vanadium	V	0.12		0.12
Zinc	Zn	3.0		3.0
Sulphate	SO_4		no emission	
Nitrate	NO_3		no emission	
Polycylic Organic Matter	POM		no emission	
Nitrosamines	NNA		no emission	

1 Emission calculated on the basis of 500 ppm NO_x in the stack with equal parts of NO and NO_2.

2 Emission calculated on the basis of a maximum of 0.1 grains per standard cubic foot with the use of electrostatic percipitators.

3 Emission calculated on the basis of 0.45 kg CO per ton of coal.

4 Emission calculated on the basis of 0.14 kg HC per ton of coal.

5 Calculated from test burn sample analysis and coal consumption of 42 630 t/d

Source: Environmental Research and Technology, Inc. 1978.

TABLE 4-6

MAXIMUM PREDICTED GROUND-LEVEL CONCENTRATIONS
DUE TO THE HAT CREEK GENERATING STATION

Contaminant	Averaging Time (Arithmetic Means)	Maximum Concentration (ug/m^3) 244m/MCS	366m/MCS	366m/FGD	Assumed PCB Brief Guidelines
Sulphur Dioxide	3-hours	622	647	366	655
	24-hours	260	260	208	260
	1-year	9.3	8.3	4.5	53
Total Suspended Particulates	24-hours	32[1]	32[1]	26[1]	150
	1-year	1.1[1]	0.9[1]	1.2[1]	60
Carbon Monoxide	1-hour	96.1	91.3	88.2	40,000-60,000
	8-hours	18.6	17.9	31.4	15,000-20,000
Fluoride (Gaseous)	24-hours	0.42	0.33	0.4	-
	1-year	0.0075	0.006	0.008	-
Lead (Particulate)	24-hours	0.0042	0.003	0.004	-
	1-year	0.000085	0.00007	0.00008	-
Zinc (Particulate)	24-hour	0.005	0.004	0.004	-
	1-Year	0.00009	0.00007	0.00009	-
Cadmium (Particulate)	24-hours	0.00025	0.0002	0.0003	-
	1-Year	0.000005	0.000004	0.000006	-
Mercury	24-hours	0.01	0.0075	0.008	-
	1-Year	0.00017	0.00015	0.0002	-
Arsenic	24-hours	0.03	0.024	0.03	-
	1-Year	0.0005	0.0005	0.0006	-

[1]Concentrations above assumed background levels of 10 to 20 ug/m^3.

Source: Environmental Resource and Technology, Inc., 1978.

Table 4-7

IMPACT MATRIX FOR INCREMENTAL ANNUAL SULPHUR DIOXIDE CONCENTRATIONS
DUE TO HAT CREEK POWERPLANT

Resource	Existing Quality	366 m/FGD		366 m/NCS		244 m/NCS		Impact Significance				
		Absolute ($\mu g/m^3$)	% Resource	Absolute ($\mu g/m^3$)	% Resource	Absolute ($\mu g/m^3$)	% Resource	Extreme	High	Moderate	Low	Insignificant
Annual Concentration												
ZONE A	N/I	0	0	0	0	0	0					X
ZONE B												
B-1	N/I	4.5	8	3.6	6	4.9	8				X	
B-2	N/I	4.0	7	5.1	9	6.8	11				X	
B-3	N/I	2.3	4	8.3	14	9.3	16				X	
B-4	N/I	2.9	5	7.0	12	7.7	13				X	
ZONE C												
C-1	N/I	0.6	1	0.6	1	0.6	1				X	
C-2	N/I	1.2	2	1.2	2	1.2	2				X	
C-3	N/I	1.2	2	1.2	2	1.2	2				X	
C-4	N/I	0.5	1	0.5	1	0.5	1				X	
ZONE D												
D-1	N/I	0.4	1	0.4	1	0.4	1				X	
D-2	N/I	1.3	2	1.3	2	1.3	2				X	
D-3	N/I	1.3	2	1.3	2	1.3	2				X	
D-4	N/I	0.3	1	0.3	1	0.3	1				X	

Source: *CRT 1978 - Appendix C.*

The amount of the air resource "used" by the project is defined by ERT in terms of the fraction of the appropriate ambient guideline corresponding to the maximum predicted concentration. The significance of impacts corresponds positively with changes in the fraction. ERT[9] asserts that the annual average would probably be the most appropriate value for judging the amount of the air quality resource that might be "used" by powerplant operation.

Impacts are assessed for four zones: -- Zone A includes the site and immediate environs; Zone B is an ellipse centered at the site with a north/south axis of 30 km and an east/west axis of 20 km; Zone C is a concentric ellipse entered at the site with north/south and east/west axes of 60 and 32 km respectively; and Zone D is a circle centered at the site with 100 km radius. Table 4-7 shows that, for all configurations, the significance of impacts would be identical. Insignificant impact is predicted for all configurations in Zone A and only low significance in Zones B, C and D.

B. Forestry Damages

The estimated potential physical loss of timber growth with the Hat Creek project are presented in the revised Reid Collins & Associates, Ltd. Forestry report.[12] The losses due to predicted SO_2 ground level concentrations are as follows:

Configuration	Volume (m^3/a)	Economic Value (1979 $/a) ($5.5/m^3 * m^3/a)
244m/MCS	509	2800
366m/MCS	345	1898
366m/FGD	18	99

Analogously the losses due to fluoride ground level concentrations have been predicted by Reid Collins & Associates, Ltd. according to a "probable" and a "worst probable" fluoride emission level as shown below:

	Annual Predicted/Physical Losses of Timber Growth and Economic Value			
SO_2 Control Configuration	Probable Fluoride Emission Level		Worst Probable Fluoride Emission Level	
	m^3/a	$/a	m^3/a	$/a
244m/MCS	2283	12 557	25135	138 243
366m/MCS	2119	11 655	24971	137 341
366m/FGD	1792	9 856	24644	135 542

The value of timber growth losses has been estimated by taking the appropriate annual loss amount (m^3/a) and multiplying by a constant real value of timber equal to $5.5/$m^3$. The $5.5/$m^3$ figure is assumed to be representative of the present and future average value of standing timber authorized for cutting in the Hat Creek region. On an annual basis, the forest resource losses would be marginally greater with a 244m/MCS than with a 366m/MCS alternative. The maximum and minimum physical damage with a MCS configuration would be $138,243/a with a 244 m chimney under the worst probable scenario and $11,655/a with a 366m chimney under the probable scenario. The present value of these losses are listed below:[13]

Forestry Damage	Present Value of Losses at Indicated Discount Rate ($)			
	6%	8%	10%	12%
244m/MCS (maximum)	1525	1107	832	643
366m/MCS (minimum)	122	83	61	47

C. Summary of Environmental Effects

Table 4-8 provides an environmental comparison of the sulphur dioxide control alternatives. The results of numerous environmental studies, as indicated in the references to the table, denote some amounts of damage or injury but nevertheless, in almost all cases the qualitative and quantitative evidence leads to a conclusion of insignificant impact and protection of the environment.

(c) Flue Gas Desulphurization

(i) *Introduction*

Flue gas desulphurization systems (FGD) provide continuous control over powerplant emissions at the source. There are several FGD technologies in use outside Canada at various stages of development.[14] Although major engineering issues must be addressed in a complete analysis of the possible use of FGD at Hat Creek, for the purposes of this study nonregenerative-wet type of FGD system using

TABLE 4-8

ENVIRONMENTAL COMPARISON OF ALTERNATIVE
SULPHUR DIOXIDE CONTROL SYSTEMS

RESOURCE AREA	ENVIRONMENTAL CONSIDERATIONS	IMPACT MEASURES & SIGNIFICANCE 244m/MCS	366m/MCS	366m/FGD
Air Quality/Meteorology 9, 14, 15				
• Local (25km)	Airshed Commitment (maximum annual average SO_2 concentration as a percent of the proposed ambient guideline)	L or I (4.5$\mu g/m^3$; 18%)	L or I (8.3$\mu g/m^3$; 33%)	L or I (9.3$\mu g/m^3$; 37%)
• Regional (25km; 100km)	Ground Level Concentrations (1.7$\mu g/m^3$ - maximum)	I	I	I
	Cumulative Concentrations of Air Contaminants (incremental effect of Hat Creek plume)	I	I	I
• Climatic	Acid Rain	I	I	I
	Visibility Degradation (6% reduction)	I	I	I
	Global Atmospheric Processes (temperature; energy balance)	I	I	I
	Stratospheric Process (chemical radiation)	I	I	I

TABLE 4-8
(Continued)

RESOURCE AREA	ENVIRONMENTAL CONSIDERATIONS	IMPACT MEASURES & SIGNIFICANCE 244m/MCS	366m/MCS	366m/FGD
Epidemiology[16]	Effect of Proposed Ambient Guidelines for SO_2, TSP, & CO on Human Health	I	I	I
Wildlife[17, 18]	Direct effect of SO_2 & trace elements in terms of measurable terrestrial wildlife injury through habitat modification, inhalation, ingestion, etc.	I	I	I
	Indirect wildlife injury as a result of vegetation stress	?	?	?
Water Resources[15, 19, 20]				
(43 our of 205 water bodies potentially vulnerable to audi-fication)	Acid precipitation of water resources	I	I	I
	Aquatic ecological impacts from acid precipitation	I	I	I
Agriculture[21]	Effect of SO_2 and NO_2 on irrigated land-reduction of alfalfa production	-16 ha	-13 ha	0 ha
	Effect on Beef Industry	I	I	I

TABLE 4-8
(Continued)

RESOURCE AREA	ENVIRONMENTAL CONSIDERATIONS	IMPACT MEASURES & SIGNIFICANCE 244m/MCS	366m/MCS		366m/FGD
			A	B	
Natural Vegetation[22]					
• Potential Injury to vegetation within 25km of project	Species injured by SO_2/NO_2				
	• Alpine fir		7.8	1-9	
	• Engelmann spruce		53.2	1-4	
	• Lodgepole pine		43.6	1-4	
	• Ponderosa pine		0.4	1-4	
	• Douglas-fir		19.7	1-5	
	• Trembling aspen*		0.1	9	
	• Serviceberry		1.8	1-5	
	• Fringid sagebush		0.2	1-5	
	• Willow*		26.9	12-65	
	• Kentucky Bluegrass*		2.1	2-26	
	• Pleurozium schreberi*		62.5	1-13	
	• Drepanocladus uncinatur		2.0	1	
	• Alectoria jubata		17.0	1-5	
	*possible visible damage; persistant injury might cause die-back of willow and decreased productivity in other cases.				
	Vegetation Association Areas Affected	$324.41 km^2$	$238.47 km^2$		$23.38 km^2$

A --- TOTAL VEGETATIVE COVER AFFECTED (km^2)

B -- PREDICTED INJURY RANGE (%)

L -- LOW

I -- INSIGNIFICANT

TABLE 4-8
(Continued)

RESOURCE AREAS	ENVIRONMENTAL CONSIDERATIONS	IMPACT MEASURES & SIGNIFICANCE 244m/MCS	366m/MCS	366m/FGD
Forestry[12]				
	Economic value lost due to SO_2 (annual)	$ 2,800	$ 1,898	$ 99
	Economic value lost due to fluoride in plume path (annual)			
	--probable case	$ 12,557	$ 11,655	$ 9,856
	--worst probable case	$ 138,243	$ 137,341	$ 135,542
Recreation[23]				
(ranks determined by resource consultant extended to a preference ordering by preparer of this report)	Relative impact on recreation activities --preference order in terms of least overall impact	2	3	1

lime/limestone as a reagent is used for comparative analysis. The partial FGD scheme would wash about one half of the flue gases, and the flue FGD scheme would wash all of the flue gases.

(ii) Costs of Flue Gas Desulphurization

The costs of the partial and full scrubbing schemes are itemized in Table 4-2. The annual total owning and operating costs for the partial and full scrubbing schemes with a 366m chimney are about $46 million and $70 million dollars. On a station total kilowatt basis, the total capitalized costs of the partial and full FGD systems are approximately $112/KW and $157/KW respectively.[11]

(iii) Benefits of Flue Gas Desulphurization

A flue gas desulphurization system does not have any associated powerplant benefits but rather complicates the operation of the powerplant, results in increased costs and consumes considerable quantities of water, lime/limestone, and energy. An FGD system may actually increase particulate emissions and aggravate the solids disposal problems.

The environmental benefits of flue gas desulphurization would be the resource savings identified and measured in sub-section (b) above. Table 4-8 suggests that flue gas desulphurization would have less of an impact than would meteorological control but most impacts are insignificant, undetermined, and cannot be expressed in money terms.

(d) Summary Analysis of Sulphur Dioxide Control Systems

Three major methods have been evaluated in this sub-section for control of sulphur dioxide: coal beneficiation, meteorological control, and flue gas desulphurization. The approximate comparative costs of the alternatives are listed below:

ALTERNATIVE	CAPITALIZED COST ($\$10^6$)
244m/MCS	22
366m/MCS	33
366m/FGD (53%)	300
Coal Washing (full)	333
Coal Washing (partial)	135
Coal Washing (partial & 244m/MCS)	157

The MCS alternatives have obvious financial advantage over the coal washing and FGD alternatives. The partial FGD system is the most expensive control system and relative to a MCS system it would not be cost effective in terms of incremental reduction of sulphur dioxide per dollar of expenditure for abatement. The summary table shown above in conjunction with the detailed evaluation in sub-section (b) leads to the conclusion that the 244m/MCS configuration would be the least costly system for the "base scheme".

The environmental and powerplant benefits have been compared with the costs of the sulphur dioxide systems and integrated into the benefit-cost calculus where expressed in money terms. Although the sulphur dioxide systems have different environmental effects at the proposed ambient SO_2 guidelines, the potential impacts are all considered low or insignificant with few exceptions. The potential forest damage due to sulphur dioxide and fluorides are contrasted with control costs on an annual basis below:

SO_2 Control Configuration	Control Cost $/a	Forestry Damages (SO_2) $/a	Forestry Damage (F) Probable $/a	Forestry Damage (F) Worst Probable $/a
244m/MCS	3,337,555	2,800	12,557	138,243
366m/MCS	4,941,031	1,898	11,655	137,341
366m/FGD	45,598,647	99	9,856	135,542

The estimated costs of sulphur dioxide removal at Hat Creek exceed the forestry benefits for the worst probable case by a factor of 24, 36, and 336 for the 244m/MCS, 366m/MCS and 366m/FGD configurations.

4.2 - PARTICULATE CONTROL SYSTEMS

Ash in the fuel is either removed from the bottom of the boiler as bottom ash or carried with the flue gas as fly ash. The actual proportions of the total ash generated as bottom ash varies with the ash properties of the coal and the boiler design. Ash production rates at Hat Creek would be 29.3 kg/s per unit, of which about 80% may be fly ash.

Electrostatic precipitators (ESP) and fabric filters (FF) (baghouses) are compared on a cost/benefit basis as alternative control systems. The full evaluation of alternatives has included engineering issues such as the degree to which baghouses are proven as reliable on large-scale applications.

(a) Costs of Electrostatic Precipitators and Fabric Filters[25, 26]

The comparative capitalized present worth of capital and annual operating charges for hot and cold side precipitators and a baghouse are listed in Table 4-9 below. The costs in Table 4-9 are the average costs based on alternative manufacturer's systems. Figure 4-2 disaggregates costs into capital, power, and other relevant components for comparative purposes. The cost estimates suggest that cold side ESP and baghouses would be about equal in cost but less expensive than a hot side ESP installation at Hat Creek.

TABLE 4-9

COMPARATIVE PARTICULATE CONTROL COSTS

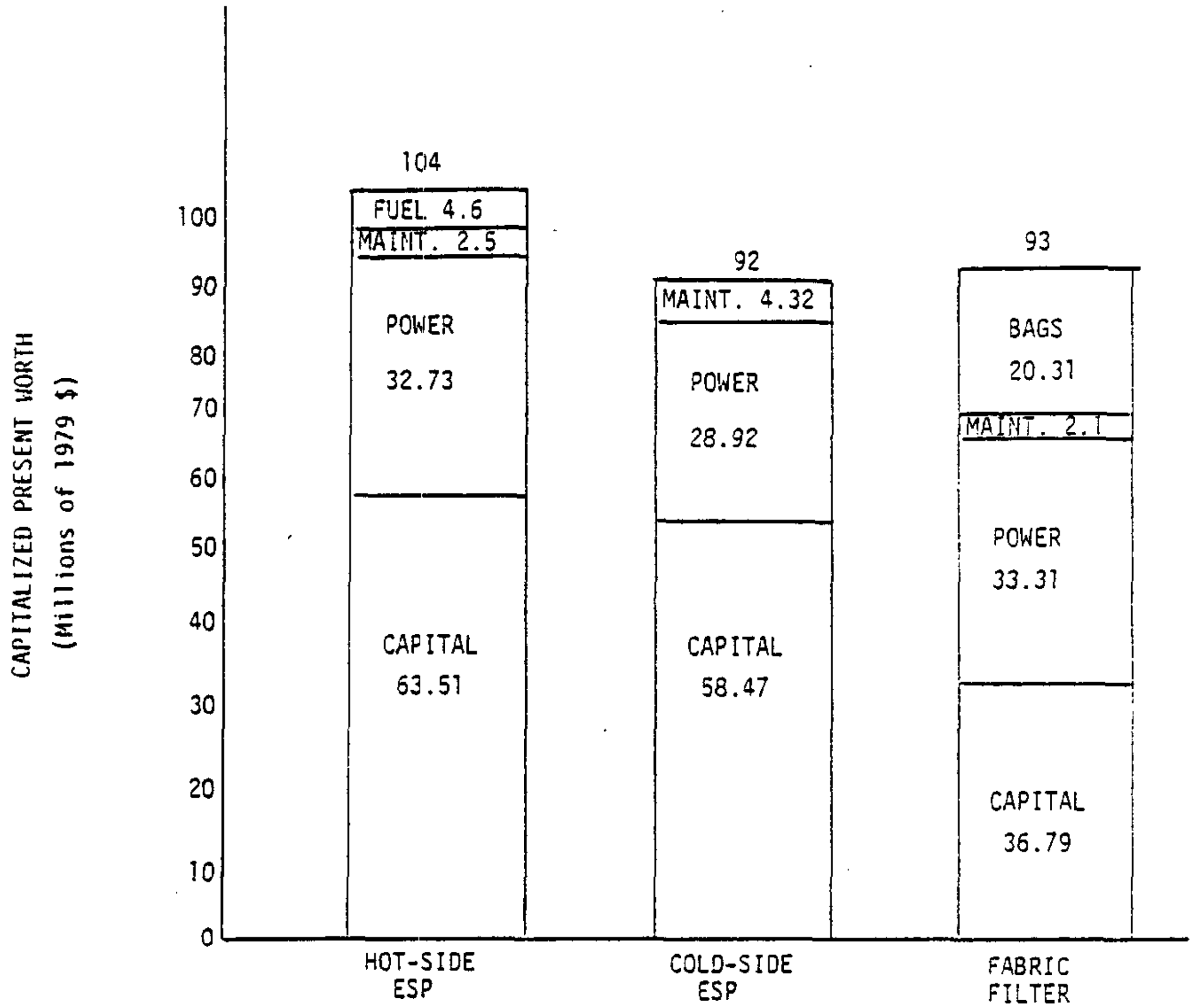
Particulate Control System	Capitalized Costs (10^6 of 1979 $)
Electrostatic Precipitation	
Hot - side	104
Cold - side	92
Fabric Filter	93

Source: Integ-Ebasco, 1977.

The baghouse cost of $93 million assumes a two-year baglife. It is estimated that a three-year baglife would reduce the average capitalized present worth of the baghouse to about $86 million. A discount rate of 10 percent has been used in the calculations. The

FIGURE 4-2

COMPARATIVE
PARTICULATE CONTROL
SYSTEM COSTS



Source: Integ-Ebasco, 1979.

baghouse would become relatively less costly than ESP's if the discount rate is increased or the proposed load factor of the Hat Creek station is reduced. Also, the cost calculations are based on efficiencies of 99.52% for cold-side precipitators and at least 99.92% for baghouses.

(b) Benefits of Electrostatic Precipitators and Fabric Filters[27-32]

High collection efficiencies have been achieved with fabric filters on an industrial scale and some utility applications. The primary advantage of a fabric filter (baghouse) is its insensitivity to fly ash chemical properties and that electrical resistivity is not a consideration in baghouse design. In addition, collection efficiency is not affected by particle size. However, the porous fabrics have not been reliably demonstrated on large coal-fired utility boilers. With very high inlet grain loadings, about 18 gr/scf, as at Hat Creek, the baghouse is an unproven technology, and actual operating costs can only be estimated. Appendix D contains a current list of actual and proposed baghouse installations on utility boilers in the United States.

The conventional method for fly ash removal in the electric utility industry is by electrostatic precipitators. The selection of a hot-side or cold-side precipitator depends on many site-specific precipitator variables, especially the electrical resistivity of the fly ash. With other factors held constant, hot-side precipitators would alleviate the resistivity concern better than cold-side precipitators. However, Southern Research Institute[33] (SRI) has recommended against hot-side precipitators based on burn tests utilizing Hat Creek coal. SRI cited the uncertainty in electrical conditons that would be expected for the high altitude (low atmospheric pressure, high temperature installation) as the reason for their recommendation. Also, problems have been encountered on hit-side precipitators installed on powerplants burning low-sulphur western coals. In addition, the operating power consumption of hot-side precipitators tend to exceed that of cold-side precipitators as denoted below for the Hat Creek powerplant:

	Operating Power (KW)		
Precipitator	Average	Minimum	Maximum
Hot-side	3,812	2,046	4,528
Cold-side	2,945	1,579	4,099

As stated earlier, the electrostatic precipitator would be designed to meet the assumed Provincial particulate emission objective (0.1 grains/SCF). The proposed ambient 24-hours guideline is 150 $\mu g/m^3$, and the annual guideline is 60 $\mu g/m^3$ for total suspended particulates (TSP). The maximum annual TSP ground level concentration predicted by ERT is 1.2 $\mu g/m^3$, and the maximum 24-hour TSP concentration is 32 $\mu g/m^3$ for controlled emissions except for an ESP. ERT considers that these ground level concentrations are insignificant or low. The predicted particle or fly ash emission rate by ERT is 0.17 lb /10^6 Btu fuel.

(c) Selection of Preferred Particulate Control Alternative

At the present time, ESP's are, in general, the best device for large-scale utility applications. Recent application of fabric filters (baghouses) on large coal-fired generating stations will provide economic and technical performance data based on experience. Therefore, recognizing the overall costs and benefit consideration, the cold-side ESP would be the preferred particulate control system for the "base scheme" powerplant.

(d) Trace Element Considerations

Trace elements in coal have been defined by ERT[18] as any elements in concentrations varying from the lowest level capable of analytical detection to 0.1 percent (1000 mg/kg or parts per million (ppm)). The release of trace elements from source material such as stack emissions into the environment could be a potential hazard to environmental resources. ERT studied nine elements (As, Cd, Cr, Cu, F, Pb, Hs, V, and Zn) in detail based on assumed values (from limited sampling) of concentrations in the Hat Creek coal deposit. Tables 4-5 and 4-6 contain predicted trace element emissions and maximum ground level concentrations. The Epidemiology[16] and Trace Element Reports[18] for Hat Creek conclude that no adverse health risk is foreseen; and barring extraordinary events, no significant impact on local or regional biological communities is expected from trace elements. Therefore, the selection of ESPs for particulate control should also provide sufficient mitigation from the effects of trace elements.

Coal washing might helo in removing some trace elements in organic combinations with minerals.[5] A recent trace element study[34, 35] performed by the U.S. Environmental Protection Agency, concluded that a wet scrubber, installed for particulate removal is an efficient trace element collector and that the wet scrubber has an advantage over dry collection methods in collecting more of the fine-particle size trace element and vapour stage trace elements. Because fabric filters can achieve greater mass collection efficiencies than ESP and are not sensitive to particle size, they should be more efficient than ESPs in trace element removal. In general, greater concentrations of particulates are deposited closer as stack height is reduced.

SECTION 5.0 - ECONOMIC EFFECT OF 1979 PROVINCIAL POLLUTION CONTROL OBJECTIVES

This section is concerned with the economic impact of the new Pollution Control Board (PCB) objectives on the Hat Creek Project related to sulphur dioxide, total particulate and opacity emission levels. The emission levels for SO_2 and particulates are listed below and illustrated in Figure 5-1; the opacity emission level has a range between 10 and 40%

Emission Parameter	Units	Range	
Total Particulate	mg/kJ fuel	0.01	0.04
	lb/10^6 Btu fuel	0.02	0.09
Sulphur Dioxide	mg/kJ fuel	0.09	0.34
	lb/10^6 Btu fuel	0.2	0.8

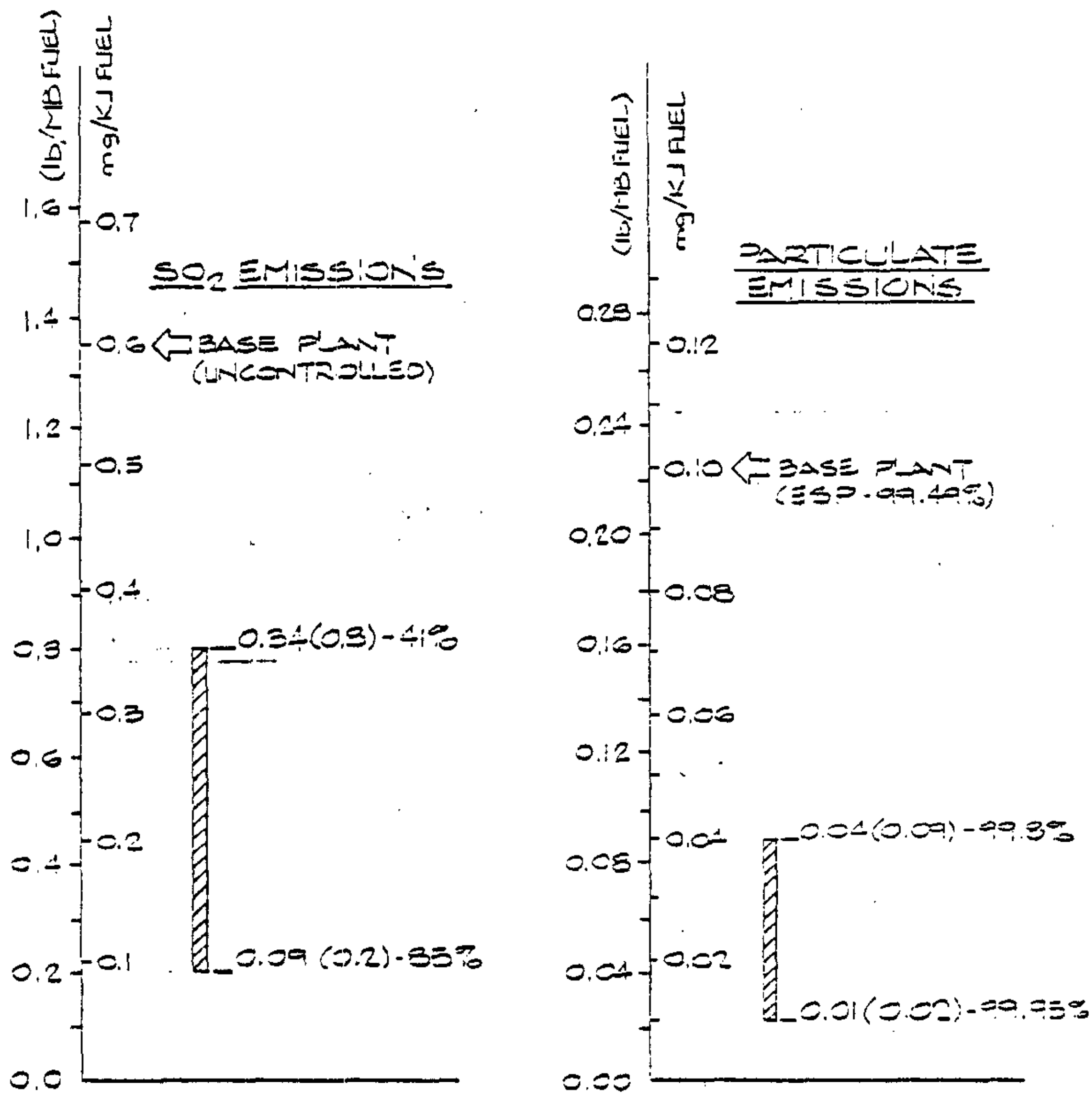
The AQCS systems selected by Integ-Ebasco to attain the extremes of the emission ranges include electrostatic precipitators or fabric filters, dry spray or wet flue gas desulphurization devices. The systems evaluated would be installed with each powerplant unit development. The base scheme powerplant incorporated cold-side electrostatic precipitators and space allowance for retrofitting a flue gas desulohurization system.

The specific assumptions made by Integ-Ebasco in their 1979 AQCS study are listed below:

1) Coal Quality: Worst Blended HHV (as received) 12.21 MJ/kg (5250BTU/lb)
   Ash content 29% (as received)
   Moisture content 25%
2) Flue Gas Flow corresponding to 105% Load (Turbine Valves Wide Open)
3) Inlet particulate loading: 80% total ash as fly ash
4) Inlet SO_2 FGD loading: 0.6 mg/kJ (1.34 lb/10^6 Btu) based on 95% total S in coal (i.e., 5% S assumed removed with mill rejects and bottom ash)
5) Base Scheme Precipitator Efficiency: 99.49%
6) Base Scheme Precipitator Emission: 0.1 mg/kJ (0.225 lb/10^6 Btu fuel)

FIGURE 5-1

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



PROPOSED PCB OBJECTIVES EMISSION RANGES

Source: Integ-Ebasco, 1979.

(a) Particulate Control

(i) Selected Air Quality Control System

A summary of the AQCS alternatives and the associated level of emission control attained is presented in Table 5-1. In cases 1 to 3, an electrostatic precipitator is intended for particulate control. Case 1 represents the "base scheme" cold-side precipitator which has an expected collection efficiency of 99.49%; cases 2 and 3 correspond with ESPs designed to achieve the higher collection efficiencies dictated by the 1979 PCB objectives by means of increased surface collection areas (SCA). The list presented below provides a comparison of SCA and efficiencies for precipitators when firing worst quality blended coal.

Case	Efficiency (%)	Southern Research Institute SCA Data $m^2/m^3/s$ (ft^2/1000 acfm)
1	99.49	91.9 (467)
2	99.8	126 (640)
3	99.95	198.8 (1010)

Source: Integ-Ebasco, 1979.

Integ-Ebasco expect that the range of particulate emissions identified in the 1979 PCB objectives can be attained with ESPs providing design and operational considerations are taken into account.

Case 4 consists of a fabric filter, instead of an ESP, plus a mechanical collector. The mechanical dust collector has been added on the presumption that due to the high inlet ash loading, they would be needed to pre-clean the gas and reduce the inlet loading

TABLE 5-1

HAT CREEK PROJECT

SUMMARY OF AQCS ALTERNATIVES

PLANT EMISSIONS

(Worst Quality Blended Coal)

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

Source: Integ-Ebasco, 1979

to the fabric filter. This combination employing gas pre-cleaning is expected to achieve the 99.95% efficiency needed to comply with the lower PCB particulate objective of .01 mg/kJ (0.21 lb/MBtu).

(ii) Costs of Selected Air Quality Control Systems

Table 5-2 provides a comparative cost evaluation of the selected AQCS systems discussed in sub-section (i). Based on the total annual owning and operating costs, the increased cost over the "base scheme" to achieve the .09 lb/MBtu emission level would be about $2.4 million and either $5.3 million or $0.4 million to achieve the .02 lb/MBtu level with the higher efficiency ESP or FF respectively.

(b) Combined Sulphur Dioxide and Particulate Control

(i) Selected Air Quality Control Systems

Cases 5 and 6 represent a partial and full (wet) flue gas desulphurization system respectively. With the partial FGD system, 50 percent of the flue gas is washed resulting in a 42 percent overall SO_2 removal efficiency; reheating of the flue gas is not required to prevent water fallout within the plant area. In case 6, 100 percent of the flue gas is washed for an 85% removal of SO_2; reheating is required. Cases 5 and 6 include the "base scheme" ESP for particulate control. The partial FGD system (case 5) is expected to comply with the PCB objective of 0.34 mg/kJ and the full FGD system (case 6) with 0.09 mg/kJ.

TABLE 5-2

COST EVALUATION FOR AQCS CASES

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

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

Source: Integ-Ebasco, 1979

Dry scrubbing and fabric filters are combined in cases 7 (partial) and 8 (full) for sulphur dioxide and particulate control. The dry scrubbing systems can achieve 85 to 90 percent SO_2 removal efficiencies for the portion of flue gas treated and is often used with fabric filters. The size of this AQCS plant would necessitate the relocation of the chimney. The partial dry FGD system would treat about 50 percent of the flue gas to satisfy the PCB SO_2 emission limit of 0.34 mg/kJ (0.8 lb/MBtu); and in the full dry FGD system, all the flue gas would be washed to comply with the lower limit of 0.09 mg/kJ (0.2 lb/MBtu).

(ii) Costs of Selected Air Quality Control System

Based on the total annual owning and operating costs contained in Table 5-2, the increased cost over the "base scheme" to achieve the 0.34 mg/kJ emission level for SO_2 would be about $31 million with an ESP and partial wet FGD and about $22 million with a FF and a partial dry FGD system. The increased cost over the "base scheme" to comply with the 0.09 mg/kJ emission objective for SO_2 would be approximately $48 million and $35 million for the ESP and full wet FGD combination, and FF and full dry FGD configuration respectively.

SECTION 6.0 - CONCLUSIONS

For the base scheme evaluations, the conclusions arrived at in the benefit-cost study are: (1) meteorological control with a 244m chimney would be the preferred alternative for the control of sulphur dioxide; (2) an electrostatic precipitator would be the preferred option for the control of particulates. Although there is some concern about the environmental effects of some trace elements, fluorine for example, the Detailed Environmental Studies concluded that no significant impact to the terrestrial or aquatic environment would occur. Therefore, no additional removal of trace elements over that provided by electrostatis precipitators appears warranted.

The 1979 Pollution Control objectives would eliminate meteorological control as a method to control sulphur dioxide and would necessitate greater investment and operating expenditures on high efficiency equipment in order to satisfy the designated ambient and emission criteria for sulphur dioxide and particulate control. Because these increased costs associated with complying with the 1979 Pollution Control objectives are not offset by a greater or even equal amount of environmental resources damage savings or powerplant benefits, public investment of scarce capital resources on the required abatement equipment cannot be justified on the basis of benefit-cost analysis.

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APPENDIX A

Compliance with 1979

Pollution Control Objectives

COMPLIANCE WITH 1979 PCB OBJECTIVES *

(a) Ambient Concentrations

(i) Sulphur Dioxide

The 244m stack with the MCS would be able to comply with the annual, 24-hour, and 3-hour upper ranges. The ERT prediction for 1-hour concentrations was considerably in excess (1700 $\mu g/m^3$) of the upper range (900 $\mu g/m^3$).

(ii) Asbestos

ERT did not analyse for this; the project is not expected to produce significant asbestos emission.

(iii) Dustfall

Although ERT did not analyse directly for dustfall, dust from the powerplant stack would probably not exceed one ton per square mile in an entire year for less than the 15 tons in a month. Dustfall is not expected to be a problem.

(iv) Trace Elements

ERT analysed for all but two of the trace elements in the PCB table (antimony and molybdenum). It is not clear whether the PCB objectives

(*) Personal communication 15 August 1979. Memorandum of K.E. Winges of ERT to E.C. Lesnick of ESCLEC.

are for 1-hour concentrations, 24-hour concentrations, or annual average concentrations. However, assuming the worst case (1-hour concentrations) the project still complies with the upper level for all elements.

Element	Range(ug/m^3)		ERT Predictions For Hat Creek (1-hour)
Antimony	0.1	0.5	Not analysed
Arsenic	0.1	1.0	0.1
Berllium	0.0005	0.1	0.003
Cadmium	0.05	0.03	0.001
Chromium	0.05	0.1	0.012
Copper	0.25	2.5	0.000
Fluorine	0.1	2.0	1.522
Lead	1.0	2.5	0.039
Mercury	0.1	1.0	0.031
Molybdenum	0.1	2.5	Not analysed
Nickel	0.01	0.1	0.016
Selenium	0.1	0.5	0.001
Uranium	0.01	6.0	0
Vanadium	0.05	1.0	0.001
Zinc	1.0	2.5	0.016

(v) Total Suspended Particulates

If the mine is taken into consideration, the Project does not comply with the PCB objectives for either annual or 24-hour concentrations. However, recent re-examination of the mining impacts has led to the conclusion that particulate concentrations were undoubtedly unduly conservative in ERT's original analysis. The powerplant emmissions certainly comply with ambient TSP objectives and the conclusion was that mining should comply as well if all factors are taken into consideration.

(vi) Radon Daughter Concentration

This was not analysed by ERT.

(b) Emission Objectives

Table II of the 1979 PCB objectives presents control objectives not specific to coa-fired generating stations. The following list compares predicted levels with these objectives:

Pollutant	Range(mg/mol)		Projected Hat Creek Level (mg/mol)
Particulates	1	8	4.9
Antimony	0.16	0.27	Not Analysed
Arsenic	0.16	0.27	0.002
Asbestos	-	-	Not Analysed
Cadmium	0.16	0.27	0.000
Copper	0.16	0.27	0.000
Fluoride as HF	0.02	0.20	0.037
Lead	0.16	0.27	0.001
Mercury	0.03	0.27	0.001
NO_x as NO_2	14	46	30.8
Opacity	-	-	Not Analysed
SO_2	16	64	39.8
Zinc	0.16	0.27	0.000

In addition Table III of the 1979 PCB objectives places further restrictions on coal-fired boilers.

Pollutant	Units	Range	ERT Predicted Hat Creek Levels
TSP	$lb/10^6$Btu fuel	0.02 - 0.09	0.17
NO_x as NO_2	$lb/10^6$Btu fuel	0.35 - 0.70	1.07
SO_2	$lb/10^6$Btu fuel	0.2 - 0.8	1.39
Opacity	percent	10 - 40	Not Analysed
Trace elements	--	- - -	--

(c) Conclusions

The data presented just above denote that Hat Creek does not comply with TSP and SO_2 levels. The boiler would be designed to achieve the NO_x emission level of $.7 lb/10^6$Btu. The ambient objective for SO_2, particulates, and trace elements levels can be achieved with exceptions as denoted in sub-section (a).

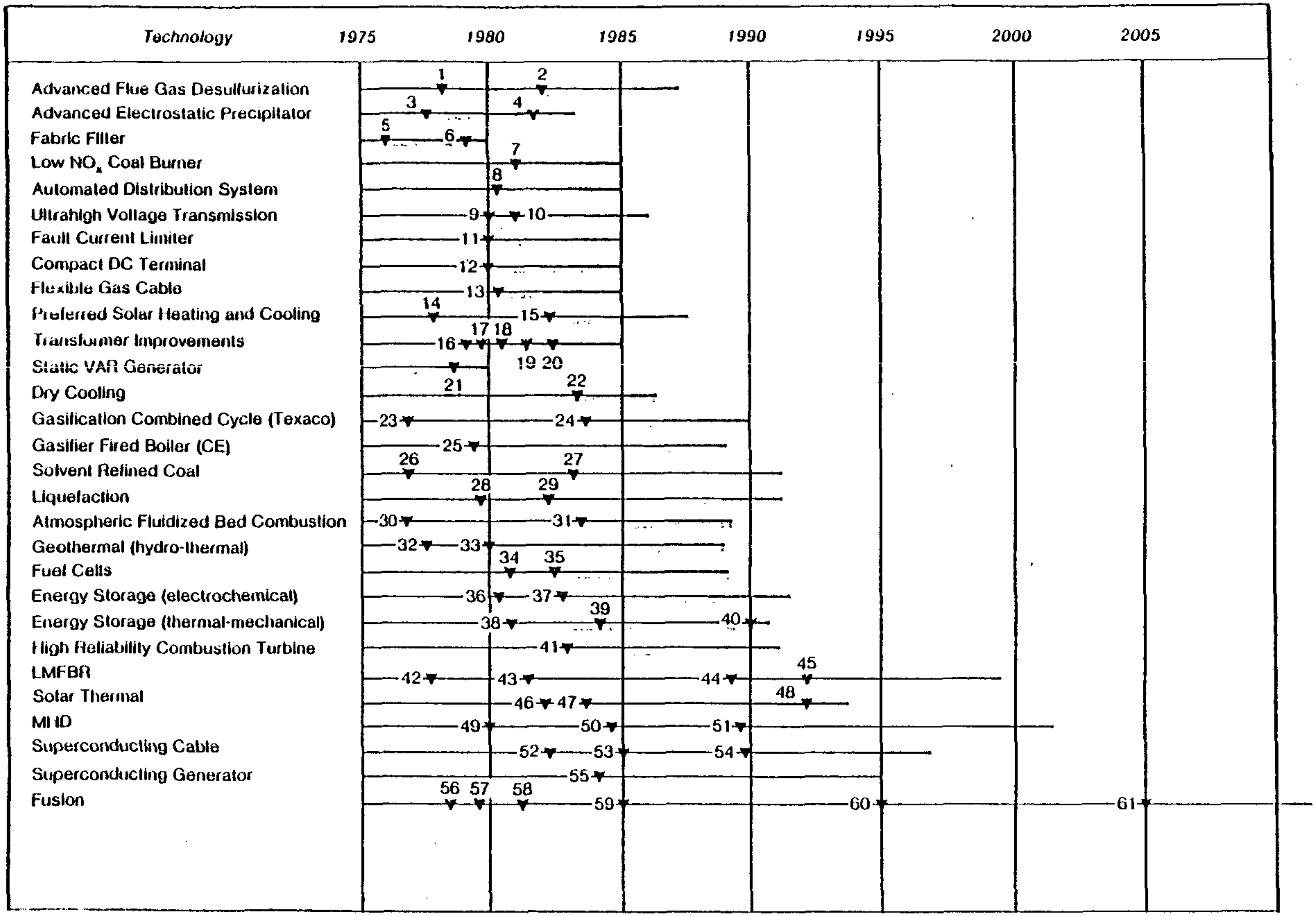
APPENDIX B

COMMERCIAL AVAILABILITY OF AIR QUALITY CONTROL AND OTHER TECHNOLOGIES FOR THE ELECTRIC UTILITY INDUSTRY

This appendix contains information about the progress of developing air quality control as well as other technologies in the electric utility industry. The timetable and data were obtained from EPRI Special Report PS-830-SR, July 1, 1978 entitled Research and Development Program Plan for 1979-1983.

A number of important air quality control systems such as advanced FGD and ESP, atmospheric fluidized bed combustion, and low NO_x coal burner and their anticipated dates of commercial availability are presented in figure B-1. Key events resulting in commercial availability are listed. EPRI mentions that caution must be exercised in interpreting the term "commercial availability". On page IV-2 of their report, EPRI states that "commercial availability" is the time when utilities could start placing orders for the first commercial units with reasonable confidence of acceptable economic and technical performance." The triangles in figure B-1 indicate the range of uncertainty in the estimate.

FIGURE B-1
TIMETABLE FOR NEW ELECTRIC UTILITY TECHNOLOGY OPTIONS



.. Available for Commercial Order *(length of triangle indicates uncertainty)*

▼ Represents key events. Numerals refer to event descriptions beginning on next page

NEW ELECTRIC UTILITY TECHNOLOGY OPTIONS
KEY EVENT DESCRIPTIONS

Event Number

1. Complete state-of-the-art design guidelines for alkali scrubbing system.
These are being prepared with the cooperation of the Prime Mover Committee. The guidelines will provide utilities with material to prepare site specific scrubber system design and operating specifications together with the costs, reliability, and maintenance requirements which can be expected.

2. Complete utility cosponsored prototype development of advanced regenerable scrubber processes.
Pilot scale developoment of steam stripping and RESOX regeneration subsystem currently underway.

3. Complete prototype development of High Intensity Ionizer.
Guidelines for use by utilities and EPRI-licensed vendors are being developed. Two utilities are having units designed for retrofit into commercial plants.

4. Complete prototype demonstration of fine particulate agglomerator for electrostatic precipitator.
Successful pilot scale development is being completed at Stanford University. Prototype tests began in 1978 at EPRI's Advanced Particulate Control Development and Test Facility (Arapahoe).

5. Evaluate the Colorado-Ute Nucla Coal-fired Plant.
Superior particulate control of bag filters effected.

6. Complete fabric filter optimization for utility use.
Fabric filter module development underway at EPRI's advanced Particulate Control Development and Test Facility (Arapahoe).

7. Complete EPRI-sponsored prototype demonstration of low NO_x coal combustion technology.
Cosponsored laboratory development work has successfully shown combustion can achieve NO_x levels of 150 – 185 ppm.

8. Complete field demonstrations of communication equipment for automated distribution system. (a)
Four manufacturer-utility teams performing field tests of four alternative communication systems, each suitable for metering up to 750 customers.

9. Complete Project UHV research on corona phenomena, insulation requirements, and electric fields and publish the second edition of the EPRI Transmission Line Reference Book – 345 kV and Above.
Three-phase testing of transmission lines in the voltage range up to 1500 kV is proceeding on schedule at the EPRI Transmission Research Facility in Pittsfield, Mass.

10. Optimize design, construction and maintenance criteria available for three phase transmission circuits rated to 1500 kV. (a)
Testing is in progress of circuits up through 1200 kV. Tests of different conductor bundle configurations include corona measurements, radio/TV interference, audible noise, and electric field intensity.

11. Design initial field test of a prototype fault current limiter for transmission system application.
Prototype, switched resistor, fault current limiter under construction. Also, a tuned circuit fault current limiter has been modeled in the laboratory and preliminary design data is available.

12. Complete initial test plan for the DC Prototype Link. (a)
All main circuit equipment in place at Astoria Station, Queens, N.Y., at end of 1977. Partial commissioning planned for June, 1978.

(a) Program jointly funded with DOE and/or other parties.

Event
Number

13. Demonstrate prototype, isolated phase, flexible gas cable.
100 meter length of the flexible gas cable (300 mm outside diameter) manufactured in Germany and shipped on a reel to the U.S. for installation at Waltz Mill in late 1977. Evaluation initiated in 1978.

14. Demonstrate preferred solar heating and cooling systems for residential application.
Ten demonstration homes incorporating more than 100 experiments under construction in New Mexico and New York.

15. Complete demonstration testing of preferred commercial and light industry solar heating and cooling.
Project proceeding to procure commercial buildings, solar systems and test equipment.

16. Field test hot-spot detectors.
Two different hot-spot detectors are now undergoing laboratory tests. It is anticipated that field tests of detectors installed in utility transformers will commence in early 1979.

17. Establish advanced solid insulation for power transformers.
Research activites pertaining to this technological milestone will commence in late 1979.

18. Demonstrate 1MVA and 5MVA vapor-cooled transformers.
Fabrication and lab tests are now in progress.

19. Complete laboratory studies on feasibility of vapor-cooled transformers of up to 100 MVA size.
Research activities pertaining to this technological milestone will commence in late 1979.

20. Evaluate tank designs of transformers fitted with external noise shells.
The first engineering prototype has been successfully tested. The next unit, a commercially acceptable unit, is in fabrication and scheduled for installation in a utility system during the third quarter of 1978.

21. Field test prototype static VAR generator.
Installation of the generator on a utility system is complete. Field tests are scheduled to begin by mid-1978.

22. Complete two and one-half years of testing of dry cooling with ammonia, phase change intermediate loop and conventional, low back pressure turbine at utility site.
Component tests now underway. Demonstration site selection and planning proceeding under EPRI/DOE direction.

23. Demonstrate operation of slagging bottom Lurgi gasifier. (a)
Two successful 8-day runs of the 6-foot diameter BGC slagging gasifier were completed in the first half of 1976. Further development is being funded by DOE and a consortium of coal and gas companies.

24 Perform a three year test of the Gasification Combined Cycle Test Facility (Powerton). (a)
Detailed design underway.

25. Test the 120 T/D Combustion Engineering gasifier for one year. (a)

26. Complete SRC combustion tests. (a)

27. Operate the SRC demonstration plant. (b)

28. Complete 250 ton/day H-Coal pilot plant tests. (a)
Pilot plant at Catlettsburg, Ky. under construction.

29. Initiate test program at the Exxon Donor Solvent, 250 ton/day pilot plant. (a)
Initial test program complete. Design and construction of pilot plant underway.

30. Operate DOE's Rivesville, 30-MW fluidized bed pilot plant. (b)
Rivesville fluidized bed boiler pilot plant preparing for 100 hr. test run.

31. Operate 200 MWe atmospheric fluidized bed combustion (AFBC) plant. (a)
EPRI 6' x 6' Fluidized Bed Development Facility operational.

32. Initiate design of geothermal demonstration plant.
Heber, California site selected for the low-salinity hydrothermal plant.

33. Operate a geothermal demonstration. (b)
Design underway.

34. Complete FCG-1 fuel cell (4.8-MWe) tests. (b)
1 MWe "breadboard" operational; Consolidated Edison selected as host utility for 4.8 MWe demo. Demo plant under construction.

35. Fabricate second generation fuel cell demonstration module (1-5 MW).
19-cell molten carbonate stack operated successfully in 1976.

36. Operate the Battery Energy Storage Test (BEST) Facility. (b)
Design completed and construction of the BEST Facility initiated with Public Service Electric and Gas Company of New Jersey. Joint DOE/EPRI project.

37. Test one candidate advanced battery system at 10 MWh scale in BEST Facility.
Research on four different advanced battery concepts proceeding on schedule.

38. Complete preliminary designs for an underground pumped storage and compressed air storage demonstration plant (250-500 MW). (b)
EPRI and DOE are sponsoring utility-led teams in the preliminary, site-specific designs of compressed air and underground hydro storage plants.

39. Operate compressed air storage demonstration plants.
Operational

40. Operate first underground pumped hydro storage commercial plant.

41. Complete full-scale tests of high reliability, fuel flexible combustion turbine test engine.
Contract negotiations are in progress with three firms who will complete different conceptual designs of the engine.

42. Complete the design for the Experimental Large Breeder Reactor (ELBR).
Design studies for the ELBR are continuing under EPRI sponsorship.

43. Complete the specifications, engineering, licensing and safety requirements for the ELBR.

44. Operate the Experimental Large Breeder Reactor plant.

45. Begin operation of first commercial scale liquid metal fast breeder reactor plant.

46. Complete 10 MWe, central receiver Rankine (steam) cycle pilot plant and initiate the plant test program. (b)
DOE has selected Barstow, CA as plant site.

47 Construct 10 MWe scale, Brayton (gas turbine) cycle central receiver pilot plant and complete checkout.
Two contractors are building 1 MW bench-scale receiver. Receiver tests will begin in 1978 at DOE's Albuquerque Solar Thermal Test Facility.

48. Operate commercial-scale, solar thermal, central receiver power plant.

49. DOE's MHD Component Development and Integration Facility (CDIF) available for tests of MHD components. (b)

50. Complete DOE's pilot-scale MHD Engineering Test Facility and initiate test program. (b)
EPRI is monitoring the federal MHD research program, conducting analyses of MHD operations in electric utility systems to help set design requirements and developing power conditioning and control equipment for the CDIF.

51 Complete prototype, commercial-scale (500 MW) MHD plant and initiate test program. (b)

52. Make available prototype of an advanced, efficient helium refrigerator and install in a superconduct-loop for testing.
Ability to accomplish key event is dependent upon major funding in period beyond 1983.

53. Initiate performance tests on a short length of superconducting cable sized for transmission application (69-kV ~ 138-kV).
Ability to accomplish key event is dependent upon major funding in period beyond 1983.

54. Install first long length of a superconducting cable in a utility system for field evaluation.
Ability to accomplish key event is dependent upon major funding in period beyond 1983.

55. Complete initial tests on a prototype, 300 MVA superconducting generator.
Two competitive design studies have been completed for a 300-MVA superconducting machine.

56. Complete initial evaluation of alternative confinement configurations for fusion systems to meet utility needs.
Eight alternatives are now being evaluated.

57 Complete Phase I evaluation of operational and environmental issues related to fusion.

58. Achieve reactor grade plasma. (b)

59. Operate the Pilot Scale Power Reactor or Ignition Test Reactor. (b)

60. Operate the Engineering Power Reactor (EPR) plant. (b)

61 Operate a fusion demonstration plant. (b)

(a) Program jointly funded with DOE and/or other parties.

(b) Program currently funded or planned by the government, or other parties, not EPRI.

APPENDIX C

FINANCIAL CRITERIA

ECONOMIC FACTORS

Factor	Updated Values (1978)	Initial Values (1977)
- Net Unit Rating	4 x 500 MW	4 x 500 MW
- Capacity Factor (lifetime Average)	65%	65%
- Annual Net Generation	11,388 GWh	11,388 GWh
- Base Date for Costs	October 1978	Sept. 1977
- Indirect Construction Cost (Indirect + Contingency + Engineering as % of Direct Cost)	28%	NA
- Levelizing Factor (5.75% inflation rate, 10% interest rate, 38 year life)	1.98	1.78
- Fixed Charge Rate (Not including O&M Costs)	12.33%	12.33%
- Levelized Fixed Charge Rate (Not including O&M Costs)	14.25%	13.85%
- Coal Cost (1978 Dollars)	\$0.679/GJ	\$0.5/GJ
	\$0.717/MB	\$0.53/MB
- Limestone Cost (1978 Dollars)	\$10.08/tonne	NA
- Lime Cost (1978 Dollars)	\$52.30/tonne	NA
- F.F. Bag Cost (1978 Dollars)	\$60.00/ea	NA
- Labour Cost (1978 Dollars)	\$18.3/hour	NA
- Incremental Energy Cost (1978 Dollars)	9.55 Mills/kWh	NA
- Water Cost (1978 Dollars)	\$0.56/m^3	NA
- Levelized Water Cost (1978 Dollars)	\$0.71/m^3	\$0.96/m^3
- Cost of Steam (1978 Dollars)	\$0.36/MB	NA
- Incremental Capacity Cost (1978	\$450/kW	NA
- Plant In-Service Date	1986	1984
- Inflation Rate: (Yearly Percent)		
1977 - 78	—	Base
1978 - 79	Base	9%
1979 - 80	7.5%	8%
1980 - 81	7.25%	7%
1981 - 82	6.25%	5%
1982 - 83	5.75%	5%
Thereafter	5.75%	5%

Source: Integ — Ebasco

NA = Not Applicable

APPENDIX D

BAGHOUSE INSTALLATIONS ON U.S. UTILITY BOILERS

BAGHOUSE INSTALLATIONS ON UTILITY BOILERS - U.S.

	Name/location	Manu-facturer	Cleaning mechanism	Boiler firing method	Size $(MW)_e$	A/C*	acfm+	Startup date
1.	Board of Public Utilities Kansas City, Kans.	Tbd	Tbd	PC	44	Tbd	300,000	1979
2.	Central Telephone and Utilities Corp. Pueblo, Colo.	Tbd	Tbd	S	20	Tbd	Tbd	1979
3.	City of Colorado Springs Colorado Springs, Colo.	WP	RA	PC	200	1.9/1	1.0×10^6	1980
4.	City of Colorado Springs Colorado Springs, Colo.	Tbd	Tbd	PC	85	Tbd	Tbd	1978
5.	City of Columbia Columbia, Mo.	CAR	RA	(2)-PC	(2)-40	2.75/1	264,900	1979
6.	City of Fremont Fremont, Nebr.	CAR	RA	(2)-PC	(2)-38.5	2.6/1	270,000	1978
7.	City of Rochester Rochester, Minn.	CAR	RA	(2)-S	(2)-16	2.43/1	160,000	1978
8.	Colorado-Ute Electric Assoc. Craig No. 3	Tbd	Tbd	PC	400	Tbd	Tbd	1981
9.	Colorado-Ute Electric Assoc. Nucla, Colo.	WF	RA, sa	(3)-S	(3)-39	2.8/1	258,000	1973
10.	Colorado-Ute Electric Assoc. Montrose, Colo.	ICA	RA	PC	12	3/1	44,000	1977
11.	Crisp County Power Co. Cordele, Ga.	ZU	RA	PC	10	3.1/1	60,000	1975
12.	Golden Valley Electric Assoc. Healy No. 1 Fairbanks, Alas.	Tbd	Tbd	PC	20	Tbd	Tbd	1980
13.	Marquette Board of Light and Power Shiras No. 3 Marquette, Mich.	Tbd	Tbd	PC	40	Tbd	Tbd	1982
14.	Minnesota Power & Light Cohasset, Minn.	Tbd	Tbd	PC	75	Tbd	348,000	1978
15.	Montana-Dakota Utilities* Coyote Station, Beulah, N. Dak.	WF	RA, sa	C	440	2.49/1	1.9×10^6	1981
16.	Nebraska Public Power Kramer Station Bellevue, Nebr.	ICA	RA	(4)-PC	(4)-113	1.7/1	558,000	1978
17.	Ohio Edison Company W. H. Sammis Station Stratton, Ohio	AAF	RA	-	(4)-185 each	2/1	~ 600,000 each	1982

(continued)

(continued).

Name/location	Manu-facturer	Cleaning mechanism	Boiler firing method	Size (MW)	A/C*	acfm†	Startup date
18. Pennsylvania Power & Light Brunner's Island Allentown, Pa.	CAR	RA	PC	350	2.31/1	1.2×10^5	1980
19. Pennsylvania Power & Light Holtwood, Pa.	WF	RA, sa	PC	79	2.3/1	200,000	1975
20. Pennsylvania Power & Light Sunbury Station Shamokin Dam, Pa.	WP	RA	(4)-PC	(4)-175	1.9/1	688,000	1973
21. Public Service of Colorado Cameo No. 1 Palisade, Colo.	CAR	RA	PC	22	2.85/1	170,000	1978
22. Sierra Pacific Power Co. North Valley No. 1 Reno, Nev.	CAR	RA	PC	250	2.71/1	1.246×10^6	1980
23. South California Edison Alamitos Station Long Beach, Calif.	ME	RA	OF & GF	320	5.7/1	820,000	1965
24. Southwestern Public Service Harrington Station Amarillo, Tex.	WF	RA, sa	(2)-PC	(2)-350	3.27/1	1.65×10^6	1978-1979
25. Tennessee Valley Authority Shawnee Steam Plant	ES	RA	(10)-PC	175 each	1.84/1	6.5×10^5 each	1981
26. Texas Utilities Monticello, Tex.	WF	RA, sa	(2)-PC	(2)-575	2.7/1	3.68×10^6	1977
27. Texas Utilities Robertson City, Tex.	Tbd	Tbd	PC	1500	Tbd	6.71×10^6	1980
28. United Power Association Coal Creek Station Underwood, N. Dak.	WF	RA, sa	(2)-S	(2)-26	2.94/1	175,000	1977

*A/C - given in ft/min. To convert to m/min, multiply by 0.3048

†To convert acfm to acm/min, multiply by 2.8317×10^{-2}

Manufacturers

AAF - American Air Filter
CAR - Carborundum Co.
ES - Envirotech-Buell Div.
ICA - Industrial Clean Air, Inc.
ME - Menardi Southern
WF - Wheelabrator-Frye, Inc.
WP - Joy Mfg. Co.-Western Precip. Div.
ZU - Zurn Industries

Symbols

A/C - air-cloth ratio
c - cyclone-fired
GF - gas-fired
OF - oil-fired
PC - pulverized coal
RA - reverse air
RA, sa - reverse air, shake assist
S - stoker
Tbd - to be determined

Source: U.S. EPA, 1979, Research Triangle Park, N.C.