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NATIONAL COAL UTILIZATION
ASSESSMENT

The Impact of Increased Coal Consumption in the Pacific Northwest

March 1978

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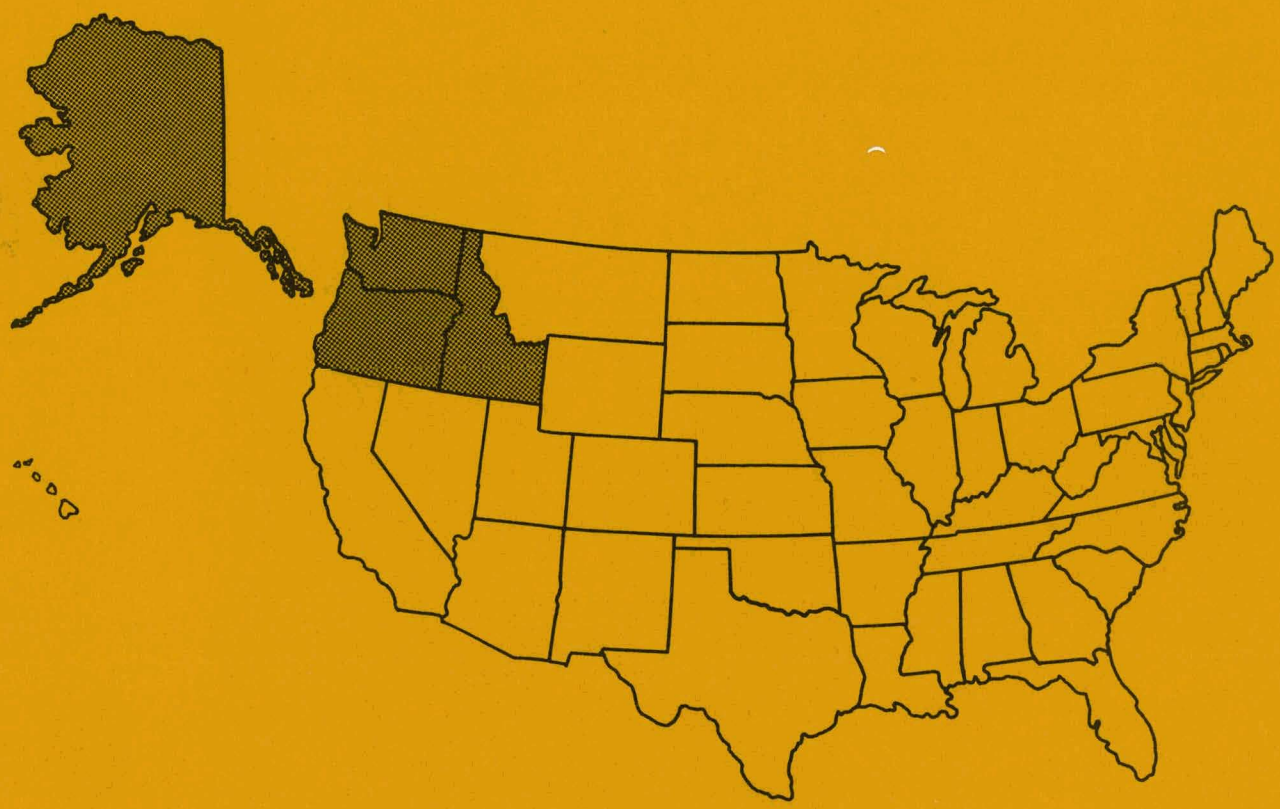

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The Impact of Increased Coal Consumption on the Pacific Northwest

This report was prepared as part of the National Coal Utilization Assessment sponsored by the Division of Technology Overview, Assistant Secretary for Environment, Department of Energy.

Compiled by
John B. Burnham

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2	Summary of Major Findings	J. B. Burnham
3	Scenarios and Technology Assumptions	D. W. Fraley W. H. Swift A. E. Davis G. L. Wilfert
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9	Health Effects	A. R. Olsen
10	Socioeconomic Impacts	M. E. Olsen J. J. Jacobsen Jane Sears Marjorie Green

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY 1.0
2.0 SUMMARY OF MAJOR FINDINGS 2.1
2.1 OBJECTIVES 2.1
2.2 ISSUES OF CONCERN IN THE REGION 2.1
2.2.1 Mining 2.1
2.2.2 Transportation 2.2
2.2.3 Combustion 2.2
2.2.4 Waste Disposal 2.3
2.2.5 Institutional Constraints 2.3
2.3 IMPACTS QUANTIFIED IN STUDY 2.4
2.3.1 Rate of Growth of Coal Utilization 2.5
2.3.2 Siting 2.6
2.3.3 Air Quality 2.7
2.3.4 Water Resources and Impacts 2.8
2.3.5 Land Use Impacts 2.9
2.3.6 Impacts on Ecosystems 2.10
2.3.7 Health Effects 2.11
2.3.8 Socioeconomic Impacts 2.12
3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS 3.1
3.1 REGIONAL ALLOCATION 3.2
3.2 COAL-FIRED GENERATION IN THE REGION 3.6
3.2.1 Idaho, Oregon, and Washington 3.8
3.2.2 Alaska 3.9
3.3 COAL AND CONVERSION TECHNOLOGY 3.9
3.3.1 Coal in the Region 3.11
3.3.2 Conventional Steam Electric Power Plants 3.13
3.4 ROLE OF THE ASSUMPTIONS 3.19
REFERENCES FOR CHAPTER 3 . . . . . 3.20
4.0 CANDIDATE COUNTY SITING 4.1
4.1 RATIONALE FOR SELECTION OF SITES 4.3
4.2 TRANSPORTATION 4.6
4.3 SELECTION OF CANDIDATE SITES 4.9
REFERENCES FOR CHAPTER 4 . . . . . 4.9
5.0 AIR QUALITY IMPACTS 5.1
5.1 AIR QUALITY ISSUES 5.2
5.1.1 Regional Climate 5.2
5.1.2 National Ambient Air Quality Standards 5.2
5.1.3 Air Quality Maintenance Areas 5.3
5.1.4 Regulations for the Prevention of Significant Deterioration . . . 5.4
5.1.5 Standards of Performance for New Coal-Fired Power Plants . . . 5.6
5.1.6 Provisions for the Protection of Visibility 5.7

CONTENTS (contd)

5.2 ESTIMATED IMPACTS OF COAL DEVELOPMENT SCENARIOS 5.8
5.2.1 Projected Emissions 5.8
5.2.2 Short-Range (<50 km) Annual Average Concentrations 5.10
5.2.3 Short-Term (3-hr, 24-hr) Maximum Concentrations 5.16
5.2.3 Comparison of Air Quality Estimates to Regulatory Constraints . . 5.17
5.2.4 Long-Range Transport of Sulfur Dioxide and Sulfates 5.19
5.3 ISSUES REQUIRING FURTHER ANALYSIS 5.25
REFERENCES FOR CHAPTER 5 . . . . . 5.28
6.0 IMPACTS ON WATER USE AND QUALITY 6.1
6.1 IMPACTS ON WATER SUPPLY AND USE 6.4
6.1.1 Physically Available Supplies 6.4
6.1.2 Institutional Constraints on Availability 6.5
6.1.3 Water Requirements of Projected Coal-Fired Power Plants . . . 6.6
6.2 IMPACTS ON WATER QUALITY 6.11
6.3 IMPACTS OF ALASKAN COAL DEVELOPMENT 6.18
6.3.1 Water Needs and Availability 6.18
REFERENCES FOR CHAPTER 6 . . . . . 6.21
7.0 LAND USE IMPACTS 7.1
7.1 ALASKA 7.5
REFERENCES FOR CHAPTER 7 . . . . . 7.5
8.0 IMPACTS ON ECOSYSTEMS 8.1
8.1 PLANT COMMUNITIES OF THE STUDY AREA 8.2
8.1.1 Forest Zones of Western Washington and Northwestern Oregon . . 8.3
8.1.2 Forest Zones of Southwestern Oregon 8.5
8.1.3 Forest Zones of Eastern Oregon and Washington 8.5
8.1.4 Steppe and Shrub-steppe of the Columbia Basin, Owyhee Upland and Basin and Range Provinces 8.5
8.1.5 Vegetation of Some Unique Habitats 8.5
8.1.6 Agricultural Lands 8.6
8.2 POTENTIAL IMPACTS OF COAL DEVELOPMENT 8.7
8.2.1 Impacts on Species of Special Interest 8.7
8.2.2 Alteration of Terrestrial Communities Due to Power Station Emissions 8.10
8.2.3 Alteration of Aquatic Communities 8.17
REFERENCES FOR CHAPTER 8 . . . . . 8.20
9.0 HEALTH EFFECTS 9.1
9.1 MINING, PROCESSING AND TRANSPORTATION RELATED HEALTH EFFECTS . . . 9.2
9.2 COMBUSTION RELATED HEALTH EFFECTS 9.3
9.3 THE NATURE OF HEALTH EFFECTS 9.3
9.4 DOSE-RESPONSE FOR AIRBORNE EFFLUENTS 9.5
9.5 REFERENCE POWER PLANT HEALTH EFFECT ESTIMATES 9.5
9.6 HEALTH EFFECTS SUMMARIZED BY SCENARIO 9.7
REFERENCES FOR CHAPTER 9 . . . . . 9.8

CONTENTS (contd)

10.0 SOCIOECONOMIC IMPACTS 10.1
10.1 SOCIOECONOMIC IMPACT ASSESSMENT 10.2
10.1.1 Meaning of Socioeconomic Impacts 10.2
10.1.2 Units of Analysis 10.3
10.1.3 Theoretical Perspective 10.3
10.1.4 Social Indicators 10.3
10.2 CURRENT COUNTY CHARACTERISTICS 10.5
10.3 MODEL IMPACT FORECASTS 10.5
10.3.1 Indicators Used 10.5
10.3.2 Forecasts 10.6
10.3.3 Summary of Forecasts 10.10
10.3.4 Scenario Comparisons 10.11
10.4 OTHER IMPACT FORECASTS 10.14
10.4.1 Factors Examined 10.14
10.4.2 Major Trends Expected 10.14
10.5 IMPACT MANAGEMENT OPTIONS 10.17
10.5.1 Current Planning Capabilities 10.18
10.5.2 Impact Management Techniques 10.18
10.5.3 Illustrative Management Approaches 10.20
REFERENCES FOR CHAPTER 10 . . . . . 10.22
APPENDIX A - ENERGY SUPPLY AND DEMAND IN THE REGION A.1
A.1 PRESENT PATTERNS IN IDAHO, OREGON AND WASHINGTON A.2
A.1.1 Hydro Predominance A.2
A.1.2 Current Generation Mix A.4
A.1.3 Natural Gas Supplies A.5
A.1.4 Petroleum A.7
A.1.5 Coal Supply A.8
A.2 ALASKA A.10
A.2.1 Electrical Energy Demand and Generating Capacity A.11
A.2.2 Oil and Natural Gas Situation A.12
A.2.3 Coal A.13
A.3 MAJOR SHIFTS EXPECTED IN FUTURE ELECTRICAL GENERATION A.16
A.3.1 Utility Projections and Trends in the Pacific Northwest A.16
A.3.2 Beyond Current Projections A.20
A.3.3 Electrical Capacity Additions A.21
REFERENCES FOR APPENDIX A A.24
APPENDIX B - SCHEDULES FOR CONSTRUCTION OF COAL-FIRED ELECTRICAL GENERATING CAPACITY ADDITIONS IN ALASKA, IDAHO, OREGON, AND WASHINGTON B.1
APPENDIX C - BACKGROUND DATA AND MODEL DESCRIPTIONS C.1
C.1 BACKGROUND EMISSIONS AND AIR QUALITY DATA C.1
C.2 DESCRIPTION OF THE MODELS--CLIMATOLOGICAL DISPERSION MODEL C.3

CONTENTS (contd)

C.3 SHORT-TERM MAXIMUM CONCENTRATIONS C.5
C.4 LONG-RANGE TRANSPORT MODEL C.6
REFERENCES FOR APPENDIX C C.8
APPENDIX D - BASELINE WATER QUANTITY AND QUALITY DATA FOR PARTS OF IDAHO, OREGON AND WASHINGTON D.1
D.1 ASA 1701: CLARK FORK-KOOTENAI-SPOKANE D.1
D.2 ASA 1702: UPPER COLUMBIA-YAKIMA-MID-COLUMBIA D.4
D.3 ASA 1703: UPPER SNAKE-CENTRAL SNAKE D.5
D.4 ASA 1704: LOWER SNAKE D.5
D.5 ASA 1705: LOWER COLUMBIA-WILLAMETTE-COASTAL D.5
D.6 ASA 1706: PUGET SOUND D.6
D.7 ASA 1707: OREGON CLOSED BASIN D.6
REFERENCES FOR APPENDIX D D.7
APPENDIX E - ANCILLARY ECOLOGICAL DATA FOR IDAHO, OREGON AND WASHINGTON E.1
E.1 PHYSIOGRAPHIC PROVINCES E.1
E.1.1 Olympic Peninsula Province E.1
E.1.2 Coast Ranges Province E.1
E.1.3 Klamath Mountains Province E.1
E.1.4 Puget Trough Province E.2
E.1.5 Southern Washington Cascades Province E.2
E.1.6 Okanogan Highlands Province E.2
E.1.7 Blue Mountains Province E.2
E.1.8 Columbia Basin Province E.2
E.1.9 Basin and Range and Owyhee Upland Provinces E.3
E.1.10 Northern Cascades Province E.3
E.2 VEGETATION TYPES AND ZONES E.3
E.2.1 *Picea sitchensis* Zone E.3
E.2.2 *Tsuga heterophylla* Zone E.4
E.2.3 Mixed-Evergreen (*Pseudotsuga*-Sclerophyll) Zone E.5
E.2.4 Mixed-Conifer (*Pinus-Pseudotsuga-Abies*) Zone E.5
E.2.5 *Pinus ponderosa* Zone E.6
E.2.6 *Abies grandis* Zone E.6
E.2.7 *Tsuga heterophylla* Zone E.7
E.2.8 Shrub-steppe Zonal Associations E.7
REFERENCES FOR APPENDIX E E.14
APPENDIX F - SOCIOECONOMIC IMPACT ASSESSMENT METHODOLOGY F.1
F.1 THE IMPACT ASSESSMENT PROCESS F.1
F.2 SOCIOECONOMIC INDICATORS F.1
F.3 TECHNIQUES OF IMPACT FORECASTING F.3
F.3.1 Trend Extrapolation F.3
F.3.2 Standardized Multipliers F.4

CONTENTS (contd)

F.3.3 System Models F.4
F.3.4 Flowcharts F.4
APPENDIX G - LIMA MODEL DESCRIPTION G.1
G.1 POWER PLANT SECTOR G.3
G.2 POPULATION SECTOR G.3
G.3 PUBLIC SERVICE CAPITAL SECTOR G.5
G.4 RETAIL AND PRIVATE SERVICE CAPITAL SECTOR G.5
G.5 SOCIAL INDICATOR SECTOR G.5
REFERENCE FOR APPENDIX G G.5
APPENDIX H - CURRENT COUNTY CHARACTERISTICS H.1
H.1 DEMOGRAPHIC CHARACTERISTICS H.1
H.2 ECONOMIC CHARACTERISTICS H.2
H.3 COMMUNITY STRUCTURE CHARACTERISTICS H.4
H.4 PUBLIC SERVICE CHARACTERISTICS H.4
REFERENCES FOR APPENDIX H H.11
APPENDIX I - PROJECTED COUNTY CHARACTERISTICS I.1
APPENDIX J - GOVERNMENT INVOLVEMENT IN COAL UTILIZATION: NORTHWEST STATES J.1
J.1 FEDERAL J.1
J.1.1 Land Management J.5
J.1.2 Regulatory J.6
J.1.3 Safety Standards J.7
J.1.4 Research and Development J.7
J.1.5 Policy Evaluation J.7
J.2 STATE J.8
J.2.1 Alaska J.14
J.2.2 Idaho J.14
J.2.3 Oregon J.15
J.2.4 Washington J.17
J.3 COAL UTILIZATION ISSUES J.18
REFERENCES FOR APPENDIX J J.22

FOREWORD

The Office of the Assistant Secretary for Environment of the Department of Energy provides environmental policy guidance based on environmental, health, and safety research and balanced impacts analysis perspectives. The Office of Technology Impacts (OTI) supports the Assistant Secretary through energy system assessments and policy analyses that concentrate on environmental, health, and safety perspectives. In OTI the Division of Technology Overview (DTO) maintains a state-of-the-art awareness of existing and emerging technologies. Among DTO's responsibilities is the comprehensive assessment of the impacts of technologies as they emerge or are deployed. This report is sponsored by DTO as part of its National Coal Utilization Assessment.

A preliminary draft of this report was circulated for comment. The authors sincerely thank the numerous reviewers who gave us the benefit of their time and expertise. This, the final report, reflects the many constructive comments offered. Thanks to these and the considerable efforts of our editor, Lynn Carson, the report should be easier to read and a more useful reference.

A comment made by many reviewers alluded to the title: A Preliminary Assessment of the Health and Environmental Effects of Coal Utilization in the Pacific Northwest. The authors concur that this title overemphasizes the magnitude of the health effects analysis performed. We have, accordingly, changed the title to one which more properly reflects the contents of the report. We hope this change does not prove too confusing to our readers.

1.0 EXECUTIVE SUMMARY

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

1.0 EXECUTIVE SUMMARY

The objectives of the National Coal Utilization Assessment (NCUA) are: 1) identification of the environmental, health and socioeconomic impacts to be expected from the increased use of coal, 2) investigation of mitigation strategies that might be used to manage these impacts, and 3) establishment of working relationships with state and regional agencies and utilities. The work described in this report is primarily addressed toward the first of these objectives.

The Pacific Northwest Laboratory (PNL) is responsible for analyzing coal utilization under various growth scenarios for the Pacific Northwest (Alaska, Idaho, Oregon and Washington). This report will be combined by Argonne National Laboratory with those of five national laboratories, each studying a different region of the country. The result will be an aggregation of regional assessments, all performed on a common basis, into a national analysis of the implications of increased coal use in the country.

A number of energy issues were identified in the course of the study. Probably the most signficant issues in this region are the siting of coal-fired power plants and the tradeoff in water allocation between energy and agriculture. Choices of coal-fired generation sites and water use determine the level of impacts to air, water, land, terrestrial and aquatic ecosystems, and human health and socioeconomics. In some cases the sites with the lowest environmental impact were found to have the highest socioeconomic disruption.

Issues in Alaska, which is rich in energy resources but low in demand for these resources, are dramatically different from those in the three contiguous states where the converse conditions occur. Hence, analysis of Alaskan energy futures should properly be separated from those of the other three states.

Candidate siting areas were designated on the assumption that each state would, after 1985, site its coal-fired plants based on energy demand. The counties of Bingham, Elmore, Gooding and Power in Idaho; Cowlitz, Douglas, Klickitat, Grant, Grays Harbor, Lewis, Lincoln, Franklin and Whatcom in Washington; Clatsop, Coos, Gilliam, Malheur, Morrow and Sherman in Oregon; and the Standard Metropolitan Statistical Area (SMSA) of Anchorage in Alaska were used as candidate sites in the region.

Air quality impacts for two scenarios were studied by developing current and projected emission inventories for the Pacific Northwest. These data were incorporated into both short-range and long-range air quality diffusion models. Model results indicate that annual average ambient air quality standards will not be exceeded at any of the sites. Short-term maximum concentrations indicate that several sites may approach but not exceed the 24-hour SO_2 standards. Long-range air transport calculations for the western United States showed that the Four Corners and mid-Columbia region of the Pacific Northwest would be expected to have the highest SO_2 concentrations under the assumed siting conditions.

It was concluded that surface water supplies are more than adequate to meet the needs of new coal-fired generating plants that may be located on the Columbia or Snake River. In most cases less than 1% of the mean flow would be used. It was concluded, however, that future conflicts could arise with agriculture over allocation of water rights.

Water quality impacts would be minimal, even in the delicate estuarine and coastal sites under the assumed control and cooling designs.

Land use impacts were generically analyzed on a county level. Except for a growing competition with agriculture for relatively level sites near water, no serious conflict was detected.

Terrestrial ecosystems in Idaho, Oregon and Washington do not appear to be threatened as long as specific sites were selected to avoid identified areas of "critical" habitat. Alaska ecosystems are less well-cataloged than those of the three contiguous states. The Alaskan environment is more diverse than that of the other states, and generalizations on its ecosystem should be avoided.

Impacts on aquatic biota and habitats seem manageable as long as existing regulations are met. Several rare or endangered species are identified. Potential conflict may arise between energy and fish preservation when plants are located on systems (such as the Snake River) subject to low flow conditions.

Health effects are calculated from data prepared by Brookhaven National Laboratory. Estimates are made of the annual excess deaths in the general population due to increased air pollution. Occupational deaths in the mining, processing and transportation components of the cycle are also estimated. While no quantitative estimate of occupational disease-related morbidity and mortality effects is made, it is qualitatively concluded that these would be less than national data, based largely on underground mining experience, would indicate.

A computer model (LIMA) was used to facilitate the analysis of socioeconomic impacts that might be expected from the addition of coal-fired generating capacity at the candidate sites. Analysis was based on a number of social indicators such as population, personal income, public services, jobs available, etc. It is concluded that counties with populations of less than 25,000 would likely suffer considerable impact unless extensive mitigation planning were utilized. Of the candidate sites, Elmore County in Idaho; Gilliam, Malheur and Morrow Counties in Oregon; and Douglas and Lincoln Couties in Washington fall into this category.

There are a number of issues which are largely unresolved and deserve further attention. Some of the more prominent of these are:

- the impact of the Clean Air Act Amendments of 1977 on siting strategy
- the tradeoff between water use for energy or agriculture
- the environmental-economic benefits and costs of once-through cooling for Alaskan and coastal sites
- the effect of pending land use legislation on the Alaskan energy supplies and generation siting options
- the environmental impact of changing the region's hydro facilities from baseload to peaking operation as new coal capacity is added
- the uncertainties involved in the calculation of health effects from coal combustion
- the verification of the adequacy of the social indicators used in this study to calculate socio-economic impact.

2.0 SUMMARY OF MAJOR FINDINGS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- **Objectives**
- **Issues of Concern in the Region**
- **Impacts Quantified in Study**

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2.0 SUMMARY OF MAJOR FINDINGS

This report is part of the National Coal Utilization Assessment sponsored by the Office of Technology Impact of the Department of Energy. The Pacific Northwest Laboratory (PNL) is responsible for analyzing coal utilization under various growth scenarios for the Pacific Northwest (Idaho, Oregon, Washington and Alaska). This report will be combined by Argonne National Laboratory with those of five national laboratories, each studying a different region of the country. The result will be an aggregation of regional assessments, all performed on a common basis, into a national analysis of the implications of increased coal use in the country.

2.1 OBJECTIVES

PNL's primary objective was to identify for the Pacific Northwest (which, for this analysis, corresponds to Federal Region Ten) the major impacts to be expected from the use of coal. This will provide DOE with needed information on expected impacts to insure that its coal research programs emphasize solving the significant environmental and social issues.

The second objective of the study was the analysis of mitigation strategies that might be used to manage the expected environmental and socioeconomic impacts. While a few of these possible management methods are discussed, most of this analysis will be performed in the second year of the study.

The third objective was to establish working relationships with state and regional agencies and utilities to insure that the best available data was utilized and that the results were useful to the regional energy community. These contacts also help identify the energy issues of local concern.

2.2 ISSUES OF CONCERN IN THE REGION

Many issues identified through interviews are common to all regions of the country; others are unique to the Pacific Northwest. The regional issues raised varied widely in their nature. Some of them are highly person-oriented and deal with questions of expected changes in lifestyle and quality of life. Others tend toward complicated questions about the influence of new plans to pool public and private power resources in the region. One way to present these issues is to categorize them according to the various steps in the coal fuel cycle, e.g., mining, transportation, combustion, and waste disposal. Another category "institutional constraints" covers the remainder of the issues.

2.2.1 Mining

The major impacts from using coal are normally associated with the mining part of the cycle. However, only limited coal deposits are located in the three contiguous states of the region (Idaho, Oregon, Washington). At present only one of these, at Centralia, Washington, is being mined. The major coal resources of the region are located in Alaska, but only the Usibelli Mine near Healy, Alaska is currently in operation.

Many coal deposits could be developed in Alaska. The one likely to be developed first is the Beluga field on Cook Inlet. A number of questions were raised in discussions with energy authorities in the region about the development of this field. Some felt that opposition to

the Susitna hydro project and the demand from the lower 48 states and Japan would combine to stimulate the opening of this field by 1985. The thrust of the national energy plan could stimulate demand for this coal as a local substitute for gas and oil. However, other interviewees felt that opening the field could be indefinitely delayed due to the Clean Air Act (as amended), the costs of opening the mine and building a loading facility, and the transportation costs to export markets. Unanimous concern was expressed, though, that the socioeconomic impact of such a major development in this semiremote area be thoroughly understood and proper mitigation strategies be developed before the project was started.

There was some concern about the impact on the fish (the Chuitna River is an important salmon spawning stream) and wildlife of the area as well as the rehabilitation of the mined land. Of particular concern was the potential impact of a large development on the air quality of the Anchorage air shed. Fairbanks, Alaska is subject to a meteorological phenomenon called ice fog. This is a very dense fog caused by the formation of ice crystals. The effluents from mining or combustion operations can exacerbate this fogging condition. Anchorage is subject to the same fogging problem, though to date it has had much less than Fairbanks. Land use regulations, currently under debate in Congress, native land claims, and rights-of-way questions could combine to restrict the development of Alaskan coal to a very small percentage of the total resource.

2.2.2 Transportation

The transport of coal from mine to generating facility is a major cost item, an aesthetic impact, and a health factor. If mine-mouth generation is used, the transportation impacts are avoided but all of the mining and combustion impacts are concentrated at a single location. The coal can be transported by rail, slurry or, in some locations, barge.

Rail transportation is the most likely mode for most sites in the Pacific Northwest. A 1000 MWe plant requires about one unit train per day, which must return empty. If stack scrubbers are used, limestone must be imported to the plant and sludge exported. The noise pollution along the rail route, the inconvenience of traffic tieups at rail crossings, and the potential for automobile-train wrecks at these crossings caused some concern to those interviewed.

Long hauls, such as from Wyoming to the Pacific Northwest, will show the most favorable economic situation for the use of slurry pipelines. Several of the individuals interviewed were concerned that rights-of-way altercations could present a constraint to the development of this transportation mode. It was also felt that the restrictions on the export of water instituted by several coal producing states would further hamper the development of slurry pipelines.

2.2.3 Combustion

With the limited mining of coal in our region, the greatest cumulative effects can be expected from the combustion step of the cycle. Since over 90% of current coal usage is concentrated in the generation of electricity, the impacts from this use were the chief concern of this study.

Present policy in Idaho, Oregon and Washington is to pool power supplies. Power generated from dams or nuclear reactors in one state may be used as needed in others. Some coal-generated

power is imported from Montana (Colstrip) and Wyoming (Jim Bridger). For this study it was assumed that all coal generation after 1985 would be sited on a "ship-and-burn" basis. This approach creates the greatest impact within the region using the power. It is essential, then, to this assumption that each state constructs within its own boundaries those coal-fired plants required to meet its demands. While the validity of this assumption can be questioned, it has the advantage of coupling each state's energy demand with the concomitant impacts.

Siting is a continuing problem within states. Should generating plants be located near demand centers or in less populated areas where environmental impact may be less, but transmission costs and social impacts may be larger? If remote, low population sites are selected, it is a general rule that appreciable socioeconomic disturbances be expected. What transfer payments, if any, should be made to these communities to mitigate such impacts?

Another concern voiced by a number of people was the effect of the amended Clean Air Act on siting policy. The impact of the Prevention of Significant Deterioration and the designation of Class I areas may reverse the present trend toward the concentration of large capacity at a single location.

As present transmission corridors reach full capacity, the cost of long-range power transmission will undoubtedly be reexamined. Will these costs and the increasing resistance to new transmission corridors change siting policy?

Another major issue in the Northwest is the priority of water use. Hydroelectric power generation can compete seriously with agricultural and other water uses (fisheries, recreation and transportation). Thermal power plants will require an increasing allocation of water for cooling purposes. A number of questions have been asked about the methods and priorities to be used for the allocation of water between its various uses.

2.2.4 Waste Disposal

Several respondents pointed out the need for increasing attention to the problems of waste disposal from coal combustion. Depending on the sulfur content of the coal, the type of SO_2 scrubber used, and the amount of dewatering of the sludge, the total solid waste from a coal-fired plant can range from 0.2 to 1 ton per ton of coal burned. The sludges from SO_2 scrubbing are subject to leaching. Unless proper precautions are taken, the potential exists for the pollution of surface and subsurface water systems.

2.2.5 Institutional Constraints

Many issues pertain to the institutional problems facing the energy future of the Pacific Northwest. While some of these questions are not indigenous to coal-fired generation but rather to thermal generation in general, they are pertinent to this study. Most of the same issues would arise if nuclear, geothermal or solar power additions were being considered.

The need for power and the expansion of facilities to meet that demand are continuing problems. A considerable diversity exists in the projected rate of growth of electrical demand in the Pacific Northwest. Current forecasts range from an annual compound growth rate of 1.4% to about 4.5%. Compounded over a period of time, rates as markedly different as these will yield grossly divergent indicated demands for capacity addition. This in turn will lead to markedly different conclusions about the optimum energy policies to be pursued.

Questions have been raised about the assignment of responsibilities for making these energy projections. Should overall responsibility for this forecasting be assigned to a federal or state body, or rather to individual utilities?

Critical hydro conditions of the past year and projected future short falls of generating capacity indicate both a short-term and a long-term shortage of electrical power in the region. Questions arise about what methods should be used to allocate power during times of shortage, and how these measures should be implemented.

As the present generating system, which is predominantly hydro, adds new thermal capacity, it is predictable that costs will rise rapidly. As these costs are passed on to consumers, economic theory says that the long-term price elasticity of demand will operate to reduce the rate of growth of demand. While this economic principle is well accepted, the magnitude of the price elasticity is still debated.

There is also a question about the operability of the economics of demand. If power rates are maintained artificially low through one mechanism or another, the price elasticity drive cannot be effective in decreasing demand. A corollary social question arises: should these economic forces, with their attendant hardship on fixed, low income users be allowed to operate unrestrained? Should the present price schedule be revised to discourage very large users of electrical power? Should, rather, marginal pricing concepts, which discourage new power users, be instituted? Should draconian measures such as power rationing or mandatory insulation be instituted? Should prices be allowed to rise rapidly by eliminating regulatory delay, or by allowing pass-through costs, in order to encourage conservation?

Lastly, the question arises of an equitable method for evening out the impacts of siting. For example, most generating plants are located in remote sites that must bear almost all of the economic and environmental impacts of their construction and operation. These sites suffer almost all of the disbenefits in return for a small percentage of the benefits. What transfer payments, if any, should be made to those communities suffering large socioeconomic dislocations and environmental insults? What agency should be designated to adjudicate and administer such payments?

Some of the above issues were analyzed in the course of the first year's work on the National Coal Utilization Assessment (NCUA). Other issues should be examined in the future, while many others are clearly beyond the scope of this work.

2.3 IMPACTS QUANTIFIED IN STUDY

The NCUA provides a nationally consistent basis for the assessment of impacts expected from increased coal use in various regions of the country. To do this in a consistent manner, four national scenarios were developed. These were disaggregated into the six regions under study. These scenarios are not intended to be forecasts but merely a logical basis for studying potential impacts.

The four scenarios adopted are:

1) Recent Trends - a base case derived from a simple extrapolation of recent trends.
2) High Coal Electric - expanded use of coal-derived electric energy.

3) Accelerated Synfuels - major use of coal conversion into synthetic fuels.
4) A combination of the latter two cases.

From economic analysis it was deemed unlikely that coal would be imported into the region for the production of synthetic fuels. Hence the first and second scenarios were emphasized. In the future there is a possibility that Alaska's coal could be converted to gaseous or liquid products for export. The economic-environmental tradeoffs of such an operation need to be analyzed in detail.

Energy demand in Federal Region Ten can best be appraised by viewing the three contiguous states of Idaho, Oregon and Washington separately from Alaska. With the exception of a well developed hydroelectric system, the three contiguous states are not blessed with significant energy resources, yet they house significant industrial and agricultural economies. Alaska, on the other hand, possesses vast natural resources that are in the initial stages of development. These contrasting features create diverse problems in analyzing the energy future of the region. The national scenarios were disaggregated to numerical values for Region Ten; while not precisely matching other short-term projections, these represent a logical basis for studying the growth of coal demand.

2.3.1 Rate of Growth of Coal Utilization

Tables 2.1 and 2.2 summarize the growth scenarios used in the analysis. The trends of other energy elements are also illustrated. The role of coal in filling energy demand is indicated to be growing at a 4.5% rate nationally in the Recent Trends scenario between 1975 and 1985; growth rates are 1.75% and 1.68% for the periods of 1985 to 2000 and 2000 to 2020, respectively. Reducing the same national scenario to a Pacific Northwest base results in

TABLE 2.1. Pacific Northwest[a] Recent Trends Electrical Generation Scenario by Alternative Technologies (10^{15} Btu)

	Baseline 1975	All Scenarios 1985	Recent Trends 2000	Recent Trends 2020
Coal	0.041[b]	0.077[c]	0.221	0.502
Peaking turbine	0.003	0.003	0.003	--
Nuclear	0.021	0.073	0.397	0.765
Hydro: Conventional	0.361	0.474	0.495	0.516
Pumped storage	--	0.005	0.021	0.021
Geothermal	--	--	0.017	0.067
Solar	--	--	--	--
Less:				
Pumping losses	--	(0.001)	(0.005)	(0.005)
Distribution losses	(0.021)	(0.038)	(0.068)	(0.109)
Total	0.405	0.593	1.081	1.757

(a) States of Alaska, Idaho, Oregon and Washington
(b) 0.025 x 10^{15} Btu generation in region, balance from Montana and Wyoming
(c) 0.027 x 10^{15} Btu generated in region

TABLE 2.2. Pacific Northwest[a] High Coal Electrical Generation Scenario by Alternative Technologies (10^{15} Btu)

	Baseline 1975	All Scenarios 1985	High Coal 2000	High Coal 2020
Coal	0.041[b]	0.077[c]	0.533	1.159
Peaking turbine	0.003	0.003	0.003	--
Nuclear	0.021	0.073	0.222	0.394
Hydro: Conventional	0.361	0.474	0.495	0.516
Pumped storage	--	0.005	0.021	0.021
Geothermal	--	--	0.017	0.067
Solar		--	--	--
Less:				
Pumping losses	--	(0.001)	(0.005)	(0.005)
Distribution losses	(0.021)	(0.038)	(0.068)	(0.109)
Total	0.405	0.593	1.218	2.043

(a) States of Alaska, Idaho, Oregon and Washington
(b) 0.025 x 10^{15} Btu generation in region, balance from Montana and Wyoming
(c) 0.027 x 10^{15} Btu generated in region

greater growth rates--6.5%, 7.3% and 4.2% for the same time periods. The larger regional growth rates can be accounted for primarily by the small base of coal-fired generation that is now in place.

The supply of coal to the region was assumed to be primarily from Wyoming and Montana. It was concluded that the Beluga coal field on Cook Inlet near Anchorage, Alaska could potentially supply deepwater sites in the lower states. The extent of Alaska's coal development will be strongly influenced by potential land use constraints that are presently the subject of legislative debate. The competitiveness of these coal supplies will also be affected by transportation costs and the implementation of the "Best Available Control Technology" section of the Clean Air Act Amendments of 1977.

A Technology Characterization Committee agreed upon a standard plant technology to be used in the study. For calculational purposes a "standard" plant was used. Also, Northern Great Plains Province coal was assumed with a heat content of about 9000 Btu/lb and 0.5% sulfur.

2.3.2 Siting

Candidate sites were designated on the basis that each state would construct plants sufficient to meet its own power demands. The location and timing of plants within each state were determined as follows:

1. A discrete size (500 MWe) for individual plants was assumed.
2. A set of criteria was developed to be used as a basis for selecting candidate counties for siting.
3. On the basis of the above, a number of plants were allocated to favorable counties on a time schedule that matched the demand growth for the individual states.

Criteria used for the selection of candidate siting areas were:

- availability of water for cooling,
- availability of relatively flat terrain with good atmospheric ventilation,
- access to either rail or water transportation,
- nearness to existing transmission corridors,
- nearness to load centers.

Many other local factors influence siting. For example, there are county zoning ordinances and other institutional constraints (such as the Coastal Zone Management Act of Washington). These criteria are so specific that in a generalized county level analysis, such as the one performed in this study, they cannot be included in a meaningful way. Clearly these factors and the preferences of siting councils (such as operate in the states of Washington and Oregon) would influence the selection of specific sites for construction.

Alaska has unique siting constraints that arise from complicated, and as yet unresolved, land use questions. Severe meteorological and ecological factors further restrict siting choices.

Based on these methods, the counties of Elmore, Bingham, Gooding and Power in Idaho; Lewis, Lincoln, Grays Harbor, Cowlitz, Douglas, Grant, Franklin, Whatcom and Klickitat in Washington; Morrow, Coos, Gilliam, Clatsop, Malheur and Sherman in Oregon; and the Standard Metropolitan Statistical Area (SMSA) of Anchorage in Alaska (Alaska does not have counties) were designated as candidate siting areas for the study. This selection in no way should be interpreted as a definitive siting study. On closer inspection some of the counties may be found to be unsuitable; almost certainly other counties not designated here are excellent future sites. On the basis of the above data, potential effects on air quality, water supply, water quality, land use, terrestrial ecosystems, aquatic biota, human health and socioeconomic conditions were studied.

2.3.3 Air Quality

Short-range (50 km) pollutant concentrations were studied with two different models. The first provided estimates of annual average air quality concentrations while the second considered short-term maximum concentrations that might be found within a few kilometers of the facility. Based on the assumption that emissions from the coal plants will equal those allowed under the New Source Performance Standards specified at the time of the calculation, the annual average incremental increase in sulfur dioxide, particulates and nitrogen oxides was found to be small compared to the concentrations allowable under the National Ambient Air Quality Standards (NAAQS). Calculations showed, however, that short-term maximum concentrations could, under certain meteorological conditions, exceed the NAAQS near a power plant. Implementation of Best Available Control Technology would predictably decrease these calculated concentrations.

The regulations for the Prevention of Significant Deterioration as promulgated in the Clean Air Act Amendments of 1977 impose severe constraints on power plant development in the vicinity of Class I areas, which currently include all national parks greater than 6000 acres and all wilderness areas over 5000 acres in size. Regulations also restrict power plant development in Class II areas where meteorological conditions are such that short-term maximum

concentrations are high. The implications of these Amendments on siting alternatives will require further study after implementing regulations have been issued.

The long-range transport of SO_2/SO_4 from all existing sources was calculated for the western United States. The incremental concentrations to be expected in the year 2020 from the High Coal Electric scenario were also calculated. The largest incremental SO_2 values found were 19 $\mu g/m^3$ in northwest New Mexico and 11 $\mu g/m^3$ in southcentral Washington. These are the two regions with the most capacity in the High Coal Electric scenario. Incremental concentrations are less than 10 $\mu g/m^3$ for all other candidate areas of the west. When the incremental concentrations were added to the levels caused by existing sources, it was found that a number of additional areas showed concentrations above 10 $\mu g/m^3$. When existing and new sources were combined, several areas of high SO_2 were found. The Four Corners region showed concentrations about 23 $\mu g/m^3$ and the mid-Columbia region of the Pacific Northwest, which presently has no major sources, had estimated concentrations of 11 $\mu g/m^3$.

An unresolved issue in this phase of the study is the effects on air quality to be expected from implementation of the Clean Air Act Amendments of 1977. The implementation of Best Available Control Technology would be expected to decrease the emission levels below the New Source Performance Standards assumed in these calculations. In this case the constraints imposed on power plant development in the west by the regulations for the Prevention of Significant Deterioration would be substantially less than indicated in this phase of the study.

A second major issue not examined in this phase of the study concerns the air transport models used here. They are "flat terrain" models that do not account for the influence of topography, which can cause markedly different dispersion characteristics. Since many mandatory Class I areas are located in regions of complex terrain, future coal assessments need to be refined, using air quality models that incorporate complex terrain.

2.3.4 Water Resources and Impacts

Water consumption impacts in the three contiguous states were assessed by comparing the estimated withdrawals in consumptive use by projected power plants within each "aggregated subarea" (ASA) to total surface water flows and, where appropriate, historic and projected low monthly flows of the Columbia and Snake Rivers at key points. Analysis was made on the assumption that all plants would use wet-tower evaporative cooling and would withdraw their water supply from the largest surface source in the identified candidate county. For the two Alaskan candidate areas, power plant water requirements were compared to the limited data on low flows in the major nearby rivers.

Water quality impacts were assessed assuming that all coal-fired plants collect, treat and release all liquid effluents as necessary to meet Federal New Source Performance Standards. Resulting pollutant releases were compared qualitatively to existing background conditions in the ASAs and in the relevant Alaskan rivers.

It was concluded that surface water supplies are more than adequate to meet the needs of new coal-fired generating plants that may be located on the Columbia or Snake Rivers. In most cases less than 1% of the mean low flow would be used under the scenarios studied.

Increasing competition for available supplies among alternative uses--principally power generation, irrigated agriculture and fisheries maintenance--may result in institutional constraints on water availability for energy generation. Offstream storage reservoirs may be used to minimize conflicts with other uses during critical low flow periods.

Though current national (EPA) policies strongly favor the use of cooling towers or ponds instead of once-through cooling, the choice of cooling technology to be used may become a debated subject in the region due to high volume stream flows, ocean access, and the value of water in alternative uses. If once-through cooling is not allowed, coastal candidate counties (Grays Harbor, Clatsop, Coos) may lose much of their attractiveness for plant siting.

Competition for water is most intense on the Snake River. The State of Idaho is considering setting aside adequate supplies for power generation through administrative allocations.

Under Federal New Source Performance Standards, effluent releases will essentially be limited to dissolved solids, which are expected to have little impact on a regional scale. Heavy metals and abnormally acid or alkaline waters accidentally released by surface runoff from coal and ash storage piles, or released by leaching from ash and sludge disposal areas, pose the greatest threat of localized water pollution.

The region's unique dependence on hydroelectric generating facilities suggests that an important potential impact of coal-fired plants (or other thermal base-load power plants developed in the future) is that hydro facilities may be changed to peak power operation, resulting in more rapid and extreme fluctuations in river flows. These fluctuations could conflict with recreational use of the rivers, increase river bank erosion and resulting suspended sediment loads, and result in additional stresses on important anadromous fish populations.

Potential Alaskan coal development poses a unique situation. Preliminary data indicate that adequate surface water supplies are available to serve the postulated mines and power plants, but streams exhibit extreme seasonal fluctuations in flow. The impacts of sedimentation and other potential water quality effects of mining are highly uncertain, particularly under low flow conditions. The availability of ground water to meet energy development needs has not been determined.

Three important issues remain to be resolved: analysis of the economic and environmental tradeoffs among competing alternative water uses in the Columbia and Snake Rivers, the relative environmental benefits and costs of once-through cooling for Alaskan and coastal sites (a corollary issue is potential use of heated effluents for fish culture), and the feasibility and implications of using ground water sources for new thermal plants, particularly for Snake River, mid-Columbia and Alaskan sites.

2.3.5 Land Use Impacts

Land acreages required for projected power plants in designated candidate counties in Idaho, Oregon and Washington and two areas of southcentral Alaska were quantitatively estimated. Land use changes resulting from associated urban growth were also estimated. Other potential important land use changes secondarily related to power plant construction, such as new transmission and transportation corridors and new industry attracted to the area, were not quantitatively estimated.

Estimated land requirements for new power plant sites and associated urbanization averaged about 1 acre/MWe. Rural counties typically had land use above this average, while urban counties were slightly less.

Land use changes exceeding 3000 acres were estimated under the High Coal Electric scenario for the counties of Cowlitz, Douglas, Franklin, Grant, Grays Harbor, Klickitat and Lincoln in Washington; for Elmore County, Idaho; and for Gilliam County, Oregon. It was concluded that power plants and related developments will most probably compete with agriculture for desirable siting areas along the Columbia and Snake Rivers.

Activities of state councils on land use and facility siting will play a major role in siting generating plants. Portions of several designated candidate counties, particularly in Oregon, appear to conflict with current policies of these commissions.

Development of coal resources west of Cook Inlet in Alaska may trigger substantial regional development attracted by the new transportation facilities and support communities.

Pending land ownership settlements and possible air quality buffer zones around parks and wilderness areas will strongly influence the future siting of coal development facilities in Alaska.

Unresolved issues requiring further analysis are 1) the availability and suitability of sites in relation to environmental concerns and state land use controls, and 2) the potential scope of development west of Alaska's Cook Inlet should be investigated to determine the critical development stimuli, project the rate and type of development, and identify alternatives for minimizing undesirable growth patterns.

2.3.6 Impacts on Ecosystems

In analyzing the potential ecological impacts of the designated candidate siting counties, four major types of impacts were considered: loss of habitats or species of special interest, alterations in vegetation due to deposition of airborne emissions, alterations in aquatic ecosystems due to changed stream flows. Prediction of detailed impacts requires data that is highly specific for each site and is beyond the scope of this study. General ecological conditions extant in the candidate siting counties were, however, considered in judging the probability of impacts. Due to the scarcity of ecological baseline data in Alaska, no conclusions were drawn on the expected impacts in that state. These will be the subject of more extensive investigation in the second year of the study.

The most significant impacts expected are losses of habitats or species of special interest displaced by land use changes. The Olympic mudminnow occurs in the Satsop and Deschutes Rivers of Washington (Grays Harbor and Lewis Counties). The prairie falcon occurs in all nonforested counties. The peregrine falcon occurs in Bingham and Elmore Counties, Idaho and Malheur County, Oregon; seasonally it occurs in all counties, nesting in the western mountains. Columbia white-tailed deer occur in Clatsop County, Oregon and Cowlitz County, Washington. These species have been recognized as threatened. The ferruginous hawk, although not yet recognized by the federal agencies as endangered, must be mentioned specifically. It nests in Franklin County, Washington near the Columbia River. Only 20 pairs are known in the state; of these, 14 pairs nest at the Franklin County sites.

Official designation of endangered plant species includes species in nearly every county. Only a few occur in habitats along the Columbia and Snake Rivers' shorelines and in coastal streams and marshes. Until specific sites are identified, it is impossible to quantify the expected damage to any identified habitats or species.

Airborne emissions with the apparent greatest potential for damaging vegetation are fluoride and oxides of sulfur. Assuming the deposition rates for SO_2 and SO_4 given in Chapter 5, however, such damage appears unlikely. In fact, increased plant growth may result from the deposition of sulfur on the typically sulfur-deficient soils of the region. Estimates of the magnitude of impacts from fluoride or other airborne pollutants, including trace elements, were not made due to the lack of data on expected deposition rates and plant responses specific to a site. Additional study of plant responses in the field is essential to more definitive impact prediction.

Impacts of waterborne pollutants on aquatic ecosystems are similarly specific to each site. However, if New Source Performance Standards are adhered to and towers or ponds are used for power plant cooling, no significant impacts are expected. To the extent that such impacts do occur, they will most likely result from accidental release from runoffs of coal or ash piles or from leaching of buried ash and sludge into ground water. The potential for such accidental releases is significantly greater in areas west of the Cascade Mountains where precipitation is high and the materials may be more readily leached into ground water.

Minor reductions in the stream flow of the Columbia and Snake Rivers (discussed in Chapter 6) from power plant withdrawals are not expected to significantly impact aquatic ecosystems. Impacts may occur, however, if simultaneous large withdrawals for expanded irrigated agriculture occur within a short stream reach or if generating station capacity is too highly concentrated. Anadromous fish losses are also possible if the switch of hydro systems from baseload to peaking generation occurs. This change in operating mode is expected as more baseload thermal capacity is built in the region. Peaking operation is expected to cause more severe fluctuations in river level than at present. Further investigation is needed to determine the location and possible extent of such fluctuations and to estimate the size of resulting fish losses.

2.3.7 Health Effects

The components of coal combustion effluent that have been identified as possible causes of health changes in the general population are carbon monoxide, nitrogen oxides, sulfur dioxide, particulate polycyclic organic compounds, vapor phase organics, selected trace metals and radionuclides. Sulfates, nitrates and ozone are also listed because of chemical transformations in the atmosphere. No definitive epidemiological study of the low-level chronic exposures has been done that establishes a well-defined dose-response relationship between individual pollutants and specific health effects. In view of this, estimates were not made by individual pollutants or by individual health effects. A qualitative assessment of morbidity effects related to air pollution was made. The laboratories participating in the NCUA adopted as a standard procedure a non-threshold, linear dose-response function developed by the Biomedical and Environmental Assessment Division of Brookhaven National Laboratory (BNL). This dose-response function relates the air pollution index (atmospheric sulfate concentration) to the health effects index (annual excess deaths).

Based on this methodology, the estimated impacts to the general population due to increased air pollution are 0.8 annual excess deaths for the Recent Trends scenario and 1.1 for the High Coal Electric scenario. These estimates are for the year 2020 for all counties in Idaho, Oregon and Washington selected for power plant sites. The uncertainty in these health effect estimates is reflected in an 80% confidence statement which gives a range from zero excess deaths to a factor of 10 higher than the estimate given. The BNL procedure will be reviewed in the future.

The occupational health effects of the coal system include those related to the mining, processing and transportation components of the cycle. Although many of these effects occur outside the Pacific Northwest (since little mining is done in the region), they are included for completeness. The reliability of these estimates is considerably better than that for public health effects due to air pollution. For the Recent Trends scenario, eight accidental deaths in 2020 are attributable to surface mining, two to coal processing, and 135 to transportation. For the High Coal Electric scenario, 18 annual accidental deaths in 2020 are attributable to surface mining, four to coal processing, and 312 to rail transportation.

No quantitative estimate was made of occupational disease-related morbidity and mortality in surface mining. Studies of occupational health effects related to coal mining have used a mix of underground and surface mine workers that is markedly different from that expected in the West. Available data indicate that pneumoconiosis and progressive massive fibrosis result from prolonged exposure to coal dust. Since these diseases are primarily associated with underground mining conditions, the increased proportion of strip mining in the West would result in a lower incidence than indicated by national data.

The large uncertainty associated with the estimates and the controversial nature of the public health effects related to air pollutant emissions from coal-fired plants imply that dose-response relationships between specific pollutants and specific health effects must be established. This issue is not unique to the Northwest; in fact, the higher current pollutant levels in the eastern United States make the problem even more important. The resolution of these dose-response relationships will have important ramifications on emission control requirements. Regional data are also needed for the Northwest to obtain an accurate assessment of the expected accidental deaths and disabling injuries related to rail transportation of coal.

2.3.8 Socioeconomic Impacts

The likely socioeconomic impacts of constructing and operating coal-fired plants in the Pacific Northwest were assessed. Possible planning and management techniques that could be used by local governments to deal with these impacts were also investigated.

As a baseline from which to predict future impacts under the Recent Trends and High Coal Electric scenarios, the current socioeconomic characteristics of 15 candidate counties were described in terms of a set of social indicators. Potential socioeconomic impacts of coal development were then predicted using the Local Impact Management and Assessment (LIMA) computer model and several impact flow charts.

The analysis suggested that the most severe adverse impacts would probably occur in Elmore County, Idaho; in Gilliam and Morrow Counties, Oregon; and in Lincoln County, Washington. All of these counties have relatively small and rural populations, limited public services, and few planning capabilities. To minimize the potential effects of power plant developments in these four counties, the anticipated impacts should be studied carefully and the county planning and management capabilities should be greatly expanded.

In contrast, relatively few serious adverse impacts should occur for Coos County, Oregon, and Cowlitz, Grant, Grays Harbor and Whatcom Counties, Washington. In all these counties the rates of population and economic growth would be relatively small and slow so that whatever problems resulted from projects could presumably be handled with minimum disruption to these areas. None of them would experience a process of rapid urbanization; their needs for additional housing and public services would rise slowly enough to be handled on an ongoing basis; and they would not encounter any serious social problems (with the possible exception of conflict due to differing educational levels in Coos County). Moreover, all of these counties already have adequate to excellent planning capabilities. Consequently, in relation to minimizing adverse socioeconomic impacts, these five counties appear to offer the most desirable areas in the Pacific Northwest for constructing coal-fired generating plants during the next 40 years.

The major limitation of this study is that its broad scope precludes accounting for any unique features of the separate candidate counties. The second limitation lies in the many arbitrary assumptions contained in the LIMA model. Because of these limitations the study should be viewed only as a preliminary screening analysis, not as a set of site-specific impact assessments.

Future research in this area should deal with the following critical problems: 1) defining the unique case of Alaska, which is expected to undergo extensive resource developments during the next 20 years but which could not be included in our computer forecasts because of lack of data, 2) verifying the adequacy of the social indicators used in this analysis by using them to collect data on ongoing development projects (as we are presently doing with the nuclear power plants being constructed in Skagit County, Washington), and 3) testing and refining the LIMA model under varying sets of assumptions and with several sets of actual impact data.

The environmental and socioeconomic impacts identified in this study are useful in identifying those effects that may be expected from the increased use of coal in the region. While these results identify impacts that are specific to each region, they are not a substitute for detailed analysis which can be performed only on specific sites. This analysis will, then, provide decision makers with a generic assessment of the expected impacts and some suggestions for their possible mitigation. It will not substitute, though, for the detailed assessment that is possible only when specific sites are designated and baseline data for those sites have been collected.

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- **Regional Allocations**
- **Coal-Fired Generation in the Region**
- **Coal and Conversion Technology**
- **Role of the Assumptions**

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS

The National Coal Utilization Assessment (NCUA) provides a nationally consistent basis for the assessment of potential coal use scenarios in various regions. The assumed scenarios for regional energy development and associated coal technologies are presented in this chapter.

It is emphasized that the scenarios are not intended to be forecasts. Given the long time frame (to the year 2020) and numerous possible assumptions for alternate futures, four national scenarios of energy utilization were developed for the NCUA. The scenarios consist of the following: 1) Recent Trends—a base case derived from simple extrapolation of recent trends; 2) High Coal Electric—expanded use of coal-derived electric energy; 3) Accelerated Synfuels—major use of coal conversion into synthetic fuels; and 4) a combination of the latter two cases. Analytical efforts in this study concentrate on the effects of coal-fired electrical generating facilities since they are expected to the the primary coal consumers in the region. It was deemed unlikely that coal would be imported into the region for the production of synthetic fuels. Hence, the first and second scenarios are emphasized.

The general growth rates and the many underlying national and regional assumptions are founded upon the base case represented in the Federal Energy Administration's *National Energy Outlook,* published in 1976. The numerical values given in this chapter are only representative levels for our region that might reasonably be associated with the specific scenarios. The Recent Trends and High Coal Electric scenarios are decomposed from the national scenarios for the Pacific Northwest region; electric generation is differentiated by fuels for the years 1975, 1985, 2000, and 2020. Associated projections for petroleum and gas consumption are also provided although they have no direct bearing on the coal analysis.

The role of coal in filling energy demand is expected to grow (during the NCUA's time frame) for each scenario. Nationally, the Recent Trends scenario shows a 4.53% annual growth in coal used for electricity generation from 1975 to 1985, with 1.75% and 1.68% per annum for the periods 1985-2000 and 2000-2020 respectively. Reducing the same national scenarios to a Pacific Northwest base resulted in greater growth rates of 6.5%, 7.3% and 4.2% for the same respective time periods. The larger regional growth rates can be accounted for by the small base of coal-fired generation that is now in place.

The characterization of the coal technologies assumed in the study are summarized. The combination of the emissions from these plants and the number of plants derived from the scenarios provide the background conditions for evaluation of potential impacts.

The physical and chemical characteristics of coal that are expected to be utilized in the Pacific Northwest are described. They are generally lower in sulfur content (0.2 to 1.0%) and heat content (7,500-10,000 Btu/lb) than eastern coals.

As further background to Chapter 3, an appendix is provided. Appendix A, "Energy Supply and Demand in the Region," discusses the current system and its implications for future trends in energy supply in the region. Energy related characteristics are discussed, emphasizing electrical energy and coal utilization, the major scope of the assessment. This provides a comparative basis for the ground-rule assumptions used in the study.

This section presents the regional scenarios for the National Coal Utilization Assessment (NCUA). On a national basis, four different scenarios of future energy utilization are considered. Due to the particular characteristics of Federal Region Ten, notably a lack of large coal deposits in the three contiguous states and abundant fossil resources in Alaska, this study concentrates on only two of the following scenarios. Based upon the national data, allocations are made for this region which form the foundation for subsequent assessment.

3.1 REGIONAL ALLOCATION

Countless alternative patterns of coal utilization can be envisioned for the nation's energy future. To narrow the scope of the study, four representative coal development pathways, or scenarios, were postulated. Besides providing consistency, the scenarios characterize the basic features of coal development choices, provide bounds upon the potential range of coal utilization, and provide a mechanism for comparing the impacts of alternative coal technologies. The scenarios are not forecasts but rather, a set of nationally consistent background conditions for assessing the impacts of coal development on social and environmental systems.

The following are brief descriptions of the four national scenarios:

- Recent Trends: Represents a "best" estimate of future patterns of coal utilization based upon recent trends. It forms a base case against which the other national development options may be compared. No major changes in governmental policy or social institutions are assumed to occur.
- High Coal Electric: Assumes that the coal fuel mix in the years 2000 and 2020 is approximately 25% greater than the proportion of coal-fired generation in the Recent Trends scenario. On a national basis, coal provides 50% of the generation in the year 2000 for the Recent Trends case and 62% for this scenario. In the year 2020 the shares are 38% for the Recent Trends case and 50% for the High Coal Electric case.
- Accelerated Synfuels: This scenario defines a major growth of coal conversion into synthetic fuels. High Btu synthetic gases are the major product of the technologies postulated for the scenario.
- Accelerated Coal Electric and Synfuels: A combination of the High Coal Electric and Accelerated Synfuels scenarios. This case represents the upper bound of coal extraction considered for the NCUA.

The general growth rates and the many national and regional assumptions are based upon the base case represented in the Federal Energy Administration's National Energy Outlook, published in 1976. Economic growth and demographic patterns are assumed to be "best estimates" and are the same for all scenarios. The major differences between the scenarios pertain to the potential role of coal in filling energy demands.

National scenarios are decomposed on a regional basis by census regions, and energy demands are differentiated by fuels for the years 1975, 1985, 2000, and 2020. The growth in energy demand and potential for interfuel substitution is largely constrained for the period from 1975 to 1985 by current industrial and utility plans. All scenarios are approximately the same through 1985; variations in coal utilization among the scenarios occur in the year 2000.

The role of coal in filling energy demand is expected to grow during the time frame of the NCUA for each scenario. Nationally the Recent Trends scenario gives a 4.55% annual growth in total coal demand from 1975 to 1985 with 2.08% and 2.28% per annum for the periods 1985-2000 and 2000-2020, respectively. In the Pacific Census Region growth in coal demand is greater, with growth rates of 7.94%, 3.00%, and 2.72% for the same time periods. Growth rates for the High Coal Electric scenario are proportionately higher. In the Pacific Region electric utilities will account for the principal coal demand.

The NCUA has provided national scenarios that also estimate energy consumption at the regional level. However, the national scenarios are for the Pacific Census Region, which includes the states of California, Hawaii, Oregon, Washington and Alaska. Federal Region Ten includes the state of Idaho and excludes California and Hawaii.

This section allocates the NCUA scenarios for the Pacific Census Region to Federal Region Ten, our region of consideration. For Federal Region Ten accelerated synfuels are not expected to have significant impact. Although some fossil fuel demands may possibly be satisfied in the future by synthetic fuel, their production is not expected to occur in the region. With the availability of Canadian and later, Alaskan gas, it was not felt that synfuels will capture a significant share of the regional market. Therefore, the Recent Trends and High Coal Electric scenarios are primarily considered.

Since the primary impact of coal consumption within Region Ten is expected to relate to coal's potential share of electrical generation, the electrical system of the three contiguous states of the Pacific Northwest was analyzed. Analysis included electrical supply/demand modeling and extensive contacts with regional energy planning organizations and electrical utilities. The results of the analysis are presented in Appendix A.

Determining electrical generation requirements for a given region can be difficult. For Federal Region Ten the three states of Idaho, Oregon and Washington have a well-developed electrical system and common planning, whereas Alaska is in the incipient stages of development. For the three contiguous states the situation is further compounded by some power being generated outside the states and by the major coordinating organization, the West Group of the Northwest Power Pool, having a small service area outside the states as well.

Several meetings were held with representatives of Lawrence Berkeley Laboratory to determine Federal Region Ten's allocation of energy shares from the national scenarios. The general rule was to determine a reasonable decomposition of the national scenarios for the Pacific Census Region into shares for California and Hawaii compared with the states of Alaska, Oregon, and Washington. The final allocation among the various states was assumed to be fixed at a total equal to the national allocation for the Pacific Census Region.

The national forecasts for electrical growth rates in the Pacific Census Region are 3.7% for the period from 1975 through 1985 and 2.9% from 1985 to the year 2020. For Federal Region Ten, slightly higher growths are predicted, whereas projections for California are somewhat lower. Therefore, a linear allocation among the separate states would not reflect current expectations.

The first step in decomposing and allocating the Pacific Census Region scenarios was to extract predicted California and Hawaii generation from the regional scenarios. The remainder was then assigned to Alaska, Oregon, and Washington. Based upon the national scenarios, current trends, and actual utility plans for the region, a share for Idaho was next determined. The results were then reviewed and compared to independent estimates. The allocation process required several iterations for resolution.

The scenarios given in Tables 3.1 and 3.2 include the following considerations.

- The national scenarios predict significant growth in hydroelectric capacity, whereas the majority of sites in the region, with the exception of Alaska, are almost fully exploited.
- The High Coal and Recent Trends cases indicate equal amounts of nuclear generation capacity, whereas the market can be assumed to be competitive. For a High Coal scenario it is assumed that coal will gain a cost advantage over nuclear generation, resulting in a higher share for coal.

TABLE 3.1. Pacific Northwest[a] Recent Trends Electrical Generation Scenario by Alternative Technologies (10^{15} Btu)

	Baseline 1975	All Scenarios 1985	Recent Trends 2000	Recent Trends 2020
Coal	0.041[b]	0.077[c]	0.221	0.502
Peaking turbine	0.003	0.003	0.003	--
Nuclear	0.021	0.073	0.397	0.765
Hydro: conventional	0.361	0.474	0.495	0.516
pumped storage	--	0.005	0.021	0.021
Geothermal	--	--	0.017	0.067
Solar	--	--	--	--
Less:				
Pumping losses	--	(0.001)	(0.005)	(0.005)
Distribution losses	(0.021)	(0.038)	(0.068)	(0.109)
Total	0.405	0.593	1.001	1.757

(a) States of Alaska, Idaho, Oregon and Washington.
(b) 0.025 x 10^{15} Btu generation in region, balance from Montana and Wyoming.
(c) 0.027 x 10^{15} Btu generated in region.

TABLE 3.2. Pacific Northwest[a] High Coal Electrical Generation Scenario by Alternative Technologies (10^{15} Btu)

	Baseline 1975	All Scenarios 1985	High Coal 2000	High Coal 2020
Coal	0.041[b]	0.077[c]	0.533	1.159
Peaking turbine	0.003	0.003	0.003	--
Nuclear	0.021	0.073	0.222	0.394
Hydro: conventional	0.361	0.474	0.495	0.516
pumped storage	--	0.005	0.021	0.021
Geothermal	--	--	0.017	0.067
Solar	--	--	--	--
Less:				
Pumping losses	--	(0.001)	(0.005)	(0.005)
Distribution losses	(0.021)	(0.038)	(0.068)	(0.109)
Total	0.405	0.593	1.218	2.043

(a) States of Alaska, Idaho, Oregon and Washington.
(b) 0.025 x 10^{15} Btu generation in region, balance from Montana and Wyoming.
(c) 0.027 x 10^{15} Btu generated in region.

- Pumping losses and pumped storage are factors of the overall efficiency of the hydroelectric system. Pumped storage is expected to be developed in the region for peak electrical generation.
- In the long run, Alaska is expected to significantly develop its coal resources. This will be an additional factor to consider for the overall share of coal-fired electrical generation in the region.

Tables 3.1 and 3.2 show the Federal Region Ten electrical generation scenarios for the Recent Trends and High Coal Electric cases. The results include the generation shares for Alaska, Idaho, Oregon, and Washington. In both tables the baseline 1975 and 1985 results are the same. Note that for coal generation of 0.041 x 10^{15} Btu in 1975, that 0.025 x 10^{15} Btu is generated within the region. Coal-fired generation of 0.027 x 10^{15} Btu in 1985 is generated in the region.

No distinction is made between oil and gas generation of electricity in Tables 3.1 and 3.2. The only oil or gas generation will be for peaking in the foreseeable horizon. The specific fuels to be used for peaking turbines will depend upon the region's future supply situation.

Nationally, the Recent Trends scenario shows a 4.53% annual growth in coal utilized for electrical generation from 1975 to 1985 with 1.75% and 1.68% per annum for the periods 1985-2000 and 2000-2020, respectively. Table 3.1 gives greater growth rates of 6.5%, 7.3%, and 4.2% for the same respective time periods. Similar increases occurred for the High Coal scenario, as shown in Table 3.2.

Tables 3.3 and 3.4 provide breakdowns for the Federal Region Ten for petroleum and natural gas scenarios. These tables are the result of similar efforts with investigators at Lawrence Berkeley Laboratory to separate regional shares. By agreement between the laboratories, the total shares allocated equate to the mix for the Pacific Census Region, with an adjustment for Idaho. The shares for Idaho are based on current trends.

In summary, coal development in the Pacific Northwest is expected to be primarily based in the generation of electricity. As a result, the electrical system in the region was considered in detail. Several factors characterizing the region's electrical system are elaborated in Appendix A. These factors assisted in determining a reasonable allocation of the national scenarios to our region. The scenarios themselves are consistent with the allocation of the national scenarios, yet they reflect a different mix of electrical generation, resulting from separating California and Hawaii from our consideration.

3.2 COAL-FIRED GENERATION IN THE REGION

The national scenarios are used in combination with other assumptions summarized below to identify possible coal-fired electrical generating capacity growths in each state. The given scenarios decomposed to Federal Region Ten are based on average estimates and do not factor current regional projections. The tabulations given here reflect various regional considerations in specifying capacity addition requirements within the constraints of the national scenarios.

The Recent Trends and High Coal Electric scenarios are considered applicable to the region. To interpret the capacity growths into candidate siting area scenarios, the following assumptions are made:

- Energy demands in each state will be met by in-state additions to capacity, i.e., additional mine-mouth capacity from out-of-state will not be available and none of the three states will add capacity for export. Bonneville Power Administration will smooth out modest deviations.

TABLE 3.3. Pacific Northwest[a] Petroleum Scenario 1975 to 2020 by Alternative Technologies (Btu 10^{15})

Category	Baseline 1975	All Scenarios 1985	All Scenarios 2020	Recent Trends and High Coal Electric 2020
Supply				
Production				
Lower 48 states	--	--	--	--
Alaska	--	0.712	1.030	1.685
Regional imports	0.099[b]	0.101[b]	0.123	0.145
Foreign crude imports	0.609	--	--	--
Total refined inputs	0.708	0.813	1.153	1.830
Less process use	0.043	0.031	0.093	0.251
Total refined products	0.665	0.782	1.060	1.579
Total demand	0.665	0.782	1.060	1.579

(a) Includes Washington, Oregon, Alaska and Idaho.
(b) To Idaho primarily.

TABLE 3.4. Pacific Northwest[a] Gas Scenario 1975 to 2020 by Alternative Technologies (Btus 10^{15})

	Baseline 1985	All Scenarios 1985	Accelerated Synfuels and High Coal Electric 1985	All Scenarios 2000	Accelerated Synfuels 2000	Accelerated Synfuels and High Coal Electric 2020	Recent Trends and High Coal Electric 2020	Accelerated Synfuels 2020	Acceleratec Synfuels and High Coal Electric 2020
Supply									
Production									
Lower 48 states	0.064	--	--	--	--	--	--	--	--
Alaska	--	0.403	0.401	0.358	0.358	0.356	0.313	0.315	0.311
Less processing energy	--	0.030	0.028	0.030	0.030	0.028	0.030	0.033	0.029
Regional imports	0.578	--	--	--	--	--	--	--	--
Foreign imports	--	--	--	--	--	--	--	--	--
Foreign exports	0.055	--	--	--	--	--	--	--	--
Less pipeline use	--	0.013	0.013	0.009	0.009	0.009	0.005	0.004	0.004
Total demand	0.596	0.360	0.360	0.319	0.319	0.319	0.278	0.278	0.278

(a) Includes Washington, Oregon, Alaska and Icaho.

- Utility service area considerations will not be constraining, i.e., joint financing and power exchanges will continue as in the past.

Based on these assumptions, Tables 3.5 and 3.6 summarize the two coal-fired electrical generation scenarios for the states of Idaho, Oregon and Washington, and Alaska. The capacities indicated in the region reflect a judgmental melding of the national scenarios and current utility plans and trends.

TABLE 3.5. Coal-Fired Electric Generation Scenario for Idaho, Oregon, and Washington

Three State Total

	Recent Trends			High Coal Electric		
Year	Capacity (1000 MWe)	Annual Gen: (10^9 kWh)	Coal Demand[a] (MMTPY)	Capacity (1000 MWe)	Annual Gen: (10^9 kWh)	Coal Demand (MMTPY)
1975	1.3	6.8	3.4	1.3	6.8	3.4
1985	1.8	8.0	4.0	2.4	9.3	4.7
2000	14.2	63.3	31.6	31.6	142.1	71.0
2020	23.8	125.1	62.5	53.3	280.1	140.0

State Breakdown

	Recent Trends Capacity (1000 MWe)			High Coal Electric Capacity (1000 MWe)		
Year	ID	OR	WA	ID	OR	WA
1975	0	0	1.3	0	0	1.3
1985	0	0.5	1.3	0	0.67	1.3
2000	2.5	5.5	7.8	5.0	11.0	17.3
2020	3.5	8.0	12.3	8.5	17.5	27.3

(a) Based on 9000 Btu/kWh, 9000 Btu/lb.

3.2.1 Idaho, Oregon, and Washington

Current (1975) coal-fired electrical generation serving the three contiguous states is 2509 MWe. Some of the coal-fired power production occurs outside the region, primarily in western Wyoming and eastern Montana. The two plants included in this generation are: 1) Jim Bridger #1 in Wyoming, and 2) 179 MWe as the region's share of Colstrip #1 in Montana. (This was noted in Tables 3.1 and 3.2.) The 1300 MWe Centralia Station, located in Lewis County, Washington, is the only plant located within the three-state region.

For the near term (1978 to 1988), regional utility plans indicate that electricity from coal combustion will continue to be generated outside the region. Table 3.5 presents coal-fired generating capacities of 1300 MWe for the year 1975 for each scenario. To meet the production required by the scenarios, it was necessary to add some capacity in the region subsequent to the initial year. In the longer term (after 1990), further additions in coal-fired capacity, beyond current utility projections, are assumed to occur in the states requiring the electricity. This reflects a "ship-and-burn" philosophy. The additional capacity requirements, based on this assumption, show significant increases during the period for both scenarios.

TABLE 3.6. Alaska Coal-Fired Electrical Generation Scenarios

	Recent Trend 2000	High Coal 2000	Recent Trend 2020	High Coal 2020
Coal-fired generation (10^{15} Btu)	0.005	0.045	0.048	0.150
Capacity (1000 MWe)[a]	0.28	2.5	2.7	8.4
Coal consumption (millions of tons per year)	0.88	7.9	8.4	26.3

(a) Based on 9000 Btu/kWh, 7500 Btu/lb.

3.2.2 Alaska

In 1975, Alaska had a share of approximately 3% of the total electrical generation in the region. However, Alaska's growth in the next decade is expected to continue at a rate from 8-17% per year.[1]

Electrical generation during the time horizon of the NCUA is expected to come from Alaska's fossil resources and undeveloped hydroelectric potential. Coal resources from Alaska are expected to be a factor in the supply to the contiguous states, particularly Oregon and Washington, and in the generation of electricity within the state. Table 3.6 provides estimates for Alaska's coal-fired electrical generation in the key years of the scenarios. Depending on the fate of the Upper Susitna hydro projects and the implementation of the National Energy Plan, this data could underestimate the rate of growth of coal-fired generation.

For the years 1975 and 1985, coal-fired generation in Alaska is expected to be negligible. This will continue through the year 2000 for the Recent Trends case. Several hydroelectric projects are planned in the state: Watana Dam (3.1×10^9 kWh/yr) installed on line between 1985 and 1990, Devil Canyon (3.0×10^9 kWh/yr) on line between 1990 and 1995, Bradley Lake and Chakachamna (total 1.6×10^9 kWh/yr) after 1995.

As shown in Table 3.6, coal generation may significantly increase during the period 2000 to 2020 in the High Coal scenario. The tons of coal consumed are based on a heat rate of 9000 Btu/kWh for Beluga coal with a heat content of 7500 Btu/lb.

Overall electrical generation in Alaska is expected to grow between 8-16% to the year 2000. Beyond that time growth is expected to taper off to approximately 5% to the year 2020. These estimates were factored into the scenarios in Tables 3.1 and 3.2.

3.3 COAL AND CONVERSION TECHNOLOGY

This section surveys the resource requirements and environmental residuals associated with the technologies assumed for the study. The technologies are assumed on a nationally consistent basis. Although the NCUA considers conversion of coal to synthetic fuels, the impact analyses for Federal Region Ten focus principally upon combustion of coal for electrical generation. The characteristics of coals expected to be consumed, the assumed combustion technology and technical aspects that could be problem areas are discussed.

TABLE 3.7. Status of DOE Fossil Energy Technology Programs[3]

Technology	Process Scheme	Laboratory to PDU[a] Phase	Pilot-Plant Phase	Demonstration-Plant Phase
Coal Liquefaction	Direct hydrogenation	H-Coal Synthoil Zinc chloride catalyst Disposable catalyst	H-Coal pilot plant in design phase	
	Solvent extraction	Solvent refined coal Solvent extraction in lignite; Co-Steam Donor solvent liquefaction	Solvent refined coal pilot plant in operation[b]	SRC in conceptual design phase Fisher-Tropsch in conceptual design
	Pyrolysis	Hydrocarbonization Clean metallurgical coke/liquids Flash liquefaction Fluid coke	COED pilot-plant operation terminated[b]	COALCON demo plant program suspended in design phase. COED in conceptual design phase
	Indirect liquefaction	Supporting studies		
Coal Gasification	High Btu	Selfagglomerating ash Hydrane	Bi-Gas[b] Hygas[b] CO_2-Acceptor Synthane[b]	Conceptual designs being solicited
	Low Btu	Fixed bed, stirred process Fixed bed, slagging process Two stage, pressurized Three stage, pressurized Entrained bed atmospheric Molten salt		
	Low Btu/combined cycle		Pilot plant in design phase	
Advanced Power Systems	Open-cycle gas turbine	Laboratory testing for use with coal and coal-derived fuels		
	Closed-cycle gas turbine	Gas turbine/steam turbine Alkali metal turbine/steam turbine		
Direct Combustion	Atmospheric fludized bed		30 MWe plant in operation[b]	In design phase
	Pressurized fluidized bed		13 MWe pilot plant in design	
Magnetohydrodynamics	Coal-fired MHD	Open-cycle MHD Closed-cycle MHD		
Petroleum and Natural Gas Extraction	Fluid injection enhanced recovery		Thermal methods - oil Thermal methods - tar sands	Chemical methods
	Nonnuclear fracturing		Hydraulic fracturing Chemical explosive fracturing	
In Situ Conversion	Oil production	Shale oil recovery		
	Gasification	Oil shale gasification Coal gasification		

(a) Process Development Unit - bench-scale testing.
(b) Potential process for first year assessment.

A Technology Characterization Committee, with members from all participating national laboratories, was established to characterize the power plant designs to be considered under the NCUA. The work of this committee has been compiled by Argonne National Laboratory and reported.[2] Much of the information in this chapter is based upon the above reference.

It is often difficult to anticipate the state-of-the-art of technology in the years 1985 and beyond. The technology of conventional steam electric power generation is generally well established; the only areas of major technological advancement expected are in pollution controls applied either before or after combustion. Thus, the nature of this technology can be predicted with relative confidence.

Table 3.7 describes the status of advanced coal conversion technologies being developed in the U.S. Much of the work in high-Btu coal gasification and coal liquefaction is still in the pilot-plant stage; no demonstration plants are operating or even yet under construction.

In general, the characteristics of a coal conversion facility, whether a power plant or gasification plant, will ultimately be determined by such factors as the type of coal, the availability of water, local climatic or atmospheric dispersion conditions, existing air or water quality, design practices of the engineering contractors, the utility market characteristics, and the preferences of the individual utility. Because of so many variables, most of the ranges in inputs and outputs that might be encountered for a given technology and why they occur will be discussed, rather than specific facility designs that possibly have limited application. The numerical values used for this assessment are given in subsequent chapters dealing with the particular impacts.

The data given here for these characterizations are based on surveys of numerous sources. Emissions are defined on two levels: that level which can be achieved through control technologies (either demonstrated or predicted for the time frame of the NCUA); and the upper level of emissions allowed by applicable state or federal standards. Those input and effluent parameters that can be directly related to the coal characteristics (e.g., coal input, ash output) are assumed to be based on the regional average coal compositions for Northern Great Plains Province and Alaskan coals described below.

3.3.1 Coal in the Region

Currently, Federal Region Ten is not a large producer of steam coal. The active mining subregions are at Healy, Alaska and Centralia, Washington. Except for Alaska and Centralia, the region's coal resources, (though substantial in total amount) are difficult to mine and transport due to remote locations or steeply dipping beds. The development of new mining techniques (e.g., hydraulic) or in situ gasification could result in further development, particularly in western Washington. In the time frame of this analysis it is assumed that subbituminous coals from the Northern Great Plains (Montana and Wyoming) or southern Alaska will supply the region's coal needs.

Table 3.8 lists the U.S. Geological Survey ultimate and proximate analyses of the coals that may be used in the region.[4] Alaskan and Montana subbituminous coals are listed separately because of their different characteristics. The data indicate the high degree of variance in coal characteristics within individual regions. The coal of the Green River Basin of

TABLE 3.8. Characteristics of As-Received Regional Coals and Solvent Refined Coals: Proximate and Ultimate Analyses in Weight Percent

Wt%	Alaska-Beluga		Alaska-Nenana		Washington-Centralia		Northern Great Plains		SRC	
	Average	Range	Average	Range	Average	Range	Average	Range	Average	Range
Moisture	28	--	--	17.8-27.1	--	16.8-29.0	24.7	19.1-31.5	4.6	0.2-12.0
Volatile matter	32	--	--	33.2-42.0	--	29.7-34.8	31.4	26.3-38.1	60.3	59.1-64.4
Fixed carbon	30	--	--	27.1-35.3	--	28.6-33.9	36.0	28.3-41.7	35.1	25.7-43.7
Ash	10	--	--	3.5-13.2	--	7.6-19.7	7.8	4.2-15.5	0.2	0.1-0.3
Hydrogen	--	--	--	--	--	--	6.3	5.8-6.6	5.5	5.0-5.8
Carbon	--	--	--	--	--	--	50.0	44.4-56.6	83.3	75.3-88.6
Nitrogen	--	--	--	--	--	--	0.8	0.6-1.4	1.6	1.3-1.9
Oxygen	--	--	--	--	--	--	34.0	28.0-40.7	4.5	4.0-5.1
Sulfur	0.15	--	0.2	0.1-0.13	--	0.6	0.5	0.2-4.2	0.6	0.1-0.8
Btu/lb	7,500	--	9,000	7,570-9,430		7,530-8,763	8,640	7,810-9,710	14,620	13,670-15,240

Wyoming is subbituminous with higher heating values (HHVs) of around 9500 Btu/lb. The limited data available on the extensive reserves of subbituminous coals in southcentral Alaska, accessible to the Railbelt (Anchorage to Fairbanks) or to tidewater, indicate that the as-mined coal is of lower Btu content due primarily to high moisture content. The sulfur content, however, is considerably below that of Montana and Wyoming coals, even on a Btu basis.

Also included are the characteristics of Solvent Refined Coal (SRC) based upon a limited number of pilot-plant samples.[5,6,7] The high heat content and low sulfur, ash and moisture content make it an attractive fuel for use in steam generators. Although these early data indicate rather large ranges in composition, the SRC product is expected to be more uniform in composition as progress is made on the solvent refining process.

3.3.2 Conventional Steam Electric Power Plants

The coal combustion technology assumed for the NCUA represents roughly the state-of-the-art in new power plants using either high-sulfur coal with flue gas desulfurization (FGD) or low-sulfur coals without SO_2 controls. Each unit will be based upon a tangentially-fired (or equivalent burner configuration for NO_x control) pulverized coal boiler and a steam turbine/generator operating on a single reheat condensing Rankine cycle. Maximum steam temperatures are assumed to be approximately 1000°F, with operating pressures ranging from 2500 to 3500 psi.[8]

The power plants considered in this characterization will have the following basic subsystems: coal receiving, storage, and handling; boiler; turbine/generator; condenser cooling system; particulate control device (ESP, scrubber, etc.); SO_2 control device (optional); ash disposal; water system. A standard power plant design does not exist; what may be an efficient design for one type of coal may give only marginal performance for another. For example, no boiler manufacturer would consider designing and building a utility boiler without prior knowledge of the fuel to be burned. Any coal, including lignite, can be burned efficiently in a unit specifically designed for it. It is when a change in fuel is made (e.g., high to low Btu content) that problems arise.

The following gives ranges for the various factors characterizing the power plants and emissions assumed for this assessment. Specific numerical values used for quantifying impacts are given in the respective chapters to follow.

Size

For siting purposes, units of 500 MWe are assumed. For actual increased coal utilization, facility size will be determined by the total size and nature of the utility grid system. Although economies of scale in construction costs favor large generating units, small dispersed facilities may appear to be more desirable environmentally. Where utility system loads are small and major interconnecting grids do not exist, as in Alaska, smaller units in the range of 100 to 200 MWe are likely.

Heat Rate

No significant increase in thermal efficiency over 40% is anticipated in the future due to the thermodynamic limitations of the condensing steam cycle. For new units burning bituminous coals or SRC and having once-through cooling systems and no scrubbers, the best current

heat rates range from about 8800 to 8900 Btu/kWh. Use of subbituminous western coals or lignites tends to derate coal-fired plants because their low heating values and high moisture contents require the use of additional pulverizers and draft fans. Baseline heat rates for new plants burning these coals are on the order of 9200 to 9400 Btu/kWh.

Table 3.9 lists approximate increases in plant heat rate that might result from the use of closed system cooling or scrubbing.[9] Actual increases will naturally depend upon the climatic conditions, the scrubber efficiency, etc. In general, NO_x control and electrostatic precipitators would cause negligible increases in the plant heat rate.

More thermally efficient coal technologies could potentially replace conventional combustion as a means of producing electric power. Pressurized fluidized bed combustion, low-Btu gasification with combined cycles, and advanced cycles with organic bottoming cycles or alkali vapor topping cycles are all expected to have baseline thermal efficiencies above 40% and to be commercially available before the year 2000. Coal-fired open-cycle magnetohydrodynamics (MHD) has the potential for thermal efficiencies over 50% and has other attractive features, such as nearly instantaneous load response.

Water Use

In electric power plants water is used for evaporative cooling, steam, solids handling, and miscellaneous cleaning operations. Cooling water evaporation is based largely on the facility's power production and on the type of system used. Once-through cooling and artificial cooling lakes can both have rather large consumptive losses through evaporation from the surface of the receiving body of water. Evaporative cooling towers are the principal cooling devices that will be considered here. Mechanical draft and natural draft cooling towers both have similar consumption rates, about 0.5 to 0.7 gal/kWh, depending upon ambient air temperature and relative humidity.

TABLE 3.9. Approximate Increases in Power Plant Heat Rate Due to Ancillary Systems[9]

	Btu/kWh
Cooling Systems:	
Mechanical Draft Wet Towers	145
Natural Draft Wet Towers	120
Spray Canals	150
Artificial Lakes	70
Mechanical Draft Dry Towers	575
SO_2 Scrubbers:	
Limestone Throwaway	360
Lime Throwaway	345
Magnesia Regenerable	530
Sodium Regenerable	1150
Catalytic Oxidation	10

Representative consumptive uses of water for several alternative methods of power plant cooling are listed in Tables 3.10 and 3.11. The ranges reflect differences in consumption due to variations in the local climate (humidity, temperature, cloud cover, etc.), and are based on EPA[10] and GE[11] estimates.

TABLE 3.10. Water Consumption by Coal Electric Power Generating Plants

Cooling System	Water Consumption (gal/kWh)
Once-through	0.1-0.3
Cooling Pond (1 acre/MWe)	0.6-1.0
Spray Pond or Canal	0.4-0.6
Mechanical Draft Wet Tower	0.5-0.7
Natural Draft Wet Tower	0.5-0.7
Mechanical Draft Dry Tower	0-0.01

Other water uses, on an annual basis, are directly related to plant size rather than to power output. This water is used as the makeup for ash handling systems, wet scrubbing devices, boiler tube cleaning, potable water, etc. The actual volume of water that is used and then discharged depends upon the care and expense taken to recycle water internally in the plant. The table below lists the major flow streams and losses and the approximate amounts of water necessary to support these streams, based upon actual flow data and estimates made by EPA.[10]

TABLE 3.11. Miscellaneous Water Use in Coal Electric Generating Plants

Water Stream or Loss	Water Used (gal/day/MWe)
Cooling tower blowdown	2000-7500
Ash handling discharge	100-400
Metal cleaning wastes	15-20
Boiler blowdown	50-60
Losses in ash	70-100
Low volume and miscellaneous uses	100-125

Air Emissions

This section is primarily concerned with criteria pollutants--sulfur dioxide, oxides of nitrogen, and particulate matter. The behavior and emissions of trace elements released from coal combustion boilers are the subjects of a more thorough report to be released later by Argonne National Laboratory and are not discussed here in any detail.

Sulfur Oxides

Two common techniques are applied to coal combustion to limit the emission of SO_2 within the current Federal New Source Performance Standard (NSPS) of 1.2 lb/10^6 Btu. (New Source Performance Standards may be revised downward). The first is to limit the amount of sulfur available to be converted by ensuring that the fuel has less than 0.6 lb/10^6 Btu of sulfur. The second approach is to physically remove (scrub) the SO_2 from the combustion products. Figure 3.1 shows the removal efficiencies necessary to obtain current NSPS. Other options

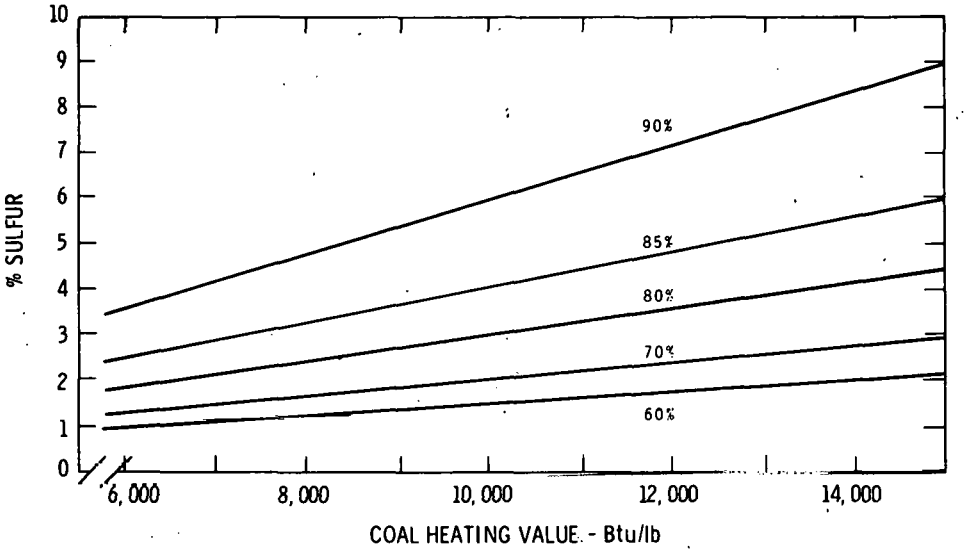

FIGURE 3.1. Required SO_2 Control Efficiency to Meet NSPS

include washing or chemical cleaning of the coal to remove both inorganic and organic sulfur, conversion of coal to low-Btu gas, and conversion of coal to a low-sulfur liquid via solvent refining or some other liquefaction process.

Flue gas desulfurization (FGD) is the principal method for scrubbing SO_2. In FGD the SO_2-laden flue gases enter a reaction chamber where they are contacted with a chemical solution or slurry that absorbs the SO_2. The reacted sorbent is removed from the scrubber and is either disposed of (throwaway process) or regenerated to produce a byproduct sulfur compound and the recycled sorbent (regenerable process). Throwaway processes, using limestone and lime scrubbers, will continue to be the primary cleaning method used in the near to midterm of the assessment. Demonstrated removal efficiencies vary from about 50% to over 90%[11]

An important problem associated with throwaway FGD is disposing of the large volume of waste sludge. Sludge from the lime, limestone, and double alkali processes consist of hydrated calcium sulfite and sulfate crystals, which must be chemically stabilized to make them suitable for landfills. These effluents are discussed in more detail under "Solid Wastes" paragraph below.

Regenerative FGD systems are attractive future options because they can regenerate their own sorbents and can produce byproducts that can be more easily disposed of than sludges. Widespread use of these systems would require increased storage of certain acid byproducts. Potential risks to the environment, the public, and the workers resulting from this "cycle" require further investigation.

No successful demonstration of regenerable processes on large coal-fired units has yet been accomplished; it is likely that regenerable FGD systems will not be commercialized until at least 1985.[11] Fluidized bed combustion (FBC) is another sulfur dioxide control technique that is anticipated to replace conventional FGD. Atmospheric fluidized bed combustion (AFBC) is expected to be available in the 1985-1990 period, with pressurized FBC operation commercially available about 1995.[12]

Particulate Matter

The coal ash that enters the furnace will eventually exit by two pathways--either as large bottom ash particles, or with the flue gases as fly ash. The relative proportioning between these two is a function of the method of coal firing, burner configurations, furnace designs, coal ash fusion temperatures, and other coal characteristics. The table below lists the fraction of coal ash that would normally exit as fly ash for three different boiler designs.

Boiler Design	Fraction to Flue Gas (%)
Dry bottom pulverized coal	80-90
Wet bottom pulverized coal	60-65
Cyclone	20-25

In this assessment it will be assumed that all boilers will be of the pulverized coal, dry bottom type.

Electrostatic precipitator (ESP) technology is such that fly ash removal efficiencies of 99 to 99.5% on a mass basis can be consistently achieved, with efficiencies over 99.8% possible for eastern coals. The ashes of low-sulfur coals have higher electrical resistivities than those of higher sulfur coals, making fly ash capture much more difficult and costly. Achievement of the above levels of collection for western coals would necessitate either a high-temperature ESP or conditioning of the flue gas by chemical additives to reduce the resistivity of the fly ash.

Two other particulate removal technologies are wet scrubbers and fabric filters (baghouses). Wet scrubbers are not as efficient in removal of fine particles as are ESPs. Other problems associated with wet particle scrubbers are water consumption and water pollution; and in addition, this process has rather substantial energy penalties. Baghouses, however, have been proven to provide overall collection efficiencies of well over 99% by weight, with efficient removal of fine particles. Further research is needed, especially in the area of fabric material life. It is anticipated that fabric filters could be in widespread use by at least 2000.

Nitrogen Oxides

Oxides of nitrogen (NO_x) are pollutants which cannot be directly predicted from the coal characteristics. The determining factors for the emissions of NO_x are peak flame temperatures in the furnace, the amount of excess air available, and the residence time of the gases in the peak temperature zones. The Federal NSPS for NO_x is 0.7 lb NO_2 per 10^6 Btu input. The emission rate of NO_x from uncontrolled pulverized coal can range from 0.5 to 1.2 lb/10^6 Btu.

To date the primary method of NO_x control has been through the use of external combustion modifications to control peak flame temperatures and available excess air. Low excess air firing, staged combustion, flue gas recirculation, and water injection have all been used with varying degrees of success to limit the excess air available for thermal NO_x formation or to lower peak flame temperatures.[13] The current state-of-the-art plant using tangential firing, staged combustion, and low excess air can have NO_x emissions in the range of 0.35 to 0.4 lb/10^6 Btu.

Solid Wastes

The major sources of solid waste output from coal-fired power plants are the coal ash, scrubber sludge (if applicable), and the sludges from water treatment. The volume of the latter are generally negligible compared to the other sources, and in this characterization they are assumed to be disposed of with the ash.

Except for the small percentage of the ash that escapes from the particulate control device, virtually all of the coal ash input to the boiler is collected as either bottom ash or fly ash. Fly ash is usually handled dry in the western states. Ponds, when used, are on the average of 10 to 30 ft deep. The size of the pond depends upon the amount of ash to be handled over the lifetime of the facility. The ash storage volume can be determined by assuming that the wetted ash has a density of approximately 2600 ton/acre-ft. Mine-mouth plants will return the ash to the mine for burial with the mine spoils.

If a wet throwaway type SO_2 scrubber is used, a wet sludge will also be formed. The actual amount of sludge produced from a disposable FGD system is a function of such parameters as:

- solvent used
- SO_2 removal efficiency
- sulfur content of coal
- Ca/S ratio
- plant load factor
- coal input.

For example, approximately 450 tons per day of limestone would be required to remove 85% of the SO_2 from a 3000 MWe reference plant burning Northern Great Plains coal with 0.5% sulfur.

As a rough estimate it could be assumed that the dry solids output from lime/limestone FGD will approximately equal the sorbent input. The calcium sulfite content of the sludges make them hard to dewater beyond 50 to 65%, especially for high-sulfur coals. It will be assumed in this characterization that all nonregenerable FGD sludges will be stabilized to at least 80% solids content.

Water Effluents

No standard design for water usage in a power plant exists. The paths that water follows and the rates at which they flow are all subject to the power plant design. It was necessary to make a few assumptions about the nature of the facility in order to estimate possible water pollutant loadings. In general, there are eight major streams to be considered:

- cooling tower blowdown
- bottom ash discharge
- fly ash discharge
- coal pile runoff
- FGD water
- sanitary sewage
- metal cleaning
- miscellaneous low-volume wastes.

Of these streams, only the cooling tower blowdown and bottom ash discharge are continuous streams that might be discharged. To be consistent with the EPA guidelines on the use of best available control technology, it is assumed that fly ash will be handled pneumatically so no water will be discharged. Coal pile runoff depends upon the local rainfall and will therefore be an intermittent source. All runoff will be collected and sent to a holding basin. Metal cleaning (very infrequent) and low-volume wastes are intermittent sources but are impounded. Sanitary sewage is negligible in volume compared with other sources and is not considered here.

3.4 ROLE OF THE ASSUMPTIONS

To properly evaluate the scenarios and technology characterization given in this chapter, it is important that the reader understand the purposes for which they will be used in the NCUA. The scenarios are intended as guidelines, which when coupled with technology assumptions, serve to bound and standardize the assessment of potential effects.

Following the scenarios and technology characterization, a siting analysis is given in the next chapter. The analysis further distributes regional energy utilization to the substate level. This information, developed with regional knowledge under the given assumptions, is the basis for conducting impact analyses in six major areas: 1) air quality, 2) water resources, 3) land use, 4) ecosystems, 5) health and 6) socioeconomics. Each area is the subject of a subsequent chapter of this report.

The development of the national scenarios and their decomposition to an assignment for our region are not based on a specific power forecast. Although it was attempted to factor regional plans and current policy into the ground rules and framework described by the scenarios, it would be impossible to achieve a consensus on their reality.

A similar point can be made regarding interpretation of the study results. The impacts elaborated in this report are based on assumptions each step of the way; the objective is to identify potential environmental, social, and economic problems that may arise. Identification of problems associated with increased coal use at a given level will assist in guiding future environmental research and mitigation efforts.

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4.0 CANDIDATE COUNTY SITING

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- **Rationale for Selection of Sites**
- **Transportation**
- **Selection of Candidate Sites**

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

4.0 CANDIDATE COUNTY SITING

To provide consistent assessments of the health and environmental effects of future coal utilization in the region, a common set of plant sites for coal-fired electrical generating facilities must be used in all assessments. In this chapter trial siting plans are developed for the states of Alaska, Idaho, Oregon and Washington for the Recent Trends and High Coal Electric scenarios over the 1980-2020 time period. For Idaho, Oregon and Washington the location of the plants is specified to the county level. Because of the large census regions in Alaska (there are no counties in Alaska), plant location is specified to an "area" around a coal field or town. To develop these siting plans, five criteria were developed and used to allocate plants to candidate counties or areas.

These siting plans represent a tradeoff between the necessity of having a common set of facility sites to insure consistent analyses in the following chapters and the impossibility of selecting the best 20 to 50 sites in the four-state region over the next 43 years. The authors realize that actual site selection will be determined through the interaction of the various utilities, state and local governments, and interest groups, given the economic, technological, environmental and social conditions existing at the time a plant is to be built. The possibility exists that almost any county or area in the region might be the future site of a generating facility. Selection of the candidate county-level sites then is based on logic, which should not be considered a definitive siting analysis.

This chapter develops schedules complete with dates and sizes for discrete coal-fired electrical generating capacity additions in Alaska, Idaho, Oregon and Washington. For Idaho, Oregon and Washington the schedules are derived from data presented in Table 3.5. For Alaska the schedules are based on forecasts of Alaskan electricity demand.[1,2]

To develop these schedules three steps were taken:

1) A discrete size for the individual generating plants was assumed.
2) A set of criteria was developed to be used as a basis for siting individual plants.
3) Using these criteria and the plant size assumptions, generating plants were allocated to specific counties or areas.

The siting exercise in this section is cursory. For a long-range scenario assessment it was not necessary to specify plant location within counties; as a result, site-specific siting criteria are not used. The criteria used are quite general but still useful in pointing out counties that represent areas that are suitable locations for coal-fired electrical generating plants.

Regional utilities were consulted about their future plants and perspectives, and these plants, even though conceptual, are taken into account. Utility service areas are not considered to be a siting constraint because of the joint financing and power exchange options available to them.

Generating capacity is added in discrete units of capacity. For Idaho, Oregon and Washington a constant individual plant size of 500 MWe is assumed. Because of the relatively

small initial demand base in Alaska, plant sizes are individually selected. It is further assumed that plants will come on-line on January 1 of a specified year after a five-year construction and startup period (4 years of construction and one year for startup). In cases where two plants or units are built in the same location, the second unit is assumed to come on-line six months after the first. When periods of an excess or shortage of generating capacity exist within a state, it is assumed that the compensating shortage or excess will be available through the utility intertie system from another state or type of electrical generating capacity. Using these assumptions, graphs representing individual generating plant additions can be derived. These are shown in Figure 4.1 and 4.2.

The next task is to develop a set of criteria to be used to select individual counties as candidate siting areas. The siting criteria used in this study are:

- availability of water for cooling purposes
- availability of relatively flat terrain with good atmospheric ventilation
- access to either rail or waterborne transportation for coal shipment
- nearness to existing transmission corridors, and
- nearness to electrical load centers.

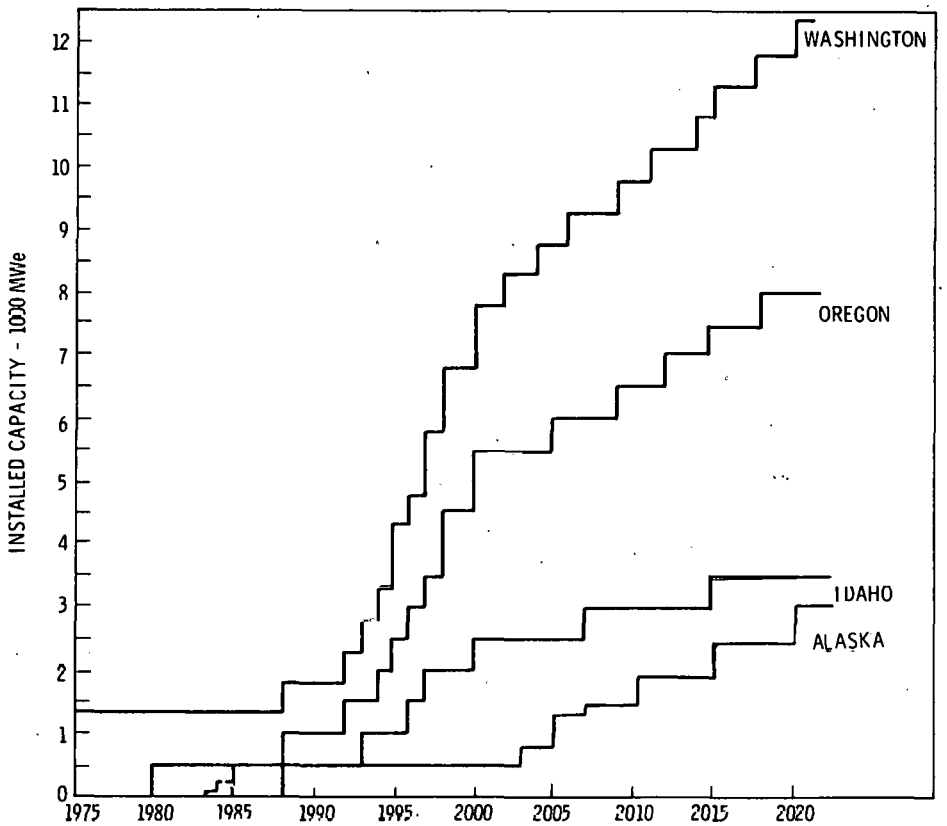

FIGURE 4.1. Coal-Fired Electrical Generating Capacity by State - Recent Trends Scenario

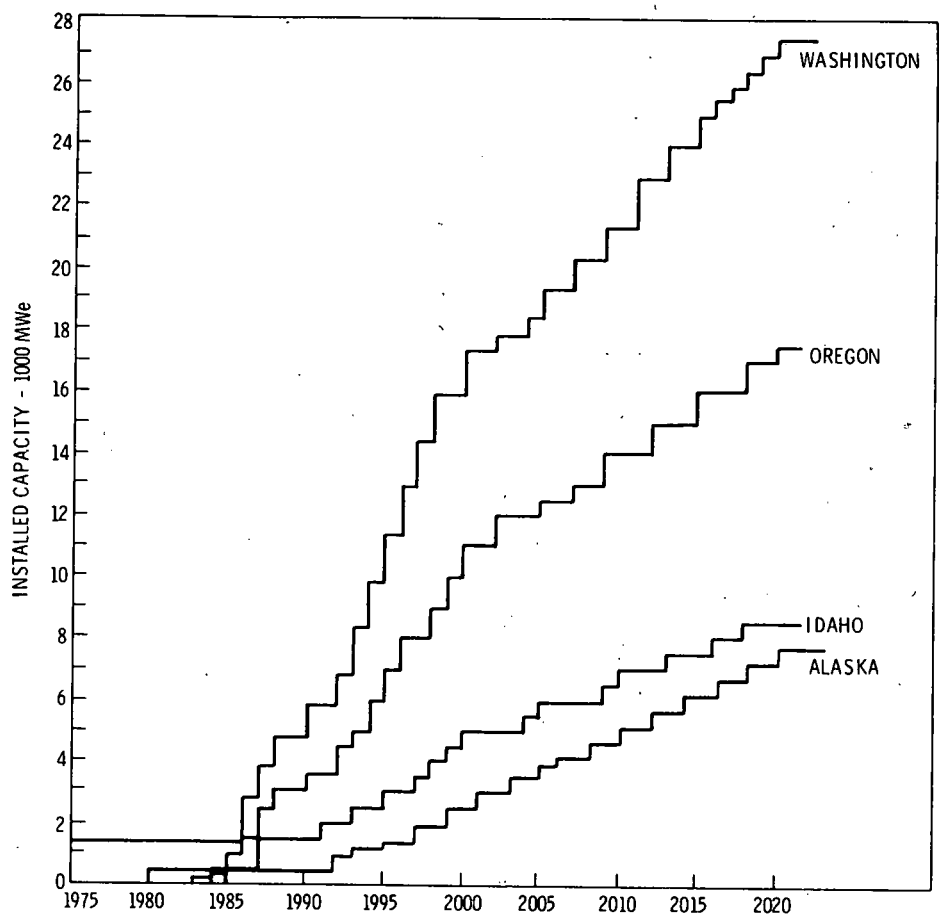

FIGURE 4.2. Coal-Fired Electrical Generating Capacity by State - High Coal Electric Scenario

Although no formal weighting scheme was used to judge the relative importance of these five criteria, the first three were considered to be more important than the last two. The siting results are summarized in Figures 4.3 and 4.4. The total coal-fired electrical generating capacity to be built in the various counties and areas assuming the Recent Trends and High Coal Electric scenarios are shown. The detailed schedules including power on-line dates and capacities are listed in Appendix B.

4.1 RATIONALE FOR SELECTION OF SITES

The availability of water for cooling and the location of areas with good atmospheric conditions are determined primarily by the topography of a region. The major topographical features of the region are shown in Figure 4.5. Idaho, Oregon and Washington have five distinct topographical areas: 1) coastal lowlands and mountains along the Oregon-Washington coast, 2) Willamette Valley, Oregon and Puget Sound Lowland, Washington, 3) Cascade Mountains across Oregon and Washington, 4) a broad basin-plains area through eastern Oregon and Washington and into southern Idaho, and 5) Rocky Mountains stretching from extreme northeast Washington down through northern and central Idaho.

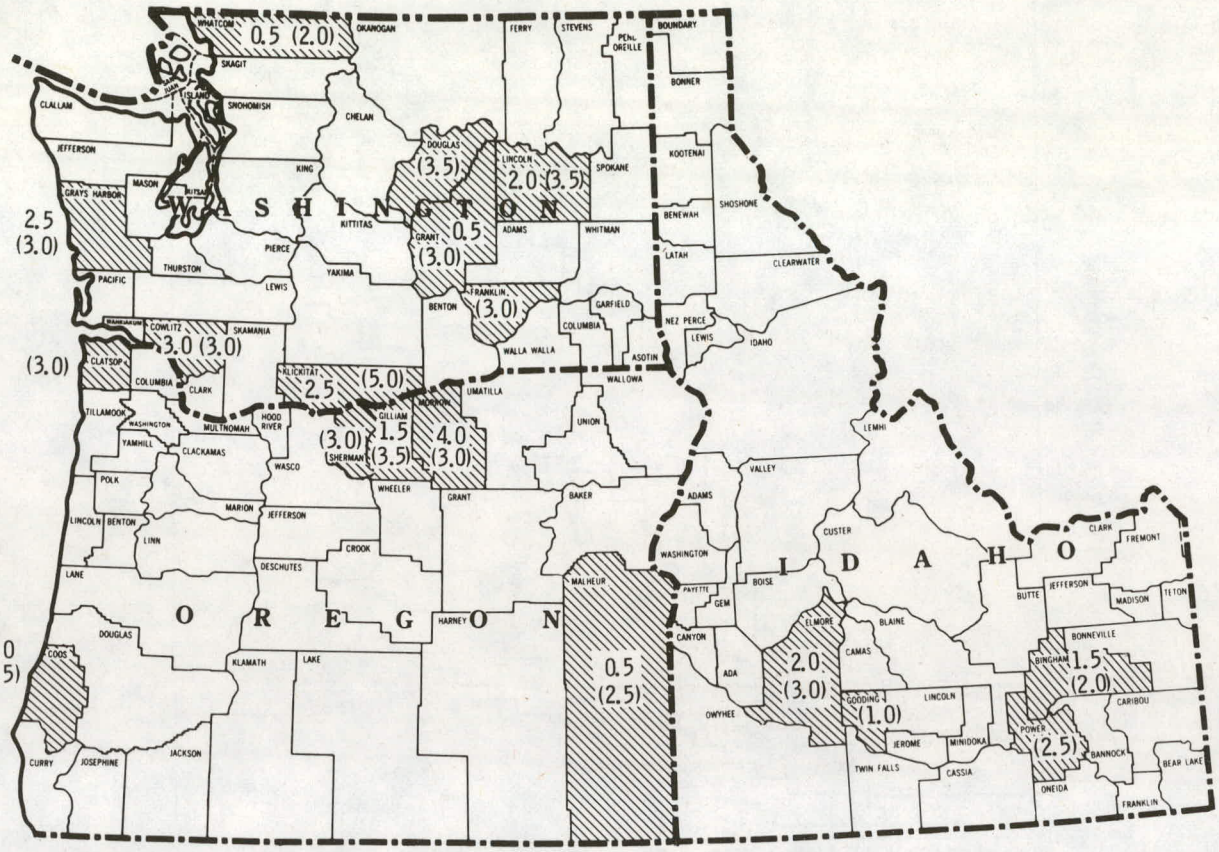

FIGURE 4.3. Candidate Siting Areas Showing 1000's of Megawatts of Capacity Under Recent Trends and (High Coal Electric) Scenarios to the Year 2020 for Idaho, Oregon and Washington

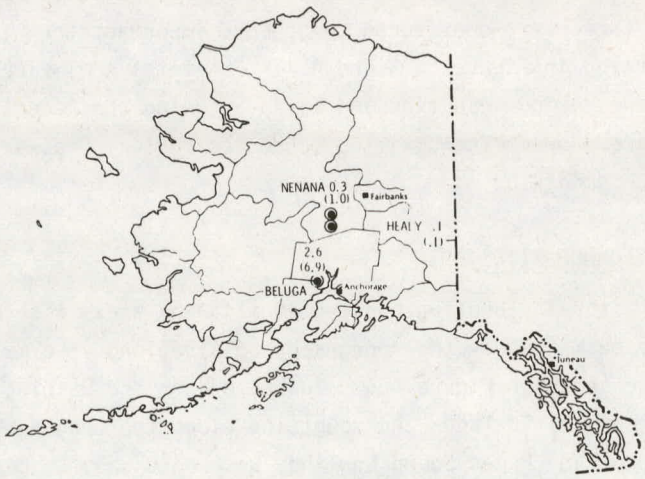

FIGURE 4.4. Candidate Siting Areas Showing Capacity (in 1000's MWe) Under Recent Trends and (High Coal Electric) Scenarios to the Year 2020 for Alaska

Alaska contains four major topographical areas: 1) Arctic coastal plain, 2) Rocky Mountain system, 3) Intermontane Plateaus, and 4) Pacific Mountain system. The Arctic coastal plain forms Alaska's northernmost land areas. This area is very sparsely populated; the people live in isolated villages. The Brooks Mountain Range is the northern extension of the Rocky Mountain system, and it averages 3000-6000 ft above sea level. The Intermontane Plateaus consist of dry uplands and broad alluvial basins. The Pacific Mountain system is a continuation of the coastal mountain system along the Washington-Oregon coast.

4.2 TRANSPORTATION

The location of rail and waterborne transportation is shown in Figure 4.6. Three major ocean ports occur along the Washington-Oregon coast: Coos Bay along the southern coast of Oregon, the mouth of the Columbia River between Washington and Oregon, and Puget Sound in

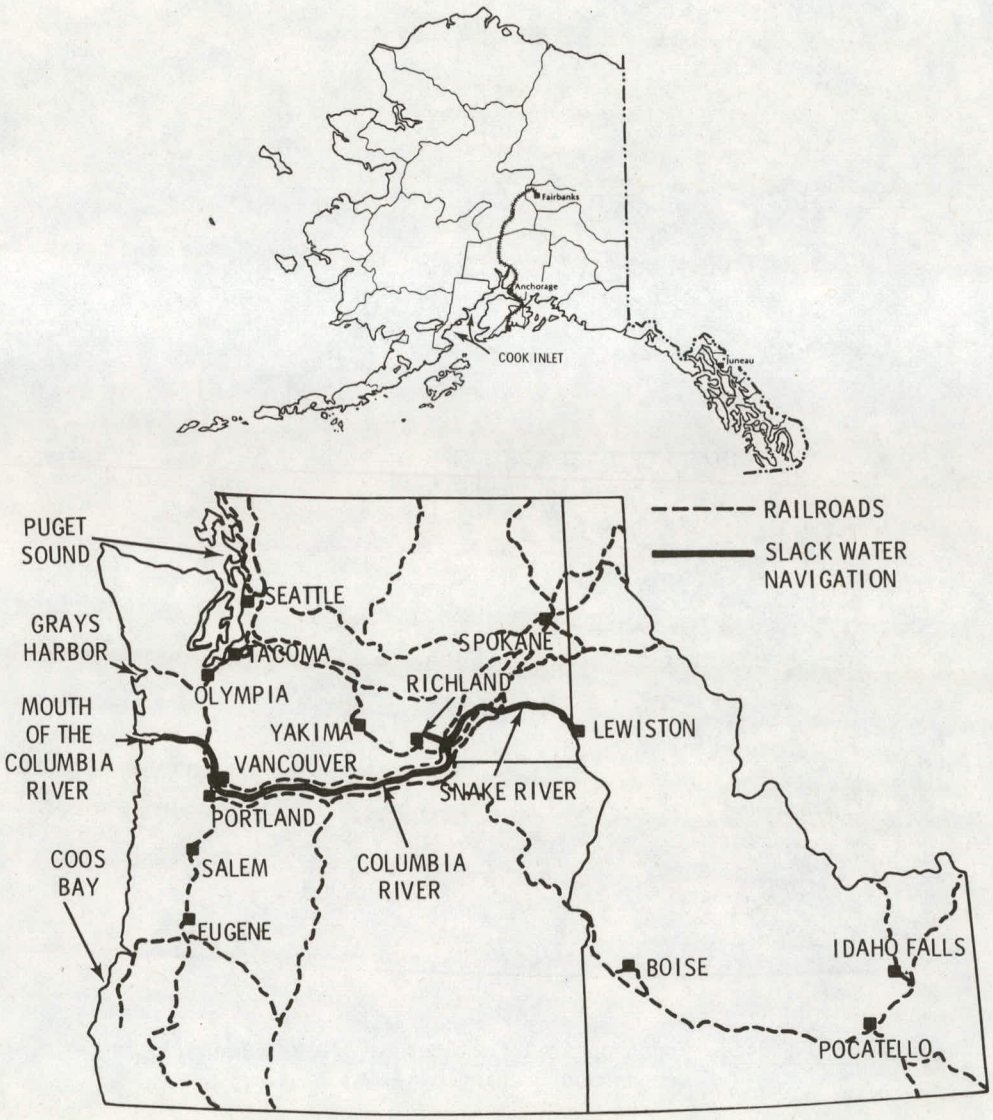

FIGURE 4.6. Railroad Lines and Slack Water Navigation of Alaska, Idaho, Oregon and Washington

The coastal lowland and mountain areas contain little level land but have several ports and estuaries and much river valley bottomland. The Willamette Valley and Puget Sound Lowland have broad river valleys, salt and freshwater resources, and extensive forests. The Cascade Mountains divide the lowlands and basin-plains area. They are mostly forested and quite rugged. The basin-plains area is rather dry but has relatively abundant water resources because of the Columbia and Snake River drainage systems. The Rocky Mountain areas are rugged with several large rivers flowing westward that eventually flow into the Columbia. Areas meeting the first two siting criteria are generally located along the Washington-Oregon coast and along one of the rivers that flow through the basin-plains area.

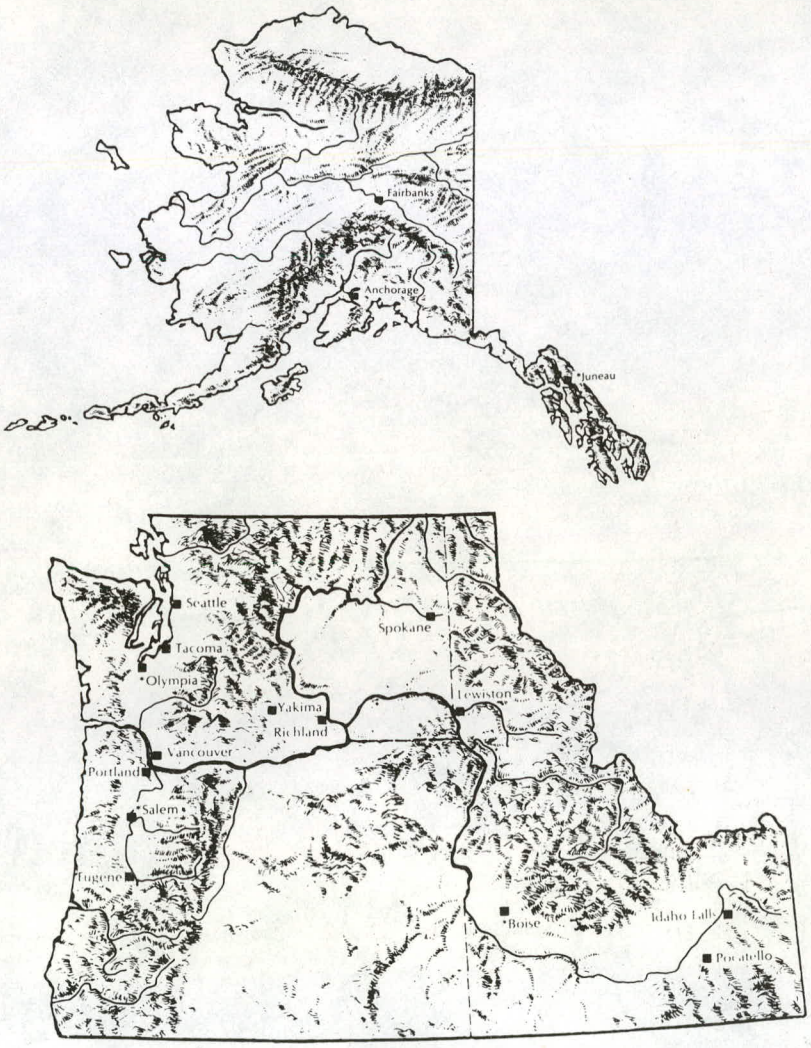

FIGURE 4.5. Topographical Features of Alaska, Idaho, Oregon and Washington(3)

Washington. Slack water navigation is available along the Columbia River to Richland, Washington and the Snake River to Lewiston, Idaho. Railroad transportation in Alaska is limited to the Alaska Railroad, which runs from Seward to Anchorage and on to Fairbanks. Alaska has many natural harbors; however, major coal fields are located close to Cook Inlet. Waterborne transportation may afford an attractive and cost-competitive method of transporting Alaskan coal to coastal areas of the Pacific Northwest.

Coal from Montana and northern Wyoming is likely to be moved to the Pacific Northwest by rail lines running through northern Idaho. Coal from southwestern Wyoming is likely to be shipped through southern Idaho and eastern Oregon.

Existing electrical transmission lines, major hydroelectric sites and steam plants in Idaho, Oregon and Washington are shown in Figure 4.7. The existing electrical generating system is shown; it is largely hydroelectric and is highly intertied. The existence of power transmission corridors that closely parallel the river system make plant sites that are close to rivers doubly attractive.

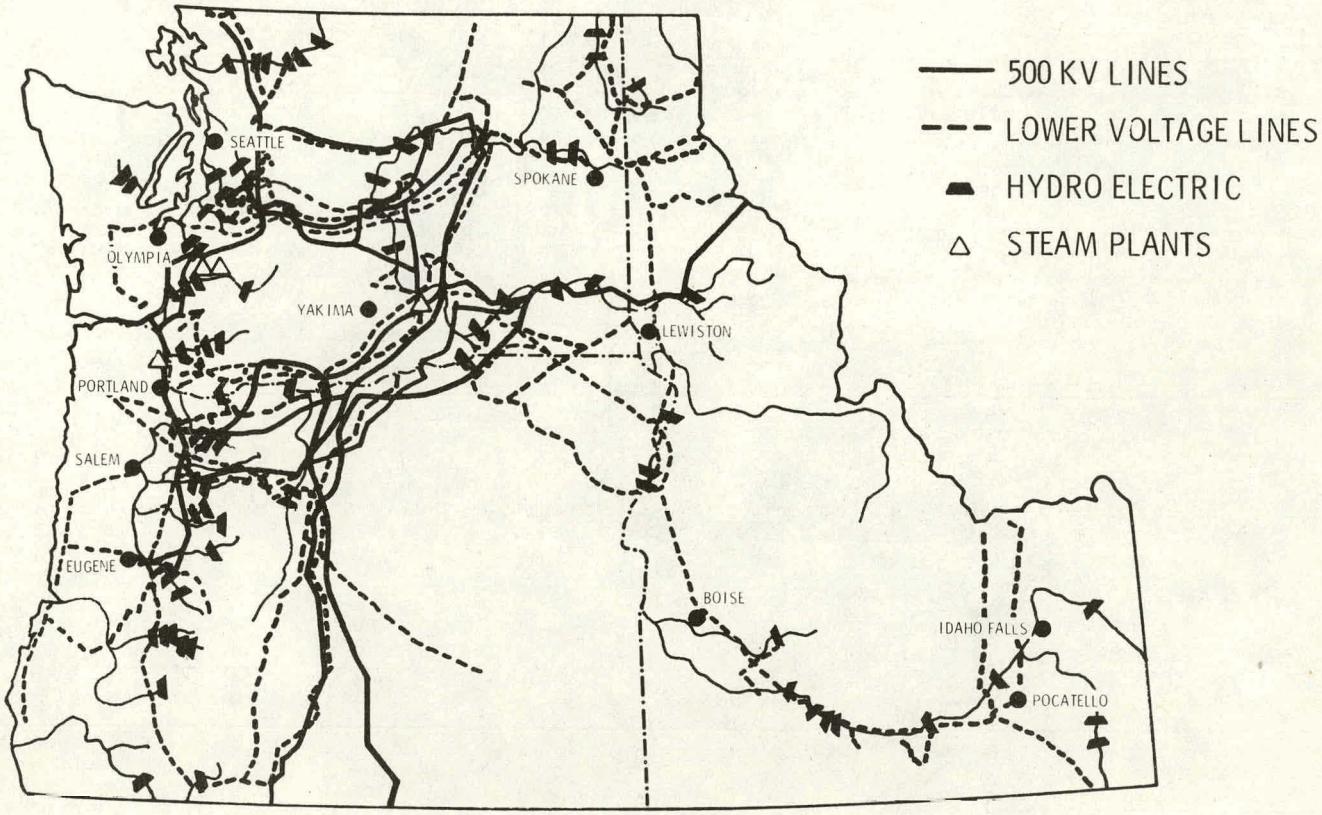

FIGURE 4.7. Major Electrical Generating Plants and Transmission Lines in Idaho, Oregon and Washington[3]

Present generating sites (mostly hydroelectric) are generally located east of the Willamette Valley-Puget Sound load centers. As a result, most of the electrical power going to these load centers is transported along relatively few transmission corridors. Because of this situation, generating sites lying west of the load centers (coastal sites) would be preferable to inland sites from the standpoint of transmission system reliability and losses. Alaska has relatively few transmission lines and no major hydroelectric facilities.

The location of electrical load centers in the region can be seen in the population density map presented in Figure 4.8. The major load centers are located in the Willamette Valley-Puget Sound trough. Smaller load centers are located in the Spokane area and along the southern Idaho area around Boise, Pocatello and Idaho Falls. The Anchorage and Fairbanks areas are the major electrical load centers in Alaska.

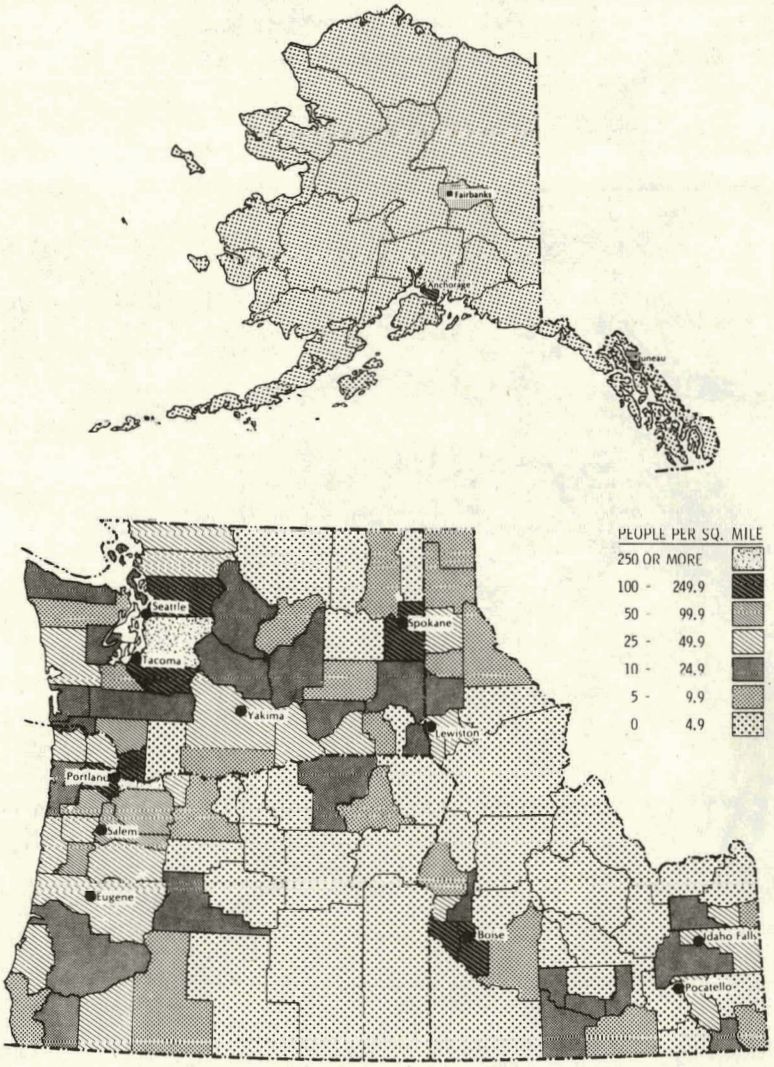

FIGURE 4.8. 1970 Population Density for Alaska, Idaho, Oregon and Washington[3]

4.3 SELECTION OF CANDIDATE SITES

Selection of the candidate counties and areas was based on the criteria outlined above and the data summarized in Figures 4.5 through 4.8. Selection of sites is ultimately subject to specific seismic, aesthetic and land use planning considerations not included in this rough selection process. While in some cases important criteria may have been overlooked, it is felt that the criteria used are sufficient for the purposes of this report.

The candidate counties for Idaho, Oregon and Washington are shown shaded in Figure 4.3. While some counties may eventually host capacities larger than 3,000 MWe, air quality calculations (see Chapter 5) indicate that single-site capacities greater than 3,000 MWe may present air quality problems. Hence, capacity additions greater than this would require particular scrutiny.

The areas in Alaska designated for candidate sites are shown in Figure 4.4. The major siting area is in the Beluga area, with some additional capacity to be added at Nenana.

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5.0 AIR QUALITY IMPACTS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- **Air Quality Issues**
- **Estimated Impacts of Coal Development Scenarios**
- **Issues Requiring Further Analysis**

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

5.0 AIR QUALITY IMPACTS

Chapter 5 discusses the impact of sulfur dioxide, particulates and nitrogen dioxide emissions from a reference 3,000 MWe coal-fired power plant on the ambient air quality in the Pacific Northwest (excluding Alaska). These impacts are investigated in several different time and space scales so that ambient air quality standards and Regulations for the Prevention of Significant Deterioration, as promulgated in the Clean Air Act Amendments of 1977, can be addressed. This chapter also investigates the transformation of sulfur dioxide to sulfates as it is transported over long distances and the deposition of sulfur dioxide and sulfates onto the terrestrial environment.

Two air quality diffusion models were used to estimate the impacts on air quality within 50 km of a reference coal-fired power plant. One model, the Climatological Dispersion Model, provides estimates of annual average air quality concentrations. It uses climatological data available from National Weather Service Stations or from meteorological towers. The other model, a version of the Environmental Protection Agency's PTMPT model, provides short-term maximum concentrations that would be expected within a few kilometers of the facility. This model uses "worst case" meteorological conditions. A regional transport, transformation and removal model is used to provide regional estimates of ground-level concentrations of sulfur dioxides and sulfates and deposition of these pollutants onto the earth's surface.

The results of the modeling studies show that, based on the assumption that emissions from coal plants will equal those allowed under the New Source Performance Standards, the annual average incremental increase in sulfure dioxide, particulates and nitrogen oxides due to the two coal development scenarios will be small compared to the concentrations allowable under the National Ambient Air Quality Standards (NAAQS). However, short-term maximum concentrations can, under certain meteorological conditions and emission assumptions, exceed the NAAQS in the vicinity of a power plant. In addition, the Regulations for the Prevention of Significant Deterioration severely constrain power plant development in the vicinity of Class I areas, which currently include all national partks greater than 6,000 acres and all wilderness areas over 5,000 acres in size. The regulations also restrict power plant development in some Class II areas where meteorological conditions are such that short-term maximum concentrations increments are high.

One major issue arising from this study is the provision in the Clean Air Act Amendments of 1977 that all future coal-fired power plant facilities must use Best Available Control Technology to control stack emissions. The calculations for this study were made before this legislation, and it was assumed that all facilities would operate at the New Source Performance Standards. If a facility burning western low-sulfur coal also used the Best Available Control Technology for cleaning sulfur dioxide from the stack gases, emissions from these facilities could be markedly lower than the New Source Performance Standards. In such a case, the constraints imposed on power plant development in the west by the Regulations for the Prevention of Significant Deterioration are substantially less severe than this study indicates.

A second major issue relates to the models applied to this study. They are "flat terrain" models that do not account for the influence of topography on locally high pollutant concentrations. Since many mandatory Class I areas are located in regions of complex terrain, future coal assessments need to be refined, using air quality models that incorporate complex terrain, particularly as the states establish additional Class I areas.

Chapter 5 describes the impact of atmospheric sulfur dioxide, particulates and nitrogen dioxide emissions from coal-fired power plant facilities on the ambient air quality. Possible constraints to coal utilization in the Pacific Northwest (Washington, Oregon, and Idaho) imposed by federal air quality regulations are identified on the basis of this evaluation. The long-range transport of sulfur dioxide and its transformation to sulfates for large major existing sources and future coal-related scenarios are also evaluated for the western United States (west of 100° W). These estimates of impacts on air quality are also inputs to other sections of the report dealing with evaluation of risk to human health and natural ecosystems.

5.1 AIR QUALITY ISSUES

5.1.1 Regional Climate

The Pacific Northwest region is characterized by a diverse topography and climatology. Three major mountain ranges, the Coast Range, the Cascades, and the western slope of the northern Rocky Mountains strongly influence the regional climate. A major factor controlling this climate is the region's proximity to the Pacific Ocean. Frequent storms pass through the region in the late fall and early winter, and again in the spring, providing generally good air ventilation. However, between stormy periods high-pressure ridges can settle over the region, limiting ventilation, particularly in the basins bounded by the major mountain ranges and in interior mountain valleys. In the late summer and early fall these interstorm periods can last for several weeks. In mid-winter these nonstormy periods can result in particularly severe air stagnation; this is most noticeable in the interior basins. This episode phenomena is one of the most intense in the United States, as shown in Holzworth.[1] His report discusses the frequency of episodes, and the average length of each episode is shown for a particular atmospheric criteria, based on standard National Weather Service upper air data.

The nature of the regional climate and topography requires careful siting studies for any major emission facility in the Northwest. Such detailed siting studies are beyond the scope of this report; nevertheless, the regional climate and topography can combine to present a possible constraint to future development in certain locales.

5.1.2 National Ambient Air Quality Standards

Under the mandate of the Clean Air Act of 1977, as amended, the EPA has promulgated air quality standards for six pollutants: carbon monoxide, nitrogen dioxide, particulate matter, sulfur dioxide, hydrocarbons, and photochemical oxidants. In this study, only the emissions of SO_2, particulates, and NO_x from coal-fired power plants are studied. Emissions of hydrocarbons and carbon monoxide from these facilities are generally small. As noted in an NCUA report by Argonne National Laboratory,[2] levels of ozone have exceeded the 24-hr photochemical oxidant standard of 160 $\mu g/m^3$ in the vicinity of coal-fired power plants; however, no conclusive evidence exists as to what extent these levels are attributable to plant emissions alone. The National Ambient Air Quality Standards (NAAQS) for all pollutants are given in Table 5.1.

TABLE 5.1. National Ambient Air Quality Standards

Pollutant	Primary ($\mu g/m^3$)	Secondary ($\mu g/m^3$)
Particulate		
Annual average	75	60
24-hr maximum	260	150
SO_2		
Annual average	80	
24-hr maximum	365	
3-hr maximum		1300
NO_2		
Annual average	100	100
CO		
8-hr maximum	10	
1-hr maximum	40	
Photochemical oxidant		
1-hr maximum	160	
Hydrocarbons		
30-hr maximum	160	

5.1.3 Air Quality Maintenance Areas

Air Quality Maintenance Areas (AQMAs) have been designated by the states to identify areas to the EPA in which the potential exists to exceed any NAAQS by the year 1985. The methodology the states used to determine the AQMAs included the compilation of 1970 emissions from state files, State Implementation Plans, and the National Emission Data Service (NEDS) data bank. In the Pacific Northwest, these emissions were projected to 1985 by 1) applying State Implementation Plan (SIP) control strategies to existing sources, including the emissions from planned power plants that would come under the new regulations, and 2) assuming increases in proportion to Bureau of Economic Analysis (BEA) growth indicators.[3] Air quality for 1985 was estimated using these projected emissions in an atmospheric dispersion model. Areas with air quality projections exceeding NAAQS for a given pollutant were then designated as AQMA. The designated AQMAs in the Pacific Northwest are shown in Figure 5.1. No AQMAs are currently designated for the state of Idaho.

Besides the requirement for states to designate to the EPA AQMAs, the 1977 Amendments to the Clean Air Act further require each state to submit to the EPA a list identifying those air quality control regions that presently do not meet a primary ambient air quality standard for any air pollutant other than sulfur dioxide or particulates. The list must also include those areas that may not attain any national primary ambient air quality standard for sulfur dioxide or particulates within the time period required by an applicable implementation plan. Furthermore, the states must include in this list those regions not meeting national secondary air quality standards for any pollutant and those regions where insufficient data exist to make any determination. This list must be submitted within 120 days of enactment of the Act. The Clean Air Act spells out procedures for preparing adequate implementation plans to attain and maintain the NAAQS for these "nonattainment" areas. In particular these plans, with the exception of certain provisions, are required to show that no major stationary source shall be constructed or modified[a] in any nonattainment area after June 30, 1979.

(a) The term "modified" here means a change in the source such that an increase in emissions results.

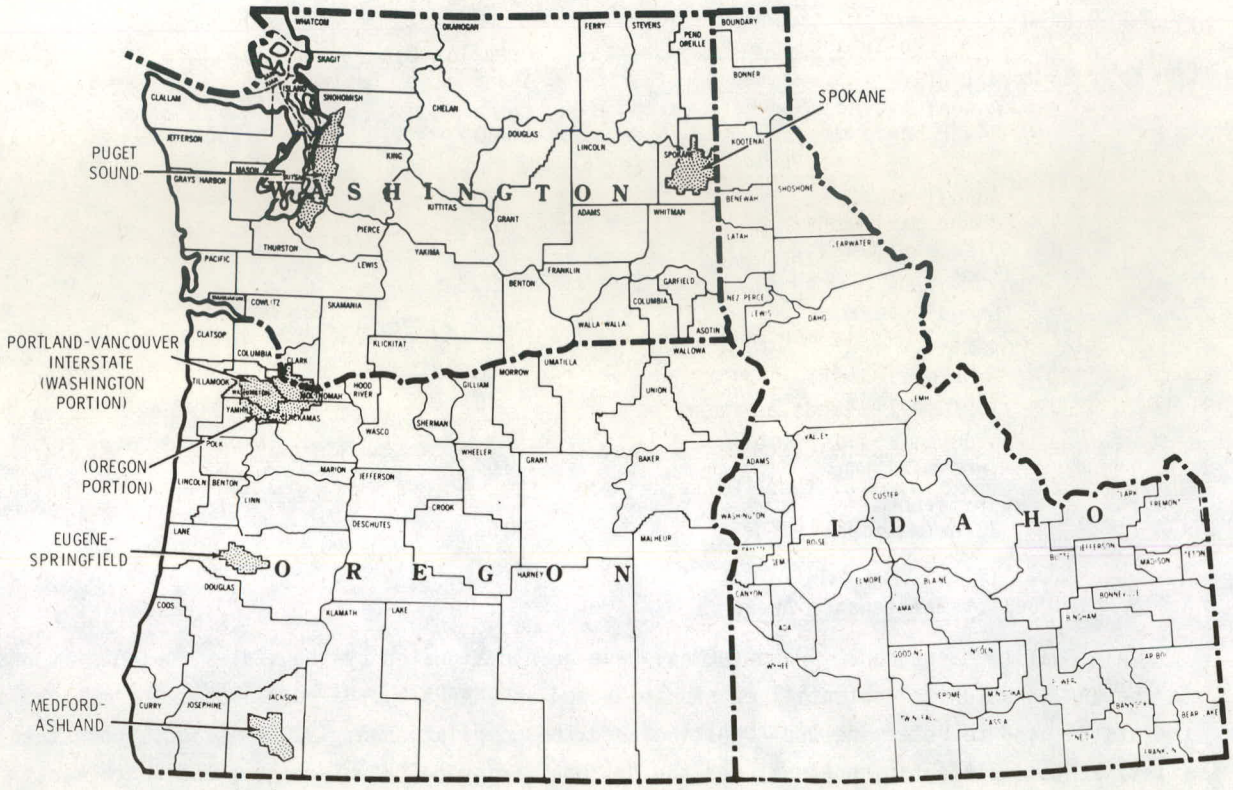


FIGURE 5.1. Designated Air Quality Maintenance Areas (AQMAs) in the Pacific Northwest

5.1.4 Regulations for the Prevention of Significant Deterioration

A regulation that is potentially more constraining to coal-fired power plant development than the NAAQS, particularly in the western United States, is the regulation for the Prevention of Significant Deterioration (PSD). This regulation was promulgated by the EPA in December 1974 after a suit had been filed against the Administrator in June of 1972 stating that no State Implementation Plan was designed to protect clean areas from significant air quality deterioration. These regulations, as modified by Congress, are now incorporated into the Clean Air Act Amendments of 1977. The regulations specify that all states must designate all regions into one of three classes: Class I, where only very limited air quality deterioration may occur, allowing little or no industrial development; Class II, where moderate, well-controlled growth would be allowed; and Class III, where concentrated industrial growth may occur as long as air quality is not degraded beyond the secondary NAAQS. Air quality in each class cannot exceed certain specified incremental increases (summarized in Table 5.2), and in no case can it exceed the national ambient secondary standard for SO_2 and particulates. Also, all international parks, national wilderness areas greater than 5000 acres in size, national memorial parks greater than 5000 acres in size, and all national parks greater than 6000 acres in size in existence as of August 3, 1977, must be designated Class I. Currently all states, with the exception of some areas of Montana, are designated entirely as Class II (excluding mandatory Class I areas), although each region is subject to redesignation as Class I or Class III subject to state and local initiative. It is anticipated, for example, that AQMA will be designated as Class III areas.

TABLE 5.2. Allowable Air Quality Increments Specified in Clean Air Act Amendments of 1977

Pollutant	Averaging Time	Allowable Increments ($\mu g/m^3$) Class I	Class II	Class III
SO_2	Annual	2	20	40
	24-hr maximum	8	91	182
	3-hr maximum	25	512	700
Particulates	Annual	5	19	37
	24-hr maximum	10	37	75

A list of all federally-mandated Class I areas was published in the Federal Register on November 3, 1977.[4] All Class I areas for the Pacific Northwest are shown in Figure 5.2. This figure shows that Class I areas are concentrated in the three major mountain ranges within the region--the Coast Range, the Cascades, and the west slope of the Northern Rockies. Table 5.3 shows the names and sizes of these Class I areas. These Class I regions amount to approximately 3.6% of the total area of the Pacific Northwest states.

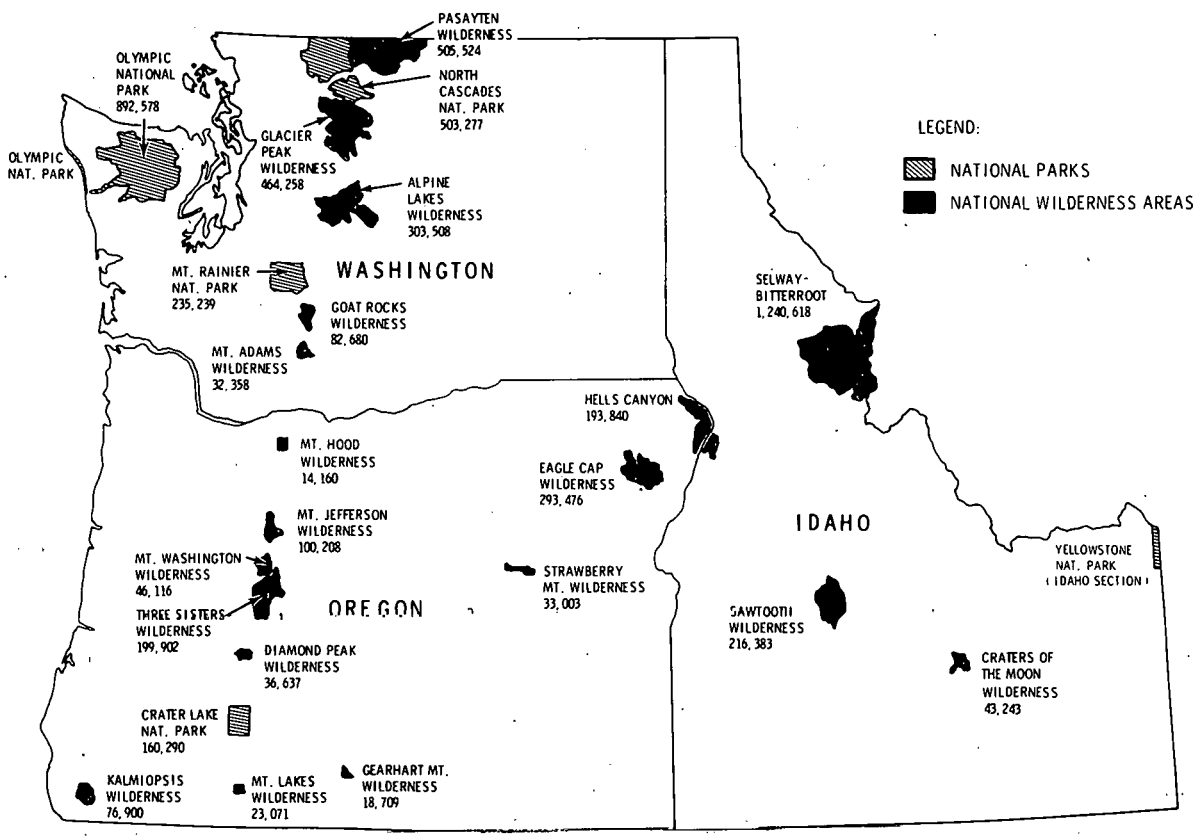


FIGURE 5.2. Mandatory Class I Areas in the Pacific Northwest

TABLE 5.3. Mandatory Class I Areas in the Pacific Northwest

State/Area	Total Acreage
Washington	
Mount Rainier National Park	235,239
North Cascades National Park	503,277
Olympic National Park	892,578
Alpine Lakes Wilderness Area	303,508
Glacier Peak Wilderness Area	464,258
Goat Rocks Wilderness Area	82,680
Mount Adams Wilderness Area	32,356
Pasayten Wilderness Area	505,524
Oregon	
Crater Lake National Park	160,290
Diamond Peak Wilderness Area	36,637
Eagle Cap Wilderness Area	293,476
Gearhart Mountain Wilderness Area	18,709
Kalmiopsts Wilderness Area	76,900
Mountain Lakes Wilderness Area	23,071
Mount Hood Wilderness Area	14,160
Mount Jefferson Wilderness Area	100,208
Mount Washington Wilderness Area	46,116
Strawberry Mountain Wilderness Area	33,033
Three Sisters Wilderness Area	199,902
Idaho	
Yellowstone National Park (Idaho Sector)	(a)
Craters of the Moon Wilderness Area	43,243
Hells Canyon Wilderness Area (Oregon)	193,840
Sawtooth Wilderness Area	216,383
Selway-Bitterroot	1,240,618[b]
Pacific Northwest Total:	5,716,006

(a) Total park acreage = 2,219,737; Idaho section acreage not given.
(b) Includes Montana section.

5.1.5 Standards of Performance for New Coal-Fired Power Plants

The 1977 Clean Air Act Amendments require the EPA Administrator to promulgate revised standards of performance for new stationary sources. For fossil-fuel fired stationary sources, this implies a standard that establishes allowable emissions for these sources. These standards will require a percentage reduction in the emissions that would have resulted from the use of fuels not treated before combustion. The standard of performance must reflect the application of best available control technology (BACT), which may include fuel cleaning before combustion.

This provision goes far beyond the New Source Performance Standards (NSPS) promulgated for fossil-fuel fired steam generators after the Clean Air Act was amended in 1970. At the time, those standards, published in the Federal Register in 1971,(5) reflected the concept of

reasonable available control technology. According to those standards, emissions from fossil-fuel fired steam generation plants could not exceed the following rate:

SO_2: 1.2 lb $SO_2/10^6$ Btu input
Particulates: 0.1 lb part./10^6 Btu input
NO_x: 0.7 lb $NO_x/10^6$ Btu input

In this study, the NSPS were applied to the diffusion models to provide air quality estimates. Use of the NSPS eliminates the variability of heat and sulfur content of coal supply and reflects the upper regulatory limit of the emissions from new facilities. However, with the 1977 amendment to the Clean Air Act, the concept of BACT now prevails. This will require a revision of the NSPS to be made within a year.

This is one of the major unresolved issues in this coal assessment. In a study of western coal reserves Renne[6] showed that roughly half of all strippable and mineable resources in Montana and Wyoming could be burned without controls and not exceed the NSPS. Nevertheless the Clean Air Act now specifies that BACT must be applied to all new facilities; in the West this could represent an additional reduction in sulfur dioxide emissions (beyond the NSPS) of as much as 90%. However, considering the economic costs of applying such strict controls on facilities that are already burning low-sulfur coal, the result could be a case-by-case review of each proposed facility to determine the level of control required. With the uncertainties at this time concerning how BACT will be interpreted and how the NSPS may be revised in the next year, and with the knowledge that they will not be revised upward to allow more emissions in the future than they presently do, the NSPS were applied to the calculations in this study to present an upper limit to the estimated impacts. Applying BACT to stack emissions in western facilities would result in markedly lower air quality estimates.

5.1.6 Provisions for the Protection of Visibility

In the 1977 Amendments to the Clean Air Act, Congress declared as a national goal the maintenance of good visibility in mandatory Class I areas. Visibility here is defined as reduction in visual range and atmospheric discoloration. To achieve this goal the following timetable was established:

- Not later than six months after enactment of the Act, all Class I areas shall be reviewed by the Secretary of the Interior, in consultation with other federal land managers to identify those where visibility is an important value.
- Within one year of enactment the Secretary of the Interior shall promulgate a list of mandatory Class I areas in which he determines visibility is an important value.
- Within 18 months of enactment, a report shall be submitted to Congress by the EPA Administrator describing available methods for implementing this national goal.
- Within 24 months of enactment the EPA Administrator shall promulgate regulations to assure that this national goal is met.

The visibility provisions state specifically that existing fossil-fuel power plants operating in the vicinity of Class I areas may have to retrofit their stacks with cleaning devices if their emissions are impairing the visibility of the Class I region. However, facilities that are less than 750 MWe in capacity may be exempt from this rule.

Currently, only one fossil-fuel power plant is located near mandatory Class I areas in the Northwest--the Centralia plant in western Washington State. However, as visibility regulations are promulgated and techniques for assessing visibility impacts are developed, these provisions may be an important issue to the Pacific Northwest.

5.2 ESTIMATED IMPACTS OF COAL DEVELOPMENT SCENARIOS

The issues presented in the previous section (with the exception of visibility) are assessed quantitatively in this section by application of air quality models. Other potential issues, such as health and ecological effects caused by airborne or deposited pollutants, use the results of this modeling effort and are reported in other chapters. Potential issues that are not addressed directly in this assessment include such issues as global climatic changes associated with an expanded fossil-fuel technology, and secondary air quality impacts.

The modeling effort was carried out to identify the annual concentrations of SO_2, TSP and NO_x from coal-fired power plants at the candidate sites. This effort incorporated the predicted emissions from the facilities and the various meteorological conditions occurring at each of the candidate sites into the Climatological Dispersion Model (CDM).[7] This model has certain limitations; it is only applicable to 50 km maximum from the source and is not applicable in complex terrain. Nevertheless, it has received wide application and produces useful first-order estimates of air quality impacts. These estimates were made for both the Recent Trends and the High Coal Electric scenarios projected to the year 2020 in the Pacific Northwest. These scenarios were selected to illustrate the maximum scope of the coal-related emissions.

Short-term maximum concentrations have been estimated by Argonne,[2] incorporating the emissions estimates into a modeling technique used in a study by General Electric.[8] Argonne's estimates of short-term maximum concentrations are for nonspecific sites and are considered applicable to the Pacific Northwest. (See Appendix C for more detail.)

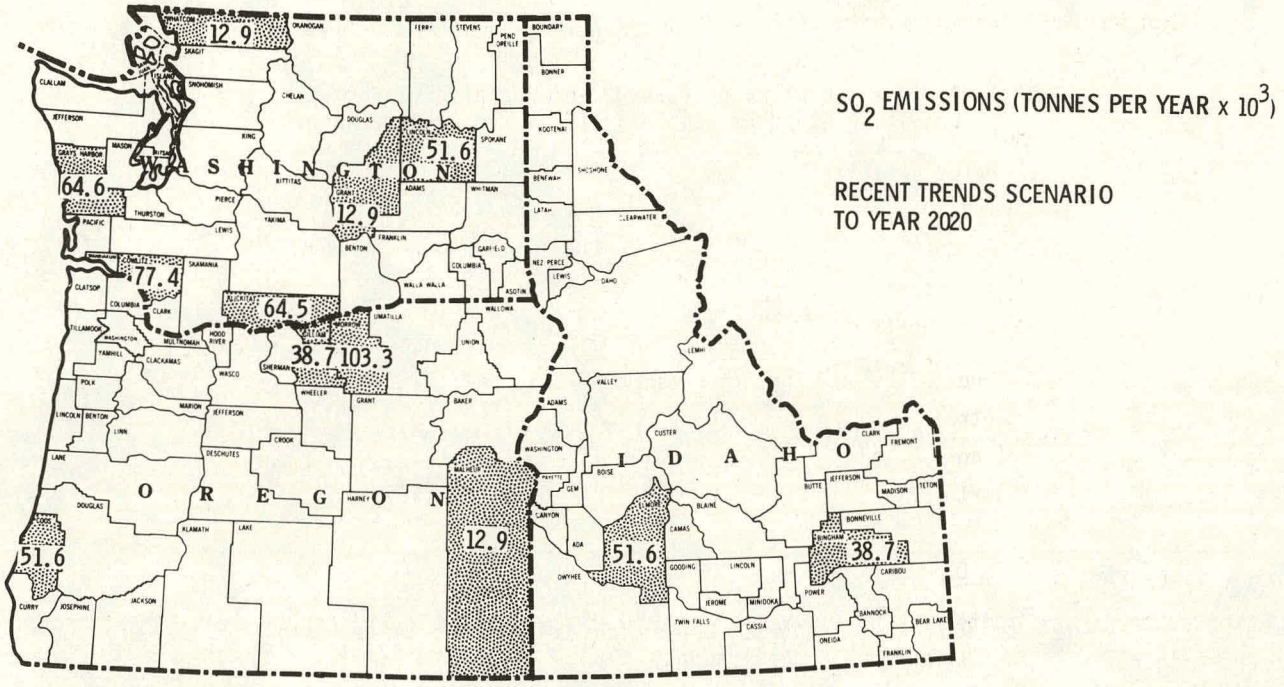
5.2.1 Projected Emissions

Emissions for a reference 3000 MWe coal-fired power plant have been estimated assuming that the emissions meet the NSPS and that the plant operates at a 60% load factor with a 38% thermal conversion efficiency. This information is used to estimate additional emissions in the Pacific Northwest projected to the year 2020 for both scenarios. Figure 5.3 summarizes these projected emission increments by county for point source SO_2 emissions, and Table 5.4 summarizes the total SO_2 emissions by state.

TABLE 5.4. Total Electrical Generation Capacity (MWe) and SO_2 Emissions[a] (tonne/yr x 10^3) for the Year 2020 Scenarios

	Recent Trends		High Coal Electric	
	MWe	Tonne/yr x 10^3	MWe	Tonne/yr x 10^3
Washington	12,300	318 x 10^3	27,300	705 x 10^3
Oregon	8,000	207 x 10^3	17,500	452 x 10^3
Idaho	3,500	90 x 10^3	8,500	219 x 10^3
Total	23,800	615 x 10^3	53,300	1,376 x 10^3

(a) Based on Federal NSPS. Use of NSPS eliminates the emission variations due to coal supply.



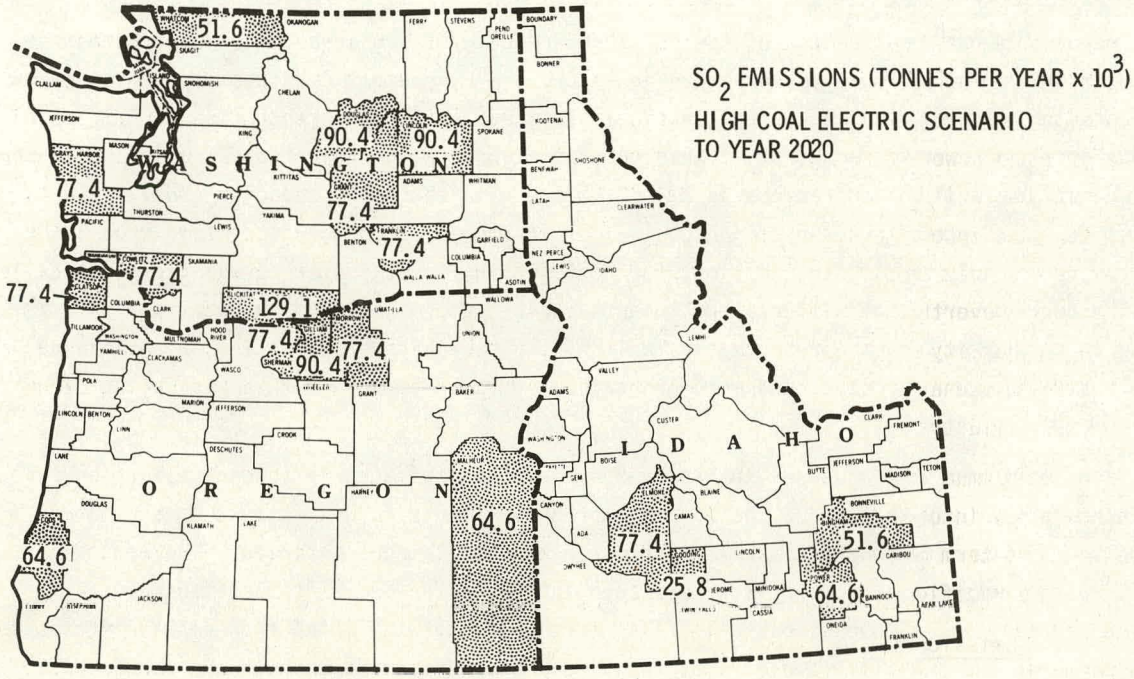


FIGURE 5.3. Point Source SO_2 Emission Inventory by County in the Pacific Northwest for a) Recent Trends and b) High Coal Electric Development Scenarios Projected to the Year 2020

Table 5.5, taken from the Argonne report, summarizes the pertinent plant operating information and the resulting stack emissions. These factors were chosen so as to be consistent with other regional evaluations in the NCUA.

TABLE 5.5. Pertinent Coal-Fired Power Plant Operating Information and Resulting Stack Emissions[a] (from the Argonne Report)[2]

Total rated capacity	3000 MW
Heat rate	8970 Btu/kWh (2260 kcal/kWh)
Stack height	244 m
Stack diameter	11.3 m
Exhaust velocity	14.2 m/sec
Exhaust temperature	394 K
Load factor	60%
Ambient air temperature	293 K
SO_2 emissions	2.45×10^3 g/sec[a]
Particulate emissions	2.03×10^2 g/sec[a]
NO_x emissions	1.42×10^3 g/sec[a]

(a) Based on Federal NSPS. Use of NSPS eliminates the emission variations due to coal supply.

5.2.2 Short-Range (<50 km) Annual Average Concentrations

The results of the application of the CDM for candidate siting areas around the Northwest are shown in the series of analyses provided in Figure 5.4. Appendix C discusses the details of this modeling effort. The concentrations in this figure are SO_2 concentrations ($\mu g/m^3$) for a 3000 MWe reference coal-fired plant. These concentrations can be adjusted for a specific plant size by multiplying the concentrations by N/3000, where N is the plant capacity (MWe). Plant capacities for the Recent Trends and High Coal Electric scenarios can be determined from information provided in Chapter 4. In addition, the analyses in Figure 5.4 are presented generically, so that the concentrations of different pollutants can be determined from the same analysis according to the coding scheme presented in Table 5.6. The analyses were based on an assumed pollutant half-life of four days, and were generated from a 50-km grid with a resolution of 5 km.

It is evident from the analyses in Figure 5.4 that the estimates of concentration levels and patterns vary widely throughout the Pacific Northwest. This is due in part to the large variation in climate between the coastal regions and the mountainous interior. The coastal region is characterized by frequent storm passages in the winter and a stable atmosphere in the summer and fall. The mountainous climate is more complex, with local topography affecting the wind patterns and stability features of the atmosphere throughout much of the year. However, it can also be seen from Figure 5.4 that variations of concentration levels of a factor of two or more can exist between sites as close as 15 km apart, (e.g., Ephrata and Moses Lake, Washington). Thus, model results are quite sensitive to the meteorological input data, as would be expected. In addition, large differences in estimates occur between analyses using National Weather Service data and those using tower meteorological data. The manner in which

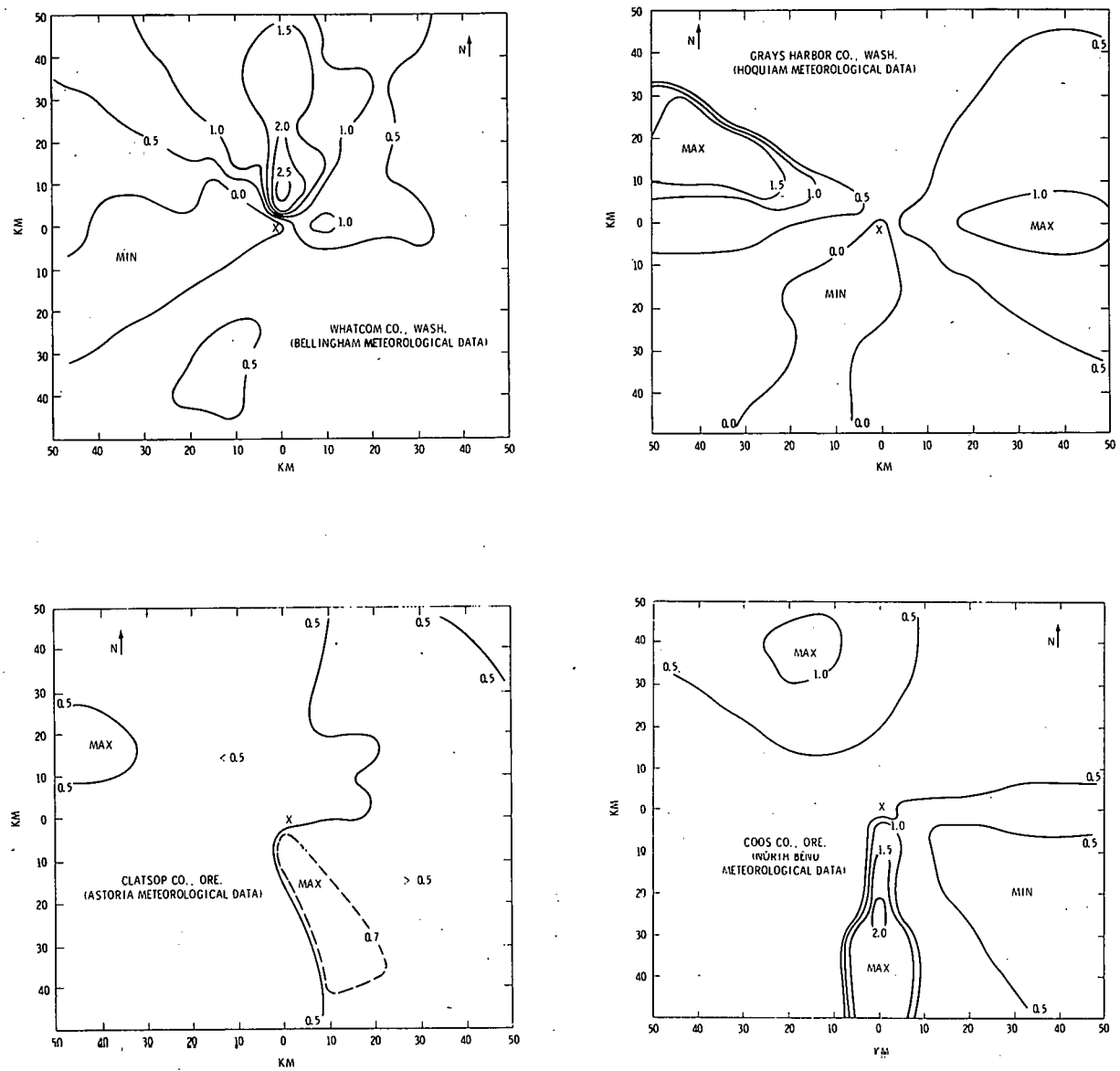


FIGURE 5.4. Isopleths of Annual Average SO_2 Concentrations ($\mu g/m^3$) for a 3000 MWe Reference Facility for Each of the Candidate Areas Using Meteorological Stations in the Northwest (see Appendix C)
I. Coastal Areas

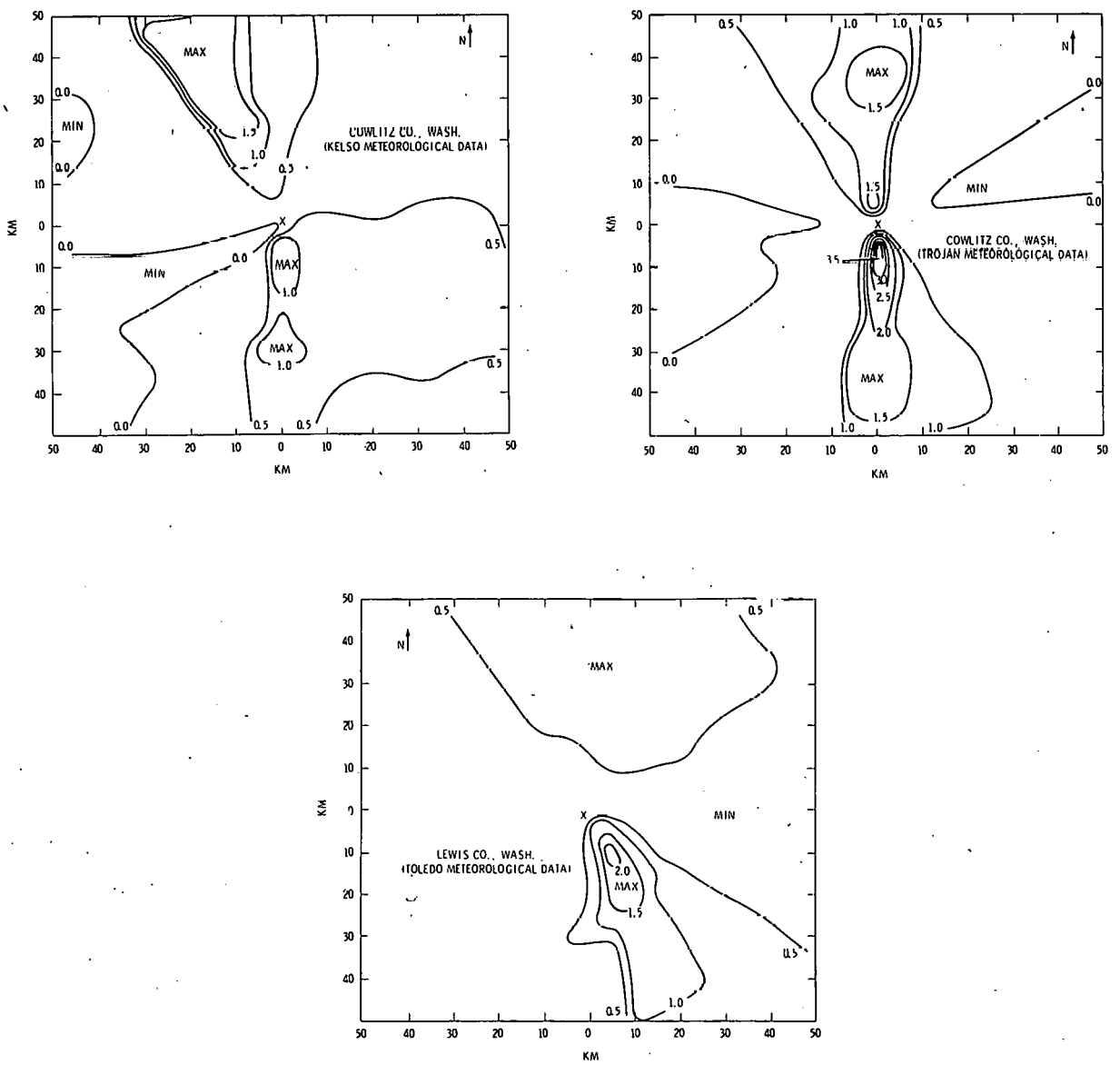


FIGURE 5.4. Annual Average SO_2 Concentrations ($\mu g/m^3$) for a 3000 MWe Reference Facility
II. Inland Western Washington

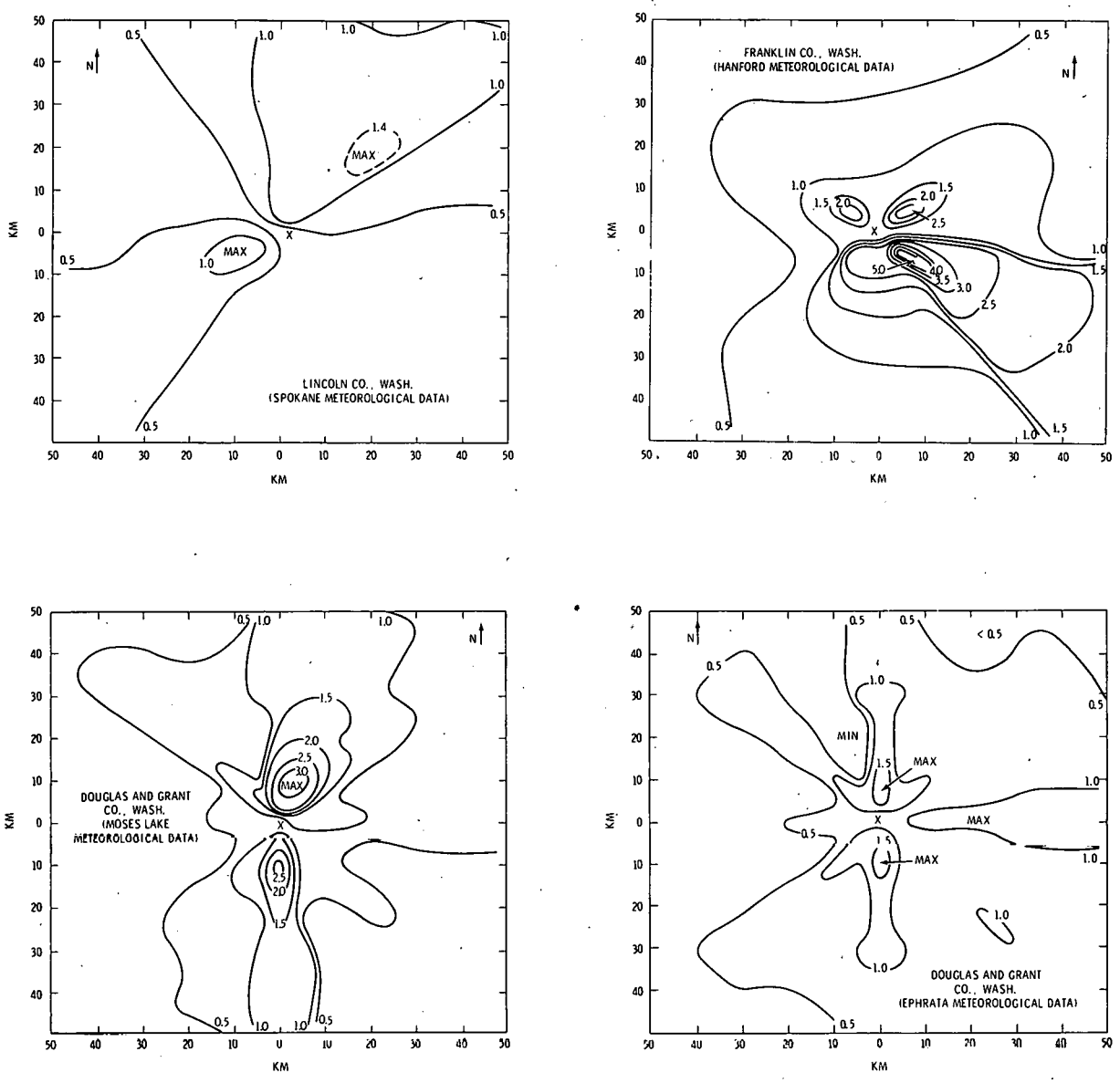


FIGURE 5.4. Annual Average SO_2 Concentrations ($\mu g/m^3$) for a 3000 MWe Reference Facility III. Eastern Washington

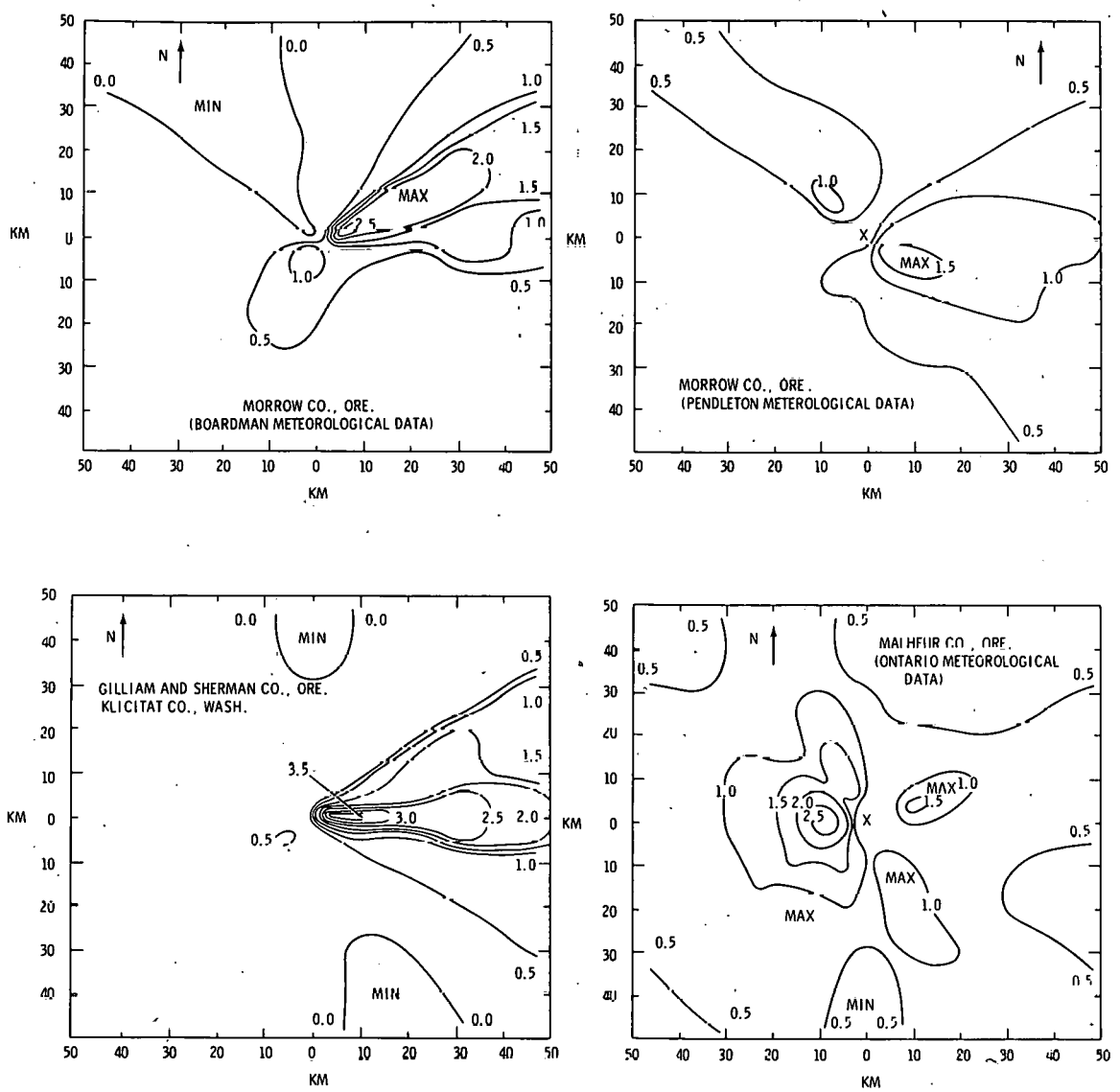


FIGURE 5.4. Annual Average SO_2 Concentrations ($\mu g/m^3$) for a 3000 MWe Reference Facility IV. Eastern Oregon and Klickitat County, Washington

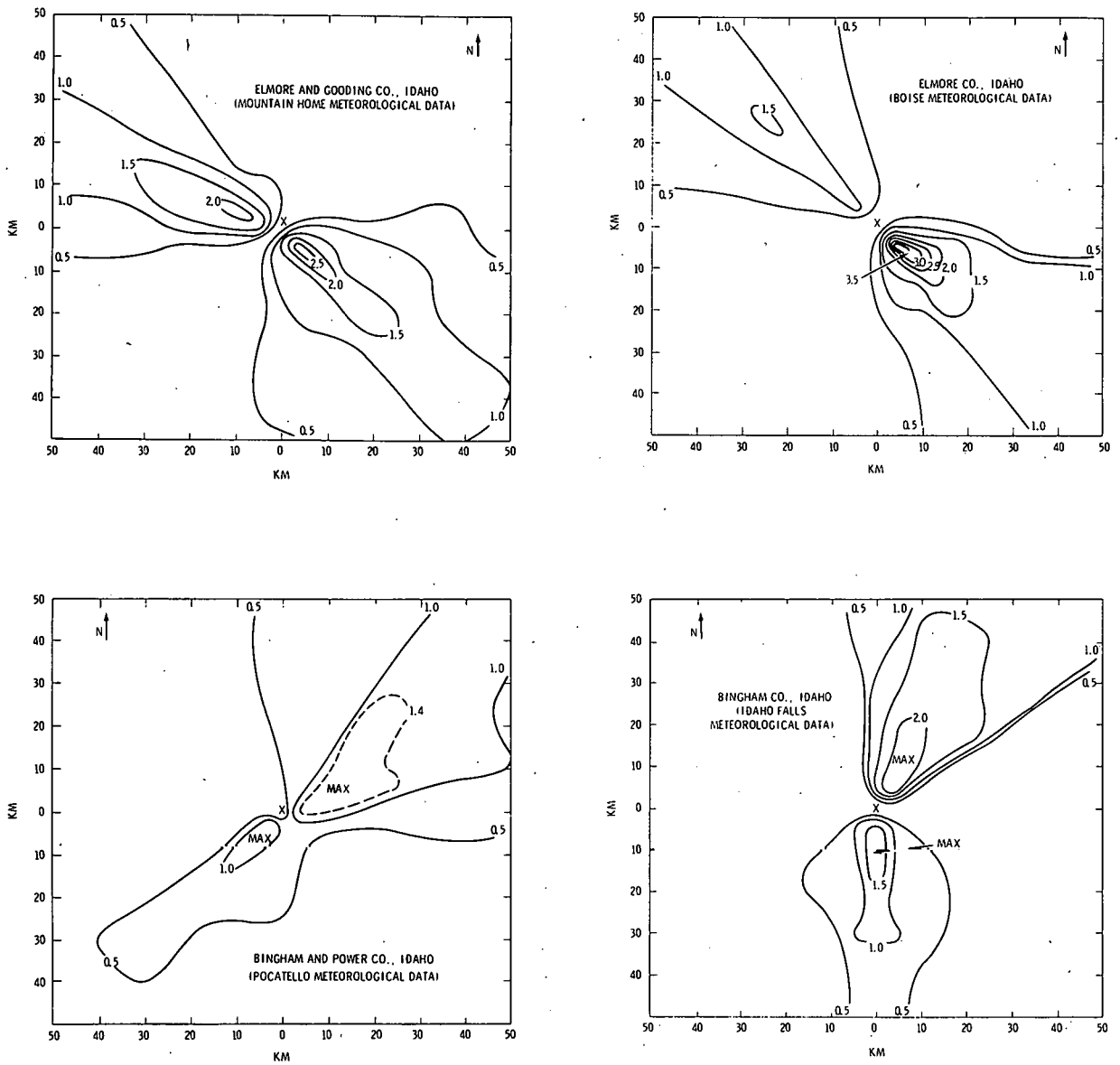


FIGURE 5.4. Annual Average SO_2 Concentrations ($\mu g/m^3$) for a 3000 MWe Reference Facility
V. Southern Idaho

stability classes are selected are entirely different between these two techniques. Hence, analytical differences result from the sensitivity of the model to the atmospheric stability data. (See Appendix C for a further discussion of this.)

TABLE 5.6. Various Pollutant Concentrations Corresponding to SO_2 Isopleths in Figure 5.4

Pollutant	Concentration ($\mu g/m^3$)									
SO_2 Isopleth	0.50	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50	5.00
NO_x	0.29	0.58	0.87	1.16	1.45	1.74	2.03	2.32	2.60	2.90
Particulates	0.04	0.08	0.12	0.16	0.21	0.25	0.29	0.33	0.37	0.41

5.2.3 Short-Term (3-hr, 24-hr) Maximum Concentrations

Short-term maximum concentrations were estimated primarily from the results of the GE study[8] cited earlier, and described in detail in the Argonne report.[2] The Argonne report discusses the results of the analysis and the methodology used. Their analysis is used here so that an assessment consistent with other regions in the NCUA is made. In the Argonne analysis, worst case meteorological conditions were applied to an air quality diffusion model, discussed in Appendix C, to obtain maximum possible concentrations. Because of the way the model works, these worst case conditions are associated with a highly unstable atmosphere and high wind speeds. The instability causes a plume to be transported to the ground rapidly after release from the stack (before it has undergone extensive diffusion). The high wind speeds limit the height to which the plume rises after release from the stack. However, it is not expected that these conditions would occur continuously over a 24-hr period. During that time, even under worst case situations, other atmospheric conditions would prevail, resulting in a lower concentration averaged over the 24-hr period from that calculated using only the worst conditions. Consequently, to account for this, Argonne also performed maximum expected concentrations for a 60% plant factor as well as a 100% plant factor. The results of these calculations are shown in Table 5.7.

TABLE 5.7. Maximum 3-hour and 24-hour Concentrations of SO_2, Particulates and NO_x for Different Meteorological Conditions and Plant Factors

	SO_2	Particulates	NO_x
24-hour			
Plant factor = 100%			
Mean wind = 5 m/s	490	41	290
Mean wind = 2.5 m/s	415	35	240
Plant factor = 60%			
Mean wind = 5 m/s	300	25	170
Mean wind = 2.5 m/s	250	21	150
3-hour			
Plant factor = 100%			
Mean wind = 5 m/s	760	--	--
Plant factor = 60%			
Mean wind = 2.5 m/s	380	--	--

Several factors exist that can alter the ground-level maximum concentrations from a power plant. Some of these factors are controllable. For example, emission control devices can limit the amount of pollutants coming out of the stack. Another controllable factor is the stack height. In the Argonne report, it was shown that ground level concentrations could be increased by 50% if a stack height of half of that used in the calculations (i.e., 122 m instead of 244 m) is assumed. A third factor is the distribution of the stacks. For a 3000 MWe plant it is possible that emissions will come out of several stacks around a given area, and not just one large stack. By dispersing the pollutants in this manner, maximum ground level concentrations could be lowered, although the area covered by the high concentrations could increase.

Of course, meteorological factors such as atmospheric stability, wind speed, and mixing height can result in a wide variation in ground level concentrations. The only way any control can be exerted over these factors is in the siting of the plant and in controlling the release of emissions during certain meteorological episode situations. The calculations presented in Table 5.7 should represent the worst case conditions that can be expected for a plant sited anywhere in flat terrain.

5.2.3 Comparison of Air Quality Estimates to Regulatory Constraints

In this section the results of the calculations are presented in light of regulatory issues. Table 5.8 reiterates the NAAQS for the pollutants under consideration in this assessment (SO_2, NO_x and particulates) and the PSD increments. It also includes the estimates of the impacts from the 3000 MWe electric generation facility with emissions as given in Table 5.4.

Table 5.8 clearly illustrates that the coal-fired generating stations considered do not, of themselves, contribute a significant fraction of the annual average concentration allowed by the NAAQS. The largest increment associated with a 3000 MWe facility contributes less than 5% of the annual average NAAQS. However, the short-term maximum 24-hr standard for SO_2 can

TABLE 5.8. Comparison of NAAQS and PSD Increments with Estimated Maximum Concentrations from Coal-Fired Power Plants

		Maximum Concentrations or PSD Increments, $\mu g/m^3$				
		SO_2		Particulates		
Averaging Time		(Primary)	(Secondary)	(Primary)	(Secondary)	NO_x [a]
Annual average	NAAQS	80	--	75	60	100
	PSD (Class I)	2	--	5	--	--
	PSD (Class II)	20	--	19	--	--
	PSD (Class III)	40	--	37	--	--
	3000 MWe	3.8 [b]	--	0.3 [b]	--	2.2 [b]
24-hour	NAAQS	365	--	260	150	--
	PSD (Class I)	8	--	10	--	--
	PSD (Class II)	91	--	37	--	--
	PSD (Class III)	182	--	75	--	--
	3000 MWe	250-490 [c]	--	21-41 [c]	--	--
3-hour	NAAQS	--	1300	--	--	--
	PSD (Class I)	--	25	--	--	--
	PSD (Class II)	--	512	--	--	--
	PSD (Class III)	--	700	--	--	--
	3000 MWe	--	380-760 [c]	--	--	--

(a) Primary and Secondary Standard.
(b) Based on CDM estimates using STAR data from Boise, ID.
(c) Based on Reference 8.

limit the size or emission rate of the electrical generation facilities. The 3000 MWe facilities considered for this study appear to represent the upper limit in plant size if emissions are at the allowable New Source Performance Standard. If emissions based on the Hittman study[9] were used, much larger facilities with controlled stack effluents would be possible, but much smaller facilities would be necessary if there were no stack gas controls.

Emissions of particulates from coal-fired generation facilities contribute a significantly smaller fraction of their respective 24-hr standards than do emissions of SO_2. However, existing ambient particulate concentrations are generally higher relative to standards than are SO_2 levels. For example, Stern[10] shows annual average background concentrations in the Pacific Northwest to range from 10-20 $\mu g/m^3$ or about 20% of the annual standard, while background SO_2 levels are between 1% and 10% of "polluted air" values; hence, particulate impacts must be carefully considered when assigning priority to facility siting.

The following is an initial evaluation of how the Clean Air Act Amendments of 1977 would constrain the coal utilization scenarios based on the short-range concentrations in the Northwest. From Table 5.8 it is evident that the maximum annual concentrations of SO_2 from a 3000 MWe reference facility will prevent siting within Class I areas. In fact, it will be necessary, based on these estimates, to establish a "buffer zone" around any Class I area for siting of large coal facilities, since the transport of pollutants over distances of perhaps a few tens of kilometers could still result in concentrations greater than the increments allowed for Class I areas. Class I areas themselves will not be considered for development under these regulations. By comparing the location of the candidate siting counties (Figure 5.3) with the location of mandatory Class I areas (Figure 5.1), it can be seen that possible siting constraints due to PSD regulations could occur in some areas. Portions of many candidate siting counties, with the exception of those in the eastern portion of the Columbia Gorge and in the central Columbia Basin region of eastern Washington State, are within 100 km of the boundaries of Class I areas.

Particulate concentrations are not as serious a problem for siting coal facilities near Class I areas. Nevertheless, the 24-hr concentrations estimated here for new coal facilities will limit development within Class I areas. Utilization of BACT will, however, most likely revise the concentration estimates downward, although extensive controls would be required beyond the NSPS before siting within Class I regions would be feasible. It is safe to assume here that virtually all coal development will have to take place in regions other than Class I areas.

According to the 24-hr estimates in Table 5.8, additional controls beyond those necessary for compliance with the New Source Performance Standards (NSPS) will be necessary to site large facilities within Class II regions. Currently all states are designated as Class II, with the exception of the mandatory Class I regions. For a 3000 MWe reference plant with emissions equivalent to the NSPS, SO_2 emissions would have to be reduced by a factor of at least 2.75 to comply with the 24-hr PSD incremental standard, and particulate emissions would have to be reduced by as much as 10%. Some further reduction beyond compliance with the NSPS could be necessary to maintain the 3-hr maximum SO_2 incremental PSD standard as well. Multiple facilities totaling more than about 5000 MWe could clearly require additional controls according to Table 5.8. In essence, this implies that for large-scale coal development in the West, BACT

must reduce SO_2 and particulate emissions by more than the NSPS to comply with PSD regulations for Class II regions. As shown by Renne,[6] even to comply with NSPS would require controls on facilities burning Montana or Wyoming coal for over half of the strippable or underground resources in those two states.

The allowable increments for Class III regions are large enough to accommodate about 2200 MWe of coal-fired generating capacity in a region if the facilities operate within the NSPS, according to the 24-hr maximum allowable increments of SO_2 under PSD. The 24-hr increment of the PSD standards is the most constraining for coal-fired power plant development, according to this analysis. In addition, many areas, according to the Clean Air Act Amendments of 1977, cannot be designated Class III by the states, including national monuments, primitive areas, preserves, recreation areas, wild and scenic rivers, wildlife refuges, lakeshores and seashores of greater than 10,000 acres in size, and national parks and wilderness areas, established after the Amendments, greater than 10,000 acres in size. This represents a significant amount of land in the West.

5.2.4 Long-Range Transport of Sulfur Dioxide and Sulfates

A significant impact of coal-fired power plant emissions is the long-range transport of sulfur dioxide and its transformation to sulfate aerosols before being removed from the atmosphere by wet and dry deposition processes. Evidence exists that sulfate aerosols may have certain health effects, and over long periods of time they can build up in the soil profile and have important ecological and agricultural implications, even at large distances from the source.

A regional transport, transformation, and removal model that uses actual upper air meteorological data to account for the temporal and spatial variability of the wind field has been applied to the year 2020 coal-related energy development scenario for the entire western United States (west of the 100th meridian). This model allows an assessment of the sulfur to sulfate problem to be made, as well as an assessment of the impact of multiple sources on the air quality of a region. The model is also useful in assessing the impact of PSD regulations on future coal development. This model has been described as it was applied in two earlier studies.[11,12] This section describes the application of this model to the western United States for the year 2020 scenario and the results of the model calculations for a one-month period of meteorological data. (See Appendix C for a detailed description of the model.)

5.2.4.1 Existing Emissions

The inventory of existing large point SO_2 emitters in the western United States was compiled using currently available data from the NEDS[13] and state air pollution control agencies. Only source locations with greater than 4500 tonnes/yr were used in the regional model. In areas where emission sources were relatively close (within 50 km of each other), the emissions were combined for calculational facility.

The year for which the emission data is applicable varies from state to state and source to source. In some cases, updated emissions data were obtained directly from state air pollution control agencies. The emissions data used from this inventory included everything except coal-fired power plants. Emissions for coal-fired power plants have been estimated by assuming that all facilities operate at the NSPS and at a 60% load factor. In the western United States

data base, 66 source locations with SO_2 emmissions of 4500 tonnes/yr or more exist. Twenty of the 66 locations are coal-fired power plants. The largest SO_2 emitters are smelters, and the majority of these are located in southeast Arizona. The SO_2 emissions have been reduced considerably in some areas of the West through environmental control equipment and practices. For example, the total SO_2 emissions from smelters in Arizona were reduced by approximately 50% from 1972 to 1976.[14]

5.2.4.2 Projected Emissions for Year 2020 Scenarios

Candidate siting areas for coal-fired power plants and coal-gasification plants in the western United States are based on data supplied by Argonne National Laboratory (North Dakota, South Dakota, Nebraska, and Kansas), Lawrence Berkeley Laboratory (California), Los Alamos Laboratory (Rocky Mountain states), and Oak Ridge National Laboratory (Texas and Oklahoma). Emission estimates to the year 2020 for the projected coal-fired power plants are based on current NSPS and a 60% plant load factor, the same criteria applied to existing plants. No attempt has been made in this study to project the growth of other types of SO_2 emitters, such as smelters and refineries.

Fifty-six candidate sites for new facilities to 2020 have been specified for the western United States. Table 5.9 gives a breakdown of existing versus projected emissions used in the assessment for the western United States.

TABLE 5.9. Total SO_2 Emissions Used in the Western Region Assessment

	SO_2 Emissions (tonnes/yr x 10^3)
Existing (industrial + power plants)	3316
Year 2020 High Coal Electric scenario	3061
Total	6377

5.2.4.3 SO_2 Concentrations

Three different scenarios of SO_2 concentrations for the western United States are described: 1) the existing, 2) the incremental from the High Coal Electric scenario to the year 2020, and 3) the sum of the above. Figure 5.5 shows the estimated existing SO_2 concentrations. Regions of highest concentrations are primarily in areas with large smelters, refineries or power plants. The maximum existing concentrations calculated for the western region are 15 $\mu g/m^3$ in southeast Arizona due to large smelters in that area. This is well below the NAAQS maximum allowable annual concentrations (80 $\mu g/m^3$) and state standards. However, the model calculations are averaged for an area of 4075 km^2, and much higher concentrations are actually being observed in the vicinity of these sources.[14] This situation could also exist for other areas with large point SO_2 emissions in this assessment. Also, the estimates may understate actual conditions since mobile and small stationary sources of SO_2 have not been included.

The incremental SO_2 concentrations predicted for the High Coal Electric scenario to the year 2020 are shown in Figure 5.6. Largest incremental values are 19 $\mu g/m^3$ in northwest New Mexico, and 11 $\mu g/m^3$ in southcentral Washington. These are the two regions with the most capacity in the High Coal Electric scenario. Incremental concentrations are less than 10 $\mu g/m^3$

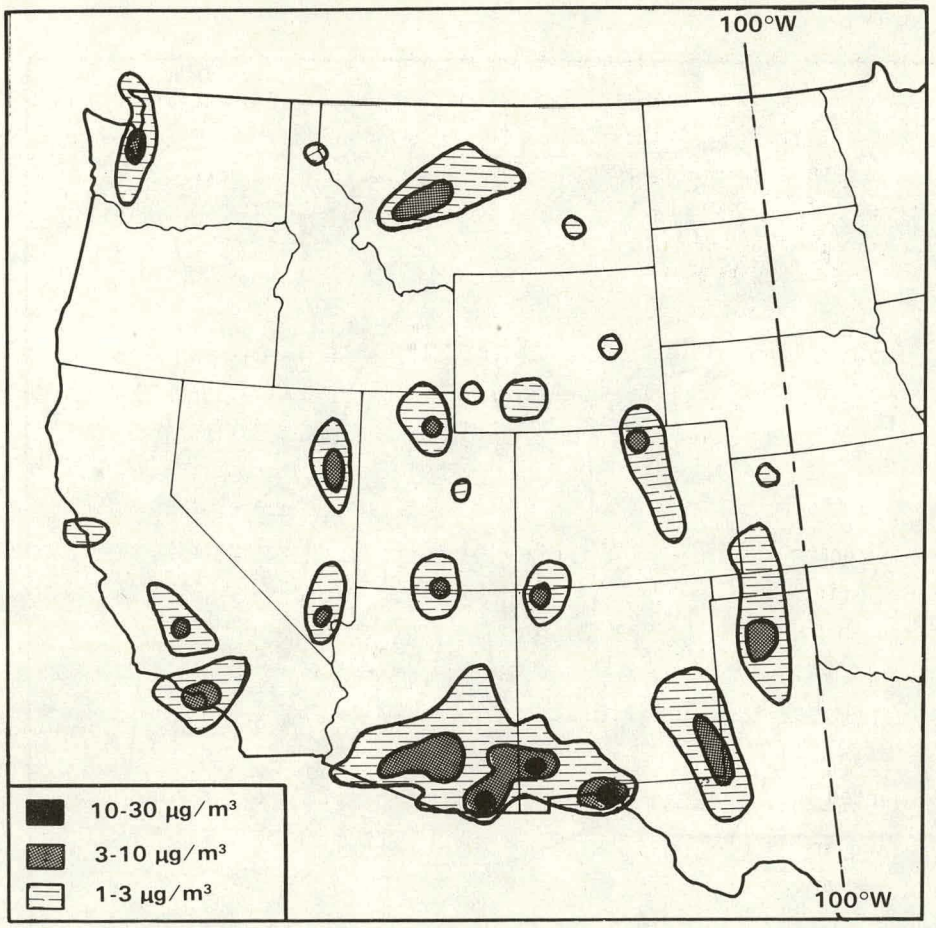


FIGURE 5.5. Estimated SO_2 Concentrations for Existing Large Point Sources West of 100° W. Values represent average for October 1974 upper air data.

for all other candidate areas of the West. While these incremental concentrations are a small fraction of the maximum allowable annual concentrations, they could be quite important if they extend over areas where only small increases in SO_2 concentrations, such as 2 $\mu g/m^3$ for Class I areas, are allowed under PSD Regulations. (These constraints are described in Section 5.1.) However, the regional air concentrations could be markedly lower if plants apply BACT to reduce emissions.

Figure 5.7 shows the combined concentrations of the existing plus the High Coal Electric scenario to the year 2020. Although the background concentrations from the industrial and other noncoal related SO_2 emitters can be expected to change considerably by the year 2020, this analysis shows where problem areas can develop under the assumed siting patterns. New candidate siting areas are primarily located where existing concentrations are low. However, the analysis shows that regional-scale interactions of concentrations greater than 2 $\mu g/m^3$ would cover a significant portion of the West and this could pose problems with respect to the PSD Regulations.

5.2.4.4 Sulfate Concentrations

Figure 5.8 shows the combined sulfate concentrations resulting from the existing sources plus the High Coal Electric scenario to the year 2020. Largest sulfate concentrations are

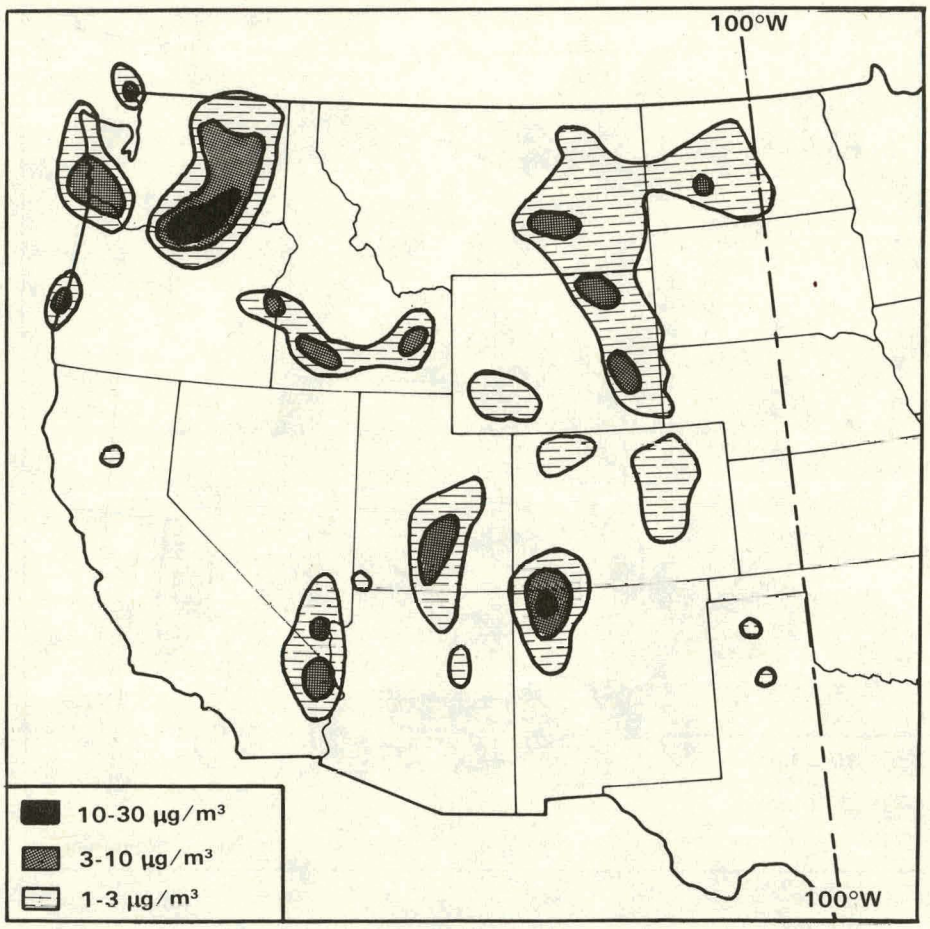


FIGURE 5.6. Estimated SO_2 Concentration Increments for the High Coal Electric Scenario Projected to the Year 2020. Values represent average for October 1974 upper air data.

calculated to be 5 to 6 $\mu g/m^3$. In contrast to SO_2 concentrations, the sulfate concentrations decrease much more slowly with distance from the source. Thus, regional-scale interactions are more apparent with sulfate than with SO_2 concentrations, as sulfate concentrations of 3 $\mu g/m^3$ or greater cover large areas in the Great Plains, Southwest and Northwest.

NAAQS for sulfates have not been established. However, some evidence exists that sulfates can cause health problems, and some states have established their own air quality standards for sulfates (e.g., Montana and North Dakota, where the maximum allowable annual sulfate concentration is 4 $\mu g/m^3$). Thus, sulfate concentrations could prove to be a limiting constraint to future siting in some regions if emission levels up to the Federal New Source Performance Standards are permitted.

5.2.4.5 SO_2 and Sulfate Depositions

Depositions of SO_2 and sulfates for the existing and High Coal Electric scenario to the year 2020 are shown in Figures 5.9 and 5.10, respectively. These values represent the total amount deposited on the surface for the month. Large variations in the sulfate deposition patterns are expected due primarily to the seasonal variations in the precipitation throughout the western United States.

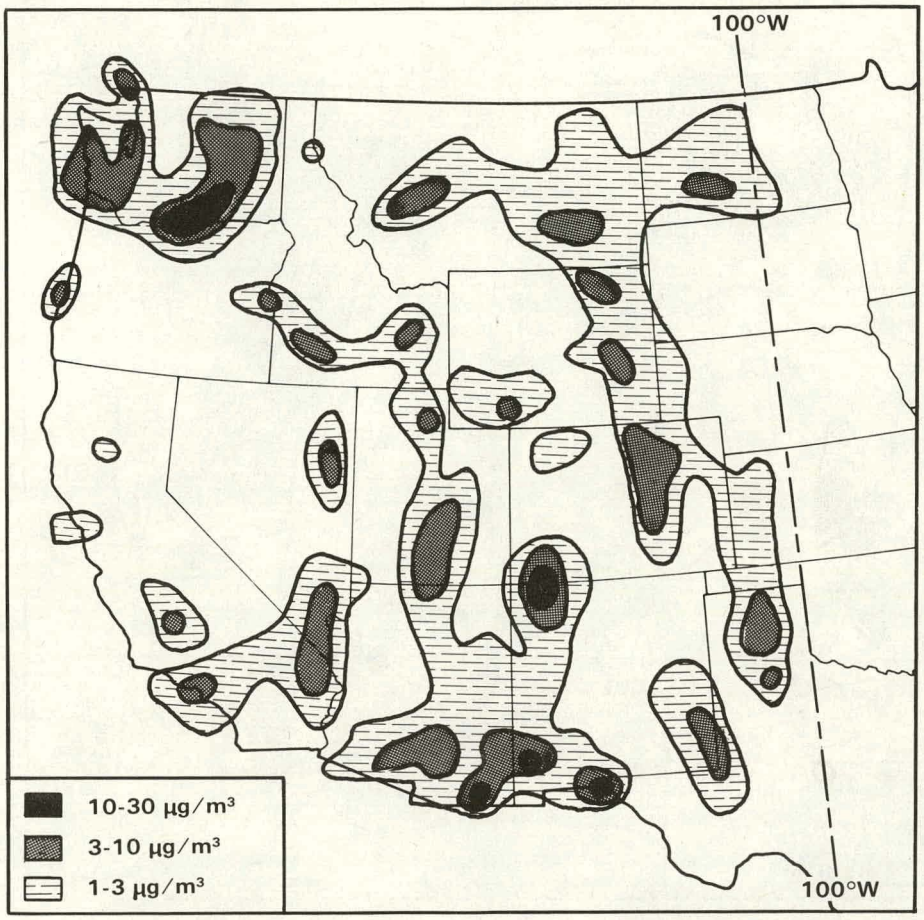


FIGURE 5.7. Estimated SO_2 Concentrations for Existing Sources West of 100° W and the High Coal Electric Scenario Projected to the Year 2000. Values represent average for October 1974 upper air data.

The SO_2 deposition patterns are similar to the SO_2 concentration patterns. The analysis shows that 1 g/m^2, or 9 lb/acre, or more of SO_2 can be deposited onto the terrestrial environment in some areas. Assuming that the top foot of a soil profile weighs roughly 6×10^6 lb/acre, this would result in a sulfur concentration in the soil profile of 0.75 ppm. Although damage could occur as the SO_2 passes through the plant canopy to the soil, this increase of sulfur within the soil profile could benefit agriculture in some regions.[11]

The largest sulfate depositions are roughly a factor of 5 to 10 smaller than SO_2 depositions. This is due in part to the deposition of much of the SO_2 (by wet and dry removal processes) before being transformed to sulfate.

5.2.4.6 SO_2-Sulfate Budgets

The total SO_2-sulfate budgets (percent of the total mass emitted during the month that is deposited, remains in the air, or transported off the grid) for the combined existing and High Coal Electric scenario to the year 2020 for the western United States grid are presented in Table 5.10. The budgets are based on 122 source locations with SO_2 emissions totaling 7014.5 kilotons/yr. The percent of the SO_2 and sulfates deposited and transported off the grid is strongly influenced by the location of the largest emitters in the region. For example,

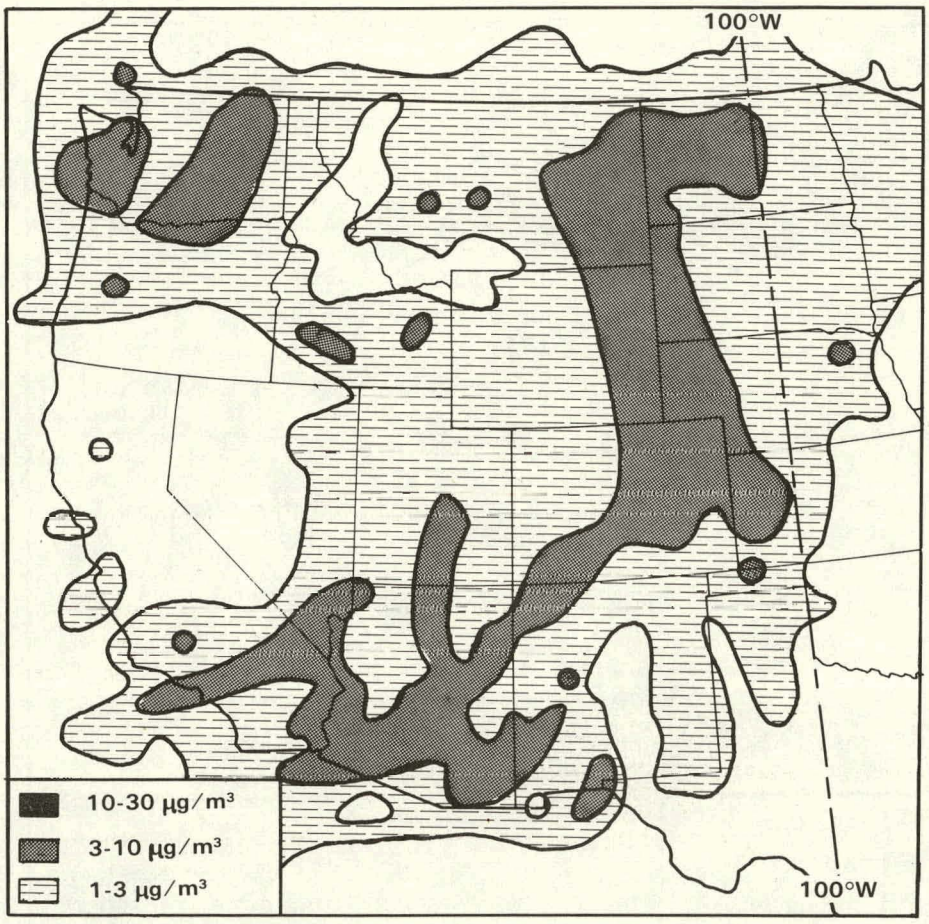


FIGURE 5.8. Estimated Sulfate Concentrations for Existing Sources West of 100° W and the High Coal Electric Scenario Projected to the Year 2020. Values represent average for October 1974 upper air data.

over 45% of the SO_2 was transformed into sulfates in Wyoming, while less than 30% was transformed into sulfates in Washington and Oregon. These differences are primarily due to variations in meteorological conditions and terrain characteristics that affect the removal of SO_2 before being transformed to sulfate.

TABLE 5.10. Total SO_2-Sulfate Budget for the Western United States

	Percent						
	Left in Air Over Grid		Deposited on Surface of Grid		Transported Beyond Grid		
Period	SO_2	SO_4	SO_2	SO_4	SO_2	SO_4	Total
October 1-31, 1974	2.2	2.3	62.1	19.7	2.0	11.6	100.0

5.2.4.7 Acid Rainfall

The long-range transport model used in this assessment also has the capability to calculate the pH balance of rainfall where precipitation scavenging of airborne SO_2 and sulfates occurs. Although patterns of pH levels are not shown here, minimum pH values are calculated

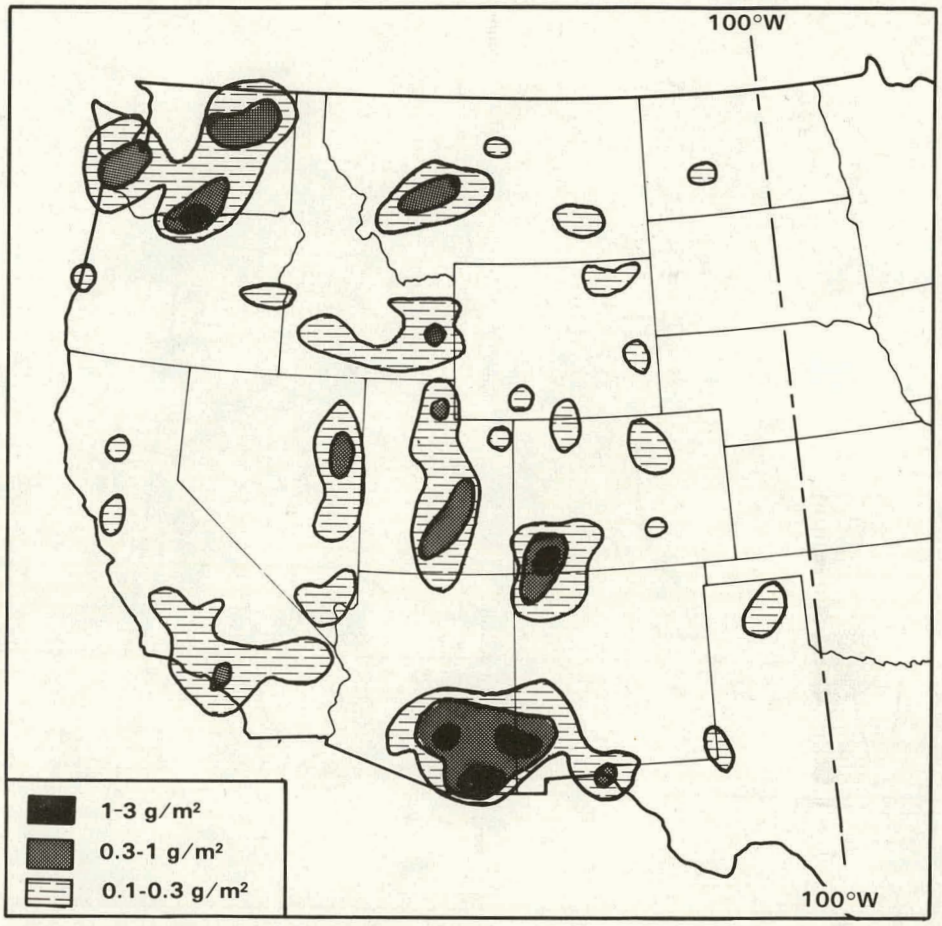


FIGURE 5.9. Estimated SO_2 Depositions for Existing Sources West of 100° W and the High Coal Electric Scenario Projected to the Year 2020. Values represent total deposition in October 1974.

to be as low as 4.0 in the Columbia Basin region and in the southwest United States. However, because of the low rainfall that occurs in these regions, the low pH values are not expected to represent a significant impact.

5.3 ISSUES REQUIRING FURTHER ANALYSIS

On the basis of the study presented here, several issues require further analysis. One is the issue of BACT and the determination of the appropriate emission factors to be used in a coal assessment. Clearly, the NSPS represent the upper limit for emissions from new coal-fired power plants. Plants burning western low sulfur coal, and applying BACT, will emit far less pollutants than the NSPS. It remains to be seen what regulations on the standard of performance for coal-fired power plants will evolve based on the concept of BACT; when they do, it will be necessary to analyze the coal development scenarios using the new emission factors. The possibility that these emissions could be varied for different meteorological conditions to control ground level concentrations also needs to be assessed.

A second major issue relates to the scenarios themselves. Siting scenarios are always difficult to develop for a large region. Nevertheless, they are necessary in order to address

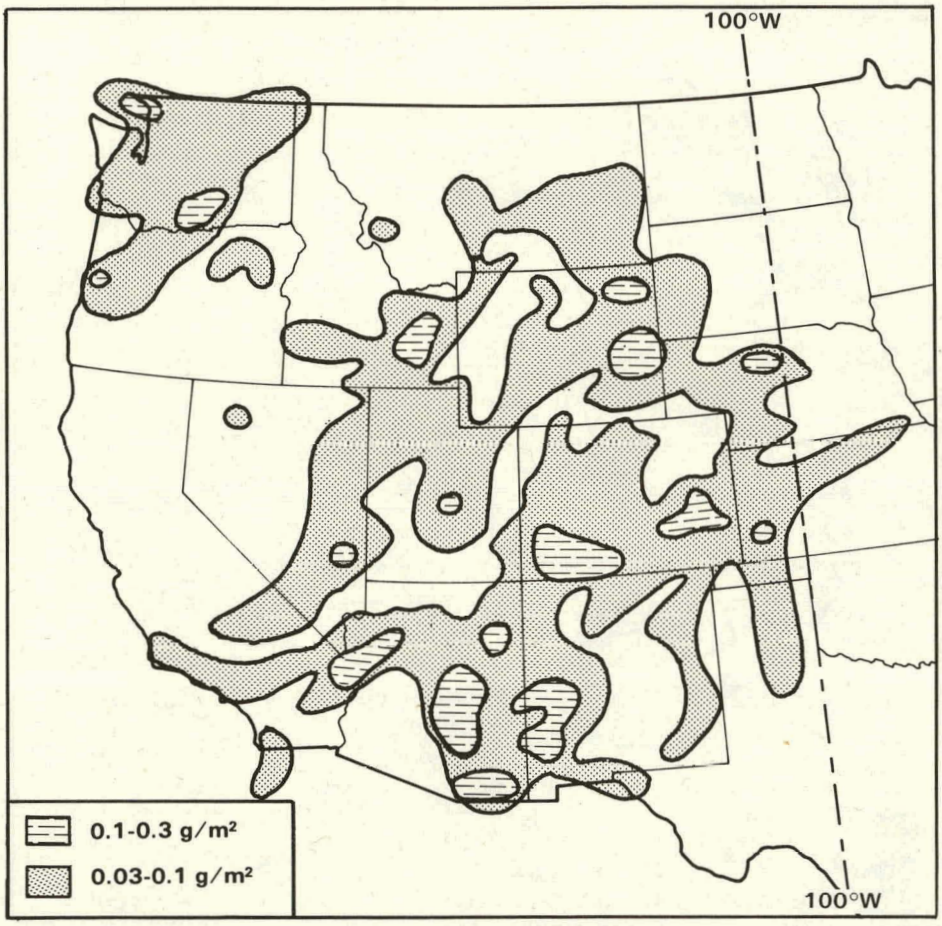


FIGURE 5.10. Estimated Sulfate Depositions for Existing Sources West of 100° W and the High Coal Electric Scenario Projected to the Year 2020. Values represent total deposition in October 1974.

the impact of the development on air quality. As siting scenarios are refined, additional analyses of coal development scenarios should be made.

A third major issue concerns the modeling used in the analyses. The models used in this study are models that have received wide application. Nevertheless, they are flat terrain models and do not account for the effect that local terrain features may play on the distribution and concentration of pollutants. As more specific siting scenarios are established, it will be appropriate to apply complex terrain models, which may cover different space scales than those used here, to future coal development. This type of analysis is particularly important for the short-term maximum concentration estimates, which appear to be the most critical constraint to coal development based on the allowable air quality limits imposed by the Clean Air Act.

Along with the types of models used in the analysis, the sensitivity of the model results to various input parameters, and the uncertainty of the input parameters themselves, need to be assessed. Some of the analyses shown in this report indicate the models can be highly sensitive to input information such as atmospheric stability and mean wind speed.

A fourth major issue is visibility. As the timetable for establishing visibility regulations proceeds, a special assessment needs to be performed on this issue. The types of models that are currently available and the kinds of information these models can provide need to be surveyed immediately. Those models that best describe the visibility impacts addressed in the Clean Air Act need to be applied to the western region High Coal Electric scenario to assess the extent of visibility impairment that could occur in the national parks and wilderness areas of this region.

A fifth major issue is a clear definition of the current background air quality situation that exists in the Pacific Northwest. Although current data are available, the sources of these data are fragmented. These data need to be collected and summarized in a format that will allow a more detailed quantitative assessment of the impact of future coal development on existing air quality in the region than was presented here.

Finally, other issues continue to arise from time to time. For example, the issue of global climatic change due to the large-scale release of CO_2 and particulates from burning of fossil fuels needs to be assessed. As another example, the secondary impacts on air quality associated with the growth of other emission sources due to the development of the coal resource need to be examined.

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6.0 IMPACTS ON WATER USE AND QUALITY

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- **Impacts on Water Supply and Use**
- **Impacts on Water Quality**
- **Impacts of Alaskan Coal Development**

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

6.0 IMPACTS ON WATER USE AND QUALITY

Chapter 6 assesses the water consumption and water quality impacts of two scenarios of coal-fired power generation for the period 1975-2020. The analysis is conducted for the seven "aggregated subareas" (ASAs) into which the states of Idaho, Oregon and Washington have been divided by studies of the Water Resources Council, and for three areas of southcentral Alaska.

Water consumption impacts in the three contiguous states are assessed by comparing the estimated withdrawals and consumption of water by projected power plants within each ASA to total surface water flows. Where appropriate, water withdrawals and consumption are also compared to historic and projected monthly low flows of the Columbia and Snake Rivers at key points, as simulated by the U.S. Army Corps of Engineers. In developing these comparisons we have assumed that all plants would use wet-tower evaporative cooling and would withdraw their water supply from the largest surface source in the identified candidate county. Thus, all water is assumed to be withdrawn from the Columbia or Snake Rivers or from coastal estuaries. No attempt has been made to assess the legal availability of surface water supplies, but possible conflicts with other water uses are identified. For the two Alaskan areas, power plant water requirements are compared to the very limited data on low flows in the major nearby rivers.

Water quality impacts are assessed on the assumption that all coal-fired power plants collect, treat and release all liquid effluents as necessary to meet Federal New Source Performance Standards. Resulting pollutant releases are compared qualitatively to existing background conditions in the ASAs and in the relevant Alaskan rivers. On the basis of this analysis, our conclusions follow.

Surface water supplies are more than adequate to meet the needs of new coal-fired generating plants that may be located on the Columbia or Snake Rivers. In most cases less than 1% of the mean low flow would be used under the scenarios studied.

Increasing competition for available supplies among alternative uses—principally power generation, irrigated agriculture, and fisheries maintenance—may result in institutional constraints on water availability for energy generation.

Off-stream storage reservoirs may be used to minimize conflicts with other water uses during critical low flow periods.

Though current national (EPA) policies strongly favor the use of cooling towers or ponds instead of once-through cooling, the choice of cooling technology to be used may become a debated subject in the region due to high-volume stream flows, ocean access, and the value of water in alternative uses. If once-through cooling is not allowed, the coastal candidate counties will lose much of their attractiveness for plant siting.

Competition for water is most intense in the Snake River. The state of Idaho is considering setting aside adequate supplies for power generation through administrative allocations.

Assuming Federal New Source Performance Standards, routine effluent releases will essentially be limited to dissolved solids, which are expected to have little impact on a regional scale.

Heavy metals and abnormally acid or alkaline waters accidentally released by surface runoff from coal and ash storage piles, or released from leaching from ash and sludge disposal areas, are the greatest threat of localized water pollution.

The region's unique present dependence on hydroelectric generating facilities suggests that an important potential impact of coal-fired plants (or other thermal base-load power plants developed in the future) is that hydro facilities may operate to supply peak loads, resulting in more rapid and extreme fluctuations in river flows.

Potential Alaskan coal development poses a unique situation. Our preliminary data indicate that adequate surface water supplies are available to serve the postulated mines and power plants. However, streams exhibit extreme seasonal fluctuations in flow, and the impacts of sedimentation and other potential water quality impacts of mining are highly uncertain. The availability of ground water to meet energy development needs has not been determined.

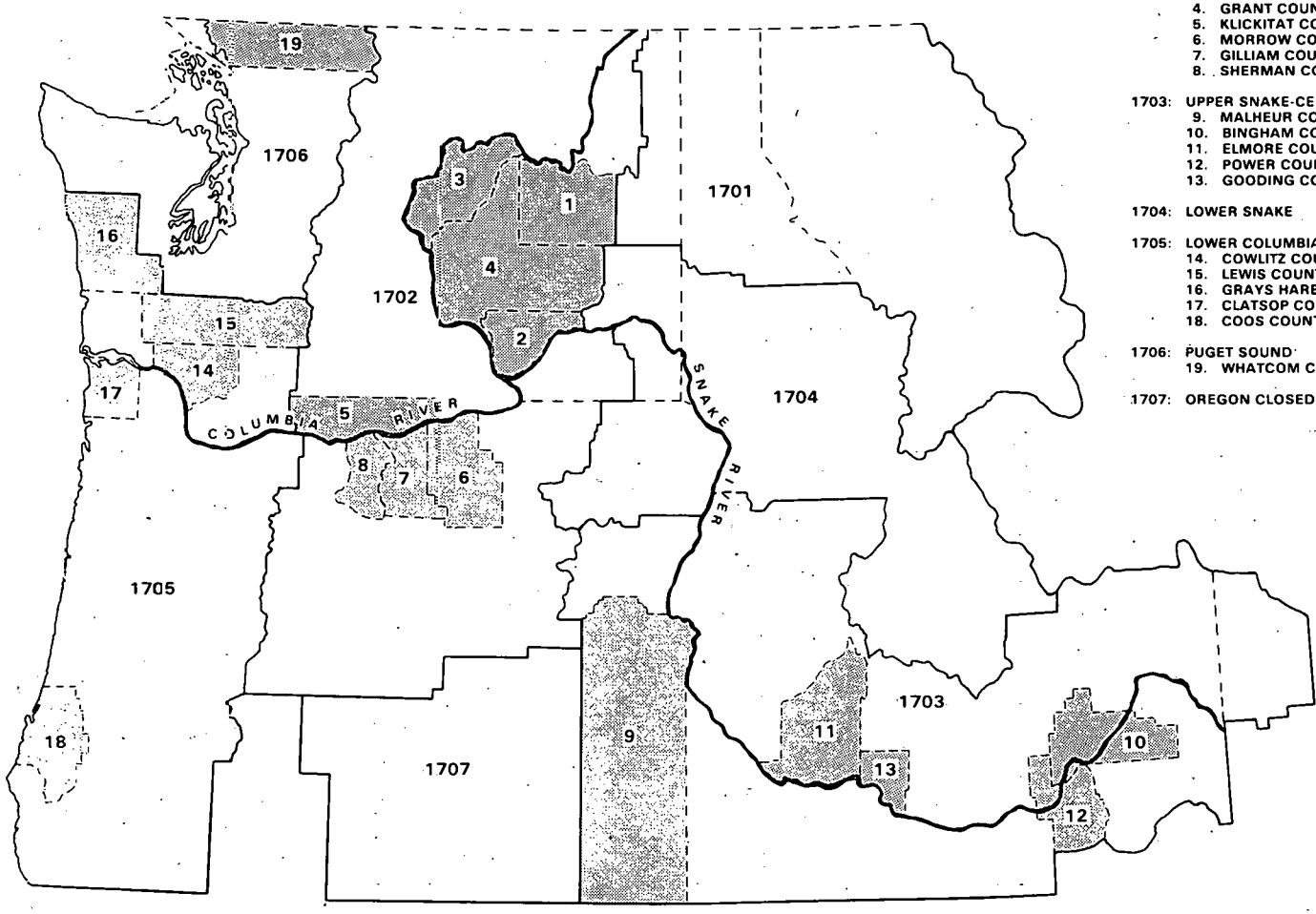
The following important topics for additional research are identified:

- **Research is needed to assess the environmental and economic tradeoffs among competing alternative water uses in the Columbia and Snake Rivers.**
- **The relative environmental benefits and costs of once-through cooling need to be investigated for coastal and Alaskan sites. The potential use of heated effluents for fish culture in Alaska should also be investigated.**
- **The feasibility and implications of using ground water sources for new thermal plants should be investigated, particularly for Snake River, mid-Columbia and Alaskan sites.**

The Pacific Northwest Region, as defined for this analysis, consists of seven aggregated subareas (ASAs) delineated by the U.S. Water Resources Council. These aggregated subareas are shown in Figure 6.1. In total, they comprise a region of great physical and climatic diversity. The 267,309 square miles of the region include all of Washington, all but small portions of Idaho and Oregon, and the westward flowing drainages of northwest Montana.[1]

Precipitation in the region ranges from less than 10 in. per year in portions of the Columbia Basin and Snake River Plateau to nearly 200 in. per year in some coastal areas. In the areas of greater precipitation (coastal, Cascade Mountains, western slopes of the Rocky Mountains), a marked seasonal distribution occurs, with most precipitation in the fall, winter, and spring. The arid interior basins and plateaus are heavily dependent on snow melt from bordering mountainous areas, including Canadian portions of the Columbia River drainage. Natural streamflows, therefore, exhibit extreme seasonal fluctuations throughout the region with winter-spring peaks west of the Cascades and spring-summer peaks east of these mountains. The operation of numerous dams for hydroelectric power generation and other purposes has substantially altered and reduced extremes in natural streamflow patterns, particularly in the Columbia and Snake Rivers.

Of the seven ASAs in the Pacific Northwest Region, only four play a direct role in this assessment of the impacts of future energy from coal on water resources. The other three subareas (1701: Clark Fork-Kootenai-Spokane; 1704: Lower Snake; and 1707: Closed Oregon Basin) are not projected to contain, within the scenarios examined in this study, any coal fired power plants, mines, or coal conversion facilities. The Clark Fork and Lower Snake subareas will be indirectly affected by the scenarios, however, since they contain hydroelectric generating facilities that may experience shifts toward greater use as peaking power facilities as new thermal plants come on line to provide a greater share of the region's base load. Figure 6.1 shows the location of counties identified as sites of new coal-fired power plants in the two scenarios examined in this study. Except for the existing power plant and mine near Centralia, Washington, which use the Skookumchuck River, all these sites are assumed to draw their water supplies from the largest water source available in the county--either the



1701: CLARK FORK-KOOTENAI-SPOKANE

1702: UPPER COLUMBIA-YAKIMA-MID COLUMBIA
1. LINCOLN COUNTY, WA
2. FRANKLIN COUNTY, WA
3. DOUGLAS COUNTY, WA
4. GRANT COUNTY, WA
5. KLICKITAT COUNTY, WA
6. MORROW COUNTY, OR
7. GILLIAM COUNTY, OR
8. SHERMAN COUNTY, OR

1703: UPPER SNAKE-CENTRAL SNAKE
9. MALHEUR COUNTY, OR
10. BINGHAM COUNTY, ID
11. ELMORE COUNTY, ID
12. POWER COUNTY, ID
13. GOODING COUNTY, ID

1704: LOWER SNAKE

1705: LOWER COLUMBIA-WILLAMETTE-COASTAL
14. COWLITZ COUNTY, WA
15. LEWIS COUNTY, WA
16. GRAYS HARBOR COUNTY, WA
17. CLATSOP COUNTY, OR
18. COOS COUNTY, OR

1706: PUGET SOUND
19. WHATCOM COUNTY, WA

1707: OREGON CLOSED BASIN

FIGURE 6.1. Aggregated Subareas of the Pacific Northwest and Candidate Counties for Coal-Fired Power Plant Sites

Columbia River, the Snake River, estuaries, or the Pacific Ocean. As a result, the discussions of resource availability and impacts of coal utilization that follow are confined to these water bodies.

6.1 IMPACTS ON WATER SUPPLY AND USE

6.1.1 Physically Available Supplies

The gross water supplies of the Columbia and Snake Rivers are very large, as illustrated by observed and projected low flows. The U.S. Army Corps of Engineers has used 30 years of historical data, modified by 1970 levels of irrigation depletion, to simulate river flows.[a] Even for the months of lowest flow in the driest years, flows averaged between 28,000 and 74,000 million gallons per day (MGD) for observation points along the Columbia from Chief Joseph Dam to Bonneville Dam, the river reach in which the projected power plants would be located. For the Snake River a minimum flow of 3230 MGD (5000 cfs) is required at Brownlee Dam, which is downstream from all projected plant sites. Simulated flows approach this minimum only in extreme circumstances and typically are 2-3 times the minimum. Similar simulations, using expected levels of water use by irrigated agriculture, for the year 2020, project lowest month Columbia River flows at 20,000 to 76,000 MGD, and Snake River flows frequently approaching or at the minimum allowed flow level of 3230 MGD. By comparison, a typical 1000 MWe coal-fired power plant requires approximately 16 MGD, two-thirds of which are consumed, mostly in evaporative cooling. More complete simulation results for 1970 and 2020 depletion levels are presented in Appendix D, Tables D.2 and D.3.

Though the physical limits of supply on the mainstem Columbia and Snake Rivers in no way constrain possible increased coal utilization, competition with other water uses and institutional-legal requirements may play a much more important role in the future availability of water for coal-fired power plants in the region. The net annual recharge to and discharge from the major groundwater aquifers of the region are estimated as 70 million acre-feet. The total quantity of water in groundwater storage may be 550 million acre-feet.[2] Since current withdrawals total less than 10% of the net annual recharge and discharge, significant underground water supplies remain unused. However, most of the groundwater discharge is to surface streams in the region so further exploitation of the groundwater resource would result in related decreases in surface flows.

The chief advantages of using groundwater as a supply source for thermal power plants or other new developments are 1) the location of the groundwater supply may be more advantageous than the downstream area where the water would otherwise be discharged to surface streams and 2) groundwater may be used during periods of low streamflow (typically July-September) to provide an assured supply without causing corresponding decreases in streamflow since the resulting reduced discharge to the stream will occur over a longer period of time due to slower subsurface flow rates. A disadvantage is that high pumping rates will lower the water table and may potentially affect neighboring groundwater users.

(a) Unpublished data, U.S. Army Corps of Engineers, Portland, OR, July 22, 1977.

Alluvial deposits form important aquifers along the Columbia River downstream from Grand Coulee Dam and near the Snake River. In the central and eastern Washington and eastern Oregon plateaus, basalts are the most widespread aquifer types. Basalt is also the major aquifer in the eastern Snake River plain in Idaho. About 60% of all the groundwater use in the region occurs in Idaho.[2] More than 75% of the groundwater withdrawn throughout the region is used in irrigation. Irrigation return flows constitute a major source of recharge for many arid regions, including the Snake River plain.

6.1.2 Institutional Constraints on Availability

The existence of sufficient streamflow and groundwater storage in the region does not necessarily imply that adequate water supplies to support coal-fired power plants will be readily available. Competition among potential water users is increasing as aggregate demand approaches physical supply limits. Institutional mechanisms for water allocation and some unresolved water rights issues must be considered in assessing the availability of water for energy in the Pacific Northwest.

Idaho, Oregon, and Washington are all appropriation doctrine states; that is, the right to the use of water is obtained by permit from the individual states and junior to all prior rights issued for the same water source. The total annual flows of the Columbia and Snake River systems exceed all current or projected demands, but seasonal low flows occur during the same months as maximum water use in agriculture, the major regional water user. Under appropriation doctrine, whenever all rights cannot be met, the right to withdraw water is temporarily suspended, starting with the last issued water rights ("junior" rights) and proceeding through more senior rights until supply meets demand. Any new rights obtained for coal-fired power plants would be junior to all previous water uses. Thus, the dependability of the supply may be uncertain.

To assure an adequate year round supply, most plants will probably have to obtain rights to store water during high runoff periods for use during the critical summer months. The existing coal-fired power plant at Centralia, Washington, utilizes a 35,000 acre-feet capacity reservoir on the Skookumchuck River.[3] New coal-fired plants might also obtain assured water supplies by purchasing more senior rights. Changes in the point of diversion, place of water use, or type of use require approval of appropriate state officials (e.g., the State Engineer in Oregon) and may be prohibited if other users are adversely affected. For example, if water rights previously used for irrigation were purchased for power production, other users could prevent this transfer if they could prove that their use depended on the reasonable return flows from the previous agricultural use.[4]

Additional sources of uncertainty about the availability of water for future use are the issues of federal reserved water rights and Indian water rights. In principal, any federal reservation may use the waters flowing on or by it for uses consistent with the reservation's purposes--regardless of state laws concerning these waters.[5] Similarly, Indian reservations have been found to have rights to adjacent waters. The Pacific Northwest states contain many millions of acres of national forests, national parks, and Indian reservations, so that these implied reserved rights might be invoked in the future. Because these rights have not been quantified, it is uncertain what, if any, impact they might have on the future availability of

water for other uses. In all states, reserved rights will require adjudication on a case-by-case basis as controversies arise. The State of Idaho is now completing a study of issues and state positions on the various Indian reservations within the state.

In managing the water resources within their borders, states of the region have the authority to take other actions that can restrict the availability of water for energy development. These actions include allocating unappropriated water to various uses, thus, limiting new water rights issued to the amount of the allocation for that use. Idaho and the other two states can also establish minimum flows needed for protection of instream uses such as maintenance of fisheries. These flows are provided by issuing water rights for instream uses which have a priority within the total water rights structure dating from the time of issuance. States also have the power to close streams to further rights application. All of these programs--allocation, minimum flows, and closed basins--can potentially limit the institutional availability of water for power plant cooling. Conversely, Idaho is considering allocating 170,000 acre-feet per year of Snake River water to cooling thermal power plants.[6]

Water resource concerns may also result in constraints on thermal power plant construction through state energy facility siting programs. In Oregon, an Energy Facility Siting Council reviews applications for power plants according to rules established in 1974. These rules include the division of the entire state into areas judged "suitable" or "unsuitable" for plant sites for fossil fuel, nuclear, or geothermal energy facilities. The Council may not accept applications for areas designated "unsuitable."[7] A major factor used to establish suitability was the potential effect of a plant on streams, estuaries, and associated fish and wildlife resources. Of the counties identified as possible plant sites in this study, several appear to involve sites in areas designated "unsuitable." All Columbia River and coastal sites in Clatsop County are so designated, as is Coos Bay in Coos County. Much of the Columbia River frontage in Morrow County is also designated "unsuitable." Fisheries and water-related concerns are the basis of the unsuitable designations in all these areas.[8] Snake River sites in Malheur County are also designated unsuitable, due to air quality concerns.

In Washington an Energy Facility Site Evaluation Council reviews applications for power plants. Though no specific areas have been identified as suitable or unsuitable, impacts on water resources and instream water uses are considered in reviewing applications.[9]

Idaho does not have a comparable comprehensive siting review program, but preparation of a state electrical energy plan, including plant siting and inventory and reservation of potential sites, has been proposed.[10]

A final issue potentially affecting the availability of water for power plant use within the time frame of this study (1975-2020) is the possible allocation of Columbia or Snake River waters between the states through interstate compacts. The desirability of such allocations is an issue of debate in the region at present.

6.1.3 Water Requirements of Projected Coal-Fired Power Plants

Projected electrical generating capacity and water requirements for coal-fired power plants during the period 1975-2020 are shown in Tables 6.1 and 6.2. These projections assume all plants use evaporative cooling and use 8 million gallons per day (MGD) per 500 MWe, of which two-thirds, or approximately 5 MGD per 500 MWe, is consumed. These figures correspond to approximately 9000 acre-feet per year and 6000 acre-feet per year for a 500 MWe plant.

TABLE 6.1. Projected Water Requirements for Coal-Fired Power Plants, 1975-2020, Recent Trends Scenario[a]

Aggregated Subarea (ASA)	1975 Generating Capacity (MWe)	1975 Water Withdrawals (MGD)	1975 Water Consumed (MGD)	2000 Generating Capacity (MWe)	2000 Water Withdrawals (MGD)	2000 Water Consumed (MGD)	2020 Generating Capacity (MWe)	2020 Water Withdrawals (MGD)	2020 Water Consumed (MGD)
1701: Clark Fork-Kootenai-Spokane	0	0	0	0	0	0	0	0	0
1702: Upper Columbia-Yakima-Mid Columbia									
Lincoln County, WA	0	0	0	1500	24.0	16.0	2000	32.0	21.4
Franklin County, WA	0	0	0	0	0	0	0	0	0
Douglas County, WA	0	0	0	0	0	0	0	0	0
Grant County, WA	0	0	0	0	0	0	500	8.0	5.3
Klickitat County, WA	0	0	0	0	0	0	2500	40.1	26.7
Morrow County, OR	0	0	0	3000	48.1	32.0	4000	64.1	42.7
Gilliam County, OR	0	0	0	0	0	0	1500	24.0	16.0
Sherman County, OR	0	0	0	0	0	0	0	0	0
TOTAL FOR ASA	0	0	0	4500	72.1	48.1	10,500	168	112
1703: Upper Snake-Central Snake									
Malheur County, OR	0	0	0	500	8.0	5.3	500	8.0	5.3
Bingham County, ID	0	0	0	1000	16.0	10.7	1500	24.0	16.0
Elmore County, ID	0	0	0	1500	24.0	16.0	2000	32.0	21.4
Power County, ID	0	0	0	0	0	0	0	0	0
Gooding County, ID	0	0	0	0	0	0	0	0	0
TOTAL FOR ASA	0	0	0	3000	48.1	32.0	4000	64.1	42.7
1704: Lower Snake	0	0	0	0	0	0	0	0	0
1705: Lower Columbia-Willamette-Coastal									
Cowlitz County, WA	0	0	0	2500	40.1	26.7	3000	48.1	32.0
Lewis County, WA	1300	20.8	13.9	1300	20.8	13.9	1300	20.8	13.9
Grays Harbor County, WA	0	0	0	2000	32.0	21.4	2500	40.1	26.7
Clatsop County, OR	0	0	0	0	0	0	0	0	0
Coos County, OR	0	0	0	2000	32.0	21.4	2000	32.0	21.4
TOTAL FOR ASA	1300	20.8	13.9	7800	125.0	88.3	8800	141.0	94.0
1706: Puget Sound									
Whatcom County, WA	0	0	0	500	8.0	5.3	500	8.01	5.3
1707: Oregon Closed Basin	0	0	0	0	0	0	0	0	0
TOTALS FOR REGION	1300	20.8	13.9	15,800	253.0	169.0	23,800	381.0	254.0

(a) Totals may not add due to rounding.

TABLE 6.2. Projected Water Requirements for Coal-Fired Power Plants, 1975-2020, High Coal Electric Scenario[a]

Aggregated Subarea (ASA)	1975 Generating Capacity (MWe)	1975 Water Withdrawals (MGD)	1975 Water Consumed (MGD)	2000 Generating Capacity (MWe)	2000 Water Withdrawals (MGD)	2000 Water Consumed (MGD)	2020 Generating Capacity (MWe)	2020 Water Withdrawals (MGD)	2020 Water Consumed (MGD)
1701: Clark Fork-Kootenai-Spokane	0	0	0	0	0	0	0	0	0
1702: Upper Columbia-Yakima-Mid Columbia									
Lincoln County, WA	0	0	0	2500	40.1	26.7	3500	56.1	37.4
Franklin County, WA	0	0	0	3000	48.1	32.0	4500	72.1	48.1
Douglas County, WA	0	0	0	2000	32.0	21.4	3500	56.1	37.3
Grant County, WA	0	0	0	1500	24.0	16.0	3000	48.1	32.0
Klickitat County, WA	0	0	0	0	0	0	5000	80.1	53.4
Morrow County, OR	0	0	0	3000	48.1	32.0	3000	48.1	32.0
Gilliam County, OR	0	0	0	3500	56.1	37.3	3500	56.1	37.3
Sherman County, OR	0	0	0	0	0	0	3000	48.1	32.0
TOTAL FOR ASA	0	0	0	15,500	248	165	29,000	465	309.5
1703: Upper Snake-Central Snake									
Malheur County, OR	0	0	0	500	8.0	5.3	2500	40.1	26.7
Bingham County, ID	0	0	0	2000	32.0	21.4	2000	32.0	21.4
Elmore County, ID	0	0	0	3000	48.1	32.0	3000	48.1	32.0
Power County, ID	0	0	0	0	0	0	1000	16.0	10.7
Gooding County, ID	0	0	0	0	0	0	1000	16.0	10.7
TOTAL FOR ASA	0	0	0	5500	88.1	58.7	9500	152	101.5
1704: Lower Snake	0	0	0	0	0	0	0	0	0
1705: Lower Columbia-Willamette-Coastal									
Cowlitz County, WA	0	0	0	2500	40.1	26.7	3000	48.1	32.0
Lewis County, WA	1300	20.8	13.9	1300	20.9	13.9	1300	20.8	13.9
Grays Harbor County, WA	0	0	0	2500	40.1	26.7	3000	48.1	32.0
Clatsop County, OR	0	0	0	2000	32.0	21.4	3000	48.1	32.0
Coos County, OR	0	0	0	2000	32.0	21.4	2500	40.1	26.7
TOTAL FOR ASA	1300	20.8	13.9	10,300	165	110	12,800	205	136.6
1706: Puget Sound									
Whatcom County, WA	0	0	0	2000	32.0	21.4	2000	32.0	21.4
1707: Oregon Closed Basin	0	0	0	0	0	0	0	0	0
TOTALS FOR REGION	1300	20.8	13.9	33,300	534	356	53,300	854	570

(a) Totals may not add due to rounding.

For the Recent Trends scenario, the total coal-fired generating capacity within the region is projected to be 15,800 MWe in the year 2000 and 23,800 MWe in 2020. As shown in Table 6.1, these generating capacities would result in water withdrawals of 253 MGD in 2000 and 381 MGD in 2020. Corresponding water consumption would be 169 MGD in 2000 and 254 MGD in 2020.

Under the High Coal Electric scenario, projected coal-fired generating capacity reaches 33,300 MWe by 2000 and 53,300 by 2020. Water withdrawals are projected for 2000 and 2020 at 533 MGD and 854 MGD, respectively. Water consumption would total 356 MGD in 2000 and 569 MGD in 2020.

Tables 6.3 and 6.4 compare estimated requirements in each of the region's seven ASAs to 1975 and projected future mean streamflows. It is evident from these tables that coal plant requirements are but a small fraction of gross supplies. The significance of such water use would depend on the specific location and time of withdrawal.

When the water requirements of the coal-fired power plants projected by the two scenarios are separated by water source and compared to river flows (see Appendix D, Tables D.2 and D.3), it is apparent that only very small percentages of total streamflow would be required for coal-fired power generation under either scenario. In the more severe High Coal Electric scenario, for example, power plants in Lincoln, Franklin, Douglas, and Grant Counties, Washington would draw water from the upper Columbia River. The total withdrawal requirement for these sites in the year 2000 is 144 MGD--0.5% of the lowest July flow at Chief Joseph Dam of 29,172 MGD (from Table D.2), assuming 1970 levels of irrigation depletions.

For a "worst case" comparison, the water requirements of all power plants drawing from the Columbia and Snake Rivers in the year 2020 under the High Coal Electric scenario can be compared to projected flows of the Columbia at Bonneville Dam, shown in Table D.3. Water withdrawal requirements for the Columbia and Snake Rivers sites (ASAs 1702, 1703, and Cowlitz County in 1705) are estimated to total 665 MGD, about 1% of the simulated lowest July flow at Bonneville, assuming the 2020 level of irrigation depletion. If groundwater supplies were used to supply part of the projected water needs, the impacts upon surface streamflows would be further reduced. The potential for use of groundwater appears greatest in Idaho.

For localized areas, particularly on the Snake River, the impact of projected coal-fired power plant water withdrawals might be more severe. As Tables D.2 and D.3 show, during low flow years Brownlee Dam and other reservoirs on the upper and middle Snake can be expected to operate at or near minimum allowable streamflow levels. Additional water demands of new coal-fired power plants could only exacerbate the situation. These conditions demonstrate the probable need to store water during higher flow seasons for use by power plants in summer months. The Idaho portion of the Snake River (equivalent to the Upper Snake-Central Snake ASA) is the only area for which specific allocations of unappropriated streamflow to power plant cooling have been proposed. The total allocation is 170,000 acre-feet per year.[10]

To gauge the relative impact of power plant related water withdrawals, note that expansion of irrigated agriculture in the region may withdraw an <u>additional</u> 7565 MGD (8-1/2 million acre-feet per year) by 2020;[11] more than eight times the total projected requirement for all

TABLE 6.3. Projected Coal Related Water Use Compared to Mean Modified Streamflow, 1975-2020, Recent Trends Scenario[1]

Aggregated Subarea	1975 Modified Flow[a] (MGD)	1975 Coal Water Withdrawals[b] (MGD)	2000 Modified Flow[c] (MGD)	2000 Coal Water Withdrawals[b] (MGD)	2020 Modified Flow[c] (MGD)	2020 Coal Water Withdrawals[b] (MGD)
Clarkfork-Kootenai-Spokane	31,397	0	30,740	0	30,740	0
Upper Columbia-Yakima-Mid-Columbia	114,664	0	110,767	72	110,767	168
Upper Snake-Central Snake	10,562	0	9,741	48	9,741	64
Lower Snake	29,720	0	28,435	0	28,435	0
Lower Columbia-Willamette-Coastal	211,554	21	206,671	125	206,671	141
Puget Sound	25,732	0	25,334	8	25,334	8
Oregon Closed Basin	0	0	-1,106	0	-1,106	0

(a) Estimated mean streamflow, assuming 1975 water uses and streamflow regulation
(b) Water withdrawals projected by this study
(c) Estimated mean streamflow, assuming 2000 water uses and 1975 streamflow regulation

TABLE 6.4. Projected Coal Related Water Use Compared to Mean Modified Streamflow, 1975-2020, High Coal Electric Scenario[1]

Aggregated Subarea	1975 Modified Flow[a] (MGD)	1975 Coal Water Withdrawals[b] (MGD)	2000 Modified Flow[c] (MGD)	2000 Coal Water Withdrawals[b] (MGD)	2020 Modified Flow[c] (MGD)	2020 Coal Water Withdrawals[b] (MGD)
Clarkfork-Kootenai-Spokane	31,387	0	30,740	0	30,740	0
Upper Columbia-Yakima-Mid-Columbia	114,664	0	110,767	248	110,767	465
Upper Snake-Central Snake	10,562	0	9,471	88	9,471	152
Lower Snake	29,720	0	28,435	0	28,435	0
Lower Columbia-Willamette-Coastal	211,554	21	206,671	165	206,671	205
Puget Sound	25,732	0	25,334	32	25,334	32
Oregon Closed Basin	0	0	-1,106	0	-1,106	0

(a) Estimated mean streamflow, assuming 1975 water uses and streamflow regulation
(b) Water withdrawals projected by this study
(c) Estimated mean streamflow, assuming 2000 water uses and 1975 streamflow regulation

coal-fired power plants.[a] Even this comparison is understated since about one-third of the total power plant water requirement will be provided at coastal or estuarine sites downstream of other water uses.

These projected levels of water withdrawal and consumption represent substantial increments to overall regional water demands and would probably arouse considerable controversy in an environment of growing competition for water. They represent, however, only small percentages of projected demands of other water uses. A 1968 study by the Water Resources Council projected water withdrawals and consumptive use levels associated with irrigated agriculture in the region as 50,400 MGD and 21,500 MGD, respectively, for the year 2000 and 64,500 MGD and 28,400 MGD respectively, for the year 2020.[10] Comparable projections for other water uses (rural domestic, municipal, industrial other than steam electric power, livestock, recreation) are 11,300 MGD withdrawn and 1,100 MGD consumed by 2000 and 17,200 MGD withdrawn and 1,600 MGD consumed by 2020.[b]

Water use for thermal power plant cooling may become a regional issue of broader concern when the alternative water uses foregone are considered. The 854 MGD of water withdrawn under the High Coal Electric scenario in 2020 is sufficient to irrigate approximately 240,000 acres of agricultural land. The water would have other important but unquantified value to instream uses, including fisheries, recreation, navigation, and hydropower production. Although there is no present means of comparing the benefits derived from one type of use against the benefits of other uses, it is clear that <u>any</u> pattern of water use in the region implies tradeoffs and opportunity costs in other uses. The U.S. Army Corps of Engineers is currently examining some of these tradeoffs as part of the Columbia River and Tributaries Review Study. Impacts of alternative levels of agricultural development and alternative minimum instream flow levels have been described in a recent paper.[11]

Other major impacts associated with coal-fired power development result from the region's unique present dependence on hydroelectric power. As thermal plants come on-line, they will likely be used to supply baseload power, and existing hydro facilities will be operated to meet peaking requirements. As a result, flows in the Columbia and Snake Rivers will probably fluctuate more widely than at present, especially diurnally. These fluctuations may impact instream water uses, particularly fisheries and recreation. Though these impacts have not been quantified, they appear to be, potentially, some of the most important water-related issues of the projected coal developments.

6.2 IMPACTS ON WATER QUALITY

Waste heat and a variety of chemicals may be released in coal-fired power plant liquid effluents. Actual releases vary greatly from plant to plant due to such factors as coal characteristics, source water quality, type of cooling and other equipment used, amount of water reuse, and regulatory and licensing constraints. Table 6.5 lists the potential pollutants and

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(a) Increased irrigation will also require increased electrical energy. These increases have been included in demand projections presented elsewhere in this report.

(b) Under the Recent Trends scenario, much of the region's power would be supplied by nuclear plants. The considerable water requirements of these plants have not been estimated in this study but may be slightly larger than those of the coal-fired plants.

TABLE 6.5. Applicability of Parameters to Chemical Waste Streams[12]

Parameter	Condenser Cooling System		Water Treatment			Boiler Blowdown	Chemical Cleaning			Ash Pond Overflow	Coal Pile Drainage	Floor Drains	Air Pollution Devices	Sanitary Wastes	Low Rad Wastes
	Once Through	Recirculating	Clarification Wastes	Ion Exchange Wastes	Evaporator		Boiler Tubes	Air Preheater	Boiler Fireside				SO_2 Removal		
Alkalinity	X	X	X	X	X	X	X	X	X	X			X		
BOD		X	X	X	X	X	X	X		X		X	X	X	
COD		X	X	X	X	X	X	X	X	X		X		X	
TS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
TDS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
TSS		X	X	X	X	X	X	X	X	X	X	X	X	X	
Ammonia		X	X	X	X	X	X	X	X	X	X			X	
Nitrate		X	X	X	X	X	X			X	X			X	
Phosphorous		X	X	X	X	X	X			X	X		X	X	
Turbidity		X	X		X	X	X	X	X	X	X	X	X	X	
Fecal Coliform														X	
Acidity							X	X	X	X	X	X	X		
Hardness, Total		X	X	X	X	X	X			X		X	X		
Sulfate		X	X	X	X	X	X	X	X	X	X	X	X		
Sulfite								X	X	X		X	X		
Bromide							X								
Chloride		X	X		X	X	X	X	X	X	X			X	
Fluoride		X	X	X			X			X					
Aluminum		X	X		X	X	X		X	X	X		X		
Boron															X
Chromium		X	X	X	X	X	X	X	X	X	X				
Copper	X	X	X	X	X	X	X	X	X	X	X				
Iron		X	X	X	X	X	X	X	X	X	X		X		
Lead										X	X	X			
Magnesium		X	X	X	X	X	X	X	X	X	X	X	X		
Mercury				X	X		X			X	X				
Nickel		X	X	X	X	X	X	X	X	X	X				
Selenium							X			X	X				
Vanadium									X	X			X		
Zinc		X	X	X	X	X	X			X	X				
Oil and Grease				X			X			X		X	X		
Phenols		X	X		X					X	X				
Surfactants					X		X			X		X		X	
Algicides	X	X													
Chlorine	X	X												X	
Manganese		X		X	X	X	X		X	X	X		X		

NOTE: Miscellaneous streams such as laboratory sampling, stack chemical cleanings, etc. are not included since the species are accounted for in other streams.

the waste streams containing them.[12] Actual releases of potential pollutants to the environment are controlled (for the new plants projected in this study) by New Source Performance Standards promulgated by the U.S. Environmental Protection Agency (EPA); other controls are promulgated in individual National Pollutant Discharge Elimination System (NPDES) permits issued by EPA for Idaho or by the authorized state agencies in Oregon and Washington. New Source Performance Standards are shown in Table 6.6.[13]

Besides the chemical pollutant limitations listed in Table 6.6, EPA has promulgated thermal limitations specifying that no discharge of heat from the main condensers shall occur (with the exception of blowdown from the cold side of a closed-cycle cooling system) for new plants of 500 MWe or greater. These limitations effectively require closed-cycle cooling systems--typically evaporative cooling towers or ponds. Exceptions permitting once-through cooling may be allowed under Section 316(a) of the Federal Water Pollution Control Act Amendments (P.L. 92-500). Because of the large flows of the Columbia River and the potential for coastal siting, it is possible that once-through cooling might be considered in the Northwest. However, the Washington Department of Ecology which administers the permit program in that state has a policy of not considering Section 316(a) exceptions for either coastal or inland sites. In Oregon, the Department of Environmental Quality might consider a coastal site but approval seems uncertain at best. We have, therefore, assumed closed-cycle cooling will be used for all plants projected in this study.

In view of NPDES restrictions based on the New Source Performance Standards, it is expected that the only direct releases of potential environmental concern are dissolved solids not now covered by the standards. Tables 6.7 and 6.8 provide estimates of total dissolved solids (TDS) releases at the various plant sites projected under the Recent Trends and High Coal Electric scenarios. These estimates are derived from a Hittman study that assumed compliance with the New Source Performance Standards and a coal of national average characteristics.[14]

Table 6.7 indicates that a total of 284 tons per year of dissolved solids will be released to waters in the region as a result of the projected coal-fired power generation in the year 2000 and 428 tons per year in 2020 under the Recent Trends scenario. In 2000, 44% of these releases would be to coastal or estuarine waters in Cowlitz, Grays Harbor, Clatsop, Coos, and Whatcom Counties. In 2020, 34% of the total would be released in these counties.

Table 6.8 indicates comparable regional totals of 599 tons per year in 2000 and 959 tons per year in 2020 under the High Coal Electric scenario. Releases to coastal or estuarine waters represent 33% and 25% of the regional totals for 2000 and 2020, respectively.

On the regional scale it seems unlikely that these emission levels will have a measurable impact on the receiving waters, based on the large flows and existing TDS levels in the Columbia and Snake Rivers (see Appendix D). The specific constituents released and their impacts on localized areas must, however, be examined on a case-by-case basis.

Potential water pollution problems related to handling and disposal of plant waste merit special mention. Fly ash, bottom ash, and desulfurization sludge are typically transported as slurries to settling basins, after which the settled solids are disposed of by landfill. The concentrations of potentially toxic trace contaminants in the ash and transport waters are high, as shown in Table 6.9.[15] Of Particular concern are the elements As, Cd, Co, Cu, Fe, Mo, Ni, Pb, Sc, Se, U, and Zn.[16]

TABLE 6.6. Liquid Effluents Guidelines and Standards[13]

Effluent Characteristic/ Effluent	pH	Poly-Chlorinated Biphenol Compounds Allowed	Allowable Discharge is Flow Multiplied by the Following Concentrations in mg/ℓ: Total Suspended Solids Max.	Total Suspended Solids Avg.	Oil and Grease Max.	Oil and Grease Avg.	Copper, Total Max.	Copper, Total Avg.	Iron, Total Max.	Iron, Total Avg.	Free Available Cholrine[a] Max. Ever	Free Available Cholrine[a] Daily Avg.	Corrosion[b] Inhibitor
Low Volume Wastes	6.0-9.0	None	100	30	20	15	NAP	NAP	NAP	NAP	NAP	NAP	NAP
Bottom Ash Transport	6.0-9.0	None	100[c]	30[c]	20[c]	15[c]	NAP	NAP	NAP	NAP	NAP	NAP	NAP
Fly Ash Transport	6.0-9.0	None	None	None	None	None	NAP	NAP	NAP	NAP	NAP	NAP	NAP
Metal Cleaning Wastes	6.0-9.0	None	100	30	20	15	1.0	1.0	1.0	1.0	NAP	NAP	NAP
Boiler Blowdown	6.0-9.0	None	100	30	20	15	1.0	1.0	1.0	1.0	NAP	NAP	NAP
Cooling Tower Blowdown	6.0-9.0	None	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	0.5	0.2	NDA
Area Runoff	6.0-9.0	NAP	Not to exceed 50		NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP

Abbreviations used: Max. = Maximum for one day; Avg. = Average of daily values for 30 consecutive days; NAP = Not applicable; NDA = No detectable amount

(a) Neither free available chlorine nor total residual chlorine may be discharged on the average from any unit for more than two hours in any one day, and not more than one unit in any plant may discharge free available chlorine or total residual chlorine at any one time; the latter provision being subject to waiver in special circumstances (Federal Register, 1974).
(b) Materials added for corrosion inhibition including, but not limited to, zinc, chromium and phosphorous.
(c) After multiplying the flow of these numbers, one must divide the product by 20.

TABLE 6.7. Total Dissolved Solids Released by Coal-Fired Power Plants 1975-2020, Recent Trends Scenario

Aggregated Subarea (ASA)	1975 Generating Capacity (MWe)	1975 TDS (tonne/yr)	2000 Generating Capacity (MWe)	2000 TDS (tonne/yr)	2020 Generating Capacity (MWe)	2020 TDS (tonne/yr)
1701: Clark Fork-Kootenai-Spokane	0	0	0	0	0	0
1702: Upper Columbia-Yakima-Mid Columbia						
Lincoln County, WA	0	0	1500	27	2000	36
Franklin County, WA	0	0	0	0	0	0
Douglas County, WA	0	0	0	0	0	0
Grant County, WA	0	0	0	0	500	9
Klickitat County, WA	0	0	0	0	2500	45
Morrow County, OR	0	0	3000	54	4000	72
Gilliam County, OR	0	0	0	0	1500	27
Sherman County, OR	0	0	0	0	0	0
TOTAL FOR ASA	0	0	4500	81	10,500	189
1703: Upper Snake-Central Snake						
Malheur County, OR	0	0	500	9	500	9
Bingham County, ID	0	0	1000	18	1500	27
Elmore County, ID	0	0	1500	27	2000	36
Power County, ID	0	0	0		0	0
Gooding County, ID	0	0	0		0	0
TOTAL FOR ASA	0	0	3000	54	4000	72
1704: Lower Snake	0	0	0	0	0	0
1705: Lower Columbia-Willamette-Coastal						
Cowlitz County, WA	0	0	2500	45	3000	54
Lewis County, WA	1300	23	1300	23	1300	23
Grays Harbor County, WA	0	0	2000	36	2500	45
Clatsop County, OR	0	0	0	0	0	0
Coos County, OR	0	0	2000	36	2000	36
TOTAL FOR ASA	1300	23	7800	140	8800	158
1706: Puget Sound						
Whatcom County, WA	0	0	500	9	500	9
1707: Oregon Closed Basin	0	0	0	0	0	0
TOTALS FOR REGION:	1300	23	15,800	284	23,800	428

TABLE 6.8. Total Dissolved Solids Released by Coal-Fired Power Plants 1975-2020, High Coal Electric Scenario

Aggregated Subarea (ASA)	1975 Generating Capacity (MWe)	1975 TDS (tonne/yr)	2000 Generating Capacity (MWe)	2000 TDS (tonne/yr)	2020 Generating Capacity (MWe)	2020 TDS (tonne/yr)
1701: Clark Fork-Kootenai-Spokane	0	0	0	0	0	0
1702: Upper Columbia-Yakima-Mid Columbia						
Lincoln County, WA	0	0	2500	45	3500	63
Franklin County, WA	0	0	3000	54	4500	81
Douglas County, WA	0	0	2000	36	3500	63
Grant County, WA	0	0	1500	27	3000	54
Klickitat County, WA	0	0	0	0	5000	90
Morrow County, OR	0	0	3000	54	3000	54
Gilliam County, OR	0	0	3500	63	3500	63
Sherman County, OR	0	0	0	0	3000	54
TOTAL FOR ASA	0	0	15,500	279	29,000	522
1703: Upper Snake-Central Snake						
Malheur County, OR	0	0	500	9	2500	45
Bingham County, ID	0	0	2000	36	2000	36
Elmore County, ID	0	0	3000	54	3000	54
Power County, ID	0	0	0	0	1000	18
Gooding County, ID	0	0	0	0	1000	18
TOTAL FOR ASA	0	0	5500	99	9500	171
1704: Lower Snake	0	0	0	0	0	0
1705: Lower Columbia-Willamette-Coastal						
Cowlitz County, WA	0	0	2500	45	3000	54
Lewis County, WA	1300	23	1300	23	1300	23
Grays Harbor County, WA	0	0	2500	45	3000	54
Clatsop County, OR	0	0	2000	36	3000	54
Coos County, OR	0	0	2000	36	2500	45
TOTAL FOR ASA	1300	23	10,300	185	12,800	230
1706: Puget Sound						
Whatcom County, WA	0	0	2000	36	2000	36
1707: Oregon Closed Basin	0	0	0	0	0	0
TOTALS FOR REGION	1300	23	33,300	599	53,300	959

TABLE 6.9. Typical Ash Transport Water Chemical Constituents[15]

Constituent	Concentration in Fly Ash Transport Water (ppm)	Concentration in Bottom Ash Transport Water (ppm)
Silica (SiO_2)	4,824 - 11,040	4,656 - 11,736
Aluminum Oxide (Al_2O_3)	4,176 - 9,768	4,536 - 8,688
Iron Oxide (Fe_2O_3)	1,824 - 7,896	2,808 - 9,600
Calcium Oxide (CaO)	24 - 1,464	2.4 - 1,008
Sulfur Trioxide (SO_3)	2.4 - 1,080	2.4 - 240
Potassium Oxide (K_2O)	288 - 576	408 - 672
Titanium Oxide (TiO_2)	312 - 480	312 - 432
Magnesium Oxide (MgO)	96 - 288	120 - 216
Sodium Oxide (Na_2O)	72 - 192	48 - 192
Phosphorous Pentoxide (P_2O_5)	2.4 - 120	2.4 - 96
Arsenic (As)	<0.25 - 1.44	<0.25
Boron (B)	<2.4	<2.4 - 7.2
Magnesium (Mg)	28.8 - 1,200	240 - 720
Titanium (Ti)	216 - 480	120 - 360
Sodium (Na)	28.8 - 288	48 - 192
Cesium (Ce)	2.4 - 192	0.36 - 19.2
Vanadium (V)	2.76 - 3.6	2.4 - 7.2
Lead (Pb)	2.64 - 3.6	3.6 - 6
Nickel (Ni)	2.64 - 3.6	3.6 - 6
Manganese (Mn)	2.64 - 3.6	3.6 - 4.8
Copper (Cu)	2.16 - 3.6	0.00024 - 7.2
Chromium (Cr)	2.16 - 2.88	1.92 - 3.6
Arsenic (As)	0.192 - 2.88	0.048 - 6
Cobalt (Co)	0.168 - 2.16	0.48 - 1.92
Selenium (Se)	0.6 - 1.8	0.072 - 0.24
Tin (Sb)	0.00024 - 0.36	0.048 - 0.36
Cadmium (Cd)	0.00024 - 0.192	0.00024 - 0.36
Mercury (Hg)	0.0168 - 0.036	0.024 - 0.048

Potential effects, should any of these materials be released either through pond discharge or via leaching to ground or surface waters, are described by Van Hook and Shults.[16]

> The very high pH encountered in ash settling basins may influence the behavior of trace elements if this pH influence extends beyond the confines of the ash settling basin (i.e., into subsurface and surface waters). This high pH results from the hydrolysis of alkali and alkaline earths and may often exceed 11. In most ash settling basins it appears that atmospheric CO_2 diffusion into the water is not rapid enough to lower the pH. For many metals one would predict that they would precipitate either as hydroxides or by co-precipitation (e.g., calcium carbonate). If settling is not complete, however, particulate matter containing elevated levels of metal carbonates, hydroxides, or sulfates could reach the discharge waters...Upon reaching lower pH discharge waters, these particulate phases might redissolve, thus producing an increase in available metals to aquatic plants and organisms. Alternatively,

high pH effluent waters might produce a beneficial effect, in terms of metal removal, on lakes and rivers with low buffering capacity. The change in pH, however, might also affect the plants and organisms in the receiving waters. These implications should be considered before predictions are made on the impact of coal-fired steam plants on the aquatic ecosystem.

Surface discharges from settling ponds are easily monitored and controlled, but goundwater leaching in the ponds or leaching after final disposal in landfills is more difficult to detect. Its impacts are also uncertain. Potential leaching to groundwater is not covered under the current NPDES permit system but may be considered under two other programs. Section 1442 of the Safe Drinking Water Act (P.L. 93-423) authorizes EPA to study the extent to which surface impoundments such as pits or ponds may contaminate groundwater supplies. Section 8002 of the Resource Conservation and Recovery Act (P.L. 94-580) provides for special studies on such topics as the composition of solid waste streams and the different types, origins, disposal methods, and alternative uses of sludge. Subtitle C of this act provides for the regulation and control of the management of hazardous wastes from initial generation to ultimate disposal. The high pH and metals content of ash may be considered under this program.

The extent to which these waste handling issues may result in environmental impacts under the two scenarios cannot be determined at this time. These are simply identified as potential issues that will require closer examination on a case-by-case basis. These concerns are expected to be more pertinent in areas west of the Cascade Mountains where precipitation is high, resulting in increased area runoff and potential for leaching to groundwater.

6.3 IMPACTS OF ALASKAN COAL DEVELOPMENT

The two scenarios project coal-fired power plants at three points in south central and central Alaska: in the Beluga area near Tyonek on the west side of the Cook Inlet, near Nenana in central Alaska, and at the existing small (approximately 100 MWe) plant near Healy, south of Nenana. Water resource impacts associated with these sites are markedly different from those for the Washington-Oregon-Idaho area. Chief differences are the result of the generally undeveloped character of Alaskan regions, the projection of new mines in Alaska, and the unique streamflow patterns there. This section provides a brief introduction to water resource conditions associated with the Beluga and Nenana areas; it is limited to impacts of new coal-fired power plants. The new mines, support communities, transportation systems, and other new facilities needed to support the power plants will have significant impacts on the areas' water resources, but these impacts have not been examined in the present study.

6.3.1 Water Needs and Availability

Table 6.10 lists projected generating capacities in the Beluga, Healy, and Nenana areas and related water withdrawals and consumptive use for the years 2000 and 2020 under each development scenario. As shown in Table 6.10, plants near Nenana in the year 2020 would require withdrawals of 8 MGD under the Recent Trends scenario and 16 MGD under the High Coal Electric scenario. Available surface water supplies include the Tanana River and its tributary, the Nenana River. The average flow of the Tanana River at Nenana is 23,850 cfs (15,407 MGD).[a] Average flows in

(a) U.S. Geological Survey, Anchorage, AK, unpublished data, August 1977.

TABLE 6.10. Generating Capacities and Water Use by Project Coal-Fired Power Plants in Alaska, 1990-2020

	1990			2000			2020		
	Generating Capacity (MWe)	Water Withdrawals (MGD)	Water Consumed (MGD)	Generating Capacity (MWe)	Water Withdrawals (MGD)	Water Consumed (MGD)	Generating Capacity (MWe)	Water Withdrawals (MGD)	Water Consumed (MGD)
Recent Trends Scenario									
Beluga area	0	0	0	0	0	0	2250[a]	36.1	24
Nenana area	0	0	0	0	0	0	500	8	5.3
Healy area	100	1.6	1	100	1.6	1	100	1.6	1
Total	100	1.6	1	100	1.6	1	2850	45.7	30.3
High Coal Electric Scenario									
Beluga area	250[a]	4	2.7	2000	32	21.4	6500	104	69.4
Nenana area	0	0	0	500	8	5.3	1000	16	11
Healy area	100	1.6	1	100	1.6	1	100	1.6	1
Total	350	5.6	3.7	2600	41.6	27.7	7600	121.6	81.4

(a) Beluga and Nenana generating capacities rounded off to 250 MWe units.

the Nenana River at Healy have been recorded at 3,557 cfs (2298 MGD).[a] Flows in both rivers show extreme seasonal variation; peak flows occur in summer and low flows in late winter or early spring. Floods are common with peak flows of record, occurring in July 1967, running 186,000 cfs (120,156 MGD) in the Tanana and 46,800 cfs (30,233 MGD) in the Nenana River. Recorded low flows are 3800 cfs (2455 MGD) for the Tanana River and 500 cfs (323 MGD) for the Nenana.[a]

Groundwater supplies are also available in the Nenana area where alluvial aquifers near the rivers provide significant water storage. The community of Nenana, located at the confluence of the Tanana and Nenana Rivers, currently obtains its water supplies from individual wells 20 to 70 ft deep.[17] Coal for the projected Nenana area power plant(s) would probably be mined near Healy, where mines are presently operating, and shipped by rail. Water impacts associated with the mining activities have not been examined in this study.

Power plants projected for the Beluga area would withdraw 36 MGD in 2020 under the Recent Trends scenario and 104 MGD under the High Coal Electric scenario, as shown in Table 6.10. These calculations and those for the Nenana area, assume evaporative cooling. The technical and meteorological considerations of cooling tower operation in this region bear further study.

The major surface water resources of the Beluga area are the Chakachatna and Beluga Rivers. Lesser streams in the Beluga area may also be used for water supplies, or impacted by mining and other development activities. Most prominent among these is the Chuitna River, which flows southeast in a 350-ft-deep canyon, bisecting one of the existing coal lease areas. Average flow of the Chakachatna River at its headwaters at Chakachamna Lake is 3646 cfs (2355 MGD).[a] Average flow data for the Beluga River is not available, but runoff from its drainage area has been estimated at 1,800,000 acre-feet per year (1602 MGD).[18] As in the Nenana area, flows are highly variable, exhibiting summer peaks and late winter low flows. The peak flood flow of the Chakachatna River, measured at its mouth near Tyonek in 1971, was 90,000 cfs (58,140 MGD).[18] Unlike most smaller streams in the region, the Chakachatna, Beluga, Tanana, and Nenana rivers do not fully freeze over in the winter.[a] The recorded minimum flow of the Chakachatna is approximately 400 cfs (258 MGD).[a]

Though detailed mining plans are not yet available, it is possible that mine and power plant development may have little impact on the flows of the Beluga area rivers. Much of the potential mined area is located on high ground at the head of drainages. Adequate groundwater supplies may also exist and could be used without the problems of storage, seasonal freezing, and environmental impacts of surface water use. Potential groundwater yields from wells in the area have been estimated as 0.01-0.1 MGD.[17] The only existing settlement in the area, the native village of Tyonek on Cook Inlet, draws its water supply from wells. In the Alaskan environment, waste heat such as the projected power plants would produce may be considered a resource. Power plant cooling ponds might, for example, be used for fish production. Because of the proximity of Cook Inlet, once-through cooling at a coastal site may be considered, eliminating power plant withdrawals from area rivers or groundwater. The feasibility of aquaculture and once-through cooling in the Beluga area requires further investigation.

(a) U.S. Geological Survey, Anchorage, AK, unpublished data, August 1977.

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7.0 LAND USE IMPACTS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- **Alaska**

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

7.0 LAND USE IMPACTS

Chapter 7 assesses land use impacts of two scenarios of coal-fired power generation for the period 1975-2020. Land acreages required for projected power plants in 19 candidate counties in Idaho, Oregon and Washington, and in two areas of southcentral Alaska are quantitatively estimated. Estimates of urban growth, resulting from projected population increases in 14 example counties, show the importance of other related land use changes. Some potentially important land use changes resulting from power plant construction, such as new transmission and transportation corridors and new industries attracted to the area, have not been quantitatively estimated. Because sites have not been identified below the county level, no attempt is made to assess the significance of the projected changes. Conclusions emerging from this analysis follow.

Estimated land requirements for new power plant sites and associated urbanization average about 1 acre/MWe. Typically, impacts are above this average for predominantly rural counties and below this average for more rural counties.

Land use changes exceeding 3,000 acres are estimated under the High Coal Electric scenario for the Washington counties of Cowlitz, Douglas, Franklin, Grant, Grays Harbor, Klickitat and Lincoln; for Elmore County, Idaho; and for Gilliam and Morrow Counties of Oregon.

Development related to power plants may compete with agriculture for desirable areas along the Columbia and Snake Rivers.

Activities of state commissions on land use and energy facility siting will play a major role in siting generating plants. Portions of several candidate counties, particularly in Oregon, appear to conflict with current policies of some of these commissions.

Development of coal resources west of Cook Inlet in Alaska may trigger substantial regional development attracted by the new transportation facilities and support communities.

Pending land ownership settlements and possible air quality buffer zones around parks and wilderness areas will strongly influence future siting of coal development facilities in Alaska.

The following important topics for future research are identified:

- The availability and appropriateness of sites in relation to environmental concerns and state land use controls must be assessed on a case-by-case basis.
- The potential scope of development west of Cook Inlet should be investigated to determine what the critical development stimuli are, to project the rate and type of development, and to identify alternatives for minimizing undesirable growth impacts.

The construction of new coal-fired power plants will cause both direct and indirect land use changes. Direct changes include the land required for plant sites, for water storage reservoirs, and for new transmission corridors. Indirect changes include increased urbanization, reflecting the influx of the plant construction and operating work forces and growth associated with increased economic activity in the plant site area. In this study we have developed quantitative estimates of the land requirements of plant sites, reservoirs (for a "worst case" analysis we have assumed all plants use water storage reservoirs), and, for 14 counties, increased urbanization. The primary land requirements not estimated are those of new transmission corridors. These cannot be assessed without more specific plant site designations.

The area required for plant sites is estimated as 540 acres per 1000 MWe with no economies of scale assumed for larger plants. In addition to the plant proper, this estimate includes space for cooling towers, temporary coal and ash storage, and space for landfill disposal of ash and flue gas desulfurization sludge. (Ash and sludge disposal may use approximately 5 acres per year over an average plant operating life of 30 years).[1,2] For the purpose of this study, we have assumed the landfill areas will be successfully revegetated or built upon, without any additional land impacts. Potential water pollution resulting from such landfilling is discussed in Chapter 6.

Reservoir size is estimated as 38 acres per 1000 MWe. This estimate assumes a one month supply of water (1500 acre-ft for an annual withdrawal rate of 18,000 acre-ft per year per 1000 MWe, as estimated in Chapter 6) stored to a depth of 20 ft.[a]

Land requirements for power plant related urbanization are strongly influenced by the nature of specific site areas. The previous degree of urbanization is important, as are availability of unoccupied housing units, commuting distances from existing urban areas, rate of power plant construction, and the proportion of the work force that occupies temporary quarters (e.g., mobile homes). As an indication of the possible magnitude of plant related urbanization, we have used the county-by-county projections of needed new permanent housing (given in Appendix I, Tables I.1-I.14) and multiplied these by 0.6 acres per dwelling unit. This is a typical ratio for low-density sprawl development nationwide and includes open space, vacant land, transportation, public facilities, etc. in addition to residential areas.[3] The resulting urbanization estimates, shown in Tables 7.1 and 7.2 may be low in that we have not included consideration of the additional land required for higher density mobile home parks, that 50% or more of the construction work force might use. The estimates are, therefore, useful only as rough indicators of the magnitude of land use changes that might be expected.

(a) Reservoir area (acres) $= \dfrac{\text{throughput x average retention time}}{\text{water depth}}$

$= \dfrac{\text{1500 af/month x 15 days}}{\text{20 ft}}$

$= 37.5$ acres

TABLE 7.1. Projected Peak Land Requirements of Coal-Related Development, Recent Trends Scenario[a]

State-County	Power Plant Sites	Reservoirs	Urbanization	Total
Idaho				
Bingham	810[b]	60	860	1730
Elmore	1080	80	1850	3010
Gooding	0	0	0	0
Power	0	0	0	0
Oregon				
Clatsop	0	0	0	0
Coos	1080	80	1180	2340
Gilliam	810	60	860	1730
Malheur	270	20	1180	1740
Morrow	2160	150	1580	3890
Sherman	0	0	0	0
Washington				
Cowlitz	1620	110	1250	2980
Douglas	0	0	0	0
Franklin	0	0	0	0
Grant	270	20	610	900
Grays Harbor	1350	100	1210	2660
Klickitat	1350	100	(c)	(c)
Lincoln	1080	80	800	1960
Whatcom	270	20	810	1110

(a) Peak requirements for plant sites and reservoirs reflect development to the the year 2020. Since construction dates will differ by county, urbanization peaks will be reached in different years and may in some cases decline by the year 2020.
(b) All figures are rounded to the nearest 10 acres.
(c) No data available.

Comparing the estimates given in Tables 7.1 and 7.2 to the projected total generating capacities by county, an average of approximately 1100 acres are required for each 1000 MWe of installed capacity. Land use changes somewhat greater than this average (under the High Coal Electric scenario) are projected for Elmore County, Idaho; Gilliam and Malheur Counties, Oregon; and Grays Harbor and Watcom Counties, Washington. Less than average land use changes are projected for Clatsop County, Oregon and Franklin County, Washington.

The significance of the projected land use changes cannot be assessed in this study because sites have not been identified below county level. However, throughout the Northwest maintaining high quality agricultural lands in that use and further expansion of agriculture into areas with water supplies adequate for irrigation are issues of concern. Since relatively level sites near water are also required for new coal-fired power plants, potential exists for competition between power production and agriculture. This competition may be particularly intense in areas along the mid- and upper-Columbia River and along the Snake River in southwestern Idaho.

State and local land use controls and energy facility siting programs will play a major role in determining the significance of land use changes. In Oregon, statewide planning goals

TABLE 7.2. Projected Peak Land Requirements of Coal-Related Development, High Coal Electric Scenario[a]

State-County	Power Plant Sites	Reservoirs	Urbanization	Total
Idaho				
Bingham	1080[b]	80	1140	2300
Elmore	1620	110	2470	4200
Gooding	540	40	(c)	(c)
Power	540	40	(c)	(c)
Oregon				
Clatsop	1620	110	230	1960
Coos	1350	100	1240	2690
Gilliam	1890	130	2030	4050
Malheur	1350	100	1480	2930
Morrow	1620	110	1300	3030
Sherman	1620	110	(c)	(c)
Washington				
Cowlitz	1620	110	1560	3290
Douglas	1890	130	1730	3750
Franklin	2430	170	1770	4370
Grant	1620	110	1550	3280
Grays Harbor	1620	110	1730	3460
Klickitat	2700	190	(c)	(c)
Lincoln	1890	130	1680	3700
Whatcom	1080	80	1270	2430

(a) Peak requirements for plant sites and reservoirs reflect development to the year 2020. Since construction dates will differ by county, urbanization peaks will be reached in different years and may in some cases decline by the year 2020.
(b) All figures are rounded to the nearest 10 acres.
(c) No data available.

and guidelines have been developed and are overseen by the Land Conservation and Development Commission (LCDC). Pertinent concerns include the identification of critical areas and the conservation of agricultural lands, shorelines, and open space. All cities and counties must develop implementation plans and, in contrast to many other states, local zoning ordinances must conform to these plans.[4] Oregon also has an active Coastal Zone Management Program that will affect sites in Clatsop and Coos Counties. The Oregon Energy Facility Siting Council has prepared maps of areas judged "suitable" or "unsuitable" for coal, nuclear, or geothermal power plants. Some portions of Clatsop, Coos, Malheur, and Morrow Counties are classed as unsuitable for coal-fired plants.[5]

Washington and Idaho do not have comparable comprehensive land use legislation, though a concern for encroachment of development on valuable food, fiber, and resource producing lands has caused several bills to be considered by legislatures.[4] Whether or not these concerns produce statewide action, they will likely result in closer local scrutiny of land use changes. Washington does have an Energy Facility Site Evaluation Council, however, which reviews applications for new plants. Washington also has an approved Coastal Zone Management Plan and an important Shoreline Management Act under which local governments classify shorelands and establish use regulations.[4] These programs may affect sites in Grays Harbor and Whatcom Counties. Plant siting issues in Idaho are reviewed by the Public Utilities Commission.

7.1 ALASKA

Regionally significant impacts are expected from projected coal development in Alaska. Direct land use changes will be caused by new mines and possible new power plants in both the Beluga and Nenana areas. Table 7.3 shows estimates of projected land requirements of the power plants only. Estimates of mine, reservoir, or urbanization requirements were not made in this study.

Land use changes in the Beluga area may be particularly large because of the need for new transportation facilities and towns to serve coal facilities, and because coal development may trigger other development in the region by providing needed transportation and other facilities. No attempt has been made in this study to assess the likelihood or rate of such coal-triggered regional development.

The more obvious regulatory influences on the siting of coal facilities in Alaska are the still emerging pattern of federal "d-2" lands (new federal reservations from public domain), state lands, and native claims. Other factors, such as the possibility of an air quality buffer zone around parks and wilderness areas, may also affect the location of new coal facilities, particularly in the Nenana area, which lies northeast of Mt. McKinley National Park.

TABLE 7.3. Estimated Acreage Needs for Projected New Coal-Fired Power Plants in Alaska, 1990-2020

	Recent Trends Scenario			High Coal Electric Scenario		
	1990	2000	2020	1990	2000	2020
Beluga area	--	--	1220[a]	140	1080	3510
Nenana area	--	--	270	--	270	540

(a) All figures are rounded to the nearest 10 acres.

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8.0 IMPACTS ON ECOSYSTEMS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- **Plant Communities of the Study Area**
- **Potential Impacts of Coal Development**

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

8.0 IMPACTS ON ECOSYSTEMS

Chapter 8 discusses potential ecological impacts of increased coal-fired power generation in the Pacific Northwest. Three major types of impacts are considered: loss of habitats or species of special interest, alterations in vegetation due to dispostion of airborne emissions from generating stations, alterations in aquatic ecosystems due to waterborne emissions, and alterations in aquatic ecosystems due to changed stream flows. Prediction of specific impacts requires detailed study for each site beyond the scope of this research. General ecological conditions extant in the candidate siting counties (identified in Chapter 4) are, however, considered in judging the probability of impacts. Impacts on Alaskan ecosystems are not addressed due to the less well-defined potential sites for generating stations, the unique impacts of surface mining that will not occur on a large scale elsewhere in the study region, and the wide variety of potentially impacted ecosystems.

The most significant impacts expected are losses of habitats or species of special interest displaced by land use changes. The Olympic mudminnow occurs in the Satsop and Deschutes Rivers of Washington (Grays Harbor and Lewis Counties). The prairie falcon occurs in all non-forested counties. The peregrine falcon occurs in Bingham and Elmore Counties, Idaho, and Malheur County, Oregon; seasonally it occurs in all counties, nesting in the western mountains. Columbia white-tailed deer occur in Clatsop County, Oregon and Cowlitz County, Washington. These species have been recognized as threatened. The ferruginous hawk, although not yet recognized by the federal agencies as endangered, must be mentioned specifically. It nests in Franklin County, Washington near the Columbia River. Only 20 pairs are known in the state; of these, 14 pairs nest at the Franklin County sites.

Official designation of endangered plant species includes species in nearly every county. Only a few occur in habitats along the Columbia and Snake Rivers' shorelines and in coastal streams and marshes. Until specific sites are identified, it is impossible to quantify the expected damage to any identified habitats or species.

Airborne emissions with the apparent greatest potential for damaging vegetation are fluoride, ozone, and oxides of sulfur. Assuming the deposition rates of SO_2 and SO_4 given in Chapter 5, however, such damage appears unlikely. In fact, increased plant growth may result from the deposition of sulfur on the typically sulfur-deficient soils of the region. Estimates of the magnitude of impacts resulting from fluoride or other airborne pollutants, including trace elements, are not made due to the lack of data on expected deposition rates and plant responses specific to a site. Additional study of plant responses in the field and of expected deposition rates is essential to more definitive impact prediction.

Impacts of waterborne pollutants on aquatic ecosystems are similarly specific to each site. However, if New Source Performance Standards are adhered to and towers or ponds are used to cool power plants, no significant impacts are expected. To the extent that such impacts occur, they are most likely to result from accidentally released runoff from coal and ash piles or from leaching of buried ash into ground water. The potential for such accidental releases is significantly greater in areas west of the Cascade Mountains where precipitation is high and materials may more readily be leached to ground water.

Minor reductions in stream flows in the Columbia and Snake Rivers estimated in Chapter 6 to result from power plant withdrawals are not expected to significantly impact aquatic ecosystems. Impacts may occur, however, if simultaneous large withdrawals for expanded irrigated agriculture occur within a short stream reach or if generating stations are too closely clustered. Anadromous fish losses are also possible if the switch of hydro systems from baseload to peaking generation occurs. This change in operating mode is expected as more baseload thermal capacity

is built in the region. Peaking operation is expected to cause more severe fluctuations in river level than at present. Further research is needed to determine the location and possible extent of such fluctuations and to estimate the size of resulting fish losses.

This study assumes that closed-cycle cooling will be used at all sites. If once-through cooling is considered at some sites (because of large river flows or ocean access), possible impingement and entrainment losses at plant intakes and waste heat impacts at discharge points will need to be examined on a site-by-site basis. The cumulative effect of clustered plants on the mid- or upper-Columbia River would be of particular concern. Estuarine sites are also of special concern due to their typically high biological productivity and importance in food webs involving species of commercial importance.

This chapter discusses potential impacts of two scenarios of coal development on regional ecosystems. Major vegetation zones in the study area are described in Section 8.1. Section 8.2 discusses possible impacts on plants and animals in these zones, including loss of communities and species of special concern, impacts of airborne emissions on terrestrial communities, and impacts on aquatic communities due to controlled and uncontrolled releases to water and changes in stream flows. More detailed descriptions of physical features, vegetative types, and water quality characteristics of importance to aquatic organisms are contained in Appendix E.

Only broad ecosystem categories and potential impacts in the states of Idaho, Oregon, and Washington are considered. Ecosystems and potential impacts of mining and power station operations in Alaska are unique and less well understood, thus requiring further study before impacts can be assessed.

8.1 PLANT COMMUNITIES OF THE STUDY AREA

The counties that are important in the National Coal Utilization Assessment (NCUA) in the Pacific Northwest include a wide variety of habitats and geographic provinces, ranging from rocky coastal headlands to conifer-clothed mountain slopes to shrub-steppe plains. The brief description included here can only outline the diversity to be found and list some of the important aspects of the ecosystems included in these habitats. A full and thoroughly documented description of the vegetation of Washington and Oregon is available[1] from which the following summary is abstracted. Figure 8.1 shows the locations of candidate counties in relation to four general vegetation types.

Table 8.1 lists the physiographic provinces occurring in Washington and Oregon that contain portions of the NCUA counties. The four counties in Idaho lie in regions with vegetation resembling the eastern portions of Oregon and Washington[2] and will be included in the discussions of Washington and Oregon. The inaccuracies inherent in such agglomeration are not crucial in this context. Also included in Table 8.1 are the major descriptors of the vegetation types in the counties, separated by the physiographic provinces in which they occur. (See Appendix E for more detail.) These vegetation types are briefly described below.

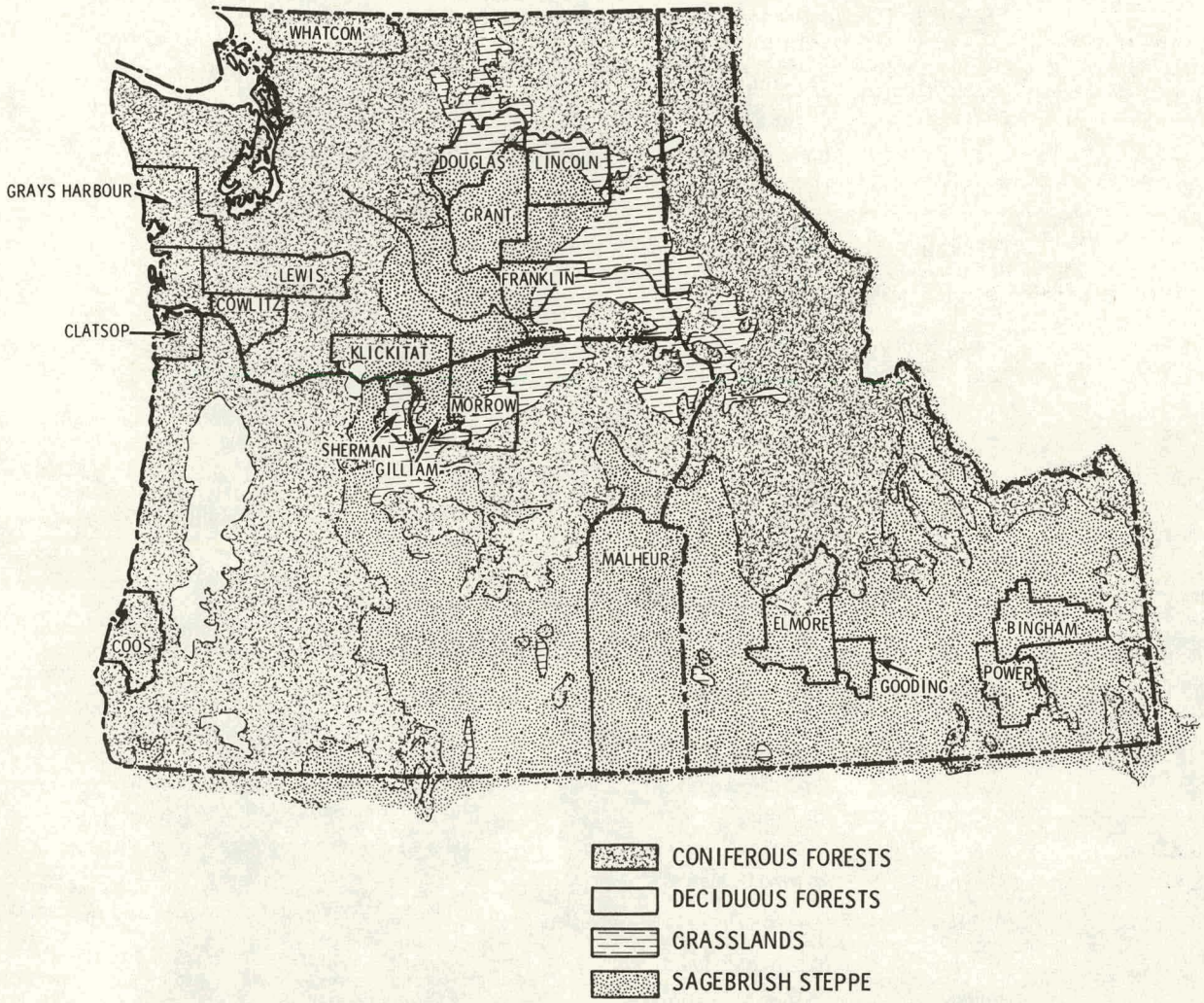

FIGURE 8.1. Vegetation Map of Idaho, Oregon, and Washington Showing Candidate Counties for Potential Coal-Fired Power Station Sites[3]

8.1.1 Forest Zones of Western Washington and Northwestern Oregon

Western Washington and northwestern Oregon comprise the most densely forested region in the United States. These forests represent the maximal development of temperate coniferous forests in the world in terms of extent and size. Few have appreciated how truly unique these forests are among the mesic temperate forests of the world.

One of the most outstanding features of these forests is the nearly total dominance of coniferous species. A second feature is the size and longevity of the dominant species. In other parts of North America or the world, individual species rival, in height and trunk diameter, the northwestern American species or exceed them in longevity, i.e., redwood forests of California. In no region, however, is found a group of dominant trees that are the overall match of these. Every coniferous genus represented finds its largest (and often most long-lived)

TABLE 8.1. Vegetation Types Important in NCUA Scenarios

State	County	Physiographic Province(s)[a]	Vegetation Type(s)[a]
Washington	Cowlitz	Puget Trough	*Tsuga heterophylla* Zone
		Southern Washington Cascades	*Tsuga heterophylla* Zone
	Douglas	Columbia Basin	Steppe Shrub-Steppe
	Franklin	Columbia Basin	Steppe Shrub-Steppe
	Grant	Columbia Basin	Shrub-Steppe
	Grays Harbor	Olympic Peninsula	*Picea sitchensis* Zone
		Coast Range	*Tsuga heterophylla* Zone
	Klickitat	Southern Washington Cascades	*Tsuga heterophylla* Zone *Pinus ponderosa* Zone
		Columbia Basin	Shrub-Steppe
	Lewis	Puget Trough	*Tsuga heterophylla* Zone, Puget Sound area
		Southern Washington Cascades	*Tsuga heterophylla* Zone
	Lincoln	Columbia Basin	Steppe Shrub-Steppe *Pinus ponderosa* Zone
	Whatcom	Northern Cascades	*Tsuga heterophylla* Zone
Oregon	Clatsop	Coast Ranges	*Picea sitchensis* Zone *Tsuga heterophylla* Zone
	Coos	Coast Ranges	*Picea sitchensis* Zone *Tsuga heterophylla* Zone
		Klamath Mountains	Mixed Conifer Zones
	Gilliam	Columbia Basin	Steppe Shrub-Steppe
	Malheur	Owyhee Upland Basin and Range	Shrub-Steppe Desert Shrub
	Morrow	Columbia Basin	Steppe Shrub-Steppe
		Blue Mountains	*Pinus ponderosa* Zone *Abies grandis/Pseudotsuga menziesii* Zones
	Sherman	Columbia Basin	Steppe Shrub-Steppe
Idaho	Bingham	Owyhee Upland type	Shrub-Steppe *Pinus ponderosa* Zone *Abies grandis/Pseudotsuga menziesii* Zones
	Elmore	Owhyee Upland type	Shrub-Steppe *Pinus ponderosa* Zone *Abies grandis/pseudotsuga menziesii* Zones
	Gooding	Owyhee Upland type	Shrub-Steppe
	Power	Owyhee Upland type	Shrub-Steppe *Pinus ponderosa* Zone *Abies grandis/Pseudotsuga menziesii* Zones

(a) See Appendix E for description of physiographic provinces and vegetation zones.

species represented here--and sometimes its second and third largest as well: *Abies, Picea, Pseudotsuga, Pinus, Chamaecyparis, Thuja, Sequoia, Larix, Lebocedrus,* and *Tsuga*.

8.1.2 Forest Zones of Southwestern Oregon

Southwestern Oregon is an extremely complex region. Climate ranges from cool and moist in the coastal regions to hot and dry in the interior valleys, which are among the driest locales west of the Cascade Range. The geology and, consequently, soils are extremely varied. The region combines elements of northern California coastal and eastern Oregon floras, with a large number of species indigenous only to the Klamath Mountains region. This environmental and floristic diversity combines with a long history of prehistoric and historic disturbances, primarily by fire, to produce an extremely varied array of plant communities, described in Appendix E.

8.1.3 Forest Zones of Eastern Oregon and Washington

In this region, elements of the continental Rocky Mountain forests meld with some of those from coastal areas. Forest species also mix with species from steppe and shrub-steppe communities, especially near lower timberline. It is a country typified by ponderosa pine forests. These zones are described in Appendix E.

8.1.4 Steppe and Shrub-steppe of the Columbia Basin, Owyhee Upland and Basin and Range Provinces

In the rain shadow of the Cascade Range is a large area of steppe and shrub-steppe vegetation including most of central and southeastern Washington and much of eastern Oregon. Typical community dominants include shrubs such as Great Basin, stiffleaf and black sagebrush, bitterbrush and saltbush; large perennial grasses such as bluebunch wheatgrass, Idaho fescue, giant wild rye, and Thurber needlegrass; and alien invaders such as cheatgrass, Kentucky bluegrass, and Medusa head. Forest vegetation is generally confined to mountain slopes with sufficient precipitation, either regionally (e.g., approaching the Rocky Mountains) or locally (e.g., higher elevations on interior ranges such as the Blue Mountains).

Climatically, the steppe areas can be typified as arid to semiarid with warm-to-hot dry summers and relatively cold winters. Some marine influences are still felt (conditions are not so extreme as those in the Great Basin, for example), but continental-type climatic conditions prevail.

8.1.5 Vegetation of Some Unique Habitats

Many habitats support unusual floras or communities of particular interest. These are typically "azonal" types of habitats that result from unusual substrates, unique topographic features, or other unusual environmental factors. Only two such areas are important in this context, the oceanfront community complex, including sand dune and strand communities and tidelands; and the Columbia Gorge.

Ocean-Front Communities

A rich variety of specialized community types are found along the edge of the Pacific Ocean that reflect a mosaic of distinctive habitat types--estuaries, tidal flats, sand dunes, headlands, etc. Some features of shoreline vegetation are immediately obvious--e.g., communities

of sand colonizers and stabilizers, the often impenetrable, bordering belts of shrubs and forests of lodgepole pine (*Pinus contorta*) and Sitka spruce (*Picea sitchensis*). Strong, onshore winds greatly influence composition and form of the vegetation by dessicating foliage, transporting salt spray, and abrading the plants with sand. Consequently, the stands of lodgepole pine and Sitka spruce are frequently deformed on the oceanside and increase in height to the lee. Three major categories of ocean-front communities exist:

1) sand dune and strand communities
2) tideland communities
3) herb- and shrub-dominated communities.

Sand dunes are the major locale where ocean-facing vegetation types have been studied by ecologists. Oregon and Washington have extensive areas of such dunes; out of 500 km of shoreline, Oregon has 225 km of sand dunes. The greatest development is the Coos Bay dune sheet covering 86 km of continuous coastline.

A variety of tideland communities are associated with estuaries along both the Oregon and Washington coasts, but their characteristics are little known. In the lower Columbia River, a large number of islands are subject to major tidal influences. The composition of these communities is presently unknown, as well as the degree to which each is influenced by salt water. The islands closer to the mouth of the river are mainly marshlands; those farther upriver are characterized by dense, tall shrub communities. The coastal climatic influence, as indicated by the presence of Sitka spruce, seems to disappear east of Cathlamet, Washington. Sitka spruce is the characteristic tree species of tideland areas and has been referred to as "tideland spruce" almost since its discovery. Sprawling, open-grown Sitka spruce border tidal flats and channels all along the Oregon and Washington coasts.

The Columbia Gorge

The Columbia Gorge is an unusual physiographic feature of considerable biological importance. The Columbia River cut this nearly sea level route directly across the axis of the Cascade Range. This is the only point between the Fraser River (in British Columbia) and Klamath River (in California) where a feature of this type is found. It has provided a major route for both plant and animal migration between the western and eastern halves of Washington and Oregon. It also contains many species that are endemic or constitute relic populations.

8.1.6 Agricultural Lands

Agriculture is a major and expanding use of land in the Pacific Northwest. Table 8.2 indicates the relative importance of agricultural crops as a land cover in the candidate counties (1974 data) and the products of greatest market value produced in these counties. The land devoted to agriculture varies from approximately 5% of the county area in counties west of the Cascade Mountains, such as Clatsop and Cowlitz Counties, to more than 95% in some areas in the rural eastern parts, such as Lincoln and Gilliam Counties.[4-6]

The arid areas east of the Cascades typically have large acreages devoted to dry land wheat farming. Where irrigation has been developed, as in the Columbia Basin, the trend toward irrigated crops, such as alfalfa, sugar beets, potatoes, and grapes has increased. Irrigated pasture is also becoming common. Table 8.2 indicates that as much as one-fourth to one-third of the farm land in some counties is presently irrigated.

TABLE 8.2. Agricultural Activity in Candidate Counties, 1974[4-6]

	Land in Farms (acres)	Percent of County in Farms	Percent of Farmland Irrigated	Major Farm Products[a]
Idaho				
Bingham	1,048,833	79.4	24.6	Field crops, cattle
Elmore	430,814	22.1	14.9	Field crops, cattle
Gooding	227,994	49.5	36.6	Field crops, cattle
Power	495,745	54.8	16.2	Field crops, cattle
Oregon				
Clatsop	26,560	5.2	3.8	Dairy products, cattle, other livestock
Coos	159,225	15.5	5.2	Dairy products, cattle, fruits-nuts-berries
Gilliam	744,653	96.3	1.0	Wheat, cattle
Malheur	1,477,029	23.4	14.2	Cattle, field crops, vegetables
Morrow	1,107,480	84.0	5.3	Wheat, field crops, cattle
Sherman	474,495	89.3	0.1	Wheat, cattle, poultry
Washington				
Cowlitz	38,020	5.2	5.0	Dairy products, poultry, cattle
Douglas	955,630	81.5	2.3	Wheat, fruits-nuts-berries, cattle
Franklin	600,959	74.9	24.2	Field crops, wheat, forage
Grant	1,081,599	63.2	27.0	Field crops, wheat, cattle
Grays Harbor	49,581	4.1	6.7	Dairy products, cattle
Klickitat	786,736	64.4	2.1	Wheat, cattle, forage
Lewis	137,078	8.8	5.0	Dairy products, poultry, cattle
Lincoln	1,469,010	99.6	2.4	Wheat, cattle
Whatcom	132,921	9.8	18.6	Dairy products, poultry, cattle

(a) Highest value cash crops in order

8.2 POTENTIAL IMPACTS OF COAL DEVELOPMENT

8.2.1 Impacts on Species of Special Interest

The Pacific Northwest provides habitats for several species that are under considerable pressure to survive. Many of these species have been accorded official recognition to publicize their situation. Threatened animal species are listed in the "Red Book" published in 1973 by the U.S. Bureau of Sport Fisheries and Wildlife.[7] Plant species are included in a list prepared by the Smithsonian Institution.[8] All the candidate counties for possible new coal-fired power stations identified in this study contain at least one species currently threatened, as shown in Table 8.3.[9] Land use changes caused by coal development may increase

TABLE 8.3. Threatened Species Occurring in Candidate Counties

Location	Plants	Animals
Idaho		
Bingham County	*Astragalus ceramicus*	Peregrine Falcon (*Falco peregrinus anatum*) Prairie Falcon (*Falco mexicanus*)
Elmore County	*Lepidium montanum*, var. *papariferum*	Peregrine Falcon Prairie Falcon
Gooding County		Prairie Falcon
Power County		Peregrine Falcon Prairie Falcon
Oregon		
Clatsop County	*Arenaria paludicola* *Cardamine pattersonii* *Douglasia laevigata* var. *ciliolata* *Erythronium revolutum* *Filipendula occidentalis* *Lewisia columbiana* var. *rupicola* *Saxifraga occidentalis* var. *latipetiolata* *Synthyris schizantha*	Columbian White-Tailed Deer (*Odocoileus virginianus leucurus*)
Coos County	*Arenaria paludicola* *Cordylanthus maritimus*	
Gilliam County	*Arenaria franklinii* var. *thompsonii* *Collomia macrocalyx* *Silene scaposa* var. *scaposa*	Peregrine Falcon Prairie Falcon
Malheur County	*Astragalus alvordensis* *Lupinus biddlei* *Rhysopterus plurijugus* *Thelypodium brachycarpum*	Peregrine Falcon Prairie Falcon
Morrow County	*Arenaria franklinii* var. *thompsonii*	Peregrine Falcon Prairie Falcon
Sherman County		Peregrine Falcon Prairie Falcon
Washington		
Cowlitz County	*Salix fluviatilis*	Columbian White-Tailed Deer
Douglas County	*Iliamna longisepala*	Peregrine Falcon Prairie Falcon
Franklin County	*Allium robinsonii*	Prairie Falcon Ferruginous Hawk (*Buteo regalis*)
Grant County	*Allium robinsonii* *Balsamorhiza rosea*	Prairie Falcon
Grays Harbor County	*Anemone oregana* var. *felix*	Olympic Mudminnow (*Novumbra hubbsi*)
Klickitat County	*Calmagrostis howellii* *Haplopappus hallii* *Hiericium longiberbe* *Hydrophyllum capitatum* var. *thompsonii* *Lomatium suksdorfii* *Ranunculus reconditus* *Penstemon barrellius* *Penstemon subserratus*	Prairie Falcon
Lewis County		Olympic Mudminnow
Lincoln County		Prairie Falcon
Whatcom County	*Claytonia lanceolata* var. *chrysantha*	Peregrine Falcon

the pressure on these species. Table 8.3 lists, by county, those species that occur near the Columbia or Snake Rivers, or near coastal estuaries where development appears most probable. An assessment of actual impacts on threatened species must await more specific plant site designation.

Threatened Animal Species

Four species listed in the Red Book occur in the scenario counties. The most widespread species is the prairie falcon (*Falco mexicanus*), which probably occurs in all nonforested counties (although never in very large numbers). It seems likely that the prairie falcon nests throughout its range in the Northwest wherever suitable sites can be found; i.e., rocky cliffs far removed from human disturbance.

Another very widespread species is the peregrine falcon (*Falco peregrinus anatum*), which may occur in all the counties, although its numbers are so small that it may be observed irregularly. Elmore, Power, and Bingham counties in Idaho have habitats favorable for these raptors along the Snake and Boise Rivers. The peregrine may nest in Malheur County and the western counties of Oregon and Washington (particularly in northwestern counties). It may be only a seasonal visitor in the remaining counties, being very sensitive to human disturbance.

Another raptor requiring isolated valleys for nesting is the ferruginous hawk (*Buteo regalis*). This species has not yet been officially designated as threatened, but such action is thought appropriate by many familiar with the species. Its population is very small; only 20 pairs nest in Washington,[10] by comparison 15 or 20 dozen pairs of prairie falcons may nest in the state. The ferruginous hawk is important to note because about two-thirds of the nesting pairs choose Franklin County, Washington for their nest sites.

Another species listed in the Red Book is the Columbian white-tailed deer (*Odocoileus virginianus leucurus*). This species occupies river bottom lands in the lower Columbia River and may occur in either Clatsop or Cowlitz counties. The population is small, possibly only several dozen, and under considerable pressure due to habitat modification along the Columbia River shoreline.

Large national wildlife refuges that might offer some protection for these species within candidate counties occur only in central Grant County, Washington and western Power County, Idaho.

The fourth species listed in the Red Book is the Olympic mudminnow (*Novumbra hubbsi*), which occurs only in the Satsop and Deschutes Rivers in Washington. Its very restricted habitat in Grays Harbor and Lewis Counties leaves it quite vulnerable to elimination.

Three other fish species occurring in the candidate counties are considered rare.[11] The Millicoma dace (*Rhinichthys* sp.), a species (or race) of Cyprimid, is restricted to the Coos River system in Coos County, Oregon. The white sturgeon (*Acipenser transmontanus*) is considered rare in Idaho portions of the Snake River system. White sturgeon are common in the lower Columbia River areas; however, populations have been declining in impoundment areas above Bonneville Dam. The Shoshone Sculpin (*Cottos greenei*) is a rare species in portions of the upper Snake River system, Idaho. The extent of its range is unknown.

Threatened Plant Species

Many species of plants are currently identified as threatened and have been so classified in an authoritative listing.[8] Most of the species occur in relatively restricted habitats that may not be impacted by the projected coal development. An analysis for each site will be needed to determine the degree of impact on these species. Only two counties have an extensive list of species: Clatsop County, Oregon and Klickitat County, Washington. Most of the species in Clatsop County are restricted to Saddle Mountain, Sugarloaf Mountain, and Onion Peak. However, several of the species found in Klickitat County occur along the Columbia River near the east end of the Columbia Gorge, in habitats potentially open to disturbance. Many of the other species in Klickitat County, and in the other, nonforested counties, occur in sagebrush uplands not closely tied to potential development sites (but open to disturbance from agronomic activities and other land use changes). Again, site-specific analyses will be needed.

There is a major contrast between the approach to impact assessment required for many of the threatened animals and the approach for threatened plants. The animals may be wide ranging, requiring large areas, and therefore rather easy to relate to human activities. Plants, however, may be restricted to habitats only a few hundreds of hectares in extent, requiring closer scrutiny for assessment.

Other Habitats and Species of Special Interest

Oregon and Washington contain four national parks and several national wildlife refuges that protect ecosystems of special scenic and scientific value. Airborne emissions from new coal-fired power plants could result in visual impairment or actual damage to plants and animals in these areas. The national parks have been accorded Class I status under the Clean Air Act Amendments to protect against such impacts.

The candidate counties contain many game birds and mammals of important recreational and aesthetic value. These include mule deer, elk, white-tailed deer, cottontails, quail, chukar partridge, pheasant, grouse, and numerous species of waterfowl. The habitat required by these animals will be reduced due to power development; protection of existing refuges from damage by airborne or aqueous pollutants will be particularly important. These animals may be more sensitive to environmental pollutants than domestic animals because of possible bioaccumulation of toxic materials, such as mercury, through their more complex food chains.

Towers, transmission lines, roadways, and fences that accompany power development create additional hazards and barriers for bird and mammal populations.

8.2.2 Alteration of Terrestrial Communities Due to Power Station Emissions

Air pollutants released by coal-fired power stations will be deposited on vegetation and soils downwind of the stations. Visible damage to vegetation may or may not occur, depending on a number of factors, including the type of pollutants deposited, deposition rates, the species of plant present, and soil-plant chemistry at the site. Emissions may affect plants by entering through the stomates in the leaves and altering internal leaf biochemistry, by depositing particulates on leaf surfaces thereby decreasing the amount of light reaching the plant and decreasing photosynthesis, or by depositing materials directly on the soil that either alter soil chemistry or enter the plant via root uptake.

Effects on individual plants and on the entire plant and animal community can be categorized by the period of exposure required to produce an observable effect. Exposure may be acute (hours or less), chronic (weeks-months), or long-term (years). The damage from an acute exposure is often readily evident in damage or death to individual plants. Chronic or long-term effects, however, may be less visible but of greater importance to the ecosystem as a whole. For example, a temporary failure of control equipment and a simultaneous atmospheric inversion that increases local deposition might subject a prairie to acute exposure. Resulting leaf damage is soon replaced by new leaves, and the composition of the prairie remains unchanged though production may be temporarily decreased. In contrast, chronic or long-term exposure may or may not cause obvious foliar damage but will damage plants and select against those plant and animal species less able to tolerate the emissions. Changes in species composition or community character may result. Most of our present knowledge of possible coal-fired power station effects on vegetation is of acute exposure effects, and much of this has been gained in laboratory studies where conditions may differ in important aspects from those encountered by plants growing in the field. The effects of power station emissions on natural communities or croplands is not well understood.

Symptoms of damage to conifers and deciduous trees from possible power station emissions have been observed as shown in Table 8.4.[12] In general, leaves may discolor, partially die, and fall early in response to fumigants. Even if the leaf remains on the plant, foliar damage can lead to reduced photosynthesis and production. Visual damage generally is not a dependable indication of reduced productivity. The toxicity of possible fumigants to plants is very specific for each species and site. Examples of damage and the associated fumigation levels for some gases typical of coal combustion are shown in Table 8.5.[13-15]

Possible Pollutants of Concern

The power station emissions of principal concern are sulfur oxides (SO_x), nitrogen oxides (NO_x), ozone, fluoride, and particulates containing various trace contaminants, including heavy metals. As shown in Table 8.5, impacts of SO_x are probably best known. In reviewing Table 8.5, it is significant that field grown plants tolerated higher levels of SO_2 than laboratory plants. This may be because part of or all plant sulfur requirements may be met from SO_2 in the atmosphere,[26] suggesting that the response to a particular emission depends on the mineral balance for that element in the plant. Plants grown in the laboratory under ideal conditions (as is usually the case) can absorb less atmospheric SO_2 without damage than plants growing in sulfur deficient soil. However, even plants in such soil can be damaged by sufficiently high levels of SO_2.

Even for SO_x, the most studied pollutant, our understanding of effects is uncertain. Fluoride may be the cause of much of the damage generally attributed to sulfur.[27,28]

Sulfur dioxide emitted to the atmosphere may also combine with atmospheric water, resulting in acid rain. Acid rain can affect both the above-ground and below-ground segments of the vegetation. Above-ground, acid rain has been associated with damage to young conifer needles[29] and bean leaves.[30] However, species differ in their response to acid rain and to atmospheric SO_2. Below-ground, the excess of H^+ in acid rain may leach mineral nutrients from the root zone

TABLE 8.4. Common Air Pollutants Injurious to Trees, Sources, Symptoms, and Age of Leaves Affected[12]

Pollutant	Sources	Symptoms	Age of Leaves Affected
Sulfur dioxide (SO_2)	Combustion of coal and oil in generating electricity, home and space heating, refining and smelting of ores (iron, copper, lead, nickel, zinc), plus the manufacture of sulfuric acid related products.	*Broadleaved trees*: Yellow, tan or ivory, papery, blotches between the leaf veins. Veins usually stay green. Injury normally extends through the leaf. *Conifers*: Yellowing or browning of needles, often with a tan to reddish-brown dieback or banding of needles. Growth suppression and early defoliation may occur.	Younger, fully expanded leaves
Ozone (O_3)	Produced when sunlight reacts with nitrogen oxides and hydrocarbons formed in automobile, bus, truck and airplane exhaust, refuse burning, combustion of fossil fuels. Electrical storms are a minor source.	*Broadleaved trees*: Flecks or stippling of upper leaf surface. Markings vary from white-to-tan, brown, red, purplish or black. *Conifers*: Needles mottled green and yellow or brown; may turn reddish-brown and die back. Growth often stunted, sparse or tufted due to premature defoliation.	Younger, fully expanded, nearly mature leaves
Hydrogen fluoride (HF)	Manufacture and/or processing of aluminum, steel, brick, tile, pottery, ceramics, glass, fiberglass, cement, phosphate fertilizers, refineries, and the combustion of coal.	*Broadleaved trees*: Tips and margins of leaves turn pale green to yellow or chlorotic, tan, and finally a dark reddish-brown. A narrow, reddish-brown band or line often separates healthy and injured leaf tissue. *Conifers*: Yellowing, tan, finally reddish-brown tip-burn of needles. Pines are generally very susceptible. Dwarfing of shoot growth and leaf abscission are common.	Mature leaves; current season needles on conifers
Peroxyacetyl nitrate (PAN)	Formed by oxides of nitrogen (NO_x) reacting with hydrocarbons in the exhaust gases of automobiles, buses, trucks and airplanes in the presence of sunlight.	*Broadleaved trees*: Glazing (slightly oily or waxy), silvering or bronzing of the underleaf surface in bands. *Conifers*: Needles turn yellow. Also, early maturity or senescence, growth suppression and premature and heavy leaf drop.	Young, rapidly-growing leaves
Nitrogen oxides (NO_x) (mostly NO_2, NO_3 and N_2O_4)	Automobile exhaust, petroleum refining, combustion of fossil fuels, burning of organic wastes, manufacture of nitric and sulfuric acids, stainless steel, paint, roofing, rubber, soap and nylon, etc.	Small, irregular white to tan, bronze or brown dead areas form near the tips, margins and between the veins. Symptoms may closely mimic those induced by SO_2. Growth suppression and leaf abscission without foliar markings results from low-level, continuous exposure.	Middle-aged leaves
Particulates, smoke, dust, fly ash, and liquid particles	Combustion of fossil fuels and organic wastes, cement production and lime-kiln operation, metal refining and foundry operations, agricultural activities, and incineration.	Unsightly dust coating on leaves resulting in reduced photosynthesis, general vigor and hardiness. Usually more unsightly than harmful, except for acid liquid particles that may kill small areas in leaves.	

TABLE 8.5. Physiological Responses and Associated Fumigant Level

Fumigant	Species	Experimental Conditions	Response	Concentration C = Chronic A = Acute	Reference
SO_2	Pine	Lab	Chloroplast injury in older, less active tissues	A 0.1 ppm	13
SO_2	30 native and ornamental	Field	Typical SO_2 foliar damage	A < 0.46 ppm	14
SO_2	Prairie grasses	Field	No phenologic differences; older leaves show more foliar damage	C 0-0.10 ppm	15
SO_2	Prairie grasses	Field	No effects on growth	C 0-0.1 ppm	16
SO_2	Prairie above-ground insects	Field	No effect	C 0-0.1 ppm	17
SO_2	Prairie soil insects	Field	No difference in small insects; fewer grasshopper eggs in high SO_2	C 0-0.1 ppm	18
SO_2	Geranium	Lab	Stomatal closure in response to SO_2	A 0.25-2 ppm	19
SO_2 $SO_2 + NO_2$	87 desert species	Field	Damage to older leaves first. No difference between SO_2 and $SO_2 + NO_2$	A 2-11 ppm	20
$SO_2 + O_3$	Tobacco	Lab	Gases together reduced growth more than each gas alone	C 0.05 ppm O_3 0.05 ppm SO_2	21
	Alfalfa and radish	Lab	Growth reduction same for exposure to single or combined gases		
$SO_2 + O_3$	11 crop species	Lab	Typical oxidant (ozone) leaf injuries	A 0.05-0.1 ppm O_3 0.25-0.1 ppm SO_2	22
$SO_2 + O_3$	Soybean	Lab	Decreased growth	C 0.05-0.1 ppm O_3 0.05, 0.2 ppm SO_2	23
$SO_2 + O_3$	Pine, young needles	Lab	Visible histological damage, primarily due to SO_2	C 0.45 ppm SO_3 0.45 ppm O_3	24
O_3	Radish	Lab	Decreased root growth at all temperatures	A 0.4 ppm	25

to groundwater. The pH of the soil can slowly become lower, which will increase the solubility and leachability of plant nutrients and trace contaminants. Depending on soil-plant chemistry, increased plant uptake can be either beneficial or damaging.

Photochemical oxidants, particularly ozone and peroxyacyl nitrates may be of particular concern due to their impacts on agriculture and forestry. As shown in Table 8.5, ozone effects are observable at concentrations as low as 0.05 ppm.[21-23,31] Photochemical oxidants are not known to directly affect animals.[32] No estimates of possible oxidant caused damage have been made in this study, but in view of the high plant sensitivities reported, potential damage should be further investigated.

Trace contaminants from coal combustion can change the availability of micronutrients in the soil, but whether such a change is significant is difficult to predict. Coal typically contains many elements (Table 8.6) that are concentrated in the ash during the combustion process and may be released in various quantities depending on the coal used and the combustion

TABLE 8.6. Elemental Concentrations of a Typical Midwestern Coal[33,34]

Element	Concentration (ppm)	Element	Concentration (percent)
As	14.02	Al[b]	1.29
B[a]	102.21	Ca[a]	0.77
Be	1.61	Cl[a]	0.14
Br	15.42	Fe[a]	1.92
Cd	2.52	K[a]	0.16
Co[b]	9.57	Mg[a]	0.05
Cr	13.75	Na[b]	0.05
Cu[a]	15.10	Si[b]	2.49
F	60.94	Ti	0.07
Ga	3.12	S[a]	3.27
Ge	6.59	C[a]	70.28
Hg	0.20	H[a]	4.95
Mn[a]	49.40	N[a]	1.30
Mo[a]	7.54	O[a]	8.68
Ni	21.07		
P[a]	71.10		
Pb	34.78		
Sb	1.26		
Se[b]	2.08		
Sn	4.79		
V	32.71		
Zn[a]	272.29		
Zr	72.46		

(a) Elements are known to be essential for normal plant growth.
(b) Elements may be essential for normal plant growth.

and pollution control technologies employed.[33] Many of these elements are essential for plant growth and are so identified in Table 8.6.[34] A small change in the concentration of some elements, such as boron, may change an element from a beneficial micronutrient to a toxic trace contaminant.

Vaughan, et al.[35] calculated that only 6% of the particulate emissions (and their associated trace elements) of a hypothetical western coal-fired power station fell within 50 km of the station, indicating that a very large area would receive a small dose of trace contaminants. Lack of information on expected emission rates, atmospheric transport and deposition rates, and availability of the various possible trace contaminants makes prediction perilous, but attempts have been made to reach qualitative conclusions about the materials of apparent greatest concern. Table 8.7 provides one assessment of the potential toxicity of various trace elements to terrestrial and aquatic plants and animals.[36] In light of these judgments and other available data, Cd, Ni, Tl, Cu, and F were ranked as being of greatest potential biological impact on terrestrial plants and animals. Similarly; Hg, Cd, Be, Co, and Cu were ranked as having greater potential for aquatic ecosystem effects.[36]

One of the very few field studies of increased trace element concentrations in ecosystems from power station emissions was conducted in South Carolina.[37] From 1952-1975 this plant burned approximately 360,000,000 kg of coal per year using mechanical collectors to remove fly ash before combustion products were released to the air. These collectors were 75% efficient at best.[37] Of 29 trace elements measurable in the fly ash, 10 produced statistically significant increases in concentration in area soil, vegetation, and groundwater. These were: Ba, Be, Cu, Hg, Se, and Sr in soil; Be, Co, Mo, Sr, and V in vegetation; and Co and Mn in groundwater.[37] Only two of these, Mn in groundwater and Se in soil, were present in concentrations that could require "further consideration."[37]

The panel whose judgments are reflected in Table 8.7 concurred with the South Carolina findings in that they concluded "there was general agreement, based on an insufficient data base, that atmospheric releases of trace elements are not likely to have significant, detectable effects on the chemical composition of soil, vegetation, and water. Fluoride may be an exception to this generality."[36] These judgments may represent the current "best guess" about the significance of possible trace element impacts, but in view of the lack of available data and the primitiveness of current techniques for modeling long-term effects they should be considered as provisional only.

Impacts of the Projected Coal Development Scenarios

In Chapter 5, maximum atmospheric concentrations of SO_2 expected in some portions of the study region were estimated as 10-30 $\mu g/m^3$ (approximately 0.0038-0.0114 ppm). These levels are substantially below concentrations reported in Table 8.5 as toxic to plants. Similarly, maximum SO_2 deposition levels were estimated in Chapter 5 as 1-3 g/m^2, with estimated resulting soil concentrations of 0.75-2.25 ppm. These estimates are simulated averages over a one-month period (chronic exposure) and provide no information on possible acute exposure levels. They are for broad geographic regions and do not account for local topographic effects. The soil concentration estimates make no allowance for that portion of the deposited sulfur that may

TABLE 8.7. Potential Toxicity of Trace Elements in Coal[36]

Element	Terrestrial Plant	Terrestrial Animal	Aquatic	Comments
As	Low	Low	Low	
B	High	Medium	Low[a]	Know enough on toxicity for terrestrial ecosystems; in some instances may be beneficial
Be	Medium	High	High[a]	Speciation important
Bi	Medium	Low	Low[a]	
Cd	High	High	High	
Co	High	Medium	High	
Cr	High	Medium	Medium	Cr^{+6} very toxic--need to know speciation
Cu	High	Medium	High	Complexion in soil reduces toxicity; in some instances may be beneficial
F	High	High	Low	
Hg	Medium	High[a]	High	Enriched in plants, toxicity in food cycle
Mn	Low	Low	Low	Potential for net beneficial effects
Mo	Low	Medium	Low	High enrichment in plants--beneficial or adverse effects
Ni	High	High	Medium	Very mobile in plants
Pb	Low	Medium	Medium	
Sb	Medium	High[a]	Low[a]	
Se	Medium	High	Low[a]	Interacts with other trace metals, e.g., Ni, Hg
Sn	Low	Low	Low	
Ti	Low	Low[a]	Medium[a]	
Tl	High	High	Medium[a]	
V	High	Low[a]	Medium[a]	
W	Medium	Medium[a]	Low[a]	Very mobile in plants
Zn	Low	Medium	Medium	Potential for net beneficial effect

(a) Uncertain

not be chemically available (in soluble form) for plant uptake. Several other assumptions have been made in producing these estimates, which should be regarded as illustrative only. Nevertheless, we find no evidence from this work to suggest that significant plant damage will occur anywhere in the region due to chronic exposure to SO_x emissions from the projected power plants. The additional sulfur accumulated in sulfur deficient soils of the region may actually increase plant growth.

This study has not included any independent analyses of potential concentrations or deposition rates of pollutants other than SO_x, but based on the literature reviewed, we find no reason to expect damage from chronic exposure to SO_x or NO_x. Acute and long-term effects of SO_x, NO_x, ozone, and fluoride emissions require further study before judgments of impacts are possible.

Similarly, we find no evidence to suggest that acid rain will cause significant impacts, at least in the areas east of the Cascade Mountains where most of the projected new generating facilities are sited. This judgment is based on the general aridity of the region east of the Cascades, the lack of contributing background sources of SO_x in this region, the very low levels of runoff experienced, and adequate pH buffering capacity of the soil. Conclusions on possible impacts in western areas of high precipitation and higher background SO_x and NO_x levels from other sources must await further study.

Effects of trace contaminants including heavy metals are too poorly understood to permit reliable prediction, but based on the findings of Horton, Dorsett, and Cooper,[37] and Van Hook and Shults,[36] we do not expect adverse effects from acute exposure. The elements Cd, Ni, Tl, Cu, and F merit additional study for possible impacts on terrestrial plants and animals due to their toxicity and the unknown effects of chronic or long-term exposure. Similarly, Hg, Cd, Be, Co, and Cu may be identified as of particular concern in aquatic communities.

In general, the potential for damage to plants and animals of the region due to power generating station emissions appears greatest in areas west of the Cascades because:

- higher rainfall levels will result in increased wet deposition
- higher rainfall and runoff increase the possibility of contaminants being leached to surface and groundwaters
- existing population and industrial centers have created higher background pollutant levels
- western regions include extensive conifer forests that exhibit a greater potential for long-term accumulations of contaminants than do the shrub-steppe and agricultural lands further east due to their long life, year-round photosynthetic activity, and greater observed sensitivity to pollutants.[31] Agricultural areas may be best able to withstand pollution damage because crop harvest reduces accumulation, and fertilizers may buffer plants against damage.

8.2.3 Alteration of Aquatic Communities

The new coal-fired generating stations projected in this study may cause changes in the quantity, quality, and timing of streamflows, thus impacting aquatic communities. Assuming all inland stations draw their water from and release any liquid effluents to the Columbia or Snake Rivers, use closed-cycle cooling systems, and conform to New Source Performance Standards (as discussed in Chapter 6), no severe impacts are anticipated on aquatic organisms that can be identified at the regional level of analysis. Several potential impacts, however, may be of concern for specific sites or might be expected in other regions of the nation. This section describes these potential impacts, why they are not expected to be significant under the scenarios examined, and under what conditions they might become serious concerns.

Chemical Effluent Releases. Coal and ash contain a number of chemical constituents that are toxic to aquatic organisms if sufficiently concentrated in surface waters (see Table 8.6).[38-41] Trace elements including Hg, Cd, Be, Co, Cu and Ni are the potential contaminants of greatest concern.[36] Also very high or low pH levels can have undesirable effects.[36] The relatively small

releases of these materials in controlled generating station waste streams are unlikely to have significant adverse effects due to the large flows and generally good water quality in the Columbia and Snake Rivers (see Tables D.2, D.3, and E.1). Significant localized impacts could occur, however, if there are uncontrolled releases of contaminants from coal and ash piles by runoff or leaching to surface and groundwater from ash settling ponds and disposal areas.

Several trace elements of concern, their impact on aquatic life, and recommended concentration limits in fresh and salt water are described in Appendix E, Table E.2. Many of the candidate county power station sites identified in this study are near impounded portions of the Columbia and Snake Rivers, where lowered flow velocity may permit some settling of suspended material and its associated trace contaminant load. Long-term accumulation of trace elements in bottom sediments could result.

Although the study assumes that plants will be located on the Columbia or Snake Rivers, offsite disposal of ash and sludges may impact smaller streams. Accidental siltation of smaller streams from washout or runoff from ash storage could also damage aquatic populations. Salmon and trout spawn by depositing eggs in the gravel of river beds where the eggs are incubated by intragravel water. Water associated with gravel may contain less oxygen than water in the stream above. Abundant evidence exists that salmonid eggs are adversely affected in direct proportion to reduction in DO. Sedimentation, resulting from deposition of fine suspended materials (such as coal ash) can penetrate or overlay streambed gravel, reduce intragravel flow, and cause a marked decline in O_2 content of intragravel water.

Presently, no spawning of anadromous salmonids occurs in the Columbia River above Grand Coulee Dam or in the Snake River above Hells Canyon Dam.[42] These fish spawn in coastal streams of Whatcom, Grays Harbor, Lewis and Cowlitz Counties, Washington and of Clatsop and Coos Counties, Oregon. Adult salmon also spawn in cooler mountain streams of eastern Washington, Oregon, and Idaho and use the Columbia River as a migration route. Many of these streams also support populations of trout and char.

Waste Heat. The damaging effects of waste heat releases from power plants on aquatic organisms are well known.[43-45] However, current EPA regulations specify that there shall be no discharge of heat, except for blowdown from the cold side of a closed-cycle cooling system,[46] for new plants of 500 MWe or greater. As discussed in Chapter 6, exemptions permitting open-cycle cooling are possible but not likely to be granted in the Pacific Northwest. Therefore, this study has assumed closed-cycle cooling will be used exclusively with only small releases of heated effluent expected. During low flow conditions several impounded portions of the Snake River approach temperatures considered damaging to anadromous and resident fish species. Waste heat releases to these areas at that time could be particularly damaging.

Alteration of pH. The effect of pH on aquatic life is well documented.[47,48] Addition of either acids or alkalies to water may harm aquatic biota by producing acid or alkaline conditions, by increasing the toxicity of various compounds in water, and by affecting the availability of many nutrients. Low pH may be important in areas where coal is mined since reactions of iron sulfide in the coal and spoils may result in acid drainage. Leachates from coal storage

piles may also lower pH levels in receiving waters. Air emissions of SO_x and NO_x may also react with water in the atmosphere to produce acid rain that could alter stream pH directly or through runoff. Leachate from bottom ash disposal areas can be very high in pH.

None of these possible sources of pH alterations are expected to be of significance in the scenarios under study. The response of surface waters to additions of acidity or alkalinity depends on the buffering capacity of the receiving waters. Carbonate (CO_3) and bicarbonate (HCO_3) ions, if present in sufficient concentrations, tend to neutralize acids and bases and thus control pH fluctuations. Columbia and Snake River waters, as listed in Table D.5, meet or exceed the national average of 68 ppm of bicarbonate and thus have considerable buffering capacity.[49] Acid mine drainage is not likely to be of concern because of limited mining in Idaho, Oregon, and Washington. Direct fall of acid rain would have no significant impact on normal pH levels in view of the flow volume and buffering capacity of regional streams, unless unusual atmospheric conditions and clustering of generating stations should result in locally higher deposition levels. Acidity in runoff will be adequately buffered by soil, and in the eastern portions of the region where many candidate county sites are located, precipitation and runoff are very low.

Reduced streamflows. Though the projected water requirements of regional coal-fired generating plants are small compared to present or projected flows of the Columbia and Snake Rivers, they will contribute to the increasing criticality of low flow periods. Minimum flows are required to sustain runs of anadromous fish in the Columbia system. Conditions in the Snake River are already seasonally critical for salmon and steelhead populations due to low flows and high water temperatures created by withdrawals and impoundments.[50] Increased consumptive withdrawal of water from the upper and middle Snake River will further imperil white sturgeon, now rare in Idaho.

Peaking at Hydroelectric Dams. Perhaps the greatest potential for impacts on aquatic communities exists in using existing hydro facilities to produce peak power as coal-fired and other thermal electric units take up a larger share of the regional base load. If diurnal flow fluctuations are increased, a number of undesirable effects could occur, including:

- stranding of fish on exposed bars where they may be dessicated or exposed to predators
- reduction in size and productivity of the littoral (near shore) zone, an important area of fish food production
- entrapment of fish in temporary ponds
- changes in anadromous fish behavior due to daily and seasonal temperature changes
- reduction of fish egg survival due to exposure of spawning areas to air.

The extent to which these impacts may occur, and their effect on population levels of fish and other aquatic organisms, require further study.

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9.0 HEALTH EFFECTS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- **Mining, Processing and Transportation Related Health Effects**
- **Combustion Related Health Effects**
- **The Nature of Health Effects**
- **Dose-Response for Airborne Effluents**
- **Reference Power Plant Health Effect Estimates**
- **Health Effects Summarized by Scenario**

10.0 SOCIOECONOMIC IMPACTS
- Socioeconomic Impact Assessment
- Current County Characteristics
- Model Impact Forecasts
- Other Impact Forecasts
- Impact Management Options

9.0 HEALTH EFFECTS

The health effects related to the Recent Trends and High Coal Electric scenarios are important but difficult to assess. This assessment has been completed by identifying the components of the coal combustion process that may be related to changes in the general population's health; quantitative estimates were made of the potential impact, using an air pollutant index to predict a change in a health index for the exposed population. The indices selected were atmospheric sulfate concentrations due to the coal combustion process and the number of expected annual excess deaths. Occupationally related health effects were also compiled.

The components of the coal combustion effluent that have been identified as possible causes of health changes in the general population are carbon monoxide, nitrogen oxides, sulfur dioxide, particulate polycyclic organic compounds, vapor-phase organics, selected trace metals and radionuclides. Sulfates, nitrates and ozone are also listed because of chemical transormations in the atmosphere. No definitive epidemiological study of low-level chronic exposures has been done that establishes a well-defined dose-response relationship between individual pollutants and specific health effects. In view of this, estimates are not given by individual pollutants or by individual health effects.

A non-threshold, linear dose-response function developed by the Biomedical and Environmental Division at Brookhaven National Laboratory (BNL) was designated by the Health Effects Committee as the standard procedure to be used in assessing the public health impact of the scenarios. This dose-response function relates the air pollution index (atmospheric sulfate concentration) to the health effects index (annual excess deaths). Based on this methodology, the impacts to the general population due to increased air pollution are 0.8 annual excess deaths for the Recent Trends scenario and 1.1 for the High Coal Electric scenario. These estimates are for the year 2020 for all counties in Idaho, Oregon and Washington selected for power plant sites. The uncertainty in these health effect estimates is reflected in an 80% confidence statement which gives a range from zero excess deaths to a factor of 10 higher than the estimate given.

The occupational health effects related to the mining, processing and transportation components of the coal energy system include occupational disease and accidental deaths and injuries. Although many of these occur outside Idaho, Oregon and Washington, they are included for completeness. The reliability of these estimates is considerably better than that for public health effects from air pollution. For the Recent Trends scenario, the annual accidental deaths in 2020 attributable to surface mining are 18, coal processing 4, and rail transportation 312.

No quantitative estimate of occupationally induced morbidity and mortality related to surface mining is made. Studies of occupational health effects related to coal mining have used a mix of underground and surface miners that is different from that expected in the West. Available data indicate that pneumoconiosis and progressive massive fibrosis result from prolonged exposure to coal dust. Since these diseases are primarily associated with underground mining conditions, the increased proportion of strip mining in the West would result in a lower incidence.

The large uncertainty associated with the estimates and the controversial nature of public health effects related to air polluting emissions from coal-fired power plants imply that dose-response relationships between specific pollutants and specific health effects must be established. This issue is not unique to the Northwest. In fact, the higher current pollutant levels in the eastern United States make the problem even more important. The resolution of these dose-response relationships will have important ramifications on emission control requirements. Regional data are needed for the Northwest to obtain an accurate assessment of the expected accidental deaths and disabling injuries related to rail transportation of coal.

The assessment of the impact on health of the Recent Trends and High Coal Electric scenarios is based on the coal-fired power plant fuel cycle. The components of the fuel cycle used are mining, processing, transportation and combustion. For each of these components health effects are qualitatively identified and, wherever possible, quantified. All quantitative estimates are calculated for a reference 500 MWe coal-fired power plant. Based on the appropriate scenario, the quantitative health effects estimates are summarized across individual power plants to obtain regional estimates.

In this report "health effect" is intended to mean excess mortality, morbidity and injury among occupational workers and the general public. Thus, it includes occupationally related risks such as accidental mining deaths and disabling injuries; increased risk of disease such as pneumoconiosis, due to occupational exposure of pollutants; and increased risks to the general public due to chronic exposure to air pollutants and due to accidental death related to rail transportation of coal. The term "excess" means effects that occur at a higher than normal rate. All quantitative estimates of excess risks are on an annual basis.

The knowledge and information available for a reasonably precise assessment of health effects related to the coal-fired power plant fuel cycle are inadequate. However, health effects must be carefully considered as a part of the fuel cycle assessment even though the estimates may lack precision. An integral part of this assessment is the specification of the limitations and shortcomings of both the qualitative and quantitative statements and an estimate of the uncertainty associated with a quantitative estimate. In some cases, such as mining accident rates, the uncertainty of the estimates is low since they are based on adequate data. In others, such as health effects related to air pollution, the uncertainty is considerably higher since no definitive cause-effect relationship has been established.

9.1 MINING, PROCESSING AND TRANSPORTATION RELATED HEALTH EFFECTS

Health effects, such as occupational disease, accidental death and disabling injuries, are associated with the mining, processing and transportation components of the fuel cycle. The health effects attributable to these components occur at the mine and processing plant and on the route used for transportation. Although they may occur in regions other than the Pacific Northwest, they are included for completeness in the assessment. All estimates given in this section are taken from the compilation by Morris and Novak.[1]

For surface mining the accidental death rate for mines is 0.10 deaths per 10^6 tons (95% confidence interval of 0.09 to 0.12) of coal mined. Accidental injury rate is estimated at 5.2 disabling nonfatal injuries per 10^6 tons of coal (95% confidence interval of 4.5 to 6.0). These estimates are based on 1965-1973 mining accident statistics. Occupationally induced mortality and morbidity in surface mine coal workers is subject to much greater uncertainty than accident related effects. Studies on the prevalence of disease in miners indicate that pneumoconiosis and progressive massive fibrosis are major factors and that they are related to prolonged exposure to coal dust in underground mines. Also, high mortality rates have been observed in miners in a number of studies. A major limitation of many of the studies is that

they do not permit a separation of surface and underground mining in estimating health effects. Since the mix of underground and surface mining used in those studies is different from that assumed for the Pacific Northwest, no estimates of occupational disease mortality and morbidity rates are given.

Only accidental deaths and injuries are considered for coal processing and rail transportation. In coal processing plants 0.021 deaths per 10^6 tons (95% confidence interval of 0.017 to 0.027) and 1.3 disabling injuries per 10^6 tons (95% confidence interval of 1.0 to 1.6) of coal are estimated. No breakdown of these rates by mechanical crushing or cleaning operations are available.

For health effects related to coal transportation, the basic unit used to quantify the accidental rates is the ton-mile. This choice is based on the assumption that the crucial parameters related to rail accidents are the amount of coal hauled and the haul distance. The accidental rates are estimated to be 2.5 deaths per 10^9 ton-mile and 12.0 disabling injuries per 10^9 ton-mile. These estimates are based on national rail transportation accident statistics. Although moderate variations occur in the accident rates by regions of the nation, no quantitative adjustment is made. The influence of unit trains on the accident rates is unknown.

9.2 COMBUSTION RELATED HEALTH EFFECTS

The health effects considered for the combustion component are related to the possible increased risks to the general public due to low-level chronic exposure to air pollutants from effluents of the combustion process. No analysis of health effects resulting from accidents in coal-fired power plants is available. The effluent from coal combustion has a number of components that can detrimentally affect human health. The combustion of coal produces the potentially hazardous pollutants: carbon monoxide, nitrogen oxides, sulfur dioxide, particulate polycyclic organic components, vapor-phase organics, selected trace metals and radionuclides. Sulfates, nitrates and ozone are added to the list due to chemical transformations in the atmosphere.

For the preceding list of pollutants, no well-defined dose-response relationships are established between individual pollutants and specific health effects. Studies on laboratory animals, controlled human experiments, and occupational health studies have established relationships between specific health changes and short-term exposure to high doses of specific pollutants. Those studies do not provide quantitative dose-response information for the low-exposure levels typical for the general public. An alternate approach is to use an air pollutant index and a health effects index to establish one possible dose-response relationship. Although a quantitative estimate is obtained, it does not provide the quantitative relationship between exposures to specific pollutants and their health effects that is needed to justify the type and amount of control measures for stack effluent.

9.3 THE NATURE OF HEALTH EFFECTS

The distinction between good health and poor health is not sharp. Conceptually, if an individual's health is adversely affected due to a particular environmental stressor, then a health effect has occurred. The importance of the effect depends not only on its type and

severity but also on the individual. For example, a case of influenza, which might be considered a mild annoyance in a high school student, could be cause for alarm in an elderly person with a heart condition. The quantification of health effects is complex and may not be amenable to representation by single-valued functions.

Nevertheless, an objective definition of health is needed; mortality is most commonly used because it is most easily measured. More useful measures of the health status of a population are far less readily available. These are the incidence of disease (the rate at which unaffected persons develop a given disease per unit time) and disease prevalence (the proportion of the population having the given disease at any time).

Can the impact of airborne pollutants from coal-fired power plants on the health of the general population be determined? A simple answer is not possible. For some pollutants qualitative statements concerning the possible physiological effects can be based on animal experimentation or human epidemiological studies. Quantitative measures of the magnitude of effects or dose-response relationships are more difficult and are subject to considerable uncertainty.

Most of the effluents from coal utilization that have a direct impact on human health are found in the stack emissions from coal burning facilities.[a] These airborne pollutants characteristically have three major types of health impacts: irritation, direct toxicity and carcinogenesis. In the case of irritation, the pollutant causes an inflammatory reaction in the affected organs. For direct toxicity the pollutant causes direct damage to the cells it contacts. A carcinogenesis effect implies that the pollutant or its metabolic by-products stimulate the development of tumors.

The responses may have different outcomes depending on the actual physical composition, and concentration of the pollutants and the duration of exposure to it. The outcome may also depend on the victim's age and condition. Four clinical manifestations are typically observed among persons exposed to coal combustion airborne pollutants: acute respiratory disease, chronic respiratory disease, aggravation of preexisting conditions and neoplastic diseases. The incidence of influenza, pneumonia and other acute pulmonary diseases tends to be elevated in exposed populations due to the increased susceptibility, caused by inflammation, of the respiratory tract to infection. Prolonged exposure to airborne pollutants may lead to irreversible damage to lung tissue, e.g., emphysema or chronic bronchitis. The influence of coal effluents in causing cancer is uncertain at this time. A comprehensive review of the epidemiological studies and a description of the health effects observed are contained in the comprehensive review of current work in air pollution edited by A. C. Stern.[3]

The possible health effects ascribed to airborne pollutants from coal combustion are measured as changes in either morbidity or mortality rates in epidemiological studies. Dose-response relationships between a specific pollutant and a health effect are generally lacking. This is especially the case for the low-level chronic exposure due to coal combustion expected in the Pacific Northwest.

(a) This section is based on a similar section in A Preliminary Assessment of the Health and Environmental Effects of Coal Utilization, Argonne National Laboratory, January 1977.[2]

9.4 DOSE-RESPONSE FOR AIRBORNE EFFLUENTS

Although our present knowledge of the dose-response relationship for individual, or combinations of, pollutants does not justify a rigorous assessment, an example of a type of assessment is informative. The example assumes that sulfates represent the principal biologically effective agent in the power plant effluent[1] and that their effects can be associated with a number of excess deaths in the exposed populations. The term "excess deaths" is a convenient way to express an increase in the mortality rate.[4] The example is certainly an oversimplification of the problem. The approach and the basic quantitative estimate are those of the Biomedical and Environmental Assessment Division at Brookhaven National Laboratory (BNL).[1] Their estimate is slightly modified to account for differences in the sulfur content of the coal, the power plant size and population exposed. The modifications are explicitly stated.

The Brookhaven National Laboratory approach is based on the effect of a typical 1000 MWe coal-fired power plant in the eastern United States burning 3% sulfur coal. The energy content of the coal is assumed to be 12,500 Btu/lb, and the plant has a 75% plant load factor with 37% thermal conversion efficiency. The effluent is discharged through a 1000-ft stack, which is not equipped with control devices for sulfur effluent. Within a 50-mile radius of the plant the population base is 3 million people; the distribution resembles that expected for a plant located in the area surrounding Pittsburgh. With these assumptions and the background sulfate concentration typical in the East, the BNL investigators have estimated that approximately 20 excess deaths are attributable to the pollution from the power plant.[1] At an 80% confidence limit, the estimated excess deaths range from 0 to 100.[1] This estimate does not include effects outside the 50-mile radius. The model is linear in sulfur emission rates and in exposed population.

It is important to recognize that the sulfate level is being used as an index for all the air pollutants. All of the estimated effects are not attributable necessarily to sulfates. The mortality measure is intended to be an index of the overall effect on the general public's health, including morbidity and mortality. Generally, the interpretation intended is that as the number of premature deaths (i.e., excess mortality) increases, correspondingly, the morbidity rates for selected diseases will also increase. The dose-response function underlying the Brookhaven model is assumed to be linear over the entire range of sulfate levels used. Additionally, no threshold is assumed, i.e., no positive dose exists below which individuals are not affected. Both of these assumptions are open to question.

A final caveat on the underlying dose-response function used in the Brookhaven study is in order. This exposure function was derived from Lave and Seskin's studies,[5,6] which have known limitations and methodological problems. Some of these have been pointed out by Lave and Seskin in a subsequent article.[7] Others are under consideration in a study now being conducted in this laboratory.

9.5 REFERENCE POWER PLANT HEALTH EFFECT ESTIMATES

All quantitative health effect estimates are given for the components of the fuel cycle for a reference 500 MWe coal-fired power plant. These estimates, presented in Table 9.1, form the basis for the Recent Trends and High Coal Electric scenario health effects estimates. The

TABLE 9.1. Annual Health Effect Estimates for Reference 500 MWe Coal-Fired Power Plant by Location and Fuel Cycle Component

Fuel Cycle Component	Idaho, Oregon, Washington	Alaska
Surface Mining		
Accidental deaths	0.15 (0.14-0.18)[a]	0.18 (0.16-0.22)[a]
Accidental injuries	7.8 (6.8-9.0)	9.4 (8.1-10.8)
Processing		
Accidental deaths	0.03 (0.02-0.04)	0.04 (0.03-0.05)
Accidental injuries	2.0 (1.5-2.4)	2.3 (1.8-2.9)
Rail Transportation		
Accidental deaths	3.0	0
Accidental injuries	14.4	0
Combustion		
Excess deaths/10^5 population	0.1 (0.0-1.1)[b]	--

(a) Interval is an approximate 95% confidence interval.
(b) Interval is an approximate 80% confidence interval.

500 MWe capacity plant is assumed to have a 65% plant load factor and a heat rate of 9650 Btu/kWh. It is assumed that all coal supplied to the plant is from surface mines from either Montana or Wyoming if the plant is located in Idaho, Oregon, or Washington, or in Alaska from mines at the plant location.

For Montana/Wyoming coal, assuming an energy content of 9060 Btu/lb, a 500 MWe plant requires 1.5×10^6 tons of coal per year. Since the heat content, 7500 Btu/lb, is lower for Alaskan coal, 1.8×10^6 tons per year are required for plants using Alaskan coal.

For rail transportation of coal the average haul distance is approximately 800 miles for coal obtained from Montana and Wyoming. Hence, 1.2×10^9 ton-miles per year are involved for the typical plant using Montana/Wyoming coal. It is assumed that the Alaskan power plants are located at the mine mouth. Consequently, no transportation related health effects estimates are given for Alaskan coal plants.

To translate the air pollution related health effects estimates from BNL's 1000 MWe power plant to the 500 MWe reference plant in the Pacific Northwest, adjustments for the sulfur emission rates, the generating capacity of the plant and the population base around the plant must be made. The sulfur emission rates in the BNL model assume 3% sulfur coal and no emission control devices. Since Montana/Wyoming coal has a sulfur content from 0.5% to 1%, with Alaskan coal even lower at 0.15%, a downward proportional adjustment is necessary. Also the New Source Performance Standard (NSPS) for SO_2 emission translates to a 0.75% sulfur content if no emission control devices are used. Although "best available technology" requirements may be necessary in the future and although the NSPS would not be met, it is conservatively assumed that the sulfur emission rate from the reference plant corresponds to using 1% sulfur coal with no emission control. This results in a one-third reduction in the number of estimated excess

deaths. The change to a 500 MWe capacity instead of the 1000 MWe plant further reduces the estimate by one-half. For the reference plant the population exposed within the 50 mile radius is 100,000. The population adjustment further reduces the estimate by 1/30.

Based on the above translation to the 500 MWe power plant located in the Pacific Northwest, the impact on the general population due to the increased air pollution from the reference plant is 0.1 annual excess death. The uncertainty in this estimate is reflected in an approximate 80% confidence interval of 0 to 1 annual excess deaths. This interval reflects the uncertainty in the basic BNL estimate and an additional factor of two due to the translation to the Pacific Northwest where atmospheric conditions relative to background pollution concentrations and pollutant transformation rates are different. Since the interval includes zero as a lower limit, it is possible that air pollutants from the combustion process may not have a significant adverse health effect impact.

9.6 HEALTH EFFECTS SUMMARIZED BY SCENARIO

For the Recent Trends and High Coal Electric scenarios the quantitative estimates of the health effects impact are given for the year 2020 in Table 9.2. These estimates are based on the 500 MWe reference coal-fired power plant calculations in Section 9.5, the county siting patterns described in Chapter 4 and the population projections given in Chapter 10. The estimates given reflect the addition of coal-fired power plants only. Effects related to other sources of energy, such as nuclear, are not dealt with in this report. Moreover, the total impact on health due to coal-fired power plants is not accounted for by the estimates given. In particular, increases in mortality and morbidity due to occupational pollutant exposures are not included. The health effect estimates for the general population's exposure to air pollutants do not reflect possible increases in morbidity.

TABLE 9.2. Annual Health Effect Estimates for the Year 2020 by Scenario and Fuel Cycle Component

Fuel Cycle Component	Recent Trends	High-Coal Electric
Surface Mining		
Accidental deaths	8 (7-9)[a]	18 (17-22)[a]
Accidental injuries	398 (344-459)	952 (824-1098)
Processing		
Accidental deaths	1.6 (1.3-2.1)	3.8 (3.1-4.9)
Accidental injuries	100 (77-122)	238 (183-293)
Rail Transportation		
Accidental deaths	135	312
Accidental injuries	648	1498
Combustion		
Annual excess deaths	0.8 (0.0-8.0)[b]	1.1 (0.0-10.6)[b]

(a) Interval is an approximate 95% confidence interval.
(b) Interval is an approximate 80% confidence interval.

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10.0 SOCIOECONOMIC IMPACTS

SUMMARY CONTENTS

1.0 EXECUTIVE SUMMARY

2.0 SUMMARY OF MAJOR FINDINGS
- Objectives
- Issues of Concern in the Region
- Impacts Quantified in Study

3.0 SCENARIOS AND TECHNOLOGY ASSUMPTIONS
- Regional Allocations
- Coal-Fired Generation in the Region
- Coal and Conversion Technology
- Role of the Assumptions

4.0 CANDIDATE COUNTY SITING
- Rationale for Selection of Sites
- Transportation
- Selection of Candidate Sites

5.0 AIR QUALITY IMPACTS
- Air Quality Issues
- Estimated Impacts of Coal Development Scenarios
- Issues Requiring Further Analysis

6.0 IMPACTS ON WATER USE AND QUALITY
- Impacts on Water Supply and Use
- Impacts on Water Quality
- Impacts of Alaskan Coal Development

7.0 LAND USE IMPACTS
- Alaska

8.0 IMPACTS ON ECOSYSTEMS
- Plant Communities of the Study Area
- Potential Impacts of Coal Development

9.0 HEALTH EFFECTS
- Mining, Processing and Transportation Related Health Effects
- Combustion Related Health Effects
- The Nature of Health Effects
- Dose-Response for Airborne Effluents
- Reference Power Plant Health Effect Estimates
- Health Effects Summarized by Scenario

10.0 SOCIOECONOMIC IMPACTS
- **Socioeconomic Impact Assessment**
- **Current County Characteristics**
- **Model Impact Forecasts**
- **Other Impact Forecasts**
- **Impact Management Options**

10.0 SOCIOECONOMIC IMPACTS

Chapter 10 assesses the likely socioeconomic impacts of constructing and operating coal-fired electric generating plants in the Pacific Northwest and investigates possible planning and management techniques that local governments could use to deal with these impacts.

As a baseline from which to predict future impacts under the Recent Trends and High Coal Electric scenarios, the current socioeconomic characteristics of 15 candidate counties are described in terms of a set of social indicators. Potential socioeconomic impacts of coal development are then predicted using the Local Impact Management and Assessment (LIMA) computer model and several impact flowcharts. The present capabilities of these counties for coordinated social planning are also listed, and a number of relevant impact management strategies are elaborated upon.

The analysis suggests that the most severe adverse impacts would probably occur in Elmore County, Idaho; in Gilliam and Morrow Counties, Oregon; and in Lincoln County, Washington. All of these counties have relatively small and rural populations, limited public services, and few planning capabilities. To minimize adverse impacts of power plant developments in these four counties, the anticipated impacts should be planned for and the county planning and management capabilities should be greatly expanded.

In contrast, relatively few serious adverse impacts should occur for Coos County, Oregon; and Cowlitz, Grant, Grays Harbor and Whatcom Counties, Washington. In all these counties the rates of population and economic growth would be relatively small and slow so that whatever problems resulted from the projects could presumably be handled with minimal disruption to these areas. None of them would experience a process of rapid urbanization; their needs for additional housing and public services would arise slowly enough to be handled on an ongoing basis; and they would not encounter any serious social problems (with the possible exception of conflict due to differing educational levels in Coos County). Moreover, all of these counties already have adequate to excellent planning capabilities. Consequently, in relation to minimizing adverse socioeconomic impacts, these five counties appear to offer the most desirable areas in the Pacific Northwest for constructing coal-fired electric generating plants during the next 40 years.

The major limitation of this study is that its broad scope precludes accounting for any unique features of the separate candidate counties. A second limitation lies in the many arbitrary assumptions contained in the LIMA model. Because of these limitations, the study should be viewed only as a preliminary screening analysis, not as a set of site-specific impact assessments.

Future research in this area might deal with the following critical problems:

- Defining the unique case of Alaska, which is expected to undergo extensive resource development during the next 20 years but which could not be included in our computer forecasts because of lack of data.
- Verifying the adequacy of the social indicators used in this analysis by using them to collect data on ongoing development projects (as we are presently doing with the nuclear power plants being constructed in Skagit County, Washington).
- Testing and refining the LIMA model under varying sets of assumptions and with several sets of actual impact data.

The two purposes of this chapter are to 1) assess the socioeconomic impacts likely to result from the construction and operation of coal-fired electric generating plants throughout the Pacific Northwest under both the Recent Trends and High Coal Electric scenarios, and 2) explore possible planning and management strategies that local governments might use to mitigate undesirable impacts and to enhance desirable impacts. Because the analysis covers numerous potential projects throughout the region, it provides only a broad overview of the range of possible socioeconomic impacts and does not include any unique features of particular projects or candidate areas. Hence, this study should be viewed as a preliminary overall screening analysis, not as a set of site-specific impact assessments.

10.1 SOCIOECONOMIC IMPACT ASSESSMENT

Any large development project like a power plant will bring into its location several hundred workers and their families, millions of dollars in new income, and numerous potential social and economic problems. The goal of a socioeconomic impact assessment is to predict as accurately as possible the nature and scope of these changes created by a proposed project and to evaluate the consequences of these changes for the surrounding area.

10.1.1 Meaning of Socioeconomic Impacts

Socioeconomic impacts are alterations in people's living conditions that occur in conjunction with a new policy, program or project, and that a) add to all concurrent changes produced by other factors, and b) are experienced as significant social events. Since any social environment is constantly changing, the crucial problems in analyzing socioeconomic impacts are to identify those social alterations that are a direct or indirect result of the specific project under examination, apart from all other events and changes, and then determine which of these alterations significantly affect the people involved.

Three features of this concept of socioeconomic impacts should be noted. First, although impacts are often thought of as undesirable or detrimental, they can be desirable or beneficial, so that impact assessments must always explore the full range of both positive and negative consequences of the action being analyzed. Second, although impacts are often described as caused by prior intervening innovations, in reality they always interact with their original causes in a reciprocal process, either immediately or after some time lag. Hence, impacts occur in conjunction with an activity rather than resulting from it. Third, the purpose of social impact assessment is to enable policy makers to anticipate and plan for potential impacts before they occur, which enables them to take steps to prevent or mitigate undesired impacts. As a result of such impact management efforts some predicted impacts never actually occur.

Socioeconomic impact assessments have traditionally tended to focus on adverse impacts such as rapid population growth, housing shortages, and inadequate public services. Our analysis reflects that tendency to some extent, largely because of the nature of the available data. However, we do include potential beneficial impacts whenever possible, such as overall growth of the local economy and rising personal incomes.

10.1.2 Units of Analysis

All of the laboratories performing socioeconomic impact analyses within the NCUA program agreed to use counties as their units of analysis for three reasons: 1) Many socioeconomic impacts of large construction projects are not limited to a single community but are experienced throughout the surrounding area. 2) Much of the data required for socioeconomic impact analysis are collected on a county basis. 3) Although the impacts of some projects may spread beyond a single county, the likelihood of that happening depends largely on the location of the project within the county; hence, it is site-specific to that particular project. This analysis focuses on 14 counties in the Pacific Northwest that are considered to be likely candidates for siting new generating plants. (Baseline data are also reported for Anchorage, Alaska, which is likely to be an area of extensive resource development in the near future, but the development plans for that area have not yet been specified in enough detail to enable us to forecast possible socioeconomic impacts.) The 14 candidate counties for this analysis are as follows:

Idaho: Bingham and Elmore
Oregon: Clatsop, Coos, Gilliam, Malheur, and Morrow
Washington: Cowlitz, Douglas, Franklin, Grant, Grays Harbor, Lincoln, and Whatcom

10.1.3 Theoretical Perspective

This analysis is grounded in the theoretical perspective of human ecology, which views mankind as inexorably dependent on the natural and social environment. Hence human social life is always constrained and shaped by the basic ecological factors of natural resources, population characteristics, material and social technology, and the economic order that satisfies people's sustenance needs. To this ecological perspective we add two further assumptions:

1) Collective social activities are generally aimed at attaining goals that reflect the values and interests of the participants so that social impact assessments must reflect both the ecological conditions prevailing in an area and the values, interests and goals of the local residents.

2) A community can be viewed as a problem-solving social system in which challenges, such as new environmental or technological conditions, initially disrupt existing social conditions and practices; this creates temporary problem situations, which generate collective responses to cope with these problems. The responses act back as either positive or negative feedback on the initial disruptive conditions.

This theoretical perspective is portrayed in the General Social Impact Assessment and Management Diagram shown in Figure 10.1, which provides a framework for our analysis.

10.1.4 Social Indicators

The impact assessment methodology employed in this report uses sets of social indicators to measure the predicted impacts of a new project. Social indicators are standardized quantitative measures of specified social conditions that are collected periodically as a time series to describe both current conditions and ongoing change trends. The term "social" is used generically to include all realms of human affairs--demographic, economic, organizational, political and cultural--although a distinction is often made between economic and noneconomic (e.g., all others) indicators.

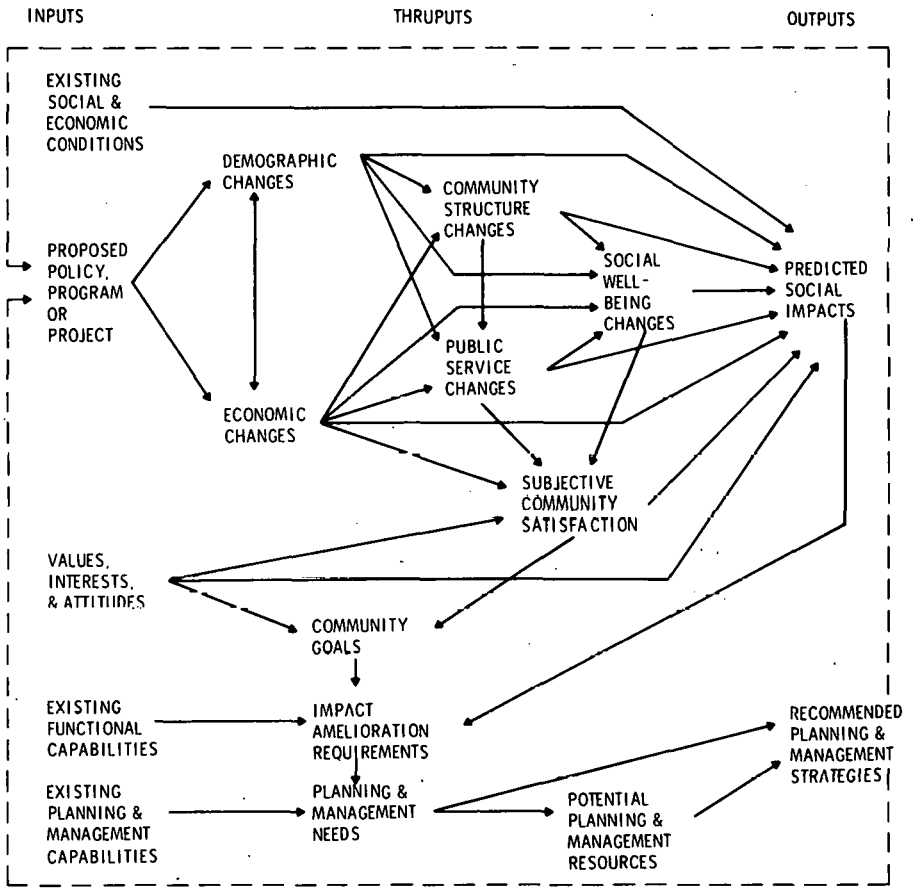

FIGURE 10.1. General Social Impact Assessment and Management Diagram

We divide the total array of potential social impacts into five sectors: demography, economy, community structure, public services, and social well-being. Each of these sectors is composed of numerous factors or characteristics, although the exact number and nature of the factors comprising a sector can vary depending on the purpose of the analysis. We have identified between eight and twelve factors in each sector--50 factors over all--that appeared to be relevant for assessing social impacts. Each factor is measured with a standardized social indicator, the data for which are obtainable from existing records and documents or from public officials. The adequacy and relevance of many of these indicators are open to debate, for this methodological approach has not yet been fully verified.

Twenty-five of those 50 indicators were selected for use in this analysis, following two criteria: a) substantive importance and b) data availability. These indicators are listed in Appendix F and used in Tables H.1 through H.4 in Appendix H.

Social indicators can be used in a variety of ways to assess socioeconomic impacts, including trend extrapolation, standardized multipliers, system models, and flow charts. These techniques, all of which are used in this analysis, are discussed in greater detail in Appendix F.

10.2 CURRENT COUNTY CHARACTERISTICS

Data on the current (1975) demographic, economic, community structure, and public services of the 14 candidate counties (plus Anchorage) are given in Appendix H and Tables H.1 through H.4. The profiles provided by these data portray the socioeconomic conditions existing in the counties at the present time, prior to the introduction of any new generating plants. They thus provide a set of baseline conditions on which to base predictions of future impacts, as well as other kinds of socioeconomic analyses. These data were obtained from a variety of sources, including U.S. Census reports, various state and community reports, and state and local public officials.

10.3 MODEL IMPACT FORECASTS

Our purpose is to forecast the likely demographic and economic changes that would occur in the candidate counties as a result of power plant development under both the Recent Trends and High Coal Electric scenarios. The Local Impact Management and Assessment (LIMA) computer model, described in Appendix G, was used to compute these forecasts. This model is based on a number of assumptions concerning demographic and economic growth rates, so that its forecasts should be viewed only as planning guidelines, not factual predictions. Moreover, the model does not consider any other development projects in the candidate counties (such as the nuclear reactors being constructed in Grays Harbor County) that could seriously compound the impacts created by coal-fired generating plants.

Tables I.1 through I.14 in Appendix I present data for 14 candidate counties on 12 selected demographic and economic indicators at five-year intervals between 1980 and 2020. (The model computes data forecasts on a year-by-year basis, but the major trends are all evident in these five-year interval data.) Anchorage is omitted from these tables because the coal development projections in Chapter 4 do not specify plant sizes or locations there. Because of the anticipated extensive development of coal and other resources in Alaska in the near future, however, a thorough socioeconomic impact assessment of that area is clearly needed. Such a detailed site-specific study could also include the many unique characteristics of Alaska, such as its rapid population growth rate, its unbalanced sex ratio, its high cost of living, and the abundance of government officials in its workforce.

10.3.1 Indicators Used

The 12 indicators used in these forecasts follow.

Population Size. This includes total population of the county, including normal growth (based on current state forecasts) and growth that would be generated by the projected power plant development through direct employment and through secondary economic growth stimulated by the projects. These forecasts for both direct and indirect project-generated population growth are based on a set of assumptions about resident versus migrant status, marriage rates, and family sizes among construction, operational, and secondary workers. They do not include population changes that might result from any other development projects in these candidate counties.

Population Growth. This indicator is the average annual percent change in the population during the preceding five years.

Urbanization. This is the proportion of the population living in communities of 10,000 or more. It is assumed that all project-generated population growth occurs in the largest community in the county.

Median Age. The median age of the total population includes the fact that most construction workers are relatively young.

Median Education. This is the median number of years of formal education completed by the total population.

Gross Sales Amount. This indicator is total sales receipts from all economic activity in the county, per capita. It is based on an assumed ratio between disposable incomes and expenditures.

Gross Sales Growth. This indicator is the average annual percent change in gross sales during the preceding five years.

Personal Income. This is average personal income, per capita, in constant 1975 dollars (which assumes no inflation). It includes the fact that both construction and operational workers generally have higher incomes than other nonproject workers.

Property Value. This is the total value of all real property, per capita, in constant 1975 dollars. It covers only the value added by new power plants and new housing due to these plants; it assumes no other new construction.

Housing Requirements. This indicator is the number of additional permanent housing units required to take care of population growth generated by the project. It does not include mobile homes, which typically provide housing for over half the construction labor force.

Retail and Private Service Capital. This is the total amount of capital, per capita, in constant 1975 dollars, that must be invested in retail and private service facilities to maintain the present ratio between population size and total expenditures. It assumes a time lag between population growth and capital investment. It includes the fact that many construction workers live in mobile homes.

Public Services Operating Expenditures. These are additional annual operational expenditures (beyond present expenditures), in constant 1975 dollars, required by project-induced population growth, in order to maintain all public services at their present levels.

Public Services Capital Expenditures. These are additional annual capital expenditures (beyond present expenditures), in constant 1975 dollars, required by project-induced population growth, in order to maintain all public services at their present levels.

Population size and growth are the only indicators that include "natural" expected changes not generated by power plant development. All other indicators are assumed to remain constant throughout this period. We are not implying that they will actually remain constant, but we use this procedure as a way to isolate changes that are caused specifically by power plant development.

10.3.2 Forecasts

The major changes predicted in each county under the High Coal Electric scenario are described in the following paragraphs. Predicted changes under the Current Trends scenario

are generally of a very similar nature but somewhat less rapid and extensive. For more complete details, see Tables I.1 through I.14.

Bingham County, Idaho (Table I.1). Total population of the county would grow steadily until 1990, and then more rapidly between 1990-2005, increasing from 39,900 to 53,600 during those 15 years (66% growth between 1975 and 2005). Although no towns over 10,000 presently exist in the county, by 1990 the county would become 29% urbanized (by this criterion), and by 2000 this would rise to 41%. The level of economic activity in the county (indicated by total gross sales) would rise rapidly during the brief period of 1990-1995 from $7,830 per capita to $9,710 per capita (24% growth) although average personal income would increase by less than $200. The total amount of property value per capita (and hence the tax base of the county) would also more than triple between 1990 and 2000 from $6,600 to $23,220. As a result of this growth, the county would require 1,900 new housing units by 2005; and to maintain an adequate level of public services, local and county governments would have to spend an additional $1,010,000 per year for capital facilities by 2000, plus an additional $3,310,000 per year for operating expenses by 2005.

Elmore County, Idaho (Table I.1). The population of the county would more than double by 2005, increasing from its present size of 19,800 to 53,100 (168% growth). During the same period it would change from being completely rural to 58% urban, and the level of education would increase significantly. Economic growth would occur even more rapidly with gross sales per capita jumping from the present level of $4,530 to $9,510 by 1985 (110% growth). Average real personal income would rise only $400 but a ten-fold increase would occur in property value per capita by 1995 from $2,620 to $31,960. By this time, the county would need 4,110 additional housing units, $6,710,000 in additional funds per year for public services operating costs, and $2,320,000 per year in additional public services capital investments.

Clatsop County, Oregon (Table I.3). Total population would grow fairly steadily from its present size of 29,100 to 57,500 (98% growth) in 2005 and then gradually level off. All the other changes occurring in this county would also peak at the year 2005. Urbanization would increase moderately from 37% to 55% (but later fall to 49%), the median age would drop from 33 to 29 (but later rise to 31), total gross sales would climb from $5,570 to $9,630 per capita (73% growth), personal income would increase by $400, and property value per capita would more than double from $16,550 to $39,800. The county would need 380 additional housing units, $5,990,000 in annual public services operating funds, and $1,820,000 in annual public services capital investments.

Coos County, Oregon (Table I.4). The population of this county is predicted to grow steadily until at least 2010, from 59,000 to 103,400 (75% growth) but with only a slight increase in urbanization, from 23% to 29%. Most of the changes produced by power plant development would occur between 1980 and 1985, however. During that period, gross sales per capita would rise from $8,000 to $9,700 (22% growth), average personal income would increase by approximately $250, and property value per capita would almost double, from $11,030 to $20,000. This growth would require an additional 2,070 housing units, $3,110,000 per year in public services operating funds, and $980,000 per year in capital investments in service facilities.

Gilliam County, Oregon (Table I.5). The population would increase only moderately up to 1990, but between then and 2005 it would grow five-fold from 3,800 to 19,700 (418% growth); urbanization would jump from 0% to 88%. By 2005 the median age of the population would have dropped from 31 to 24, and median education will have risen from 12.7 to 13.3. Most of the economic activity stimulated by power plant development would occur between 1985 and 1995, however, with gross sales per capita rising from $12,390 to $21,500 during those ten years (73% growth). A drop in average personal income of over $2,000 during that same period would be rather startling; this would result from the extremely high income levels of the present residents in comparison with those of in-migrating workers. Property value per capita would jump from $34,380 to $216,350 during this period. Due to the population growth, the county would require 3,360 additional housing units and an additional $5,780,000 per year in public services operating funds by that time. It would also need to invest $3,080,000 more per year in public services capital facilities by 1995.

Malheur County, Oregon (Table I.6). This county is predicted to experience moderate but steady population growth throughout the entire period up to 2020 from its present size of 24,400 to 49,000 (101% growth). As a result it would go from 0% to 47% urbanized. Economic growth generated by power plant development would peak at about 2015, however, with gross sales per capita rising slightly from $10,600 to $13,560 by that time (27% growth). Average personal income would increase by about $200 during that period but then decline to its present level. Property value per capita would more than triple from $10,590 to $33,600 by 2015. By that time the county would require 2,470 additional housing units, $4,010,000 more per year for operating expenditures and $1,430,000 more per year for capital investments in public services.

Morrow County, Oregon (Table I.7). All of the growth generated by power plant development in this county would occur between now and 1990 or 1995. The present population of 5,200 will almost triple to 15,200 by 1990 (192% growth), and the county would go from 0% to 80% urbanized (later declining to 69%). The median age would drop from 31 to 25 (rising later to 27), and the median educational level would rise from 12.6 to 13.0 years by 1995. Overall economic activity would also increase sharply during this period with gross sales per capita rising from the present level of $8,510 to $20,520 in 1990 (141% growth). Average personal income would decline sharply, however, from its current extremely high level of $9,530 to $7,600 in 1995. Property value per capita would almost quadruple from its present level of $30,550 to $114,490 by 1995. By 1990 an additional 2,170 housing units would be needed, as well as an additional $3,700,000 in annual public services operating funds and $3,250,000 in annual capital investments for public services.

Cowlitz County, Washington (Table I.8). Population growth would be moderate but steady from now until 2010, rising from the present size of 71,000 to 111,900 (58% growth) and no other significant demographic changes would occur. Gross sales per capita would rise only slightly from $11,510 to $13,280 in 1990 (15% growth) and thereafter remain steady at about $12,500. Personal income would not change, although property value per capita would go up somewhat, from $19,830 to $31,600. Nevertheless, by 1990 the county would need 2,600 more housing units to accommodate its growing population plus $4,050,000 in additional annual public services operating funds and $1,340,000 in annual capital facilities for public services.

Douglas County, Washington (Table I.9). The population of this county is predicted to grow in two steps, the first of which would occur between 1990 and 1995 and the second between 2005 and 2010. Consequently, by 2010 the population would rise from 19,000 to 35,200 (85% growth), and the county would shift from 0% urbanization to 42% (later declining to 39%). The median age would decline during that time from 30 to 27, while median education would rise from 12.5 to 12.8. The first period of population growth, from 1990 to 1995, will stimulate considerable economic growth. Gross sales per capita would jump from $3,350 to $9,450 (182% growth) while personal income would go up $800 from $5,300 to $6,120 and property value per capita would increase from $11,480 to $36,550. From 1995 to 2005 a mild economic downturn would be followed by more economic growth during the second period of population growth, 2005-2010. In 1995 2,140 additional housing units, a $3,490,000 per year increase in operating funds, and a $1,930,000 per year increase in capital investments would be needed. Then, in 2010, these needs would increase to 2,880 housing units, $4,700,000 of operating funds and $2,050,000 of capital expenditures.

Franklin County, Washington (Table I.10). Most of the population growth here would take place between 1985 and 2000, during which time the number of people would go from 30,000 to 48,000 (75% growth from 1975). The degree of urbanization would also increase somewhat during that period from 53% to 65%. Similarly, most economic growth would also occur during those 15 years; gross sales per capita would rise modestly from $9,980 to $12,890 (29% growth). Real personal income would decline slightly during that time but property value per capita would expand from $14,400 to $42,000. At that end of that period the county would require 2,810 additional housing units (which would increase to 2,930 in 2005), plus $4,710,000 additional funds per year for public services operations ($5,050,000 in 2005), and $1,630,000 per year in capital investments for public services.

Grant County, Washington (Table I.11). In this case population growth would proceed fairly smoothly until 2015, rising from 43,900 to 75,100 (71% growth), while urbanization would expand from 23% to 36%. Because of the present high level of economic activity in the county, however, economic growth would be considerably slower; gross sales per capita would go from $14,950 to $16,420 by 2015 (20% growth). Average personal income would decline just slightly during that time while property value per capita would increase from $12,480 to $20,100. By 2015 an additional 2,590 housing units, an annual increase of $4,450,000 in operating funds for public services and $840,000 more per year in capital funds for such services would be needed. Note, however, that these needs would first arise by 1995 when the housing shortage would be 2,290 units, the additional operating funds required would be $3,380,000 and the need for new capital investments would reach $1,580,000.

Grays Harbor County, Washington (Table I.12). In general the changes predicted in this county from coal development would be relatively small compared to the other candidate counties. Population would grow steadily but slowly between now and 2010, increasing from 60,500 to 99,200 (64% growth), and the rate of urbanization would increase slightly from 49% to 54%. Gross sales per capita would rise from $8,510 at present to $10,280 in 2000 (21% growth) and then decline very slightly. Real personal income would remain constant throughout, although property value per capita would double from $12,200 to approximately $25,000. Despite this slow growth rate, pressing housing and public service needs would become evident as early as

1985 when 2,880 more housing units would be required and the county would have to spend $4,430,000 in additional operating funds per year for public services, plus $1,150,000 more per year for capital investments.

Lincoln County, Washington (Table I.13). This would be another case of two-step growth. Between 1985 and 1990 the population would jump from 12,700 to 16,500; between 2010 and 2015 it would go from 21,700 to 24,900. Overall the population would increase from 9,500 at present to 24,900 in 2015 (157% growth). The county would remain without a town of 10,000 until 2015, at which point it would jump to 59% urbanized as a result of its largest town going over the 10,000 mark. The median age would drop considerably during this period from 37 to 29, while median education would rise significantly from 12.2 to 12.7. Economic growth would accompany the first period of population growth as gross sales per capita would increase from $11,640 in 1980 to $19,260 in 1990 (65% growth). This indicator would then decline somewhat until 2015 when it would return to its 1990 level. Personal income would go up over $600 between 1980 and 1990 from $6,540 to $7,160; after that it would decline slightly and remain level. Property value per capita would continue to expand until 1995, increasing from $29,900 to $82,400, decline modestly between 1995 and 2015, then rise to $85,500. The housing requirements of the county would continue to mount steadily until 2015 when they would reach 2,800 additional units. This would also be true of public services operating expenses, with $4,630,000 more funds needed annually for this purpose by 2015. The need for additional capital investments in public services facilities would rise much more rapidly, however, reaching $1,570,000 per year as early as 1990.

Whatcom County, Washington (Table I.14). Of all the candidate counties this one should experience the smallest changes from coal plant development. Population would grow slowly from 90,000 at present to 132,700 in 2015 (47% growth). Urbanization would rise just slightly from 47% to 51%. Gross sales per capita would increase very modestly between 1985 and 1990 from $9,510 to $10,490 (10% growth) but thereafter remain constant; personal income would remain constant throughout the entire period. Property value per capita would go up somewhat between now and 1995 from $13,700 to $21,400. Nevertheless, more housing would still be needed, reaching a peak of 2,100 in 2000. Similarly, the county would need to invest an additional $1,000,000 each year in facilities for public services by 1995, and by 2005 would have to spend an additional $3,500,000 annually to operate its public services.

10.3.3 Summary of Forecasts

From an overall perspective, the 14 candidate counties can be divided into three categories in terms of the seriousness of the adverse socioeconomic impacts they would likely experience as a result of power plant development. The most severe adverse impacts would probably occur in Elmore County in Idaho, in Gilliam and Morrow Counties in Oregon, and in Lincoln County in Washington. Moderate adverse impacts would likely occur in Bingham County in Idaho, Clatsop and Malheur Counties in Oregon, and Douglas and Franklin Counties in Washington. Relatively small adverse impacts would be felt in Coos County in Oregon, and in Cowlitz, Grant, Grays Harbor, and Whatcom Counties in Washington. The four most heavily impacted counties would experience the following kinds of problems:

Elmore County would undergo rapid and extreme population and economic growth, resulting in extensive urbanization and vast housing and public services needs. It would also experience several serious social impacts, such as shifting occupational structure, extensive governmental growth, an unbalanced sex ratio and family instability.

Gilliam County would also experience extreme population and economic growth, although it would not begin until 1991, which would give the county time to develop impact management programs. With this growth would come extensive urbanization, great housing needs, and pressing needs for expanded public services. This county would also have to cope with a declining average personal income and potentially serious problems in maintaining social cohesion.

Morrow County would be another case of rapid and extreme population and economic growth and extensive urbanization, although its housing and public service needs would not be as great as in the preceding two counties. However, it would experience several serious social problems, including loss of social cohesion, shifting occupational structure, changing age composition, declining average income, and inadequate police protection.

Lincoln County would undergo population and economic growth in a two-step process, with some "readjustment time" between them, but in the long run it would experience almost as extensive population and economic growth as the other three severely impacted counties. It would have the advantage, however, of not having to face serious housing and public services shortages until well into the 21st century, which gives it plenty of lead planning time. Maintenance of social cohesion could also be a major problem in this county.

10.3.4 Scenario Comparisons

The differences between the forecasts for the Recent Trends and High Coal Electric scenarios are relatively slight in most of these candidate counties. No power plant development is scheduled under the Recent Trends scenario for Clatsop County, Oregon and Douglas and Franklin Counties, Washington, so no comparison between the effects of the two scenarios can be made in those three cases. The forecasts for the two scenarios are virtually identical for Bingham County, Idaho; Coos County, Oregon; and Cowlitz and Grays Harbor Counties, Washington. In five of the remaining counties--Elmore, Idaho, Malheur and Morrow, Oregon, and Grant and Whatcom, Washington--population growth forecasts differ between the two scenarios by no more than 10,000 people from now to 2020, while the forecasts for gross sales per capita differ by no more than $1,700.

Consequently, only in Gilliam County, Oregon and Lincoln County, Washington would the Recent Trends scenario produce significantly fewer demographic and economic changes--and hence presumably fewer serious socioeconomic impacts--than would the High Coal Electric scenario. In Gilliam County the Recent Trends scenario results in only half the population growth expected with the High Coal Electric scenario and considerably diminishes most of the other rather extreme rates of change observed in Table I.5. In Lincoln County the Recent Trends scenario eliminates the two periods of rapid growth that would occur with the High Coal Electric scenario, producing a more gradual and less erratic growth process.

Figures 10.2 to 10.5 illustrate some of these differences between the two scenarios in Gilliam and Morrow Counties. The first pair of plots (Figures 10.2 and 10.3) represents Gilliam County under the two alternative scenarios, while the second pair (Figures 10.4 and

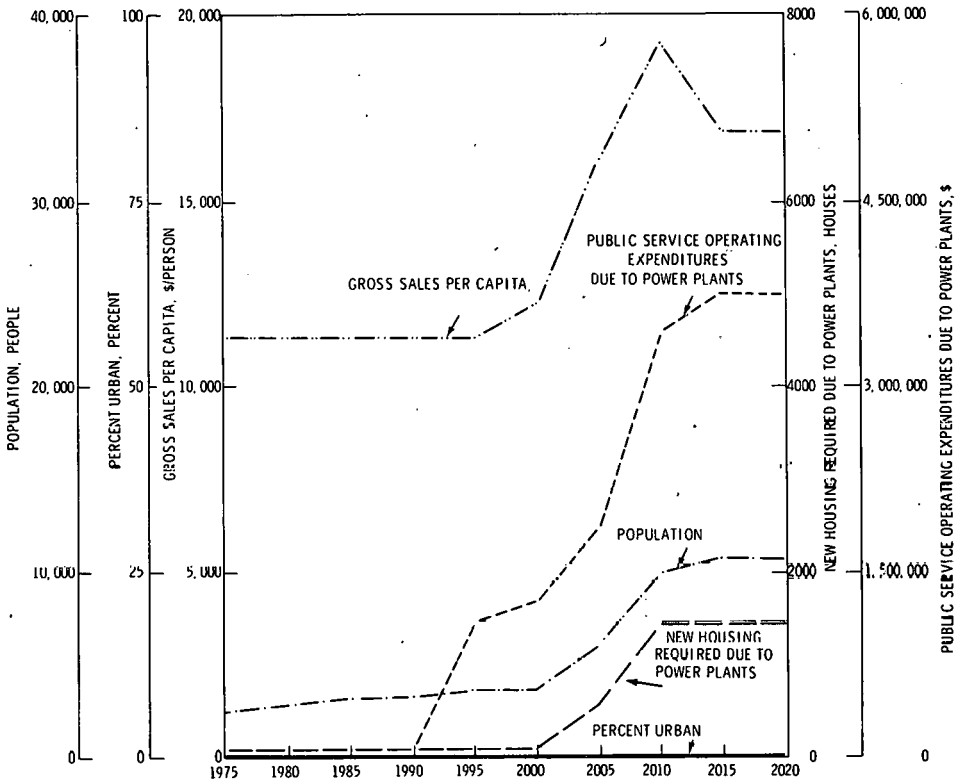

FIGURE 10.2. Forecasts for Gilliam County, Oregon Under the Recent Trends Scenario

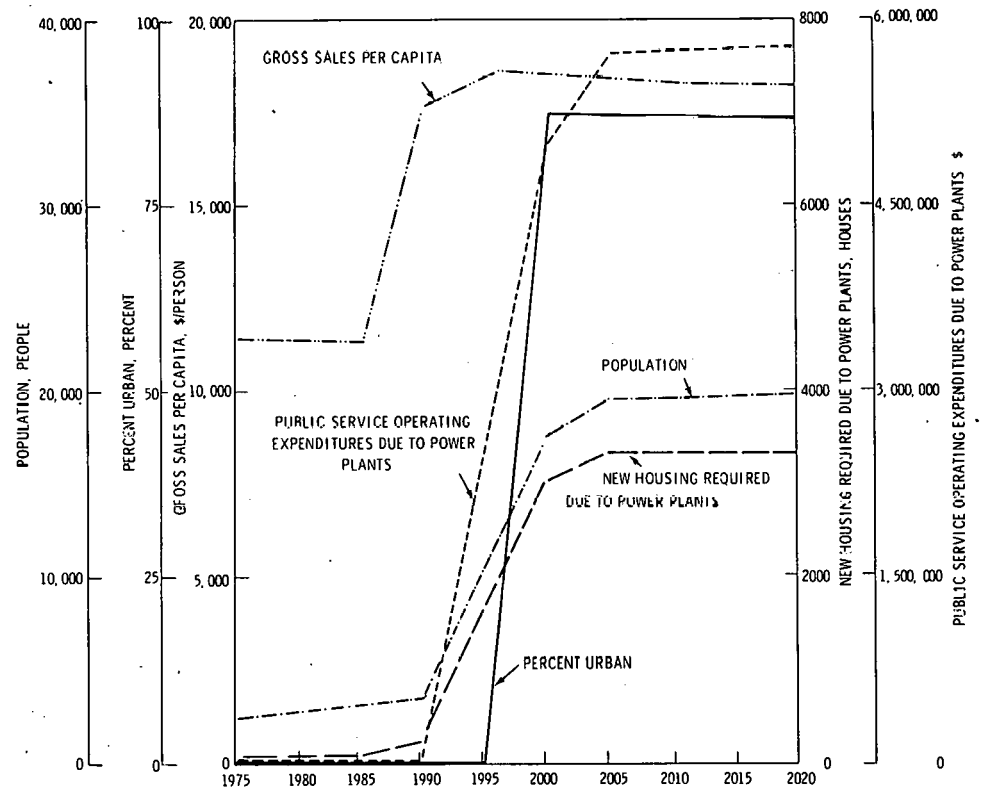

FIGURE 10.3. Forecasts for Gilliam County, Oregon Under the High Coal Electric Scenario

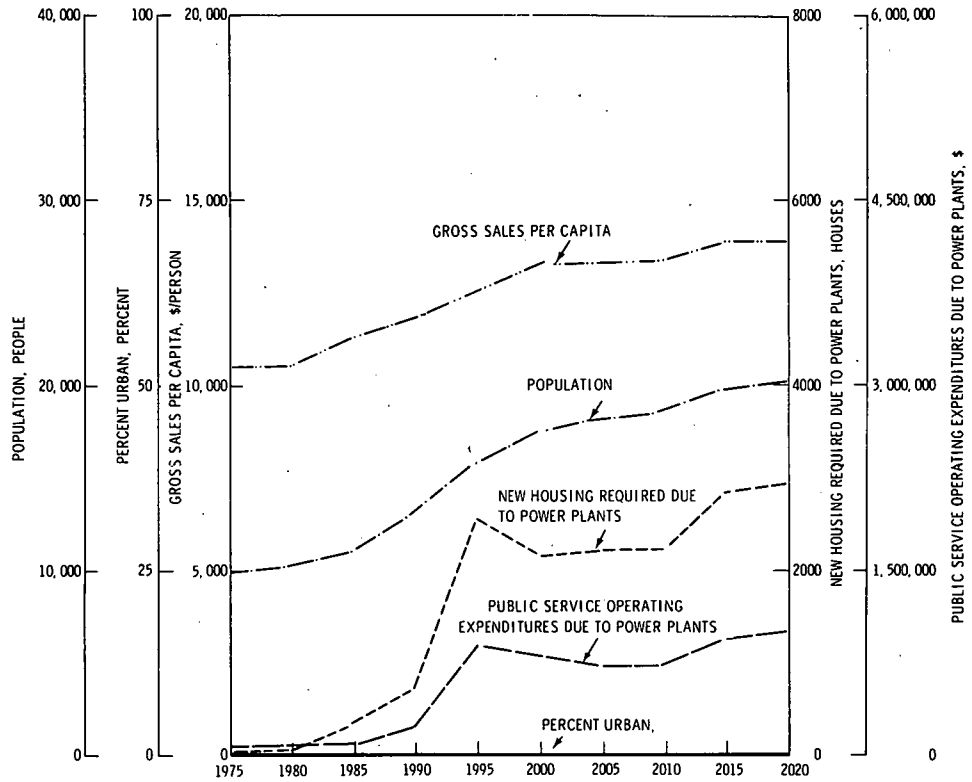

FIGURE 10.4. Forecasts for Lincoln County, Washington Under the Recent Trends Scenario

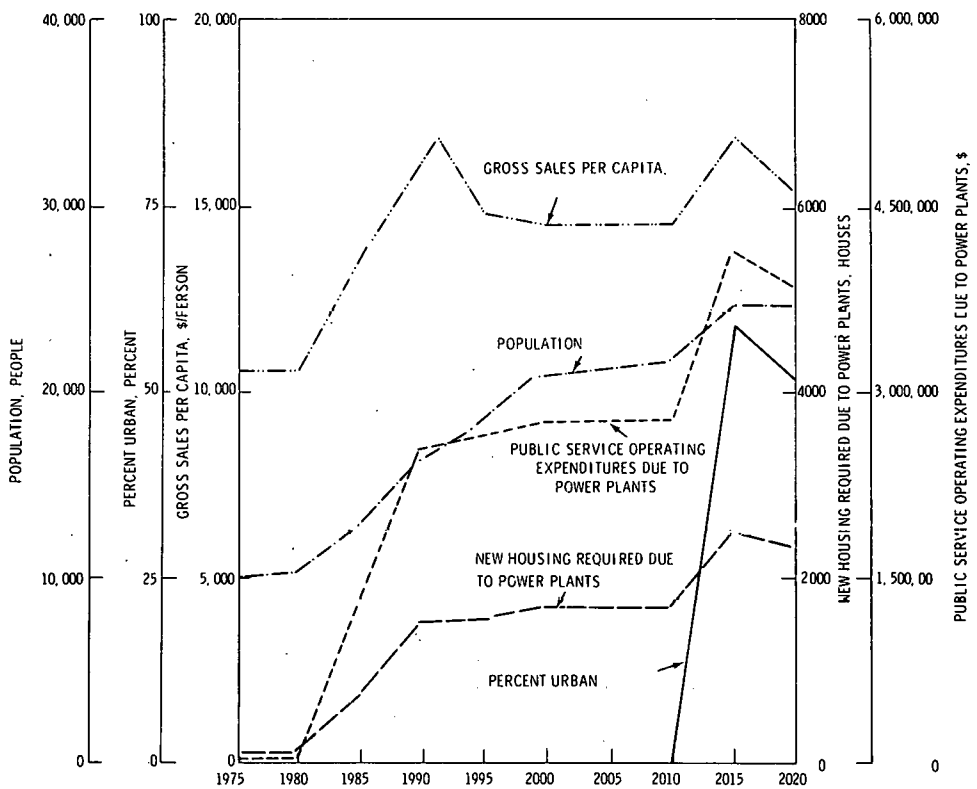

FIGURE 10.5. Forecasts for Lincoln County, Washington Under the High Coal Electric Scenario

10.5) represents Lincoln County. For simplicity only five of the indicators are plotted here: population size, urbanization, gross sales amount, housing requirements, and public services operating expenditures. Since each indicator is plotted on a different scale of magnitude, the slopes of the five indicators in each plot cannot be meaningfully compared. What can be meaningfully compared are the two slopes for any given indicator under alternative scenarios.

When the two plots for Gilliam County are compared in this way, the slopes of four of the indicators are noticeably less rapid and steep under Recent Trends than under High Coal Electric. Gross sales per capita do eventually reach approximately the same height under both scenarios, but the Recent Trends scenario avoids the period of extremely rapid economic expansion between 1985 and 1990 that would occur with the High Coal Electric scenario. Comparison of the two plots for Lincoln County, meanwhile, reveals that four of the five indicators rise much more slowly and steadily under Recent Trends than under High Coal Electric. Public services operating expenditures do continue to evidence a two-step process of growth under both scenarios, although it is less pronounced under the Recent Trends scenario.

10.4 OTHER IMPACT FORECASTS

The LIMA computer model does not include any social factors, so it is not possible to forecast these kinds of impacts quantitatively. The flowcharts described in Appendix F enable us to estimate the major expected trends in these areas, however.

10.4.1 Factors Examined

The following eight social factors will be examined for potential significant impacts within the candidate counties:

- Occupational Structure. Proportion of the labor force holding professional, executive, managerial or technical jobs.
- Service Associations. Number of permanent community-wide service associations (fraternal, community service, professional, educational, health, ethnic, etc.).
- Governmental Size. Number of local governmental employees per 1000 population.
- Social Conflict. Number of significant public conflicts per year.
- Social Cohesion. Extent to which residents are satisfied with their community as a place to live.
- Personal Safety. Number of violent crimes per year per capita.
- Family Stability. Number of divorces per year per capita.
- Economic Security. Proportion of families with annual incomes below the poverty line.

10.4.2 Major Trends Expected

Occupational Structure. The occupational structure of an area tends to shift toward high status professional, executive, technical and managerial jobs as a result of a) a switch from construction to operation of a large power plant or similar facility, b) expansion of business rather than manufacturing firms, c) growth of governmental activities, and d) rising wealth of the community. The first factor would be most relevant in these candidate counties since the construction crews will be replaced by highly trained technicians and administrators as

the generating plants become operational. Because the operating staffs of these plants are relatively small, however, the occupational structure of most of the candidate counties should not change drastically. Counties such as Elmore, Idaho and Morrow, Oregon that presently have very small proportions of their labor forces in these occupations will probably experience a noticeable shift, but elsewhere the change should not be great enough to significantly impact the overall social structure of the county.

Service Associations. Most people who participate in voluntary associations that perform various public services in the community are relatively well educated and have high occupational status and above average incomes. These three status factors are expected to rise in almost all of the candidate counties (except for income in Morrow County, Oregon and Franklin County, Washington). Most of these increases will be quite small, however, with the result that participation in voluntary service associations should not expand markedly. Moreover, since most newcomers to a community tend not to join such organizations for at least a year or two after their arrival, this dampening effect on participation in associations should offset any potential increase caused by rising socioeconomic status. Hence, we would not expect to see any significant changes in participation in associations in these counties due to power plant development.

Governmental Size. Municipal and county governments in these candidate counties will almost certainly have to expand their functional capabilities to handle the socioeconomic impacts generated by a large project. This will include hiring additional people (including planners, administrators, engineers, professional service workers, construction and maintenance crews, etc.). In an absolute sense, therefore, all these governments can be expected to grow, often quite extensively. If the number of local governmental employees is standardized against total population size, however an unexpected trend occurs. Presently, the number of governmental employees per 1000 population is highest in the least populated counties, such as Gilliam and Morrow, Oregon and Lincoln, Washington (Table I.3). In contrast this ratio is quite low in the populous areas of Anchorage, Alaska and Bellingham, Washington (Whatcom County). This inverse relationship is due to the fact that a certain minimal number of personnel are needed to operate a county or municipal government no matter how small the total population. On the other hand, many communities tend to resist growth in government so the size of local governments does not keep pace with total population growth. Economies of scale can also be realized in governmental activities as the size of the governmental staff increases.

Thus, although most of these local governments will grow in absolute size as a result of power plant development, their size relative to the total population will steadily decline. This will be particularly evident in sparsely populated counties that presently have a high ratio of governmental employees to total population. However, two exceptions to this generalization may be Bingham and Elmore Counties, Idaho. These counties have quite small numbers of governmental employees in relation to total population even though their populations are not presently large. They may experience a relative, as well as an absolute, growth in governmental size with power plant development.

Social Conflict. Social conflicts can be caused by an infinite number of conditions, but the most likely sources of conflict in these candidate counties will be differences between the current residents and the in-migrating workers. Regardless of whether these differences

are demographic, ethnic, social or economic in nature, the current residents will resent the influx of people who differ from themselves in significant ways, and this resentment can easily erupt in overt conflicts.

The following areas are where potentially significant differences might occur. 1) In Elmore County, Idaho the sex ratio is already extremely high (more men than women). A large influx of predominantly male construction workers could easily exacerbate this already unstable condition. 2) Most of these counties (except Franklin and Grant in Washington) have only small nonwhite populations. If a significant proportion of the incoming construction workers were nonwhite, serious racial/ethnic conflicts could develop. 3) The median age of the population is relatively high in Clatsop and Morrow Counties, Oregon and in Lincoln County, Washington. Since construction workers tend to be relatively young, significant age differences could occur in these counties. 4) The average educational level of Coos County, Oregon is well below average. The technicians and administrators who would operate the proposed power plants in that county would therefore be considerably better educated than the present residents, which might cause problems. 5) Personal income per capita is exceptionally high in Gilliam and Morrow Counties, Oregon. Although the rates of pay for both construction and operational workers on the power plants would be above the national average, the incomes of these people would be considerably below the present averages in the two counties. The current very affluent residents therefore might resent the influx of less well-to-do people.

Social Cohesion. The social cohesion of a community is invariably disturbed whenever the population grows rapidly. This is particularly true when the resident population is relatively small, when the community has not previously experienced rapid growth, when the newcomers differ from the current residents in significant ways, and when local values are relatively traditional or unique. These conditions are most evident in Gilliam County, Oregon and Lincoln County, Washington. In both cases the population is quite small, virtually no growth has occurred for the past five years (Gilliam has had a declining population), both are completely rural (no towns over 10,000), and each has a unique characteristic that would likely be altered by in-migrating workers. (Personal income in Gilliam is well above average, while the median age in Lincoln is very high.) Hence, the cohesion of these two counties could be seriously threatened by power plant development, especially since the High Coal Electric scenario would produce extreme population and economic growth in both counties.

Maintenance of social cohesion could also be a significant problem for Morrow County, Oregon because of its very small population relative to the expected number of in-migrants. It could also cause problems for Bingham and Elmore Counties, Idaho and Morrow County, Oregon because all of them would shift from being completely rural to predominantly urban within the next 10 to 15 years. Finally, Clatsop County, Oregon and Franklin and Grays Harbor Counties, Washington have experienced almost no population growth during the past several years, so a rapid influx of new people could disturb their social cohesion also.

Personal Safety. The rates of violent crimes are relatively low in all the candidate counties at the present time, so any significant increase in the crime rate would pose a critical problem. However, no evidence exists from previous development projects that the rates of murder, robbery and other violent crimes increase faster than population growth. The crimes that do become particularly evident under these rapid growth conditions are ones that

reflect underlying problems of social disruption and rootlessness, such as public drunkenness, gambling, fighting, and otherwise "disturbing the peace." These activities do create problems for the affected communities, but they do not normally pose threats to personal safety. Coping with such activities might be especially difficult in Gilliam and Malheur Counties, Oregon and in Lincoln County, Washington, all of which have very small police forces. However, many of these problems can be prevented by providing adequate social and recreational facilities for the in-migrating workers and their families.

Family Stability. Marital problems and divorce often become quite prevalent in areas of rapid growth and these problems are not limited to the new residents. These people do experience the most severe marital strains, for three reasons: 1) many construction workers do not bring their families with them and see them only on weekends or less frequently; 2) families that do accompany in-migrating workers (both construction and operational) find themselves in a new community that is likely experiencing numerous strains from rapid growth and therefore can provide few social supports for the newcomers; and 3) wives of in-migrating workers often have a very difficult time finding employment in the new community because of the surplus of women seeking employment, which leaves them feeling frustrated and isolated.

At the same time many old residents may also experience marital and family problems as their customary lifestyle erodes and is replaced by one that stresses individual autonomy and mobility rather than family stability. These problems might be most serious in Bingham and Elmore Counties, Idaho where an unusually large proportion of the population consists of families with children. Since many construction workers are unmarried or without families, their lifestyles could differ markedly from those of the present residents. Wives seeking employment would have particularly difficult times in Clatsop County, Oregon and in Cowlitz, Franklin and Whatcom Counties, Washington, all of which have very few job openings. It is important to note, however, that much can be done to alleviate such problems if a community recognizes them and takes action to eliminate their underlying causes.

Economic Security. Poverty is an especially acute problem in Malheur County, Oregon and is also fairly extensive in Bingham and Elmore Counties, Idaho, in Morrow County, Oregon and in Grant County, Washington. Neither development scenario will produce a significant increase in personal income in Bingham, Malheur and Grant Counties, although expanding employment opportunities should enable many presently unemployed people to find work of some kind. Elmore County would experience a significant rise in personal income under both scenarios, which should definitely help (along with greater employment) to reduce poverty in that county. Also, although average personal income will drop sharply under both scenarios in Morrow County, this does not mean that poverty will necessarily increase. Again, expanding employment opportunities could help considerably to eliminate poverty while at the same time lowering the average income of the total population. In general, the additional employment opportunities generated by a large development project, through both direct employment on the project and indirect economic growth stimulated by the project, should in all cases significantly reduce, if not totally eliminate, poverty in these candidate counties.

10.5 IMPACT MANAGEMENT OPTIONS

Once a decision has been made to proceed with a development project, the principal purpose of an impact assessment is to enable the people likely to be affected to manage or mitigate

those impacts as fully as possible. In this section we first examine the current planning capabilities of the 15 candidate counties to ascertain their resources for developing adequate impact management plans. We then survey the range of impact management techniques available to communities facing severe socioeconomic impacts. Finally, for illustrative purposes we examine two of the candidate counties that were forecasted to experience extensive demographic and economic changes from power plant development. Our concern here will be to suggest the kinds of steps that might help each county cope adequately with the expected impacts.

10.5.1 Current Planning Capabilities

The planning capabilities of the 15 candidate counties (including Anchorage) at the present time are summarized in Table H.5 in Appendix H. Two sets of information are given for each county: 1) the capabilities of the county planning department plus any city planning departments in that county, and 2) the capabilities of whatever regional planning organization the county belongs to. For each set, data are given on the total number of professional planners, the total annual budget(s), and whether or not a current comprehensive plan exists.

Anchorage is unique among these counties in having the most extensive planning capabilities, even though it does not belong to a regional organization. The city currently employs 30 professional planners and spends $1 million annually on planning.

In Idaho both Bingham and Elmore Counties have quite small planning departments. Elmore's planning budget is particularly minimal and it has no comprehensive plan. However, both counties belong to regional organizations with relatively large planning staffs and budgets, and most of the planning for these counties is probably done through those bodies.

In Oregon, Clatsop County (including Astoria), Coos County (including Coos Bay), and Malheur County all have fairly extensive planning capabilities in terms of both staff and budgets, although Coos County does not have a comprehensive plan. All three counties also belong to regional organizations with moderately large planning capabilities. Gilliam County has almost no planning budget or staff, although it does belong to a good-sized regional organization. Morrow County has extremely limited planning capabilities and does not belong to a regional organization.

Among the counties in Washington, Whatcom (including Bellingham) has the largest planning capabilities. Those in Cowlitz County (including Longview), Franklin County (including Pasco), and Grays Harbor County (including Aberdeen and Hoquiam) are all moderately sized, although the Grant-Lincoln-Adams Conference of Governments gives little attention to planning. Lincoln and Douglas Counties, meanwhile, both have only minimal planning capabilities and virtually no support from regional organizations.

Overall, if the planning capabilities of these counties were to be categorized as either strong, moderate or weak, the strong category would consist of Anchorage, Clatsop, Coos, Malheur and Whatcom; the weak category would contain Elmore, Gilliam, Morrow, Douglas and Lincoln; and the rest of the counties would fall into the moderate category.

10.5.2 Impact Management Techniques

In outlining the range of impact management techniques available to a county or community that is anticipating or experiencing severe socioeconomic impacts from a large energy development project, we do not attempt to specify which techniques would be most appropriate for any

particular situation. That must be determined by a number of inter-related factors, including the projected magnitude and severity of the impacts, the agency or developer expected to assume responsibility for these impacts, the local governmental structure, and prevailing cultural values.

Our purpose here is merely to indicate the range of potential impact management techniques that might be used to mitigate or control undesired socioeconomic impacts and to enhance desired impacts. These techniques vary considerably, depending on the governmental level or agency responsible for implementing the management program and the role of the developer in this process. The range of techniques available to each of the governmental and private agencies potentially involved in impact management are described below.

Local Government. Local governmental units, particularly in small and rural areas where energy development projects are most likely to occur, usually do not have many financial resources to use for impact management planning and programs. Therefore, these governments must rely primarily on other governmental levels or on the project developer to provide the funding necessary for impact management. Local governments can, however, establish community panels and advisory groups to work with the developer and other governments that are providing financial and technical assistance. They can set up their own impact-monitoring programs to determine what effects the project actually has on their county or community. They can manipulate and rearrange some of the existing social and economic infrastructure to handle immediate pressures generated by rapid population growth, such as operating schools in the evening for community workshops and classes, providing portable classrooms, and double-shifting the schools.

Local governments can also develop and use regulatory tools such as subdivision ordinances, zoning requirements, comprehensive plans, and mobile home park regulations. They can require the project developer to participate in the impact management efforts through joint planning and program development. With a private utility, the local government can insist, as a requirement for zoning approval, that the utility prepay several years of local taxes. This is now being done in Skagit County, Washington (as specified in the Rezone Contract between Puget Power Company and the Skagit County Commissioners). With a public utility or agency, the local government can request special impact assistance payments to help finance additional public services, as done in Richland, Washington, by the Washington Public Power Supply System.

Local governments can also expand their ability to deliver social and health services through such techniques as an incentive program to recruit physicians or neighborhood-based service programs. They can use circuit-riding administrators to increase their management capabilities. They can also obtain technical assistance from various other local organizations such as universities and professional associations.

State Government. Many state governments have become involved in providing financial and technical assistance to impacted counties and communities. The state can set up local branches of relevant state agencies in the impacted areas. The state can create its own community development authority. Various state agencies, such as the Department of Education, can make impact loans available. The state can provide financial aid to impacted communities from various state taxes.

Moreover, the state can open an impact office in the local area to administer impact funds and to handle local requests for assistance. It can establish a state housing authority to

sell bonds for impact housing assistance. It can develop a state land use plan that would offer guidance to local governments in planning for future growth. It can enact power plant siting laws that require social and economic impact assessment and management programs. And the state can create a revolving loan fund, a state bonding authority, or a state finance agency as a mechanism for generating additional financial assistance to impacted communities.

Federal Government. The role of the federal government in impact management has usually been limited to providing additional funding for planning and impact mitigation programs. Several federal agencies also provide technical assistance, although usually not as extensively as the states. Federal agencies can also use the Federal Regional Council to coordinate federal, state and local activities. Federal agencies can provide a variety of planning grants, including grants for specific areas such as health care, as well as more comprehensive planning grants such as those under the HUD "701" program. Federal agencies can also provide federally funded planning staff through some of their programs. Finally, a variety of special financial assistance programs are available through such agencies as the Law Enforcement Assistance Administration, the Department of Agriculture, the Civil Service Commission, and the Environmental Protection Agency.

Project Developer. The role of the project developer in this process varies widely, depending on the nature of the developer and the type of project. It can range from substantial involvement in impact monitoring and mitigation to virtually no involvement in any local affairs. Several ways in which a project developer can become involved in impact management processes include the following: a) set up training programs for residents who will be employed by the project, b) establish impact monitoring systems in collaboration with local officials, c) create joint industrial-governmental planning groups, d) make direct financial payments (often in the form of prepayment of local taxes) for the most substantial expected impacts, e) provide needed community facilities such as community centers, parks, etc., and f) plan their projects to minimize peak overloads on public services, such as staggering shift hours to reduce traffic congestion.

10.5.3 Illustrative Management Approaches

To illustrate the ways in which any county might plan for and manage severe socioeconomic impacts, the approaches that might be taken in Morrow and Gilliam Counties in Oregon are described. Although the sketches are specific to these two counties, the general approaches illustrated here could easily be adapted to other counties in the region. Both Morrow and Gilliam counties would experience rapid population and economic growth under the High Coal Electric scenario, but the growth in Morrow County would begin immediately and peak by 1990, whereas that in Gilliam County would not begin until 1991 and would last until at least 2000. Hence, the counties differ significantly in the time frames within which they must plan for anticipated socioeconomic impacts from coal development projects.

Morrow County. The High Coal Electric scenario calls for construction of a 500 MW generating plant beginning in 1977, another one in 1982, and a third one in 1985. As a result the population of the county would grow rapidly from its present level of 5,200 to 15,200 by 1990. Consequently, serious socioeconomic impacts would be experienced almost immediately. The median age would drop, the median educational level would rise, gross sales per capita would

double within the next eight years, property value per capita would more than triple during that period, hundreds of new dwelling units would be needed, and the need for expanded public services and facilities would begin rising rapidly.

Because the lead time prior to these impacts would be so brief, the county should begin immediately to expand its planning capabilities. Currently, it has only two planners, no comprehensive plan, and no regional planning organization. County officials could begin by asking the state to provide the services of several state planners to the county on a temporary basis to provide technical assistance. They could also request financial assistance from various state agencies. At the same time the county should seek to increase its revenues in whatever way possible, such as raising taxes or issuing bonds. Even if it is successful in these efforts, however, there will not be time to develop many necessary public facilities and services (schools, hospitals, etc.) on a permanent basis. Hence county officials should explore the possibilities of providing and financing these services on a temporary or mobile basis.

The county could also seek additional state or federal funds with which to hire at least one or two more planners. Working with local citizens, these planners could quickly put together a comprehensive plan to guide growth, on the basis that it would need continual revision as the project progressed.

Although 13% of all dwelling units in the county are presently unoccupied, these would quickly fill up, and an additional 2,170 permanent units would be required by 1990 to accommodate anticipated population growth. County planners and officials should work closely with private contractors to ensure that these needs are met. It would also be necessary to develop accommodations for approximately 3,000 mobile homes. County planners should anticipate that rapid growth will likely bring land speculation and rising property values. To handle these trends, the county comprehensive plan must be supplemented with such tools as subdivision ordinances, zoning codes, mobile home park requirements, and similar statutes.

It would also be wise to quickly establish ongoing communication between county planners and the project developer to obtain as much information as possible about the expected labor force increase, the construction schedule and related factors. This communication process might even be formalized in a standing citizen advisory board that would meet regularly with the developer. Local officials should also begin negotiating with the development company or agency on its responsibilities for mitigating expected socioeconomic impacts through prepayment of property taxes or other procedures.

The absence of any lead time in this case also means that the state may have to play a larger role than usual in helping the county to obtain needed financial and technical assistance. Since several years are often needed to obtain assistance under many federal programs, the state might have to step in and provide emergency financial assistance for at least the first few years.

In short, the county, the state and the developer should all begin at once to plan and develop programs for managing the substantial socioeconomic impacts that will begin very soon under the High Coal Electric scenario.

Gilliam County. The High Coal Electric scenario specifies that two 1,000 MW generating plants would be constructed in this county beginning in 1991-92, and three more 500 MW plants

beginning in 1996-97. During that six-year period the population would climb from 3,800 to 16,400; at the end of that time, 88% of the population would be living in towns of 10,000 or more. The median age would rise significantly. Gross sales per capita and property value per capita would both nearly double, thousands of new dwelling units would be needed, and several million dollars would have to be added to the annual budgets for public facilities and services.

In this case, however, the county would have 14 years in which to plan and prepare for these anticipated socioeconomic impacts. If it began these efforts now, it should be well prepared to handle this explosive growth when it does occur.

Currently, the county has virtually no planning capabilities of its own, although it does belong to the East Central Oregon Association of Governments, which employs nine planners. Initially, most of its planning effort will have to be done by this regional organization, although the county will undoubtedly find it useful to build up its own planning staff in the near future. It would then be possible to establish a coordinated planning team involving local citizens, county planners and other officials, the regional organization, state planners and agencies, and the prospective developer. The long lead time available will allow for extensive communication among all these parties, leading to the preparation of a comprehensive master plan for the county to rationally control growth.

This planning team will have time to seek out all possible sources of financial assistance on the state and federal levels; local officials can then gradually increase the revenues of the county and municipal governments. With these resources in hand, they could adequately plan for and develop the public facilities and services that will be needed in the future. They could also work out a long-term plan with private contractors to construct needed housing by the time the population influx began. Finally, local government officials could carefully consider and enact whatever legal provisions would be required to enforce the comprehensive plan.

In short, although the High Coal Electric scenario would bring explosive demographic and economic growth to Gilliam County, the 14-year lead time will enable the county to plan and develop management strategies for handling the resulting socioeconomic impacts. This assumes, however, that the county will begin the planning process now.

REFERENCES FOR CHAPTER 10

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APPENDICES

APPENDIX A

ENERGY SUPPLY AND DEMAND IN THE REGION

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ENERGY SUPPLY AND DEMAND IN THE REGION

Current problems and their implications for future trends in energy supply in Federal Region Ten are discussed in this appendix. The various implications are analyzed in the context of the potential for coal as an energy source in the region.

The major objectives of this appendix are to characterize the region and to indicate potential future trends, both qualitative and quantitative. Present patterns of the energy system are discussed, indicating a predominance of hydroelectric generation in the states of Idaho, Oregon and Washington and vast undeveloped resources in Alaska. The region's unique aspects are discussed briefly to preface the changes indicated from recent patterns. This provides a comparative basis for the assumed national scenarios and background for the impacts and assessments made in this study.

Due to the diversity between Alaska and the Pacific Northwest, the two areas are discussed in separate sections of this appendix. The second section characterizes the three states of Idaho, Oregon and Washington, while Alaska is considered in the third section. Each area has specific environmental, social and economic factors that must be considered separately in energy planning.

Major shifts in the region's energy use pattern are expected as generation changes from hydroelectric to thermal. The fourth section addresses this issue. Utility projections for the Pacific Northwest are provided for current planning horizons. Electrical demand and coal-fired electrical generation are analyzed for comparison with the given scenarios.

Although designated as Federal Region Ten, the four states are not contiguous: Alaska is separated by climate, physical features, population density, distance, and other factors. The region is markedly different from others in the United States. Except for hydropower, Idaho, Oregon and Washington are not blessed with significant resources, yet they house significant industrial and large agricultural economies. Alaska, however, is endowed with vast resources in the initial stages of development. These contrasting features unify the region through future energy and economic interdependencies.

The geography and topography of Federal Region Ten influence the accessibility of its energy resources. The region is large--Alaska, Idaho, Oregon and Washington cover more than 835,000 square miles, nearly one-quarter of the total United States. The four-state region had an estimated 1975 population of more than 7 million, about half in Washington. Oregon is the next most populous state, followed by Idaho and Alaska. The entire region contains less than 4% of the national population. During the period from 1970 to 1975 the population in the Pacific Northwest region generally grew at a rate significantly above the national average. While the nation grew 5.1% during the period, these states had population increases of: Alaska, 20.8%; Idaho, 14.9%; Oregon, 9.5%; Washington, 4.5%.[1]

Regional employment projections expect nearly 3.2 million workers by 1980, up from the current level of 2.8 million. The largest increase in workers is expected in government--

more than 19% between 1974 and 1980. Commerce and trade are expected to increase more than 18% during the same time. Energy-intensive industries, such as transportation, utilities, paper and pulp, primary metals, food processing, and petroleum refining also expect significant gains in the next 10 years. Meeting the energy requirements of this expected growth entails significant energy planning.

Alaska has the greatest potential as a supplier for the region's needed energy resources. It contains all regional reserves of oil and natural gas and most of the coal. Washington contains some coal and most of the region's known uranium reserves. Alaska is predicted to contain significant uranium resources, but it has not been extensively explored. All four states have one important energy source--hydropower. Alaska has the largest share of untapped hydroelectric potential. The three Pacific Northwest states have already developed most of their sites that have hydroelectric potential.

A.1 PRESENT PATTERNS IN IDAHO, OREGON AND WASHINGTON

Idaho, Oregon and Washington have five distinct topographical areas: 1) coastal lowlands and mountains along the Oregon-Washington coast, including Washington's rugged Olympic Mountains, 2) the Willamette Valley in Oregon and the lowlands of Puget Sound in Washington, the region's most densely populated area containing about 4 million people, 3) the Cascade Mountains of Oregon and Washington, supporting a large wood products industry, recreation and orchards on the lower slopes, 4) a broad basin-plains area through eastern Oregon and Washington and southern Idaho, best known for agriculture and the food products industry, and 5) the Rocky Mountains in extreme northeastern Washington and central Idaho. This area's economy is based on mining, logging and tourism.

A.1.1 Hydro Predominance

Currently the Pacific Northwest has a total of 160 hydroelectric projects consisting of federal, private and public utility installations. Federal hydroelectric power development began in the 1930s with the construction of Bonneville Dam near Portland, Oregon by the U.S. Army Corps of Engineers. During the same period the Bureau of Reclamation, Department of the Interior, undertook construction of Grand Coulee Dam on the Columbia in northeast Washington. By January 1, 1976 the federal system had 29 hydroelectric facilities on line with a total installed capacity of 12,500 MWe, providing more than half the power generated in the three state region.[2] Municipal and publicly owned hydroelectric facilities accounted for 7367 MWe and privately owned hydroelectric facilities accounted for 2744 MWe.[3]

The development of electric power began in the Pacific Northwest before 1900. Both public and private utilities contributed to the development of electric generating capacity and transmission and distribution facilities. Small investor-owned utilities were established to meet the needs of local communities. These utilities eventually developed into the seven large investor-owned utilities that currently operate in the Pacific Northwest.

The first large municipal utility was established in Tacoma around 1900. Electric cooperatives were also established in the region early in the century but only began their rapid growth after the Rural Electrification Administration was formed in 1935. Public Utility Districts were established in the Pacific Northwest after the Bonneville Project Act of 1937 was

passed. The Bonneville Power Administration (BPA) was created to be the marketing agent for the power produced from federal dams in the Pacific Northwest. BPA also manages the development of the regional power transmission network. Currently, the transmission system consists of more than 12,000 circuit miles, acting as a common carrier for all Northwest utilities. Besides enhancing reliability of the overall power system, the transmission grid has enabled coordinated regulation of hydro facilities.

Throughout the history of electric power development in the Pacific Northwest, hydroelectric generation has contributed the majority of the generating capacity. Before the construction of the large federal hydro projects, small privately owned hydroelectric facilities accounted for nearly 70% of the installed generating capacity.

In 1964, Congress approved construction funding for the Pacific Northwest-Pacific Southwest Intertie. The intertie benefits both regions, including power exchanges that reduce the need for investment in each region to meet growing loads. It also provides for reciprocal exchanges of energy during shortages or emergencies. For example, from July through November, 1973 adverse water conditions occurred in the Northwest and approximately 1 billion kWh of electric power were dispatched to the Northwest by Southwest utilities. In 1974, approximately 10 billion kWh of surplus hydroelectric energy were shipped to the Southwest.

Interties also exist between BPA and British Columbia Hydro in Canada. These lines provide the means for sales and exchange of power between the power systems in both countries. They also increase the reliability of the power systems during system emergencies.

To meet the growing needs of the region, the Hydro-Thermal Power Program was established in the late 1960s. This long-term plan, developed by the region's utilities and power agencies, was designed to meet the needs of the Pacific Northwest into the 1980s. The Hydro-Thermal Power Program envisions construction of large thermal plants to meet increasing baseload needs; existing hydroelectric facilities will be expanded to provide peaking power. The new thermal facilities are being constructed by the regional utilities while the hydro peaking and high-voltage transmission facilities are being developed by the federal government.[4]

Since nearly all of the most productive hydro sites have been developed, and those not developed are subject to increasing social pressure by conservationists, the potential for adding firm energy from hydro is limited. For the foreseeable future, large thermal facilities, either nuclear or coal-fired, will be the most feasible means of adding generating capacity in the Pacific Northwest.

The utility network which effectively covers Federal Region Ten is the West Group Area of the Northwest Power Pool. Shown in Figure A.1, it covers the states of Washington, Oregon, and Idaho and a small portion of Montana west of the Continental Divide. The West Group Area systems include Bonneville Power Administration, Pacific Power and Light Company, Portland General Electric Company, Puget Sound Power and Light Company, Washington Water Power Company and 115 public agency customers of BPA.[5]

Since the West Group does much of the planning for the three contiguous states, frequent references will be made in this appendix to their projections. The reader should keep in mind that these references will exclude the portion of Idaho serviced by Idaho Power Company and include a small portion of Montana west of the Continental Divide.

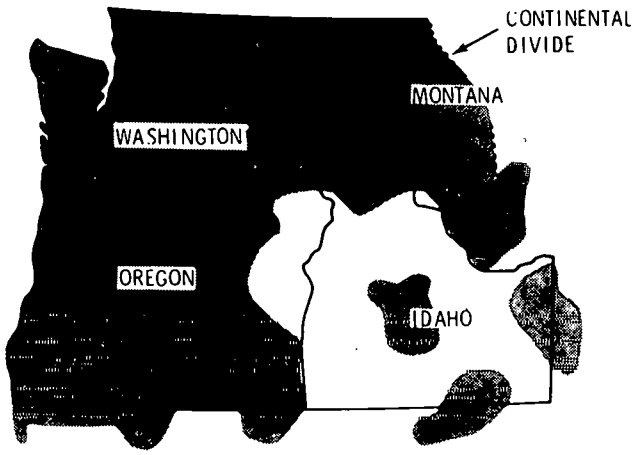

FIGURE A.1. West Group Area of the Northwest Power Pool

A.1.2 Current Generation Mix

In addressing current 1975 generation mix, two concepts, energy and peak capability, need to be clarified.

- Energy capability - the rating given by a manufacturer at which the equipment can operate continuously. Here the capacity ratings are adjusted for scheduled maintenance, hydro-realization factor, etc., to assess the system's potential.
- Peak capability - the capacity at which the equipment may be run for short periods. Capacities given in this discussion are usually peak capability.

The Edison Electric Institute lists the four states as containing 26,803 MWe of capacity at the onset of 1975, distributed as follows:

Washington	16,056 MWe
Oregon	7,643 MWe
Idaho	1,700 MWe
Alaska	604 MWe

In assessing generating capacity for the region, it is important to account for power supplied from outside the region. Some dams and coal-fired plants in the West Group System are located in Montana and Wyoming.[a] The total electrical generating capacity of the region, about 27,000 MWe, is taken from the West Group analysis plus the Idaho Power Company with the following generating mix:

Hydro	22,306 MWe
Nuclear	2,016 MWe
Coal[a]	2,509 MWe
Oil and Gas	652 MWe
	27,483 MWe

(a) Includes Jim Bridger No. 1 in Wyoming and 179 MWe as the region's share of Colstrip No. 1 in Montana.

Beyond hydroelectric, the Northwest region also contains other potential energy sources--geothermal, wind, solar, wood and organic waste. These sources have a large energy potential but will not be tapped until economics and technology make them feasible. Geothermal energy is available in each of the states. It is being used for heating in Klamath Falls, Oregon and Boise, idaho. The region also has several geothermal pilot demonstration projects.

A.1.3 Natural Gas Supplies

Natural gas and petroleum are the two major fuels consumed in the Pacific Northwest. Neither is produced in the region. At present, the supply of natural gas presents some problems; much of the supply is Canadian import (Alberta or British Columbia). Table A.1 summarizes the proven reserves of natural gas in the Northwest and surrounding environs.

The three-state area is served with pipelines operated by the Northwest Pipeline Corporation and distributed by six gas utilities. Northwest Pipeline system's main pipeline can carry as much as 1.45 billion ft^3(BCF) per day. The six utilities handling natural gas in the region are: California-Pacific Utilities, serving Oregon; Cascade Natural Gas Corporation and Northwest Natural Gas Company, serving Washington and Oregon; Intermountain Gas Company, serving Idaho; Washington Natural Gas Company, serving Washington; and Washington Water Power Company, serving Idaho and Washington. The region has natural gas storage facilities: a liquefying facility and storage tank in southwest Idaho; a storage facility near Portland, Oregon; two underground facilities near Chehalis, Washington and a liquefied natural gas facility at Plymouth, Washington.

Figure A.2 illustrates the flows and consumption patterns in these states during 1975. A total of 743 BCF were imported (86% from Canada) and 404 BCF flowed through to Northern California. Net consumption within the three states was 339 BCF or approximately 3.3×10^{14} Btu. This compares to the approximately 3.6×10^{14} Btu of electrical energy consumed in the three states.

TABLE A.1. Proved Reserves of Natural Gas in Western Areas, December 31, 1974 (in trillions of cubic feet)

	Nonassociated	Associated-Dissolved	Underground Storage	Total[a]
Washington	--	--	0.017	0.017
Colorado	1.61	0.25	0.024	1.88
Montana	0.68	0.08	0.143	0.90
New Mexico	9.48	2.43	0.026	11.94
Utah	0.55	0.47	0.003	1.03
Wyoming	3.24	0.62	0.053	3.92
Alberta	34.13	7.56	0.020	41.7
British Columbia	8.29	0.34	--	8.63

(a) Totals may not add due to independent rounding.

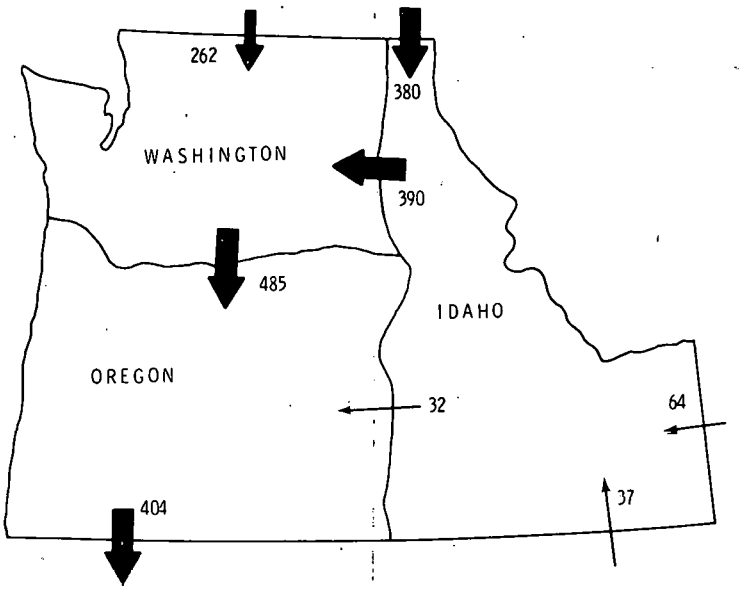

FIGURE A.2. Natural Gas Flow and Consumption (BCF) in the Northwest States - 1975

The current heavy dependence upon Canadian supplies has raised some concerns because contracted amounts have not been met in recent years; the Canadian government policy is to export only amounts that are in excess of Canadian needs, and the demands of Canada have been increasing.

Canadian imports are purchased under two long-term contracts with the West Coast Transmission Company Ltd. (WESCO). The main contract calls for delivery at Sumas, Washington of 809 million ft^3 (MMCF) per day. This contract expires in 1989. Due in part to field operating difficulties, actual deliveries have been running somewhat less than contract deliveries. As of January 1, 1977 the price of Canadian natural gas at the United States border was raised to $1.94 per MMCF (from $1.60 before September 1976). The value of new gas in Canada has been set at $2.10 by the National Energy Board of Canada, i.e., on an energy par with $13 per barrel oil.

Table A.2 summarizes historical natural gas consumption for the three Pacific Northwest states since 1960. Total consumption has generally leveled out since 1972 primarily due to shortages and consequent limitation on new hookups, particularly in the industrial sector. Consumption for the three contiguous states in 1975 was 316,641 MMCF.

TABLE A.2. Idaho, Oregon, and Washington Natural Gas Consumption (in millions of cubic feet)

	Residential	Commercial	Industrial	Electric	Other	Regional Total
1975	77,187	59,051	179,372	21	1,010	316,641
1970	59,382	34,481	179,616	1,010	1,220	275,709
1965	33,137	21,312	143,500	113	--	198,062
1960	16,969	12,377	88,455	700	--	118,501

Natural gas supplies over the next 20 years depend upon a number of factors, as follows:

- Alaskan Natural Gas Delivery System

  Selection of the overland (Alcan) delivery system for North Slope natural gas to the lower 48 states was made in 1977. Total flow from Alaska will be approximately 2.0 BCF per day. It is currently planned that a portion (80%) will be routed eastward and a portion will tie into the existing West Coast transmission systems.

- Canadian Development

  Exploration in British Columbia and Alberta is accelerating under revised Canadian pricing policies. The potential for extremely large gas reserves in the Alberta sandstones has recently been announced. Depending on the outcome of the exploration and development efforts and on Canadian export policies, continued gas supplies could be available past the expiration dates of current contracts.

- Alternative Alaskan Gas Supplies

  Exploration is currently underway on the North Slope offshore in the eastern Gulf of Alaska and is expected to begin early in 1978 in Lower Cook Inlet. Both associated and nonassociated gas are expected to be discovered and produced. Gas from these regions would be available to the lower 48 states via liquefied natural gas (LNG) carriers to the West Coast. Additional gas and oil resources have been discovered in the Flaxman Island-Point Thompson area and off the McKenzie Delta. Commercial potential of these areas has not been determined.

Given the above factors and the estimated costs of delivery (city-gate prices) of natural gas competitive with No. 2 fuel oil, it appears that natural gas supply to the region is assured at least until 2000. The market potential for high Btu synthetic natural gas from coal is not foreseen unless its costs can be reduced to below $3.18 per MBtu.

A.1.4 Petroleum

Petroleum production in the United States peaked in 1970 at 3.5 billion barrels per year, then declined to about three billion barrels in 1975. Completion of the Alaska pipeline is expected to boost regional petroleum supplies significantly.

Pacific Northwest petroleum facilities include refineries and pipeline or tanker transportation for crude and refined oil products. Washington's Puget Sound area receives crude oil by tankers. It is also supplied by Canadian pipeline from Edmonton, Alberta, via a tank farm and terminal at Burnaby, B.C. The United States' share of this pipeline capacity can carry 300,000 barrels of crude oil a day, but Washington refineries actually received only 179,000 barrels a day in 1975. Alaska, Oregon and Washington contain the region's refineries for converting crude oil into finished petroleum products. Total current capacity of these facilities is 449,000 barrels a day. The fact that the region's refining capacity for oil and pipeline capacity for both oil and gas are not fully utilized illustrates the region's dependence on Canadian imports. Part of this capacity will be available for future Alaskan supplies as import contracts expire.

Regional petroleum consumption is illustrated in Figure A.3.

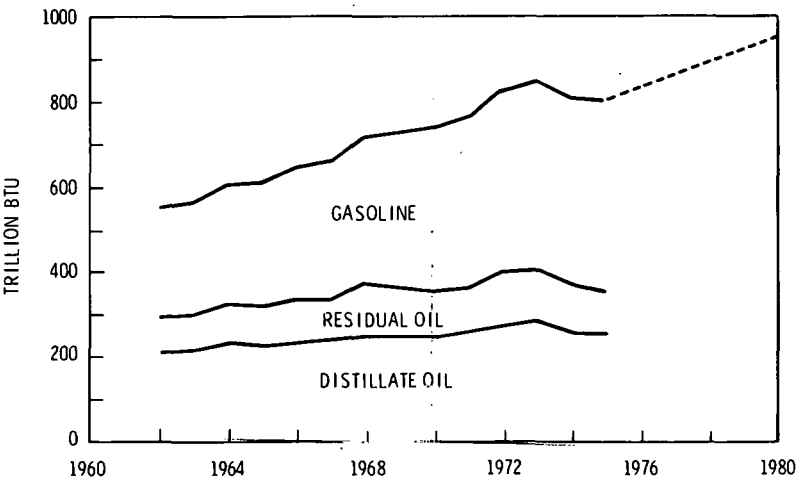

FIGURE A.3. Regional Petroleum Consumption

In 1975, Washington consumed 16.7 million barrels of distillate oil, Oregon 13.2 million barrels, Idaho 7.4 million barrels, and Alaska 7.0 million barrels. All states except Washington have slightly increased consumption each year since 1960; Washington's consumption has remained basically stable. Regional distillate oil consumption peaked at 48.8 million barrels in 1973, then fell to 44.3 million barrels in 1975. The region accounted for over 4% of total U.S. distillate oil consumption in 1975.

Regional residual oil consumption totaled 14.7 million barrels in 1975, with Washington consuming 8.6 million barrels, Oregon 4.4 million, Alaska 1.1 million, and Idaho just over 700,000 barrels. The region accounted for 1.6% of all U.S. residual oil consumption.

Nationally, gasoline use hit a peak of 104.5 billion gallons in 1973, fell almost 3% in 1974, then rose to 104.3 billion gallons in 1975. That 1974 dip ended a steady 4.7% annual growth from 1962.

The region used 3.6 billion gallons of gasoline in 1975. More than 47% of that was used in Washington. Oregon used nearly 34% of the region's total, Idaho more than 13%, and Alaska just over 5%[6] The total is approximately 3-1/2% of the nation's gasoline consumption.

A.1.5 Coal Supply

Idaho and Oregon do not contain large, economically recoverable reserves of coal. Only Washington has substantial reserves; it is currently producing significant quantities (3.74 million tons in 1975) in Lewis County, supporting the 1300 MW Centralia station. Although other reserves exist in Washington, the steep dipping of the seams would result in high mining costs.

Major sources of coal for future imports to the three-state region include Alaska, British Columbia, Montana, Utah and Wyoming. The region is served by two primary coal-hauling railroads: Union Pacific from southern Wyoming and Burlington Northern from Montana. Gulf Interstate has proposed a slurry pipeline from Wyoming through southern Idaho to eastern Oregon. Alaskan coal could be shipped to coastal sites via bulk carriers. Coal in Montana is most likely to come from Rosebud County, and in Wyoming from Campbell, Converse, Lincoln and Sweetwater Counties.

The economics of coal supply for a coal importing region are complex; transportation costs are a major component. Further, the transportation system cost includes both capital charges not subject to escalation and operating costs that will be subject to escalation. The relative exposure to inflation, coupled with the cost of capital needed to finance the system, will influence the selection of transportation mode along with the actual mine supply source. Public utilities that can rely on bond funds for expenses may tend to favor capital intensive systems and invest in at least portions of the transportation system (for example, railroad rolling stock or bulk carriers). Private utilities that must finance capital expenses at higher cost may take an entirely different approach.

Examples of delivered coal costs are:

Wyoming Coal

Cost Components:	$/ton	$/MMBtu
FOB mine	6.91	0.38
Transportation to Boardman, Oregon	14.18	0.78
Total	21.09	1.16

The above costs are for an existing coal supply contract and include a $0.0123/ton mile transportation cost that may not be representative of future cost contracts; these may approach the $0.008/ton mile representative of unit train costs for transport eastward from Montana and Wyoming. Assuming a 60% plant factor, a 9000 Btu/kWh heat rate, and 9000 Btu/lb heating value, the above translates to approximately 2.62 MMTPY for every 1000 MWe of electrical generating capacity. Assuming 100 car unit trains, this is equivalent to 250 trains (one way) per year, or 357 trains per year if 70 car unit trains are used.

Alaskan Coal

Cost components: (Coal barged as slurry)[7]	$/ton	$/MMBtu
FOB mine	6.40	0.40
Preparation	3.47	0.22
Transportation to Washington Coast	10.19	0.64
Dewatering	1.10	0.07
Total	21.15	1.32

Again, assuming a 60% plant factor and a 9000 Btu/kWh heat rate with a 7500 Btu/lb heating value, the above translates to 3.15 MMTPY, and for 100,000 DWT bulk carriers with 65% solids, 48 trips per year. A second estimate of Beluga coal mining costs suggests a mine-mouth cost of $5.36/ton or delivered by rail at tidewater on Cook Inlet at $8.47/ton ($0.56/MMBtu) for a 4 MMTPY operation.[8] These costs, however, do not include the development of supporting infrastructure. Costs of shipping to the Northwest coast of the continental United States would be at least $6.00 per ton. The Placer Amex Company, holder of major leases, has indicated mine-mouth costs as high as $1.00/MMBtu FOB mine at an annual production rate of 6 million tons.

It appears, then, that Alaskan coal may be competitive on the Northwest coast, assuming a large mine is opened. Since such a mine would be in frontier territory with little supporting structure, and experience in such an operation is lacking, further evaluation of its competitiveness is needed.

A.2 ALASKA

Alaska differs markedly from the contiguous states in almost all respects, having both its special problems and its special opportunities. Alaska has the least population of any state (∿400,000), and by far the largest land area. It ranks at the top in terms of fossil energy reserves and resources. The state has a history of successive booms--the Gold Rush, World War II, and the near explosive growth associated with the North Slope oil development and the construction of the TransAlaska Pipeline.

Alaska is also heterogeneous in terms of economic activity, climate, population and energy resources or supplies. Southeastern Alaska is best characterized by industries centered on forest products and fishing, high precipitation, small isolated communities linked only by air and marine transportation, and large dependence on imported domestic oil and hydroelectric energy. With the exception of hydropower, no significant energy sources exist in this part of the state.

Southcentral Alaska contains the major population center, Anchorage (∿200,000); the major trade, transportation and service industries in the state; the major port facilities; and a sizeable energy-related industrial base associated with the Cook Inlet oil and gas reserves. The relatively cold climate is modified by marine influences. Natural gas is the major energy source for both direct heating and for electric power generation. Besides the significant oil and gas reserves, very large surface mineable (>2.25 billion tons) reserves of subbituminous coal are available; however, they are largely unused. An additional trillion tons of coal is believed present under Cook Inlet but is not recoverable by traditional mining methods.

Central Alaska contains the second largest city in the state, Fairbanks, with economic activity centered in the service industries. Fairbanks is linked by rail and highway to Anchorage, the port of Whittier in the Southcentral Region, and via the Alaska Highway to the "lower 48", and hence serves as the distribution center for interior and northern Alaska. The climate exhibits wide seasonal variations. Surface mineable coal reserves exist and provide (∿700,000 tons/year) the major electric power generation base for the Fairbanks-McKinley Park region. Fairbanks is subject to atmospheric inversions with occasionally severe air pollution due to ice fog and windblown glacial silt in the winter months.

The remainder of the state is best characterized by small (population 100 to 4000), generally isolated communities dependent upon oil-based energy, often at very high costs due to the severe logistics problems. Some communities receive their oil supplies only once a year via river barges or coastal tankers.

Presently, no significant electric power interties exist between load centers. In the future an intertie between the two major load centers, Anchorage and Fairbanks, may be justifiable along the existing Railbelt Corridor. This will be particularly true if construction

of hydroelectric capacity proceeds on the Upper Susitna River, as is now being considered. The latter could provide up to 1552 MWe of capacity and 6.8 x 10^9 kWh of average annual energy located about midway between the load centers.

A.2.1 Electrical Energy Demand and Generating Capacity

The historical growth in electric power generation in Alaska is illustrated in Figure A.4. The two most rapidly growing regions are the Southcentral (primarily the Anchorage-Kenai Peninsula area) and to a lesser extent, the Yukon (interior) region with the Fairbanks load center. Both regions have been heavily impacted by the North Slope oil field and piepline developments. The compound energy growth rate for 1960 through 1976 has been 11.4, 12.6, and 11.5% per year for Interior and Southcentral regions and for Alaska as a whole, respectively. For the period 1970 to 1975, the time of significant petroleum development, the growth for the whole state was 12.2% per year.

The historic distribution of installed capacity between energy sources is shown in Figure A.5. When natural gas production began in the Cook Inlet region in the early 1960s, natural gas-fired turbines started providing an increasing share of capacity, principally in the Southcentral region. The natural gas was available at extremely low cost ($0.16 per MMCF) and was regarded almost as a nuisance by the producers. More recently, competing demands for export (by LNG to Japan) and for agrichemicals (ammonia and urea) have resulted in greatly increased value of the gas. Although low cost, long-term contracts continue, new gas prices are much higher ($0.65-0.85 per MMCF) but are less than those in the "lower 48".

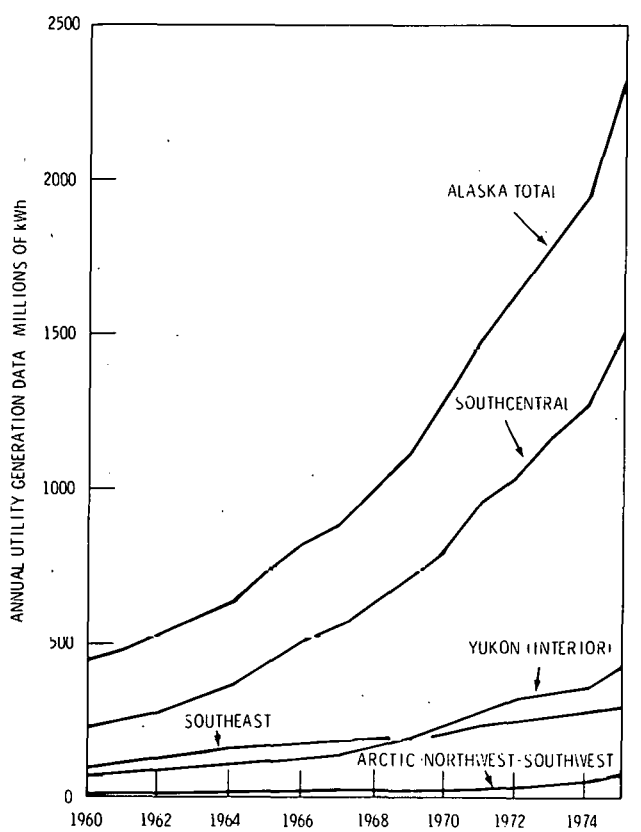

FIGURE A.4. Alaska Annual Utility Generation Data

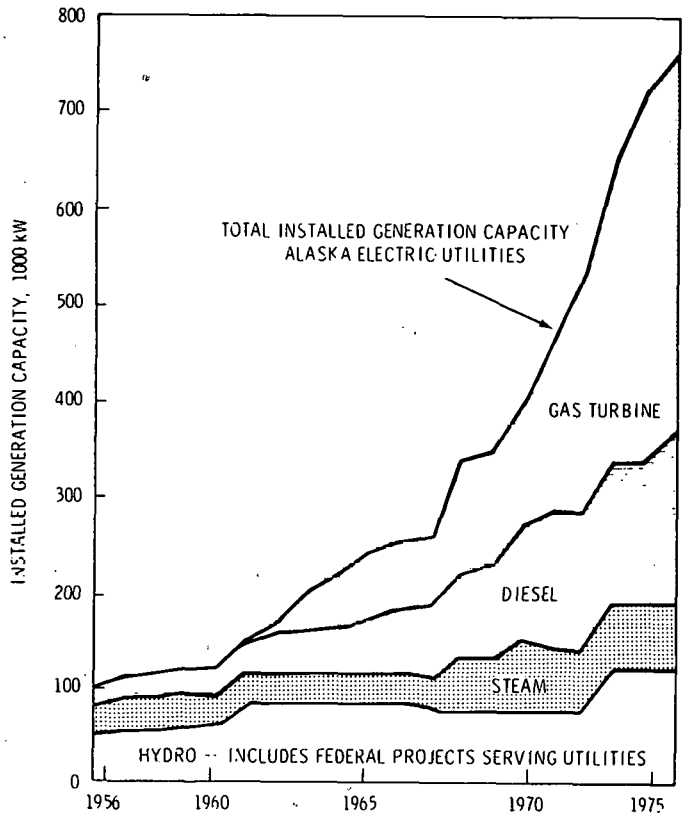

FIGURE A.5. Alaska Installed Generating Capacity

A.2.2 Oil and Natural Gas Situation[9]

Natural gas from Cook Inlet plays a major role in Alaska's energy balance for nontransportation uses. The more populated Cook Inlet Region is highly dependent upon this source. In 1975, production was 255 trillion Btu, consumed in the following ways: export LNG, ammonia and urea--88.7 trillion Btu or 30.8%; reinjection for oil field pressure maintenance--95.2 trillion Btu or 33.1%; electrical generation--48.4 trillion Btu or 16.8%; residential and commercial--10.6 trillion Btu or 3.7%; and industrial and military--44.7 trillion Btu, or 15.5%. The fact that natural gas provides about 53% of the state's electric power generation and almost all of that associated with the Cook Inlet region is significant. Implementation of the National Energy Plan could cause a rapid change in the use pattern with coal substituted for gas in electrical generation.

Several areas of Alaska are excellent speculative prospects for natural gas (see page A.7). However, the Cook Inlet region is the only current major producer. The estimated undiscovered reserves in the region, according to USGS (Cir. 725, 44.8 TCF) and the State of Alaska (OFR.50, 84.79 TCF), are 76.5 TCF and 428.9 TCF, respectively.

In 1975 the Cook Inlet region produced about 154 BCF of natural gas, 69 BCF of which were for in-state use not related to export. Forecasts for subsequent year's demands are as follows:

	Billions of Cubic Feet (BCF)				
	1980	1985	1990	1995	2000
In-state use	104	139	154	168	185
Export	106	266	278	302	310
Total	210	405	432	470	495

The above forecast assumes that beyond 1983 no further gas turbine-fired electric power generation capacity is added. All future electrical load growths are accommodated by coal or hydroelectric power. Based on the forecasted demand and the currently known status of natural gas reserves in Cook Inlet, the following dates are significant:

1987 - Currently committed reserves are exhausted.

1993 - Known reserves in currently producing Cook Inlet fields are exhausted.

1995 - Total estimated Cook Inlet reserves are exhausted; beyond this date, dependence is upon resources yet to be discovered.

Natural gas will become available from the North Slope in the mid-1980s. The known recoverable reserve in the North Slope Sadlerochit formation is estimated at 26 TCF, over 11% of the total known U.S. reserves. Production of the reserve will likely begin in 1983-84 at a rate of 2 BCF per day and possibly as high as 2.5 BCF per day. For comparison, the total 1975 Cook Inlet net production was about 440 MMCF per day. The energy content of the known North Slope natural gas is about 50% of that associated with the North Slope oil reserve.

Crude oil has been produced in Alaska on- and off-shore in the Cook Inlet Basin since 1958, and production peaked in 1970 at about 230,000 barrels per day.(10) Production in 1976 averaged 183,000 barrels per day.(11) Of the oil produced, a net of about 70% is exported to the "lower 48".

The Prudhoe Bay oil field started producing at 600,000 barrels per day in mid-1977 and will increase to 1.2 million barrels per day in the near future. Ultimate production of this field will be at about two million barrels per day. Total known recoverable reserves are 9.6 trillion barrels, with expectations of additional reserves yet to be discovered primarily off-shore in the Beaufort Sea and from different strata (Kuparuk River, Lisburne formations), in the Prudhoe structure.

Additional oil and gas development activity is expected in the state. A lease sale for Lower Cook Inlet was held in October 1977 with 87 bids accepted. Exploration is underway on National Petroleum Reserve-A (formerly Naval Petroleum Reserve No. 4) on the western North Slope. Exploratory drilling is also occurring in the interior Kandic Basin and off-shore in the eastern Gulf of Alaska.

A.2.3 Coal

Only one coal mine (Usibelli Coal Company) is now active in Alaska. The mine, located near Healy in the Nenana Coal Field, produces approximately 700,000 tons/year for utilities and military power production in the Fairbanks area. The coal is subbituminous with the following properties:(12)

Heating value	8500-8700 Btu/lb
Sulfur	0.2%
Ash	11-15%
Moisture	20-25%

The 1977 mine-mouth price of coal from the Usibelli mine is about $0.65 MMBtu or about $11/ton.

The Usibelli lease has estimated reserves of 450 to 500 million tons with dipping beds that range from 30 to 50 ft thick. The mining method is open-pit and 75 to 80% of the coal is shipped to Fairbanks via the Alaska Railroad. The remainder is consumed by the Golden Valley Electric Cooperative plant, located eight miles from the mine.

A successful reclamation program has been conducted since 1972, involving aerial reseeding of mined lands with grasses and legumes. The resulting vegetation attracted a herd of Dall's sheep, and the mine and surrounding area have been declared a state game preserve, partially to avoid hunter interference with the mining operation.

Major coal resources have at least a dozen locations in the state. Table A.3 summarizes Alaskan coal resource data as of 1975.[13] Although the largest coal resources are located north of the Brooks range, they are essentially inaccessible. Other coal deposits of interest are the Matanuska Region bituminous coal resources at 10,400 to 14,400 Btu/lb, 0.2 to 1.0% sulfur and the subbituminous Beluga coal at 7500 Btu/lb and 0.15% sulfur.

The Beluga coals in the Susitna region are interesting due to their location near tidewater on the west side of Cook Inlet and very low sulfur content. However, no development to date has occurred. The resource is significant--2.4 billion tons demonstrated or indicated. The Beluga coals are subbituminous, "C" in rank, with the following average quality:[7]

	As Received
Moisture	20-24%
Ash	9-18%
Volatile material	32
Carbon	30
Sulfur	0.15-0.175%
Btu/lb	7,500

One of the promising areas, located 15 miles from tanker loading point has six beds, up to 40 ft thick with an average overburden ratio of 3:1. Mining costs have been estimated at $6.40 per ton on a clean, dry basis. The coal would be prepared at mine-mouth and delivered as a slurry to the tanker loading point. Delivered cost to Northwest ports would be about $21.15 per ton, or $1.32/MMBtu (1975 dollars)[7] at a production level of 8.76 million tons per year. A new community for a 250 man labor force would be required.[14]

A similar study of Beluga coals by Stanford Research Institute involving dry shipment (rather than a slurry) suggests a cost of $0.82 to $1.00/MMBtu landed in California at a higher level of production.

TABLE A.3. Estimate of Remaining Alaska Coal Resources
July, 1977 (millions of short tons)

Region	(1) Measured	(2) Indicated	(3) Demonstrated (1) (2)	(4) Inferred	(5) Total Identified (3) (4)	(6) Hypothetical	(7) Speculative	(8) Total Undiscovered (6) (7)	(9) Total Resources (5) (8)
Arctic	35.0	2,742.4	2,777.4	118,436.1 118,686.1	121,213.5 121,463.5	120,000 2,300,000	100,000 1,050,000	220,000 3,350,000	341,213 3,471,463
Northwest	--	--	--	--	--	--	--	--	--
Interior	861.6	2,700.0	2,023.9 3,566.9[a]	3,383.5	5,407.4 6,950.4	8,897.8	--	8,897.8	14,305 15,848
Southwest	--	--	--	--	--	2,390.0 3,390.0	--	2,390.0 3,390.0	2,390 3,390
Southcentral	6.6	2,770.6	2,811.0 2,811.2[a]	7,852.0 7,878.0	10,663.0 10,719.2	54,759	1,300,000	1,454,759	1,365,422 1,365,478
Southeast	--	--	--	--	--	--	--	--	--
Statewide Totals	903.2	8,213.0	7,6[illegible]2.3 9,185.5	129,671.6 129,947.6	137,283.9 139,133.1	186,046.8 2,367,046.8	1,400,000 2,350,000	1,586,046.8 4,717,046.8	1,723,330 4,856,179

Two numbers in a column indicate a low and high range for the estimate.

(a) Some estimates were made for demonstrated resources only, with no estimate breakdown for measured (Col. 1) or indicated (Col.2). Thus Col. 3 sometimes differs from the sum of Col. 1 and Col. 2.

A.3 MAJOR SHIFTS EXPECTED IN FUTURE ELECTRICAL GENERATION

This section discusses current plans and possible trends for electrical generation in the three contiguous states of the region. Utility projections are provided for the current planning horizon. Forecasts for electrical demand and coal-fired electrical generation are presented. These factors were taken into account where possible in the determination of the region's share of electrical generation for the given national scenario. Computer simulations were also performed for electrical growth to provide a comparison of the national scenarios for time periods beyond utility planning horizons.

A.3.1 Utility Projections and Trends in the Pacific Northwest

Electric power has been an inexpensive source of energy in the states of Idaho, Oregon and Washington, with hydroelectric generation supplying most electrical energy requirements. However, forecasted load growth and the limited number of potential new hydroelectric sites will result in a heavier reliance on thermal generation in the future. The transition from hydroelectric to thermal power generation will cause significant changes in the Northwest. The future path of electric power supply will be largely determined by the demand for electric power, basic energy prices, public policy, and environmental consequences of thermal generation. In view of the coming changes, it is important that the possible electric energy supply alternatives be understood.[15]

Figures A.6 and A.7 show the Edison Electric Institute (EEI) data for the growth of electric consumption in the three contiguous states of the Pacific Northwest. Figure A.6 shows the total growth in consumption and the growth in the three major end use sectors: Residential, Commercial, and Industrial. The "Other" category includes state and local government use. The annual rate of increase of total consumption is also noted on the curve. Figure A.7 illustrates the historical change in percent of consumption for each of the four sectors.

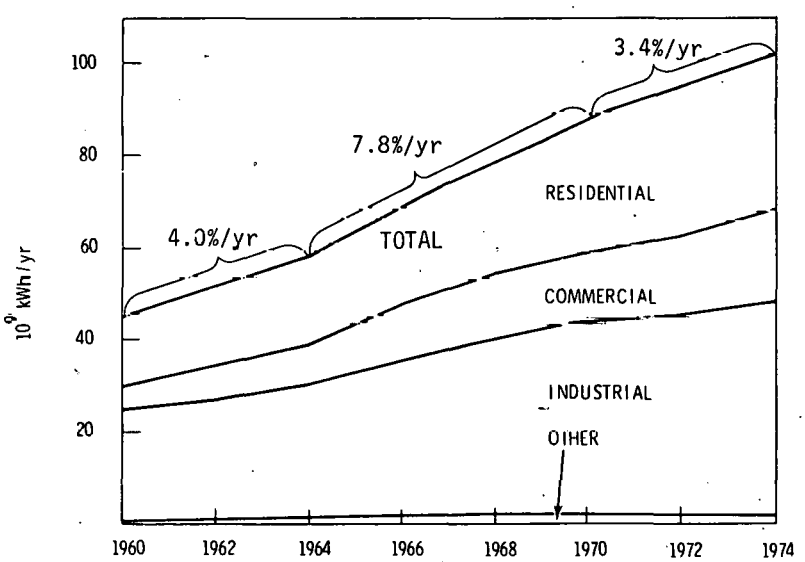

FIGURE A.6. Electrical Consumption[15]

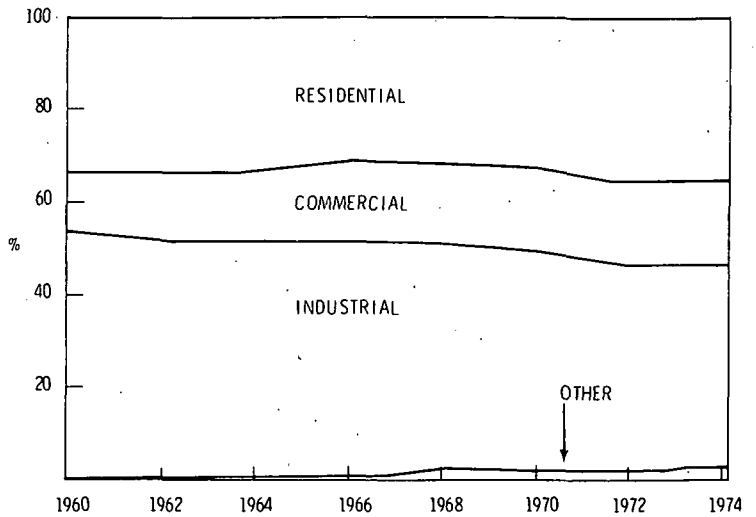

FIGURE A.7. Mix of Electricity Consumption[15]

The availability of low-cost electricity has caused many energy intensive processing plants to locate in the Pacific Northwest. As of January 1976, the Pacific Northwest chemical processing industry included: 5 electrochemical plants for production of chlorine and caustic soda, 24 pulp and paper mills, a glass-making furnace plant, 10 electric furnace plants for production of calcium carbide, elemental phosphorous and silicon, abrasives, refractory metals and ferroalloys. The region also hosts 10 large electrolytic reduction plants; these altogether account for 31% of the total U.S. capacity for aluminum metal.[16]

According to the West Group load forecasts, demand for electricity in the Pacific Northwest will continue to increase through the year 2000. The West Group currently forecasts growth rates of about 4.5%/yr.[5] Other groups, such as the Northwest Energy Policy Project, estimate growth rates ranging from 1.4 to 4.4%.

Table A.4 shows the estimated peak and average electrical loads forecast by the West Group. As indicated previously, thermal facilities will be the most feasible means for generating energy in the Pacific Northwest in the foreseeable future. These thermal plants are most economically operated at high load factors and thus may be operated as baseload plants. Table A.4 also compares loads and resources for meeting base energy demand in the West Group Area through the late 1980s, based on critical hydro conditions.[a]

To meet peaking requirements, generating capacity will have to double over the next 20 years. However, rather than providing baseload capacity, hydrogeneration facilities will increasingly provide peaking power. Planned additions of generators between the present and the mid to late 1980s will make it possible for hydro to carry higher loads during the peak hours of the day.

Table A.5 summarizes resources through 1987 forecasted by the West Group.[5] This table also identifies new baseload hydro and thermal generating capacity expected during the time period.

(a) System planning is based on years with minimum streamflow or "critical hydro" conditions.

TABLE A.4. West Group Forecast - Estimated Loads[5] and Resources, July 1977-June 1988

(Figures are megawatts)	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88
1. Total area peak load (January)	24,020	25,202	26,742	27,963	29,229	30,561	31,815	33,187	34,633	36,128	37,744
2. Total peak resources[a]	28,187	31,589	32,668	34,580	37,325	37,462	39,325	41,861	44,177	46,191	46,847
3. Reserve requirements	(2,882)	(3,276)	(3,744)	(4,194)	(4,677)	(5,195)	(5,727)	(6,306)	(6,927)	(7,226)	(7,549)
4. Peak resources	25,305	28,313	28,924	30,386	32,648	32,267	33,599	35,555	37,250	38,965	39,298
5. Peak surplus (over total load)	1,285	3,111	2,182	2,423	3,419	1,706	1,783	2,368	2,617	2,837	1,554
6. Total July-June energy load	15,545	16,326	17,335	18,178	18,948	19,770	20,565	21,401	22,281	23,183	24,128
7. Total energy resources[a]	15,032	15,489	15,693	16,703	18,126	18,929	19,306	20,700	22,277	23,337	23,414
8. Reserve requirements	(313)	(322)	(330)	(351)	(386)	(368)	(388)	(407)	(421)	(444)	(478)
9. Energy resources	14,719	15,167	15,363	16,352	17,740	18,561	18,918	20,293	21,856	22,893	22,936
10. Energy surplus (over total load)	(826)	(1,159)	(1,972)	(1,826)	(1,208)	(1,209)	(1,647)	(1,108)	(425)	(290)	(1,192)
11. Interruptible load (included in lines 1 and 6) - Peak	1,006	1,066	1,199	1,237	1,195	1,143	1,153	1,164	1,174	1,185	1,195
- Energy	975	1,046	1,149	1,200	1,159	1,108	1,118	1,128	1,138	1,149	1,159
12. Fossil-Thermal & miscellaneous resources (not included above)[b] - Peak	--	--	--	--	--	--	--	--	--	--	--
- Energy	554	611	617	611	611	611	611	611	603	603	603

(a) Resources include hydro; small fossil-fuel plants; Hanford-NPR through June 1983; Centralia; Trojan; Colstrip #1 and #2 (50%), #3 and #4 (70%); WPPSS Nuclear #1, #2, #3, #4, #5; Boardman Coal; Skagit #1 and #2; Pebble Springs #1; and net contractual imports/exports with utilities outside the area. Hanford is not included as a peak resource. Estimated amounts for scheduled maintenance (energy only), hydro realization factor (peak only) and incremental losses have been deducted. All existing thermal units and future thermal units under 500 MW (peak and energy) are included in amounts as submitted by respective project owners. The energy availability of all future thermal units 500 MW or larger has been included as 50% of the first full year and 75% thereafter.

(b) The energy MWs tabulated in line 12 reflect the amounts of energy available from existing fossil and gas turbine installations which may be considered available as reserve energy resources. These amounts are in addition to those included as firm energy resources in line 7.

TABLE A.5. Summary of Resources

Contract Year Energy Capability--MW	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88
1. Columbia mainstem hydro	10,512	10,588	10,593	10,574	10,616	10,615	10,640	10,623	10,594	10,593	10,593
2. Seasonal hydro	1,147	1,148	1,147	1,181	1,181	1,182	1,182	1,182	1,182	1,182	1,182
3. Pondage & minor hydro	319	319	319	319	319	319	319	319	319	319	319
4. Small existing thermal	130	131	131	130	130	130	130	130	128	128	128
5. Miscellaneous (industrial)	9	9	9	9	9	9	9	9	9	9	9
6. Hanford steam[a]	512	515	515	515	515	515	--	--	--	--	--
7. Centralia #1 and #2	919	919	919	919	919	919	919	919	919	919	919
8. Colstrip #1 and #2	274	280	255	293	293	274	280	280	280	280	280
9. Trojan	758	847	847	847	847	847	847	847	847	847	847
10. WNP #2	--	--	55	674	825	825	825	825	825	825	825
11. Boardman coal	--	--	--	191	334	358	358	358	358	358	358
12. Coalstrip #3	--	--	--	122	325	368	368	368	368	368	358
13. WNP #1	--	--	--	--	562	891	938	938	938	938	938
14. Colstrip #4	--	--	--	--	172	337	368	368	368	368	368
15. WNP #4	--	--	--	--	--	188	797	938	938	938	938
16. WNP #3	--	--	--	--	--	0	124	775	930	930	930
17. Skagit #1	--	--	--	--	--	--	--	709	950	966	966
18. Pebble Springs #1	--	--	--	--	--	--	--	--	756	945	945
19. WNP #5	--	--	--	--	--	--	--	0	496	868	930
20. Skagit #2	--	--	--	--	--	--	--	--	--	709	950
21. Exports to East	(210)	(160)	(141)	(162)	(159)	(155)	(157)	(159)	(161)	(163)	(165)
22. Imports from East	814	968	1,118	1,161	1,152	1,058	1,037	949	911	836	790
23. Exports to Pacific Southwest	(496)	(435)	(432)	(429)	(282)	(128)	(40)	(40)	(40)	(40)	(40)
24. Imports from Pacific Southwest	416	429	429	429	429	429	415	415	415	268	90
25. Incremental losses[b]	(25)	(23)	(23)	(23)	(14)	(5)	(3)	(3)	(3)	(3)	(3)
26. Estimated hydro maintenance	(47)	(46)	(48)	(47)	(47)	(47)	(50)	(50)	(50)	(51)	(51)
27. Total energy resources	15,032	15,489	15,693	16,703	18,126	18,929	19,306	20,700	22,277	23,337	23,414
28. Thermal & miscellaneous resources	554	611	617	611	611	611	611	611	603	603	603

(a) Hanford-NPR operation is assumed available through June 1983.
(b) Incremental losses from generator to border associated with deliveries under contracts with Pacific Southwest utilities.

A.3.2 Beyond Current Projections

As indicated in Chapter 3, regional allocations of electrical generation were determined based upon national scenarios provided for this study. To provide a comparative basis for the scenarios, regional projections were considered in the previous section of this appendix. These projections cover the near-term time period (through 1985) of the NCUA. To consider the mid-term period (through 2000), the two scenarios considered in the study were simulated for our region.

The results summarized in this section are not forecasts. They represent, rather, an independent analysis of the Recent Trends and High Coal Electric scenarios. These scenarios were simulated in order to assist in the decomposition and interpretation of the national scenarios at the regional level.

To give a picture of the electric energy system in the Northwest to the year 2000, two models were developed. The first of these models, the ELectric Power Supply Analysis Model (ELSA),[17] is an aggregated policy model of the Pacific Northwest's electricity supply system. The ELSA model is linked with ELDA (ELectricity Demand Analysis model), an econometric model for the demand of electric power. ELDA is an adaptation of a model developed by National Economic Research Associates, Inc.[18]

ELSA allows the analyst to examine the structure of the region's utility industry, to postulate possible scenarios and policy decisions, and to simulate their effect on the cost and availability of power and on the market share of various generating sources. ELSA was adapted from a series of simulation models constructed at Dartmouth College for analyzing the national electric utility industry.[19] Extensive modifications were made in adopting or "regionalizing" the model to reflect the unique characteristics of the Pacific Northwest. Many of these characteristics, such as the historical abundance of inexpensive hydro power and the development and influence of BPA have been discussed previously.

ELDA is an econometric electricity demand model. It uses own- and cross-elasticities of demand along with externally specified rates of growth of key variables, such as the prices of electricity and fossil fuels, population, personal income, and value added to forecast electric consumption.

The combined models can be used to assess the impact on electricity consumption and price of fossil fuels, regional demographic characteristics, and regional incomes as well as plant construction and operating costs, and regulatory policy. The assumptions regarding the future values of some independent variables have considerable impact on the forecast results. The specification of the exogenous variables and the internal characteristics of the models are based on the best available information on these factors.

For the NCUA program, the models have been used to help determine the role of fossil fuels, particularly coal, in the electrical generation system of the region. Two alternative scenarios have been exercised and are referred to as Recent Trends and High Coal. The former is based on an assumption of current economic conditions while the latter assumed accelerated coal development. The two scenarios are derived from the NCUA scenarios described in Chapter 3.

The Recent Trends case approximates the 4.4% load growth forecast developed by the Pacific Northwest Utilities Conference Committeee in an independent manner. The growth of hydroelectric generating capacity is accepted as a "known" for the base case. Both the forecasted load growth and the projected hydroelectric generating capacity were given in Table A.4.

The linked ELSA/ELDA models were used to simulate electric power demand and supply information to the year 2000 for the two coal utilization assessment scenarios. This information is summarized in Tables A.7 through A.12 below.

TABLE A.7. Recent Trend Electricity Demand for the Pacific Northwest Region

(10^9 kWh)

	Washington	Oregon	Idaho	Total
1975	59.7	33.2	13.1	105.9
1980	73.1	41.1	16.2	130.4
1985	85.9	49.5	20.6	155.9
1990	107.3	64.0	28.4	199.7
1995	132.3	81.6	37.8	251.7
2000	154.2	100.7	46.2	301.1
Compound growth rate	3.87%	4.54%	5.17%	4.26%

Table A.7 shows that the assumptions of the Recent Trends case lead to a compound growth rate of total regional electrical demands of 4.25%. Results are shown on the basis of each state and the region as a whole. When the High Coal Electric scenario is assumed, quantities demanded grow at a slightly lower rate of around 4.17% This is shown in Table A.8. The reduced growth rate is the result of model assumptions on energy prices. The High Coal simulation assumed slightly higher coal prices than the Recent Trends case due to decreased competition from alternative thermal generation. Thus, if the policy decision to accelerate coal development increases prices, the model's price elasticities cause a reduced demand.

Note that the rational scenarios, as allocated to our region, assume increased electrical usage for the High Coal Electric scenario. The national scenario allocations, rather than the results given here, are used in the assessment. The differences between the scenarios and simulation results are due to national averages used in the scenarios and the expected lower growth rates in California for the High Coal scenario. Our regional scenarios are based on an allocation of national assumptions with California.

A.3.3 Electrical Capacity Additions

The ELSA model, using demands specified by the ELDA model, translates the demand into the capacity additions necessary to satisfy the demand. First, actual and desired capacity addition rates are determined by the model based on financial constraints. Second, new hydro capacity is developed. In ELSA the hydro capacity initiation rate is exogenously specified to match historical behavior and announced future plans. The remainder of new capacity will be thermal-generated. Fossil fuels compete with nuclear fission for shares of this new capacity.

TABLE A.8. High Coal Electricity Demand for Pacific Northwest Region

(10^9 kWh)

	Washington	Oregon	Idaho	Total
1975	59.7	33.2	13.1	105.9
1980	72.9	41.1	16.2	130.2
1985	85.3	49.1	20.4	154.9
1990	104.9	62.5	27.6	195.0
1995	126.3	78.6	35.6	240.5
2000	149.2	98.9	44.4	292.5
Compound growth rate	3.72%	4.46%	5.00%	4.17%

The results shown below are based on the West Group area shown in Figure A.1, and Idaho Power Company. Demanded quantities of electricity given in Tables A.7 and A.8 were based on Washington, Oregon and Idaho. Table A.9 shows the average delivered price of electricity for the Recent Trends and High Coal cases, assuming average streamflow conditions. The prices for the High Coal scenario are essentially shifted up by a fixed increment because of the reliance on the more expensive coal.

TABLE A.9. Price of Electricity (mills/kWh, 1975 dollars)

	Recent Trends	High Coal
1975	11.3	11.3
1980	13.8	13.9
1985	15.4	16.0
1990	16.5	17.8
1995	19.1	21.5
2000	22.9	26.3
Compound growth rate	2.9%	3.4%

The relationship between demand and generation is exhibited by comparing Tables A.7, A.8, and A.9. In response to the High Coal scenario, which assumes higher coal prices, the electricity prices increase at a slightly faster rate. It is the higher electricity price, brought about by assumed higher coal prices, that causes the quantity demanded to decline (relative to the Recent Trends scenario) as shown in Table A.8.

Total generating capacity is given in Table A.10. Table A.11 shows simulated coal-fired generating capacity through the year 2000 for the Recent Trend and High Coal cases. A third table, Table A.12, gives the hydroelectric generating capacity for the same time horizon. In comparing the three tables, hydroelectric generating capacity continues to dominate in the region throughout the period being considered. As seen in Table A.15, the hydro phase of energy production is markedly less. As mentioned previously, hydroelectric capacity is the main reason for the current low cost of electricity in the Pacific Northwest.

TABLE A.10. Total Generating Capacity (10^3 MWe)

	Recent Trends	High Coal
1975	26.0	26.0
1980	32.7	32.7
1985	37.3	37.4
1990	38.6	38.8
1995	46.7	46.4
2000	64.7	60.4
Compound growth rate	3.7%	3.4%

TABLE A.11. Coal-Fired Generating Capacity (10^3 MWe)

	Recent Trends	High Coal
1975	1.54	1.54
1980	3.07	3.07
1985	3.41	3.67
1990	3.98	5.17
1995	6.86	11.09
2000	12.58	21.82
Compound growth rate	8.8%	11.2%

TABLE A.12. Hydroelectric Generating Capacity (10^3 MWe)

	Recent Trends	High Coal
1975	24.13	24.13
1980	29.19	29.19
1985	33.20	33.20
1990	32.77	32.77
1995	32.68	32.68
2000	32.79	32.79
Compound growth rate	1.23%	1.23%

The role of the simulation relative to the NCUA was indicated previously. The ELSA/ELDA model has been used and the results presented here to characterize the region's electrical generation system independent of the national scenarios. This information has provided a comparative basis for the disaggregation of the national scenarios to our region. In addition, the three states which primarily comprise the generation system modeled in the simulation have some specific characteristics unlike other regions in the nation. The simulation reflects the expected behavior of the electrical system during the critical years when new capacity is expected to consist of thermal plants.

The ELSA/ELDA model has been found to be useful in forecasting beyond 10 to 12 years of planning by the region's utilities. Although the model results give capacity additions incrementally rather than on a per plant basis, the results have been found to track well historically. For the intermediate to long term, the results presented here can be compared to the national scenarios. One should bear in mind, however, that these results are based on a number of specific assumptions. Complete sensitivity of the model's results to changes in these assumptions has not been fully tested. Also the division of new thermal capacity between coal and nuclear is extremely policy-sensitive and unlikely to be based solely on technical and economic considerations.

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APPENDIX B

SCHEDULES FOR CONSTRUCTION OF COAL-FIRED GENERATING CAPACITY ADDITIONS IN ALASKA, IDAHO, OREGON AND WASHINGTON

TABLE B.1. Coal-Fired Generating Capacity to be Added--
1980-2020 Recent Trends Scenario

Year	1000 MWe Installed Coal Capacity	1000 MWe Capacity Addition	Plant Location (County)
Washington			
1980-1988	1.3	--	Lewis (existing)
1989	1.8	0.5	Lincoln
1989-1991	1.8	--	--
1992	2.3	0.5	Grays Harbor[a]
1993	2.8	0.5	Grays Harbor[a]
1994	3.3	0.5	Grays Harbor[a]
1995	4.3	0.5	Cowlitz[a]
		0.5	Grays Harbor[a]
1996	4.8	0.5	Lincoln
1997	5.8	1.0	Cowlitz[a]
1998	6.8	0.5	Whatcom[a]
		0.5	Lincoln
2000	7.8	1.0	Cowlitz[a]
2002	8.3	0.5	Klickitat
2004	8.8	0.5	Klickitat
2006	9.3	0.5	Grays Harbor[a]
2009	9.8	0.5	Cowlitz[a]
2011	10.3	0.5	Klickitat
2014	10.8	0.5	Klickitat
2015	11.3	0.5	Lincoln
2018	11.8	0.5	Grant
2020	12.3	0.5	Klickitat
Oregon			
1980-1987	0.5	0.5	Morrow
1988	1.0	0.5	Morrow
1992	1.5	0.5	Coos[a]
1994	2.0	0.5	Coos[a]
1995	2.5	0.5	Morrow
1996	3.0	0.5	Coos[a]
1997	3.5	0.5	Coos[a]
1998	4.5	0.5	Morrow
		0.5	Malheur
2000	5.5	1.0	Morrow

(a) Indicates coastal sites that may use Alaskan coal after 1985. Inland sites will most probably use Montana and Wyoming coal. This assumption is based on discussions with Northwest utilities, recent reports and analyses of Beluga (Alaska) coal field mining and transportation economics, and rail transportation costs.

TABLE B.1. (contd)

Year	1000 MWe Installed Coal Capacity	1000 MWe Capacity Addition	Plant Location (County)
Oregon (contd)			
2005	6.0	0.5	Gilliam
2009	6.5	0.5	Gilliam
2012	7.0	0.5	Gilliam
2015	7.5	0.5	Morrow
2018	8.0	0.5	Morrow
Idaho			
1980-1987	0		
1988-1992	0.5	0.5	Elmore
1993	1.0	0.5	Elmore
1996	1.5	0.5	Elmore
1997	2.0	0.5	Bingham
2000	2.5	0.5	Bingham
2007	3.0	0.5	Elmore
2015	3.5	0.5	Bingham
Alaska			
1983	0.1	0.1	Healy
1984	0.3	0.2	Beluga
1986	0.5	0.2	Beluga
2003	0.8	0.3	Nenana
2005	1.3	0.5	Beluga
2007	1.5	0.2	Beluga
2010	2.0	0.5	Beluga
2015	2.5	0.5	Beluga
2020	3.0	0.5	Beluga

TABLE B.2. Coal-Fired Generating Capacity to be Added--
1980-2020 High Coal Electric Scenario

Year	1000 MWe Installed Coal Capacity	1000 MWe Capacity Addition	Plant Location (County)
Washington			
1980-1985	1.3	--	Lewis (existing)
1986	2.8	1.5	Grays Harbor[a]
1987	3.8	0.5	Grays Harbor[a]
		0.5	Lincoln
1988	4.8	0.5	Grays Harbor[a]
		0.5	Cowlitz[a]
1990	5.8	1.0	Cowlitz[a]
1992	6.8	0.5	Cowlitz[a]
		0.5	Lincoln
1993	8.3	0.5	Cowlitz[a]
		0.5	Whatcom[a]
		0.5	Lincoln
1994	9.8	0.5	Whatcom[a]
		0.5	Whatcom[a]
		0.5	Franklin
1995	11.3	0.5	Franklin
		0.5	Whatcom[a]
		0.5	Lincoln
1996	12.8	0.5	Franklin
		0.5	Lincoln
		0.5	Franklin
1997	14.3	1.5	Douglas
1998	15.8	1.5	Grant
2000	17.3	0.5	Douglas
		1.0	Franklin
2002	17.8	0.5	Grays Harbor[a]
2004	18.3	0.5	Cowlitz[a]
2005	19.3	0.5	Klickitat
		0.5	Klickitat
2007	20.3	0.5	Klickitat
		0.5	Klickitat
2009	21.3	0.5	Grant
		0.5	Grant
2011	22.8	0.5	Grant
		0.5	Klickitat
		0.5	Klickitat
2013	23.8	0.5	Douglas
		0.5	Douglas
2015	24.8	0.5	Douglas
		0.5	Klickitat

(a) Indicates coastal sites that may use Alaskan coal after 1985. Inland sites will most probably use Montana and Wyoming coal. This assumption is based on discussions with Northwest utilities, recent reports and analyses of Beluga (Alaska) coal field mining and transportation economics, and rail transportation costs.

TABLE B.2 (contd)

Year	1000 MWe Installed Coal Capacity	1000 MWe Capacity Addition	Plant Location (County)
Washington (contd)			
2016	25.3	0.5	Klickitat
2017	25.8	0.5	Lincoln
2018	26.3	0.5	Lincoln
2019	26.8	0.5	Klickitat
2020	27.3	0.5	Klickitat
Oregon			
1980-1984	0.5	0.5	Morrow
1985	1.0	0.5	Morrow
1986	1.5	0.5	Coos[a]
1987	2.5	1.0	Coos[a]
1988	3.0	0.5	Morrow
1990	3.5	0.5	Coos[a]
1992	4.5	1.0	Morrow
1993	5.0	0.5	Morrow
1994	6.0	1.0	Gilliam
1995	7.0	1.0	Gilliam
1996	8.0	1.0	Clatsop[a]
1998	9.0	0.5 0.5	Clatsop[a] Malheur
1999	10.0	0.5 0.5	Clatsop[a] Gilliam
2000	11.0	0.5 0.5	Gilliam Gilliam
2002	12.0	0.5 0.5	Clatsop[a] Clatsop[a]
2005	12.5	0.5	Coos[a]
2007	13.0	0.5	Sherman
2009	14.0	0.5 0.5	Sherman Sherman
2012	15.0	0.5 0.5	Sherman Malheur
2015	16.0	0.5 0.5	Malheur Malheur
2018	17.0	0.5 0.5	Malheur Sherman
2020	17.5	0.5	Sherman

(a) Indicates coastal sites that may use Alaskan coal after 1985. Inland sites will most probably use Montana and Wyoming coal. This assumption is based on discussions with Northwest utilities, recent reports and analyses of Beluga (Alaska) coal field mining and transportation economics, and rail transportation costs.

TABLE B.2 (contd)

Year	1000 MWe Installed Coal Capacity	1000 MWe Capacity Addition	Plant Location (County)
Idaho			
1980-1984	0	--	--
1985	0.5	0.5	Elmore
1987-1990	1.5	1.0	Elmore
1991	2.0	0.5	Elmore
1993	2.5	0.5	Elmore
1995	3.0	0.5	Bingham
1997	3.5	0.5	Elmore
1998	4.0	0.5	Bingham
1999	4.5	0.5	Bingham
2000	5.0	0.5	Bingham
2004	5.5	0.5	Gooding
2005	6.0	0.5	Gooding
2009	6.5	0.5	Power
2010	7.0	0.5	Power
2013	7.5	0.5	Power
2016	8.0	0.5	Power
2018	8.5	0.5	Power
Alaska			
1983	0.1	0.1	Healy
1984	0.3	0.2	Beluga
1985	0.5	0.2	Beluga
1990	0.4	0.3	Beluga
1992	0.9	0.5	Beluga
1993	1.2	0.3	Nenana
1995	1.4	0.2	Beluga
1997	1.9	0.5	Beluga
1999	2.4	0.5	Beluga
2001	2.9	0.5	Beluga
2003	3.4	0.5	Beluga
2005	3.8	0.4	Nenana
2006	4.1	0.3	Nenana
2008	4.6	0.5	Beluga
2010	5.1	0.5	Beluga
2012	5.6	0.5	Beluga
2014	6.1	0.5	Beluga
2016	7.0	0.5	Beluga
2018	7.5	0.5	Beluga
2020	8.0	0.5	Beluga

APPENDIX C

BACKGROUND DATA AND MODEL DESCRIPTIONS

APPENDIX C

BACKGROUND DATA AND MODEL DESCRIPTIONS

C.1 BACKGROUND EMISSIONS AND AIR QUALITY DATA

An emission inventory of the major pollutants--sulfur dioxide (SO_2), particulate matter, hydrocarbons (HC), carbon monoxide (CO), and oxides of nitrogen (NO_x)--has been compiled by the Environmental Protection Agency (EPA), with assistance from state air pollution control agencies, and is available through the National Emissions Data System (NEDS).[1] The primary pollutants of interest in coal utilization facilities such as electrical generation plants are SO_2, particulates, and NO_x, and are the only pollutants considered in this assessment.

The year for which the emission inventory is applicable varies from state to state and source to source. The inventory is categorized into two major components--point sources and area sources. The point sources are individual plant or stack releases, while areas sources, which are averaged over each county in the region, incorporate emissions from automobiles, home space heating, commercial establishments, etc. Figure C.1 gives the total point source emissions for SO_2 by county in the Pacific Northwest. Table C.1 summarizes total emissions of point and area sources for each of the three states. These data show that the predominant source of SO_2 emissions in the region are in Washington State (most notably in the Puget Sound region) due to copper smelters, refineries, and a large coal-fired power plant. Large sources in the Willamette Valley of Oregon are due primarily to paper products industries; and in northern Idaho to a copper smelter.

An attempt has been made to assess the present air quality in the Pacific Northwest by compiling available air quality data and reviewing relevant literature on local air pollution problems. Although this survey is not yet complete, it is possible to identify several potential areas where air quality is presently so poor that they would be poor candidates for siting of coal-fired power plants.

The Puget Sound Air Pollution Control Agency publishes annual summaries of air quality measurements in the Puget Sound region.[2] Their 1976 summary shows that no annual average SO_2 standards are exceeded, but that at a number of locations around the Seattle area, short-term maximum concentration standards have been exceeded at least once in the year. Annual average total suspended particulate concentrations were exceeded in 1976 at stations in both Seattle and Tacoma. As shown in Figure 5.1 in Chapter 5, the Seattle-Tacoma region has been designated an Air Quality Maintenance Area (AQMA) due to high particulate concentrations.

All the AQMAs designated for the Pacific Northwest are due to particulate concentrations. The Portland-Vancouver interstate AQMA has also been identified as a potential region for exceeding SO_2 standards. This region is also sensitive to further carbon monoxide and photochemical oxidant emissions.

Additional data on particulate concentrations have been provided by the Region Ten EPA. They show a number of sites throughout the Pacific Northwest where annual average particulate

FIGURE C.1. Total Point Source Emissions of SO_2 in the Pacific Northwest, 1975

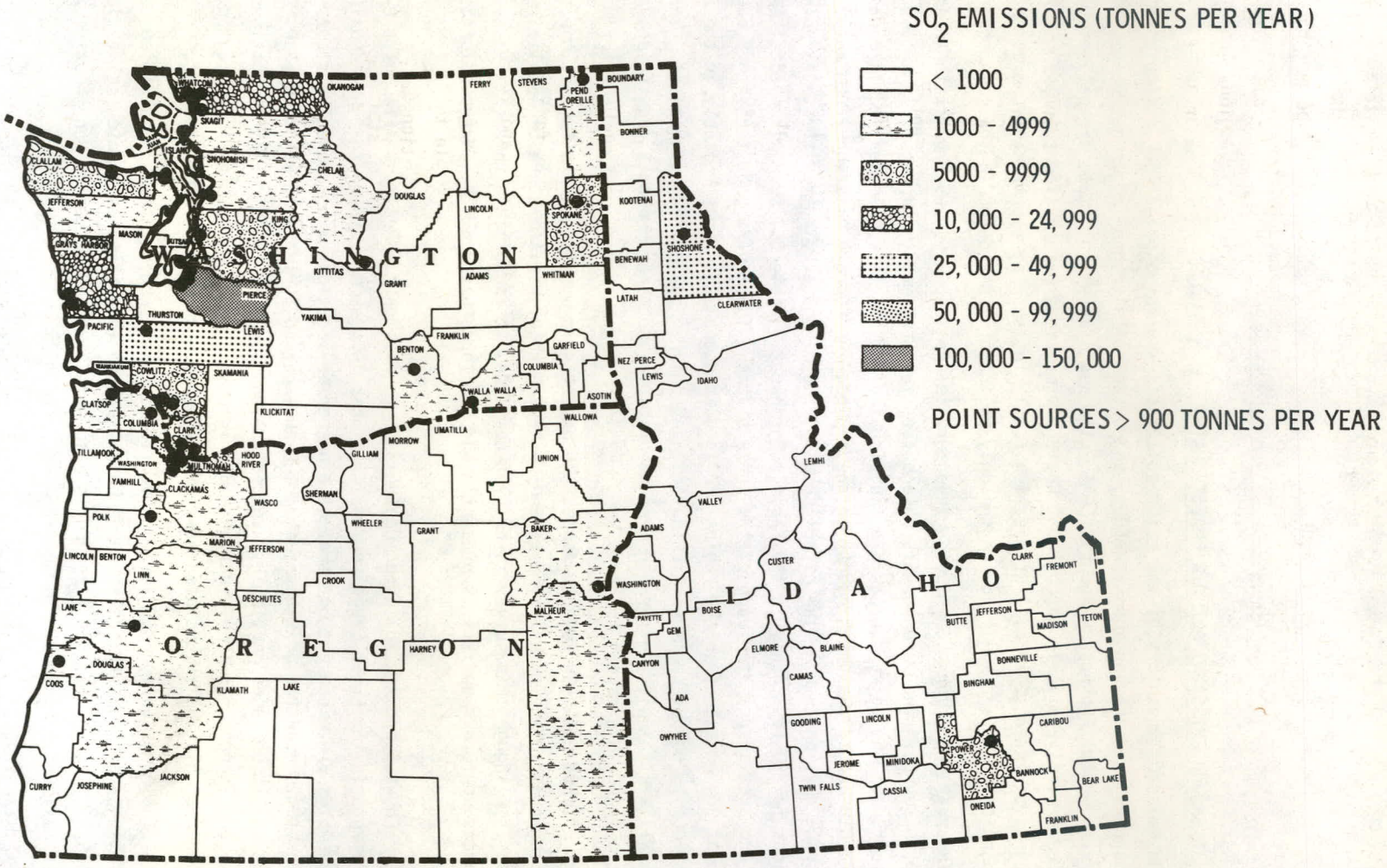


TABLE C.1. Emissions of SO_2 and Particulate Matter in the Pacific Northwest

	SO_2 (tonnes/year)		Particulate Matter (tonnes/year)	
	Point Sources	Area Sources	Point Sources	Area Sources
Washington	240,770	26,610	132,910	29,370
Oregon	22,810	22,060	124,420	45,390
Idaho	44,180	6,920	32,830	22,780

concentrations approach or exceed standards. Some of the stations where total suspended particulate (TSP) standards are exceeded are located in semiarid climates; the relative contribution of fugitive dust emissions to the total concentration values could be quite high.

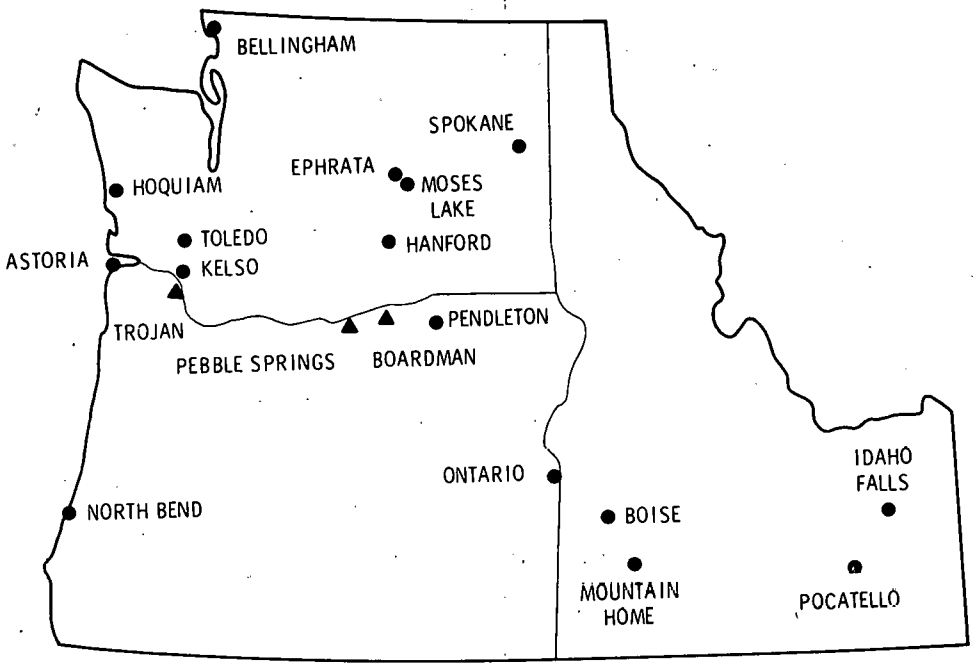
Two areas in the Pacific Northwest have received considerable study due to large emissions of SO_2 causing potential local health and aesthetic problems. These regions are near Tacoma, Washington[3] and Kellogg, Idaho[4] and would also be poor candidates for additional emission sources, such as those caused by coal-fired power plants.

C.2 DESCRIPTION OF THE MODELS--CLIMATOLOGICAL DISPERSION MODEL

The Climatological Dispersion Model (CDM), developed by the U.S. Environmental Protection Agency,[5] predicts long-term (seasonal or annual) quasi-stable pollutant concentrations at ground-level receptors using average emission rates from point and area sources and a joint frequency distribution of wind direction, wind speed and stability. The fundamental physical basis for the model is the assumption that the long-term average concentration distribution from an elevated, continuously emitting point source is given by the Gaussian plume formula, averaged over all possible combinations of meteorological conditions. The model uses a Briggs' plume rise formula[6] and an assumed power law increase in wind speed with height; the model results are dependent on stability conditions. Based on an assignment of a climatological mean value of mixing height and a minimum nocturnal mixing height (from a tabulation by Holzworth[7]), the CDM uses a mixing height that varies with stability.

The meteorological stations from which data were obtained to use in the CDM for the air quality assessment at the various candidate sites are shown in Figure C.2. In most cases data were obtained from National Weather Service (NWS) stations where hourly or three-hourly wind and cloud cover information are obtained. These data are then converted into "STAR" program data by the National Climatic Center in Asheville, North Carolina, for direct use into the CDM. The "STAR" Program data consist of a joint wind speed, direction, and stability frequency function. In a few cases, tower meteorological data, collected for the purpose of obtaining permits to construct coal or nuclear power plants, were also made available to this study. These data use vertical temperature gradients instead of cloud cover information to obtain the stability classes. Figure C.2 indicates the type of data available at each station. Table C.2 summarizes the data used for each of the candidate site locations.

As shown in Chapter 5, use of different types of meteorological data (e.g., towers versus NWS stations) results in different concentration values, even for data sources from the nearby locations. To further illustrate these differences in concentration estimates, Table C.3 shows



STATIONS USED FOR ESTIMATING AIR QUALITY IMPACTS FROM PROJECTED COAL PLANT DEVELOPMENT SCENARIOS

● WEATHER STATIONS WITH STAR PROGRAM DATA

▲ METEOROLOGICAL TOWER DATA

FIGURE C.2. Meteorological Stations Used for Input into the Climatological Dispersion Model

TABLE C.2. Meteorological Data Used for Each of the Candidate Site Locations

State	Candidate Site Location	Meteorological Data
Idaho	Bingham County	Idaho Falls; Pocatello
	Elmore County	Boise; Mountain Home
	Gooding County	Mountain Home
	Power County	Pocatello
Oregon	Clatsop County	Astoria
	Coos County	North Bend
	Gilliam County	Pebble Springs
	Malheur County	Ontario
	Morrow County	Boardman; Pendleton
	Sherman County	Pebble Springs
Washington	Cowlitz County	Kelso; Trojan
	Douglas County	Ephrata; Moses Lake
	Franklin County	Hanford
	Grant County	Ephrata; Moses Lake
	Grays Harbor County	Hoquiam
	Klickitat County	Pebble Springs
	Lewis County[a]	Toledo
	Lincoln County	Spokane
	Whatcom County	Bellingham

(a) Existing plant

TABLE C.3. Maximum Annual Average Concentrations Calculated for a 3000 MWe Plant[a]

Meteorological Station	Maximum SO_2 Concentration ($\mu g/m^3$)[b]	Distance and Direction of Maximum from Source
Bellingham, WA	2.6	10 km N
Ephrata, WA	1.7	10 km N, 10 km S
Hanford, WA[c]	7.1	5-10 km SE
Hoquiam, WA	1.6	20-40 km NW
Kelso, WA	1.6	25-40 km NNW
Moses Lake, WA	3.2	10 km NNE
Spokane, WA	1.4	25-35 km NE
Toledo, WA	2.1	10 km SSE
Astoria, OR	0.8	5-10 km S
Boardman, OR[d]	2.9	5 km E
North Bend, OR	2.0	25 km S
Ontario, OR	2.7	10 km W
Pebble Springs, OR[d]	5.7	5 km E
Pendleton, OR	1.9	5-10 km SE
Trojan, OR[d]	6.4	5 km S
Boise, ID	3.8	5-10 km SE
Idaho Falls, ID	2.2	5-10 km NE
Mountain Home, ID	2.6	5-10 km SE
Pocatello, ID	1.4	5-30 km NE, 5 km SW

(a) Based on NSPS standards. Emission rate for a 3000 MWe plant with a 60% load factor is 77.4×10^3 tonnes/year.
(b) Stack height = 244 m. Grid resolution is 5 km.
(c) Stability classified as a function of wind speed only by day/night; no account was made for cloud cover.
(d) Tower data with stabilities based on temperature change with height.

the maximum computed concentrations of SO_2 for a reference 3000 MWe power plant located at each meteorological station used in the study. The variations are nearly an order of magnitude throughout the Northwest. This reflects the range in meteorological conditions throughout the region. The table further illustrates the differences that can occur between stations only a few kilometers apart (e.g., Ephrata and Moses Lake, Washington) and between nearby NWS and tower meteorology data (e.g., Kelso, Washington and Trojan, Oregon). These differences at nearby stations are primarily due to the way that stability classes are determined. However, the wind flow characteristics may also change significantly at sites only a few kilometers apart in areas of complex terrain. These flow patterns are based on measured surface winds, which are strongly influenced by local topographically-induced flow. The wind flow pattern at the level of the plume height computed for the 3000 MWe plant (300 to 700 m) may be considerably different from that near the surface. (The model accounts for an increase of wind speed with height, but not for directional shear.)

C.3 SHORT-TERM MAXIMUM CONCENTRATIONS

Estimates of short-term maximum concentrations were derived from the Argonne report[8] cited in Chapter 5, which used results of a GE[9] study. That study made use of the U.S. Environmental Protection Agency PTMTP model, which is a coning-plus-trapping model with Gaussian diffusion. The model employs Pasquill-Gifford dispersion parameters.[10] and a Briggs' plume rise formula.[4] It is assumed that the pollutants do not transform in the calculation's time period and that no interference from topographic features occurs. The hourly meteorological

information required consists of wind direction and speed, stability class, mixing height, and ambient air temperature. Hourly concentrations at receptor locations can be estimated for up to 24 hours.

Argonne adjusted the results of the G.E. study for emissions from a 3000 MWe power plant and 250 x 10^6 scf/day coal gasification plant. Maximum ground-level pollutant concentrations from the power plant for 15-minute averaging times are obtained under stability class A and a 5 m/sec wind speed. However, arguments are presented to use a 2.5 m/sec wind speed with stability class A with 60% plant load factor to estimate 24-hour maximum concentrations. The results of the calculations using these different assumptions were shown in Table 5.7 in Chapter 5. As shown in the table the latter assumptions result in markedly reduced short-term maximum concentrations.

C.4 LONG-RANGE TRANSPORT MODEL

The regional model applied in this study computes ground-level air concentrations and surface depositions of SO_2 and sulfates, accounting for chemical transformation, dry deposition, and precipitation scavenging. The regional model and techniques applied to approximate the effects of complex terrain on pollutant transport and removal are briefly described here. More complete descriptions of the model and techniques are available.[9,10]

Transport of the effluents is determined from the spatial and temporal variations of the observed upper-level rawinsonde and pibal winds interpolated to a uniformly spaced grid over the region. The winds are averaged over a specified layer to provide a "layer average" transport, and gridded wind fields are produced for each hour by interpolating between the routine 12-hr observations. Pollutant plume centerlines are simulated by the hourly sequential release of a series of particles from each source location into the wind fields. Average ground-level air concentrations and surface depositions are computed by sampling the plumes over an array of grid squares.

The vertical dispersion parameter, σ_z, is computed using the formulas of Eimutis and Konicek.[11] The stability and mixing height that influence the vertical dispersion of the pollutant plumes are varied through the typical diurnal cycle. Horizontal dispersion is accounted for by the spatial and temporal meandering of the plume in the wind field.

A linear oxidation reaction rate is assumed for the transformation of SO_2 to sulfate. For computing dry removal, the model uses the techniques of source depletion. Wet deposition is assumed to be directly proportional to the precipitation rate, which is determined from hourly precipitation data.

Three techniques were used to approximate the effects of the complex terrain on pollutant transport and removal. The first was to increase the network density of upper air observations by incorporating stations with upper air pilot balloon wind observations (pibals) at 0600 GMT and/or 1800 GMT. The second technique involved specifying the appropriate layer of winds for transporting the pollutant. For the majority of stations, winds averaged over a layer between 100 and 1000 m above the ground were used to estimate the pollutant transport. However, in mountain valleys and coastal locations the low-level winds are strongly influenced by mesoscale

effects such as slope winds and sea breeze circulations. Thus, for rawinsonde stations located in mountain valleys or coastal locations away from the emission sources, 1000 to 2000 m layered winds were used to better approximate the long-range transport. The third technique involved varying dry deposition velocities with terrain types. Deposition velocities were increased by a factor of 2 for forested terrain and 5 for mountainous terrain.

Ground-level air concentrations and surface depositions of SO_2 and sulfates from existing facilities and projected coal-related facilities were computed using October 1974 meteorological data. October was chosen as a typical worst case month to exemplify the maximum impact of SO_2 emissions on regional air quality. This month is characterized by lighter mean wind speeds than the annual average for most of the western United States.[12] Thus, the computed concentrations for October 1974 are assumed to equal or exceed typical annual average concentrations, since higher concentrations (on a regional scale) and air pollution episodes are normally associated with periods of low wind speeds and shallow mixing heights.[7] Of course, the patterns shown may vary somewhat from annual patterns, due to seasonal variations in prevailing wind directions.

The verification of the model results with actual data is being examined in an assessment for the northeast United States.[13] However, the model results are certainly no more accurate than the collective assumptions of model input and the quantity of available meteorological data (e.g., density of upper air stations). Nevertheless, the model predictions in this study should be fairly representative (as a first order approximation) of the regional-scale air quality impacts.

The model input parameters used in the western regional assessment are shown in Table C.4.

TABLE C.4. Regional Transport Model Input Data

Time period	1-31 October 1974
Grid spacing for wind data	255.6 km
Grid spacing for hourly precipitation data, terrain types, and sampling of results	63.9 km
Effective stack height for sources of SO_2	400 m
Maximum daytime mixing height	1500 m
Minimum daytime mixing height	200 m
Maximum nighttime mixing height	400 m
Minimum nighttime mixing height	100 m
Stability	Varied through the diurnal cycle
Dry deposition velocities[a]	
SO_2	1.0 cm/sec
Sulfates	0.1 cm/sec
Wet removal coefficients[b]	
SO_2	0.03 P/hr
Sulfates	0.25 P/hr
Transformation rate of SO_2 to sulfates	0.02/hr

(a) These were the values for low roughness terrain. Deposition velocities were varied over different terrain types.
(b) P = Rainfall rate, mm/hr. Temporal and spatial variations in P were determined from hourly precipitation data.

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APPENDIX D

BASELINE WATER QUANTITY AND QUALITY DATA FOR PARTS OF IDAHO, OREGON, AND WASHINGTON

APPENDIX D

BASELINE WATER QUANTITY AND QUALITY DATA FOR PARTS OF IDAHO, OREGON, AND WASHINGTON

Areas of the seven aggregated subareas (ASAs) of the Pacific Northwest are shown in Table D.1.

TABLE D.1. Aggregated Subareas of the Pacific Northwest[1]

ASA No.	Name	Area (mi^2)
1701	Clark Fork-Kootenai-Spokane	37,500
1702	Upper Columbia-Yakima-Mid-Columbia	59,456
1703	Upper and Central Snake	66,155
1704	Lower Snake	31,661
1705	Lower Columbia-Willamette-Coastal	38,359
1706	Puget Sound	15,781
1707	Oregon Closed Basin	18,397
		267,309

Simulated flow levels for key points on the Columbia and Snake Rivers, assuming 1970 and 2020 levels of irrigation depletion, are presented in Tables D.2 and D.3, respectively. Flows may be compared to coal-fired power plant water requirements estimated in Chapter 6.

Existing water quality in each ASA is described below. Summary comparisons of production residuals--biochemical oxygen demand (BOD), and total suspended solids (TSS)--generated in the subareas are shown in Table D.4. All data are taken from a technical memorandum prepared by the Pacific Northwest River Basins Commission.

Data indicating total dissolved solids (TDS) and bicarbonate ion (HCO_3) concentrations at gauging stations on the Columbia and Snake Rivers are presented in Table D.5. These data represent observed ranges between October 1974 and September 1975. They are not averages and should be regarded as illustrative only.

D.1 ASA 1701: Clark Fork-Kootenai-Spokane

Generally, the surface and ground waters of this ASA are of good quality. The exceptions relate to organic waste generated by municipalities and industry, and sediment and biologically toxic concentrations of heavy metals from mining and milling of primary metals. One-half of the ASA's current BOD discharge to water is attributable to point sources. With best practicable treatment, the current load of 189 MM lb BOD/yr could be reduced by 40%. The ASA produces 39% of the region's total TSS load (44,883 MM lb TSS/yr). Nearly 60% of the TSS production is due to point sources, principally mining. Best practicable treatment could reduce the total current discharge to water from 44,883 to 21,510 MM lb TSS/year. No coal-fired power plants are projected by this study for this ASA under either the Recent Trends or High Coal Electric scenarios.

TABLE D.2. Mean and Lowest Monthly Flows Simulated for Key Points on the Columbia and Snake Rivers, 1970 Irrigation Depletion Level[a][b]

	June		July		August		September	
	Mean[c] (MGD)	Lowest[c] (MGD)	Mean (MGD)	Lowest (MGD)	Mean (MGD)	Lowest (MGD)	Mean (MGD)	Lowest (MGD)
Columbia River								
Chief Joseph Dam	66,340	28,150	45,564	29,162	54,084	40,296	43,953	35,640
Priest Rapids Dam	83,132	35,180	55,875	36,909	58,568	45,633	48,029	40,479
McNary Dam	141,218	72,701	81,586	57,854	73,295	60,632	64,689	57,952
John Day Dam	140,588	69,945	82,419	59,465	74,149	61,159	65,248	58,710
The Dalles, OR	144,086	72,459	85,344	61,506	76,651	64,020	68,079	62,021
Bonneville Dam	147,982	74,794	87,700	63,185	78,000	65,406	69,599	63,462
Snake River								
Brownlee Dam	9,753	4,616	6,779	3,230[d]	6,571	5,066	7,459	5,056
Lower Granite Dam	54,965	18,947	22,725	8,252	12,425	8,200	14,509	8,908
Little Goose Dam	55,025	19,025	22,990	8,265	12,607	8,129	14,634	8,862
Lower Monumental Dam	55,017	19,133	23,638	8,640	13,151	8,167	14,990	8,785
Ice Harbor Dam	55,017	19,133	23,638	8,640	13,188	8,180	14,990	8,785

(a) U.S. Army Corps of Engineers, Portland, OR, unpublished data, July 22, 1977.
(b) Flow data have been adjusted to reflect current storage operation with year 2020 load levels and have been reduced for irrigation depletions under 1970 development levels. Based on 1928-1958 flow data.
(c) Flows based on the average flow experienced during a month for each of 30 years of simulation. Mean is the mean monthly average for the 30 years; lowest is the lowest monthly average experienced in any one of the 30 years.
(d) Required minimum flow is 5000 cfs (3230 MGD).

TABLE D.3. Mean and Lowest Monthly Flows Simulated for Key Points on the Columbia and Snake Rivers, 2020 Irrigation Depletion Level[a][b]

	June		July		August		September	
	Mean[c] (MGD)	Lowest[c] (MGD)	Mean (MGD)	Lowest (MGD)	Mean (MGD)	Lowest (MGD)	Mean (MGD)	Lowest (MGD)
Columbia River								
Chief Joseph Dam	56,312	20,144	42,642	23,831	47,276	38,449	41,392	33,290
Priest Rapids Dam	73,402	34,245	53,204	35,411	52,192	44,226	45,871	38,679
McNary Dam	128,025	66,105	73,603	50,526	61,962	53,336	59,229	53,159
John Day Dam	126,738	63,773	73,884	50,268	62,442	54,007	59,780	53,432
The Dalles, OR	130,218	65,995	76,791	53,325	64,975	56,929	62,569	56,124
Bonneville Dam	134,083	67,158	79,108	55,845	66,283	58,064	64,078	57,603
Snake River								
Brownlee Dam	8,574	3,230[d]	3,776	3,230[d]	3,598	3,230[d]	4,326	3,230[d]
Lower Granite Dam	53,427	16,545	19,614	8,134	9,457	6,309	11,460	7,087
Little Goose Dam	53,487	16,629	19,880	8,147	9,638	6,238	11,585	7,042
Lower Monumental Dam	53,479	17,410	20,528	8,525	10,183	6,277	11,940	6,965
Ice Harbor Dam	53,119	17,049	20,174	8,168	9,903	5,974	11,766	6,789

(a) U.S. Army Corps of Engineers, Portland, OR, unpublished data, July 22, 1977.
(b) Flow data have been adjusted to reflect current storage operation with year 2020 load levels and have been reduced for irrigation depletions under 2020 development levels. Based on 1928-1958 flow data.
(c) Flows based on the average flow experienced during a month for each of 30 years of simulation. Mean is the mean monthly average for 30 years; lowest is the lowest monthly average experienced in any one of the 30 years.
(d) Required minimum flow is 5000 cfs (3230 MGD).

TABLE D.4. Production Residuals Discharged to Water, 1973[1]

Aggregated Subarea	Biochemical Oxygen Demand (million lb/yr)	Percent	Total Suspended Solids (million lb/yr)	Percent
1701	189	20	44,883	39
1702	96.6	10	34,701	30
1703	39.5	5	2,697	2
1704	81.1	9	15,456	13
1705	319	34	15,325	13
1706	220	23	904	1
1707	3.77	4	1,597	1
	948.97	100[a]	115,563	100[a]

(a) Does not add due to rounding.

TABLE D. 5. Total Dissolved Solids and Bicarbonate in Selected Columbia and Snake River Water Samples, October 1974-September 1975[2,3,4]

	Total Dissolved Solids[a] (mg/l)	Bicarbonate (HCO_3) (mg/l)
Columbia River		
Grand Coulee Dam, WA	71 - 110[b]	60 - 81
Vernita Bridge, WA	78 - 123[b]	62 - 87
Umatilla, OR	80 - 100	(d)
The Dalles, OR	50 - 71[c]	66 - 96
Warrendale, OR	40 - 76[c]	48 - 103
Snake River		
Blackfoot, ID	127[c]	178
Neeley, ID	203 - 285	117 - 190
King Hill, ID	200 - 204[c]	120 - 254
Murphy, ID	188 - 193[c]	189 - 198
Brownlee Dam, ID	160 - 341	61 - 217

(a) TDS expressed as residue at 180°C.
(b) Calculated: TDS = 0.65 x specific conductance.
(c) Calculated: TDS = sum of constituents - 0.5 x bicarbonate.
(d) No data.

D.2 ASA 1702: Upper Columbia-Yakima-Mid Columbia

The quality of waters of the ASA is generally adequate for all uses. In some areas, however, water quality has deteriorated through either natural or man-made pollution, and this deterioration has impaired the use of certain waters. Existing problems relate to bacterial and biological contamination, temperature, and dissolved gases. High levels of dissolved nitrogen in the Columbia River pose a severe problem to anadromous fish. High water temperatures in the Columbia River and tributary streams adversely affect fish life and reduce the capacity of streams to assimilate pollutants. Localized water quality problems include contamination of ground water in certain areas of the Columbia Basin Project; bacterial problems on the Yakima, Lower Okanogan, Colville, Entiat and other streams; and lake and stream enrichment problems, particularly in Moses Lake. The food processing industry is the principal source of

industrial wastes. Irrigation return flows and feedlot drainage are significant sources of organic wastes. Low summer flows aggravated by irrigation withdrawals impair the capacity of many streams to assimilate waste.

Adoption of best practicable treatment could reduce the BOD load by 24%, from 96.6 to 73.4 million lb/yr. Total suspended solids could be reduced by 43%, from 34,701 to 19,890 million lb/yr.

New coal-fired electrical generating capacity in this ASA by the year 2020 is projected at 10,500 MWe in the Recent Trends scenario and 29,000 MWe in the High Coal Electric scenario.

D.3 ASA 1703: Upper Snake-Central Snake

Heavy algal production is a problem in lower main-stem reservoirs and in the lower reaches of some tributaries. Significant sediment and mineral loads also occur in some Snake River tributaries. Bacterial concentrations are above recommended limits for recreation near a number of populated areas, and dissolved oxygen deficiencies have occurred at several points. High water temperatures are also a problem in some downstream areas. At present, 39.5 million lb of BOD are discharged to water annually. This figure could be reduced by 51% if best practicable treatment were used, since 83% of the BOD load originates from point sources. The current release of 2697 million lb/yr of TSS to water could be reduced 11% with best practicable treatment. Projected generating capacities for the ASA in the year 2020 are 4000 MWe under the Recent Trends scenario and 9500 MWe under the High Coal Electric scenario.

D.4 ASA 1704: Lower Snake

Water quality in this ASA is generally good; however, some problems exist with low dissolved oxygen, turbidity, nuisance algal growth and nitrogen supersaturation. The Snake River and streams in the Palouse drainage suffer the most serious water quality degradation. Dissolved oxygen-deficient water in lower levels of Brownlee and Oxbow Reservoirs (located in ASA 1703), caused by decomposing algae and residual waste loadings, is passed downstream through low-level turbine intakes. In recent years, floating aquatic slimes, stimulated by nutrient concentrations, have appeared in the Snake River below Oxbow Dam. Nitrogen supersaturation is a severe problem in the Snake River throughout the ASA. High water temperatures in the Snake River in late summer adversely affect fish life.

Two-thirds of the 81.1 million lb/yr of BOD discharged to water are from non-point sources. Therefore, only a 21% decrease could be achieved by applying best practicable treatment. Less than 1% of the 15,456 million lb/yr of TSS discharged to water are from point sources.

No coal-fired power plants are projected for this ASA under either scenario.

D.5 ASA 1705: Lower Columbia-Willamette-Coastal

Water quality of the lower Columbia River is generally good, but problems have been created by slime growth attributable mostly to the pulp and paper industry, and by bacterial pollution resulting from municipal effluents. High water temperatures have also been a cause for concern. Coastal streams are generally of good quality and suitable for all uses. The most common problems include high coliform bacterial counts, high temperatures and high nutrient

levels. A few instances of low dissolved oxygen are found, and high turbidities and sedimentation are encountered during some periods of the year.

BOD discharged to water could be reduced by 47%, from 319 to 149 million lb BOD/yr, by using best practicable treatment. Since only about 10% of the TSS load is attributable to point sources, the possible reduction is only 3%, from 15,325 to 14,900 million lb/yr.

Projected coal-fired generating capacity totals 8800 MWe for the Recent Trends scenario and 12,800 MWe for the High Coal Electric scenario.

D.6 ASA 1706: Puget Sound

The major rivers in the ASA contain high quality water suitable for almost all uses. However, in the lower reaches near the Sound, urban and industrial buildup has had a measurable effect on water quality. In several streams bacterial counts are higher and oxygen levels lower than desirable levels. In addition, some bays, harbors, and inlets have shown water quality degradation. Municipalities and industries are the largest sources of organic wastes in the Puget Sound area. The pulp and paper industry is the major source of oxygen-demanding wastes. Other important waste sources result from navigation and dredging operations, recreation, and land use and management practices.

Point sources account for 98% of the BOD and 40% of the TSS discharged to water. Possible BOD reductions are, therefore, 85% under best practicable treatment from 220 to 32.7 million lb BOD/yr. A 29% reduction in TSS is achievable, from 904 to 644 million lb TSS/yr.

Five hundred MWe of coal-fired generating capacity are projected for the ASA under the Recent Trends scenario and 2000 MWe are projected under the High Coal Electric scenario.

D.7 ASA 1707: Oregon Closed Basin

This ASA is sparsely populated and is essentially in a natural condition, relatively undisturbed by man's activities. As a result, the streams are uniformly of high water quality. However, evaporation in the numerous shallow lakes with large surface areas has resulted in brackish water conditions in the terminal water bodies. Ground water quality is generally poorer than the rest of the region.

BOD discharged to water is estimated at 3.77 million lb BOD/yr. TSS discharges are estimated at 1597 million lb TSS/yr. Since these are of non-point origin, no reductions through application of best practicable treatment are possible.

No energy generating facilities are projected for this ASA.

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APPENDIX E

ANCILLARY ECOLOGICAL DATA FOR IDAHO, OREGON, AND WASHINGTON

APPENDIX E

ANCILLARY ECOLOGICAL DATA FOR IDAHO, OREGON, AND WASHINGTON

The first section of this appendix describes those physiographic provinces of the Northwest which occur in candidate counties for power plant sites.[1,2] The second section describes the vegetation types found in the provinces. The third section consists of two extensive tables of water quality conditions or requirements for aquatic ecosystems in the Northwest.[3,4]

E.1 PHYSIOGRAPHIC PROVINCES

E.1.1 Olympic Peninsula Province

The Olympic Peninsula Province is made up of a central core of the rugged Olympic Mountains surrounded by almost level lowlands. On the east, the lowland strip is 3 to 16 km wide and is part of the Puget Trough. The lowland strips are very narrow on the north, but 16 to 32 km wide on the west and 48 km wide along the south side of the peninsula. Most ridges in the Olympic Mountains are 1200 to 1500 m in elevation; some higher peaks attain elevations of 2100 to 2420 m. Glaciation has strongly influenced landforms. All main river valleys are broad and U-shaped, and all major peaks are ringed with cirques, many containing active glaciers. The extremely high precipitation (perhaps as high as 6350 mm per year in the interior) has caused rapid down-cutting by streams, resulting in many precipitous mountain slopes.

E.1.2 Coast Ranges Province

The Coast Ranges Province extends from the middle fork of the Coquille River in Oregon northward into southwestern Washington where it includes the area known as the Willapa Hills. The entire southern section of the province is topographically mature--i.e., steep mountain slopes with ridges that are often extremely sharp. Except for the area drained by the Wilson and Trask Rivers, the proportion of steep slopes decreases in the northern section of the Coast Ranges. Mountain passes are generally located on the eastern border of the range due to faster rates of headward erosion by the numerous westward-flowing streams. Elevations of main ridge summits in the province range from about 450 to 750 m. Scattered peaks, often capped with intrusive igneous rocks, rise well above surrounding ridges. Marys Peak, Oregon, 1249 m high, is the highest peak in the Coast Ranges.

E.1.3 Klamath Mountains Province

The Klamath Mountains Province encompasses a complex of ranges in southwestern Oregon and northern California. The northernmost portion of range in Oregon is commonly identified as the Siskiyou Mountains. This region is logically set apart from the remainder of southern Oregon by the boundary separating its pre-Tertiary rocks from Tertiary rock formations outside the area. The pre-Tertiary rocks of this province probably include the oldest in Oregon.

The Klamath Mountains Province is largely a region of rugged, deeply dissected terrain. Mountain crests, comprised of steeply folded and faulted pre-Tertiary strata, vary in elevation from 600 m near the coast to approximately 1200 m in the east. Ridge accordance suggests an

ancient and now greatly dissected peneplain. Many peaks rise above this summit peneplain. The highest of these monadnocks in Oregon is 2280 m Mount Ashland, which rises 1060 m above the general level of its surroundings.

E.1.4 Puget Trough Province

The Puget Trough Province extends the entire length of Washington from the Canadian border to Oregon where the Willamette valley is its physiographic and geologic continuation. The northern half of the province includes Puget Sound, and the southern half is largely the Cowlitz River valley and upper basin of the Chehalis River. Relief is moderate, and elevations of the trough floor seldom exceed 160 m.

E.1.5 Southern Washington Cascades Province

The Southern Washington Cascades Province extends south from Snoqualmie Pass to the Columbia River. Unlike the Northern Cascades Province, andesite and basalt flows dominate with only minor amounts of igneous intrusive, sedimentary, and metamorphic rocks.

The area is characterized by generally accordant ridge crests separated by steep, deeply dissected valleys. The general ridge elevation is approximately 2000 m in the northern section and 1200 m in the southern. An extensive area around Mount Adams is composed mainly of recent lava flows; it comprises a gently sloping plateau at 900- to 1500-m elevation, differing markedly from the rest of the province. Three dormant volcanoes dominate the surrounding landscape: Mount Rainier (4392 m), Mount Adams (3801 m), and Mount Saint Helens (2948 m).

E.1.6 Okanogan Highlands Province

The Okanogan Highlands Province is characterized by moderate slopes and broad, rounded summits; thus, it differs markedly from the rugged Northern Cascades Province on the west. Excepting the main river valleys, much of the province lies above 1200 m. A scattering of peaks attain elevations of over 2400 m. The province is made up of several upland areas separated by a series of broad, north-south river valleys. These south-flowing rivers are, from west to east, the Okanogan, Sanpoil, Columbia, Colville, and Pend Oreille (Clark Fork) Rivers.

E.1.7 Blue Mountains Province

The Blue Mountains Province is made up of several mountain ranges separated by faulted valleys and synclinal basins. The mountainous areas include the Ochoco, Blue, and Wallowa Mountains, as well as the Strawberry, Greenhorn, and Elkhorn Ranges. Relief within the various mountain ranges is highly variable. Moderate slopes are common within the Blue and Ochoco Mountains, whereas the heavily glaciated Wallowa Mountains exhibit the greatest relief. Maximum elevations range from about 2100 m in the Ochoco Mountains to 2900 m at Eagle Cap in the Wallowa Mountains. Valley elevations are about 750 m in the vicinity of the Ochocos and 900 m in the broad basin between the Blue and Wallowa Mountains (near La Grande and Baker, Oregon). Spectacular Hells Canyon comprises the eastern boundary of the province. This canyon, occupied by the Snake River, ranges up to 1660 m in depth and is 24 km wide at its broadest point.

E.1.8 Columbia Basin Province

The Columbia Basin is the largest single province; it occupies an extensive area south of the Columbia River between the Cascade Range and Blue Mountains in Oregon and roughly two-thirds

of the area east of the Cascades in Washington. Topography varies from very gently undulating to moderately hilly. Steep slopes occur sporadically and are restricted to isolated basaltic buttes or canyons cut by some of the major rivers; for example, the Deschutes River in Oregon. Over most of the area, elevations range from 300 to 600 m, although they are less than 150 m adjacent to the Columbia River.

E.1.9 Basin and Range and Owyhee Upland Provinces

Southeastern Oregon has been divided into two physiographic provinces: Basin and Range and Owyhee Upland. Although topography differs, the two provinces are similar geologically.

The Basin and Range Province is characterized by fault-block mountains enclosing basins with internal drainage. The Owyhee Upland Province exhibits considerably less faulting and, in general, may be described as a north-facing basin that is drained by the Owyhee River. Elevations in both provinces range from about 1200 m to 2930 m atop Steens Mountain. Except for slopes of the fault-block mountains, much of the area is rolling with low relief. Since annual precipitation in the area averages only 180 to 300 mm, most streams are intermittent, and numerous undrained basins contain shallow, saline lakes.

E.1.10 Northern Cascades Province

The Northern Cascades Province extends north from Snoqualmie Pass to the Canadian border. Unlike the southern Cascades, these mountains are to a large extent comprised of ancient sedimentary rocks, most of which are folded and at least partially metamorphosed. Intrusions of large granitic batholiths are also common.

The province is a topographically mature area of great relief. Valleys are uniformly very deep and steep sided. An outstanding feature of the main eastward- and westward-flowing streams is their low gradient to within 6 or 7 km of the main divide. On this basis, it may be concluded that the northern Cascades are as deeply dissected as possible with their present elevation, and that their relief within the current erosion cycle is at a maximum. Another striking topographic feature is the approximately uniform elevation of the main ridgetops. Near the middle of the range, this level varies from 1800 to 2600 m. Towering above this relatively even crest are two dormant volcanoes--Mount Baker and Glacier Peak. There are also several granitic peaks of exceptional height.

Many ridges and peaks have glacial features. Hundreds of cirques exist; some peaks, ringed by cirques, have been eroded to matterhorns. In addition, main east-west valleys probably owe their very low gradients to glaciation. Today, this portion of the Cascades contains more active glaciers than any other area within the continental United States.

E.2 VEGETATION TYPES AND ZONES

E.2.1 *Picea sitchensis* Zone

Picea sitchensis (Sitka spruce) characterizes this long narrow zone which stretches the length of Washington's and Oregon's coasts. It is just part of a coastal forest zone that extends north into Alaska and south into northern California where it grades, in part, into coastal redwood (*Sequoia sempervirens*) forest. The *Picea sitchensis* Zone is generally only a

few km in width, except where it extends up river valleys. On the west side of the Olympic Peninsula, where an extensive coastal plain exists, it is much broader. Although the zone is generally found below elevations of 150 m, it goes to 600 m when mountain masses are immediately adjacent to the ocean. This zone could be considered a variant of the *Tsuga heterophylla* Zone distinguished by Sitka spruce, frequent summer fogs, and proximity to the ocean.

The *Picea sitchensis* Zone has what could be considered the mildest climate of any northwestern vegetation zone. Extremes in moisture and temperature regimes are minimal; the climate is uniformly wet and mild. Precipitation averages 2000 to 3000 mm, but frequent fog and low clouds during the relatively drier summer months are probably as important in ensuring minimal moisture stresses. Fog drip adds precipitation as a consequence of condensation in tree crowns.

Some of the finest forest soils in the region are found in this zone--deep, relatively rich, and fine textured. Surface soils are typically acid (pH 5.0 to 5.5), high in organic matter (15 to 20%) and total nitrogen (0.50%), and low in base saturation (10%).

The coniferous forest stands in this zone are typically dense, tall and among the most productive in the world.[1] Constituent tree species are Sitka spruce (*Picea sitchensis*), western hemlock (*Tsuga heterophylla*), arborvitae (*Thuja plicata*), Douglas fir (*Pseudotsuga menziesii*), grand fir (*Abies grandis*), and Pacific silver fir (*A. amabilis*) (in Washington). The first three are by far the most common. Red alder (*Alnus rubra*) is one of the most abundant trees on recently disturbed sites, and lodgepole pine (*Pinus contorta*) is common along the ocean. Coastal redwood (*Sequoia sempervirens*), California bay (*Umbellularia californica*), and Port Orford cedar (*Chamaecyparis lawsoniana*) are found in this zone in southwestern Oregon.

E.2.2 *Tsuga heterophylla* Zone

The *Tsuga heterophylla* (western hemlock) Zone is the most extensive vegetation zone in western Washington and Oregon and the most important in terms of timber production. This is the region famous for subclimax Douglas fir and climax western hemlock-arborvitae (*Thuja plicata*) formations. The *Tsuga heterophylla* Zone extends south from British Columbia through the Olympic Peninsula, Coast Ranges, Puget Trough, and both Cascade physiographic provinces in western Washington. In Oregon it is split into two major segments--located in the Coast Ranges and in the Western and High Cascades Provinces--by the Willamette and other dry interior valleys. The southern limits are the Klamath Mountains on the coast (except for the narrow coastal strip) and the divide between the North and South Umpqua Rivers in the Cascade Range (about 43° 16' N. lat.). Elevational range in the Cascade Range varies from essentially sea level to 600 or 700 m at 49° north latitude and from 150 to 1000 m at 45° north latitude. In the Olympic Mountains, the *Tsuga heterophylla* Zone occurs between 150 and 550 m on the western slopes and from nearly sea level to 1125 m on the drier eastern slopes. Where conditions are favorable, elements of this zone appear on the east side of the Cascade Range and in the northern Rocky Mountains.

The *Tsuga heterophylla* Zone has a wet, mild, maritime climate. Since the zone lies farther from the ocean, moisture and temperature extremes are greater than in the *Pica sitchensis* (Sitka spruce) Zone. Also, a great deal of climatic variation occurs in this widespread zone, associated with latitude, elevation, and the location in relation to mountain massifs. Precipitation averages 1500 to 3000 mm and occurs mainly during the winter. Summers are relatively dry with

only 6 to 9% of the total precipitation. Moisture stresses are sufficient to result in distinctive community spectra along moisture gradients. Mean annual temperatures average 8° to 9°C, and neither January nor July temperatures are extreme.

Despite the fact that soils in the *Tsuga heterophylla* Zone are derived from a wide variety of parent rocks, they tend to have some common general features. Surface horizons are well aggregated and porous. Organic matter content ranges from moderate in the Cascades to high in portions of the Coast Ranges and Olympic Peninsula, where thick, very dark A1 horizons are especially common. Forest floor depths are generally less than 7 cm, except at higher elevations where they may reach 15 cm in thickness. Depending on degree of profile development, amounts of clay accumulation in the B horizon vary from low to medium. Most soils in the zone are of medium texture, ranging from sandy loam to clay loam. In some areas, well-developed soils are limited to moderate slope positions, but on the steeper slopes, poorly developed, often shallow, soils are encountered most often.

E.2.3 Mixed-Evergreen (*Pseudotsuga*-Sclerophyll) Zone

In the western Siskiyou Mountains, modal sites are generally occupied by a mixed forest of evergreen needle-leaved trees (upper strata) and sclerophyllus broad-leaved trees (lower strata). Mixed-Evergreen Forests could be recognized as a major community type of North America. Several studies of the vegetation in this zone are in progress and should greatly expand our knowledge of it during the next decade.

Environmentally, this zone is almost unknown. It is relatively warm and wet during the winter months and hot and dry during the summer. Annual precipitation would appear to be between 600 and 1700 mm or more, depending on elevation and distance from the coast. Less than 20% falls during the growing season. Average annual temperatures of about 47° to 49°F, average July temperatures of 62° to 66°F, and average January temperatures of 32° to 36°F are likely.

E.2.4 Mixed-Conifer (*Pinus-Pseudotsuga-Abies*) Zone

Mixed forest of Douglas fir (*Pseudotsuga menziesii*), Sugar pine (*Pinus lambertiana*), Ponderosa pine (*P. ponderosa*), incense cedar (*Libocedrus decurrens*), and white fir (*Abies concolor*) (or grand fir [*A. grandis*]) type midelevations in the southwestern Oregon Cascade Range and eastern Siskiyou Mountains. The Mixed-Conifer Zone occurs from about 43° north latitude south along the western flanks of the Cascade Range at elevations of about 750 to 1400 m. It is also found in the eastern Siskiyou Mountains, but usually at slightly higher elevations. The Mixed-Conifer Zone is generally bounded by the Interior Valley and the *Abies concolor* (white fir) Zone at its lower and upper limits, respectively; to the north it grades into the *Tsuga heterophylla* (western hemlock) Zone.

Very few environmental data are available for the Mixed-Conifer Zones except for the eastern Siskiyou Mountains. Precipitation varies from about 900 to 1300 mm, with very little occurring during the summer months. Mean temperatures are about the same as in the *Tsuga heterophylla* Zone, but summers are distinctly warmer and drier.

Forest soils in the Mixed-Conifer Zone of southwestern Oregon are extremely varied due to the complex geological history and topography.

E.2.5 *Pinus ponderosa* Zone

Ponderosa pine (*Pinus ponderosa*) forests are widely distributed in eastern Oregon and Washington. They occupy:

1) a narrow band (15 to 30 km wide) on the eastern flanks of the entire Cascade Range (generally);
2) much of the high pumice plateau extending east from the High Cascades Province;
3) large areas in the Blue Mountains Province (Ochoco, Blue, and Wallowa Mountains) of northeastern Oregon and extreme southeastern Washington; and
4) extensive tracts in the Okanogan Highlands Province of northeastern Washington.

The band of Ponderosa pine forests generally increases in elevation from north to south. Throughout much of Washington they are at approximately 600 to 1200 m in elevation. In the Blue Mountains Province and northeastern Oregon generally, the elevational range is about 900 to 1500 m. Elevations in the south-central Oregon pumic area are considerably higher--about 1450 to 2000 m.

At their upper limits, Ponderosa pine forests may grade into forests of Douglas fir, grand fir (*Abies grandis*), or white fir (*A. concolor*) depending on the locale. Throughout much of Oregon, they abut Great Basin sage (*Artemisia tridentata*) steppe or open juniper (*Juniperus occidentalis*)--Great Basin sage woodland at their lower limits. At lower elevational limits in Washington, Ponderosa pine forests grade into either grassland or sage shrub-steppe. At some locations in northern Oregon and southern Washington, an ecotonal belt of Oregon oak (*Quercus garryana*) exists between Ponderosa pine forest and steppe.

The climate of the *Pinus ponderosa* Zone is characterized by a short growing season and minimal summer precipitation. Average annual precipitation ranges from about 355 to 760 mm, much of it falling as winter snow. Diurnal summer temperatures fluctuate widely, with hot days and cold nights. In many areas, frost may occur any night of the year. The months of July, August and September are very dry, with rainfall averaging less than 25 mm. Much of this summer rain is ineffective, as it usually comes during brief, high-intensity convection storms. Winter temperatures are generally low; as a result, snow often accumulates to considerable depths.

Since Ponderosa pine occupies drier sites than any other forest type (except juniper [*Juniperus occidentalis*]), its distribution is closely correlated with supplies of available soil moisture. This is often reflected by a distinct relationship between the occurrence of Ponderosa pine and soil texture, especially at the dry end of its range. On xeric sites, a mosaic of Ponderosa pine communities (on coarse-textured soils) and steppe or shrub-steppe communities (on finer textured soils) is common. An extreme example is a disjunct stand of Ponderosa pine forest. Despite less than 250 mm annual precipitation, abundant regeneration attests that the stand is maintaining itself. The existence of this anachronistic forest is primarily due to the uniformly sandy soil it occupies.

E.2.6 *Abies grandis* Zone

The *Abies grandis* (grand fir) Zone is the most extensive midslope forest zone in the Oregon and southern Washington Cascade Range and Blue Mountains of eastern Oregon. The *Abies grandis*

Zone typically occurs at 1100 to 1500 m in the central Oregon Cascade Range, 1500 to 2000 m in the Ochoco and Blue Mountains and 1650 to 2000 m (*Abies concolor* [white fir] Zone) in south-central Oregon.

The *Abies grandis* Zone is typically bounded by the *Abies lasiocarpa* (subalpine fir) Zone at its upper limits and the *Pseudotsuga menziesii* (Douglas fir) or *Pinus ponderosa* (Ponderosa pine) Zones at its lower limits. However, locally at higher elevations or on more mesic sites in the Cascade Range, it may abut forests in which Pacific silver fir (*Abies amabilis*), western hemlock (*Tsuga heterophylla*), arborvitae (*Thuja plicata*), or black hemlock (*Tsuga mertensiana*) are climax. At its lower limits, it may be adjacent to sage shrub-steppe without an intervening belt of climax Douglas fir or Ponderosa pine.

The *Abies grandis* Zone provides the most moderate environmental regime of any of the east-side forest zones (except for the areas where hemlock or arborvitae are present). Neither moisture nor temperature conditions are extreme. Precipitation is generally higher and temperature lower than in lower forested zones. Differences in summer dryness and soil drought differentiate the grand fir and western hemlock from the Douglas fir associations. Soil drought is of minor ecologic significance in the *Abies grandis* Zone. The *Abies grandis* Zone is distinguished climatically from subalpine forests by its higher temperatures and lesser accumulations of snow.

E.2.7 *Tsuga heterophylla* Zone

Habitats where the western hemlock or arborvitae are climax are encountered on the eastern slopes of the Cascade Range in Washington and northern Oregon. These constitute the *Tsuga heterophylla* Zone. It is essentially an eastern extension of the widespread coastal *Tsuga heterophylla* Zone, although the composition of several forests and understory is somewhat altered.

Interior western hemlock and arborvitae forests are most common in the eastern Washington Cascades at elevations between 800 and 1200 m. In Oregon, they are increasingly rare to their southern limit at about 44° 30' north latitude. Both species are absent from the Blue and Wallowa Mountains. Habitats sufficiently mesic to support western hemlock or arborvitae are very often disjunct, occurring within areas of *Abies grandis* Zone.

The *Tsuga heterophylla* Zone occurs under what appears to be the most equitable climatic regime of all the interior forest zones, a precipitation range of 560 to 1700 mm and mean annual temperature of 2.5° to 7.5°C.

E.2.8 Shrub-steppe Zonal Associations

Nine zonal associations, communities that can occur as climatic climaxes, have been recognized in the steppe region of the Columbia Basin province. Six occur in the counties of the NCUA. These are:

- *Artemesia tridentata* (Great Basin sage)/*Agropyron spicatum* (bluebunch wheatgrass)--in Douglas, Franklin, Grant and Lincoln counties.
- *Artemesia tridentata/Festuca idahoensis* (fescue)--in Lincoln County.
- *Agropyron spicatum-Poa sandbergii* (Sandbergs' bluegrass)--in Douglas and Lincoln counties.

- *Agropyron spicatum-Festuca idahoensis* - in Franklin county.
- *Festuca idahoensis/Symphoricarpos albus* (snowberry) - in Lincoln county.
- *Artemesia tripartita* (Great Basin sage)/*Festuca idahoensis* - in Douglas and Lincoln counties.

The last two associations are found on the periphery of the steppe region near its contact with forest vegetation. These tend to be lush, meadowlike communities with conspicuous amounts of large perennial grasses and broad-leaved forbs. The term "meadow steppe" has often been applied to these types. The other four zonal associations lie in the more arid interior of the Columbia Basin Province. Vegetation is more open and forbs are less conspicuous in these communities.

Steppe and shrub-steppe communities are widespread in Oregon, dominating the entire southeastern quarter of the state and a strip around the northwestern and western margins of the Blue Mountains. The communities found in the latter area, near the Columbia River, are very similar to those described for Washington.

In some respects, the steppes of southeastern Oregon are similar to those of the Columbia Basin Province:

1) both areas have hot, dry summers and cold winters; and
2) there are similar communities, e.g., the *Artemesia tridentata/Agropyron spicatum* and *Artemisia tridentata/Festuca idahoensis* associations.

Contrasts between the two areas are notable, however:

1) southeastern Oregon shrub-steppes average much higher in elevation;
2) deep, loamy soils are not common in southeastern Oregon;
3) desert or salt desert shrub communities are common enough to appear on regional vegetation maps;
4) *Artemisia cana* (silver sage) on moister habitats.

TABLE E.1. Concentration Values in Freshwaters of the Pacific Northwest of Inorganic Elements Occurring in Coal[3]

Element	Primary Source	Location	Concentration (mg/ℓ)	Year
Aluminum (Al)	Industrial waste, mine drainage	Pacific Northwest Basin	0.03 (mean positive)	1962-67
	Weathering of rock	Columbia River above Dalles, Oregon	0.089-0.238	1958-59
Antimony (Sb)	Weathering of rock	Pincipal rivers of the U.S.	None	
		Selected drinking water supplies in:		
		Washington	< 0.002-0.02	1962-63
		Oregon	< 0.008	
		Idaho	< 0.06	
Arsenic (As)		Pacific Slope Basins in Washington and Upper Columbia River Basin	0.0-0.01	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.0-0.01	1964-65
		Snake River Basin	0.0	1964-65
		Pacific Northwest Basin	0.068 (mean positive)	1962-67
		Selected drinking water supplies in:		
		Washington	< 0.01	1962-63
		Oregon	< 0.01	
		Idaho	< 0.01	
		Principal rivers of the U.S.	None detected	1958-59
Barium (Ba)	Weathering of rock	Pacific Northwest Basin	0.027 (mean positive)	1962-67
		Columbia River above Dalles, Oregon	0.033-0.048	1958-59
		Selected drinking water supplies in:		
		Washington	0.002-0.06	1962-63
		Oregon	0.005	
		Idaho	< 0.01-0.01	
Berillium (Be)	Industrial effluents of various types, weathering of mineral beryl	Pacific Northwest Basin	0.00002 (mean positive)	1962-67
		Selected drinking water supplies in:		
		Washington	< 0.00001-0.00008	1962-63
		Oregon	< 0.0004	
		Idaho	< 0.0003-0.005	
Boron (B)	Weathering of boron-bearing rock; cleaning wastes	Pacific Northwest Basin	0.03 (mean positive)	1962-67
	Weathering of rock	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.0-0.15	1964-65
		Pacific Slope Basin in Oregon and Lower Columbia River Basin	0.0-0.12	1964-65
		Snake River Basin	0.0-0.09	1964-65
		Selected drinking water supplies in:		
		Washington	0.000-0.1	1962-63
		Oregon	0.04	
		Idaho	0.17-0.21	
Bromine (Br)	Rainfall, combustion of leaded gasoline containing ethylene dibromide	No data for Pacific Northwest		
Cadmium (Cd)	Electroplating, weathering of ores	Pacific Northwest Basin	0.005 (mean positive)	1962-67
		Selected drinking water supplies in:		
		Washington	< 0.006-< 0.005	1962-63
		Oregon	< 0.002	
		Idaho	< 0.02	
	Weathering of rock	Principal rivers of the U.S.	None detected	1958-59
Calcium (Ca)		Surface water in 98 U.S. rivers	11.-408.	1961
		Drinking water in 163 U.S. metropolitan areas	31.1 (average)	1950-51
		Pacific Slope Basins in Washington and Upper Columbia River Basin	2.-52.	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	2.-53.	1964-65
		Snake River Basin	6.8-54.	1964-65
		Selected drinking water supplies in:		
		Washington	6.4-32.	1962-63
		Oregon	13.	
		Idaho	54.-56.	
Chloride ion (Cl^-)		Surface water of 98 U.S. rivers	1.-702.	1961
		Drinking water in 163 U.S. metropolitan areas	20.1	1950-51
	Weathering of rock	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.2-60.	1964-65

TABLE E.1. (contd)

Element	Primary Source	Location	Concentration (mg/ℓ)	Year
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.5-30.	1964-65
		Snake River Basin	0.0-26.	1964-65
		Selected drinking supplies in:		
		Washington	1.5-3.9	1962-63
		Oregon	--	
		Idaho	45.-50.	
Chromium (Cr)	Industrial wastes	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.0-0.02	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.0-0.02	1964-65
		Snake River Basin	0.0	1964-65
	Industrial wastes	Pacific Northwest Basin	0.005 (mean positive)	1962-67
		Selected drinking water supplies in:		
		Washington	< 0.0003-0.01	
		Oregon	< 0.0008	
		Idaho	< 0.006	
Cobalt (Co)	Weathering of rock	Pacific Northwest Basin	0.008 (mean positive)	1962-67
		Selected drinking water supplies in:		
		Washington	< 0.0004-< 0.002	1962-63
		Oregon	< 0.002	
		Idaho	< 0.01	
Copper (Cu)	Corrosion of copper and brass tubing; industrial effluent; herbicides; weathering of rock	Pacific Northwest Basin	0.009 (mean positive)	1962-67
		Pacific Slope Basins in Washington and Upper Columbia River Basin	0.0-0.1	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.01-0.05	1964-65
		Snake River Basin	0.01-0.05	1964-65
		Selected drinking water supplies in:		
		Washington	0.001-0.06	1962-63
		Oregon	0.008	
		Idaho	0.006-0.01	
Fluoride ion (F^-)	Weathering of rock	Drinking water of 163 U.S. metropolitan areas	0.25 (average)	1950-51
		Pacific Slope Basins in Washington and Upper Columbia River Basin	0.0-1.0	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.0-0.5	1964-65
		Snake River Basin	0.0-0.9	1964-65
		Selected drinking water supplies in:		
		Washington	0.0-0.4	1962-63
		Oregon	0.0	
		Idaho	0.7-0.8	
		Community water supplies with natural F- content of 0.7 ppm or more:		
		Washington	0.5-2.1	
		Oregon	0.7-2.1	
		Idaho	0.7-4.2	
Gallium (Ga)		Principal rivers of the U.S.	None detected	1958-59
		Lower Mississippi River Basin	< 0.0005-0.4	
Germanium (Ge)		Principal rivers of the U.S.	None detected	1958-59
		Lower Mississippi River Basin	< 0.00025-< 0.02	1964-65
Iron (Fe)		98 U.S. rivers	0.02-3.0 (1 year range)	
	Dissolved mineral matter	Drinking water in 163 U.S. metropolitan areas	0.12 (average)	1950-51
		Pacific Northwest Basin	0.032 (mean positive)	1962-67
	Weathering of rock, acid waters, etc.	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.00-074	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.03-0.32	1964-65
		Snake River Basin	0.0-0.43	1964-65
		Selected drinking water supplies in:		
		Washington	0.01-0.3	1962-63
		Oregon	0.05	
		Idaho	0.02-0.1	
Lead (Pb)	Weathering of limestone and galena; various mining and effluents	Pacific Northwest Basin	0.015 (mean positive)	1962-67

TABLE E.1. (contd)

Element	Primary Source	Location	Concentration (mg/ℓ)	Year
		Columbia River above Dalles, Oregon	< 0.0012-0.005	1958-59
		Selected drinking water supplies in:		
		Washington	0.0020-0.05	1962-63
		Oregon	< 0.004	
		Idaho	< 0.03	
Magnesium (Mg)		Drinking water of 163 metropolitan areas	9.75 (average)	1950-51
	Weathering of rock	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.2-32.	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.5-20.	1964-65
		Snake River Basin	0.2-22.	1964-65
		Selected drinking water supplies in:		
		Washington	4.-16.	1962-63
		Oregon	0.7	
		Idaho	39.-48.	
Manganese (Mn)	Dissolved mineral matter	Surface and ground waters of U.S.	0.0-0.16	1961
		Pacific Northwest Basin	0.0028 (mean positive)	1962-67
		Columbia River above Dalles, Oregon	0.0055-0.014	1958-59
		Selected drinking water supplies in:		
		Washington	< 0.005-0.03	1962-63
		Oregon	< 0.003	
		Idaho	< 0.02-< 0.03	
Mercury (Hg)	Industrial effluents; mines with Hg-containing ores	Principal rivers of U.S.	None detected	1958-59
Molybdenum (Mo)	Mineral weathering	Pacific Northwest Basin	0.03	1962-63
		Columbia River above Dalles, Oregon	0.0021	1958-59
		Selected drinking water supplies in:		
		Washington	< 0.0004-0.005	1962-63
		Oregon	< 0.002	
		Idaho	< 0.01	
Phosphorus (P)	Detergents	U.S. rivers	0.01-10	
		Pacific Northwest Basin	0.047 (mean positive)	1962-67
		Columbia River at Dalles, Oregon	0.0	1958-59
Phosphate ion (PO_4^-)	Detergents, water treatment, domestic and industrial sewage, fertilizer	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.0-0.99	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.0-0.48	1964-65
		Snake River Basin	0.08-1.0	1964-65
Potassium (K)	Weathering of rock	Pacific Slope Basins in Washington and Upper Columbia River	0.0-20.	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River	0.1-7.8	1964-65
		Snake River Basin	0.4-5.8	1964-65
Selenium (Se)		Selected drinking water supplies in:		
		Washington	< 0.01	1962-63
		Oregon	< 0.01	
		Idaho	< 0.01	
Silicon (Si)		No Pacific Northwest data		
Silicon dioxide (SiO_2)	Weathering of rock	Surface waters of 98 U.S. rivers	8.-48.	1961
		Pacific Slope Basins in Washington and Upper Columbia River Basin	0.9-32.	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	3.6-39.	1964-65
		Snake River Basin	3.7-34.	1964-65
Sodium (Na)	Weathering of rock, etc.	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.7-139.	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River	1.6-16.	1964-65
Tin (Sn)		Selected drinking water supplies in:		
		Washington	< 0.004-< 0.002	1962-63
		Oregon	< 0.002	
		Idaho	< 0.01	
Titanium (Ti)		Columbia River above Dalles, Oregon	0.0021-0.0052	1958-59

TABLE E.1. (contd)

Element	Primary Source	Location	Concentration (mg/ℓ)	Year
Vanadium (V)	Minerals	Pacific Northwest Basin	0.013 (mean positive)	1962-63
		Columbia River above Dalles, Oregon	0.0-0.004	1956-59
		Selected drinking water supplies in:		
		Washington	< 0.004-< 0.003	1962-63
		Oregon	< 0.0020	
		Idaho	< 0.003-0.05	
Zinc (Zn)		Pacific Northwest Basin	0.040 (mean positive)	1962-67
	Industrial waste; some rock weathering	Pacific Slope Basins in Washington and Upper Columbia River Basin	0.05-0.4	1964-65
		Pacific Slope Basins in Oregon and Lower Columbia River Basin	0.05	1964-65
		Snake River Basin	0.05	1964-65
Zirconium (Zr)		No data for Pacific Northwest		

TABLE E.2. Recommended Values of Certain Elements for Protection of Aquatic Life in Freshwater and Saltwater Areas[4]

Element	Water Quality Limits, ppm			
	Freshwater		Saltwater	
	Goal[a]	Standard[b]	Goal[a]	Standard[b]
Barium (Ba)	0.1	0.05	0.05	0.06

Remarks: Pacific Northwest streams generally contain sufficient bicarbonate to precipitate all but minute amounts of barium. Ba can be present in colloidal suspension, a chelate, an organic compound, or other ways. Water quality criteria tentatively suggest 5.0 ppm is sufficient to protect aquatic life, but this appears excessive.

Boron (B)	0.1	0.3	4.7	5.5

Remarks: Boron can be toxic in high concentrations, but it is not considered a hazard as the possibility is low that lethal levels may be reached. Only trace amounts occur in most Pacific Northwest waters.

Cadmium (Ca)	0.0005	0.001	0.00011	0.00013

Remarks: Fish are quite sensitive to cadmium. Also, cadmium combines with other metals, notably zinc, to exert synergistic effects. The lowest level indicated lethal to fish is the Public Water Supply maximum 0.01 ppm. Salmon fry have been killed by 0.03 ppm cadmium with 0.15 ppm zinc.

Chromium (Cr)	Trace	0.01	0.00005	0.00006

Remarks: Fish are less sensitive to chromium than other organisms in aquatic food webs. Concentrations of 0.016 ppm and less appear toxic to microscopic water organisms such as *Daphnia magna*, but the evidence is not secure. Hexavalent chromium is difficult to detect below 0.05 ppm.

Copper (Cu)	0.02	0.05 above natural background	0.05	0.06

Remarks: Copper combines to act synergistically with zinc, cadmium, phosphate, chlorine, mercury and other materials upon fish. Copper concentrations as low as 0.015 ppm have been reported toxic. Copper effects are pronounced in soft water, possibly because copper carbonate precipitates from hard water and limits the amount of copper in solution. Maximum level of copper sulfate for trout is 0.014, carp--0.30, and goldfish--0.50 ppm. Aquatic food organisms of fish are highly sensitive. Marine biota are also sensitive. Oyster larvae require some copper (0.05-0.06 ppm), but toxic effects begin at 0.1-0.5 ppm.

Fluoride (F-)	0.5	--	1.3	1.5

Remarks: Fish appear affected by fluoride at about the same levels and in much the same way as land animals. The lowest concentration reported to exert adverse effects (retarded and poorer hatching eggs) is 1.5 ppm.

TABLE E.2. (contd)

Element	Water Quality Limits, ppm			
	Freshwater		Saltwater	
	Goal[a]	Standard[b]	Goal[a]	Standard[b]
Iron (Fe)	0.0 Total Fe above natural content	0.1	0.1	0.2

Remarks: Fish may be adversely affected by iron, although the amount in solution (ferrous iron) will be low in aerated streams supporting fish. In come cases, levels as low as 0.2 ppm ferrous iron may be harmful, but some fish thrive at higher levels.

Lead (Pb)	Limit of Detectability	0.02	0.00003	0.004

Remarks: Lead is more toxic to fish in soft water (as is Cu) than hard water. Low oxygen levels appear to accentuate the effect of lead slightly. Toxic effects in fish have occurred as low as 0.01 ppm lead, but other tests have shown no toxicity at levels up to 0.4 ppm.

Manganese (Mn)	Trace	0.01 total mn	0.002	0.04

Remarks: Fish appear to have some tolerance to Mn; it is probably not harmful at the maximum limit of 0.05 ppm for public water supplies.

Mercury (Hg)	Limit of Detectability	0.002	0.004	0.005

Remarks: No fish kills due to mercury have been reported. Mercury is normally inert, but enters the aquatic food web, becomes concentrated in fish and is transferred from prey to predator species.

Selenium (Se)	Limit of Detectability	0.003	0.00003	0.004

Remarks: Fish are somewhat more sensitive to selenium than humans, but quantitative data are scarce. The maximum limit of 0.01 ppm for public water supplies is probably acceptable for nearly all species of fish. Fish apparently concentrate selenium in their livers by ingesting selenium entering the food web via plankton.

Silver (Ag)	Limit of Detectability	0.003	0.00003	0.004

Remarks: Fish are sensitive to silver, lethal effects having been observed at 0.003 ppm levels. Plankton may be slightly less sensitive, but only limited data are available. The maximum limit of 0.05 ppm for public water supplies is apparently safe for most aquatic life.

Sodium (Na)	10.0 over natural levels	35.0 over natural levels	10,500	12,500

Remarks: Sodium has little adverse effect on aquatic life in limited amounts. Most sodium salts are highly soluble. In United States freshwaters supporting a varied fish fauna, levels of sodium plus potassium are less than 85 ppm about 95% of the time.

Zinc (Zn)	Limit of Detectability	Limit of Detectability	0.01	0.012

Remarks: Fish are strongly affected by zinc. Concentrations of 0.01 ppm have been found lethal and lower levels have adverse effects on reproduction. Toxicity is greatest in soft water and synergistic actions with copper and other metals can occur. Shellfish concentrate zinc from the water by ingestion of plankton. The 5.0 ppm maximum limit for zinc in public water supplies appears to be excessive for fish.

(a) "Goal", the more restrictive quality criteria, is defined as a desirable value that may or may not be practical at the present time.
(b) "Standard", the less restrictive quality criteria, is defined as an objective to be achieved or maintained immediately or in a short period of time.

REFERENCES FOR APPENDIX E

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2. R. O. Harniss and N. E. West, "Vegetation Patterns of the National Reactor Testing Station, Southeastern Idaho." Northwest Science, 47:30-43, 1973.

3. Arthur D. Little, Inc., Water Quality Criteria Data Book. Vol. 2, for the U.S. Environmental Protection Agency, Water Pollution Control Research Series, 18010 DPV 07/71, Washington, DC, July 1971.

4. M. C. Bell, Fisheries Handbook of Engineering Requirements and Biological Criteria. Fisheries-Engineering Research Program, North Pacific Division, U.S. Army Corps of Engineers, Portland, OR, 1973.

APPENDIX F

SOCIOECONOMIC IMPACT ASSESSMENT METHODOLOGY

APPENDIX F

SOCIOECONOMIC IMPACT ASSESSMENT METHODOLOGY

F.1 THE IMPACT ASSESSMENT PROCESS

The impact assessment process can be divided into the following four stages:

1) describing the socioeconomic conditions existing in the affected area at $time_1$ prior to the introduction of the project;

2) predicting the social conditions likely to exist in the affected area at a later date ($time_2$) without the project;

3) predicting the social conditions likely to exist in the affected area at $time_2$ with the project;

4) assessing which of the changes likely to be created by the project are significant enough to constitute either beneficial or detrimental impacts for the people involved.

The essential purpose of any socioeconomic impact assessment is to determine what changes, and hence what impacts, are created in an area by a project between $time_1$ (before the project) and $time_2$ (after the project), and perhaps also at subsequent intervals of $time_3$, $time_4$, etc. These project associated changes and impacts must be carefully distinguished, however, from all other changes that have or will occur in the area from other causes. The time frame involved in this process is diagrammed in Figure F.1.

In this diagram the magnitude of the changes resulting from an innovation such as an energy project is determined by comparing the social conditions predicted in the area at $time_2$ without the innovation to the conditions predicted or prevailing at $time_2$ with the innovation. Symbolically:

$$CH_i = \left\{ SC_{time_2}, w_i \right\} - \left\{ SC_{time_2}, w/o_i \right\}$$

The significant social impacts associated with this innovation are then determined by making evaluative assessments of the nature and importance of the various social changes.

F.2. SOCIOECONOMIC INDICATORS

Twenty-five social indicators were selected for use in this analysis and are described below.

Demographic Indicators

1) Population size: number of inhabitants in the county

2) Amount of population change: average annual amount of population growth or decline in the county

3) Rate of population change: average annual percentage rate of population growth or decline in the county

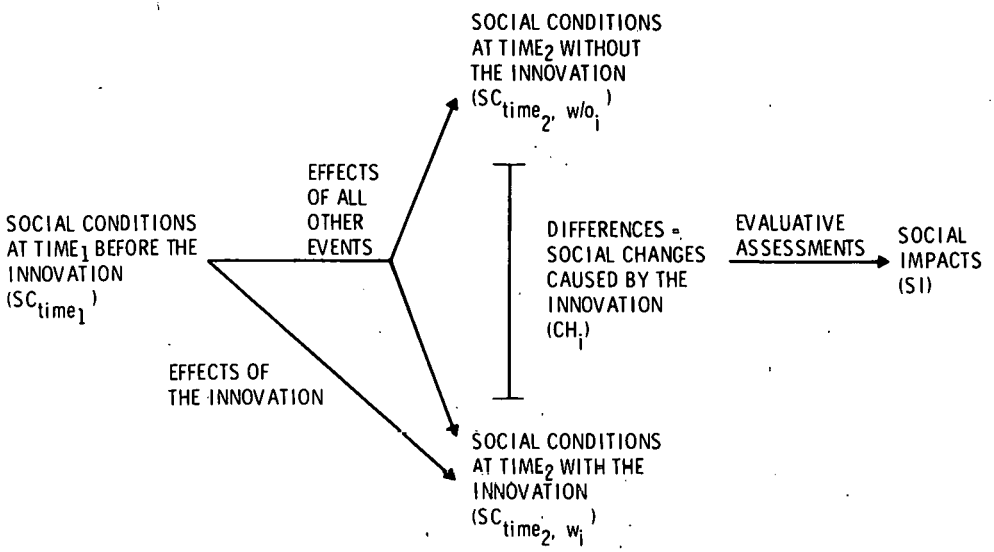


FIGURE F.1. Social Impact Assessment Process

4) Urbanization: proportion of the population of the county living in towns of 10,000 or more

5) Sex ratio: number of males per 100 females in the county

6) Ethnicity: proportion of the population of the county who are nonwhite

7) Age structure: median age of the population of the county

8) Family status: proportion of the families in the county with children under 18 present

9) Education: median number of years of school completed by persons age 25 or older in the county

Economic Indicators

10) Gross economic product size: annual gross sales receipts in the county, per capita

11) Gross economic product change: annual percentage rate of change in the gross sales receipts per capita, in constant 1967 dollars

12) Job availability: number of job openings in the county reported to the public employment office per year per 1000 persons in the labor force

13) Employment rate: proportion of the labor force in the county currently employed

14) Economic diversity: number of business firms in the community per 1000 people

15) Personal income: median annual personal income in the county, per capita

16) Property value: total full value of all assessed real estate in the county, per capita

17) Governmental income: total amount of funds received annually by all local governments in the county from all sources, per capita

Community-Structure Indicators

18) Occupational structure: proportion of the total labor force in the county holding professional, executive, technical or managerial jobs

19) Housing availability: proportion of all dwelling units in the county that are currently unoccupied

Public Service Indicators

20) Governmental public service operational expenditures: total annual expenditures for all human services by all local governments in the county, per capita

21) Governmental public facilities expenditures: total annual expenditures for streets and roads, sanitation and sewerage, water and other utilities, and public transportation by all local governments in the county, per capita

22) School capabilities: average student-teacher ratio for all grades in the public school systems in the county

23) Hospital facilities: number of hospital beds in the county per 1000 population

24) Police protection: number of police employees in the county per 1000 population

25) Fire protection: number of fire employees in the county per 1000 population.

F.3 TECHNIQUES OF IMPACT FORECASTING

Current methodological procedures for constructing forecasts of expected (without the project) and predicted (with the project) future changes can be divided into the two broad categories of univariate and multivariate forecasts. A univariate forecast involves only one predictor variable or indicator at a time, whereas a multivariate forecast considers several predictor variables or indicators simultaneously. The two main procedures for performing univariate forecasting of single factors are trend extrapolation and standardized multipliers. The former is most commonly used to estimate expected conditions without the proposed project, while the latter is more commonly used to predict changes that will likely result from the project. Multivariate forecasts, meanwhile, commonly use system models and flowcharts.

F.3.1 Trend Extrapolation

Trend extrapolation is a useful technique for short-term forecasting under relatively stable conditions. The analyst obtains data on a particular indicator at the present time and at several points in the past and then extends the observed trend into the future. Trend extrapolation is used in two different ways in this analysis:

1) To obtain 1975 values for some of the current county characteristics given in Appendix H, it was sometimes necessary to extrapolate trends from 1960 and 1970 census data.

2) Since it was not possible within the scope of this study to predict changes that may occur in all 15 counties during the next 20 years without new generating plants (except for population growth estimates, which were taken from the latest forecasts available from state planning departments), the "without project" conditions were assumed to remain the same as at present and were extrapolated to the year 2020 on a level per capita basis. We are not suggesting that all these factors will in fact remain constant but are simply forecasting the impacts of new generating facilities in the absence of other compounding growth trends.

F.3.2 Standardized Multipliers

Given an estimated work force for a proposed project, several other conditions likely to exist in the surrounding area in the future can be estimated by using standardized multipliers. These are coefficients that express expected relationships between two variables or indicators, such as the size of the project work force and the number of new secondary workers likely to be employed in the area due to economic growth stimulated by the project. A number of such multipliers are used in this analysis for predicting the impacts of a generating plant on total population growth, economic development, income levels, public service capital requirements, and other characteristics of the affected counties.

F.3.3 System Models

Multivariate forecasting, in contrast to univariate forecasting, considers a number of related variables for indicators simultaneously, treating them as an interrelated system. To perform this kind of dynamic system analysis, it is necessary to construct a system model containing the total set of variables and relationships being examined. Each variable in the model must be quantified and each relationship between variables expressed as a regression coefficient. Using computer simulation, it is then possible to determine the effect of a change in any one part of the system on all the other parts with which it is interfaced. This analysis makes extensive use of the LIMA computer model, described in detail in Appendix G.

F.3.4 Flowcharts

An initial step in constructing dynamic system models for multivariate forecasting is to develop flowcharts that depict probable causal relationships among all relevant variables. Because the relationships comprising these charts are derived primarily from theory rather than research, they are only hypotheses that must eventually be tested through empirical research. In addition, this lack of empirical data also prohibits assigning regression coefficients to any of the relationships in the flowcharts. Examples of two of these flowcharts are given in Figures F.2 and F.3. The first chart depicts the factors that would likely affect 10 different community structure indicators without a development project. The second chart then displays the factors that would likely affect these same community structure indicators if a proposed development project were carried out. These flowcharts are used in this analysis as a basis for estimating the general form and direction of social and economic impacts that cannot be quantified at the present time.

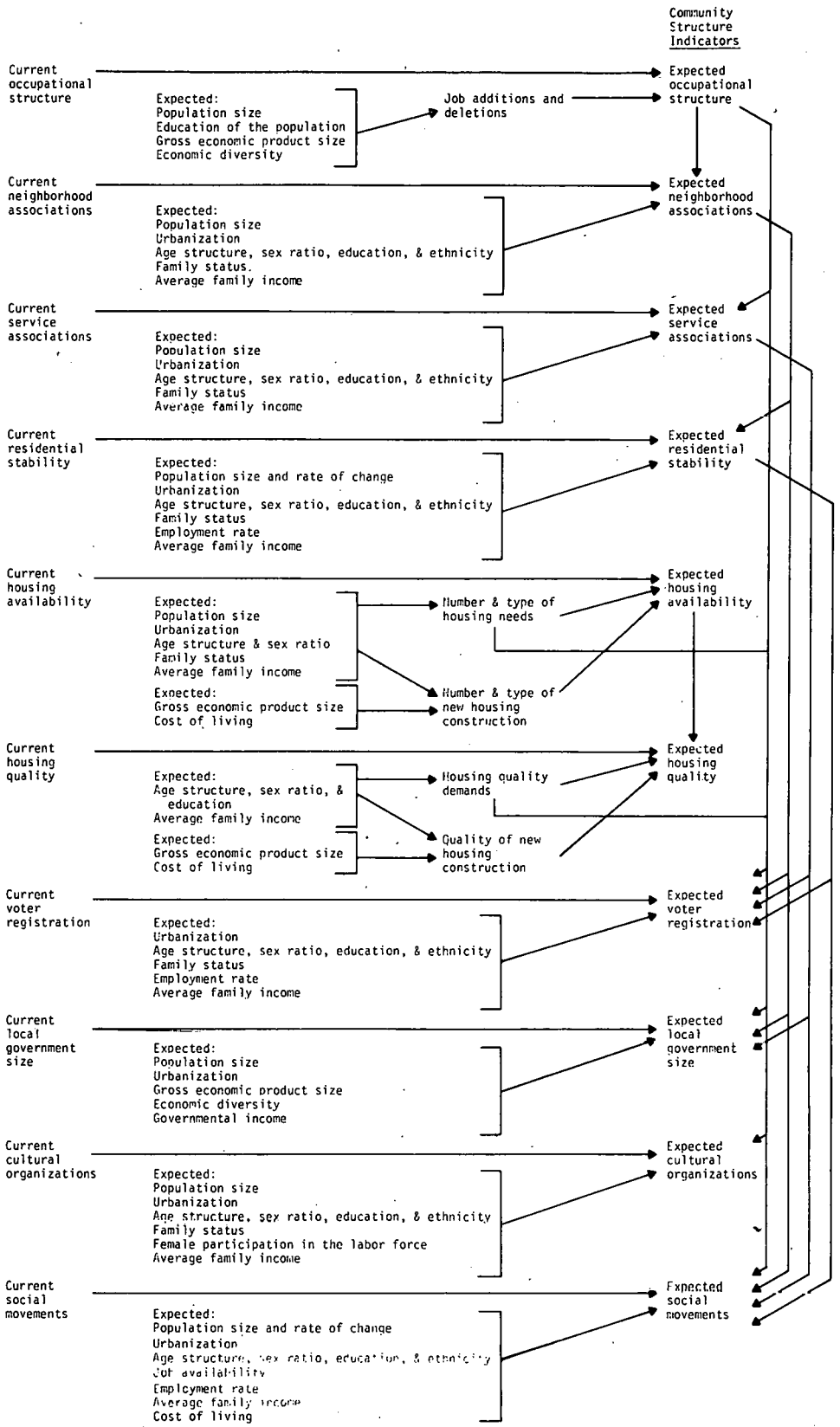
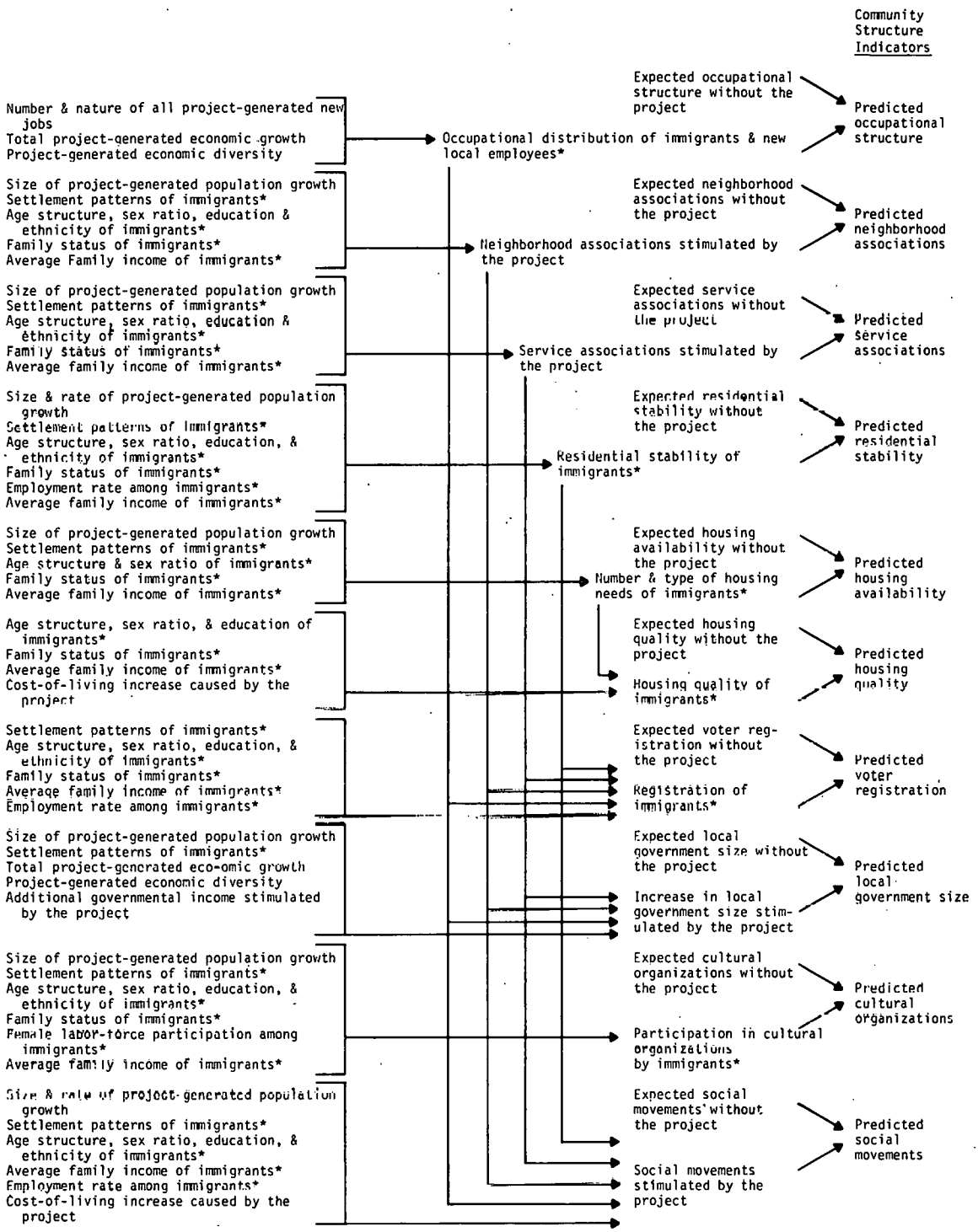


FIGURE F.2. Community Structure Flowchart Without the Proposed Project



*Immigrants generated by the project

FIGURE F.3. Community Structure Flowchart With the Proposed Project

APPENDIX G

LIMA MODEL DESCRIPTION

APPENDIX G

LIMA MODEL DESCRIPTION

The LIMA (Local Impact Management and Assessment) model is used to forecast the socioeconomic impacts on counties resulting from the construction of coal-fired electrical generation plants. Because it is a computer model it has several attractive features for use as a forecasting tool. Two of the most useful features, for the purpose of this report, are:

1. It quickly reveals the probable outcome of policy alternatives on a number of geographical regions,
2. Through the use of sensitivity analysis, parameters that maximally affect model behavior are revealed for further investigation.

The LIMA model was developed for use as a tool to rapidly and inexpensively evaluate the socioeconomic impacts in a number of geographical areas. As such its usefulness is limited to preliminary screening analyses, as in this report. Other techniques, such as regional input-output analysis and population polls, involving a more thorough examination of the factors that determine the socioeconomic impacts in a specific area, would be required before the impacts could be forecast with certainty.

The model results presented in this report required many assumptions and the collection of much data. While every effort was extended to obtain accurate data and to make reasonable assumptions, it is highly unlikely that all of these assumptions and data will be accurate over the time span of the analysis. As a result, the outputs presented here should be viewed as a series of "what if" analyses. The question addressed in each case is: "What are the impacts of power plant construction and operation in a particular county if the following set of assumptions is used?"

In making the computer analyses included in this report, a number of sensitivity tests were performed. As an example of the use of LIMA for sensitivity analysis, one such test is presented below.

Power plant construction workers can either reside in the county where the power plant is being constructed or in a surrounding area. If they choose to reside in the county they will have an impact on local conditions; however, if they choose to live in a surrounding area they are assumed to have no impact on local socioeconomic conditions.

The parameter PNCLBR (Percent New Construction Laborers Becoming Residents) is used to specify the percent of construction laborers who become residents in the county where construction is taking place. An initial data search revealed very little data or theory dealing with this parameter. At this point a sensitivity test was conducted to help determine if additional data collection efforts were warranted. These tests indicated that the local population and socioeconomic impacts were quite sensitive to the value of PNCLBR. As a result a more extensive data collection effort has been undertaken. The results of this test are presented in Figure G.1.

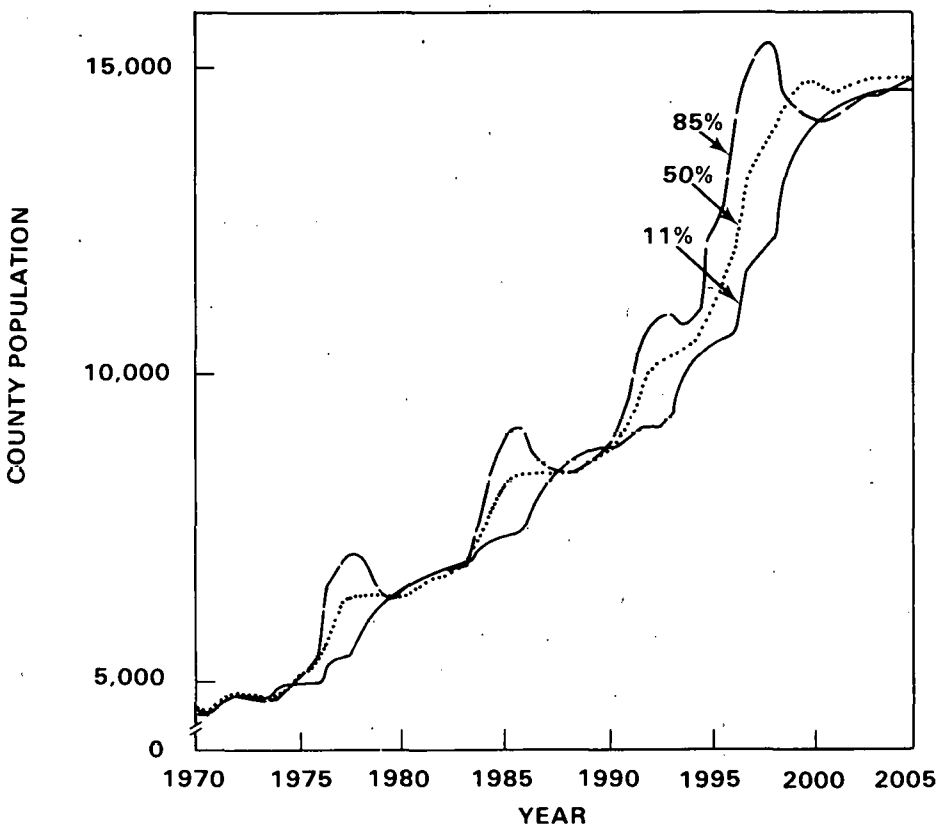


FIGURE G.1. Sensitivity of County Population to Percent of New Construction Laborers Becoming Residents

Figure G.1 shows the behavior of the population assuming values for PNCLBR of 11, 50, and 85%. In all three cases the population at the end of the run is the same since PNCLBR is the only parameter changed and it only has an influence during periods of power plant construction. In the 11% case the population increase is relatively smooth. In the 50% case the increase becomes slightly less smooth, while in the 85% case each power plant construction period induces an over-shoot and decline in the population.

Figure G.2 shows the behavior of the public service capital per capita (PSCPC) for the same cases. Public service capital is defined as the equivalent dollar value of the aggregate of all types of public services such as hospitals, water works, schools, and parks. It is assumed that in an equilibrium situation, $2000 PSCPC would exist. Because of delays involved in planning, financing, and constructing public services, it is difficult to maintain the "normal" or "equilibrium" conditions during periods of population change. The more rapid the change the more difficult it becomes to maintain a desired amount of PSCPC. During periods of population growth it is likely that a shortage of public services will exist while an excess may exist during periods of population decline. As shown in Figure G.2 the value of PNCLBR has a strong influence on the amount of public service capital maintained. In the case where 85% of the new construction laborers reside in the region, the PSCPC dips lower and for longer periods of time than either of the other cases. In the 11% case the PSCPC is maintained at the highest levels of the three cases.

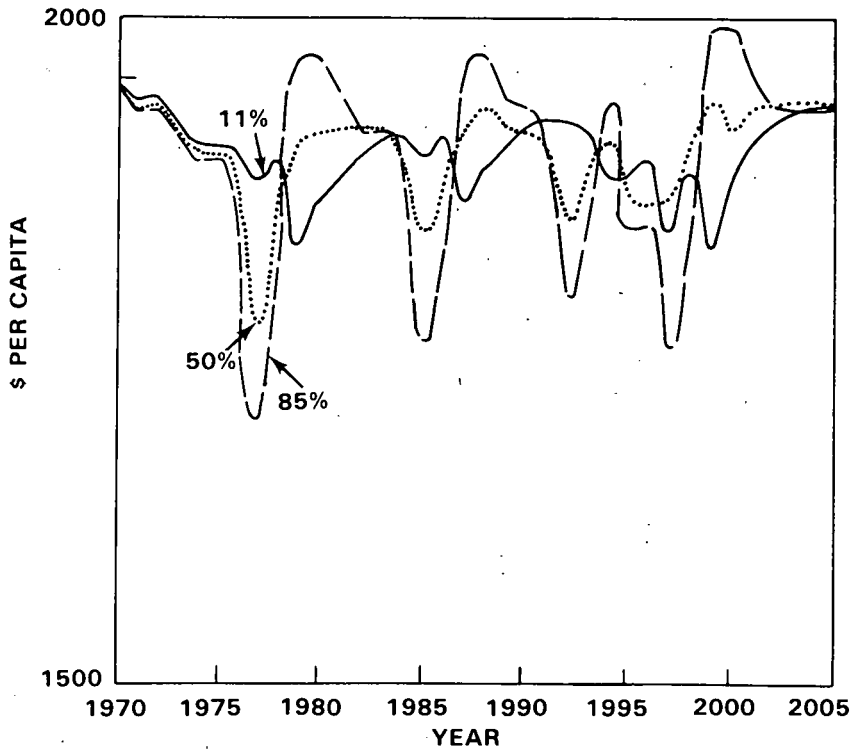


FIGURE G.2. Sensitivity of Public Service Capital per Capita to Percent of New Construction Laborers Becoming Residents

There are four major sectors in the LIMA model. These sectors and some of the interactions among them are shown in Figure G.3. Many other interactions exist within the model but are not shown here for clarity.

G.1 POWER PLANT SECTOR

The power plant sector simulates the construction and operation phases of a coal-fired electrical generating plant. In this sector the construction time, startup period, construction worker requirements, operating labor requirements, and percent construction completed are defined on a year-by-year basis.

The power plant sector supplies labor requirement information to the population sector and property value information to the public service sector for property tax assessment/generation tax assessment.

G.2 POPULATION SECTOR

The population sector of the LIMA model simulates the migration of population in response to employment opportunities. It is assumed that the relative availability of employment is the primary cause of migration. For example, if the unemployment rate in a county is lower than the unemployment rate in the surrounding region, a net migration into the county will occur. Conversely, if the unemployment rate in the county is higher than the unemployment rate in the surrounding region, a net migration out of the county will occur.

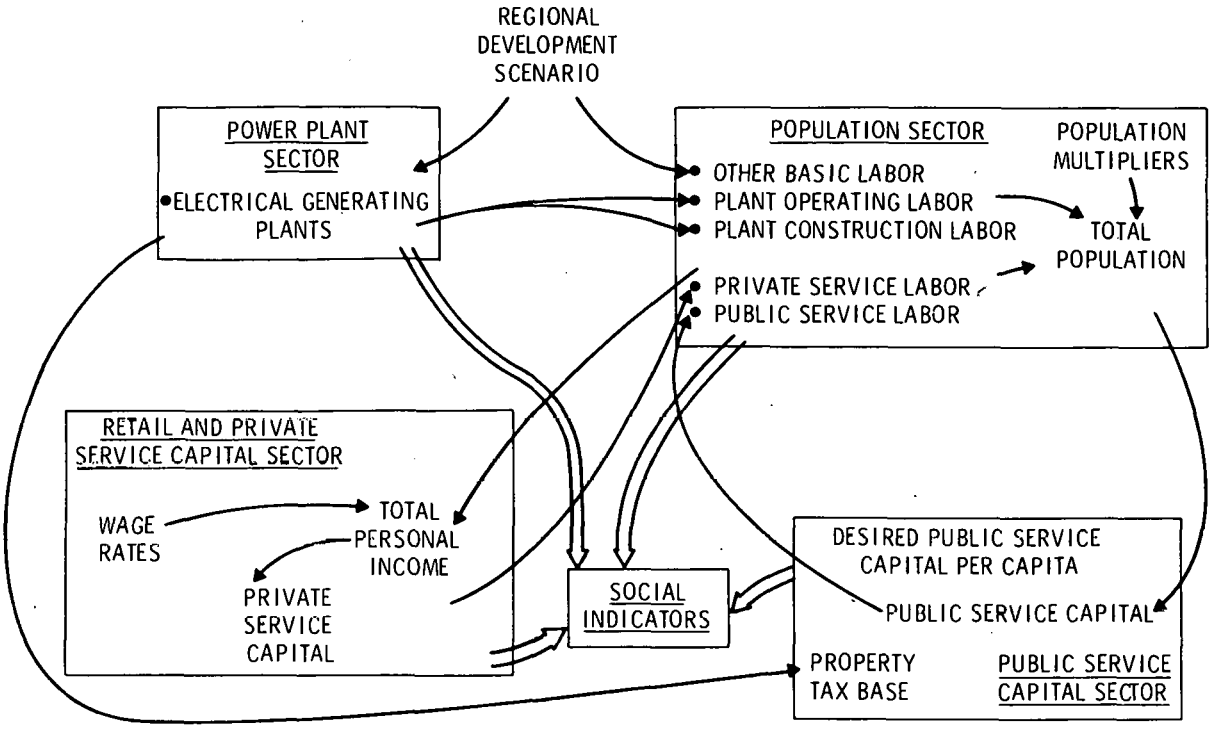


FIGURE G.3. Major Sectors and Sector Interactions in the LIMA Model

Four major job categories are explicitly represented in the model: 1) power plant construction laborers, 2) power plant operating laborers, 3) other basic laborers, and 4) service laborers. The number of power plant construction jobs and power plant operating jobs are determined by the power plant construction schedule. The other basic labor jobs are specified exogenously to represent the growth in a county in the absence of any power plant construction.

Economic base theory is used to relate the secondary or service employment to construction, operation, and other basic labor. The use of economic base theory in energy-related employment and population estimation is described by Stenehjem and Metzger.

> "According to economic base theory as new basic employment (in this instance, direct energy-related employment) increases in a region, impetus is given to the expansion of output and employment in local firms supplying inputs to the basic industry (i.e., indirect effects) as well as to local retail, commercial, and service firms that benefit from the increased personal income brought to the area by the basic industry (i.e., the income-induced effects). Estimates of the strength of these indirect and income-induced, or secondary, effects are typically measured with the aid of employment multipliers that relate the levels of secondary employment in an area to basic employment."(1)

The total population of the region is computed by adding the population associated with or accompanying the laborers in each of the four job classifications represented. The population associated with a particular job classification is computed by multiplying the number of laborers in that classification by the average number of people who are typically associated with laborers in that classification.

G.3 PUBLIC SERVICE CAPITAL SECTOR

As the number of people in a region increase, so does the amount of public service capital required. To maintain a constant amount of services per capita the amount of services must grow at the same rate as the population. The delays involved in planning, financing, and constructing public services make it doubtful that many communities will be able to plan and finance adequate public services in the face of rapid population growth. The amount of public services per capital maintained under different development scenarios is an important indicator of social well-being in the model. The major source of financing for public services is through local property taxes. The number of public service jobs available is a function of the amount of public service capital.

G.4 RETAIL AND PRIVATE SERVICE CAPITAL SECTOR

As with public services, the amount of retail and private service capital maintained is an important indicator of social well-being. When the population increases, the retail and private service capital must increase at the same rate to maintain the same amount of services per capita. By definition, retail and private services are privately financed; as a result, any additional investment in a county must be viewed as an attractive investment by private business. The primary criteria for such an investment is the presence of an adequate market for products and services as indicated by the total personal income in the area. In addition, the investor must perceive that the increased personal income will be maintained over the life of this investment. This may not be true since the construction employment is typically much greater than the operating employment for an electrical generating plant. In the runs presented in this report, it is assumed that the businesses completely disregard the personal income of the construction labor in their decision to make additional investments in private service capital.

G.5 SOCIAL INDICATOR SECTOR

The socioeconomic impacts of coal-fired electrical generating plant construction on a local area are being assessed by use of a series of quality of social life indicators. As indicated in Figure G.3, information used to compute these indicators comes from all sectors of the model.

REFERENCE FOR APPENDIX G

1. E. J. Stenehjem and J. E. Metzger, A Framework for Projecting Employment and Population Changes Accompanying Energy Development, Phase I. Argonne National Laboratory, Argonne, IL, p. 3, August 1976, (Draft).

APPENDIX H

CURRENT COUNTY CHARACTERISTICS

APPENDIX H

CURRENT COUNTY CHARACTERISTICS

H.1 DEMOGRAPHIC CHARACTERISTICS

Population Size. These 15 counties range in size from 2,000 (Gilliam, Oregon) to 177,000 (Anchorage, Alaska). The mean size of the other 13 counties is 38,000. In general, counties with a population less than 25,000 are likely to be severely impacted by the population influx from a large construction project such as a generating plant.[1] This would include Elmore County in Idaho, Gilliam, Malheur, and Morrow Counties in Oregon, and Douglas and Lincoln Counties in Washington. Moreover, if the project were especially large (such as four colocated generating plants), counties up to 50,000 might experience serious disruptions from rapid population growth. This would include all the remaining counties except Anchorage, Coos County in Oregon, and Grays Harbor and Whatcom Counties in Washington.

Population Change. General population growth can be considered a serious problem when it exceeds a rate of 10% a year.[1] Even a single project can produce population growth exceeding this rate in rural areas. And more urbanized areas can also exceed that growth rate if they are already experiencing a rapid population increase from other sources. Thus, the development project would only aggravate what was already a critical condition for that area. This would definitely be the case in Anchorage, which has recently had an annual population growth rate of over 8%, adding approximately 10,000 new people each year. Gilliam County in Oregon, however, has experienced a population decline in recent years. Presumably, therefore, it might welcome the population inflow generated by a large construction project--provided that it had not already lost its capacity to absorb additional people. Growth rates in the remaining counties range from almost zero to slightly over 3% per year.

Urbanization. Counties that are largely or wholly rural in nature (no towns with more than 10,000 people) will generally have a much more difficult time absorbing a sudden influx of construction workers than will counties containing one or more urban centers. Apart from the fact that construction workers generally prefer to live in or near towns and that most unoccupied housing will be in urban areas, such communities are also usually much better prepared to manage socioeconomic impacts and to provide needed public services and facilities. In addition, the lifestyles of both construction and operational workers are often quite different from those of rural dwellers. Seven of the 15 candidate counties contain no towns over 10,000 population and are essentially rural in character: Bingham and Elmore, Idaho; Gilliam, Malheur and Morrow, Oregon; and Douglas and Lincoln, Washington.

Sex Ratio. This factor is likely to be a problem only if the sex ratio of the current population is already unbalanced so that a sudden influx of male construction workers would add to already existing social problems. This would occur in Anchorage and in Elmore County, Idaho, which contain large surpluses of males. The rest of the counties (with the exception of Bingham, Idaho) presently have a surplus of females; thus, a construction project might help to balance the sex ratio (although the current "surplus" females tend to be elderly whereas the male immigrants would tend to be relatively young).

Nonwhite Population. The nonwhite populations of these 15 counties range from 2% to 15% of the total. Counties with very few nonwhites are Coos and Gilliam, Oregon; and Douglas and Lincoln, Washington. In contrast, Franklin and Grant Counties, Washington have relatively large nonwhite populations, as does Anchorage. Since construction work forces are likely to contain at least moderate numbers of nonwhites, racial tensions or conflicts could occur in areas where the population is presently nearly all white.

Median Age. In general the younger a population, the more adaptable it tends to be to changing conditions, especially to the in-migration of predominantly young construction workers. Older populations tend to be more resistant to change. If we set age 30 as a dividing line, counties with young populations are Anchorage (where the median age is only 19); Bingham and Elmore, Idaho; Coos and Malheur, Oregon; and Cowlitz, Franklin, Grant, Grays Harbor and Whatcom, Washington. The remaining counties could then be described as having old populations; this is most evident for Lincoln County, Washington.

Presence of Children. The proportion of families with children in the home is directly related to the median age of the population--the younger the population, the greater the number of families with children. Children are also more likely to be present in rural areas. Anchorage contains a large proportion of families with children because of its very young age structure.

Bingham and Elmore Counties, Idaho also contain many children because of both their young populations and their rural character. In contrast, Grant and Grays Harbor Counties, Washington also have relatively young populations but not large numbers of families with children, presumably because of their more urban nature. Three counties, Clatsop and Morrow, Oregon and Lincoln in Washington, contain relatively few families with children because of their older populations.

Education. With the exception of Coos County, Oregon where the median education is only 11.5 years, these counties show little variance in the educational attainments of their populations. Median figures for the other 14 counties range only between 12.2 and 12.7 years, indicating that these counties are relatively homogeneous in this characteristic.

H.2 ECONOMIC CHARACTERISTICS

Gross Sales. The two indicators, gross sales per capita and annual rate of sales growth, are both measures of the economic viability of a county. Five of these counties have very robust economies at the present time with gross sales of $10,000 or more per capita: Gilliam and Malheur, Oregon and Cowlitz, Grant and Lincoln, Washington. These counties differ considerably in their recent rates of economic growth, however.

Grant County has been growing extremely rapidly; Gilliam and Cowlitz have had moderately strong rates of growth; Malheur and Lincoln have experienced rather slow economic growth (all of these rates are based on constant dollars to account for inflation). In contrast Elmore County, Idaho, and Douglas County, Washington have fairly weak economies with gross sales of less than $5,000 per capita, although Elmore has experienced a very high growth rate in recent years. Three other counties to note are Clatsop, Oregon, whose economy has been declining rather than growing recently, and Bingham, Idaho and Grays Harbor, Washington, which have both had very slow rates of economic growth.

Job Openings. No clear relationship exists between rate of growth in gross sales and the availability of jobs in these counties. Those with the largest number of job openings (over 200 per 10,000 members of the labor force) are Anchorage, Alaska and Gilliam, Malheur (where the figure is over 500) and Morrow Counties, Oregon. At the opposite end of the scale Clatsop County, Oregon and Cowlitz, Franklin and Whatcom Counties, Washington report relatively few job openings (less than 100 per 10,000 workers).

This indicator is important because it affects the number of both construction and secondary workers who will likely migrate to the county. The greater the number of job openings in the area before starting the project, the more attractive an area should be to prospective workers.

Employment Rate. No relationship exists between number of job openings and the employment (or unemployment) rate. The lowest employment rate (88%), indicating a rather large number of people looking for work, occurs in Coos County, Oregon, which has an average number of job openings. In contrast Lincoln County, Washington has almost full employment (98%); it also has an average number of vacant jobs. Employment rates in the remaining 13 counties range between 90% and 94%.

Number of Businesses. If the shopping, service, recreational and other facilities are currently inadequate in an area, a sudden population increase is likely to place at least short-term strains on the local business community. Only three of these counties might be described as having fewer than adequate business facilities at the present time: Bingham and Elmore, Idaho and Douglas, Washington. The rest of the counties have business facilities that are probably adequate to handle the population growth created by a new generating plant, although particular kinds of stores or services may be lacking in some counties.

Personal Income. The mean personal income for the entire United States is approximately $5,400. Against this criterion, six of these counties are substantially more affluent than the United States as a whole (i.e., mean personal income at least $1,000 greater than the average). These are Anchorage, Alaska; Gilliam and Morrow Counties, Oregon (both of which have extremely high income levels); and Franklin, Grant and Lincoln Counties, Washington. Only one county, Elmore, Idaho, is more than $1,000 below the national average in personal income, while Bingham County, Idaho and Coos County, Oregon are each several hundred dollars below average. Since wages of construction workers are typically several thousand dollars above prevailing wage levels in most areas of the country, a large construction project can substantially increase the average personal income of the surrounding area. This financial inflow is commonly welcomed in low income areas, especially to the extent that the wages of construction workers are spent locally. Obviously, however, this process of raising the average personal income does not occur in high income areas, although the additional wealth flowing into the local economy may nevertheless contribute to rising prices and economic inflation.

Property Value. The differences among these 15 counties in the amounts of real property per capita are astonishing. (These figures represent full property values, or 100% of assessed valuation.) Elmore County, Idaho has only $2,600 of property per capita and Bingham County has only about $6,000, while Gilliam County, Oregon has over $34,000 and Morrow County has more than $30,000. The mean figure for all 15 counties is approximately $16,000 per capita, although

all but Clatsop County, Oregon are at least $2,000 above or below this figure. A large generating plant located in Bingham or Elmore Counties would certainly raise their total property values by a considerable amount, which could have numerous other secondary economic effects on their economies. In the six counties above the mean figure of $16,000 only Gilliam, Oregon and Lincoln, Washington, due to their very small populations, should experience substantial increases in per capita property values with the construction of a large generating plant.

Governmental Income. Gross discrepancies exist among counties in the measure of governmental income. In Anchorage local governments receive almost $3,000 per person per year and in Grays Harbor and Lincoln Counties, Washington governmental income is about $1,100 per person. In sharp contrast local governments in Douglas County, Washington receive less than $500 per person, while the figures are only slightly higher in Elmore County, Idaho and Gilliam County, Oregon.

Local governments in the latter three counties are especially likely to suffer serious financial problems with the construction of a large generating plant, for they quite likely lack adequate resources to provide the additional services and facilities needed by in-migrating workers. This financial squeeze can become a difficult problem in any community if the demands made on local governments rise very rapidly without a corresponding increase in revenues. It is particularly critical in communities that have no slack financial resources above present demand.

H.3 COMMUNITY STRUCTURE CHARACTERISTICS

Occupational Structure. The proportion of the work force in an area that is engaged in high status occupations (professional), technical, executive and managerial) is socially important for two main reasons: first, it strongly influences the socioeconomic class structure of the area; and second, it affects the distribution and exercise of social power in that area. In general the higher the proportion of high status occupations in a community, the better that community (or county) will be able to cope with rapid social changes and impacts created by a large construction project. Among these counties Anchorage and Gilliam rank highest on this measure, although 11 of the 15 counties are above the national average of 19%. The only two counties with noticeably low occupational structures are Elmore, Idaho and Morrow, Oregon.

Housing Availability. The greater the supply of available housing in the area surrounding a construction project, the more easily and inexpensively the workers can be absorbed into existing communities. In Gilliam County, 36% of all dwelling units are vacant, although this represents only about 240 actual units. The vacancy rates are also high in Grant and Grays Harbor Counties, Washington (20% and 24% respectively), and with their large populations, these percentages represent substantial numbers of housing units. Clatsop and Morrow Counties also contain a fair amount of available housing. In the other 11 counties, however, a large influx of construction workers looking for housing could become a serious problem since vacancy rates for these counties are relatively low.

H.4 PUBLIC SERVICE CHARACTERISTICS

Expenditures for Public Services. This indicator is the total amount of funds per capita spent annually by all local governmental units in the county for all human services, including

public education, hospitals and mental health facilities, police and fire protection, legal services, welfare programs, information and counseling services, children and youth programs, libraries and other cultural activities, and public recreational programs. Anchorage tops the list, spending over $1,100 per person per year on these services. In contrast seven of the counties (Bingham and Elmore, Idaho; Clatsop, Oregon; and Cowlitz, Douglas, Grays Harbor and Whatcom, Washington) spend less than $500 per person for public services. Assuming that these low expenditures indicate minimal public service programs, those seven counties could experience rather serious problems if a large number of construction workers were to suddenly descend upon them and begin needing all kinds of services from schools to welfare benefits.

Expenditures for Public Facilities. This category of public expenditures includes such physical facilities as water and other public utilities, sewerage and sanitation facilities, and streets and roads. Anchorage is currently spending over three times as much per capita ($720) for such facilities as any other area in this study. The figures for Malheur County, Oregon and all the counties in Washington except Cowlitz are also above the national average of approximately $100 per person. In striking contrast are Bingham and Elmore Counties, Idaho; and Clatsop, Coos and Gilliam Counties, Oregon, where the figures are less than $75 per capita. Again assuming that low expenditures indicate minimal facilities, these latter five counties could be seriously impacted by a large construction facility as demands quickly exceeded available capabilities and budgets.

School Capabilities. The ratio of students to teachers in the public schools of a county provides a rough indicator of the quality of education being offered. Relatively little variation on this measure occurs among the 15 counties except for the rather low ratios in Gilliam and Morrow Counties, Oregon. Maintaining such low ratios is undoubtedly made easier by the very small populations of these two counties. In all other cases, the ratio lies between 18 and 23 students per teacher. All of these school systems could, therefore, absorb at least some additional students by enlarging class sizes if necessary.

Hospital Facilities. Gilliam County, Oregon and Douglas County, Washington contain no hospitals; this could be a serious problem if a large construction project were to be located in those areas. With the exception of Lincoln County, Washington, which has 15 hospital beds per thousand population, all the other counties contain minimal hospital facilities, between three and six beds per thousand. However, all of them are below the national average of seven beds per thousand. All of these counties might find it necessary to expand their hospital facilities to accommodate a large influx of construction workers.

Police Protection. Coos County, Oregon and Franklin and Grays Harbor Counties, Washington have fairly large police forces, while those in Bingham County, Idaho; Clatsop and Morrow Counties, Oregon; and Cowlitz and Douglas Counties, Washington might be described as adequate. Police forces are extremely understaffed in Gilliam County, Oregon and somewhat understaffed in Anchorage, Alaska; Malheur County, Oregon; and Lincoln County, Washington. In at least those four areas a large population influx would likely require hiring additional police personnel.

Fire Protection. Fire departments are severely understaffed in five of these counties: Elmore, Idaho; Coos, Gilliam and Malheur, Oregon; and Douglas, Washington. Construction of a large generating plant in any of these counties would undoubtedly require enlarging existing fire protection services. The rest of the counties have relatively adequate fire services and Clatsop County, Washington has almost twice as many fire personnel as the national average.

TABLE H.1. Current County Characteristics: Demographic Indicators[a]

State/County	Population Size	Annual Population Change[b] Amount	Annual Population Change[b] Percent	Percent Urbanization[c]	Sex Ratio[d]	Percent Nonwhite[e]	Median Age	Percent Families with Children[f]	Median Education[g]
Alaska									
Anchorage	177,800	10,300	8.2	48	110	11	19	65	12.4
Idaho									
Bingham	32,300	620	2.1	0	100	8	23	62	12.4
Elmore	19,800	460	2.6	0	117	8	24	62	12.3
Oregon									
Clatsop	29,100	140	0.5	37	96	6	33	46	12.4
Coos	59,000	500	0.9	23	95	2	29	51	11.5
Gilliam	2,000	-70	-2.6	0	97	2	31	50	12.7
Malheur	24,400	240	1.0	0	96	5	28	54	12.2
Morrow	5,200	150	3.2	0	96	7	33	47	12.4
Washington									
Cowlitz	71,000	540	0.8	56	97	3	28	51	12.3
Douglas	19,000	260	1.6	0	97	2	30	53	12.5
Franklin	27,500	140	0.5	53	95	15	26	58	12.6
Grant	43,900	680	1.6	23	98	14	24	56	12.3
Grays Harbor	60,500	220	0.4	49	98	5	24	52	12.2
Lincoln	9,500	20	0.2	0	96	2	37	44	12.2
Whatcom	90,000	1,720	2.1	47	95	5	27	52	12.5

(a) Circa 1975
(b) Between 1970-1975
(c) In cities ± 10,000
(d) Males per 100 females
(e) Including Spanish surname people
(f) Under age 18 present in the home
(g) Persons age 25+

TABLE H.2. Current County Characteristics: Economic Indicators[a]

State/County	Annual Gross Sales Receipts Per Capita	Annual Gross Sales Receipts Percent Growth[b]	Job Openings Per 1000 Workers[c]	Employment Rate[d]	Businesses Per 1000 People	Personal Income Per Capita[e]	Property Value Per Capita[f]	Governmental Income Per Capita[g]
Alaska								
Anchorage	$ 6,140	8.3	210	93	20	$ 7,160	$ 18,180	$ 2,980
Idaho								
Bingham	7,700	3.2	150	94	15	4,910	6,100	610
Elmore	4,530	14.2	170	93	13	4,280	2,620	570
Oregon								
Clatsop	5,570	-3.1	80	90	26	5,050	16,550	650
Coos	8,000	4.2	100	88	23	4,560	11,030	780
Gilliam	12,390	9.6	200	92	23	8,820	34,380	540
Malheur	10,660	3.9	510	93	25	5,300	10,590	790
Morrow	8,510	6.1	250	93	22	9,530	30,550	730
Washington								
Cowlitz	11,510	7.5	90	93	19	5,430	19,830	680
Douglas	3,350	4.9	120	91	12	5,260	11,480	490
Franklin	9,980	8.9	80	93	25	7,520	14,430	810
Grant	14,950	17.9	150	91	22	6,930	12,480	690
Grays Harbor	8,510	2.8	160	92	25	5,110	12,170	1,100
Lincoln	11,640	4.7	150	98	26	6,540	24,880	1,120
Whatcom	9,510	7.5	90	90	24	5,020	13,740	816

(a) Circa 1975
(b) Between 1967-1975, in constant dollars
(c) Reported to the Public Employment Office
(d) Of the labor force
(e) In 1974 dollars
(f) Full actual value
(g) Received annually by all local governmental units from all sources (excluding local transfers)

TABLE H.3. Current County Characteristics: Community Structure Indicators[a]

State/County	Percent High-Status Occupations[b]	Percent Housing Vacant[c]	Local Government Employees[d]	Percent Families Poor[e]
Alaska				
Anchorage	27	7	24	5
Idaho				
Bingham	22	8	27	12
Elmore	14	9	23	12
Oregon				
Clatsop	25	14	31	10
Coos	18	4	29	9
Gilliam	27	36	55	9
Malheur	23	7	35	16
Morrow	13	13	42	13
Washington				
Cowlitz	19	4	29	8
Douglas	21	6	24	10
Franklin	22	5	35	9
Grant	24	20	38	14
Grays Harbor	18	9	28	10
Lincoln	20	24	59	8
Whatcom	23	8	21	10

(a) Circa 1975
(b) Labor force in professional, technical, executive and managerial jobs
(c) Dwelling units currently unoccupied
(d) All local governments, per 1000 population
(e) Below the official poverty line

TABLE H.4. Current County Characteristics: Public Services Indicators[a]

State/County	Annual Local Governmental Expenditures Per Capita: Public Services[b]	Annual Local Governmental Expenditures Per Capita: Public Facilities[c]	School Student-Teacher Ratio[d]	Hospital Beds Per 1000 People	Police Personnel Per 10,000 People[e]	Fire Personnel Per 10,000 People[f]
Alaska						
Anchorage	$ 1,160	$ 720	21	6	15	12
Idaho						
Bingham	420	67	21	3	23	16
Elmore	410	58	18	3	18	1
Oregon						
Clatsop	430	53	18	5	22	26
Coos	590	72	20	4	29	7
Gilliam	610	44	14	0	10	0
Malheur	700	140	18	6	15	5
Morrow	610	69	15	4	21	10
Washington						
Cowlitz	370	92	21	4	21	11
Douglas	310	230	23	0	22	7
Franklin	540	230	21	3	28	16
Grant	680	120	21	4	18	14
Grays Harbor	400	110	21	4	27	15
Lincoln	750	170	20	15	15	10
Whatcom	480	160	21	3	17	12

(a) Circa 1975
(b) Annual operational expenditures for all human services
(c) Annual expenditures for streets, utilities, and sanitation
(d) All public schools
(e) All police employees
(f) All fire employees

TABLE H.5. Current County Planning Capabilities[a]

State/County	County and City Planning Departments: Unit(s)	Total Professional Staff	Total Annual Budget(s)	Comprehensive Plan	Regional Planning Organizations: Name	Total Professional Staff	Total Annual Budget	Comprehensive Plan
Alaska								
Anchorage	City	30	$1,000,000	yes	None			
Idaho								
Bingham	County	3	50,000	yes	SE Idaho Coun. of Gov.	10	$800,000	Land use
Elmore	County	2	19,000	no	ID-OR Reg. Devel.	8	170,000	yes
Oregon								
Clatsop	County and Astoria	7	84,000	yes	Clatsop-Tillamook Intergovern. Council	13	300,000	no
Coos	County and Coos Bay	8	179,000	no	Coos-Curry Council of Government	10	266,000	yes
Gilliam	County	1/2	5,000	yes	E.C. OR Assoc. of Gov.	9	384,000	no
Malheur	County	7	103,000	yes	ID-OR Reg. Devel.	see above		
Morrow	County	2	42,000	no	None			
Washington								
Cowlitz	County and Longview	5	117,000	yes	Cowlitz-Wahkiakum Governmental Council	4	134,000	no
Douglas	County	2	64,000	no	Grand Coulee Dam Area Conf. of Govs.	0	0	yes
Franklin	County and Pasco	4	89,000	yes	Benton-Franklin Governmental Council	8	262,000	no
Grant	County and Moses Lake	6	208,000	no	Grant-Lincoln-Adams Conf. of Govs.	1	20,000	no
Grays Harbor	County, Aberdeen, Hoquiam	4	79,000	yes	Grays Harbor Regional Planning Commission	4	88,000	yes
Lincoln	County	1	21,000	no	Grant-Lincoln-Adams	see above		
Whatcom	County and Bellingham	11	426,000	yes	Whatcom County Council of Govs.	1	107,000	yes

(a) Circa 1976

REFERENCES FOR APPENDIX H

1. U.S. Department of Housing and Urban Development, Regional Growth from Energy Projects. GPO, Washington, DC, 1976.

APPENDIX I

PROJECTED COUNTY CHARACTERISTICS

TABLE I.1. Projected County Characteristics: Bingham County, Idaho

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	33,600	1.6	0	23	12.4	$7,700	0.0	$4,940	$6,100	0	$ 1,660	$ 0	$ 0
1985	36,700	1.8	29	23	12.4	7,700	0.0	4,940	6,100	0	1,660	0	0
1990	39,900	1.7	29	23	12.4	7,700	0.0	4,940	6,100	0	1,660	0	0
1995	43,500	1.8	36	23	12.5	9,160	3.8	5,110	12,080	1,030	1,610	1,510	420
2000	47,400	1.8	36	23	12.5	8,590	-1.3	4,920	15,420	930	1,610	1,590	430
2005	49,100	0.7	36	23	12.5	8,590	0.0	4,890	15,140	950	1,620	1,650	340
2010	50,000	0.4	35	23	12.5	8,670	0.2	4,890	15,370	950	1,620	1,650	330
2015	51,800	0.1	38	23	12.5	8,950	0.6	4,890	18,900	1,400	1,590	2,440	550
2020	52,400	0.2	38	23	12.5	8,950	0.0	4,870	18,790	1,430	1,600	2,490	460
High Coal Electric													
1980	33,600	1.6	0	23	12.4	7,700	0.0	4,940	6,100	0	1,660	0	0
1985	36,700	1.8	0	23	12.4	7,700	0.0	4,940	6,100	0	1,660	0	0
1990	39,900	1.7	29	23	12.4	7,830	0.3	4,940	6,600	0	1,660	0	0
1995	45,300	2.7	39	23	12.5	9,710	4.8	5,130	18,480	1,520	1,560	2,330	870
2000	51,500	2.7	41	23	12.6	9,360	-0.7	4,910	23,220	1,840	1,560	3,180	1,010
2005	53,600	0.8	41	23	12.6	9,320	-0.1	4,860	22,610	1,900	1,580	3,310	680
2010	54,600	0.4	41	23	12.6	9,300	0.0	4,860	22,340	1,900	1,580	3,310	650
2015	54,700	0.0	41	23	12.6	9,290	0.0	4,850	22,300	1,900	1,580	3,330	610
2020	54,700	0.0	41	23	12.6	9,290	0.0	4,850	22,300	1,900	1,580	3,330	600

TABLE I.2. Projected County Characteristics: Elmore County, Idaho

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	23,100	3.2	0	24	12.3	$4,530	0.0	$4,310	$2,620	0	$1,200	$ 0	$ 0
1985	27,000	3.4	49	24	12.5	6,870	10.3	4,610	10,930	1,220	1,150	1,720	720
1990	32,000	3.7	53	24	12.5	7,370	1.5	4,610	16,610	1,780	1,150	2,680	1,130
1995	36,600	2.9	50	24	12.5	6,590	-2.1	4,440	20,780	1,590	1,180	2,590	640
2000	42,200	3.1	51	24	12.5	6,590	0.0	4,400	18,700	1,820	1,200	3,090	840
2005	45,900	1.8	56	24	12.6	7,910	4.0	4,580	22,730	3,090	1,170	4,930	1,350
2010	48,700	1.2	53	24	12.6	6,910	-2.5	4,410	21,180	2,450	1,210	4,170	1,000
2015	49,300	0.3	53	24	12.6	6,900	0.0	4,400	21,010	2,480	1,210	4,250	800
2020	49,300	0.0	53	24	12.6	6,900	0.0	4,400	21,000	2,480	1,210	4,260	770
High Coal Electric													
1980	23,100	3.2	0	24	12.3	4,750	1.0	4,310	3,480	0	1,200	0	0
1985	30,700	6.6	61	23	12.6	9,510	20.0	4,980	24,700	2,610	1,050	4,050	2,240
1990	38,100	4.8	61	23	12.7	8,730	-1.5	4,720	31,520	3,140	1,140	5,020	1,800
1995	46,500	4.4	63	23	12.7	8,990	0.5	4,660	31,960	4,110	1,150	6,710	2,320
2000	50,900	1.9	59	23	12.7	7,950	-2.3	4,470	29,220	3,660	1,200	6,230	1,650
2005	53,100	0.9	58	23	12.7	7,830	-0.3	4,460	28,190	3,690	1,200	6,320	1,380
2010	54,800	0.6	58	23	12.7	7,720	-0.3	4,450	27,380	3,700	1,200	6,330	1,350
2015	55,200	0.2	58	23	12.7	7,720	0.0	4,440	27,240	3,720	1,210	6,400	1,180
2020	55,200	0.0	58	23	12.7	7,720	0.0	4,440	27,240	3,720	1,210	6,410	1,160

TABLE I.3. Projected County Characteristics: Clatsop County, Oregon

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980													
1985													
1990													
1995													
2000						No Coal Power Plants Scheduled							
2005													
2010													
2015													
2020													
High Coal Electric													
1980	33,800	1.9	37	33	12.4	$5,570	0.0	$5,050	$16,600	0	$1,570	$ 0	$ 0
1985	36,700	1.7	37	33	12.4	5,570	0.0	5,050	16,600	0	1,570	0	0
1990	39,600	1.6	37	33	12.4	5,570	0.0	5,050	16,600	0	1,570	0	0
1995	45,100	2.8	49	30	12.5	8,710	11.6	5,390	33,500	210	1,470	3,110	780
2000	52,000	3.1	46	31	12.5	7,480	-2.8	5,520	33,400	170	1,550	2,800	820
2005	57,500	2.1	55	29	12.6	9,630	5.7	5,450	39,800	380	1,480	5,990	1,820
2010	59,500	0.7	49	31	12.6	8,090	-3.2	5,250	38,700	260	1,560	4,310	1,000
2015	60,000	0.2	49	31	12.6	8,080	0.0	5,230	38,500	260	1,560	4,370	800
2020	60,100	0.0	49	31	12.6	8,080	0	5,230	38,500	260	1,560	4,370	790

TABLE I.4. Projected County Characteristics: Coos County, Oregon

Year	Population Size	Population Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales Amount Per Capita	Gross Sales Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s) Operating ($1000)	Public Services Expenditures Due To the Plant(s) Capital ($1000)
Recent Trends													
1980	67,200	1.9	23	29	11.5	$8,000	0.0	$4,590	$11,000	0	$1,550	$24,070	$ 0
1985	73,000	1.7	23	29	11.5	8,000	0.0	4,590	11,000	0	1,560	26,190	0
1990	80,600	2.1	27	29	11.6	8,900	2.3	4,710	15,300	1,130	1,520	28,960	500
1995	89,100	2.1	30	28	11.7	9,300	0.9	4,750	20,900	1,960	1,510	32,400	780
2000	95,700	1.5	29	29	11.6	8,830	-1.0	4,650	20,100	1,500	1,540	34,730	600
2005	98,900	0.7	28	29	11.6	8,800	0.0	4,640	19,800	1,500	1,550	36,000	530
2010	101,600	0.5	28	29	11.6	8,790	0.0	4,640	19,500	1,500	1,550	36,990	520
2015	102,200	1.2	28	29	11.6	8,730	0.0	4,630	19,500	1,500	1,550	37,310	460
2020	102,200	0.0	28	29	11.6	8,780	0.0	4,630	19,500	1,500	1,550	37,340	460
High Coal Electric													
1980	67,200	1.9	23	29	11.5	$8,000	0.0	$4,590	$11,000	0	$1,550	$ 0	$ 0
1985	76,600	2.8	32	28	11.7	9,790	4.5	4,850	20,000	2,070	1,480	3,110	980
1990	85,300	2.3	29	28	11.7	8,930	-1.8	4,670	21,200	1,480	1,530	2,450	680
1995	91,000	1.3	29	28	11.5	8,880	-0.1	4,650	20,600	1,500	1,540	2,490	590
2000	95,900	1.1	29	29	11.6	8,880	0.0	4,650	20,300	1,500	1,540	2,490	580
2005	100,200	1.9	30	28	11.7	8,990	0.3	4,660	21,900	1,870	1,540	3,120	690
2010	103,400	0.6	29	28	11.7	8,970	0.0	4,650	21,500	1,880	1,540	3,150	660
2015	104,000	0.1	29	28	11.7	8,960	0.0	4,640	21,500	1,890	1,550	3,180	580
2020	104,000	0.0	29	28	11.7	8,960	0.0	4,640	21,500	1,890	1,550	3,180	570

TABLE I.5. Projected County Characteristics: Gilliam County, Oregon

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	2,800	1.5	0	31	12.7	$12,390	0.0	$8,950	$34,380	0	$ 4,850	$ 0	$ 0
1985	3,100	2.1	0	31	12.7	12,390	0.0	8,930	34,380	0	4,850	0	0
1990	3,300	1.3	0	31	12.7	12,390	0.0	8,920	34,380	0	4,850	0	0
1995	3,600	1.8	0	31	12.7	12,390	0.0	8,900	34,380	0	4,850	1,280	310
2000	3,800	1.1	0	31	12.7	13,720	2.2	8,900	39,710	0	4,850	1,360	510
2005	6,000	11.6	0	27	13.0	18,500	7.0	8,000	89,050	570	3,360	2,090	1,670
2010	9,900	13.0	0	24	13.1	22,000	3.8	7,500	101,710	1,460	2,470	3,520	2,040
2015	10,800	1.8	0	26	13.2	19,140	-2.6	6,530	96,350	1,430	2,600	3,950	960
2020	10,800	0.0	0	26	13.1	19,120	0.0	6,510	96,110	1,440	2,600	3,990	730
High Coal Electric													
1980	2,800	1.5	0	31	12.7	12,390	0.0	$8,950	$34,380	0	$ 4,850	$ 0	$ 0
1985	3,100	2.1	0	31	12.7	12,390	0.0	8,930	34,380	0	4,850	0	0
1990	3,800	4.5	0	28	12.8	20,100	12.5	9,000	74,900	270	4,260	410	310
1995	10,700	36.3	0	25	13.2	21,500	1.4	6,790	126,350	1,650	2,100	2,560	3,080
2000	17,600	12.9	88	24	13.3	21,270	-0.2	6.140	120,660	3,010	1,900	4,960	3,040
2005	19,700	2.4	88	24	13.3	21,030	-0.2	5,880	112,860	3,360	1,970	5,780	1,260
2010	19,900	0.2	88	24	13.3	20,970	-0.1	5,890	112,280	3,370	1,990	5,810	1,090
2015	19,900	0.0	88	24	13.3	20,960	0.0	5,880	112,120	3,380	1,990	5,830	1,060
2020	19,900	0.0	88	24	13.3	20,960	0.0	5,880	112,120	3,380	1,990	5,830	1,060

TABLE I.6. Projected County Characteristics: Malheur County, Oregon

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbarization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	27,500	1.9	0	28	12.0	$10,660	0.0	$5,330	$10,600	0	$1,900	$ 0	$ 0
1985	29,900	1.8	0	28	12.0	10,660	0.0	5,330	10,600	0	1,900	0	0
1990	32,300	1.6	33	28	12.0	10,660	0.0	5,330	10,600	0	1,900	0	0
1995	35,800	2.2	40	27	12.1	12,160	2.8	5,510	16,700	920	1,830	1,350	410
2000	38,200	1.3	37	28	12.1	11,220	-1.6	5,320	16,300	430	1,870	720	180
2005	39,600	0.7	35	28	12.1	11,200	0.0	5,300	16,100	430	1,870	730	160
2010	40,700	0.6	36	28	12.1	11,190	0.0	5,300	16,000	430	1,870	730	150
2015	41,000	0.2	36	28	12.1	11,190	0.0	5,300	16,000	430	1,880	740	140
2020	41,000	0.0	36	28	12.1	11,190	0.0	5,300	16,000	430	1,880	740	130
High Coal Electric													
1980	27,500	1.9	0	23	12.0	$10,560	0.0	$5,330	$10,500	0	$1,900	$ 0	$ 0
1985	29,900	1.8	0	23	12.0	10,560	0.0	5,330	10,500	0	1,900	0	0
1990	32,300	1.6	33	28	12.0	10,660	0.0	5,330	10,500	0	1,900	0	0
1995	35,800	2.2	40	27	12.1	12,160	2.8	5,510	16,700	920	1,800	1,350	470
2000	38,200	1.3	37	28	12.1	11,220	-1.6	5,320	16,300	430	1,900	720	180
2005	39,600	0.7	36	28	12.1	11,200	0.0	5,300	16,100	430	1,900	730	160
2010	42,300	1.4	43	27	12.2	12,700	2.7	5,480	21,900	1,420	1,800	2,210	580
2015	47,100	2.3	49	26	12.3	13,560	1.4	5,500	33,600	2,470	1,700	4,010	1,430
2020	49,000	0.8	47	27	12.3	12,870	-1.0	5,260	33,000	2,160	1,800	3,720	780

TABLE I.7. Projected County Characteristics: Morrow County, Oregon

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	6,500	6.8	0	31	12.6	$11,100	3.3	$9,050	$63,630	300	$2,320	$ 490	$ 180
1985	8,700	6.8	0	27	12.7	15,710	8.3	9,030	78,460	840	2,010	3,070	1,010
1990	9,100	0.9	0	30	12.7	13,100	-3.3	8,500	79,940	630	2,270	1,050	320
1995	12,200	5.8	0	27	12.8	17,000	6.0	8,550	101,200	1,410	1,890	2,300	1,490
2000	14,900	4.4	70	27	12.9	15,470	-1.8	7,820	116,470	1,790	1,930	2,950	970
2005	16,100	1.6	70	27	13.0	15,440	0.0	7,610	110,440	1,930	2,020	3,230	700
2010	16,300	0.2	70	27	13.0	15,650	0.3	7,630	110,540	1,930	2,030	3,250	630
2015	19,000	3.3	76	26	13.0	17,600	2.5	7,790	119,860	2,640	1,810	4,380	1,960
2020	19,300	0.3	74	26	13.0	16,240	-1.6	7,400	119,540	2,570	1,940	4,310	970
High Coal Electric													
1980	6,500	6.8	0	31	12.6	$11,870	4.9	$9,050	$66,730	300	$2,320	$ 490	$ 180
1985	9,900	10.4	0	27	12.8	16,600	8.0	8,820	94,140	1,090	1,870	1,770	1,390
1990	15,200	10.7	80	25	12.8	20,520	4.7	8,690	112,770	2,170	1,500	3,700	3,250
1995	15,300	0.1	71	27	13.0	15,750	-4.7	7,600	114,490	1,900	1,980	3,150	1,010
2000	15,900	0.8	70	27	13.0	15,530	-0.3	7,590	111,570	1,930	2,000	3,230	680
2005	16,100	0.3	70	27	13.0	15,440	-0.1	7,610	110,340	1,930	2,020	3,250	640
2010	16,300	0.3	69	27	13.0	15,350	-0.1	7,630	109,310	1,930	2,020	3,250	630
2015	16,400	0.1	69	27	12.9	15,340	0.0	7,620	109,120	1,940	2,030	3,260	590
2020	16,400	0.0	69	27	12.9	15,340	0.0	7,620	109,120	1,940	2,030	3,260	590

TABLE I.8. Projected County Characteristics: Cowlitz County, Washington

Year	Population Size	Population Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales Amount Per Capita	Gross Sales Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s) Operating ($1000)	Public Services Expenditures Due To the Plant(s) Capital ($1000)
Recent Trends													
1980	74,600	0.9	56	28	12.3	$11,510	0.0	$5,430	$19,800	0	$1,710	$ 0	$ 0
1985	79,900	1.4	56	28	12.3	11,510	0.0	5,440	19,800	0	1,710	0	0
1990	85,500	1.4	56	28	12.3	11,570	0.1	5,440	20,[illegible]00	0	1,710	0	0
1995	95,100	2.3	60	27	12.4	12,950	2.4	5,600	27,000	2,050	1,640	3,120	980
2000	102,800	1.6	60	23	12.4	12,380	-0.9	5,468	30,300	1,690	1,670	2,790	700
2005	107,600	0.9	60	23	12.4	12,520	0.2	5,460	30,300	1,890	1,690	3,120	680
2010	111,700	0.8	60	23	12.4	12,540	0.0	5,450	31,400	2,080	1,690	3,470	750
2015	112,400	0.1	60	23	12.4	12,530	0.0	5,440	31,400	2,090	1,690	3,510	640
2020	112,500	0.0	60	28	12.4	12,530	0.0	5,440	31,400	2,090	1,690	3,520	630
High Coal Electric													
1980	74,600	0.9	56	28	12.3	$11,510	0.0	$5,430	$19,800	0	$1,710	$ 0	$ 0
1985	81,100	1.7	58	28	12.3	12,190	1.2	5,520	22,700	800	1,680	1,180	350
1990	92,200	2.7	61	27	12.4	13,280	1.8	5,640	31,600	2,600	1,620	4,050	1,340
1995	98,600	1.4	60	28	12.4	12,480	-1.2	5,460	30,800	1,720	1,680	2,870	700
2000	104,300	1.2	60	28	12.4	12,550	0.1	5,460	31,200	1,880	1,680	3,100	740
2005	108,800	0.9	60	28	12.4	12,570	0.0	5,450	31,700	2,080	1,690	3,470	760
2010	111,900	0.6	60	28	12.4	12,540	0.0	5,450	31,400	2,080	1,690	3,480	722
2015	112,400	0.1	60	28	12.4	12,530	0.0	5,440	31,400	2,090	1,690	3,510	640
2020	112,500	0.0	60	28	12.4	12,530	0.0	5,440	31,400	2,090	1,690	3,520	630

TABLE I.9. Projected County Characteristics: Douglas County, Washington

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1930													
1935													
1940													
1945													
2000					No Coal Power Plants Scheduled								
2005													
2010													
2015													
2020													
High Coal Electric													
1980	18,100	0.9	0	30	12.5	$3,350	0.0	$5,290	$11,480	0	$2,000	$ 0	$ 0
1985	19,400	1.4	0	30	12.5	3,350	0.0	5,300	11,480	0	2,000	0	0
1990	20,700	1.3	0	30	12.5	3,350	0.0	5,300	11,480	0	2,000	0	0
1995	26,800	5.9	0	26	12.7	9,450	36.4	6,120	36,550	2,140	1,650	3,490	1,930
2000	30,200	2.5	0	28	12.7	6,090	-7.1	5,350	40,300	1,570	1,810	2,650	960
2005	31,800	1.0	0	28	12.7	6,000	0.0	5,280	39,000	1,620	1,840	2,780	590
2010	35,200	2.1	42	27	12.8	8,250	7.5	5,600	46,260	2,880	1,700	4,700	2,050
2015	37,500	1.3	39	27	12.8	7,240	-2.4	5,330	52,040	2,780	1,750	4,740	1,390
2020	38,400	0.1	39	27	12.8	7,200	0.0	5,270	51,290	2,850	1,760	4,910	920

TABLE I.10. Projected County Characteristics: Franklin County, Washington

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980													
1985													
1990													
1995													
2000					No Coal Power Plants Scheduled								
2005													
2010													
2015													
2020													
High Coal Electric													
1980	28,000	0.9	53	26	12.6	$9,980	0.0	$7,560	$14,400	0	$2,880	$ 0	$ 0
1985	30,000	1.4	53	26	12.6	9,980	0.0	7,580	14,400	0	2,880	0	0
1990	32,300	1.5	54	26	12.6	10,590	1.2	7,610	18,400	210	2,860	290	770
1995	39,100	4.2	62	25	12.7	12,410	3.4	7,350	37,400	1,760	2,600	2,810	680
2000	48,300	4.7	65	25	12.8	12,890	0.8	7,020	42,000	2,810	2,430	4,710	1,630
2005	51,200	1.2	55	25	12.8	12,890	0.0	6,900	40,600	2,930	2,440	5,030	1,060
2010	52,300	0.4	55	25	12.8	12,820	-0.1	6,910	40,000	2,940	2,450	5,040	1,020
2015	52,600	0.1	55	25	12.8	12,820	0.0	6,890	40,000	2,950	2,460	5,080	930
2020	52,600	0.0	55	25	12.8	12,820	0.0	6,890	40,000	2,950	2,460	5,080	920

TABLE I.11. Projected County Characteristics: Grant County, Washington

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	45,500	0.9	23	24	12.3	$14,950	0.0	$6,580	$12,480	0	$2,130	$ 0	$ 0
1985	48,700	1.4	23	24	12.3	14,950	0.0	6,590	12,480	0	2,130	0	0
1990	52,100	1.4	23	24	12.3	14,950	0.0	6,590	12,480	0	2,130	0	0
1995	55,300	1.2	23	24	12.3	14,950	0.0	6,590	12,480	0	2,130	0	0
2000	58,500	1.2	23	24	12.3	14,950	0.0	6,580	12,480	0	2,130	0	0
2005	60,600	0.7	23	24	12.3	14,950	0.0	6,570	12,480	0	2,130	0	0
2010	62,300	0.6	23	24	12.3	14,950	0.0	6,570	12,480	0	2,130	0	0
2015	64,100	0.6	28	24	12.3	15,800	1.1	6,630	15,940	1,020	2,090	1,460	350
2020	64,700	0.2	25	24	12.3	15,300	-0.6	6,510	15,890	430	2,110	730	140
High Coal Electric													
1980	45,500	0.9	23	24	12.3	$14,950	0.0	$6,580	$12,480	0	$2,130	$ 0	$ 0
1985	48,700	1.4	23	24	12.3	14,950	0.0	6,590	12,480	0	2,120	0	0
1990	52,100	1.4	23	24	12.3	14,950	0.0	6,590	12,480	0	2,130	0	0
1995	59,000	2.7	35	24	12.4	17,130	2.9	6,760	20,520	2,290	1,990	3,380	1,580
2000	64,200	1.8	30	24	12.4	15,970	-1.4	6,480	22,760	1,270	2,040	2,150	600
2005	67,200	0.9	31	24	12.4	16,310	0.4	6,460	24,290	1,610	2,040	2,650	620
2010	72,500	1.6	35	24	12.5	16,670	0.4	6,420	30,570	2,420	1,990	4,060	900
2015	75,100	0.7	36	24	12.5	16,720	0.1	6,330	30,100	2,590	1,990	4,450	840
2020	75,100	0.0	36	24	12.5	16,720	0.0	6,330	30,100	2,590	1,990	4,460	800

TABLE I.12. Projected County Charactersitics: Grays Harbor County, Washington

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	64,700	0.9	49	24	12.2	$8,510	0.0	$5,100	$12,200	0	$1,940	$ 0	$ 0
1985	69,200	1.4	49	24	12.2	8,510	0.0	5,120	12,200	0	1,940	0	0
1990	77,400	2.4	55	24	12.3	10,260	4.1	5,330	19,700	2,020	1,860	2,970	1,010
1995	84,800	1.9	53	24	12.3	9,490	-1.5	5,190	22,400	1,480	1,890	2,440	670
2000	90,200	1.3	53	24	12.3	9,430	-0.1	5,170	21,800	1,490	1,900	2,470	580
2005	93,600	0.8	53	24	12.3	9,570	0.3	5,180	23,700	1,780	1,900	2,920	560
2010	97,400	0.8	54	24	12.3	9,580	0.0	5,170	23,300	1,880	1,900	3,120	650
2015	97,900	0.1	54	24	12.3	9,580	0.0	5,160	23,300	1,890	1,900	3,150	580
2020	97,900	0.0	54	24	12.3	9,580	0.0	5,160	23,300	1,890	1,900	3,150	570
High Coal Electric													
1980	64,700	0.9	49	24	12.2	$8,510	0.0	$5,110	$12,200	0	$1,940	$ 0	$ 0
1985	74,300	3.0	57	24	12.3	11,230	6.4	5,480	27,000	2,880	1,810	4,430	1,150
1990	82,600	2.2	54	24	12.3	9,770	-2.6	5,200	25,300	1,860	1,880	3,080	820
1995	87,400	1.2	54	24	12.3	9,700	0.0	5,180	24,600	1,870	1,890	3,100	720
2000	93,600	1.4	56	24	12.3	10,280	1.2	5,260	25,300	2,840	1,860	4,530	1,150
2005	96,600	0.6	54	24	12.3	9,800	-0.9	5,180	25,700	2,250	1,890	3,750	800
2010	99,200	0.5	54	24	12.3	9,780	0.0	5,180	25,300	2,250	1,890	3,750	780
2015	99,700	0.1	54	24	12.3	9,770	0.0	5,170	25,300	2,260	1,900	3,790	690
2020	99,700	0.0	54	24	12.3	9,770	0.0	5,170	25,300	2,260	1,900	3,790	680

TABLE I.13. Projected County Characteristics: Lincoln County, Washington

Year	Population: Size	Population: Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales: Amount Per Capita	Gross Sales: Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s): Operating ($1000)	Public Services Expenditures Due To the Plant(s): Capital ($1000)
Recent Trends													
1980	10,400	0.9	0	37	12.2	$11,640	0.0	$6,540	$24,900	0	$3,150	$ 0	$ 0
1985	11,400	1.9	0	36	12.2	12,870	2.1	6,640	34,300	150	3,080	223	70
1990	13,200	3.2	0	35	12.3	13,150	0.4	6,560	41,200	330	2,960	537	165
1995	16,100	4.4	0	31	12.5	16,980	5.8	6,940	64,500	1,180	2,630	1,933	587
2000	17,800	2.1	0	33	12.5	15,030	-2.3	6,520	61,400	990	2,750	1,635	446
2005	18,300	0.6	0	33	12.5	14,940	-0.1	6,490	60,300	1,000	2,770	1,661	344
2010	18,700	0.4	0	33	12.5	15,130	0.4	6,490	60,600	1,000	2,780	1,662	339
2015	20,000	1.4	0	33	12.6	15,650	0.7	6,530	68,100	1,310	2,680	2,176	520
2020	20,300	0.3	0	33	12.6	15,620	0.0	6,470	67,500	1,330	2,670	2,228	414
High Coal Electric													
1980	10,400	0.9	0	37	12.2	$11,640	0.0	$6,540	$24,900	0	$3,150	$ 0	$ 0
1985	12,700	4.4	0	32	12.4	16,140	7.9	6,990	43,400	750	2,751	1,200	510
1990	16,500	6.0	0	30	12.6	19,260	3.9	7,160	65,700	1,530	2,410	2,510	1,570
1995	18,600	2.5	0	31	12.6	16,590	-2.8	6,610	82,400	1,480	2,550	2,460	450
2000	20,800	2.4	0	32	12.6	16,460	-0.2	6,480	76,800	1,650	2,590	2,740	650
2005	21,300	0.5	0	32	12.6	16,360	-0.1	6,470	76,600	1,660	2,600	2,770	560
2010	21,700	0.4	0	32	12.6	16,270	-0.1	6,470	74,600	1,660	2,610	2,770	560
2015	24,900	2.9	59	29	12.7	19,570	4.1	6,890	85,500	2,800	2,290	4,130	1,950
2020	24,700	-0.2	51	31	12.7	17,340	-2.3	6,470	86,100	2,320	2,490	3,860	870

TABLE I.14. Projected County Characteristics: Whatcom County, Washington

Year	Population Size	Population Average Annual Percent Growth	Percent Urbanization	Median Age	Median Education	Gross Sales Amount Per Capita	Gross Sales Average Annual Percent Growth	Personal Income Per Capita	Property Value Per Capita	Housing Requirements	Retail Capital Per Capita	Public Services Expenditures Due To the Plant(s) Operating ($1000)	Public Services Expenditures Due To the Plant(s) Capital ($1000)
Recent Trends													
1980	88,900	0.9	47	27	12.5	$9,510	0.0	$5,020	$13,700	0	$1,830	$ 0	$ 0
1985	96,300	1.7	50	27	12.5	10,210	1.5	5,110	16,100	1,350	1,800	1,840	530
1990	104,000	1.6	48	27	12.5	9,770	-0.9	5,040	15,900	520	1,810	860	220
1995	110,600	1.3	48	27	12.5	9,760	0.0	5,030	15,800	520	1,820	860	210
2000	116,800	1.1	48	27	12.5	9,740	0.0	5,030	15,600	520	1,820	860	200
2005	120,900	0.7	48	27	12.5	9,740	0.0	5,020	15,600	530	1,820	870	190
2010	124,400	0.6	48	27	12.5	9,730	0.0	5,020	15,500	530	1,820	870	180
2015	125,200	0.1	48	27	12.5	9,730	0.0	5,010	15,500	530	1,820	880	160
2020	125,200	0.0	48	27	12.5	9,730	0.0	5,010	15,500	530	1,820	880	160
High Coal Electric													
1980	88,900	0.9	47	27	12.5	$9,510	0.0	$5,020	$13,700	0	$1,830	$ 0	$ 0
1985	95,000	1.4	47	27	12.5	9,510	0.0	5,030	13,700	0	1,830	0	0
1990	103,500	1.8	50	27	12.5	10,490	2.1	5,120	17,500	1,770	1,800	2,420	730
1995	116,100	2.4	51	27	12.6	10,440	-0.1	5,080	21,400	2,070	1,780	3,380	1,000
2000	124,200	1.4	51	27	12.6	10,390	-0.1	5,050	21,000	2,100	1,790	3,470	820
2005	128,400	0.7	51	27	12.6	10,360	-0.1	5,040	20,700	2,110	1,790	3,500	740
2010	131,900	0.6	51	27	12.6	10,340	0.0	5,040	20,500	2,110	1,790	3,500	720
2015	132,700	0.1	51	27	12.6	10,340	0.0	5,030	20,500	2,120	1,790	3,540	650
2020	132,700	0.0	51	27	12.6	10,340	0.0	5,030	20,500	2,120	1,790	3,540	640

APPENDIX J

GOVERNMENT INVOLVEMENT IN COAL UTILIZATION: NORTHWEST STATES

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Among the various levels of government (federal, state and local) a number of agencies are actively and passively involved in mining, transport and ultimate use of coal. Their direct participation in coal utilization decisions may result from 1) outright ownership of the coal resources or rights-of-way, 2) economic, environmental, health or safety considerations, or 3) directly-related energy projects and programs. Historically, government has treated coal as an ordinary marketable commodity with private industry responsible for resource development and commodity marketing.

Marketing of coal as an ordinary commodity contrasts greatly with natural gas and electricity, which are delivered through "natural monopolies" and are closely regulated by the public sector. In general, the government influence on coal utilization has been directed toward protection of public health and safety while minimizing environmental impacts.

Thus the private sector has been encouraged to be both the initiator of actions and the real implementor of policy. Overall energy policies and priorities, however, are set by government. The fact that no clear policy exists creates its own set of problems: first, because the various levels of government may not be in agreement, and secondly, because industry may get mixed signals from within a level of government as it pursues specific energy objectives.

Federal and state institutional arrangements that influence coal development and utilization are still evolving. Efforts are being made to define the role of government at both the federal and state levels. Recently the state governors of Idaho, Oregon and Washington, through the Pacific Northwest Regional Commission, initiated the Northwest Energy Policy Project (NEPP), a two-year study to identify and evaluate a number of energy policy options for the region. A recently published NEPP report[1] suggests that significant changes will occur in the region's energy entities and institutions. These changes will affect all levels of regional government. The report goes on to say, however, that even with changes in government institutions, private industry will continue to play a principal role in coal development and utilization.

Just how federal and state institutions are currently involved in regional energy development and utilization is summarized below. Much of this information has been drawn from a report entitled Energy Northwest[2] and NEPP information as well as from discussions with federal and state personnel.

J.1 FEDERAL

An important factor currently influencing federal authority over coal development in western states is management of the vast coal resources found on land owned by the federal government. Management of these government-owned lands also influences coal transportation and utilization through right-of-way permits, eminent domain legislation and air and water quality standards.

Land use permits offer the most direct control. They are issued for development of mineral reserves and rights-of-way on federal lands. The permit process may vary depending on how the government acquired the land and on the administrative process adopted by the agency responsible for land management. Federal land is essentially divided into two categories--public domain and acquired lands.

Public domain lands are distinguished from acquired lands by never having passed from federal to private ownership. Except for Indian trust lands and other minor exceptions, the Bureau of Land Management (BLM) of the Department of the Interior has primary land management and leasing responsibilities for public domain lands. Responsibility for managing and leasing Indian trust lands and for issuing rights-of-way over these lands falls to the Department of the Interior's Bureau of Indian Affairs (BIA). The separate leasing and land management responsibilities for Indian lands was designed to ensure that Indian interests would not be compromised.

The U.S. Forest Service of the Department of Agriculture has land management responsibility over some public domain forest lands. However, leasing and issuance of rights-of-way for these lands are conducted by the BLM.

Similarly, the National Park Service, the Bureau of Outdoor Recreation, and the Bureau of Reclamation of the Department of the Interior have land management responsibilities over public domain lands in national parks and recreation lands. In these cases the BLM retains leasing responsibility.

The General Services Administration (GSA) can handle, under limited circumstances, the disposition of public domain lands. GSA is authorized to sell property to utilities on an administrative basis. Recent litigation involving a nuclear power plant, while upholding GSA's authority to dispose of public domain lands, now prohibits such disposal before completion of an Environmental Impact Statement (EIS) and an economic feasibility study.

Mineral development rights on public domain lands are obtainable through several mechanisms that may include either the actual leasing for mineral deposits with a royalty provision or other fee payments to the federal government.

Acquired lands may be lands for which the federal government obtained either or both surface or subsurface rights. For example, the Forest Service may purchase or otherwise receive rights to subsurface lands and mineral resources to develop and preserve forest resources. While the BLM may or may not have land management control over acquired lands, BLM is responsible for leasing these lands.

Permit procedures for land use on acquired lands vary somewhat from those on public domain lands. All development of minerals require prior leases and royalty payments, unlike the development of minerals on public domain lands. Procedures for obtaining right-of-way and facility siting permits for energy facilities on public and acquired lands are the same in most cases.

Over 82% of the region's 523 million acres are federally owned. Allocation on federal lands among the states of Alaska, Idaho, Oregon and Washington is presented in Table J.1. Besides being the largest state, Alaska leads all states in the percentage of land that is

TABLE J.1. Federally Owned Lands Comparison for the States, Region, and United States as of June 30, 1975 (In Thousands of Acres)[3]

	Total Land Area (Acres)	Federally Owned Land (Acres)	Percent of Respective Total Area	Percent of Region	Percent of United States
Alaska	365,482	352,408	96.4	81.8	46.3
Idaho	52,933	33,742	63.7	7.8	4.4
Oregon	61,599	32,370	52.6	7.5	4.2
Washington	42,694	12,588	29.5	2.9	1.7
Region	522,708	431,108	82.5	100.0	56.7
United States	2,271,343	760,414	33.5	--	100.0

classified under federal ownership (96.4%). The smallest state in the region, Washington, has the lowest percentage of federal lands (29.5%).

In addition to direct management responsibilities over federal lands, the federal government establishes environmental regulations that influence development of energy resources and their utilization. No attempt is made here at a legal interpretation of federal legislation. The following legislation is, however, presented because it indirectly influences coal utilization within the region:

1) National Environmental Policy Act of 1969 (42 U.S.C.A. 4321 et seq.) requires extensive formal consideration of the environmental impact of major federal actions--a category likely to cover all federal activities related to energy development at the regional level. The act is implemented by the writing of an environmental impact statement (EIS) by the agency, to be submitted for review by other agencies and the public, with rather permissive rules of challenge. NEPA requirements in at least two significant Department of Interior actions, outer continental shelf leasing and coal leasing on federal lands, may be modified by special purpose federal legislation. Congress appears to be taking the position that both actions are too vital to national interests to leave them subject to "open session" legislation. As in the case of the Alaskan pipeline, EIS's would be prepared, but cutoff dates on other limits may be placed on the challenges anticipated.

2) Clean Air Act, as amended (42 U.S.C.A. 1957 et seq.) is administered by the U.S. Environmental Protection Agency. The regulation of air quality, particularly in presently unpolluted areas, poses important constraints on fossil energy development. In 1977, the act was amended to include best available control technology (BACT) and visibility requirements.

3) Federal Water Pollution Control Act, as amended (42 U.S.C.A. 1251 et seq.) prescribes major water pollution control efforts, partially subsidized by federal grants-in-aid. Thermal pollution from power plants is a specific target of control. More generally, the planning responsibilities required of watershed regions by the act could affect both energy-related land use and energy demand over the long term.

4) Wild and Scenic Rivers Act (16 U.S.C.A. 1271 et seq.) permits Congressional oversight over rivers of special wilderness value. For example, the inclusion of selected reaches of the Skagit River in northwest Washington has affected licensing of a nuclear plant that would draw upon its waters. Similar cases may develop for coal-fired plants.

5) Coastal Zone Management Act (16 U.S.C.A. 1451 et seq.) requires extensive state planning for land use in shoreline areas. Recently Congress has authorized a coastal zone energy impact fund, recognizing the impact of energy development on the coastal zone.

6) Alaska Native Claims Settlement Act (43 U.S.C.A. 160) gives Congress the responsibility to determine which public lands shall receive special protection as national parks, wildlife refuges, scenic rivers and national forests. Section 17(d)(2) authorizes the Secretary of Interior to withdraw "national interest" lands to be closed to development. Congress is to establish these areas officially by December 1978. Several legislative proposals to locate and provide permanent protection for d-2 lands have been introduced in Congress. The final form of this legislation and its impact on mineral development and transportation is uncertain. Beyond the basic question of which areas to designate as d-2 lands is the issue of how much land should be given formal wilderness protection. It is clear, though, that this Act will affect both the coal resources that can be developed and the potential location of generating plants.

Federal institutions are also beginning to move toward the development of unconventional coal uses, such as coal conversion to synthetic natural gas (SNG) or to liquid, coal-based fuels. This involvement may include the utilization of public funds to perform engineering research, subsidize new plants, and provide industry loans.

Other areas where federal policy may significantly influence energy development and utilization include:

- Strip mine standards--requirements for surface land restoration, recovery techniques for subsurface drainage and acidity control, leasing and monitoring of operations on federal or state lands.
- Transportation--rate setting for rail shipments, and the (potential) granting of eminent domain power for coal slurry pipelines across railroad rights-of-way.
- Pricing of competitive fuels--the pricing of interstate natural gas which, together with oil, is the historic competition for coal.

Specific federal agencies responsible for administering the federal government's role in coal utilization are identified below. These federal agencies influence coal utilization in five important ways: land management, regulation, setting safety standards, coal technology research and development, and identification of policy options. A brief summary of these principal agencies and their activities under each of the five categories follows.

J.1.1 Land Management

Within the region nine federal agencies hold management responsibility over most of the federal lands: Bonneville Power Administration, Bureau of Indian Affairs, Bureau of Land Management, Bureau of Reclamation, Department of Defense, Department of Energy, Fish and Wildlife Service, Forest Service, and National Park Service.

1) Bonneville Power Administration (BPA), Department of Energy. The BPA requires a joint-use permit for those portions of energy facilities that cross or are directly adjacent to its electric power line rights-of-way.

2) Bureau of Indian Affairs (BIA), Department of the Interior. Separate applications must be made to the superintendent of the appropriate Indian Agency for rights-of way over tribal trust lands. These rights-of-way must be acquired by negotiation or by authority given in an appropriate special Act of Congress. Negotiations for easements across tribal lands presently require payment of an annual fee.

3) Bureau of Land Management (BLM), Department of the Interior. The BLM issues right-of-way grants and permits to cross lands under its jurisdiction, including submerged lands of the outer continental shelf. The BLM also issues prospecting permits; however, prospecting for coal is currently suspended.

4) Bureau of Reclamation (BR), Department of the Interior. The BR requires an individual contract for each crossing of land and facilities within an existing irrigation project developed by the BR.

5) Department of Defense (DOD). The Army and Air Force require information on the proposed land use and an environmental impact statement. This information is reviewed by the DOD. Evaluation findings are turned over to the Corps of Engineers who issue the permit. The Navy requires the same information but issues right-of-way permits directly.

6) Department of Energy (DOE). DOE negotiates an easement deed over DOE lands. In specific situations, limited land use permits will also be issued but can be revoked if the user fails to meet the requirements called for in the permit.

7) Fish and Wildlife Service (FWS), Department of the Interior. The FWS issues right-of-way permits over the land it administers. These primarily include lands administered by the National Wildlife Refuge Service and some areas over which it has easements for waterfowl management rights. The FWS also reviews any Corps of Engineers permits for their effect on wildlife habitat.

8) Forest Service (FS), Department of Agriculture. A special use permit is required from the FS for rights-of-way on national forest land. Application must be made to each national forest separately.

9) National Park Service (NPS), Department of the Interior. Any construction or easement necessary across national park lands will require a right-of-way permit. Environment impacts are also of concern to the NPS, and thus actions that affect the environment of existing or planned units of the NPS or properties listed or eligible for the National Register of Historic Places or the National Registry of National Landmarks should develop an environment statement or review addressing these areas.

J.1.2 Regulatory

A number of federal agencies serve as regulatory agencies. Those related to the coal cycle but not limited to it are: Coast Guard, Corps of Engineers, Environmental Protection Agency, Federal Aviation Administration, Department of Energy, Federal Communications Commission, Federal Railroad Administration, Interstate Commerce Commission, Geological Survey, and the Security and Exchange Commission.

- Coast Guard (CG), Department of Transportation
  The CG issues permits for all bridges constructed across navigable waters of the United States. The permits require specific clearances from the Environmental Protection Agency, Fish and Wildlife Service, and National Marine Fisheries Service.

- Corps of Engineers (CE), Department of Army
  The CE is responsible for processing applications and issuing permits for placement of structures and work on navigable waters of the United States, the discharge of dredged or fill material in navigable waters, and the transportation of dredged material to be dumped into ocean waters. The CE review process includes comment by Environmental Protection Agency, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Department of Interior, Fish and Wildlife Service, and affected state and local governments.

- Environmental Protection Agency (EPA)
  The EPA has primary responsibility for issuing National Pollution Discharge Elimination System (NPDES) permits. This permit regulates the quantity and quality of liquid effluents discharged into rivers and waterways. EPA also has regulations to prevent significant deterioration of air quality. These regulations require preconstruction review and approval for certain types of industrial sources of air emissions.

- Federal Aviation Administration (FAA)
  The FAA determines the effects of proposed structures on safety in air commerce. Thus, the FAA requires prior notice of any obstruction more than 200 feet high, obstructions near airports and seaplane bases, and any construction near or on airports.

- Economic Regulatory Administration (ERA), Department of Energy
  The ERA assures that in the case of energy shortages, priority needs for energy are met and the burden of the shortages is borne with equity. ERA also administers a program to encourage utilities to utilize coal.

- Federal Communications Commission (FCC)
  Entities that maintain pipelines often operate microwave relay stations for monitoring purposes. Notification of station operation must be filed with the FCC. Construction contractors who use radio communication equipment must also have a license from the FCC.

- Federal Railroad Administration (FRA), Department of Transportation
  The FRA administers and enforces the federal laws and related regulations designed to promote safety on railroads. In this capacity it issues permits for special designs for coal cars.

- Interstate Commerce Commission (ICC)
  The ICC would regulate coal pipelines. The ICC regulation is concerned primarily with the reasonableness of rates. Prior to operating a pipeline, the ICC must approve a tariff for the pipeline.
- Geologic Survey (GS), Department of the Interior
  The USGS approves mining plans and develops assessments of coal resources.
- Security and Exchange Commission (SEC)
  The SEC's interests are primarily in protecting the investor. The SEC monitors activities that raise public money and approves mergers and acquisitions of oil, gas or electric companies.

J.1.3 Safety Standards

The design and construction of energy facilities must conform to certain federally-set safety standards. Federal agencies responsible for setting standards affecting coal facilities include: Office of Pipeline Safety and Occupational Safety and Health Administration.

1) Office of Pipeline Safety (OPS), Department of Transportation. The design and construction of pipelines must conform to the standards established by the OPS.
2) Occupational Safety and Health Administration (OSHA), Department of Labor. OSHA develops and promulgates occupational safety and health standards and develops and issues regulations.

J.1.4 Research and Development

The offices and functions dealing with energy research and development under the jurisdiction of the Department of Interior, the Atomic Energy Commission, the National Science Foundation, the Federal Energy Administration, and the Environmental Protection Agency were consolidated in 1975 and now reside within the Department of Energy (DOE). The mission of DOE research and development is to develop all available domestic energy sources, assist the nation in becoming self-sufficient in energy, and protect the environment, public health and welfare.

J.1.5 Policy Evaluation

Federal agencies responsible for identifying and recommending policy include the Council on Environmental Quality, which formulates and recommends national policies to improve the quality of the environment, and the Department of Energy, which establishes policy to ensure that the supply of energy available to the United States will continue to be sufficient to meet our total energy demand.

1) Council on Environmental Quality (CEQ). The CEQ advises the President on energy-related environmental issues. The CEQ also monitors and coordinates environmental assessments and regulatory authorities on energy-related activities in the federal government. This includes evaluating and determining priorities of energy requirements in the United States as opposed to certain environmental regulations that restrict complete energy resource development.
2) Department of Energy (DOE). The DOE's responsibilities include developing, recommending, coordinating and implementing national energy policies designed to identify and resolve

existing and prospective United States energy problems. The Assistant Secretary for Policy and Evaluation is responsible for assuring that adequate consideration is given competition, antitrust policies and consumer impact in department decision making.

A summary of the activities of the federal agencies discussed above is provided in Table J.2. Federal agencies directly or indirectly influence production, transportation, and conversion components of the coal cycle. Their input may be provided through a variety of mechanisms from issuing final project approval to funding technological advances. Table J.3 summarizes the type of involvement each of the federal agencies may have in the coal cycle.

J.2 STATE

Until recently states in the Northwest have not been active in shaping energy policy. In general, planning and implementation of energy facilities and distribution systems have been initiated and carried out by the private sector or by federal agencies. Local levels of government, through public and municipal utility districts, were more active than the state in energy planning and implementation. The states' primary role in energy planning was limited to the regulating powers held by the various state public utility commissions. The commissioners represented the state's position on utility rates and other aspects of private utility operation; they did not have a significant role in energy planning or implementation.

In recent years the region has been faced with several energy crises that have moved state governments toward more active roles in energy planning. The oil embargo by the OPEC nations in the fall and winter of 1973 had been preceded in late 1972 through the fall of 1973 by below-average waterflow in Northwest rivers and streams. Thus, the region faced an electrical shortage, then a gasoline shortage. The states came away from these crises with a heightened interest in establishing a direct role in energy planning.

One of the first steps was the creation of state energy offices to assist the governors on energy matters. These offices are also responsible for setting up state conservation programs. However, NEPP, in reviewing the state energy offices, noted that the various state energy offices are likely to differ widely in the scope and degree of their planning activities.

Besides the state energy offices and public utility commissions, state agencies have jurisdiction regarding economic development, program planning, ecology and other areas that vary in scope, title and authority from state to state. With this authority the states have substantial capability to influence energy planning.

While state power planning activities have been limited, considerable potential for involvement does exist:

> One point that emerges clearly from a study of the statutes and from state programs under them over the past few years is that the state government is not undertaking something new when it engages in planning and regulation of development and of land use. It is already profoundly in that business. The state resource and development management programs ... reflect an ongoing and extensive involvement by state government in this area. What is missing is an explicit recognition of this fact, and a more concerted effort to develop a coherent, coordinated approach to the execution of these responsibilties.[4]

TABLE J.2. Summary of Federal Agencies Impacting National Coal Utilization

Federal Agency		Principal Area of Operation				
		Land Management	Regulation	Safety Standards	Research and Development	Policy
Bonneville Power Administration	(BPA)	x	--	--	--	--
Bureau of Indian Affairs	(BIA)	x	--	--	--	--
Bureau of Land Management	(BLM)	x	--	--	--	--
Bureau of Reclamation	(BR)	x	--	--	--	--
Coast Guard	(CG)	--	x	--	--	--
Corps of Engineers	(CE)	--	x	--	--	--
Council on Environmental Quality	(CEQ)	--	--	--	--	x
Department of Defense	(DOD)	x	--	--	--	--
Department of Energy	(DOE)	x	--	--	x	x
Economic Regulatory Administration	(ERA)	--	x	--	--	--
Environmental Protection Administration	(EPA)	--	x	--	--	--
Federal Aviation Administration	(FAA)	--	x	--	--	--
Federal Communications Commission	(FCC)	--	x	--	--	--
Federal Railroad Administration	(FRA)	--	x	--	--	--
Fish and Wildlife Service	(FWS)	x	--	--	--	--
Forest Service	(FS)	x	--	--	--	--
Geologic Survey	(GS)	--	x	--	--	--
Interstate Commerce Commission	(ICC)	--	x	--	--	--
National Park Service	(NPS)	x	--	--	--	--
Occupational Safety and Health Administration	(OSHA)	--	--	x	--	--
Office of Pipeline Safety	(OPS)	--	--	x	--	--
Securities and Exchange Commission	(SEC)	--	x	--	--	--

TABLE J.3. Summary of Federal Agency Involvement in the Coal Cycle

Federal Agency	Production			Transportation				Conversion				
	Exploration	Extraction	Local Processing	Railroad	Barge	Truck	Pipeline	Direct Heat	Process Steam	Electric Generation	Gasification	Liquefaction
BPA	--	--	--	--	--	--	P	--	--	--	--	--
BIA	F	--	F	F	--	--	F	--	--	--	--	--
BLM	F	--	F	F	--	--	F	--	--	--	--	--
BR	F	--	F	F	--	--	F	--	--	--	--	--
CG	--	--	--	--	--	--	P	--	--	--	--	--
CE	P	--	P	--	--	--	P	--	--	--	--	--
CEQ	E	E	E	E	E	E	E	--	--	--	E	E
DOD	--	--	--	P	--	--	P	--	--	--	--	--
DOE	--	--	--	F	--	--	P	R&D	R&D	R&D	R&D	R&D
EPA	P	—	P	--	--	--	P	--	--	--	--	--
FAA	--	—	--	--	--	--	--	--	--	P	--	--
FCC	--	--	--	--	--	--	--	--	--	--	--	--
FRA	--	--	--	P	--	--	--	--	--	--	--	--
FWS	A	--	A	--	--	--	A	--	--	--	--	--
FS	F	--	F	F	--	--	F	--	--	--	--	--
GS	--	M	--	--	--	--	--	--	--	--	--	--
ICC	--	--	--	P	P	P	P	--	--	--	--	--
NPS	F	--	F	F	--	--	F	--	--	--	--	--
OSHA	S	S	S	S	S	S	S	S	S	S	S	S
OPS	--	--	--	--	--	--	S	--	--	--	--	--
SEC	S	S	S	S	S	S	S	--	--	S	S	S

A - Major approval or clearance of facility
D - Funds technology development
E - Distributes and/or coordinates environmental impact statements
F - Grants permits, leases, or rights-of-way for federal land administered by that agency
M - Manages leases of federal lands
P - Requires permit
R - Funds research
S - Enforces standards and laws which may relate to energy facilities

The greatest potential for state influence exists in the cases of plants that have not received licenses. By being involved in land use planning decisions, the states could have considerable authority. The licensing procedures that are partly responsible for the present frustrations of the electrical utilities could be modified to speed up or slow down construction schedules.

The possibility also exists that states could individually or collectively influence the region's energy picture by modifying their environmental protection standards and policies. Key environmental constraints now affect the region's electric power program, and similar constraints exist with oil transportation and industrial utilization of coal.

Waste heat and air and water pollution are subject to various state jurisdictions and could conceivably be modified by legislative or administrative action to establish either more or less severe restrictions on power plant operation and support. Licensed power plants could be affected by such changes with a resulting effect on the region's electric power supplies. For example, effluent limitations can have an important impact on project location, design and costs. Coal mining operations, particularly in Montana and Wyoming, could be impacted by changes in those states' environmental standards. Such actions would have major implications for the region.

One important consideration is the possibility of federal preemption in the name of national energy goals. If state air standards were relaxed, for instance, federal jurisdictions such as those under the Clean Air Act or other statutes could reduce or eliminate the impact of state action.

Existing constraints at least partly under state and local government control include:

- Air quality standards enforcement.
  On a statewide (or better, region-wide) basis isolated "coal burning districts" could be created in which point emission levels higher than in other areas would be permitted as long as dispersed levels remained acceptable. Also particulate emission standards for coal-derived fly ash could be made an exception.

- Facility and plant siting.
  Should utilities and industries accept the "district" approach above, then governments could make further siting concessions, e.g., coastal zone siting for utility generation to permit seawater cooling and barge access, thus lowering total operating costs significantly.

- Dedicated "public" bulk storage sites and transportation facilities.
  These could be provided from state or county land inventories or through the exercise of powers of eminent domain. In addition, state chartered port districts (including inland ports) could be given encouragement to install coal handling components and bulk storage areas.

- Public utility status for coal distributors.
  This would enable them to compete on equal terms with gas and electricity, i.e., to raise capital through utility type security issues and to petition for exercise of eminent domain. This could be extended to cover common carrier coal slurry pipelines.

States can also influence energy projects through leases and right-of-way easements on state-owned lands. Coal deposits are found in all four states (see Figure J.1). Generally, the coal fields in Idaho and Oregon are small or have physical characteristics restricting their development at this time, yet Alaska and Washington have relatively large coal deposits. Some of these deposits occur on state lands and thus require direct state participation in exploration and extraction. State-owned lands may also play an important role in providing rights-of-way for transport of coal to market, especially in the case where coal slurry pipelines are used.

Coal-fired steam generation plants are strong candidates for increasing the electric generating capacity in each of the Northwest states. One coal-fired power plant is now operating at Centralia, Washington; another is under construction at Boardman, Oregon. Recently a coal-fired plant was proposed but rejected on the basis of air quality considerations for an area near Boise, Idaho. Coal-fired steam generation plants in Alaska are being considered to meet the state's rapidly expanding electric demand.

Each of the four states is establishing some authority in the areas of energy conservation and energy facility siting. The public utility commissioners of each state have been regulating the rate structure of private utilities and natural gas companies for some time. Conservation programs have been operated out of the state energy offices. However, only in Oregon have the functions of the energy office and energy facility siting been administered under one office. Recently the Oregon Department of Energy published a report, Future Energy Options for Oregon; an energy demand forecasting model for the state was developed for this report. This was a unique step among the four states in that it helps the state determine the future need for energy--an arena previously attended only by the utilities, BPA and some specialized consultants.

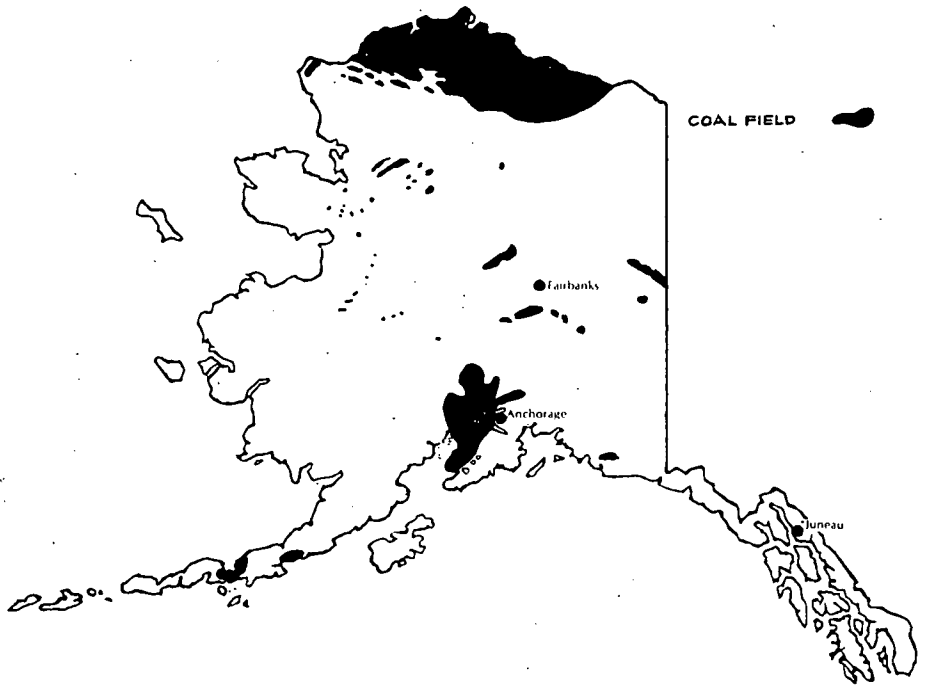
A listing of the state agencies responsible for each state's conservation program, siting of energy facilities, and utility regulation is provided in Table J.4.

Local government agencies interface with coal utilization primarily in the areas of energy facility siting, local infrastructure impacts, and building codes. Basically local agencies may be involved in two ways in the facility siting process. The first is as temporary members of the state siting council. The second is as agencies of local government who identify, characterize and mitigate anticipated local impacts. It is important that local government adequately plan for minimizing adverse social and economic impacts.

The precise nature of local government involvement in siting decisions varies from state to state. In Oregon and Washington representatives of county legislative authorities from the affected counties sit on or are advisors to the respective siting councils for the duration of the siting decision affecting them. Just how the local representative is to represent all local government (including cities and towns) is not clear. In some counties the local governments and county governments do not communicate regularly.

In addition to the question of how local governments are to be involved in the decision process is the issue of how much consideration should be given to the local government perspective in siting. These issues have not yet been fully resolved.

The following information discusses state and local agency involvement in energy planning.



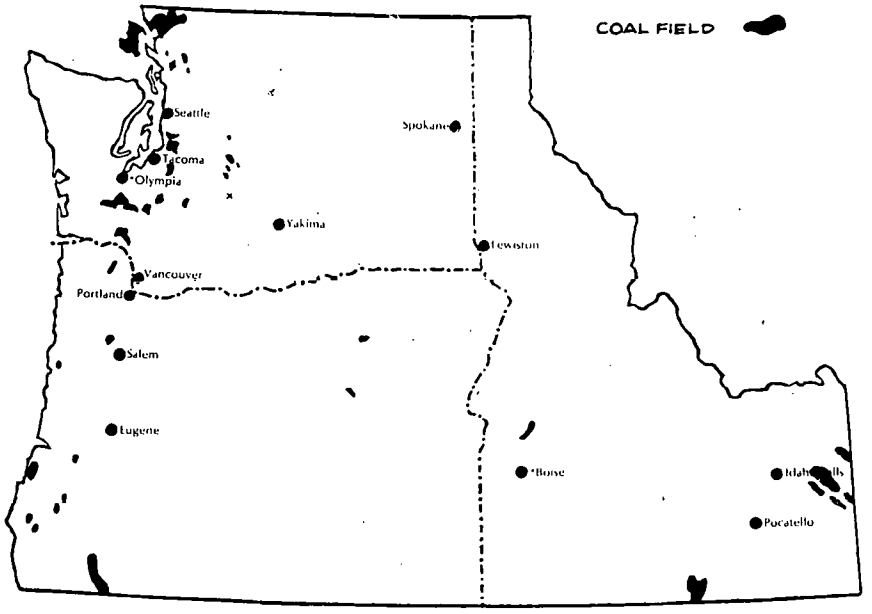


FIGURE J.1. Location of Regional Coal Fields

TABLE J.4. State Agencies Responsible for Energy Conservation, Facility Siting and Utility Regulation Programs

State	Conservation	Energy Facility Siting	Public Utility Regulation
Alaska	Alaska Department of Power and Energy Management	Alaska Coastal Zone Management Council Alaska Department of Natural Resources Alaska Power Authority Alaska Department of Fish and Game	Alaska Public Utilities Commission
Idaho	Idaho State Office of Energy	Idaho Public Utilities Commission	Idaho Public Utilities Commission
Oregon	Oregon Department of Energy	Oregon Department of Energy	Oregon Public Utility Commissioner
Washington	Washington State Energy Office	Washington Energy Facility Site Evaluation Council	Washington Utilities and Transportation Commission

J.2.1 Alaska

Discussions with state officials indicate that the State of Alaska owns lands containing significant coal resources. The primary responsibility for managing these lands falls within the purview of the Department of Natural Resources. The Department handles all requests for coal exploration and mining on state lands and right-of-way permits over state lands for access to the mine or for transport of coal to market. The Department is also responsible for water right permits.

The Department coordinates the state response and state approval of bulk energy supply facilities. To facilitate state review, the Department requests a Plan of Operation from the applicant. The Department reviews the Plan of Operation for compliance with Department regulations and standards. The Department also requests review by the Department of Environmental Conservation for air and water quality regulations, the Department of Fish and Game for ecological considerations, and the Department of Policy Development and Planning for overall state policy. Other state agencies review the Plan of Operation when they have a vested interest. The Department of Natural Resources will also request comment from the borough and hold hearings for public impact.

The Department of Natural Resources routinely circulates requests for coal exploration, mining, right-of-way and water rights permits; it is noted, however, that the Department of Fish and Game is responsible under Alaska statute for designated anadromous streams throughout the state. The Department of Fish and Game can require the submission and review of developer and user plans directly for review and approval of any work affecting anadromous fish waters.

J.2.2 Idaho

In Idaho the state agencies primarily governing energy policy and planning are the Office of Energy and the Public Utility Commission (PUC). The PUC represents the state in evaluating the needs of privately owned utility service areas for electric power, physical siting of power plants and pipelines, and environmental assessments. The state does not have a state environmental policy act and does not specifically require an environmental impact statement. When available, the state will use and supplement the federal environmental impact statement.

The Commission, after deliberation of need, environmental considerations and other related factors, issues a Certificate of Convenience and Necessity. It has the authority to preempt other state, county and local jurisdictions, with the exception of the Department of Health and Welfare, which has authority over administering air and water quality standards. However, the federal Environmental Protection Agency has not (at the time of this writing) delegated authority to the State of Idaho to issue National Pollution Discharge Elimination System (NPDES) permits.

State agencies directly involved in issuing the required site certificate and necessary permits include:

- Public Utility Commission - Certificate of Public Convenience and Necessity
- Department of Health and Welfare - Permit to Construct and Permit to Operate
- Department of Water Resources - Water Use Permit.

J.2.3 Oregon

In July 1975, the Oregon State Legislature created the Department of Energy whose duties include engaging in research projects related to energy, collecting data on energy and informing the public. The Department annually provides a preliminary and final forecast of energy supply and demand which defines the state's need for power. The same legislation created the Energy Facility Siting Council (EFSC) along with the Department of Energy. The Council is a seven-member group comprised of private citizens appointed by the Governor for four-year terms with one renewal. While the Council is not a true one-stop siting authority it is a one-step coordinating authority. At the conclusion of the siting process and the issuance of a Site Agreement by the Governor, the Agreement becomes binding in all state, county and local jurisdictions. Each state agency must, however, issue and enforce its own permits as separate actions apart from the Site Agreement.

Coal facilities falling under the State Energy Facility Siting Council's certification process include:

1) conversion facilities that have a generating capacity of 25,000 kW or more
2) coal pipelines six inches or greater in diameter and five miles or more long.

The applicant for an energy facility site certificate for a specific site must file with the EFSC a notice of intent at least one year before application for site certification. The Council then distributes copies of the notice of intent to interested parties and solicits comments from the following 11 state government bodies:

- Department of Environmental Quality
- Water Policy Review Board
- State Fish and Wildlife Commission
- Health Division
- State Geologist
- State Forestry Department
- Public Utility Commissioner of Oregon

- State Department of Agriculture
- Department of Transportation
- Department of Land Conservation and Development
- Economic Development Department.

Copies are also distributed to any city or county affected by the construction or operation of the facility.

Besides the Site Certificate Agreement state agencies require their own permits. The Mined Land Reclamation Division of the Department of Geology and Mineral Industries requires a Surface Mining Operation Permit and Bond if more than one acre per year is to be disturbed. No permits are required from the Department for underground mining. If Oregon's coal deposits were to be mined, underground mining would be the primary type of mining.

The Division of State Lands manages among other lands the state's submerged and submergable lands. Permits are required for alteration or use of these tidelands such as may be the case when introducing coal transportation by barge into an area not previously used for barge transportation. State permits cover fill, removal and riprap on state lands. However, the construction of a simple wharf for unloading coal would not require a permit. Permits for wharfs and other facilities in navigable waters are obtained from the Corps of Engineers with review and comment solicited from the Division of State Lands, which then coordinates input from other state agencies in their reply to the Corps.

The Department of Transportation (DOT) has jurisdiction over state highway right-of-way lands. These lands are important in that they provide right-of-way access for more than just highways. For a pipeline to use a state highway right-of-way would require a permit. Construction of an approach to a state highway also requires a DOT permit.

The Department of Environmental Quality (DEQ) discharges the state's interest in air and water quality matters. State air quality and waste quality concerns apply to all three activities of the coal cycle (production, transportation and conversion). DEQ requires the following notices and permits:

- Notice of Construction and Approval of Plans for Air Contaminant Sources
- Air Contaminant Discharge Permit
- Water Pollution Control Facility Permit
- Waste Discharge Permit (NPDES).

The Department of Water Resources handles water appropriations. Among the permits obtained through the Department are:

- Water Rights
- Permit to Construct Reservoir
- Permit to Appropriate Ground Water
- Permit to Appropriate Public Water.

The Department of Fish and Wildlife has approval authority over activities that cross waterways such as pipelines, railroad spurs, etc., and provides permits for blasting in water.

The Railroad Divsion of the Public Utility Commissioner provides permits for track clearances, railroad-highway crossings, and variances.

State and local governmental agencies are bound by the EFSC decision when issuing their permits. The Governor may refuse to execute a site certificate approved by the Council. He cannot, however, execute a site certificate application rejected by the Council. The Governor must sign the certificate within 30 days after receipt; if not, the certificate is void.

J.2.4 Washington

The Washington State Energy Office responsibilities include identifying state energy policy options, collecting and compiling data necessary to develop and implement an overall management and conservation program for the state government, and advising the Governor on energy matters. The office does not get into the business of energy demand forecasting but does collect available information (from utilities, etc.) and critiques these attempts to forecast demand.

The Washington State Legislature in March 1976 established the Energy Facility Site Evaluation Council (EFSEC), a one-stop energy facility siting authority. EFSEC is an outgrowth of the original Thermal Power Plant Site Evaluation Council, established in 1970. EFSEC is basically a reactive body in that its purpose is to react to specific proposals for siting energy facilities in the state. Its scope covers all new energy facility siting and major modifications of existing facilities and includes associated facilities.

The Council consists of representatives of 14 state entities plus a representative from the city or county where the site is located. If more than one incorporated area or county is involved, a representative of each sits on the council during hearing proceedings for that entity only. When an application for a proposed port facility is filed, a port district member or designee may be appointed to the council as a nonvoting member. Membership is restricted to those times the council considers the proposed site for the port district represented. Agencies represented on the Council include:

- Department of Ecology
- Department of Fisheries
- Department of Parks and Recreation
- Interagency Committee for Outdoor Recreation
- Utilities and Transportation Commission
- Department of Natural Resources
- Department of Emergency Services
- Department of Game
- Department of Social and Health Services
- Department of Commerce and Economic Development
- Office of Program Planning and Fiscal Management
- Planning and Community Affairs Agency
- Department of Highways
- Department of Agriculture.

The Council's authority in siting approval supersedes that of any of the state's departments, agencies, divisions, bureaus, commissions or boards whether a member of the Council or

not. The Site Certification Agreement, when signed by the Governor and the applicant, is binding upon each party. The Governor must act on the certification recommendation within 60 days of its receipt.

Under circumstances where coal is produced or used for direct heat or process steam outside the jurisdiction of EFSEC, the normal functional laws hold and application for state permits are made directly with each state or local agency.

The Department of Natural Resources manages a large holding of land owned by the State of Washington. There are significant coal deposits on state owned lands; however, the extent of these resources has not been determined. Currently a moratorium has been placed by the Department of Natural Resources on coal leasing while rental rates, royalties and lease terms are being worked out. The moratorium is expected to be lifted soon.

The Department of Natural Resources also administers the state's surface mining reclamation permits. Presently four Surface Mining Permits are active. One is for the mine supporting the Centralia coal-fired generation plant, and the others are for much smaller operations in the state. The Department also issues permits for pipeline, transmission line and other right-of-way easements over state lands.

Other agency permits that apply to the various coal cycle activities include air and water permits from the Department of Ecology and from the Regional Air Pollution Control Agency (considered a local government agency as it administers permits over a county or multicounty area), hydraulic permits for in-stream work from the Department of Fisheries and the Department of Game, and Shoreline Management Substantial Development Permits from the county. The county also administers zoning, rezoning, conditional use and building permits.

State agency involvement in coal utilization is summarized in Table J.5. The table lists the primary state agencies involved in energy matters and identifies the mechanism used by the agency to participate in or provide input to the narrow components of the coal cycle.

J.3 COAL UTILIZATION ISSUES

The electric utility industry is the industry having the largest potential for expanding regional coal utilization. Key issues influencing the extent to which coal will be used by this industry include: 1) need for power, 2) electric generation mix, and 3) defining acceptable levels of environmental impact.

Recent forecasts indicate an electrical use growth rate of 1.4-4.5% each year for the next ten years. These forecasts suggest power shortages will cause major curtailments in interruptible loads between 1978-1983. The validity of these power forecasts has been questioned by public interest groups and private parties.

The time needed to plan and build new power plants is increasing to 10 years. A number of approvals are now required by federal, state and local entities. Although need-for-power questions are generic and not site-specific, the site-specific proceedings now required are the earliest opportunity that the public has to challenge the power forecast. This confuses the power plant siting issue. Somehow need-for-power considerations need to be separated from the power plant siting process, and institutional arrangements that allow public participation in forecasting need for power need to be set up.

TABLE J.5. Summary of State Agency Involvement in the Coal Cycle

State Agency	Production			Transportation				Conversion		
	Exploration	Extraction	Local Processing	Railroad	Barge	Truck	Pipeline	Direct Heat	Process Steam	Electric Generation
Alaska										
Department of Natural Resources	P	P	P	P	P	P	P	--	--	P
Department of Environmental Conservation	--	--	--	--	--	--	--	P	P	--
Department of Fish and Game	A	A	A	A	A	A	A	--	--	A
Department of Highways	--	--	--	--	--	P	--	--	--	--
Department of Policy Development and Planning	--	Z	Z	Z	Z	Z	Z	--	--	Z
Idaho										
Public Utility Commission	--	--	--	--	--	--	--	--	--	C
Department of Health and Welfare	--	P	P	--	--	--	--	P	P	P
Department of Water Resources	--	--	P	--	--	--	P	--	--	--
Department of Lands	--	--	--	--	--	--	P	--	--	--
Oregon										
Energy Facility Siting Council	--	--	--	--	--	--	S	--	--	S
Department of Environmental Quality	--	P	P	--	--	--	--	P	P	P
Public Utility Commissioner	--	--	--	P	--	--	--	--	--	--
Division of State Lands	--	--	--	--	P	--	P	--	--	--
Department of Water Resources	--	--	P	--	--	--	P	--	P	P
Department of Geology	--	P	--	--	--	--	--	--	--	--
Department of Fish and Wildlife	--	A	--	--	--	--	A	--	--	A
Department of Transportation	--	--	--	--	--	P	--	--	--	--
County	--	Z	ZB	Z	Z	Z	Z	ZB	ZB	ZB
Washington										
Energy Facility Site Evaluation Council	--	S	--	--	--	--	--	--	--	S
Department of Natural Resources	L	L	--	--	--	--	P	--	--	--
Department of Ecology	--	--	P	--	--	--	--	P	P	--
Department of Fisheries	--	--	--	--	P	--	--	--	--	--
Department of Game	--	--	--	--	P	--	--	--	--	--
Department of Social and Health Services	--	--	--	--	--	--	--	P	P	--
Regional Air Pollution Control Agency(a)	--	--	P	--	--	--	--	P	P	--
County(a)	--	Z	B	--	--	--	--	ZB	ZB	Z

(a) Local government
A - Approval
B - Building Permit
C - Certificate of Convenience and Necessity
L - Lease
P - Permit
S - Site Certification Agreement
Z - Zoning, Rezoning, Conditional Use

The State of Oregon is developing an "Energy Demand Forecasting Model", which will help the state to determine the future need for energy. State energy forecasts are published semi-annually: first, a preliminary draft for comment and review, and later a final forecast.

A second issue that influences coal utilization in power generating facilities is the appropriate role of various electrical generation technologies, i.e., hydro, coal, nuclear, geothermal, wind and solar power, in meeting future demands in the region. Idaho, Oregon and Washington rely primarily on low cost hydroelectric power. Their hydroelectric potential has essentially been developed, and increased consumption must now be provided by electricity from more costly fossil or nuclear plants. To meet the present demand for electricity, the three states now have two operating nuclear power plants with three under construction and six planned. Centralia, Washington has a coal-fired generating facility, and a coal-fired generating facility is under construction at Boardman, Oregon.

With nuclear fuel prices increasing rapidly, construction time for nuclear facilities exceeding that for coal facilities, and questions remaining about disposal of high-level radioactive wastes, coal-fired plants may assume a large percentage of future additions. Alternative energy sources such as geothermal, wind and solar are not expected to contribute much to overall system supply soon. Currently the federal government (DOE) has primary government responsibility for developing technology and proving economic feasibility. States such as Oregon are evaluating the role that these alternatives, once they become technically and economically feasible, could have in the state's energy system.

Another alternative often considered as a source of power is conservation. Conservation could have a significant impact and accomplish much in meeting the power requirements of the region. Again, the states may assume a large role in the promotion of conservation through land use planning, insulation standards and transportation decisions.

Another issue is the adequacy of site evaluations in locating coal-fired generating plants in terms of land use planning and economic/social/ecological impacts. Recently Idaho Power Company proposed construction of two 500 MWe coal-fired generating plants near Orchard, Ada County, Idaho. Idaho's Public Utility Commission rejected the proposed site primarily because of anticipated air quality problems. The Commission noted that:

> Although the social and economic cost of the proposed Pioneer plant is a major concern, our primary reason for denying the application is that we are not satisfied that the plant is environmentally and ecologically acceptable in the proposed location. If continued growth and the demand for electricity require the construction of additional generation in 1982 or 1983, we are satisfied that it must be at a site other than Orchard. Some environmental consequences will be felt no matter where such a plant is located. But the siting of the facility in the relatively populous Boise Valley tends to maximize environmental damage, particularly the damage resulting from air pollution.[a]

(a) Idaho Public Commission Order No. 12663, dated September 17, 1976, Case No. U-10006-98.

Until recently, the states within the region had only indirect participation in the region's energy industry. The result is that institutional mechanisms designed to specifically address the region's energy problems are just beginning to evolve. Whereas in the past a patchwork of regulations and reviews were in use, state governments now have energy offices and energy facility siting agencies.

Today as private industry and public entities pursue development of coal resources and expansion of coal utilization--the points where government involvement is directly required for approval, permit, or review and comment--the procedure is becoming more clear. This has to some extent changed the institutional problems. It has acted to expand the paperwork. The Kaiparowitz plant is an example. Resources For the Future (RFF) recently noted that for the proposed Kaiparowitz plant (a large coal-fired steam plant in southern Utah) government bureaucracy was at best cumbersome. Because of its location and a number of other factors, environmentalists were opposed to the plant. RFF suggested, however, that "although environmentalists' opposition made the headlines, red tape was probably the proximate cause of the demise of Kaiparowitz." It was noted that "after 13 years of planning, several hearings, and hundreds of pages of environmental impact statement, there still remained 220 permits and authorizations to be obtained through some 42 federal, state and local agencies."

Not all projects face this level of entanglement with the government infrastructure. However, it is not always clear which level of government is responsible for addressing specific activities of a proposed project, and which agencies of these governments have the authority for discharging that government's responsibilities.

The role and authority of local governments in facility siting is less clear than that of the states. It is at the local level, however, where the social/economic/ecological effects are the greatest. If one local agency is informed of a potential energy development, this does not guarantee that all the other affected local agencies will subsequently be informed. Coordination of communications is important to local governments, particularly those impacted directly by energy developments. Local governments need to learn early about contemplated development to ensure effective planning for the expected impacts. The length of time needed depends on the anticipated size of the work force and the existing carrying capacity of the community.

Implicit in the question of government's involvement in coal utilization decisions is the question of when, where and how does the public, by individuals and/or by groups, provide input to decision makers? How does the private individual present his values and views for consideration in designing answers to the energy questions that are making headlines today? The states are aware of the need for developing institutions to handle these issues. Progress is being made and various proposals for improvement are under consideration.

The technical/economic approach provides opportunities for regional cooperation and suggests some opportunities for developing new coal sources. The State of Alaska owns large reserves of bituminous and lignite coal, notably the Beluga field northwest of Anchorage. With reasonably close access to salt water, it is logical to think of delivering coal to Oregon and Washington in barges. Once loaded, a barge can be moved almost any reasonable distance at minimal cost; in most areas barges are competitive with pipelines even for liquid products.

Coal is particularly amenable to barging because of its uniformity, stability, safety and non-polluting character in the marine environment. "Unit barges" (i.e., like unit trains, standardized for mechanical cargo handling) could go to either industrial centers like Portland, Tacoma and Seattle; to electric utilities sited on the coast; or further inland on the Columbia River system for industrial uses. At both ends of the system, from the mine and to the consuming points, state-sited slurry pipelines for overland transportation may also be built.

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