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Preconstruction Schedules, Costs, and Permit Requirements for Electric Power Generating Resources in the Pacific Northwest

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July 1990

Prepared for the
Office of Energy Resources
Bonneville Power Administration
under a Related Services Agreement
with the U.S. Department of Energy
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Richland, Washington 99352

PREFACE

This report was prepared by the Pacific Northwest Laboratory for the Office of Energy Resources, Bonneville Power Administration. Robert J. Moulton was BPA's technical representative. Paul Hendrickson prepared Sections 1 and 2. Ray Watts wrote Section 3. Steve Weakley, Steve Smith, and Alison Thurman wrote Section 4 and the appendices.

SUMMARY

This report was prepared for the Generation Programs Branch, Office of Energy Resources, Bonneville Power Administration (BPA). The principal objective of the report is to assemble in one document preconstruction cost, schedule, and permit information for twelve specific generating resources. The report is one of many documents that provide background information for BPA's Resource Program, which is designed to identify the type and amount of new resources that BPA may have to add over the next twenty years to maintain an adequate and reliable electric power supply in the Pacific Northwest. A predecessor to this report is a 1982 report prepared by the Pacific Northwest Laboratory (PNL) for the Northwest Power Planning Council (the "Council"). The 1982 report had a similar, but not identical, content and format.

The twelve generating resources that are examined in this report are listed in Table S.1. The resources were selected to be consistent with the current generating resource planning assumptions of BPA and the Council.

TABLE S.1. Generating Resources Examined

1. 50-MW Geothermal Plant
2. 10-MW Wind Park
3. 10-MW Municipal Solid Waste Incinerator
4. 10-MW Solar Photovoltaic Plant
5. 10-MW New Hydroelectric Plant
6. Two 603-MW Pulverized-Coal-Fired Plants
7. 197-MW Atmospheric Fluidized-Bed Coal Plant
8. Two 139-MW Single-Cycle Combustion Turbine Units
9. 420-MW Combined-Cycle Combustion Turbine Plant
10. 10-MW Wood-Products-Based Cogeneration Plant
11. 10-MW Natural-Gas-Based Cogeneration Plant
12. 420-MW Coal Gasification Combined-Cycle Plant

The following information is discussed in the report for each of the resources listed in Table S.1: 1) the principal siting and environmental licenses/permits that need to be obtained for a generating plant located in Idaho, Montana, Oregon, and Washington; 2) the estimated preconstruction schedule for the resource; 3) estimated preconstruction costs associated with bringing the resource on line; and 4) the estimated cost of delaying bringing a resource on line at selected preconstruction delay points.

Tables 2.1 through 2.4 in Section 2 of the report contain summary information on license and permit requirements by resource for each of the four Pacific Northwest states. Although not a license or permit, environmental impact statement requirements are also included in the summary tables.

Table S.2 summarizes estimated preconstruction times in years for the twelve resources. Also shown are the comparable time estimates included in the 1982 PNL report. In general, the time estimates have increase. The increase is largely attributable to longer estimates for the acquisition of

TABLE S.2. Estimated Preconstruction Schedules

Power Resource	Preconstruction Times in Years PNL90	PNL82
50-MW Geothermal Plant	7	6.2
10-MW Wind Park	4	5
10-MW Municipal Solid Waste Incinerator	5	3.5
10-MW Solar Photovoltaic Plant	3	1.8
10-MW Hydroelectric Plant	6	2
Two 603-MW Pulverized-Coal-Fired Plants	8	6
197-MW Atmospheric Fluidized-Bed Coal Plant	8	
Two 193-MW Single-Cycle Combustion Turbine Units	4	2.1
420-MW Combined-Cycle Combustion Turbine Plant	5	2.1
10-MW Wood-Products-Based Cogeneration Plant	6	2.3
10-MW Natural-Gas-Based Cogeneration Plant	5	2.3
420-MW Coal Gasification Combined-Cycle Plant	8	4

permits and the environmental review process. The schedule estimates are conservative. Specific resources at specific sites could potentially be completed in shorter periods.

Table S.3 contains estimated preconstruction and delay costs for the twelve generating resources for preconstruction phases. The activities included in each phase are resource specific and are included in the tables accompanying the discussion for each resource in Section 4 of the report. The delay costs represent the incremental cost of delaying construction of the particular resource one year. All costs in Table S.3 are in constant 1989 dollars.

As shown in Table S.3, the total preconstruction costs varied from a high of $560/kW for a 10-MW solar photovoltaic (PV) plant to a low of $20/kW for two 139-MW combustion turbine (CT) units. Some of the factors that cause this wide variation in total preconstruction costs are

- the wide range of resource sizes (from a 10-MW plant to two 603-MW units)
- the stage of technology development for the resource (from conventional coal plants to advanced solar PV)
- the complexity of the resource (from single-cycle CT units to a complex geothermal field).

Because of the influence of the above factors, all costs should be viewed as estimates only. In addition, costs should be updated periodically to reflect changes in technology and resource availability.

TABLE S.3. Preconstruction and Delay Costs

Generating Resource	Phase I Costs		Phase II Costs		Phase III Costs		Total
	Preconstruction Cost ($/kW)	Delay Cost ($/kW/yr)	Preconstruction Cost ($/kW)	Delay Cost ($/kW/yr)	Preconstruction Cost ($/kW)	Delay Cost ($/kW/yr)	Preconstruction Cost ($/kW)
1. 50 MW Geothermal Plant	28	3	149	22	260	63	437
2. 10 MW Wind Park	18	2	34	7	--	--	52
3. 10 MW Muni. Solid Waste Incinerator	129	4	289	18	--	--	418
4. 10 MW Solar PV Plant	56	6	504	57	--	--	560
5. 10 MW Hydroelectric	10	1	65	8	30	11	105
6. 2 X 603 MW Coal Plant	18	1	5	2	51	10	75
7. 197 MW AFBC Plant	15	5	28	7	75	32	119
8. 2 x 139 MW CT Units	4	<1	16	5	--	--	20
9. 420 MW Combined Cycle CT Plant	11	1	61	14	--	--	72
10. 10 MW Wood Products Cogeneration Plant	10	1	166	18	--	--	176
11. 10 MW Natural Gas Cogeneration Plant	8	<1	156	16	--	--	164
12. 420 MW Coal Gasification Plant	39	4	12	5	116	27	167

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FIGURES

TABLES

ABBREVIATIONS AND ACRONYMS

A/E	Architect/Engineer
AFBC	Atmospheric fluidized bed coal
BACT	Best available control technology
BAT	Best available technology economically achievable
BCT	Best pollution control technology
BPA	Bonneville Power Administration
CFR	Code of Federal Regulations
Cir	Circuit
Cogen	Cogeneration facility
Corps	U.S. Army Corps of Engineers
Council	Northwest Power Planning Council
CWA	Clean Water Act
CT	Combustion turbine
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
EA	Environmental assessment
EIS	Environmental impact statement
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FUA	Powerplant and Industrial Fuel Use Act
GNP	Gross National Product
IOU	Investor-Owned Utility
LAER	Lowest achievable emission rate
kW	Kilowatt
M	Million
MCA	Montana Code Annotated
MSW	Municipal solid waste
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NEPA	National Environmental Policy Act
NESHAPS	National Emission Standards for Hazardous Air Pollutants
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPDES	National Pollution Discharge Elimination System
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
Pacific Northwest	Idaho, western Montana, Oregon, and Washington
PNL	Pacific Northwest Laboratory
PSD	Prevention of significant deterioration
POTW	Publicly owned treatment works
POU	Publicly owned utility
Power Plan	Northwest Conservation and Electric Power Plan
PV	Photovoltaic
PUC	Public Utilities Commission
QF	Qualifying Facility
RCW	Revised Code of Washington

RCRA	Resource Conservation and Recovery Act
Region	Areas served by utilities that buy firm power from BPA
SEPA	State environmental policy act
SIP	State implementation plan
Tpy	Tons per year
TSD	Treatment, storage, and disposal
UIC	Underground injection control
USC	United States Code
WAC	Washington Administrative Code

1.0 INTRODUCTION

The Bonneville Power Administration (BPA) is one of five regional Federal power marketing agencies within the U.S. Department of Energy (DOE). BPA was created in 1937 to market electric power from the Bonneville Dam. The Agency now markets power from 30 federal hydroelectric projects, most of which are located in the Columbia River Basin, and several non-federal projects. BPA sells and exchanges power under contracts with over 100 utilities and with several industrial customers. The primary customer service area is Idaho, western Montana, Oregon, and Washington, an area referred to in this report as the "Pacific Northwest." Customers in small portions of California, Nevada, Utah, and Wyoming are also served by utilities which purchase power from BPA. Collectively, the geographic areas served by utilities that buy firm power from BPA are referred to in this report as the "Region."

Under Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (the "Northwest Power Act"), BPA has a statutory obligation to sell to requesting utilities serving the Region that amount of the utilities' firm power requirements which exceeds the power resources available to such utilities to meet their firm load requirements.[1] This obligation extends to publicly owned utilities (POUs), cooperatives, and to investor-owned utilities (IOUs). BPA is not permitted to own or construct electric power generating facilities. It is authorized, however, under Section 6 of the Northwest Power Act to acquire sufficient electric power, including the planned or actual capability of generating resources, to meet its contractual power sales obligations. BPA is also authorized under Section 6 to achieve load reduction through acquisition of renewable resources and conservation. BPA's acquisition of resources must generally be consistent with the current Northwest Conservation and Electric Power Plan (the "Power Plan") prepared by the Northwest Power Planning Council (the "Council") and/or the criteria and considerations in Section 4(e) of the Northwest Power Act. One criterion in Section 4(e) is cost-effectiveness.

BPA annually prepares a 20-year forecast of its contractual electric power loads based on five potential rates of load growth (high, medium high, medium, medium low, and low). The most recent forecast was prepared jointly by BPA and the Council and was published in August 1989.[2] Based on this load forecast, BPA has estimated nearly a 50% chance that existing resources will not be adequate to meet its loads in the 1990s, and roughly a 10% chance of deficits exceeding 1,000 average megawatts (MW) in the mid-1990s.[3]

BPA's Resource Program is designed to identify the type and amount of new resources that BPA may have to add over the next 20 years to maintain an adequate and reliable power supply. The most recent Program was published in July 1988; the 1990 Program will be published later this year. BPA uses a number of decision factors in identifying the resources required, including 1) present value costs, 2) compatibility with both high and low load growth, 3) rate impact, 4) environmental impact, and 5) the likelihood of a particular resource being available given such uncertainties as the need for permits from governmental entities.[4] BPA is giving active consideration to a competitive acquisition process for new generating resources.[5]

This report was prepared to provide background information for BPA's Resource Program. The report contains information on permit requirements and preconstruction schedules and costs to bring 12 specific generating resources online. Permit requirements of the Federal government and each of the four Pacific Northwest states for the resources are discussed in Section 2. Preconstruction schedules are discussed in Section 3. Preconstruction costs are discussed in Section 4. Section 4 also includes information on the estimated cost of delaying the resource acquisition process at an intermediate preconstruction stage.

The 12 generating resources that are analyzed in this report are listed in Table 1.1. The rated capacity of the resources in net MW is also shown. The resources were selected to be consistent with the current resource planning assumptions of BPA and the Council. The resources are discussed in current planning documents on the pages shown in the reference column of Table 1.1. The Washington Public Power Supply System's uncompleted nuclear

TABLE 1.1. Generating Resources Examined

	Resource	References
1.	50-MW Geothermal Plant	A (p. 45)
2.	10-MW Wind Park	A (p. 72)
3.	10-MW Municipal Solid Waste Incinerator	C (p. 72)
4.	10-MW Solar Photovoltaic Plant	C (p. 6-14)
5.	10-MW New Hydroelectric Plant	A (p. 52)
6.	Two 603-MW Pulverized-Coal-Fired Plants	A (p. 9); B (p. 4-50)
7.	197-MW Atmospheric Fluidized-Bed Coal Plant	A (p. 9); B (p. 4-56)
8.	Two 139-MW Single-Cycle Combustion Turbine Units	A (p. 22); B (p. 4-65)
9.	420-MW Combined-Cycle Combustion Turbine Plant	A (p. 22); B (p. 4-63)
10.	10-MW Wood-Products-Based Cogeneration Plant	A (p. 17)
11.	10-MW Natural-Gas-Based Cogeneration Plant	A (p. 17)
12.	420-MW Coal Gasification Combined-Cycle Plan	A (p. 22); B (p. 4-65)

Key to References:

A. BPA, Draft 1990 Generating Resources Supply Document, January 1990.
B. Council, 1989 Supplement to the 1986 Northwest Conservation and Electric Power Plan.
C. Council, 1986 Northwest Conservation and Electric Power Plan.

projects 1 and 3 are not discussed in this report. These projects have been extensively analyzed elsewhere by the Supply System, BPA, and the Council.[6]

A predecessor to the present document is a 1982 report prepared by the Pacific Northwest Laboratory (PNL) for the Council.[7] The 1982 report had a similar format. Differences from the present report include the fact that the 1982 report 1) was not limited to preconstruction costs; 2) had a somewhat different resource list that included, for example, conservation and nuclear powerplants; and 3) did not focus on particular resource sizes.

REFERENCES FOR SECTION 1

1. 16 USC 839c.

2. BPA and the Council. 1989. Forecast of Electricity Use in the Pacific Northwest.

3. BPA. December 1989. Draft 1990 Resource Program. DOE/BP-1302, p. 3. Portland, Oregon.

4. BPA. December 1989. Draft 1990 Resource Program: Technical Report. DOE/BP-1281, p. 17. Portland, Oregon.

5. BPA. January 1990. Draft 1990 Resource Program Supplement: Draft Resources Acquisition Approaches Plan. DOE/BP-1329, p. 10. Portland, Oregon.

6. King, J. 1990. "Nuclear Power Prospects in the Pacific Northwest." Northwest Energy News, published by the Northwest Power Planning Council, January/February 1990, pp. 14-17.

7. Moore, E. B., Jr., R. L. Watts, B. J. Harrer, and P. L. Hendrickson. 1982. Development and Characterization of Electric Power Conservation and Supply Resource Planning Options. DOE/RL/01830-T9. Prepared for the Northwest Power Planning Council.

2.0 LICENSING AND PERMIT REQUIREMENTS

This section describes licensing and permit requirements for the 12 generating resources identified in Table 1.1. Requirements of the federal government; the four Pacific Northwest states; and, to a lesser extent, units of local government are discussed. Except for legislation requiring preparation of environmental impact statements (EISs), federal statutes requiring environmental reviews (but not a license or permit) are not discussed. The focus of the discussion is environmental and siting permit/licensing requirements needed at the site of electricity generation. Permits and licenses required for 1) fuel procurement, e.g., coal mining, and 2) transportation of fuel to the generation site, e.g., natural gas pipelines, are also important topics, but are outside the scope of this document.

Although the discussion in Section 2 is intended to be reasonably comprehensive, some permit and license requirements may not be covered. In addition, various miscellaneous permit requirements are not discussed.[a] These permits include a business license, building and occupancy permits, electrical and plumbing permits, a permit to construct a public or private road, a grading permit, a permit to dump land clearing debris, permits for septic and water drainage systems, a permit to interconnect with and obtain water from an existing water system, a permit to interconnect with and discharge to an existing sewer system, a permit to burn wood or slash and nonhazardous construction debris, special transportation permits for such things as oversized loads, a steam boiler or furnace permit, licenses needed by facility operators (e.g., a boiler operator's license), a permit to temporarily move a

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(a) Many of these permit requirements are discussed in the following reports prepared for BPA:
1. Idaho Department of Water Resources. 1986. Permitting Guidebook for Bioenergy Projects in the State of Idaho. Boise, Idaho.
2. Montana Department of Natural Resources and Conservation. 1986. Montana's Bioenergy Project Permitting Guidebook. Helena, Montana.
3. Oregon Department of Energy. 1984. Guide to Oregon's Environmental Permits for Biomass Energy Projects. Salem, Oregon.
4. Washington State Energy Office. 1988. Guide to Washington's Permits for Biomass Energy Projects, WAOENG-88-11. Olympia, Washington.

survey marker, etc. Although permits such as these can likely be obtained at less cost and more quickly than major environmental permits, they are nevertheless important, and potential developers of generating resources need to have direct contact with all levels of government to ensure that applicable regulatory requirements are identified and met. Tables 2.1 through 2.4 summarize the licensing and permit requirements for the 12 generating resources for each of the four Pacific Northwest states.

2.1 ENVIRONMENTAL IMPACT STATEMENTS

NEPA is the basic national charter for protection of the environment.[1] The Act declares that it is a national policy to "encourage productive and enjoyable harmony between man and his environment and to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man."[2] NEPA requires that federal agencies give appropriate consideration to environmental impacts in their decision making.[3] Regulations to aid federal agencies in implementing NEPA have been issued by the Council on Environmental Quality.[4]

The most important action-forcing provision of NEPA is Section 102(C) which requires that federal agencies prepare an EIS for major federal actions significantly affecting the quality of the human environment.[5] Although not a permit, the EIS is an important part of the resource development process. Several types of actions undertaken by the federal government in connection with a proposed new power resource project can trigger the EIS requirement when the environmental impacts from the proposed project are significant. Such actions can include issuance of a license or permit from a federal agency; a lease, easement, or other transfer of federal lands; and federal financial assistance for a project. In some cases an environmental assessment (EA) is prepared to provide sufficient evidence and analysis for determining whether to prepare an EIS or to aid compliance with NEPA when preparation of an EIS is not deemed necessary.[6] When preparation of an EIS is indicated, the federal agency will normally require the applicant to submit an environmental report which then becomes the basis for the EIS.[7]

TABLE 2.1. Idaho Permit Requirements

License/Permit	50 MW Geothermal	10 MW Wind	10 MW MSW Incinerator	10 MW PV	10 MW Hydro	883 MW Coal	197 MW Fluidized Bed Coal	139 MW Single Cycle CT	420 MW Combined Cycle CT	10 MW Wood Cogen	10 MW Gas Cogen	420 MW Coal gasif. Combined Cycle
NEPA EIS or EA	P	P	P	P	Y	P	P	P	P	P	P	P
SEPA EIS	N	N	N	N	N	N	N	N	N	N	N	N
Certificate of Convenience and Necessity	Yes if constructed by an IOU											
State siting agency approval	N	N	N	N	N	N	N	N	N	N	N	N
Local land use approval	P	Y	Y	Y	P	Y	Y	Y	Y	Y	Y	Y
Optional FERC QF certification	Y	Y	Y	Y	Y	N	N	N	N	P	P	N
FERC hydroelectric license	N	N	N	N	Y	N	N	N	N	N	N	N
State hydroelectric permit(s) related to bed, banks, and diversion	N	N	N	N	Y	N	N	N	N	N	N	N
Federal geothermal lease	P	N	N	N	N	N	N	N	N	N	N	N
State geothermal permit(s)	P	N	N	N	N	N	N	N	N	N	N	N
State/local emission permit	P	N	Y	N	N	Y	Y	Y	Y	Y	Y	Y
Nonattainment permit	P	N	P	N	N	P	P	P	P	P	P	P
PSD permit	P	N	P	N	N	P	P	P	P	P	P	P
NESHAPS permit	N	N	P	N	N	N	N	N	N	N	N	N
NPDES permit	P	N	P	N	N	Y	P	P	P	P	P	P
UIC or state underground injection permit	Y	N	N	N	N	N	N	N	N	N	N	N
Corps permit for structure in navigable water	N	N	N	N	Y	P	P	N	P	P	P	P
Corps dredge and fill permit	P	P	P	P	Y	P	P	P	P	P	P	P
FUA certification to DOE	N	N	N	N	N	N	N	P	P	N	P	N
State/local MSW incinerator permit	N	N	Y	N	N	N	N	N	N	N	N	N
State/local permit for ash/waste disposal	P	N	Y	N	N	Y	Y	N	N	Y	N	Y
Water acquisition permit	Y	N	P	N	Y	Y	Y	N	Y	P	P	Y

Key: Y = Probably yes; N = Probably not; P = Possibly

TABLE 2.2. Montana Permit Requirements

License/Permit	50 MW Geothermal	10 MW Wind	10 MW MSW Incinerator	10 MW PV	10 MW Hydro	803 MW Coal	197 MW Fluidized Bed Coal	139 MW Single Cycle CT	420 MW Combined Cycle CT	10 MW Wood Cogen	10 MW Gas Cogen	420 MW Coal gasif. Combined Cycle
NEPA EIS or EA	P	P	P	P	Y	P	P	P	P	P	P	P
SEPA EIS	P	P	Y	P	P	Y	Y	P	Y	P	P	Y
Certificate of Convenience and Necessity	N	N	N	N	N	N	N	N	N	N	N	N
State siting agency approval	Y	N	N	N	N	Y	Y	Y	Y	N	N	Y
Local land use approval	P	Y	Y	Y	P	Y	Y	Y	Y	Y	Y	Y
Optional FERC QF certification	Y	Y	Y	Y	Y	N	N	N	N	P	P	N
FERC hydroelectric license	N	N	N	N	Y	N	N	N	N	N	N	N
State hydroelectric permit(s) related to bed, banks, and diversion	N	N	N	N	Y	N	N	N	N	N	N	N
Federal geothermal lease	P	N	N	N	N	N	N	N	N	N	N	N
State geothermal permit(s)	P	N	N	N	N	N	N	N	N	N	N	N
State/local emission permit	P	N	Y	N	N	Y	Y	Y	Y	Y	Y	Y
Nonattainment permit	P	N	P	N	N	P	P	P	P	P	P	P
PSD permit	P	N	P	N	N	P	P	P	P	P	P	P
NESHAPS permit	N	N	P	N	N	N	N	N	N	N	N	N
NPDES permit	P	N	P	N	N	Y	P	P	P	P	P	P
UIC or state underground injection permit	Y	N	N	N	N	N	N	N	N	N	N	N
Corps permit for structure in navigable water	N	N	N	N	Y	P	P	N	P	P	P	P
Corps dredge and fill permit	P	P	P	P	Y	P	P	P	P	P	P	P
FUA certification to DOE	N	N	N	N	N	N	N	P	P	N	P	N
State/local MSW incinerator permit	N	N	Y	N	N	N	N	N	N	N	N	N
State/local permit for ash/waste disposal	P	N	Y	N	N	Y	Y	N	N	Y	N	Y
Water acquisition permit	Y	N	P	N	Y	Y	Y	N	Y	P	P	Y

Key: Y = Probably yes; N = Probably not; P = Possibly

TABLE 2.3. Oregon Permit Requirements

License/Permit	50 MW Geothermal	10 MW Wind	10 MW MSW Incinerator	10 MW PV	10 MW Hydro	603 MW Coal	197 MW Fluidized Bed Coal	139 MW Single Cycle CT	420 MW Combined Cycle CT	10 MW Wood Cogen	10 MW Gas Cogen	420 MW Coal gasif. Combined Cycle
NEPA EIS or EA	P	P	P	P	Y	P	P	P	P	P	P	P
SEPA EIS	N	N	N	N	N	N	N	N	N	N	N	N
Certificate of Convenience and Necessity	N	N	N	N	N	N	N	N	N	N	N	N
State siting agency approval	Y	N	N	N	N	Y	Y	Y	Y	N	N	Y
Local land use approval	P	Y	Y	Y	P	Y	Y	Y	Y	Y	Y	Y
Optional FERC QF certification	Y	Y	Y	Y	Y	N	N	N	N	P	P	N
FERC hydroelectric license	N	N	N	N	Y	N	N	N	N	N	N	N
State hydroelectric permit(s) related to bed, banks, and diversion	N	N	N	N	Y	N	N	N	N	N	N	N
Federal geothermal lease	P	N	N	N	N	N	N	N	N	N	N	N
State geothermal permit(s)	P	N	N	N	N	N	N	N	N	N	N	N
State/local emission permit	P	N	Y	N	N	Y	Y	Y	Y	Y	Y	Y
Nonattainment permit	P	N	P	N	N	P	P	P	P	P	P	P
PSD permit	P	N	P	N	N	P	P	P	P	P	P	P
NESHAPS permit	N	N	P	N	N	N	N	N	N	N	N	N
NPDES permit	P	N	P	N	N	Y	P	P	P	P	P	P
UIC or state underground injection permit	Y	N	N	N	N	N	N	N	N	N	N	N
Corps permit for structure in navigable water	N	N	N	N	Y	P	P	N	P	P	P	P
Corps dredge and fill permit	P	P	P	P	Y	P	P	P	P	P	P	P
FUA certification to DOE	N	N	N	N	N	N	N	P	P	N	P	N
State/local MSW incinerator permit	N	N	Y	N	N	N	N	N	N	N	N	N
State/local permit for ash/waste disposal	P	N	Y	N	N	Y	Y	N	N	Y	N	Y
Water acquisition permit	Y	N	P	N	Y	Y	Y	N	Y	P	P	Y

Key: Y = Probably yes; N = Probably not; P = Possibly

TABLE 2.4. Washington Permit Requirements

License/Permit	60 MW Geothermal	10 MW Wind	10 MW MSW Incinerator	10 MW PV	10 MW Hydro	603 MW Coal	197 MW Fluidized Bed Coal	139 MW Single Cycle CT	420 MW Combined Cycle CT	10 MW Wood Cogen	10 MW Gas Cogen	420 MW Coal gasif. Combined Cycle
NEPA EIS or EA	P	P	P	P	Y	P	P	P	P	P	P	P
SEPA EIS	P	P	Y	P	P	Y	Y	P	Y	P	P	Y
Certificate of Convenience and Necessity	N	N	N	N	N	N	N	N	N	N	N	N
State siting agency approval	Y	N	N	P	N	Y	Y	Y	Y	N	N	Y
Local land use approval	P	Y	Y	Y	P	Y	Y	Y	Y	Y	Y	Y
Optional FERC QF certification	Y	Y	Y	Y	Y	N	N	N	N	P	P	N
FERC hydroelectric license	N	N	N	N	Y	N	N	N	N	N	N	N
State hydroelectric permit(s) related to bed, banks, and diversion	N	N	N	N	Y	N	N	N	N	N	N	N
Federal geothermal lease	P	N	N	N	N	N	N	N	N	N	N	N
State geothermal permit(s)	P	N	N	N	N	N	N	N	N	N	N	N
State/local emission permit	P	N	Y	N	N	Y	Y	Y	Y	Y	Y	Y
Nonattainment permit	P	N	P	N	N	P	P	P	P	P	P	P
PSD permit	P	N	P	N	N	P	P	P	P	P	P	P
NESHAPS permit	N	N	P	N	N	N	N	N	N	N	N	N
NPDES permit	P	N	P	N	N	Y	P	P	P	P	P	P
UIC or state underground injection permit	Y	N	N	N	N	N	N	N	N	N	N	N
Corps permit for structure in navigable water	N	N	N	N	Y	P	P	N	P	P	P	P
Corps dredge and fill permit	P	P	P	P	Y	P	P	P	P	P	P	P
FUA certification to DOE	N	N	N	N	N	N	N	P	P	N	P	N
State/local MSW incinerator permit	N	N	Y	N	N	N	N	N	N	N	N	N
State/local permit for ash/waste disposal	P	N	Y	N	N	Y	Y	N	N	Y	N	Y
Water acquisition permit	Y	N	P	N	Y	Y	Y	N	Y	P	P	Y

Key: Y = Probably yes; N = Probably not; P = Possibly

Montana[8] and Washington[9] have state environmental policy acts (SEPAs) that require agencies to prepare an EIS for state actions with significant environmental effects. Issuance of a permit by a state agency in these states can trigger the EIS requirement. It is unlikely that both a federal and a state EIS would be required for the same project. Federal agencies are to cooperate with state agencies to avoid duplication of effort in the EIS process.[10]

2.2 POWERPLANT SITING LAWS

Montana, Oregon, and Washington have state powerplant siting laws that are discussed in this section.

2.2.1 Montana

The Montana Major Facility Siting Act requires that a certificate of environmental compatibility and public need be obtained from the Board of Natural Resources and Conservation before construction is initiated on certain facilities and associated facilities, including 1) powerplants capable of generating 50 MW or more, facilities utilizing or converting 500,000 tons per year (tpy) or more of coal, and facilities producing 25 million cubic feet or more of gas derived from coal per day; 2) additions to the preceding facilities having an estimated cost of $10 million or more; and 3) facilities that make use of geothermal resources.[11] Associated facilities include such things as transportation links, substations, reservoirs, and storage ponds.[12] Detailed applications for a certificate are to be filed with the Board and the Montana Department of Health and Environmental Sciences. The facility must have been included in the utility's long-range plan submitted to the Montana Department of Natural Resources and Conservation at least two years prior to submittal of the application.[13] The Board is not to grant a certificate until it makes an extensive series of findings, including a finding that the facility will meet all applicable environmental requirements as well as minimize environmental impact.[14] After issuance of a certificate, no other state or local permits or approvals are to be required other than for compliance with air and water pollution requirements.[15] The period of time between acceptance of an application and issuance of a certificate will vary, but is approximately three years. Construction must begin within six years of certificate issuance and continue with due diligence.[16]

2.2.2 Oregon

A site certificate is needed from the Oregon Energy Facility Siting Council for construction or expansion of powerplants with a capacity greater than 25 MW and solar collecting facilities using more than 100 acres of land.[17] For cogeneration plants fired by agricultural or wood waste, a certificate is not needed unless the plant has a capacity of 50 MW or more. Evaluation of applications can take up to six months for facility expansions, nine months for combustion turbine and geothermal powerplants, two years for base load plants with a capacity of 200 MW or more, and one year for all other powerplants.[18] If the Siting Council determines that pending applications for hydroelectric facilities could have cumulative impacts, it is to conduct a consolidated review of the applications. No time limits apply to this review. Hydroelectric projects subject to review by the Siting Council must meet a number of minimum standards including compliance with the Columbia River Basin Fish and Wildlife program established under the Northwest Power Act.[19] After issuance of a site certificate, state and local agencies are to issue all appropriate permits necessary for the facility.[20]

2.2.3 Washington

Construction of a thermal powerplant with a capacity of 250 MW or more requires a certificate from the Washington Energy Facility Site Evaluation Council.[21] The Site Evaluation Council is to make a recommendation on issuance of a certificate within one year after the application is filed.[22] The Governor then has 60 days to make a decision on the application or to request further action by the Council. A certificate issued by the Site Evaluation Council is in lieu of all other state and local permits.[23]

2.3 CERTIFICATE OF CONVENIENCE AND NECESSITY

Construction of a generating resource by an IOU in Idaho requires a certificate of convenience and necessity issued by the Idaho Public Utilities

Commission.[24] The Commission's review is based on an analysis of the need for power, the financial ability of the certificate applicant, the good faith of the applicant, and the public convenience and necessity. Environmental impact can be considered under the Commission's residual jurisdiction.[25] The Commission's procedures provide for public notice of an application, optional hearings, the right of intervention, and the right of appeal.[26]

2.4 LAND USE APPROVAL

Except for activities on federal lands, all generating plants and associated infrastructure such as transmission lines and access roads must generally be in compliance with applicable municipal, county, regional, state, and interstate zoning and land use requirements. Activities on federal lands are generally exempt from local land use requirements under the Property and Supremacy Clauses of the U.S. Constitution unless Congress chooses to make such activities subject to state and local regulation.[27] In some cases it may be possible to obtain a variance or a conditional use permit authorizing a proposed project if the project is inconsistent with existing zoning or land use restrictions. The principal zoning/land use requirements are those at the local level. These can be supplemented by additional requirements of regional (e.g., the Puget Sound Water Quality Authority)[28] state (e.g., the Oregon Land Conservation and Development Commission),[29] and even interstate (e.g., the Columbia River Gorge Commission)[30] entities. The state siting agencies in Montana,[31] Oregon,[32] and Washington[33] can preempt inconsistent local land use restrictions for facilities that require the agencies' approval, however the actual exercise of such preemptive power is controversial and, consequently, is not common.

In some cases a permit may be needed to comply with applicable land use requirements. For example, construction in an area designated as a floodplain will often require a special permit. In Montana construction of artificial obstructions or nonconforming uses in a designated floodplain or floodway requires a permit from the local planning and zoning commission or from the Montana Department of Natural Resources and Conservation if no local commission exists.[34] In Washington, construction within 200 feet of a shoreline generally requires a special shoreline development permit from the local government.[35] Substantial progress toward completion of the permitted activity is to be made within two years after approval of the permit.[36]

2.5 LEASES AND PERMITS FOR USE OF GOVERNMENT LANDS

Construction of a generating plant and/or associated infrastructure such as transmission lines or access roads on lands owned by a unit of government will require the approval of the agency administering the lands and, possibly, an elected body such as a city council or board of county commissioners. The approval may be a special use permit or authorization, a lease, or an easement. In some cases an exchange of lands between the agency and the project developer may be possible. Various conditions will often be attached to the approval requiring, for example, compliance with applicable environmental requirements and any special environmental requirements deemed applicable to the particular site.

The source of approval requirements for various federal agencies are listed below. The general heading used in the Code of Federal Regulations (CFR) is shown in parenthesis.

Bureau of Land Management	43 CFR 2800 (rights-of-way) 43 CFR 2900 (leases and permits)
Bureau of Reclamation	43 USC 3871
Federal Highway Administration	23 CFR 645 (utilities)
Fish and Wildlife Service	50 CFR 29, Subpart B (rights-of-way)
Forest Service	36 CFR 251 (special uses)
National Park Service	36 CFR 14 (rights-of-way)

Special requirements for lands owned by or held in trust for Indian tribes or individual Indians are at 25 CFR 162.

2.6 FERC CERTIFICATION OF QUALIFYING FACILITIES

Sections 201 and 210 of the Public Utilities Regulatory Policies Act create a class of power generating facilities known as qualifying facilities

(QFs).[37] To qualify as a QF, a facility must meet certain criteria related to size, fuel use, and ownership.[38] Facilities that meet these requirements are allowed to generate and sell power to utilities while generally being exempt from the Federal Power Act, the Public Utility Holding Company Act, and most state regulations applicable to public utilities.[39] Electric utilities are required to purchase power made available by QFs at the utilities' marginal (i.e., avoided) cost of power.[40]

QF facilities include cogeneration facilities and small power production facilities. Cogeneration QFs must meet an efficiency standard and at least 5% of total energy output must be useful thermal energy.[41] A small power facility must be 80 MW or less and obtain 75% of its fuel from biomass, waste, renewable resources, geothermal resources, or any combination thereof.[42] Special restrictions apply to hydroelectric small power production facilities as a result of Section 8 of the Electric Consumers Protection Act of 1986.[43]

Facilities which meet the size, fuel use, and ownership criteria are QFs. Owners of such facilities must provide information on the facility to Federal Energy Regulatory Commission (FERC), a part of the U.S. Department of Energy (DOE).[44] Alternatively, the owner may file an application with FERC seeking certification as a QF. Filing such an application may be useful for securing project financing and resolving uncertainty about the qualifying status of a proposed facility. The principal disadvantages of seeking FERC certification are the cost involved and the potential for delay.

2.7 FERC LICENSING OF HYDROELECTRIC FACILITIES

Section 23(b) of the Federal Power Act requires that developers of hydroelectric facilities that do not qualify for an exemption must obtain a license prior to the construction and operation of dams, reservoirs, water conduits, power houses, and other related works.[45] Licenses are issued by FERC. FERC has extensive regulations applicable to the licensing process at 18 CFR 4. The license application requirements for major hydroelectric projects are at 18 CFR 4, Subparts E and F. As part of the application process, a license applicant is required to prepare a detailed environmental report that is commensurate with the scope of the proposed project.[46] FERC will normally prepare an EIS for newly constructed hydroelectric projects.[47] FERC is required to consider the effect of its licensing decisions on fish and wildlife.[48]

Applicants seeking a hydroelectric license from FERC are also to conduct a detailed consultation with all appropriate federal and state agencies before submitting an application to FERC and to perform any reasonable studies necessary for the Commission to make an informed decision regarding the merits of an application.[49] The consultation process is to include the state water pollution control agency that makes certifications under Section 401 of the Clean Water Act.[50] In the Pacific Northwest these agencies are the Idaho Department of Health and Welfare, the Montana Department of Health and Environmental Sciences, the Oregon Department of Environmental Quality, and the Washington Department of Ecology. In addition, the applicant is to explain the consistency of the proposed plan with relevant state, local, and regional plans, including the Northwest Power Plan and the Columbia Basin Fish and Wildlife Program.[51] Moreover, FERC has been directed to take the Columbia Basin Fish and Wildlife Program into account "at each relevant stage" of its actions.[52]

Hydroelectric facility developers have the option of seeking a preliminary permit that will preserve priority to a site and enable time to conduct a feasibility study and prepare a license application. The maximum term for a preliminary permit is three years.[53]

The FERC licensing process is simplified for certain small scale hydroelectric projects. Run-of-river projects with an installed capacity of 5 MW or less and no new manmade impoundments can be exempted from the licensing requirements. An application for exemption must be filed with FERC.[54] Hydroelectric facilities with an installed generating capacity of 15 MW or less that are added to a manmade water distribution conduit can also be exempted upon application to FERC.[55] A simplified license application process exists for projects with an installed capacity of 5 MW or less that are not otherwise exempted.[56]

2.8 STATE REQUIREMENTS APPLICABLE TO HYDROELECTRIC PROJECTS

Under the Federal Power Act, applicants for FERC hydroelectric licenses are to comply with state laws relating to "bed and banks and to the appropriation, diversion, and use of water for power purposes."[57] Within this deference to state law, the Pacific Northwest states have various requirements applicable to hydroelectric facilities. Idaho,[58] Montana,[59] Oregon,[60] and Washington[61] require a permit to appropriate water for hydroelectric purposes.[(a)] Idaho requires a permit from the Department of Water Resources for actions that will modify the channel of a continuously flowing stream.[62]

In Montana, any physical alteration or modification of a natural perennial flowing stream or river, its bed, and immediate banks requires the approval of the Board of Supervisors of a conservation district, the directors of a grass conservation district, or the applicable board of county commissioners when a proposed project is not in a district.[63] The statutory approval process takes approximately four months. A dam safety permit will generally be required from the Department of Natural Resources and Conservation for impoundments of 50 or more acre-feet of water.[64]

Washington requires approval from the Department of Fisheries or Wildlife for projects that will "use, divert, obstruct, or change the natural flow or bed" of any waters of the state.[65] The objective of the approval process is to protect fish life. Construction of a dam for the storage of 10 or more acre-feet of water requires a safety approval from the Washington Department of Ecology.[66] A reservoir permit from the Department of Ecology is required for a dam storing water to a depth of 10 or more feet or retaining 10 or more acre-feet of water.[67]

2.9 GEOTHERMAL RESOURCE DEVELOPMENT ON FEDERAL LANDS

Permits from federal agencies will be needed to develop geothermal resources on federal lands. The basis for the regulatory approach is the

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(a) The U.S. Supreme Court recently ruled that the Federal Power Act gives FERC exclusive authority to determine minimum flow rates for hydroelectric projects. California v. FERC, No. 89-333 (U.S. May 21, 1990).

Geothermal Steam Act of 1970, as amended.[68] Under the act the Department of the Interior (DOI) is given authority to execute leases for development of geothermal resources on lands that it administers, on lands administered by the U.S. Department of Agriculture with that Department's consent, and on lands in which the U.S. has retained a mineral interest.[69] Competitive leasing is required for land located within any known geothermal resources area. DOI has extensive rules relating to the leasing process at 43 CFR Parts 3200, 3210, 3220, 3240, and 3280. A permit is required for exploration activities prior to execution of a lease.[70]

DOI also has extensive rules at 43 CFR 3260 relating to operations conducted under geothermal leases. The rules are designed to prevent waste of the resource and protect the environment.[71] A plan of operation[72] and a separate plan for use[73] of the geothermal resource must be approved by DOI. DOI may impose additional environmental protection requirements beyond existing federal and state requirements.[74] A permit to drill, redrill, deepen, or plug-back a well must be obtained from DOI before work is begun.[75] A separate permit from DOI is needed before construction is begun on facilities to use the geothermal resource.[76] In addition, construction of such facilities requires a license from DOI to use surface lands covered by a geothermal lease. DOI has extensive regulations covering the licensing process at 43 CFR 3250. A license does not cover utility service or transmission lines crossing federal lands. Separate right-of-way authorizations must be obtained for such lines from the appropriate land management agency.

States generally do not require permits for geothermal resource exploration, drilling, or production on federal lands.[77] Any state or local requirement inconsistent with a federal geothermal lease could be preempted by the Supremacy and Property Clauses of the U.S. Constitution.[78]

2.10 STATE PERMIT REQUIREMENTS SPECIFICALLY APPLICABLE TO POWERPLANTS USING GEOTHERMAL RESOURCES

Each of the four Pacific Northwest states has permit requirements applicable to use of geothermal resources for power generation. The permit requirements can be found in legislation specifically directed at geothermal resources and also in legislation related to use of groundwater. In addition, separate underground injection permit requirements may apply to the reinjection of geothermal resources (see Section 2.13).

In Idaho, a permit to construct a well to withdraw or inject geothermal resources must be obtained from the Department of Water Resources.[79] Use of groundwater with a temperature of less than 212°F is regulated under the groundwater appropriation process (see Section 2.18).[80] In Montana, developers of geothermal resources must follow the procedures for groundwater appropriation (see Section 2.18).[81] In Oregon, drilling permits for geothermal resources from wells with a bottom hole temperature of 250°F or more or any well 2000 or more feet deep must be obtained from the Department of Geology and Mineral Industries.[82] Production of geothermal resources from wells not regulated by the Department requires a groundwater appropriation permit issued by the Oregon Water Resources Commission.[83] In Washington geothermal resource drilling permits are obtained from the Department of Natural Resources.[84]

2.11 EMISSION PERMITS UNDER THE CLEAN AIR ACT

The basic statute for regulating air quality in the U.S. is the federal Clean Air Act.[85] This is a complex statute with many important provisions. Section 108 of the Act directs the U.S. Environmental Protection Agency (EPA) to identify air pollutants "which may reasonably be anticipated to endanger public health or welfare." Section 109 directs EPA to establish national primary and secondary ambient air quality standards for these pollutants. To date EPA has adopted ambient standards for sulfur dioxide, particulates, carbon monoxide, ozone, nitrogen dioxide, and lead.[86] Section 107 of the Act directs states to classify areas within their boundaries on a pollutant-specific basis into those areas that 1) do not meet primary or secondary ambient air quality standards, 2) cannot be classified because of insufficient data or information, and 3) have ambient air quality levels that exceed any national primary or secondary ambient air quality standard. Section 110 of the Act directs states to develop for EPA approval state implementation plans (SIPs) that provide for attainment of national ambient air quality standards. Section 111 directs EPA to develop new source performance standards for sources determined by EPA to contribute significantly to air pollution that may be reasonably anticipated to endanger public health or welfare. Section 112 directs EPA to establish national emission standards for hazardous air pollutants (NESHAPS) for which no ambient air quality standard is applicable. Section 161 requires that SIPs contain provisions to prevent significant deterioration of air quality in clean air areas. Section 116 of the Act allows states to adopt their own air standards or limitations provided they are as strict as the federal requirements. Montana, Oregon, and Washington have adopted ambient air standards that supplement and in some cases are more stringent than the EPA requirements.

Four Clean Air Act-related permits could apply to a new or modified power resource: 1) a state emission permit, 2) a nonattainment permit, 3) a prevention of significant deterioration (PSD) permit, and 4) construction approval under the NESHAPS program for sources of hazardous air pollutants.[a] Each state is to provide for the permit programs in its SIP.[87] Descriptions of each state's SIP and its approval status are in 40 CFR 52.[b] EPA has approved the permit portions of the plans for the four Pacific Northwest states; consequently, all four categories of permits, with one exception, are issued by state agencies[c] or local air pollution agencies such as the Puget Sound Air Pollution Control Agency located in Seattle. The one exception is that construction approval for sources of radionuclide emissions is issued by the EPA Region 10 office for Idaho, Oregon, and Washington and the Region 8 office for Montana.

State emission permit programs are designed to ensure that new or modified sources of air emissions will not result in a violation of a federal or

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(a) Senate Bill 1630, the Clean Air Act Amendments of 1990, is currently being considered by a conference committee in the U.S. Congress. Title V of the bill would require many emission sources to also have an operating permit issued for no more than five years.
(b) Idaho's SIP is described in Subpart N, Montana's in Subpart BB, Oregon's in Subpart MM, and Washington's in Subpart WW.
(c) The applicable state agencies are the 1) Idaho Department of Health and Welfare, Division of the Environment, Air Quality Bureau; 2) Montana Department of Health and Environmental Sciences, Air Quality Bureau; 3) Oregon Department of Environmental Quality, Air Quality Control Division; and 4) Washington Department of Ecology, Office of Central Programs and Enforcement.

state ambient air standard. Additionally, the programs require permit applicants to show that they will comply with standards of performance based on technology or the plume's visible appearance. EPA's standards of performance for new stationary sources of air pollution appear at 40 CFR 60. The standards for new electric utility steam generating units at Subpart Da, coal preparation plants at Subpart Y, and stationary gas turbines at Subpart GG are among the standards potentially applicable to new electric power generation sources. EPA has recently issued a proposed new source performance standard for municipal waste combustors[88] and proposed guidelines for control of emissions from existing municipal waste combustors.[89] States can have new source performance standards that are more stringent than the EPA requirements.[90] The State of Washington, for example, has special emission standards for solid waste incineration facilities.[91] A detailed review of the applicable state and local requirements for emission permits at a proposed generating plant location is needed to ensure compliance.

Nonattainment permits are required for new or modified major stationary sources that emit a pollutant for which the region is designated nonattainment, i.e., the ambient air standards are not being met.[92] A major stationary source is one that has the potential to emit 100 tpy or more of any pollutant subject to regulation under the Clean Air Act.[93] If a nonattainment permit is required, the permit conditions in Section 173 of the Clean Air Act must be met. One condition is emission control to the lowest achievable emission rate (LAER).[94] LAER is defined as the most stringent emission limitation in any SIP (unless it is shown to be unachievable) or the lowest emission limit achieved in practice by any comparable source, whichever is more stringent.[95] LAER may not be less than a new source performance standard. A second condition is a demonstration that emissions of the nonattainment pollutant will not impede the region's progress toward attainment of ambient air standards or cause the nonattainment pollutant level allowed under the SIP for industrial growth purposes to be exceeded. A third condition is that all of the permit applicant's other facilities are in compliance with the Clean Air Act.

The PSD permit program applies by specific pollutant in geographic areas designated as meeting ambient air standards, i.e., attainment areas, and in unclassified areas. It is designed to prevent deterioration of air quality in these areas. Under the PSD program new major stationary emission sources or major modifications to such sources must obtain a PSD permit setting forth emission limitations.[96] The term "major emitting facilities" is defined to include certain specifically designated stationary sources[(a)] with the potential to emit 100 tpy of any air pollutant subject to an ambient air standard and all other sources with the potential to emit 250 tpy of any pollutant.[97] If a PSD permit is determined to be required for a particular source, a number of requirements in the EPA regulations become applicable. These include

1. demonstration that the source will not violate the maximum allowable increase in pollutants for Federal Class I, II, and III areas[98]

2. application of the best available control technology (BACT)[(b)] for each pollutant with a significant net emissions increase[99]

3. demonstration that the new source will not result in violation of any national ambient air quality standard in any air quality region or any applicable maximum allowable increase over the baseline concentration in the area[100]

4. an analysis of ambient air quality for each pollutant resulting in a significant net emissions increase[101]

5. an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source and associated community growth.[102]

Construction approval is required for those new power resources subject to EPA's NESHAPs requirements at 40 CFR 61.[103] Standards have been issued for certain types of facilities and specified pollutants including asbestos, arsenic, benzene, beryllium, mercury, radionuclides, and vinyl chloride.[(c)]

(a) Such sources include 1) fossil-fuel-fired steam electric plants and boilers of more than 250 million Btu/hr heat input, and 2) municipal solid waste incinerators capable of charging more than 250 tons of refuse per day.

(b) BACT is determined on a case-by-case basis and is defined as the maximum degree of emission reduction taking into account energy, environmental, and economic impacts, and other costs [40 CFR 52.21(a)(12)].

(c) Title III of Senate Bill 1630 designates an additional 191 hazardous air pollutants subject to regulation under Section 112 of the Clean Air Act.

2.12 DISCHARGE PERMITS UNDER THE CLEAN WATER ACT

The Clean Water Act (CWA) is the principal federal law governing water pollution control. The Act was passed in its present form in 1972 and was amended in 1977 and 1987. It authorizes federal and state control of discharges of pollutants into waters of the U.S. and into municipal sewer systems. A person responsible for a discharge of pollutants into any waters of the U.S. from a point source must obtain and comply with a permit issued under the national pollution discharge elimination system (NPDES) established under Section 402 of the Act.[104] Permits are issued by EPA or by a state with an EPA-approved permit system. Montana, Oregon, and Washington have been delegated authority by EPA to issue NPDES permits.[(a)] Permits in Idaho are issued by the EPA Region 10 office in Seattle. Discharges without a permit or in violation of the terms of a permit are illegal.[105]

There are two basic regulatory controls on dischargers under the CWA: water quality-based requirements and technology based requirements. Dischargers must comply with the more restrictive of the two types of controls. Water quality-based requirements are designed to achieve a given level of water quality for a natural water body. Technology-based requirements are designed to reflect the level of effluent quality achievable through the use of pollution control technology. The CWA also provides for the establishment of national standards of performance for new sources[106] and for pretreatment standards for discharges into a publicly owned treatment works (POTW).[107]

Section 303 of the CWA requires states to establish water quality standards for all waters within their jurisdiction. The standards are to protect the public health or welfare, enhance the quality of water, and serve the purposes of the CWA.[108] One purpose of the CWA is to obtain "an interim goal of water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water," commonly referred to as "fishable/swimmable" water.[109] The standards are to be reviewed at least every three years. States generally are to establish

(a) The applicable state agencies are the 1) Montana Department of Health and Environmental Sciences, Water Quality Bureau; 2) Oregon Department of Environmental Quality, Water Quality Division; and 3) Washington Department of Ecology, Office of Water and Shorelands.

specific pollution concentrations which will enable the standards to be met.[110] In addition each state is to have a policy of no degradation of water bodies except that high quality waters can be lowered in some cases "to accommodate important economic or social development in the area in which the waters are located."[111] EPA may promulgate changes to state water quality standards if the standards do not meet the requirements of the CWA. All NPDES permits are to include necessary limitations to ensure that applicable water quality standards are not violated.[112] In Idaho, where EPA issues NPDES permits, the state is asked by EPA Region 10 to certify under Section 401 of the CWA that the proposed discharge will comply with all limitations necessary to meet water quality standards, treatment standards, or schedules of compliance. Certification must be granted or denied within a reasonable time period or the state will be deemed to have waived its right of certification.[113] States with NPDES programs approved by EPA are generally free to allocate pollution loads as they wish among permit applicants provided that water quality standards are met.[114]

There are several technology-based discharge standards provided for in the CWA. New dischargers of conventional pollutants are to incorporate the best pollution control technology (BCT).[115] Conventional pollutants include biological oxygen demand, suspended solids, fecal coliform, pH, and oil and grease.[116] The BCT standard is to reflect the cost of attaining a reduction in effluents and the resulting benefits.[117]

Dischargers of toxic and nonconventional pollutants are to incorporate the best available technology economically achievable (BAT).[118] Toxic pollutants are listed at 40 CFR 401.15. Effluent standards for certain toxic pollutants are in 40 CFR 129. Nonconventional pollutants are pollutants other than heat, conventional pollutants, and toxic pollutants. The BAT level of control is to take into account the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as EPA deems appropriate.[119]

EPA's approach to establishing BAT requirements has generally been to set pollution limits achievable by the optimally operating plant.[120] EPA has maintained that BAT is designed to force cleanup technology and that BAT discharge limits may be based on pilot plant operating data or other data sufficiently reliable to show that the limits can be applied and are achievable.[121] In setting BAT limits, EPA often relies on the ability of pollution control technology to be transferred from one industry to another. If EPA finds that the technology is available in another industry and that it can be reasonably transferred to the industry in question, a BAT limit based on EPA's judgment will ordinarily be upheld.[122] In some cases a discharger may request a credit to a BAT discharge limitation to reflect the presence of pollutants in the intake water.[123] Section 301(b)(2)(A) of the CWA states that BAT limitations "require the elimination of discharges of all pollutants if ... such elimination is technologically and economically achievable." EPA has occasionally adopted a "no discharge" limit for a pollutant under this test.[124] A number of cases have involved challenges to BAT requirements based on the cost of meeting the requirements. EPA has largely been successful in defending BAT standards against cost challenges. The courts have found that EPA's obligation to consider costs in setting BAT requirements does not require a cost-benefit analysis, but only consideration of costs in a reasoned way. After reviewing the cases where the cost of meeting BAT requirements has been litigated, one commentator concluded that the cost of meeting a BAT obligation can withstand challenge if "an industry can afford the technology, has access to markets to pass the costs along, and the technology is not demonstrably extravagant."[125]

EPA does not have BAT regulations for heat discharges from point sources. Most dischargers of heat seek to take advantage of the variance from BAT afforded by Section 316(a) of the CWA.[126] This section allows a relaxed thermal discharge standard if the applicant can show that the new standard will ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in and on the water body. EPA's criteria for determining alternative effluent limitations under Section 316 are at 40 CFR 125, Subpart H.

EPA has issued effluent guidelines and standards for approximately 50 categories of sources including steam electric powerplants.[127] The regulations contain effluent limitation guidelines for existing sources of water pollution, standards of performance for new sources, and pretreatment standards for new and existing sources that discharge into POTWs. The new source performance standards are generally identical to BAT limits for existing direct dischargers.[128] For steam electric powerplants, the BAT guidelines are at 40 CFR 423.13, the new source performance standards are at 40 CFR 423.15, and pretreatment standards are at 40 CFR 423.16,17.

EPA has general pretreatment regulations for existing and new sources of water pollutants at 40 CFR 403. In the event a new generating resource discharges to a POTW, these regulations would need to be met. A general requirement is that no discharge is permitted which will inhibit or disrupt a POTW or will result in pollutants that would not be authorized under an NPDES permit if discharged directly to pass through the POTW into waters of the U.S.[129] In effect, BAT standards are likely to apply whether discharges are made directly to water bodies or to a POTW.

2.13 UNDERGROUND INJECTION PERMITS UNDER THE SAFE DRINKING WATER ACT

The principal federal program applicable to intentional discharges to groundwater is the Underground Injection Control (UIC) Program established by Section 1421 of the Safe Drinking Water Act.[130] The Act directs EPA to issue regulations for state underground injection programs that "contain minimum requirements for effective programs to prevent underground injection which endangers drinking water sources." The UIC program is administered directly by states whose program has been approved by EPA. In the Northwest, UIC permits are issued by state agencies in Idaho,[131] Oregon,[132] and Washington.[133] In Montana, UIC permits are issued by the EPA Region 8 office.[134] EPA has established five categories of injection wells under the UIC program. Injections to any category of well except as authorized by permit or rule issued under the UIC program are prohibited.[135] An injection well associated with the recovery of geothermal resources would be a Class III well.[136] Criteria and standards applicable to Class III wells appear at 40 CFR 146, Subpart D.

2.14 PERMITS FROM THE ARMY CORPS OF ENGINEERS

The U.S. Army Corps of Engineers (Corps) administers several permit programs which may apply to certain new power resource projects. Procedures for the application and processing of permit applications are at 33 CFR 325.

A permit from the Corps is needed under Section 9 of the Rivers and Harbors Act of 1899 for construction of a dam or a dike in navigable waters.[137] The term "navigable waters" is defined at 33 CFR 329. In general, the term covers waters subject to the ebb and flow of the tide and/or waters likely to be used for transport of commerce. For hydroelectric projects licensed by FERC, the Corps normally recommends appropriate provisions for inclusion in the FERC license rather than issuing a separate permit under Section 9.[138] A permit from the Corps will be needed for hydroelectric projects on navigable waters that are exempt from the FERC licensing process.

A permit from the Corps is also required under Section 10 of the Rivers and Harbors Act for construction of structures or work in or affecting navigable waters.[139] Construction of a cooling water intake structure in navigable waters, for example, would require a permit under these regulations. In addition construction of electric power transmission lines across navigable waters would require a permit unless the lines are part of a water power project subject to FERC regulation.[140]

The discharge of dredged or fill materials into waters of the U.S. requires a permit from the Corps issued under the authority of Section 404 of the CWA.[141] The term "waters of the United States" is defined at 33 CFR 328. In general, the term is defined very broadly and includes almost every surface body of water in the U.S., including wetlands. Permits are issued only after the state where the dredge or fill activity is to be located certifies under Section 401 of the CWA that existing water quality standards will not be violated if the permit is issued. Permits must also be consistent with the environmental guidelines established by EPA under Section 404(b) of the CWA.[142] EPA can veto permits authorized by the Corps if EPA finds that the discharge will have an unacceptable adverse effect on the environment.[143] A FERC license for a hydroelectric facility does not eliminate the need for a Section 404 permit.[144]

2.15 CERTIFICATION TO DOE UNDER THE POWERPLANT AND INDUSTRIAL FUEL USE ACT

The Powerplant and Industrial Fuel Use Act of 1978, as amended in 1981 and 1987, requires that no electric powerplant may be operated as a base load powerplant with natural gas or petroleum as the primary energy source unless the plant has the capability to use coal or another alternate fuel as its primary energy source in lieu of natural gas or petroleum.[145] A self-certification to this effect is to be submitted to DOE before a new powerplant is constructed or an existing powerplant is converted to base load operation. Petitions for temporary[146] or permanent[147] exemptions to this requirement can be submitted to DOE. Base load powerplants are defined as those powerplants whose electrical generation in any 12-month period in kilowatt hours exceeds the powerplant's design capacity multiplied by 3500 hours.[148] Regulations for implementing the extensive 1987 amendments to the Act were issued by DOE in December 1989.[149] The background statement accompanying the new regulations states that since passage of the 1987 amendments, self-certifications have been received by DOE for 113 new gas-fired powerplants, and no requests for exemptions have been received.

2.16 PERMITS UNDER THE RESOURCE CONSERVATION AND RECOVERY ACT

The Resource Conservation and Recovery Act (RCRA), as amended, is designed to provide a comprehensive program for the management and control of hazardous waste by imposing requirements on generators and transporters of such waste and upon owners and operators of treatment, storage, and disposal (TSD) facilities. Each TSD facility owner or operator is required to have a permit issued by EPA or the state in which the facility is located.[150] EPA has extensive regulations implementing RCRA at 40 CFR 260-272.

Regulations relating to identification of those solid wastes subject to regulation under RCRA as hazardous wastes appear at 40 CFR 261. Materials which are not considered solid wastes for purposes of RCRA are listed at 40 CFR 261.4. Among the materials not considered to be solid waste are 1) household waste;[151] 2) fly ash, bottom ash, slag, and flue gas emission control wastes generated primarily from the combustion of coal or other fossil fuels;[152] and 3) drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy.[153] In addition, the regulations provide that a facility burning municipal solid waste will not be deemed a TSD facility or to be otherwise managing hazardous waste under RCRA if the facility receives and burns only household waste and other material not containing hazardous wastes.[154] EPA has stated that it sees a need to develop a management scheme for handling and disposing of municipal solid waste (MSW) combustor ash under RCRA. A notice of proposed rulemaking is tentatively scheduled to be issued in September 1990.[155] Two federal district courts have held that ash produced by MSW incinerators is not subject to regulation under RCRA as a hazardous waste provided the particular facility does not accept hazardous waste and has appropriate mechanisms in place for ensuring that no hazardous waste is accepted.[156] At the present time, it is likely that the solid wastes resulting from fossil fuel and geothermal powerplants, biomass combustion facilities, and most MSW incinerators are not subject to the complex regulations issued under RCRA. Facilities used for the disposal of such wastes, however, must generally have a permit issued by a state or local agency (see Section 2.17).

2.17 PERMITS FOR MUNICIPAL SOLID WASTE INCINERATORS AND ASH DISPOSAL

Some special permit requirements apply to MSW incinerators and to disposal of the ash resulting from the incineration process. More general requirements such as the need for an emission permit or PSD permit are not discussed here.

In Idaho, separate permits for an incinerator and a facility used for ash disposal will be needed from the Idaho Department of Health and Welfare.[157] The Department's regulations include general operation standards for solid waste management sites (Section 01.6007), special requirements for sanitary landfills (Section 01.6008), and special requirements for incinerators (Section 01.6009).

In Montana, operators of incinerators and facilities used for disposal of incinerator ash must have a license issued by the Montana Department of Health and Environmental Sciences.[158]

In Oregon, operators of MSW incinerators need to obtain a permit from the Department of Environmental Quality.[159] The Department has special rules covering plans, specifications, design, construction, and operation of incinerators.[160] Operators of facilities for ash disposal need a separate permit from the Department. The Department also has special rules pertaining to landfills.[161]

Operators of MSW incinerators in Washington need to obtain a permit from the local health department.[162] Applications for permits must include detailed environmental, construction, and operating information.[163] Preparation of a state EIS is required.[164] Operators of facilities used for ash disposal must obtain a permit from the Department of Ecology.[165] Operators who incinerate 12 or more tons of MSW per day must also have a generator management plan approved by the Department of Ecology.

2.18 WATER ACQUISITION PERMIT

A permit from a state agency will be needed to acquire and exercise a surface water[166] or groundwater[167] right for powerplant cooling or other purposes. The administering agencies are the Idaho Department of Water Resources, the Montana Department of Natural Resources and Conservation, the Oregon Water Resources Commission, and the Washington Department of Ecology. In Oregon and Washington the water must generally be put to beneficial use within five years or the water right is forfeited.[168] In Montana, all or part of a water right that is unused for ten years is presumed to be abandoned.[169]

The acquisition of surface water may involve changes to natural stream beds. Permit requirements related to such changes are discussed in Section 2.8.

2.19 NOTICE TO THE FEDERAL AVIATION ADMINISTRATION

Construction of certain tall facilities such as a cooling tower at a power generation site may require notice to the Federal Aviation Administration (FAA). Specifically, construction of any facility that is 200 or more feet above ground level requires prior notice to the FAA.[170] The FAA has standards for determining obstructions to air navigation at 14 CFR 77, Subpart C.

2.20 MAXIMUM PERMIT HOLDING TIME FOR UNINITIATED PROJECTS

Some permits will lapse if construction of a generation project is not initiated within a specific time period. The period varies by permit, and a detailed review of the conditions attached to a permit and the regulations of the issuing agency is needed. The maximum holding time can become quite important if a decision is made to delay a proposed project (see Section 4). The following representative permits will lapse if not used within the stated timeframe: 1) FERC hydroelectric preliminary permit (3 years),[171] FERC hydroelectric license (4 years),[172] PSD permit (18 months),[173] water withdrawal permit (5-10 years, see Section 2.18), and a siting certificate from the Montana Board of Natural Resources and Conservation (6 years).[174]

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3.0 PRECONSTRUCTION SCHEDULES FOR INDIVIDUAL GENERATING RESOURCES

Estimates of the preconstruction periods required (before construction can begin) for the electric power supply resources identified in Section 1 are presented in this section. A number of these preconstruction time estimates represent updates of the estimates developed in the August 1982 PNL report prepared for the Northwest Power Planning Council (see Section 1). The schedule estimates in this section do not include construction times.

The methods used to revise the estimates from the 1982 report are discussed in Section 3.1. Section 3.1 also contains definitions of preconstruction activities and a generic preconstruction schedule. The latter was developed to break the preconstruction process down and to facilitate common dialogue with utilities, government agencies and industry. Section 3.2 contains a summary of the preconstruction times and compares the estimates in this report with those made by other investigators. Section 3.3 contains individual preconstruction activity schedules. In many cases, the individual schedules are different from the generic schedule.

The estimates in this section are conservative and preconstruction times may be less at specific sites for some of the resources.

To a limited extent, preconstruction periods can be related to the size of the project. For example, a 1-MW hydro installation and a 10-MW installation may have similar preconstruction times if both operate on "run of the river" stream flow. On the other hand, a 50-MW hydroelectric generating plant will likely require construction of an impoundment and, consequently, would require significantly increased engineering and permitting time compared with installations requiring no impoundment.

The permitting process paces all other preconstruction activities and clearly dominates the schedule before the beginning of major construction. Moreover, it is significant that, for many of the generating resources discussed in this report, preconstruction activities will likely take longer than actual construction.

A number of the generation options use "off the shelf" equipment or standard packaged units. In these instances, the pressure to order equipment before the permit process is complete is reduced; and actual construction times can be quite short, even if ordering equipment is delayed until all of the preconstruction activities are complete.

A number of generating projects in the region have already had much of the preconstruction process completed. To estimate the time to complete them, each project should be considered individually, taking into account the unique circumstances that apply, rather than applying the estimates from this section.

3.1 ESTIMATION METHODOLOGY

Estimates of the duration of preconstruction activities were derived from a combination of literature review and discussions with those involved with developing potential generating resources. Literature references frequently include estimates for two phases of the acquisition process: preconstruction and construction. A generic schedule of preconstruction activities and definitions was developed to facilitate communication with those involved in the acquisition process. It was recognized in advance that the generic schedule shown in Figure 3.1 and in Gantt chart form in Figure 3.2 would not accurately portray any specific preconstruction schedule. The activities shown in Figures 3.1 and 3.2 are not unique and would often overlap and some of them would not apply to all generating resources. However, the generic schedule provided a "checklist" and general representation of activities likely to be involved in the preconstruction stages of bringing new generating resources on line. A number of individuals involved in the acquisition process were asked to review and comment on the generic schedule and a list of activity definitions. For most resources it was not possible to obtain schedule estimates for all individual activities. The activities defined in Table 3.1 provided a language basis for initiating discussions of schedules and costs. This early review process with outside contacts and literature reviews provided information that was used in constructing a set of preliminary draft individual schedules and preliminary cost estimates which were also sent to the various contacts for review. The schedule estimates in this section were then modified based on reviewer response.

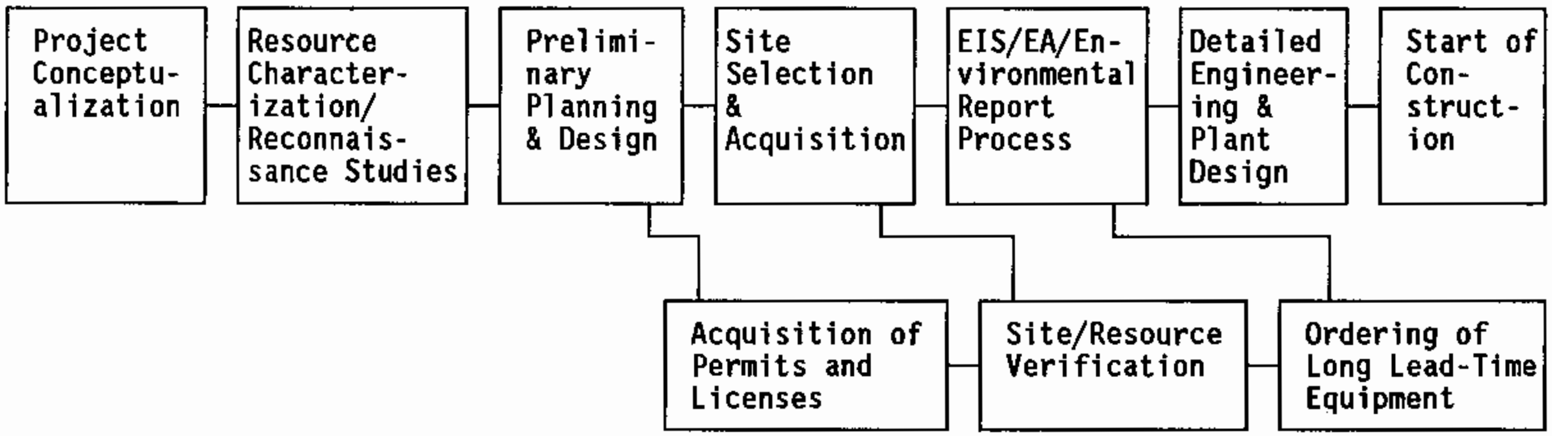

FIGURE 3.1. Generic Schedule of Preconstruction Activities for Electric Power Generating Resources

```
 ===                                              Project Conceptualization
   ====                                           Resource Reconnaissance
      ==                                          Preliminary Planning and Design
        ====                                      Site Selection and Acquisition
        ==============                            Acquisition of Permits and Licenses
           =================                      EIS/EA/Environmental Report Process
                       ========                   Site/Resource Verification
                         =========                Detailed Engineering and Plant Design
                               =====              Ordering of Long-Lead-Time Equipment
                                     #            Start of Plant Construction

Time -->
```

FIGURE 3.2. Generic Preconstruction Schedule for Electric Power Generating Resources

TABLE 3.1. Definition of Terms Used in Preconstruction Schedules

Activity	Definition
Preconstruction Activities	Those activities occurring before ground breaking and initiation of construction.
Project Conceptualization	Activities that involve securing participant agreements and defining the project before a feasibility study is initiated.
Resource Characterization	Studies carried out to determine suitability of the region for use of a specific power generation option.
Preliminary Planning and Design	The feasibility study and preliminary design work necessary to initiate licensing and permitting and to support the selection of the site and architect/engineer firm (if one is to be selected at this time). This work brings the project to the point where a business plan shows that the option is a good investment opportunity.
Site Selection and Acquisition	Selecting the site, securing purchase/lease options on the site, and the road and utility easements to the site.
Acquisition of Permits and License	Application for and activities in support of the acquisition of permits and licenses.
EIS/EA/Environmental Report	Preparation of an Environmental Impact Statement, Environmental Assessment, or Environmental Report; conducting hearings; revising and publishing the environmental documents in their final version.
Site/Resource Verification	Site-specific work such as drilling and exploration at geothermal sites necessary to verify the resource before major investments are made.
Detailed Engineering Design	Completion of detailed engineering and plant design.
Ordering of Long Lead-Time Equipment	Ordering of capital goods having long delivery times.
Start of Plant Construction	Actual ground-breaking and commencement of foundation construction, etc.

3.2 SUMMARY AND COMPARISON OF ESTIMATED PRECDNSTRUCTION SCHEDULES

Preconstruction schedule estimates from various sources are shown in Table 3.2. The first column shows the schedule estimates developed during preparation of this report. The second column shows schedule estimates from the 1982 PNL report prepared for the Council. The reader should keep in mind that specific installations can take less time or more time than shown in Table 3.2. Some of the specific reasons preconstruction times may vary are

- differing regulations in different states and local jurisdictions
- differing degrees of local support/opposition
- changing political climate and federal regulations
- unique geographical/geologic/climatic differences
- territorial ownership/jurisdiction of the generation site and energy resource
- degree to which installation is standardized
- size of installation.

3.3 PRECONSTRUCTION SCHEDULES

Developing electric power generation options requires completion of several major phases involving considerable financial investment before hardware purchases and major construction can begin. The first phase involves identifying a good business investment opportunity. This step frequently involves completion of three preconstruction activities (see Figure 3.1): Project Conceptualization, Resource Characterization/Reconnaissance, and Preliminary Planning and Design. These three activities are frequently complete by the time an architect/engineering (A/E) firm is selected. When asked how long it will take to develop a specific generating option, an A/E firm would likely emphasize activities following completion of the first phase. The first phase could easily require eight months to a year to complete; it is relatively inexpensive to accomplish compared with the investment involved in the

TABLE 3.2. Estimated Preconstruction Schedules

Generating Resource	Preconstruction Time in Years PNL90	PNL82
50-MW Geothermal Plant	7	6.2
10-MW Wind Park	4	5
10-MW Municipal Solid Waste Plant	5	3.5
10-MW Solar Photovoltaic Plant	3	1.8
10-MW Hydroelectric Plant	6	2
Two 603-MW Pulverized-Coal-Fired Plants	8	6
197-MW Atmospheric Fluidized-Bed Coal Plant	8	
Two 193-MW Single-Cycle Combustion Turbine Units	4	2.1
420-MW Combined-Cycle Combustion Turbine Plant	5	2.1
10-MW Wood-Products-Based Cogeneration Plant	6	2.3
10-MW Natural Gas Cogeneration Plant	5	2.3
420-MW Coal Gasification Combined-Cycle Plant	6	4

phase/phases that follow. Individual resource schedules show two or more phases to indicate where it may be logical to delay the acquisition process.

The first point at which a potential power generation option could logically be placed "on hold" for use later (when electrical demand has increased) is at the completion of the first phase. Some specific options have other points at which they could logically be placed on hold until their output is scheduled.

3.3.1 50-MW Geothermal Plant

Completion of the first three activities shown in Figure 3.3 for the geothermal option may take as little as a year if the site has already been acquired. However, it could take longer. The process of locating a suitable site involves numerous complex issues. In general there is sufficient thermal energy in the earth to allow generation of great amounts of electricity. However, this energy cannot be obtained economically and reliably unless

- the geothermal energy is located fairly close to the surface
- the energy is in an appropriate geologic formation with suitable fracturing

```
                                                        Phase
 =                                                        I          Project Conceptualization
  ===                                                     I          Resource Reconnaissance
   ==                                                     I          Preliminary Planning and Design
      =                                                  II          Site Selection and Acquisition
      ==== ==== ====                                     II          Acquisition of Permits and Licenses
           ==== ==== ====                                II          Exploratory Wells and Temp. Gradient Holes
                     ====  ==== ====                     II          EIS and Operating Permits
                                ====..                  III          Detailed Engineering and Plant Design
                                  == ..                 III          Financing
                                   = ..                 III          Ordering of Long-Lead-Time Equipment
                                     #                               Start of Plant Construction

Year      1    2    3    4     5    6   7
```

FIGURE 3.3. Preconstruction Schedule for a 50-MW Geothermal Plant

Legend:

```
=          Three months
==== ==== Two years with a space indicating year completion
...        Activity continuing after construction begins
#          Indicates beginning of construction
```

- an adequate water supply is pressurizing the formation.

Surface manifestations such as warm springs or lakes can be helpful in locating such formations. However, surface manifestations are frequently located in areas where acquiring them for electricity generation purposes may be difficult. Even if the geothermal resource is potentially available, the site may have inadequate temperatures or flow rates or may possess environmentally unacceptable attributes.

Currently, there is no geothermal electricity generation in the Pacific Northwest. Known resources with commercial potential are concentrated on federal lands. In such instances, an EIS is likely to be required.

The uncertainties involved with geothermal resources make it necessary to carry out an extensive program to verify the existence of an adequate and suitable resource. Such a program can involve drilling numerous exploratory wells and temperature gradient holes. This activity will require permits and licenses and will take as long as three years.

Preparing the EIS and obtaining operating licenses and other permits is likely to take an additional two to three years. Financing can be arranged during this period. Circumstances may justify ordering long-lead items before the final permits are in hand. The schedule in Figure 3.3 provides estimated preconstruction schedules for a new site where no previous electric power generation using geothermal resources has been attempted.

The schedule shown in Figure 3.3 is based on the assumption that the geothermal site is federally owned and used for public recreation. For privately owned land, the schedule could potentially be shortened.

However, the preconstruction process could also take longer than the seven years shown in Figure 3.3 because of the large number of local, state and federal agencies involved.[a] Expansion of an existing geothermal site

(a) Personal communications with: 1) Bob Edmiston, Santa Rosa, California, February 7, 1990; 2) Alex Sifford, Oregon Department Of Energy, February 19, 1990; 3) Al Yamigiwa, Seattle City Light, March 14, 1990.

can potentially be completed in less time than shown in Figure 3.3 because of knowledge and information (e.g., groundwater chemistry) gained from the prior development.

3.3.2 10-MW Wind Park

Most wind park development in the U.S. has occurred in California. Experience there indicates that it is much easier and quicker to develop a site adjacent to an existing wind site than to develop a new site.[a] There are currently no wind parks in the Pacific Northwest. An estimated preconstruction schedule for a Pacific Northwest site is shown in Figure 3.4. If California experience is a guide, additional sites developed adjacent to successful ones can be developed in as little as half of the time shown in Figure 3.4.

The wind park preconstruction process begins with a review of all potential wind sites. Some of the factors reviewed in addition to the quality of the wind resource are 1) proximity to transmission lines of suitable capacity, 2) proximity to roads, and 3) potential for interference from buildings. In the site evaluation the wind resource will probably be evaluated for several years unless the wind resource has been thoroughly evaluated already at a location that is close to the proposed site. Terrain can dramatically affect the effectiveness of the wind resource and thus affect the output of the wind park. In Figure 3.4, some data from other locations are assumed to be available which can be correlated with the specific resource at the proposed site by collecting site-specific data for approximately two years. One season would likely be sufficient to make this kind of correlation if the site was adjacent to another successful site.

Land acquisition is an important aspect of the development of a wind park. The land would normally be purchased, but could be acquired on a long-term lease.

Preliminary planning and design includes a plot plan indicating location of buildings, fences, roads, and the wind turbines. The turbines must be

(a) Personal communication with Hap Boyd, U.S. Wind Inc., January 17, 1990.

```
 | =                                  Phase
 |  === ==== =                          I      Project Conceptualization
 |           =                          I      Resource Reconnaissance (site evaluation)
 |            =                         I      Preliminary Planning and Design
 |            === ====                  II     Site Selection and Acquisition
 |                  ==                  II     Permitting and Licensing
 |                  ==                  II     Power Contract Negotiation
 |                   = ..               II     Detailed Engineering and Financing
 |                     #                II     Ordering of Long-Lead-Time Equipment
 |___________________________                  Start of Plant Construction
Year     1    2    3    4
```

FIGURE 3.4. Preconstruction Schedule for A 10-MW Wind Park

Legend:

=	Three months
==== ====	Two years with a space indicating year completion
...	Activity continuing after construction begins
#	Indicates beginning of construction

located so that interference from buildings and other wind turbines is kept as low as possible. The application for permits and licenses can be started at about the same time that the preliminary planning and design is initiated. The permitting and licensing process will probably require about two years.

Negotiations with a utility to purchase/wheel the power will probably be initiated while the permitting and licensing process is being carried out and will be finalized toward the end of this period. Financial arrangements can also be developed during this period.

3.3.3 10-MW Municipal Solid Waste Incinerator

The technology for generating electrical power through municipal solid waste incinerators is relatively mature. There are several existing plants operating in the Pacific Northwest and other plants operating around the U.S. Approximately 50% of municipal solid waste is paper and all but about 20% is combustible. From a purely technical point of view, burning it and generating electrical energy can be a desirable solution to a serious lack of landfill space in many localities.

The siting and construction of solid waste incinerators may encounter strong local opposition. The incineration process produces ashes which are said to present danger to water supplies. The combustion process also produces emissions which have the potential to degrade air quality.

The preconstruction process may take far longer than the five years indicated in Figure 3.5 if severe resistance is mounted in localities where the incinerator is to be located.

3.3.4 10-MW Solar Photovoltaic Plant

There is currently no large photovoltaic (PV) power generation plant in the Pacific Northwest. Several PV plants in the 1-10 MW size range are operating in California.[a] The solar resource at these plants is quite reliable and coincides with peak demand. These favorable conditions do not

(a) Personal communication with Larry Schlueter, Siemens Solar (formerly ARCO Solar Products), March 1, 1990.

```
                                  Phase
|==                                 I       Project Conceptualization
|    ==                             I       Resource Reconnaissance
|      = ===                        I       Preliminary Planning and Design
|            = =                    I       Site Acquisition, Easements, Right of Way
|                  === ==== ====   II       Permitting, Licensing, and EIS/EA
|                              == ...  II   Detailed Engineering and Plant Design
|                                = ..   II   Ordering of Long-Lead-Time Equipment
|                                  #        Start of Plant Construction
|____________________________________
Year   1    2    3    4    5
```

FIGURE 3.5. Preconstruction Schedule for a 10-MW Municipal Solid Waste Incinerator

Legend:

=	Three months
==== ====	Two years with a space indicating year completion
...	Activity continuing after construction begins
#	Indicates beginning of construction

apply in the Pacific Northwest, and no large successful installations exist there. Therefore, preconstruction activities for the first large-scale PV plant in the Pacific Northwest may take longer than for subsequent plants, if the first one is successful. In addition regulatory institutions of the Pacific Northwest have not had an opportunity to develop experience with PV technology. The schedule in Figure 3.6 assumes a first-time installation somewhere in the region.

The preconstruction process for a PV powerplant begins with a review of all potential sites. Some of the factors reviewed in addition to the quality of the solar resource are 1) proximity to transmission lines of suitable capacity for exporting the power, 2) proximity to roads, and 3) potential for interference from dust from industrial or farming operations that would reduce the effectiveness of the PV arrays. The site evaluation activity will probably involve measuring the solar resource for several years unless the solar resource has been thoroughly evaluated already in an area with similar climatology. In Figure 3.6, it is assumed that longer term data are available from locations with climatology similar to the proposed site and that two years will be sufficient to develop a reliable correlation with the proposed site. One season may be sufficient for a site evaluation if the site is adjacent to another successful site.

Land acquisition is an important aspect of the development of a PV powerplant. Land requirements at the site are fairly extensive and the land must be purchased or leased.

Preliminary planning and design includes a plot plan indicating location of buildings, fences, roads, and the PV arrays. The arrays must be located so that solar interference from buildings and other arrays is kept as low as possible. The application for permits can be started at about the same time that the preliminary planning and design is initiated. If an EIS is required, the process will probably require one to two years.

```
                                   Phase
 |  =                                I        Project Conceptualization
 |   === ==== =                      I        Resource Reconnaissance
 |            ==                     I        Preliminary Planning and Design
 |            ==                    II        Site Selection and Acquisition
 |             ===                  II        Permitting, Licensing, EIS/EA
 |              ==                  II        Power Contract Negotiation
 |              ==                  II        Detailed Engineering Design and Financing
 |               =                  II        Ordering of Long-Lead-Time Equipment
 |                #                           Start of Plant Construction
 |__________________
Year    1    2    3
```

FIGURE 3.6. Preconstruction Schedule for a 10-MW Solar Photovoltaic Plant

Legend:

```
=          Three months
==== ====  Two years with a space indicating year completion
...        Activity continuing after construction begins
#          Indicates beginning of construction
```

Negotiations with the utility to purchase/wheel the power will probably be initiated during the permitting process. Financial arrangements can also be developed during this period.

3.3.5 10-MW Hydroelectric Powerplant

Small hydroelectric plants differ somewhat from the generic schedule. Similar activities are involved, but the licensing and permitting processes clearly dominate and pace preconstruction activities.

An architect/engineering (A/E) firm is frequently engaged to assist with the permitting and other preconstruction activities after a client has identified a potential site. Not infrequently the landowner is also the potential developer/client. In this case a land acquisition step is not needed. Otherwise, it would be started/completed before filing for a preliminary FERC permit so that entry to the site is obtained in order to begin activities which must be completed before filing for the formal FERC license. The preliminary permit is good for up to three years. During this three-year period an environmental report will be prepared and other zoning and licensing activities will be initiated.[a] During the last six months of this period, the formal FERC license application will be prepared. The 10-MW plant is assumed to run on normal stream flow. If the plant were large enough, say 50-MW, to require water impoundment, a much longer permitting process would be likely and Figure 3.7 would not apply.

After the formal FERC license application is filed, it will be reviewed in a process which takes two to three years. During this review process, FERC will prepare an EIS. If everything is in order, FERC will issue a license for construction that is good for two years with the possibility of one extension good for an additional two years. A 10-MW plant will likely use standard turbines, generators, and switchgear so construction can likely be completed within two years. Major hardware items could be advance-ordered, but normally there is not much incentive for doing so since the plant will probably use standard equipment and hardware. The estimated schedule describing this process is shown in Figure 3.7.

(a) Personal communication with Keli Covin, Hydro West Group, Inc., Bellevue, Washington, February 8, 1990.

```
                                        Phase
 |  =                                     I        Project Conceptualization
 |   ===                                  I        Resource Reconnaissance
 |     =                                  I        Preliminary Planning and Design
 |     =                                  II       Site Selection and Acquisition
 |       ==== ==== ====                   II       Preliminary FERC Permit Activities
 |            ==== ====                   II       Site/Resource Verification
 |                      ==== ====         II       FERC Review Process and License
 |                            == ...      III      Detailed Engineering and Plant Design
 |                             = ..       III      Ordering of Long-Lead-Time Equipment
 |                               #                 Start of Plant Construction
 |______________________________________
Year   1    2    3    4    5    6
```

FIGURE 3.7. Preconstruction Schedule for a 10-MW Hydroelectric Power Plant

Legend:

```
=          Three months
==== ====  Two years with a space indicating year completion
...        Activity continuing after construction begins
#          Indicates beginning of construction
```

3.3.6 Two 603-MW Pulverized-Coal-Fired Plants

The conventional coal plant of the future is likely to be quite different from conventional coal plants of the past. Coal plants are having to meet increasingly stringent environmental performance requirements. Opposition to siting a coal plant nearby is increasing in many localities.

Some of the factors adding to the uncertainties of the preconstruction schedule shown in Figure 3.8 are the following:

- a trend toward tightening SO_2 emission standards
- increasing concern over the effect of CO_2 on the global environment
- increasing concern over the potential for groundwater contamination from the discharge of ash, raising the possibility that ash may be designated "hazardous material"
- increasing political pressure for cleaner air and water, resulting in a lack of stable performance standards and policies
- uncertainties over the availability of "clean burning coal" because of competition from existing powerplants
- uncertainties over water rights for coal plant operation.

Summarizing, the schedule shown in Figure 3.8 assumes that a totally new site would be selected and that current regulatory requirements continue to apply. Lengthening the schedule should be considered when the effect of further legislation (e.g., pending amendments to the Clean Air Act) can be assessed.

3.3.7 197-MW Atmospheric Fluidized-Bed Coal Plant

Atmospheric fluidized-bed coal plants have the potential advantage of producing less atmospheric pollution without having the expense of stack gas scrubbing. Lower combustion temperature can reduce the production of NO_x, and the inclusion of crushed limestone in the fuel mixture reduces the SO_x. The potential for reduced atmospheric pollution (NO_x and SO_x) may somewhat reduce the institutional and social constraints encountered during the preconstruction activities. However, estimating preconstruction activity schedules of atmospheric fluidized-bed coal plants encounters the same uncertainties listed previously for conventional coal plants.

```
                                                  Phase
  ==                                                    I  Project Conceptualization
    == ====                                             I  Resource Reconnaissance
         ==                                             I  Preliminary Planning and Design
            ====                                       II  Acquisition of Site, Easements
               = ==== ==== ====                        II  Permitting, Licensing, and EIS/EA
               = =                                     II  Geotechnical Studies
                             == ==== ==== ...         III  Detailed Engineering and Plant Design
                              = ==== ==== ..          III  Ordering of Long-Lead-Time Equipment
                                          #                Start of Plant Construction
Year  1    2    3     4    5    6    7    8
```

FIGURE 3.8. Preconstruction Schedule for Two 603-MW Pulverized-Coal-Fired Plants

Legend:

```
=          Three months
==== ====  Two years with a space indicating year completion
...        Activity continuing after construction begins
#          Indicates beginning of construction
```

The schedule shown in Figure 3.9 assumes that a totally new site would be selected and that current requirements continue to apply. Lengthening the schedule should be considered when the effect of further legislation can be assessed. There is more technical uncertainty over the performance of fluidized bed plants than over conventional coal plants. However, the potential for improved environmental performance may allow institutional approvals for the new approach just as quickly as for a conventional coal plant.

3.3.8 Two 139-MW Single-Cycle Combustion Turbine Units

Natural gas-fired turbines appear to be a desirable option in the Pacific Northwest to back up hydro capacity because they can be used to provide power for extended periods (in a dry year). In addition, they can supply peaking power in the event of a power overload. These turbines can be designed to use residual fuel/distillate in the event of a natural gas supply interruption. Natural gas appears to be the most desirable of the combustion sources of electrical energy because it produces less particulates, NO_x, SO_x, and CO_2 per kWh than other generation options such as coal. The technology is well advanced and presents little difficulty in its application in an industrial area (or other locations well away from residences). Combustion turbines produce no clinkers or ashes and do not require cooling water.

The political climate for use of combustion turbines is generally favorable, and the preconstruction processes are assumed to go rather smoothly (see Figure 3.10).

3.3.9 120-MW Combined-Cycle Combustion Turbine Plant

The combined-cycle turbine project will have a higher capital cost/kW of capacity but will burn only two thirds as much fuel/kWh generated as the conventional combustion turbine. A combined-cycle plant can be constructed as a retrofit to an existing conventional combustion turbine by using the exhaust gases to provide steam for a conventional steam turbine. Overall costs may be less where combustion turbines are installed initially so that their exhaust gases are used to raise steam for use in steam turbines. In this way, some of the conversion costs can be eliminated.

```
                                                    Phase
 |  ==                                                I  Project Conceptualization
 |    == ====                                         I  Resource Reconnaissance
 |         ==                                         I  Preliminary Planning and Design
 |            ====                                   II  Acquisition of Site, Easements
 |               = ==== ==== ====                    II  Permitting, Licensing, and EIS/EA
 |               = =                                 II  Geotechnical Studies
 |                             == ==== ==== ...     III  Detailed Engineering and Plant Design
 |                              = ==== ==== ..      III  Ordering of Long-Lead-Time Equipment
 |                                         #             Start of Plant Construction
 |____________________________________________
Year  1    2    3    4    5    6    7    B
```

FIGURE 3.9. Preconstruction Schedule for a 197-MW Atmospheric Fluidized-Bed Coal Plant

Legend:

```
=         Three months
==== ==== Two years with a space indicating year completion
...       Activity continuing after construction begins
#         Indicates beginning of construction
```

Year 1 2 3 4	Phase	
==	I	Project Conceptualization
== ==	I	Preliminary Planning and Design
==	II	Acquisition of Site, Easements
==== ====	II	Permitting and EIS/EA Process
== ...	II	Detailed Engineering and Plant Design
= ..	II	Ordering of Long-Lead-Time Equipment
#		Start of Plant Construction

FIGURE 3.10. Preconstruction Schedule for Two 139-MW Single-Cycle Combustion Turbine Units

Legend:

=	Three months
==== ====	Two years with a space indicating year completion
...	Activity continuing after construction begins
#	Indicates beginning of construction

Because its efficiency is higher, the combined-cycle turbine plant reduces particulates, NO_x, SO_x, and CO_2, even further than does the conventional combustion turbine. Therefore, it should also encounter a favorable political climate. Because of its increased capital cost/kW of capacity, it will be used less for peaking and more for firm power generation. It will need more makeup water, and cooling tower blowdown may need to be evaporated. Cooling water is required. Because of the additional agencies involved, the permitting process may be somewhat more costly and may take a little longer than that for a conventional combustion turbine (see Figure 3.11).

3.3.10 10-MW Wood-Products-Based Cogeneration Plant

In the Pacific Northwest wood-products (biomass)-based generation of electricity seems to be a particularly attractive resource because "hog fuel" has historically been used to generate steam for heating dry kilns. The most likely application would be to generate electricity from high-pressure steam using (Carnot Cycle) turbines and then to route the steam to the dry kilns. A number of such installations are operating in the Pacific Northwest. Biomass has been regarded as a renewable energy; therefore, it might be expected that the political climate would be quite favorable. However, the decision to proceed with a cogeneration plant may be delayed by various "business realities" such as discussed in Section 3.3.11.

Generating electricity from this source also has several disadvantages. Burning wood waste in steam boilers produces fly ash in the smoke and bottom ash containing leachable material that may contaminate groundwater. In addition, the burning of wood waste produces NO_x, SO_x, CO, and CO_2. Thus, the permitting process is becoming more difficult as air and groundwater pollution laws become stricter. Although wood-products-based cogeneration units are much smaller than conventional coal plants, they may get just as close a scrutiny during the preconstruction process (shown in Figure 3.12.)

3.3.11 10-MW Natural Gas Cogeneration Plant

The natural gas cogeneration plant permitting process will likely proceed more quickly than the permitting process for a similarly sized cogeneration plant operating on wood waste. Natural gas cogeneration is an

```
                                             Phase
| ==                                           I           Project Conceptualization
|    == ==                                     I           Preliminary Planning and Design
|          ==                                  II          Acquisition of Site, Easements
|               ==== ==== ====                 II          Permitting and EIS/EA Process
|                         ==== ...             II          Detailed Engineering and Plant Design
|                              = ..            II          Ordering of Long-Lead-Time Equipment
|                                #                         Start of Plant Construction
|_______________________________________
Year   1    2    3    4    5
```

FIGURE 3.11. Preconstruction Schedule for a 420-MW Combined-Cycle Combustion Turbine Plant

Legend:

```
=            Three months
==== ====    Two years with a space indicating year completion
...          Activity continuing after construction begins
#            Indicates beginning of construction
```

```
                                                  Phase
 ==                                                 I          Project Conceptualization
   ==                                               I          Resource Reconnaissance
    = ===                                           I          Preliminary Planning and Design
         = ==== =                                   I          Negotiation of Power Sales Contract
                ==== ==== ====                      II         Permitting and EIS/EA Process
                             == ...                 II         Detailed Engineering and Plant Design
                              = ..                  II         Ordering of Long-Lead-Time Equipment
                                 #                             Start of Plant Construction

Year   1    2    3    4    5    6
```

FIGURE 3.12. Preconstruction Schedule for a 10-MW Wood-Products-Based Cogeneration Plant

Legend:

```
=          Three months
==== ====  Two years with a space indicating year completion
...        Activity continuing after construction begins
#          Indicates beginning of construction
```

attractive option for manufacturing operations presently using natural gas to provide process heat. The environmental concerns are much less than for cogeneration based on wood products. Natural gas produces no fly ash or bottom ash to create potential contamination of groundwater at the disposal site. Natural gas produces less SO_x, NO_x, CO_2, or airborne particulates per Btu or kWh produced than other combustible energy sources.

Other parts of the preconstruction process are important and could take a substantial amount of time for completion. The decision of the plant management to proceed may require extensive study and deliberation. Some of the issues to be considered in such a decision are the following:

- Payback periods as short as 1 year are sometimes used as the investment cutoff point in deciding on plant maintenance/repairs because of "opportunity costs."
- Each installation tends to be a custom design requiring an A/E firm to develop plans and estimates for a "custom package."
- Production may be lost unless downtime of the production facility for other maintenance programs is planned.
- The facility may be under corporate directions to do only routine maintenance because of plans to shut it down.

These points do not apply in the case of new plant construction but these considerations do make it difficult for utilities or regulatory agencies to initiate such projects. Utilities may offer incentives, but the other factors involved may need time to mature into a decision on the part of plant management to proceed with the installation. The schedule in Figure 3.13 may be longer than needed where management has completed its analysis and is already waiting for favorable economic conditions.

3.3.12 420-MW Coal Gasification Combined-Cycle Plant

Because of their design and their greater thermal efficiency, coal gasification combined-cycle plants have a potential for less environmental impact/kWh generated than do conventional coal plants. However, estimating schedules for preconstruction activities involves all of the uncertainties faced in estimating preconstruction activity schedules for conventional coal plants as listed in Section 3.3.6. These plants are required to meet

```
                                              Phase
  ==                                            I        Project Conceptualization
     =                                          I        Resource Reconnaissance
      =                                         I        Preliminary Planning and Design
        ==== ==                                 I        Negotiation of Power Sales Contract
               == ==== ====                     II       Permitting and EIS/EA Process
                         == ...                 II       Detailed Engineering and Plant Design
                          = ..                  II       Ordering of Long-Lead-Time Equipment
                            #                            Start of Plant Construction

Year    1    2    3    4    5
```

FIGURE 3.13. Preconstruction Schedule for a 10-MW Natural Gas Cogeneration Plant

Legend:

=	Three months
==== ====	Two years with a space indicating year completion
...	Activity continuing after construction begins
#	Indicates beginning of construction

environmental performance requirements that are likely to continue to change before a plant can be built. Opposition to siting any coal-fired plant nearby is increasing in many localities. Preconstruction schedules for all coal-fired plants are much more uncertain than the actual construction schedules.

Summarizing, the schedule shown in Figure 3.14 assumes that a totally new site would be selected and that current requirements apply. Although industry has less experience with the technology of coal gasification combined-cycle plants than with conventional coal plants, the technology is assumed to be ready for application.

```
      Phase
|==                                      I   Project Conceptualization
|  == ====                               I   Resource Reconnaissance
|       ==                               I   Preliminary Planning and Design
|          ====                         II   Acquisition of Site, Easements
|             = ==== ==== ====          II   Permitting, Licensing, and EIS/EA
|             = =                       II   Geotechnical Studies
|                          == ==== ==== ...   III   Detailed Engineering and Plant Design
|                           = ==== ==== ..    III   Ordering of Long-Lead-Time Equipment
|                                      #           Start of Plant Construction
|_____________________________________________
Year  1    2    3    4    5    6    7    8
```

FIGURE 3.14. Preconstruction Schedule for a 420-MW Coal Gasification Combined-Cycle Plant

Legend:

```
=          Three months
==== ====  Two years with a space indicating year completion
...        Activity continuing after construction begins
#          Indicates beginning of construction
```

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4.0 PRECONSTRUCTION AND DELAY COSTS FOR INDIVIDUAL POWER RESOURCES

This section presents estimates of the costs of preconstruction activities at key decision points for the twelve power generating resources described in Section 1. In addition, the costs of delaying the acquisition of each resource at the key decision points are also estimated. The methodology and common assumptions used to estimate the cost of preconstruction activities and delays are discussed in Section 4.1. The acquisition and delay cost estimates for each resource are then discussed in Section 4.2 and results summarized in a number of tables.

4.1 METHODOLOGY AND ASSUMPTIONS

Based on the activity schedules for each generating resource shown in Section 3, key decision points were identified for each resource. These decision points represent a time in the preconstruction process where delays could logically be incurred with minimum project disruption. Seven of the resources have two decision points while the other five resources have three. The activities that take place between these decision points are said to take place in consecutive phases that are divided by the key decision points.

To estimate the preconstruction acquisition costs for the generating resources, information from historical records, literature, and interviews was used. The questionnaire (shown in Appendix A) sent to a number of industry and government representatives contains many questions dealing with costs, both acquisition and delay costs, as well as where the key decision points in the process should be located. After a first estimate of acquisition costs was compiled for each resource, a number of outside individuals were presented with the results for their comments. The results, shown in Section 4.2 for each resource, incorporate the individuals' comments.

All acquisition and delay costs are presented in 1989 dollars and 1989 dollars per kW of capacity to facilitate comparisons among resources of different sizes. All costs that were not in 1989 dollars were adjusted to 1989 dollars using the implicit price deflator for the Gross National Product (GNP).[1]

Accounting for land acquisition is an important element in estimating acquisition costs in the preconstruction cycle for many of the supply resources. At some point during the preconstruction cycle of a generating resource, land must usually be optioned, leased, or purchased. Which of these three alternatives is used will depend upon the developer's perception of particular economic and regulatory conditions. However, for the resources analyzed in this study, the following assumptions were used regarding land acquisition during preconstruction.

- For the generic conventional coal plant, the generic atmospheric fluidized-bed coal plant, the coal gasification plant, the generic combustion turbine project, the generic combined-cycle turbine project, the wind park, and the solar photovoltaic (PV) generating plant, land is assumed to be optioned.

- For the geothermal plant, land is assumed to be leased.

- For the municipal solid waste incinerator, land is assumed to be purchased.

- For the hydroelectric and both cogeneration projects, it is assumed no land is purchased.

In general it was assumed that land for a resource would be optioned unless there were compelling reasons for early purchase. Land is assumed to be optioned at 15% of fair market value per year.[2] The land that is optioned is assumed to be purchased near the beginning of the construction period and is therefore considered a cost of construction. This is consistent with standard accounting procedures that consider the cost of land as a construction expense.

Another element in estimating the cost of land acquisition is the price per acre of land. The following assumptions were used for the price of land after consulting with an appraiser of farm, ranch, and commercial land.[a]

- For non-irrigated, dry pasture land in Eastern Washington, Eastern Oregon and Southern Idaho a price of $100/acre is assumed.

(a) Personal communication with Dana Cummings, Clark Jennings and Associates, Inc., Pasco, Washington.

- For land located in the preceding locations near a rail line and river, a price of $900/acre is assumed.
- For a small parcel of land located near a natural gas line and water, and located in Western Washington or Western Oregon, a price of $5000/acre is assumed.

Delay costs for the supply resources include the financial carrying charge for the costs incurred up to each key decision point, the cost of maintaining a land option at each key decision point, and any staffing costs incurred during the delay period. All delay costs are estimated for the first year of any delay. By their very nature, delay costs are extremely uncertain. They will depend on the cost of financing at the time of delay; the number of staff members, if any, retained at a net cost to resource development during the delay period; and a number of other factors.

As far as possible within the scope of the project, reasonable scenarios on the consequences of delay are constructed. Financing charges are assumed to vary according to the probable investor in the generating resource. Nominal costs of debt and equity capital were assumed to average approximately 15% for private developers, 13% for IOUs, and 8% for POUs or municipalities. Real financing charges were calculated by subtracting an assumed inflation rate of 5% from the nominal costs of capital.

If an engineering staff is employed at a particular key decision point, it is assumed that 50% of this staff will be retained during the delay period at a cost to the project. This estimate of retained staffing costs is obviously very arbitrary and probably conservative. Two examples of retained staffing costs during a period of resource delay have already occurred. Both of these projects were large nuclear power plant projects, Pebble Springs and the Washington Public Power Supply System Plant No. 1. The process of shutting down the projects was very slow and gradual. In many cases, it may be more cost-effective to retain engineering staff during a period of indefinite delay than to lay off all the staff and incur the cost of rehiring and coordinating a whole new staff if the project starts up again.

Some of the consequences of delay will be very difficult, if not impossible, to estimate on a generic basis. For example, breaking engineering momentum on a project could be a serious consequence of delay. In addition, plans and permits may become out of date, necessitating that the permit process be repeated in the event of a restart of the project. Delay could have a number of other consequences that were not possible to assess in this project. Such consequences include changes in contractual arrangements and increased risk that the generating resource will never be brought on line.

For the above reasons, the delay costs determined at key decision points for each of the twelve resources examined are for the first year of delay only. Most of the delay costs at each key decision point are due to financing and land option costs that will continue to be incurred as long as the delay continues. Other costs such as repermitting or redoing plans will arise in later years, but are very project specific and nearly impossible to predict. The exact time when permits would expire and plans would need to be redone is also project specific. Given the variability and uncertainty of these delay costs they are not included in the delay cost estimates for each resource's key decision points.

4.2 PRECONSTRUCTION AND DELAY COSTS

In this section, the costs of acquiring and delaying the acquisition of the twelve electric power supply resources identified in Section 1 are discussed. Each of the twelve individual resource discussions is divided into two parts: the costs of acquiring the resource and the costs of delaying the resource acquisition at key decision points. Appendix B contains the detailed calculations and assumptions in a worksheet format for each resource.

4.2.1 50-MW Geothermal Plant

Although the technology is well developed, very few geothermal power plants are currently operating in the U.S. Over 200 plants with a total generating capacity of 5400 MW are on line in 17 countries. A major limiting factor in the use of geothermal in the Pacific Northwest has been the lack of adequate natural steam or hot water reservoirs.[3]

The following conditions were assumed for estimating the preconstruction costs for the geothermal power plant:

- The facility would be located on land leased from the federal government.
- A private developer would be responsible for Phase I and II.
- An IOU would be responsible for completing Phase III.

Preconstruction Costs

Phase I activities include project conceptualization, resource reconnaissance, and preliminary planning and design. Limited cost information was available from geothermal industry contacts for these activities and therefore, costs were based on previous PNL estimates. The estimated cost for Phase I activities is $1.4M or $28/kW (Table 4.1).

Phase II activities include site selection, acquisition of permits and licenses, drilling of exploratory wells and temperature gradient holes, and preparation of the environmental documents. The costs of these activities are directly related to the location of the geothermal site and the difficulty in moving a crew and drilling equipment into a particular area. Information from the Council,[4] contacts with industry experts, and estimates from previous

TABLE 4.1. Preconstruction and Delay Costs for a 50-MW Geothermal Plant

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	28	1,411,000	3
PHASE II Site Selection Acquisition of Permits/Leases Exploratory Wells Prep. of Environmental Docs.	149	7,450,000	22
PHASE III Detailed Engineering Financing Ordering Long-Lead-Time Equip.	260	12,990,000	63
TOTAL	437	21,851,000	

reports[5] were used to estimate the costs of Phase II activities. Based on these sources, the estimated cost of Phase II activities is $7.45M or $149/kW.

Phase III activities include detailed engineering, financing, and ordering of long-lead-time equipment. These activities represent approximately 12% of the total plant cost.[6] The total geothermal plant cost (including construction) is estimated to be $2165/kW.[7] Therefore, the estimated cost of Phase III activities is $13M or $260/kW.

Delay Costs

The preconstruction activities are grouped in such a way that the delay costs would be minimized if work were stopped at the end of any one phase. Consequently, delay costs were estimated for halting work at the end of Phase I, II and III. For most resources, the delay costs include the cost of financing, holding a land option, and retaining staff during the delay period. However, because land is assumed to be leased at low cost from the federal government, land costs are not included in the delay cost calculations.

Phase I and II financing costs were estimated assuming that these activities would be performed by a private developer. These costs were estimated assuming a real interest rate of 10%. It was also assumed that no staff would be retained at the end of Phase I. The estimated delay cost at the end of Phase I is $3/kW/year.

Because interest must be paid on the total amount of money borrowed by the resource developer, the financing delay costs are cumulative. In addition, it was assumed that at the end of Phase II, two staff engineers would be retained at an estimated cost of $75,000/engineer/year. Total estimated delay cost at the end of Phase II is $22/kW/year.

Phase III preconstruction activities were assumed to be performed by an IOU. The cost of borrowing was assumed to be 8%/year. It was assumed that three private developer and 12 utility personnel were retained at the end of Phase III. The cost of utility personnel was estimated to be $50,000/person/year. The total delay cost at the end of Phase III is $63/kW/year.

4.2.2 10-MW Wind Park

Wind energy conversion system technology is well developed and currently several U.S. firms are manufacturing wind turbines and components. Many wind parks are operating in the Altamont Pass and the San Gorgonio regions of California, and new sites are being installed periodically.[8] To date, no major wind parks have been established in the Pacific Northwest.

The assumptions for estimating the preconstruction costs for a 10-MW wind park include the following:

- A private developer will be responsible for all preconstruction activities.
- The developer will option significantly more land than is actually needed for the wind park.
- Land costs are $100/acre.

Preconstruction Costs

Phase I activities include project conceptualization, resource reconnaissance, and preliminary planning and design. The major source of uncertainty in estimating the costs of these activities is resource reconnaissance. If the potential site(s) are located near a weather station, sufficient data should be available to allow proper characterization and evaluation of the site's wind resource. However, if the site is located in an area away from a weather station, site wind measurements would have to be made. The estimated cost for Phase I activities is $180K or $18/kW (Table 4.2).

Phase II activities include site selection and land optioning, permitting and preparation of environmental documents, power contract negotiations, financing, and ordering of long-lead-time equipment. The major cost uncertainty in this phase is the cost of permitting and preparation of environmental documents. This cost becomes particularly difficult to estimate when a resource will be sited in a region with no prior experience in approving and siting such a technology.

TABLE 4.2. Preconstruction and Delay Costs for a 10-MW Wind Park

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	18	180,000	2
PHASE II Site Selection/Land Option Permitting and Prep. of Environmental Documents Power Contract Negotiations Financing Ordering Long-Lead-Time Equip.	34	340,500	7
TOTAL	52	520,500	

The second major cost item in Phase II is the acquisition of a land option. Frequently, wind park developers will option significantly more land than is technically needed for establishing the wind park.[9] It is not uncommon for wind park developers to option up to 25 times the amount of land required for the wind park. For this analysis, it was assumed that the wind park developer will option 12.5 times the amount of land required for the wind park and that this land is optioned for the 2 years before plant construction.

The total estimated cost for Phase II activities is $340K or $34/kW. The total preconstruction cost for a 10-MW wind park is estimated to be $520K or $52/kW.

Delay Costs

Delay costs at the end of Phase I are only the financing costs incurred (the wind park land is not optioned until Phase II), and it is assumed that no staff are retained at the end of either phase. The estimated delay cost at the end of Phase I is $2/kW/year.

The Phase II delay cost includes both financing and land option costs. The estimated cost of delaying at the end of Phase II activities is $7/kW/year.

4.2.3 10-MW Municipal Solid Waste Incinerator

The purpose of constructing a municipal solid waste incinerator is not only to produce electricity but to reduce the amount of refuse. The technology used to convert the waste to electricity is composed of the following major components: an incinerator, a boiler, and a turbine. These major components are available from several manufacturers. The following conditions were assumed for estimating the preconstruction costs for the 10-MW municipal solid waste incinerator:

- The facility would be developed by a municipality.
- The land for the facility would be purchased rather than optioned.

Preconstruction Costs

Phase I activities include project conceptualization, resource characterization, preliminary planning and design, and site acquisition. To help reduce transportation costs, the facility will usually be located close to the refuse generation site. The site is assumed to be purchased early in the plant development process to help identify any opposition to the facility and to allow sufficient time for the permits to be approved.[10] These costs represent approximately 4% of the total plant cost or about \$1.3M or \$130/kW (Table 4.3).

Phase II activities include preparation of the environmental documents, permitting, and detailed engineering activities. The location and the amount of local opposition encountered will directly impact the actual costs of these activities. It is assumed for this analysis that a municipal solid waste incinerator is new to the area and that significant opposition is encountered. This assumption seems quite reasonable given the difficulties that many municipalities and private developers are encountering when trying to site this technology in their regions.

TABLE 4.3. Preconstruction and Delay Costs for a 10-MW Municipal Solid Waste Incinerator

	Preconstruction Costs		Delay Costs
	\$/kW	Total (\$)	\$/kW/yr
PHASE I Project Conceptualization Resource Characterization Preliminary Planning/Design Site Acquisition	129	1,290,000	4
PHASE II Prep. of Environmental Documents and Permits Detailed Engineering	289	2,887,000	18
TOTAL	418	4,177,000	

Since most municipal solid waste incinerators use well-developed technologies, the amount of detailed engineering required is relatively low and represents about 8% of the total plant cost.[11] The total cost of Phase II activities is estimated to be \$2.9M or approximately \$289/kW.

The total preconstruction cost for a 10-MW municipal solid waste incinerator is estimated to be \$4.2M or \$419/kW.

Delay Costs

Because land is purchased outright and not optioned and because no personnel are retained at the end of Phase I, the only delay costs are the financing costs. It is assumed that the plant is being developed by a municipality with a real cost of capital of 3%/year. The estimated delay cost at the end of Phase I is \$4/kW/year.

The Phase II delay cost includes financing costs from Phase I and II and staff retention costs (1 staff member for 1 year). The estimated delay cost after Phase II is \$18/kW/year.

4.2.4 10-MW Solar Photovoltaic Plant

Photovoltaics, also known as solar cells, convert sunlight directly into electricity without moving parts. Photovoltaic systems are currently operating efficiently in a wide range of applications including small, low-power devices for remote communications, mid-sized systems for residences and large power systems for utility applications. However, only limited photovoltaic applications have been installed in the Pacific Northwest.

The following conditions were assumed for estimating the preconstruction costs for the 10-MW photovoltaic power plant:

- Preconstruction activities would be the responsibility of a private developer.
- Preconstruction activity costs are similar to 1982 estimates.[12]
- The developer is familiar with the technical aspects of photovoltaic power systems.
- Acreage will be optioned.
- Land costs $100/acre.

Preconstruction Costs

Phase I activities include project conceptualization, resource reconnaissance, and preliminary planning and design. The developer is assumed to be technically familiar with photovoltaic power systems so the cost of these activities is assumed to represent a relatively minor portion of the preconstruction costs. However, because the plant is expected to be located in an area where no other photovoltaic powerplants have previously been located, it is assumed that some cost will be incurred in measuring the levels of insolation and weather conditions at a number of potential sites. The cost of these measurements will be a function of the number and the location of potential sites. These activities are quite similar to those presented in the earlier PNL report[13] and were confirmed in contacts with photovoltaic manufacturers. Phase I cost is estimated to be $560K or $56/kW (Table 4.4).

Phase II activities include site selection and land optioning, permitting and preparation of environmental documents, power contact negotiations, detailed engineering and design, and ordering of long-lead-time equipment. Site selection will be based on the quality of the solar resource, land costs, and proximity to the load. Once a site is selected, it is assumed to be optioned by the developer at a cost of <$1/kW.

TABLE 4.4. Preconstruction and Delay Costs for a 10-MW Solar Photovoltaic Plant

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	56	559,600	6
PHASE II Site Selection/Land Option Permitting and Prep. of Environmental Docs. Power Contract Negotiations Detailed Engineering/Design Ordering Long-Lead-Time Equip.	504	5,035,800	57
TOTAL	560	5,595,400	

In most instances, detailed engineering and design and ordering of long-lead-time equipment will be fairly straightforward activities because engineering firms are familiar with the technology and a number of photovoltaic manufacturers are supplying modules and other components. However, permitting and preparation of environmental documents could be expensive depending on where the plant is located and the familiarity of the permitting organizations with the technology. It is expected that most agencies will not be familiar with the technology and permitting requirements may not have been established or be known. The total cost of Phase II activities is estimated to be $5M or $504/kW.

Total preconstruction cost for a 10-MW photovoltaic plant is estimated to be $5.6M or $560/kW.

Delay Costs

Delay costs for the 10-MW photovoltaic plant will include both financing and land costs. It is assumed that no staff will be retained between phases.

The real cost of borrowing for both Phase I and Phase II is assumed to be 10%/year. Land costs are not a part of Phase I delay costs because the land is not optioned until Phase II. The estimated delay cost after Phase I is $6/kW/year.

Phase II delay costs involve both financing and land costs. The estimated delay cost after Phase II is $57/kW/year.

4.2.5 10-MW Hydroelectric Power Plant

Currently, over 85,000 MW of hydroelectric generating capacity is installed in the U.S.[14] The technology used in these generating facilities is well developed and available from a number of commercial vendors.

The assumptions for estimating the preconstruction costs for a 10-MW hydroelectric plant include following:

- The plant will be run-of-the-river (versus impoundment).
- The resource will be developed and constructed by a private developer.
- No staff will be retained at the end of any phase.

Preconstruction Costs

Phase I activities include project conceptualization, resource reconnaissance, and preliminary planning and design. The costs of these activities are typically relatively low and, based on contacts with industry experts, are estimated to be $100,000 or $10/kW (Table 4.5).

Phase II activities include site selection, acquisition of a preliminary FERC permit, site/resource verification, and acquisition of a FERC license. In most instances, candidate sites have already been identified; therefore, the majority of time for this phase will be spent in acquiring the appropriate permits. The preliminary FERC permit allows access to the potential plant site so that data for additional studies in support of the environmental documentation process can be collected. Information on FERC permit requirements is presented in Section 2.7.

The time and costs required for permitting activities would be reduced if the new capacity were being added to an existing hydroelectric facility. Phase II cost is estimated to be $650,000 or $65/kW.

TABLE 4.5. Preconstruction and Delay Costs for a 10-MW Hydroelectric Power Plant

	Preconstruction Costs $/kW	Preconstruction Costs Total ($)	Delay Costs $/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	10	100,000	1
PHASE II Site Selection Preliminary FERC Permit Acquisition Site/Resource Verification FERC License Acquisition	65	650,000	8
PHASE III Detailed Engineering/Design Ordering Long-Lead-Time Equip.	30	300,000	11
TOTAL	105	1,050,000	

Phase III activities include detailed engineering and design and ordering of long-lead-time equipment. The time and costs involved in the detailed design of the hydroelectric plant is related to the terrain of the selected site. Information from hydroelectric engineering firms indicates that this phase costs approximately $300,000 or $30/kW.[a] The total preconstruction cost is estimated to be $1.05M or $105/kW.

Delay Costs

The delay costs for the hydroelectric plant consist of the financing costs for each phase. Land costs are negligible since the plant is run-of-the-river type. In addition, it is assumed that no staff is retained at the end of either phase. The delay cost after Phase I activities is $1/kW/year. The financing delay costs are cumulative and are $8/kW/year after Phase II activities. However, the project can be delayed only a limited amount of time under current FERC rules (see Section 2). The delay cost at the end of Phase III is estimated to be $11/kW/year.

(a) Personal communication with Keli Covin, Hydro West Group, Inc., Bellevue, Washington.

4.2.6 Two 603-MW Pulverized-Coal-Fired Plants

Pulverized coal plants are a mature technology and are commercially available with more than 200,000 MW of electrical generating capacity in the United States.[15]

To estimate the preconstruction and delay costs of a "generic" plant, the following assumptions were made:

- An IOU will incur the preconstruction costs.
- A real interest rate of 8% is used.
- Approximately 33 acres/100 MW are required.[16]
- The utility will option 10 times the amount of land that is needed.
- Land costs $900/acre.

Preconstruction Costs

Activities for Phase I include project conceptualization, resource reconnaissance, and preliminary planning and design. The cost of these activities comprise the owner's administrative costs which range from roughly $14.8M to $29.5M in 1989 dollars.[17] Averaging these costs yields $22M or $18/kW (Table 4.6). The cost of this phase, however, will vary in direct proportion to the amount of time required to complete it.

Phase II activities include acquisition of site/land options and easements. Also included are geotechnical studies, permitting, and preparation of environmental documents. Approximately 400 acres of land would be required for a conventional coal plant. However, an assumption was made that ten times the amount actually needed would be optioned for siting purposes. The land option would be held until the onset of construction, at which time the required land would be purchased. According to the schedule, the land would be optioned for four years. The cost of acquiring the land option is estimated to be $2.2M or about $2/kW (see Appendix B).

TABLE 4.6. Preconstruction and Delay Costs for Two 603-MW Pulverized Coal-Fired Plants

	Preconstruction Costs $/kW	Preconstruction Costs Total ($)	Delay Costs $/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	18	22,150,000	1
PHASE II Acquisition of Site/Land Option and Easements Acquisition of Permits Geotechnical Studies Prep. of Environmental Docs.	5	6,610,000	2
PHASE III Detailed Engineering/Design Ordering Long-Lead-Time Equip.	51	61,860,000	10
TOTAL	75	90,620,000	-

The estimated cost for easements is $1.3M or about $1/kW. This figure includes the costs of acquiring easements for access roads, railroad lines, process water supply lines, potable water and wastewater lines, and telephone lines.

The schedule presented in Section 3 combines and lengthens the time estimates for permitting and the environmental documentation process to about three years. Each activity is assumed to span half of the allotted time or 1-1/2 years. The estimated cost of permitting is $0.5M or less than $1/kW.

The environmental documentation process is expected to last about six months longer than the amount of time for which there are referenceable cost estimates. Because the cost for this activity must reflect the longer time estimate, a time adjustment factor was used. The cost to the owner of preparing the necessary documents is estimated to be $0.8M or about $1/kW.

Geotechnical studies are also included in this phase. This activity includes defining the existing characteristics of the subsurface materials and incorporating guidelines into the construction specifications. This activity can help to ensure that the project is not adversely affected by avoidable site conditions.[18] The estimated cost of the studies is about \$1.8M or about \$1/kW.

Summing each activity yields a total estimated cost for Phase II of \$6.6M or about \$5/kW.

The activities included in Phase III are detailed engineering and plant design, and ordering of long-lead-time equipment. Design engineering accounts for about 4% of the total cost of plant construction,[19] that is, \$61M or about \$51/kW. The cost of ordering long-lead-time equipment is assumed to be minimal and is reflected in the design costs.

Delay Costs

All of the major existing or proposed coal generating units have been built by IOUs; thus, a real financing cost of 8% will be used to represent the interest rate during a period of delay.[20] The total estimated cost at the end of Phase I is \$22M. Multiplying the total cost by the interest rate yields a delay cost of \$1.8M/year or about \$1/kW.

Land option delay costs would also be incurred by the utility. Optioning 4000 acres at 15% of market value would cost \$0.54M/year or less than \$1/kW/year.

Since no staff would be retained at the end of Phase I, the total estimated Phase I delay cost would be the sum of the financing and land option costs, or \$2.3M/year or about \$2/kW/year.

The delay cost after Phase II also includes financing and land option costs. The total estimated cost of Phase II is \$6.6M. The total cost of Phase I, however, must be included in the calculation of financing costs to reflect the actual cost incurred up to this point. The financing cost after Phase II is estimated to be \$2.3M/year or approximately \$2/kW/year. Land option costs will remain at less than \$1/kW/year. The total estimated delay cost after Phase II is \$2.8M/year or approximately \$2/kW/year.

The Phase III delay cost includes financing costs, land option costs, and staff retention costs. Financing costs after Phase III are estimated to be \$7.2M/year or \$6/kW/year. Land option costs are estimated to be \$0.54M/year or less than \$1/kW/year.

Staff retention costs are based on the number of engineers retained and their salary. The number of engineers employed in designing a 500-MW coal plant will typically be approximately 100.[21] An assumption was made that the same number would be employed for two identical 600-MW plants. The staff retention costs are \$3.75M/year or about \$3/kW/year (see Appendix B).

The total estimated delay cost after Phase III is \$11.5M/year or approximately \$10/kW/year.

4.2.7 197-MW Atmospheric Fluidized-Bed Coal Plant

The atmospheric fluidized-bed coal (AFBC) technology is commercially available under most conditions for utility and industrial applications. Although equipment is commercially available, only a few plants are operational. Remaining technical uncertainties to be addressed include cost; reliability; and performance of the coal-feeding, fly-ash recycling, and control systems. AFBC technology is a cost-competitive energy option for utility baseload power and industrial process heat applications under most conditions.[22]

To determine the preconstruction and delay costs the following assumptions were made:

- An IOU will incur the preconstruction costs.
- A real interest rate of 8% is used.
- Approximately 500 acres are required.[23]
- The utility will option 10 times the amount of land that is needed.
- Land costs \$900/acre.

Preconstruction Costs

Activities for Phase I are the same as for the generic conventional coal plant. This phase comprises project conceptualization, resource reconnaissance, and preliminary planning and design. The cost of these activities comprise the owner's administrative costs. The cost of Phase I is estimated to be $3M or about $15 per kilowatt (Table 4.7). The cost of this phase, however, will vary in direct proportion to the amount of time required to complete it.

Phase II activities include acquisition of site/land option and easements. Also included are geotechnical studies, permitting, and preparation of environmental documents. Approximately 500 acres of land would be required for an AFBC plant.[24] An assumption was made that ten times the amount of land actually needed would be optioned for siting purposes. The total amount of

TABLE 4.7. Preconstruction and Delay Costs for a 197-MW Atmospheric Fluidized-Bed Coal Plant

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	15	3,000,000	5
PHASE II Acquisition of Site/Land Option and Easements Acquisition of Permits Geotechnical Studies Prep. of Environmental Docs.	28	5,610,000	7
PHASE III Detailed Engineering/Design Ordering Long-Lead-Time Equip.	75	14,760,000	32
TOTAL	119	23,370,000	-

land optioned would be 5000 acres. The land option would be held until the onset of construction, at which time the required land would be purchased. According to the schedule, the land would be held for four years. The cost of acquiring the land option is estimated to be \$2.7M or about \$14/kW (see Appendix B).

The cost for easements is estimated to be approximately \$1.3M or about \$7/kW. This figure includes the costs of acquiring easements for access roads, railroad lines, process water supply lines, potable water and wastewater lines, and telephone lines.

The schedule presented in Section 3 combines and lengthens the time estimates for permitting and the environmental documentation process to about three years. Each activity is assumed to span half of the allotted time or 1-1/2 years. The cost of permitting is estimated to be \$0.5M or about \$3/kW.

The environmental documentation process is expected to last about six months longer than the amount of time for which there are referenceable cost estimates. A time adjustment factor was used because the cost for this activity must reflect the longer time estimate. The cost to the owner of preparing the necessary documents is estimated to be \$0.8M or about \$4/kW.

Geotechnical studies are also included in this phase. This activity includes defining the existing characteristics of the subsurface materials and incorporating guidelines into the construction specifications. This activity can help to ensure that the project is not adversely affected by avoidable site conditions.[25] The cost of the studies is estimated to be \$0.2M or about \$1/kW.

Summing each activity yields a total estimated cost for Phase II of \$5.6M or about \$28/kW.

The activities included in Phase III are detailed engineering and plant design and ordering of long-lead-time equipment. Design engineering comprises about 4% of the total cost of plant construction[26] or \$14.8M, which amounts to about \$75/kW. The cost of ordering long-lead-time equipment is assumed to be minimal and is reflected in the design costs.

Delay Costs

An IOU real financing cost of 8% will be used to represent the interest rate during a period of delay.[27] The total estimated cost at the end of Phase I is $3M. Multiplying the total cost by the interest rate yields a delay cost of $0.24M/year or about $2/kW/year.

Land option delay costs would also be incurred by the utility. Optioning 5000 acres at 15% of market value would cost $0.68M/year or about $3/kW/year.

Because no staff would be retained at the end of Phase I, the total estimated Phase I delay cost would be the sum of the financing and land option costs, $0.92M/year or about $5/kW/year.

The delay cost after Phase II also includes financing and land option costs. The total estimated cost of Phase II is $5.6M. To reflect the actual cost incurred up to this point, however, the total cost of Phase I must be included in the calculation of financing costs. The financing cost after Phase II is estimated to be $0.24M/year or approximately $1/kW/year. Land option costs will remain at $3/kW/year. The total estimated delay cost after Phase II will be $1.4M/year or approximately $7/kW/year.

The Phase III delay cost includes financing costs, land option costs, and staff retention costs. Financing costs after Phase III are estimated to be $1.9M/year or $9/kW/year. Land option delay costs are estimated to be $0.68M/year or $3/kW/year.

Staff retention costs are based on the number of engineers retained and their salary. It was assumed that the same number of people would be required to design an AFBC plant as a pulverized coal plant. The estimated cost of retaining staff after Phase III is $3.75M/year or about $19/kW/year.

The total estimated delay cost after Phase III is $6.3M/year or approximately $32/kW/year.

4.2.8 Two 139-MW Single-Cycle Combustion Turbine Units

The single-cycle combustion turbine is a mature technology, with numerous suppliers of gas turbines for electric power generation. This resource is a cost-competitive energy option for utility peaking plant applications at current and projected fuel prices; however, future cost-effectiveness as a baseload plant depends heavily upon future fuel prices.[28]

To estimate costs for preconstruction and delay, the following assumptions were made:

- An IOU will incur the preconstruction costs.
- A real interest rate of 8% is used.
- Approximately 350 acres are required.
- Acreage will be optioned.
- Land costs $5000/acre.

Preconstruction Costs

Activities for Phase I include project conceptualization and preliminary planning and design. The cost of these activities is estimated to be 1% of the total cost of construction.[29] Since the total cost of the project is estimated to be $121M in 1989 dollars,[30] Phase I activities are estimated to cost $1.2M or about $4/kW (Table 4.8).

TABLE 4.8. Preconstruction and Delay Costs for two 139-MW Single-Cycle Combustion Turbine Units

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Preliminary Planning/Design	4	1,210,000	<1
PHASE II Acquisition of Site/Land Option Permitting and Prep. of Environmental Docs. Detailed Engineering/Design Ordering Long-Lead-Time Equip.	16	4,480,000	5
TOTAL	20	5,690,000	-

Phase II activities include site/land option acquisition, permitting and environmental document preparation, detailed engineering and plant design, and ordering of long-lead-time equipment. Single-cycle combustion turbine units were assumed to require half as much land as a combined-cycle combustion turbine plant (Section 4.2.9). Approximately 350 acres of land would therefore be required for the single-cycle combustion turbine units. The land option would be held until the onset of construction, at which time the land would be purchased. According to the schedule shown in Section 3, the land would be held for 2-1/2 years at a cost of $5000 per acre per year. The cost of acquiring the land option is estimated to be $0.66M or about $2/kW.

Estimates in the Northwest Power Plan for siting and licensing were used to determine the cost of permitting and the environmental documentation process.[31] The cost of this activity is estimated to be $1.4M or about $1/kW.

Design engineering accounts for about 2% of the total cost of plant construction.[32] The cost for this activity is estimated to be $2.42 million or about $9/kW. The cost of ordering long-lead-time equipment is assumed to be minimal and is reflected in the design costs.

Summing the activities yields a total estimated cost for Phase II of $4.5M or about $16/kW.

<u>Delay Costs</u>

An IOU real financing cost of 8% is used to represent the interest rate during a period of delay.[33] The total cost at the end of Phase I is estimated to be $1.2M. Multiplying the total cost by the interest rate yields an estimated delay cost of $0.10M/year or less than $1/kW/year. Because no land would be optioned at this point and no staff would be retained at the end of Phase I, the total Phase I delay cost would only include financing costs.

Financing, land option, and staff retention costs constitute the delay cost for Phase II. To reflect the total cost incurred to this point, the total costs of Phases I and II must be determined and multiplied by the IOU real financing rate of 8%. The financing cost after Phase II is estimated to be $0.46M/year or approximately $2/kW/year (see Appendix B).

Land option delay costs would also be incurred by the utility. Optioning 350 acres at 15% of a market value of $5,000/acre would cost $0.26M/year or approximately $1/kW/year.

Staff retention costs are based on the number of engineers retained and their salary. Four engineers would be needed to build a 75-MW combustion turbine plant.[34] Staff requirements are assumed to be proportional to the size of the plant, thus, the two 139-MW units would require about 15 engineers. It was assumed that 50% of the engineers would be retained.[35] The salary of engineers was estimated to be $75,000 in 1989 dollars. The staff retention costs are $0.56M/year or approximately $2/kW/year (see Appendix B).

The total estimated delay cost after Phase II is the sum of the activities costs or $1.28M/year or approximately $5/kW/year.

4.2.9 420-MW Combined-Cycle Combustion Turbine Plant

There are several suppliers of gas turbines for electric power generation. The combined-cycle technology is a cost-competitive energy option for utility baseload electricity applications at current and projected fuel prices; however, future cost-effectiveness depends heavily upon future fuel prices.[36]

To estimate preconstruction and delay costs, the following assumptions were made:

- An IOU will incur the preconstruction costs.
- A real interest rate of 8% is used.
- Approximately 700 acres are required.[37]
- Acreage will be optioned.
- Land costs $5000/acre.

Preconstruction Costs

Activities for Phase I include project conceptualization and preliminary planning and design. Phase I activities are estimated to cost $4.65M or about $11/kW (Table 4.9). The cost of these activities is roughly 1.7% of the total cost of construction[38] which is estimated to be $273M in 1989 dollars.[39]

TABLE 4.9. Preconstruction and Delay Costs for a 420-MW Combined-Cycle Combustion Turbine Plant

	Preconstruction Costs $/kW	Preconstruction Costs Total ($)	Delay Costs $/kW/yr
PHASE I Project Conceptualization Preliminary Planning/Design	11	4,650,000	1
PHASE II Acquisition of Site/Land Option Permitting and Prep. of Environmental Docs. Detailed Engineering/Design Ordering Long-Lead-Time Equip.	61	25,490,000	14
TOTAL	72	30,140,000	-

Phase II activities include site/land option acquisition, permitting and environmental document preparation, detailed engineering and plant design, and ordering of long-lead-time equipment. Approximately 700 acres of land would be required for a combined-cycle combustion turbine plant. The land option would be held until the onset of construction at which time the land would be purchased. According to the schedule in Section 3, the land would be held for 4-1/2 years at a cost of $5000 per acre per year. The cost of acquiring the land option is estimated to be $2.4M or about $7/kW.

The costs for siting and licensing in the Northwest Power Plan were used to determine the cost of permitting and the environmental documentation process.[40] The cost of this activity is estimated to be $2.6M or about $6/kW.

Design engineering constitutes about 7.5% of the total cost of plant construction.[41] The cost for this activity is estimated to be $20.5M or about $49/kW. The cost of ordering long-lead-time equipment is assumed to be minimal and is reflected in the design costs.

Summing the costs of the activities yields a total estimated cost for Phase II of $25M or about $69/kW.

Delay Costs

An IOU real financing cost of 8% is used to represent the interest rate during a period of delay.[42] The total cost at the end of Phase I is estimated to be \$4.65M. Multiplying the total cost by the interest rate yields an estimated delay cost of \$0.37M/year or about \$1/kW/year. Because no land would be optioned at this point and no staff would be retained at the end of Phase I, the total Phase I delay costs would only include financing costs.

Financing, land option, and staff retention costs constitute the delay costs for Phase II. To reflect the total cost incurred to this point, the total cost of Phases I and II must be determined and multiplied by the real financing rate, 8%. The financing cost after Phase II is estimated to be \$2.4M/year or approximately \$6/kW/year (see Appendix B).

Land option delay costs would also be incurred by the utility. Optioning 700 acres at a market value of 15% of \$5000/acre would cost \$0.53M/year or approximately \$1/kW/year.

Staff retention costs are based on the number of engineers retained and their salary. About 103 engineers are required to design a 550-MW plant.[43] Because the staff requirements are assumed to be proportional to the size of the plant, a 420-MW plant would require about 80 engineers. It was assumed that 50% would be retained.[44] The salary of engineers was estimated to be \$75,000 in 1989 dollars. The staff retention costs are estimated to be \$3M/year or about \$7/kW/year (see Appendix B).

The total estimated delay cost after Phase II is the sum of the costs of the activities or \$5.9M/year or approximately \$14/kW/year.

4.2.10 10-MW Wood-Products-Based Cogeneration Plant

Cogeneration facilities are being installed in a variety of industries to help reduce energy costs. Facilities can use a number of different fuels including natural gas, coal, or wood. Either topping or bottoming cycle technologies can be used. In a topping cycle cogeneration facility, electricity is produced initially from the input fuel and waste heat from this process is used for heating or other uses. The topping cycle technology is the most commonly employed cogeneration system. In the bottoming cycle technique, high-temperature thermal energy is produced first and used in an industrial process. Waste heat is then captured from this process typically by using a waste heat recovery boiler that drives a turbine, to generate electricity. The bottom cycle technology is usually employed only by industries that need very high-temperature heat applications, e.g., steel-making, glass-making, etc. Both technologies are well developed and available from a number of manufacturers.[45]

The following conditions were assumed for estimating the preconstruction and delay costs for a 10-MW wood-products-based cogeneration plant:

- The plant would be owned and developed by an industrial firm.
- No staff would be retained at the end of either phase.

Preconstruction Costs

Phase I activities include project conceptualization, resource reconnaissance, preliminary planning and design, and power contract negotiations. These activities represent a minor portion of the overall plant cost. For this analysis, these costs were estimated to be 0.5% of the total plant cost.[46] The total estimated cost for Phase I activities is $104,000 or $10/kW (Table 4.10).

TABLE 4.10. Preconstruction and Delay Costs for a 10-MW Wood-Products-Based Cogeneration Plant

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design Power Contract Negotiations	10	104,000	1
PHASE II Permitting and Prep. of Environmental Docs. Detailed Engineering/Design Order Long-Lead-Time Equip.	166	1,660,000	18
TOTAL	176	1,764,000	

Phase II activities include preparation of permits and environmental documents, detailed engineering and design, and ordering of long-lead-time equipment. Permitting and environmental work required for cogeneration plants can be quite complex. Another major cost item in this phase is the detailed engineering and design that represents approximately 8% of total plant cost.[47] The total estimated cost for Phase II is $1.6M or $166/kW.

Total preconstruction cost for the 10-MW wood-products-based cogeneration plant is estimated to be $1.7M or $176/kW.

Delay Costs

The only delay costs for a 10-MW wood-products-based cogeneration plant will be the financing costs. The facility is assumed to be developed by the industrial firm, and the real cost of capital is assumed to be 10%/year. At the end of Phase I the delay costs are estimated to be $1/kW/year. Delay costs at the end of Phase II include both Phase I and II financing costs and are estimated to be $18/kW/year.

4.2.11 10-MW Natural Gas Cogeneration Plant

Several different fuel types are available for cogeneration facilities. The technology for a natural-gas-fired plant is well developed. Both topping and bottoming cycles are available. The following conditions were assumed for estimating the preconstruction and delay costs for a 10-MW natural gas cogeneration plant:

- The plant would be owned and operated by an industrial firm.
- No staff would be retained at the end of either phase.

Preconstruction Costs

Phase I activities include project conceptualization, resource reconnaissance, preliminary planning and design, and negotiation of a power contract. These activities parallel the Phase I activities for the wood-based cogeneration plant. However, the time required to complete these activities is assumed to be approximately 9 months less than for the wood-based cogeneration plant because the pollution control requirements are less. In addition, identifying a reliable source of fuel is not a major problem with the natural gas plant.

The cost of Phase I activities is estimated to total $80,000 or $8/kW (Table 4.11).

Phase II activities include permitting and preparation of environmental documents, detailed engineering and design, and ordering of long-lead-time equipment. Both the permitting and the preparation of environmental documents are assumed to be similar to the corresponding activities for the natural gas single-cycle combustion turbine units (Section 4.2.8). Phase II preconstruction costs are estimated to be $156/kW or $1.6M. The total preconstruction costs are estimated to be $164/kW or $1.6M.

Delay Costs

Land is assumed to be optioned and no staff is assumed to be retained at the end of either phase, thus, the only delay costs are the financing costs associated with each phase. The real cost of capital is assumed to be 10%/year. The delay cost at the end of Phase I is $0.8/kW/year. The delay cost at the end of Phase II is the sum of Phase I and II delay costs or $157/kW/year.

TABLE 4.11. Preconstruction and Delay Costs for a 10-MW Natural Gas Cogeneration Plant

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design Power Contract Negotiations	8	80,000	<1
PHASE II Permitting and Prep. of Environmental Docs. Detailed Engineering/Design Ordering Long-Lead-Time Equip.	156	1,560,000	16
TOTAL	164	1,640,000	

4.2.12 420-MW Coal Gasification Combined-Cycle Plant

Based on the success of Southern California Edison's gasification facility, technology performance and reliability of this type of plant are well established. The technology is commercially available for utility applications under most conditions.[48]

To determine the preconstruction and delay costs, the following assumptions were made:

- An IOU will incur the preconstruction costs.
- A real interest rate of 8% is used.
- The amount of land needed is 75% of that needed for a conventional coal plant.[49]
- The utility will option 10 times the amount of land that is needed.
- Land costs $900/acre.

Preconstruction Costs

Activities for Phase I are the same as for the generic pulverized-coal-fired plant and the atmospheric fluidized-bed coal plant. This phase comprises project conceptualization, resource reconnaissance, and preliminary planning and design. These activities constitute the owner's administrative costs or about 2% of the total cost of construction.[50] The estimated cost of Phase I is $16M or about $39/kW (Table 4.12). The cost of this phase, however, will vary in direct proportion to the amount of time required to complete it.

Phase II activities include acquisition of site/land option and easements. Also included are geotechnical studies, permitting, and preparation of environmental documents. Approximately 75% of the land required for a pulverized coal-fired plant would be required for a coal gasification plant.[51] The total amount of land optioned would be 3000 acres, based on an assumption that ten times the amount actually needed would be optioned for siting purposes. The land option would be held until the onset of construction at

TABLE 4.12. Preconstruction and Delay Costs for a 420-MW Coal Gasification Combined-Cycle Plant

	Preconstruction Costs		Delay Costs
	$/kW	Total ($)	$/kW/yr
PHASE I Project Conceptualization Resource Reconnaissance Preliminary Planning/Design	39	16,230,000	4
PHASE II Acquisition of Site/Land Option and Easements Acquisition of Permits Geotechnical Studies Prep. of Environmental Docs.	12	5,040,000	5
PHASE III Detailed Engineering/Design Ordering Long-Lead-Time Equip.	116	48,720,000	27
TOTAL	167	70,000,000	-

which time the land would be purchased. According to the schedule, the land would be held for 4 years. The estimated cost of acquiring the land option would be $1.6M or about $4/kW.

The estimated cost for easements is $1.3M or about $3/kW. This figure includes the costs of acquiring easements for access roads, railroad lines, process water supply lines, potable water and wastewater lines, and telephone lines.

The schedule presented in Section 3 combines and lengthens the time estimates for permitting and the environmental documentation process to about 3 years. Each activity is assumed to span half of the allotted time or 1-1/2 years. The cost of permitting is estimated to be $0.52M or about $1/kW.

The environmental documentation process is expected to last about six months longer than the amount of time for which there are referenceable cost estimates. The cost for this activity must reflect the longer time estimate;

thus, a time adjustment factor was used. The cost to the owner of preparing the necessary documents is estimated to be \$0.83M or about \$2/kW.

Geotechnical studies are also included in this phase. This activity includes defining the existing characteristics of the subsurface materials and incorporating guidelines into the construction specifications. This activity can help to ensure that the project is not adversely affected by avoidable site conditions.[52] The estimated cost of the studies is about \$0.75M or about \$2/kW.

Summing each activity yields a total estimated cost for Phase II of \$5.0M or about \$12/kW.

The activities included in Phase III are detailed engineering and plant design and ordering of long-lead-time equipment. Design engineering accounts for about 6% of the total cost of coal plant construction;[53] the total for design engineering is \$49M or about \$116/kW. The cost of ordering long-lead-time equipment is assumed to be minimal and is reflected in the design costs.

Delay Costs

An IOU real financing cost of 8% is used to represent the interest rate during a period of delay.[54] The total cost at the end of Phase I is estimated to be \$16M. Multiplying the total cost by the interest rate yields an estimated delay cost of \$1.3M/year or about \$3/kW/year.

Land option delay costs would also be incurred by the utility. Optioning 3000 acres at 15% of market value would cost \$0.41M/year or about \$1/kW/year.

No staff would be retained at the end of Phase I; thus, the total Phase I delay costs would be the sum of the financing and land option costs, \$1.7M/year or about \$4/kW/year.

The delay costs for Phase II also include financing and land option costs. The total estimated cost of Phase II is \$5M. The total cost of Phase I, however, must be included in the calculation of financing costs to reflect the actual cost incurred up to this point. The financing cost after Phase II is estimated to be \$1.7M/year or approximately \$4/kW/year. Land option costs will remain at less than \$1/kW/year. The total estimated delay cost after Phase II is \$2.1M/year or approximately \$5/kW/year.

Phase III delay costs comprise financing costs, land option costs, and staff retention costs. Financing costs through Phase III are \$5.6M/year or \$13/kW/year. Land option costs are \$0.54M/year or less than \$1/kW/year.

Staff retention costs are based on the number of engineers retained and their salary. The staffing costs for a coal gasification plant are higher than for a pulverized-coal-fired plant because of higher design engineering costs per kilowatt.[55] The estimated cost of retaining staff after Phase III is \$5.25M/year or about \$13/kW/year.

Total estimated delay cost after Phase III is \$11M/year or approximately \$27/kW/year.

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APPENDIX A

DATA GATHERING SURVEY INSTRUMENT

APPENDIX A

DATA GATHERING SURVEY INSTRUMENT

BPA PROJECT DATA REQUIREMENTS LIST

1. What are the principal preconstruction activities occurring prior to ground breading and construction? For example, activities might include project conceptualization, resource characterization, preliminary planning and design, site selection and acquisition, licensing and permitting, EIS/EA preparation, site/resource verification, ordering of long-lead equipment, and engineering design.

2. What specific permits and licenses are required? When do they have to be acquired, which agency or agencies are involved, how long does the acquisition process take, and what is the total permit or license acquisition cost (in-house labor plus governmental agency fees)?

3. What is the schedule for preconstruction activities, i.e., what is the sequence, duration (media and range), and dependent or independent nature of each activity? How much flexibility does each of the activities have with regard to start and stop dates and duration; i.e., could they be stretched or compressed with minimal impact on cost?

4. Which activities could be grouped into two or three preconstruction intervals representing stages where the acquisition process could be halted prior to procurement and construction? What would be the time and cost impact, if any, of forming at least two preconstruction intervals? For example, what would be the extra cost of shutting down and later restarting an individual activity that was partly completed.

5. What additional activities or rework of old activities would be required if the energy resources acquisition process was delayed after the first, second, or third interval? For example, how long will each of the permits and licenses last? At what point would the preliminary or final engineering design work need to be reworked? More generally, what is the "decay fraction" over time for each of the preconstruction activities and what additional activities, if any, would be required to delay the acquisition process at one of the interval points?

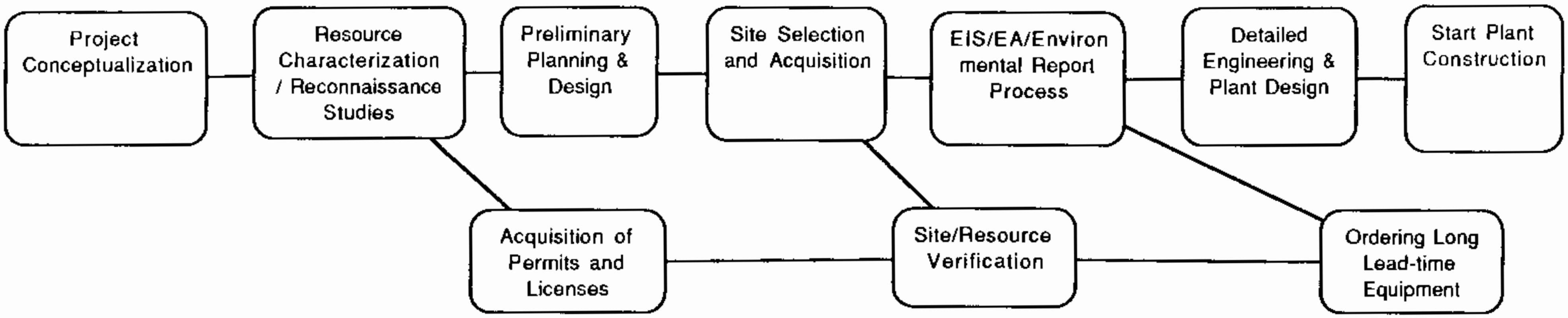
6. What is the cost for accomplishing each preconstruction activity?

7. What is the cost for accomplishing additional preconstruction activities brought on by delaying the acquisition process?

8. How much of the engineering design is completed prior to procurement and construction?

9. How much of the engineering design could be completed prior to procurement and construction? How much time and money would this engineering design approach add to the resource acquisition process?

Generic Power Resource Acquisition Schedule



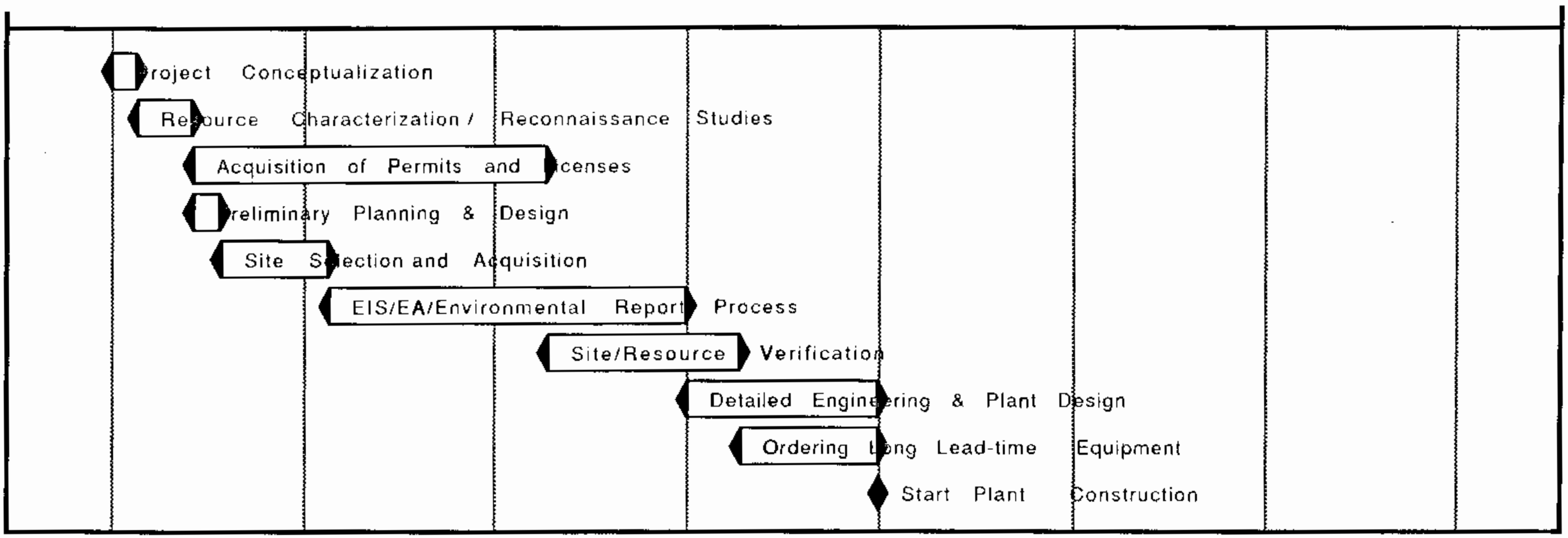


TABLE A.1. Definition of Terms Used in Preconstruction Schedules

Activity	Definition
Preconstruction Activities	Those activities occurring before ground breaking and initiation of construction.
Project Conceptualization	Activities that involve securing participant agreements and defining the project before a feasibility study is initiated.
Resource Characterization or Reconnaissance Studies	Studies carried out to determine suitability of the region for use of a specific power generation option.
Preliminary Planning and Design	The feasibility study and preliminary design work necessary to initiate licensing and permitting and to support the selection of the site and architect/engineer firm (if one is to be selected at this time). This work brings the project to the point where a business plan shows that the option is a good investment opportunity.
Site Selection and Acquisition	Selecting the site, securing purchase/lease options on the site, and the road and utility easements to the site.
Acquisition of Permits and License	Application for and activities in support of the acquisition of permits and licenses.
EIS/EA/Environmental Report	Preparation of an Environmental Impact Statement, Environmental Assessment, or Environmental Report; conducting hearings; revising and publishing the environmental documents in their final version.
Site/Resource Verification	Site-specific work such as drilling and exploration at geothermal sites necessary to verify the resource before major investments are made.
Detailed Engineering Design	Completion of detailed engineering and plant design.
Ordering of Long Lead-Time Equipment	Ordering of capital goods having long delivery schedules.
Start of Plant Construction	Actual groundbreaking and commencement of foundations, etc.

APPENDIX B

CALCULATION OF PRECONSTRUCTION AND DELAY COSTS

B.1 50-MW GEOTHERMAL PLANT PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

$19.20/kW[1] x 1.47 (GNP Deflator Adjustment) = $28.22/kW

Total Phase I Cost = $1,411,000 or $28.22/kW

Phase II:

Activities:

Site Selection
Acquisition of Permits and Leases
Exploratory Wells and Temperature Gradient Holes
Preparation of Environmental Documents

Costs:

Site selection, and acquisition of permits/leases cost: $40/kW[2] - $28/kW (Phase I costs) = $12/kW
Exploratory well costs: $83/kW[3] x 1.47 (GNP Deflator Adjustment) = $122/kW
Preparation of environmental document costs: $15/kW[4]

Total Phase II Costs = $7,450,000 or $149/kW

Phase III:

Activities:

Detailed Engineering
Financing
Ordering Long-Lead-Time Equipment

Costs:

The cost of these activities represented 12% of total costs in the PNL 1982 report.[5] The total cost of a geothermal generating facility is

\$2165/kW which is the average of the PNL 1982 and the Council's 1989[6] estimates. Consequently, the cost of this phase is:

0.12 x \$2165/kW = \$259.80/kW

Total Phase III Cost = \$12,990,000 or \$259.80/kW

TOTAL PRECONSTRUCTION COST = \$21,851,000 or \$437.02/kW

Delay Costs

Phase I Delay Costs:

Financing costs: It was assumed that a private developer would be developing the geothermal field during Phases I and II, consequently, the financing interest rate was assumed to be 10%. The delay costs at the end of Phase I are the interest payments on the total costs of this phase, or,

0.10/year x \$28/kW = \$2.80/kW/year

Land cost: No land costs are calculated since land is assumed to be leased at a low cost from the Federal government.

Staff Retention Costs: It was assumed that no staff were retained at the end of this phase.[7]

Total Delay Cost After Phase I = \$2.80/kW/Year

Phase II Delay Costs:

Financing Costs: Since interest must be paid on the total amount of money borrowed, the financing delay costs are cumulative. That is, the financing delay costs for Phase II are:

0.10/year x [\$28/kW (Phase I total costs) + \$149/kW (Phase II total costs)] = \$17.70/kW/year.

Staff Retention Costs: It is assumed that at the end of Phase II, 2 private developer engineers are retained at a cost of \$75,000/person/year. Thus the delay costs of retaining 2 individuals for 1 year are:

[2 people x \$75,000/engineer/year x 1.47]/50000kW = \$4.41/kW/year.

Total Delay Cost After Phase II = \$22.11/kW/Year

Phase III Delay Costs:

Financing Costs: Preconstruction activities in Phase III are assumed to be performed by an IOU. The cost of borrowing to the utility is assumed to be 8%/year.[8] Therefore, the financing delay costs for this phase is:

0.10/year x [$28/kW (Phase I) + $149/kW (Phase II)] + 0.08/year[$259.80/kW (Phase III)] = $38.48/kW/year.

Staff Retention: It is assumed that 3 private developer and 12 utility personnel are retained at the end of Phase II. The cost of utility personnel is estimated at $50,000/person/year. Thus, the cost of staff retention at the end of Phase III:

[3 people x $75,000/engineer/year x 1.47]/50000 kW + [12 people x $50,000/employee/year x 1.47]/50000 kW = $24.25/kW/year.

Total Delay Cost After Phase III = $62.73/kW/Year

B.2 10 MW WIND PARK PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

Project Conceptualization: $2/kW[9] x 1.47 (GNP Deflator) = $3/kW
Resource Reconnaissance and Preliminary Planning/Design: $10/kW[10] x 1.47 = $15/kW.

Total Phase I Cost = $180,000 or $18/kW

Phase II:

Activities:

Site Selection/Land Option
Permitting and Preparation of Environmental Documents
Power Contract Negotiations
Financing
Ordering Long-Lead-Time Equipment

Costs:

Permitting and Preparation of Environmental Documents: $15/kW[11] x 1.04 (GNP Deflator Adjustment) = $15.60/kW
Power Contract Negotiations
Financing — $10/kW[12] x 1.47 = $14.70/kW
Ordering Long-Lead-Time Equipment
Site Selection and Land Option:
1250 acres (50% of the land required in PNL 1982 for a wind park) x $100/acre x 2 years (based on the preconstruction activities schedule) x 15%/year[13] = $37,500 or $3.75/kW

Total Phase II Cost = $340,500 or $34.05/kW

TOTAL PRECONSTRUCTION COST = $520,500 or $52.05/kW

Delay Cost

Phase I Delay Costs:

Financing: It is assumed that the wind energy park will be privately owned and operated and that the appropriate real cost of capital is 10%. Therefore, the financing costs for Phase I are:

0.10/year x $18/kW (total Phase I costs) = $1.80/kW/year.

Land costs: Since land is not optioned until Phase II, land costs are "0" at the end of Phase I.

Staff retention costs: It is assumed that no staff are retained at the end of either phase.

Total Delay Cost After Phase I: $1.80/kW/Year

Phase II Delay Costs

Financing: Financing cost for delaying at the end of Phase II are the sum of the financing costs at the end of Phase I and the financing costs of Phase II. That is,

0.10/year[$18/kW (total Phase I costs) + $34.05/kW (total Phase II costs)] = $5.20/kW/year.

Land Costs: The option that is purchased during Phase II will have to be covered whether or not the preconstruction activities continue or are halted. Land option costs are based on the amount of acreage and the price of the option. That is,

Annual option costs = 1250 acres x $100/acre x 15%/year (annual option fee)/10000 = $1.87/kW/year.

Total Delay Cost After Phase II: $7.00/kW/year

B.3 <u>10-MW MUNICIPAL SOLID WASTE INCINERATOR PRECONSTRUCTION AND DELAY COSTS</u>

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Characterization
Preliminary Planning and Design
Site Acquisition

Costs:

Assumed to be **4%** of total plant cost.

0.04 x [$2200/kW[14] x 1.47] = $129.36/kW or $1,300,000.

Total Phase I Cost = $1,300,000 or $129.36/kW

Phase II:

Activities:

Preparation of Environmental Documents and Permits
Detailed Engineering

Costs:

Environmental reports and permits for a municipal solid waste incinerator are assumed to take twice as long as the geothermal environmental reports and permits to prepare and secure. Thus the cost for this activity is $15/kW (Cost of preparing geothermal environmental reports and permits) x 2 = $30/kW or $300,000.

Detailed engineering is assumed to represent 8% of total plant cost.

0.08[15] x [$2200/kW[16] x 1.47 (GNP Deflator Adjustment)] = $258.72/kW or $2,587,200.

Total Phase II Cost = $2,887,200 or $288.71/kW

TOTAL PRECONSTRUCTION COST = $4,180,700 OR $418.07/kW

Delay Costs

Phase I Delay Costs

<u>Financing Costs</u>: It is assumed that the municipal solid waste incinerator is developed by a municipality with a real cost of capital of 3%/year. The financing delay costs for Phase I are:

0.03/year x 129.36/kW (Phase I acquisition costs) = $3.88/kW/year.

<u>Land and Staff Costs</u>: It is assumed that the land is purchased outright and not optioned; thus, the costs of land retention are included in the financing costs. Also, it is assumed that no staff are retained at the end of Phase I.

Total Delay Cost After Phase I = $3.88/kW/year

Phase II Delay Costs

<u>Financing Costs</u>: Financing delay costs at the end of Phase II are the sum of Phase I and Phase II delay costs:

0.03/year x [$129.36 (Phase I Acquisition costs) + $288.71/kW (Phase II Acquisition Costs)] = $12.54/kW.

<u>Staff Retention</u>: It is assumed that 1 staff supervisor is retained at the end of Phase II activities at a cost of $50,000/employee/year.

1 staff x $50,000/staff/year = $50,000/year or $5/kW/year.

Total Delay Cost After Phase II = $17.54/kW/year

B.4 <u>10-MW SOLAR PHOTOVOLTAIC PLANT PRECONSTRUCTION AND DELAY COSTS</u>

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

Assumed to be 50% of the cost of preconstruction activities estimated in PNL '82 report. [$76.13/kW[17] x 1.47]0.5 = $55.96/kW

Total Phase I Cost = $559,600 or $55.96/kW

Phase II:

Activities:

Site Selection/Land Option
Permitting and Preparation of Environmental Documents
Power Contract Negotiations
Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

Assumed to be 50% of the cost of preconstruction activities estimated in PNL 1982 report for Phase I as well as the cost of Phase II activities. [$76.13/kW x 1.47]0.5 + [$304/kW x 1.47] = $502.83/kW.

Land option costs are assumed to be 15% of the total land costs.

500 acres[18] x $100/acre x 0.15 x 1 year = $7500 or $0.75/kW.

Total Phase II Cost = $5,035,800 or $503.58/kW

TOTAL PRECONSTRUCTION COST = $5,595,400 or $559.54/kW

Delay Costs

Phase I Delay Costs

Financing Costs: It is assumed that the photovoltaic energy source will be developed by a private developer, therefore the appropriate real cost of capital is 10%/year. Financing delay costs at the end of Phase I are:

0.10/year x $55.96/kW (total Phase I costs) = $5.60/kW/year.

Land Costs: Because land is not optioned until Phase II, the option costs at the end of Phase I are "0".

Staff retention costs: It is assumed that no staff will be retained at the end of either phase.

Total Delay Cost After Phase I = $5.60/kW/Year

Phase II Delay Costs

<u>Financing</u>: Delay costs at the end of Phase II are the total of the financing costs for Phase I and the financing costs for Phase II. That is,

0.10/year x [$55.96/kW (total Phase I costs) + $503.58/kW (total Phase II costs)] = $55.95/kW/year.

<u>Land Option Costs</u>: Since the land option was purchased in Phase II, this option must be paid whether or not the preconstruction activities are continued or halted. The annual land option costs are:

[500 acres x $100/acre x 0.15/year]/10000 = $0.75/kW/year.

Total Delay Cost After Phase II = $56.70/kW/Year

B.5 <u>10-MW HYDROELECTRIC POWER PLANT PRECONSTRUCTION AND DELAY COSTS</u>

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

Based on information provided by industry contacts, the cost of these activities is estimated to be $100,000 or $10/kW.

Total Phase I Cost = $100,000 or $10/kW

Phase II:

Activities:

Site Selection
Preliminary FERC Permit Acquisition
Site/Resource Verification
FERC License Acquisition

Costs:

Based on information provided by industry contacts, the cost of these activities is estimated to be \$650,000 or \$65/kW.

Total Phase II Cost = \$650,000 or \$65/kW

Phase III:

Activities:

Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

Based on information provided by industry contacts, the cost of these activities is estimated to be \$300,000 or \$30/kW.

Total Phase III Cost = \$300,000 or \$30/kW

TOTAL PRECONSTRUCTION COST = \$1,050,000 or \$105/kW

Delay Costs

Phase I Delay Costs

Financing Costs: It is assumed that the hydroelectric plant is developed by a private developer. Thus the assumed real cost of capital is 10%/year and the financing costs are:

0.10/year x \$10/kW (Phase I acquisition costs) = **\$1/kW/year**.

Land Costs: The plant will be run-of-the-river-type; thus, land costs are assumed to be negligible and do not contribute to delay costs.

Staff Retention: No staff are assumed to be retained at the end of Phase I.

Total Delay Cost After Phase I = \$1/kW/year

Phase II Delay Costs

Financing Costs: Financing costs at the end of Phase II are the sum of financing costs for Phases I and II. That is,

0.10/year x [\$10/kW (Phase I costs) + \$65/kW (Phase II costs)] = \$7.5/kW/year.

Total Delay Cost After Phase II = $7.5/kW/year

Phase III Delay Costs

Financing Costs: Financing Costs for Phase III are the sum of the financing costs for Phases I, II, and III. That is,

0.10/year x [$10/kW (Phase I costs) + $65/kW (Phase II costs) + $30/kW (Phase III costs)] = $10.5/kW/year.

Total Delay Cost After Phase III = $10.5/kW/year

B.6 TWO 603 GENERIC PULVERIZED COAL-FIRED PLANTS PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

The owner's administrative costs range from $13.3 million to $26.6 million.[19] When these figures are multiplied by the GNP deflator adjustment, 1.11, the range of costs in 1989 dollars is:

$13.3M x 1.11 to $26.6M x 1.11
= $14.76M to $29.53M.

The average for this range of values is:

($14.76M + $29.53M)/2 = $22.15M
or $22.15M/1,206,000kW = $18.37/kW.

Total Phase I Cost = $22.15 million or $18.37/kW

Phase II:

Activities:

Acquisition of Site/Land Option and Easements
Acquisition of Permits
Geotechnical Studies
Preparation of Environmental Documents

Costs:

Acquisition of Site/Land Option: The assumptions used for calculating the site/land option costs are:

- amount of land needed is:
  33 acres/100MW[20] x 1206MW ≈ 400 acres,
- 10 times the amount of land needed would be optioned,
- land would be optioned for four years at 15% of a market value of $900/acre.

Site/land option costs are:

400 acres x 10 x $900/acres x 15%/year x 4 years = $2.16M
or $2.16M/1,206,000kW = $1.79/kW.

Easements:

The cost of obtaining easements is $1.19 million.[21] Multiplying this figure by the GNP deflator adjustment, 1.11, the cost in 1989 dollars is:

$1.19M x 1.11 = $1.32M
or $1.32M/1,206,000kW = $1.09/kW.

Permitting:

The cost of the permitting process is estimated to be $0.47 million.[22] Multiplying this figure by the GNP deflator adjustment, 1.11, the cost in 1989 dollars is:

$0.47M x 1.11 = $0.52M
or $0.52M/1,206,000kW = $0.43/kW.

Geotechnical Studies:

The estimated cost of conducting geotechnical studies range from $1.33 million to $1.87 million.[23] Multiplying these figures by the GNP deflator adjustment, 1.11, the range of costs in 1989 dollars is:

$1.33M x 1.11 to $1.87M x 1.11 = $1.48M to $2.08M.

The average of this range of values is:

($1.48M to $2.08M)/2 = $1.78M
or $1.78M/1,206,000kW = $1.48/kW.

Preparation of Environmental Documents:

The cost of the environmental documentation process is estimated to be \$0.50 million for one year.[24] This figure is multiplied by the GNP deflator adjustment, 1.11, and by a time adjustment factor, 1.5, to account for the extended time allowance. The cost in 1989 dollars is

\$0.50M x 1.11 x 1.5 = \$0.83M
or \$0.83M/1,206,000kW = \$0.69/kW.

Total Phase II Cost: The total cost for Phase II is the sum of the costs of each activity:

\$2.16M + \$1.32M + \$0.52M +\$1.78M + \$0.83M = \$6.61M
or \$6.61M/1,206,000kW = \$5.48/kW.

Total Phase II Cost = \$6.61 million or \$5.48/kW

Phase III:

Activities:

Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

The cost of the Phase III is estimated to be 4% of the total cost of construction.[25] The total cost of construction is estimated by adding siting and licensing costs to the cost of construction[26] and multiplying by the GNP deflator adjustment (1.04):

(\$1,210/kW + \$23/kW) x 1.04 = \$1,282.32/kW
or \$1,282.32/kW x 1,206,000kW = \$1,546.48M.

Four percent of the total cost is:

0.04 x \$1,282.32/kW = \$51.29/kW
or \$51.29/kW x 1,206,000kW = \$61.86M.

Total Phase III Cost = \$61.86 million or \$51.29/kW

TOTAL PRECONSTRUCTION COST = \$90.62 million or \$75/kW

Delay Costs

Phase I Delay Costs

Financing costs: The formula used to calculate the financing cost is IOU real financing rate x total cost through Phase I.

Incorporating the 8% rate and the total cost of Phase I, the formula yields the annual financing costs at the end of Phase I:

0.08 x $22.15M = $1.77M/year
or $1.77M/year/1,206,000kW = $1.47/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs $900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 4,000 acres of land is:

4,000 acres x $900/acre x 0.15/year = $0.54M/year
or $0.54M/year/1,206,000kW = $0.45/kW/year.

Staff retention costs: Since no staff would be retained during the delay, no staff retention costs would be incurred.

Total Phase I delay cost: The total cost of delay at the end of Phase I is:

$1.77M/year + $0.54M/year = $2.31M/year
or $2.31M/year/1,206,000kW = $1.92/kW/year.

Total Delay Cost After Phase I = $0.54 million/year or $0.45/kW/year

Phase II Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase II (Phase I costs + Phase II costs)

Incorporating the 8% rate and the costs of Phase I and Phase II, the formula yields the annual financing costs at the end of Phase II:

0.08/year x ($22.15M + $6.61M) = $2.3M/year
or $2.3M/year/1,206,000kW = $1.91/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs $900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 4,000 acres of land is:

4,000 acres x $900/acre x 0.15/year = $0.54M/year
or $0.54M/year/1,206,000kW = $0.45/kW/year.

Staff retention costs: Since no staff are assumed to remain on the project during the delay, no staff retention delay costs would be incurred.

Total Phase II delay cost: The total cost of delay at the end of Phase II is:

\$2.3M/year + \$0.54M/year = \$2.84M/year
or \$2.84M/year/1,206,000kW = \$2.35/kW/year.

Total Delay Cost After Phase II = \$2.84 million/year or \$2.35/kW/year

Phase III Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase III (Phase I costs + Phase II costs + Phase III costs)

Incorporating the 8% rate and the total cost through Phase III, the formula yields the annual financing costs at the end of Phase III:

0.08/year x (\$22.15M + \$6.61M + \$61.86M) = \$7.25M/year
or \$7.25M/year/1,206,000kW = \$6/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs \$900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 4,000 acres of land is:

4,000 acres x \$900/acre x 0.15/year = \$0.54M/year
or \$0.54M/year/1,206,000kW = \$0.45/kW/year.

Staff retention costs: The formula for calculating staff retention costs, is the number of staff required to design a coal plant x the percentage of retained staff x salary/year.

To design a coal plant, an estimated 100 employees would be required, of which 50% would be retained.[27] The salary of engineers was estimated at \$75,000 in 1989 dollars.

100 persons x 0.50 x \$75,000 = \$3.75M/year
or \$3.75M/year/1,206,000kW = \$3.11/kW.

Total Phase III delay cost: The total cost of delay at the end of Phase III is:

\$6M/year + \$0.54M/year + \$3.75M/year = \$11.54M/year
or \$11.54M/year/1,206,000kW = \$9.57/kW/year.

Total Delay Cost After Phase III = $11.54 million or $9.57/kW/year

B.7 197 MW ATMOSPHERIC FLUIDIZED BED COAL PLANT PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

The cost of Phase I comprises the owner's costs which range from $1.8M to $3.6M.[28] The result of escalating these numbers to 1989 using the GNP deflator adjustment (1.11) is

$1.8M x 1.11 to $3.6 x 1.11
= $2.0M to $4.0M.

The average for this range of values is:

($2.0M + $4.0M)/2 = $3.0M
or $3.0M/197,000kW = $15.23/kW.

Total Phase I Cost = $3.0 million or 15.23/kW

Phase II:

Activities:

Acquisition of Site/Land Option and Easements
Acquisition of Permits
Geotechnical Studies
Preparation of Environmental Documents

Costs:

Acquisition of Site/Land Option: The assumptions used for calculating the site/land option costs are:

- 500 acres of land are needed[29]
- 10 times the amount of land needed would be optioned

- land would be optioned for four years at 15% of a market value of \$900/acre.

<u>Site/land option costs are</u>

500 acres x 10 x \$900/acres x 15%/year x 4 years = \$2.7M
or \$2.7M/197,000kW = \$13.71/kW.

Easements: The cost of obtaining easements is \$1.19 million.[30] Multiplying this figure by the GNP deflator adjustment, 1.11, the cost in 1989 dollars is

\$1.19M x 1.11 = \$1.32M
or \$1.32M/197,000kW = \$6.7/kW.

Permitting: The cost of the permitting process is estimated to be \$0.47 million.[31] Multiplying this figure by the GNP deflator adjustment, 1.11, the cost in 1989 dollars is

\$0.47M x 1.11 = \$0.52M
or \$0.52M/197,000kW = \$2.64/kW.

Geotechnical Studies: The cost of conducting geotechnical studies ranges from \$0.18 million to \$0.25 million.[32] Multiplying these figures by the GNP deflator adjustment, 1.11, the range of costs in 1989 dollars is

\$0.18M x 1.11 to \$0.25M x 1.11 = \$0.2M to \$0.28M.

<u>The average of this range of values is</u>

(\$0.2M to \$0.28M)/2 = \$0.24M
or \$0.24M/197,000kW = \$1.22/kW.

Preparation of Environmental Documents: The cost of the environmental documentation process is estimated to be \$0.50 million for one year.[33] Multiplying this figure by the GNP deflator adjustment, 1.11, and by a time adjustment factor, 1.5, to account for the extended time allowance, the cost in 1989 dollars is

\$0.50M x 1.11 x 1.5 = \$0.83M
or \$0.83M/197,000kW = \$4.21/kW.

Total Phase II Cost: The total cost for Phase II is the sum of the costs of each activity:

\$2.7M + \$1.32M + \$0.52M +\$0.24M + \$0.83M = \$5.61M
or \$5.61M/197,000kW = \$28.48/kW.

Total Phase II Cost = $5.61 million or $28.48/kW

Phase III:

Activities:

Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

The cost of Phase III is assumed to be 4% of the total cost of construction.[34] The total cost of construction is estimated by adding siting and permit acquisition costs to the cost of construction and multiplying by the GNP deflator adjustment (1.04):

($1,760/kW + $41/kW) x 1.04 = $1,873.04/kW
or $1,873.04/kW x 197,000kW = $368.99M.

Four percent of the total cost is

0.04 x $1,873.04/kW = $74.92/kW
or $74.92/kW x 197,000kW = $14.76M.

Total Phase III Cost = $14.76 million or $74.92/kW

TOTAL PRECONSTRUCTION COST = $23.37 million or $119/kW

Delay Costs

Phase I Delay Costs

Financing costs: The formula used to calculate the financing cost is
IOU real financing rate x total cost through Phase I

Incorporating the 8% rate and the total cost of Phase I, the formula yields the annual financing costs at the end of Phase I:

0.08 x $3M = $0.24M/year
or $0.24M/year/197,000kW = $1.22/kW/year.

Land option costs: The formula used to calculate the land option cost is

acres x price/acre x market value/year.

Assuming land costs $900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 5,000 acres of land is

5,000 acres x $900/acre x 0.15/year = $0.68M/year
or $0.68M/year/197,000kW = $3.45/kW/year.

Staff retention costs: No staff retention delay costs would be incurred because no staff are assumed to remain on the project during the delay.

Total Phase I delay cost: The total cost of delay at the end of Phase I is

$0.24M/year + $0.68M/year = $0.92M/year
or $0.92M/year/197,000kW = $4.67/kW/year.

Total Delay Cost After Phase I = $0.92 million/year or $4.67/kW/year

Phase II Delay Costs

Financing costs: The formula used to calculate the financing cost is IOU real financing rate x total cost through Phase II (Phase I costs + Phase II costs)

Incorporating the 8% rate and the costs of Phase I and Phase II, the formula yields the annual financing costs at the end of Phase II:

0.08/year x ($3M + $5.61M) = $0.69M/year
or $0.69M/year/197,000kW = $3.5/kW/year.

Land option costs: The formula used to calculate the land option cost is

acres x price/acre x market value/year.

Assuming land costs $900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 5,000 acres of land is

5,000 acres x $900/acre x 0.15/year = $0.68M/year
or $0.68M/year/197,000kW = $3.45/kW/year.

Staff retention costs: No staff are assumed to remain on the project during the delay so no staff retention delay costs would be incurred.

Total Phase II delay cost: The total cost of delay at the end of Phase II is

$0.69M/year + $0.68M/year = $1.37M/year
or $1.37M/year/197,000kW = $6.95M/kW/year.

Total Delay Cost After Phase II = $1.37 million/year or $6.95/kW/year

Phase III Delay Costs

Financing costs: The formula used to calculate the financing cost is IDU real financing rate x total cost through Phase III (Phase I costs + Phase II costs + Phase III costs).

Incorporating the 8% rate and the total cost through Phase III, the formula yields the annual financing costs at the end of Phase III:

0.08/year x ($3M + $5.61M + $14.76M) = $1.87M/year
or $1.87M/year/197,000kW = $9.49M/kW/year.

Land option costs: The formula used to calculate the land option cost is

acres x price/acre x market value/year.

Assuming land costs $900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 5,000 acres of land is:

5,000 acres x $900/acre x 0.15/year = $0.68M/year
or $0.68M/year/197,000kW = $3.45/kW/year.

Staff retention costs: To calculate the staff retention costs, the formula is: number of staff required to design a plant x the percentage of retained staff x salary/year.

An assumption was made that the same number of people would be required to design an atmospheric fluidized-bed coal plant as a conventional coal plant. The cost is:

100 persons x 0.50 x $75,000 = $3.75M/year
or $3.75M/year/197,000kW = $19.04kW/year.

Total Phase III delay cost: The total cost of delay at the end of Phase III is:

$1.87M/year + $0.68M/year + $3.75M/year = $6.3M/year
or $6.3M/year/197,000kW = $31.98/kW/year.

Total Delay Cost After Phase III = $6.3 million/year or $31.98/kW/year

B.8 TWO 139 MW SINGLE CYCLE COMBUSTION TURBINE UNITS PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Preliminary Planning and Design

Costs:

The cost of Phase I is estimated to be 1% of the total cost of construction.[35] The total cost of construction[36] multiplied by the GNP deflator adjustment, 1.04, is:

$418/kW x 1.04 = $435/kW
or $435/kW x 270,000kW = $120.9M.

One percent of the total cost is:

0.01 x $435/kW = $4.35/kW
or $4.35/kW x 278,000kW = $1.21M.

Total Phase I Cost = $1.21 million or $4.35/kW

Phase II:

Activities:

Acquisition of Site/Land Option
Permitting and Preparation of Environmental Documents
Detailed Engineering and Plant Design
Ordering Long-Lead-Time Equipment

Costs:

Acquisition of Site/Land Option: The assumptions used for calculating the site/land option costs are:

- amount of land optioned is 350 acres
- land would be optioned for two and a half years at 15% of a market value of $5,000/acre.

Site/land option costs are:

350 acres x $5,000/acre x 15%/year x 2.5 years = $0.66M
or $0.66M/278,000kW = $2.37/kW.

Permitting and Preparation of Environmental Documents: The cost of siting and permit acquisition, \$5/kW,[37] is multiplied by the GNP deflator adjustment, 1.04, to escalate to 1989 dollars:

\$5/kW x 1.04 = \$5.2/kW
or \$5.2/kW x 278,000kW = \$1.4M.

Detailed Engineering and Design, and Ordering Long-Lead-Time Equipment: The cost of this activity is estimated to be 2% of the total cost of construction.[38] As mentioned earlier, the total cost of construction in 1989 is \$120.9M or \$435/kW. Two percent of the total cost is:

0.02 x \$435/kW = \$8.7/kW
or \$8.7/kW x 278,000kW = \$2.42M.

Total Phase II Cost: The total cost for Phase II is the sum of the costs of each activity:

\$0.66M + \$1.4M + \$2.42M = \$4.48M
or \$4.48M/278,000kW = \$16.12/kW.

Total Phase II Cost = \$4.48 million or \$16.12/kW

TOTAL PRECONSTRUCTION COST = \$5.69 million or \$2/kW

Delay Costs

Phase I Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase I.

Incorporating the 8% rate and the total cost of Phase I, the formula yields the annual financing costs at the end of Phase I:

0.08 x \$1.21M = \$0.10M/year
or \$0.10M/year/278,000kW = \$0.36/kW/year.

Land costs: Since no land is optioned at this point, no land delay costs would be incurred.

Staff retention costs: Since no staff would be required to remain on the project during the delay, no staff retention delay costs would be incurred.

Total Delay Cost After Phase I = \$0.10 million/year or \$0.36/kW/year

Phase II Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase II (Phase I costs + Phase II costs)

Incorporating the 8% rate and the costs of Phase I and Phase II, the formula yields the annual financing costs at the end of Phase II:

0.08/year x ($1.21M + $4.48M) = $0.46M/year
or $0.46M/year/278,000kW = $1.64/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs $5,000/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 350 acres of land is:

350 acres x $5,000/acre x 0.15/year = $0.26M/year
or $0.26M/year/278,000kW = $0.94/kW/year.

Staff retention costs: To calculate the staff retention costs, the formula is:

number of staff required to design a single-cycle combustion turbine unit x the percentage of retained staff x salary/year.

For a 75-MW single-cycle combustion turbine unit, 4 employees would be required.[39] An assumption was made that the staff requirements are proportional to the size of the plant. Since the two 139-MW units are 370% the size of the 75-MW unit, the staff levels would also be 370% greater or approximately 15 engineers. It was assumed that 50% would be retained.[40] The salary of engineers was estimated at $75,000 in 1989 dollars. The staff retention delay costs are:

15 persons x 0.50 x $75,000/year = $0.56M/year
or $0.56M/278,000kW = $2.01/kW.

Total Phase II delay cost: The total cost of delay at the end of Phase II is:

$0.46M/year + $0.26M/year + $0.56M = $1.28M/year
or $1.28M/year/278,000kW = $4.60/kW/year.

Total Delay Cost After Phase II = $1.28 million/year or $4.60/kW/year

B.9 420-MW COMBINED-CYCLE COMBUSTION TURBINE PLANT PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Preliminary Planning and Design

Costs:

The cost of Phase I is assumed to be 1.7% of the total cost of construction.[41] The total cost of construction is estimated by adding siting and permit acquisition costs to the cost of construction[42] and multiplying by the GNP deflator adjustment (1.04):

($620/kW + $6/kW) x 1.04 = $651/kW
or $651/kW x 420,000kW = $273.42M.

1.7% of the total cost is:

0.017 x $651/kW = $11.07/kW
or $11.07/kW x 420,000kW = $4.65M.

Total Phase I Cost = $4.65 million or $11.07/kW

Phase II:

Activities:

Acquisition of Site/Land Option
Permitting and Preparation of Environmental Documents
Detailed Engineering and Plant Design
Ordering Long-Lead-Time Equipment

Costs:

Acquisition of Site/Land Option: The assumptions used for calculating the site/land option costs are:

- amount of land optioned is 700 acres[43]
- land would be optioned for four and a half years at 15% of a market value of $5,000/acre.

Site/land option costs are:

700 acres x $5,000/acres x 15%/year x 4.5 years = $2.36M
or $2.36M/420,000kW = $5.62/kW .

Permitting and Preparation of Environmental documents: The cost of siting and permit acquisition, $6/kW,[44] is multiplied by the GNP deflator adjustment, 1.04, to escalate to 1989 dollars:

$6/kW x 1.04 = $6.24/kW
or $6.24/kW x 420,000kW = $2.62M.

Detailed Engineering and Design, and Ordering Long-Lead-Time Equipment: The cost of this activity is estimated to be 7.5% of the total cost of construction.[45] As mentioned earlier, the total cost of construction in 1989 is $651/kW. 7.5% of the total cost is:

0.075 x $651/kW = $48.83/kW
or $48.83/kW x 420,000kW = $20.51M.

Total Phase II Cost: The total cost for Phase II is the sum of the costs of each activity:

$2.36M + $2.62M + $20.51M = $25.49M
or $25.49M/420,000kW = $60.69/kW.

Total Phase II Cost = $25.49 million or $60.69/kW

TOTAL PRECONSTRUCTION COST = $30.14 million or $72/kW

Delay Costs

Phase I Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase I.

Incorporating the 8% rate and the total cost of Phase I, the formula yields the annual financing costs at the end of Phase I:

0.08 x $4.65M = $0.37M/year
or $0.37M/year/420,000kW = $0.88/kW/year.

Land costs: Since no land is optioned at this point, no land delay costs would be incurred.

Staff retention costs: Since no staff would be required to remain on the project during the delay, no staff retention delay costs would be incurred.

Total Delay Cost After Phase I = $0.37 million/year or $0.88/kW/year

Phase II Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase II (Phase I costs + Phase II costs).

Incorporating the 8% rate and the costs of Phase I and Phase II, the formula yields the annual financing costs at the end of Phase II:

0.08/year x ($4.65M + $25.49M) = $2.41M/year
or $2.41M/year/420,000kW = $5.74/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs $5,000/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 700 acres of land is:

700 acres x $5,000/acre x 0.15/year = $0.53M/year
or $0.53M/year/420,000kW = $1.26/kW/year.

Staff retention costs: To calculate the staff retention costs, the formula is:

number of staff required to design a combined-cycle combustion turbine plant x the percentage of retained staff x salary/year.

About 103 engineers were previously estimated to be required to design a 550-MW plant.[46] An assumption was made that the staff requirements are proportional to the size of the plant. Since a 420-MW plant is 76% the size of a 550-MW plant, the staff levels of the smaller plant would also be 76% of the larger plant. The staff requirements for a 420-MW plant would be approximately 80 engineers. The salary of engineers was estimated at $75,000 in 1989 dollars. The staff retention delay costs are:

80 persons x 0.50 x $75,000 = $3M/year
or $3M/420,000MW = $7.14/kW.

Total Phase II delay cost: The total cost of delay at the end of Phase II is:

$2.41M/year + $0.53M/year + $3M/year = $5.94M/year
or $5.94M/year/420,000kW = $14.14/kW/year.

Total Delay Cost After Phase II = $5.94 million/year or $14.14/kW/year

B.10 10-MW WOOD-PRODUCTS-BASED COGENERATION PLANT PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design
Power Contract Negotiations

Costs:

Costs for Phase I activities are assumed to be 0.5% of total plant costs:

0.005 x [$1410/kW[47] x 1.47 (GNP Deflator Adjustment)] = $10.36/kW or $104,000.

Total Phase I Cost = $104,000 or $10.36/kW

Phase II:

Activities:

Permitting and Preparation of Environmental Documents
Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

Costs for Phase II are assumed to be 8% of total plant costs:

0.08 x [$1410/kW[48] x 1.47 (GNP Deflator Adjustment)] = $165.82/kW or $165,820.

Total Phase II Cost = $1,658,200 or $166/kW or

TOTAL PRECONSTRUCTION COST = $1,761,800 or $177/kW

Delay Costs

Phase I Delay Costs

Financing: It is assumed that the cogeneration plant will be developed and built by the firm that owns the resource. The cost of capital for the developer is assumed to be 10%/year. Therefore, financing costs for Phase I are

0.10/year x \$10.36/kW = \$1.04/kW/year.

Land and Staff Retention Costs: Since it is assumed that the plant is built on land already owned by the industrial cogenerator, land delay costs are assumed to be zero. In addition, it is assumed that no staff will be retained at the end of either Phases.

Total Delay Cost After Phase I = \$1.04/kW/year

Phase II Delay Costs

Financing: Financing costs at the end of Phase II are the sum of Phase I and Phase II financing costs:

0.10/year x [\$10.36/kW (total Phase I costs) + \$165.82/kW (total Phase II costs)] = \$17.62/kW/year.

Total Delay Cost After Phase II = \$17.62/kW/year

B.11 10-MW NATURAL GAS COGENERATION PLANT PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design
Power Contract Negotiations

Costs:

The cost of Phase I is assumed to be the same as for the wood-products-based cogeneration plant calibrated with a time adjustment factor. The timeframe for a natural gas cogeneration plant is estimated to be 2.5 years; the timeframe for a wood-products-based cogeneration plant is estimated to be 3.25 years. Dividing 3.25 into 2.5 yields a time adjustment factor of 0.77. The cost for Phase I is:

\$10.4/kW x 0.77 = \$8/kW
or \$8/kW x 10,000kW = \$80,000.

Total Phase I Cost = \$80,000 or \$8/kW

Phase II:

Activities:

Permitting and Preparation of Environmental Documents
Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

The cost for ordering long-lead-time equipment is assumed to be minimal and is included in the cost of design.

The two other activities are assumed to be in the same proportion to each other as they are in the estimates for the natural gas single-cycle combustion turbine unit. The costs for permitting and design for the single-cycle combustion turbine unit are $5.2/kW and $8.7/kW, respectively, for a combined cost of $13.9/kW. Permitting accounts for 37% (5.2/13.9) of the cost of these activities, and design accounts for 63% (8.7/13.9) of the cost of these activities. These percentages are attributed to the cost of Phase II for a wood-products-based cogeneration plant. Detailed engineering requires no time adjustment; therefore, the cost for design is 63% of 166/kW, or:

0.63 x 166/kW = 105/kW.

The cost of permitting must be adjusted by a time adjustment factor. Since 2.5 years are required for permitting for a natural gas cogeneration plant and 3 years are required for a wood-products-based plant, the time adjustment factor is:

2.5/3 = 0.83.

The cost for permitting is:

($166/kW - $105/kW) x 0.83 = $51/kW.

Total Phase II Cost: The total cost for Phase II is the sum of the costs of each activity:

$105/kW + $51/kW = $156/kW
or $156/kW x 10,000kW = $1.56M

Total Phase II Cost = $1.56 million or $156/kW

TOTAL PRECONSTRUCTION COST = $1.64 million or $164/kW

Delay Costs

Phase I Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase I.

Incorporating the 10% rate and the total cost of Phase I, the formula yields the annual financing costs at the end of Phase I:

0.10 x \$80,000 = \$8,000/year
or \$8,000/year/10,000kW = \$0.8/kW/year.

Land costs: Since no land is optioned, no land delay costs would be incurred.

Staff retention costs: Since no staff would be required to remain on the project during the delay, no staff retention delay costs would be incurred.

Total Delay Cost After Phase I = \$8,000/year or \$0.8/kW/year

Phase II Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase II (Phase I costs + Phase II costs).

Incorporating the 10% rate and the costs of Phase I and Phase II, the formula yields the annual financing costs at the end of Phase II:

0.10/year x (\$80,000 + \$1.56M) = \$164,000/year
or \$164,000/year/10,000kW = \$16/kW/year.

Land Option Costs and Staff Retention Costs: Since it is assumed that the facility is built on land already owned by the industrial cogenerator, no land delay costs will be incurred. Also, it is assumed that no staff will be retained at the end of either Phase.

Total Delay Cost After Phase II = \$164,000/year or \$16/kW/year

B.12 420-MW COAL GASIFICATION COMBINED-CYCLE PLANT PRECONSTRUCTION AND DELAY COSTS

Preconstruction Costs

Phase I:

Activities:

Project Conceptualization
Resource Reconnaissance
Preliminary Planning and Design

Costs:

The cost of Phase I is assumed to be 2% of the total cost of construction.[49] The total cost of construction is estimated by adding siting and permit acquisition costs to the cost of construction[50] and multiplying by the GNP deflator adjustment (1.04):

(\$1,820/kW + \$38/kW) x 1.04 = \$1,932.32/kW
or \$1,932.32/kW x 420,000kW = \$811.57M.

Two percent of the total cost is:

0.02 x \$1,932.32/kW = \$38.65/kW
or \$38.65/kW x 420,000kW = \$16.23M.

Total Phase I Cost = \$16.23 million or \$38.65/kW

Phase II:

Activities:

Acquisition of Site/Land Option and Easements
Acquisition of Permits
Geotechnical Studies
Preparation of Environmental Documents

Costs:

Acquisition of Site/Land Option: The assumptions used for calculating the site/land option costs are:

- amount of land needed is 75% of that needed for a pulverized-coal-fired plant[51] or, 0.75 x 400 acres = 300 acres
- 10 times the amount of land needed would be optioned
- land would be optioned for four years at 15% of a market value of \$900/acre.

Site/land option costs are:

300 acres x 10 x \$900/acres x 15%/year x 4 years = \$1.62M
or \$1.62M/420,000kW = \$3.86/kW.

Easements: The cost of obtaining easements is estimated to be \$1.19 million.[52] Multiplying this figure by the GNP deflator adjustment, 1.11, the cost in 1989 dollars is:

\$1.19M x 1.11 = \$1.32M
or \$1.32M/420,000kW = \$3.14/kW.

Permitting: The cost of the permitting process is estimated to be \$0.47 million.[53] Multiplying this figure by the GNP deflator adjustment, 1.11, the cost in 1989 dollars is:

\$0.47M x 1.11 = \$0.52M
or \$0.52M/420,000kW = \$1.24/kW.

Geotechnical Studies: The estimated cost of conducting geotechnical studies ranges from \$0.56 million to \$0.78 million.[54] Multiplying these figures by the GNP deflator adjustment, 1.11, the range of costs in 1989 dollars is:

\$0.56M x 1.11 to \$0.78M x 1.11 = \$0.62M to \$0.87M.

The average of this range of values is:

(\$0.62M to \$0.87M)/2 = \$0.75M
or \$0.75M/420,000kW = \$1.79/kW.

Preparation of Environmental Documents: The cost of the environmental documentation process is estimated to be \$0.50 million for one year.[55] Multiplying this figure by the GNP deflator adjustment, 1.11, and by a time adjustment factor, 1.5, to account for the extended time allowance, the cost in 1989 dollars is:

\$0.50M x 1.11 x 1.5 = \$0.83M
or \$0.83M/420,000kW = \$1.98/kW.

Total Phase II Cost: The total cost for Phase II is the sum of the costs of each activity:

\$1.62M + \$1.32M + \$0.52M +\$0.75M + \$0.83M = \$5.04M
or \$5.04M/420,000kW = \$12/kW.

Total Phase II Cost = \$5.04 million or \$12/kW

Phase III:

Activities:

Detailed Engineering and Design
Ordering Long-Lead-Time Equipment

Costs:

The cost of the Phase III is estimated to be 6% of the total cost of construction.[56] The total cost of construction is estimated by adding siting and permit acquisiton costs to the cost of construction[57] and multiplying by the GNP deflator adjustment (1.04):

($1,820/kW + $38/kW) x 1.04 = $1,932.32/kW
or $1,932.32/kW x 420,000kW = $811.57M.

Six percent of the total cost is:

0.06 x $1,932.32/kW = $116/kW
or $116/kW x 420,000kW = $48.72M.

Total Phase III Cost = $48.72 million or $116/kW

TOTAL PRECONSTRUCTION COST = $70 million or $167/kW

Delay Costs

Phase I Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase I.

Incorporating the 8% rate and the total cost of Phase I, the formula yields the annual financing costs at the end of Phase I:

0.08 x $16.23M = $1.3M/year
or $1.3M/year/420,000kW = $3.1/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs $900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 3,000 acres of land is:

3,000 acres x $900/acre x 0.15/year = $0.41M/year
or $0.41M/year/420,000kW = $0.98/kW/year.

Staff retention costs: Since no staff are assumed to be required to remain on the project during the delay, no staff retention delay costs would be incurred.

Total Phase I delay costs: The total cost of delay at the end of Phase I is:

\$1.3M/year + \$0.41M/year = \$1.71M/year
or \$1.71M/year/420,000kW = \$4.07/kW/year.

Total Delay Cost After Phase I = \$1.71 million/year or \$4.07/kW/year

Phase II Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase II (Phase I costs + Phase II costs).

Incorporating the 8% rate and the costs of Phase I and Phase II, the formula yields the annual financing costs at the end of Phase II:

0.08/year x (\$16.23M + \$5.04M) = \$1.7M/year
or \$1.7M/year/420,000kW = \$4.05/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs \$900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 3,000 acres of land is:

3,000 acres x \$900/acre x 0.15/year = \$0.41M/year
or \$0.41M/year/420,000kW = \$0.98/kW/year.

Staff retention costs: Since no staff are assumed to be required to remain on the project during the delay, no staff retention delay costs would be incurred.

Total Phase II delay cost: The total cost of delay at the end of Phase II is:

\$1.7M/year + \$0.41M/year = \$2.11M/year
or \$2.11M/year/420,000kW = \$5.02/kW/year.

Total Delay Cost After Phase II = \$2.11 million/year or \$5.02/kW/year

Phase III Delay Costs

Financing costs: The formula used to calculate the financing cost is: IOU real financing rate x total cost through Phase III (Phase I costs + Phase II costs + Phase III costs).

Incorporating the 8% rate and the total cost through Phase III, the formula yields the annual financing costs at the end of Phase III:

0.08/year x (\$16.23M + \$5.04M + \$48.72M) = \$5.6M/year
or \$5.6M/year/420,000kW = \$13.3/kW/year.

Land option costs: The formula used to calculate the land option cost is:

acres x price/acre x market value/year.

Assuming land costs \$900/acre and land option costs are assessed at 15% of market value, the annual cost for optioning 3,000 acres of land is:

3,000 acres x \$900/acre x 0.15/year = \$0.41M/year
or \$0.41M/year/420,000kW = \$0.98/kW/year.

Staff retention costs: The figures in the PNL report show that for a gasification plant the staff retention costs at the end of the design engineering phase are 1.4 times higher than that of a pulverized-coal-fired plant. The two plants in the PNL report were of the same capacity size. Therefore, total costs rather than costs per kilowatt are used to estimate staff retention delay costs since the plants in this report are of different sizes. The calculation is:

Pulverized-coal-fired plant staff retention costs x 1.4.

\$3.75M x 1.4 = \$5.25M
or \$5.25M/420,000 = \$12.5/kW.

Total Phase III delay cost: The total cost of delay at the end of Phase III is:

\$5.6M/year + \$0.41M/year + \$5.25M/year = \$11.26M/year
or \$11.26M/year/420,000kW = \$26.81/kW/year.

Total Delay Cost After Phase III = \$11.26 M/year or \$26.81/kW/year

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