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PURPA Resource Development in the Pacific Northwest

Case Studies of Ten Electricity Generating Powerplants

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Preface

This document is the second of three related studies that were completed to assist the Bonneville Power Administration in the development of its Generating Resources Acquisitions process.

The first study addresses the effectiveness of the PURPA acquisition approach within each Northwest state. It considers enabling authority, financial incentive, and required environmental protection legislation; summarizes resource development activities; and lists power purchase prices and contractual provisions. In addition, generating resources and emerging activities such as least cost planning and competitive bidding are examined.

The case studies in this document describe the PURPA development process for a variety of generating technologies. Developer interactions with regulatory agencies and power purchasers are described in some detail. Equipment, installation, and maintenance costs are identified; power marketing considerations are taken into account; and potential environmental impacts, with corresponding mitigation approaches and practices are summarized. The project development case studies were prepared by the energy agencies of the four Northwest states, under contract to the Bonneville Power Administration.

The third study examines competitive bidding policies and resource acquisition procedures used outside of the Northwest. This study resulted in a joint Oregon Department of Energy/Washington State Energy Office staff issue paper that examines resource acquisition goals and objectives, illustrates competitive bidding program issues and choices, and makes recommendations regarding the structuring of a Northwest competitive resource acquisition program.

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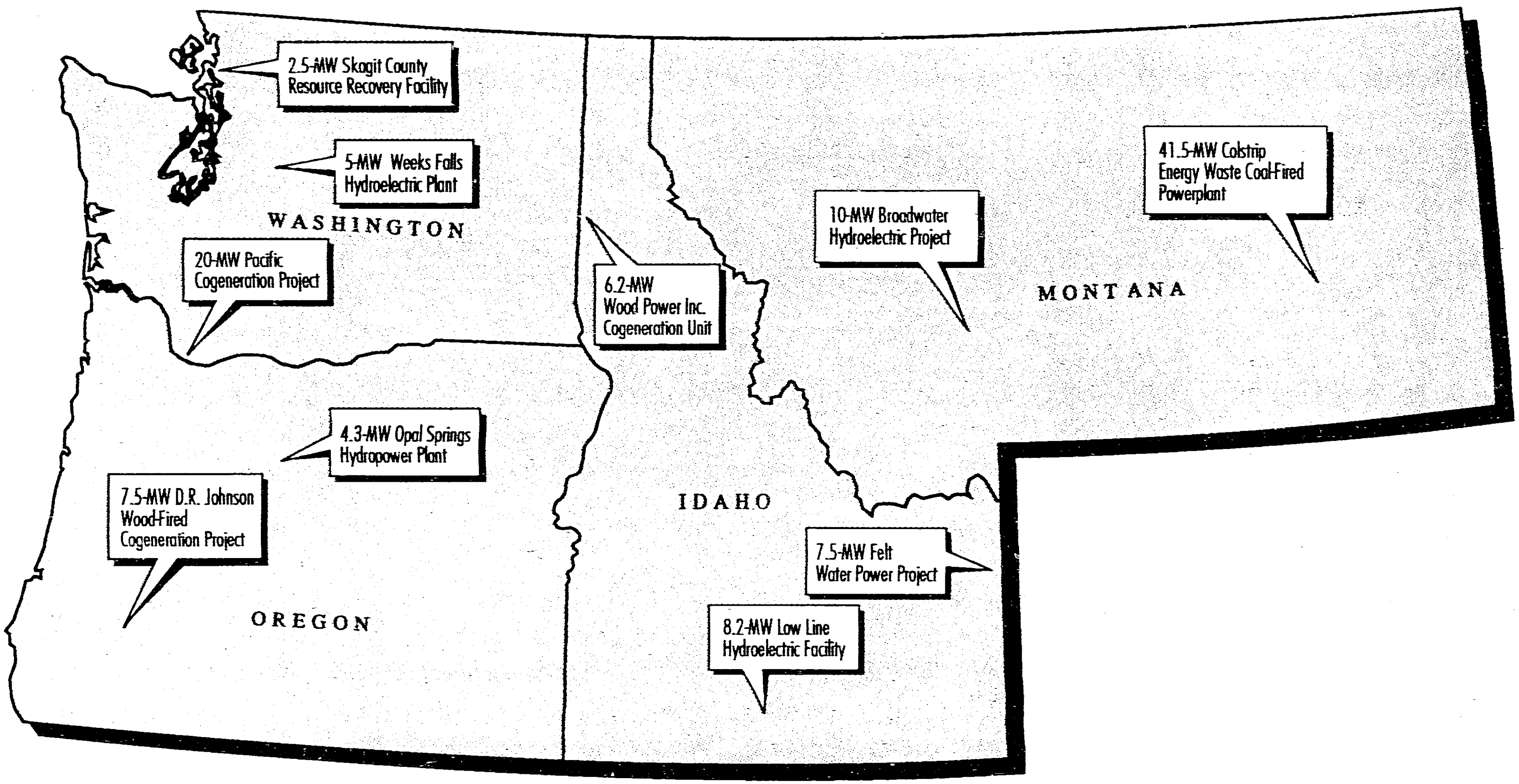
CASE STUDY LOCATIONS



Executive Summary of Case Studies

Introduction

This document contains ten cogeneration and renewable resource development case studies. The case studies document the development process and summarize the lessons learned for generating projects that were sited and licensed and came on-line in the Northwest region during the PURPA environment of the 1980s. The ten projects, summarized below in Table S-1, have a total generating capacity of 111.5 MW and an aggregate installed cost exceeding $205 million; they annually produce more than 747 million kWh of electrical energy.

Technologies for which case studies were prepared include municipal solid waste and waste coal energy projects, biomass and gas-fired cogeneration facilities, and hydropower plants. The hydroelectric sites considered range from new high head run-of-the-river projects to irrigation drop structure units, water supply applications, and expansions of existing facilities or the installation of generating equipment at an existing dam.

The case studies examine developer organizational structures; agreements with steam-using host facilities and site owners; project licensing and permitting requirements; anticipated environmental impacts and the incorporation of mitigation strategies into project design and operation; financing and risk minimization issues; unanticipated occurrences; and utility power purchase agreements.

The case studies demonstrate that non-utility producers, once they identify their site, settle on a design, and obtain credible backing, can readily build cost-effective and environmentally acceptable generating facilities that can contribute to meeting Northwest energy needs.

Table S-1
PURPA Case Studies

Project Name	Capacity (MW)	Cost (Millions)	Annual Energy Output (kWh, Millions)
1. Skagit County Resource Recovery Facility	2.5	13.0	13.1
2. PACCO/Great Western Malting Cogeneration	20.4	12.6	176.5
3. Weeks Falls Hydroelectric Facility	5.0	7.7	18.0
4. D.R. Johnson Lumber Company (Co-Gen II)	7.5	8.4	63.0
5. Opal Springs Hydropower Plant	4.3	14.3	23.0
6. Felt Water Power Project	6.3	8.4	34.7
7. Low Line Hydroelectric	8.0	13.3	46.8
8. Wood Power, Inc. Cogeneration Plant	6.2	5.1	42.0
9. Broadwater Dam	10.0	25.3	62.0
10. Colstrip Waste Coal Generating Station	41.5	97.1	261.0
Totals:	111.5	$205.2	747.2

2.5-MW Skagit County Resource Recovery Facility Skagit County, Washington

The 178-ton-per-day (tpd) Skagit County resource recovery facility consists of two rotary kiln incinerators, two waste heat recovery boilers, two filter bag house and acid gas scrubber trains, and a 2.5-MW turbine generator set. Electricity produced is sold to Puget Power at a 20-year fixed price of 49 mills/kWh. The $13 million facility came on-line in July of 1988 and is expected to produce 13.1 million kWh of electrical energy annually. The refuse tipping fee is $35/ton.

This case study emphasizes the risk minimization techniques employed by Skagit County in its relationships with Wright Schuchart Harbor, the design, build, and operate contractor. The County's consultant developed a risk matrix and assigned probabilities and expected costs to possible outcomes. The County then decided whether to assume the risk, obtain insurance, or compensate its contractor for undertaking the risk.

The County protected its interests through an array of on-line dates, performance guarantees, acceptance testing protocols, monitoring requirements, and liquidated damages clauses. The facility must meet guaranteed standards for minimum waste throughput, plant availability, incinerator rating, steam raising, waste reduction, turbine/generator performance, energy consumption, and emissions.

Some unexpected difficulties still occurred. Fly ash samples failed the EPA toxicity tests because of spikes in lead concentration. For a time, plant operators were required to cast their fly ash into concrete blocks, incurring an unanticipated operating cost of $365,000. As the expected annual revenues from electricity sales are only $645,400, effects on project economics were dramatic. This requirement was waived when the County established a flashlight and automotive battery rebate and recycling program.

Pacific Cogeneration / Great Western Malting 20-MW Gas Fired Cogeneration Facility Vancouver, Washington

The 20.4-MW Pacific Cogeneration (PACCO) facility came on-line in Vancouver, Washington in December 1982. The facility includes a GE-LM-2500 combustion turbine, a waste heat recovery boiler, and three circulating water pumps. Recovered heat is used to dry malt in three kilns operated by Great Western Malting (GWM). Total cost of the project was approximately $8.9 million, with an additional $3.7 million required for backup/peaking boilers, circulating water pumps and piping, and kiln water-to-air heat exchangers.

All electrical output from the facility is purchased by Clark County PUD. Under an agreement negotiated when the WPPSS nuclear projects were used to determine avoided costs, the utility reimburses PACCO for all costs associated with installing, maintaining, and operating the cogeneration facility, and in addition provides a guaranteed rate of return of 9 percent on the initial investment. Waste heat is supplied at no cost to GWM in quantities adequate to supply about 85 percent of the host facility's thermal load. This arrangement allows GWM to reduce its operating costs while assuming absolutely no risk.

As the combustion turbine uses in excess of 18 million therms per year of natural gas, obtaining a reliable and low-cost source of fuel is essential. Gas for the combustion turbine is purchased by GWM under an interruptible schedule for 16 cents/therm at the Northwest Pipeline gate station. Northwest Natural Gas (NWNG) then assesses a 7 cent/therm transport charge in the summer, increasing to 9 cents/therm in the winter. Ironically, when the project was built, PACCO paid $450,000 to install a 3.5-mile-long, 6-inch-diameter, high-pressure gas transmission line. Such direct access to 350-psi gas offsets the need to install and maintain a 1,500-hp gas compressor. PACCO then deeded the line over to the gas utility. PACCO is now negotiating with the gas utility to decrease its transportation charges. It is cost effective for PACCO to install a new bypass pipeline if the transport rate is not reduced to 2.5 - 2.7 cents/therm.

PACCO increases the value of the electrical energy produced by scheduling hot section and major overhauls during the summer. Monthly outages of approximately 4 hours for compressor blade washing are also scheduled during nonpeak periods. Operators are experimenting with different wash cycles in an attempt to optimize the tradeoff between improved efficiency and increased outage time. A new procedure allows the operators to do every other wash while the unit is operating.

5-MW Weeks Falls Run-of-River Hydroelectric Facility North Bend, Washington

The 5-MW run-of-river Weeks Falls hydropower project came on-line in May of 1987. The $7.7 million project, built by private developers on the South Fork of the Snoqualmie River near North Bend, Washington, is expected to produce 18 million kWh of electrical energy annually. Electricity from the remotely operated and unattended project is purchased by Puget Power at a levelized price of 75 mills/kWh over a 35-year period.

A number of features were incorporated into the project design to minimize both environmental and aesthetic impacts, including the following:

Provision of an inflatable rubber diversion weir to maintain a constant water surface elevation (and head on the turbines of 89 feet) and provide an instream flow of 38 cfs over an 850-foot bypass reach.

- Installing 14 traveling-belt fish screens with differential water level monitors. Costing $1 million, the screens have a 0.5 feet/second approach velocity limitation to prevent resident fish from entering the power plant penstock.

- Incorporation of a permanently open outlet pipe in the diversion weir to facilitate bedload passage.

- Establishing ramping rate limitations and designing the intake structure with sufficient submergence to prevent vortices, air entrainment, and consequent nitrogen supersaturation.

- Racking the tailrace outlet to prevent resident adult fish from entering the powerhouse and providing a maximum water velocity leaving the tailrace to prevent scouring of the river bank and bottom.

- Revegetation of disturbed streamside areas and use of erosion control methods such as drainage controls, settling ponds, and sediment disposal.

- Scheduling major construction events to avoid impacts on incubating or spawning trout.

- Burying the 3,800-foot-long, 34.5-kV transmission line to maintain aesthetics and protect raptors; redesign of the powerhouse to render it visually attractive; burial of the intake structure; and relocation of the powerhouse to physically separate it from the falls.

- Providing recreational amenities including a hiking trail, fisherman access routes handicapped parking, and a falls overlook.

An interesting security requirements clause in the power purchase contract stipulates that South Fork II (the project developer) provide an amount of energy in the second half of the project's operating period which is at least equal to that provided in the first half. If an inadequate amount of electricity is provided, the utility may, at its option, extend the operating period. This clause is designed to ensure that Puget's ratepayers will enjoy the full benefits of securing a long-term supply of energy at a fixed price.

D.R. Johnson Lumber Company (CO-GEN II) 7.5-MW Wood-Fired Cogeneration Plant Riddle, Oregon

In 1987, the D.R. Johnson Lumber Company completed a 7.5-MW wood-fired topping cycle cogeneration facility in Riddle, Oregon. Electrical generation from the $8.4 million project is sold to Pacific Power & Light under a 20-year contract (signed in September 1983). Approximately 63 million kWh/year should be produced at design conditions. The developer receives a capacity payment of $7.57/kW/month and an escalating energy payment, equal to 7.0 cents/kWh in 1990. Extraction steam is used in kiln dryers at the lumber mill.

Annual hog fuel needs are 76,000 bone dry tons. Fuel supplies are valued at $15/bone dry ton delivered to the power plant. The Johnson mill in Riddle contributes about 20,000 tons/year while an additional 18,000 tons of chips and shavings are produced by the company. A mill expansion scheduled for 1990 should result in waste streams adequate to supply the entire needs of the cogeneration plant.

Johnson Lumber Company obtained one federal, four state, and six local permits for its project. Oregon Public Utility Commission approval of the power purchase agreement was also obtained. The company additionally received an Oregon Business Energy Tax Credit for 35 percent of the cost of qualifying energy equipment. This tax credit is spread out over 5 years.

Because of its high bark content, hog fuel is not a good fiber feedstock and traditionally has been landfilled or burned in "teepee" burners with no pollution controls. Cogeneration provides efficient solid waste disposal and controls combustion emissions. The CO-GEN II project design includes exhaust gas recirculation and a multiclone for particulate control. Because the plant emits less than 250 tons/year of particulates, carbon monoxide, nitrogen oxides, volatile organic compounds, or sulfur dioxide, it is exempt from conducting an air quality analysis of pollutants, and is exempt from New Source Performance Standards and Hazardous Air Contamination Procedures review.

Fuel, operating, and maintenance costs are expected to amount to $2 million annually. Plant labor costs are based on 16 new, full-time positions, including 10 operations staff, 5 maintenance personnel, and one supervisor.

4.3-MW Opal Springs Hydropower Plant Madras, Oregon

In January, 1985, the Deschutes Valley Water District (DVWD) began commercial operation of a 4.3-MW hydroelectric project located near Madras, Oregon. Before construction of the project, the DVWD diverted water from the Crooked River to drive hydraulic pumps. The $14.3 million power project consists of raising an existing diversion dam from 6 to 10 feet in height; installing two 12.5-foot-diameter, 1,200-foot-long conduits; and providing a 175-foot-long penstock capable of delivering 1,500 cubic foot per second to the powerhouse at a rated head of 40 feet. The powerhouse contains a 4.3-MW turbine/generator set with appropriate control equipment and switchgear.

The expected annual electrical production of 23 million kWh is sold to Pacific Power. The 36-year contract, negotiated in 1982, calls for a fixed capacity payment of $8.21 per kilowatt per month and a partially levelized energy payment. The 1990 energy payment is 7.24 cents/kWh.

DVWD financed the Opal Springs powerplant using the Oregon Small Scale Energy Loan Program (SELP). SELP allows the developer to finance the project using no equity and 100 percent debt. Debt financing was thus a 30-year loan at 10.25 percent, reflecting the tax-exempt market rate in 1983. Annual operating and maintenance charges, less pumping expenses, are expected to be $180,000.

The DVWD obtained six federal, three state, and two local permits for the project. It was estimated that negotiating the power sales contract cost about $71,000. In addition to the permits, DVWD signed an agreement with the Oregon Department of Fish and Wildlife to maintain a minimum instream flow of 50 cubic feet per second in the bypass reach, determine fish mortality caused by plant operations, compensate for fish losses, and provide habitat enhancement as mitigation for fish mortality not replaced.

7.5-MW Felt Water Power Project Tetonia, Idaho

The Felt project is located near Tetonia, Idaho, at the site of an existing dam and powerhouse. The development consists of the refurbishment of an existing generating station to upgrade its capacity from 1,220 to 2,000 kW, and construction of a new 5.5-MW powerplant. The annual average electrical generation of 31.6 million kWh is sold to the Utah Power and Light (UP&L) Company under a 35-year agreement.

The rates paid for the purchase of energy are composed of a fixed component (4.049 cents/kWh) and a variable rate of approximately 1.4 cents/kWh, which is updated annually to reflect the current average price of coal purchased by UP&L. The total installed cost of the Felt project was $12 million while the expected annual running cost, including debt service, operation and maintenance expenses, site lease, and taxes, is $1.46 million.

The original FERC preliminary permit for the project was filed by Fall River Rural Electric Cooperative. Fall River subsequently hired a consultant and submitted a license application. After the license was obtained, the cooperative sought a developer to construct, operate, finance, and maintain the proposed hydropower project. Bonneville Pacific was ultimately selected and the FERC license was amended to recognize Hydro Valley Development, a wholly owned subsidiary of Bonneville Pacific, and the cooperative as co-licensees. Fall River leased all lands, water rights, and other project interests to Bonneville Pacific for a duration of 35 years. In return, Bonneville Pacific agreed to pay Fall River the following sums:

- $300,000 for land and water rights
- $200,000 upon award of a joint license
- $250,000 upon execution of a power sales contract
- $88,000 upon commencement of power productions

The greater of $110,000 or 3.12 mills/kWh of net generation for the first 10 years plus $15,337 for existing facility rental. The annual payment increases in stepped increments through the 35 years of operation.

Bonneville Pacific was entitled to receive all federal and state tax benefits and was obligated to cover tax liability and annual permit fees in addition to assuming responsibility for project operation and maintenance. Bonneville Pacific was entitled to assign its interests in the project and subsequently sold its subsidiary (Hydro Valley Development) to CDM Hydroelectric, a limited partnership, for $12.2 million.

Environmental impact mitigation measures designed to protect and enhance the resident fisheries resource included seasonally varying minimum instream flow requirements to maintain habitat and allow upstream migration during the spawning season; construction of a fish ladder; and $60,000 for raceway construction plus an annual payment of $18,400 per year for rearing of trout to compensate for lost wild trout production.

The Felt project was constructed under a fixed price or turn-key contract with risks minimized through incorporation of acceptance testing procedures and performance guarantees.

8.2-MW Low Line Hydroelectric Project
Hansen, Idaho

The Low Line project makes use of a natural drop of 95 feet as water is diverted from the Twin Falls main canal into the Low Line. The $13.28 million turn-key project, which came on- line in March 1985, consists of a diversion structure, a 2,200-foot-long, 12-foot-diameter pipeline, and a powerhouse containing two vertical Francis turbines rated at 4.1 MW each. Using irrigation water, the project is expected to produce 46.8 million kWh/year during its 7-month operating season. A 4.5-mile-long, 69-kV transmission line connects the facility substation with the utility grid.

The site is leased by Twin Falls Canal Company to the Bonneville Pacific Corporation for 35 years. Bonneville Pacific constructed, operates, and maintains the project and compensates the Canal Company with an initial payment of $355,000 plus 10 percent of the project's gross annual income for the first 10 years of the agreement, increasing to 40 percent for the second 10 years and 80 percent thereafter.

The plant can be operated manually at the site or automatically with a programmable controller. Annual operating costs are estimated at $2.6 million. Under a 35-year firm energy contract, Idaho Power pays a levelized or fixed price of 7.33 cents/kWh in December-February and June-August, declining to 4.89 cents/kWh in March-May and September-November. A variable payment, subject to change by the Idaho Public Utilities Commission, of 0.54 to 0.8 cents/kWh is also awarded. In the event of a cessation of energy deliveries prior to the end of the agreed-upon period, Bonneville Pacific must pay a lump sum repayment equal to a time-variant $/MWh charge multiplied by the difference in megawatt-hours between the contracted annual net energy amount and the quantity of energy actually produced.

As the Low Line project makes use of a manmade water conveyance system, it was eligible to receive a conduit exemption from FERC's hydroelectric project licensing requirements. Environmental impacts from project construction and operation are minimal. As the canal is dry some months of the year, it does not support a fisheries population. Recreation and wildlife uses are minimal, with the only mitigation requirement being that the electrical transmission system be planned and constructed to prevent possible electrocution of raptors. Most of the land disturbed was agricultural.

Measures taken to preserve the aesthetic values at the site and promote safety include construction of an attractive brick powerhouse, paving the road and powerhouse parking area, planting grass, burying the penstock, and providing fencing around the electrical substation. The facility's surge tower was also painted with unobtrusive colors and is designed to somewhat resemble a large grain silo.

Wood Power Inc.
6.2-MW Wood Waste-Fired Cogeneration Plant
Plummer, Idaho

In 1984, Wood Power Inc. built a 6.2-MW wood waste-fired cogeneration plant on property adjacent to the Pacific Crown Timber Products Sawmill. The $5.16 million project was constructed almost entirely with used equipment by Yanke Energy of Boise, Idaho.

The turn-key project consists of a fuel storage building, fuel handling equipment, a hog fuel boiler, and a steam turbine coupled to an electrical generator. Wood Power trades process steam to the Pacific Crown sawmill in return for waste wood fuel. Pacific Crown uses the steam and waste heat in its kiln to dry lumber products.

Wood Power consumes approximately 80,000 tons of hog fuel each year, is on-line an average of 92 percent of the time, and delivers about 42 million kWh/year of electrical energy to a Washington Water Power (WWP) substation. Wood Power annually purchases an average of 5.79 million kWh of electricity at an average price of 3.65 cents/kWh from the city of Plummer to operate the cogeneration plant, while WWP pays Wood Power the equivalent of 5.36 cents/kWh for energy and capacity produced. It is thus in Wood Powers' interest to purchase electricity rather than use the electricity it generates to run the plant.

Under its power sales agreement, Wood Power receives a capacity payment of $307/kW-year plus a seasonally varying energy rate that varies between 0.7 and 1.4 cents/kWh. Energy deliveries in excess of 39.42 million kWh receive only the energy portion of the payment. Twenty days of downtime are scheduled each year for maintenance and repair.

Wood power was originally equipped with two multi-cyclones. They proved to be inadequate and the project was cited for opacity violations by the Idaho Air Quality Bureau. Corrective actions included redesigning the combustion air control system to limit particulate carryover, installing additional overfire air injectors, installing an improved combustion chamber refractory, and constructing a covered fuel storage area to reduce fuel moisture content. Ultimately, a wet scrubber system was installed.

Ash is disposed of in a settling pond located on the Coeur d'Alene Indian Reservation. The EPA is now examining regulations pertaining to the disposal of municipal solid waste incinerator ash. To the extent that these guidelines may apply to wood ash residues, the cost of disposal may increase.

A major problem associated with operating a cogeneration plant built with used equipment is repair or replacement of broken parts. To reduce down times, Wood Power has obtained a spare turbine generator set. While operators of the cogeneration plant have encountered some problems, the economic and employment benefits to the community have justified the risks. The cogeneration plant has made the sawmill a stabler and sounder business. While other mills in the vicinity have shut down, Pacific Crown continues to grow.

10-MW Broadwater Hydroelectric Project
Toston, Montana

The Broadwater Hydroelectric Project, dedicated in September 1989, is a 10-MW run-of-river hydroelectric plant added to an existing irrigation dam on the Missouri River. The $25.3 million project was built by the Montana Department of Natural Resources and Conservation (DNRC) and is expected to produce 62 million kWh annually. The project was financed primarily with variable-rate tax-exempt revenue bonds backed by Montana's coal severance tax receipts.

The Broadwater project's development process was complicated, stretching almost 13 years from conception to completion. DNRC entered hydroelectric development to generate funds to repair or rehabilitate other DNRC-managed dams that did not meet current design and safety standards.

In 1977, DNRC retained an engineering firm to perform feasibility studies at Broadwater Dam, Deadman's Basin, and Painted Rocks Reservoir. All three sites were found to be suitable for cost-effective generating projects. DNRC and the Vigilante Electric Cooperative submitted competing preliminary permit applications to the FERC for Broadwater, with DNRC ultimately receiving the permit because of the preference it received as a municipality. The cooperative had a bill introduced in the 1979 state legislature to prohibit DNRC from building or operating generation projects on state-owned dams. The bill passed, but was vetoed by the governor, and efforts to override were narrowly defeated.

Subsequent legislation in 1981 authorized DNRC to construct and operate small hydroelectric facilities only after offering the site for lease. DNRC ultimately took nearly 2 years to prepare a leasing request for proposals, released in 1984. Only one proposal, an offer to negotiate a lease, was received. Since this offer was not responsive to the request, it was rejected. DNRC then prepared to build the project itself, but delayed in the face of economic factors such as declining avoided costs, higher interest rates, and increases in the projected equipment and construction costs, which threatened the project's feasibility.

DNRC began construction at Broadwater late in 1987, but was beset by numerous problems, due in part to the tight schedule, change orders, and DNRC's limited project management experience. Private developers continued to seek control of the project, even after construction began, but failed to make offers that clearly provided DNRC an adequate return for the value of the project.

Earlier in 1987, DNRC had negotiated a 35-year power purchase agreement with Montana Power Company, with levelized capacity payments ($15.11 per kilowatt in the winter and $8.34 per kilowatt in the summer) and an escalating energy payment. DNRC estimates an average first-year value to be 37.4 mills/kWh. DNRC had declined to sign a contract when higher rates were available earlier, believing that those rates overstated avoided costs and therefore effectively required ratepayers to subsidize QF developers.

A major environmental issue was the potential effect of the project on fisheries. Incorporating fish passage at the dam was rejected as it would provide access for unwanted predatory fish (such as northern pike and walleye) to the upper Missouri basin. Instead, DNRC allocated $394,000 to improve trout spawning habitat below the dam. This improvement in the downstream fishery was intended to mitigate any losses caused by the hydroelectric project. A 10-acre emergent vegetation pond and three acres of waterfowl nesting islands were provided as mitigation to offset the acreage flooded when the project raised the highest pool elevation by 1.6 feet and maintained a stable reservoir level year round. The FERC license also required recreational improvements, excavation and mapping of a historic site, and some other archaeological and historic preservation work.

The site required minimal alteration to protect adjacent structures. DNRC built an earthen dike to protect Montana Rail Link tracks from potential ice damage caused by the higher winter reservoir levels. DNRC also contributed funds used to raise the floor of a Bureau of Reclamation pumping station, located about one mile upstream of the dam, out of danger of flooding.

Many lessons were learned from this project. Fast-track projects, multiple prime contractors, and inexperienced project management should be avoided. Public agencies respond to their constituencies and to public oversight, even when it hurts their project's economic feasibility. And lastly, outside parties, private and public, will use government regulations to extract environmental and financial concessions from the developer.

41.5-MW Colstrip Waste-Coal-Fired Generation Facility Colstrip, Montana

With commercial operation scheduled for June, 1990, Colstrip Energy Limited Partnership is nearing completion of a 35-MW net waste-coal-to-energy plant located near Colstrip, Montana. The facility is expected to have an 85 percent capacity factor and produce 261 million kWh annually. The project will be fueled with approximately 223,000 tons per year of culm, a high-sulfur waste coal, from the Western Energy Company's Rosebud mine. Combustion will occur in a circulating fluidized bed boiler to produce superheated steam for a condensing turbine, which in turn will drive a synchronous generator. Waste limestone will be added to the fluidized bed to control sulfur dioxide emissions. The plant was designed to be a cogeneration facility, producing liquid fuels from coal in addition to power. The liquefaction portion of the project has been placed on indefinite hold.

Colstrip Energy Limited Partnership consists of Rosebud Energy Corporation, Harrier Power Corporation (a subsidiary of Pacific Gas and Electric Enterprises), and Spruce Limited Partnership (an affiliate of Bechtel Construction Company). Day-to-day operation and maintenance services will be provided under a contract with UC Operating Services, a partnership between subsidiaries of Baltimore Gas and Electric Company and the Hadson Corporation.

The $97.1 million project is financed primarily by tax-exempt Resource Recovery Revenue Bonds issued by the Montana Board of Investments. A levelized power purchase contract was negotiated with Montana Power in October of 1984. Montana Power offered to buy out the project contract in 1988. This offer was refused and the contract was renegotiated. Colstrip Energy agreed to take lower rates during the first 15 years of project operation, with a first-year rate of approximately 46 mills/kWh. After that, annual escalation rates would reflect inflation. Colstrip Energy paid $205,000 to provide automatic trip relay protection, telemetry, and metering equipment necessary to interconnect with a nearby 115-kV Montana Power transmission line.

Air quality was the environmental issue that aroused the most public controversy. Local residents and public interest groups, worried about air pollution, ash disposal, and trucking the waste coal to the powerplant, demanded that the state conduct an EIS. Local businesses and workers supported the project, citing job and economic benefits. The Department of Health and Environmental Sciences issued a permit in September 1985. The permit was appealed, but the State Board of Health ruled that an EIS would not be necessary and the permit would stand.

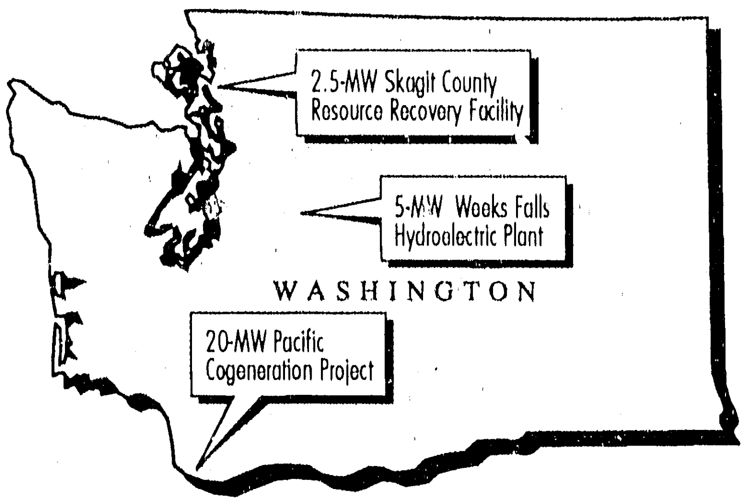
Annual significant pollutant emission limitations based upon best available control technology are:

Pollutant	**Emissions, tons/year**	
SO_2	1,840	@ 3 percent sulfur in fuel
NO_x	1,435	
Particulates	27	
Carbon monoxide	232	

While the public was more vocal about the air quality issue, the developers were more concerned about the Montana Groundwater Pollution Control permit. They didn't seriously pursue this permit until 1988, as they were making final arrangements for financing. Lenders were reluctant to commit to a project that might be caught up in regulatory delay. The state informally told the developers that no problems in issuing the permit were anticipated. Once the developers actually applied, the permit was quickly granted in January 1989.

Overall, state environmental review was expeditious. The developers reduced many potential environmental impacts through site selection and project design modifications. The Colstrip case study demonstrates that non-utility producers, once they settle on a practical design and obtain credible backing, can readily build facilities to supply energy to the utility system.

WASHINGTON CASE STUDIES



Chapter 1

2.5-MW Skagit County Resource Recovery Facility Skagit County, Washington

Project Description

The 178-ton-per-day (tpd) Skagit County Resource Recovery Facility began operation in July 1988. Located on March Point north of State Route 20 in Skagit County, Washington, the municipal solid waste-to-energy facility comprises a tipping floor and refuse storage pit, crane and fuel feed systems, two 89-tpd Technitalia rotary kiln incinerators, two Zurn waste heat recovery boilers (which produce 39,200 pounds per hour of 450-psig saturated steam), a 2.5-MW turbine/generator set and associated switchgear, two filter bag house and acid gas scrubber emission control units, and a fly ash conditioning system. Total construction cost for the project was $13 million. The County sells electricity produced by the facility to Puget Sound Power and Light Company (PSP&L) under a 20-year agreement for Firm Power Purchase.

Alternatives Considered

The Skagit County Solid Waste Management Plan, 1981 Update, and the more recent 1985 Update called for incineration as the preferred disposal alternative for county-wide domestic and commercial waste. (The plan also recommended establishment of a recycling program.) The County examined incineration only, incineration with steam sales, cogeneration with steam sales to a host facility, and electricity production disposal alternatives.

The County sent a questionnaire to all industrial facilities adjacent to potential project sites and approached representatives of the Shell and Texaco petroleum refineries. The refineries were not suitable as host facilities because the proposed waste-to-energy facility would be capable of providing only a small portion of their steam requirements. The County also examined the possibility of steam sales to the PSP&L, with PSP&L supplying and owning all electrical generating equipment; and it explored opportunities for supplying steam to the Smith and Ardussi Sulfur Prilling plant. Although steam sales were seriously pursued (revenues from steam sales could result in a $4/ton reduction in tipping fees when compared to an incineration only baseline), contract negotiations proved difficult.

While the Smith and Ardussi plant steam requirements, in particular, provided a good match with the Resource Recovery Facility's thermal output, in order to obtain financing the County required long-term assurances that the plant would remain in business and exhibit a constant steam demand. Smith and Ardussi could not offer that degree of assurance over the life of the proposed waste-to-energy facility. After a "long and agonizing process," the County decided that steam sales were not feasible. Direct electrical production with power sales to the serving utility offered the safest financing path and provided the security necessary for the County to proceed with the project.

Project Milestones

The County identified the following eight milestones associated with its development of a waste-to-energy facility:

1. Approval of the County's Solid Waste Management Plan by the Washington State Department of Ecology (WDOE).

2. Selection of a qualified consultant (R.W. Beck and Associates)

3. Procurement of financing. With Referendum 39 funding, WDOE offered 50 percent matching funding for feasibility studies, licensing, and construction of waste-to-energy projects. The County submitted a WDOE funding application (the project was considered financially impossible without WDOE grant approval). Skagit County has estimated that the 50 percent matching grant allows the tipping fee, which is required to offset disposal operation and maintenance expenses and debt service, to be reduced from $49.50 to $35 per ton.

4. Negotiation of an energy sales contract. The County signed a 20-year agreement for firm power purchase with PSP&L at a levelized price of 49 mills/kWh.

5. Obtaining environmental and operating permits.

6. Issuance of a request for proposals (RFP) and contractor selection. Skagit County elected to select a single contractor (Wright Schuchart Harbor Co. [WSH]) to design, build, and operate the waste-to-energy project.

7. Project testing, commissioning, and acceptance.

8. Negotiation of outstanding claims.

Fuel Supply Availability and Security

Under Washington State law, counties are charged with the disposal of solid waste. Cities, however, are not obligated to make use of the counties' services. Skagit County has assured its waste stream by signing Interlocal Agreements with the county's cities (Anacortes, Burlington, Sedro Woolley, Mount Vernon). The waste stream has broad seasonal variations with more vegetation and a higher volume in the summer months. A municipal waste analysis by weight is given in Table 1-1.

Table 1-1
Municipal Solid Waste Analysis by Weight

Aluminum and non-ferrous metals	1%
Textiles	2%
Plastics	4%
Rubber/leather	3%
Glass	10%
Ferrous metals	9%
Paper	35%
Food wastes	15%
Yard wastes	16%
Miscellaneous	5%
Total	100%

The waste stream has a heating value of approximately 4,500 Btu/lb. The waste-to-energy facility is currently receiving 132 tpd based on a 7-day week. As the waste is burned, it is reduced to an ash residue. Under typical operations, a 65 to 75 percent weight reduction and a 90 percent volume reduction are expected.

At the Skagit County facility, approximately 2.64 pounds of 450-psig, 465F steam is produced per pound of refuse burned. From 50 to 51 MWh per day of electrical energy is produced when the plant is firing at a rate of 162 tpd. However, the efficiency of converting unprepared solid waste to electrical energy is dependent upon the facility's firing rate. Both steam turbines and generators have characteristics curves or efficiency curves such that the electrical output from combustion of an incremental unit of refuse depends upon the percentage of full-rated load.

Even with the Interlocal Agreements, waste stream losses can occur. The cities are examining the establishment of composting programs for grass clippings and yard wastes. While there is no market for these products, cost recovery is possible through avoidance of the County's disposal fee. Additional losses could occur through the dumping of construction and demolition products (including roofing and wood wastes) in designated landfills. While the County technically has the power to forbid these activities, it uses this power sparingly to foster harmonious relationships.

Financing, Installation, and Operating Costs

Skagit County financed the waste-to-energy project through limited General Obligation bonds. The bonds are backed by the assets of the facility plus the credit of the County. Revenue bonds were not used because of the relatively small size of the project and because they would require a vote, with the potential existing for this "fast-track" project to be seriously delayed or terminated. Ultimately, the County decided that the General Obligation bonding mechanism could be used with no adverse effects.

It is extremely difficult to isolate the portion of the project's capital, administration, and operating and maintenance costs that can be ascribed solely to energy production. Waste-to-energy plants do not eliminate the requirement for a county to continue to operate at least one landfill. Municipal waste must be diverted from the incineration/resource recovery facility during planned or unplanned outages, and fly ash must be disposed of, as well as appliances and demolition debris. In the County's 1986 Supplemental Draft EIS for this facility, base case (incineration only) versus total costs (with heat recovery boiler plus electrical generating capability) are given for ten project alternatives. Costs of the electricity generating portion of the plant range from $2.4 to $3.4 million.

Costs of operating the County's entire Solid Waste Division are given in Table 1-2. Annual Resource Recovery Facility operating and maintenance costs are $1.14 million, while debt service on the facility's limited General Obligation bonds is $723,000. Revenues from the sale of electricity are projected at $645,000 per year.

Table 1-2
Construction and Operating Costs
Skagit County Resource Recovery Facility

Construction cost*	$13,000,000
Operation and maintenance (county solid waste costs)	
Administration	80,000
County forces (including landfill)	299,500
Site maintenance	85,000
Resource Recovery Facility operation	1,144,600
Total	$1,609,100
Debt service	
Landfill bonds	$153,200
Resource Recovery Facility bonds*	723,300
Total	$876,500
Total annual costs	$2,485,600
Revenues	
Sale of electricity	$645,420
Net annual cost	1,840,180
Tipping fee (with state grant)*	$35/ton

*Note: Skagit County received a 50 percent matching WDOE grant for the project. Without this grant, the tipping fee would be $49.50/ton because of increased debt service.

Power Purchase Contract Negotiations

On January 12, 1987, Skagit County and PSP&L negotiated a 20-year Agreement for Firm Power Purchase. Under the terms of the agreement, PSP&L would purchase energy from the waste-to-energy facility at a levelized price of 49 mills/kWh. Energy delivered before the "date of commercial operation" (the date upon which the project is capable of delivering energy on a continuous basis) would be purchased in accordance with the lower rates specified by Schedule 91 of PSP&L's Electric Tariff on file with the Washington Utilities and Transportation Commission (WUTC).

The power purchase contract has several unusual clauses. A termination amount would be paid to PSP&L in the event that the County abandons the project or fails to promptly return the project to commercial operating status following a breakdown. The termination amount is generally specified as an excess payment equal to the levelized purchase price less PSP&L's variable rate plus interest, computed monthly and compounded annually at the lesser of a rate of 11.6 percent or the maximum rate permitted under applicable usury law.

The agreement gives PSP&L the option to purchase electricity produced by the project beyond the 20-year period of the contract. The County is obligated to provide one year's advance notice to PSP&L. The purchase price would be negotiated by representatives of the County and PSP&L. If agreement could not be reached, an arbitrator would be retained to determine a fair, just, and reasonable purchase price, taking into account the cost to the County of owning, operating, and maintaining the facility; estimated tipping fees and other revenues; purchase prices for output from similar waste-to-energy projects in the Pacific Northwest; and PSP&L's cost of power. If PSP&L does not exercise its acquisition option, then the utility is obligated to provide transmission services to wheel the output of the project to another interconnected utility. The County would provide "reasonable" wheeling compensation to PSP&L.

Another clause requires the County to furnish PSP&L with documentation and information to verify that the project is a "qualifying small power production facility" (QF) under guidelines established by the Federal Power Act.

Finally, the purchase agreement would not go into effect unless and until approved by the WUTC. PSP&L was required to exercise reasonable efforts in good faith to obtain such approval. Ultimately, PSP&L and County staff made two presentations to the WUTC to address and resolve issues of fairness to the ratepayer.

Permitting and Licensing Requirements

The County was required to obtain an Approval to Operate from the Northwest Air Pollution Control Authority; a Prevention of Significant Deterioration (PSD) determination from the WDOE; and a Solid Waste Disposal Site Permit, a Variance for On-Site Sewage Disposal, a Review of Notice of Construction, and an inspection of closed landfills from the Skagit County Building and Health Departments. The lead agency for preparation of a State Environmental Policy Act (SEPA) EIS was the Skagit County Department of Planning and Community Development. A Special Use Permit also had to be obtained from Skagit County.

It is the responsibility of the Northwest Air Pollution Control Authority to determine what constitutes the "best available control technology" (BACT) for each new point source of emissions to the atmosphere. BACT is defined in the State Clean Air Act and the Washington Administrative Code (WAC 173-403-030) as: "...technology which will result in an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each air pollutant subject to this regulation..." BACT would be determined: "...on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs..."

The BACT review considers initial installation costs, maintenance expenses, control equipment energy consumption, and the location, size, and nature of the proposed facility. The reviewing agency may prescribe a design, equipment, work practice, operational standard, or combination thereof to meet the BACT requirements.

Prevention of Significant Deterioration (PSD) is a program to prevent the deterioration of air quality in areas that meet the National Ambient Air Quality Standards (NAAQS). While a New Source Review is made by the local air pollution control authority, the PSD is administered by the WDOE.

Under the PSD process, the applicant submits a scoping document. The document must contain a description of process and flow diagrams, design and operating parameters, and estimates of potential emissions for all pollutants. Potential emissions are determined by assuming that the equipment is operating at maximum capacity, 24 hours a day 365 days a year, taking air pollution control equipment into account.

WDOE applies a PSD screening and an applicability test. Projects that release more than 250 tons per year (tpy) of any regulated pollutant (not including fugitive emissions) or sources falling within one of 28 special categories having potential emissions of 100 tpy (including fugitive emissions) of any regulated pollutant must undergo an application test. Municipal incinerators capable of charging more than 250 tpd are one of the named PSD source categories. The Skagit waste recovery project has a capacity of only 178 tpd and would produce emissions of approximately 17 tpy of carbon monoxide, 85 tpy of nitrogen oxides, 0.8 tpy of sulfur dioxides, and 30 tpy of particulate matter. As the project would not produce emissions of criteria pollutants in sufficient quantities to exceed the 250 tpy screening criteria, a PSD review was not required.

In 1985, WDOE promulgated its Minimum Functional Standards for Solid Waste Handling (Chapter 173-304 WAC). While the state has the responsibility for coordinating the development of a Solid Waste Management Plan, the local governments must establish management concepts for waste handling, transportation, recycling, processing, treatment, resource recovery, energy recovery, incineration, and landfilling. Management and operational functions must be consistent with the priorities of waste reduction, recycling, energy recovery and incineration, and landfilling established in RCW 70.95.010.

The local health departments are charged with enforcing the minimum functional standards, while WDOE reviews and provides technical assistance. Disagreements are appealed to the Pollution Control Hearings Board. Thus, a key development milestone is the issuance of the Solid Waste Disposal Permit by the Skagit County Health Department. Although the Skagit County Resource Recovery Facility is operating, permit conditions are still under discussion and WDOE has yet to issue a notice of approval.

Several relevant pieces of legislation were passed during and after the design and construction of the Skagit County waste-to-energy facility. Chapter 70.95 RCW was enacted in 1969 and amended in 1986 to deal with solid waste management, recovery, and recycling. The Act establishes a Solid Waste Advisory Committee to provide consultation to the WDOE; directs cities and counties to prepare comprehensive solid waste management plans; and mandates that boards of health adopt regulations governing solid waste handling that would result in implementation of comprehensive solid waste management plans. Goals of the legislation are to protect the public health, prevent air and water pollution, and avoid the creation of nuisances.

Chapter 173-434 WAC (Solid Waste Incinerator Facilities), promulgated in 1987, establishes strict emissions standards, combustion zone time and temperature requirements, design requirements, monitoring requirements, and performance standards for solid waste incineration facilities.

Chapter 70.138 RCW (Incinerator Ash Residue), also enacted in 1987, deals with the management of special incinerator ash and calls for generators to develop plans to reduce the quantity and toxicity of special incinerator ash. The Act also directs WDOE to establish minimum requirements for the management and safe disposal of special incinerator ash and to define the elements of generator ash management plans. In addition, it requires that special ash be disposed of at facilities that are in compliance with all standards. WDOE followed up with a Draft Report on Ash Management Standards in March 1988.

Chapter 184 of the Washington Laws of 1988 directs WDOE to determine best management practices for different categories of solid waste. A comprehensive solid waste stream analysis and evaluation would determine:

- Solid waste generation rates for each category
- Rates of recycling for each category
- Current and potential rates of solid waste reduction
- The feasibility of segregating solid waste
- Methods available to increase the rate of solid waste reduction
- New and existing technologies available for solid waste management

WAC 173-304-012 (a new section) requires that each comprehensive solid waste management plan contain an analysis for waste reduction and recycling. The analysis must include a description of markets for recycled materials, a review of waste generation trends, a description of waste composition, and a cost analysis of proposed recycling or reduction programs. Finally, ESHB 1671 requires the presence of certified operators at resource recovery facilities.

Environmental Impacts and Mitigation Strategies

The Skagit County Resource Recovery Facility will add small increments to existing emissions of pollutants in the project area. In addition to carbon monoxide, nitrogen oxides, sulfur dioxide, and particulates, the project has the potential to release small quantities of trace metals and organic compounds as well as odors and fibrogenic dusts.

Emission releases are mitigated through:

- Proper selection, maintenance, and operation of air pollution control equipment
- Regulation of waste stream contents to prevent hazardous and dangerous wastes from entering the incinerator
- Operation of the incinerator to ensure proper combustion temperature, quantity of excess air, and residence or burnout time
- Operator proficiency training
- Emissions compliance monitoring

Solid waste incinerators are required to use the best available control technology as defined at the time of construction. The Skagit County plant is equipped with two filter bag house and lime injection acid gas scrubber trains.

Current emission standards at the incinerator stack are an hourly average of 0.03 grains per dry standard cubic foot (grains/dscf) of particulate matter, 50 parts per million (ppm) of hydrogen chloride, and 50 ppm of sulfur dioxide (when corrected to 7 percent oxygen) with an opacity as measured by transmissometer not exceeding 10 percent for more than 6 consecutive minutes in any 60-minute period.

The County believes that its plant is very clean and that it may be the best-performing waste-to-energy facility in North America. The project produces no visible emissions, with particulate emissions running at 0.004

grains/dscf. Opacities typically run at 1 percent or less with sulfur dioxide concentrations of approximately 0.5 ppm.

Complete combustion is ensured by forced and induced draft fans, which maintain 90 to 110 percent of excess combustion air, and the provision of at least a one-second residence time in a secondary combustion chamber. Odor control is achieved by taking the combustion air from the tipping floor. Natural gas burners are used during plant startup and when combustion temperature falls below minimum values.

The County did experience some difficulty with fly ash disposal. Combining or diluting fly ash with bottom ash is not allowed. Two of 11 fly ash samples failed the Environmental Protection Agency (EPA) toxicity tests mainly because of spikes in lead concentration. For a period of time, the plant operators were required to cast their fly ash into one-ton concrete blocks, incurring an unanticipated operating cost of $365,000. This requirement was waived when the County established and publicized a battery purchase and recycling program. Rebates of 5¢ each are paid for flashlight batteries and 50¢ each for automotive batteries. The rebate for auto batteries is set low enough not to divert the flow of batteries to existing recycling centers. The County is responsible for preparing and submitting a report to WDOE on the effectiveness of this program.

The County has found that the fly ash composition is also sensitive to the quantity of lime carried over from the dry scrubber to the filter bag house and to impurities contained within the lime. Typically, 70 percent of the fly ash is carried over from the scrubber. The presence of lime also causes plant washdown and wastewater to be high in pH. The pH must be neutralized by acid addition before discharge into the sewer system and the Burlington Wastewater Treatment Facility.

Risk Management Issues

The County avoided undertaking undue project development risks through (1) anticipation and planning; (2) liquidated damages clauses inserted into the agreement with the design/build/operate contractor (Wright Schuchart Harbor Co.); and (3) specification of insurance carrying requirements.

The County directed its consultant, R.W. Beck and Associates, to perform a risk assessment for each phase of project development. Beck developed a risk matrix and assigned probabilities and costs associated with possible outcomes. The County ultimately had to decide whether to assume the risk at expected cost, obtain insurance, or pay its contractor to undertake the risk.

Early identification of risks and possible outcomes provided the County with a realistic perspective on licensing and scheduling of project construction activities. For instance, the County actually expected to go to court over procedural matters relating to Environmental Impact Statement review, and it anticipated protests and legal challenges from vendors that were not selected in the RFP process. Through early incorporation of review, appeal procedures, and time requirements into its critical development path, the County suffered neither unexpected delays nor unanticipated costs. Nine contractors responded to the County's RFP and a short list of five respondents made presentations before WSH was selected. Even though a challenge to the County's decision was expected, the project could have been delayed had the protesting vendors been able to halt work with a court injunction. Although such an injunction was sought, it was not granted.

The County also minimized initial investments and obtained protections against risk through their Incineration/Resource Recovery Construction and Operation Contract with WSH. First, the contractor was obligated to provide, at its own expense, all of the necessary preliminary design, engineering, architectural, and technical specifications and construction schedule details necessary to the County for permitting, planning, review, and equipment definition. The contractor also incurred all the costs of preparing final plans, specifications, and drawings. The contractor was also charged with obtaining all construction and operating permits except for environmental permits such as the Special Use Permit, Air Quality Permit, Solid Waste Construction Permit, Federal Aviation Administration Permit, Airport Permit, and the Solid Waste Operating License from the Skagit County Health Department.

WSH was also obligated to construct an incineration/resource recovery facility that would comply with all applicable federal, state, and local laws, ordinances, environmental standards, and regulations in effect on the contract date (January 12, 1987). The County would pay a fixed price of $12.2 million plus sales and use taxes. County prepayments were protected as WSH granted the County a security interest in work in progress and in all raw materials, inventory, and parts paid for by the County.

The cornerstone of the contract is a set of on-line dates, performance guarantees, acceptance testing protocols, monitoring requirements, and liquidated damages clauses. WSH is obligated to construct a facility that meets guaranteed standards for minimum waste throughput, plant availability, incinerator rating, steam raising, waste reduction, turbine generator performance, electrical energy and fuel consumption, and emissions. Guaranteed levels of performance are summarized in Table 1-3.

Failure to comply with schedule or performance specifications results in liquidated damages payments to the County. For instance, if the facility does not achieve commercial operation within 540 days from the date of issuance of the first Notice to Proceed with design, the contractor shall be assessed a penalty of $1,450 per day. Similarly, if a Certificate of Final Acceptance is not issued within 570 days from the contract effective date, the per-day liquidated damages charge must be paid prorated based upon the difference between the guaranteed performance level and the actual performance level divided by the guaranteed performance level. The daily liquidated damage charge would continue to be levied until the guaranteed minimum performance levels are achieved.

WSH is additionally liable for providing corrective actions, at its own cost, if air emission standards are not met. The contractor also holds a responsibility to reimburse the County if plant auxiliary fuel consumption or electrical consumption performance guarantees are exceeded. WSH must also compensate the County for guarantee noncompliance that results in lost steam and electricity revenues.

Finally, WSH must pay the County for waste it disposes in the County's landfill that is in excess of the amount allowed. The payment must cover hauling and disposal costs, cost impacts for reduced landfill life, and lost energy value, including penalties levied against the County for nondelivery of steam or power.

WSH must make modifications to the plant at its own cost to ensure continued performance acceptability. For instance, air injectors were retrofitted onto the rotary kilns to eliminate problems with glass slagging. WSH is also obligated to pay all ash residue hauling expenses while the County incurs disposal costs. Outstanding claims involve the substantial cost of casting the fly ash into concrete blocks, cooling tower blowdown wastewater treatment, and operation and maintenance charges for an optional shredder desired by the County.

Table 1-3
Minimum Performance Guarantees
Skagit County Resource Recovery Facility

A.	Minimum annual waste throughput	58,400 tpy
B.	Maximum continuous rating (MCR) per incinerator	3.71 tph 89 tpd
C.	MCR for the facility 178 tpd	7.42 tph
D.	Guaranteed available steam raising rate (450 psig, saturated)	2.64 lbs. steam per lb. throughput
E.	Waste reduction (excluding ferrous recovery)	
	By volume	95%
	By weight	80%
F.	Excess combustion air	90-110%
G.	Maximum putrescible material in incineration residue	Less than 1% by weight
H.	Maximum combustible material in incineration residue	Shall not exceed 5% by weight
I.	On-site electricity consumption	80 kWh/ton throughput
J.	Annual availability for each incineration/boiler line	90%
K.	Annual availability for total facility	90%
L.	Maximum auxiliary fuel consumption	
	During operation	None
	During startup	146,800 Btu/ton throughput
M.	Maximum particulate emissions	0.02 grains/dscf corrected
N.	Maximum acid gas emissions	
	Hydrogen chloride	50 ppm corrected to 7% oxygen
	Sulfur dioxide	50 ppm corrected to 7% oxygen
O.	Exit flue gas temperatures	
	Minimum	210°F
	Maximum	290°F

Note: Tons, tons per year (tpy), tons per hour (tph), tons per day (tpd) are short tons.

The County compensates WSH to fully operate and maintain the facility. Operating charges include labor, employee fringe benefits, payroll taxes and insurance, operating supplies, maintenance spare parts, utilities charges, general administration fees, and an allowance for overhead and profit. WSH has subcontracted with Energy Resource Recovery, Inc., of Mount Vernon to operate the facility. Staffing requirements consist of four shifts of four members each plus maintenance personnel and drivers.

WSH also receives 25 percent of revenues resulting from the sale of electricity (over the prior 12 months) that exceeds the facility's performance guarantee WSH is obligated to segregate and haul recovered ferrous metal, and retains all revenues from the sales of processed metal.

WSH is required to file a Certificate of Insurance with the County for each required coverage. The contractor is required to obtain builders all-risk coverage in the amount of the contract, fire and perils insurance, $1 million in general liability and property damage coverage, an additional $1 million in vehicle liability, and a $4 million umbrella/excess liability policy. The contractor also must post a bond in an amount not less than the contract sum and hold errors and omissions coverage of not less than $1 million. Costs of bonds and deductibles are borne by the contractor.

Construction Time Line

The driving force for exploring waste disposal alternatives was the establishment by WDOE of Minimum Functional Standards for Solid Waste Handling and Disposal. Among other things, WDOE required all landfills to be lined by November 1989. As a result of the new and more stringent requirements, the Gibraltar Landfill near Anacortes was closed in early 1989, while the County's Sauk Landfill near Rockport was converted to a transfer station. The Inman Landfill received a Special Use Permit to continue operation until 1995. This permit was later amended to allow ash disposal under WDOE's Interim Guidelines.

Because of these mandated landfill closures, the waste-to-energy project was put on a "fast track." The construction and operation contract was signed in January 1987 and the facility began operation only a year-and-a-half later.

Chapter 2

20-MW Pacific Cogeneration/Great Western Malting Gas-Fired Cogeneration Facility Vancouver, Washington

Project Description

The 20-MW Pacific Cogeneration (PACCO) plant came on-line in Vancouver, Washington, in December 1982. This facility consists of a GE LM-2500 combustion turbine (which is rated at 20.4-MW at 59°F), a 12.45-kV generator, and an 85 million Btu/hr Econotherm waste heat recovery boiler. Exhaust gas heat is recovered as 320°F hot water, which is circulated by three 100-hp pumps to three banks of kilns operated by Great Western Malting (GWM). Peaking and host facility backup heating requirements are provided by three 1,600-hp Johnstone boilers rated at 58 million Btu/hr each.

Background

The GWM management became interested in heat recovery and/or cogeneration alternatives in 1977, when Rocket Research was completing an industrial survey and assessment of regional cogeneration opportunities. Rocket Research attempted to match GWM thermal requirements with heat rejected from adjacent companies. A match was proposed with the Alcoa Aluminum plant, which was 4 miles away. GWM requires low quality energy, i.e., 245°F hot water to produce 180F air for its kiln drying process. It was proposed that Alcoa's waste heat could be recovered and used to preheat GWM's water to 160°F. A $4 to $6 million investment would be required for heat recovery equipment, a pumping station, and transfer pipeline

Negotiations ensued and the project proponents found that it was difficult to "marry" two different industries while providing the investment security assurances necessary to obtain financing.

A subsidiary of Rocket Research, TransEnergy Systems, then approached GWM regarding possible cogeneration opportunities. Since GWM was interested in reducing operating costs, it obligated $30,000 to $35,000 in 1979 for conceptual design and feasibility studies. The timing for this project was ideal, for the following reasons:

- The Public Utility Regulatory Policies Act (PURPA) enacted in 1978 guaranteed GWM a market for electrical energy.
- Regional droughts in 1973 and 1977 had raised concerns about brownouts or electrical curtailments.
- The region was forecasted to suffer electricity supply deficits throughout the mid 1980s.
- Projected avoided costs, based upon the costs of building and operating large-scale coal or nuclear plants, were high.
- GWM was going to have to install new boilers to convert from a direct to an indirect kiln firing process.

Since 1937, GWM had direct-fired its kilns with diesel or Number 6 fuel oil. Sulfur in the fuel provided the acidic conditions necessary for bleaching the barley. Unfortunately, however, nitrogen oxide (NO_x) combustion products combine with natural chemicals in the barley to form dimethyl nitrosamine, a known carcinogen. As demand for diesel-dried malt diminished, malters across the country began converting to indirect firing with SO_2 gas injection systems. GWM was thus in the position of obligating approximately $3 million to construct a new natural gas-fired heating plant. The time was ripe for an assessment of cogeneration alternatives.

Plant Operational Characteristics

GWM employs 160 people in Vancouver and produces 20 million bushels of product annually making it the third largest maltster in the United States. With

GWM's purchase by Canada Malting in March 1989, it is part of the largest malting company in the world.

In the malting process, six varieties of barley are steeped in water for 48 hours, then allowed to germinate (converting starches into fermentable sugars) in rotating drums under cool, moist conditions for 96 hours; the barley is then kiln dried before being blended into a finished product and shipped to brewers. GWM's Vancouver plant uses three malting processes with three different kiln drying cycles. With the ability to stagger its kilns at 12-, 24-, and 32-hour drying cycles, the GWM plant has a nearly continuous thermal requirement and is thus compatible with base-loaded electric powerplant operation.

A constant thermal load is essential for a cogeneration project's success. At GWM's malting facility in Pocatello, Idaho, which has a single kiln operating on a 16-hour cycle, a cogeneration plant would not be cost effective; the plant would have to shut down for several hours while the kiln was being charged and emptied. In contrast, the Vancouver plant offers a nearly continuous heat load, 24 hours per day, 365 days per year.

The malting process is thermal energy-intensive, requiring three times more thermal than electrical energy. The electrical load at GWM averages 4 MW, while the typical heat load is 90 million Btu/hr. While the cogeneration plant is thermal following, with electricity produced as a byproduct, the facility's thermal loads are such that the average on-line time for the cogeneration facility, not including overhauls, exceeds 98 percent.

The cogeneration plant is sized so that combustion turbine exhaust gas at 910°F is converted to 85 million Btu/hr of 320°F hot water in the finned tube heat recovery boiler. The cogeneration plant provides approximately 85 percent of the facility's process heating requirements. Three 58 million Btu/hr Johnstone boilers are maintained in hot standby and used to provide peaking services. The hot water is routed through secondary heat exchanges to produce 130 to 180°F air. The kiln supply air temperature is modulated to produce 90 to 110°F wet bulb discharge air.

Kiln exhaust air heat recovery could reduce the plant's thermal energy requirements by 15 to 18 percent. While this technology is employed at GWM's Pocatello facility, its energy savings potential and cost effectiveness is degree-day and humidity dependent. This technology would not be cost effective, for example, at GWM's City of Commerce, California, facility. Heat recovery would be reconsidered at Vancouver only if the facility were expanded to include a fourth set of kilns. In that event, the installation of heat recovery on all kilns would eliminate the necessity to expand the existing boiler plant.

Utility Agreement

In 1982, PACCO signed an agreement with Clark County PUD whereby the utility would reimburse PACCO for installing, maintaining, and operating the cogeneration project. The cash payments cover the amortized cost of financing and provide PACCO with a guaranteed 9 percent rate of return on its investment. PACCO holds the legal title to the plant and provides thermal energy (steam) to GWM at no cost. PACCO subsequently paid approximately $8.9 million to procure and install the combustion turbine, generator, utility switchgear (12.45 kV to 115 kV), and a 4-mile-long, 6-inch-diameter gas transmission pipeline. All electricity produced goes to the utility.

The utility also pays all maintenance and fuel costs necessary to power the combustion turbine and supply waste heat to GWM. When the debt service is retired after 12 years, the agreement terminates, with PACCO retaining all ownership rights to the cogeneration project, except the utility substation.

Under the agreement, perceived at the time as mutually beneficial, Clark County PUD would additionally be responsible for compensating GWM for "excess" fuel consumed during combustion turbine maintenance overhauls, outages, shutdowns, or curtailments of interruptible gas service. This agreement was voluntarily negotiated outside of PURPA.

GWM provided the generating site and managed construction activities. It purchases transport gas and performs routine maintenance. At a cost of $3.7 million, GWM also funded the backup/peaking boilers, hot water circulating water pumps and piping, and the kiln water-to-air heat exchangers. A side benefit to GWM was the removal and replacement of much asbestos-insulated piping at fairly low cost during construction of the cogeneration unit.

The utility holds an option to renegotiate the power purchase agreement at the end of the 12-year contract. While the utility is obligated to purchase power and energy at a rate based upon its full avoided costs, negotiation may not occur unless favorable terms are received.

Transport Gas Issues

Natural gas for the cogeneration project is purchased from Northwest Natural Gas (NWNG) under two rate schedules. GWM purchases firm 50-psi street gas for use in its peaking boilers. Approximately 2,000 therms of gas per day (or 700,000 therms per year) are purchased at a current rate of 36¢ to 37¢/therm. Boiler gas consumption increases to an absolute baseload of 18,000 to 20,000 therms/day when the combustion turbine is off-line.

Gas for the combustion turbine is purchased by GWM under an interruptible schedule. The current rate is 16¢/therm at the Northwest Pipeline gate station plus a wheeling fee levied by NWNG. NWNG currently assesses a 7¢/therm transport charge in the summer with a 9¢/therm charge in the winter.

As the combustion turbine consumes 18 million therms per year, in aggregate the cogeneration facility is NWNG's second largest customer. Transport gas is procured for the combustion turbine powerplant, with a gas marketer such as McCall Oil or Westar selected by competitive bid. Gas volumes are nominated on both a daily and monthly basis.

When the cogeneration plant was built, a 3.5-mile-long, 6-inch-diameter gas line was installed to convey 350-psi gas from the Northwest Pipeline to the generating site. Direct access to the high pressure gas offset the need for the project developers to install and maintain a 1,500-hp gas compressor. PACCO paid for the $450,000 gas transmission line and then deeded over to NWNG.

Since 1985, natural gas rates have declined from a firm rate of about 60¢/therm to an interruptible rate of 22¢/therm. (The combustion turbine was shut down for one year in the early 1980s when it was not cost effective to produce electricity at the project because of high gas prices.) This decision was made by PACCO with input from Clark County PUD. The PUD has no right to restrict or control the output of the generating facility. Electricity generating costs subsequently declined from 6.5¢/kWh in 1984 to 3.5¢/kWh today. A portion of the high price in the early years of project operation was due to a 20¢/therm transport fee assessed by NWNG to wheel the product over the deeded 4-mile transmission line. By not taking title to the gas, PACCO is able to pay a utility tax (approximately 4 percent) versus the higher state sales tax.

Although NWNG has reduced its transport fee, further reductions are sought by the project developers. In 1987, the gas utility was paid approximately $3.5 million for transportation services. It is cost effective for PACCO to install a new bypass pipeline if the transport rate is not reduced to 2.5-2.7¢/therm. A proposed Transportation Service Agreement calling for a rate of 2.5¢/therm is currently awaiting approval from the Washington Utilities and Transportation Commission. PACCO will obtain negotiating leverage as it has applied for permission to build a bypass line under FERC's 7-C process. Right-of-way could readily be obtained as the proposed line would be routed on Port of Vancouver property.

Under bypass conditions, PACCO would negotiate directly with gas producers and the pipeline company. NWNG need not be involved and the transaction would not come under the purview or regulatory powers of the Washington Utilities and Transportation Commission.

Turbine Selection and Design Criteria

General Electric's aircraft-derivative LM-2500 combustion turbine was selected during conceptual design and analysis because it matched the GWM facility's thermal loads. Solar turbines were examined, but three 8-MW MARS units would have been required. The equipment cost for GE's package unit amounted to $6.5 million.

GWM had two overriding design goals:

- To operate an unmanned facility (it costs approximately $160,000 per year to provide single person, around-the-clock coverage)
- To provide 100 percent backup capability for the combustion turbine

Hot water was selected over a steam distribution system because of manning considerations. (GWM was told it has the largest hot water boiler system in operation west of the Mississippi River.) Originally, 247°F water was proposed, because under the Power Boiler

Code, piping class, specification, and weld inspection requirements increase above a 250°F temperature. It was later found that the temperature could be increased to 320F with no penalties. Economic advantages occurred with the ability to reduce both pipe and coil sizes.

The design contract with TransEnergy Systems was written for $450,000. TransEnergy came back with a charge of $890,000; a lawsuit ensued, went to arbitration, and was settled for $500,000. GWM paid the design costs, with Clark County PUD designing and installing the substation at its cost. By providing a GWM staff person to coordinate purchases and serve as a construction manager, the overall design fees were held to only 3.8 percent of the total project cost.

Typically, the combustion turbine would produce about 18 MWa, with the heat recovery boiler providing approximately 85 percent of GWM's 90 Btu/hr average thermal load. With the turbine running, a single peaking boiler would be in operation. The combined plant consumes 18.7 million therms of natural gas annually.

Maintenance Requirements and Project Scheduling

Combustion turbines generally can be expected to produce 103 percent of rated capacity when new. The efficiency drops by 5 percent over the first 6 months, then slowly decreases by 10 to 15 percent because of blade degradation. A $700,000 hot section overhaul was scheduled after 23,000 hours of operation. A second major $1.5 million overhaul is typically scheduled at 50,000 hours and includes combustion turbine hot section, generator, and compressor refurbishment. This overhaul is expected to take 4 months with the turbine pulled and rebuilt at General Electric's Ontario, California, shop. The second overhaul was actually scheduled at 46,000 hours to coincide with the Clark County PUD's low load summer period. PACCO is obligated to supply heat to GWM (with PUD reimbursement) during these scheduled maintenance outages.

Another hot section overhaul will occur after 23,000 additional hours, with the second major overhaul expected in 1994-1995. During this overhaul, the combustion turbine, compressor, and generator will again be refurbished and the heat recovery boiler will be retubed. A $2.5 to $3 million investment will be required and will undoubtedly be a negotiated item in future power purchase contract discussions.

With overhauls not included, the combustion turbine is on-line approximately 98.5 percent of the time. The project sponsors had originally anticipated a total downtime of 10 percent per year.

Once a month, the combustion turbine is shut down for a 4-hour chemical/water wash. Additional maintenance is accumulated and performed during this short planned outage. An operational ground rule is always to schedule the water wash after 10 a.m. to ensure that the unit is not taken off-line during the utility's peak load period.

The maintenance operators have experimented with different wash cycles, ranging from 2 weeks to 2 months. Because of compressor blade fouling, the unit loses about 1 MW over the course of a month, with the bulk of the loss occurring in the first week. Thus, there is a direct tradeoff between improved efficiency and increased outage time. A new procedure allows the operators to do perhaps every other water wash while the unit is on-line.

Care is taken to clean the turbine's combustion air. Air flow is first routed through an inertial filter (similar to a cyclone), then through filter plates. Waste heat from the compressor is used for icing control.

GWM feels that the impressive performance posted by its generating plant is due to following proper maintenance procedures and from not driving the unit too hard. The facility could be uprated to 22 MW by increasing the combustion temperature from 1,407°F to 1,558°F. However, the engine would degrade faster. The expected life of a gas-fired combustion turbine ranges between 80,000 and 90,000 hours.

The annual maintenance budget for the cogeneration plant is $75,000, plus 1,200 hours of preventive maintenance performed by the crew. At $20/hour, the staffing requirement is $24,000 per year. An additional 1,200 hours is budgeted by GWM for work performed on the peaking boilers and hot water distribution system. With off-shift work (averaging 1/2 hour per day), the staffing maintenance budget will increase to $60,000 per year. Keeping track of and allocating maintenance charges is complicated and time consuming. In the future, PACCO is expected to assign a full-time person to the site.

Ownership Transfers and Project Financing

In 1976, Univar Corporation purchased GWM from the Columbia Corporation of Portland. PACCO was created as a subsidiary corporation with ownership of the cogeneration facility. Under the 1982 contract with Clark County PUD, the utility would reimburse PACCO for costs incurred for purchasing, installing, and maintaining the electrical generating portion of the plant. A heat agreement was signed with GWM. The cogeneration project has been described as a joint and generally harmonious effort between Clark County PUD, GWM, Univar Corporation, and the Northwest Natural Gas Company.

In 1984, Univar Corporation spun off PennWest Limited of Bellevue, Washington. PACCO became a part of PennWest. GWM was then sold to Canada Malting of Toronto. Participants in the power purchase contract/heat agreement renegotiation in 1994 thus may include Clark County PUD, PennWest, PACCO, GWM, and Canada Malting.

Financing for the entire project was arranged by Univar Corporation with SeaFirst Bank. The short-term construction loan was at prime plus approximately 3 or 4 percent, while long-term financing ran close to 10 percent. A major driving force for expedient project construction is the availability of lower interest rate "take-out" financing.

Clark County PUD received a rebate for a portion of its electricity acquisition expenses under BPA's Exchange Transmission Credit Agreement. The utility was able to exchange a block equal to the residential portion of its load60 percentand receive credit for the difference between its average system costs and BPA's Priority Firm rate. This agreement was terminated in 1988 with the utility receiving a lump sum cash settlement.

Licensing and Permitting

Project licensing and permitting was completed by GWM in approximately one year. Upon examination of an Environmental Checklist, the lead agency issued a Determination of Non-Significance. As it was determined that the proposed project would have no probable significant adverse effect upon the environment, an Environmental Impact Statement was not required under the State Environmental Policy Act (SEPA).

Three key permits were required: An exemption from the federal powerplant and Industrial Fuel Use Act of 1978; a declaration by the Federal Energy Regulatory Commission (FERC) that the project is a PURPA Qualifying Facility (QF); and a Permit to Construct from the Southwest Air Pollution Control Authority. Two legal firms were retained to obtain the federal permits.

The Air Pollution Control Authority requires the plant operators to maintain NO_x emissions below 64 parts per million (ppm). A water injection emissions package was supplied by GE. Continuous natural-gas-to-water ratio monitoring is required by the Environmental Protection Agency. Typically 8 to 9 gpm is required for NO_x control. Although the NO_x control package reduces the natural gas combustion efficiency, it increases the rated output of the turbine/generator.

Tax Credits and Incentives

The cogeneration plant was brought on-line in December 1982, and operated for the minimum of 48 hours required to qualify for federal tax credits and depreciation allowances. The facility operators do not recall the type, timing, or amount of credits received. A short summary of the credits available at that time can be extracted from the December 1980 *Cogeneration Handbook* published by the Washington State Energy Office (WSEO):

> The Internal Revenue Service (IRS) allows a one-time Investment Tax Credit (ITC) of 10 percent of the cost of business equipment bought or put into use; building or components of buildings do not qualify. The Energy Tax Act of 1978 also created a Business Energy Investment Tax Credit which is an additional credit against an individual or corporate tax liability of 10 percent of the cost of energy-saving or producing business equipment as well as buildings and property that have alternate energy structural components.
>
> The Crude Oil Windfall Profit Tax Act of 1980 amends several provisions from the Energy Tax Act...and provides a 10 percent nonrefundable energy credit from 1 January 1980 through 31 December 1982 for equipment that enables a boiler or burner at an existing facility both to produce steam, heat or other useful energy and also produce electricity (i.e., cogeneration equipment).

The state of Washington also provided incentives for cogeneration project development. Substitute House Bill No. 1013 of 1979 gives tax credits to industrial cogenerators and assigns WSEO to provide technical assistance for the Department of Revenue with respect to certifying cogenerators. This bill sunsetted in December 1989.

Benefits the bill provides for cogenerators include the following:

- Business and Occupation Tax credits in the amount of 2 percent of the capital cost of a facility. The credit must not exceed 50 percent of the developer's tax liability and is limited to 50 percent of the cost of the facility. Federal tax credits are deductible from this tax credit.
- Exemption from property taxation for 7 years.
- Exemption from state utility regulations (when nonpolluting renewable sources such as wood wastes, municipal solid wastes, and agricultural wastes are used).

Chapter 3

5-MW Weeks Falls Hydroelectric Facility North Bend, Washington

Project Description

The run-of-the-river Weeks Falls hydroelectric project (FERC #7563) came on-line in May 1987. Electrical output is sold to Puget Sound Power and Light Company (PSP&L). The project is located on the South Fork of the Snoqualmie River at River Mile (RM) 13.6 in King County, Washington, approximately 8 miles southeast of the town of North Bend. The South Fork Snoqualmie River is a tributary of the Snoqualmie River, a primary component of the 1,780-square-mile Snohomish River Basin, the second largest drainage system in the Puget Sound region.

As a run-of-the-river installation, the project has a diversion weir that lacks the capability to regulate streamflow. Project structures consist of a low diversion weir and intake facility, fish screens, a tunnel, a powerhouse containing a 5-MW turbine generator, switchgear, and a buried transmission line. The $7.7 million project is expected to produce 18 million kWh of electrical energy annually. Project features are briefly summarized in the following section and in Table 3-1.

Project Features

The Weeks Falls project consists of a run-of-the-river development, using the power potential of a drop of approximately 89 feet in the profile of the South Fork Snoqualmie River. The following are the project's significant features.

Diversion Weir

A rubber diversion weir, approximately 80 feet long and 8 feet high, was constructed across the river. The weir has a variable height, such that under flood flows a constant water surface elevation is maintained. Provision was made for the passage of the required 38 cubic feet per second (cfs) instream flow through the diversion weir to provide for the downstream passage of resident fish and to prevent the accumulation of sediment upstream of the weir structure.

Intake Structure

A concrete-lined channel was constructed leading from the pool above the diversion weir to a reinforced concrete intake structure housing trash racks, fish screens, and a closure gate.

Located on the bank of the river, the intake structure is approximately 20 feet wide, 90 feet long, and 30 feet high from foundation to the access deck level. At the upstream end of the structure, stoplog slots and inclined trash racks consisting of steel bars are provided. After passing through the racks, water flows through 14 travelling-belt, wire-mesh fish screens, having a total wetted area of 1,500 square feet.

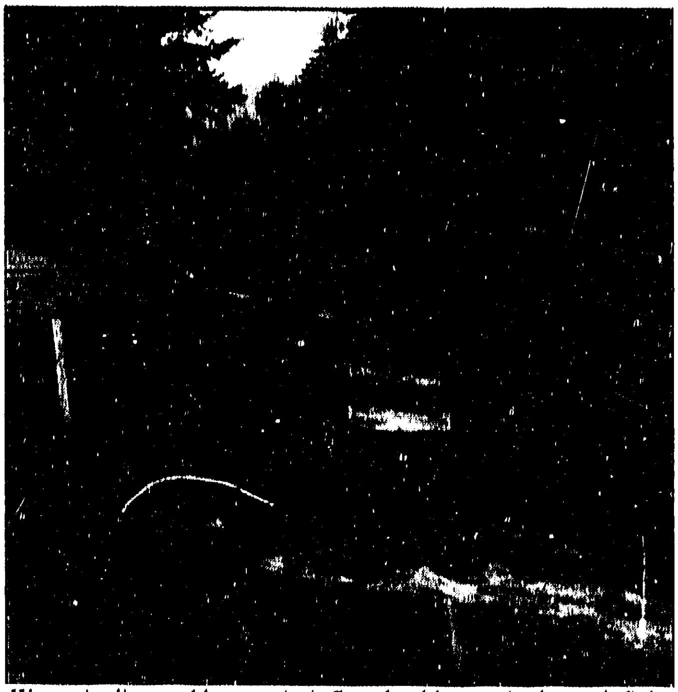
Power Conduit and Penstock

Water passing through the screens enters a subsurface tunnel inlet, where it is conveyed to the powerhouse. Approximately 600 feet of the tunnel is in rock that did not require lining. The downstream portion of the tunnel required a steel liner because of insufficient rock cover for the operating pressure.

Flowing over Weeks Falls the South Fork of the Snoqualmie River drops 87 feet in a distance of 750 feet.

Table 3-1
Summary of Project Features
Weeks Falls Hydroelectric Project

Location of powerplant	South Fork Snoqualmie River, RM 13.5 Sec. 34, T23N, T9E, W.M. Longitude 121 38' 50" Latitude 47 26' 00"	
Diversion weir	Length	80 feet
	Height	9 feet
	Crest elevation	1,239 feet MSL - variable
Impoundment	Normal water surface elevation	1,289 feet MSL
	Water surface area	3 acres - maximum increase
	Gross storage	3 acre-feet
Intake channel	Length	40 feet
	Bottom width	20 feet
	Bottom elevation	1,270 feet MSL
Intake structure	Length	60 feet
	Width	20 feet
	Invert elevation	1,268 feet MSL
	Access deck elevation	1,292 feet MSL
	Minimum wetted area of fish screens	1,160 square feet
Tunnel	Length	650 feet
	Diameter	10 feet
	Liner	60-foot steel liner
Powerplant	Total plant capacity	5.0 MW
	Type of operation	Automatic, run-of-the-river
	Number of units	1
	Type	Horizontal Kaplan
	Rating	
	Flow, cfs	711
	Head, feet	89
	Output, kW	5,000
Transmission line	Length	3,830 feet
	Voltage	34.5 kV
	Type	Buried cable
Estimated annual energy production	18 million kWh	
Total project capital cost	$7.7 million	



Water is diverted by an air-inflated rubber weir through fish screens to a powerhouse containing a 5-MW turbine/generator set.

Powerhouse and Tailrace

The main powerhouse structure is approximately 35 feet by 50 feet in area. The superstructure of the building was designed to blend appropriately with the surroundings.

The layout of the powerhouse provides for a single turbine-generator (a horizontal-shaft, double-regulated Kaplan unit), to be located on the machine floor, with the turbine draft tube discharging horizontally to the tailrace. As the available streamflow is allocated to minimum instream flow and power production requirements, outside of limited high flow periods, no space is available or necessary for the siting of future turbines.

Water leaving the turbine draft tube is directed to the river in a concrete-lined tailrace channel. Racks are provided in the tailrace for the protection of fish life.

Turbine and Generator

The turbine-generator equipment selected for the project consists of a single 5-MW horizontal-shaft Kaplan unit. The turbine is rated to produce approximately 6,500 hp at a rated head of 86 feet and a flow of 711 cfs. The synchronous generator is rated at 5,000 kVa, at 0.95 power factor, 4,160 V, 3-phase, and 60 Hz, and is equipped with rotating brushless excitation.

Transmission Line

A new transmission line was constructed to convey power generated by the project to the regional power network. The 34.5-kV underground transmission line connects to an existing 34.5-kV PSP&L line located alongside I 90.

Controls

The powerhouse control system is designed for fully automatic (unattended) operation with remote alarm monitoring. The control system allows the hydro unit to be operated manually or automatically from a main control switchboard located in the powerhouse.

Partnership Agreements, Financing, and Installed and Operational Costs

Project Ownership and Financing

The owner, South Fork II Associates, is a partnership consisting of two general partners: South Fork II, Inc., and Western Power, Inc., both Washington corporations. Western Power, Inc., is a wholly owned subsidiary of Pacific Hydropower, which in turn is owned by Pacific Lighting Energy Services, a subsidiary of Pacific Lighting of California. South Fork II, Inc., is an investor owned corporation. The project civil contractor was Gilbert-Pacific of Camas, Washington. The turbine-generator, controls, and substation equipment were provided by Axel Johnson Engineering Corporation of San Francisco, California.

South Fork II originated in the summer of 1980, when a group of investors contributed $10,000 to $15,000 each to raise $100,000 for project feasibility assessment and licensing. (At that time, licensing costs were on the order of $60,000 to $70,000.) The group submitted an Environmental Checklist to the King County Department of Community Development in September 1982. A Declaration of Non-Significance was issued by the County in November of 1982. As it was determined that the project would not have a serious adverse impact on the environment, an Environment Impact Statement was not required under the State Environmental Policy Act (SEPA). In August 1983, South Fork II followed up with an application to the Federal Energy Regulatory Commission (FERC) to construct, operate, and maintain the Weeks Falls project. The license was ultimately issued in April 1985. The original application was for a 3.5-MW powerplant consisting of two turbine-generator sets. The capacity was increased to 5 MW and the annual electrical production estimate raised from 13.5 to 18 million kWh following turbine-generator bidding and selection.

Project costs escalated in large part because of significant redesign requirements imposed on the fish screens by the regulatory agencies (primarily the Washington Department of Game, now the Washington Department of Wildlife). Project fish screen installation costs increased almost fourfold, from $285,000 to approximately $1 million.

With increased project costs and high interest rates, the project was marginal and some of the original investors could no longer participate. The investors also had to raise $1.5 to $2 million for equity purposes. Thus, new partners were brought in and some of the original investors were bought out at a 10 percent return on investment.

Two of the investors were integral to the project's success. Harry Hosey, of Hosey and Associates Engineering Company, performed project feasibility, licensing, design, specification preparation and equipment selection, power purchase contract negotiation, and construction management functions. Hosey also oversees two part-time attendants who maintain and operate the project.

The second key actor was Pacific Energy. Pacific brought capital, guarantees, and banking contacts to the project team. The project was able to get a $5.5 million construction loan from Citibank of New York at 2 percent less than prime. The availability of financing at an interest rate of less than 6 percent has considerably helped the project economics. Take-out financing has not yet been concluded.

It is important to note that the project would not have been cost-effective without the availability of the 10 percent investment tax credit, the 11 percent energy tax credit, and rapid depreciation (5 years under the accelerated cost recovery system).

Installed and Operating Costs

The total installed cost of the Weeks Falls project was $7.7 million ($1,542 per installed kilowatt). Project costs by component are given in Table 3-2. An early cost estimate with itemization by component is given in Table 3-3.

Table 3-2
Cost Summary
Weeks Falls Hydroelectric Project

Design and construction management	$1,100,000
Equipment	1,600,000
General construction	4,600,000
Nature trail	12,000
Utility interconnection	400,000
Total	$7,712,000

Table 3-3
Estimated Equipment and Construction Costs
Weeks Falls Hydroelectric Project

Powerhouse Equipment	
Turbine	$550,844
Generator	344,369
Hydraulic power unit	33,897
Turbine gate controller	12,500
Station service switchgear	38,094
Plant battery system	11,270
Main control switchboard	126,190
Generator breaker	49,930
Substation transformer and switchgear	84,340
Tailrace gate	40,000
Maintenance hoist	7,656
Sump and dewatering pump and piping	65,000
Oil/water separator	27,000
HVAC	25,000
	$1,416,090
Intake/Diversion Structure Equipment	
Inflatable rubber weir	255,000
Intake gate	40,000
Traveling belt fish screens	285,000
Diversion sluice gates	20,000
Sump pumps and piping	35,000
HVAC	15,000
Level control system	21,300
I/O panel	45,000
Motor control center	15,500
Service transformer	12,200
	$744,000
Powerhouse Equipment Total	$1,416,090
Intake/Diversion Structure Equipment Total	744,000
Access road	70,000
Transmission line	100,000
Powerhouse and tailrace structure	900,000
Intake/diversion structure	850,000
Power conduit	560,000
*Total	$4,640,090

*The ultimate project cost, including design and construction management, was $7.7 million.

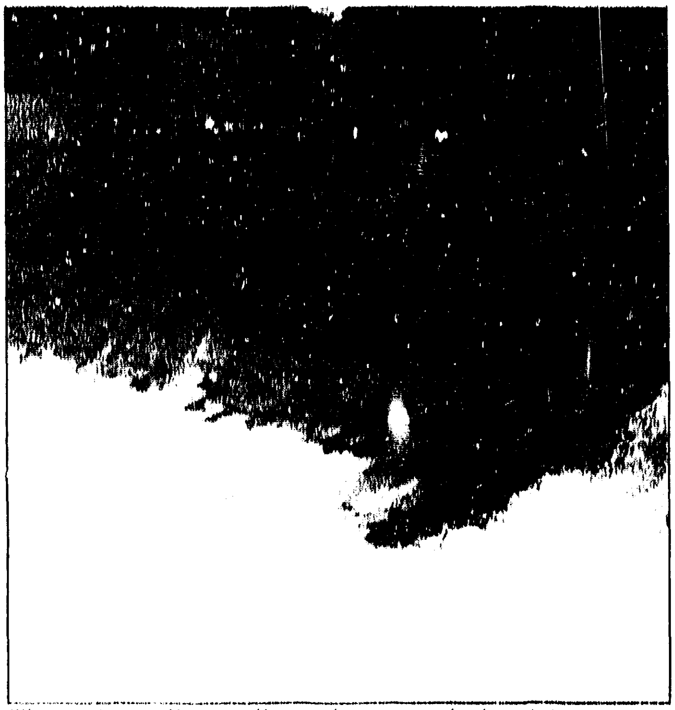
Small changes in the on line date can have a significant impact on the project's cash flow. As a run of the river project, Weeks Falls provides output from rainfall runoff from lower elevations during the fall, winter, and spring, and from high mountain snowmelt during April through July. The project would typically be shut down because of low flows in August and September. (Note: While the minimum instream flow requirement is only 38 cfs, a minimum discharge of 50 cfs is necessary to "roll the turbine." Thus, the power plant does not operate when the streamflow falls below 88 cfs.)

Because of equipment delivery delays, the project took 4 months longer to complete than was expected and had approximately $0.5 million in cost overruns. This delay was critical; the May startup missed the high flow, winter-spring runoff period. The plant operated for only 20 days and then was shut down until December (the project also had the misfortune of coming on-line during the drought of 1987). While the operators recovered some liquidated damages from the contractors, a good portion of the year's production was lost. Tax credit and depreciation benefits could also have been obtained one year earlier had the project been able to operate by December 1986.

Estimates of operating expenses (in 1987 dollars) include $32,000 for operations and maintenance, $15,000 for administration, $35,000 for insurance, $12,000 for property leases, and $63,000 for property taxes. A $20,000 repair and replacement account will be established in 2002.

Power Purchase Contract Negotiations

The project proponents approached Tacoma City Light (TCL), Seattle City Light (SCL), and PSP&L regarding purchase of electrical output from the Weeks Falls project. Initially, TCL was selected, with discussions of price in the 60-80 mill/kWh range. A power purchase contract was prepared and awaited presentation to the board. Two events, however, soured the deal. First, WPPSS occurred and Tacoma's appetite for new resources waned. Second, the Wallup Amendment changed the tax law such that the developers would receive no tax benefits if they sold to TCL. The possibility of TCL's purchasing and operating the generating plant was discussed, but the deal fell through.



The project will annually produce enough electricity to serve 800 average Washington homes.

The developers then again approached PSP&L and renewed their original offer. In 6 weeks, a power purchase contract was executed. The October 1984 contract calls for a fixed or levelized purchase price of 75 mills/kWh over a 35-year period. No capacity payments are included.

The Weeks Falls project benefited from the fact that South Fork II was also developing and negotiating a power purchase contract for the nearby 20-MW Twin Falls project. Taken together, the projects represent enough capacity to be of interest to the utility. In addition, both projects are located within PSP&L's territory. Both sites also produce the bulk of their energy during the winter heating period, when it is of greatest value to PSP&L.

Unusual sections of the power purchase contract include a provision designed to protect against overpayments under the levelized price agreement. A provision stipulates that "the amount of energy delivered to PSP&L during the first half of the Operating Period shall not be more than the amount of energy so delivered during the remainder of the Operating Period." If the amount of energy delivered during the first half of the Operating Period exceeds the amount delivered during the remainder of the Operating Period, then PSP&L may, at its option, extend the Operating Period until the earlier of the following two events: (1) energy in the amount of such excess has been delivered to PSP&L; or (2) PSP&L has given South Fork II written notice of termination.

This type of provision is better, from the point of view of the developer, than the frequently imposed but expensive requirement that the developer post a bond to cover the cumulative amount of overpayment in the event of a default or contract termination.

PSP&L also included a project buyout or "right of first refusal" clause. This restriction states that "South Fork II shall not transfer or permit the transfer of all or any portion of its interests in the project or this agreement, except as follows:

1. To any person or entity that directly or indirectly is controlled by the persons who control South Fork II;

2. To any person or entity within six (6) months after the expiration of the option described in paragraph 6.2, provided that such option is not exercised therein; or

3. To any other person or entity without the written consent of PSP&L."

The option clause gives PSP&L the right to purchase all of the project interests that are subject to the proposed transfer on terms not less advantageous to PSP&L than those which South Fork II is willing to accept from the proposed transferee. The option is exercisable at any time within 60 days after PSP&L receives written notice from South Fork II.

The contract also provides assurances and protection to the project developers by stating that while the agreement is subject to the rules, regulations, and orders of governmental authorities having jurisdiction over the project, the purchase price is not subject to adjustment by any governmental authority.

Permits and Licenses

All grid-interconnected hydropower projects must go through federal, state, and local licensing processes. On August 29, 1983, South Fork II filed an application with FERC to construct, operate, and maintain the Weeks Falls project. The Tulalip Tribes, the Washington Department of Fisheries (WDF), and the Washington Department of Game (WDG) filed petitions to intervene.

In their motions to intervene, the Tribes, WDF, and WDG contended that the construction and operation of Weeks Falls and other projects in the Snohomish River Basin would cumulatively contribute sediment to the rivers such that the anadromous fishery resources of the basin would be adversely affected. The petitioners further requested that a basin-wide Cumulative Environmental Impact Study be completed before a licensing decision was made.

In response to these assertions, South Fork funded two studies to determine the potential sediment load during both project construction and operation. The study found that, with control measures in place, construction of the project would contribute less than one ton of soil from the project site. In addition, potential erosion and sedimentation impacts associated with long-term operation of the project would be minimal.

As Weeks Falls is located 17 miles upriver from Snoqualmie Falls, an impassable barrier to the migration of anadromous fish, sedimentation was the only potential source of adverse cumulative impact. FERC thus found that it was not necessary for the project to be included in, or subject to, any Cumulative Impact Assessment Process (CIAP) that might be approved for the basin. The FERC license for Weeks Falls was issued on April 25, 1985.

Because of increased costs and lengthy as well as undetermined delays, inclusion in the CIAP process would have been a "project stopper." In fact, the Final Environmental Impact Statement for the other projects in the Snohomish River Basin was not released until June 1987.

The FERC license contains 37 articles that require South Fork II, among other things, to:

- Acquire title or the right to use all lands necessary for the construction, maintenance, and operation of the project

- Install and maintain stream-gaging stations and keep records

- Prepare a Report on Recreational Resources and construct, maintain, and operate reasonable recreational facilities

- Prepare a plan to control erosion, dust, and slope stability to minimize sedimentation and water pollution

- Maintain a continuous minimum instream flow of 38 cfs in the bypass reach
- Conduct studies to determine a ramping rate that ensures protection of downstream aquatic resources
- Design, after consultation with the U.S. Fish and Wildlife Service and the WDG, functional fish screens
- Coordinate with the Washington State Historic Preservation Officer (SHPO) regarding cultural resources survey and salvage work
- Begin construction within 2 years

In addition to the federal licensing process, the project developers had to obtain permits or approvals from the State Departments of Ecology, Game, Fisheries, Transportation, and Natural Resources; from the State Parks and Recreation Commission, the Office of Archaeology, and Historic Preservation, and from King County. Permits required by the State of Washington are summarized in Table 3-4. A preliminary time line for permit approvals is shown in Figure 3-1.

Potential Environmental Impacts

Fish, Wildlife, and Botanical Resources

The Washington State Departments of Ecology (WDOE), Game (WDG), and Fisheries (WDF); the U.S. Fish and Wildlife Service; the Tulalip Tribes; the National Marine Fisheries Service; and the Bureau of Indian Affairs were consulted prior to preparing a Report on Fish, Wildlife, and Botanical Resources.

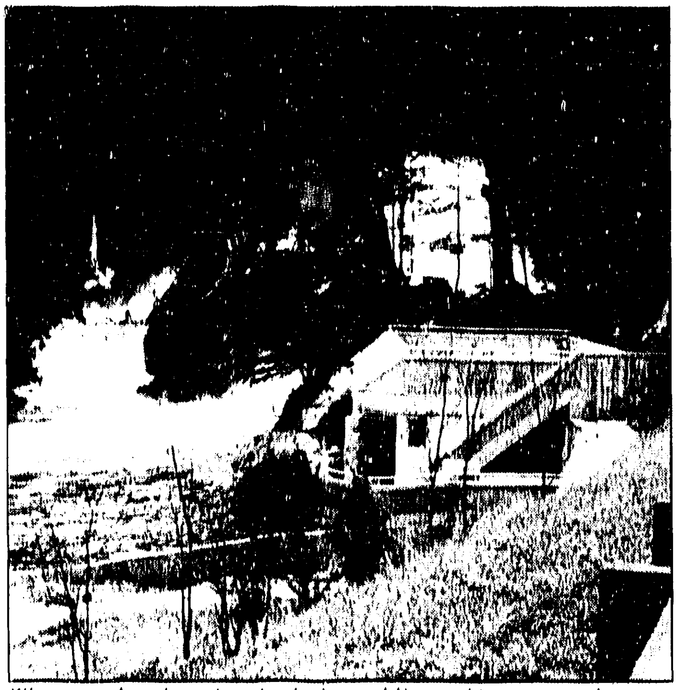
While the fish population in the proposed project area and its vicinity is limited, the pool downstream and the falls reach include high quality habitat utilized by resident trout species. WDG indicated that the project would have minimal impact on fish and wildlife resources and accepted a minimum instream flow (as established by the WDOE) based primarily upon the protection of aesthetic values and recreational resources.

The primary impacts on fish resources arise as a result of short-term increases in suspended sediments in the river caused by streambed disturbance and erosion of the adjacent streambank during construction. Timing restrictions for instream construction and appropriate construction techniques were specified to minimize this impact.

Consultation with the WDOE, the Natural Heritage Data System, the Washington Natural Heritage Program, and the WDOE-Nongame Program established that no special animal species occur in the project area. Consultation with the U.S. Fish and Wildlife Service Endangered Species Team determined that "there are no listed or proposed species occurring within the project area."

While smaller animals such as small mammals, song birds, and reptiles do reside within the project site, the steepness, narrowness, and riprap composition of the riverbank adjacent to the intake site limit its use by all animals. The lowland forest surrounding the powerhouse site does provide favorable habitat. The amount of land disturbed, however, is limited.

Consultation with the Washington Natural Heritage Program determined that *Lycopodium alpinum*, which has been classified SP (special plant) occurs in the general area. However, this species is unlikely to occur in the project vicinity because it is usually found above timberline and under boreal conditions.



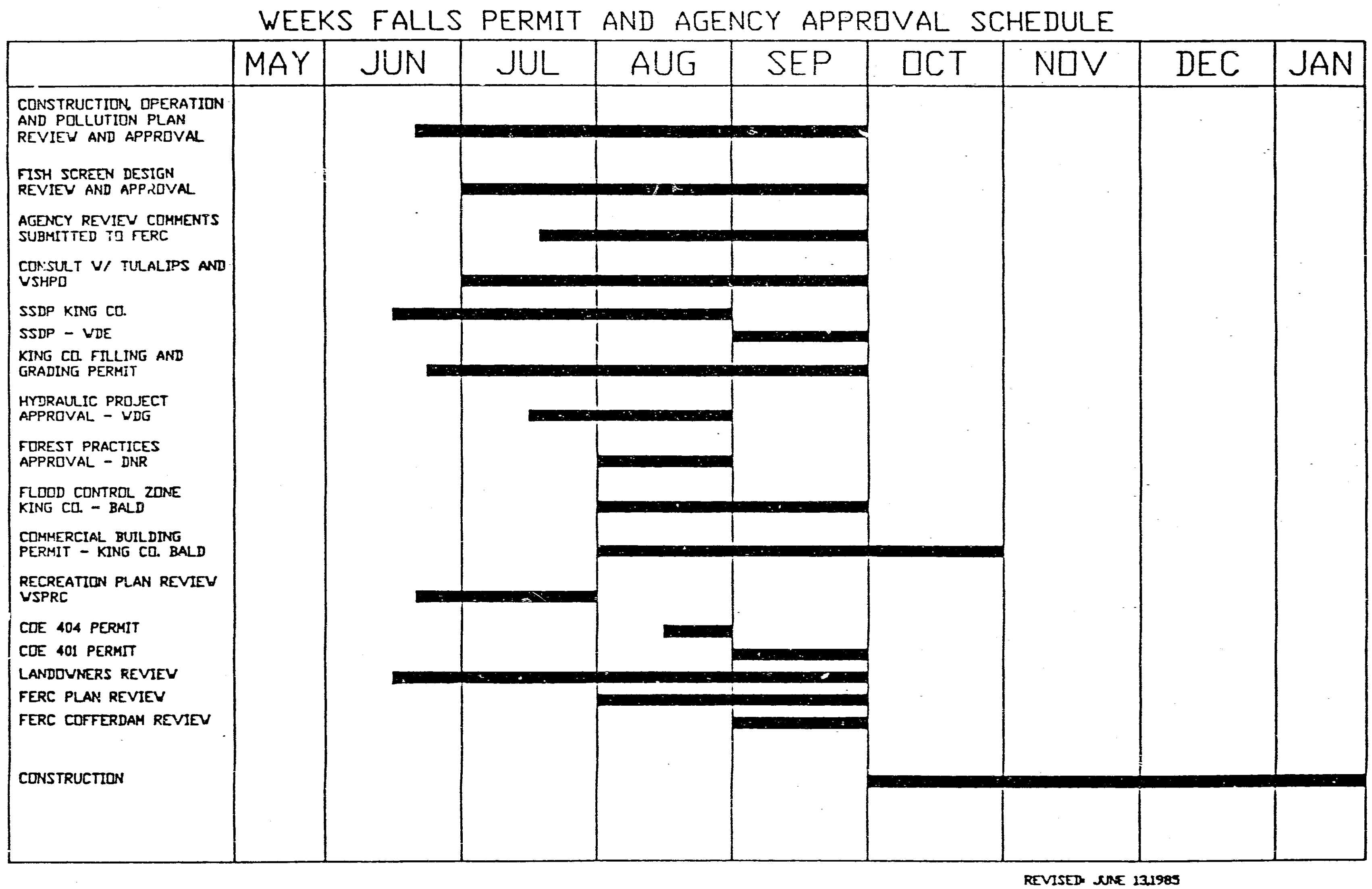
The completed project includes public parking, natural landscaping, handicapped access to a falls viewpoint, and nature trail with interpretive language.

Table 3-4
Permits and Approvals
Required by the State of Washington
Weeks Falls Hydroelectric Project

Agency	Statute or Regulation	Permit or Approval	Status
Dept. of Ecology	RCW 90.03	Permit to appropriate public waters (Water Right)	Permit applied for.
Dept. of Ecology	RCW 90.03 508-12 WAC	Reservoir Permit and Dam Safety Approval	Not required.*
Dept. of Ecology	PL 92-500 & 95-217 RCW 90.48 WAC 173-201 WAC 173-225	Water Quality Modification and Certification	Certification applied for.
Dept. of Ecology	RCW 86.16	Flood Control Zone Permit	King County; permit to be applied for as required.
Dept. of Ecology	RCW 90.16.050 RCW 90.16.060 RCW 90.16.090	Power Production License Fee	To be applied for.
Dept. of Ecology	RCW 90.58 173-14 WAC	Shoreline Management Review	Assigned to King County.
King County	RCW 90.58.140 173-14 WAC	Shoreline Management Substantial Development Permit	Permit applied for.
Dept. of Ecology	RCW 43.21C 197.10 WAC	State Environmental Policy Act of 1971 (SEPA) Compliance	Assigned to King County.
Dept. of Game	RCW 7520.100.	Hydraulics Project Approval	To be applied for prior to construction.
Dept. of Fisheries	RCW 75.20.100	Hydraulics Project Approval	To be applied for prior to construction.
Office of Archaeology & Historic Preservation	Executive Order No. 11593	Archaeological Approval	Approval granted.
Dept. of Health Services	248-54 WAC	Public Water Supply Approval	Permit to be applied for if required.
State Parks & Recreation Commission	RCW 43.51	Approval to occupy state land	To be applied for.
Dept. of Transportation	RCW 47.12.120	Airspace Lease Agreement	To be applied for.
Dept. of Natural Resources	RCW 76.09.010	Forest Practices Application	To be applied for.

*Because of the small size of the proposed diversion weir, the Washington Department of Ecology (WDOE) did not require a formal dam safety approval for the project. A reservoir will not be constructed; therefore, a reservoir permit is not required.

Figure 3-1
Time Line for Permit Approvals



At the powerhouse, one-half acre of Douglas fir (125 trees, mean diameter 9 inches) and one-quarter acre of red alder (50 trees, mean diameter 7 inches) were removed. Where feasible, areas not occupied by project features were revegetated. No major vegetation removal was required for the excavation and construction of the buried 3,830-foot-long transmission line and only a few individual red alder or Douglas fir had to be removed during construction of the power tunnel.

Water Use and Quality

A report was prepared and impact mitigation approaches developed in consultation with the federal, state, and local agencies with responsibility for management of water quality and quantity for the South Fork of the Snoqualmie River. These agencies include the WDOE, U.S. Army Corps of Engineers, the U.S. Environmental Protection Agency, and King County.

The WDOE has established water quality standards for the streams and rivers of the state, depending on their location and use. In the project's vicinity, the South Fork Snoqualmie River is a Class AA stream. To benchmark the existing water quality, South Fork II monitored dissolved oxygen, dissolved solids, suspended solids turbidity, temperature, nutrients, bacteria, and chlorophyll *a* for a period of one year. Special care was taken by the contractor to prevent cement or petroleum products from entering the river during placement of coffer dams for the construction of the diversion weir and powerhouse.

Recreational Resources

A report was prepared in consultation with the Washington State Parks & Recreation Commission (WSP&RC), the National Park Service, and the Washington Interagency Committee for Outdoor Recreation. The study considered the recreational opportunities offered by the project with respect to needs expressed in the Washington Statewide Comprehensive Outdoor Recreation Plan.

The project boundary doe not encompass restricted areas such as river segments that have been included in or designated for study for inclusion in the National Wild and Scenic Rivers System, lands within the National Trails System, or wilderness areas designated under the Wilderness Act.

Historic and Archaeological Resources

An on-foot reconnaissance of the site was conducted to record and evaluate any archaeological resources, study the shape of the terrain and its suitability for ancient habitation, visually survey the site for artifacts, and assess the site's importance to the total history and prehistory of the area. As there are no existing records or indications of use of the immediate project area by the Snoqualmie Tribe, it was determined that the project would have no significant impact on cultural resources.

Impact Mitigation Strategies

A variety of construction techniques and operating measures were/are employed by the project developers to preserve aesthetics, maintain fish and wildlife habitat, and eliminate adverse water quality impacts. Mitigation strategies include the following:

- Establishment of a 38-cfs instream flow requirement. Instream flows are reduced during project operation over an 850-foot stretch of the river. A 38-cfs instream flow was established for this bypass reach, which is equivalent to the 7-day, 10-year low flow event. This discharge approximates typical summer low flow conditions and is maintained for aesthetic purposes.

- Installation of 14 travelling-belt fish screens with differential water level monitors. Measures to protect resident fish populations include one-quarter-inch screen spacing to prevent fish entry into the penstock, a fish return pipe to direct fish that have entered the intake structure back to the river, and a maximum design velocity of 0.5 feet per second for flow approaching the fish screens.

- Provision for bedload passage. A permanently open outlet pipe in the weir allows for continuous downstream passage of natural bedload. During high flows, the rubber weir deflates as needed to maintain the headwater level up to the point where the rubber weir is completely deflated and lies flat on its apron. This facilitates bedload movement since the primary transport mechanism is via flood flows.

- Establishment of ramping rate limitations. Studies performed on the diversion reach indicate that because of the river gradient in the diversion reach (approximately 10 percent), little increase in water level will occur (estimated to be less than one foot with full load rejection). Because of the width of the river downstream of the powerhouse, the stage increase from minimum flow will also be less than one foot.

- Design to eliminate dissolved gas problems. The intake structure is designed and located to achieve sufficient submergence to prevent vortices, air entrainment, and consequent supersaturation of dissolved gases. The buried penstock will minimize temperature rise of diverted waters. The project design features an upstream control mechanism to monitor flows entering the reach, with automatic controls to operate the bypass or the intake gate to assure that the prescribed instream flows are maintained.

- Racking the tailrace pipeline outlet with a bar spacing of one inch to prevent resident adults from entering powerhouse discharge waters.

- Establishing a maximum water velocity leaving the tailrace to prevent scouring of the natural bank and river bottom.

- Revegetation of disturbed streamside areas according to WDG guidelines.

- Burying the 34.5-kV transmission line in order to protect raptors.

- Scheduling major construction activities during the summer months, when the flow is expected be less than 200 cfs, to avoid impacts on incubating or spawning trout.

- Disposal of approximately 8,000 cubic yards of spoils (rock and till) in a nearby gravel pit. Surface soil materials were stockpiled and utilized for site restoration, corrective grading, and landscaping.

- Use of such erosion control methods as contained excavation, drainage controls, settling ponds, and sediment disposal.

During the course of consultation with WSP&RC staff, South Fork II developed a formal recreation and aesthetic design program for the project. The design program areas include: (1) developed recreation facilities; (2) architectural design of the powerhouse; (3) development of a formal fails overlook; (4) aesthetic treatment of the diversion weir and intake structure; and (5) aesthetic treatment of plant electrical equipment and the transmission line.

WSP&RC required the physical area of impact caused by the presence of the powerhouse to be limited, while at the same time asking that all electrical equipment normally placed outside be housed internally within the powerhouse superstructure. The design solution included excavating the foundation as deep as was cost effective and siting the powerhouse slightly downstream of the technically optimum location to tuck the structure into a more prominent side slope that exists there. Additional aesthetic treatment included board-formed concrete construction, which was painted to blend with neighboring trees and exposed geological features.

The recreation plan was designed to preserve use patterns and facilitate public use of Weeks Falls. To attain this goal, South Fork II included: a hiking trail joining a remote parking area with the powerhouse and falls overlook; fisherman access routes leading from the trail to river's edge; public contact with and access around the powerhouse; handicapped parking accessible to the falls overlook; and a formal falls overlook that enables safe access to views of the falls. The cost for the construction of the proposed trail and overlook was approximately $30,000.

Additional expenditures required to accommodate WSP&RC design criteria included an estimated $50,000 for powerhouse redesign to render it visually aesthetic, $100,000 for the burial of the transmission cable, $20,000 for burial of the intake structure, and $20,000 for location of the powerhouse downstream 50 feet more than required technically to separate it from the falls. The total cost of the recreation proposal and the additional mitigating measures is estimated to be $220,000. This cost is incorporated in the total direct construction cost.

Land Use Agreements

The project site lies immediately adjacent to Interstate 90, the major east-west thoroughfare across the Cascade Mountains from western Washington. The character of the site was dramatically influenced by the development of I 90 and parallel railroad and transmission line corridors. In fact, realignment of I 90 (1969-1971) required rechanneling the South Fork Snoqualmie River and obliterating the uppermost of three waterfalls.

Little additional impact occurred to terrestrial resources since the project area is limited in extent (less than 2 acres) and confined to a narrow strip between the river and Homestead Valley Road.

The property on which the site is located is owned by the state of Washington and divided into two administrative jurisdictions. The diversion weir, powerhouse, and portions of the intake structure, penstock, and transmission line, are located on land administered by the WSP&RC. The penstock, transmission line, and most of the intake structure are located on land administered by the Washington State Department of Transportation (WDOT).

WDOT required South Fork II to secure a temporary construction permit, an airspace lease (for construction of the intake structure and tunnel), and a franchise for the underground transmission line and access roads.

South Fork II's airspace lease for project grounds has a term of 50 years or the term of the lessee's existing FERC license, as it may be amended, whichever is later. South Fork also holds an option to renew the lease. Rent for the leased premises consisted of a lump sum payment of $10,775 plus a Washington State Leasehold Excise Tax of $1,383. South Fork II also obtained a "utility" franchise to construct, operate, and maintain its buried 34-kV power line and appurtenances, and paid $450 to obtain a perpetual easement to construct and maintain a roadway. South Fork II also signed a Construction Agreement with WDOT that addressed timber protection and timber salvage. South Fork II was required to post a surety blanket bond of $75,000.

South Fork II negotiated a January 1986 Construction Entry and Perpetual Use Permit with the WSP&RC. The agreement calls for an annual payment of $12,000, which is reduced to $2,500 per year plus an inflation adjustment after a permit is negotiated and payment is made for use of the adjacent Twin Falls hydropower site.

WSP&RC required the project owner to provide replacement lands for a public trail corridor between Twin and Weeks Falls. The permittee must also maintain a policy of combined bodily injury and property damage insurance in an amount of not less than $5 million, naming WSP&RC as coinsured.

Finally, South Fork II negotiated an October 1984 Memorandum of Understanding (MOU) with the Tulalip Tribes. Under the terms of the agreement, South Fork would present the Tribes with detailed construction and operation plans and a soils report. South Fork would also reimburse the Tribes for legal and biological costs incurred during project monitoring.

Project Construction

Construction was initiated in April 1986 and the project started up in May 1987. The construction schedule for the Weeks Falls project is shown in Figure 3-2. A bonus was offered to the construction company for early completion.

The on-site manpower requirement for the duration of project construction was expected to average 20 people per day and to generate $80,000 in monthly payroll. In peak periods of construction, on-site personnel increased to approximately 40 persons with a monthly payroll of $160,000. Operation and maintenance of the automatic, remotely operated project requires two part-time employees.

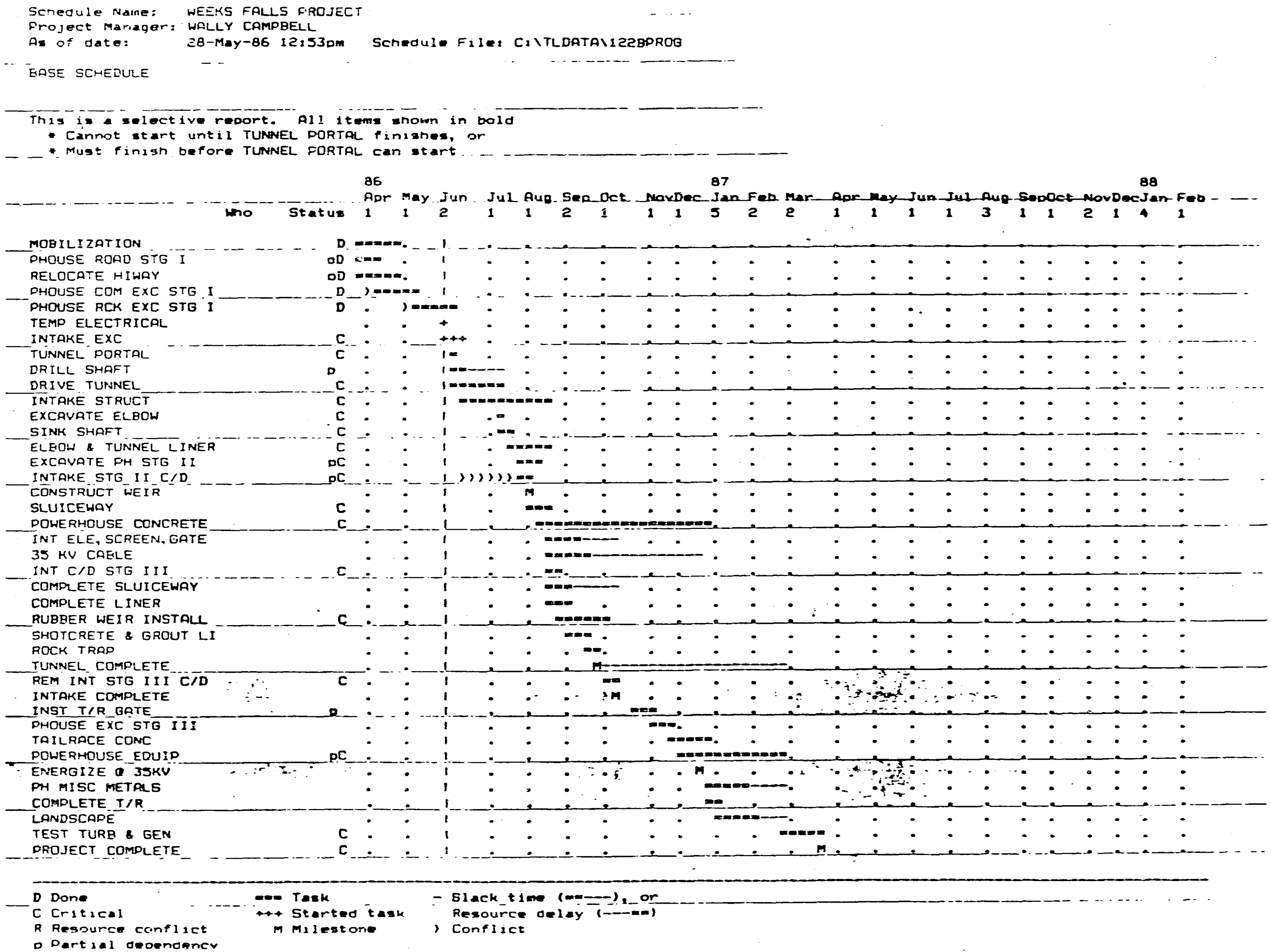
A critical construction item was the agency requirement that instream work be completed during the August to September low flow period. Missing this window could lead to a one-year delay in project completion.

South Fork II carries a full spectrum of insurance coverage, including $25 million in public liability, boiler and machinery coverage, property damage, fire, and business interruption. The insurance company was somewhat concerned over the public entry and access aspects of the project concept. Cost of the insurance is about $35,000 per year.

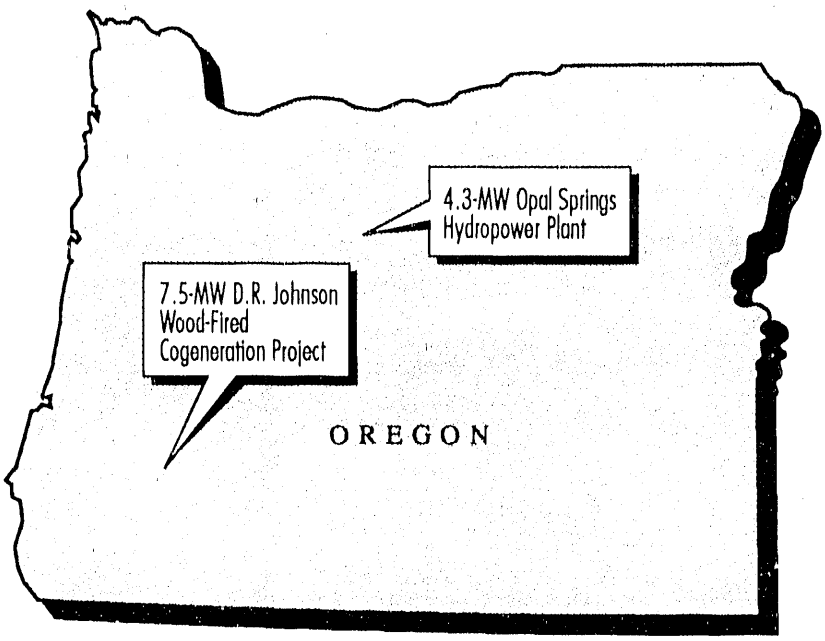
Interconnection, Transmission, and Wheeling Considerations

Wheeling (to Seattle or Tacoma City Light) was not an issue. When PSP&L was selected as the power purchaser, the project developer ran a 3,830-foot, 34.5-kV buried transmission line to interconnect with a 34.5-kV PSP&L circuit running underneath I 90. PSP&L originally estimated an interconnection cost of $100,000. Final charges came to $350,000, with the developer covering the cost overruns.

Figure 3-2
Construction Schedule for Weeks Falls Project



OREGON CASE STUDIES



Chapter 4

D. R. Johnson Lumber Company (CO-GEN II) 7.5-MW Wood-Fired Cogeneration Plant Riddle, Oregon

Project Description

In 1987, the D.R. Johnson Lumber Company completed a 7.5-megawatt (MW) wood-fired cogeneration plant located in Riddle, Oregon. The project is called CO-GEN II, after the partnership that owns the plant. The developer is a private limited partnership, wholly owned by Don and JoAnne Johnson and immediate family. Hog fuel from the adjacent company-owned mill supplies the plant. The hog fuel feeds a Wellons 4-cell combustion unit and boiler that generates an average 105,000 pounds of steam per hour. The cogeneration plant is a topping cycle system, i.e., it produces electricity first and process heat second. Steam drives a rebuilt General Electric turbine generator rated at 7,500 kW. Steam is then extracted from the turbine to supply dry kilns at the same mill. Electrical generation is 63 million kWh per year at design conditions.

Table 4-1
CO-GEN II Plant Capital Costs

Item	Amount
Boiler, turbine refurbish, etc.	$7,117,520
Fuel handling system	487,000
Capitalized interest	319,050
Insurance & bonds	90,000
Loan & bank fees	75,000
Switchyard & interconnection	56,000
Engineering	25,000
Makeup water system	20,000
Site preparation	20,000
Permits	5,000
Subtotal	$8,214,570
Startup & contingency	230,000
Total	$8,444,570

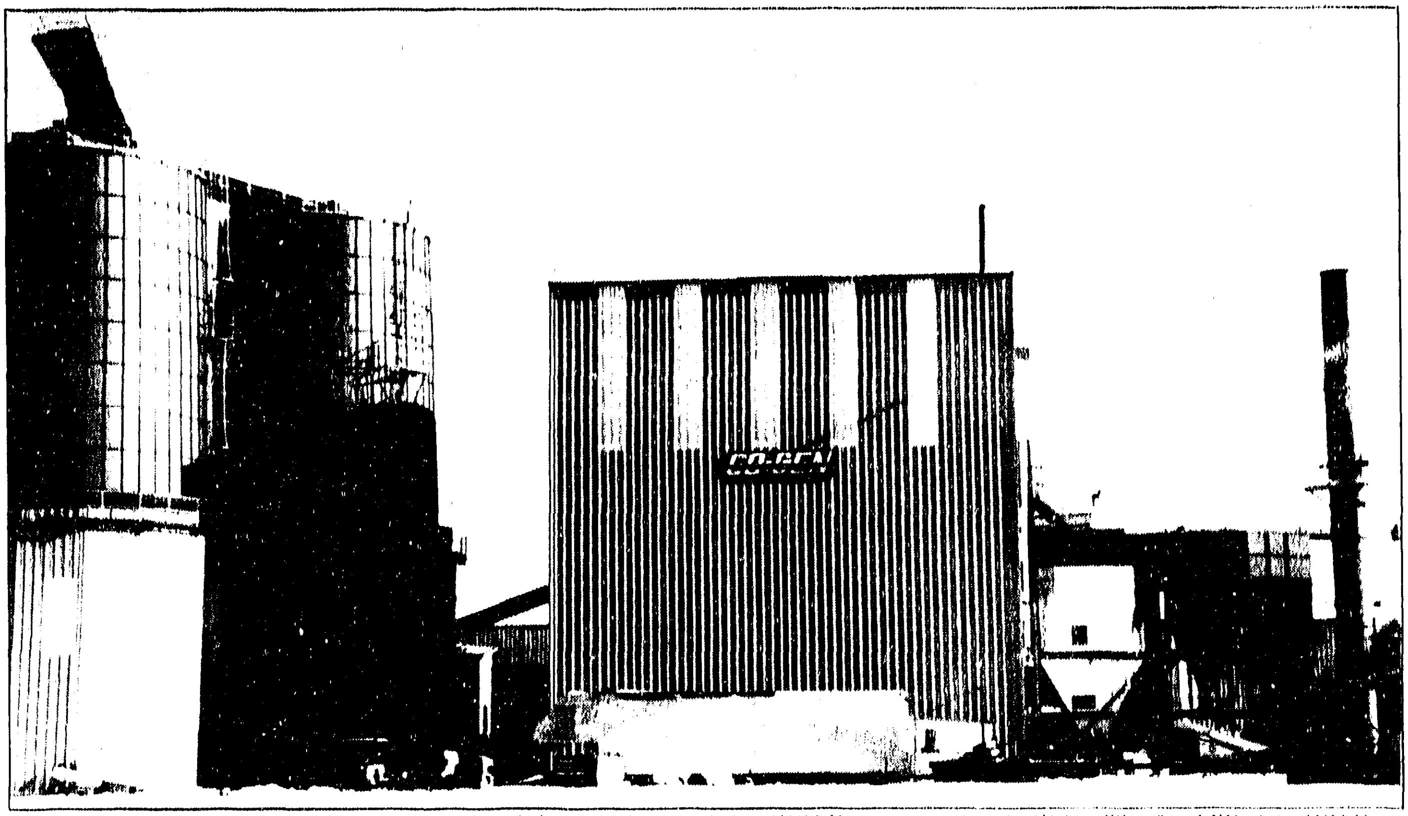
Project Costs

Cost data for the CO-GEN II plant are shown in Table 4-1. Project capital costs are grouped into general categories. Primary cost items are the combustor, boiler, and turbine generator. The turbine is a refurbished General Electric turbine, which was bought in New York and extensively refurbished by the primary contractor, Wellons Inc., of Sherwood, Oregon. Wellons supplied the combustors and boiler as well, in one turn-key bid. It is therefore difficult to determine subcomponent costs.

Table 4-2 shows a range of operating and maintenance costs for CO-GEN II, projected from the company's identical plant operating in Prairie City, Oregon. Costs will vary at different sites, hence the range is provided.

Table 4-2
CO-GEN II Plant Operating and Maintenance Costs

Item	$/Year (thousands)
Fuel	850 - 1,400
Operating labor	150 - 300
Maintenance labor	120 - 180
Property taxes	100 - 140
Supervision	60 - 100
Maintenance parts	60 - 90
Shutdown costs	48 - 72
Chemicals	40 - 80
Overhead	25 - 45
Operating supplies	24 - 36
Contract repairs	24 - 36
Insurance	8 - 12
Total	$1,509 - 2,491



The D.R. Johnson Lumber Company completed the CO-GEN and CO-GEN II cogeneration facilities. The 7.5-MW CO-GEN II project came on-line in 1987 at an installed cost of $8.2 million. The 63-million kWh of annual electrical generation is sold to Pacific Power & Light while process steam is used to supply dry kilns.

Annual hog fuel needs are 76,000 bone dry tons. Fuel supplies are valued at $15 per bone dry ton delivered to the plant. This price represents the historically recent average price in the Riddle area. D.R. Johnson mills in Riddle produce about 20,000 bone dry tons per year of hog fuel. The company will increase that amount if any mill expansions occur in the future.

Until then, hog fuel is bought from any of six nearby forest products mills. These mills indicated to the developer that over 100,000 bone dry tons of hog fuel are available in the immediate area. The only large consumer of hog fuel in the area, Hanna Nickel Co., does not currently buy it. Should it prove economic, the developer may continue purchases of lower value hog fuel and sell his higher value chips and shavings. Finally, logging residues are available. The surrounding Forest Service and Bureau of Land Management lands could provide an additional 200,000 dry tons of fuel per year if the plant required it. However, logging residues would cost substantially more than hog fuel.

Plant labor costs are conservatively estimated for 16 new, full-time positions. These include 10 operations staff, 5 maintenance personnel, and one supervisor. Included in operating supplies is water bought from Douglas County. The developer pays $11,520 per year for 199 acre-feet of water. The water comes from the Galesville Dam.

Power Sales

Negotiations between D.R. Johnson and Pacific Power & Light (PP&L) began in 1982. On September 17, 1982, PP&L filed its then-current avoided costs with the Oregon Public Utility Commission. Avoided costs submitted in that filing formed the basis of discussions between the developer and PP&L.

The parties signed a Power Purchase Agreement on September 29, 1983. The contract called for power sales to begin by December 31, 1987. The term is for 20 years, expiring on December 31, 2006. Power prices include both capacity and energy payments. A capacity payment of $7.57/kW/month is provided for. Energy prices are partially levelized; they escalate according to the schedule shown in Table 4-3.

Thus, PP&L is paying more for energy in the first years of the contract. PP&L will recover payments in the later contract years. This is reflected by the moderate escalation rates (1.3 to 2.6 percent) during all years of the contract. Such power pricing mirrors the utility Revenue Requirements accounting method used to recover plant capital costs.

Table 4-3
CO-GEN II Plant Energy Prices

Contract Year	Cents/kWh
1987	6.72
1988	6.81
1989	6.90
1990	7.00
1991	7.11
1992	7.22
1993	7.34
1994	7.46
1995	7.59
1996	7.73
1997	7.88
1998	8.04
1999	8.21
2000	8.39
2001	8.57
2002	8.77
2003	8.98
2004	9.21
2005	9.45
2006	9.70

Steam generated by the cogeneration plant is put to a process use after generating electricity via extraction from the turbine. Kiln dryers at the lumber mill nearby use approximately 16,000 pounds of steam per hour. Since the same company owns both the powerplant and lumber mill, the developer chose not to account for steam sales in project revenues; power sales are the driving force of this project.

Project Financing

The developer successfully built an identical plant in 1986 at another subsidiary lumber mill in Prairie City, Oregon. D.R. Johnson Lumber Company, using a wholly owned limited partnership (CO-GEN I), financed that plant in 1984, using the Oregon Small Scale Energy Loan Program (SELP). This program functions as an "energy bank," managed by the Oregon Department of Energy. SELP raises funds by selling Oregon's general obligation bonds on the open market. The bonds are exempt from both state and federal tax. SELP then finances projects that either produce or conserve energy. Resulting energy (and dollar) earnings or savings must be sufficient to repay the loan. SELP loans are conventional, low risk, credit-backed financings. Such loans require additional security and collateral beyond the project.

For the Prairie City cogeneration plant, SELP allowed the developer to put up 10 percent equity for the project and borrow the remaining 90 percent. Debt was a 10-year loan at about 11 percent, the tax-exempt market rate in late 1984.

D.R. Johnson sought similar terms from SELP for the CO-GEN II project, as both plant configuration and ownership were the same as in Prairie City. However, the demonstrated success of CO-GEN I made commercial lenders more comfortable providing attractive repayment terms. Interest rates were also well below 1984 levels. The company ended up financing the plant through an Oregon bank.

The State of Oregon provides other incentives for energy projects. The Business Energy Tax Credit (BETC) program allows a 35 percent state tax credit based on the cost of the qualifying energy equipment. The tax credit is spread out over 5 years: 10 percent in years 1 and 2, and 5 percent each in years 3, 4 and 5. The Riddle project applied for and received a state energy tax credit.

Permits and Licenses

D.R. Johnson Lumber Company obtained one federal, four state, and six local permits for this project. Table 4-4 lists these permits, the issuing agency, the date applied for, and the cost, where known.

One additional approval the developer sought was not required by law. A condition of the Power Purchase Agreement was Oregon Public Utility Commission (OPUC) approval of the contract prices. Approval was given in December 1983. OPUC rules require only that utilities submit either a copy or a summary of the contract to the OPUC. However, past practice had the utility submitting the actual contract to the OPUC for approval. OPUC staff would review contracts and make approval recommendations to the Commission. That practice changed in early 1987. The OPUC no longer approves such contracts, and has so informed regulated utilities.

Table 4-4
CO-GEN II Plant Permits

Permit	Agency	Date Issued	Cost ($)
Notice of Qualifying Facility Status	FERC	10-20-86	n/a
Boiler/Pressure Vessel Installation	OBCA	10-26-86	10
Electrical Safety Inspection	OBCA	12-09-86	n/a
Air Contaminant Discharge	ODEQ	12-15-86	2,685
Water Pollution Control Facilities	ODEQ	12-15-86	800
Conditional Use	DCPD	8-14-86	25
Land Use Compatibility Statement	DCPD	8-15-86	0
Solid Waste Disposal	DCED	10-29-86	0
Building	DCBD	11-18-86	1,336
Plumbing	DCBD	11-25-86	75
Road Right-of-Way Use	DCR	3-27-87	0

Note:
FERC = Federal Energy Regulatory Commission
ODEQ = Oregon Department of Environmental Quality
OBCA = Oregon Building Codes Agency
DCPD = Douglas County Planning Department
DCBD = Douglas County Building Department
DCED = Douglas County Engineer Department
DCR = Douglas County Roadmaster

Environmental Impacts

A chief environmental aspect of this project is positive: solid waste disposal. For high quality forest product mill residues (chips and shavings), fiber market demand remains fairly constant. Chips and shavings supply pulp, paper and particleboard-type products. In contrast, hog fuel is traditionally not a good fiber feedstock because of its high bark content. It is a good industrial energy fuel, but demand varies widely with lumber production. In the past, hog fuel disposal was frequently simple incineration, using "teepee" style burners with no pollution controls. An energy market for hog fuel developed and continues in densely populated areas such as the Willamette Valley. Remote sites, however, suffer a transportation cost penalty that limits hog fuel uses. Therefore, disposal still occurs in many remote areas either through burning or landfilling. Both disposal methods are unsatisfactory, wasting air, fuel, and land. Cogeneration efficiently disposes of hog fuel, controls combustion emissions, and recovers maximum energy in the process. Ash from the burner, about 1 percent by volume of the fuel, is disposed of in the county landfill.

The environmental tradeoff for burning wood, however, is air emissions. Experience shows that proper combustion itself minimizes air pollution. The combustion system designer and manufacturer, Wellons Inc., guaranteed compliance with state and federal permit requirements. Combustion at the CO-GEN II plant incorporates four "cyclo-blast" round fuel cells. Each cell has overfire combustion air inlets at three levels through the walls in addition to the undergrate air. The CO-GEN II plant system design includes an economizer, a combustion air preheater, an exhaust gas recirculation system, and a Wellons multiclone particulate collector. This design results in optimum combustion, especially for particulates. Exhaust gas recirculation allows a second chance to burn particulates and carbon monoxide. The multiclones are a standard 8-inch-diameter tube size. These cyclones are effective at removing remaining particulates from stack gases.

Hog fuel is by nature sulfur-free. Emissions of concern are particulates, carbon monoxide, nitrogen oxides, and volatile organic compounds. Requirements of the Air Contaminant Discharge permit issued by ODEQ call for periodic source tests to measure these emissions. Table 4-5 shows permitted emissions for CO-GEN II.

Table 4-5
CO-GEN II Plant Emissions

Item	Tons/Yr
Particulate	149
Carbon monoxide	179
Nitrogen oxides	126
Volatile organic compounds	63
Sulfur dioxide	7

Because the CO-GEN II plant emits less than 250 tons/year total for each of these pollutants, it is subject neither to New Source Performance Standards nor Hazardous Air Contamination Procedures review. It is also exempt from conducting an air quality analysis of pollutants. ODEQ staff determined that CO-GEN II would not have a significant impact on a nonattainment area (Riddle is an attainment areai.e., its air quality meets federal standards).

Water impacts center around sources for makeup and cooling water, and disposal after use. For CO-GEN II, makeup water comes from a County reservoir. There are no surface or groundwater withdrawal impacts to mitigate. Wastewater comes from boiler and cooling tower blowdown and demineralizer water. It is all discharged to a seepage pond. No direct discharge to state waters occurs. All blowdown is neutralized such that the pH ranges between 6.0 and 8.0. The developer measures seepage pond discharge flow and pH daily. Sodium, chloride, total dissolved solids, and specific conductance are measured quarterly.

Land use impacts are minimal. Many factors contributed to site selection: the plant site had an existing wood-fired boiler and fuel silo on it; the site is only 4 acres in size; part of that 4 acres is in a heavy industrial zone; it adjoins industrial property (the mill) to the south; and the existing mill buffers the powerplant from the nearest residential development.

Project Construction

The CO-GEN II plant construction schedule was determined by two external factors--the construction of the plant at Prairie City and the power purchase contract, which called for electricity delivery to PP&L by December 31, 1987. D.R Johnson negotiated power purchase contracts at roughly the same time in 1982 and 1983. However, the Prairie City plant contract called for operation two full years (December 31, 1985) before CO-GEN II. Efforts therefore focused on building that plant first. Construction of CO-GEN I finished in November 1985. The 2-year window between contract power delivery dates to the utilities then allowed D.R. Johnson to focus on CO-GEN II.

At that time, preliminary work was already underway on CO-GEN II. D.R. Johnson bought the turbine in 1984 and began refurbishment in early 1986. Plant construction began in the third quarter of 1986. The facility went into commercial operation October 1, 1987.

Interconnection and Transmission Factors

The electrical interconnection equipment consists of the switchyard, switchgear, main and auxiliary transformers, bus duct, control equipment, and powerline connection. Total cost was about $56,000. The switchyard is between the plant building and an existing power line. CO-GEN II paid for all interconnection equipment. PP&L reviewed protective devices used in the interconnection. Actual connection to the utility system was under the direction of PP&L. CO-GEN II generates 13,800 volts of electricity, which is stepped up at the transformer bank to 69,000 volts to match PP&L's system. No transmission or wheeling issues arose because the power purchaser is the local utility.

Chapter 5

4.3-MW Opal Springs Hydropower Plant Madras, Oregon

Project Description

In January 1985, the Deschutes Valley Water District (DVWD) began operating the 4.3-MW Opal Springs hydroelectric plant, located near Madras, Oregon. The project is named after source springs in the bottom of the Crooked River Canyon. The springs supply domestic water for the Culver area south of Madras, and have been used since the early 1900s. The developer is a municipally incorporated domestic water supply district, which operates the Opal Springs water system. Prior to the project, the DVWD diverted water from the river upstream of the springs to drive turbines, which in turn drove pumps. The pumps lifted spring water over 900 feet out of the Crooked River Canyon to the surrounding plateau. This project adds to the original function of pumping domestic water.

The project consists of diversion, conduit, penstock, surge tank, powerhouse, and transmission facilities. Other related features include a new bridge and pumphouse. An existing diversion dam was first raised from 6 to 10 feet high. The dam is to build head, not storage. River water flows first into two 12.5-foot-diameter, 1,200-foot-long conduits. From the conduits, water then enters a single 16-foot-diameter penstock, going 175 feet to the turbine. Diversion design provides a head of about 40 feet. Diversion supplies an average 1,500 cubic feet per second (cfs) of Crooked River water to the powerplant. The project is a run-of-river project, with flows over 2,000 cfs cresting the dam. Water drives a turbine generator rated at 4,300 kW. Electrical generation is 23 million kWh per year at design conditions.

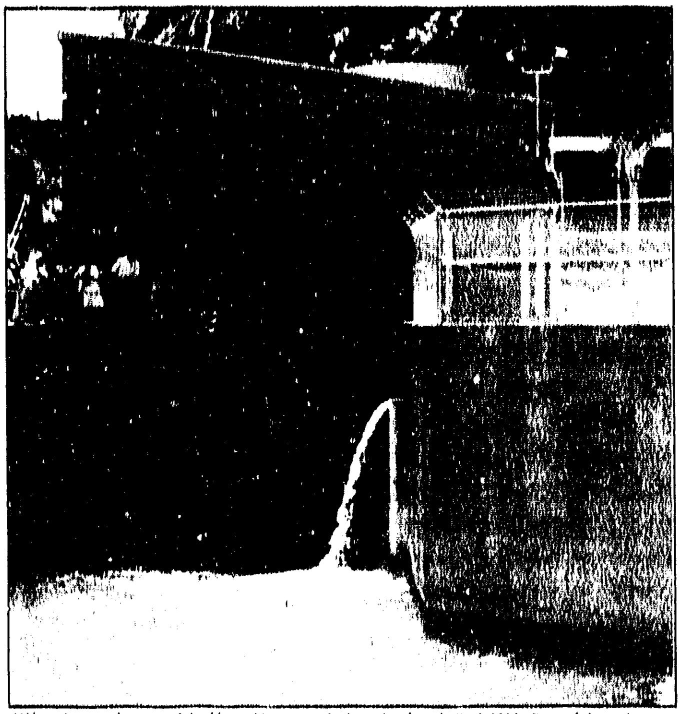
Project Costs

Cost data for the Opal Springs project are shown in Table 5-1. The primary cost items are the diversion and intake structures, conduits, powerhouse, turbine generator, and transmission lines. The turbine is a new Allis-Chalmers horizontal grated, tube-type, 3-meter turbine.

Table 5-1
Opal Springs Plant Capital Costs

Item	Amount
General civil	
Site preparation	$300,000
Diversion	556,500
Intake	830,000
Conduits	526,100
Bifurcation	640,000
Penstock	570,000
Pumphouse	1,611,500
T-G installation	180,000
River channel	5,000
Subtotal	5,219,100
Telemetering	77,230
Steel culverts	401,140
Pumphouse mechanical & electrical	250,000
Turbine generator	1,925,000
Substation	30,000
Transformer	93,895
Transmission line	518,700
Bridgework	200,000
Startup	10,000
Engineering	1,106,920
Contingency	910,515
Revenue reserves	1,684,500
District expenses	356,500
Capitalized interest	2,931,500
Earnings during construction	(1,415,000)
Total	$14,300,000

Table 5-2 contains operating and maintenance costs for Opal Springs. Plant labor costs are based on three new, full-time positions. These include two operators and one supervisor. In addition, the new plant will account for a portion (20 percent) of the general manager's time and salary. Figures in the table are conservative first-year estimates. Actual costs have been slightly lower. "Fuel" costs nothing, a big cost savings unique to hydroelectric plants. Domestic water pumping is included in the Opal Springs operations and maintenance costs.



The Deschutes Valley Water District's 4.5-MW Opal Springs powerplant produces 23 million kWh of electricity per year. Energy from the $14.3 million project is sold to Pacific Power & Light at a rate based upon projected avoided costs. The Water District financed the Opal Springs project using the Oregon Small Scale Energy Loan program.

Table 5-2
Opal Springs Plant Operations and Maintenance Costs

Item	$/Year
Operating labor	100,000
Administration/general	15,000
Domestic pumping	100,000
Capital replacement	30,000
Insurance	30,000
Licenses/permits	5,000
Total	$280,000

Power Sales

Negotiations between DVWD and Pacific Power & Light (PP&L) began in November 1981. PP&L's then-current avoided costs, filed with the Oregon Public Utility Commission, formed the basis of discussions between the developer and PP&L.

The parties signed a Power Purchase Agreement on November 15, 1982. Power sales under the contract began on October 1, 1985. The term is for 36 years, expiring on December 31, 2020. Power prices include both capacity and energy payments. A capacity payment of $8.21 per kilowatt per month is provided for. Energy prices are partially levelized; they escalate according to the schedule shown below in Table 5-3.

Table 5-3
Opal Springs Project Energy Prices

Contract year	Cents/kWh
1985	6.92
1986	6.92
1987	6.99
1988	7.07
1989	7.15
1990	7.24
1991	7.33
1992	7.43
1993	7.53
1994	7.64
1995	7.76
1996	7.88
1997	8.02
1998	8.15
1999	8.30
2000	8.46
2001	8.62
2002	8.80
2003	8.99
2004	9.18
2005	9.39
2006	9.61
2007	9.85
2008	10.10
2009	10.36
2010	10.64
2011	10.94
2012	11.25
2013	11.58
2014	11.94
2015	12.31
2016	12.71
2017	13.13
2018	13.57
2019	14.05
2020	14.55

Several issues came up in contract negotiations. PP&L's proposed prices included the actual variable operations and maintenance costs of their Wyodak coal plant. Since these were unknown, the item was changed to a stated amount. Another issue was PP&L's operation and maintenance for lines to the plant. The DVWD agreed to perform operation and maintenance on the transformer and to buy a new one if the line voltage is changed. A no-fault insurance clause was settled on because other variations were uninsurable. The proposed electrical standards were too strict and were later changed. Finally, contract format had to be changed so that a municipal corporation could sign it. The contract took 10 months to negotiate, costing the DVWD about $71,000. This cost is not included in capital costs, as it occurred before project financing.

Contract duration certainly reflects the energy resource. Rarely do powerplants using fuels negotiate such long-term contracts. The certainty of available energy is highest with hydroelectric projects. The Opal Springs project's hydro supply assurances are met with both general long-term hydrologic data, i.e., precipitation and river flow, and specific flow maintenance programs at upstream Ochoco Lake & Prineville reservoir. The DVWD has flow records dating back to 1905. Basin snow and rain, reflected in stream flow and spring flows, are the primary, stable "fuel" for this project.

Project Financing

DVWD financed the Opal Springs project in August 1983, using the Oregon Small Scale Energy Loan Program (SELP). This program functions as an "energy bank," administered by the Oregon Department of Energy. SELP raises funds by selling Oregon's general obligation bonds on the open market. These bonds are exempt from both state and federal tax. SELP then finances projects that either produce or conserve energy. Resulting energy (and dollar) earnings or savings must be sufficient to repay the loan. SELP loans are conventional, low risk, credit-backed financings. Such loans require additional security and collateral beyond the project.

For the Opal Springs project, SELP allowed the developer to finance the project using no equity and 100 percent debt. Debt financing was a $14,300,000, 30-year loan at about 10.25 percent, the tax-exempt market rate in May 1983. Monthly payments are about $140,375. Debt service coverage ratios range from 1.32 at minimum streamflows to 1.55 at average conditions.

The state of Oregon provides other incentives for projects that either produce or conserve energy; the Business Energy Tax Credit (BETC) program allows a 35 percent state tax credit based on the cost of the qualifying energy equipment. However, since this incentive applies only to taxpaying entities, DVWD could not benefit from it.

Permits and Licenses

DVWD obtained six federal, three state, and two local required permits for this project. Table 5-4 indicates these permits, the issuing agency, the date issued for, and the cost, where known. Cost data are limited. Permit costs were apparently part of normal district overhead. As noted earlier, it is estimated that negotiating the power sales contract cost about $71,000.

In addition to the required permits listed in Table 5-4, DVWD voluntarily signed an agreement with the Oregon Department of Fish and Wildlife (ODFW) in July 1982, in which it agreed to do the following: (1) maintain a minimum stream flow of 50 cfs; (2) determine fish mortality at the plant; (3) replace any fish killed; and (4) enhance habitat that ODFW estimates will compensate for any fish not replaced.

The ODFW does not issue any permits or licenses for hydroelectric plants; it exercises control indirectly through the water rights permit process of the Water Policy Review Board (now the Water Resources Commission). DVWD's agreement with ODFW was part of the Permit Application Approval Order issued by the Water Policy Review Board.

Unlike other, later projects, the Opal Springs power sales contract did not have a clause requiring Oregon Public Utility Commission (OPUC) approval of the contract prices. Yet the OPUC did review and approve the contract rates. OPUC rules required that utilities submit either a copy or a summary of the contract to the OPUC. In the past, the utilities submitted their entire contracts. OPUC staff would review them and make its recommendations to the Commission. That practice changed in early 1987. The OPUC no longer approves such contracts, and has so informed regulated utilities.

Environmental Impacts

Opal Springs produces no air pollutants and no solid wastes. The environmental aspects of this project concern impacts on fish and wildlife, land use, and water. The DVWD took a proactive role in dealing with fish and wildlife responsibilities. As discussed above, DVWD signed an agreement with ODFW to maintain

Table 5-4
Opal Springs Plant Permits

Permit	Agency	Date Issued	Cost ($)
Hydroelectric License	FERC	11-02-82	n/a
Section 404 Fill	ACOE	11-22-82	n/a
Free Use & Mining	USDI	3-16-83	n/a
Land Use	USDI	3-16-83	n/a
Special Use	USDA	3-23-83	n/a
Blasting Safety Plan	USDA	7-29-83	n/a
Water Rights Appropriation	OWRD	8-03-83	n/a
Permit Application Approval	WPRB	9-17-82	n/a
Water Quality	ODEQ	10-01-82	n/a
Conditional Use	JCPD	8-30-82	25
Building	JCBD	7-20-83	1,336

Note:
ACOE= Army Corps of Engineers
FERC= Federal Energy Regulatory Commission
USDA= U.S. Dept. of Agriculture
(Crooked River National Grassland)
USDI=U.S. Dept. of Interior (Bureau of Land Management)
ODEQ=Oregon Department of Environmental Quality
JCPD=Jefferson County Planning Department
JCBD=Jefferson County Building Department
WPRB=Water Policy Review Board

minimum stream flows and replace any fish killed from the project.

Land use impacts are minimal, as the site is in a remote location with no public access, except via the Crooked River. Many factors contributed to site selection. The diversion-site had an existing dam; the existing conduit could be used to site new steel culverts; the powerhouse site is only 4 acres in size; and the site was zoned exclusively for farm use, with the project an allowed conditional use in the zone. All water needs are met using Crooked River water. Therefore, the project has no impacts on groundwater that would require mitigation.

Project Construction

The Opal Springs power sales contract called for electricity to be delivered to PP&L by October 1, 1985. Plant final design began in December 1982 and was finished in June 1983. Construction began in September 1983, turbine startup in December 1984, and final completion in March 1985. The facility went into commercial operation December 21, 1984.

Interconnection and Transmission Factors

The electrical interconnection equipment consists of the switchyard, switchgear, main transformer, bus duct, control equipment, and powerline connection. Total cost was about $643,000. DVWD paid PP&L to install all interconnection equipment. The switchyard is located adjacent to the powerhouse. Protective devices were reviewed by PP&L. Actual connection to the utility system was under the direction of PP&L. Opal Springs generates 4,160 volts of electricity. A transformer brings the electricity up to 69,000 volts (69 kV). A 2.9-mile-long, 69-kV transmission line interconnects with PP&L. No wheeling issues arose because the power purchaser is the local utility.

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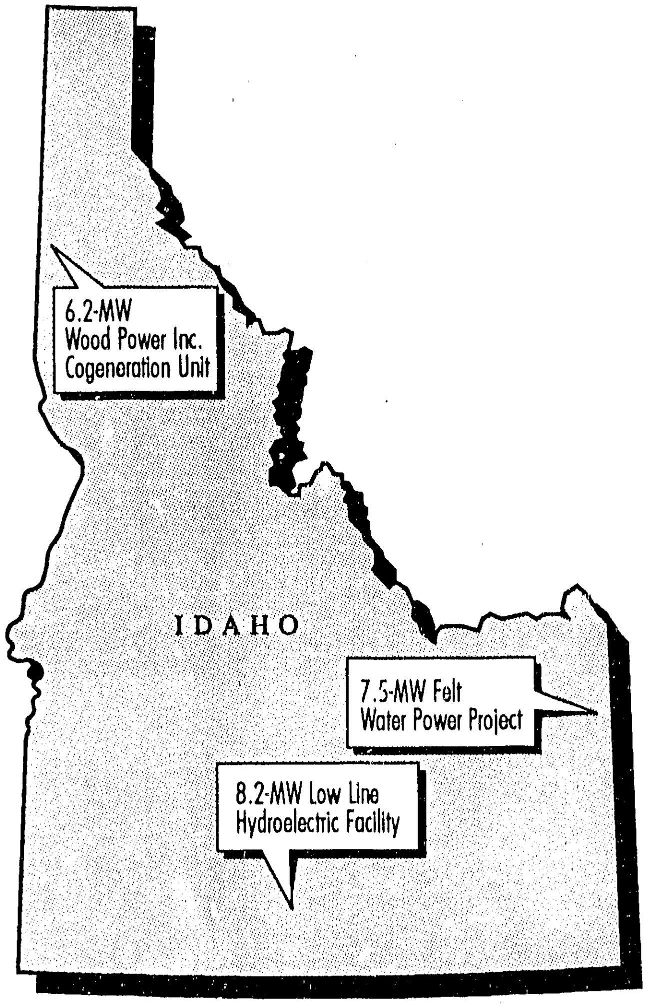

Chapter 6

7.5-MW Felt Water Power Project Tetonia, Idaho

Project Description

The Felt Water Power Project is located at the site of an existing dam on the Teton River about one mile upstream from its confluence with Badger Creek. The site is approximately 9 miles northwest of the town of Tetonia in eastern Idaho.

The original dam and powerplant were built in 1921. The development consisted of a low timber-crib dam diverting flows into a tunnel through a bend on the side of the river. A wood-stave penstock then conveyed the flow to the powerhouse located several hundred feet downstream, developing a head of about 75 feet. The powerhouse contained three turbine generator units, one rated at 150 kW and two rated at 250 kW each.

In 1947, two additional units were installed in a new powerhouse adjoining the original building. They were supplied with water diverted by the original dam into two additional tunnels and penstocks. These units were rated at 720 kW and 500 kW, respectively.

In 1963, the timber-crib dam overtopped and failed as a result of an ice jam on the river. It was replaced in 1963 by the present concrete structure. The three units in the original powerhouse were operated until 1968. Increasing costs and the availability of inexpensive power from BPA made their operation uneconomical. They have not been operated since.

The two units in the second powerhouse were operated from 1946 to 1968. Between 1968 and 1980, the equipment was operated periodically for maintenance purposes. In 1980 the capacity of the units was increased from 1,220 kW to 2,000 kW, and the units have operated continuously since.

The Felt project consists of refurbishment of an existing powerplant to upgrade its capacity from 1,220 kW to 2,000 kW, and construction of a new 5,500-kW powerplant. The new powerplant is located 1,500 feet downstream of the existing plant. Both plants use an existing 12-foot-high diversion dam and existing power tunnels. The average annual energy generation of the two plants is 31,400 megawatt hours (MWh). Power from the $9.4 million (1981 cost) project is sold to Utah Power and Light Company.

Felt Dam is a low concrete gravity structure whose purpose is to divert water into the intake structures for the powerplant. It is about 135 feet in length and 12 feet high. About 90 feet of the dam's width serves as an uncontrolled overflow spillway. A gated sluiceway section 16 feet in width is located at one abutment. A fish ladder, installed as a fisheries mitigation measure, is also located in the dam. The dam impounds about 40 acre-feet of water with a reservoir area of about 10 acres. The dam has very little capacity to regulate the flow of the river, and has never historically been used for that purpose.

Some of the features of the project are summarized in the following sections and in Table 6-1.

Intake Structures

Three intake tunnels are still in place from the original facility. The first intake supplied the old wood-stave penstock connected to the three earliest units at the site. A bulkhead has been added to this intake, and it is currently being used to supply water to the old powerhouse.

The second and third intakes supply the new powerplant. Small wood-frame buildings house the intake gates and trashracks. The gate structures are located against the canyon wall and cover the entrances to the two power tunnels.

Power Conduit and Penstock

Each of the two power tunnels supplying the new powerplant is approximately 8 feet square in cross section, and in unlined rock. The tunnels extend about 200 feet in length where they transition to 78-inch diameter welded steel penstocks. The penstocks are then joined to a 7.5-foot-diameter penstock, 1,850 feet long, that leads to the new powerplant.

Table 6-1
Summary of Project Features
Felt Water Power Project

Diversion Dam (Felt Dam)	Length	135 ft
	Height	12 ft
	Crest elevation	5,530 ft MSL
Impoundment	Normal water surface elevation	5,530 ft MSL
	Water surface area	10 acres
	Gross storage	40 acre-ft
Waterways	Number of intakes	3
	Power tunnels	Unlined rock
	Tunnel length	215,180, 120 feet
	Tunnel size	8 ft square
Penstocks	Number of penstocks	2
	Construction	Welded steel
	Diameter	72 in, 96 in
	Length	55 ft, 1,850 ft

Powerplants	**New Plant**	**Old Plant**
Plant capacity	5,500 kW	2,000 kW
Type of operation	Run-of-river	Run-of-river
Type of control	Manual or automatic	Manual
Number of units	2	2
Type of units	Vertical Francis	Horizontal Francis

Rating, each unit	**Units 1 & 2**	**Units 4 & 5**
Flow, cfs	232	210
Head, ft	159	80
Output, kW	2,613	1,000

Transmission Lines				
Length	700 ft	1,400 ft	1,400 ft	2,600 ft
Voltage	4.16 kV	4.16 kV	24.9 kV	24.9 kV
Type	Buried	Aerial	Aerial	Buried

Projected Annual Average Energy Production	31,554 MWh
Total Project Capital Cost	$12.0 million

Powerhouse and Tailrace

The new powerplant is a reinforced concrete structure 38 feet wide by 40 feet long by 30 feet high. The top of the structure extends approximately 15 feet above the natural ground. An insulated metal sandwich building provides an enclosure for the inside equipment. Switchgear and an office are located on an upper deck of the powerhouse, while two vertical-shaft, Francis-type turbine generator units are located on the lower deck. Water leaving the turbine draft tubes exits through two 11-foot-by-16-foot concrete-lined tailraces.

Turbines and Generators

The project, consisting of construction of a new powerhouse and refurbishment of an old one, has a total output of 7.5 MW and an average annual generation of 36,100 MWh. Characteristics of the turbines and generators at each powerhouse are summarized in Table 6-2.

Table 6-2
Turbine and Generator Characteristics

Upper Plant (Existing)	**Single Unit at Capacity**	**Two Units at Capacity**
Gross static head (ft)	83	83
Design discharge (cfs)	210	420
Net head at design discharge	80	74
Turbine type	Francis	Francis
Turbine horsepower	1,400	2,800
Generator type	Synchronous	Synchronous
Generator rating (kVA at 0.2 power factor)	1,053	2,105
Generator output (kW)	1,000	2,000
Generator voltage	2,300	2,300

Lower Plant (New)	**Single Unit at Capacity**	**Two Units at Capacity**
Gross static head (ft)	162	162
Design discharge (cfs)	232	464
Net head at design discharge	159	156
Turbine type	Francis	Francis
Turbine horsepower	3,487	6,974
Generator type	Synchronous	Synchronous
Generator rating (kVA at 0.2 power factor)	2,750	5,500
Generator output (kW)	2,613	5,226
Generator voltage	4,160	4,160

Transmission Line

Power is stepped up from 4,160 V at the new plant and 2,300 V at the existing plant to 24.9 kV at the power substation located adjacent to the powerhouse. The substation transformer is rated at 7,500 kVA.

Existing overhead lines are used to transfer power from the existing powerhouse to a newly built transformer pad adjacent to the new powerhouse. From there, a 1,400-foot transmission line spans the Teton River Canyon, where it connects with a 2,600 foot buried line to its point of interconnection with Utah Power and Light.

Mode of Operation

The plant is designed to be operated either manually from a main control switchboard located in the powerhouse or automatically and remotely through a telephone modem connection from the operator's home or from any other telephone location. Access to the plant is secured by password.

Dependable Capacity and Annual Energy Production

The powerplant has an installed capacity of 7,500 kW and a projected gross average annual energy production of 31,594,000 kWh. The plant's output is summarized in Table 6-3.

Table 6-3
Expected Powerplant Output

	Adverse Water Year (1955)	Average Water Year	High Water Year (1971)
Installed capacity (MW)	7.5	7.5	7.5
Annual energy (MWh)	23,075	31,594	36,973
Plant capacity factor (%)	42	54	59

Minimum and Maximum Flow Rates

The minimum discharge necessary for generation, which is available 99.9 percent of the time, is 93 cfs, which corresponds to generating capability of 840 kW. Ninety-five percent of the time the plant could generate 1,950 kW or more.

The maximum hydraulic capacity of the plant is a total of 884 cfs. This includes capacities of 464 cfs at the lower powerplant and 420 cfs at the upper plant.

Project Ownership

Fall River Electric

The property on which the project is located is owned by the U.S. government, under the jurisdiction of the Bureau of Reclamation, and by Fall River Electric, a rural cooperative formed in 1938. Within the project boundary, 50.2 acres are owned by the United States and 4.2 acres are owned by Fall River Electric.

The original project at the site was first owned by the Teton Valley Power and Milling Company. In 1960, Fall River Electric purchased the assets, including the Felt Dam, powerplant, tunnels, penstocks, and land, together with transmission and distribution facilities.

Fall River Electric holds a lease for use of the 50.2 acres of federally owned land. A fee is paid annually to the U.S. government for use of the lands.

Upon purchase of the existing project in 1960, Fall River Electric also acquired ownership of the existing water rights. In anticipation of expanding the capacity of the project, Fall River Electric applied for, and received, water rights for an additional 300 cfs.

Fall River Electric first applied for a preliminary permit from the Federal Energy Regulatory Commission (FERC) in September 1981. Two years later, in September, 1983, a license was issued for the project. When it was first issued, the license was held solely by Fall River Electric.

Bonneville Pacific Corporation

After Fall River Electric had obtained a license from FERC to construct the project, it sought out a developer to actually construct, finance, operate, and maintain the project. Bonneville Pacific Corporation, a cogeneration and small power project developer with projects throughout the U.S. and Canada, was selected.

Once Bonneville Pacific became involved as the project developer, an agreement was made to make Bonneville Pacific and Fall River Electric co-licensees. Bonneville Pacific, in turn, assigned its right as a co-licensee to a wholly owned subsidiary, Hydro Valley Development Inc. The FERC license was transferred in August, 1985 to Fall River Electric and Hydro Valley Development as co-licensees.

In order to facilitate the license transfer, Fall River Electric and Bonneville Pacific, parent corporation of Hydro Valley Development, entered into a lease and assignment agreement on December 18, 1984, under which Fall River leased to Bonneville Pacific all lands, water rights, and other necessary project interests. The term of the agreement is 35 years, the same as the term of the power sales contract. Fall River retained fee title in all the leased property and interests and Bonneville Pacific gained authority to own the power facilities.

As consideration for the lease and assignment agreement, Bonneville Pacific agreed to pay Fall River as follows:

- $300,000 for acquisition of the land rights and water rights
- $200,000 upon awarding of a joint license from FERC
- $250,000 upon execution of the power sales contract
- $88,000 upon the production of first power
- During each of the first 10 years of power production, the greater of (i) $0.003125 per kWh of net generation during each calendar year, or (ii) $100,000 per year
- $15,337 per year for the first 10 years of power production for rental of the existing generating facilities with the right to renovate the facilities as necessary

Included in the terms of the agreement were the following:

- Bonneville Pacific as owner of the project was to receive all federal and state tax benefits.
- Bonneville Pacific assumed all responsibility for operation and maintenance.
- Bonneville Pacific assumed all responsibility for paying property taxes, FERC assessments, and state kilowatt hour taxes.

CDM Hydroelectric Company

Through the terms of the agreement between Fall River Electric and Bonneville Pacific, Bonneville was authorized to assign its interests in the project to any other entity for purposes of financing the project. A limited partnership called CDM Hydroelectric Company was subsequently formed and purchased the project in June 1985, prior to the completion of project construction.

As of December 1, 1986, the ownership of the co-partnership was as follows:

Kal Zeff	97.8%
Ron Zeff	1.0%
CDM Pipeline Company	1.0%
Bonneville Pacific Corporation	0.1%
Hydro Valley Development, Inc.	0.1%

To facilitate the transfer of ownership from Bonneville Pacific to CDM Hydroelectric, Bonneville Pacific sold and transferred all of the stock of Hydro Valley Development, its subsidiary, to CDM Hydroelectric. Thus, Hydro Valley became a wholly owned affiliate of CDM Hydroelectric. The project's water rights, having been leased to Hydro Valley Development by Bonneville Pacific, were now available to CDM Hydroelectric. In addition, Hydro Valley's rights as a co-licensee were also now available to the partnership. In acquiring the project from Bonneville Pacific, CDM Hydroelectric became responsible for operation, maintenance, and payment of all taxes. However, it also acquired the interest in the power sales contract and all tax benefits associated with the project.

As consideration for the purchase and lease agreement between Bonneville Pacific and CDM Hydroelectric, CDM agreed to pay the following:

- $12 million for the power facility and improvements
- $200,000 for the project's water rights, FERC license, land leases, power contract, and other intangibles
- $15,337 per year for each of the first 10 years for rental of the existing power facilities
- For each of the first 15 years, the greater of (1) $0.003125 per kWh of net generation during each year, or (2) $100,000 per year
- During the 16th through the 20th years, 10% of the gross power revenue
- During the 21st through 25th years, 15% of the gross power revenue
- During the 26th through 30th years, 20% of the gross power revenue

- During the 31st through 35th years, 25% of the gross power revenue

Project Financing

Construction financing for the project was obtained by Bonneville Pacific from First Interstate Bank of Utah. Permanent financing in the form of a $7 million loan from the Prudential Interfunding Corporation, a Delaware company, was obtained by CDM Hydroelectric. In both cases, as security for the loans a first lien security interest in the project, property rights, and water rights was assigned to the financial institutions.

Tax credits in the form of energy tax credits, investment tax credits, and cost recovery deductions from use of the Accelerated Cost Recovery System of depreciation (ACRS) were claimed for the project in 1985, the year construction was completed. The project was depreciated over 5 years, as allowed by the ACRS. Had the project been built after 1986, these tax credits would not have been available, since they were eliminated by the Tax Reform Act.

Project Operation and Maintenance

CDM Hydroelectric, as owner of the project, is responsible for operation and maintenance of the project. However, soon after its purchase of the project, the company signed an operation and maintenance agreement with Bonneville Pacific. The agreement says that Bonneville shall produce for CDM the maximum amount of salable electric energy that may be expected. In this effort, Bonneville must do all that is necessary to maintain the facility. In addition, Bonneville is responsible for maintaining all licenses, agreements, and permits, as well as being responsible for all necessary replacement parts, with provisions for reimbursement of costs by the project owner.

Bonneville Pacific receives, as an operating fee, 7.9 percent of the gross revenue for each year, but never less than $135,000 nor more than $165,000, with the minimums and maximums adjusted on an annual basis by the percentage change in the Producer's Price Index for Energy Crude Materials. The fee is set up so that CDM Hydroelectric pays Bonneville $12,500 monthly, with adjustments made at the end of the year to adjust for the operating fee that was actually earned.

The project is not actually operated by Bonneville Pacific, but rather by a subsidiary company called Bonneville Pacific Services Company, Inc. The subsidiary company has an operation and maintenance contract with Bonneville Pacific in which it receives 7 percent of the gross monthly power revenue or $9,500 per month, whichever is greater.

Installed and Operating Costs

The total installed cost of the Felt project was $8.4 million ($1,120 per installed kilowatt), according to the 1985 application for FERC license amendment contract for design and construction. Table 6-4 shows a breakdown of the project costs made prior to project construction. Actual out-of-pocket cost to develop and construct the project was $10.6 million.

Table 6-4
Felt Project Cost Summary
(1984 Dollars)

Hydroelectric Plant Accounts	
Lands and land rights	$ 13,000
Structures and improvements	700,000
Reservoirs, dams, and waterways	1,318,000
Waterwheels, turbines, and generators	2,500,000
Accessory electric equipment	460,000
Miscellaneous powerplant equipment	150,000
Roads, railroads, and bridges	250,000
Transmission Plant Accounts	
Land and land rights	5,000
Structures and improvements	14,000
Station equipment	120,000
Towers and fixtures	30,000
Poles and fixtures	8,000
Overhead conductors and devices	35,000
Underground conduit	50,000
Underground conductors and devices	9,000
Roads and trails	5,000
Subtotal	$5,667,000
Contingencies	1,133,000
Subtotal	$6,800,000
Sales Tax (3% of materials)	108,000
Total Construction Cost	$6,908,000
Engineering and owners' cost	1,382,000
Total Project Cost (1984)	$8,290,000

The annual costs of the project, based upon Bonneville Pacific's preconstruction estimates for the year 1986 are given in Table 6-5.

The projected annual generation of the project is 31,554,000 kWh. Based upon the projected annual operating costs for 1986, the unit energy cost is 4.65¢/kWh. However, as the interest payments on the loan decrease over time, the unit energy costs should also decrease.

Table 6-5
Estimate of Felt Project
Annual Operating Costs (1986)

Operation and maintenance	$ 150,000
Idaho state kWh tax ($0.00050/kWh)	15,777
Interest	1,283,040
Property tax	24,000
Site lease	123,821
Water rights amortization	5,714
Total annual cost	$1,467,352

Power Purchase Contract

Bonneville Pacific Corporation signed a power purchase contract with Utah Power and Light on December 4, 1984. The term of the agreement is 35 years from the date of first energy production. The contract specifies that Utah Power and Light will purchase all energy produced by the project. There is no contracted capacity, nor annual energy production quota. The rates paid by the utility are not seasonalized; i.e., the same rate is paid year round.

The rates paid for purchase of energy are composed of a fixed and a variable component. The fixed component is for 4.049 cents per kWh, reflecting a 1985 scheduled in-service date and a 35-year term. This rate is not subject to escalation throughout the life of the contract.

A variable rate of 1.4 cents per kilowatt hour is added to the fixed component to arrive at the total price paid for purchase of the power (4.049 + 1.4 = 5.449¢/kWh). The variable rate is updated annually, subject to approval by the Idaho Public Commission. The variable rate is changed to reflect the current average price of coal to Utah Power and Light for use in its coal-fired generating stations. Consequently, the rate can be adjusted up or down, but the adjustments are usually minor.

The power sales agreement requires that Bonneville Pacific pay all interconnection costs. These costs totaled $91,313. Included in these costs were the installation of 57 new wooden power poles and their associated spans of conductor, installation of metering equipment, and the removal of 10 power poles and conductor spans.

Provisions are made in the contract to adjust the payment due in the event the contract is terminated prior to its 35-year term. The agreement requires Bonneville Pacific to refund to Utah Power and Light an amount equal to one-half the difference between: (1) the sum of the fixed energy payments paid prior to the date of termination, and (2) the sum of the fixed energy payments that would have been paid based on a term of agreement extending to the date of termination.

Example:

Assuming the contract was terminated at the end of 10 years and the annual generation from the facility had been 2 million kWh for each year of the 10-year period, then the refund that Bonneville Pacific would have to pay to Utah Power and Light would be calculated as follows:

Total 10-year generation = 20,000,000 kWh

Total payment to Bonneville = 20,000,000 kWh x 4.049¢/kWh
= $809,800

Total payment if Bonneville had contracted for 10 years = 20,000,000 kWh x 2.0¢/kWh*
= $400,000

Refund to UP & L = ($809,800 - $400,00) / 2
= $204,900

*Rate for a 10-year contract term with 1985 on-line date

Permits and Licenses

FERC

The Felt project's permitting and licensing process began in September of 1981 when the Fall River Rural Electric Cooperative filed a preliminary permit application with FERC. In the application, Fall River indicated plans to study three alternate proposals, each for redevelopment of existing facilities. The three proposals were as follows:

1. Replace the existing generating units (five units with a total capacity of 1,870 kW) with new units having a total rated capacity of 2,700 kW.

2. Construct a 200-foot-long penstock and a new powerhouse containing a generating unit having a rated capacity of 3,700 kW.

3. Construct a 2,600-foot-long penstock and a new powerhouse containing two generating units having a total rated capacity of 6,670 kW.

The average annual energy output was estimated at between 15,000 MWh and 38,100 MWh, depending upon the alternative selected.

After the preliminary permit was issued, Fall River proceeded to hire an engineering consultant to study the project's feasibility. An application for a FERC license (major license - existing dam) was prepared and filed with FERC in February of 1982. The license application proposed construction of a new powerhouse with a capacity of 6,025 kW located approximately 1,200 feet downstream of the existing powerhouse. Under this plan, the new project could develop 50 feet more head than the existing plant and would be capable of generating about three times as much energy.

No protests or petitions to intervene were received in response to the license application. However, interested federal, state, and local agencies did submit comments expressing their concerns about the project. All of the concerns expressed by the agencies were satisfied by prior agreements with Fall River that were contained in the mitigation plans of the license application.

As final design proceeded for the project, it was decided that the project plans should be changed to improve the economics of the project and maximize utilization of the resource. The new plan entailed relocating the proposed new powerhouse to a site approximately 300 feet further downstream to increase the available hydraulic head. At the same time, the size of the turbines in the new powerhouse would be reduced to enable more efficient operation over longer periods of time throughout the year by providing a closer match of equipment to historic stream flows. In addition, two units in the existing powerhouse would be refurbished. These changes resulted in a net increase in capacity over the previous plan of 1.5 MW and an increase in annual net energy production of 4,700 MWh.

An application for amendment of license was filed with FERC in May 1985. The license amendments were approved by FERC in July 1985. Again, no agencies filed protests or petitions to intervene, although additional mitigative measures were required in accordance with agency comments.

As the project approached the start of construction and financing arrangements were worked out, it became necessary to transfer the license from Fall River as the sole licensee to Fall River and Hydro Valley Development, Inc. as joint licensees. Fall River leased land, water rights, and other interests necessary for the construction, operation, and maintenance of the project to Bonneville Pacific Corporation, parent company of Hydro Valley Development, Inc. Since ownership of the project was shared between Fall River and Hydro Valley, it was necessary that they become joint licensees to facilitate financing of the project. The application for transfer of the license was made in April 1985, and approval was granted by FERC in August 1985.

The Felt project was certified as a qualifying facility in 1985 through the formal application process.

Other Permits and Approvals

Fall River, in compliance with FERC regulations, consulted with other federal, state, and local resource and managerial authorities concerning potential impacts of the project. This consultation process helped identify areas of concern and also identified various permits and approvals that would have to be obtained. Some of the permits and approvals required are summarized in Table 6-6. Some of the agencies that were consulted but had no concerns or applicable permits and approvals are also listed. Details of specific areas of concern and the associated mitigation strategies are discussed in later sections.

Table 6-6
Felt Water Power Project
Required Permits, Approvals, and Consultations

Agency	Permit, Approval, or Consultation
Idaho Dept. of Water Resources	• Water Rights - Application for Resources Permit - Approval of permit - Proof of beneficial use
	• Dam Safety Permit
	• Determination of minimum streamflow requirement
	• Stream Channel Alteration Permit for construction of a temporary cofferdam/access road for construction of fish screens, excavation of tailrace area, removal of material from the stream channel in compliance with mitigation plan
Idaho Dept. of Fish and Game	• Approval of designs for and construction of fish ladder, trash rack, and fish screens
	• Consultation on potential impacts to wildlife
	• Fishery and Habitat Mitigation Agreement between Fall River Electric and Fish and Game
Idaho Dept. of Health & Welfare	• Water Quality Certificate (401 Clean Water Act)
	• Certification of compliance with the Idaho Water Quality Standards and Wastewater Treatment Requirements
Idaho Dept. of Lands	• Consultation on state land easement (not required since stream is non-navigable and there are no state lands adjoining the project boundary)
Teton County Planning and	• Zoning Commission Conditional Use Permit
Teton County	• Building Permit
Idaho State Historical Society	• Consultation on historical and archaeological resources society (no significant impact)
U.S. Fish and Wildlife Service	• Consultation on endangered species (no significant impact)
	• Approval of fish ladder and screening
Idaho Dept. of Parks and Recreation	• Consultation on recreational impacts
U.S. Bureau of Reclamation	• Lease of property and land easement
	• Consultation on possible conflict with reconstruction of the Teton Dam
U.S. Bureau of Land Management	• Right-of-way permit for construction of transmission lines
U.S. Soil Conservation Service	• Consultation on erosion hazards and preservation of water quality

U.S. National Park Service	• Consultation on Wild and Scenic River status (not designated Wild or Scenic, not in designated study area covered by Wilderness Act, not a study river)
U.S. Army Corps of Engineers	• Consultation on 404 Permit - Required for placement of fill to construct temporary cofferdam/access road for construction of fish screens, removal of material from the stream channel in compliance with mitigation plan
	• Approval of fill removal and bank stabilization measures to be performed along the river
	• Approval of relocation of the powerhouse
	• Agreement concerning Mitigation Plan
Federal Energy Regulatory Commission	• Application for Preliminary Permit
	• Application for License (Major)
	• Order Issuing License (Major)
	• Order Granting Extensions of Time for Start and Completion of Construction
	• Application for Amendment of License
	• Order Amending License
	• Application for Transfer of License
	• Order Approving Transfer of Major License
	• Application for Certification of Qualifying Facility Status
	• Order Granting Qualifying Facility Status
	• Order Approving Functional Design Drawings of Fish Passage Facilities
	• Order Approving Fishery Mitigative Plan
	• Order Approving and Modifying Measures to Protect and Enhance Fish and Wildlife Resources
	• Order Requiring Construction of Recreational Facilities
	• Order Approving As-Built Exhibits
	• Order Granting Two Year Extension of Time to Complete Studies Recommending Minimum Flow Releases
	• Letter Granting Exemption from Filing an Emergency Action Plan

Environmental Impacts

Fisheries Resources

Probably the greatest environmental concern as a result of the project was its potential effect on fisheries resources. The portion of the Teton River where the project is located supports a significant fishery consisting mostly of stocked rainbow trout, both above and below the project area. The primary movement of trout is downstream; thus, downstream migrants would be the most affected.

The steep river slope downstream of Felt Dam (20 percent slope) historically inhibited upstream migration; since its construction in 1921, the dam has served as a migratory block. Before construction of the new project, the river below the dam was essentially dewatered during most of the year. Since the project included constructing a new powerplant downstream of the existing plant, an additional 1,900 feet of the stream channel would have been dewatered. Thus, the upstream migration problem would be compounded, unless minimum streamflow requirements were established.

No major alterations to the penstock intakes, dam, or reservoir were proposed. Therefore, there was no increase in downstream sediment loading or reservoir volume, nor changes in channel configuration as a result of these activities. There were also no additional impacts to the fisheries or aquatic resources upstream of the dam.

Adverse impacts to fisheries resulted when construction of an access road resulted in approximately 4,000 cubic yards of material being bulldozed over the edge of the canyon into the Teton River below by mistake. This caused excessive short-term sediment loading in the stream. The effect on fisheries was never determined. The rock and other material not washed away by the flow created a barrier for upstream fish migration. The developer was required later to remove this material from the stream.

Turbine mortality was also an expressed concern prior to construction. Fish screening devices were initially proposed by Fall River and agreed to by the Idaho Department of Fish and Game and the U.S. Fish and Wildlife Service. Ultimately, a combination of fish screens and annual payments was required to mitigate this concern.

Wildlife and Botanical Resources

Impacts to wildlife resources as a consequence of the project consisted primarily of a loss of habitat. Construction of the penstock, transmission lines, powerhouse, and tailrace affected about 10 acres of land. Much of the disturbance of these areas was short-term during construction only, however. The greatest loss of habitat was caused when the road to the powerhouse was surveyed incorrectly, which resulted in the unnecessary clearing of extra land of brush, trees, and vegetation. A revegetation plan was later prepared and implemented to help minimize the adverse impact.

About 1,500 feet of riparian habitat was lost because of reduced streamflows; however, because of the steepness of the stream gradient in the affected reach, little of the habitat was heavily used. About one acre of riparian woody vegetation was destroyed by construction activities.

Mule deer are known to use the stream corridor as a migratory route and occasional wintering area. However, since construction did not take place during the winter, and since most of the penstock was buried, the impacts were minimal.

Bald eagles are the only threatened or endangered species potentially affected by the project. But since the Felt Dam Reservoir was not modified, no adverse impacts were anticipated.

Consultation with the Idaho Department of Fish and Game and the U.S. Fish and Wildlife Service determined that there would be no significant impact to wildlife as a result of the project.

Water Quality

Water quality at the Felt site is generally very good, but some degradation of water quality occurs as a result of return flows from irrigation use. However, the amount of return flows from irrigation use is usually quite minimal. Operation of the Felt project does not alter water quality at the site. Within the river and the impoundment, the water is near saturation levels for dissolved oxygen, and the powerplant does not suppress dissolved oxygen levels.

Construction activities caused short-term impacts to water quality. Construction of a cofferdam around the powerhouse area probably contributed the most turbidity and sediment to the river. Disturbance of surface soils as a result of construction of the access road had substantial adverse effects on water quality. Construction of the penstock and transmission line had little or no effect on water quality, since little land was disturbed by their construction.

Recreational Resources

A very limited amount of fishing occurs at the site. Before the new project, access was extremely poor down a steep four-wheel-drive road. In the past it had been posted with "no trespassing" signs because of the danger of travel. No adverse impacts to recreational resources were identified; however, opportunities for improvements to existing recreational resources were identified and requested by the Bureau of Reclamation in pre-project consultations.

The project area river reach is not a designated Wild or Scenic River and has not been identified as a study river for possible inclusion in the Wild and Scenic River System. The project is not within a designated or study area covered by the Wilderness Act.

Historical and Archaeological Resources

There are no known archaeological or historical sites in the project area. The Idaho State Historical Preservation Office (SHPO) has not conducted any cultural resources studies in the area. The SHPO did not expect any archaeological or historical resources to be found in the project area and did not recommend that any additional studies be conducted.

Land Management and Aesthetics

The Felt site has been used for hydropower since 1921. Consequently, considerable manmade impact already existed at the site due to the presence of an access road, existing powerplant, high voltage transmission line, irrigation pipeline, pumping station, and footbridge crossing the river. New construction added a powerhouse and tailrace to the riverbank, a new transmission line that crossed the river and ascended the hill, and a disturbed area where a new penstock was buried and where construction activity took place. In addition, 1,900 feet of the stream channel were dewatered.

The additional land disturbance caused by mislocating the access road was most detrimental to the aesthetics of the area. However, the damage was short term, as a revegetation plan was implemented that has led to substantial recovery of the area over the past several years.

The significance of new impacts was minimized in several ways. First, the new penstock was installed parallel to the access road, eliminating the need for a separate corridor. The overhead and underground transmission lines were installed within existing Fall River Electric rights-of-way and parallel to an existing line. Sparse vegetation at the site also minimized the effect, characteristic of projects located at other mountainous areas, of a bare swath and clearcut area. Finally, the aesthetic effect is minimized since the project site cannot be seen from any roads, and is visible only by the few people who visit the site.

Impact Mitigation

Fisheries

Impact mitigation to protect and enhance fisheries resources included implementing minimum streamflow requirements, construction of a fish ladder, and annual payments for rearing of trout to compensate for wild trout production lost as a result of the development of the project.

Minimum Streamflow Requirements. A great deal of field inspection and consultation between the project developer and the Idaho Department of Fish and Game and the U.S. Fish and Wildlife Service took place in order to establish minimum streamflow requirements that would adequately protect the fisheries resources. In the beginning, a minimum streamflow of 106 cfs was requested by the Department of Fish and Game based upon earlier minimum streamflow studies. However, after objections by the developer, a field demonstration was conducted to allow concerned parties to view stream conditions at various flow rates. The demonstration was successful in bringing about a consensus between the developer and the Department of Fish and Game.

The final agreement requires the project to maintain a minimum flow release of 20 cfs in the bypass reach, except during the period from March 15 through June 30 when 50 cfs are required. The higher flow requirement in the spring and early summer is to enable cutthroat trout to migrate upstream during their spawning season. The 20-cfs requirement was deemed adequate to allow trout to migrate downstream, to eliminate fish stranding and the potential for fish kills, and to flush pools between the dam and tailrace so that dissolved oxygen and benthos production will be sufficient to provide rearing habitat.

Construction of Fish Ladder. A fish ladder capable of operating with flow in the range of 10 to 30 cfs was constructed to permit upstream fish migration past Felt Dam. No fish ladder existed prior to construction of the new powerplant; consequently, no fish passage had been possible since 1921.

The ladder is a vertical slot type, and rises about 8 feet. The overall dimensions of the reinforced concrete structure are 5 feet by 45 feet. The ladder is equipped with vertical slide gates at its upstream and downstream ends. Each step of the ladder rises one foot in elevation.

Fisheries Mitigation Payments. Payments by the project developer to the Idaho Department of Fish and Game were included as part of the Fisheries Mitigative Plan. The purpose of the payments is to provide for the rearing of trout, to compensate for wild trout production lost as a result of the development of the project.

The developer was given an option of either (1) providing payment for the annual stocking of 350,000 cutthroat trout (200 per pound) in the Teton River; or (2) providing payment for the annual stocking of 20,000 cutthroat trout in the river and providing adequate fish screening devices. The developer chose the first option, since maintaining fish screens was judged to be too tedious a task. The developer was required to fund the construction of raceways at the Mackay, Idaho Hatchery at a cost of $60,000 and provide an annual operating fund of $18,400 for 35 years.

Channel Improvement. One component of the project's Fisheries Mitigative Plan required the developer to pay the Idaho Department of Fish and Game to break up a few large boulders in the channel. The purpose of the work was to improve fish passage. Rock pushed into the river during construction of the access road and the powerhouse was also removed in accordance with the requirements of state and federal agencies.

Other Impact Mitigation Measures

Numerous measures, including various construction and operation techniques, were employed to mitigate impacts other than those to fisheries. Mitigation strategies include the following:

- Construction of recreational facilities at the site. The facilities include a barrier across the powerplant access road with a pedestrian walkthrough device for fisherman access to the canyon bottom; a 10-vehicle parking lot on the canyon rim with refuse and sanitation facilities; and a sign adjacent to the parking lot to inform visitors of access into the canyon.

- Performing channel improvement activity between mid-July and December so as not to affect trout spawning migrations.

- Monitoring water temperatures and dissolved oxygen concentrations in the bypass reach during July and August 1989, the low flow period. If the minimum flow releases required by the license are insufficient to sustain trout during this period of the year, new measures must be prescribed for maintaining suitable water temperatures and dissolved oxygen concentrations.

- Reducing construction activity during the period when wintering mule deer are present.

- Limiting the disturbed surface area to the absolute minimum necessary, especially near the river, to reduce overall project impacts on both wildlife and water quality. Disturbed areas not supporting permanent project features were planted with native grasses and forbs to minimize erosion into the stream and speed the recovery of wildlife habitat.

- Transmission-line poles were designed to protect bald eagles and other raptors.

- Burying the major length of new penstock so as not to create a permanent barrier to wildlife.

- Scheduling construction activities that must occur adjacent to or within the existing streambed during the months when flows are naturally low (August to April) to minimize impact on water quality.

Project Construction

Construction Schedule. The original license application filed with FERC proposed that project construction begin in July 1983. It was planned that, in order to minimize development time and project cost, the turbine/generator specifications would be prepared and advertised and bids evaluated while issuance of the license was pending. That way, major equipment supply contracts could be awarded immediately upon issuance of the license. The design, specifications, and construction drawings for the prime construction contract were also planned to be completed during the license processing phase so that the prime contract could be advertised as soon as the license was issued. This approach would allow construction to start within 4 months of licensing.

Construction of the project was initially expected to require two summers because the heavy snowfall and cold temperatures common at the site would curtail winter construction. Equipment installation was scheduled for the second summer, to allow approximately one year for delivery after the equipment contract award.

The initial construction schedule was contingent upon a FERC license being issued early in 1983. However, the license was not issued until September 9, 1983. It was impossible to follow the initial construction schedule since construction could not realistically begin until the following summer.

The original FERC license required that construction be initiated by September of 1984 and completed by September 1986. In April 1984, Fall River Electric requested from FERC an extension of time to start and complete project construction. They stated that they had planned to start construction in September 1984, but that because of expected poor winter weather, much of the preliminary work would not be able to be completed until the following spring. They also pointed out that some of the first construction activities to be undertaken would be road construction and other excavations. Under the proposed schedule, these activities could just be initiated before weather conditions would terminate efforts. This would result in steep, freshly excavated or filled slopes that would be unprotected and subject to erosion for all the winter months before vegetation cover could be established. Thus, Fall River recommended that a one-year extension be granted for initiation of construction. FERC granted this request and allowed a 2-year extension to complete construction.

In mid-1984, Fall River elected to allow Bonneville Pacific to develop the project. Bonneville Pacific examined new options for developing the project that would increase the project's capacity and annual generation potential. A new project design was selected; consequently, an amended license had to be filed with FERC. An amended license was approved on July 8, 1985.

With the amended license, a revised project schedule was prepared. The revised schedule is shown in Figure 6-1. A preliminary detailed construction schedule is shown in Figure 6-2.

Construction Contract

A turn-key contract for design and construction was executed between Bonneville Pacific and Water Power Company, a Utah corporation. The $8.4 million contract was signed on November 5, 1984. It called for completion of construction by December 23, 1985.

Bingham Engineering of Salt Lake City served as the designer and construction manager of the project. The prime construction contractor was Summit Construction of Twin Falls, Idaho. The turbine and generator package was supplied by Hydro West Group, Inc. of Bellevue, Washington.

Construction Problems

Actual construction at the site began in July of 1985. The first activity undertaken was construction of an access road from the top of the canyon to the powerhouse. Shortly after construction started, a major problem was encountered. First, the route of the road to the powerhouse was surveyed incorrectly, which resulted in the unnecessary clearing of extra land of brush, trees and vegetation. Next, the correct route was identified, but in building the road, approximately 4,000 cubic yards of material were bulldozed over the edge of the canyon into the Teton River below.

Later inspections of the site led state and federal agencies, including the Idaho Department of Water Resources, the Idaho Department of Fish and Game, the U.S. Bureau of Reclamation, the U.S. Fish and Wildlife Service, the Army Corps of Engineers, and FERC to order a halt to construction. A cease and desist order was issued by the Corps of Engineers on July 26, 1985.

Meetings to resolve the problem were subsequently held between Fall River Electric; Bonneville Pacific, the developer; Bingham Engineering, the project design and construction manager; and Summit Construction, the prime construction contractor. An agreement was reached requiring the developer to use plastic sheeting held in place with sandbags along the construction area along the river to prevent silting, to place hay bales below fill slopes on the access road as temporary soil stabilization, to run turbidity tests in the river upstream and downstream of the project twice a day, to remove rocks from the Teton river and nearby Badger Creek, and to prepare a plan for stabilizing the soil and replanting slopes that were disturbed by mistake.

The shutdown of construction caused a delay of about 2 months. Construction activity was allowed to resume in mid-September 1985.

Because of the delay in construction, some of the construction work had to be completed during inclement winter weather. This directly resulted in additional costs of about $170,000. Additional costs associated with mitigation of damage caused by road construction is estimated at approximately $900,000.

Construction of the remainder of the project proceeded without major incident. Construction was completed in December, so that the project could be put on-line to meet the terms of the power sales agreement.

Figure 6-1
Felt Project Schedule

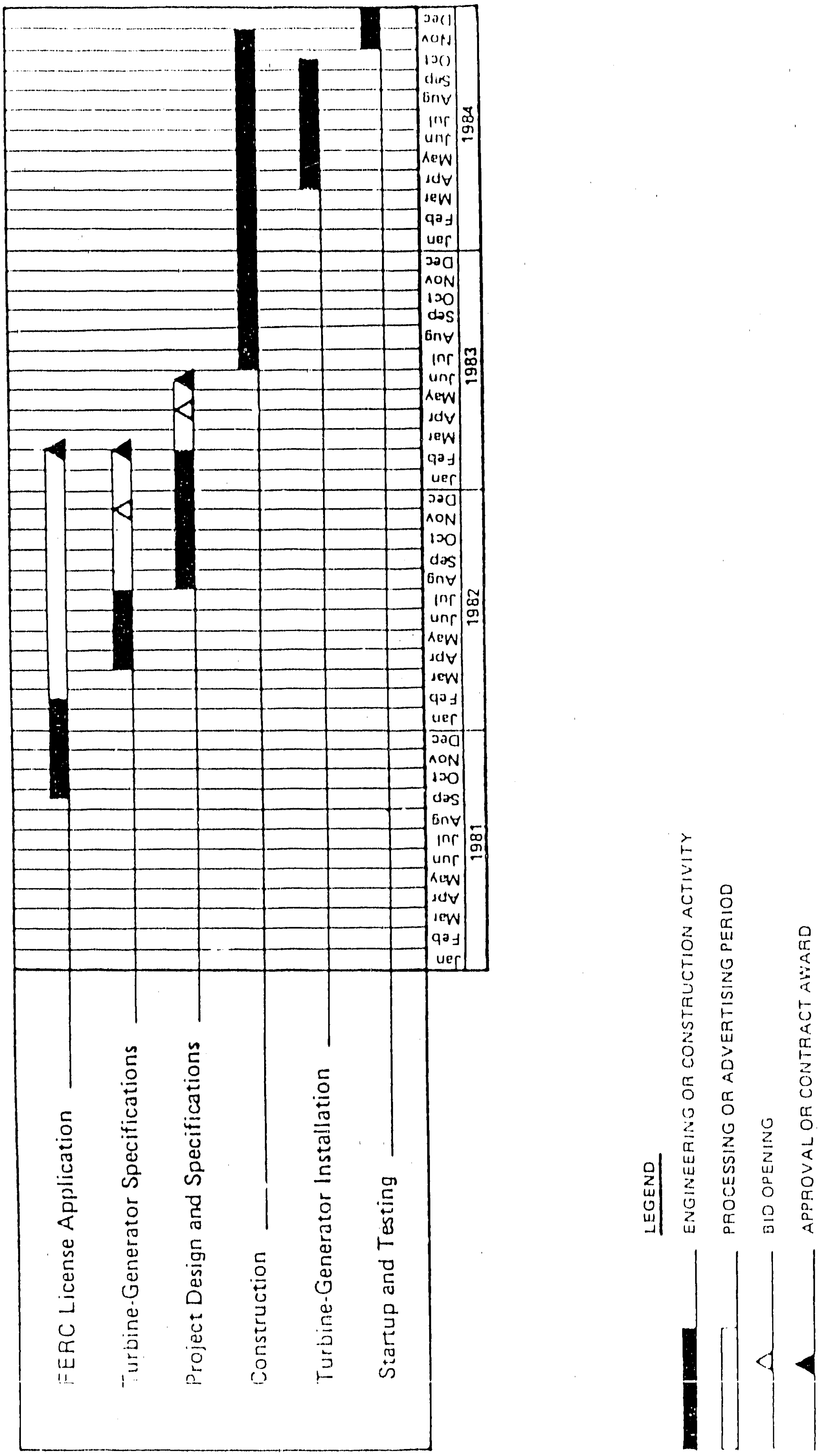

Figure 6-2
Felt Dam Construction Schedule

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                        MONTH:   APRIL       MAY         JUNE        JULY        AUGUST   SEPTEMBER   OCTOBER
TASK                    WEEK: 1  2  3  4  1  2  3  4  1  2  3  4  1  2  3  4  1  2  3  4  1  2  3  4  1  2  3
-----------------------------------------------------------------------------------------------------------------
BUILD ACCESS ROAD             *************************
INSTALL SURGE PIPE                        ****************
CONSTRUCT TAILRACE                        ****************
REMOVE OLD PENSTOCK                       **********
TUNNEL ACCESS                                      *************
TIE PENSTOCK TO TUNNEL                                         *******
INSTALL 90" PENSTOCK                                                 **********************************
CONST. VALVE BAY                                      **********
POWERHOUSE FOUNDATION                                          *************
REBUILD OLD PENSTOCK                                           *************
CONST. FISH LADDER                                             *************
SWITCHYARD                                                           *************
SET TURBINE                                                                **** 
FORM TURBINE BLOCK                                                            *******
PLACE TURBINE BLOCK                                                                 ****
REBUILD INTAKE SHEDS                                                 *******
SET & WIRE GENERATORS                                                      ****************
INSTALL VALVES                                                                               *******
PLANT START-UP                                                                                     ****
SITE CLEAN-UP                                                                                         ****
RESEED SITE                                                                                           ****
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Project Performance

The projected average annual energy output of the project was 34.7508 GWh, according to the purchase agreement between CDM Hydroelectric and Bonneville Pacific. However, in an acceptance test performed shortly after the completion of construction, the projected average annual output was only 31.554 GWh.

The purchase agreement between CDM Hydroelectric and Bonneville Pacific includes a provision to adjust the purchase price to reflect nonfulfillment of performance guarantees. The purchase price adjustment is still under negotiation.

Interconnection, Transmission, and Wheeling Considerations

Fall River Electric is a statutory preference customer of the Bonneville Power Administration (BPA). In the early planning stages of the project, Fall River proposed to sell the output of the project to BPA. At the time the project was proposed, BPA was forecasting shortages in its firm energy supply after 1983.

Under the Northwest Power Planning Act, utilities were given responsibility to develop sufficient resources to meet their own forecasted load growth after the 1982-83 operating year. Provisions were made, however, to allow utilities to sell output from their own resources to BPA, since the cost of new power exceeded the cost of power from BPA. BPA, in turn, was required to meet the firm needs of the utilities. Under this arrangement, utilities could satisfy their own loads, while new resource costs are borne by the region through the BPA power marketing system, rather than by the utility and its ratepayers.

Plans changed, however, once Bonneville Pacific became the project developer. Revenue from the project became the primary motivating factor. BPA's rates were not high enough to satisfy the developer as long as power could be sold to an investor-owned utility at a much higher rate, as required by PURPA. Consequently, a power sales contract was negotiated with Utah Power and Light.

When the plan was still to sell power to BPA, it was proposed that a transmission line would be constructed from the project's substation tower to the Badger Substation, where the power would be fed into Fall River's system. However, once plans changed, it was determined that it would be most economical to construct new transmission lines to cross the Teton River, then parallel existing Fall River lines, before connecting with Utah Power and Light Co. lines. As a result, there was no wheeling involved in the project.

Chapter 7

8.2-MW Low Line Hydroelectric Project Hansen, Idaho

Development History

The Low Line Hydroelectric Project was conceived in 1977 as one means of generating revenue that could be used by the Twin Falls Canal Company to maintain and rehabilitate a canal system sorely in need of repair. The project was initiated by applying to the Idaho Department of Water Resources for a water appropriation permit for power purposes. The application was submitted on March 30, 1977.

Following the application for water rights, inquiry was made of the Federal Power Commission (predecessor to the Federal Energy Regulatory Commission [FERC]) on the proper procedure to obtain approval to construct the project. At the time the project was first proposed, PURPA had not yet been passed by Congress; thus, it was not likely the project could be developed without help from a utility.

No further significant activity took place until August 1980, when an exemption application was filed with FERC. The exemption was granted on December 18, 1980.

In October 1981, Idaho Power Company contracted with International Engineering Company, a subsidiary of Morrison-Knudsen Company, to prepare a study of the energy development potential of the upper reaches of the Low Line Canal. The study was completed in June 1982; it recommended development of an 8.2-MW facility at the site of the present facility. As a result of the greater returns offered by developing the project under PURPA, the Canal Company chose to pursue the project independently from Idaho Power. Early in 1984, Bonneville Pacific Corporation was contacted to develop the project. A construction contract was signed in March 1984, and construction was completed the following fall and winter. The project went on-line in March 1985.

Project Description

The Low Line Hydroelectric Project is located in southern Idaho, about 10 miles southeast of the city of Twin Falls, and two miles directly south of the town of Hansen. At this location the Twin Falls Main Canal forks into two canals, the High Line Canal, a continuation of the Main Canal in a southerly direction, and the Low Line Canal, which branches off in a westerly direction.

The Twin Falls Main Canal is the primary artery of the canal system that services over 200,000 acres of land located on the southern edge of the Snake River Plain. The water delivered by this system is diverted from the Snake River at Milner Dam, about 15 miles to the east. Flows are further controlled and impounded upstream of Milner by the American Falls Reservoir, Palisades Reservoir, and Jackson Lake Dam. The delivery system and associated water rights are the result of over 80 years of irrigation development and federal dam construction.

The Low Line project (FERC #3216) utilizes a natural drop in elevation of about 95 feet in a distance of approximately 2,500 feet, as water is diverted from the Twin Falls Main Canal into the Low Line Canal. The project consists of a diversion structure to direct up to 1,500 cfs of water into a steel penstock 12 feet in diameter, which will transmit the water, under pressure, to a powerhouse located 2,200 feet downstream to the west of the diversion. The water is controlled with steel gates and valves as it is delivered to a manifold connected to two vertical Francis turbines rated at 4.1 MW each. Since the project uses primarily irrigation water, it produces power only 7 months of the year. The annual net energy of the project is 30,000,000 to 46,841,000 kWh, subject to canal operation. Some of the features of the project are summarized in the following sections and in Table 7-1.

Table 7-1
Summary of Features
Low Line Hydroelectric Project

Location of Powerplant		Low Line Canal T11S, R18E, B.M., Sec. 1 & 2 Longitude 114 18' 00" W Latitude 42 29' 30" N
Regulating Structure High Line Canal	Type Length Height No. of gates Control	Concrete with radial gates 54 ft 8.5 ft 3 Motorized, manual
Bypass Structure	Type Length Height No. of gates Control Fish screens	Concrete with radial gates 32.5 ft 8.5 ft 2 Motorized, manual None
Intake Structure	Type Length Height No. of gates	Concrete with radial gates 32 ft 9 ft 2
Impoundment	None	
Penstock	Construction Diameter Length Bifurcation	Welded steel, 7/16" 144 in 2,350 ft 12 x 8 x 8 ft
Powerplant	Capacity Type of control No. of units Type of units	8,000 kW Manual or automatic 2 Vertical Francis
Rating/unit	**One unit**	**Two units**
Flow, cfs	650	1,300
Head, ft	87	87
Output, kW	4,000	8,000
Transmission line	Length Voltage Type	4.5 mi 69 kV Aerial
Average Annual Energy Production		30,686,000 kWh
Total Project Capital Cost		$13,285,000 (1984 cost)

Diversion Structure

Diversion of water to the powerplant occurs at the point where the Main Line Canal divides into the High Line Canal and the Low Line Canal. For this reason, it is more complicated than a simple diversion structure.

Three facilities were constructed initially at the point of diversion; a structure to control the flow of water to the High Line Canal, an intake structure with trash rack leading to the penstock, and a structure to release water to bypass the powerplant when needed.

The control structure leading to the High Line Canal is a 54-foot-wide concrete structure with three 8.5-foot-high by 16-foot-wide, motor-operated, manually controlled radial gates.

The intake structure admitting water to the powerplant consists of a 32-foot-wide concrete structure with two 15.25-foot-by-9-foot openings leading to a transition from rectangular to round preceding the penstock. A sloping trash rack with an automatic debris-cleaning rake was constructed on the upstream face of the structure. Two radial gates 7.5 feet high by 15.25 feet wide can be used to control the water to the penstock. There are no fish screens, since the canal does not support a fisheries population.

The bypass structure to allow water to bypass the penstock and continue on down the Low Line Canal consists of a 32.5-foot-wide concrete structure with two radial gates 8.5 feet high by 14.0 feet long, motor-operated and automatically controlled.

Because of operational problems and excessive head loss, numerous changes were made in the diversion area over a period of 3 years.

A concrete weir wall 13 feet high projecting some 140 feet upstream was constructed in the shape of a V to divide the water and direct it to the High Line gates or the powerplant intake. The bypass gates remained dry behind the weir. Load rejections at the powerplant caused the water to build up and overtop the weir wall and continue through the bypass structure and down the old Low Line Canal channel.

The ponding of water and overtopping of the weir wall upon load rejections proved unsatisfactory to canal operations. The next winter, four 7-foot-wide by 13-foot-high hydraulically operated slide gates were installed in the weir wall. Two were located next to the High Line Canal gates and the other two adjacent to the intake to the penstocks. These gates were automated to open upon load rejection and reduce the sag in flow in the Low Line Canal to acceptable limits.

The following year the entire intake structure was removed to the end of the penstock and replaced. The invert was lowered and the area increased so that trash rack velocities could be lowered to acceptable values. The two radial gates were removed and replaced by two 16-foot-wide by 18.5-foot-high bulkhead gates for use to dewater the penstock.

Power Conduit and Penstock

A concrete transition section connects the intake structure and the penstock. The facility uses one steel penstock, 12 feet in diameter and 2,350 feet long. The penstock is buried the full distance between the intake structure and the powerhouse. About midway between the diversion and the powerhouse, it passes under a heavily travelled county road. Approximately 50 feet before entering the powerhouse, the penstock joins a 12-foot-by-8-foot-by-8-foot steel bifurcation. Two 8-foot-diameter penstocks enter the powerhouse. An 8-foot-diameter butterfly valve is located upstream of each turbine.

Surge Tower

One of the most prominent features of the facility is a steel surge tank, 10 feet in diameter and 63 feet tall. The purpose of the surge tank is to relieve high water pressures in the penstock that would occur during load rejection by the generators. During load rejection, the wicket gates controlling flow into the turbines would close rapidly, forcing the surge tower to fill until it overtopped. Initially, a spill rate of 1,300 cfs could be expected, gradually dampening until the water hammer effects are relieved. A 35-foot by 43.5-foot impact basin is constructed around the base of the surge tower.

A second function of the surge tower is to supply water to the turbines during startup until the flow in the penstock has reached a steady state. The volume of the tank must be large enough that it will not drain and admit air into the turbines during startup.

Powerhouse and Tailrace

The powerhouse is a structure with a reinforced concrete foundation, reinforced masonry walls with brick facing, a prefabricated glu-lam truss and roof structure, and a built-up roof. The powerhouse measures 40 feet by 80 feet and is built in three levels. The two lower levels house the turbines, generators, and other operating equipment, while the upper level contains primarily the electronic control systems. The two lower levels are below ground on three sides of the powerhouse, making the powerhouse look from above like an attractive, single-story brick building. Thermostatically controlled louvers allow ventilation of the building.

The tailrace is located at the rear of the powerhouse. It is excavated primarily in basalt, with a shallow layer of topsoil. The tailrace joins the main channel of the canal within a short distance of the powerhouse.

Turbines and Generators

The rated capacity of the project is 8,000 kW. The peak capacity of each of the two generators, however, is 4,135 kW, slightly greater than the 4,000 kW rated capacity. The turbines are vertical Francis-type, and were supplied by the Hydro West Group, Inc., of Bellevue, Washington. The generators were manufactured by Ideal Electric Company. The annual rated output of the equipment is 46,841,000 kWh. Characteristics of the turbines and generators are listed in Table 7-2.

Table 7-2
Turbine and Generator Characteristics

Turbines (two):

	Each	Total
Head, static	91 ft	91 ft
Head, effective	87 ft	87 ft
Flow	650 cfs	1,300 cfs
Power	5,350 hp	10,700 hp
Speed	257 rpm	

Generators (two):

	Each	Total
Power	4,000 kW	8000 kW
Rating	4,210.5 kVA	8,421 kVA
Speed	257 rpm	
Voltage	4,160 V	
Temp. Rating	Full class "FFFX" capability	
Type	Synchronous	

Transmission Line

Power is stepped up from 4,160 volts at the powerplant to 69 kV at the substation adjacent to it. The substation occupies an area of about 40 feet by 40 feet and provides space for the main transformer, an oil circuit breaker, disconnect switches, current transformers, potential transformers, and take-off structures. The main transformer is rated 7,400/9,250 kVa, OA/FA, 13.8/69 kV, 3-phase. A 69-kV transmission line connects the substation with an existing line about 4.5 miles to the east.

Mode of Operation

The plant is designed to be operated either manually or automatically from a main control switchboard located in the powerhouse, or remotely from the offices of Bonneville Pacific Services Company (the plant operator). Bonneville Pacific Services' office is located about 10 miles away in Twin Falls, Idaho.

The plant is equipped with a programmable controller that monitors forebay elevations, wicket gate openings, shaft vibration, rotational speed, bearing temperatures, and numerous other operating characteristics. It adjusts these to maintain optimum plant performance and can shut down the plant under abnormal conditions. Computer monitors can interface with the programmable controller to keep plant operators informed of performance or to allow adjustments to be made manually.

Flow Rates and Generator Capacity

The Twin Falls Canal system is very highly regulated. Although there is some potential in the Low Line and Main Canals for flow gains caused by natural inflow, runoff, or irrigation return flow, and some potential for losses from evaporation, seepage, or diversions, they are considered very minor in the reaches between the diversion at Milner Dam and the powerplant. As a result, flows to the powerplant are highly predictable.

Water rights of the Twin Falls Canal Company allow up to 1,500 cfs to be diverted into the Low Line Canal. However, the normal maximum flow of the canal is only 1,300 cfs. Thus, the powerplant was sized for a maximum flow rate of 1,300 cfs.

Meeting the water needs of irrigators is, without a doubt, the highest priority of the Twin Falls Canal Company. Power generation is second. However, the Canal Company does have some flexibility in how to manage flows in the system. Consequently, the company agreed that once the plant went on-line, it would use its best efforts to manage the system to maximize the amount of energy produced, within the constraints of supplying irrigation water. However, management to accommodate increased generation has never been possible since the project went on-line, because of irrigation demands as determined by the Canal Company.

Table 7-3
Average Monthly Flow Rates and Energy Production
Low Line Hydroelectric Project

Month	1985	1986	1987	1988	1989	GWh
April	558	681	793	611	414	1.757
Days	17-30	8-30	11-30	12-30	12-30	
May	1,330	1,205	1,203	1,094	1,147	5.000
June	1,298	1,274	1,137	1,221	1,304	5.440
July	1,385	1,324	1,175	1,287	1,358	5.694
Aug.	1,366	1,289	1,188	1,227	1,365	5.609
Sept.	906	1,098	1,012	801	1,120	4.164
Oct.	694	841	923	743	802	2.737
Days	1-27	1-26	1-21	1-20	1-31	
Nov.					454	0.285
Days					1-3	
Total						**30.686**

Table 7-3 summarizes the historical flows, the managed flows, and the monthly energy production.

Project Ownership

For the most part, the land upon which the project is located is owned by the Twin Falls Canal Company. Two perpetual easements also had to be obtained from private land owners for property adjacent to the project works. The project's water rights and FERC exemption were leased for 35 years by the Canal Company to Bonneville Pacific Corporation for constructing, operating, and maintaining the project. In exchange for the leased items, the Canal Company receives the following compensation:

- $355,000 upon first lease of the items
- 10% of the gross annual income for the first 10 years
- 40% of the gross annual income for the second 10 years
- 80% of the gross annual income for the last 15 years of the power sales agreement

Bonneville Pacific Corporation assumed responsibility for constructing the project, negotiating the power sales agreement, providing construction and permanent financing, and operating the project. It also has complete control over the operation and maintenance of the project and is required by the lease agreement with the Canal Company to maintain the project in good order and repair and in a safe and clean condition. At the end of the 35-year lease, Bonneville Pacific has the option of removing any of the project works at its own expense. The only assurance the Canal Company has that Bonneville Pacific will operate the project for 35 years is a default clause in the lease agreement. The clause would allow the Canal Company to bring action for specific performance or action for damages incurred as a result of the default.

Bonneville Pacific was the original owner of the project; however, in order to facilitate financing, the project was sold to a limited partnership, Magic Valley Hydroelectric Partners, Ltd. The partnership is a group of about 140 private investors from across the country. Bonneville Pacific, however, still assumes responsibility for managing and operating the project.

Project Financing

The project was constructed on a turn-key basis at a total cost of $13,285,000. Other project-related costs raised the total project cost to $19,250,000. (See next section for a complete breakdown of project costs.) A construction loan of $10,200,000 was obtained by Bonneville Pacific Corporation from First Interstate Bank of Utah. The loan was permanently financed by Prudential Interfunding Corporation, a Delaware company.

The project was sold to Magic Valley Hydroelectric Partners, Ltd., for $18,050,000. Of this amount, $6,752,000 was funded through equity contributions of the partners and the remainder was borrowed.

Project Operation and Maintenance

Bonneville Pacific Corporation is responsible for operating and maintaining the project. However, day-to-day operation and maintenance is performed by Bonneville Services Company, Twin Falls, a wholly owned subsidiary of Bonneville Pacific. As operator, Bonneville Services receives 6 percent of the gross revenue of the project. From these fees, Bonneville Services pays for replacement of minor parts, insurance, recordkeeping, and real estate taxes, in addition to those services necessary to operate the facility.

The Twin Falls Canal Company is responsible for operating the canal system. It must attempt to regulate flows in the canal to maintain pre-agreed monthly flow rates. Operation of the powerplant is in no way to interfere with operation of the canal for irrigation purposes.

The plant can be operated manually or automatically using a programmable controller. The programmable controller also permits the plant to be operated remotely. The plant operator operates numerous other small hydropower projects in the area from an office in Twin Falls.

Installation and Operating Costs

The total construction cost of the project was $13,285,000. A breakdown of costs by category is given in Table 7-4. The estimated annual operating costs of the project based upon 1985-1989 experience are shown in Table 7-5.

Table 7-4
Low Line Canal Project
Construction Costs

Item	Cost
Diversion and bridge	$1,300,000
Canal excavation	400,000
Intake structure	430,000
Penstock	2,200,000
Turbine/generator	5,600,000
Powerhouse	35,000
Substation	600,000
Intertie	120,000
Road access and site work	600,000
Engineering	2,000,000
Subtotal	$13,285,000
Other Project-Related Costs	
Legal fees	$ 200,000
Construction interest and loan fees	700,000
Permits and fees	150,000
Debt reserve	500,000
*Bonding and developer fee	1,835,000
Management	580,000
Contingency	2,000,000
Total	$19,250,000

*Includes payments to Canal Company

Table 7-5
Low Line Canal Project
Annual Operating Costs

Property tax	$ 96,912
State kWh tax	19,942
Maintenance, repair and operations, including insurance premiums	197,642
Debt service, including trust fees	1,920,000
Operations and maintenance charge on facilities owned by the utility	21,405
Royalty to Twin Falls Canal Co. (10%)	202,780
Accounting, legal and office overhead	20,000
Capital improvements	50,000
Total	$2,528,681

Power Purchase Contract

An agreement for sale of firm energy was made between Bonneville Pacific and Idaho Power Company on June 6, 1984. The 35-year agreement is summarized in Table 7-6.

The contracted annual net energy of the project is 46,841 MWh. The fixed payments shown in Table 7-6 remain the same throughout the life of the contract. The variable components, however, are subject to change by the Idaho Public Utilities Commission when retail rates are reviewed. Any surplus energy produced over and above the annual contracted amount would be purchased by Idaho Power at the non-firm avoided energy rate in effect at the time of delivery. The rate is calculated monthly and filed with the IPUC.

The power sales agreement provides that all disconnect and metering equipment is to be installed, operated, and maintained by Idaho Power Company. The costs of installing the equipment were paid by Bonneville Pacific. A total of $325,000 was paid for special facilities and metering equipment, and $80,000 was paid for disconnect equipment. Bonneville Pacific must also pay an operation and maintenance charge of 0.7 percent per month times the interconnection costs specified above.

The agreement contains provisions in the event of the failure of the facility to deliver the contracted power for the entire 35-year term of the agreement. In the event of permanent curtailment of net energy deliveries, Bonneville Pacific must pay a lump sum repayment amount as specified in Table 7-7, multiplied by the difference in megawatt-hours between the contracted annual net energy amount (46,841) and the annual amount of energy actually produced.

Table 7-6
Power Sales Contract Summary

Season	Months	Contracted Energy (MWh)	Fixed Payment (¢/kWh)	Variable Payment (¢/kWh)
Season 1	December January February	1,404	7.33	0.8
Season 2	March April May	11,782	4.89	0.54
Season 3	June July August	17,459	7.33	0.8
Season 4	September October November	16,196	4.89	0.54

Table 7-7
Lump Sum Refund Payment for Permanent Curtailment of a Portion or All of Annual Net Energy Amount Under 35-Year Contract

Contract Year of Curtailment Commencement	Dollars Per Annual Megawatt-hour
1	20
2	40
3	60
4	80
5	100
6	120
7	140
8	160
9	180
10	195
11	210
12	230
13	250
14	265
15	290
16	315
17	340
18	365
19	390
20	410
21	425
22	440
23	455
24	465
25	470
26	470
27	465
28	445
29	420
30	390
31	345
32	280
33	200
34	100
35	0

Although a contract for sale of power was successfully negotiated, Idaho Power was compelled by the Idaho Public Utilities Commission, and probably would not have agreed to a contract if left on its own. Its reluctance is evidenced by the following statement contained in the power sales agreement:

> Idaho [Power] has advised the Commission that Idaho [Power] believes that the rates contained in this Agreement are too high, and that Idaho [Power] does not believe that entering into this Agreement is in the public interest. The parties acknowledge that prior to the execution of this Agreement, the Commission has ordered Idaho [Power] to enter into fixed-term contracts for the purchase of power offered by cogenerators and small power producers at the rates set forth in this Agreement; and that the Commission has ordered that all payments to be made under this Agreement shall be allowed as prudently incurred expenses for ratemaking purposes.

Permits and Licenses

FERC

Because of the nature and location of the Low Line project, the project was eligible for a small conduit exemption from FERC. Its total installed capacity was less than 15 MW; it was not located on federal land; and it used a manmade conduit that was constructed primarily for another purpose. In addition, it did not require construction of a dam to provide the head necessary for power generation, and it received from, and discharged back into, the conveyance system.

An application for a small conduit exemption was filed on August 1, 1980. The exemption was granted on December 18, 1980. The project as described in the exemption from FERC was considerably different from what was actually built. In the exemption, a single 9,000-kW turbine-generator unit was proposed, instead of two 4,000-kW units, as were installed. The proposed turbine was a modified version of a standardized "tube" type manufactured by Allis Chalmers, a propeller-type turbine, very different from the Francis-type turbines actually installed. The original plan also included a pressure relief valve installed on a separate branch of the penstock to discharge water around the plant and back into the canal in the event of a plant shutdown. A large vertical surge tank was installed instead.

Application for qualifying facility status was filed on June 5, 1980. The project was certified as a qualifying facility on September 2, 1980.

Other Permits and Approvals

Compared to many other small hydropower projects, very few permits and approvals were required to construct and operate the Low Line project. In part, this could be due to the fact that it was one of the earlier projects developed in the state. Mostly, however, it was due to the location of the project.

Since the project uses a privately owned irrigation canal and is not located on or near any federal lands, the approval of land management agencies was not required. In addition, the canal, since it is dry some months of the year, does not support a fisheries population. The canal has never been used for recreational purposes, and the effect of the project on wildlife has been almost negligible.

A water right application was filed in March 1977 to divert 1,500 cfs from the Snake River for power generation. Although the Twin Falls Canal Company previously held water rights in excess of 1,500 cfs, these were for the purpose of irrigation, not power generation. In Idaho, a water right is granted for an amount and a purpose. Thus, it is possible for multiple water rights to be granted for the same volume of water, but for different purposes. A permit was granted on July 28, 1977. A water rights license could be granted in the future, although it would most likely be only for 1,300 cfs, since that is the maximum capacity of the Low Line Canal.

The water rights permit for the project is subordinated. This means that the project's water use is subordinate to all other consumptive uses (e.g., domestic, stock water, irrigation), whether those uses are senior or junior to its permit. Since most of the water used in the powerplant is also used for irrigation, this is not generally a problem. However, future upstream uses of water during the non-irrigation season could potentially be problems.

Another potential conflict over water rights could arise if flows in the Snake River were too low during the non-irrigation season. Since the Low Line project receives water diverted from the Snake River, senior water rights downstream of the point of the diversion must be satisfied. This would include water rights held by the Idaho Power Company for two hydropower projects with earlier priority dates. It is not anticipated that flows in the Snake River would go low enough that a problem would be encountered; however, a formal agreement between Idaho Power Company and the Twin Falls Canal Company was signed as a precaution.

The location of the Low Line project carries an agricultural zoning designation. Consequently, a Conditional Use Permit had to be obtained from the Twin Falls County Planning and Zoning Board. In addition, various building permits had to be obtained from the county.

A permit to use right-of-way was also obtained from the Twin Falls Highway District. This permit was to allow for construction of the penstock, since it crossed a county highway.

Potential Environmental Impacts

Fisheries

The Low Line Canal does not support a fishery. There is no way fish can migrate to the location of the powerplant unless they follow the canal system for 15 miles downstream from Milner Dam, passing through several regulating structures along the way. Downstream from the project area, the canal crosses Rock Creek, a natural stream that does support a fishery. However, the crossing is a closed siphon that could not permit the entry of fish into the canal system. Planting fish in the canal system is probably out of the question, since the canal does not flow year round and does not offer a very suitable habitat. As a result of these factors, the impact of the project on fisheries is negligible.

Wildlife and Botanical Resources

The project area has generally been known as favorable ring-necked pheasant habitat. However, the population of these birds has declined since the late 1950s, and the decline has been attributed to reduced habitat in the agricultural areas because of changes in farming practices (e.g., cleaner farming, conversion from gravity to sprinkler irrigation, and fall plowing). Other species of game and nongame wildlife are also dependent to some degree on the same habitat base and have also been adversely affected by changing farm practices. Hungarian partridge, songbirds, mammals, reptiles, muskrats, badger, skunk, and some other furbearing animals such as ground squirrels and groundhogs inhabit the general area. Some waterfowl use the canal system during their annual migration through the area.

Construction of the project has had very little, if any, impact on wildlife or wildlife habitat. Over 2,000 feet of the canal channel is dewatered as a result of the project; however, the dewatered reach was very swift, and in a rocky, highly erodible area. Some minimal natural cover and stubble may have been lost as a consequence of burying the penstock and dewatering the canal, but little existed, because of the eroded condition of the channel.

Since the project is located in a predominantly agricultural area, there are very few trees and little native vegetation. Most of the land disturbed by construction was agricultural; it was used for pasture or planted primarily with row crops such as beans, peas, sugar beets, or small grains. There are no endangered or threatened plant or animal species in the general area, nor are there critical habitats.

Water Quality

The project's water supply comes from the Snake River by way of Milner Dam, located about 15 miles to the east. The quality of water at the project site is generally as good as water in the Snake River. Nearly 3 million acres of irrigated land lie to the east of the project. During the irrigation season, silt concentrations are high in Snake River water because it receives return flows from irrigation. The project does not affect water quality in the Snake River, however, because all of the water leaving the plant is discharged back into the canal to be used eventually for irrigation before being returned to natural stream channels. If the project has any effect on water quality, it probably improves it, since water no longer flows through the highly eroded channel that was dewatered as a result of the project.

Recreational Resources

Recreational activities in the project area include bird hunting, fishing, and motorcycle, bicycle, and horseback riding. Pheasants and Hungarian partridge are hunted, along with some migratory waterfowl. Groundhogs and ground squirrels are hunted in some areas along the canals.

Fishing in the area is generally confined to natural streams, Rock Creek being the only one in close proximity to the project site. No fishing occurs in the canal system.

Motorcycle and bicycle traffic along some of the canal rights-of-way occurs, but is discouraged for safety reasons. Horseback riding is not uncommon.

While some tubing and rafting occurs in parts of the canal systems in the valley, they are discouraged because of the safety hazards and the liability problems created for the irrigation companies. The flow in the reach of the canal developed for the project is too swift and turbulent for kayaking or whitewater rafting. In summary, the project has had very little, if any, effect on recreation in the area.

Historical and Archaeological Resources

There are no known historical or archaeological sites close to the project area. The old Oregon Trail passed to the north, and several cabins of early pioneers still exist to the south, although both are several miles distant from the project site.

Land Management and Aesthetics

Land usage in the project area has, for the most part, been unaffected. The canal system and diversion works have existed since the early 1900s and are relatively unchanged except for the new diversion structures and the powerhouse. The penstock supplying water to the site is buried for almost its entire length, minimizing the visual effect. The existing, highly eroded, dewatered canal reach is still visible, however, since it may be needed to carry flows when the plant is shut down.

The powerhouse has some effect on the aesthetics of the area. The powerhouse structure is concrete in the lower floors, with an attractive brick exterior above ground level, and a built-up roof. Grass has been planted in the surrounding areas. A paved road leads from the county road to a small paved parking area adjacent to the powerhouse.

Power lines leading from a substation at the powerhouse and the large surge tower outside of the powerhouse are the only prominent features associated with the project. The 10-foot diameter by 63-foot-tall surge tower is steadied with guy wires. The tower has been painted with the logo of the Twin Falls Canal Company to improve its appearance.

Impact Mitigation

Since the impacts of the Low Line project were relatively minor, few impact mitigation measures were required. The FERC order granting an exemption included a standard article requiring compliance with any conditions that federal or state fish and wildlife agencies have determined appropriate to prevent loss of, or damage to, fish and wildlife resources. Neither the U.S. Fish and Wildlife Service nor the Idaho Department of Fish and Game had any objection to the issuance of the exemption.

The U.S. Fish and Wildlife Service offered the only specific comment in response to the exemption application. They required that the electrical transmission system be planned and constructed so as to prevent possible electrocution of raptors.

Some mitigative measures were taken to minimize the aesthetic impact of the project. The powerhouse was given an attractive brick exterior, grass was planted, and the road to the powerhouse and parking area were paved to minimize dust and improve the appearance. The surge tower was painted using relatively unobtrusive colors and was made to somewhat resemble a large grain silo.

Additional mitigative measures included locating the route of the penstock within Canal Company right-of-way as much as possible, and burying the penstock. The electrical substation was fenced for public safety.

Land Use Agreements

Most of the land on which the project is located is owned by the Twin Falls Canal Company. The property was leased to Bonneville Pacific to construct and operate the project. This lease was assigned to Magic Valley Hydroelectric Partners, Ltd., upon its purchase of the project works.

Two easements were obtained from private land owners to enable construction, operation, and maintenance of the project. One easement for use of 3.66 acres was obtained from Porter Pringle and Clara Pringle Ostrander, and the other, for the use of 4.80 acres, was obtained from the limited partnership of Peter and Charlotte Link and Link Land and Livestock.

Project Construction

A contract for design, fabrication, installation, and startup of the project was signed on March 5, 1984, by Bonneville Pacific Corporation and Water Power Company, a Utah corporation. Bingham Engineering of Salt Lake City did the primary design of the project. The turbines, generators, switchgear, and supervisory control system were designed and fabricated by the Hydro West Group of Bellevue, Washington. The general contractor for construction of the civil works was PMF, Inc. of Twin Falls, Idaho.

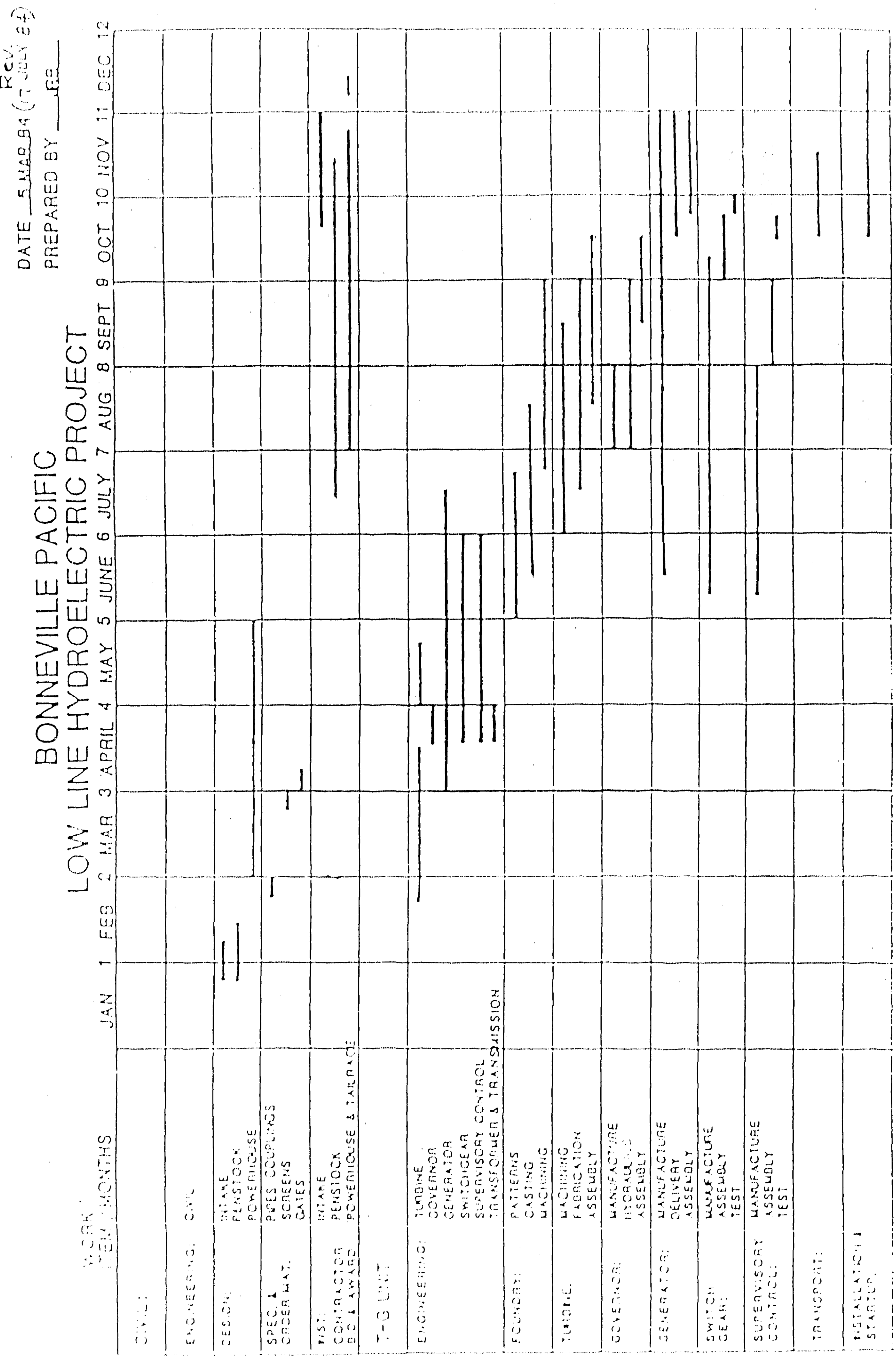
Construction of the project began in the summer of 1984. Some elements of the project, such as the powerhouse, tailrace, and penstock, could be worked on during the irrigation season, since they did not interfere with delivery of irrigation water. Other elements, such as the diversion works, could only be worked on after the irrigation season had ended, when the canal was dry. Construction was completed in the winter of 1984-85. The facility went on-line at the start of the following irrigation season on March 1, 1985.

A construction schedule for the project is shown in Figure 7-1.

Interconnection, Transmission and Wheeling Considerations

The output of the Low Line project is sold to Idaho Power Company. Since there are no other utilities in the area, transmission and wheeling were not concerns. Interconnection of the facility was a shared responsibility between Bonneville Pacific and Idaho Power, although all expenses were borne by Bonneville Pacific. Idaho Power installed, operates, and maintains all disconnect and metering equipment. The cost to Bonneville Pacific of Idaho Power's interconnection expenses was $405,000.

Figure 7-1
Low Line Canal Project Construction Schedule



Chapter 8

Wood Power, Inc.
6.2-MW Wood Waste-Fired Cogeneration Plant
Plummer, Idaho

Project Description

In 1984, Wood Power, Inc. completed a 6.2-MW cogeneration plant on property adjacent to the Pacific Crown Timber Products sawmill. The plant, constructed by Yanke Energy of Boise, Idaho under a $5.16 million turn-key contract, consists of a fuel storage building, fuel handling equipment, hog fuel boiler, steam turbine, and electric generator. Wood Power Inc. trades process steam to the Pacific Crown sawmill for waste wood fuel and sells electricity to Washington Water Power (WWP). Pacific Crown uses steam and waste heat from Wood Power's plant to dry lumber products.

The cogeneration plant was built almost entirely with used equipment. This is one of the reasons it was economically feasible. Construction costs came to about $800/kW. Steam and electric generating equipment specifications are given in Table 8-1.

Wood Power, Inc. plant supervisor Rick Bowen stands in front of the steam turbine (right) and 6.2 MW electric generator (left).

Table 8-1
Wood Power, Inc.
Steam and Electric Generating Equipment Specifications

Manufacturer	Riley Stoker Corporation
Efficiency Equipment	Superheater, economizer, and low and high temperature feedwater preheaters
Grate	Traveling
Stoker	Spreader
Steam output	66,000 lbs of 760 to 780F, 400 psig
Rated heat capacity	88 million Btu/hr
Make-up water	8,000 gallons/day
Air cleaning equipment	Fly ash classifier reinjection system, multiclone and wet scrubber
Cooling tower make-up water	100,000 gallons/day
Steam Use	
Turbine	50,000 lbs/hr, 760 to 780F, 400 psig
Kilns	6,000 lbs/hr, 510F, 45 to 50 psi
Power Generation: Steam Turbine	
Manufacturer	Westinghouse
Type	Extraction, condensing
Rated kW	5,000
Max kW	6,250
Initial pressure	400 psig
Initial temp.	750F
Exhaust	28.5 in Hg vacuum
R.P.M.	3,600

The steam turbine has steam extraction at three stages. Steam from the high pressure extraction point heats boiler feedwater in a high pressure feedwater preheater. Wood Power sends 6,000 lb/hr of 50-psig, 510F superheated steam from the intermediate pressure extraction point to Pacific Crown for use in its dry kilns.

An unusual feature of this installation is that Wood Power also sends hot air produced by bearing friction, generator cooling, and boiler heat loss from the top of the cogeneration plant building to Pacific Crown for use in one of its drying kilns. In the summer, this kiln can dry wood in 9 days, while in the winter it takes 9 weeks. (By contrast, the kilns that use steam can dry wood in 30 hours in the summer and 50 to 60 hours in the winter.)

Operating the cogeneration plant has not been without troubles and financial risks, but the plant also provides considerable benefits to the Pacific Crown sawmill and the community of Plummer. Besides being a profitable operation in its own right, the Wood Power cogeneration plant provides the Pacific Crown sawmill with a way to get rid of its wood waste. Because the sawmill meets all its dry kiln steam requirements with steam from Wood Power, it no longer has to maintain and operate its own boiler. The cogeneration plant emits far less pollution than the teepee burner the sawmill previously used to eliminate wood waste; consequently, the air quality in the Plummer area is greatly improved. The cogeneration plant has also made the sawmill a much stabler and stronger business. Since the installation of the cogeneration plant, the sawmill has remained open during the winter; previously it was not always able to do so. While other sawmills in the area have shut down, Pacific Crown continues to grow.

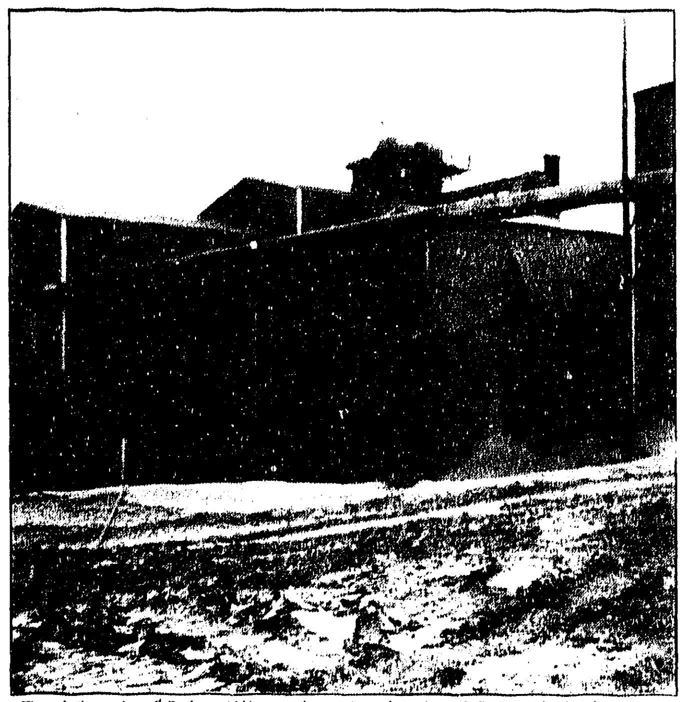
Energy Production and Use

In the summer of 1981, representatives of Wood Power, Inc. and Washington Water Power met to talk about a power sales agreement. A 35-year contract was signed on August 19, 1981. Yanke Energy, contractor for the plant, had done preliminary work on the contract for about 13 months before it was signed. The power sales contract requires Wood Power to deliver a minimum of 39.42 million kWh annually to the WWP substation about one mile away. Although the nameplate capacity of the steam turbine is 6.25 MW, the contract capacity is 6.0 MW. Wood Power must deliver 6 MW of power at a 75 percent availability factor to meet its annual energy minimum. Wood Power exceeds this availability and actually delivers an average of about 42 million kWh a year to WWP.

Line losses between the plant and the WWP substation are about 5 percent. According to the plant supervisor, the solid-fuel water tube boiler operates best at 5.2 to 5.3 MW output; thus, with the line losses, an average of 4.9 to 5.0 MW is delivered to the WWP substation. This means that the plant must operate about 90 percent of the time, or about 8,000 hours a year, to produce its contracted annual energy minimum. If the plant delivered 6 MW to the substation it would have to operate only 75 percent of the time, or 6,570 hours a year.

The plant uses an estimated 10 tons per hour of hog fuel at about 50 percent moisture content wet basis. Operating 8,000 hours a year requires 80,000 tons of fuel. Assuming an energy value of 4,250 Btu per pound of hog fuel and 42 million kWh of electricity delivered to the substation, the efficiency of the plant in converting hog fuel into delivered electricity is approximately 21 percent.

Wood Power purchases electricity to operate the plant from the City of Plummer, a municipal customer of WWP, at an average of 3.65¢/kWh. WWP pays Wood Power an average of 5.36¢/kW for the electricity Wood



Fuel for the $5.1 million plant is obtained from the adjacent Pacific Crown Timber Products sawmill. Electricity produced is sold to Washington Water Power while extracted steam is used in the sawmill's dry kilns.

Power delivers. Because of this difference, it is to Wood Power's advantage to buy electricity rather than to use its own electricity to run the plant.

The average power usage at the cogeneration plant is 718 kWh per hour. Over a year it uses 5.79 million kWh. From December 1988 to November 1989, the monthly peak electric demand of the plant averaged 1,777 kW. The wet scrubber used for pollution control is one of the larger energy consumers at the plant. Over the course of a year, the wet scrubber uses $17,890 of electricity. Wood Power management is considering replacing it with a unit that requires less maintenance and energy to operate.

Fuel Supply

All the fuel that Wood Power uses is waste wood from the adjacent Pacific Crown Timber Products sawmill. The sawmill can supply all the fuel Wood Power needs. Wood Power has not bought or taken in fuel from any other sources for 2 to 3 years.

Wood Power management has considered mixing hog fuel with other fuels. In early 1987, they requested permission from the Idaho Air Quality Bureau to test-burn a mixture of one part fused oil with 200 parts hog fuel. A company near Plummer also requested permission from the Bureau for Wood Power to burn chips from the company's railroad tie reclamation operation. Although these requests were approved, Wood Power has not tried either of these fuel mixtures. They are, however, fuel options for the future.

Hog fuel from the sawmill is piped pneumatically to a fuel storage building 200 feet by 200 feet by 40 feet high. It can hold a 48-day supply of fuel if filled to a depth of 30 feet.

Project Economics

The original cost of the project including the fuel storage building was $5,136,000. Including interest, Wood Power now pays about $73,000 a month for debt service. The plant supervisor estimated that operation and maintenance costs at the plant are about $40,000 a month.

WWP pays Wood Power a capacity payment of $307/kW-year as well as monthly energy payments equal to the number of kWh produced in a month times the latest approved avoided energy cost. The contract capacity is 6,000 kW, so Wood Power receives $1,842,000 a year or $153,000 a month capacity payment. Current avoided energy costs for WWP are shown in Table 8-2.

Table 8-2
WWP Avoided Energy Costs

Period	Energy Payments (¢/ kWh)
July-Oct	0.8
Nov-Feb	1.4
March-June	0.7

Wood Power is on-line an average of 92 percent of the time and produces about 42 million kWh a year. Assuming 60 percent of the downtime is during the March-June period when the annual maintenance shutdown is scheduled, 25 percent during the July/October period, and 15 percent during the November/February period, then about 35 percent of the year's production is at 1.4¢/kWh, 34 percent at 0.8¢/kWh, and 31 percent at 0.7¢/kWh. The annual income from energy payments would be $91,182 for the March/June period, $114,000 for the July/October period, and $205,373 for the November/February period. This is $410,991 for the year, or an average of about $34,000 a month.

Using the above assumptions, with both capacity and energy payments, Wood Power's income averaged about $187,000 a month from 1986 to 1989. During this period, utilities costs averaged about $16,000 a month. Not including overhead, income exceeded expenses by about $58,000 a month.

Permitting and Licensing Requirements

Air Quality Permit

The air quality permit is usually the most detailed permit for a bioenergy project, and the Wood Power cogeneration plant is no exception. Wood Power requested an air quality permit to construct in August 1982. It was approved one month later. The limitations on emissions as listed in the permit are as follows:

- Visible Emissions - Emissions cannot exceed 20 percent opacity for a period or periods aggregating more than 3 minutes in any 60-minute period.

- Particulate Emissions - Emissions of particulate matter cannot exceed 0.080 grains per standard dry cubic foot of effluent gas corrected to 8 percent oxygen.

The original design and construction of the plant used two multicyclones in series to clean the effluent gas. Yanke and Wood Power personnel suspected the multiclones might not clean the gas enough to meet limitations, but tried them anyway because of the high capital and maintenance costs of a wet scrubber. Yanke guaranteed that the plant would meet air permit requirements. It made good on this guarantee when additions were required to meet air quality requirements. The plant came on-line in February 1984 and on August 8, 1984, the Idaho Air Quality Bureau evaluated the emissions from Wood Power's cogeneration plant and found they exceeded the opacity limitations contained in the Permit to Construct.

On October 3, 1984, the Air Quality Bureau issued a Notice of Violation to Wood Power for exceeding opacity limitations. Wood Power management was already aware of the problem and had spent considerable time and effort trying to correct it. Cinders from the boiler had caused fires in the primary "roughing" multicyclone during the spring and summer of 1984. Since this was only a couple of months after plant startup, these problems could probably be considered startup bugs. Nonetheless, management at Wood Power realized they would have to improve the design of the stack gas cleaning system to meet the emissions limitations of the air quality permit.

The following excerpts from a stipulation order adopted February 14, 1985, with the Idaho Department of Health and Welfare (representing its Air Quality Bureau) as complainant and Wood Power, Inc. as respondent, give a good description of the problem and its solutions:

> Wood Power acknowledges that the particulate control system currently in place and as presently operated is, without repair and additional modifications, insufficient to control particulate emissions in a manner consistent with the limitations contained in the Air Regulations. . . Wood Power represents, however, that in response to the apparent deficiencies in the particulate emissions control system, it has to date, taken the following corrective actions: (1) redesigned and installed a new automated combustion air control system to limit particulate carryover out of the combustion chamber; (2) designed and installed additional overfire air injectors; (3) redesigned and retrofitted new cinder classifier/reinjection system; (4) redesigned and installed combustion chamber refractory to increase combustion efficiency to limit carryover; and (5) construction of a covered fuel storage to prevent precipitation degradation of the fuel supply. Wood Power further represents that the installed capital cost of the original dual multiclone particulate control system was $341,000; and that Wood Power has incurred additional capital costs, not including lost revenue due to construction downtime, to date of $355,000 in the design, modifications, retrofits and installations stated above.
>
> Wood Power represents that the existing multiclone system was selected based on its high proven reliability in below freezing temperatures and its ability to meet the required emissions limitations. It is conceded that the dual multiclone system has not to date met the designed for and intended control efficiency under continuous operation. Wood Power's studies indicate that the primary factor in the system's shortcomings is due to higher than anticipated or designed for fuel moisture content, which results in high cinder carryover from the combustion chamber and an overloading of the primary "roughing" multiclone. Wood Power's efforts to date have been directed to remedying the fuel moisture/combustion problem. . .Wood Power represents that its present inability to meet the limitations contained in the Air Regulations was caused, in whole or in part, by fire damage to the primary "roughing" multiclone, which occurred from cinder fires in the multiclone ash hoppers in the spring and summer of 1984. The damage to the individual tube gaskets and discharge valves was not discovered until a maintenance shut-down of the facility in November of 1984. In a November 30, 1984 letter to the Air Quality Bureau, Wood Power advised the Bureau of the damage and acknowledged the fact of its noncompliance. Further, Wood Power committed itself to the repair and modification of the particulate control system by installation of a wet scrubber system. A scrubber is presently being designed for the facility and Wood Power continues to commit to its installation and operation on or before June 1, 1985. The estimated cost of the multiclone repair and scrubber installation is $60,000.

In April 1985, after Wood Power installed the wet scrubber, Yanke Energy tested it. The results of this test are shown in Table 8-3.

Table 8-3
Wood Power Inc.
Boiler Scrubber Stack Emissions Test Results[a]

Boiler	
Excess Air (percent)	64.7
Fuel H_2O (percent)	49.5
Steaming Rate (lb/hr)	65,000
Pressure (psi)	400
Stack	
Temperature (F)	149.3
Flow (dscfm)	3,266
H2O (percent)	26.6
O_2 (percent)	8.2
Particulate Emissions[b]	
gr/dscf at 8% O_2	0.0486
lb/hr	13.8

[a]Average of three tests
[b]Maximum particulate allowed: 0.08 grains per dry standard cubic foot (gr/dscf) corrected to 8% O_2.

Since the installation of the wet scrubber, except for a period in the spring of 1989 when demisting blades in the wet scrubber had fallen out, Wood Power has maintained emissions well within permit standards.

Boiler Permit

The State of Idaho does not inspect boilers. Wood Power's insurance company, Travellers, annually inspects the boiler and gives Wood Power an inspection certificate good for one year.

Solid Waste Permit

Wood Power, Inc. is on the Coeur d'Alene Indian Reservation. Since the state has no jurisdiction over landfills on Indian reservations, Wood Power was not required to obtain a solid waste permit to dispose of its ash. Ash is disposed of in a settling pond located in a low area between the plant and a nearby elementary school. The school district owns the property and was in favor of filling it in to create some usable property. Eventually the area will be covered with topsoil. Plant operators take bottom ash to the same pond with a front loader.

The EPA is now looking at regulations for disposal of municipal solid waste incinerator ash. It is likely that the guidelines for wood ash will be the same as those for municipal solid waste incinerator ash, even though wood ash is considerably different. It is expected that the guidelines for incinerator ash disposal will call for a landfill with a composite clay and plastic liner. If regulatory agencies apply these standards to wood ash, the cost of disposal will increase.

Power Sales Contract

Although Yanke Energy had done some preliminary work, the power sales agreement between Wood Power, Inc. and WWP took about 2 months to negotiate. It follows the guidelines set forth by PURPA and the Idaho Public Utilities Commission's interpretation of PURPA.

WWP pays Wood Power for all electricity delivered to WWP's substation about a mile from the Wood Power cogeneration facility. Up to the annual energy minimum (i.e., the contract capacity times the total number of hours in a year times an equivalent availability factor of 75 percent), Wood Power is paid a capacity rate plus an energy rate. For all energy delivered above the annual energy minimum, WWP pays Wood Power an energy rate only.

Because Wood Power delivers less than the 6,000 kW contract capacity rating to the WWP substation, Wood Power must operate at least 90 percent of the time to deliver its annual energy minimum. To be on-line 90 percent of the time at normal peak capacity, the plant must operate 327 days a year. This leaves 18 days for unscheduled shutdowns. In spite of this, the contract has not been difficult for Wood Power to meet.

The penalties for stopping delivery of electricity or reducing the contract capacity provide strong incentives for Wood Power to maintain both its annual energy minimum and its contract capacity throughout the term of the contract. Wood Power would have to pay WWP half the difference between the capacity payments it already received under the 35-year contract and the capacity payments it would have received if the contract were for the shorter period represented by stopping production of electricity before the end of the contract. This applies to the portion of contract capacity subject to early termination. For example, if Wood Power stopped production February 1, 1990, it would owe WWP $3,042,000. If Wood Power and WWP agreed to reduce the contract capacity to 5,000 kW on February 1, 1990, Wood Power would owe WWP

$507,000. A contract rating of 6 MW means that a capacity payment is made based on an avoided capacity of 6 MW. The capacity avoided is assumed to have a 75 percent availability factor. Wood Power can have a contract rating of 6 MW with a plant that puts out 5.3 MW by having an actual availability factor of about 90 percent.

Two amendments have been made to the contract. The original contract language implied that WWP could require Wood Power to comply with all applicable laws and regulations, and that WWP would not sign the contract until it knew that Wood Power had indeed complied. The first amendment, made June 15, 1983, changes the contract to state that all parties will comply with all applicable laws and regulations, but that it is not up to either party to verify the other party's compliance before signing the contract. The second amendment, made January 28, 1988, changes the beginning of the contract power sales year from January 26 to July 1.

Wood Power schedules the annual maintenance shutdown to take place after it has fulfilled its annual minimum energy delivery. When the end of the contract year was January 25, the annual repair and maintenance shutdown occurred in January. Since it was much more difficult to accomplish repairs in midwinter because of the weather, changing the contract year to July 1 not only increased the value of energy delivered to WWP but also made maintenance much easier.

The power sales contract calls for Wood Power to try to maximize production of power between 8 a.m. and 8 p.m. on a daily basis. Wood Power does not do this for two reasons: 1) it does not have enough excess capacity, and 2) there are no monetary incentives in the contract to do it.

Project Ownership, Organization and Financing

The collateral requirements for the original loan from Washington Trust Bank were quite stringent. The company was required to maintain minimum levels of cash deposits and net worth, and was restricted in the amount of annual expenditures for fixed assets and officer compensation. All assets of Wood Power were pledged as collateral for the loan and, in addition, Chopot and affiliated companies were guarantors.

The project has done well financially, with retained earnings of $3.2 million in June 1989. (Retained earnings is the term used to describe the increase in stockholders' equity resulting from the profitable operation of a corporation. The retained earnings balance can be viewed as the net earnings from the date of incorporation to the present, less the sum of dividends declared during the same period.) Therefore, in 1987, the original loan from Washington Bank and Trust was renegotiated with somewhat less stringent collateral requirements. The new loan is for $3.5 million, due in equal sums over 5 years plus, interest at prime plus 0.5 percent. Chopot's demand note loan has remained in place and the demand note loan from Pacific Crown has been retired. In fact, Wood Power has loaned $1,444,000 to Pacific Crown at 8 percent interest.

Operating Experience

The power sales contract calls for Wood Power to submit to WWP each June a power production schedule for the following two operating years. Last year, Wood Power planned for 20 days of scheduled shutdowns. This included a 10-day shutdown in June for annual maintenance. In addition to the annual maintenance, every 5 years operators take the turbine apart and reset the diaphragms. The diaphragm blades are brought to their original specifications to keep the turbine operating efficiently.

The annual maintenance shutdown involves several other items, including inspection of the turbine and generator bearings and inspection of the motors for vibrations. The generator rotor is continuously monitored for vibration. It rotates at 3,600 rpm and weighs 7,400 lbs. It usually takes a day to fix a balance problem on the rotor. Wood Power also has the oil in the step-up transformer tested annually. Every 2 years Wood Power has all the electric switchgear checked.

Because hog fuel is made up of any and all wood waste that can be found at the sawmill, it includes some dirt. Bringing the fuel into the plant creates an abrasive environment for the generator. The plant supervisor said it would have been better if the generator had been placed on the other side of the boiler so prevailing winds would have carried dirt and dust away from the generator side of the building. The plant operators have greatly improved the air filtering system on the generator to counteract this problem and to help increase the generator's life.

One of the problems in operating a cogeneration plant built with used equipment is the cost and time involved in repairing or replacing broken parts. The generator rotor once broke down because of failed insulation. As far as the plant operator knows, the generator had not been serviced since Westinghouse built it in the forties or early fifties.

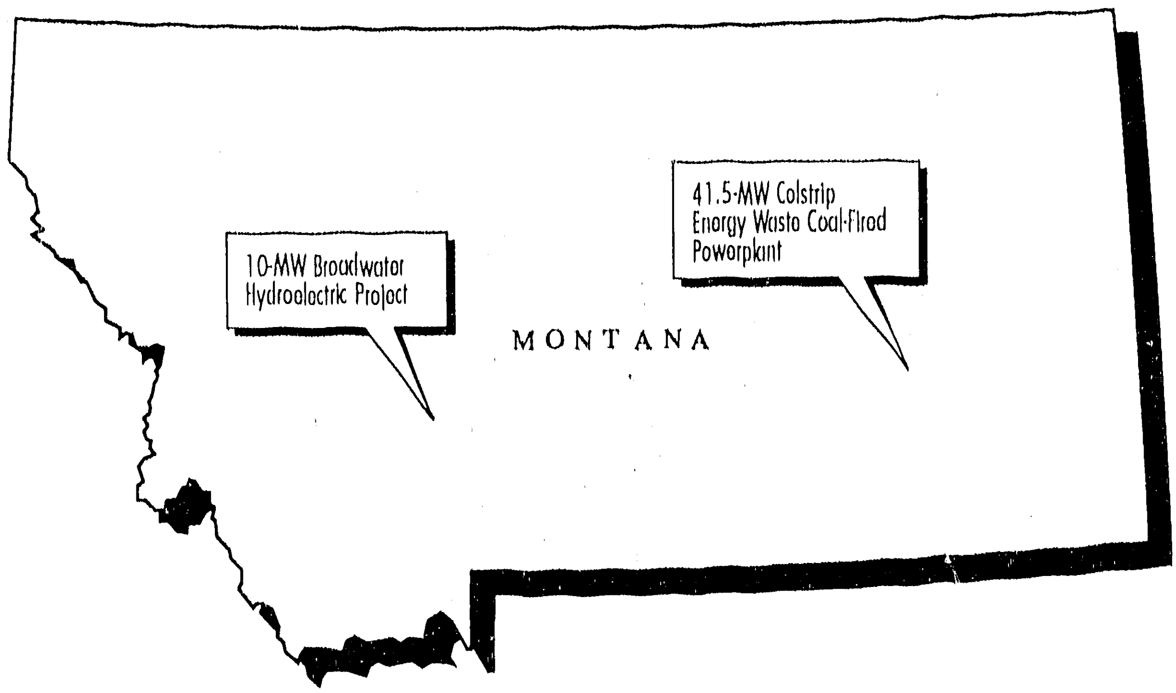
This problem highlighted one of the biggest maintenance problems at the plant--the difficulty of getting replacement parts. Parts ordered from Westinghouse require at least a 9- month wait for delivery, since they must be manufactured. When the rotor broke down and had to be rewound, Wood Power had to rent a rotor at considerable expense. To avoid problems in the future, in the summer of 1989 Wood Power purchased a used turbine and generator set that can be used for replacement parts.

Coordinating the schedule of the cogeneration plant and the sawmill's dry kilns has not been a major problem because the cogeneration plant operates 90 percent of the time. The only time of the year when problems could arise is in June during the 10-day maintenance shutdown. Although the cogeneration plant does not provide any steam to Pacific Crown for its dry kilns during the shutdown, the sawmill can plan ahead to avoid running out of dry wood for its planer.

Interconnection and Transmission Considerations

Wood Power constructed a new power line to deliver power to the WWP substation. According to Idaho Public Utilities records, the interconnection costs were $121,800. the line carries six wires. Three deliver power at 13.8 kV from the plant to the WWP substation, and three bring power back to the sawmill. The power for the sawmill splits off before the line gets to the cogeneration plant.

MONTANA CASE STUDIES



Chapter 9

10-MW Broadwater Dam Hydroelectric Project Toston, Montana

Introduction

The Broadwater Hydroelectric Project is a 10-MW run-of-river hydroelectric facility installed on an existing irrigation dam. The project was built by the Montana Department of Natural Resources and Conservation (DNRC or the Department) and dedicated in September 1989. Broadwater was the first significant qualifying facility (QF) to come on-line in Montana.

The Broadwater development process took almost 13 years from conceptualization to completion. Although Broadwater, being built by a state agency, may be unique, any independent power facility can be expected to go through at least some of the same experiences. Utility plans that rely on these facilities must be flexible enough to incorporate a fair amount of uncertainty.

The intent of this case study is to capture the complexity of the overall project, rather than to focus on two or three "roadblocks" and how they were overcome. Discussions of roadblocks that hinder projects often carry the implication that, except for the roadblocks, the project would have been completed sooner. The history of Broadwater suggests that substitute roadblocks often wait in the wings; if one is removed, another takes its place.

The cast of characters and agencies involved in Broadwater was extensive. Most of DNRC's work on the project was done by the Engineering Bureau of the Water Resources Division. Personnel from the Water Rights Bureau, Water Management Bureau, and Water Development Bureau in the Water Resources Division also played a role, as did personnel from the Energy Division. Although the personality interplay within an organization is often fascinating, for planning purposes the interaction between organizations is more important.

A brief chronology of the Broadwater project follows:

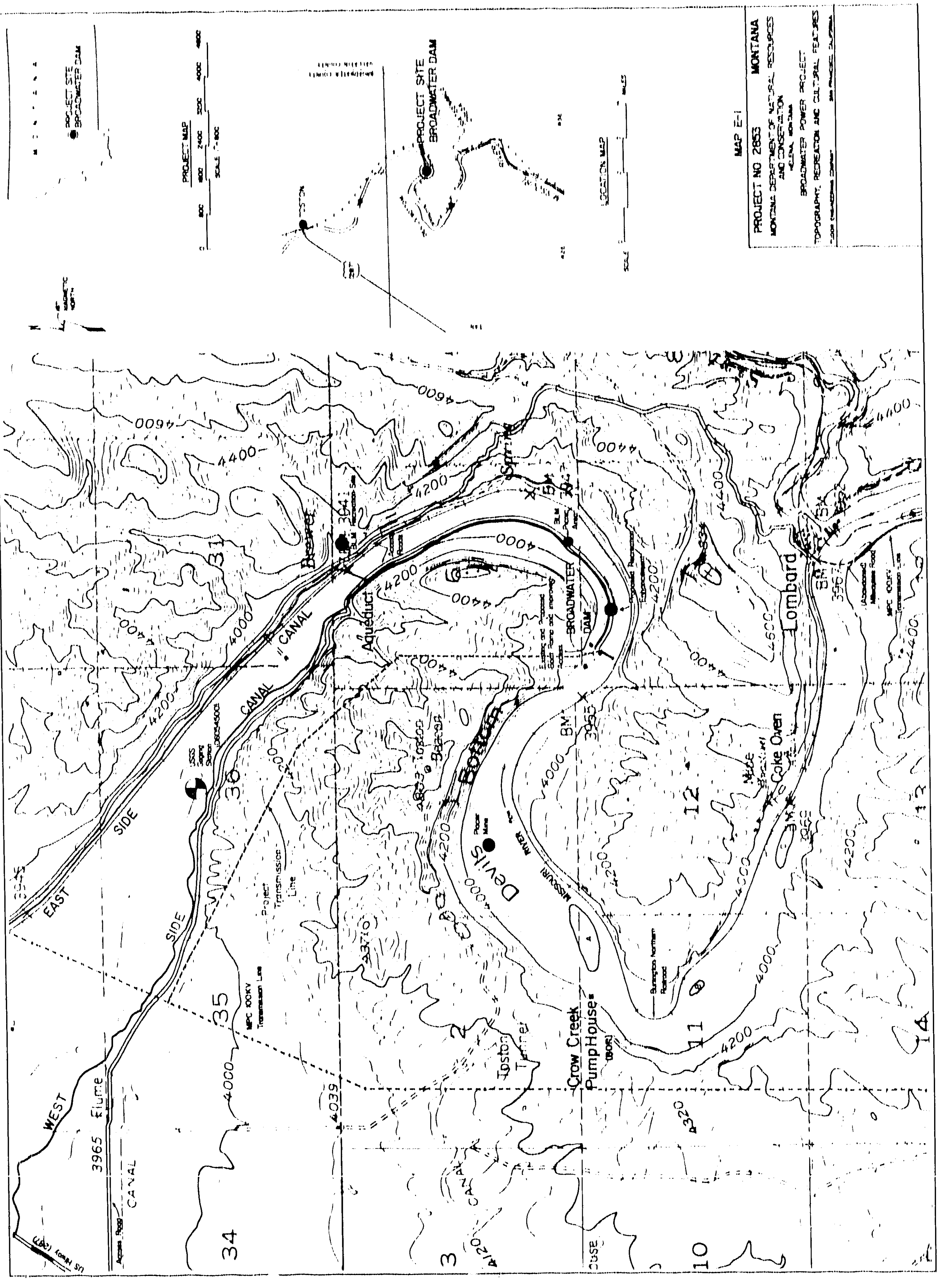
Fall 1976	Tudor Engineering Company presents DNRC with the concept of installing hydroelectric facilities at existing state dams.
6-13-78	DNRC files an application with the Federal Energy Regulatory Commission (FERC) for a preliminary permit.
6-4-80	FERC issues DNRC preliminary permit #2853 for Broadwater.
6-1-82	DNRC files a license application with FERC.
4-23-84	FERC grants a license to build and operate Broadwater.
10-85	Project put on hold because of economics.
2-87	Project again deemed to be viable.
6-4-87	Montana Board of Natural Resources and Conservation gives final authorization to start project.
11-2-87	Contractors mobilize equipment on-site.
9-11-89	DNRC dedicates the Broadwater Hydroelectric Project.

The first part of this paper is chronological, from 1976 to 1989, focusing primarily on the evolution of the decision to build. The second part of the paper covers the individual issues of DNRC's contract to sell the power, the interconnection with the grid, water rights, and various environmental impacts. A final section discusses the conclusions one can draw from this case study.

Project Description

The Broadwater (or Toston) Dam is located on the Missouri River 4 miles south of Toston, Broadwater County, Montana, about 21 miles upstream from Canyon Ferry Reservoir (see Figure 9-1). The Missouri River at this point has an average flow of 5,200 cubic feet per second (cfs). In addition, flows of up to 420 cfs are diverted into a canal system at the dam to irrigate 20,000 acres of land. The original dam was completed

Figure 9-1
Broadwater Dam Location Map



in November 1940, using federal and state funds. The dam is a concrete gravity overflow diversion dam. The flow passes over seven ogee weir sections; the total spillway length is 378 feet. Average usable head is 22 feet; total height of dam from foundation to spillway crest is 40 feet. The reservoir in back of the dam is 5 miles long, with a surface area of 327 acres.

The final design of the hydroelectric project located the 10-MW powerplant on the western end of the dam. The operating level of the reservoir was raised from a maximum of 3,951 feet during the irrigating season to 3,952.6 feet year round. The turbine is a single horizontal pit Kaplan turbine capable of producing 14,000 hp at 22 feet net head. The horizontal synchronous generator produces 11,110-kVa output at 4.16 kV. Three miles of new 100-kV line connect the project to the Montana Power Company (MPC) grid.

The budget for the hydroelectric project addition was $25.35 million which included $2.2 million held aside in a debt service account. The project was financed primarily with tax-exempt revenue bonds backed by the state's coal severance tax receipts. Output of the project is sold to MPC under standard rates for QFs as set by the Montana Public Service Commission (PSC). The consulting engineer was Tudor Engineering Company, San Francisco.

This project required a number of permits. Besides the preliminary permit and license obtained from FERC, DNRC obtained a discharge permit and a short-term exemption from surface water quality turbidity standards from the Montana Department of Health and Environmental Sciences, a 404 permit (water quality) from the U.S. Army Corps of Engineers, a 124 permit (streambed preservation) from the Montana Department of Fish, Wildlife and Parks, and a building permit from the Montana Department of Commerce.

DNRC's Decision to Build

DNRC entered hydroelectric development because its irrigation dams were in danger of failing. During reorganization of the state's executive agencies in 1972, DNRC inherited the irrigation projects of the old State Water Conservation Board. Some of the dams on those projects were under-designed, poorly built, or inadequately maintained; they were a threat to people and property downstream. The state legislature had not appropriated enough funds to rehabilitate these water projects. DNRC eventually decided to install hydroelectric projects at some dams to generate funds that could be used to fix the other dams and reduce liability.

Tudor Engineering was instrumental in DNRC reaching this decision. Tudor offered to assist DNRC to obtain a federal Department of Energy grant to study dam retrofits. As a first step, DNRC staff and Tudor reviewed a DNRC status report, *State Water Conservation Projects* (issued March 1977), on the physical characteristics, present condition, and bond repayment situation of 35 major state-owned water projects and a number of smaller or inactive projects.

Using information from this and other reports, Tudor identified Broadwater Dam (Broadwater County), Deadman's Basin (Wheatland County), and Painted Rocks Reservoir (Ravalli County) as warranting further review. With the initial review completed, DNRC hired Tudor in June 1977 to prepare a preliminary permit application to develop Broadwater Dam. This application to FERC was part of a larger reconnaissance-level feasibility study of the installation of hydroelectric power at the three dams.

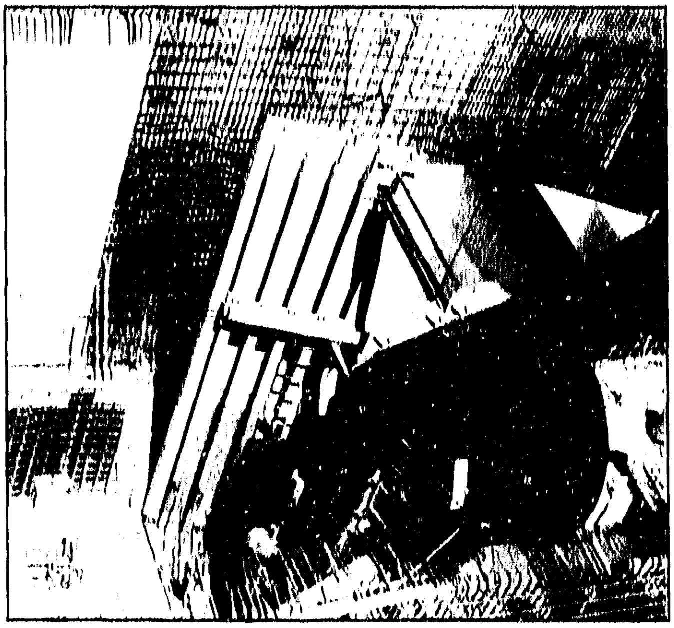
After several delays, the final report, *Potential Hydroelectric Power for State Owned Dams*, was completed in January 1978. Tudor found all three sites to be suitable for cost-effective generating projects given FERC benefit-to-cost guidelines. Broadwater Dam had the best benefit/cost ratio (1.84), followed by Painted Rocks (1.40) and Deadman's Basin (0.95). The benefit/cost ratios were calculated assuming the dams would replace coal-fired publicly owned plants producing power at 26 mills/kWh (in 1976 dollars). Recommendations in the report included the following: (1) Bonneville Power Administration (BPA) should be contacted for assistance in preparing the license application and to arrange wheeling of the power produced; (2) the output should be sold to rural electric cooperatives so that the interest on the bonds would be tax exempt; and (3) the state should develop the projects through "a partnership arrangement where the state's partner or partners will operate, maintain, and market the power to others within the state."

Preliminary Permit Applications

DNRC was not alone in evaluating the potential of Broadwater Dam. Vigilante Electric Cooperative, serving a large part of southwestern Montana, also was interested. In 1976, BPA had issued its customers, including Vigilante, a notice of insufficiency, saying that it could not guarantee power supply for small users

Montanas' Department of Natural Resources and Conservation installed a 10-MW hydroelectric turbine at the State owned Broadwater Dam.

The $24.3 million project is expected to generate 62 million kWh of electrical energy annually. Electrical power produced is sold to the Montana Power Company.



after July 1983. Since BPA was its sole supplier, Vigilante began casting about for alternative sources of power.

In March 1977, Vigilante asked BPA to look at U.S. Geological Survey data from Broadwater to determine whether there was any possibility for installing generation. The next month, BPA suggested that two units of 5.5 MW each might be feasible. Vigilante filed a preliminary permit application with FERC for Broadwater Dam on September 22, 1977.

In March 1978, Montana's Board of Natural Resources and Conservation (the Board) approved a *Conceptual Plan for Montana Water Resources Projects*, prepared by DNRC, which reaffirmed and expanded the commitment of the state to the water resources development business. "The crucial element in the proposed plan is the hydroelectrification of state-owned dams and subsequent sale through long-term contracts of the electricity generated." Broadwater was one of the three dams initially slated for development; additional dams were scheduled to be developed in later years. The revenue from the dams would be used to repair and maintain existing projects and to construct new water resources projects. The facilities were to "maximize income to the state rather than produce electricity at minimum cost."

On March 20, 1978, with the Conceptual Plan approved by the Board, Governor Judge authorized DNRC to file preliminary permit applications with FERC for development of hydropower at Broadwater, Painted Rocks, and Deadman's Basin. On May 5, 1978, DNRC petitioned to intervene on Vigilante's application. DNRC claimed the right to intervene as owner of the dam and as an entity preparing a preliminary permit itself. DNRC filed its own preliminary permit application June 13, 1978.

The competition did not sit well with either party. Vigilante accused the state of double-dealing, and of only going after Broadwater when the Cooperative expressed interest in it. DNRC staff were equally upset, calling Vigilante's application, which failed even to mention that DNRC owned the dam, "an affront to this Department."

Once the application was filed, DNRC started squabbling with the rural co-ops, especially Vigilante, over the appropriateness of the state's involvement. No mutual agreement could be reached, and Vigilante pointed out in a petition to FERC that "the State of Montana is not in the generation or utility business, and therefore, has no public responsibility in this respect." More succinctly, the co-ops later called the Conceptual Plan "a proposed new boondogle (sic) to try and bail the state out of a previous boondogle (sic)."

The co-ops approached the legislature in the next session (January 1979) with a bill (HB555) to prohibit DNRC from building or operating generation projects on state-owned dams. The bill would have given nonprofit organizations (e.g., co-ops) first option to build on such projects, and would have set the minimum lease payment to the state at 1 mill per kWh, with half of the lease revenues going to maintenance and repair of the dam and associated irrigation projects. The bill passed both houses (House, 60 to 38; Senate, 38 to 11) but was vetoed by Governor Judge. An effort to override the veto passed in the Senate but was defeated by three votes in the House.

Designing Broadwater

Even before it had formally decided to apply for a preliminary permit, DNRC was pursuing federal funds to design a hydroelectric facility at Broadwater. Following up on an effort by Vigilante, DNRC encouraged the Bureau of Reclamation to undertake a development-level study of Broadwater, and to consider studying Painted Rock and Deadman's Basin as well. DNRC also investigated the possibility of participating in a U.S. Army Corps of Engineers study of small dam hydropower. These efforts were unsuccessful.

Tudor Engineering's entrepreneurial efforts to locate funding for engineering studies at Broadwater Dam were more successful. Tudor prepared a proposal and had DNRC submit it in March 1978 to DOE under a program that provided grants to finance feasibility studies on hydroelectric generating facilities at small dams. DNRC formally received a $95,000 grant to study the feasibility of projects at the three dams, including Broadwater, in September 1978. All the grant money went to Tudor for the engineering study. The probability of receiving this grant--DNRC knew by April that it had been selected for possible funding--gave DNRC extra cause to seek a preliminary permit from FERC.

Tudor's study, completed in April 1979, found that installing a hydroelectric facility at Broadwater would be economically feasible. Tudor recommended four vertical-shaft turbines with a total capacity of 9.76 MW, mounted in an open-flume configuration on the downstream face and apron of the existing spillway structure. Tudor had compared this to a conventional configuration with four 2.5-MW tube turbines installed on the left abutment of the dam. Tudor examined various funding mechanisms and ultimately recommended tax-exempt bonds for financing the project.

Early Marketing of Broadwater

DNRC knew it wanted to sell power, but wasn't sure who to sell it to or for how much. After filing for a preliminary permit, DNRC sent letters asking potential purchasers if they would like to buy the output from Broadwater and whether they would be interested in operating and maintaining the facility. These offers went to MPC, the Central Montana Generation and Transmission (G&T) Cooperative, the Upper Missouri G&T, and six co-ops near potential state generating facilities.

Meanwhile, DNRC debated internally the price to charge for hydroelectric power, should buyers prove interested. One approach was to evaluate a proposed project from a utility system perspective, attempting to base the value of the project on the costs a utility would avoid by purchasing the project's output. For example, Tudor had calculated the value of potential projects at Broadwater, Painted Rocks, and Deadman's Basin by assuming their output would displace power from generic coal plants. This approach would maximize revenues for the state.

An alternative approach discussed at DNRC started from the perspective of repairing irrigation facilities. Proponents of this approach argued that the annual goal for net profits from the hydroelectric projects should be based upon the cost of site-specific irrigation project repairs. A target figure of $1 million per year combined net profit from Broadwater and the other two projects was widely mentioned. On the whole, in these early discussions DNRC appears to have leaned more toward the irrigation repair perspective.

Issuing the Preliminary Permit

FERC took a long time issuing a preliminary permit for Broadwater. Competing applications slowed down the processing. DNRC had petitioned to intervene on Vigilante's permit and vice versa. MPC also intervened on both applications to protect the operation of its dams upstream and downstream from Broadwater.

Vigilante and DNRC both actively worked to support their preliminary permit applications. Their major task was addressing the comments offered by the U.S. Army Corps of Engineers, the Department of the Interior, the U.S. Fish and Wildlife Service, the Bureau of Reclamation, the U.S. Forest Service, the Montana Department of Fish and Game (after 1980, Montana Department of Fish, Wildlife and Parks), and the Montana Department of Health and Environmental Sciences. Two of the concerns raised by the agencies eventually proved especially problematic. The Bureau of Reclamation was concerned that the proposed raising of the reservoir level could damage or affect the operation of the Bureau's Crow Creek Pumping Station about a mile upstream from the Broadwater Dam. Montana Fish and Game wanted DNRC to consider installing a fish passage structure to allow spawning runs from Canyon Ferry to use the river above Broadwater.

FERC issued its order on the preliminary permits on June 4, 1980, almost 3 years after Vigilante first filed. FERC awarded the permit to DNRC. This decision did not surprise any of the parties. DNRC was a "municipality" within the meaning of the Federal Power Act, whereas Vigilante was not. Therefore, under section 7(a) of the Act, DNRC was entitled to preference for a preliminary permit if its plans were at least equal to those of a non-municipality such as Vigilante. DNRC had 24 months, until June 1, 1982, to submit a license application.

Marketing Broadwater, Phase II

Two days after FERC granted a preliminary permit to DNRC, the Board of Natural Resources and Conservation granted the Department the authority to negotiate power rates, subject to final approval. Some Board members told DNRC not to go below what the Department had described as a compromise price, one half-way between the cost of power production and "full-market value" for the power. The Board did not object to the Department's plan to maximize profit from the dam.

During the summer of 1980, DNRC personnel met with Western Area Power Administration (WAPA), MPC, and Vigilante to discuss selling power from DNRC projects. WAPA could not pay enough to justify the cost to DNRC of building hydroelectric projects. MPC suggested a weighted price based on its past power purchases, a price considerably below what DNRC hoped to get; however, with PURPA finally being implemented, both parties eventually decided to wait for the Public Service Commission to set rates to be paid to QFs.

Negotiations with Vigilante were rocky. Vigilante had offered to pay cost plus up to 10 percent, an offer that fell far short of what DNRC had anticipated. Furthermore, Vigilante claimed that federal law forbade selling the power to MPC or private utilities. Vigilante held that Broadwater power had to be sold to "preference customers," e.g., Vigilante, because the dam was built with federal dollars. Vigilante threatened court action if the power was sold to non-preference customers. Although Vigilante was DNRC's "preferred customer," DNRC eventually gave up on Vigilante because of its failure to negotiate.

At the same time, the PSC was drawing up regulations to implement the mandate of PURPA. Among other things, the federal legislation required utilities to purchase the output from QFs. The PSC was to set avoided cost rates, the rates at which the utilities were to pay the QFs for their output. Staff in the Water Resources Division spent a great deal of time becoming unofficial experts on QF rates and contracts, while Energy Division staff testified before the PSC with suggestions on how to structure the rates. DNRC spent more time on these activities than it would have had it not been itself a prospective developer.

First Plans to Finance Broadwater

Besides parties to purchase power from the projects, DNRC needed to find funds for the construction of Broadwater and the other potential hydroelectric facilities.

Financing was intertwined with the question of whether DNRC could build hydroelectric facilities at all. Hydropower was mentioned as one of the works in which DNRC could engage, but the legislature clearly had not thought of it as a top priority. The authority of the State Water Conservation Board to issue revenue bonds to finance its projects never had been revoked and presumably had passed on to the Board of Natural Resources and Conservation when the previous agency was absorbed. Although the Department recognized that it lacked definitive authority to build and finance hydroelectric facilities, it felt sufficiently confident to proceed with its planning, based on the Water Resources Act.

Once the preliminary permit was received, DNRC assembled a financing team. It did this by simply drafting the companies and personnel that already were working on a plan to rehabilitate the Tongue River Dam, a DNRC irrigation structure in eastern Montana. The lead financial adviser was The First Boston Corporation (New York). The organizational meeting of the financial team was September 18, 1980. First Boston hoped to have the bonds sold by 1982.

First Boston immediately assembled a generic contract for DNRC to use in its negotiations. It called for power from DNRC's dams to be sold at the purchaser's avoided cost of power. This was defined as the QF rate to be set by the PSC under PURPA. For purchasers not covered by PURPA, the rate would equal the purchaser's highest cost of power per kWh, as regularly updated, for firm capacity of 10 MW or greater. DNRC would acquire financing and contract for construction of the hydroelectric facility.

1981 Legislature

By 1981, DNRC was progressing nicely on the Broadwater project, but some Montanans thought the state should not be involved in the development of hydroelectric facilities at all. And if it were to be involved, they felt it should not try to get market value for the power. Nonetheless, the law that was enacted during the 1981 session did not put the state out of the hydroelectric business; in fact, DNRC participated in revising drafts of the legislation in an effort to retain some control over its dams.

The Legislation established a framework for the development of hydroelectric projects at state-owned dams. This framework came with a list of conditions. Senate Bill 229 (later MCA Title 85 Chapter 1 Part 5) authorized DNRC to construct and operate small-scale hydroelectric facilities. First, however, DNRC had to find that a site was feasible for a facility, and then offer the site for lease. Only utilities, co-ops, or Montana corporations planning to use a substantial portion of the output internally were allowed to apply. Potential applicants had 180 days to submit an application. Only if the Board found that the bids received were not advantageous to the state, or if no bids were received, could the Department pursue construction of hydroelectric facilities.

Preparation of Application for FERC License

Funding was a continuing problem for DNRC's effort to build a hydroelectric facility at Broadwater. In April 1979, DNRC queried DOE regarding the possibility of obtaining a loan to fund the FERC license application. In response to DNRC's inquiries, DOE sent information about an upcoming Loan Program for Small Hydroelectric Feasibility Studies. The program had the attraction of forgiving the loans if the projects proved economically or technically unfeasible or if licensing was denied.

After FERC issued the preliminary permit in June 1980, DNRC submitted a loan application to DOE requesting $55,000 of the $61,700 projected cost of preparing the license application. A loan of $50,000 was granted in February 1981. The first payment was due 4 years after signing, with the last payment due 10 years after signing.

DNRC began work on the license application immediately after receiving the preliminary permit. Tudor had responsibility for assembling the engineering, cost, and performance data and drawings. DNRC's Facility Siting Division (FSD) was given responsibility for preparing Exhibit E, the environmental assessment. FSD's schedule was very tight. Less than three months was allowed to proceed from a scoping meeting to circulation of a draft assessment for departmental review.

Exhibit E covered water use and quality, fish, wildlife, and botanical resources, historical and archaeological resources, recreational resources, and land management and aesthetics. For the most part, only minor impacts were identified. The biggest mitigation issues identified were the protection and enhancement of fisheries, coordination of recreation development with the federal Bureau of Land Management (BLM), and preservation of a prehistoric campsite and a post-1900 coke oven. DNRC pledged to fund or conduct studies and mitigation activities as needed if the license was granted.

The fisheries issue was to be a major one throughout the Broadwater project. Upon first learning about Broadwater, the Montana Department of Fish, Wildlife and Parks (DFWP) requested a study to determine appropriate instream flows. Given the information that Broadwater would be a run-of-river dam, DFWP revised its position, arguing for a fisheries study. DFWP maintained that insufficient quantitative data were available, "even though (the stream section) had been designated by the Montana Fish and Game Commission as one of Montana's 'Blue Ribbon' waterways." In particular, DFWP wanted DNRC to consider the possibility of installing a fish ladder. DNRC felt that a fish ladder could cause more harm than good, as it might allow unwanted exotic fish from Canyon Ferry into the upper Missouri drainage; more importantly, it would be a source of extra cost, reduced revenue, and delay. Tudor argued, after initial thoughts to the contrary, that the licensing could be delayed unless DNRC agreed to follow the recommendations of the fishery agencies and conduct a study.

Work on the license application proceeded at a fast pace. At the time DNRC filed its second Six Month Statement to FERC (June 1981), DNRC thought the application would be ready for submittal in August. However, the discovery that in the future the Bureau of Reclamation might have legal rights to up to 300,000 acre-feet of water upstream, and the resulting concern over the economic viability of the project, put preparation of the application on hold. DNRC directed Tudor to conduct a study to determine the impact of the Bureau's rights in the admittedly unlikely event that the Bureau could find a user for the water. Tudor concluded that Broadwater still looked viable, and work resumed on the license application.

FERC received the license application on June 1, 1982, right on the deadline. Review time for divisions and agencies outside the Water Resources Division had been limited, causing some unhappiness. Complaints by the environmental staff about the tight schedule sounded similar to those frequently raised when dealing with private developers.

Once the application was in, DNRC could do little more than sit and wait. FERC requested some minor modifications to the application, and on November 15, 1982, sent copies of it to relevant agencies for their comments. DNRC staff checked regularly with FERC to encourage expeditious treatment of their application. However, with the "hydro gold rush" still on, FERC was inundated with applications and was moving slowly.

Leasing Broadwater

Before DNRC could proceed with the lease or development of Broadwater, it needed the Board to approve the feasibility study of the project and to authorize public notice of the site's availability for lease. Therefore, immediately after filing its license application with FERC, the Department went to the Board to seek approval and authorization. The Board approved offering the Broadwater site for lease. The intent, in keeping with directions from the legislature, was to give non-government organizations a chance to develop the project.

Somewhat optimistically, in retrospect, DNRC envisioned no problem in getting responses to the lease offering within 90 days. In fact, DNRC anticipated having the leases in hand and evaluated by the end of 1982. This did not happen. Preparation of a request for proposals (RFP) took nearly 2 years. Interpreting the relevant legislation and figuring out the issues pertaining to leasing took time. The more noteworthy delays, however, were intra-departmental struggles to obtain adequate and appropriate legal advice for preparation of the RFP, and a Montana Supreme Court case which eventually affirmed the constitutionality of using coal severance tax bonds to back the hydro projects.

DNRC staff spent the summer and fall of 1982 figuring out what was involved in leasing a site. Questions to be addressed ranged from how to post notice of the RFP in the newspapers, to the amount of control DNRC should have over the lessee's plans, to calculation of the royalty. Legislation was prepared (and adopted in 1983) to amend the leasing process so that DNRC could build and finance a facility itself if that became necessary to avoid forfeiting the FERC license. Most of the discussions took place within the Engineering Bureau and among the Department's legal staff; Tudor, which prepared the first draft of the RFP, also was involved, as eventually were all the legal and financial consultants.

RFP for Broadwater

FERC issued DNRC a license for Broadwater on April 23, 1984. The license initially required construction to begin within 2 years. Actually, construction did not begin until late in 1987. The biggest issues faced in the intervening time were, first, who would build the project, and later, whether the project would be economical to build at all.

Shortly before the license was issued, DNRC had retained Tudor Engineering to reevaluate the economics of Broadwater and three other projects. The benefit/cost ratio was found to have improved. In the 1979 study, the benefit/cost ratio ranged between 1.29 and 1.80; the 1984 *Feasibility Update*, using current power purchase rates while testing a wider range of discount rates and costs per kWh, found the ratio to be between 1.14 and 2.05. The report concluded, "the Broadwater Hydroelectric Project appears to be very feasible."

The RFP for Broadwater was based on an RFP previously developed for Painted Rocks Dam. The Broadwater RFP was issued in July 1984. At least ten parties requested a copy of the RFP. At the end of August, when letters of intent were required, four of those parties stated that they would consider submitting a proposal: Westinghouse Electric Corporation, Western Energy Corporation (a coal mining subsidiary of MPC), Western Montana G&T, and Energy Associates (a private investment firm). Energy Associates expressed interest even though under the law passed in 1981 it was not eligible to hold a lease on a state dam. At DNRC's request, this law was modified during the 1985 legislative session to make any party eligible to seek a lease at a state dam.

Only one proposal was received by the January 28, 1985 closing date. This proposal from Western Montana G&T, however, did not comply with the RFP. Western Montana G&T submitted an offer to negotiate a lease, rather than an actual lease proposal. G&T claimed the time for response was too brief and the project too complex to warrant risking the $2 million bid bond DNRC had requested. Western Energy cited similar concerns.

DNRC advised the Board that G&T's proposal was deficient in almost all respects and asked the Board to find that since no acceptable lease proposals were received, DNRC could consider developing the site itself. The Board did so at its March meeting.

Even though the RFP process was over, outside parties continued to express interest in Broadwater. Western Montana G&T wanted to start negotiations for a lease, an offer that was declined. In April, Ideal Cement Company, located a few miles upriver at Trident, inquired about building Broadwater for its own use. Negotiations followed, but foundered that summer over issues of ownership and financing. Finally, Sithe-Energies, through its agent Winner/Wagner and Associates, Inc. (New York), expressed interest, first in an outright purchase of DNRC's rights to develop Broadwater, and later in building and operating a turn-key facility. Negotiations were getting under way when the economic viability of Broadwater collapsed.

Problems with Economic Viability

The cause of the collapse was the revision of the avoided cost rates MPC was obliged to pay QFs. The PSC had begun a revision of the methodology for calculating avoided cost in the fall of 1984. The PSC had recognized that its previously approved methodology yielded avoided cost rates that were higher than the costs actually faced by the utility. Water Resources Division favored signing a contract with MPC quickly, while the old higher rates were still in effect. The Energy Division took a more sanguine position on the new rates, arguing that it would not be good public policy to sign a contract that effectively required ratepayers to subsidize DNRC. Shortly after his appointment in January of 1985, DNRC's new Director declined the opportunity to sign a power purchase contract under the old rates.

The PSC released its draft rate order September 12, 1985. The order drastically reduced the rates private utilities were obligated to pay QFs. With the PSC's decision, Broadwater no longer appeared to be economically viable. The Water Division decided on October 31 that the possible range of project costs, given a range of mitigation costs and a 9.375 percent interest rate, was equivalent to 42 to 59 mills per kWh (in 1986 dollars). This was above the range of avoided costs predicted to be set by the PSC in its forthcoming order. Even without any mitigation costs, Broadwater would have been economically marginal at 9.375 percent interest. Although the interest rate was almost at the middle of the range considered in the 1984 study, and although estimates of capital costs had dropped, Broadwater was simply too expensive.

Stalling for Time

At that point, DNRC chose to limit itself to work that was "absolutely required to maintain the FERC license." That work still covered an extensive list of topics: completing current studies on archaeology and fish ladders; proceeding with the water right application; applying for exemption from FERC's required review of dam hazards by an independent consultant; requesting assistance from the U.S. Army Cold Regions Laboratory on the problem of project-induced ice buildup on the adjacent railroad; negotiating with the U.S. Bureau of Reclamation to assign responsibility for protecting the Crow Creek Pumping Station from flooding; and requesting a schedule extension for meeting the FERC license requirements. While this list is extensive, the amount of staff time required was low enough that individuals previously working on the Broadwater Dam project were reassigned to other work.

A request to FERC for a license extension was submitted December 12, 1985. Such extensions are issued routinely. On January 27, 1986, FERC granted DNRC until April 22, 1988, to start construction, and until April 22, 1991, to complete construction. However, the license required DNRC to undertake certain studies and mitigation actions beyond what DNRC was willing to do. Given the dubious nature of the project's economics, DNRC stalled, a time-honored tactic of public and private developers alike.

The economics did not improve while this stall was on. A March 1986 estimate of construction costs had climbed from the previous estimate of $21,318,000 to $26,895,000 (in January 1986 dollars). About 40 percent of that increase was due to using more pessimistic assumptions about the cost of protecting the adjacent railroad. DNRC tried that month to convince MPC to take over the dam as an alternative to its proposed upgrades on its own dams; the idea never went beyond preliminary discussions. It was against this background that Pete Gross and Potosi Power offered to take over the Broadwater project.

Pete Gross and Potosi Power

Pete Gross had been involved since 1984 with efforts to develop hydroelectric projects on state dams. He had made offers to develop Broadwater even when he was not eligible to do so under state law. In September 1986, he, as Potosi Power, renewed discussions with DNRC over Broadwater. DNRC was reluctant to spend any more money on the project; however, Gross thought Potosi might be able to work with the state to develop it. Potosi offered to continue the work necessary to keep the license--and DNRC's chance at Broadwater--alive. Water Resources left this decision up to Potosi. Nevertheless, DNRC staff has grave concerns with the lack of a formal agreement and reservations about the ability of Potosi to meet the very tight timelines.

On January 20, 1987, Potosi met with DNRC to present a formal agreement to become DNRC's agent and work to bring the license into compliance, in return for which DNRC would agree to negotiate in good faith a contract for Potosi to operate the project as a turn-key arrangement.

Potosi asked for "the exclusive right to finance, construct, and operate a hydroelectric power generation project at Broadwater Dam upon such terms and conditions as the parties shall determine to be reasonable." DNRC rejected this and asked for a detailed proposal by February 9. Potosi responded with a proposal that offered DNRC 2 percent of the project gross for the first 35 years, an offer Potosi projected to be worth between $3,104,848 and $3,444,129. DNRC responded that "the proposal (was) not within the standard of the industry for even a project of much less complexity, and (did) not afford the state any certainty upon which to base an agreement." Furthermore, the return offered DNRC seemed low compared to the value of the project. DNRC told Potosi that other options would be pursued.

One Last Review of Broadwater's Economic Feasibility

DNRC's enthusiasm for other options had been revived by another review of Broadwater's economics. Interest rates had dropped since 1985. Moreover, the 1986 Tax Reform Act still permitted tax-exempt bonds to be sold for certain projects if they already had a FERC license and could be expected to be completed by the end of 1988.

Toward the end of 1986 the Energy Division reviewed the financial feasibility of Broadwater. The construction cost figures used in Energy's analysis were basically the same, adjusted for inflation, as those used in the analysis that led to the 1985 decision that Broadwater was not economically feasible. The major differences were (1) the use of a 7.5 percent interest rate rather than 9.375 percent, and (2) reducing the estimated cost of mitigating ice damage to the railroad track by dropping winter reservoir levels rather than by raising the tracks. Avoided cost rates also were slightly higher than previously anticipated. The actual 1987 rates for a long-term contract with a facility like Broadwater were equivalent to 37 mills/kWh. The analysis also looked at the possibility of setting up a cash reserve to protect against the possibility of negative cash flows in the early years. This time, Broadwater looked feasible.

The Final Decision

DNRC went to the Board on March 13, 1987, to announce it planned to build Broadwater. Potosi also presented its own offer at the Board's meeting. The Board directed DNRC to search for a private concern to finance and construct the Broadwater project. Although DNRC did not think another RFP was feasible at this late date, it issued one in early April.

The May 1 deadline for responses to the RFP came and Potosi was the only group to submit a proposal, although other firms continued to express interest after that date. Potosi presented a more detailed and revised offer to finance, construct, and operate Broadwater for 35 years. With this offer, Potosi would get 40 percent of the net income (before taxes) and pay taxes, while DNRC would get 60 percent and pay royalties to the local irrigation association. Potosi figured its new offer would have a present value to DNRC of $14,166,336 to $16,524,243.

Subsequently, Potosi formed a partnership with Independent Hydro Developers (IHD), a limited partnership based in Minneapolis and formed in 1982 to develop and construct hydroelectric projects. Only days before the Board was scheduled to make a decision, Potosi/IHD submitted yet another offer to DNRC. In return for developing and operating Broadwater, Potosi/IHD would give DNRC one percent of gross revenues, 60 percent of net revenue (after equity had received a 13 percent rate of return), and an option to buy or renew the project after 35 years. IHD estimated this would have a present value to DNRC of $5.8 to $8 million dollars.

The Board met June 4. DNRC argued that its own proposal offered the best investment for the state. Further, DNRC emphasized that because DNRC had exercised its preference rights as a municipality to get the license in the first place, FERC regulations required DNRC to retain control of the project (e.g., DNRC could not develop the license with a partner, even though it could hire a private group to develop the project). Whatever was to happen, however, DNRC insisted that a decision had to be reached immediately, in order to comply with FERC deadlines and to obtain tax-exempt financing. The Board felt pressured and short on information, but voted 4 to 3 to find that using coal severance tax financing, as proposed by DNRC, was more feasible than private offers.

Broadwater-Missouri Water Users' Association

With the Board's June 4, 1987, decision, DNRC had a clear mandate to build the project. What it lacked--at least in some people's minds--was clear title to the dam itself. The Broadwater-Missouri Water Users' Association (BMWUA) argued that it owned the dam.

This debate had run, on and off, from the earliest days of the Broadwater hydroelectric project, starting in 1978. BMWUA maintained that it was paying off the irrigation project bonds. DNRC's position was that BMWUA "(had) not paid for the project, but for the water supplied by the project, in an amount calculated to enable the state to recoup its investment." In 1983, BMWUA offered to settle for 50 percent of the net project revenue.

DNRC and BMWUA finally settled in July 1987. BMWUA had raised the possibility of filing suit. The suit might have been without merit, but the DNRC no longer had time to pursue the matter without endangering the bond sale. DNRC agreed to deposit one-quarter of the net revenues from Broadwater into an account until the total reached $1 million. The state Board of Investments would manage the account for BMWUA. BMWUA could use the interest income, but only for rehabilitation, improvement, and repair of the irrigation project facilities. DNRC retained approval authority for purchases over $5,000.

Financing

The legislature had been willing to finance the Broadwater project since 1983. That year, the legislature authorized up to $28.6 million in coal severance tax bonds for the project. The following session, in 1985, $23,044,000 was reauthorized. In 1987, the legislature once more reauthorized the sale of bonds, this time at $26 million, to build the hydroelectric project at Broadwater. The project was initiated under this last authorization.

The financial team retained by DNRC was slightly different from the one first assembled in 1980. First Boston Corporation (California office) was still the lead bank and Dorsey & Whitney (Minneapolis) still the lead bond counsel. A notable addition to the financial team was Evensen Dodge (Minneapolis) to serve as financial adviser to DNRC. DNRC had realized the deal was too complex to manage without expert advice from a consultant without a stake in the project. DNRC was able to move immediately once it received the go-ahead. Deadlines imposed by FERC, and, more importantly, by the Tax Reform Act of 1986, required DNRC to move very quickly.

DNRC had to issue two separate series of bonds, one taxable and one tax-exempt. This was done because project costs expected to be incurred after December 31, 1988, could not be financed with bonds exempt from federal taxes. Certain other project features (e.g., transmission lines) could not be financed with tax-exempt bonds at all. As had been intended since 1982, the bonds were revenue bonds, to be repaid by proceeds from the project itself, with the coal tax revenues to provide additional security. On November 5, 1987, the Board of Examiners, on behalf of DNRC, issued and sold $22,200,000 of tax-exempt bonds. At the same time, the Montana Board of Investments agreed to purchase up to $3,150,000 of taxable bonds to complete the project.

Since the Board of Investments is a state authority, it pays no taxes even on taxable bonds. DNRC agreed to an interest rate comparable to the Board's earnings on other investments with equivalent risk, in this case 10.5 percent. For its part, the Board agreed to accept private placement of the bonds. The issue was non-rated and subordinated in all respects with the lien on project revenues. The Board of Investments also agreed to purchase the taxable bonds only when and as requested. This arrangement was advantageous to DNRC, because it eliminated the need to reinvest bond proceeds, probably at a loss, until the funds were required. Further, DNRC saved the closing costs associated with public bond issues.

The bonds covered all capital costs, including a debt service fund required by the underwriters. It did not cover any of the money DNRC had spent planning the project. The total spent between 1978 and 1987 was $387,000, including the cost of the feasibility study, the FERC license, water right application, environmental studies, and so forth. This amount also included one-time costs, such as developing a leasing proposal, that would not be repeated for subsequent projects. Part of this cost was covered by federal grants and loans.

In its final economic analysis in February 1987, DNRC had modeled establishing a cash flow reserve fund of $500,000 to cover the possibility of low water--and therefore insufficient income--during the early years. This was dropped from the bond issue at the insistence of the Director, who wanted to encourage the Broadwater project to come in on budget. Dropping the cash flow reserve fund also meant the bond issue could be smaller. Since the price MPC paid for the power rose over time, the possibility of income shortfalls would diminish and eventually disappear if historical water flow patterns continued. In any event, the project still was backed by the coal tax revenues. These could be used as needed and repaid at a later date.

The most innovative aspect of the Broadwater financing was the use of variable rate bonds. The interest rate on these bonds changes weekly. While they carry some additional risk, the history of these bonds is quite favorable. They consistently have been two to three percentage points below the current rate on new long-term fixed-rate bonds. However, issuance costs are higher on variable-rate bonds. A letter of credit had to be obtained to make the variable yield bonds marketable. Most of the bidders were Japanese banks; the letter of credit was purchased from Sumitomo Bank. DNRC intends to convert the variable rate bonds to fixed rate bonds if interest rates drop sufficiently. The market floating rate for the first 2 years ranged between 4.6 and 7.9 percent when fixed rates were between 6.5 and 9.2 percent. The actual apparent rate paid by DNRC was higher because of extra costs associated with variable rate bonds; that cost averaged 6.3 percent during the first 2 years.

Contract and Licensing Issues

Construction Contracts

Immediately following the Board's finding that DNRC should build the project, DNRC began the process of bidding contracts. At Tudor's recommendation, the project was separated into multiple contracts in hopes of meeting the December 31, 1988, deadline imposed by the 1986 Tax Reform Act. By issuing multiple contracts, construction could proceed on some portions of the project while design work was under way on other portions. Tudor Engineering was selected to design and oversee construction of the project. Tudor had done all the preliminary engineering and the Engineering Bureau was comfortable working with Tudor; more importantly, DNRC had no time to bring a new engineering company up to speed on the project. Estimated engineering costs were $2.3 million.

The Broadwater project was divided into six major contracts. These were (1) furnishing and installing the turbine, generator, electrical, and auxiliary equipment; (2) excavation and powerhouse construction; (3) furnishing electrical equipment and construction of a 100-kV substation; (4) transmission line construction; (5) furnishing inflatable rubber dams to replace existing flashboards on the spillway; and (6) modifying the spillway and piers, installing the rubber dams, and post-tensioning the dam (e.g., anchoring the dam to bedrock with steel cables or tendons).

The contract for turbine/generator design and manufacture was awarded to Voith Hydro Inc. of York, Pennsylvania on September 22, 1987. Voith was the low bidder at $5,435,584. This was considerably more than the engineering estimate of $4,486,000, even though Voith's bid was almost $400,000 less than the next lowest. From the start, design and construction proceeded rapidly. Installation of the turbine and generator into the powerhouse began on January 5, 1989. The plant first produced commercial power on June 14, 1989.

Sletten Construction Company of Great Falls was the low bidder for the excavation and powerhouse construction contract at $6,071,593, about $800,000 lower than the engineering estimate. Sletten began construction at the project site November 2, 1987. Sletten's work was substantially complete in May 1989, and complete in fall 1989, save for testing one item.

Lamb Engineering of Salt Lake City, Utah, was awarded the bid for the 100-kV substation at $881,337. Construction began on-site in July 1988 and was substantially complete by December 31, 1988.

A low bid of $205,178 by Harp Line Constructors of Kalispell was accepted by DNRC for the transmission line contract. Work began in September 1988 and was substantially complete by December 31, 1988.

Originally the spillway was designed and bid to have steel radial gates installed in at least two spillway bays. The bids that came in March 1988 were higher than expected and more than the funds available; all bids were rejected. A DNRC engineer and inspector at the dam suggested an alternative design to lower the cost of the spillway modifications. Based on his suggestion, DNRC decided to install inflatable rubber dams in the spillway bays. DNRC procured the rubber dams from Bridgestone Corporation, U.S.A., for $1,150,500 and accepted a proposal from Gracon Corporation of Loveland, Colorado, to modify the spillway bays, post-tension the dam, and install the rubber dams for $1,717,000. This saved approximately $450,000 over the lowest radial gate bid. The rubber dams also provided better control of the reservoir level, reduced long-term operation and maintenance costs, and increased generating capability.

Numerous other smaller contracts were let to cover environmental mitigation, cultural resource surveys, acquisition of flood easements, development of recreational facilities, improvement of the access road, and so forth. Approximately $928,000 was allocated for these contracts.

Construction Problems

The actual construction was beset by numerous delays and confusions. Many of these could be traced to the tight schedule and DNRC's lack of experience with projects of this magnitude. Final design for much of the project was completed after construction had begun. Tudor was sufficiently concerned about the schedule to request protection from the extra liability involved in a fast-track project. DNRC threatened to terminate the project if Tudor could not offer a reasonable expectation of substantial completion by December 31, 1988. Without that certification, DNRC could not issue tax-exempt bonds. Tudor balked right up to the time the bonds were to be issued. Having no other choice, DNRC specifically accepted the extra risks of running a fast-track project, including potentially higher costs or delayed construction. With that, Tudor made the guarantees DNRC needed to sell the bonds.

This certification of the construction schedule was the first in a series of strained exchanges. For instance, DNRC contracted with Tudor to provide an on-site Resident Engineer to manage and coordinate the contractors, and to inspect and ensure compliance with specifications. Tudor's first engineer quit late in 1988 after submitting his own independent bid on the spillway modifications. The next Resident Engineer left after two months for medical reasons unrelated to the project. The third Resident Engineer stayed throughout most of the remaining construction, but continuity in project oversight was lost, diminishing DNRC's control of the project.

The powerhouse contractor, Sletten Construction, missed its schedule, which in turn delayed other contractors on-site. The target operational date of the project slipped from March 15, 1989, to early May 1989 and then to mid-July. Sletten made claims against DNRC for additional payment virtually from the day work began on-site. Numerous change orders that resulted from design work proceeding concurrently with construction increased DNRC's potential exposure to claims from its contractors.

Altogether, Sletten requested approximately $2.8 million in claims and change order compensation. DNRC maintained that it would pay any legitimate claims and any contract changes required by itself or Tudor; DNRC figured these totalled to approximately $906,000. On March 17, 1989, DNRC reached settlement with Sletten on all claims at an adjusted contract price of $7,225,000, roughly $248,000 above the previously recognized contract adjustments.

Other contractors also made claims against DNRC. For example, Gracon, the spillway contractor, filed approximately $300,000 in claims against DNRC, claiming Sletten did not provide timely access across the powerhouse (because it was not built) and Sletten's actions physically blocked approved access across the upstream cofferdam. Gracon eventually received $125,000 over the adjusted contract amount.

DNRC also made claims against its contractors. For example, one of these claims arose when DNRC found that the curb ring, a part of the turbine assembly that was embedded in concrete, had been misaligned. As a result, the parts that attached to the misaligned ring had to be sent back to Voith for machining to accommodate the misalignment. This had a direct cost of nearly $200,000 and an additional cost associated with the 38-day delay of approximately $228,000. Tudor made a preliminary determination that Voith and Sletten shared responsibility for the misaligned curb ring.

Some delays caused change orders. For instance, Lamb Engineering, the substation contractor, and Harp, the transmission line contractor, were delayed in making the final connections at the powerhouse because Sletten had not completed backfill of the powerhouse or poured footings for the transmission tower next to the transformer. This work was dropped from their contracts to avoid delay claims and was completed by other contractors through change orders.

Another problem arose when Voith was supposed to test the turbine-generator unit to ensure that the equipment was performing according to specifications. This "index testing" would enable DNRC to correlate flow and electrical output on the basis of actual performance rather than on the theoretical performance curve derived from model tests. However, because of construction delays, Voith could not start testing until June 1989, after the river's flow had dropped below the maximum capacity of the turbine. Some testing was delayed until spring 1990.

DNRC eventually overcame all these delays and problems, the plant was completed and is producing. The formal dedication was September 11, 1989. As could be expected, numerous bugs continue to plague the project but are slowly being resolved.

The final total cost for the project is not yet available. Some work continues, especially for environmental mitigation, and some claims still are being negotiated. The total expended or accrued to date is shown in Table 9-1. The table does not include anticipated claims settlements or most wages paid to DNRC personnel working on Broadwater. The debt service is net of interest on the bond sales proceeds as of the end of January. Over $1.6 million remains from the bond proceeds as of January 31, 1990.

Power Sales Contract

Power from Broadwater is being sold through a power sales contract that DNRC negotiated under the PSC 1986 order on avoided cost rates for QFs. The negotiations leading to this contract were protracted because of DNRC's changing estimation of the economic merit of Broadwater.

Table 9-1
Broadwater Project Costs (March 1990)

Engineering	$2,834,333
Land easements	76,521
Environmental mitigation	486,573
Civil works	9,686,958
Turbine/generator	5,548,921
Transmission lines/substation	1,249,894
Bond issuance costs	358,458
Debt service reserve	2,220,000
Debt service	1,304,791
Other	583,663
Total	$24,350,112

The negotiations began in October 1984. By this time, DNRC was focusing only on marketing power to MPC, its rates being much more attractive than any the rural electric co-ops would offer. MPC provided a discussion draft to serve as the basis for negotiating a long-term power purchase agreement while the RFP on Broadwater still was out. DNRC's main concern was to begin serious negotiations before the PSC reduced the power purchase rates.

DNRC wanted a 35-year contract, with the option of deferring some considerations (e.g., determination of contractually defined generating capacity and selection of full or partial levelization) until 1989. MPC accepted the 35-year term but not the deferred decisions. Though negotiating for its own interests, DNRC wanted a contract that could accommodate the ongoing leasing process. DNRC wanted a clause that would allow DNRC to transfer the contract to the lessee. MPC opposed this because the security and insurance requirements for the lessee would be different than for the state.

By December 1984, DNRC and MPC were close to finalizing a contract. DNRC's retiring director leaned towards signing a contract, but opted to leave that decision to the incoming director. The new director thought it would be inappropriate for DNRC, a public agency, to be subsidized, in effect, by ratepayers through the incorrectly high avoided cost rates. He declined to sign the contract, and DNRC lost its right to receive the higher QF rates of the old tariff. When the new and lower QF rates were published in the fall, DNRC put Broadwater and contract negotiations with MPC on hold.

Contract negotiations resumed in April 1987. In general, MPC's standard contract form for QFs was used. The most significant departure from the standard contract was the absence of security payments; MPC was willing to accept that the plant was backed by the state. Negotiation was substantially completed by the end of June, and the contract was signed October 30, 1987.

DNRC chose nominally levelized capacity payments and escalating energy payments. The capacity payment is $15.11 per kilowatt in winter and $8.34 per kilowatt per month in the summer. The energy payment is revised each year according to a fixed escalation rate.

DNRC's contract gives it up to a year to determine what monthly contract capacities it would offer. The delay in Voith's testing until spring 1990 hampered DNRC in making these determinations. Tudor had conservatively estimated that monthly capacities should vary between 1.4 MW in August and 9.1 MW in November. Once the contract capacities are fixed, DNRC will be penalized if it falls 30 percent below those capacities. It will have to refund payments made for firm capacity that was found to be non-firm, plus a 10 percent interest charge. For shortfalls of less than 30 percent below contract capacity, MPC can drop the contract capacity to the lowest monthly capacity DNRC actually produces.

Until DNRC settles on the monthly generating capacities for which it is prepared to guarantee delivery, the average price per kWh of the contract cannot be calculated. For planning purposes, DNRC estimated the first-year value to be 37.4 mills/kWh.

Interconnection

In 1985, DNRC started looking seriously at the problem of connecting Broadwater with the power grid. In its license application to FERC 3 years earlier, DNRC had assumed that the connection would be a 100-kV line running about one mile south to an MPC line near Lombard, on the east side of the river. Brief discussions with MPC in 1983 added the possibility of connecting to the Trident-to-East Helena 100-kV line, which ran west of the river, but no interconnection studies were done. DNRC renewed discussions in 1985, inspired by the FERC license requirement to submit a transmission line design plan by April 23, 1985. DNRC had obtained tentative agreement earlier that year from MPC to allow connection to its lines.

The transmission design report included four options. Of those, Tudor recommended a line about 3 miles long that would follow the existing Broadwater canal and access road to connect with MPC's Trident-to-East Helena 100-kV line (see Figure 1). The choice was based on minimizing the construction cost and the environmental impacts associated with river crossings and agricultural land. Under this option, DNRC was to construct a 100/4.16-kV substation at the dam, using a 10-MVA transformer and a 4.16-kV breaker. The Broadwater line would use three 100-kV breakers to tap MPC's line.

Discussion of the final design of the interconnection to MPC's system began in May 1987, shortly before the Board gave final approval for Broadwater. The major issues MPC identified were possible changes in relay equipment at both the East Helena and Trident Substations as a result of bisecting that line, and the need to telemeter certain project operating parameters from Broadwater switchyard to MPC's System Operation Control Center (SOCC) at Butte. In subsequent meetings MPC also alluded to rerouting its existing line slightly to accommodate the substation; DNRC only belatedly realized that this would cost the Department an additional $37,000.

MPC's concern about possible relaying changes eventually proved to be founded. MPC had decided that a new relay panel at Trident and a 100-kV transformer would be necessary. Tudor originally felt that the problems introduced by breaking the 57-mile line segment between East Helena and Trident into a 45-mile East Helena to Broadwater and a 12-mile Broadwater to Trident segment would not require additional protective relay requirements. In May 1988, MPC, as requested by DNRC, produced a detailed explanation of the relay requirements. DNRC reluctantly agreed to the $98,000 expense to install equipment required by MPC.

The substation and the line were completed and ready for testing by the end of 1988. The final arrangement was that DNRC would own the substation and MPC would operate it at the state's expense. A leased phone line, permitting both voice and data communications, connected DNRC's powerhouse with MPC's SOCC. A Sangamo Quantum Meter was installed for billing purposes at the connection between the Broadwater line and MPC's line.

Water Rights

On December 30, 1977, DNRC filed for the right to appropriate water for hydroelectric generation at Broadwater and the other two projects. Little happened on those applications until after the preliminary Broadwater project permit was granted by FERC. DNRC did not even go to the Board for authority to obtain a water use permit for Broadwater until 2 months after receiving the preliminary FERC permit.

In conjunction with its work on the application for a FERC license, DNRC started on a Preliminary Environmental Review (PER) on the granting of water rights for the Broadwater Project. The PER described environmental impacts as minimal. One of the more troublesome issues was water availability. DNRC, in the spring of 1981, conducted a study of water availability in the Missouri basin above Broadwater. The study found that, most of the time, upstream water development would be limited by the Bureau of Reclamation's water rights for its turbines and irrigation projects at Canyon Ferry Dam, and not DNRC's prospective rights at Broadwater. However, the study also turned up the Bureau's claim that it had rights for 200,000 acre-feet upstream, a claim later raised to 300,000 acre-feet. DNRC eventually concluded that the legal questions raised by the Bureau's claims were not easily resolved, and that an EIS would resolve no more than would a PER. All that taken into account, DNRC finally decided that a PER would be sufficient.

While the PER was being prepared, the local water rights field office notified the Engineering Bureau of the Water Resources Division that its application was deficient. It lacked definitive information on the amount of water requested and payment of a filing fee. The Engineering Bureau settled on 7,200 cfs as its claim, debated going to the Board to seek exemption from the filing fee, but eventually paid a $26,385 application fee to the Water Rights Bureau. At the time DNRC still expected these costs to be repaid by whoever eventually developed Broadwater.

DNRC's water rights application was publicized in the newspapers in May 1981. Objections were received from three parties. Byron Johnson, Toston, was worried about the effect on his placer mining at Devil's Bottom, slightly upstream from the dam. The Bureau of Reclamation objected because the project would raise the pool elevation and threaten to flood the Crow Creek Pumping Station. Later that year, Maurice and Lucia Ferrat, who leased the placer mine to Johnson, objected to protect their property rights and their 1875 water right.

The Bureau's objection was dismissed because it did not fall within the Department's jurisdiction under water law. The Ferrats' objection was rejected as untimely. Only Johnson's objection was accepted. The

Ferrats later were given standing based on Johnson's objection because they actually held the water rights on which it was based.

A hearing on the subject was initially set for June 23, 1982. Because of DNRC's involvement in the case, a lawyer from the Justice Department was appointed to serve as hearing officer. The hearing itself was put off continually as DNRC and the Ferrats engaged in desultory negotiations aimed at compensating the Ferrats sufficiently for them to drop their objection. Neither side was in a hurry. The Ferrats were using the water rights issue to guarantee they got a fair price for their property rights, which DNRC did not want to buy until it actually was ready to start on Broadwater.

By April 1985, the Water Rights Bureau was sufficiently worried about the slow pace of the Broadwater filing to voice its concern to the division administrator. Evidently, the Broadwater project team had hoped to negotiate a settlement rather than force the issue, since any such settlement would cost less than the legal costs of condemning the land. Hearing dates were set once again, and DNRC and the Ferrats negotiated a little more seriously. Several postponements later, in September 1986, DNRC and the Ferrats signed an agreement to negotiate a settlement and the Ferrats withdrew their objection. A provisional water use permit was issued in December 1986, good until April 1991; the 1991 deadline was set at the request of the Engineering Bureau.

Negotiations with the Ferrats dragged on until September 1988. The Ferrats were determined to obtain full value for their placer mine, even though independent appraisers had determined that is was close to worthless. Many compromise offers later, DNRC purchased an easement for the reservoir, a flood easement, and a right-of-way for the transmission line for $36,000.

Environmental Impacts

DNRC believed that Broadwater would have only minor impacts; however, others disagreed from the start. Government agencies raised concerns about fisheries, wildlife, recreation, and archaeological/historical resources. Burlington Northern Railroad was concerned about the possible impact on its tracks from raising the pool elevation. The Bureau of Reclamation was similarly worried about impacts on its Crow Creek Pumping Station, which supplies irrigators upstream from Broadwater Dam. The fisheries issue caused the longest-running problems for DNRC; the uncertain but potentially high costs of mitigating the fisheries impacts could have seriously affected the economic feasibility of Broadwater.

Fisheries. The Montana Department of Fish and Game (after 1980, Department of Fish Wildlife and Parks--DFWP) was the lead advocate for the fisheries. When first asked in 1980, the Department said, "the key to protecting and enhancing (the fish and wildlife) resource will be the amount and pattern of instream flows." It therefore recommended a study of instream flows. When it learned later that year that Broadwater would be a run-of-river dam, Fish and Game reevaluated its original impression of possible impacts and submitted a proposal for a $51,000 study to determine if a fishway and associated turbine bypass system (i.e., fish ladder) would be necessary. The study also proposed to look at wildlife impacts of raising the pool elevation. Neither DNRC nor Tudor felt the study would find impacts of any consequence, but decided that offering to do the study as a condition of the license was the only way to obtain the license in a timely manner; objections raised by any agency would have slowed the licensing process. The study represented a minimal cost to gain some certainty in planning the project.

After the FERC license was issued in 1984, DNRC had 2 years to complete the study. The study plan was a revision of the 1980 proposal, with a budget reduced to $35,000; the cost dropped in part because the study fit in with other work DFWP was doing. The fisheries portion of the study was prepared by CH2M Hill. The study concluded that a fish ladder would not be a good idea. CH2M Hill based its conclusion on a number of reasons; the most significant concern was that unwanted fish (e.g., predatory fish eaters such as northern pike and walleye) would get into the trout streams of the upper Missouri basin. Though more broadly based, its conclusion was similar to that previously reached by DNRC in its license application to FERC. In the revised report on fish, wildlife, and botanical resources submitted to FERC in April 1986, DFWP specifically recommended against a fish ladder.

FERC staff found the fisheries portion of the revised report insufficient. They demanded more information on downstream movements of fish, on possible impacts on fish going through the turbines, and on fish screens that could be used at Broadwater. Neither DNRC nor DFWP understood why FERC requested such a massive amount of supplementary information. They doubted that the likely impacts would warrant the effort FERC was requesting. DFWP staff suggested spending money for actual mitigation instead of for the time-consuming and expensive study FERC requested. The U.S. Fish and Wildlife Service (USFWS) preferred running extensive studies to ensure the level of mitigation matched the level of impacts; nonetheless, it grudgingly supported mitigation without study.

DNRC, needing a fixed project cost estimate to take to its bankers and assurances that a 2- or 3-year study would not be necessary, was in no position to bargain with the fisheries agencies. DNRC was about to request permission from FERC to change Broadwater's design from four apron-mounted turbine-generator units to a conventional configuration with a single turbine. Negative comments by the fisheries agencies could have led FERC to require DNRC to submit a license amendment, with all its attendant paperwork. DNRC agreed to spend $394,000 to increase the number of trout below Broadwater by improving spawning habitat. The option preferred by DNRC and DFWP was a channel to connect Big Spring Ditch (a spring-fed irrigation canal downstream from the dam) and the Missouri River; however, the departments promised FERC they would study a range of possibilities. This improvement in the downstream fishery was intended to mitigate any losses caused by the hydroelectric project.

On July 6, 1987, DNRC sent FERC its proposed turbine design changes, along with letters from the various reviewing agencies, which did not object to the proposed changes. FERC ruled August 18 that the changes did not require an amendment to the license.

On August 14, DNRC submitted a revised fish, wildlife, and botanical resources report, which contained the plans that had forestalled fishery agency objections. FERC again rejected the fisheries portion of the report. DNRC requested several extensions as it and DFWP tried to develop a reasonable solution. Further study by DNRC and DFWP indicated that the Big Spring plan was both high cost and high risk. By the summer of 1989, the departments were considering some combination of constructing a smaller spawning/rearing channel, possibly in the Canyon Ferry Wildlife Management Area, and restoring habitat on some tributaries between Canyon Ferry Dam and Broadwater Dam. Their strategy was to diversify the mitigation to lower the risk of failure. In a progress report to the Board of Natural Resources and Conservation, DNRC observed that it was "relying heavily on DFWP not only to assess those aspects of biological feasibility and risk for mitigation alternatives, but also to help implement the measures. Since DFWP has such a major role in carrying out the mitigation package, the sort of (reviewing agency) dissatisfaction that typically results in fines levied by FERC is highly unlikely." DNRC hoped to avoid damage both to the environment and to the economics of Broadwater.

Wildlife and Botanical Resources. The potential impacts on wildlife and vegetation would result primarily from DNRC's proposed change in operating the pool behind the dam. In the past, the pool was lowered each winter by about 9 feet and brought up again during the irrigation season. DNRC proposed to raise the level by 1.6 feet above the maximum summer level and maintain a stable pool elevation year round. This meant that about 10 acres of willows and emergent plants (e.g., cattails) along the shores and on some small islands would be destroyed. This destruction would decrease cover and food for waterfowl and some mammals. In particular, inundation of the islands would eliminate some nesting habitat used by Canada geese and other wildfowl.

As it had done with fisheries, FERC, in its September 10, 1986, letter asked for a significant amount of supplemental information about impacts on vegetation. The following May, DFWP, as it had done for fisheries, proposed skipping the requested studies and going directly to mitigation, based on information previously collected by DFWP on the Canyon Ferry Wildlife Management Area. The mitigation eventually agreed upon included construction of a 10-acre emergent vegetation pond and 3 acres of waterfowl nesting islands at Canyon Ferry. DNRC and DFWP agreed on a maximum allowable expenditure of $52,510 for these features.

Recreation. Recreational development at Broadwater was minimal prior to construction of the hydroelectric project. There were two pit toilets, one trash can, and one picnic table, all poorly maintained. A sloping unsurfaced area just upstream from the dam served as a boat access, and open space downstream was used for parking.

The development of the recreational plan got tangled up in DNRC's negotiations with BLM to obtain rights to flood BLM land in the project's backwater. BLM added a stipulation to DNRC's existing right-of-way agreement that forced DNRC to include those recreation facilities it previously had discussed with BLM and DFWP.

DNRC filed a recreational resources report on April 23, 1986, revising the recreation section of its license application. The revised report called for maintaining a walkway across the dam to the east bank, razing the existing boat ramp and adjacent waste dump, and constructing a new concrete boat ramp, a restroom, a graveled entry road and parking area with BLM-designed traffic barriers, a bulletin board, and an interpretive sign. DNRC would have preferred less extensive and expensive recreational improvements. However, since DNRC was purchasing land and flood rights from BLM, its freedom to negotiate was limited.

DNRC tried to gain something from the recreation development by asking BLM to take that development as compensation for the BLM land and rights-of-way that DNRC acquired. The local BLM office was willing to consider the issue; however, FERC staff announced that they probably would veto it, since the recreation improvements already were required by the license.

A related improvement, a boat restraining barrier, was required as a safety item. This was one of the items DNRC had stalled on, back in 1985 through early 1987, as it reassessed its commitment to the project. When DNRC finally did propose a design in the spring of 1987, FERC was not satisfied. FERC first suggested a cable and float design. DNRC accepted. Then FERC required an "on-the-water" design. DNRC responded by proposing a log boom, but identified problems with it. So FERC again suggested DNRC consider a cable and float design. A cable and float barrier was installed during the summer of 1988.

Cultural Resources. DNRC, as part of its license application to FERC, was obliged to identify any cultural resource sites that might be affected by the project. DNRC documented four sites. Two of these appeared to meet the criteria for inclusion in the National Register of Historic Places. The first site was a post-1900 coke oven structure with an associated coal mine, slag piles, and other facilities. It was located about a mile downstream from Lombard, or about 3.5 miles above the dam. The second site was a partially buried prehistoric campsite about 2.5 miles upstream from the dam. Part of the campsite was exposed in a river bank that was collapsing into the existing reservoir.

The license required further study of these sites and development of mitigation plans. DNRC had to work with the State Historic Preservation Office (SHPO). The studies were carried out during 1985. Two other sites were added to the list, but only the two sites previously identified as significant were found to warrant mitigation plans. The coke oven site was not directly affected by the higher reservoir levels; however, SHPO feared that possible increases in recreational use of the reservoir, caused by improvements mandated in DNRC's license, could lead to increased vandalism. SHPO wanted DNRC to take responsibility or liability for the site in the event of vandalism; DNRC agreed to monitor the site for 5 years and to take action if any increases in vandalism were noted. The campsite, because it already was collapsing, was to be excavated and mapped by a team of archaeologists. This was carried out in 1988. As a requirement of the license, DNRC also pledged to monitor the other minor sites twice a year.

The study of the cultural resources and the development of mitigation plans went relatively smoothly. These activities were cheap enough to be continued even in 1985 and 1986 when the future of the project looked uncertain.

Railroad Tracks. Montana Rail Link owns the rail line that runs along the east shore of the reservoir. It purchased the line from Burlington Northern (BN) in 1987. DNRC started planning Broadwater when BN still owned the track. BN was particularly worried that the higher winter pool elevations caused by the hydroelectric project would undermine the roadbed or make it vulnerable to ice damage. The section of track through the canyon above Broadwater was one of the worst in the system, with accidents a regular occurrence, and BN did not want any more problems. DNRC was concerned because mitigating the impacts on the railroad could be expensive; at one point, DNRC estimated the cost of that mitigation in the worst case could be $5 million.

DNRC and BN started talking about impacts of the project on the railroad track in the fall of 1984, after FERC issued a license to DNRC. Possible solutions to potential problems ranged from adding more riprap, through raising the elevation of the entire length of track along the reservoir, to building a tunnel to avoid the reservoir.

With such expensive solutions being suggested, DNRC wanted to determine exactly what effects icing conditions caused by the project would have on the railroad. During the winter of 1985-1986, DNRC personnel, in cooperation with BN, conducted a survey of existing icing conditions. The following summer, DNRC contacted the U.S. Army Corps of Engineers Cold Regions Research and Engineering Laboratory (CREEL), Hanover, New Hampshire, about conducting a study of icing and the Broadwater project. DNRC authorized CREEL to begin the study in the fall of 1986, concurrent with the reappraisal of the economics of Broadwater.

The study found that the ice conditions and their impacts on the railroad would not be aggravated by DNRC's proposed project. BN agreed with these conclusions, and proposed that DNRC protect the tracks by building a new culvert, installing a 200-foot earthen dike, and agreeing to maintain riprap along the reservoir below the track. Negotiations continued into 1988, with the major change being the elimination of the riprap provision. The agreement was dated February 24, 1988; Montana Rail Link, which had purchased the track from BN the previous fall, also was a signatory to the agreement. The total estimated cost of mitigation was $34,216, using the railroad's design and labor.

Crow Creek Pumping Station. The Bureau of Reclamation built and operates the Crow Creek Pumping Station to irrigate land drawing water from above the Broadwater Dam. The pumping station is located about one mile upstream from the dam. Raising the pool elevation for the hydroelectric project threatened to flood the pumping station. From the very start, the Bureau's goal was to protect the station, or at least get someone else to pay for flood proofing.

The Bureau was concerned about flooding possibilities even before DNRC formally took up the Broadwater Project. In May 1978, after Vigilante had filed its preliminary permit, the Bureau wrote to DNRC asking it not to grant any permits if Vigilante's development would submerge the Bureau's pumps. After DNRC got its preliminary permit, the Bureau tried to block the project by objecting to DNRC's water rights application; the objection was denied.

The Bureau's next move was to get DNRC to pay to mitigate possible effects of submerging the pumps. The Bureau maintained that the Broadwater project would worsen the existing intermittent flooding of the pumping station. In a November 16, 1982 meeting among DNRC, the Bureau, and the Broadwater Irrigation District, the Bureau suggested that raising the floor of the pumphouse (estimated cost: $100,000) was the most probable solution. DNRC countered by sending the Bureau a copy of its 1941 agreement with the Bureau that gave DNRC the prior right to flood the land upon which the Crow Creek Pumping Station was located. Negotiations continued over the next 2 years. The major concerns were ice damage and flooding caused by the higher reservoir levels during the winter.

As a fall-back position, the Department of the Interior, on behalf of the Bureau, petitioned FERC to amend the license to provide specific protection for the pumping station. FERC treated Interior's proposal as a complaint, the resolution of which might have required a full-blown hearing before FERC with DNRC as the defendant. The parties involved eventually agreed to negotiate a good faith cost-sharing arrangement among DNRC, the Bureau, and the Irrigation District.

The Bureau's Billings office continued to insist that an ice jam during spring thaw could result in serious flooding of the pumping station. DNRC offered to address the effects of ice on the Crow Creek Pumping Station in its ice study. That study concluded that serious ice damage was unlikely. Even so, the study done by CREEL for DNRC did recommend raising the pump units and surrounding service yard to provide some freeboard and prevent nuisance ice from affecting the pumphouse.

The negotiations proceeded slowly while the project was on hold. When they started up again in 1988, the Bureau still was asking DNRC to pick up two-thirds of the costs. DNRC still thought the Bureau's argument had little merit. However, the Bureau was in a position to deny or attempt to deny DNRC's request to mitigate the impacts of Broadwater by placing nesting islands and an emergent vegetation pond at Canyon Ferry. The Bureau also, if it wished, could charge operation and maintenance costs caused by conditions at the reservoir over which DNRC has no control, and thereby add additional uncertainty to DNRC's total costs. Notwithstanding the flood easement DNRC already held, DNRC's project manager recommended trying to settle a 50-50 cost share arrangement with the Bureau, but to settle in any event.

The Bureau's final objection was that it had neither legal authority nor money to spend on raising the pumping station out of danger of flooding. Whether that was true or not, DNRC needed the Bureau to provide some matching funds. DNRC ultimately went to Montana's congressional delegation, and $150,000 was added to the Bureau's budget for the pumping station, with the understanding that DNRC would match up to that amount as necessary. The pumping station was raised in the fall of 1988.

Conclusions

This paper does not completely document the Broadwater Project. The participants suffered through many more events than one needs to know for energy planning purposes. Managing the construction itself was messy and complicated, like any other fast-track project, even if the amount of litigation spawned to date is less than typical. Monthly reports to FERC and regular inspections at each stage of construction were unavoidable facts of life for the project team. Obtaining easementsdealing with current owners, surveyors, appraisers, and county courthouseswas time consuming, but not unique to Broadwater. Pending is the decision on contracting out project operation and maintenance; DNRC personnel will handle the operation and maintenance at least through the end of 1991. These issues and more took up the time of those working on Broadwater.

Several lessons can be drawn from the long history of Broadwater. First, fast-track projects, multiple prime contractors, and inexperienced project management should be avoided. Second, public agencies will respond to their constituencies and to public oversight, even when it is not in the best interest of the project. Third, outside parties will use government regulations, both environmental and financial, to extract concessions from the developer. Finally, cost and schedule estimates are just that; any convergence with later facts is in part fortuitous. (See Appendix for a summary of the evolution of Broadwater's design and budget estimate.)

These lessons are nothing new. And that may be the most important lesson to draw from Broadwater. Things happen. Circumstances and events are unpredictable. They surprise even people who know they will be unpredictable. The uncertainty only recently incorporated into utility planning models does have a real world correlate. The Broadwater Project is ample proof of that.

Evolution of Broadwater Project Design and Budget

Both the proposed design and the estimated budget for Broadwater went through a number of changes. The following list is drawn from a variety of reports, letters, and memos prepared on the project; the dates represent the first time the design or budget appeared in documents now on file with DNRC. The estimated budgets have not been adjusted for inflation.

4-77 Two 5.5-MW turbines might be feasible. (BPA to Vigilante Electric Cooperative, 4-12-77)

5-77 Six tube-type hydraulic turbines and generators of 2,400 kW capacity each, for a total of 14.4 MW, are suggested. These would be installed on the left abutment (looking downstream) of the dam with a separate canal with a capacity of 7,000 cfs. A 31-foot head is assumed. Average production is estimated at 88 million kWh. Installed cost is estimated at $8 million, plus transmission costs. (Tudor to DNRC, 5-5-77)

7-77 An innovative design involving mounting the six turbines on the downstream apron below the spillway is proposed. (Tudor to DOE, 7-11-77)

12-77 The innovative design could save 20 percent of the total capital cost compared to a more conventional design. (Tudor to DNRC, 12-6-77)

1-78 Head now assumed to be 28 feet, using the innovative design with 14.4 MW capacity Annual output estimated at 78 million kWh. Estimated cost is $14,963,000 (Fall 1977 dollars). (*Report on Potential Hydroelectric Power For State Owned Dams*, by Tudor for DNRC, 1-78)

6-78 DNRC's preliminary permit application to FERC uses the same design and costs as in the 1-78 report, but average annual output is estimated at 90 million kWh.

4-79 Design now is four 2.44-MW turbines on spillway face and apron. Head is assumed to be 22 feet. Average production estimated at 56.44 million kWh. Construction cost is $11,847,000 (March 1979 dollars). (*Vertical Turbine-Spillway Combine, Broadwater Dam*, prepared by Tudor for DNRC to submit to U.S. Department of Energy)

5-82 DNRC's application for a FERC license is based on the 4-79 report. Construction cost, with contingencies, is estimated at $14 million

(February 1982 dollars); total capital cost (i.e., all construction and preparation costs plus interest during construction) is estimated at $22,900,000 (February 1984 dollars), assuming 12 percent interest costs.

8-84 Design is same as in FERC license. Construction cost plus contingencies estimated at $14,953,000 (January 1984 dollars). Total capital cost ranges between $21,577,000 (6 percent interest) to $23,044,000 (12 percent interest) in February 1986 dollars. (*Feasibility Update Report on Hydroelectric Projects*, prepared by Tudor for DNRC)

9-85 Tudor recommends switching to a conventional turbine design, mounted to the side of the dam. (Meeting with DNRC staff on 9-3-85)

10-85 Previously excluded mitigation costs could add $2,690,000 to the 1984 estimates in the most probable case; the range of those costs was $1,005,000 to $7,150,000. (Norm Barnard and Glen McDonald to Rick Bondy, 11-15-85)

3-86 Total capital costs estimated at $28,358,000 (February 1987 dollars). (Rick Bondy to Don Porter, First Boston, 3-26-86)

5-87 Project would be a single 10-MW conventional design. Average annual production estimated at 62.02 million kWh. Total construction cost is $20,665,000 (December 1987 dollars). Total capital costs estimated at $26,000,000. Unlike previous estimates of capital cost, this estimate includes financing costs on the bond sales, reserve funds, and interest earnings on the bond proceeds. (*Definitive Project Report: Broadwater Power Project*, prepared by Tudor for DNRC)

Chapter 10

41.5-MW Colstrip Energy Waste-Coal-Fired Generation Facility Colstrip, Montana

Introduction

Colstrip Energy Limited Partnership is nearing completion of a 35-MW (net), waste-coal-fired generation facility near Colstrip, Montana. The original developers did business until 1988 under other names, primarily as AEM Corp. In this paper, both the current developers and the facility are referred to as Colstrip Energy.

Planning for the project began in 1984. The plant originally was planned to be a combination coal liquefaction and cogeneration facility. The developers signed a contract with Montana Power Company (MPC) to sell the output of the Colstrip Energy Project as a qualifying facility (QF) under PURPA. Although objections were raised on environmental grounds, the most significant problem the developers faced was financing.

Project Description

The Colstrip Energy Project will be a 35-MW net (41.5-MW gross) electric generation facility. It is expected to have an 85 percent capacity factor, and, therefore, to produce 29.75 aMW. The project will be fueled primarily with approximately 223,000 tons per year of high-sulfur waste coal from the top of the seam at Western Energy Company's nearby Rosebud Mine. The net efficiency of the facility will be just under 25 percent, lower than that of a large-scale conventional plant.

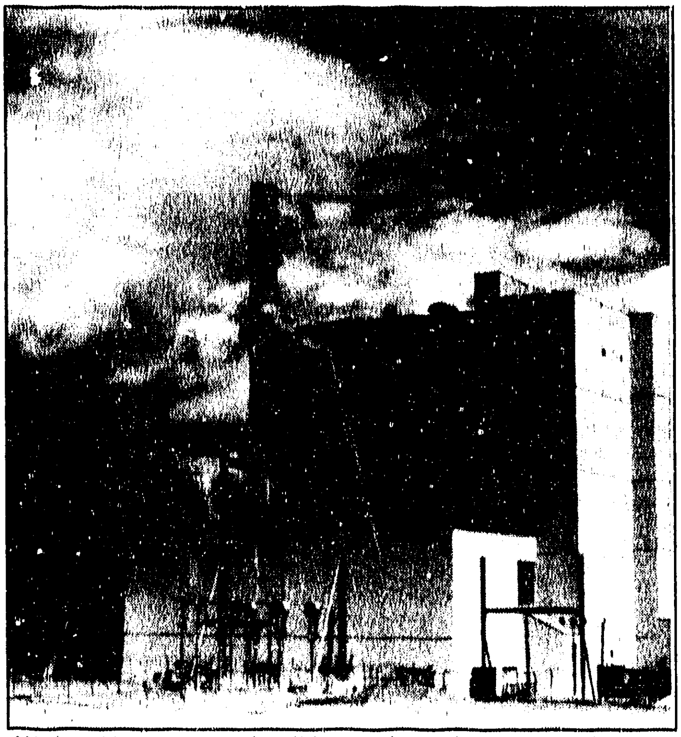
The plant is located at a 64-acre site approximately 7 miles north of Colstrip, in southeastern Montana. The project will include a fuel handling system to move the coal from the truck unloading hopper to a circulating fluidized bed boiler. The boiler will produce superheated steam at 955F and 1,300 psig. Steam will be supplied to a condensing turbine (from which process steam can be extracted) and will drive a synchronous generator. Regenerative feedwater heating will be used to increase cycle efficiency. Turbine exhaust will be condensed in an air-cooled condenser. The project will use waste limestone to control sulfur oxide emissions. Flue gases exiting the boiler will pass through a bag house to remove particulates. Cooled bed ash and fly ash will be collected and disposed of on-site.

History

The project was conceived originally as a coal liquefaction-cogeneration facility. The intent was to produce 150,000 to 200,000 barrels of coal-derived liquid distillate and about 150,000 tons of char (a combustible residue remaining after the destructive distillation of coal) per year; the char would have been burned to produce electricity. Planning for the project began in 1984. A long-term contract was signed with Montana Power Company late that year and publicly announced in January 1985. The contract stipulated the relatively high rates set by the Montana Public Service Commission (PSC) in its 1983 avoided cost docket. DNRC estimates the projected, levelized 35-year rate to be equivalent to 72 mills/kWh; the first-year rate originally was estimated at the equivalent of 64 mills/kWh.

The original developer was AEM Corp. (previously known as Alaska Energy Management), an affiliate of SGI (previously known as Synfuel Genesis International) of La Jolla, California. SGI developed the liquids from coal (LFC) pyrolysis technology AEM planned to use. At the time, AEM and SGI were considering plans to build plants in six states in addition to Montana.

In January 1985, AEM announced plans to start construction during the summer of 1985, with completion scheduled for September 1986. During 1985, AEM sought a state air quality permit, which it received, and financing, which it did not. It continued to search for financing through 1986. In November, 1986, AEM requested transferral of its permit to Montana One Partners, a limited partnership for which SGI was the general partner.



High-sulfur waste coal will be combusted in fluidized bed boilers at the 41.5-MW Colstrip Energy Project. Approximately 261 million kWh of annual energy production from the $97.1 million plant will be sold to the Montana Power Company.

In 1987, Montana One Partners revised their project. Early in 1987, they switched designs from two stoker boilers to a fluidized bed combustor. This change raised the installed capacity from 39 MW to 41.5 MW. By June, they were seeking assurances from the Montana Department of Health and Environmental Sciences that their air quality permit still would be valid even if only the generating unit was built. The plant's QF designation remained valid since waste-fired facilities also were covered by PURPA. In September 1987, SGI and Montana Limestone Company signed a limestone supply agreement. An SGI affiliate and Western Energy Company entered into agreements in December 1987 for the supply of refuse coal, the supply of run-of-mine coal as a standby fuel source, and coal transportation from the mine to the project. In April 1988, an SGI affiliate hired Bechtel Construction, Inc. to build the project. Union acceptance of a 10 percent cut in base wages helped Bechtel compete against two non-union bidders for the project.

Site preparations began in July 1988. Groundbreaking ceremonies were held in October. Colstrip Energy Limited Partnership, the entity that has owned Colstrip Energy since mid-1988, expects to first roll the turbine in February 1990. Commercial operation is expected in June 1990.

Day-to-day operation and maintenance services for the project will be provided under a services agreement (signed June 1988) by UC Operating Services (UCOS), a California general partnership between COSI Ultra, Inc., a subsidiary of Baltimore Gas and Electric Company, and Ultrapower Services, Inc., a subsidiary of Hadson Corporation. UCOS' services agreement has an initial 5-year fixed labor budget (subject to inflation) and a non-labor budget that is negotiated each year. The contract contains performance bonuses and penalties. It may be renewed for up to three additional 5-year terms.

As of September 1988, the general partner in Colstrip Energy still was working to finance the $25 million coal liquefaction portion of the plant. The intent was to start construction in 1990. No further public reports have been issued on this matter.

Current Corporate Structure

Colstrip Energy Limited Partnership was formed on June 30, 1988, to develop, own, and operate the project. Rosebud Energy Corp. was formed earlier in 1988 to be the general partner for Colstrip Energy. Neither SGI nor Montana One Partners has any continuing interest in Rosebud. Harrier Power Corporation, a subsidiary of Pacific Gas and Electric Enterprises, was formed in 1988 for the purpose of being a limited partner in Colstrip Energy. Spruce Limited Partnership was formed in 1988 for the same purpose. Spruce Power Corporation, a wholly owned subsidiary of Bechtel Enterprises, Inc., is the general partner of Spruce; Bechtel Enterprises currently is the sole limited partner. Bechtel Enterprises is a subsidiary of the Bechtel Group, Inc.

Rosebud will operate the project and manage the affairs of the partnership. It has received a development fee and a construction management fee. Harrier and Spruce have the contingent right to convert all or part of their limited interests into a general partnership interest, if the facility becomes a cogenerator. Harrier and Spruce own a substantial portion of the project, initially over 90 percent of the limited partnership. The partnership agreement has a term of 40 years. Rosebud contributed all the rights, agreements, and permits necessary to build and operate the project; these had been transferred to it by SGI and its affiliates. Harrier and Spruce each will contribute $11,375,000 in equity.

Project Financing

Colstrip Energy is financed primarily by tax-exempt Resource Recovery Revenue Bonds issued by the Montana Board of Investments. According to the Official Statement for the bond issue (October 13, 1989), the project budget is $97,110,000.

Financing plans went through a number of changes. In 1986, an AEM spokesman said the plant was being financed on a lease-back basis, with the development costs coming from a limited partnership. Other possibilities, including foreign financing, were explored. One of the problems was that AEM hoped to replace the security payments required by MPC with a corporate guarantee of the project, but AEM was unable to close such an arrangement with any construction corporation. A new arrangement was announced in August 1988, when Bechtel told reporters that Bechtel and PG&E would contribute $26 million in equity, Bank of New England would provide $34 million in financing, and the Trust Company of the West, on behalf of the Boilermakers Cogeneration Fund, would provide $20 million.

Two months later, shortly after site preparation had begun, Colstrip Energy applied to the Montana Board of Investments under the Stand-Alone Economic Development Bond Program. The state, through this program, assists companies in gaining access to the tax-exempt bond market. The applicant is entirely responsible for obtaining and securing bond financing. Neither the state nor the Board backs the bonds under any circumstance whatsoever. The state charges a minimal issuance fee, $7,500 for the first $1 million and $1,000 for each additional $1 million. The only other requirement is that the project meet certain public interest criteria involving economic development. A public hearing is required to determine compliance. Each state has a limit on the amount of tax-exempt financing it can issue, but Montana has never approached its $150 million annual limit.

As a waste disposal facility, Colstrip Energy qualified for tax-exempt financing under the "exempt facility" clause. IRS rules require such a facility to use at least 65 percent waste for fuel. (The IRS requirement is less strict than that for PURPA. PURPA requires a facility to use at least 75 percent waste coal to be a QF.) The federal Tax Reform Act of 1986 did not eliminate the tax-exempt status of waste disposal facilities.

In its application to the Board of Investments in September 1988, Colstrip Energy requested $40,850,000 in tax-exempt bonds. This figure changed several times. Eventually, $60,800,000 in bonds was issued by the Board of Investments on October 13, 1989; the proceeds in turn were loaned to Colstrip Energy. The tax-exempt bonds have a floating interest rate, initially on a weekly basis; the partnership has the option of converting them to a fixed rate. For purposes of the official statement for the bond issue, Fuji Bank (San Francisco) is listed as issuing the initial letter of credit backing the bonds; this letter expires in 1997. Colstrip Energy believed that the tax-exempt bonds would carry an interest rate two to three percentage points lower than would otherwise be the case.

Obtaining tax-exempt financing led Colstrip Energy to restructure its previous financing arrangements. A total of $60.8 million will come from tax-exempt bonds. Of the remaining $36,310,000 needed to finance the project, Harrier and Spruce each will contribute $11,375,000 in equity when the project is complete. The Bank of New England will issue fixed-rate term notes for the remaining $13,560,000. The Boilermakers Trust Fund no longer is involved in the project.

Issuing the bonds created controversy. Northern Plains Resource Council (NPRC), which had opposed the plant on environmental grounds, argued that it was inappropriate for the state to subsidize Colstrip Energy. NPRC pointed out that the facility was nearly complete and thus didn't need state support. NPRC further argued that the power was too expensive and was unneeded, since MPC was still in surplus. Although some Board members expressed similar concerns, the vote was 7 to 0 in favor of granting the bonds.

Project Budget

The most recent public estimate of the budget totals $97,110,000. The estimated budget for the project has increased significantly over time. AEM's first statement to the press set the budget for both the generating and coal-liquefaction facilities at $40 million. Besides selling electricity, AEM planned to sell LFC distillates at $27.50 per barrel. Reestimation of the project costs and the drop in the price of oil contributed to the difficulty AEM had in obtaining financing. Colstrip Energy's application to the Board of Investments in September 1988 contained the following budget:

BUDGET (September 1988)

Turn-key fixed price construction contract	$57,370,000
Insurance	593,000
Limestone stockpile	500,000
Construction management	750,000
Startup costs	2,015,000
Interest rate protection	500,000
Other equipment, costs, and fees	7,146,000
Capitalized closing costs	2,090,000
Interest during construction	8,828,000
Debt service reserve fund	3,708,000
Construction contingency	2,000,000
Total	$85,500,000

Colstrip Energy presented a higher and more abbreviated budget the following year, when it issued the Official Statement for its bond issue.

BUDGET (October 1989)

Turn-key fixed price construction contract as of 7/1/88	$54,320,000
Other equipment, costs, and fees	22,746,000
Reserve fund	6,080,000
Costs of issuance	2,677,000
Interest during construction	8,787,000
Contingencies	2,500,000
Total	$97,110,000

Power Contract and Contract Negotiations

The power contract negotiations with MPC went smoothly. The contract is dated October 15, 1984. According to the contract, the project was expected to go on-line in March 1986. The contract was a standard form for QFs, as prepared by MPC. AEM guaranteed to provide only 30 MW of capacity, even though the net capacity of the plant was 35 MW. In this way, AEM hoped to avoid any penalties for failing to provide contracted capacity.

AEM chose partially levelized rates for both capacity and energy. The bulk of both rates was set at contract signing, with much smaller portions to be set annually based on the PSC-approved methodology. The partially levelized rates meant that in the early years AEM would receive more than the projected avoided cost of power; therefore, MPC required a substantial security payment to protect itself in the event AEM quit producing before the end of the contract. In the first year, this security payment equaled about 28 percent of the money AEM expected to receive.

The contract was amended March 28, 1988. At that time, MPC was trying to buy out 19 QF contracts it was carrying on its books. MPC apparently planned to offer $1 million to buy out AEM. AEM refused. Instead, the two parties renegotiated the contract. AEM committed to a much more definite construction schedule and agreed that failure to meet that schedule would be grounds to terminate the contract. The operation date was set at December 31, 1990.

AEM also renegotiated its security arrangement. Rather than making security payments, AEM asked to take lower rates in the first 15 years; these rates still would be fixed in the contract. After that, the escalation rates would reflect previous inflation and would be calculated annually. As a consequence, Colstrip Energy will receive less money the first year than would have been the case under the previous security arrangement. However, Colstrip Energy's cash flow will look much better in the middle years under this arrangement. This arrangement had financial advantages for the partners, especially in terms of improving their ability to obtain financing. The revised rate schedule does offer some benefits to Montana ratepayers by bringing the cost of the resource more in line with the projected avoided cost of power.

The contract language on rates Colstrip Energy will receive is included as Attachment 1. Colstrip Energy estimates the first-year rate to be equivalent to 46 mills/kWh.

Interconnection and Transmission

The negotiations over Colstrip Energy's interconnect with MPC were described as straightforward. Colstrip Energy will tie into an MPC 115-kV line that runs right next to it. The line serves the Nichols Pump on the Yellowstone, which provides water to Colstrip Units 1-4. Four spans of the line had to be rerouted slightly to accommodate Colstrip Energy's connection. MPC originally proposed a three-breaker scheme, one on either side of the tap from Colstrip Energy and one on the tap itself. AEM argued for the less expensive single breaker on the tap, which was the option installed; if additional breakers turn out to be necessary, they will be paid for by Colstrip Units 1-4. Colstrip Energy built about 200 feet of line to tap MPC's line.

Because of the importance of the 115-kV line to the operation of the Colstrip Units 1-4, MPC insisted on certain precautionary measures. Colstrip Energy had to pay for the Acceleration Trend Relay (ATR) computerized system for monitoring line and plant loading; the ATR is capable of tripping the plant in the event of faults. (The Colstrip Units 1-4 also use ATR equipment.) Colstrip Energy also paid to beef up the relays at the Nichols Pump.

Total costs of tying to the MPC system were:

Reroute of 115-kV line	\$57,000
Relay work at Nichols Pump	11,000
ATR	40,000
Connection to MPC's operations center	7,000
Metering equipment for billing & tie-point telemetry	90,000
	\$205,000

Permits, Environmental Impacts, and Public Approval

The most significant regulations affecting Colstrip Energy were federal regulations and actions. Without PURPA, Colstrip Energy would not have been viable. FERC granted Colstrip Energy approvals and waivers from applicable Federal Power Act regulations. Colstrip Energy also obtained a "No-Action Letter" from the staff of the Securities and Exchange Commission expressing the opinion that neither Harrier nor Spruce should be deemed an electric utility holding company under the Public Utility Holding Company Act of 1935. Letters from these two agencies were required to complete the initial financing in July 1988.

The most significant environmental permit required for Colstrip Energy, in terms of major public hearings and public objections, was the air quality permit. The partnership, however, was more concerned about the Montana Groundwater Pollution Control System permit, since a delay in obtaining it would have jeopardized its ability to meet the requirements of the financing.

Colstrip Energy (then AEM) initially applied to the Montana Department of Health and Environmental Sciences (DHES) for an air quality permit on March 25, 1985. A public meeting was held in Colstrip on April 18. Both proponents and opponents spoke at the meeting. Proponents stressed the economic development benefits. Opponents cited air pollution, ash disposal, and problems with trucking the coal to the plant as major concerns. The most detailed set of environmental objections was filed by MPC. Based on the hearing and the Department's own review, DHES ruled the application incomplete on April 24, 1985.

AEM's consultant submitted additional information on June 25. On July 19, DHES completed its preliminary review and decided that no EIS was required. The air quality permit was granted September 11, 1985.

The NPRC and the Rosebud Protective Association, its local affiliate, promised to appeal the Department's decision to the state Board of Health (the Board). The environmental groups wanted a full EIS completed. They were worried about the experimental nature of the liquefaction process, the odors and pollutants that any liquefaction plant could be expected to produce, and the indeterminate plans to bury the ash from the plant.

Others, including local businesses and workers, supported the project. A union group sponsored a "problem solving meeting" in Colstrip in October 1985, to deal with people's concerns. The union group thought the project could be built in an environmentally sound and economically beneficial manner; they were more than ready to support the project. The project was supported and denounced at the meeting. The technical adequacy of AEM's descriptions of both the liquefaction and combustion process were questioned, as was AEM's analysis of the facility's impacts. The meeting aired the concerns but did not resolve them.

NPRC and the Rosebud Protective Association filed an appeal as threatened. On November 15, 1985, the Board ruled that an EIS would not be necessary.

The developers made little effort to obtain state permits during the next two years, being caught up in financing issues. On October 7, 1987, they applied to amend their air quality permit to take account of design changes in the combustor and the postponing of the liquefaction unit. The revised permit was granted December 22, 1987.

Table 10-1 lists the annual limits for the significant pollutants, and the change between the original permit and the revised permit. The limits are based on "best available control technology" (BACT). Accordingly, a change in the design and the process altered the allowable emission limits. Should the liquefaction plant come on-line, the SO_2 requirement will revert to the level set in 1985.

Table 10-1
Air Pollutant Limits Set by DHES Permit

	1985	1987	
SO_2	184	1840	@ 3.0% sulfur in waste coal
NO_x	1,435	1,435	
Particulate matter	26.6	26.6	
CO	61	232	

Note: All quantities are in tons/year.

These permitted releases, especially for SO_2, provoked comment because they are less strict than the requirements for the tightly regulated Colstrip Units 3 and 4. Colstrip Energy has less than 5 percent of the capacity of one of the 770-MW Colstrip units, but on a proportionate basis it will release more pollutants. For instance, while Colstrip Units 3 and 4 are each allowed to emit 0.18 pounds of sulfur dioxide per million Btu fired in a 24-hour period, Colstrip Energy is allowed 0.87 pounds. Colstrip Energy can release 420 pounds of sulfur dioxide per hour compared with each Colstrip unit's 761 pounds.

NPRC lost its effort to prevent AEM from receiving a permit without extensive review; however, it has continued to pursue the air quality issue. NPRC plans to go to FERC, contrasting the mix of coal needed to meet the facility's DHES-mandated air quality obligations with the mix needed to meet its PURPA requirements. A facility must burn at least 75 percent waste coal to be a QF. But to meet the air quality requirements, the waste coal used at Colstrip Energy must have an average sulfur content of no more than 3.7 percent. Depending on the authority cited, waste coal from Rosebud Mine does or does not have an average sulfur content above that. Coal from the Rosebud Mine burned at Colstrip Units 1-4 has a sulfur content of 0.8 percent. The waste coal, if it is particularly high in sulfur, can be blended with this run-of-mine coal to achieve the 3.0 percent average sulfur content called for in the permit.

DHES monitoring will detect any impacts on air quality caused by excessive use of high sulfur coal. The air quality permit calls for stack emission monitoring for the life of the plant. Ambient air quality will be monitored for 2 years, at which point DHES will assess the need for the kind and amount of further ambient air monitoring. No state agency currently monitors for PURPA compliance.

In September 1987, when SGI (general partner in the successor partnership to AEM) again began actively seeking permits, the state set up an interagency group to facilitate issuing permits. Montana Department of Natural Resources and Conservation (DNRC) served as the coordinator. DNRC had responsibility for issuing the water right permit for the facility. AEM originally had planned to use water from the Yellowstone River, 30 miles to the north, in its wet cooling tower. In January 1988, SGI announced its decision that a dry cooling process would be adequate. Therefore, all that the facility required was two on-site wells with a combined capacity of 64 gallons per minute. This change considerably reduced the significance of the water right issue; it also eliminated the Department of Highways' involvement with a right-of-way for the water pipeline.

The only significant permit remaining was that required under the Montana Groundwater Pollution Control System. These permits generally aren't obtained until the project is under construction; however, Bank of New England, which was financing the project, wanted assurances that the permit would be obtained so as to minimize its risk. The bank, in May 1988, asked for a meeting with the Governor "to get a feel for the attitude of the state of Montana concerning the project." Also, Colstrip Energy, through its counsel, asked for and received a letter from DHES indicating that no problems were anticipated in processing the permit application.

Colstrip Energy finally filed its application for a groundwater pollution control permit on October 18, 1988. It requested permission to dispose of about 85,000 dry tons of bottom ash and fly ash in a landfill on the property. It had obtained the additional land that DHES pointed out would be necessary for disposing of the ash. Colstrip Energy encouraged DHES to work fast, fearing an extended process could jeopardize its financing.

A public hearing was held on January 5, 1989. This was unusual in that such permits usually don't require hearings; however, DHES received numerous requests for a hearing because of local concern about groundwater quality. The permit was issued 11 days later, January 16, 1989. The permit is good until December 31, 1994, at which point it could be renewed, subject to evaluation of Colstrip Energy's performance. No degradation of state waters outside the property boundaries is permitted. The permit requires six monitoring wells, with quarterly reporting on key indicator parameters, including boron and total dissolved solids; annual reports on a much longer list of pollutants also are required.

A number of other minor state permits were required, such as a building permit from the Montana Department of Commerce and a driveway approach permit from the Montana Department of Highways. Obtaining these presented little problem.

Conclusion

If anything, Colstrip Energy was a project made, not hurt, by regulation. Its QF status made the project feasible in the first place. State regulatory authorities, especially DHES, which granted the major permits, were expeditious. The site and the eventual design were selected to reduce many of the potential environmental impacts. Environmental groups opposed Colstrip Energy but had little success; such public controversy as there was did not appear to affect the project. Financing was the only real roadblock to Colstrip Energy. Once that was obtained, the project moved rapidly towards completion. The case of Colstrip Energy demonstrates that non-utility producers, once they settle on a practical design and obtain credible backing, can readily build facilities to supply a utility system.

Attachment 1 - Contracted Rates for Colstrip Energy

First Amendment - Attachment 1

Definitions

1. Contract Year 1:

Contract Year 1 is that period which begins with the actual commercial Operation Date and ends on or about the following June 30. Commercial Operation Date is defined as the date of the first meter read occurring after Company has received a Registered Professional Engineer's Certificate stating that all necessary acceptance tests have been completed to determine if the facility can reliably produce energy and capacity under the Power Sales Agreement.

Annually, the Company submits to the Montana Public Service Commission (MPSC), on or about June 1 of each year, a compliance filing pursuant to Docket 83.1.2, Orders 5017 and 5017a. This compliance filing, must be approved each year by the MPSC. To the extent that MPSC approval occurs on a date other than June 30, the following procedure will be followed:

Assume AEM production meter read on June 3, June 30 and July 31.

Assume MPSC approval on July 10:

Then:

AEM production from June 3 - June 30 (June 30 meter read) will be purchased at rates in effect on June 30.

AEM production from June 30 - July 31 (July 31 meter read) will be purchased at rates based on July 10 approval.

In other words, there will be no proration of the rates; all production recorded on a meter reading taken before approval date will be purchased at year n rates and all production recorded on a meter reading taken after approval date will be purchased at year n+1 rates.

2. n = Contract Year for which new rate is being calculated.

3. ESC ER_n = "Escalating Energy Rate" approved annually by the MPSC pursuant to Docket 83.1.2, Orders 5017 and 5017a. For example, at the time Contract No. COG 84101535-PL was executed, ESC ER_n = 3.644 ¢/kWh (QFLT-84, Supplement #1).

4. ESC CR_n = "Escalating Capacity Rate" approved annually by the MPSC pursuant to Docket 83.1.2, Orders 5017 and 5017a. (ESC CR_n = $56.94/kW/Yr; QFLT-84, Supplement #1).

5. PESC ER_n = Escalating energy portion of the "Partially Levelized" rate. (PESC ER_n = 1.421 ¢/kWh; QFLT-84, Supplement #1).

6. PESC CR_n = Escalating capacity portion of the "Partially Levelized" rate. (PESC CR_n = $1.00/kW/Yr; QFLT-84, Supplement #1).

7. ER_n = Fixed energy rate - Column (D) of Table I.

8. CR_n = Fixed capacity rate - Column (D) of Table II.

9. TER_n = "Total Energy Rate" for Contract Year n (Column (F), Table I) TER_n = PESC ER_n + ER_n.

10. TCR_n = "Total Capacity Rate" for Contract Year n (Column (F), Table II) TCR_n = PESC CR_n + CR_n.

Table I
Determination of Energy Rates

Contract Year n	(A) Tariffed Partially Levelized Energy Rate (¢/kWh)	(B) Security Reqment. Refund To MPC (¢/kWh)	(C) Refund of Security Deposit To AEM (¢/kWh)	(D) Fixed Energy Rate ER_n (¢/kWh)	(E) ESCAL Component Partially Levelized Rate PESC ER_n (¢/kWh)	(F) Total Energy Rate TER_n (¢/kWh)
1	3.751	1.529	0.000	2.222	1.421	3.643
2	3.751	1.406	0.000	2.345	(Example Only)	
3	3.751	1.289	0.000	2.462		
4	3.751	1.154	0.000	2.597		
5	3.751	1.011	0.000	2.740		
6	3.751	0.860	0.000	2.891		
7	3.751	0.701	0.000	3.050		
8	3.751	0.533	0.000	3.218		
9	3.751	0.356	0.000	3.395		
10	3.751	0.170	0.000	3.581		
11	3.751	0.000	0.027	3.778		
12	3.751	0.000	0.235	3.986		
13	3.751	0.000	0.454	4.205		
14	3.751	0.000	0.686	4.437		
15	3.751	0.000	0.930	4.681		
16 - 35	3.751	0.000	ER_n-3.751	ER_n		

For Contract Years 1-15:

ER_n will be as specified in Column (D), Table I

PESC ER $_n$ will be determined annually and approved by the MPSC (Docket 83.1.2, Orders 5017 and 5017a).

$TER_n = ER_n + \text{PESC } ER_n$

For Contract Years 16 and Beyond:

$ER_n = ER_{n-1} \times [(\text{ESC } ER_n - \text{PESC } ER_n)/(\text{ESC } ER_{n-1} - \text{PESC } ER_{n-1})]$

PESC ER_n will be determined annually and approved by the MPSC (Docket 83.1.2, Orders 5017 and 5017a).

$TER_n = ER_n + \text{PESC } ER_n$

Table II
Determination of Capacity Rates

Contract Year n	(A) Tariffed Partially Levelized Capacity Rate ($/kW-Yr)	(B) Security Reqment. Refund To MPC ($/kW-Yr)	(C) Refund of Security Deposit To AEM ($/kW-Yr)	(D) Fixed Capacity Rate CR_n ($kW-Yr)	(E) ESCAL Component Partially Levelized Rate PESC CR_n ($/kW-Yr)	(F) Total Capacity Rate TCR_n ($/kW-Yr)
1	91.54	35.60	0.00	55.94	1.00	56.94
2	91.54	32.52	0.00	59.02		(Example Only)
3	91.54	29.57	0.00	61.97		
4	91.54	26.16	0.00	65.38		
5	91.54	22.57	0.00	68.97		
6	91.54	18.78	0.00	72.76		
7	91.54	14.77	0.00	76.77		
8	91.54	10.55	0.00	80.99		
9	91.54	6.10	0.00	85.44		
10	91.54	1.40	0.00	90.14		
11	91.54	0.00	3.56	95.10		
12	91.54	0.00	8.79	100.33		
13	91.54	0.00	14.31	105.85		
14	91.54	0.00	20.13	111.67		
15	91.54	0.00	26.27	117.81		
16 - 35	91.54	0.00	CR_n-91.54	CR_n		

For Contract Years 1-15:

CR_n will be as specified in Column (D), Table II

PESC CR_n will be determined annually and approved by the MPSC (Docket 83.1.2, Orders 5017 and 5017a).

$TCR_n = CR_n + \text{PESC } CR_n$

For Contract Years 16 and Beyond:

$CR_n = CR_{n-1} \times [(\text{ESC } CR_n - \text{PESC } CR_n)/(\text{ESC } CR_{n-1} - \text{PESC } CR_{n-1})]$

PESC CR_n will be determined annually and approved by the MPSC (Docket 83.1.2, Orders 5017 and 5017a).

$TCR_n = CR_n + \text{PESC } CR_n$

END

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