

EXHIBIT D—STATEMENT OF COSTS AND FINANCING

Klamath Hydroelectric Project
(FERC Project No. 2082)

PacifiCorp
Portland, Oregon

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D1.0 INTRODUCTION

PacifiCorp owns and operates the Klamath Hydroelectric Project (FERC No. 2082) (Project) under a federal license from the Federal Energy Regulatory Commission (FERC). The license expires on March 1, 2006. PacifiCorp is applying for a new license to continue operation of the Project. This Exhibit D presents responses to information describing Project costs and financing.

Exhibit D is organized into eight sections which generally parallel the sequence of information requested in the Code of Federal Regulations (CFR). Following this introduction, Section D2.0 discusses the capital and operations and maintenance (O&M) costs associated with proposed Project modifications. In addition, the estimated annual increase or decrease in generation at existing Project developments is provided in tabular format. Section D3.0 presents financial information estimating the Project's net worth. This section also includes an estimate of the cost to develop the license application, and identifies remaining undepreciated net investment or book value of the Project. Section D4.0 presents data on the annual project costs. Section D5.0 provides estimates of the value of the Project power, including identification of on-peak and off-peak values of Project power and the basis for the value determinations. Section D6.0 presents a discussion of alternative or replacement sources for Project power. The consequences of license denial to PacifiCorp customers are discussed in D7.0. PacifiCorp's financial resources are summarized in Section D8.0.

D2.0 CAPITAL AND O&M COSTS OF PROPOSED PROJECT MODIFICATIONS AND RESOURCE ENHANCEMENT MEASURES

PacifiCorp is proposing Project modifications and certain nonpower resource enhancements as a result of detailed technical studies and consultations with state and federal agencies, tribes, and the public. These enhancements affect fisheries, recreation, terrestrial resources, water quality, and cultural resources, among other studies. Exhibit E provides detailed information on PacifiCorp's proposed environmental and social enhancements.

Based on the results of numerous studies and consultations, PacifiCorp maintains that the proposed resource enhancement measures and Project modifications represent a cost-effective, efficient, and environmentally and socially balanced use of water resources for the Project.

Capital and O&M costs of the proposed nonpower resource enhancements and the Project modifications have been estimated for a future 30-year license that begins in 2006. The current license expires on March 1, 2006 (see Tables D2.0-1 and D2.0-2, respectively).

The capital and O&M cost have been estimated at a conceptual level by associated resource researchers. The estimated annual increase or decrease in generation at existing developments is presented in Table D2.0-3. The generation changes were estimated using a proprietary model.

Table D2.0-1. Capital and O&M cost estimates for nonpower resource enhancements over a 30-year new license period.

Project Costs (In Thousands of Nominal Dollars)		
Category		Costs *
Nonpower Resource Enhancements		
1.	Water Use and Quality	Capital = \$1,283 O&M = \$9,799
2.	Aquatics	Capital = \$21,496 O&M = \$23,778
3.	Terrestrial	Capital = \$1,210 O&M = \$4,104
4.	Cultural	Capital = \$7,844 O&M = \$5,890
5.	Recreation and Visual	Capital = \$18,093 O&M = \$12,163
TOTALS		Capital = \$49,926 O&M = \$55,734 \$105,660

* Based on 30-year FERC license period beginning in calendar year 2006.

Table D2.0-2. Capital and O&M cost estimates for Project modifications.

Project Costs (in Thousands of Nominal Dollars)		
Category		Costs
	Project Modifications	
1.	Decommission the East Side development	\$442*
2.	Decommission the West Side development	\$508*
3.	Include Spring Creek diversion dam	Facility is already in place. Total Annual O&M = \$67
TOTAL		\$1,017

* Based on one-time decommissioning project cost in calendar year 2006.

Table D2.0-3. Estimated annual increase or decrease in generation by existing Project development under proposed Project modifications and operations.

Category		Change in Annual Generation Between Current Operations and Proposed License Conditions. Hours Based on Long-Term (30-Year Average) Generation
1.	East Side	Loss of 15,417 megawatt-hours (MWh)
2.	West Side	Loss of 3,419 MWh
3.	Keno	No change – the Keno development does not generate electricity
4.	J.C. Boyle	Loss of 4,030 MWh
5.	Copco No. 1	Gain of 443 MWh
6.	Copco No. 2	Gain of 35 MWh
7.	Fall Creek	Loss of 1,008 MWh
8.	Iron Gate	Gain of 180 MWh
PROJECT TOTAL		Loss of 23,216 MWh

D3.0 ESTIMATED AMOUNT IF THE PROJECT WERE TAKEN OVER PURSUANT TO SECTION 14 OF THE FEDERAL POWER ACT

According to Section 14 of the Federal Power Act, if the Project were to be taken over by another entity, PacifiCorp would be entitled to its net investment in the Project plus severance damages.

D3.1 ESTIMATE OF FAIR VALUE

The fair value of the proposed Project has been estimated based on the net present value of the after-tax cash flow analysis of the Project assuming a 30-year license that starts in calendar year 2006. In review of the assumptions of this analysis, the most influential assumption is the future value of power, which can typically swing the fair value up or down millions of dollars from the base value. The fair value of the Project is estimated to be \$216.1 million using the base power value assumption. Note that this valuation has not been reduced by the future cost of new Project operations and enhancement measures that will come out of the relicensing process.

D3.2 NET INVESTMENT

The company's undepreciated net investment in the Project as of March 31, 2003, is \$41.8 million. In addition to the net investment, \$12.6 million has been spent on the current relicensing process through March 31, 2003.

D3.3 ESTIMATE OF SEVERANCE DAMAGES

Based on Section 14 of the Federal Power Act, in the event of Project takeover, PacifiCorp would be entitled to its net investment plus severance damages.

Severance damages are difficult to quantify. There are many factors affecting the fair value of the Project, such as the future cost of replacement power, the cost of replacing old equipment, and future O&M costs, in addition to the environmental and social measures costs associated with relicensing.

Based on the estimate of the fair value above, which does not include new license implementation, estimated severance damages would be \$161.7 million.

D4.0 ANNUAL COSTS OF THE PROJECT

The estimated levelized annual cost of operating the Project over a 30-year new license term is presented in Table D4.0-1.

Table D4.0-1. Estimated annual cost of future Project operations for a 30-year license period that starts in calendar year 2006.

Description (in thousands)	Levelized Annual Cost (in thousands)
CONTINUING OPERATIONS	
Sunk Costs	
Net Investment of \$41,828	
Fixed Cost ¹	\$3,991
Capital	
Planned Investment of \$151,797 ²	
Fixed Cost ¹	\$7,862
O&M	
Operations and Maintenance	\$5,689
Subtotal	\$17,542
IMPLEMENTATION COSTS	
Capital	
Planned Investment of \$49,926 ³	
Fixed Cost ¹	\$3,344
O&M	
Operations and Maintenance of \$55,734 ³	\$1,259
Lost Generation ⁴	\$1,181
Subtotal	\$5,784
TOTAL	\$23,326

¹ Assuming calendar year 2003 as the start year for this analysis, with 3.0 percent inflation, 33-year model period, and 7.5 percent discount rate. Includes components for cost of capital, book depreciation, property taxes, deferred taxes, and income taxes.

² Planned investment in nominal capital dollars over 33 years (includes relicensing process costs and operations capital).

³ See Table D2.0-1 for details.

⁴ See Table D2.0-3 for details.

D5.0 ESTIMATED ANNUAL VALUE OF POWER

The market value of energy is based on incremental power cost estimates provided by internal market clearing price models. These represent the marginal opportunity cost (or market value) of power, using an average of California-Oregon-Border (COB) and Mid-Columbia values. The market value of energy is calculated using the on-peak and off-peak prices times the long-term (30-year) average on-peak and off-peak megawatt-hours (MWh) generated by the proposed Project.

The annual average value of power for the 30-year license period (starting in 2006) is estimated to be \$70 per MWh. The range around this estimate is from a low of \$56 MWh to a high of \$83 MWh. Elements that influence the estimate include actual river flows through the Project and the value of power at any given time.

The Project operates during peak and off-peak demand periods. The average value of on-peak generation, assuming a 30-year average value of COB and Mid-Columbia values (\$74 per MWh) and a future on-peak generation of 447,209 MWh (proposed Project), is \$32.9 million per year. The average value of off-peak generation, assuming a 30-year average value of COB and Mid-Columbia values (\$62 per MWh) and a future off-peak generation of 249,834 MWh (proposed Project), is \$15.6 million per year.

D6.0 ALTERNATIVE POWER SOURCES

PacifiCorp could meet its energy and capacity needs in part by the Project or by alternative sources of power. Reasonable alternative sources of power are discussed below.

As a part of PacifiCorp’s recent Integrated Resource Plan (IRP) analysis, a variety of alternative supply-side and demand-efficiency resource acquisitions were evaluated (see Exhibit H for additional IRP information). For comparative purposes, capital costs of alternative supply-side resources are presented in Table D6.0-1. The replacement cost is specific to the Project and is based on a future Project total generating capacity of 147.2 MW. The annual cost is based on an average annual Project generation of 697,043 MWh. This is the total Project long-term (30-year) average generation, not including generation from the East Side and West Side developments, both of which are proposed for decommissioning. Costs are developed annually by the PacifiCorp Hydro Resources Department. Of this average annual generation, 447,209 MWh per year are estimated to be on-peak generation and 249,834 MWh per year are estimated to be off-peak generation.

Table D6.0-1. Capital cost of alternate supply-side resources.

Source	\$/kW	Project Replacement Cost (\$ millions) ¹	Estimated Annual Cost to Replace Project Power ² (\$ millions)
Natural Gas	697	103	27.7
Cogeneration	917	135	31
Wind	1,067	157	26.7
Coal	1,754	258	21.6

¹ Cost estimates derived from January 2003 IRP Appendix C, Table C.18.

² Cost estimate includes the Project replacement cost.

If PacifiCorp were not able to generate power at the Klamath Hydroelectric Project, replacement power would likely be purchased, at least in the short-term, on the open power market. As previously noted, the Project operates during peak and off-peak demand periods. The average cost of on-peak generation, assuming a 30-year average value of COB and Mid-Columbia values (\$70 per MWh) and a future on-peak generation of 447,209 MWh (proposed Project), is \$32.9 million per year. The average cost of off-peak generation, assuming a 30-year average value of COB and Mid-Columbia values (\$62 per MWh) and a future off-peak generation of 249,834 MWh (proposed Project), is \$15.6 million per year.

The closest generating facility to the Klamath Hydroelectric Project is the Klamath Cogeneration Project, which is located in Klamath Falls, Oregon. The 484-MW Project is owned by the city of Klamath Falls and operated by PPM Energy, an unregulated subsidiary of Scottish Power. Scottish Power also owns PacifiCorp. As an unregulated project, generation is available only on the open market. Currently the Cogeneration Project has long-term contracts in place for its Project generation. Direct power transactions between PPM Energy and PacifiCorp are forbidden by code of conduct.

Absent the Project, PacifiCorp would need to acquire spinning reserve equitable to what is currently provided at Copco No. 1 and No. 2 developments (total of 47 MWs) from other resources (most likely thermal).

D6.1 D6.1 NATURAL GAS-FIRED RESOURCES

The best available technology for using natural gas is a combined-cycle combustion turbine (CCCT). CCCT technology is mature and commercially available. Construction lead times are about 2 years, with another 2 years needed for the necessary permits. Environmental impact is low, with the greatest problem being nitrogen oxide (NO_x) emissions, but control technologies are available.

The advantage of a CCCT is the relatively low capital cost. The main disadvantages of a CCCT are its high heat rate (the CCCT requires more fuel to produce a kilowatt-hour [kWh] of electricity than a coal plant, for example) and uncertainty over the future cost and supply of natural gas. The estimated capital cost for a CCCT unit in Oregon is \$697/kW. To meet the Project production using natural gas-fired resources would cost an estimated \$103 million in capital to build a plant. Annual operations with the cost of capital would be an estimated \$27.7 million per year.

D6.2 COGENERATION

Cogeneration facilities require extraction steam from a factory or industrial plant. The technology is mature and commercially available. Siting a cogeneration plant should be relatively straightforward. The difficulty with this technology is partnering with the industrial user. The estimated capital cost for siting a cogeneration facility in Oregon, Washington, or California is \$917/kW. To meet the Project production using cogeneration facilities would cost roughly \$135 million in capital to build a plant. Annual operations with the cost of capital would be an estimated \$31 million per year.

D6.3 WIND

Wind turbine technology has changed significantly during the past decade and is now entering a third generation of development and testing. Units in the 50- to 500-kW range are a proven technology. Advantages of wind power include size flexibility, minimum environmental impact, no fuel cost, and a short lead time for construction.

Disadvantages of wind power include a low capacity factor, variable energy source (i.e., wind), and potential aesthetic and avian impacts. Wind is also a difficult resource to schedule without disrupting existing resources, and requires additional reserves from other resources to offset its output variations. Thus, wind turbines do not provide predictable capacity (or reserves). Potential environmental consequences of wind power development include adverse impacts to aesthetic resources and wildlife concerns, particularly impacts to raptors resulting from collisions with turbine propellers. Noise and public safety are also potential concerns.

Capital cost for wind resource development is estimated at \$1,067/kW for the Oregon, Washington, and California region. To meet the Project production using wind facilities would cost an estimated \$157 million in capital to build a plant. Annual operations with the cost of capital would be an estimated \$26.7 million per year.

D6.4 COAL

Large coal reserves exist in western North America. While coal-fired generation has higher capital cost and longer lead-time for construction, coal fuel operating costs can be much lower than the operating cost of a natural gas generator. This is especially true if the coal plant can be built near the coal reserve, thus avoiding the need to transport the coal great distances. Further, coal costs are historically less volatile than natural gas costs. Because coal reserves are not located close to large metropolitan areas (i.e., where the large blocks of retail load are located), it becomes necessary to carefully assess the capability of the transmission grid to move the electricity from a new coal-fired generating plant to the load it will be serving.

Integrated Gasification Combined Cycle (IGCC) is a clean coal technology that uses a coal gasification process to produce clean fuel gas. The fuel gas can then be used to fuel a combined-cycle gas turbine. This technology can achieve slightly lower pollutant emission levels and higher efficiencies than a conventional coal-fired plant. However, IGCC is only now beginning to reach full commercialization. There are a half a dozen or so commercial plants in the world to date and most of these are fueled by petroleum residuals. Work is being done to improve their operation on both coal and petroleum residuals and progress in this area is expected. Capital and operating costs are now higher than those of traditional coal-fired plants, but these could come down as larger economies of scale are reached.

PacifiCorp is in need of future generation to meet forecasted customer demands. Consequently, the company currently is reviewing the economics of three possible coal projects in the Utah or Wyoming area. The capital cost of the projects range from \$1,582/kW to \$2,056/kW. The average of the three estimated capital costs for coal options is \$1,754/kW (this number was used to estimate replacement costs and annual operations). Replacement of the Klamath Hydroelectric Project production using coal resources would cost an estimated \$258 million in capital. Annual operations including the cost of capital would be an estimated \$21.6 million per year.

D7.0 CONSEQUENCES OF LICENSE DENIAL

Given the numerous influential variables, it is challenging to quantitatively evaluate the consequences of license denial. Two broad consequences are discussed below: the impact of license denial on PacifiCorp customers, and the impact of license denial on the local environment of the Project site.

D7.1 IMPACT OF LICENSE DENIAL ON PACIFICORP CUSTOMERS

Power from the Project serves PacifiCorp residential and commercial customers in the communities of southern Oregon and northern California. The larger communities include Klamath Falls, Medford, and Ashland in Oregon, and Yreka in California. Without the local generation, PacifiCorp would likely need to purchase power from the closest available generation facility or wheel generation into the southern Oregon and northern California areas via Bonneville Power Administration (BPA) transmission lines, incurring fees for purchasing the power and wheeling.

In the event of license denial, PacifiCorp would be required to complete any transmission and distribution system reinforcement projects in the local area to compensate for the lost energy supply and voltage control provided by the Project. Absent the Klamath Hydroelectric Project, PacifiCorp would need to install two additional capacitors in the Project area, install a transformer at Copco, and complete reconductoring of two 230-kilovolt (kv) lines.

Absent the Project and in review of the above replacement alternatives, PacifiCorp's least cost resource for energy supply to replace the current Project is a coal project similar to those the company is currently reviewing to meet future customer demands (see Section D6.4). However, coal projects do not typically operate as peaking plants and therefore may not meet the peaking capacity now provided by the Project. The economic consequences of replacement alternatives are discussed in Section D6.0.

D7.2 IMPACT OF LICENSE DENIAL ON THE LOCAL ENVIRONMENT

Public use of Project lands has resulted in potential resource conflicts and impacts on cultural, biological, and other resources. PacifiCorp's license application includes a number of proposals to improve current conditions and provide a balanced use of resources in the Project area. If PacifiCorp's license application is denied, or if operations are continued under current conditions (annual) license, none of these measures will be implemented, resulting in potential resource degradation.

There are no indications that other entities intend to compete for the Project license. However, license denial could result in competition for the license. Competition would delay the licensing process, thereby forestalling the proposed Project operational changes and enhancement measures. Finally, denial of the license application could lead to decommissioning to all developments of the Project. While this scenario is unlikely, such an action would have significant cost implications for PacifiCorp customers and investors.

D8.0 SOURCES AND EXTENT OF FINANCING AND ANNUAL REVENUES

PacifiCorp has the resources for financing and sufficient annual revenues to provide for the current capital needs associated with the continued and proposed operation of the Project. If additional financing is necessary, the capital will be financed using the company's traditional sources of debt and common equity.

Annual financial information is provided in the PacifiCorp annual report to shareholders and in FERC Form 1.