Eagle Mountain Pumped Storage Project

Draft License Application

Exhibit D

Project Costs and Financing

Palm Desert, California

Submitted to: Federal Energy Regulatory Commission
Submitted by: Eagle Crest Energy Company

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Project No. 080470

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Tables

1 Estimated Construction Costs

1.1 Summary

The construction costs for the 1300 MW Eagle Mountain Pumped Storage Project are summarized in Table 1-1, categorized by FERC account numbers. The Project cost estimate is $1,325 million, including a provision for the main transmission interconnection line cost.

Table 1-1. Eagle Mountain Pumped Storage Project Preliminary Construction Cost Estimate (2008 Dollars)

Account No.	Description	Amount ($)
330	Land and Water Rights	**$24,200,000**
331	Structures & Improvements	95,806,000
332	Reservoirs, Dams, & Waterways	311,466,000
333	Waterwheels, Turbines, & Generators	216,000,000
334	Accessory Electrical Equipment	96,782,000
335	Miscellaneous Power Plant Equipment	40,390,000
336	Road, Rails, & Bridges	54,322,000
353	Substation & Switch Station Equipment	24,168,000
354/356	Transmission Lines	**90,540,000**
	Subtotal Direct Cost	**$953,674,000**
71	Engineering, Permitting and CM	82,415,000
75	Sales Tax	18,786,000
76	Owners Administration and Legal	12,605,000
77	Interest During Construction	127,700,000
	Subtotal Overhead Costs	**$241,506,000**
	Subtotal Estimated Cost of Project	1,195,180,000
	Contingency and Mobilization	130,119,000
	Subtotal Contingency	**$130,119,000**
	TOTAL COST OF PROJECT	**$1,325,299,000**

1.2 Land and Water Rights

Project lands will be acquired within the Project boundaries. The majority of this will be in the area of the two reservoirs, switchyard, and administration areas; which were a combination of BLM and Kaiser Resources land. An exchange of lands between Kaiser and the Bureau of Land Management (BLM) is pending, awaiting a legal decision from the Ninth Circuit Court of Appeals. The ownership of a small portion of the proposed Project lands is affected. In any case, these lands will either be privately held, or held by the United States and managed by the BLM.

A long-term lease is the preferred vehicle for use of the land. However, no agreement has been reached at this time. Most of the additional lands, primarily for the electrical transmission line and water delivery pipeline, will be on BLM and other private lands. Long-term agreements will be negotiated for the use of these lands when the exact land needs are known.

Water for initial filling of the reservoir dead storage and the active volume (total of 24,200 acre-feet) and for annual makeup supplies will be obtained from wells. The cost for the initial filling groundwater supply (conservatively assumed at $1,000 per acre-foot of supply) is treated as a component of the capital cost. Annual makeup water supply costs are a component of the O&M cost.

The land lease costs will occur on an annual basis and are also included in the annual operating cost, rather than in the construction cost estimate.

1.3 Construction Cost Estimate

The construction cost estimate is based on quantity takeoffs developed from the feasibility-level drawings presented in Exhibit F.

Cost estimates for tunneling and underground work were developed based on researching recently completed projects. Other construction costs are based upon unit costs and allowances derived from experience with similar types of projects in comparable areas and conditions and adjusted to reflect conditions in the project area. Costs were developed to correspond to prices as of early 2008.

1.4 Equipment Cost Estimate

The costs for the major equipment items have been based upon budget price quotations from suppliers of this equipment. Other mechanical and electrical equipment costs were estimated based on experience and information from comparable projects. Costs were developed to correspond to materials and labor prices as of early 2008.

1.5 Engineering and Administration

An allowance of 8 percent and 1 percent of the estimated total direct construction cost has been included to cover the costs of engineering (design engineering and all engineering and management during construction) and owner's administration, respectively.

This allowance will cover the estimated cost of preliminary and final engineering design; preparation of contract construction drawings and contract documents; engineering during construction and construction management; project closeout and preparation of as-built drawings; and the cost associated with the owner's administration of the contracts.

Also included are the expenditures already made for studies, as well as the estimated costs to obtain federal, state, and local permits and licenses; site investigations and surveys; and environmental studies.

1.6 Interest During Construction

The interest during construction was estimated based on expected cash flow requirements during construction. The cash flow was predicted on the basis of an estimated expenditure schedule for similar projects.

1.7 Escalation

Cost escalation from early 2008 to future years will be based on an assumed inflation rate of 3 percent per year.

1.8 Contingencies

A contingency factor of 10 percent was added to all estimated civil costs, and a contingency of 10 percent was applied to major mechanical/electrical equipment cost estimates. This allowance is in addition to an allowance of 10 percent for unlisted items in the quantity takeoffs and lump sum estimates, providing a total effective contingency allowance of 20 percent.

2 Existing Facilities

There are no existing licensed or unlicensed water power structures or facilities that will be used or incorporated into the Project.

3 Takeover Costs

There are no takeover costs.

4 Estimated Average Annual Cost

The estimated annual Project costs are shown in Table 4-1. The costs are based upon several assumptions as discussed below.

Table 4-1. Eagle Mountain Pumped Storage Project Estimated Annual Project Costs (2008 Dollars)

Operating Cost Elements	Amount ($/yr)
Property Tax	8,390,000
Land Leases	2,000,000
Makeup Water and Pumping	2,400,000
Water Treatment	720,000
Property Insurance	4,200,000
Salaries	1,800,000
Home Office Administration	900,000
Supplies and Parts	2,500,000
FERC Fees	1,500,000
TOTAL OPERATING COST	**$24,410,000**

4.1 Cost of Capital

It is expected that the Project will be financed using a combination of debt and equity. The actual structure of the financing will depend on conditions at the time of financing. The annual costs have been calculated based on debt financing for 70 percent of the total Project cost. The debt has been assumed to be for a 20-year period. The equity portion is expected to return a variable amount, averaging about 15 percent over the life of the project.

4.2 Taxes

A local property tax equal to 1.0 percent of the direct Project cost has been assumed. The tax was taken to be constant over the analyzed project life, with any increase in rate offset by project depreciation. State and federal income taxes have been calculated at current tax and depreciation rates, based on the profit shown by the operation of the Project.

4.3 Land and Water Costs

The costs to be paid to Kaiser, BLM, and others for land acquisitions required for the Project, has been assumed to be $2 million per year.

4.4 Insurance

The estimated insurance premium is 0.5 percent of the direct Project cost.

4.5 Operation and Maintenance Costs

The operation and maintenance costs are those associated with the Project operation and upkeep. They include the cost of the direct salaries and administrative support of plant administration, operating and maintenance personnel, and of maintenance equipment and materials and repairs and spare parts.

4.6 Permit Fees

The only known recurring permit fee will be for the FERC license. This fee has historically been variable, depending upon FERCs' costs of administering their duties. It has been assumed to be $1.5 million per year, escalating at the rate of 3 percent per year.

Costs for environmental monitoring per the expected terms of the Project license are estimated to be $500,000 per year, which is part of the administrative expense in Table 4-1.

4.7 Energy Costs

The cost to the Project for purchasing pumping energy will depend upon the terms of agreements with potential suppliers. The primary candidates to supply pumping energy are:

- Wind energy from the existing facilities at San Gorgornio Pass, Tehachapi, and other sites under development or planned to be on-line during the next 10 years.
- Palo Verde Nuclear Generation Station near Phoenix AZ.
- Other off-peak power available on the market from generation sources in California, Arizona, Nevada, and New Mexico.

Wind production costs in the investor-owned utility sector (Table 4-2) are) in the range of $61 per MWh compared to $90 to $100 per MWh for combined cycle plants and well over $200 per MWh for energy produced by gas turbines. Off-peak nuclear energy from Palo Verde trades as low as $30 per MWh, as shown in Table 4-3. The difference in cost between on-peak and off-peak energy costs will provide the financial returns to the Eagle Mountain Project. Weekly generation potential is 58,530 MWh and pumping energy use is estimated to be 73,160 MWh with a cycle efficiency of 80 percent. Applicant expects the cost differential between on-peak and off-peak energy will be significant; however, the absence of a market pricing history in California makes forecasting of energy prices difficult. Applicant will be discussing the project with utility companies and will negotiate contracts for sales and purchase that meet its financial and rate-of-return objectives.

Table 4-2. Levelized 2007 Energy Production Costs in California (CEC 2008)

In-Service Year =2007 (Nominal 2007$)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Conventional Combined Cycle (CC)	500	505.82	102.19	10.22	466.86	94.47	9.45	428.32	86.84	8.68
Conventional CC - Duct Fired	550	512.39	103.52	10.35	472.40	95.59	9.56	432.97	87.78	8.78
Advanced Combined Cycle	800	476.97	96.36	9.64	438.22	88.68	8.87	399.62	81.02	8.10
Conventional Simple Cycle	100	250.43	599.57	59.96	195.59	468.46	46.85	132.84	318.33	31.83
Small Simple Cycle	50	270.36	647.28	64.73	212.08	507.98	50.80	146.70	351.55	35.15
Advanced Simple Cycle	200	295.96	236.12	23.61	253.22	202.10	20.21	201.13	160.60	16.06
Integrated Gasification Combined Cycle (IGCC)	575	566.58	126.51	12.65	476.15	106.32	10.63	361.52	80.72	8.07
Advanced Nuclear	1000	862.70	118.25	11.83	757.78	103.87	10.39	664.78	91.12	9.11
Biomass - AD Dairy	0.25	924.52	143.61	14.36	826.57	128.39	12.84	800.93	109.77	10.98
Biomass - AD Food	2	450.97	70.05	7.00	350.30	54.41	5.44	218.82	33.99	3.40
Biomass Combustion - Fluidized Bed Boiler	25	866.25	118.72	11.87	793.99	108.82	10.88	839.92	115.12	11.51
Biomass Combustion - Stoker Boiler	25	810.99	111.15	11.12	745.45	102.17	10.22	799.74	109.61	10.96
Biomass - IGCC	21.25	849.18	123.66	12.37	768.58	111.92	11.19	744.62	108.46	10.85
Biomass - LFG	2	382.50	56.11	5.61	345.95	50.86	5.09	352.73	52.36	5.24
Biomass - WWTP	0.5	514.65	97.34	9.73	466.63	88.84	8.88	366.54	71.78	7.18
Fuel Cell - Molten Carbonate	2	886.11	114.66	11.47	910.60	117.83	11.78	754.94	97.69	9.77
Fuel Cell - Proton Exchange	0.03	1409.63	182.41	18.24	1281.28	165.80	16.58	1025.67	132.72	13.27
Fuel Cell - Solid Oxide	0.25	955.64	123.66	12.37	868.61	112.40	11.24	695.29	89.97	9.00
Geothermal - Binary	50	477.23	75.85	7.58	396.31	63.53	6.35	394.23	65.55	6.56
Geothermal - Dual Flash	50	453.91	73.66	7.37	379.23	62.07	6.21	384.36	65.26	6.53
Hydro - In Conduit	1	213.72	52.84	5.28	183.96	45.68	4.57	188.71	47.78	4.78
Hydro - Small Scale	10	567.71	138.74	13.87	481.05	118.08	11.81	347.96	87.09	8.71
Ocean Wave (Pilot)	0.75	1239.92	1030.50	103.05	1005.64	837.65	83.76	733.96	617.12	61.71
Solar - Concentrating PV	15	620.48	424.84	42.48	631.79	434.00	43.40	442.11	308.09	30.81
Solar - Parabolic Trough	63.5	497.33	277.30	27.73	504.17	281.37	28.14	355.71	199.31	19.93
Solar - Photovoltaic (Single Axis)	1	1035.07	704.98	70.50	1019.48	695.59	69.56	681.74	468.67	46.89
Solar - Stirling Dish	15	855.55	518.69	51.89	868.93	527.00	52.70	648.77	393.47	39.35
Wind - Class 5	50	245.94	84.24	8.42	196.08	67.16	6.72	179.19	61.38	6.14

Price quotations for off-peak nuclear energy are available daily through the Dow Jones Palo Verde Electricity Index. The expected "all in" cost of off-peak pumping energy from this source is expected to average about $80 per MWh in current dollars, based on the information provided in Table 4-3. However, the lowest off-peak rates are in the $30 to $40 per MWh range providing a greater margin between peak and off-peak energy prices.

Table 4-3. Palo Verde Energy Price Indices

DOWJONES Indexes

Dow Jones U.S. Electricity Price Indexes Weekly Report (Off Peak Hours)

As of 12/30/2005*

Dow Jones Electricity Price Index	Price ($USD/MWH)							Volume(MWH)					
	30 Day Average	Weekly Trend	30 Day High	High Date	30 Day Low	Low Date	30 Day Range	30 Day Average	Weekly Trend	30 Day High	High Date	30 Day Low	Low Date
Palo Verde	$80.56	-	$103.38	12/12/05	$27.87	12/30/05	$75.51	4488	-	8578	12/1/05	800	12/26/05
Four Corners	$80.87	-	$103.25	12/12/05	$28.62	12/30/05	$74.63	1835	+	3300	12/27/05	800	12/29/05
North Path 15 (NP15)	$89.14	-	$110.75	12/12/05	$33.56	12/30/05	$77.19	5441	+	10240	12/29/05	2400	12/3/05
South Path 15 (SP15)	$87.83	-	$111.78	12/12/05	$33.40	12/30/05	$78.38	10765	-	15200	12/19/05	4760	12/8/05
Mid-Columbia	$92.62	-	$124.43	12/19/05	$44.00	12/30/05	$80.43	13973	+	22330	12/30/05	888	12/16/05
California Oregon Border	$94.10	-	$121.09	12/19/05	$41.89	12/30/05	$79.11	2066	-	3898	12/30/05	936	12/13/05
Mead/Marketplace	$82.27	-	$103.78	12/12/05	$29.82	12/30/05	$73.84	2069	-	4800	12/19/05	184	12/26/05

* Includes end of day index pricing

NOTES:

1. All figures provided are based on the Daily Off Peak Firm Trades Data
2. Weekly trends reflect movement up (+) or down (-) in the average from the 30 day average one week ago

Dow Jones Electricity Price Index	Price Correlation with the Dow Jones U.S. Electricity Index		
	1 Year	3 Month	1 Month
Palo Verde	0.58	0.35	0.39
Four Corners	0.57	0.36	0.39
North Path 15 (NP15)	0.55	0.35	0.34
South Path 15 (SP15)	0.56	0.34	0.31
Mid-Columbia	0.47	0.39	0.45
California Oregon Border	0.49	0.35	0.42
Mead/Marketplace	0.59	0.33	0.39

5 Estimated Annual Value of Project Power

Eagle Mountain Project benefits will include: delivery of peaking capacity and energy, spinning reserve, load-following, voltage regulation, system stability enhancements, and black start capability.

The value of the Project to user utilities will depend upon Market Clearing Prices established by the California Independent System Operator (CAISO). The CAISO provides day ahead hourly forecasts of load and market clearing prices. With an energy production capability of 58,530 GWh per week at power levels of up to 1,300 MW at the maximum head and the capacity to use up to 1,200 MW for pump back at minimum head, the Project can tailor its operation to assure reasonable return on investment.

5.1 Capacity Cost of the Project

The levelized annual cost of the Project is estimated to be approximately $101 per kW-year in 2008 dollars (Table 5-1), based on the following assumptions.

(a) Cost of Capital

The project finance terms are the most significant factor in determining annual cost of the project. The key variables influencing capital cost are debt/equity ratio, return on equity, interest rate, and finance period. The values used in the comparison are:

Debt/Equity ratio .... 70/30 percent
Interest Rate .... 6 percent
Finance Period .... 20 years

(b) Plant Life

The return on equity was computed using a life of 50 years for the Project.

(c) Discount Rate

A discount rate of 6 percent was used to compute the net present value (NPV) of the cash flow streams. The internal rate of return, before taxes, for the Equity Investors is projected to be about 15 percent.

(d) Annual Operating Costs

Annual operating costs are assumed for this comparison to be fixed and independent of energy costs. Costs shown in Table 4-1 are estimated to be $23.24 million in 2008.

5.2 Energy Costs of the Project

On-peak energy will be produced by the Project at a levelized cost of $138.33 per kW-yr, as shown in Table 5-1.

Table 5-1. Pumped Storage Project Cost

Overall	
Cycle Efficiency	80%
Total Project Cost ($1000)	$1,325,000,000
Installed Capacity (kW)	1,300,000
Project Life, Years	50
Cost per kW	$1,019
Debt Structure	
Equity	30%
Return on Equity (ROE)	15%
Equity Amount	$397,500,000
Annual Return on Equity (ROE)	$59,625,000
Debt	70%
Debt Amount	$927,500,000
Interest Rate	6%
Terms, Years	20
Annual Debt Service	$80,864,000
Total Debt Service + ROE	
Yr (1-20)	$140,489,000
Yr (21-50)	$59,625,000
Annual Expenses	
O&M	$24,410,000
Levelized O&M	$39,341,000
Cost of Debt Service + ROE ($/kW)	$108.07
Fixed Expense ($kW)	$30.26
Total Levelized Cost ($kW)	**$138.33**

In addition to on-peak energy production, project benefits will include system and voltage regulation, black-start capability, and spinning reserve. The project will be available to adapt wind power to the system load curve on an hourly basis, thereby increasing the value of this renewable energy source to utilities and consumers in California. The combined value of these benefits has not yet been estimated.

5.3 Estimated Cost of Lowest Cost Alternative Source of Power

The value of generation capacity provided by the Eagle Mountain Project will be dependent on the negotiation of contracts for peaking power sales and for buying low-cost off-peak energy for pumping. Contract negotiations will not occur until later stages of project development. However, the value of capacity provided by the project can be approximated by the annual cost of obtaining an equivalent amount on on-peak power from the reasonable, least-cost alternative source.

Functionally, large pumped storage projects are similar to large capacity simple-cycle, natural gas-fired peaking units and large combined cycle units. Data published by the CEC in 2007 is provided in Table D4-1 indicates that the levelized 2007 energy production cost for investor-owned utility combined cycle plants in California is on the order of $95 per MWh and that simple-cycle combustion turbine energy production costs can exceed $500 per MWh.

The Market Monitoring Report of the CAISO (April 2008) indicates that the annualized average fixed cost of a combined cycle generating unit (500 MW) is $132.6 per kW-year. The same cost for a 50 MW combustion turbine is $162.1 per kW-year. Table 5-2 shows the estimated cost for an 800 MW combined-cycle plant developed using common assumptions made by the CAISO in the Market Monitoring Report for 2007 (April 2008). Based on those common assumptions, the cost of generation would be $137.71 per kW-yr, compared to the $138.33 per kW-year for the 1300 MW Eagle Mountain Project.

Table 5-2. Combined Cycle Plant Cost

Overall	
Capacity Factor	60%
Projected Generation kWH	4,204,800,000
Total Project Cost	$680,000,000
Installed Capacity (kW)	800,000
Project Life, Years	50
Cost per kW	$850
Debt Structure	
Equity	30%
Return on Equity (ROE)	15%
Equity Amount	$204,000,000
Annual Return on Equity (ROE)	$30,600,000
Debt	70%
Debt Amount	$476,000,000
Interest Rate	6%
Terms, Years	20
Annual Debt Service	$41,500,000
Total Debt Service + ROE	
Yr (1-20)	$72,100,000
Yr (21-50)	$30,600,000

Annual Expenses	
Fixed O&M @ $8.50/kW-yr	$6,800,000
Variable O&M @ $4.00/MWh	$16,819,000
Cost of Debt Service + ROE ($/kW)	$90.13
Levelized Fixed Expense ($kW)	$13.70
Levelized Variable O&M ($/kW)	$33.88
Total Levelized Cost ($kW)	**$137.71**

6 Alternative Pumped Storage

The Applicant believes the unique aspects of this project make it the most competitive pumped storage project available.

7 Consequence of Denial of Application

If the Application is denied, other generating alternatives, predominately gas- or oil-fired combustion turbines, will be developed to meet the increasing demand for reliable peaking power generation. Consumers will likely increase additional loads shedding to the maximum level tolerable. There are dynamic benefits, which can be provided by the proposed pumped storage facility, that are not available when using conventional combustion turbines and would be foregone. This may result in earlier retirement of existing base load thermal facilities, rather than the extended life that is possible with a pumped storage facility in place.

8 Sources and Extent of Financing and Annual Revenues

8.1 Licensing Phase

The Applicant intends to use internal and private sources to finance costs through the licensing phase of the project. These costs, associated with engineering and environmental studies, public relations, project management, legal services, option payments, and power sales negotiations, are estimated to be approximately $4,700,000, in addition to the $4,000,000 already invested in permitting, licensing, and related activities since 1992.

8.2 Construction Phase

All of the financing for the construction of the Project is proposed to be through bank debt (the "Construction Debt") lent to the Project on a non-recourse basis. Draw downs on the Construction Debt will be based on achieving milestones during construction. The accrued interest during construction will be capitalized and form part of the Term Loan.

8.3 Term Financing

The principal and accrued Interest of the Construction Debt will convert to a Term Loan upon completion of the construction of the Project and commercial operation of the plant. The final draw down of the construction Debt will be sufficient to cover refinancing expenses, working capital, debt service reserve and any other requirements under the Loan Facility. Long term financing will be a combination of senior and subordinated debt and equity.

The repayment schedule for the Term Loan is based on equal installments of interest and principal over a term of approximately 20 years of operation at full output.

8.4 Annual Operating Revenues

The Applicant expects the annual revenue from the Project to be approximately $290 million in the initial year of operation. Revenues from the Project will be adequate to meet annual cost obligations of the project and provide a suitable return on investment. Project revenues will derive from the sale of capacity, ancillary benefits to the electric system, and the sale of on-peak energy.

9 List of Literature

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