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June 22, 2009

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: ***Eagle Crest Energy Company,***
Eagle Mountain Pumped Storage Project, FERC Project No. 13123;
Final Application for License for Major Unconstructed Project

Dear Secretary Bose:

Eagle Crest Energy Company ("ECE") submits herewith its final application for license ("Application") for the Eagle Mountain Pumped Storage Project, FERC Project No. 13123 ("Project").

ECE applied for a preliminary permit on June 1, 2004, and the Federal Energy Regulatory Commission ("FERC" or "Commission") issued the preliminary permit for a period of 36 months from March 1, 2005 in Project No. 12509. On January 10, 2008, ECE filed a Notice of Intent to File an Initial License Application, Pre-Application Document, and a Request to use the Traditional Licensing Process for the Project. On March 3, 2008, ECE filed a second preliminary permit application, and the Commission granted ECE a preliminary permit on August 13, 2008.[1] Pursuant to that preliminary permit, ECE prepared this application as an application for license for a major unconstructed waterpower project under 18 C.F.R. §4.41.

Consistent with 18 C.F.R. §4.41(h), three sets of Exhibit G maps on CD in text form are also being filed this same day with the Commission. As required by 18 C.F.R §4.32(a)(3)(i), ECE has also, on this same day, conveyed copies of Exhibit G by certified letter to "every property owner of record of any interest in the property within the bounds of the project," and "any other Federal, state, municipal or other local government agencies that there is reason to believe would likely be interested in or affected by" ECE's application.

Exhibit E is entitled "Applicant Prepared Environmental Impact Statement" and is intended to serve as the Applicant Prepared Environmental Assessment that the Commission has authorized.

Exhibit F of the enclosed Application is designated and filed separately as Critical Energy Infrastructure Information ("CEII"). The Application contains the following volumes:

Volume 1: Initial Statement and Exhibits A, B, C, and D

[1] *Eagle Crest Energy Company*, 124 FERC ¶ 62,126 (2008).

Volume 2:	Exhibit E, Applicant Prepared Environmental Impact Statement
Volume 3:	Appendices to Exhibit E, Applicant Prepared Environmental Impact Statement
Volume 4:	Privileged information for Exhibit E, Applicant Prepared Environmental Impact Statement
Volume 5:	Exhibit F, Supporting Design Report, CEII
Volume 6:	Exhibit G

Additionally, as required by 18 C.F.R. §§ 4.38(d), 4.32(b)(1), ECE has made the public version of the Application available to the Commission's Regional Office, resource agencies, Indian tribes, other government offices, and consulted members of the public. ECE is also sending two paper copies to the Commission to the Office of Energy Projects, Room 61-02 and OGC-EP Room 101-56.

Pursuant to 18 C.F.R. § 4.32(b)(6), ECE will publish notice of the filing of the Application in a daily or weekly newspaper of general circulation in Riverside County. As required by 18 C.F.R. § 4.32(b)(3),(4), ECE will also make a copy of the public version of the Application available at the ECE offices and the following libraries:

- Indio Library, 200 Civic Center Mall, Indio, CA 92201;
- Palo Verde Valley District Library, 125 W. Chanslor Way, Blythe, CA 92225, and
- Lake Tamarisk Library, P.O. Box 260, 43-880 Tamarisk Drive, Desert Center, CA 92239

ECE looks forward to continuing consultation with interested stakeholders and coordination with FERC as this application for original license is being processed. Should you have any questions regarding this matter, please contact Stephen Lowe, President of ECE or the undersigned.

Respectfully Submitted,

Donald H. Clarke

Donald H. Clarke

Counsel to Eagle Crest Energy Company

Eagle Mountain Pumped Storage Project

License Application

Initial Statement

Application for License for Major Unconstructed Project P-13123

Palm Desert, California

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

Date: June 22, 2009
GEI Project No. 080473

Initial statement

Before the Federal Energy Regulatory Commission: Application for License for Major Unconstructed Project or Major Modified Project

Application for License for Major Unconstructed Project

Information required by 18 C.F.R. § 4.41:

(1) Eagle Crest Energy Company applies to the Federal Energy Regulatory Commission for a license for the Eagle Mountain Pumped Storage water power project FERC Project No. 13123, as described in the attached exhibits.

(2) The location of the proposed project is:

State or territory: California
County: Riverside
Township or nearby town: Desert Center, California
Stream or other body of water: none

(3) The exact name, business address, and telephone number of the applicant are:

Eagle Crest Energy Company
One El Paseo West Building, Suite 204
74199 El Paseo Drive
Palm Desert, CA 92260

(4) The applicant is a domestic corporation and is not claiming preference under section 7(a) of the Federal Power Act. *See* 16 U.S.C. 796.

(5)(i) The statutory or regulatory requirements of the state(s) in which the project would be located and that affect the project as proposed with respect to bed and banks and to the appropriation, diversion, and use of water for power purposes, and with respect to the right to engage in the business of developing, transmitting, and distributing power and in any other business necessary to accomplish the purposes of the license under the Federal Power Act, is: the Water Quality Certification pursuant to Section 401(a) of the Clean Water Act of 1977, 33 U.S.C. 1341(a) (2000).

(ii) The steps which the applicant has taken, or plans to take, to comply with each of the laws cited above are: As required by 18 C.F.R. § 4.34(b)(5)(i), ECE filed a request for a Water Quality Certification to the California State Water Resources Board (SWRCB) on September 26, 2008. On October 15, 2008, the SWRCB determined that the application met the requirements for a complete application and was acceptable for processing.

Every person, citizen, association of citizens, domestic corporation, municipality, or state that has or intends to obtain and will maintain any proprietary right necessary to construct, operate, or maintain the project;

Eagle Crest Energy Company
ATTN: Stephen Lowe
One El Paseo West Building, Suite 204
74-199 El Paseo Drive
Palm Desert, CA 92260

Information Required by 18 C.F.R. §4.32:

For a preliminary permit or a license, identify (providing names and mailing addresses):

Every county in which any part of the project, and any Federal facilities that would be used by the project, would be located;

Riverside County
County Administration Center
4080 Lemon Street
Riverside, California 92501

Every city, town, or similar local political subdivision:

(A) In which any part of the project, and any Federal facilities that would be used by the project, would be located; or

The Project is not within any town or city limits

(B) That has a population of 5,000 or more people and is located within 15 miles of the project dam;

The Project is not within 15 miles of any town of 5,000 or more people

(iii) Every irrigation district, drainage district, or similar special purpose political subdivision:

(A) In which any part of the project, and any Federal facilities that would be used by the project, would be located; or

(B) That owns, operates, maintains, or uses any project facilities or any Federal facilities that would be used by the project;

No irrigation district, drainage district, or similar special purpose district owns, operates, maintains, or uses any Project facility of any federal facility that the Project proposes to use.

(iv) Every other political subdivision in the general area of the project that there is reason to believe would likely be interested in, or affected by, the application; and

Bureau of Land Management
California Desert District
22835 Calle San Juan De Los Lagos
Moreno Valley, CA 92553

Joshua Tree National Park
74485 National Park Drive
Twentynine Palms, CA 92277-3597

(v) All Indian tribes that may be affected by the project.

Morongo Band of Mission Indians
11581 Potrero Road
Banning, CA 92220

Agua Caliente Band of Cahuilla Indians
5401 Dinah Shore Drive
Palm Springs , CA 92264

(3)(i) For a license (other than a license under section 15 of the Federal Power Act) state that the applicant has made, either at the time of or before filing the application, a good faith effort to give notification by certified mail of the filing of the application to:

(A) Every property owner of record of any interest in the property within the bounds of the project, or in the case of the project without a specific boundary, each such owner of property which would underlie or be adjacent to any project works including any impoundments; and

(B) The entities identified in paragraph (a)(2) of this section, as well as any other Federal, state, municipal or other local government agencies that there is reason to believe would likely be interested in or affected by such application.

(ii) Such notification must contain the name, business address, and telephone number of the applicant and a copy of the Exhibit G contained in the application, and must state that a license application is being filed with the Commission.

The applicant has made a good faith effort at the time of filing to notify, by certified mail, the parties listed in section (3)(i)(A) and (3)(i)(B).

(4)(i) As to any facts alleged in the application or other materials filed, be subscribed and verified under oath in the form set forth in paragraph (a) (3)(ii) of this section by the person filing, an officer thereof, or other person having knowledge of the matters sent forth. If the subscription and verification is by anyone other than the person filing or an officer thereof, it shall include a statement of the reasons therefore.

(ii) This (application, etc.) is executed in the:

State of New York
County of New York

By: Stephen Lowe

74-199 El Paseo Drive, Palm Desert, CA 92260

being duly sworn, deposes and says that the contents of this (application, etc.) are true to the best of his knowledge or belief. The undersigned applicant has signed the (application, etc.) this 6TH day of JUNE, 2009.

STEPHEN LOWE

(Applicant(s))

By:

Subscribed and sworn to before me, a [Notary Public, or title of other official authorized by the state to notarize documents, as appropriate] of the State of California this day of 6/9, 2009

/SEAL/ [if any]

GARY PATICK
NOTARY PUBLIC STATE OF NEW YORK
NO. 01PA6181693
QUALIFIED IN ROCKLAND COUNTY
COMMISSION EXPIRES OCT 15, 2010

(Notary Public, or other authorized official)

PUBLIC

Eagle Mountain Pumped Storage Project No. 13123
Final License Application
Volume 1 of 6

Exhibit A
Project Description

Palm Desert, California

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

Date: June 22, 2009
GEI Project No. 080473

Table of Contents

Figure

This license application is organized into six volumes, as described below:

Volume 1	Initial Statement and Exhibits A, B, C, and D	Public
Volume 2	Exhibit E, Applicant Prepared Environmental Impact Statement	Public
Volume 3	Appendices to Exhibit E, Applicant Prepared Environmental Impact Statement	Public
Volume 4	Privileged information for Exhibit E, Applicant Prepared Environmental Impact Statement	Privileged, not for release
Volume 5	Exhibit F, Supporting Design Report	Critical Energy Infrastructure Information (CEII), not for release
Volume 6	Exhibit G	Public

Executive Summary

The Eagle Crest Energy Company (ECE) proposes to develop the Eagle Mountain Pumped Storage Project near the town of Eagle Mountain in Riverside County, California. The proposed project is a hydroelectric pumped storage project that will provide system peaking capacity and transmission system regulating benefits to regional electric utilities.

The Project will use off-peak energy to pump water from the lower reservoir to the upper reservoir during periods of low electrical demand and generate valuable peak energy by passing the water from the upper to the lower reservoir through the generating units during periods of high electrical demand. The low demand periods are expected to be during weekday nights and throughout the weekend, and the high demand periods are expected to be in the daytime during weekdays. The Project will provide an economical supply of peaking capacity, as well as load following, system regulation through spinning reserve, and immediately available standby generating capacity.

According to the California Energy Commission (CEC), the California Independent System Operator (CAISO), and the major electric utilities in the State, large scale energy storage is essential for successful integration of wind and solar renewable power generation and maintaining reliable transmission grid operations (CEC Workshop on Energy Storage Technologies, April 2, 2009). The CEC's recognition of the need for storage as an essential element in attaining the State's Renewable Portfolio Standard (RPS) goals of 2020 is very important, as is the recognition that storage is not generation, transmission, or distribution, but rather a special and distinct function required for reliable grid operations and power flow management. Specific transmission operations – known collectively as "ancillary services" – include spinning reserves, voltage regulation, load following, black start, and possibly protection against over-generation. This recognition is consistent with the unanimous consensus among the transmission system operator and the major utilities that adding significant storage capacity is the only means to successfully integrate wind and solar power to meet the State's 33 percent renewable power generation goals and maintain reliable grid operations. As a related consequence, large scale energy storage will also be essential to meeting the State's goals for reductions in greenhouse gases (GHG) by displacing existing natural gas peak power generation.[1]

Pumped storage hydroelectric generation is recognized as one of only two feasible "bulk storage" technologies (Compressed Air Energy Storage – CAES – being the other), and the only one to have been proven on large scales. Other emerging technologies (mainly batteries and flywheels) are much smaller in scale and have significant research and development timelines, but are

[1] Workshop participants and CEC staff indicated that California will need an estimated minimum of 4,000 MW of energy storage by 2020.

expected to play a role in small scale applications and management of electricity distribution systems.

The Eagle Mountain Pumped Storage Project's location in the southern California transmission grid is complimentary to support existing wind power generation in the San Gorgonio Pass, Tehachapi, and the Salton Sea area, and thousands of megawatts of proposed wind and solar power generation in the Mohave Desert, Chuckwalla Basin and Palo Verde Valley.[2] Storage is essential to integrating a high level of wind and solar renewable energy sources and to reliable operation of the transmission grid, and this storage project will be operated to integrate these renewable energy sources.

The Project will have 1,300 megawatts (MW) of generating capacity, using reversible pump-turbine units, with four units of 325 MW each. The project reservoirs will be formed by filling existing mining pits with water. The mining pits are currently empty and have been unused for decades. There is an elevation difference between the reservoirs that will provide an average net generating head of 1410 feet. The proposed energy storage volume will permit operation of the Project at full capacity for 9 to 10 hours each weekday, with 12 hours of pumping each weekday night and additional pumping during the weekend to fully recharge the upper reservoir. The amount of active storage in the upper reservoir will be 17,700 acre-feet, providing 18.5 hours of energy storage at the maximum generating discharge. Water stored in the upper reservoir will provide approximately 22,200 megawatt hours (MWh) of on-peak generation. Tunnels and penstocks will connect the two reservoirs to convey the water back and forth, and the generating / pumping equipment will be located in an underground powerhouse.

A double circuit 500 kilovolts (kV) transmission line will convey power to and from the Project to a new Interconnection Collector Substation to be constructed near Desert Center, California. Other transmission connection upgrades may be necessary as determined by the CAISO. System improvements, accessible power markets, and ancillary services functions will be investigated during upcoming system analysis performed by the CAISO in coordination with Southern California Edison.

The Project will be located entirely off-stream in that neither the upper nor lower reservoirs intercept a surface water course. The reservoirs will receive only incidental runoff from surrounding slopes in a very limited watershed area within the historically mined lands. Water to initially fill the reservoirs and annual make-up water will be pumped from groundwater within the adjacent Chuckwalla Valley. ECE is acquiring property to develop the ground water supplies required for the initial fill and for annual makeup water for evaporation and seepage losses from the two reservoirs.

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[2] Several thousand megawatts of solar power are proposed for development in the nearby Chuckwalla Basin and Palo Verde Valley that may offer opportunities for complimentary transmission operations.

Site access is currently planned to be provided by Kaiser Road, a public County road, to the entrance to property owned by Kaiser Ventures Inc.[3]

Plans are currently being developed by Mine Reclamation Corporation (MRC), a division of Kaiser Ventures Inc., to use portions of the inactive mine site for a major landfill that would serve Southern California urban areas. The pumped storage project has been formulated with the assumption that the landfill will exist as currently proposed by the landfill developers. As detailed in Exhibit E of this License Application, the landfill and pumped storage are compatible in that neither would materially interfere with the construction or operation of the other.

The characteristics and description of the major features of the Project are described in this Exhibit A and summarized in Table 1-1.

The Eagle Mountain Project, in addition to firming the energy from the growing portfolio of wind energy in the nearby area, has other environmental benefits and low potential for environmental impacts. Thus, it will be contributing to the "green" value of such renewable energy sources. Because the project is located on a large mine site with existing pits, those pits will be economical to convert into large upper and lower reservoirs. Typically, such reservoirs might dam a river and affect fisheries and water quality. Such projects also might have much larger terrestrial impacts due to construction of larger dams to store large amounts of water thus creating impacts at the "borrow areas" as well as at the footprint of the project itself. Since the site is already heavily disturbed and pits for the reservoirs already present, this will be among the lowest impact projects of its kind. In addition, since the project is quite remote from population centers, there will be little potential for impacts to people or conflicts with multiple land uses.

[3] Kaiser Ventures LLC merged with Kaiser Ventures, Inc. in November 2001. Kaiser Ventures has been involved in the landfill project by means of its subsidiaries, Mine Reclamation LLC and Kaiser Eagle Mountain, Inc. (now Kaiser Eagle Mountain, LLC). Kaiser Eagle Mountain, Inc. is the entity that completed the land exchange with Bureau of Land Management (BLM) that has been subsequently appealed to the Ninth Circuit Court of Appeals.

1 Physical Composition of the Project

The layout and major dimensions of features of the Eagle Mountain Pumped Storage Project are displayed in Figure 1-1 and described by the drawings included in **Exhibit F and published under separate cover because they are classified as Critical Energy Infrastructure Information (CEII).** These features include the upper dams and reservoir, lower reservoir, inlet/outlet (I/O) structures, water conveyance tunnels, vertical shaft, surge control facilities, underground powerhouse, access and cable tunnels, switchyard, transmission line, and water supply facilities. A summary of these significant project components is provided in Table 1-1.

Table 1-1: Significant Data for Eagle Mountain Pumped Storage Project

Project Feature	Feature Data
Hydroelectric Plant	
Total Rated Capacity	1,300 MW
Number of Units	4 (Reversible)
Unit Rated Capacity	325 MW
Maximum Plant Discharge	11,600 cfs
Pump/Turbine and Motor/Generator Unit Data	
Rated Head	1410 feet
Rated Turbine Output	319 MW
Maximum Turbine Flow	2,900 cfs
Operating Speed	333.3 rpm
Generator Rating	347 MVA
Low Pressure Upper Tunnel	
Diameter	29 feet
Length	4,000 feet
Shaft	
Diameter	33 feet
Length	1,348 feet
High Pressure Lower Tunnel	
Diameter	29 feet
Length	1560 feet
Tailrace Tunnel	
Diameter	33 feet
Length	6,835 feet
Powerhouse Cavern	
Height	130 feet
Length	360 feet
Width	72 feet

Project Feature	Feature Data
Upper Reservoir	
Dam Type	Roller-compacted concrete (RCC)
Volumes	
Total Reservoir Capacity	20,000 acre-feet
Inactive Storage	2,300 acre-feet
Active Storage	17,700 acre-feet
Operating Levels	
Minimum Operating Level	El. 2343
Maximum Operating Level	El. 2485
Water Surface Areas	
Water Surface Area at El. 2,343 feet	48 acres
Water Surface Area at El. 2,485 feet	191 acres
Dimensions of Dams	(URD-2 and URD-1)
Structural Heights	60 feet and 120 feet
Top Widths	20 feet (both dams)
Crest Lengths	1100 to 1300 feet
Crest Elevation	El. 2490 (both dams)
Lower Reservoir	
Dam Type	None
Volumes	
Total Reservoir Capacity	21,900 acre-feet
Inactive Storage	4,200 acre-feet
Active Storage	17,700 acre-feet
Operating Levels	
Minimum Operating Level	El. 925
Maximum Operating Level	El. 1092
Water Surface Areas	
Water Surface Area at El. 925 feet	63 acres
Water Surface Area at El. 1,092 feet	163 acres
Water Supply Pipeline (Including Well Piping)	
Diameter	12 inch
Length	1.3 miles
Diameter	18 inch
Length	3.3 miles
Diameter	24 inch
Length	10.7 miles
Power Transmission Line	
One Double Circuit	500 kV
Length	13.5 miles

1.1 Upper Reservoir

The Central Pit of the Eagle Mountain Mine will be utilized for the Upper Reservoir. The bottom of the pit is at El. 2,230, and the existing low point of the rim is at El. 2,380. The active storage portion of the reservoir is planned between El. 2,343 feet and El. 2,485. The volume between these elevations is 17,700 acre-feet, and the respective surface areas are 48 and 191 acres. The existing low points of the pit rim are at El. 2,380 and El. 2,440. To obtain the required volume of storage it will be necessary to construct two dams along the perimeter of the pit. These dams are identified as URD-1 and URD-2.

The dams are planned to be constructed of roller-compacted concrete (RCC) with an upstream membrane liner and foundation grouting to control seepage. The crest elevation of the dams will be El. 2,490 and the crest width will be 20 feet. The south embankment (URD-1) will have a height of 120 feet and a crest length of 1,300 feet. The west embankment (URD-2) will have a height of 60 feet and a crest length of 1,100 feet. Dam construction will require preparation of the foundation to remove any waste materials from mining, overburden, and weathered rock to expose firm, un-weathered bedrock prior to placement of dental and leveling concrete and the RCC lifts. For project planning and based on available information, we assumed an average of 10 feet of excavation would be required for the foundation. Normal freeboard was assumed to be 5 feet between the normal high-water level and the dam crest. As described in Section 1.3, a spillway will protect the upper reservoir in the very unlikely event of overtopping during an over-pumping event and to handle surface runoff from the very small surrounding watershed area into the reservoir.

Drilling and testing of the foundation and dam and testing of RCC aggregate sources will be initial design tasks performed when access rights to the site are obtained. A study plan has been prepared describing the geotechnical evaluations that will be undertaken when site access becomes available. That study plan is found in Exhibit E, Section 12.6.

The downstream face of the dam was assumed to be 0.8 (H) to 1 (V), with no chimney section. This section is conservative based on experience and judgment with dam design in southern California. Many concrete gravity dams have steeper downstream faces and chimney sections in areas with greater seismic loads. Similar to the recently completed Olivenhain Dam in San Diego County, the upstream face of the dam would be formed with grout-enriched RCC and later covered with a membrane liner to control seepage. Seepage control is in the economic and environmental interest of the project and will also protect the down-slope groundwater aquifer. The preliminary design concept includes a drainage gallery to accept flows from foundation drains provided to control uplift. The foundation would most likely require grouting for seepage control, and we assumed a double row grout curtain with depths equal to the height of the dam along the entire dam axis. Final design of the RCC will follow criteria established for RCC gravity dam design and comply with all requirements of the Federal Energy Regulatory Commission (FERC) and the California Division of Safety of Dams (DSOD).

Control of seepage from the upper reservoir will be important to minimize water losses and to limit the amount of reservoir water that could potentially reach the aquifer below the nearby Colorado River Aqueduct. Existing geologic data suggest that there is sufficient permeability of the fractured rock that underlies the Central Pit to produce seepage from the upper reservoir. The final design will include seepage control measures in the upper reservoir utilizing localized grouting and shotcrete placement and potentially other methods. During final design, geologic mapping will be performed and seepage control methods will be defined with greater certainty. Further discussion of seepage potentials and seepage control measures are provided in the Exhibit E Section 12.4 and Exhibit F Preliminary Supporting Design Report (PSDR). Exhibit E Section 12.8 also details a seepage mitigation program consisting of monitoring and pump-back recovery wells.

An excavated approach channel to the I/O structure at the east end of the reservoir will have a bottom width of 100 feet and side slopes of 0.5 horizontal to 1.0 vertical. The approach channel will have an invert at El. 2,287 and slope down to the tunnel invert at El. 2,282. The I/O structure will have a trashrack with a gross area that is about 84 feet wide by 60 feet high. Three piers within the flared portion of the I/O structure will assist in spreading flow uniformly over the trashrack area in the pumping mode. The upper reservoir I/O structure will be equipped with a fixed-wheel gate for emergency closure and tunnel inspection. As indicated on the drawings in Exhibit F, the I/O structure in the upper reservoir will be a reinforced concrete gravity structure founded on competent bedrock.

The entire upper reservoir area will be fenced and gated to prevent the entry of unauthorized personnel and the public both during and after construction. Fencing for wildlife exclusion purposes is also proposed as described in Exhibit E.

Access to the dams and reservoir will be by improved roads planned as part of the landfill operation (but that may be built initially for this project) and by new 30-foot-wide gravel roads constructed from the landfill road to the features.

1.2 Lower Reservoir

The East Pit of the Eagle Mountain Mine will form the lower reservoir for the project. The bottom of the pit is at El. 740, and the existing low point of the rim is at El. 1,100. The active portion of the reservoir is planned between El. 925 and El. 1,092. The volume between these elevations is 17,700 acre-feet, and the respective surface areas are 63 and 163 acres. The entire active reservoir volume can be contained within the pit; therefore, construction of dams will not be necessary to create the lower reservoir.

Seepage potential from the lower reservoir is expected to be more significant than from the upper reservoir because the east end of the mine pit is in alluvial material. Studies conducted by Kaiser and MRC (1991) [in EMEC, 1994] indicated that the horizontal permeability of these alluvial deposits is relatively high (EMEC, 1994). Multiple seepage control measures may be required.

Detailed geologic mapping will be performed once site access is obtained in order to identify areas where provision of a seepage blanket will be effective. This blanket will be comprised of fine tailings from the mining operation placed on the bottom and flat areas of the reservoir. Depending upon the impermeability of this material, it may also be necessary to top it with a layer of the finer tailings from the nearby fine tailings ponds or to mix the tailings with imported clay materials (bentonite) to further reduce permeability. In addition to this general blanketing at the eastern end of the pit, some localized blanketing may be required at other locations in the lower reservoir. Also, grouting and shotcrete placement may be required following identification of high permeability zones. Other seepage control options that may be explored during design include interior slope modifications and placement of RCC or soil cement over the areas with greatest seepage potentials.

To support final engineering design, geologic mapping will be performed and seepage control methods will be defined with greater certainty for the lower reservoir. In addition, as discussed in Section 3.3.3 of Exhibit E of this License Application, a seepage mitigation program consisting of monitoring and pump-back recovery wells will also be employed to ensure that seepage does not impact down-gradient groundwater or the Colorado River Aqueduct.

The I/O structure at the lower reservoir will be located near the west end of the reservoir and will be constructed in the sloping bank of the pit. The I/O structure approach channel will have an invert at El. 862 and slope down to the tunnel invert at El. 857. The structure will have a trashrack with a gross area that is about 84 feet wide by 60 feet high. A fixed-wheel gate will provide for emergency closure and for tailrace tunnel inspection. As indicated on the drawings in Exhibit F, the I/O structure in the lower reservoir will be very similar to the one planned for the upper reservoir and will be a reinforced concrete gravity structure founded on competent bedrock. The entire lower reservoir area will be fenced and gated to prevent the entry of unauthorized personnel and the public during construction and operation. Fencing for wildlife exclusion purposes is also proposed as described in Exhibit E.

Access to the reservoir will be by improved roads planned as part of the landfill operation (that may be initially developed for this project) and by new 30-foot-wide gravel roads constructed from the landfill road to the features.

1.3 Spillways

No spillway will be needed for the Lower Reservoir because there will be no dam, and because the reservoir can contain either the entire Probable Maximum Flood (PMF) inflow or the total volume of circulated water and dead storage water down to the invert of the I/O structure from the other reservoir without overflowing.

A spillway will be provided for the Upper Reservoir at URD-1. This spillway will handle any excess water that cannot be stored during the inflow design flood, which will be the PMF, and will also provide for protection of the dam if over-pumping should occur. Because the reservoirs are both off-channel and the reservoir volume used for generation is fixed, the potential for an over-pumping event causing over-topping of the upper reservoir dam is extremely small. Also, the RCC dams of the upper reservoir could be overtopped without causing dam failure. An overflow spillway with a crest length of 100 feet will be provided to pass approximately 3,000 cubic feet per second (cfs) with a water surface at El. 2489. This capacity will handle routing of the PMF and also provides capacity somewhat greater than the pumping capacity of one turbine unit. The storage capacity between El. 2485 and the dam crest would provide two hours of storage for the full pumping discharge.

The spillway will be integral with URD-1 and consist of a formed ogee crest and a stepped chute for energy dissipation. A terminal structure at the end of the chute will dissipate remaining energy not lost on the spillway chute steps. Water from the spillway will reach the lower reservoir via Eagle Creek channel, which will be routed to the lower reservoir. Level sensors and alarms will be installed to warn of potential over-pumping.

1.4 Water Conductors

A system of water conductor tunnels will convey water from the Upper Reservoir to the underground powerhouse and from the powerhouse to the lower reservoir in the generating mode. Flow will be reversed in the pumping mode of operation. From the upper reservoir I/O structure, an upper ("low head") pressure tunnel will extend 3,963 feet to a 1,348-foot-deep vertical shaft connecting the upper tunnel to the lower ("high head") tunnel; the lower pressure tunnel will extend 1,563 feet to a 35-foot-long penstock manifold; and four penstocks will extend approximately 500 feet to the turbine inlet valves at the powerhouse. From the powerhouse, the four individual tailrace tunnels will extend approximately 350 feet through a tailrace manifold, and the main tailrace tunnel will extend 6,635 feet from the manifold to the Lower Reservoir I/O structure.

The upper pressure tunnel and the main tailrace tunnel will be excavated by tunnel boring machine (TBM). The finished tunnel diameter for the upper pressure tunnel will be 29 feet. For planning, we have assumed that the upper tunnel will be concrete lined; however, depending on rock quality, the upper tunnel may be not be lined throughout its entire length. A concrete-lined manifold will connect the lower pressure tunnel to the penstocks. The four penstocks will be completed to a finished diameter of 15 feet and will be steel lined. The four tailrace tunnels upstream of the concrete-lined tailrace manifold will be completed to a finished diameter of 16 feet. These tunnels will be concrete lined. The main tailrace tunnel from the manifold to the Lower Reservoir will be completed by TBM or drill and blast methods. This tunnel will be shotcrete lined to a finished diameter of 33 feet.

The penstock lining steel is designed to be ASTM A537, Class 1, with a yield strength of 50,000 pounds per square inch (psi) and a design stress with normal pressure rise of 37,500 psi. The resulting thickness will be 1.625 inches. External pressure on the lining will be controlled with drains extending from a grout curtain at the end of the steel lining farthest from the powerhouse to the powerhouse cavern, with provisions for reaming out deposits in the future. Steel linings will be backfilled with concrete and low pressure grouted.

The penstock and tailrace manifolds will be concrete lined, as will portions of the individual penstocks and tailrace tunnels that are not steel lined. Just downstream of the tailrace manifold there will be a rock trap to collect rock spalls and prevent them from reaching the pump-turbines from downstream direction. Access to the rock traps for cleaning will be through a bulkhead door. The door is in a plugged section of a construction access tunnel.

Surge control facilities will be provided upstream and downstream from the powerhouse. The upstream surge chamber will be an enlargement of the vertical pressure shaft to a diameter of 90 feet. The surge chamber portion of the shaft will extend from El. 2,270 to the ground surface at El. 2,515 feet. The surge chamber will have a restricted orifice entrance to balance the transient pressure rise. The tailrace surge chamber will consist of two horizontal tunnels, each 550 feet long, connected with a shaft, which continues to a connection with the main tailrace tunnel immediately above a rock trap. The tunnels will be 26 feet wide by 26 feet high and horseshoe shape, and the shaft will be 12 feet in diameter. Both the tunnels and the shaft will be concrete lined. Air admission and release to and from the tailrace surge chamber will be through an air shaft extending to the ground surface outside of the landfill boundary. The tailrace surge chamber will also have a restricted orifice below the lower tunnel.

1.5 Underground Powerhouse

The powerhouse will be located in an underground chamber approximately 6,300 feet from the upper reservoir and 7,200 feet from the lower reservoir. The pump/turbine centerline will be at elevation 770 feet. The cavern will be sized to accommodate four 325 MW units. The cavern will be approximately 72 feet wide, 150 feet high and 360 feet long. A separate transformer gallery a short distance downstream from the powerhouse will be approximately 46 feet wide, 40 feet high, and 400 feet long.

The powerhouse substructure and superstructure will be constructed of cast-in-place reinforced concrete. The pump/turbine spiral cases will be permanently embedded in second-stage concrete. Floors will be supported with concrete walls and columns. Walls will also serve to partition areas. Substructure and superstructure configurations will be dictated by final mechanical and electrical equipment arrangements. The transformer chamber, located downstream from the powerhouse chamber, will be located above the tailrace manifold and connected to the powerhouse by the main access tunnel.

Suspended corrugated metal panels supported from steel trusses will extend the length of the machine hall. The false ceiling will protect against possible water seepage and rockfalls. A drain system will be provided around the powerhouse walls to carry collected seepage to the powerhouse drainage sump pit.

An unloading and erection bay will be located at one end of the unit bays, accessed by the main access tunnel. Space for the control room, workshop and office and personnel-related space will be located in the two upper levels at the end of the cavern adjacent to the erection bay.

The major equipment will be handled by two 300-ton bridge cranes that will run on rails the length of the unit and erection bays. Floor hatches will be provided for moving other equipment between floors. The turbine inlet valves will be handled with the main crane. The transformers will be moved into place on transfer rails. The draft tube gates will be installed and maintained using a dedicated under-hung bridge crane.

Personnel movement within the underground chambers will be by elevators and stairs, the locations and dimensions of which will be decided during final project planning and design.

The locations of the main and auxiliary equipment in the powerhouse are shown in the drawings in Exhibit F.

1.6 Access Tunnel

Access to the underground powerhouse will be through the main access tunnel. This will be a vehicular tunnel that is 28 feet wide and 28 feet high. The tunnel portal will be southeast of the powerhouse. The invert elevation at the portal will be approximately 1,100 feet, and it will enter the powerhouse at elevation 808 feet. The length will be approximately 6,625 feet and the slope 4.4 percent. The tunnel will be shotcrete lined and will have a concrete roadway on the invert. Rockbolts or other rock support will be used as required where areas of weak or broken rock are encountered. The top portion of the tunnel will carry a powerhouse and tunnel ventilation duct.

1.7 Other Structures

A switchyard (Project Connection Point) will be located about 4,500 feet south of the powerhouse, outside the boundaries of the proposed future landfill. It will be located on a level site at approximate elevation 1,430 feet. It will be 500 feet by 1,100 feet, with a gravel surface. This area will be surrounded by a security fence. A security and maintenance lighting system will be provided. It will also be designed to protect against bird electrocution.

This switchyard will be connected to the underground powerhouse via cables from the transformer gallery to the access tunnel portal and overhead as overhead lines from the portal to the switchyard. The high-voltage cables will run inside the length of the access tunnel to a shaft located near the lower reservoir inlet structure. Here the transmission lines will come up through the shaft to the ground surface. At the ground surface they will follow the upper edge of the lower reservoir as overhead transmission lines to the southwest, connecting to the switchyard. The overhead lines will terminate in the switchyard and be connected through protective breakers and associated switches to one double circuit 500 kV transmission line. The switchyard will contain all necessary disconnect switches, protective equipment and metering equipment.

A fenced area near the access road to the access tunnel portal will contain a storage warehouse building and an administration building.

While the primary powerhouse access will be through the main access tunnel described above, safety requires a second means of personnel egress from the underground facilities. This normally would be an elevator shaft from the ground surface directly above the powerhouse. However, to accommodate the landfill development, this access shaft will be provided approximately 800 feet north and west of the powerhouse with connection of this shaft to the powerhouse by a short, curved tunnel section. The elevator shaft would be approximately 1100 feet deep and 9 feet in diameter extending to the erection bay floor at El. 808. The tunnel section would be approximately 800 feet long and be a 14-foot horseshoe section similar in design to the main access tunnel except smaller in size.

Access to Eagle Mountain Pumped Storage Project facilities will be in part by the roads that were developed for the mining operations. The primary access road will be the existing Kaiser Road. No new road crossings of the Colorado River Aqueduct will be required. In addition to these roads, new access roads will be constructed to provide access to the upper reservoir dams, both I/O structures, the upper surge chamber and the access tunnel portal, and storage/administration area. The road to the access tunnel portal and the storage/administration will be paved with asphaltic concrete; the other roads will be gravel surfaced.

1.8 Water Supply and Conveyance Pipelines

Water to initially fill the reservoirs and annual make-up water will be pumped from groundwater within the Chuckwalla Valley. Three wells will be utilized to provide initial reservoir fill. Water to replace losses due to seepage and evaporation will also be obtained from groundwater. The new wells will be installed adjacent to a central collection pipeline corridor.

The locations of the three groundwater wells are approximately 11 miles southeast of the project area. ECE has developed estimates of pipe material, pipe sizes, pumping head, pumping costs, and construction costs for potential alternative water supply systems. The preferred groundwater supply well system will consist of the following main components:

- Three 2,000 gallons per minute (gpm), 1,000 horsepower (HP) vertical turbine pumps;
- 1.3 miles of 12-inch-diameter well field collection pipe;
- 3.3 miles of 18-inch-diameter well field collection pipe; and
- 10.7 miles of 24-inch-diameter conveyance pipe.

All three wells will be needed for the initial fill. One well will have adequate capacity for annual make-up water production to replenish water lost to evaporation and seepage. A second well will be maintained as a backup water supply for the makeup water needs.

1.9 Water Treatment Facilities

In order to maintain water quality (primarily salinity) within the reservoirs, a water treatment system will be required to remove certain constituents from the reservoir water supply. The water treatment facility would treat the make-up water supply to the reservoir system, which will come from ground water wells in the Chuckwalla Basin.

The design of the treatment facility comprises several pretreatment steps to ensure that the stored surface water is suitable for treatment by the reverse osmosis (RO) process, which will provide for the bulk of the salt concentration. Treated water will be returned to the lower reservoir while the concentrated brine from the RO process will be directed to evaporation ponds. The treatment goal will be to maintain water quality levels in the reservoirs comparable to the existing groundwater quality.

Water quality data from wells in the Chuckwalla Aquifer were used to make assumptions about the source water quality. While the total replacement water need is estimated to be 2,360 acre-feet per year for evaporation and seepage, only the evaporation component (1,760 acre-feet per year) enters into the estimation of water treatment requirements. The RO treatment system would remove water from the upper reservoir at a rate of 2,055 gpm and remove sufficient total dissolved solids (TDS) to maintain the in-reservoir TDS at the same average concentration of the source water, approximately 660 parts per million (ppm), based on available data for the existing wells in the Chuckwalla Basin.

Based on information from existing facilities, brackish water desalination uses approximately 1,300 – 3,250 kilowatt hour (kWh) of energy per acre-foot, depending largely on the source water quality, plant capacity, and technology used. Annual energy needs for RO treatment at Eagle Mountain are expected to be about 3.7 GWh, assuming water would be pumped through the RO membranes. However, the actual energy consumption for RO at Eagle Mountain will be less because of the available pressure head of over 1,000 feet between the upper reservoir and the RO treatment facility. The specific treatment process steps are: 1) dissolved air floatation, 2) automatic strainers, 3) microfiltration, 4) RO, and 5) brine concentration. Assuming desalinization requires an average of 2,000 kWh of energy per acre-foot, annual energy consumption desalinization is 0.13 percent of total energy stored annually.

A dissolved air floatation (DAF) unit is provided as the first step in the desalting process. DAF is a clarification process, provided to treat water from the reservoir for turbidity and suspended solids control. The DAF is particularly efficient in removing algae, which could be a potential problem in the reservoir system. The DAF works by passing a portion of the feed stream through an air saturator where it becomes saturated with air at high pressure. This stream is then mixed with the balance of the feed water in the floatation portion of the tank. The release of pressure generates bubbles which rise to the surface carrying with them suspended solids including algae. The DAF process can be improved by the addition of coagulants, commonly iron salts or polymers.

The two automatic backwash screens provide protection for the microfiltration (MF) system, which removes fine particles. The filtered water is pumped through the RO membrane system.

The microfiltration system will likely consist of two 50 percent capacity treatment trains in parallel. The MF systems consist of hollow fiber membranes contained in an individual unit with multiple units connected in parallel to provide the required membrane area. Filtered water leaves the MF units and is stored in a filtered water tank located just outside of the process building.

The operation of the MF systems involves the following major process steps.

1. Normal filtration where the feed water passes from outside to inside the membrane fibers. Filtered water is collected from each module in the unit and flows into the filtered water tank.

2. Backwash or reverse filtration occurs on a predetermined cycle typically every 15 to 30 minutes. During backwash, normal filtration for one unit or part of the unit is interrupted and filtered water is passed from the filtrate side of the membrane to the outside dislodging suspended solids which have collected during the filtration cycle. In addition, during the backwash cycle air is introduced to the outside of the fiber bundle to scour the fibers improving backwash efficiency. After backwash which typically takes 2 to 3 minutes the unit returns to normal filtration.

3. Maintenance Wash. On a daily basis the membranes are exposed to a hypochlorite solution to minimize biological growth and otherwise reduce membrane fouling. A waste stream of hypochlorite solutions is therefore produced daily. It is anticipated that this stream can be returned to the reservoirs.

4. Chemical Cleaning. On an infrequent basis (typically 45 to 60 days) the membranes are cleaned with more aggressive chemical cleaners including caustic solutions, detergents and dilute acids. These cleaning solutions are typically neutralized and disposed of to local sewer or hauled to an approved disposal site. Disposal of the neutralized cleaning solutions as an on-site septic system would be acceptable.

The individual membrane modules are connected together in manifold fashion forming individual MF trains. The membranes are configured vertically in this instance. Two parallel membrane trains will be located inside the treatment building. The auxiliary equipment including feed pumps, backwash pumps and membrane cleaning equipment will also be installed inside the membrane building. Filtered water from the filtered water tank is pumped through a set of cartridge filters to the RO feed pumps where it is further pressurized to provide feed to the RO vessels.

The RO concentrate, containing the bulk of the salts removed from the reservoir system, would be processed to dry salt in an evaporation pond or ponds. The evaporation rate was estimated based on the following equation:

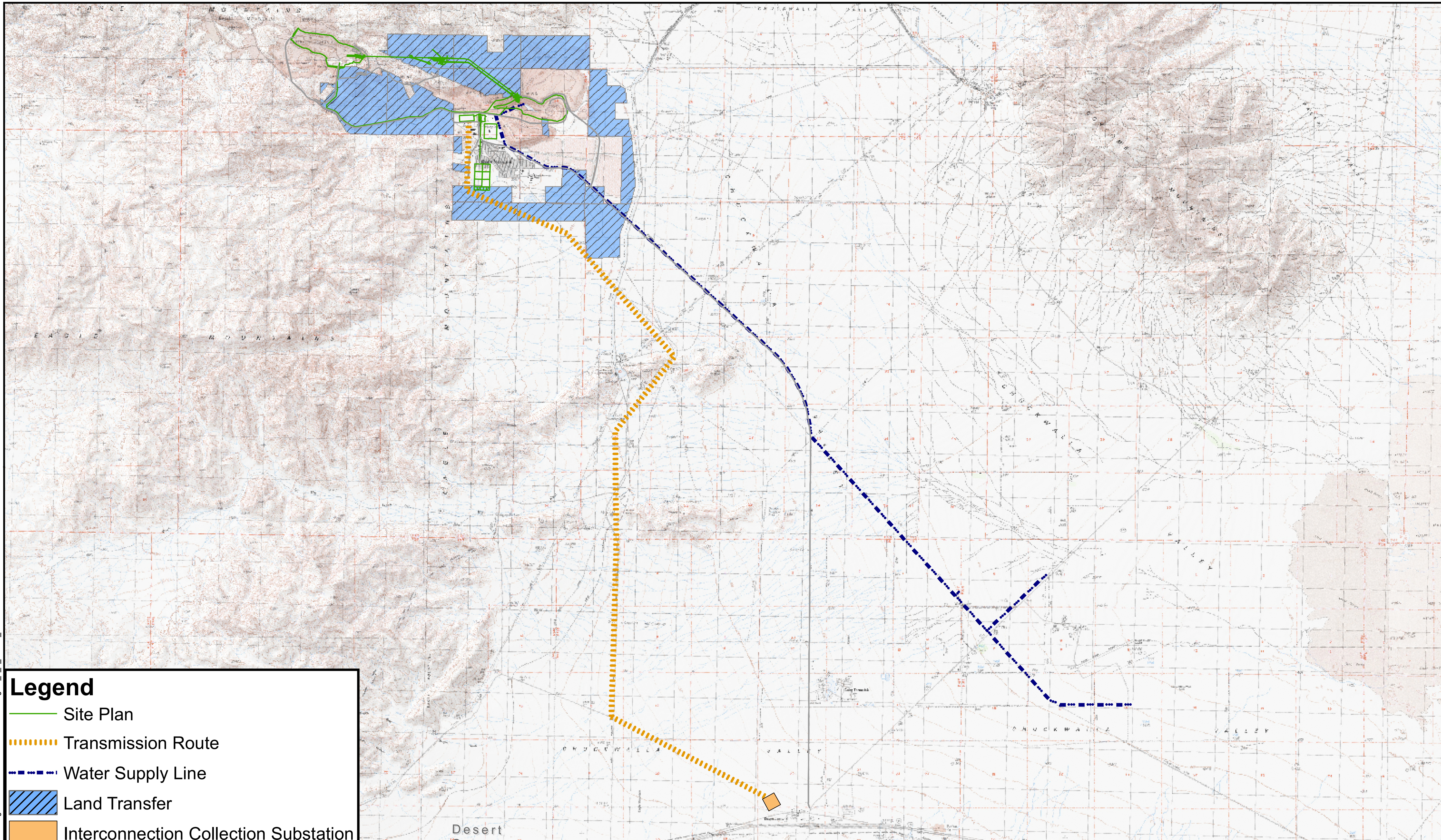
Evaporation Rate (acre-feet/year) = Area (acres) X Pan X F_L X F_S
Where Pan = Class A Pan Evaporation rate
F_L = Lake factor, typically 0.8
F_S = Salt Concentration factor, typically 0.7 for brines

From the overall material balance, the total brine to be evaporated is approximately 170 gpm or 270 acre-feet per year. This converts to a pond of about 58 acres. The proposed design for the evaporation pond is to divide the total required pond area into six varying level salinity ponds and five solidifying ponds. Each pond will be about 8.3 acres in size, and each solidifying pond will be about 1.4 acres in size. The RO concentrate would flow into one pond, then be directed to another pond while the first pond evaporates. Typical pond design includes 8-foot berms with double liners to prevent seepage. Monitoring wells would be installed to identify a potential liner failure.

Over a period of years, the salt level in the ponds will rise and salts would need to be mechanically removed from the ponds. Based on the pond size and the salt balance the estimated rate of salt build up is on the order of 0.25 to 0.5 inches per year. Salt removal would be expected to occur on the order of once every 10 years, at which time the pond liners will be inspected and replaced as needed.

1.10 Visitor Facilities

No visitor facilities are currently being proposed for the Project. The highly fluctuating water levels of pumped storage hydroelectric facilities are not suitable or safe for public recreation. Additionally, the existing disturbed, mined setting is not attractive for recreational use with the exception of some off-highway vehicle (OHV) activity. Increased OHV use would be incompatible with the proposed landfill as well, and may raise concerns related to area wildlife resources and potential intrusion into off-site National Park and Wilderness areas, and is therefore not desirable. If the landfill is developed on the site, there are additional concerns about visitor safety. For these reasons, the Project proposes to continue to prevent public access to the project area.



Legend

- Site Plan
- Transmission Route
- Water Supply Line
- Land Transfer
- Interconnection Collection Substation

0 1 2 Miles

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NO.	DATE	ISSUE/REVISION	DES	DRN	CHK	APP

Eagle Crest Energy Company

EAGLE CREST ENERGY COMPANY

GEI PROJECT 080473

EAGLE MOUNTAIN PUMPED STORAGE PROJECT
EAGLE MOUNTAIN, CALIFORNIA

LAYOUT AND MAJOR FEATURES OF THE EAGLE MOUNTAIN PUMPED STORAGE PROJECT

FIGURE 1-1

April 2009

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2 Normal Maximum Water Surface Area

2.1 Upper Reservoir

The existing Central Pit of the historic mine will serve as the Upper Reservoir. A detailed description of the proposed Upper Reservoir for the Eagle Mountain Pumped Storage Project is included in Section 1.1 above. The principal physical characteristics of this reservoir are summarized in Table 2-1.

Table 2-1: Key Data on Upper Reservoir

Parameter	Upper Reservoir
Minimum Normal Pool	
Water Surface El. (ft, msl)	2,343
Storage (acre-feet)	2,300
Surface Area (acres)	48
Maximum Normal Pool	
Water Surface El. (ft, msl)	2,485
Storage (acre-feet)	20,000
Surface Area (acres)	191

2.2 Lower Reservoir

The existing East Pit of the historic mine will serve as the Lower Reservoir. A detailed description of the proposed Lower Reservoir for the Eagle Mountain Pumped Storage Project is included in Section 1.2 above. The principal physical characteristics of this reservoir are summarized in Table 2-2.

Table 2-2: Key Data on Lower Reservoir

Parameter	Upper Reservoir
Minimum Normal Pool	
Water Surface El. (ft, msl)	925
Storage (acre-feet)	4,200
Surface Area (acres)	63
Maximum Normal Pool	
Water Surface El. (ft, msl)	1,092
Storage (acre-feet)	21,900
Surface Area (acres)	163

3 Proposed Reversible Pump-Turbines

The underground powerhouse will contain four equal-size Francis-type reversible, vertical-shaft pump-turbine units. Unit sizing has been based on typical performance characteristics obtained from information published by the U.S. Army Corps of Engineers (USACE) and U.S. Bureau of Reclamation (USBR) as well as experience and judgment. In order to obtain maximum project benefits and effectively use potentially highly variable pumping energy, ECE plans for use of variable speed technology for one or more of the units.

The project size (1,300 MW) was selected based on the available head differential and the reservoir storage volumes. The proposed configuration is 4 units, each rated at a nominal capacity of 325 MW at maximum head. Unit sizes in the 300 to 350 MW range are fairly common throughout the United States (for example Bath County, VA, Ludington, MI, and Raccoon Mountain, TN). The hydraulic capacity of each turbine will be approximately 2,900 cfs (11,600 cfs total). The operating speed of the turbines will be about 333 revolutions per minute (rpm), and the rated head for the pump/turbine units will be about 1,410 feet. The principal characteristics of the proposed pump-turbine/motor-generators are summarized in Table 3-1.

Table 3-1: Principal Characteristics of the Hydroelectric Plant

Project Feature	Value
Total Plant Capacity	1,300 MW
Number of Units	4
Unit Rated Capacity	325 MW
Maximum Plant Discharge	11,600 cfs
Rated Flow (each unit)	2,900 cfs
Approximate Maximum Gross Head	1,560 feet
Approximate Minimum Gross Head	1,250 feet
Overall Efficiency	86.6%
Efficiency (Pumping/Generating)	92% / 98%
Capacity (Pumping/Generating)	319 MW / 347 MVA
Operating Speed	333 rpm

When pumping, the units will operate the hydraulically actuated wicket gates in the fixed mode, with maximum pump discharge corresponding to the operating head. Each pump will be directly coupled to a vertical shaft, three phase, 60 Hertz (Hz), ac motor/generator. Each motor/generator will have 20 poles and be rated at 347 Megavolt amperes (MVA).

Pump starting will be accomplished with a static frequency converter (SFC). This system will bring each unit up to synchronous speed with the water in the turbine and draft tube depressed with compressed air. When the unit reaches normal speed, the compressed air will be released and the inlet valve will then be opened. Back-to-back starting will also be provided as a backup to the SFC starting.

In the generating mode the units will rotate in the opposite direction and be controlled by an electronic governor that operates the hydraulically actuated adjustable wicket gates. Each generator will have a variable frequency output that is converted electronically to 60 Hz synchronous frequency for transmission at 500 kilovolts (kV). The size of the motor/generators is determined by the pumping power requirements at minimum head. The maximum power output is controlled by the hydraulically actuated adjustable wicket gates. The objective of the variable frequency is to optimize the efficiency and meet system demands over a wide range of conditions.

4 Primary Transmission Lines

Power will be supplied to and delivered from the Project by one double circuit 500 kV transmission. The line will extend approximately 13.5 miles from the project switchyard to a proposed new Interconnection Collector Substation for interconnection to the planned Devers - Palo Verde No. 2 transmission 500-kV line owned by SCE.

The new Interconnection Collector Substation will require an estimated total area of 25 acres. This facility will be located near Desert Center, California.

The typical right-of-way for the transmission line will be about 200 feet. However the right-of-way width can be reduced in specific locations to mitigate potential impacts to resources (e.g., historic trails, adjacent land restrictions, existing roads and highways, and biological and cultural resources). The total right-of-way area is estimated to be approximately 327 acres. Additional proposed transmission line facilities and communication facilities are summarized in Table 4-1.

Table 4-1: Summary of Proposed Transmission Line Facilities and Communication Facilities

Transmission Line Facilities (500 kV, double circuit)
• Conductors: Two, three-phase AC circuit consisting of three 1.5- to 2-inch ACSR conductors per circuit.
• Minimum Conductor Distance from Ground: 35 feet at 60°F and 32 feet at the maximum operating temperature.
• Shield Wires: Two ½ to ¾-inch-diameter wire(s) for steel lattice.
• Transmission Line Tower Types:
  - Steel Lattice Tower along entire route.
  - Structure Heights (approximate): Steel Lattice - 175 to 235 feet.
• Average Distance between Towers: Steel Lattice – 1,056 feet.*
• Total Number of Towers (approximate): 54-68.*

Communications Facilities • Systems: Digital Radio System, microwave, VHF/UHF radio, fiber optics. • Functions: Communications for fault detection, line protection, SCADA, two-way voice communication.

Note: The exact quantity and placement of the structures depends on the final detailed design of the transmission line and route, which is influenced by the terrain, land use, and economics.

5 Additional Equipment

The Project will have all appurtenant equipment necessary for the safe and efficient operation of a large pumped storage project. The general characteristics of the equipment are listed in Table 5-1.

Table 5-1: General Characteristics of Additional Project Equipment

EQUIPMENT	DESCRIPTION
Upper Reservoir Inlet/Outlet Gate and Hoist	Fixed wheel leaf type gate operated by electric/ hydraulic remote controlled hoist.
Upper Reservoir Inlet/Outlet Trashracks	60 feet x 84 feet of steel bar trashrack
Lower Reservoir Inlet/Outlet Gates and Hoist	Fixed wheel leaf type gate operated by electric/ hydraulic remote controlled hoist.
Lower Reservoir Inlet/Outlet Trashracks	65 feet x 84 feet of steel bar trashrack
Pump/Turbine Inlet Valves	Four 108 inch diameter spherical valves, with full closing capability.
Pump/Turbine Draft Tube Gates	Four 10 feet x 14 feet high presser slide gates operated by electric/hydraulic hoist.
Powerhouse Bridge Crane	2 x 300 ton overhead, top running, electric bridge crane
Draft Tube Gates Crane	30 ton Under-hung electric bridge crane
Auxiliary Powerhouse Cranes and hoist	Electric monorail hoists sized and located for erection and maintenance of equipment in addition to the Powerhouse Bridge Crane.
Cooling Water System	Water intake from and discharge to the tail-race tunnel to provide cooling for pump/turbines, motor/generators, transformers, compressors and Powerhouse HVAC compressors.
Compressed Air Systems	Compressors, pipe, and accessories to provide air for draft tube depression, station service, motor generator brakes and high pressure governor.
Drainage Systems	Plant drains, piping, pumps, sump, and oil separating facilities.
Unit Dewatering and Filling	High capacity pumps, sump, pipe, and accessories connecting the unit draft tubes, pressure tunnel and tailrace tunnel.
Fire Protection Equipment	Detection, alarm, isolation and extinguishing equipment.
Potable Water and Sanitary Services	Extend existing nearby potable water system to plant. Pump sanitary wastes to surface and transfer to existing nearby sewer systems to be treated.

EQUIPMENT	DESCRIPTION
Heating, Ventilation, and Air Conditioning	Central HVAC system for control room, communication rooms, workshop and personnel spaces. Ventilation exhaust system for powerhouse cavern, transformer cavern and electrical equipment areas. Ventilation system for cable/emergency exit tunnel.
Elevator	Two electric personnel elevators.
Diesel Generator	1,000 kW emergency, diesel fueled generator.
Unit Transformers	Transformers to consist of two banks of three 500/18 kV, 167 MVA, single-phase, three winding transformers. One spare will be provided.
Bus	18 kV, isolated phase bus duct.
Generator Circuit Breakers	Metal enclosed SF6 type.
18 kV Switchgear	Generator/motor circuit breakers and motor start circuit breakers SF6 type, motorized phase reversal switches, motorized disconnect switches.
Outdoor Switchyard	500 kV switchyard, open-air bus type including 500 kV cable terminations, disconnect switches, coupling capacitor voltage transformers, current transformers, power line carrier line traps, surge arrestors and transmission line termination structures.
Station Service Power	480 volt, 3-phase, 60 hertz. Transformers will be 2,000 KVA, cast-resin dry type. Switchgear will consist of draw-out-type air circuit breakers. The system will include major control centers, panel-boards, and associated accessories. DC system for control and monitoring will consist of batteries, chargers, and the distribution system.
Controls	Fully distributed industrial grade control, monitoring, and protection system for complete manual and automatic operation including instrumentation, alarms, hardcopy recording, and limited supervisory control. Fiber and microwave link for real-time connection and control by the CAISO.

6 All U.S. Lands Identified and Tabulated

All lands of the United States, portions of which may be within the project area, have been tabulated according to legal subdivisions of public lands survey. A total of 1059.26 acres of Federal land are within the project boundary. Table 6-1 presents the location of lands of the United States within the project boundary. Note that the tabulation presents each plot identified within the project boundary. In actuality, only a portion within or adjacent to the identified plot may be within the project boundary.

Portions of the project are proposed to be located on BLM lands that have proposed to be exchanged with a private entity. The location of these lands is displayed in Figure 1-1, as "Land Exchange". This land exchange is currently in litigation. If the land exchange is effectuated, the number of acres of Federal land in the project boundary will decrease to 675.63 acres. Table 6-1 identifies the location of Federal lands within the project boundary.

Table 6-1: Location of Federal Lands Within the Project Boundary(All BLM)

Section	Township	Range
26, 26, 27, 28, 29, 32, 33, 34, 35, 36	03S	14E
1, 2, 11, 12	04S	14E
31	03S	15E
6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 27, 30, 31, 34, 35	04S	15E
1, 6, 7, 17, 18, 20, 21, 22, 27	05S	15E
5, 6, 7, 16, 17, 18	05S	16E

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PUBLIC

Eagle Mountain Pumped Storage Project No. 13123
Final License Application
Volume 1 of 6

Exhibit B:
Project Operation and Resource Utilization

Palm Desert, California

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

Date: June 22, 2009
GEI Project No. 080473

Table of Contents

Tables

This license application is organized into six volumes, as described below:

Volume 1	Initial Statement and Exhibits A, B, C, and D	Public
Volume 2	Exhibit E, Applicant Prepared Environmental Impact Statement	Public
Volume 3	Appendices to Exhibit E, Applicant Prepared Environmental Impact Statement	Public
Volume 4	Privileged information for Exhibit E, Applicant Prepared Environmental Impact Statement	Privileged, not for release
Volume 5	Exhibit F, Supporting Design Report	Critical Energy Infrastructure Information (CEII), not for release
Volume 6	Exhibit G	Public

1 Description of Alternative Sites Considered

1.1 Pumped Storage Location Alternatives

The proposed project is located at the site of the former Kaiser Iron Mine, an open-pit operation that ceased iron ore production in the early 1980s. The site is located near the Town of Eagle Mountain in Riverside County, California, approximately 30 miles east of Indio, and 13 miles north of I-10 and the town of Desert Center.

The site was selected for pumped storage for the following reasons:

- Two existing mine pits are located within 14,000 feet of each other, with an elevation difference between the pits of approximately 1,500 feet. The pits can be used for water storage, with the Central Pit serving as the upper reservoir and the East Pit serving as the lower reservoir for a hydroelectric pumped storage development. The storage space available in the two mine pits is about 28,000 acre-feet in total. Construction of dams to create this amount of storage could cost up to $190 million at sites with similar topography that would require major dams. Thus this site offers a rare opportunity to minimize costs of developing reservoir storage.

- The geology of the project area is dominated by rock formations comprised of good quality materials for construction of the dams, water conveyance tunnels, and underground chambers associated with a pumped storage project.

- The site is within about 13 miles of a National Interest Electric Transmission Corridor, which includes the Palo Verde to Devers corridor, which extends from the Palo Verde Nuclear Plant in Arizona to the Devers Substation near Palm Springs. The project proposes to interconnect to the planned Devers-Palo Verde No. 2 transmission line, 13.5 miles from the project site.

- The site is located adjacent to the Chuckwalla Basin, which has a source of water from the Chuckwalla Valley Aquifer (groundwater) to initially fill the reservoirs and to provide makeup water for evaporation and seepage.

- The site has potential to firm the energy produced by a growing regional portfolio of solar and wind power projects making it possible to integrate a high level of renewable energy generation sources and maintain reliable grid operations and provide peak power demands to meet California's energy needs. California's renewable portfolio standards (RPS) call for 33 percent of electrical generation to come from renewable sources by 2020.

The site is located near existing and proposed renewable energy generation, including the San Gorgonio Pass wind farm west of the community of Palm Springs. Major large scale solar projects are proposed for the Chuckwalla Valley and surrounding desert areas, and the Palo Verde Mesa approximately 40 miles east of the project site.

1.2 Transmission Alternatives

The preferred transmission line route has been determined to be one that interconnects the proposed Project switchyard to a proposed Interconnection Collector Substation at Desert Center, which will be adjacent to the planned Devers -Palo Verde No. 2 (DPV2) 500-kilovolt (kV) line owned by Southern California Edison (SCE). The Collector substation could serve the proposed solar projects in the Chuckwalla Valley as well. The approximate length of the interconnection line is 13.5 miles. The proposed DPV2 500-kV line will be under the operational control of the California Independent Systems Operator (CAISO).

The proposed routing from the Project was selected as the shortest route that would most economically supply power to, and receive power from, the southwestern grid, avoiding sensitive environments to the greatest extent feasible. Operational load-flow studies will be conducted by the CAISO to determine exact interconnection requirements.

The interconnection of the Project to a collector substation at Desert Center will require the construction of the DPV2 transmission line in order to enable the Project to access the California market. The CAISO has approved SCE to construct the DPV2 transmission line and the California Public Utilities Commission (CPUC) has reached similar conclusions in granting SCE a Certificate of Public Convenience and Necessity (CPCN) to construct DPV2 in 2005. The CPUC approved the DPV2 Project on January 25, 2007 in Decision D.07-01-040 and certified the California Environmental Quality Act (CEQA) Environmental Impact Report (EIR) as being in compliance with the requirements of CEQA.

The Arizona Power Plant and Line Siting Committee, a committee of the Arizona Corporation Commission (ACC), approved and recommended the project for final ACC approval in March 2007. However, the project was denied by the ACC in June 2007. In May 2008, SCE filed a petition with the CPUC seeking permission to start construction in California to satisfy interconnection requests for new renewable and conventional generation projects in the Southeastern part of the State for the benefit of the region.

Based on information provided on SCE’s website, SCE’s priority and preference is to seek a satisfactory resolution with the ACC, but SCE is assessing all options to obtain approval of the project in Arizona. SCE is simultaneously pursuing two approaches to secure regulatory approval: a new ACC filing and the FERC Transmission Line Siting process. SCE remains committed to obtaining permitting approval for DPV2 facilities in Arizona and is pursuing all available options, including applying for federal transmission line siting, per Section 1221 of the Energy Policy Act of 2005.

The Eagle Mountain Project is targeting the California, Arizona, and Nevada markets to supply peaking generation and ancillary services to the investor owned utilities as well as the municipal utilities. As the peak load demand and the addition of intermittent generating resources in these markets continue to grow, energy storage for peaking generation with load following capability, quick response spinning reserves, and voltage regulation resources will be an essential part of the Western region’s energy system resource mix.

Table 1-1 summarizes the various transmission components of the Project. The single-line diagram can be found in Exhibit F.

Table 1-1: Summary of Proposed Transmission Line Project Components

Proposed Route and Right-of-Way • Transmission Line Length: approximately 13.5 miles. • Project Connection Point: A new substation/switching station at Eagle Mountain. • Network Connection Point: The Proposed Interconnection Collector Substation at Desert Center, which will interconnect to the planned DPV2 500-kV line owned by SCE. • Right-of-Way Width: 200 feet. The right-of-way width would be reduced in specific locations to mitigate potential impacts to resources (e.g., historic trails, adjacent land restrictions, existing roads and highways, and biological and cultural resources). • Total Right-of-Way Acreage: approximately 330 acres for the linear ROW.

Transmission Line Facilities (500 kV, double circuit)
• Conductors: Two, three-phase AC circuits consisting of three 1.5 to 2-inch ACSR conductors per circuit.
• Minimum Conductor Distance from Ground: 35 feet at 60°F and 32 feet at the maximum operating temperature.
• Shield Wires: Two ½- to ¾-inch-diameter wire(s) for steel lattice.
• Transmission Line Tower Types:
  - Steel Lattice Tower along entire route.
  - Structure Heights (approximate): Steel Lattice – 175 to 235 feet.
• Average Distance between Towers: Steel Lattice – 1,056 feet.*
• Total Number of Towers (approximate): 54-68*

Substation Facilities • A new substation/switching station at Eagle Mountain requiring a total area of approximately 25 acres would be constructed. • Interconnection Collector Substation at Desert Center: A Collector Substation would be constructed at Desert Center, west of Desert Center, California, to accommodate interconnection of this Proposed Project and other proposed projects in the same area for delivery to the DPV2 transmission line.
Communications Facilities • Systems: Digital Radio System, microwave, VHF/UHF radio, fiber optics. • Functions: Communications for fault detection, line protection, SCADA, two-way voice communication.

The project has evaluated several potential points of interconnection to the transmission grid. In the initial planning stages, ECE considered an interconnection request to connect at the Devers Substation, near Palm Springs. This would have required an interconnection line of 83 miles, through an already crowded transmission corridor. Obstacles to this alternative include cost for construction; difficulty of obtaining right-of-way, particularly in the communities of Indio and Cathedral City; potentially significant impacts to the natural and human environment; and cultural resource concerns of the Aqua Caliente Band of Cahuilla Indians.

As an alternative, ECE proposed to interconnect at SCE's proposed Midpoint Substation (also known as the Colorado River Substation). This proposal was presented in the Pre-application Document (filed with FERC January 2008), and the Draft License Application (filed with FERC in June 2008). This proposed route was 50.5 miles from the project site to the point of interconnection. The proposed route crossed the Chuckwalla Valley Dune Thicket Area of Critical Environmental Concern (ACEC), and required a crossing of the I-10 Interstate Highway.

The project requires a double circuit 500 kV line, which will require construction of new transmission towers to support and route to the interconnection substation. Several stakeholders have requested ECE consider installing its transmission lines on existing transmission towers owned by Metropolitan Water District (MWD). This is not a feasible alternative given the size of the towers, the size and weight of the new lines, and alignments of existing transmission lines in the area.

A substation site located at the I-10 and Eagle Mountain Road junction was considered but dismissed due to cultural resource concerns related to the historic (World War II) Desert Training Center hospital site. In addition, this location would have conflicted with an existing high pressure gas line.

1.3 Water Supply Alternatives

The Project's proposed water supply is groundwater. ECE is acquiring the requisite property to develop ground water in the Chuckwalla Basin to initially fill the reservoirs and for annual make-up water. Three wells will be utilized to provide initial reservoir fill. Thereafter, only one of these wells will be required for water to replace losses due to seepage and evaporation, with a second well maintained as a backup water supply. ECE proposes to install new wells connected to a central collection pipeline corridor described in Exhibits A and F, and evaluated in Exhibit E.

The alternatives for water supply are limited. The Project is not located on a natural stream nor would the small watershed drainage area that would flow into either or both of the reservoirs provide nearly enough water to offset seepage losses and evaporation. Therefore, the water supply must come from either local groundwater, or through the MWD's Colorado River Aqueduct (CRA).

ECE investigated the alternative of purchasing water from a third party and having the water delivered to MWD. In exchange, MWD could provide the same amount of water to the project from the CRA. Potential sources of water supply for the exchange would most likely come from the purchase of surplus water in the San Joaquin Valley and/or Sacramento Valley. The CRA could also be the source of make-up water supplies; however, it would require long-term contracts for exchange water and for wheeling through existing facilities.

This alternative was rejected for several reasons. Several potential vendors were approached regarding the purchase of surplus surface water and banked groundwater. While it is possible to make an arrangement of this type, it is difficult to find willing sellers during drought years. In addition, the costs and environmental permitting requirements are potentially a significant barrier. The potential for an arrangement of this type was discussed with MWD staff, but the MWD Board would need to approve of any such wheeling or exchange agreement. As MWD has stated in their comment letters on the project, they have not agreed to provide water to the project through the CRA. Finally, water supplies in the CRA contain quagga mussels. The introduction of quagga mussels into the project reservoirs would be undesirable.

2 Description of Alternative Facility Designs, Processes, and Operations

Several alternative facility design configurations, and project installed capacities, were considered during project planning. These alternatives are discussed below.

2.1 Powerhouse Location

The choice between a surface and underground powerhouse was studied early in Project development. The required depth of unit setting below minimum lower reservoir pool and the limited ground cover, which would result in a long length of steel-lined power tunnel, indicated that a surface powerhouse would be more costly in comparison with an underground powerhouse. An underground powerhouse could be constructed closer to the lower reservoir; however, this arrangement would involve a longer high-head tunnel posing greater concerns about hydraulic transients and surge control.

The underground powerhouse could be located anywhere between the two reservoirs where suitable geologic conditions exist, at a depth that satisfies the unit submergence requirements. The proposed location was selected because of the expected existence of sound granitic rock away from fractured and diverse conditions associated with ore zones, a route for the power waterways that is near to a direct connection between the upper and lower reservoirs, a minimum length of steel lining of the power waterways, proximity to a suitable location for surge shafts and chambers, and a reasonable length of access tunnel at an acceptable grade from the surface to the powerhouse.

2.2 Installed Capacity

The selected installed capacity of 1,300 megawatts (MW) is judged to be consistent with the capacity needs of the southwestern U.S. at the time when the Project could be in operation, probably around 2015-2016. Staging studies indicated that an initial installed capacity of 1,000 to 1,500 MW could be economically engineered to enable a doubling of generating capacity at some future date.

2.3 Storage Capacity

The storage capacity of the reservoirs is directly related to the amount of energy storage provided by the Project. The amount of storage proposed for the Project will support continuous rated capacity generation for a period of 10 hours during each day while pumping back for a period of 12 to 14 hours during off-peak periods each day. (Off-peak periods are from 10:00 PM to 6:00 AM. Significant wind energy is produced at night as well. A working volume of 17,700 acre-feet will be provided, which corresponds to 18.5 hours of storage at full plant discharge (11,600 cubic feet per second [cfs]). The 17,700 acre-feet of active reservoir storage is equivalent to 22,000 megawatt hours (MWh) of energy production. The maximum potential energy generation on an annual basis is 4,308 gigawatt hours (GWh). Alternate generating periods and variable pump-back periods to accommodate off-peak wind and solar power generation will also be considered during further investigations. The 10-hour generating period was selected because it provides flexibility in Project operations.

2.4 Upper Reservoir

Some flexibility exists in the selection of the minimum and maximum operating levels of the upper reservoir. The respective levels of El. 2485 and El. 2343 were selected based on the required submergence for the intake structure at the upper reservoir and the energy storage required to support the intended weekly operating cycle. Also, the range of levels was checked to ensure that the maximum and minimum operating heads will remain within the range that is acceptable for reversible pump/turbines.

The foundation conditions at the upper reservoir are judged to be suitable for either a concrete-faced, rockfill dam or a roller-compacted concrete (RCC) gravity dam. Selection of the type of dam will be made during subsequent design and following intensive subsurface explorations and materials testing. The layouts presented in this application are based on constructing an RCC dam, using on-site mine tailings that would be processed and/or using materials generated from tunnel and underground structure excavations. The final decision on type of dam will be based on final engineering studies and on-site explorations, as well as cost considerations.

2.5 Lower Reservoir

The capacity of the East Pit, with the low point of its rim at 1,100 feet, is about 23,000 acre-feet, which exceeds the needed storage capacity for a 1,300 MW project (total of 21,900 acre-feet, including dead storage). Therefore, no dam structures are needed at the lower reservoir. With the invert of the I/O structure at El. 925 feet, there is approximately 4,200 acre-feet of inactive storage. The operating levels of the lower reservoir, between El. 925 and El. 1092, will maintain the operating head of the pump/turbines in an acceptable range.

2.6 Water Conductors, Penstocks, Tailrace, and I/O Alternatives

The main water conductor connecting the upper reservoir to the powerhouse would be bored with a tunnel boring machine (TBM) or drilled and blasted into and through the Eagle Mountain, with a finished diameter of 29 feet. The choice of below-grade water conductors would minimize surface area disturbance and eliminate the potential for penstock rupture that could produce surface discharge of water transported by those underground high-pressure pipelines between the upper reservoir and the powerhouse. In general, the water conductor and penstock alignments will seek to follow the most direct route between the upper reservoir and the powerhouse, taking into consideration areas topography and subsurface geotechnical conditions.

Below the powerhouse, the tailrace tunnel will also be bored with a TBM or drilled and blasted into and through the Eagle Mountains, with a finished diameter of 33 feet. Again, this would minimize surface area disturbance. Generally, the draft tubes and tailrace tunnel alignments will seek to follow the most direct route between the powerhouse and the lower reservoir, taking into consideration area topography and subsurface geotechnical conditions.

The penstocks, draft tubes and manifolds would be excavated using conventional drill and blast methods. The finished penstock diameter would be 15 feet and the finished draft tube diameter would be 17 feet.

Generally there are two types of reservoir intake structures for hydro-power projects, horizontal intakes and vertical drop intakes. The advantage of the vertical drop intakes ("morning glory" type) are that near maximum capacity is attained at relatively low heads. However, the disadvantage is that this type of inlet is ungated so that discharges from the upper reservoir cannot be stopped at the inlet in the event of an emergency. Horizontal intakes typically are gated by means of radial gates, slide gates, or an emergency bulkhead that can shut off water flow from the upper reservoir in the event of an emergency. For these reasons the intakes for the upper and lower reservoirs will be constructed horizontally.

The inlet/outlet structure at the upper reservoir will be located near the east end of the reservoir and will be constructed horizontally in the sloping bank of the pit. The inlet/outlet structure will use an approach channel and slope down to the tunnel invert. A fixed-wheel gate will be provided in the structure for emergency closure and for tunnel inspection. The inlet/outlet structure at the lower reservoir will be located near the west end of the reservoir and will be constructed horizontally in the sloping bank of the pit. The inlet/outlet structure will use an approach channel and slope down to the tailrace invert. A fixed-wheel gate will be provided in the structure for emergency closure and for tailrace inspection.

2.7 Unit Type Selection and General Arrangement

For many existing projects in the United States, and most recently proposed projects worldwide in the head range and project size at Eagle Mountain, the use of reversible, single-stage Francis units has been preferred over the use of separate pumps and turbines. Variable speed units are becoming more common because of their importance to realizing the ancillary benefits of pumped storage and their ability to pump over wide load variations. The generating head range of 1560 to 1251 feet at Eagle Mountain is well within the range of these types of units. Similarly, the nominal unit size of 325 MW is within the size range having a demonstrated history of reliable operating experience in the U.S. and overseas. For example, the reversible units at the Bath County Project in Virginia (operational since 1985) are rated at 350 MW. At the Rocky Mountain Project in Georgia (operational since 1995) the units are rated at 283 MW and at the Raccoon Mountain in Tennessee Project (operational since 1978) the units are rated at 383 MW.

The powerhouse arrangement is based on vertical-shaft units, with the turbine inlet valves and the draft tube gates located within the main powerhouse cavern. A separate cavern downstream of the main powerhouse cavern would house the power transformers, which increase voltage from 18 kV to 500 kV. A lay-down and erection area is provided at one end of the unit bays with direct access to the access tunnel. A service and controls bay is provided adjacent to the erection area.

2.8 Powerhouse Access

Access to the site is planned via Kaiser Road and from there to branch access roads, which lead to the various project features.

The normal access to the powerhouse will be through the main access tunnel. Its portal will be located at the ground surface on the northeast rim of the East Pit at El. 1100 from which it will extend 6,600 feet to the powerhouse floor at El. 837.

The alternative of access by a shaft directly above the powerhouse was considered. However, the powerhouse will be directly below the proposed landfill, which will, if constructed, ultimately place over 200 feet of fill depth over the ground surface above the powerhouse. The potential disruption of the landfill operations as well as access to the powerhouse ruled out the shaft access option. Secondary and emergency personnel access to and from the powerhouse will be from a shaft and short tunnel segment, with the shaft day-lighting in an area that is outside of the landfill to the north and west of the powerhouse location.

3 Plant Operations and Control

3.1 Mode of Operation

The basic mode of operation for the Project will be typical of most pumped storage projects: storing low-cost energy for use to provide peaking generation during periods of high power demand. In addition, this project will provide a range of ancillary grid operations services considered by the CAISO to be essential to integrating renewable energy generation sources such as wind and solar power. This pattern would use the available, unused capacity of wind and solar generation at night and on weekends, for energy to pump water from the lower reservoir to the upper reservoir. During the weekdays, and particularly during morning and afternoon peak demand periods the Project would operate as a hydroelectric generation project, releasing water from the upper reservoir through the reversible turbines to the lower reservoir to generate power. Power would also be generated as needed by the CAISO for voltage regulation, and load following, and would be available for spinning reserves.

The Project, with a cycle efficiency of 80 percent would use approximately 1.25 kWh of low cost energy to produce 1.0 kWh of much higher value energy in a different time period. A portion of the on-peak generation will offset the use of fossil fuel (mainly natural gas) for meeting peaking requirements. In addition to the straightforward use of a pumped storage project to provide on-peak generating capacity, the flexible operating characteristics of a pumped storage facility allow it to provide additional dynamic and ancillary benefits that can be quantified and priced. Two of the significant benefits are the ability of pumped storage to provide voltage regulation and load-following generation, almost instantaneously responding to changes in the system load by accepting or shedding the rapidly changing part of the load. When operating as a part of a thermal-based system, this characteristic coordinates well with the slower ramping rates of thermal units, which cannot efficiently respond as quickly or as efficiently to load changes. Other dynamic benefits include its ability to provide standby capacity, load and frequency control, and system reactive compensation, as well as black start capability.

3.2 Control

Operators in the powerhouse control room will staff the plant and be available to perform manually required monitoring, maintenance and operations as conditions dictate. Operation will be semi-automatic, entailing the initiation of controlled operations through the supervisory control equipment on the control switchboard or a remote control station. The equipment will respond by automatically performing such functions as startup, loading, unloading, synchronizing and shutdown and, in the pumping mode, draft tube depression, startup synchronizing, pump prime, loading, unloading, and shutdown. The plant will respond automatically to load dispatching instructions to start up or shut down from a remote control center. Monitoring data will be displayed locally and remotely as appropriate.

4 Dependable Capacity and Energy Production

As a peaking, voltage regulation, and load-following facility, the plant will normally operate for periods of several hours during weekdays of the peak generating season and shorter periods of rapid load change for load following and voltage regulation benefits during other periods of the week and year. Based on typical projects elsewhere in the U.S. an average annual capacity factor of 20 percent would be expected. However, the project has been sized with 18.5 hours of energy storage and could support a higher capacity factor. The annual energy production by the plant will similarly depend upon the way it is operated and the peak energy demands being met.

The rated generating capacity of the plant would be 1,300 MW. The generating capacity of the units is limited by the full-gate power produced by the turbines at a given head or by the continuous generating capacity of the motor/generators. The motor rating for pumping will be selected based upon the pumping capacity of the pump/turbines at the minimum pumping head. The plant operation is not dependent upon stream flow; therefore, the operation and plant capabilities are unchanged in adverse, mean, and high flow water years.

The level of the lower reservoir is the tailwater level in the generating cycle. As the upper reservoir level lowers during generation, the tailwater level will rise so that the available head and the full-gate turbine-generator output will vary with time.

5 Reservoir Operations

5.1 Reservoir Filling and Makeup Water Supply

The reservoirs will be filled with water from nearby wells in the Chuckwalla Basin. ECE is acquiring land and related water rights for the groundwater supply. Pipelines will deliver the water from the wells to the lower reservoir. Reservoir losses consist of evaporation and seepage. Evaporation is estimated based on an annual lake evaporation of 90 inches (7.5 feet) and the average lake surface areas provided in Table 5-1.

Table 5-1: Evaporation Estimate

Approximate Altitude (feet, msl)	Area (acres)	Estimated Lake Evaporation (ft/yr)	Annual Make up (AF/yr)
900 (Lower Reservoir)	121	7.5	908
2400 (Upper Reservoir)	114	7.5	855
Total			1,763

Average rainfall is cited as approximately 3 inches per year. The only rainfall affect on the reservoirs would be the rain that falls directly into the reservoirs, which is an average of 60 acre-feet per year (AFY) (3 inches on 235 acres). Despite efforts to effectively eliminate seepage, some recoverable losses are expected to occur. With these measures in place, a conservative allowance of 1600 AFY has been made for the seepage losses. A system of monitoring and seepage recovery wells has been designed to monitor groundwater levels and water quality, and return water lost to seepage to the lower reservoir.

The reservoir seepage losses will be replaced by water from the seepage recovery well(s). Water lost to evaporation will be replaced by water from the wells in the Chuckwalla Valley. The total amount of replacement water is conservatively estimated to be 1,703 AFY.

5.2 Reservoir Area-Capacity Curves

The area-capacity curves for the upper and lower reservoirs are presented in Figure 9-1, for the Central Pit Reservoir, and Figure 9-2 (Section 9) for the East Pit Reservoir.

5.3 Hydraulic Capacity of the Power Plant

The hydraulic capacity of the plant at maximum head is estimated to be 11,600 cfs (2,900 cfs per unit).

5.4 Power Plant Capacity vs. Head

At maximum gross head (1,560 feet), each of the 4 units will produce 325 MW in the generating mode with discharge of 2,900 cfs. At minimum gross head of 1251 feet, turbine output would be approximately 275 MW. Figure 9-3 (Section 9) shows the typical weekly operating cycle for the project.

6 Power Needs and Project Utilization

6.1 Power Needs

The following is an excerpt from the California Energy Commission 2007 Integrated Energy Policy Report, CEC-100-2007-008-CMF:

> "Statewide annual peak demand is projected to grow, on average, 850 megawatts per year for the next 10 years, or 1.35 percent annually. Population growth in California's drier, warmer areas increases peak demand more than it increases annual energy consumption. Another reason for the higher growth rate of the peak demand forecast compared to the electricity consumption forecast is the forecast's assumption that the 2005 federal air conditioning standards have no impact on peak because they result in little, if any, savings during the hottest hours when California peak demand occurs.
>
> The growth in peak demand is somewhat offset by projected increases in the electricity provided by self generation, reflecting the effects of the California Solar Initiative, the New Solar Homes Partnership, and the Self-Generation Incentive Program. The peak demand forecast represents the net amount of load the electric grid must serve so that demand by self generation reduces the electric system peak. In the forecast, the growth in photovoltaic and other self-generation installations is assumed to reduce peak demand by 650 megawatts by 2018, based on current costs and program performance. If the installed cost of photovoltaic systems declines significantly, either through reductions in component or installation costs or increases in federal/state tax credits, this projection could easily be exceeded.
>
> In the entire Central Valley and desert regions of the state, demand is projected to increase by 5,500 megawatts during the forecast period. Forty percent of this (2,200 megawatts) is in the Inland Empire area served primarily by Southern California Edison (SCE) and Riverside Public Utility. The remaining, 2,300 megawatts, is growth in the Central and Sacramento Valley areas, served by Pacific Gas and Electric (PG&E), Sacramento Municipal Utility District (SMUD), and other utilities. Projected electricity demand growth, while doubling, is noticeably less in the more developed coastal areas served by PG&E and SCE than it is in the valley/desert areas."

Figure 9-4 in Section 9 was taken from the above-mentioned report and shows the tremendous growth in peak electrical demand in Southern California expected to occur between 2012 and 2018. This is the timeframe during which the Eagle Mountain Pumped Storage Project will be coming on-line.

In November 2007, CEC prepared the California Energy Demand 2008-2018 Staff Revised Forecast. Chapter 3 of that report deals with the SCE Planning Area, which includes: 1) SCE bundled retail customers, 2) customers served by energy service providers (ESPs) using the SCE distribution system to deliver electricity to end users, and 3) customers of the various Southern California municipal and irrigation district utilities, excluding the cities of Los Angeles, Pasadena, Glendale, and Burbank and the Imperial Irrigation District. Forecasted energy consumption and peak loads for the SCE planning area, including both total and per capita values, are presented.

Forecasts for the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI) and estimates of conservation savings are also provided.

Table 6-1 from that report compares the revised electricity consumption forecast with the draft 2008-2018 forecast and 2006 forecast. The revised forecast is higher than both of the previous forecasts over the forecast period and by 2018, the revised forecast is about 2.5 percent higher than the draft forecast and 4.5 percent higher than the 2006 forecast. This results from incorporation of the new Department of Finance (DOF) long-term population projections. DOF raised its projection of population in the SCE planning area, particularly in the hotter Inland Empire region of the planning area. Table 5-2 presents a similar comparison for the peak demand forecasts. The increase in peak demand of the revised forecast is driven by the underlying changes in the energy consumption forecasts. The increase in the 2008–2016 growth rate of the revised forecast compared with the previous two forecasts is primarily driven by the revised DOF population forecast used in the revised forecast. The Table 5-2 projections are shown in graphical format on Figure 9-5, which was taken from the CEC 2008-2018 forecasts.

Table 6-1: SCE Planning Area Energy Forecast Comparison

Consumption (GWH)					
	CED 2006	**Staff Draft**	**Staff Revised**	**Percent Difference Staff Revised/*CED 2006***	**Percent Difference Staff Revised/Staff Draft**
1990	81,579	82,069	82,069	0.60%	0.00%
2000	98,346	99,148	99,146	0.81%	0.00%
2005	99,531	99,136	99,261	-0.27%	0.13%
2008	103,437	105,106	105,054	1.56%	-0.05%
2013	109,931	112,064	113,815	3.53%	1.56%
2016	113,409	115,627	118,497	4.49%	2.48%
Average Annual Growth Rates					
1990-2000	1.89%	1.91%	1.91%		
2000-2005	0.24%	0.00%	0.02%		
2005-2008	1.29%	1.97%	1.91%		
2008-2016	1.16%	1.20%	1.52%		
Historic values are shaded					

Source: California Energy Commission, 2007

Table 6-2: SCE Planning Area Peak Forecast Comparison

Peak (MW)					
	CED 2006	Staff Draft	Staff Revised	Percent Difference Staff Revised/*CED 2006*	Percent Difference Staff Revised/Staff Draft
1990	17,564	17,635	17,635	0.41%	0.00%
2000	19,465	19,408	19,408	-0.29%	0.00%
2005	21,510	21,956	21,956	2.07%	0.00%
2008	22,483	23,142	23,272	3.51%	0.56%
2013	24,059	24,674	25,258	4.98%	2.37%
2016	24,934	25,513	26,382	5.81%	3.40%
Average Annual Growth Rates					
1990-2000	1.03%	0.96%	0.96%		
2000-2005	2.02%	2.50%	2.50%		
2005-2008	1.49%	1.77%	1.96%		
2008-2016	1.30%	1.23%	1.58%		
Historic values are shaded					

Source: California Energy Commission, 2007

6.2 Power Utilization

The Eagle Mountain Project is anticipated to be on-line in 2015-2016 and will be available to assist in meeting the nearly 4,000 MW increase in peak demand over the next decade, as well as the ancillary services described above that are essentially to successful attainment of California's RPS goals of 33 percent by the year 2020, and concurrent related decreases in emissions of greenhouse gases.

6.3 Power Consumption

The maximum amount of pumping energy that could be consumed annually by the Project is in the range of 3,500 GWh, but will depend on how the project is operated to meet peak demands and how ancillary benefits are accessed and managed. ECE's station service load is expected to be negligible. The largest potential load associated directly with construction and operation of the Project will be for the reverse osmosis (RO) treatment system. Since the RO system will utilize head to run the membranous system, it will be more efficient than most desalinization plants that use electricity.

7 Plans for Future Development

The site has potential for adding capacity up to well over 1,300 MW, perhaps as much as 3,500 MW. This would require raising the upper reservoir dams and adding dams to fully contain a higher lower reservoir. Alternatively, the amount of storage could be kept the same as currently proposed (17,700 acre-feet) and the hours of generation decreased to support a higher installed capacity. Further development of the site up to its full potential may be considered by ECE in the future, depending on the performance of the currently proposed 1,300 MW development and the market for additional pumped storage capacity.

8 Literature Cited

California Energy Commission. (2007). California Energy Demand 2008-2018 Staff Revised Forecast. Staff Final Report. CEC-200-2007-015-SF2.

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9 Figures

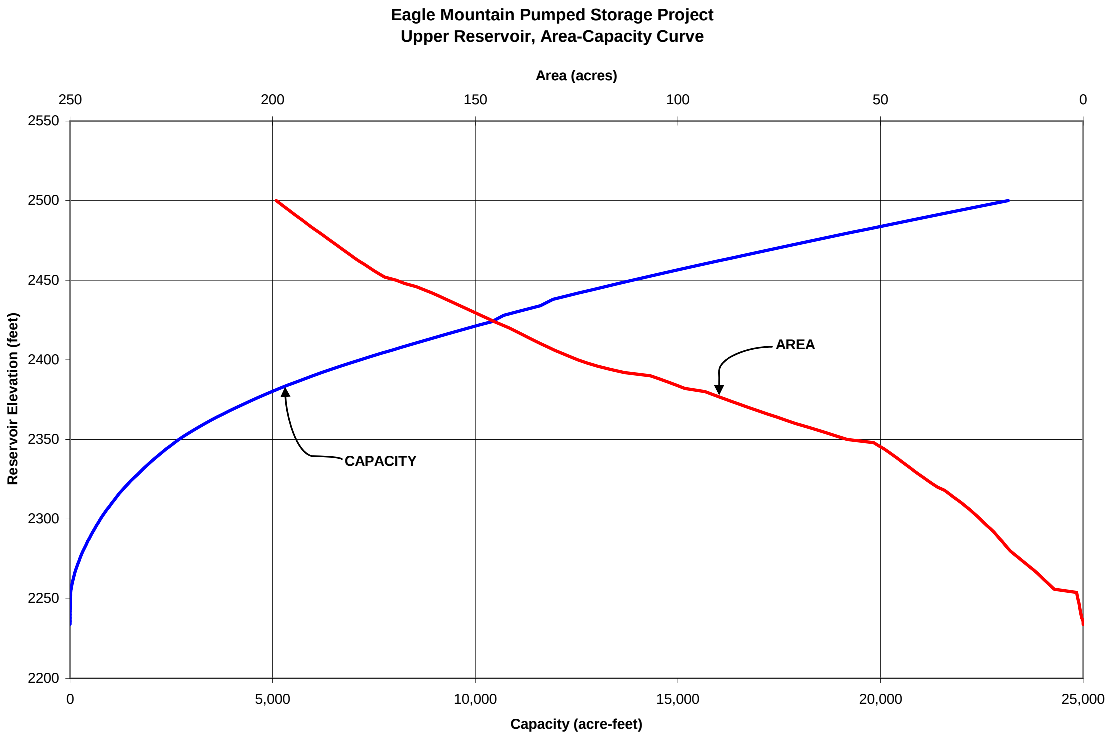


Figure 9-1: Upper Reservoir Area-Capacity Curve

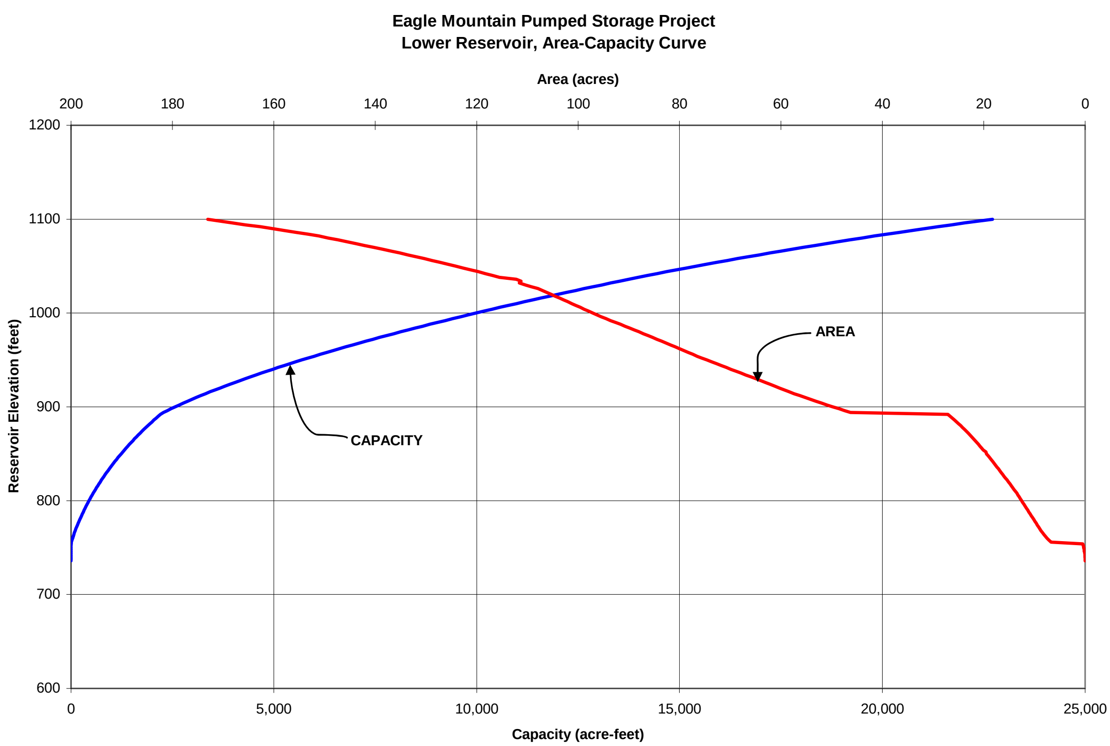


Figure 9-2: Lower Reservoir Area-Capacity Curve

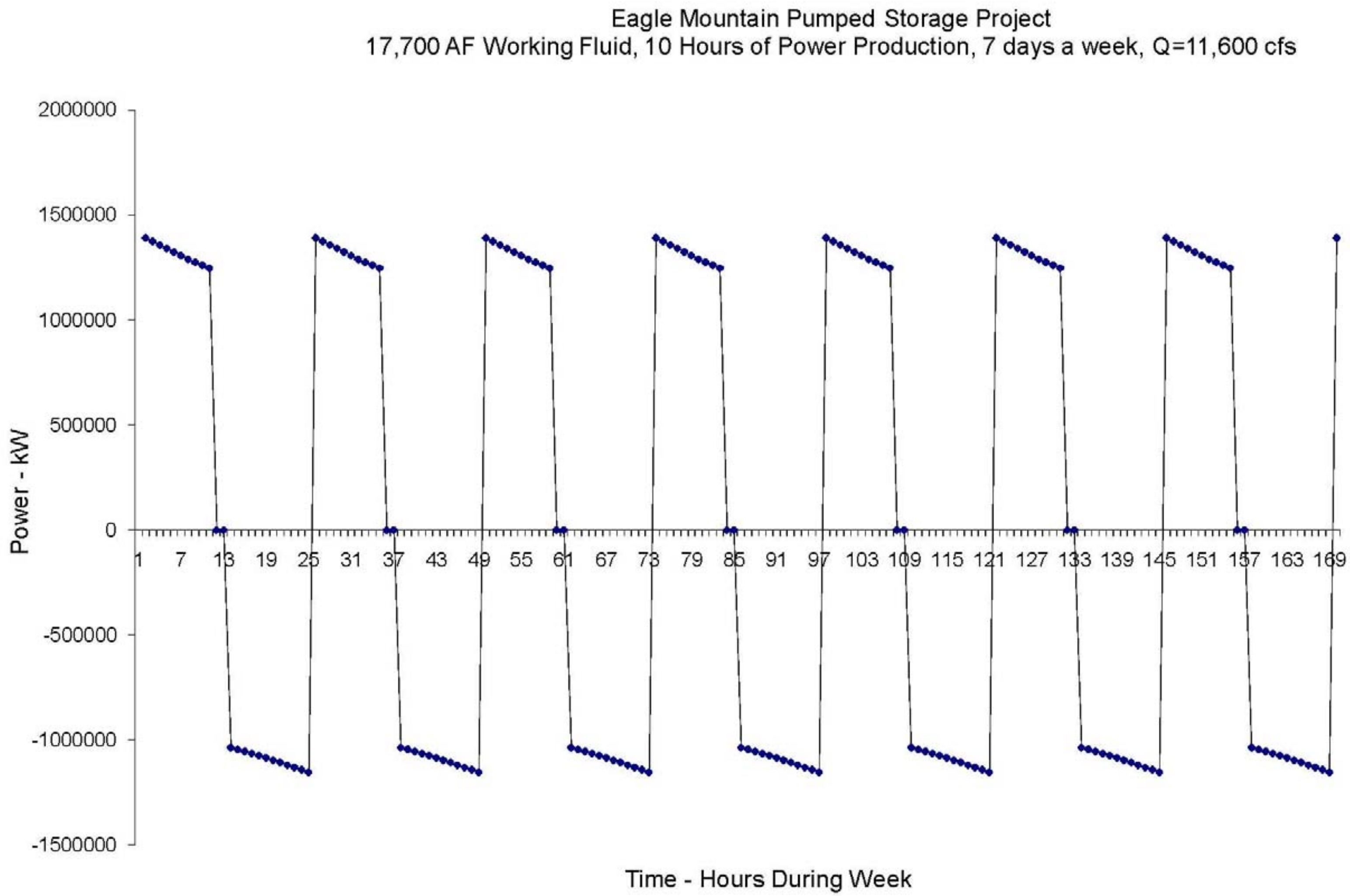


Figure 9-3: Typical Weekly Operation of the Eagle Mountain Pumped Storage Project

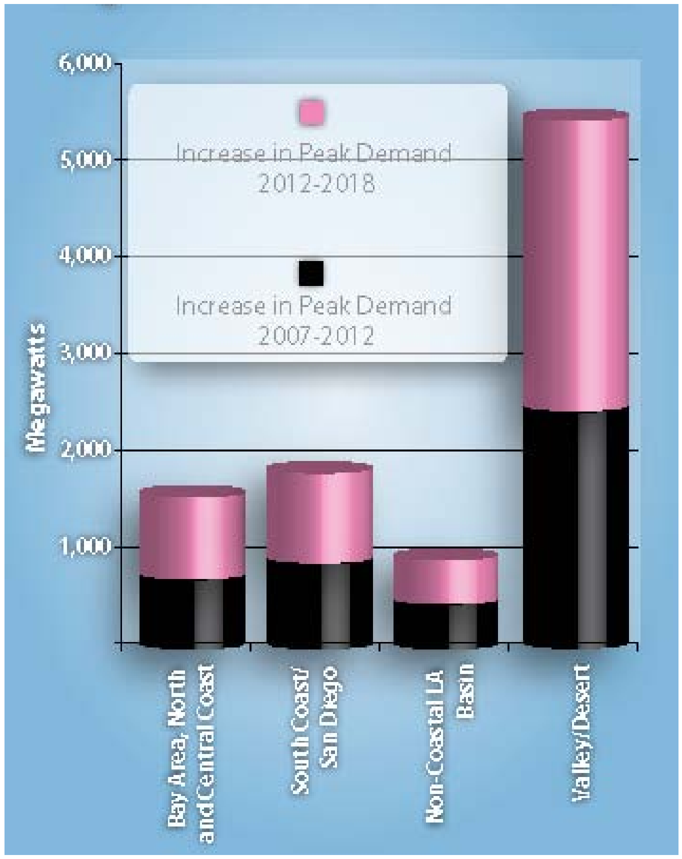
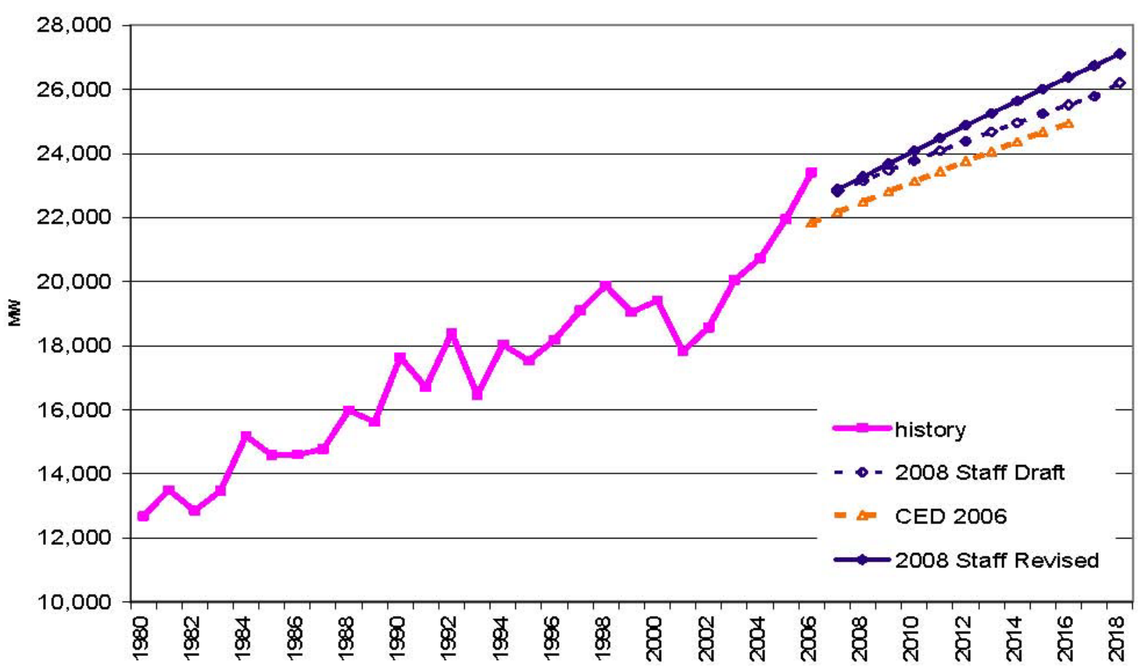


Figure 9-4: Regional Growth in Peak Demand. Source: California Energy Commission, California Energy Demand 2008–2018, CEC-200-2007-015-SF2.



Source: California Energy Commission, 2007.

Figure 9-5: SCE Planning Area Peak Demand Forecast

PUBLIC

Eagle Mountain Pumped Storage Project No. 13123

Final License Application

Volume 1 of 6

Exhibit C

Project Schedule

Palm Desert, California

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

Date: June 22, 2009
GEI Project No. 080473

Table of Contents

This license application is organized into six volumes, as described below:

Volume 1	Initial Statement and Exhibits A, B, C, and D	Public
Volume 2	Exhibit E, Applicant Prepared Environmental Impact Statement	Public
Volume 3	Appendices to Exhibit E, Applicant Prepared Environmental Impact Statement	Public
Volume 4	Privileged information for Exhibit E, Applicant Prepared Environmental Impact Statement	Privileged, not for release
Volume 5	Exhibit F, Supporting Design Report	Critical Energy Infrastructure Information (CEII), not for release
Volume 6	Exhibit G	Public

1 Proposed Commencement and Completion Dates

The preliminary development schedule for the Eagle Mountain Pumped Storage Project is presented in Figure 4-1. The key dates, which have been established or forecast, are as follows:

Table 1-1: Proposed Commencement and Completion Dates

Submission of License Application to FERC	May 2009
Granting of License by FERC	July 2010
Completion of Land Lease Arrangements	August 2010
Completion of Power Purchase Agreements	August 2010
Completion of Financing Arrangements	August 2011
Start of Construction	June 2012
Commercial Operation of First Unit	July 2015
Entire Project Commercial Operation	June 2016

The construction schedule presented herein indicates an estimated 4 years for construction of the main project facilities.

2 Operation Dates

As noted above, Unit 1 is scheduled for start of commercial operation in July 2015. Subsequent units are scheduled with an interval of three months: Unit 2 in October 2015, Unit 3 in January 2016, and Unit 4 in March 2016 to complete the plant June 2016. The reservoirs will be filled by pumping of ground water from a well-field developed as part of the project. Three wells each pumping 2,000 gallons per minute (gpm) will deliver 26.5 acre-feet per day. Water will be pumped from the water supply wells to the lower reservoir as soon as the wells and conveyance pipeline are completed and the lower reservoir has been prepared for water storage. The schedule on Figure 4-1 indicates reservoir filling would begin March 2014 and that start-up of Unit 1 would begin in July 2015.

It is very likely that storage of water in the lower reservoir could begin prior to March 2014, because preparation of the lower reservoir (mainly in seepage control measures and I/O construction) could be advanced earlier in the construction schedule than is currently shown. Even if reservoir filling did not begin until March 2014, approximately one-fourth of the active reservoir volume and all of the dead storage could be filled in approximately 14 months, sufficient to allow the initial unit start-up. Commercial operation of the project will not require that the total active reservoir volume (17,700 acre-feet) be in storage; however, full benefits may not be achievable until the full active storage volume is in place.

3 Previously Constructed Facilities

There are no previously constructed facilities associated with the hydroelectric power generation facilities that will be a part of this Project.

4 Schedule

4.1 First Year of Construction

General:

- Mobilize and construct temporary office, storage, maintenance and staging facilities.
- Construct and improve permanent and construction access roads.

Water Conduits:

- Proceed and erect Tunnel Boring Machine and start excavation of tailrace tunnel.

Power Plant:

- Construct access tunnel portal and start excavation of access tunnel.

Upper Reservoir:

- Excavation of approach channel to inlet/outlet works.

Lower Reservoir:

- Start moving unstable tailings pile.
- Start implementing seepage control measures.

Switchyard:

- Start switchyard construction.

Transmission line:

- Start construction of transmission line foundations.

4.2 Second Year of Construction

Upper Reservoir:

- Complete excavation of approach tunnel.
- Complete construction of the south and west dams.
- Start construction of inlet/outlet structures.
- Start implementing seepage control measures.

Lower Reservoir:

- Complete moving unstable tailings pile.
- Seepage control liner blanketing.
- Construct inlet/outlet works.
- Complete seepage control measures.
- Install water pipeline from wells, pumping plant, and reverse osmosis system.
- Begin to fill lower reservoir.

Water Conduits:

- Complete tailrace tunnel, manifold and draft tube tunnels.
- Move and erect Tunnel Boring Machine and excavate upper pressure tunnel.
- Excavate lower pressure tunnel, manifold and penstock tunnels.
- Excavate pressure shaft.
- Install steel tunnel linings.

Power Plant:

- Complete majority of under ground power plant access.
- Finish excavation of access tunnel.
- Excavate powerhouse cavern.
- Excavate transformer gallery caverns.
- Excavate cable tunnel and shaft, imbed spiral cases and draft tube liners.
- Start to install pump/turbines and generators.
- Start first stage and second stage concrete.
- Start to install electrical and mechanical equipment.

Transmission Line:

- Build foundations and towers.
- String high voltage transmission wires.

Switchyard:

- Complete switchyard and install equipment.

4.3 Third Year of Construction

Upper Reservoir:

- Seepage control by blanketing with fines and grouting.
- Complete inlet/outlet works.

Lower Reservoir:

- Continue filling lower reservoir.

Water Conduits:

- Finish excavation of pressure shaft.
- Construct downstream surge chambers.
- Concrete line penstock and draft tube manifolds.
- Install steel linings in penstocks and concrete linings in draft tube tunnels.

Power Plant:

- Complete excavation of transformer gallery caverns.
- Construct cable tunnel and shaft.
- Complete first stage concrete.
- Start and complete superstructure concrete.
- Continue installation of pump/turbines.
- Continue installation of motor/generators.

- Continue installation of other mechanical and electrical equipment.
- Install water delivery pipeline, pump, and reverse osmosis system.
- Installation of mechanical and electrical equipment.

Transmission Line:

- Complete foundations and build towers.
- String high voltage transmission wires.

4.4 Fourth Year of Construction

Power Plant:

- Finish installation of pump/turbines.
- Finish installation of motor/generators.
- Continue and finish installation of other mechanical and electrical equipment.
- Start architectural construction.
- Begin startup and testing of units.
- Commission unit 1.
- Commission units 2, 3 and 4 at three month intervals ending the beginning of April.
- Complete architectural work.

Transmission Line:

- Test and energize high voltage transmission line.

Commercial Operation:

- June 2016.

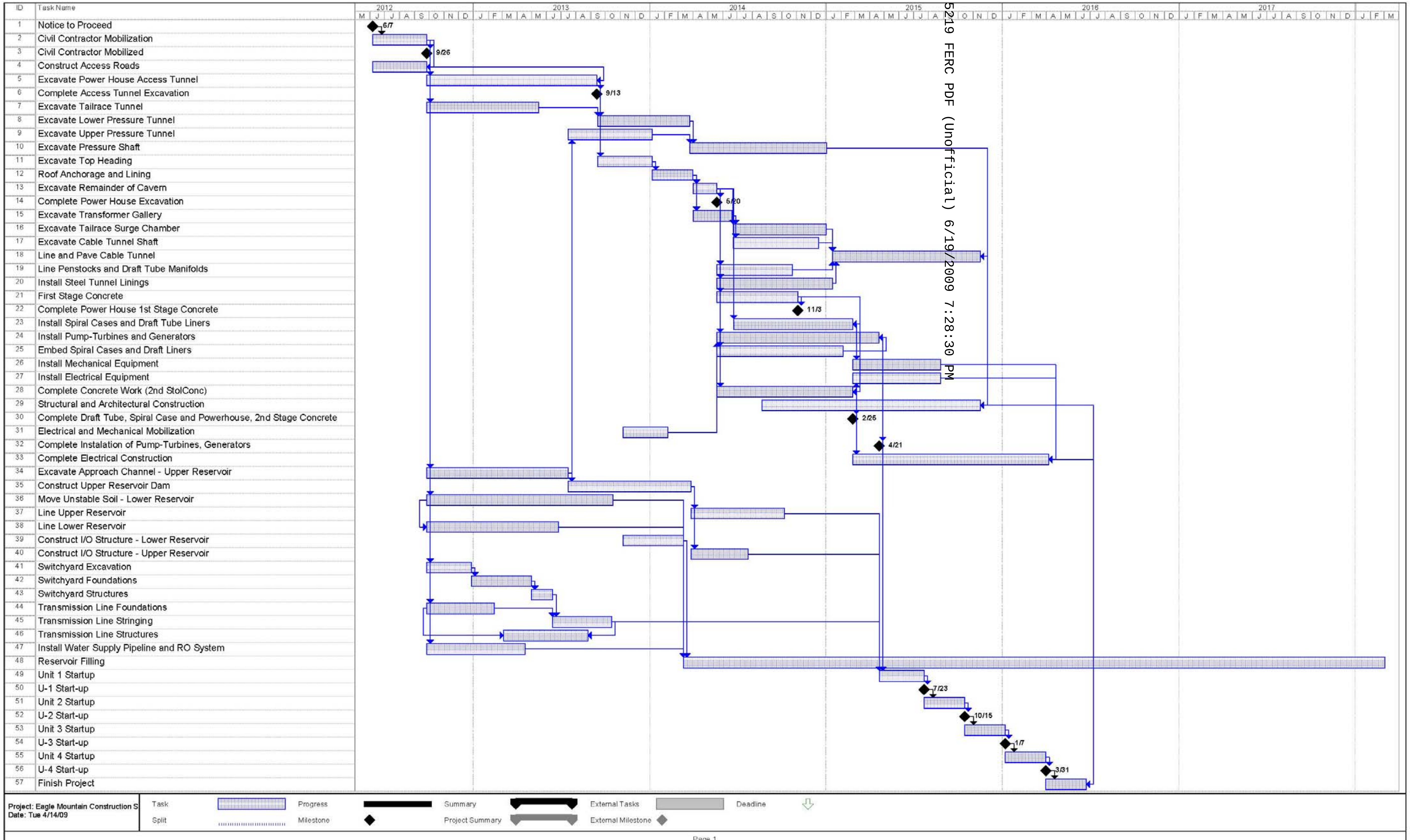


Figure 4-1: Preliminary Development Schedule

Eagle Mountain Pumped Storage Project No. 13123

Final License Application

Exhibit D

Project Costs and Financing

Palm Desert, California

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

Date: June 22, 2009
Project No. 080473

Table of Contents

Tables

1 Estimated Construction Costs

1.1 Summary

The construction costs for the 1300 megawatt (MW) Eagle Mountain Pumped Storage Project are summarized in Table 1-1, categorized by FERC account numbers. The direct project construction cost estimate is $1,171 million, including a provision for the main transmission interconnection line cost.

Table 1-1: Eagle Mountain Pumped Storage Project Preliminary Construction Cost Estimate (2009 Dollars)

Account No.	Description	Amount ($)
330	Land and Water Rights	33,264,000
331	Structures & Improvements	107,088,100
332	Reservoirs, Dams, & Waterways	392,446,900
333	Waterwheels, Turbines, & Generators	263,118,400
334	Accessory Electrical Equipment	208,635,900
335	Miscellaneous Powerplant Equipment	47,175,400
336	Road, Rails, & Bridges	68,445,600
353	Substation & Switch Station Equipment	17,249,700
354/356	Transmission Line	34,020,000
	Subtotal Direct Construction Cost	**$1,171,444,000**
71	Engineering, Permitting and CM	76,144,000
75	Sales Tax	22,697,000
76	Owners Administration and Legal	15,228,000
77	Interest During Construction	124,915,000
	Subtotal Overhead Costs	**238,984,000**
	TOTAL COST OF PROJECT	**$1,410,428,000**

Notes:
1. Contingencies, contractor mobilization, bonds and insurance are prorated into the individual line items.
2. Turbine generator and electrical equipments costs are based on quotation from Toshiba received in December 2008.

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 are a combination of Bureau of Land Management (BLM) and Kaiser Ventures, LLC. land. An exchange of lands between Kaiser and the 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. 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 following licensing and completion of the California Independent System Operator (CAISO) operational / interconnection analyses.

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 to develop the groundwater supply is treated as a component of the capital cost. Annual makeup water supply costs are a component of the operations and management cost.

The land acquisition costs will occur on an annual basis and are also included in the annual operating cost, rather than in the construction cost estimate. A lease cost allowance has been provided. The actual cost will be established in negotiations between Eagle Crest Energy (ECE) and Kaiser Ventures, LLC.

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. Costs were developed to correspond to prices as of early 2009.

1.4 Equipment Cost Estimate

The costs for the major equipment items have been based upon budget price quotations from suppliers of this equipment and discussions with multiple prospective vendors. Other mechanical and electrical equipment costs were estimated based on experience and information from similar projects. Costs were developed to correspond to materials and labor prices as of early 2009.

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 annual expenditure schedule for the project.

1.7 Escalation

Cost escalation from early 2009 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 engineering 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.

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 (2009 Dollars)

Operating Cost Elements	First 3 Years ($/yr)	Remaining Years ($/yr)
Property Tax	$7,670,000	$7,670,000
Water Pumping	$1,333,000	$170,000
Land Leases	$2,000,000	$2,000,000
Water Treatment	$720,000	$720,000
Property Insurance	$7,000,000	$7,000,000
Home Office Administration	$1,500,000	$1,500,000
Supplies and Parts	$2,500,000	$2,500,000
FERC Fees	$1,350,000	$1,350,000
Operations Staff	$800,000	$800,000
Maintenance and Parts	$4,600,000	$4,600,000
TOTAL OPERATING COST	**$29,473,000**	**$28,310,000**

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

The local property tax was estimated to be 1.1 percent of the estimated in-place facility value. 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 equivalent to $2 million per year.

4.4 Insurance

The estimated insurance premium is 1.0 percent of the estimated in-place facility value Permit Fees

The only known recurring permit fee will be for the FERC license. The FERC fee has historically been variable, depending upon FERCs' costs of administering their duties. The FERC permit fee is estimated to be $1.35 million per year, which was the maximum charge in 2008 escalated by 3 percent.

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.

4.5 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 and solar 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 Arizona.
- Other off-peak power available on the market from generation sources in California, Arizona, Nevada, and New Mexico.

The Applicant expects that the future spot market cost differential between on-peak and off-peak energy will be significant and will provide an adequate revenue stream to offset the total annual costs of the project and provide a reasonable rate of return to ECE and investors.

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. Revenues from the Project will depend upon Market Clearing Prices established by the CAISO. The CAISO provides day ahead hourly forecasts of load and market clearing prices. The Project can tailor its operations to take advantage of the marketplace.

5.1 Capacity Cost of the Project

The levelized annual cost of the Project is estimated to be approximately $140 per kilowatt –year (kW-yr) 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 $33.1 million in 2009.

5.2 Energy Costs of the Project

On-peak energy will be produced by the Project at a levelized cost of $140 per kW-yr, as shown in Table 5-1.

Table 5-1: Pumped Storage Project Cost

Overall	
Cycle Efficiency	80%
Total Project Cost ($1000)	$1,285,500,000
Installed Capacity (kW)	1,300,000
Project Life, Years	50
Cost per kW	$989
Debt Structure	
Equity	30%
Return on Equity (ROE)	15%
Equity Amount	$385,650,000
Annual Return on Equity (ROE)	$57,847,500
Debt	70%
Debt Amount	$899,850,000
Interest Rate	6%
Terms, Years	20
Annual Debt Service	$78,453,000
Total Debt Service + ROE	
Yr (1-20)	$136,300,500
Yr (21-50)	$57,847,500
Annual Expenses	
O&M	$28,310,000
Levelized O&M	$45,626,000
Cost of Debt Service + ROE ($/kW)	$104.85
Fixed Expense ($kW)	$35.10
Total Levelized Cost ($kW)	**$139.94**

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 5-1 indicates that the levelized 2007 energy production cost for investor-owned utility combined cycle plants in California is on the order of $95 per megawatt hour (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-yr. The same cost for a 50 MW combustion turbine is $162.1 per kW-yr. 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 $138 per kW-yr, compared to the $140 per kW-yr 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 opt for load shedding to the maximum level tolerable. There are dynamic benefits (voltage regulation, black start capability and load following), 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 $5 million.

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 that the annual revenue 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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