Initial Statement

SOUTHERN CALIFORNIA EDISON COMPANY
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company P-67

APPLICATION FOR LICENSE FOR MAJOR PROJECT–EXISTING DAM

1. Southern California Edison Company (SCE or Applicant) applies to the Federal Energy Regulatory Commission (Commission) for a new License for the Big Creek Nos. 2A, 8 and Eastwood Power Station Hydroelectric Power Project (Project), as described in the attached exhibits. The existing Project is designated as Project No. 67 in the records of the Commission, pursuant to a License issued by the Commission on August 9, 1978, and effective on August 1, 1978, for a period of 31 years from the expiration date of the prior long-term license, and terminating on February 28, 2009. This Application For New License for Major Project – Existing Dam is filed pursuant to 18 CFR §§ 4.51 and 16.9.

2. The location of the project is:

   State: California
   County: Fresno County
   Nearby Town: Shaver Lake
   Stream(s): South Fork San Joaquin River, Big Creek and Stevenson Creek

3. The exact name and business address of the applicant are as follows:

   Southern California Edison Company
   Attention: Nino J. Mascolo
   Senior Attorney
   P.O. Box 800
   Rosemead, California 91770
   (626) 302-4459

The exact name and business address of the person authorized to act as agent for the Applicant in this Application is

Russ W. Krieger
Vice President, Power Production
Southern California Edison Company
300 N. Lone Hill Avenue
San Dimas, CA 91773
(909) 394-8667

4. The Applicant is a domestic corporation. No municipal preference exists under section 7(a) of the Federal Power Act for this existing licensed Project.

5(i). The statutory or regulatory requirements in California, the state in which the Project is located, that affect the Project with respect to the 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 are:

California Water Code Section 1200, et seq.; Title 23 California Code of Regulations Section 650, et seq., permits an application to be filed with the California Water Resources Control Board to obtain a permit or license to appropriate water, which is otherwise declared unappropriated, for beneficial uses including power uses.

California Water Code Section 13160; Title 23 California Code of Regulations Section 3855, regulates the federally required filing of applications for water quality certification with the California Water Resources Control Board.

Public Utilities Code, Section 201, et seq., regulates the right of the public utility to produce, generate, transmit, or furnish power to the public.

5(ii). The steps which the Applicant has taken or plans to take to comply with each of the laws cited above are:

Applicant has either obtained the necessary permits and licenses or otherwise acquired water rights by appropriation and/or prescription for use of Project water.

Licensee will file an application for a water quality certificate or waiver thereof with the California Water Resources Control Board in accordance with applicable state law and the Commission's regulations.

The California Public Utilities Commission has authorized SCE to produce, generate, transmit, or furnish power to the public.

6. The Applicant is the owner and existing licensee of the Project. The dam associated with the Project is not federally owned or operated.

Date: 2|21|07

By: Russ W. Krieger

Russ W. Krieger
Vice President, Power Production

VERIFICATION

This Application For New License For Major Project – Existing Dam is executed in the

STATE OF CALIFORNIA
CITY OF SAN DIMAS
COUNTY OF LOS ANGELES

By: Russell W. Krieger
Vice President, Power Production
Southern California Edison Company
300 N. Lone Hill Avenue
San Dimas, California 91773

Russell W. Krieger, being first duly sworn, deposes and says: that he is a Vice President of Southern California Edison Company, the Licensee making the Application for New License for the Big Creek Nos. 2A, 8 and Eastwood Power Station Hydroelectric Power Project (FERC Project No. 67); that the contents of this Application are true to the best of his knowledge and belief. The undersigned Applicant has signed the Application this 21st day of February, 2007.

R W Krieger

Russell W. Krieger
Vice President, Power Production

State of California
County of Los Angeles

On Feb. 21, 2007 before me, Lisa A. Smith, Notary Public personally appeared Russell W. Krieger personally known to me to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

WITNESS my hand and official seal.

LISA A. SMITH
Commission # 1712414
Notary Public - California
Los Angeles County
MyComm. Expires Dec 23, 2010

Lisa A Smith

Notary Public

Section 4.32 General Information

This section of the Application for New License for the Project is intended to set forth the information required by 18 C.F.R. §4.32, as follows:

a) Each applicant must:

(1) For a preliminary permit or license, identify 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;

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

(i) Every county in which any part of the project, and any Federal facilities that would be used by the project, would be located:

(ii) Every city, town, or similar local potential 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 has a population of 5,000 or more people and is located within 15 miles of the project dam;

(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;

(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

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

(1) To the knowledge of Southern California Edison Company (SCE), no person, citizen, association of citizens, domestic corporation, municipality, or state, other than SCE has or intends to obtain any proprietary right necessary to construct, operate, or maintain the Project.

(2) (i) All Project boundaries and facilities are located in the County of Fresno, which has its principal administrative office located at:

Fresno County
Board of Supervisors
2281 Tulare Street, Room 301
Fresno, CA 93721

(ii) None of the Project boundaries or facilities are located within any city, town, or other similar local political subdivision. There are no communities of 5,000 or more people located within 15 miles of the Project.

(iii) There are no irrigation districts, drainage districts, or other similar special purpose political subdivisions located within the Project area or which own, operate, or maintain any Project facilities. The Project does not use any federal facilities.

(iv) The following political subdivisions or nonpolitical organizations in the general area of the Project may be interested in the application:

Shaver Lake Chamber of Commerce
P.O. Box 58
Shaver Lake, CA 93664

North Fork Chamber of Commerce
P.O. Box 426
North Fork, CA 93643

North Fork Community Development Council
P.O. Box 1484
North Fork, CA 93643

Sierra Unified School District
31795 Lodge Road
Auberry, CA 93602

Big Creek Elementary School District
55190 Point Road
Big Creek, CA 93605

Pine Ridge Elementary School District
45828 Auberry Road
Auberry, CA 93602

Chawanakee School District
P.O. Box 400
North Fork, CA 93643

Toby Horst
Director, Sierra Resource Conservation District
36281 Lodge Road
Tollhouse, CA 93667

(v) The Federally recognized Indian tribes and other Indian organizations that may be affected by, or interested in, the Project include:

Big Sandy Rancheria*
P.O. Box 337
Auberry, CA 93602

Cold Springs Rancheria*
P.O. Box 209
Tollhouse, CA 93667

North Fork Rancheria*
P.O. Box 929
North Fork, CA 93643

Dunlap Band of Mono Indians
P.O. Box 344
Dunlap, CA 93621

Picayune Rancheria*
46575 Road 417
Coarsegold, CA 93614

Table Mountain Rancheria*
23736 Sky Harbor Road
P.O. Box 410
Friant, CA 93626

Mono Nation
P.O. Box 800
North Fork, CA 93643

North Fork Mono Tribe
13396 Tollhouse Road
Clovis, CA 93611

Sierra Nevada Native American Coalition
P.O. Box 125
Dunlap, CA 93621

Bishop Tribal Council
50 Tu Su Lane
Bishop, CA 93514

Sierra Mono Museum
33103 Road 288
North Fork, CA 93643

Native Earth Foundation
34329 Shaver Springs Road
Auberry, CA 93602

Michahai Wuksachi
1174 Rockhaven Ct
Salinas, CA 93906

*Federally recognized tribal organization

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 2A, 8 AND EASTWOOD (FERC Project No. 67)

EXHIBIT A: DESCRIPTION OF PROJECT

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit A Description of Project

Exhibit A is a description of the project. This exhibit need not include information on project works maintained and operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, or any other department or agency of the United States, except for any project works that are proposed to be altered or modified. If the project includes more than one dam with associated facilities, each dam and the associated component parts must be described together as a discrete development. The description for each development must contain:

> (1) The physical composition, dimensions, and general configuration of any dams, spillways, penstocks, powerhouses, tailraces, or other structures, whether existing or proposed, to be included as part of the project;
>
> (2) The normal maximum surface area and normal maximum surface elevation (mean sea level), gross storage capacity and usable storage capacity of any impoundments to be included as part of the project;
>
> (3) The number, type, and rated capacity of any turbines or generators, whether existing or proposed, to be included as part of the project;
>
> (4) The number, length, voltage, and interconnections of any primary transmission lines, whether existing or proposed, to be included as part of the project [see 16 U.S.C. 796(11)];
>
> (5) The specifications of any additional mechanical, electrical, and transmission equipment appurtenant to the project; and
>
> (6) All lands of the United States that are enclosed within the project boundary described under each paragraph (h) of this section (Exhibit G), identified and tabulated by legal subdivisions of a public land survey of the affected area or, in the absence of a public land survey, by the best available legal description. The tabulation must show the total acreage of the lands of the United States within the project boundary.

(1) General Configuration

Three powerhouses are associated with this Project. The Big Creek Powerhouse Nos. 2A (BC 2A) and 8 (BC 8) and the Eastwood Power Station (EPS) facilities are located on the western slope of the Sierra Nevada range, northeast of the City of Fresno, California. BC 2A and BC 8 are located on Big Creek, a tributary to the San Joaquin River near the town of Big Creek, approximately 68 miles northeast of the City of Fresno. The EPS is located approximately 1 mile from the northeastern end of Shaver Lake Reservoir in an underground chamber and approximately 50 miles northeast of the City of

Fresno. Project facilities, shown in Figure A-1, are located in Fresno County, California and within the Sierra National Forest (SNF) which is administered by the United States Department of Agriculture-Forest Service (USDA-FS). The Project is operated as a reservoir-storage and pumped-storage type project with an installed operating capacity of 384.80 MW.

The two major reservoirs associated with this Project are Florence Lake, with a storage capacity of 64,406 acre-feet, and Shaver Lake, with a storage capacity of 135,568 acre-feet. In addition, there are two moderate impoundments associated with this Project, Mono Diversion Forebay, with a capacity of 46 acre-feet, and Bear Diversion Forebay, with a capacity of 103 acre-feet. Water for Powerhouse No. 2A is taken from Shaver Lake and conveyed through Tunnel No. 5. Water for Powerhouse No. 8 is taken from water impounded behind Dam 5 on Big Creek and conveyed through Tunnel No. 8. Water for the EPS is taken from the Balsam Meadow Forebay, which is supplied by water carried down the Huntington-Pitman-Siphon (Tunnel 7) from Huntington Lake and Pitman Creek in generating mode, or from Shaver Lake in pump-back mode.

There is one primary transmission line associated with the Project, the Eastwood-Big Creek No. 1 Transmission Line, which carries power between the EPS switchyard and the Big Creek No. 1 switchyard. The energy generated by the Project is transmitted to the SCE transmission and distribution system, and used for public utility purposes.

Big Creek Powerhouse No. 2A

Florence Lake Dam

Florence Lake Dam impounds the Florence Lake reservoir, with a storage capacity of 64,406 acre feet at the spillway elevation of 7,327.5 feet msl. Inflow to the reservoir comes from the South Fork of the San Joaquin River above the reservoir and from Hooper, Tombstone, North Slide, South Slide, and Crater creeks. Up to 1,760 cfs from the reservoir is normally diverted through Ward Tunnel to supply water to Huntington Lake. Part of this discharge, up to 724 cfs, passes through the non-Project Portal Powerhouse (FERC Project No. 2174) before entering Huntington Lake. Florence Lake acts as a storage reservoir for the Huntington and Shaver chains of powerhouses and as a storage reservoir for the Portal Powerhouse. Water level in the reservoir varies considerably throughout the year. The reservoir is normally drawn down to below the bottom of the dam to avoid freeze-thaw damage to the dam face in winter. A minimum pool of 1,000 acre-feet is maintained over the winter to protect overwintering fish.

Placeholder for Figure A-1
Project Facilities Big Creek 2A, 8 and Eastwood

Non-Internet Public Information

This Figure has been removed in accordance with the Commission regulations at 18 CFR Section 388.112.

This Figure is considered Non-Internet Public information and should not be posted on the Internet. This information is provided in Volume 3 of the Application for New License and is identified as “Non-Internet Public” information. This information may be accessed from the FERC’s Public Reference Room, but is not expected to be posted on the Commission’s electronic library, except as an indexed item.

Florence Lake Dam is located across the South Fork of the San Joaquin River, within Section 36, T7S, R27E, and Section 1, T8S, R27E, M.D.B. and M. It is a concrete gravity multiple-arch dam with 58 arches, 149 feet high. The Crest, at an elevation of 7,329 feet msl, is 3,156 feet long. The arches each have a 50-foot span and are inclined 48 degrees to the vertical. The thickness of the uppermost 34 feet of the arches is 18 inches, while the maximum thickness at the lowest point is about 4.5 feet. The buttresses that support the arches have a maximum thickness of 2.25 feet at the top.

The spillway is a concrete structure located near the middle of the dam with a total crest length of 100 feet at an elevation of 7,315.5 feet msl. The spillway has two 50-foot by 14-foot drum gates with an effective operating height of 12 feet. Both gates are manually operated and are positioned by adjusting the discharge elevation. The spillway has a maximum rated discharge capacity of 15,800 cfs at a reservoir elevation of 7,329 feet.

Two 36-inch diameter cast iron drain pipes pass through the base of Arch 53 at an elevation of 7,214 feet msl. Flow through the right side pipe is controlled by a permanently-closed 46 by 46-inch slide gate at the dam upstream face. Flow through the left side pipe is controlled by a permanently-open 46 by 46-inch slide gate at the dam upstream face and a manually-operated, 36-inch gate valve at the downstream end of the pipe. A 12-inch diameter steel pipe, for minimum water release, connects to the 36-inch gate valve downstream of the valve to provide fish water releases.

The dam's outlet works, located behind full-height trash racks on the western shore of Florence Lake, form the entrance to the Ward Tunnel which leads to the Portal Powerhouse (FERC Project No. 2174) and Huntington Lake (FERC Project No. 2175). Releases from Florence Lake reservoir are made through Ward Tunnel from an intake on the shore of Florence Lake about 2,000 feet from the left abutment. The 15-foot diameter Ward Tunnel has an invert at an elevation of 7,220 feet. Flow through the tunnel is controlled by two 110-foot high, 72-inch diameter cylindrical gates at the entrance to the intake. The gate stems are powered by hydraulic cylinders, driven by an electric-motor-driven pump supplied with energy from local, propane-fueled, engine-generator sets.

Crater Creek Diversion

Crater Creek Diversion Dam is located across Crater Creek within Section 34, T7S, R27E, M.D.B. and M. It is a 3-foot high concrete dam. The top, at an elevation of 8,764.6 feet msl, is 21 feet long. Water diverted by the dam is conveyed through a combination of ditch and natural channel, 7,260 feet long, to Florence Lake. The Crater Creek Diversion is proposed for decommissioning by the Licensee.

Tombstone Creek Diversion

Tombstone Creek Diversion Dam is located across Tombstone Creek within Section 31, T7S, R28E, M.D.B. and M. It is a 5-foot high masonry dam. The top, at an elevation of 7,673 feet msl, is 26.4 feet long. Water diverted by the dam is conveyed through a combination of 14-inch diameter steel pipe and natural channel, 3,299 feet long, to Florence Lake. Flow through the conduit is controlled by a manually operated 24-inch gate located on the upstream face of the dam. The Tombstone Creek Diversion is currently out of service and is proposed for decommissioning by the Licensee.

North Slide Creek & South Slide Creek Diversions

North Slide Creek Diversion Dam is located across Slide Creek within Section 30, T7S, R28E, M.D.B. and M. It is a 5-foot high masonry dam. The top, at an elevation of 7,501.5 feet msl, is 19 feet long.

South Slide Creek Diversion Dam is located across Slide Creek within Section 30, T8S, R28E, M.D.B. and M. It is a 5-foot high masonry dam. The top, at an elevation of 7,501.5 feet msl, is 22 feet long.

Water diverted by the North and South Slide Creek Diversion Dams is conveyed through an 8-inch diameter steel pipe (currently not in service) between the dams to a wye junction, and then through a 1,028-foot-long, 12-inch-diameter steel pipe into the Hooper Creek conduit. Flow through the conduits is controlled by manually operated 14-inch gates located on the upstream face of each dam.

The North and South Slide Creek Diversions are proposed for decommissioning by the Licensee.

Hooper Creek Diversion

The Hooper Creek Diversion Dam is located across Hooper Creek within projected Section 19, T7S, R28E, M.D.B. and M. It is a 30-foot high concrete dam. The crest, at an elevation of 7,507 feet msl, is 158 feet long. The spillway, which is an overpour type, located on the left side of the dam, is 75 feet long with a crest elevation of 7,505 feet msl. Water diverted by the dam is conveyed through a 34-inch diameter, 13,097 feet long, steel pipe to Florence Lake. Flow through the conduit is controlled by a manually operated 48-inch head gate located on the upstream face of the dam.

Chinquapin Creek Diversion

Chinquapin Creek Diversion Dam is located across Chinquapin Creek within Section 24, T7S, R26E, M.D.B. and M. It is an 8-foot high concrete dam. The top, at an elevation of 7,629 feet msl, is 32 feet long. The spillway, which is an overpour type, located in the center of the dam, is 4.0 feet long with a crest elevation of 7,628 feet msl. Water diverted by the dam is conveyed through an uncontrolled 14-inch diameter straight bore hole in the bottom of the diversion pool intersecting the top of Ward Tunnel. The top of the hole is 64-inches in diameter, tapering down to a 14-inch steel pipe and then a 455-foot-long bore through granite. The hole inlet is protected by trash grids. Flow through the dam is controlled by one manually operated 12-inch drain gate and one manually operated 18-inch gate located on the upstream face of the dam, and an 8-inch-diameter valve which controls an 8-inch-diameter pipe used for the instream flow release.

Camp 62 Diversion

Camp 62 Diversion Dam is located across Camp 62 Creek within Section 24, T7S, R26E, M.D.B. and M. It is a 7-foot high concrete diversion. The top, at an elevation of 7,257.5 feet msl, is 45 feet long. The 21-foot long spillway, an overpour type, is located on the right side of the dam, with a crest elevation of 7,257 feet msl. Water diverted by the dam is conveyed through an uncontrolled 14-inch diameter slanted bore hole in the bottom of the diversion pool which intersects the top of Ward Tunnel. The top of the hole is 64 inches in diameter, tapering down to a 14-inch steel pipe and then a 203-foot long bore through granite. The hole inlet is protected by trash grids. Flow through the dam is controlled by one manually operated 24-inch drain gate located on the upstream face of the dam, and a 4-inch diameter valve which controls a 4-inch diameter pipe used for the instream flow release.

Bolsillo Creek Diversion

Bolsillo Creek Diversion Dam is located across Bolsillo Creek within Section 16, T7S, R27E, M.D.B. and M. It is a 6-foot high rock and earth dam. The top, at an elevation of 7,538 feet msl, is 54 feet long. The 8-foot long spillway, an overpour type, is located on the right side of the dam, with a crest elevation of 7,532.5 feet msl. Water impounded behind the dam enters an uncontrolled 388-foot-long bore hole in the bottom of the diversion pool which intersects the top of Ward Tunnel. The top of the hole is 66 inches in diameter, tapering down to a 12-inch steel pipe and then a 10-inch bore through granite. The hole inlet is protected by trash grids. Flow through the dam is controlled by one manually operated 24-inch drain gate located on the upstream face of the dam, and a 3-inch diameter valve, which controls a 3-inch diameter pipe used for the instream flow release.

Bear Creek Diversion

Bear Creek Diversion Dam is located across Bear Creek within Section 12, T7S, R27E, M.D.B. and M. It is a 55-foot high constant-radius, concrete arch dam. The top, at an elevation of 7,356 feet msl, is 293 feet long. The ungated, overpour spillway has an effective length of 232 feet long with a crest elevation of 7,350 feet msl. Water diverted by the dam is conveyed through a 7-foot by 7-foot cross section, 7,596 feet long, bore through granite into the Mono-Bear Siphon, which ultimately feeds into the Ward Tunnel. Flow through the conduit is controlled by a manually operated 7.5-foot wide by 15-foot high radial gate located at the outlet works on the right abutment of the dam.

Mono Creek Diversion

Mono Creek Diversion Dam is located across Mono Creek within Section 35, T6S, R27E, M.D.B. and M. It is a 64-foot high constant-radius, concrete arch dam. The top, at an elevation of 7,360 feet msl, is 156 feet long. The ungated, overpour spillway has an effective length of 106 feet and a crest elevation of 7,350 feet msl. Water from Mono Creek (Edison Lake, FERC Project No. 2086) diverted by the dam is conveyed through a 92-inch diameter, 4,538-foot long steel pipe, an 8-foot by 9.5-foot cross section, 3,933-foot long bore through granite, and a 102-inch, 13,806-foot long steel pipe (Mono-Bear Siphon) into Ward Tunnel Adit No. 1. Flow through the conduit is controlled by a manually operated 6-foot by 9-foot slide gate located in the outlet works on the left abutment of the dam.

Pitman Creek Diversion

Pitman Creek Diversion is located across Pitman Creek within Section 35, T8S, R25E, M.D.M. It is an 8-foot high concrete diversion. The top, at elevation 6,998 feet, is 68 feet long. Water is diverted through a 185-foot deep bore hole, abutting the left side of the diversion face, which intersects Tunnel No. 7. The top of the hole, protected by trash grids, has a 17-foot by 31-foot cross section which tapers down to a 6-foot square bore hole through granite. Flow into the bore hole is controlled by 3 motor-operated, 4-foot by 11-foot, slide gates at the upstream end of the bore hole. A motor-operated truck crane is mounted on the intake grid for clearing accumulated debris from the trash racks.

Ward Tunnel

Ward Tunnel is a 15-foot by 15-foot horseshoe-shaped section, 67,619-foot long, unlined bore through granite. The tunnel connects to Florence Lake Dam's outlet works at its upstream end, intersects Portal Powerhouse Forebay (FERC Project No. 2174) through Adit 2, 32,860 feet downstream of the inlet portal, contains a surge chamber and rock trap at its downstream end, and terminates in the penstock for the Portal Powerhouse at its outlet portal.

Ward Tunnel surge chamber is a 15-foot diameter, 175-foot high, bore through granite, concrete lined at its upper end, with an overflow crest at an elevation of 7,180 feet msl. Overflow from the top of the surge chamber runs into a buried 72-inch diameter reinforced concrete pipe, approximately 556-feet long, which reduces to a 48-inch diameter pipe before connecting to an energy dissipation structure at its downstream end. The energy dissipation structure consists of a reinforced concrete box with various compartments that is approximately 25-feet by 25-feet by 15-feet high. The structure discharges into Rancheria Creek near the Portal Powerhouse.

Mono-Bear Siphon

Mono-Bear Conduit, more commonly referred to as the Mono-Bear Siphon, carries water from the Mono and Bear Diversions to the Ward Tunnel. A 7,596-foot unlined tunnel begins at Bear Diversion and ends at the intersection with the tunnel outlet from Mono Diversion. A 4,538-foot flowline begins at the Mono Diversion, connecting to a 3,933-foot unlined tunnel that ends at the intersection of the tunnel from Bear Diversion. Lap and butt welded steel pipe connect these two tunnels to a common 13,806-foot long siphon which connects to the Ward Tunnel at a construction adit. The conduit can carry 450 cfs from the Bear Diversion, 450 cfs from the Mono Diversion, and a maximum of 650 cfs in the common siphon.

Huntington-Pitman-Shaver Conduit

Tunnel No. 7 (or Huntington-Pitman Siphon) conveys water from Huntington Lake to Balsam Diversion Tunnel and then to Shaver Lake through EPS and Gate 2, which serves as a tailrace to EPS in generation mode. Previous to the construction of EPS, water was conveyed to Shaver Lake via the North Fork of Stevenson Creek. This outlet is currently controlled by a gate, described below, where an instream flow release is made into North Fork Stevenson Creek. The upstream end of Tunnel No. 7 connects to non-Project Huntington Lake Dam No. 2 (FERC Project No. 2175) outlet works.

The outlet works contain a 36-inch vent stack, 65 feet from its upstream end, with a top elevation of 6,955 feet msl. Flow through the outlet works is controlled by a 10-foot wide by 10-foot high slide gate at the upstream face of the dam, protected by a trash rack, and a 8-foot horizontal sliding duplex gate located in a valve house buried under the dam downstream fill. The 10-foot gate is locally operated by an electric motor-operated stem lifting device with a shaft-coupled gearbox, powered by a gasoline engine for backup. The 8-foot high duplex gate has an electric motor-driven operator and it can be operated locally or remotely from non-Project Big Creek No. 3 (FERC Project No. 120).

Tunnel No. 7 consists of four sections. The first is a 12-foot diameter, 680-foot long, earth-covered riveted steel pipe. The pipe contains a 42-inch vent stack, 421 feet from its upstream end, with the top of the pipe at an elevation of 6,957 feet msl. The second is a short tunnel that is a 14-foot by 14-foot horseshoe-shaped section, 2,642-foot long unlined bore through granite. The tunnel contains a 42-inch vent stack, which is 130 feet high. The vent stack is located at the upstream end of the second section, with a top at an elevation of 6,958 feet msl. The third is a 2,425 feet long siphon made of riveted steel pipe with a diameter varying from 120 inches to 96 inches and back to 120 inches. The fourth section is a long unlined bore through granite that has a 14-foot by 14-foot horseshoe-shaped cross-section, and is 22,843-feet long.

The Tunnel No. 7 discharge into the North Fork of Stevenson Creek is controlled by a normally-closed 10-foot by 10-foot vertical slide gate located at the “long tunnel” outlet portal, also known as “Gate 2.” The gate is locally operated by an electric motor-driven screw hoist.

Shaver Lake Dam

Shaver Lake Dam is located across Stevenson Creek, a tributary of the San Joaquin River, within Section 13, T9S, R24E, M.D.B. and M. It is a concrete gravity dam, 185 feet high. The dam was recently also tied to bedrock by a series of 46 post-tensioned anchors running vertically through the dam. The crest is 1,760 feet long and is formed by a 3-foot high concrete parapet wall situated at an elevation of 5,371 feet msl. In plan, the dam’s axis consists of two nearly equal tangents, intersecting at 26 degrees, connected by a 600-foot radius curve. A dike, designed as an earthfill, with a concrete core on bedrock, extends the left end of the dam by 409 feet.

The spillway, which is an overpour type, consists of a notch, 0.9 feet deep by 250 feet long, situated in the dam’s 3-foot high parapet wall. The spillway is located in the center of the dam at an elevation of 5,370 feet msl. The spillway rated discharge capacity at an elevation of 5,371 feet msl is 745 cubic feet per second (cfs).

The dam's outlet works, located behind full-height trash racks about 300 feet offshore of the right abutment, form the entrance to Tunnel No. 5 which leads to Powerhouse No. 2A. The tunnel has an invert at an elevation of 5,225 feet. Flow into Tunnel No. 5 is controlled by a 6-foot by 9-foot slide gate located beneath a gate house on the right abutment. The gate is locally operated by an electric motor-driven hoist. The dam has a 54-inch Howell-Bunger drain valve with a maximum capacity of 919 cfs at the base of the dam, but a culvert under Highway 168 several hundred yards downstream will only allow 450 cfs. A 10-inch pipe, controlled by a 6-inch valve coupled to an acoustic velocity meter, provides the in-stream flow release.

Tunnel No. 5

The Powerhouse No. 2A flowline consists of Tunnel No. 5, an 11-foot by 11-foot cross section, 13,900-feet long, unlined tunnel through granite which intersects the base of a surge chamber, containing a rock trap, at its downstream end. The surge chamber is 150 feet long with a 6-foot diameter shaft, which transitions to a 25-foot diameter at its upper end, extending up to the ground surface at an elevation of 5,405 feet msl. The shaft inlet is located 40 feet from the downstream end of the chamber. A 9-foot diameter, 460-foot long, riveted steel pipe, downstream of the surge tank, lines the tunnel and connects to the Big Creek No. 2A penstock as it exits the tunnel portal. The tunnel is designed to convey approximately 600 cfs under optimum conditions.

Big Creek No. 2A Penstock

The penstock consists of a 66- to 108-inch diameter combination of riveted, forged welded, and forged seamless steel pipe that is 6,218 feet long. The penstock branches into two 48-inch lines outside the Big Creek No. 2A powerhouse. Each of these lines branches a second time, reduces to 34 inches in diameter, and connects to the two turbines. A 102-inch electric motor-driven butterfly valve is located in a valve house at the upstream end of the penstock. This valve can be operated locally or remotely from non-Project Big Creek No. 3 Control Center (FERC Project No.120). Four pairs of 10-inch air & vacuum relief valves are located just downstream of the butterfly valve.

Big Creek Powerhouse No. 2A

Powerhouse No. 2A was built as an adjunct to Powerhouse No. 2 (FERC Project No. 2175) and shares its control room, switchyard, maintenance and personnel facilities. The control room is located on the second floor of Powerhouse No. 2 and houses the control equipment. Office space for supervisory personnel and a crew lunch room are also provided on the second floor.

A machine shop is located on the ground floor of Powerhouse No. 2 and is equipped with drill presses, weld table, power hacksaw, and miscellaneous small tools used to maintain and repair the equipment in Powerhouse Nos. 2 and 2A. An office is also located on this floor.

Adits

There are two adits (Adit 1 and Adit 2) connected to Tunnel No. 5. The adits were part of the construction of the tunnel and are occasionally used for inspection or maintenance of the tunnel.

In 1921, approximately five and one-half years prior to the completion of Shaver Lake Dam, and 7 years prior to the completion of Powerhouse No. 2A, the power capacity of the Big Creek system was increased by 17,500 KVA when water from Stevenson Creek was diverted through the newly constructed Tunnel No. 5 via the so-called “Adit 8 Shoo-fly Diversion” to Tunnel No.2 and finally Powerhouse No. 2. Diversion of water from Tunnel No. 5 to Tunnel No. 2 was discontinued after Powerhouse No. 2A went into service, as it was more efficient to run the water directly into the Powerhouse No. 2A penstocks and turbines. Although the diversion has been inactive since the completion of Powerhouse No. 2A, the licensee prefers to retain the Shoo-fly Diversion within the license in case problems with Powerhouse No. 2A might require its use again.

Big Creek Powerhouse No. 2A Controls

All local controls for Powerhouse No. 2A are located in Powerhouse No. 2 (FERC Project No. 2175). Controls include electrically-operated alarm circuits to warn of abnormal operation conditions; automatic trip oil circuit breakers; automatic load, speed, and voltage control; meters; relays; and remote control equipment. Telephone circuits of the company’s integrated communication system are connected to the powerhouse control room. A system has been installed which permits computer control from either Big Creek Powerhouse No. 2 or non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120) via a Local Controller (LC) to monitor and operate the units. The computer system is equipped with a printer, keyboard, and monitor to allow the operator to perform local plant control and monitoring. The LC also allows plant technicians to modify, troubleshoot, and diagnose the control system and plant parameters. The medium of control transmission is microwave radio frequency. The LC can automatically monitor and shut down the units, but operator intervention is required to put the units online.

Big Creek Powerhouse No. 8

Big Creek Dam No. 5

Big Creek Dam No. 5 is located across Big Creek, a tributary of the San Joaquin River, within Section 28, T8S, R25E, M.D.B. and M. It is a constant-radius concrete arch dam, 60 foot high. The crest of the dam is 224 feet long, at an elevation of 2,950 feet msl.

The spillway, which is an overpour type, consists of 19 ungated spans, separated by piers, with a total length of 133 feet at an elevation of 2,939 feet msl. Four-foot high flashboards are customarily installed in the spillway spans to raise maximum reservoir level to an elevation of 2,943 feet msl. The boards are handled by a power-operated trolley hoist and can be withdrawn during extreme runoff events. The spillway rated discharge capacity at zero freeboard and with all flashboards removed is 15,000 cfs.

Two 72-inch diameter steel drain pipes pass through the base of the dam at an elevation of 2,895 feet. Flow through these pipes is controlled by locally operated electric-motor-driven 72-inch diameter slide gates at the dam upstream face.

The dam’s outlet works, located behind full-height trash racks about 70 feet upstream from the dam on the left abutment, form the entrance to Tunnel No. 8 leading to Powerhouse No. 8. The tunnel has an invert at an elevation of 2,921.5 feet. This tunnel does not have an intake gate and stoplogs must be installed to dewater the tunnel.

Tunnel No. 8

The Powerhouse No. 8 flowline consists of Tunnel No. 8, a 20-foot by 20-foot cross section, 5,570-foot-long, unlined bore through granite. The tunnel downstream portal is sleeved with an 18-foot-diameter, 32-foot-long riveted steel pipe which exits from the tunnel into the surge tank. The surge tank is a 35-foot-diameter, 90-foot-high, aboveground steel tank. Two penstocks exit the downstream base of the surge tank. The tunnel is designed to convey approximately 1,385 cfs under optimum conditions.

Penstocks

The Project includes two penstocks. Each penstock is controlled by a slide gate on the inside wall of the surge tank. Both gates are operated by stems extended to an operating platform at the top of the tank, where electric motor-driven gear trains drive the gate stems. There is a gas engine standby gate operator for use if electric power fails. The gates can be operated locally or remotely from non-Project Big Creek Powerhouse No. 3 (FERC Project No. 120).

The Unit No. 1 penstock is 2,668 feet long and consists of a 96-inch diameter riveted and lap welded steel pipe which reduces to 72 inches in diameter before connecting to the turbine. An 8-foot by 8-foot slide gate is located at the upstream end of the penstock, inside the surge tank, as described above. Downstream from the slide gate, the penstock is provided with air vent valves.

The Unit No. 2 penstock is 2,698 feet long and consists of a 120-inch diameter riveted and lap welded steel pipe which reduces to 84 inches in diameter before connecting to the turbine. A 10-foot by 10-foot slide gate is located at the upstream end of the penstock, inside the surge tank, as described above. Downstream from the slide gate, the penstock is provided with air vent valves.

Big Creek Powerhouse No. 8

The control room of Powerhouse No. 8 is located on the second floor and houses the control equipment. Office space for supervisory personnel is provided on the third floor along with a crew lunch and meeting room. The ground floor houses a machine shop equipped with a drill press, weld table, grinder, and miscellaneous small tools used to maintain and repair the powerhouse equipment. The basement of the powerhouse consists of storage for tools and parts, oil storage tanks, piping, sumps, a sewer septic tank and access to lower portions of the turbines.

Big Creek Powerhouse No. 8 Controls

Controls include the necessary protection relays, instruments, switches, etc., for the main and auxiliary equipment, including remote and automatic control of the wicket gates and turbine shutoff valves. A system has been installed which permits computer control locally and from non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120), via a Local Controller (LC), to monitor and operate the units. The LC can automatically monitor, synchronize, start, and shut down units.

The powerhouse is fully automated to be controlled remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120). The computer system is equipped with a printer, keyboard, and monitor to allow the operator to perform local plant control and monitoring. The LC also allows plant technicians to modify, troubleshoot, and diagnose the control system and plant parameters. The medium of control transmission is microwave radio frequency.

Eastwood Power Station

Balsam Meadow Forebay Dam

The Balsam Meadow Forebay Dam is located on Balsam Creek, a tributary of Big Creek within Section 9, T9S, R25E, M.D.M. The forebay is the regulating reservoir that controls the water flow into the EPS. The forebay forms a lake with a surface area of 60 acres containing 1,960 acre feet of water at the spillway elevation of 6,670 feet msl.

The Balsam Meadow Forebay Dam is a compacted rockfill dam, 123 feet high, with a concrete slab on the upstream face. The crest, at an elevation of 6,674.5 feet msl, is 1,325 feet long. The top of the dam's concrete parapet wall is at an elevation of 6,677 feet msl. An earthfill/rockfill saddle dike, 12 feet high, is located approximately 500 feet to the east of the main dam. The top of the dike, at an elevation of 6,677 feet msl, is 264 feet long.

The spillway, near the left abutment of the dam, is an open channel excavated in granite. The crest, at an elevation of 6,670 feet msl, is a 280-foot long concrete weir oriented at a skew with the 140-foot wide spillway channel. The spillway channel discharges into West Fork Balsam Creek. This creek flows to the north to join Balsam Creek which discharges into Big Creek near Camp Sierra below non-Project Dam No. 4. The spillway channel is used only under extreme emergency conditions.

Inflow to Balsam Meadow Forebay is from non-Project Huntington Lake via Tunnel No. 7 (the Huntington-Pitman-Shaver Conduit) and the Balsam Diversion Tunnel. The forebay is filled with water from non-Project Huntington Lake or from water pumped back from Shaver Lake via Eastwood Powerstation.

A single 8-foot horizontal duplex slide gate located at non-Project Huntington Lake Dam No. 2 controls inflow to Balsam Meadow Forebay from Huntington Lake. This gate is remotely operated from the Eastwood Powerstation control room or from the system dispatching center at non-Project Big Creek No. 3.

A 48-inch diameter low-level outlet pipe, encased in concrete, extends through the base of the Balsam Meadow Forebay Dam at maximum section, at an invert elevation of 6,575 feet msl. Flow through the pipe is controlled by manually operated 24-inch butterfly valves located at each end of the pipe. Minimum release from the reservoir is provided through a 6-inch bypass line around the downstream butterfly valve. Redundant float and level probes are in service to warn of increasing water level in the forebay. An alarm system will warn downstream inhabitants and alert the control operator at the dispatching center in the event of a dam failure or spill.

The outlet (intake) works for the dam are located behind full-height trash racks about 1,150 feet southwest of the dam. The outlet works form the entrance to the Eastwood power tunnel. The tunnel has an invert at elevation 6,600.0 feet. Flow into the power tunnel is controlled by two 9-foot by 17-foot slide gates. The gates are locally operated by electric motor-driven, rising-stem screw hoists.

Balsam Forebay Tunnel

The Balsam Diversion Tunnel is a 16-foot by 16-foot horseshoe-shaped tunnel, 5,866-foot long, unlined bore through granite that intersects Tunnel No. 7 approximately 1,200 feet upstream of its outlet portal. Inflow into the Balsam Meadow Forebay can be shut off by a single locally controlled, hydraulically operated 12-foot by 16-foot slide gate located at the downstream end of the diversion tunnel.

Eastwood Power Tunnel

Releases from the Balsam Meadow Forebay are made through an 18-foot by 18-foot horseshoe-shaped power tunnel leading to the EPS. Two 9-foot by 17-foot vertical slide gates at the upstream end of the tunnel are provided for shutoff. The gates are locally operated by electric motor-driven, rising-stem screw hoists. These gates are locally equipped with an emergency remote close feature from non-Project Big Creek No. 3 Control Center (FERC Project No. 120), which is tested monthly. Hydraulic control is provided by the power tunnel intake slide gates and the turbine shutoff valve at Eastwood Powerstation. The dam outlet (intake) works, located behind full-height trash racks approximately 1,150 feet southwest of the dam, form the entrance (exit) to the power tunnel. The tunnel has an invert at an elevation of 6,600 feet msl. The tunnel is designed to carry approximately 1,522 cfs during pumpback and 2,306 cfs when generating under optimum conditions.

The power tunnel consists of three sections as follows:

1) The upper tunnel is an 18-foot by 18-foot horseshoe-shaped section, 2,832-foot long unlined bore through granite, with a concrete-lined invert and a rock trap situated 107 feet from the downstream end.

2) The second section is a vertical shaft that is a 1,043-foot long vertical bore, connecting the upper and lower tunnels. The upper 603 feet is unlined and 13.5 feet in diameter. The lower 440 feet is steel-lined and 11 feet in diameter.

3) The third part is the lower tunnel that is a 1,328-foot long, 12-foot diameter, steel-lined bore through granite which reduces to 83 inches in diameter before connecting to the turbine shutoff valve.

A surge chamber connects to the power tunnel. The surge chamber is a 30-foot diameter, 275-foot high, vertical shaft through granite with an 8-foot diameter ventilation shaft extending 816 feet from the top of the surge chamber to the ground surface. The surge chamber is connected to the power tunnel by a concrete-lined, 15-foot diameter, 33-foot long shaft containing a 10.25-foot diameter restricting orifice. Two 9-foot by 17-foot slide gates are located at the downstream end of the tunnel. The gates are locally operated by electric motor-driven steel cable hoists. Two 12-foot by 16-foot slide gates are located in the turbine draft tube. These gates allow the turbine to be dewatered without draining the tunnel. The gates are locally operated by hydraulic cylinders.

The power tunnel may be drained (except for the net static submersion head on the pump/turbine) by gravity through the turbine to the tailrace. The remaining water can be pumped out. A single, high total discharge head pump is provided to dewater any portion of the hydraulic system. Four separate sectors may require dewatering. These sectors consist of the following: 1) power tunnel upstream of the spherical turbine shutoff valve; 2) tailrace tunnel downstream of the lower guard valve; 3) piping and equipment between the turbine shutoff valve and the lower guard valve; and 4) turbine pit in the powerhouse.

All four of these sectors are connected by a manifold to the dewatering pump so that water may be pumped out of any sector. The pump discharge is connected through a manifold to the power tunnel and the tailrace tunnel so that discharge may be directed to either. The tailrace tunnel may be dewatered for maintenance by closing the discharge portal with stop logs and pumping the tailwater into the power tunnel.

Eastwood Tailrace Tunnel

The Eastwood Tailrace Tunnel conveys water from (into) the draft tube into (from) Shaver Lake. The tunnel is a 7,543-foot long bore through granite. The first 35 feet of the tunnel is a concrete-lined draft tube transition. This is followed by a concrete-lined, 15-foot diameter section, 440 feet long. The remainder of the tunnel is an 18-foot by 18-foot horseshoe-shaped section with a concrete-lined invert. The tunnel intersects the base of a surge chamber and rock trap 175 feet and 475 feet, respectively, downstream from the draft tube.

Eastwood Power Station

The EPS is located in an underground cavern that is 80 feet wide, 188 feet long, and 153 feet high. The cavern is carved into the native Sierra Nevada granite near the shore of Shaver Lake, at an elevation of 5,200 feet msl. The control room is located on the turbine floor of this underground powerstation and houses the control equipment. The main floor houses a weld shop and a machine shop equipped with 5-ton and 2-ton cranes, a lathe, drill press, weld table, shaper, sander, and miscellaneous small tools used to maintain and repair the powerstation equipment. A crew lunch and meeting room is also provided.

A galvanized steel stair near the northeast corner of the chamber and a galvanized vertical steel ladder provide a means of egress from the various levels of the powerhouse to the main operating floor. An electric elevator provides a means of travel between the powerhouse main floor to the switchyard building at the surface above. A stair system follows the same route.

The access tunnel portal has a large double gate made of steel bars for plant security. A solid inner second door is provided for further security and ventilation control. It is located where the access tunnel meets the powerhouse main chamber and is a bi-parting sliding door for large equipment access with a smaller door built-in for personnel access.

EPS Controls

The powerstation is designed for unattended peak-demand generation with capability for pumped storage operation. The Plant Distributed Control System (DCS) is a decentralized computer system which allows processing and control functions to be independently performed within five separate processing units (or local control centers) located adjacent to the plant processors. The system permits local startup, shutdown, monitoring and plant history capability. In addition to onsite controls provided for startup and shutdown operations, the power station permits computer control from Big Creek Powerhouse Nos. 1 and 3 Control Center, via a Local Controller (LC), to monitor and operate the unit. The LC can start up and shut down automatically. It is equipped with a printer, keyboard, and monitor to allow the operator to perform local plant control and monitoring. The LC also allows plant technicians to modify, troubleshoot, and diagnose the control system and plant parameters. The medium of control is via a duplex fiber optic cable network and microwave radio frequency.

(2) Storage Capacity

The storage capacities for the reservoirs and moderate water diversion impoundments associated with the Project are as follows:

- Shaver Lake has a surface area of 2,184 acres and a gross and usable storage capacity of 135,568 acre-feet at the spillway crest elevation of 5,370 feet msl.

- The Powerhouse No. 8 forebay (created by Dam No. 5) has a surface area of 3.3 acres, a gross storage capacity of 49 acre-feet, and a usable storage capacity of 47 acre-feet at the top of flashboard elevation of 2,943 feet msl.

- Florence Lake has a surface area of 962 acres and a gross and usable storage capacity of 64,406 acre-feet at the top of the spillway gates elevation of 7,327.5 feet msl.

- Balsam Meadow Forebay has a surface area of 60 acres, a gross storage capacity of 1,970 acre-feet, and a usable storage capacity of 1,570 acre-feet at a water surface elevation of 6,670 feet msl.

- Hooper Creek Diversion impoundment has a surface area of 0.38 acres, a gross storage capacity of 3.76 acre-feet, and a usable storage capacity of 3 acre-feet at the spillway crest elevation of 7,505 feet msl.

- Bear Creek Diversion impoundment has a surface area of 13.25 acres and a gross and usable storage capacity of 103 acre-feet at the spillway crest elevation of 7,350 feet msl.

- Mono Creek Diversion impoundment has a surface area of 6.7 acres and a gross and usable storage capacity of 47 acre-feet at the spillway crest elevation of 7,350 feet msl.

(3) Turbines and Generators

Big Creek Powerhouse No. 2A

The powerhouse contains two Pelton-type horizontal shaft, single jet, double overhung, hydraulic impulse turbines. The total powerhouse rating is 143,100 HP. The individual ratings for each turbine are as follows:

- The Unit 1 turbine is rated at 74,100 HP at a design head of 2,200 feet and operating at 300 RPM; and
- The Unit 2 turbine is rated at 69,000 HP at a design head of 2,200 feet and operating at 300 RPM.

In addition to the powerhouse turbines, a 35 HP design head 105 feet, 1,800 RPM, single stage, horizontal shaft, centrifugal pump that runs backwards as a micro hydro turbine is installed in the Shaver Lake upper dam gallery adjacent to and bypassing the existing 6-inch diameter minimum flow water release piping. Discharge water from the turbine is returned to the drain gate well for release into Stevenson Creek. The turbine is used to recover the energy of minimum flow water released from the reservoir through the dam. The turbine is directly connected to a 20 kW, 0.8 power factor, 240 Volt, three-phase, 60 Hz, KATO Engineering, synchronous generator which feeds into the 12 kV local distribution system. The unit is normally unattended, with an out-of-service alarm at Big Creek Powerhouse No. 3. When the unit trips, a station operator must restart the unit locally.

The two main generators associated with the Project consist of horizontal shaft, fully enclosed Westinghouse units. The total powerhouse installed capacity is 110,000 kW and both of the generators are rated at 55,000 kW, 1.0 power factor, 13.8 kV, three-phase, 60 Hz. Cooling is provided by individual heat exchangers. The main exciter has been removed and replaced with a static exciter. A PMG is directly connected to the end of each generator shaft by a stub shaft. Automatic voltage regulation is performed by solid-state regulators.

Each main generator is protected by two 15 kV, 3,000 Amp, vacuum circuit breakers. Disconnect switches are provided at each breaker position for isolation.

Big Creek Powerhouse No. 8

The powerhouse contains two main Francis-type, vertical shaft, hydraulic reaction turbines. The total powerhouse rating is 89,000 HP. The individual ratings for each turbine are as follows:

- The Unit 1 turbine is rated at 36,500 HP at a design head of 680 feet and operating at 514 RPM; and

- The Unit 2 turbine is rated at 52,500 HP at a design head of 690 feet and operating at 450 RPM.

The two main generators consist of vertical shaft, partially enclosed General Electric units. The total powerhouse installed capacity is 75,000 kW. The generator specifications are as follows:

- The Unit 1 generator is rated at 30,0000 kW, 1.0 power factor, 13.8 kV, three-phase, 60 Hz; and
- The Unit 2 generator is rated at 45,000 kW, 0.9 power factor, 13.8 kV, three-phase, 60 Hz.

Cooling is provided by once-through air drawn from outside of the powerhouse after passing through a humidifier system. The main exciter and a PMG are directly connected to the top of each generator. Automatic voltage regulation is performed by solid-state regulators.

The Units 1 and 2 generators are each protected by a 15 kV, 2,000 Amp, vacuum circuit breaker. Disconnect switches are provided at each breaker position for isolation.

In addition, the plant contains two "Station Service" horizontal generators that consist of 240 volt, three-phase, 60 Hz units connected to separate horizontal, impulse water turbines. The No. 1 Station Service generator, manufactured by General Electric, has a capacity rating of 150 kW, 0.8 power factor. The No. 1 Station Service generator is currently out of service. The No. 2 Station Service generator, manufactured by Allis Chalmers, has a capacity rating of 200 kW, 0.8 power factor.

Eastwood Power Station

The powerstation contains one main, Francis-type, vertical shaft, hydraulic reaction turbine/pump. The turbine is reversible and mechanically suitable for operating as a pump during pumped storage operation.

The main generator/motor is a vertical shaft, direct coupled, totally enclosed General Electric Canada unit designed for either direction of rotation and is provided with a voltage regulator, excitation system, thrust and guide bearings, brakes, cooling system and fire protection. The generator is rated at 199,800 kW, 0.9 power factor, 400 RPM, 13.8 kV, three-phase, 60 Hz with a design head of 1,266 feet. The motor is rated at 215,000 kW, 1.0 power factor, 400 RPM, 13.8 kV, three-phase, 60 Hz with a design head of 1,324 feet. The generator/motor is protected by a three single pole type, 15 kV, 12,000 Amp, silicon hexafluoride (SF6) power circuit breakers.

Motor-operated disconnect switches are provided to reverse phase rotation for operation in either direction of rotation. A shaft-mounted wound-rotor induction motor is used for startup when operating the generator/motor in the pumping mode. Speed control during startup is achieved by a liquid rheostat. Excitation for the generator/motor is provided by a static excitation system.

(4) Primary Transmission Lines

Big Creek Powerhouse No. 2A

There are no transmission lines associated with Big Creek Powerhouse No. 2A.

Big Creek Powerhouse No. 8

There are no transmission lines associated with Big Creek Powerhouse No. 8.

Eastwood Power Station

A compressed-gas insulated 230 kV rated bus in the vertical access tunnel delivers generated power to the Project switchyard at the surface and a 4.7 mile, 230 kV project transmission line connects the EPS to the Big Creek No. 1 (FERC Project No. 2175) non-Project switchyard. The transmission line consists of a 230 kV, 3-phase, single circuit line constructed of 605 MCM ACSR conductors supported by suspension-type insulators on single circuit steel towers.

In addition, the towers support two overhead stranded steel groundwires for lightning protection as well as containing six optical fibers each for communication, control, and data links between the EPS and the Big Creek No. 1 Hydroelectric Generating Plant. The normal thermal ampacity of the 605 MCM ACSR conductors used for this line is 895 amperes of 356 MVA based on a 230 kV base.

(5) Mechanical, Electrical and Transmission Equipment

Big Creek Powerhouse No. 2A

Oil Storage and Handling System

A single central oil system is used in Powerhouse No. 2A with the main supply located in Powerhouse No. 2 (FERC Project No. 2175). Also located in Powerhouse No. 2 are oil storage and transfer facilities for governor and bearing lubricating oil. Separate clean oil and used oil tanks are provided with an in-line centrifuge to purify lubricating and governor oil as needed.

Cooling Water System

Cooling water for generator heat exchangers and bearing oil coolers is obtained from the station cistern by means of cooling pumps. It is circulated in the cooling coils and returned to the tailrace after once-through use as a coolant. Water is supplied to the cistern from wheel pits of three units at Big Creek Powerhouse No. 2 (FERC Project No. 2175) and one unit at Big Creek Powerhouse No. 2A. Back-up cooling water can be supplied from the penstocks of Units 3 and 4 in Big Creek Powerhouse No. 2 (FERC Project No. 2175).

Valves

At Shaver Dam, a 48-inch fixed dispersion cone or Howell Bunger valve is situated at the downstream end of the Low Level Outlet pipe. Flow released at this location enters Stevenson Creek, a tributary of the San Joaquin River. Operation of the valve can be accomplished either manually at the local control panel near the valve or remotely from Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

Flow into Tunnel No. 5 from Shaver Lake is controlled by a 6-foot by 9-foot slide gate located beneath a gate house situated on the right abutment of Shaver Dam. The gate is locally operated by an electric motor-driven hoist.

Flow from Huntington Lake through the outlet works into Tunnel No. 7 is controlled by a 10-foot by 10-foot slide gate at the upstream face of the dam, protected by a trash rack, and an 8-foot horizontal sliding duplex gate located in a valve house buried under the dam downstream fill. The 10-foot gate is locally operated by an electric motor-driven stem lifting device with a shaft-coupled gearbox, powered by a gasoline engine, for backup. The 8-foot duplex gate has an electric motor-driven operator. It can be operated locally or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

Flow from Pitman Creek Diversion into the Tunnel No. 7 bore hole is controlled by three manually operated, 4-foot by 11-foot slide gates at the diversion upstream end. Operation of the gates can be accomplished either manually at the local control panel near the gate or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

Tunnel No. 7 discharge into the North Fork of Stevenson Creek is controlled by a normally-closed 10-foot by 10-foot vertical slide gate located at the long tunnel outlet portal. Operation of the gate can be accomplished either manually at the local control panel near the gate or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

A 102-inch electric-motor-operated butterfly valve is located in a valve house at the upstream end of the BC 2A penstock. This valve can be operated locally or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

For penstock pressure relief, Unit No. 1 utilizes a hydraulic deflector mechanism linked to the governor. There is one for each side of the unit.

The Unit 2 penstock relief valve is a vertical oil dashpot sliding cylinder valve type with a direct link to the governor operating mechanism. There is one for each side of the unit directly connected to the respective turbine tail races.

The turbine shut-off valves for Units 1 and 2 consist of 34-inch, hydraulically-operated disc valves. Valve operation is accomplished by supplying penstock pressure water to the operating cylinder by means of an electrically or manually operated, locally controlled actuation valve.

Governors

Normal turbine operating speed control is maintained by an Allis Chalmers governor for Unit 1 and a Woodward mechanical hydraulic cabinet actuator governor for Unit 2. There are two governors for each unit, one controlling the left hand power needle and one controlling the right hand power needle. The governors are controlled either manually or automatically.

The governors provide accurate speed control for synchronizing and for stable operation when the units are connected to the power system. Two separate governor oil systems are located in Powerhouse No. 2 (FERC No. 2175) and shared in common with the units of Powerhouse No. 2, providing the operating governor oil pressure. The governor oil system consists of two Woodward-screw pumping units with electric unloader valves, associated sumps and pressure tanks and one emergency back-up pump driven by a water turbine. In addition to the main pressure tanks, two cushion tanks provide extra capacity for the governor oil system. Two air compressors maintain the air cushion in the pressure tanks.

Gaging

The following gaging stations are associated with this Project:

USGS No.	SCE No.	Station Name
11229600	148	Florence Lake
11230200	114	Hooper Creek below Diversion Dam
11230215	129	South Fork San Joaquin River below Hooper Creek
11230530	175	Bear Creek below Diversion Dam
11230560	181	Chinquapin Creek below Diversion Dam
11230600	180	Camp 62 Creek below Diversion Dam
11230670	117	Bolsillo Creek below Diversion Dam
11231600	176	Mono Creek below Diversion Dam
11237700	121	Pitman Creek near Tamarack Mountain (below shaft)
11239300	99	North Fork Stevenson Creek at Perimeter Road
11239500	150	Shaver Lake
11241500	131	Stevenson Creek below Shaver Lake
11230520	102	Bear Creek Conduit at Diversion
11230500	103	Bear Creek Upstream of Diversion Dam
11230650	106	Bolsillo Creek Above Intake
11236080	99A	Huntington-Shaver Conduit Gate 2 Release
11231550	118	Mono Creek Conduit at Diversion Dam
n/a	n/a	Mono-Bear Conduit at Diversion Dam
n/a	n/a	Mono-Bear Conduit (flow meter near Camp 62)
11237500	120	Pitman Creek Above Diversion (total flow)
n/a	128	South Fork San Joaquin River above Hooper Creek
11229500	133a 133c	Ward Tunnel at Intake
Part of 11230600	109	Camp 62 Creek at Diversion Dam
Part of 11230560	110	Chinquapin Creek at Diversion Dam
n/a	111	Crater Creek Diversion Ditch near Florence Lake
Part of 11230200	113	Hooper Creek Conduit at Diversion Dam
n/a	128	South Fork San Joaquin River near Florence Lake
11231550	118	Mono Dam
11238400	161	Big Creek Powerhouse No. 2A

Generators

The two main generators associated with the Project consist of horizontal shaft, fully enclosed Westinghouse units. The total powerhouse installed capacity is 110,000 kW and both of the generators are rated at 55,000 kW, 1.0 power factor, 13.8 kV, three-phase, 60 Hz. Cooling is provided by individual heat exchangers. The main exciter has been removed and replaced with a static exciter. A PMG is directly connected to the end of each generator shaft by a stub shaft. Automatic voltage regulation is performed by solid-state regulators. Each main generator is protected by two 15 kV, 3,000 Amp, vacuum circuit breakers connected in parallel. Disconnect switches are provided at each breaker position for isolation.

In addition to the two main generators, the centrifugal pump that is operated as a micro hydro turbine to recover the energy of minimum flow water released from Shaver Lake through the dam is connected to a 20 kW, 0.8 power factor, 240 V, three-phase, 60 Hz, KATO Engineering, synchronous generator which feeds into the 12 kV local distribution system. The unit is unattended with an out-of-service alarm at the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120). When the unit trips, a station operator must restart the unit locally.

Transformers

The Main Bank transformer is located adjacent to the powerhouse and consists of a three-phase, 90/120 MVA, 230-13.8 kV, OA/FA, 60 Hz transformer.

Power Distribution Equipment

Service power in Powerhouse No. 2A is supplied from Powerhouse No. 2 (FERC Project No. 2175). Power is supplied from the station buses through two three-phase transformer banks consisting of six single-phase 150 kVA, 7.2 kV-230/115 volt transformers. The banks are used alternately to supply power to the station.

Powerhouse “DC” control power in Powerhouse No. 2A is supplied from Powerhouse No. 2 (FERC Project No. 2175). Power is supplied by a 60 cell, 440 Ampere-hour, 135 V, lead-acid storage battery bank charged by a solid-state regulator.

A 1,296-foot, 33 kV Project power line supplies power from the non-Project Kokanee 33 kV distribution line to Pitman Diversion. The 33 kV power line supplies power to operate the slide gates, crane, and emergency lighting at the diversion.

Heating, Ventilating, and Air Conditioning System

The powerhouse is ventilated by natural draft. The control room, located in Powerhouse No. 2, has an air cooler. Comfort heating for powerhouse occupancy is provided, as needed, by electric heaters.

Compressed Air System

A common motor-driven stationary air compressor (Sullair rotary compressor Model 10-30) complete with receiver and piping for general station use is located in the powerhouse and is shared with Big Creek No. 2 (FERC Project No. 2175).

Fire Protection System

Portable 150-pound Halon units are located in the powerhouse for fire protection. Portable extinguishers, fire hoses, reels, and hydrants are provided in strategic locations within the powerhouse. Fire protection is provided by an automatic carbon dioxide system for each of the units.

Sanitary Disposal System

A sanitary facility is provided in one location on the first floor inside the powerhouse. Big Creek Powerhouse No. 2A utilizes non-potable water from the penstock for service water. There is no potable water supply on site. Potable water is provided in bottled containers. Effluent from the restrooms, floor drains, and sinks is processed in an on-site septic tank located and pumped to a leach field.

Lighting

Normal powerhouse lighting service and emergency “DC” lighting is supplied from Powerhouse No. 2 (FERC Project No. 2175).

Station Crane

The powerhouse is equipped with two 150-ton traveling cranes which provide hoisting facilities for all major equipment.

Switching

The generator electrical outputs from Big Creek Powerhouse No. 2A and Big Creek Powerhouse No. 2 (FERC Project No. 2175) are connected by common buses in the same non-Project switchyard.

The non-Project switchyard is located approximately 300 feet from the powerhouse. The Project switchgear consists of two remotely-operated, three-pole, 800 Ampere, 230 kV oil circuit breakers. Gang-operated disconnect switches, grounding switches, line tuners, potential devices, and other related equipment are also located in the switchyard.

Big Creek Powerhouse No. 8

Oil Storage and Handling System

There are oil storage and transfer facilities for governor and bearing lubricating oil. Separate clean oil and used oil tanks are provided, with an in-line centrifuge to purify lubricating and governor oil as needed.

Cooling Water System

Cooling water for bearing oil heat exchangers is taken from the station cistern by means of one of two cooling water pumps and returned to the tailrace after once-through use as a coolant. The station cistern is supplied from either or both main unit tailraces. The emergency cooling water system is supplied directly from the penstocks in the event of a pump failure or other problems with the normal pump supply.

Valves

The Unit 1 turbine shut-off valve is a horizontal shaft, 72-inch butterfly valve and the Unit 2 turbine shut-off valve is a horizontal shaft, 84-inch butterfly valve. Both valves are operated remotely via electric motor (normal operation) from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120) or manually via hand wheel.

Governors

Normal turbine operating speed control is maintained by a Woodward governor on each unit. The governors are controlled either manually operation or automatically. The governor oil system consists of two identical governor oil pumps, motors, main pressure tanks, and sumps. Normally, the two main pressure tanks and the two sumps are operated in parallel, using either of the governor oil pumps. Two air compressors maintain the air cushion in the main pressure tanks.

Gaging

The following gaging stations are associated with this Project:

USGS No.	SCE No.	Station Name
11238550	165	Big Creek Powerhouse No. 8
11238500	105	Big Creek near Mouth (below Dam 5)

Generators

The two main generators consist of vertical shaft, partially enclosed General Electric units. The total powerhouse installed capacity is 75,000 kW. The generator specifications are as follows:

- The Unit 1 generator is rated at 30,0000 kW, 1.0 power factor, 13.8 kV, three-phase, 60 Hz; and,
- The Unit 2 generator is rated at 45,000 kW, 0.9 power factor, 13.8 kV, three-phase, 60 Hz.

Cooling for the main generators is provided by once-through air drawn from outside of the powerhouse after passing through a humidifier system. The main exciter and a PMG are directly connected to the top of each generator. Automatic voltage regulation is performed by solid-state regulators.

The Units 1 and 2 generators are each protected by a 15 kV, 2,000 amp, vacuum circuit breaker. Disconnect switches are provided at each breaker position for isolation.

In addition, the plant contains two "Station Service" horizontal generators that consist of 240 V, three-phase, 60 Hz units connected to separate horizontal, impulse water turbines. The No. 1 Station Service generator, manufactured by General Electric, has a capacity rating of 150 kW, 0.8 power factor. The No. 1 Station Service generator is currently out of service. The No. 2 Station Service generator, manufactured by Allis Chalmers, has a capacity rating of 200 kW, 0.8 power factor.

Transformers

The No. 1 transformer is located within the powerhouse and consists of a three-phase, 75 MVA, 235-13.5 kV, FOA, 60 Hz transformer. The transformer bank is connected to two outgoing 220 kV transmission lines.

Power Distribution Equipment

Powerhouse service power is provided by two 240 V Station Service generators with a combined rating of 350 kW and one three-phase, 150 kVA, 13.8 kV-240 volt transformer connected to the 13.8 kV leads of the main transformer bank. Circuits are controlled with the necessary disconnecting switches, buses, and fuses. Powerhouse "DC" control power is supplied by a 60-cell, 430 ampere-hour, 125 volt lead-acid type battery bank.

Heating, Ventilating, and Air Conditioning System

The powerhouse is ventilated primarily by natural draft. Comfort cooling and heating for control room occupancy is provided, as needed, by a heat pump.

Compressed Air System

The powerhouse contains two motor-driven stationary air compressors (a Sullair model 12BS-50 and an Ingersoll-Rand model U30H-SP) complete with receiver and piping for the generator brakes and general station service.

Fire Protection System

Fire protection is provided by an automatic carbon dioxide system for protection of Unit 2, the 220 kV circuit breakers, and equipment on the fifth floor. Two portable 150 lb. Halon units are located on the generator floor for fire protection. Portable extinguishers, fire hose reels and hydrants are provided in strategic locations within the powerhouse.

Sanitary Disposal System

Sanitary facilities are provided in three locations within the powerhouse. One small restroom facility is located in the control room, another small facility and a large crew restroom are located by the generator floor hallway/stairway area. Effluent from the restrooms, floor drains, and sinks is processed in an on-site septic tank and pumped to a leach field.

Lighting

Main powerhouse lighting service is provided by a three-phase 150 kVA, 13.8 kV-240V transformer on the upper 240 V bus. Alternate powerhouse lighting service is supplied by a station service generator. Emergency "DC" lighting is provided from the powerhouse battery system to facilitate safe operation in the event of a lighting system failure or system outage.

Station Crane

The powerhouse is equipped with a 150-ton traveling crane with a 15-ton auxiliary hook which provides hoisting facilities for all major equipment. Also provided is a monorail Kone electric 6-ton hoist for use on the powerhouse upper floors.

Switching

The transformer bank is connected to two non-Project 220 kV transmission lines. The non-Project switchrack and equipment are located inside the powerhouse.

Eastwood Power Station

Oil Storage and Handling System

The Project includes an oil storage and transfer facility for governor and bearing lubricating oil. Separate clean oil and used oil tanks are provided and a centrifuge is provided for purification. Contaminated (non-recoverable) oil is transferred into a holding tank for disposal.

Cooling Water System

The cooling water system provides once-through cooling water to the main transformer and isolation transformer oil cooler, the generator upper and lower guide bearing oil coolers, the turbine bearing cooling coils, the turbine shaft and runner seals, the generator stator and rotor heat exchangers. The system consists of two vertical inline centrifugal flooded-suction pumps, and two jockey pumps. The jockey pumps provide cooling water to the main transformer when the plant and main cooling water pumps are down. The suction piping to these pumps is supplied with an inline self-cleaning strainer to filter the water from the tailrace tunnel (normal source) or the main sump discharge (alternate source).

Water entering the two turbine runner seals and shaft seal is further filtered by another finer mechanical inline, self-cleaning strainer prior to entering these components. The cooling water is returned to the tailrace after once-through use as a coolant. Water from the cooling water system is also used to provide fire protection water to the fire hose stations and the fire water sprinkler loops.

Valves

Flow into the Balsam Diversion Tunnel is controlled by a 12-foot by 16-foot roller gate located in the Balsam Diversion Tunnel discharge structure at

Balsam Meadow Forebay. The gate is locally operated by a hydraulic operator.

A 48-inch diameter low-level outlet pipe, encased in concrete, extends through the base of the Balsam Meadow Dam. Flow through the pipe is controlled by manually-operated 24-inch butterfly valves located at each end of the pipe.

Releases from the Balsam Meadow Forebay reservoir are made through an 18-foot by 18-foot horseshoe-shaped power tunnel leading to Eastwood Powerstation. Two 9-foot by 17-foot slide gates at the upstream end of the tunnel are provided for shut-off. The gates are locally operated by electric-motor-driven, rising-stem screw hoists.

A spherical 83-inch turbine shut-off valve is provided in the powerhouse between the power tunnel and turbine inlet control of main water flow through the system. The TSO valve position is controlled by a motor driven cam sequencing unit. The sequencing unit is used to retract or apply the ball seats, open or close the bypass valve, release or lock the ball valve in position, and supply pressure to the hydraulic cylinder which opens and closes the ball valve. The cam can be controlled manually or fully automatically, either locally or from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120). Operating power is provided from a hydraulic power supply consisting of a dedicated air compressor, pressurized oil accumulator tank, oil reservoir, and oil pump and associated piping and control equipment.

Two 12-foot by 16-foot slide draft tube gates are provided just downstream of the turbine to isolate power station machinery from the discharge tunnel when necessary. The gates are locally operated by hydraulic cylinder operators.

Two 9-foot by 17-foot slide gates are located at the downstream end of the tailrace tunnel to isolate the tunnel from the afterbay (Shaver Lake). The gates are locally operated by electric motor-driven steel cable hoists.

Governors

Normal turbine operating speed control is maintained by a Woodward electric/hydraulic governor with a hybrid digital/analog speed sensor. It includes auxiliary devices which permit turbine control either manually, locally automatic, or remotely automatic, from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120). The governor provides accurate speed control for synchronizing and for stable operation when the unit is connected to the power system. Governor response time is coordinated with tunnel and surge chamber configurations to provide a stable speed control system. The hydraulic power supply consists of a dedicated air compressor, pressurized oil accumulator tank, oil reservoir and oil pump and associated piping and control equipment.

Gaging

The following gaging stations are associated with this Project:

USGS No.	SCE No.	Station Name
11238250	187	Eastwood Power Station
11238270	100	Middle Fork Balsam Creek below Balsam Meadow Forebay

Generators

The main generator/motor is a vertical shaft, direct coupled, totally enclosed General Electric Canada unit designed for either direction of rotation and is provided with a voltage regulator, excitation system, thrust and guide bearings, brakes, cooling system and fire protection. The generator is rated at 199,800 kW, 0.9 power factor, 400 RPM, 13.8 kV, three-phase, 60 Hz with a design head of 1,266 feet. The motor is rated at 215,000 kW, 1.0 power factor, 400 RPM, 13.8 kV, three-phase, 60 Hz with a design head of 1,324 feet. The generator/motor is protected by three single-pole, 15 kV, 12,000 amp, SF6 power circuit breakers.

Motor-operated disconnect switches are provided to reverse phase rotation for operation in either direction of rotation. A shaft-mounted wound-rotor induction motor is used for startup when operating the generator/motor in the pumping mode. Speed control during startup is achieved by a liquid rheostat. Excitation for the generator/motor is provided by a static excitation system.

Transformers

The unit main transformer consists of a three-phase, 250 MVA, 230 kV-13.8 kV, FOW, 60 Hz transformer. The transformer is located in the underground powerstation and is connected to the generator, through a circuit breaker by means of an isophase bus, and to the 220 kV switchyard by means of a compressed gas insulated bus system in the vertical access shaft. A sump sized for 120% of the transformer fluid capacity is provided, to accommodate oil spillage.

Power Distribution Equipment

Station service power is provided from two sources: the 13.8 kV generator bus and an offsite 12 kV distribution source from Edison's Timberwine

Substation. Station service transformers are provided for auxiliary power and lighting by means of two three-phase, 13.8 kV-480 volt transformers, and one 12 kV-480 volt auxiliary transformer. The local 12 kV distribution cable from the Timberwine Substation is routed to operate motorized slide gates at the Tunnel No. 7 Outlet Portal, the Balsam Meadow Forebay end of the Diversion Tunnel, and the Power Tunnel Inlet Portal.

Station "DC" control power is supplied by a 60-cell, 1,050 ampere-hour, 125 volt calcium type battery bank located in a battery room in the underground power station. The DC system supplies a reliable source of continuous power to operate control circuits and has sufficient emergency capacity to achieve safe and orderly shutdown of the unit. A stationary battery charger and associated distribution equipment is furnished with the battery.

Heating, Ventilating, and Air Conditioning System

The powerhouse is ventilated primarily by a forced air system which consists of ventilation supply fans, exhaust fans, electric unit heaters, ducting, dampers, supply registers, exhaust registers, and controls. The supply fans are located at the bottom and top of the powerhouse vent shaft. The main ventilation system consists of two supply fans, two exhaust fans, and two booster fans.

During normal plant operation, one bank of fans (one supply, one exhaust, and one booster fan) operate simultaneously at low speed in the winter and high speed in the summer. During plant maintenance periods, two banks of fans operate simultaneously at low speed in the winter and high speed in the summer. The tunnel and power station walls are a uniform temperature through all seasons and temper incoming air from both summer and winter extremes to ambient conditions suitable for installed equipment.

Space heating is provided to the general powerhouse area via electric heating coils on the supply fans. Comfort heating for occasional occupancy by maintenance or other personnel is provided as needed in localized areas by electric heaters. A heat pump provides a temperature and humidity regulated air supply to the control room.

Local exhaust fans for the toilets, elevator pit, sewage holding sump, elevator shaft, lift station holding tank, grinding room, welding room, and machine shop have been provided. The construction tunnels are vented by manually controlled, electrically operated fans. These fans are operated only during times when the tunnels are occupied.

Compressed Air System

The compressed air system supplies 125 psig air to the service air utility stations, the guide bearing seal, the turbine maintenance shaft seal, the governor for generator air brake control, the grease lubrication system, and the generator air lovers. A low pressure isolation valve sensing an established threshold is provided so that only the generator air brakes are served when the system pressure drops below a preset level. The system consists of a skid mounted Ingersoll Rand 301 air compressor and receiver tank. The air compressor is a single acting two stage reciprocating compressor with air cooled, oil lubricated cylinders. The recovery tank has a capacity of 150 cubic feet and is equipped with automatic drain traps, relief valves, and pressure indicators.

Fire Protection System

The power station fire protection system consists, in part, of ten firehose stations, portable extinguishers strategically located through the facility, and three sprinkler system loops. Water for these systems is supplied from the cooling water system. Sprinkler loops are located in the main transformer room, the isolation transformer room, and the lube oil tank area. Two independent Halon fire suppression systems also make up this system and provide fire protection for the control room and within the generator housing. The independent Halon systems consist of Halon storage tanks, a hard piped distribution system, and a control cabinet for discharge control.

The generator is supplied with a fire protection via a Halon 1301 system consisting of an alarm fire detection system and a Halon discharge manifold fitted with nozzles mounted on the housing wall in the upper bearing bracket area.

The oil-filled main transformer unit is enclosed with two-hour fire walls, removable for access. The enclosure is equipped with sensors for early detection of smoke or fire with the detectors programmed to activate a water deluge system. The lubricating oil conditioning and storage unit is monitored and has a water deluge system similar to the unit main transformer. There is a Halon protection system in the main unit and in the gallery. All devices containing quantities of oil are suitably diked to prevent spreading of potential oil leaks.

The fire detection system is closely allied to, and interlocked with, the main HVAC system. In case of fire, the fire detection system will automatically bring on the second bank of fans with all fans operating at high speed for smoke evacuation. Any of the fans can be controlled by local personnel. The fire detection system will isolate the air supply to the transformer rooms and shut down the control room heat pump and Crown access ventilation fan.

Sanitary Disposal System

The sanitary sewage system provides for the storage of sewage from the toilet facilities located in the control room and at the main access tunnel. The system consists of a sewage holding tank at the basement elevation which stores sewage from the control room toilet facility. A grinder pump in the tank pumps the sewage to the sewage holding sump at the main access tunnel. Sewage from the toilet facilities at the main access tunnel is also directed to this sump. The sewage holding sump is provided with a service water spray system for dilution of the sewage slurry and an HVAC duct connection to maintain venting of the sump. The effluent is held in the sewage sump until removed by tank truck to a suitable treatment facility.

Lighting

Normal station lighting is controlled from local 480/277 V lighting panels conveniently located throughout the plant area. Areas other than working areas have general area lighting to provide adequate illumination for safe access and security. Emergency DC lighting is provided to enable station personnel to safely operate the plant in the event of system outages or to sustain operation upon outage of the normal lighting system. This lighting system is made up of incandescent fixtures supplied from the station battery system.

Station Crane

For hoisting major equipment in the powerhouse, the powerstation is equipped with a 450-ton traveling crane with a 50-ton auxiliary hook, a 25-ton auxiliary hoist, and a boom-mounted 5-ton hoist. The crane has sufficient capacity and travel to lift all major components of the facility including the turbine, generator, TSO valve, main transformer and sump pumps.

Switching

The Project switchyard is located at ground level near the entrance of the vertical access shaft and connects the station to the Project transmission line. The switchyard contains a 40-foot high, 230 kV line dead-end structure, compressed SF6 gas-insulated bus and bushings which form the termination of the 230 kV rated bus connections from the transformer, disconnect switches, buses, line traps, line coupling capacitors, lightning arrestors, and other related equipment.

(6) Lands of the United States within Project Boundaries

Lands of the United States that are within the Project boundaries, including legal subdivisions and acreage, are listed in Table A-1.

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project. (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 24 East, MDM	
Section 22	
SE1/4 SE1/4	0.80
Section 25	
NW1/4 SW1/4	0.30
SW1/4 SW1/4	22.40
Section 26	
NE1/4 SW1/4	11.40
SE1/4 SW1/4	11.90
SW1/4 SW1/4	2.20
NW1/4 SW1/4	22.80
SW1/4 NW1/4	27.00
NW1/4 NW1/4	14.13
SE1/4 NW1/4	3.38
NE1/4 NW1/4	0.08
SE1/4 SE1/4	33.63
SW1/4 SE1/4	13.26
NE1/4 SE1/4	1.30
Section 27	
NE1/4 NE1/4	26.90
SE1/4 NE1/4	13.00
Section 35	
NE1/4 NE1/4	2.63
SE1/4 NE1/4	1.60
Section 36	
SE1/4 SW1/4	17.50
NW1/4 SW1/4	2.00
NE1/4 SW1/4	13.30
NW1/4 NW1/4	21.20
SE1/4 NW1/4	2.40
SW1/4 NW1/4	9.40
Township 9 South, Range 24 East, MDM	
Section 1	
NE1/4 NE1/4	5.20
SE1/4 NE1/4	2.90
NW1/4 NE1/4	0.20
SW1/4 SE1/4	2.70
NE1/4 SE1/4	1.00
SE1/4 SE1/4	0.20
NW1/4 SE1/4	1.00
Section 12	
NW1/4 SE1/4	3.90
SW1/4 NE1/4	3.00
NW1/4 NE1/4	3.00

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 9 South, Range 24 East, MDM (continued)	
Section 25	
SW1/4 SW1/4	0.30
Township 8 South, Range 25 East, MDM	
Section 13	
SE1/4 SE1/4	1.10
Section 22	
NW1/4 NE1/4	2.46
NE1/4 NE1/4	1.70
SE1/4 NE1/4	3.32
SW1/4 NE1/4	1.73
NW1/4 SE1/4	0.01
NE1/4 SE1/4	4.19
SE1/4 SE1/4	0.30
SE1/4 NW1/4	1.20
Section 23	
SW1/4 SW1/4	2.80
Section 26	
SW1/4 SW1/4	5.62
SE1/4 SW1/4	0.08
NW1/4 SW1/4	3.70
SW1/4 NW1/4	3.10
NW1/4 NW1/4	3.10
Section 28	
SE1/4 SW1/4	0.50
NW1/4 SE1/4	0.70
SW1/4 SE1/4	2.90
Section 32	
SE1/4 NE1/4	1.50
NW1/4 SE1/4	2.30
NE1/4 SE1/4	2.60
SW1/4 SE1/4	6.23
Section 33	
NW1/4 NW1/4	0.90
SW1/4 NW1/4	2.40
NE1/4 NW1/4	2.90
Section 34	
NE1/4 SE1/4	3.60
SE1/4 SE1/4	0.30
SW1/4 SE1/4	6.10
NW1/4 SE1/4	1.50
SW1/4 SW1/4	1.60
SE1/4 SW1/4	1.70
SE1/4 NE1/4	2.20

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 25 East, MDM (continued)	
Section 35	
NE1/4 NW1/4	5.66
SW1/4 NW1/4	1.40
NW1/4 NW1/4	11.20
Township 9 South, Range 25 East, MDM	
Section 3	
NE1/4 NE1/4	3.20
SE1/4 NE1/4	5.50
NE1/4 SE1/4	3.20
SE1/4 SE1/4	2.30
SW1/4 SE1/4	0.90
NW1/4 NW1/4	0.06
NE1/4 NW1/4	1.90
SE1/4 NW1/4	0.08
SW1/4 NW1/4	1.80
NW1/4 SW1/4	1.20
NE1/4 SW1/4	0.40
SW1/4 SW1/4	1.40
SE1/4 SW1/4	1.80
Section 4	
SE1/4 NE1/4	0.60
SE1/4 NW1/4	0.30
SW1/4 NW1/4	4.80
NW1/4 NW1/4	6.12
Section 5	
NE1/4 NE1/4	0.86
Section 10	
SW1/4 NE1/4	3.20
NW1/4 NE1/4	3.20
NW1/4 SE1/4	3.20
SW1/4 SE1/4	2.60
Section 16	
SE1/4 NE1/4	0.60
NE1/4 SE1/4	15.40
SW1/4 SE1/4	14.20
NW1/4 SE1/4	5.80
SE1/4 SW1/4	0.10
SW1/4 SW1/4	6.40
NW1/4 SW1/4	6.30
NE1/4 NW1/4	0.40
NW1/4 NW1/4	3.12
SW1/4 NW1/4	9.37

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 9 South, Range 25 East, MDM (continued)	
Section 17	
NE1/4 NE1/4	5.55
Section 20	
NE1/4 SE1/4	4.70
NE1/4 SE1/4	19.30
Section 30	
SW1/4 SE1/4	33.40
NW1/4 SE1/4	40.20
NE1/4 SW1/4	40.30
SE1/4 SW1/4	8.50
Township 7 South, Range 26 East, MDM	
Section 13	
SE1/4 SE1/4	1.40
Section 23	
NE1/4 SE1/4	0.10
SE1/4 SE1/4	3.90
SW1/4 SE1/4	0.90
Section 24	
NE1/4 SW1/4	0.70
NW1/4 SW1/4	3.90
NE1/4 NE1/4	2.40
NW1/4 NE1/4	2.40
SW1/4 NE1/4	1.50
SE1/4 NW1/4	3.20
Section 25	
SE1/4 NW1/4	0.09
Section 26	
NE1/4 NE1/4	0.70
NW1/4 NE1/4	3.40
NW1/4 SW1/4	1.20
NE1/4 NW1/4	1.80
SE1/4 NW1/4	2.20
SW1/4 NW1/4	2.70
Section 27	
NE1/4 SE1/4	3.50
SE1/4 SE1/4	0.50
SW1/4 SE1/4	4.00
SE1/4 SW1/4	0.40
Section 33	
SE1/4 NE1/4	2.10
NW1/4 SE1/4	2.90
NE1/4 SE1/4	1.80
SW1/4 SE1/4	0.90
SE1/4 SW1/4	3.80

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 7 South, Range 26 East, MDM (continued)	
Section 34	
NE1/4 NW1/4	3.50
SW1/4 NW1/4	2.60
NW1/4 NW1/4	1.20
Township 8 South, Range 26 East, MDM	
Section 4	
NW1/4 NW1/4	3.50
Section 5	
NE1/4 NE1/4	0.10
SE1/4 NE1/4	3.90
SW1/4 NE1/4	0.90
NW1/4 SE1/4	5.83
SE1/4 SW1/4	6.16
NE1/4 SW1/4	3.85
SW1/4 SW1/4	0.03
Township 6 1/2 South, Range 27 East, MDM	
Section 35	
SW1/4 NE1/4	0.30
SE1/4 NE1/4	0.80
NE1/4 SE1/4	0.50
SW1/4 SE1/4	5.00
NW1/4 SE1/4	14.90
NE1/4 SW1/4	12.90
SE1/4 SW1/4	2.90
Township 7 South, Range 27 East, MDM	
Section 3	
SW1/4 E1/2	3.10
NW1/4 E1/2	3.30
Section 10	
NE1/4 SW1/4	3.20
SE1/4 SW1/4	1.80
SW1/4 SW1/4	1.90
SW1/4 NE1/4	4.80
NW1/4 NE1/4	3.20
NE1/4 SE1/4	3.40
NW1/4 SE1/4	2.00
Section 11	
NE1/4 SE1/4	0.89
SE1/4 SE1/4	3.40
SW1/4 SE1/4	3.10
SE1/4 SW1/4	3.90
SW1/4 SW1/4	0.50
NW1/4 SW1/4	3.00

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 7 South, Range 27 East, MDM	
Section 12	
SW1/4 S1/2	10.50
NW1/4 S1/2	11.37
SW1/4 N1/2	0.60
Section 15	
NW1/4 NW1/4	3.20
Section 16	
NE1/4 NE1/4	0.50
SE1/4 NE1/4	3.40
NE1/4 SE1/4	2.20
SW1/4 SE1/4	3.30
NW1/4 SE1/4	2.00
SE1/4 SW1/4	0.40
Section 18	
SW1/4 SW1/4	5.30
NW1/4 SW1/4	0.30
Section 19	
SE1/4 NE1/4	0.90
NE1/4 NE1/4	2.60
NW1/4 NE1/4	3.20
NE1/4 NW1/4	3.20
SW1/4 NW1/4	3.40
NW1/4 NW1/4	5.80
Section 20	
SW1/4 NE1/4	2.80
NE1/4 SE1/4	3.20
NW1/4 SE1/4	0.40
SE1/4 NW1/4	3.48
SW1/4 NW1/4	3.30
Section 21	
SW1/4 SE1/4	1.08
NE1/4 SW1/4	1.85
SE1/4 SW1/4	4.36
SW1/4 SW1/4	0.01
NW1/4 SW1/4	11.59
SE1/4 NW1/4	4.33
SW1/4 NW1/4	6.60
NE1/4 NW1/4	3.20
Section 25	
SE1/2 SE1/4	0.60
Section 27	
SW1/4 NW1/4	2.80
SE1/4 SE1/4	0.80
SW1/4 SE1/4	3.90

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 7 South, Range 27 East, MDM (continued)	
Section 27 (continued)	
NW1/4 SW1/4	1.10
NE1/4 SW1/4	3.60
SE1/4 SW1/4	0.30
Section 28	
NE1/4 NE1/4	1.80
SE1/4 NE1/4	2.00
NW1/4 NE1/4	2.90
Section 34	
NE1/4 NE1/4	3.00
SE1/4 SE1/4	0.50
Section 35	
SE1/4 NW1/4	2.80
SW1/4 NW1/4	2.10
NW1/4 NW1/4	1.80
NE1/4 SE1/4	6.80
SE1/4 SE1/4	3.85
SW1/4 SE1/4	3.00
NW1/4 SE1/4	8.90
NE1/4 SW1/4	1.10
SE1/4 SW1/4	6.11
SW1/4 SW1/4	6.30
Section 36	
NE1/4 NE1/4	3.10
SE1/4 NE1/4	1.90
SW1/4 NE1/4	1.30
NE1/4 SE1/4	3.20
SE1/4 SE1/4	6.00
SW1/4 SE1/4	29.00
NW1/4 SE1/4	20.60
NW1/4 SW1/4	4.41
NE1/4 SW1/4	3.50
SE1/4 SW1/4	34.66
SW1/4 SW1/4	28.78
Township 8 South, Range 27 East, MDM	
Section 1	
NE1/4 NE1/4	0.50
SE1/4 NE1/4	9.70
SW1/4 NE1/4	25.50
NW1/4 NE1/4	8.60
NE1/4 SE1/4	38.40
SE1/4 SE1/4	40.40
SW1/4 SE1/4	39.80
NW1/4 SE1/4	40.00

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 27 East, MDM (continued)	
Section 1 (continued)	
NE1/4 SW1/4	38.60
SE1/4 SW1/4	20.60
NW1/4 SW1/4	1.50
NE1/4 NW1/4	16.50
SE1/4 NW1/4	40.00
SW1/4 NW1/4	11.70
NW1/4 NW1/4	8.70
Section 12	
NE1/4 NW1/4	0.20
NE1/4 SE1/4	16.50
SE1/4 SE1/4	0.20
NE1/4 NE1/4	40.20
SE1/4 NE1/4	39.60
SW1/4 NE1/4	14.00
NW1/4 NE1/4	31.20
Township 7 South, Range 28 East, MDM	
Section 19	
NW1/4 SE1/4	3.58
SE1/4 SW1/4	3.20
NE1/4 SW1/4	1.00
NW1/4 SW1/4	3.08
Section 30	
NE1/4 SW1/4	1.70
SW1/4 SW1/4	0.90
NW1/4 SW1/4	6.99
NE1/4 NW1/4	3.20
SE1/4 NW1/4	4.90
SW1/4 NW1/4	1.20
Section 31	
SW1/4 SW1/4	0.40
Township 8 South, Range 28 East, MDM	
Section 6	
NE1/4 W1/2	1.50
SW1/4 W1/2	1.00
NW1/4 W1/2	3.10
NW1/4 SW1/4	0.10
SW1/4 SW1/4	9.40
Section 7	
NE1/4 NW1/4	7.50
SE1/4 NW1/4	39.00
NW1/4 NW1/4	34.50
SW1/4 NW1/4	39.50
NE1/4 SW1/4	39.10

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 2A, 8 and Eastwood Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 28 East, MDM (continued)	
Section 7 (continued)	
SE1/4 SW1/4	11.80
NW1/4 SW1/4	39.60
SW1/4 SW1/4	36.40
SE1/4 NE1/4	6.40
SW1/4 NE1/4	30.80
NW1/4 NE1/4	0.20
NE1/4 SE1/4	36.80
SE1/4 SE1/4	31.60
SW1/4 SE1/4	32.60
NW1/4 SE1/4	39.90
Section 8	
NW1/4 SW1/4	3.00
SW1/4 SW1/4	0.30
Section 18	
NW1/4 NW1/4	5.70
NE1/4 NW1/4	27.60
SE1/4 NW1/4	0.50
NE1/4 NE1/4	5.10
SE1/4 NE1/4	3.30
SW1/4 NE1/4	13.20
NW1/4 NE1/4	4.80
TOTAL FEDERAL LAND ACREAGE	**2,143.25**

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK Nos. 2A, 8 AND EASTWOOD (FERC Project No. 67)

EXHIBIT B: STATEMENT OF OPERATION AND RESOURCE UTILIZATION

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit B Statement of Operation and Resource Utilization

Exhibit B is a statement of project operation and resource utilization. If the project includes more than one dam with associated facilities, the information must be provided separately for each such discrete development. The exhibit must contain:

(1) A statement whether operation of the powerplant will be manual or automatic, an estimate of the annual plant factor, and a statement of how the project will be operated during adverse, mean, and high water years;

(2) An estimate of the dependable capacity and average annual energy production in kilowatt-hours (or a mechanical equivalent), supported by the following data:

(i) The minimum, mean, and maximum recorded flows in cubic feet per second of the stream or other body of water at the powerplant intake or point of diversion, with a specification of any adjustments made for evaporation, leakage, minimum flow releases (including duration of releases), or other reductions in available flow; monthly flow duration curves indicating the period of record and the gauging stations used in deriving the curves; and a specification of the period of critical streamflow used to determine the dependable capacity;

(ii) An area-capacity curve showing the gross storage capacity and usable storage capacity of the impoundment, with a rule curve showing the proposed operation of the impoundment and how the usable storage capacity is to be utilized;

(iii) The estimated hydraulic capacity of the powerplant (minimum and maximum flow through the powerplant) in cubic feet per second;

(iv) A tailwater rating curve; and

(v) A curve showing powerplant capability versus head and specifying maximum, normal, and minimum heads;

(3) A statement, with load curves and tabular data, if necessary, of the manner in which the power generated at the project is to be utilized, including the amount of power to be used on-site, if any, the amount of power to be sold, and the identity of any proposed purchasers; and

(4)	A statement of the applicant's plans, if any, for future development of the project or of any other existing or proposed water power project on the stream or other body of water, indicating the approximate location and estimated installed capacity of the proposed developments.

(1) Type of Operation

The Big Creek Nos. 2A, 8 and Eastwood Project covers the largest geographical area of all seven projects in the BCS. The Project includes: (1) Florence Lake, and a number of small diversions in the high elevation backcountry or upper basin area; (2) Shaver Lake, located on Stevenson Creek; (3) Eastwood Power Station (EPS), which discharges to Shaver Lake; and (4) Powerhouses 2A and 8, located along Big Creek. Powerhouses 2A and 8, and the Eastwood Power Station may be operated locally from the control rooms at each powerhouse, or remotely from Big Creek Powerhouse No. 3 (FERC Project No. 120), which serves as the main control center for the entire Big Creek System (BCS).

Project Operations

Operation of SCE's seven FERC-Licensed Projects in the BCS is managed from a watershed-wide perspective and on an individual project-by-project basis. The Big Creek Hydroelectric System consists of six major reservoirs (Thomas A. Edison, Florence, Huntington, Redinger, Shaver, and Mammoth Pool) and nine powerhouses (Portal; Eastwood; Mammoth Pool; and Big Creek Powerhouse Nos. 1, 2, 2A, 3, 4, and 8). Figure B-1 presents a schematic diagram of the seven FERC-Licensed Projects and associated reservoirs, water conveyance tunnels and powerhouses in the BCS. The operation of the BCS and the individual Projects is dependent on natural run-off during periods of snowmelt and wet weather and the operation of other components in the system, the amount of generation required for SCE's customers, and the dispatching of energy in accordance with California Independent System Operator (ISO) requirements.

SCE operates the four Big Creek ALP projects within the BCS in accordance with the FERC-license conditions, which includes minimum instream flow (MIF) release requirements that are made by SCE from diversions and impoundments.

The management of water through the BCS and specifically the four Big Creek ALP Projects routes water between Projects in a manner that best meets the operational constraints that are imposed either by contractual operating agreements (i.e., licenses, permits, etc.) or by physical limitations of the Project infrastructure. The BCS is subject to several operating constraints including the following: (1) available water supply; (2) electrical system requirements; (3) both planned and unplanned maintenance outages; (4) storage limits (including both recreation minimums and year-end carryover maximums); (5) both minimum and maximum release limits (from storage); (6) various provisions contained in water rights agreements; and (7) California ISO requirements.

Water Rights and Contractual Obligations

Each of SCE's Big Creek Hydroelectric Projects either has separate water rights or shares one or more water rights with other projects for the diversion, use, and storage of water. The majority of the water rights are for non-consumptive uses associated with the generation of power. A few locations, such as the SCE's administrative offices and company housing near Big Creek No. 1 Powerhouse have minor consumptive water rights. SCE does not hold water rights for the consumptive use of water by any party other than SCE, nor does SCE sell any water rights associated with the hydropower projects to other parties.

SCE's water rights were obtained pursuant to state law and a majority of the water rights are documented by licenses and permits issued to SCE, or its predecessors, by the State Water Resources Control Board (State Water Board). Additional water rights were obtained through appropriation of water prior to the implementation of the Water Commission Act of 1914, and by prescriptive use against other parties. SCE also holds other water rights as a riparian land owner, which authorizes SCE to divert and use water on land owned by SCE.

The water rights agreements contain stipulations that stem from the senior status of certain downstream water rights holders. Generally, any water right holder with senior rights began diverting water for consumptive purposes prior to SCE or its predecessors. To protect the rights of the downstream water rights holders, SCE entered into agreements that restrict the use of water within the BCS to non-consumptive purposes, i.e., hydroelectric generation. Certain agreements limit the length of time and amount of water that SCE can store in its Project reservoirs. In a few instances, SCE's non-consumptive water use is a senior water right, and other water users hold junior water rights.

SCE operates its reservoirs consistent with the Mammoth Pool Operating Agreement (MPOA), which specifies cumulative reservoir storage constraints based on the computed natural run-off for the water year at Friant Dam. The MPOA between SCE and the U.S. Bureau of Reclamation (Bureau) specifies water storage and release requirements for the BCS reservoirs, which are upstream of Friant Dam (Millerton Reservoir) and the associated Central Valley Project water distribution system operated by the Bureau on behalf of the downstream irrigators. Millerton Reservoir is a major irrigation storage facility serving the central San Joaquin Valley agricultural community. Meetings between SCE, the Bureau, and the downstream irrigators are held following the March 1 runoff forecast each year, and periodically as needed, to coordinate and optimize hydropower production consistent with irrigation needs of the downstream agricultural users holding senior water rights and emergency flood control operations of Millerton Reservoir. The MPOA includes constraints on the annual and seasonal timing and volume of releases from SCE's reservoirs, maximum year-end storage allowed, and minimum seasonal flow from Dam No. 7 (release and diversion).

BCS Water Management

A key component of the annual water management plan for the BCS is the development of an annual run-off forecast. The annual run-off forecast is developed based on snow pack and precipitation data collected in the vicinity of the Project. This information is used along with assumptions about future median precipitation and air temperatures to produce a run-off forecast through the end of the water year (September 30). The forecast includes an estimate of both the timing and the quantity of water that will enter Project reservoirs during that run-off season. Snow pack and precipitation data are shared with the California Department of Water Resources (DWR) and the Bureau, who use it to develop individual forecasts of run-off volumes and declare water year types (critical, dry, below normal, above normal, or wet). The run-off forecast is a valuable tool for planning and ensuring compliance with the constraints of the MPOA (described above) and for planning purposes. A majority of the MPOA and other constraints are based on actual run-off volumes. The forecast also is used for directing future operational plans for: 1) instream flow release requirements; 2) reservoir recreational storage requirements; and 3) hydroelectric generation operations for the entire BCS.

The operation of the BCS is similar in all water year types in that water diverted from Project reservoirs and diversions is utilized to generate power. There are subtle differences, however, in the way that the Project is operated during different water year types and during different conditions of state energy requirements.

Some of the BCS reservoirs generally spill in wet and above normal water years and are filled to maximum capacity when spill ceases. When the BCS reservoirs stop spilling, SCE is able to manage the system with available inflows and begin managing the water to meet electric supply requirements by providing both base load and peak cycling energy. In the upper basin area, water from the upper South Fork San Joaquin River drainage is stored in Florence Lake and water from Mono Creek drainage is stored in Lake Thomas A. Edison. Water is diverted from these two lakes and various other small backcountry diversions into Huntington Lake via the Ward Tunnel and the Mono-Bear Siphon. The volumes of water that can pass through Ward Tunnel and the siphon are limited by the physical size and layout of these conduits. Water deliveries to Huntington Lake are prioritized as follows: first priority is given to water from Florence Lake; second priority is given to water from Bear Diversion and Lake Thomas A. Edison; and third priority is given to water diverted from the small diversions at Camp 61 Creek, Camp 62 Creek, Chinquapin Creek and Bolsillo Creek. The water delivered to Huntington Lake may also pass through Portal Powerhouse at the exit of the Ward Tunnel depending upon the amount of water being transported.

BCS Power Generation

The BCS has three interlinked water chains or pathways through which water may be transported and used to produce power. The three water chains are:

- Huntington Water Chain: This chain consists of Portal Powerhouse, Powerhouse No. 1, Powerhouse No. 2, Powerhouse No. 8, Powerhouse No.3, and Powerhouse No. 4.

- Shaver Water Chain: This chain consists of Portal Powerhouse, Eastwood Power Station, Powerhouse No. 2A, Powerhouse No. 8, Powerhouse No. 3, and Powerhouse No. 4.

- Mammoth Water Chain: This chain consists of Mammoth Pool Powerhouse, Powerhouse No. 3, and Powerhouse No. 4.

After passing through or bypassing the Portal Powerhouse, water entering Huntington Lake is directed to either the Huntington Chain, or the Shaver Chain. If the generation from the powerhouses of either chain is increased or decreased proportionally, the changes in load will have no effect on the MIF, or total levels of the storage reservoirs and forebays within the BCS. Changes in total loading conditions of the two chains can, however, affect Florence Lake and Lake Thomas A. Edison and can affect the amount of water leaving the project at Powerhouse No. 4. If generation from the powerhouses of either chain is changed disproportionately, the levels of Huntington Lake, Shaver Lake, and Redinger Lake can be increased or decreased.

Water from Big Creek Powerhouse Nos. 1 and 2 in the Huntington Chain joins water from the Shaver Chain, which has already passed through Eastwood Power Station and Big Creek Powerhouse No. 2A, at the Big Creek Powerhouse No. 2 and 2A Tailrace (Dam 5). Water from these two chains is then diverted through Big Creek Powerhouse No. 8, after which it joins the waters of the San Joaquin River coming from the Mammoth Chain at the Big Creek No. 8 Tailrace (Dam 6 Impoundment). Water from all three chains then continues through Big Creek Powerhouse Nos. 3 and 4.

Waters from the Middle Fork and North Fork San Joaquin River (SJR) drainages, and the South Fork SJR flows not diverted at Florence Lake, Lake Thomas A. Edison, Bear Creek Forebay, and the small backcountry diversions, are collected in Mammoth Pool Reservoir and become part of the Mammoth Chain. Mammoth Pool Powerhouse is usually run at maximum during the high flow or run-off period to prevent or delay spill at Mammoth Pool Reservoir.

For the most part, Portal Powerhouse, Eastwood Power Station, and Big Creek No. 4 Powerhouse operate independently of the other powerhouses in the BCS. Portal Powerhouse opportunistically uses water passing through the Ward Tunnel for power generation, but only operates efficiently at moderate flows through Ward Tunnel. Ward Tunnel flows outside the efficient flow range of Portal Powerhouse bypass Portal Powerhouse through the Howell Bunger (HB) valve into Huntington Lake. Eastwood Power Station generation normally occurs during the peak demand period of the day, unless water is being moved continuously from Huntington Lake to Shaver Lake to avoid spill at Huntington Lake or to increase storage at Shaver Lake for use during peak periods. Maintaining storage (water surface levels) to maintain recreational needs at Huntington Lake and above pump-back minimum water surface level in Shaver Lake are important considerations when planning operations at Eastwood Power Station. Big Creek Powerhouse No. 4 is the last power generation opportunity in the Big Creek System and therefore adjustments in the operation of the Powerhouse No. 4 will not affect other upstream powerhouses in the BCS.

Generally, the three water chains of the BCS are operated around the clock in the spring run-off period, except in dry water years. Operational flexibility is limited during normal run-off because the amount of water run-off available exceeds the combined generation and storage capacity of the project, resulting in water flowing over spillways or "spill".

After the end of the spill period, daily unit plant load schedules are established to maximize hydro resources during system peak load periods. When spring run-off is finished, if a powerhouse does not need to operate for water management, it is run preferentially during on-peak hours. Due to the nature of the energy market and SCE's resources, it is generally beneficial for the Big Creek Projects to provide power during on-peak hours, once the spring runoff has finished. Since the BCS powerhouses discharge to reservoirs or forebays, the peaking operations generally do not cause varying flows in bypass reaches. Energy load changes on these power generation chains will not affect the water surface elevation (WSE) or instream flows, as long as adjustments are made to match reservoir inflows and outflows. A proprietary computer model used for predicting inflow is also used to plan monthly flow of water through the Project to meet the operating constraints on the system while maximizing generation during the peak load periods. In addition, computer programming of load schedules to use the most efficient units first, further enhances these operating activities and improves system integrity and efficiency. These activities can ensure the efficient use and availability of hydroelectric generation resources from these reservoir storage plants.

Market constraints and pricing, as well as transmission constraints and weather, will affect generation and operations at the Big Creek Projects. Often during the spring run-off season there is a financial disadvantage for SCE to generate energy even though to avoid generation would cause spill to occur. A simplified description of the California energy market describes the Independent System Operator (ISO) as having the role of balancing energy demand and supply in the state. The ISO takes the energy demand forecast, the transmission system constraints, and the energy that is bid into the day-ahead market to determine the acceptable energy supply. The ISO then adjusts the supply load on a real-time basis to account for changing conditions. If the ISO believes that there is a surplus of energy available beyond that necessary to supply the grid, prices in the California energy market for additional energy could be negative. This situation would require SCE to pay for contributing additional energy.

Water Management for Big Creek Nos. 2A, 8 and Eastwood Project (FERC Project No. 67)

The flow of water through the Powerhouse Nos. 2A, 8 and EPS Project is dependent on natural run-off during periods of snowmelt and wet weather and the operation of other components of the BCS that are located at a higher elevation within the drainage. The Powerhouse Nos. 2A, 8 and EPS Project operate in tandem with the rest of the BCS in a parallel and stair step sequence of water chains. The EPS and Powerhouse No. 2A are in the Shaver Lake Water Chain and Powerhouse No. 8 is in both the Shaver Lake Water Chain and the Huntington Water Chain. Powerhouse No. 2A receives water from Shaver Lake and discharges to the Dam 5 impoundment on Big Creek. Powerhouse No. 8 utilizes water from the Dam 5 impoundment and discharges to the Dam 6 impoundment on the San Joaquin River. The EPS discharges to Shaver Lake and receives water from Balsam Meadow Forebay, which is filled via the Huntington-Pitman-Shaver Conduit from Huntington Lake or through water pumped back from Shaver Lake. The EPS may operate as a pump storage project in all water year types after the run-off period has ended and SCE gains control of reservoir inflows in the BCS.

The operation of all three powerhouses of Big Creek Nos. 2A and 8 and EPS are similar in all water year types, in that water being diverted into the Project from remote impoundments and diversions is utilized to generate power when the water is available. In wet water years, the Project runs at full capacity beginning in mid-April to May until the end of peak run-off, which typically occurs in late July. At that time, SCE gains control of inflows and begins managing powerhouse operations to meet grid requirements by providing both base load and peak cycling energy. Project generation is greater during wet water years and water may be also bypassed around Project powerhouses at Project reservoirs and impoundments, if necessary.

In above normal water years, the Project is generally run at full capacity beginning in May until the end of peak run-off, which typically occurs in July. Some of the BCS reservoirs generally spill in above normal water years and are filled to maximum capacity until spill ceases. At that point, SCE gains control of inflows and begins powerhouse operations to meet grid requirements by providing both base load and peak cycling energy.

During dry water years, the Project may run at full capacity for a short duration in May and June. In some dry water years the Project does not run at full capacity in order to fill the reservoirs to maximum capacity. Project generation is lower in dry water years and very little water, other than dam seepage and required MIF releases, bypasses the powerhouses.

Under the Proposed Action, water management would remain generally the same as existing operations with the exception of the decommissioning of four back-country small diversions including: North Slide Creek Diversion, South Slide Creek Diversion, Tombstone Creek Diversion, and Crater Creek Diversion.

(2) Capacity and Production

The Project is operated as a reservoir-storage type plant with an installed operating capacity of 384.80 MW and a dependable operating capacity of 370.0 MW. The average annual capacity factor for the Project between 1991 and 2005 was 34.8%. Over this period, the average annual capacity factors for Big Creek Powerhouse No. 2A, No. 8, and the EPS were 53.1%, 46.5%, and 20.4%, respectively. The annual Project generation output of Big Creek Powerhouse No. 2A, No. 8, and EPS and for the entire Project between 1991 and 2005 is provided in Table B-1. These generation statistics do not include losses from pumpback at the EPS.

(i) Daily average available flows – Powerhouse No. 2A, Powerhouse No. 8 and the EPS utilize water stored in Shaver Lake and Huntington Lake (FERC Project No. 2175) which include water diverted from the South Fork San Joaquin River drainage through the Ward Tunnel. The following statistics represent the total available flow at the points of diversion associated with the project, with the exception of the Camp 62 Creek and Chinquapin Creek diversions for which the available data set is insufficient for analysis. The Camp 62 and Chinquapin diversions are operated seasonally, primarily between May and September depending on access, and the available data for these diversions is limited to less than 4 years of cumulative data for any one month out of a total available data set of 9 years.

Florence Lake

The available flow at Florence Lake was derived by subtracting the minimum instream flow required for the South Fork San Joaquin River downstream of Florence Lake and flows in Hooper Creek below the diversion (USGS Gage No. 11230200) from the sum of the mean daily flows through Ward Tunnel (USGS Gage No. 11229500) and in the South Fork San Joaquin River below Hooper Creek (USGS Gage No. 11230215). This analysis likely overestimates available flows at Florence Lake, as it includes unaccounted and ungaged accretion flow downstream

Table B-1 Average Project Generation Output Between 1991-2005.

Year	Production in MWH (Transmitted)			
	PH No. 2A	PH No. 8	Eastwood Powerstation	Project Total
1991	300,086	201,793	182,293	684,172
1992	332,007	185,154	114,058	631,219
1993	678,695	423,044	473,826	1,575,566
1994	404,181	227,572	271,296	903,049
1995	752,803	455,504	540,359	1,748,666
1996	644,429	378,440	487,960	1,510,828
1997	582,998	395,435	511,038	1,489,471
1998	657,541	407,609	466,379	1,531,,528
1999	520,220	299,059	329,000	1,148,279
2000	513,902	305,685	325,270	1,144,857
2001	280,088	175,005	280,924	736,017
2002	425,339	241,027	302,860	969,226
2003	494,390	279,641	362,892	1,136,923
2004	401,920	237,681	255,814	895,415
2005	680,751	372,308	441,159	1,494,218
15-year average =	**511,290**	**305,664**	**356,342**	**1,173,296**

of Florence Lake which includes North and South Slide creeks and Tombstone Creek. The period of record used for this analysis was October 1, 1986 to September 30, 2002. The flow statistics for Florence Lake are presented below and the monthly flow duration curves are presented in Figure B-2.

Minimum	0 cfs
Median	144 cfs
Mean	288 cfs
Maximum	5,352 cfs

Hooper Creek Diversion

The available flow at the Hooper Creek Diversion was derived by subtracting the minimum instream flow for Hooper Creek below the diversion recorded at USGS Gage No. 11230200 from the sum of the mean daily diversion flows recorded at SCE Gage No. 113 and the mean daily flows downstream of the diversion recorded at USGS Gage No. 11230200. The period of record used for this analysis was October 1, 1991 to September 30, 2002. The flow statistics for the Hooper Creek Diversion are presented below and the monthly flow duration curves are presented in Figure B-3.

Minimum	0 cfs
Median	2.5 cfs
Mean	9.2 cfs
Maximum	110 cfs

Bear Creek Diversion

The available flow at the Bear Creek Diversion was derived by subtracting the minimum instream flow for Bear Creek below the diversion from the mean daily flows upstream of the diversion recorded at USGS Gage No. 11230500. The period of record used for this analysis was October 1, 1982 to September 30, 2002. The flow statistics for the Bear Creek Diversion are presented below and the monthly flow duration curves are presented in Figure B-4.

Minimum	1.7 cfs
Median	32 cfs
Mean	95 cfs
Maximum	1,417 cfs

Mono Creek Diversion

The available flow at the Mono Creek Diversion was derived by subtracting the minimum instream flow for Mono Creek below the diversion from the mean daily flows downstream of Edison Lake recorded at USGS Gage No. 11231500. The period of record used for this analysis was October 1, 1982 to September 30, 2002. The flow statistics for the Mono Creek Diversion are presented below and the monthly flow duration curves are presented in Figure B-5.

Minimum	0 cfs
Median	86 cfs
Mean	161 cfs
Maximum	1,287 cfs

Bolsillo Creek Diversion

The available flow at the Bolsillo Creek Diversion was derived by subtracting the minimum instream flow required for Bolsillo Creek downstream of the diversion from the sum of the mean daily diverted flow (SCE Gage No. 117) and the mean daily flow downstream of the diversion (USGS Gage No. 11230670). Due to the seasonal nature of operation of the diversion, sufficient data for analysis (greater than 5 years worth of data for each month) was only available for the months of May, June, and July between October 1, 1992 and September 30, 2002. The flow statistics for the Bolsillo Creek Diversion are presented below and the monthly flow duration curves are presented in Figure B-6.

Minimum	0.31 cfs
Median	0.87 cfs
Mean	0.98 cfs
Maximum	3.40 cfs

Tunnel 7 Diversion

The Tunnel 7 diversion transfers water from Huntington Lake to the Balsam Forebay and North Fork Stevenson Creek. The available flow at the Tunnel 7 diversion represents flow available to both FERC Project No. 2175 and FERC Project No. 67. Flow utilized for Project No. 2175 is diverted through Powerhouse No. 1. The available flow at the Tunnel 7 diversion was derived by adding the mean daily throughput flows for Powerhouse No. 1 (USGS Gage No. 11238100) and the mean daily flows through Tunnel 7 upstream of the Pitman Creek diversion. The flow data for Tunnel 7 was derived using the following methods: 1) for water year 1983, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the mean daily flow recorded at the Tunnel 7 outlet (USGS Gage No. 11239000); and 2) for water years 1990 to 2002, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the sum of the Eastwood Powerstation throughput (USGS Gage No. 11237600) and flow in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300). The analysis for water years 1990 to 2002 overestimates available flow at Tunnel 7 since the flows recorded in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300) include ungaged inflow upstream of the outlet. The period of record used in the analysis was October 1, 1982 to September 30, 1983 and October 1, 1989 to September 30, 2002. The flow statistics for the Tunnel 7 diversion are presented below and the monthly flow duration curves are presented in Figure B-7.

Minimum	0 cfs
Median	681 cfs
Mean	790 cfs
Maximum	2,439 cfs

Pitman Creek Diversion

The available flow at the Pitman Creek Diversion was derived by subtracting the minimum instream flow for Pitman Creek below the diversion from the mean daily flows upstream of the diversion recorded at USGS Gage No. 11237500. The period of record used for this analysis was October 1, 1982 to September 30, 2002. The flow statistics for the Pitman Creek Diversion are presented below and the monthly flow duration curves are presented in Figure B-8.

Minimum	0 cfs
Median	5.8 cfs
Mean	46 cfs
Maximum	2,200 cfs

Dam 5

The available flow at Dam 5 was derived by subtracting the minimum instream flow required for Big Creek downstream of Dam 5 from the sum of the mean daily flows through Big Creek Powerhouse No. 2 recorded at USGS Gage No. 11238380, Big Creek Powerhouse No. 2A recorded at USGS Gage No. 11238400, and Big Creek near the confluence with the San Joaquin River recorded at USGS Gage No. 11238500. The analysis likely underestimates available flow at Dam 5 as it does not account for flow accretion in Big Creek between Dam 4 and Dam 5. The period of record used for this analysis was October 1, 1986 to September 30, 1994 and October 1, 1995 to September 30, 2002. The flow statistics for Dam 5 are presented below and the monthly flow duration curves are presented in Figure B-9.

Minimum	0.7 cfs
Median	639 cfs
Mean	675 cfs
Maximum	4,096 cfs

Balsam Forebay

The available flow at the Balsam Forebay was derived by subtracting flows diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flows for Pitman Creek, Balsam Creek, and North Fork Stevenson Creek from the sum of the mean daily flows in Tunnel 7 and in Pitman Creek upstream of the diversion (USGS Gage No.11237500). The analysis assumes that there is no net increase or decrease in available water associated with pumpback between the EPS and Balsam Forebay. The period of record used for this analysis was October 1, 1989 to September 30, 2002. The flow statistics for the Balsam Forebay are presented below and the monthly flow duration curves are presented in Figure B-10.

Minimum	0 cfs
Median	366 cfs
Mean	442 cfs
Maximum	3,580 cfs

Shaver Lake

The available flow at Shaver Lake was derived by subtracting the minimum instream flow required for Stevenson Creek downstream of Shaver Lake recorded at USGS Gage No. 11241500 from the sum of the mean daily flows through Big Creek Powerhouse No. 2A recorded at USGS Gage No. 11238400 and Stevenson Creek downstream of Shaver Lake recorded at USGS Gage No. 11241500. The period of record used for this analysis was October 1, 1986 to September 30, 2002. The flow statistics for Shaver Lake are presented below and the monthly flow duration curves are presented in Figure B-11.

Minimum	0.1 cfs
Median	316 cfs
Mean	364 cfs
Maximum	1,305 cfs

(ii) The following figures present area-capacity curves for Project-related impoundments:

- Figure B-12 presents the area-capacity curves for Florence Lake
- Figure B-13 presents the area-capacity curves for the Bear Creek impoundment
- Figure B-14 presents the area-capacity curves for the Dam 5 impoundment
- Figure B-15 presents the area-capacity curves for the Hooper Creek impoundment
- Figure B-16 presents the area-capacity curves for the Mono Creek impoundment
- Figure B-17 presents the area-capacity curves for Shaver Lake
- Figure B-18 presents the area-capacity curves for the Balsam Meadow Forebay

(iii) The total estimated maximum hydraulic capacity for the Project is 4,253 cfs and the total estimated minimum hydraulic capacity is 472 cfs. Eastwood unit 1 operates between 309 cfs and 2,296 cfs. Big Creek 2A unit 1 operates between 9 cfs and 311cfs. Big Creek 2A unit 2 operates between 6 cfs and 314 cfs. Big Creek 8 unit 1 operates between 66 cfs and 470 cfs. Big Creek 8 unit 2 operates between 82 cfs and 862 cfs.

(iv) Tailwater rating curve – No gaging occurs in the tailraces of the Big Creek Nos. 2A and 8 Powerhouses or the EPS since there is no effect from backwatering on the Project operations. The tailrace of Powerhouse No. 2A discharges into the Dam 5 impoundment, the tailrace of Powerhouse No. 8 discharges into the Dam 6 impoundment, and the tailrace of the EPS discharges into Shaver Lake. Because there is no gaging at these discharge locations, there are no rating curves for the respective tailraces.

(v) Figures B–19, B-20, and B-21 present the powerhouse capability versus head curves for Big Creek Powerhouses No. 2A and No. 8 and the EPS, respectively.

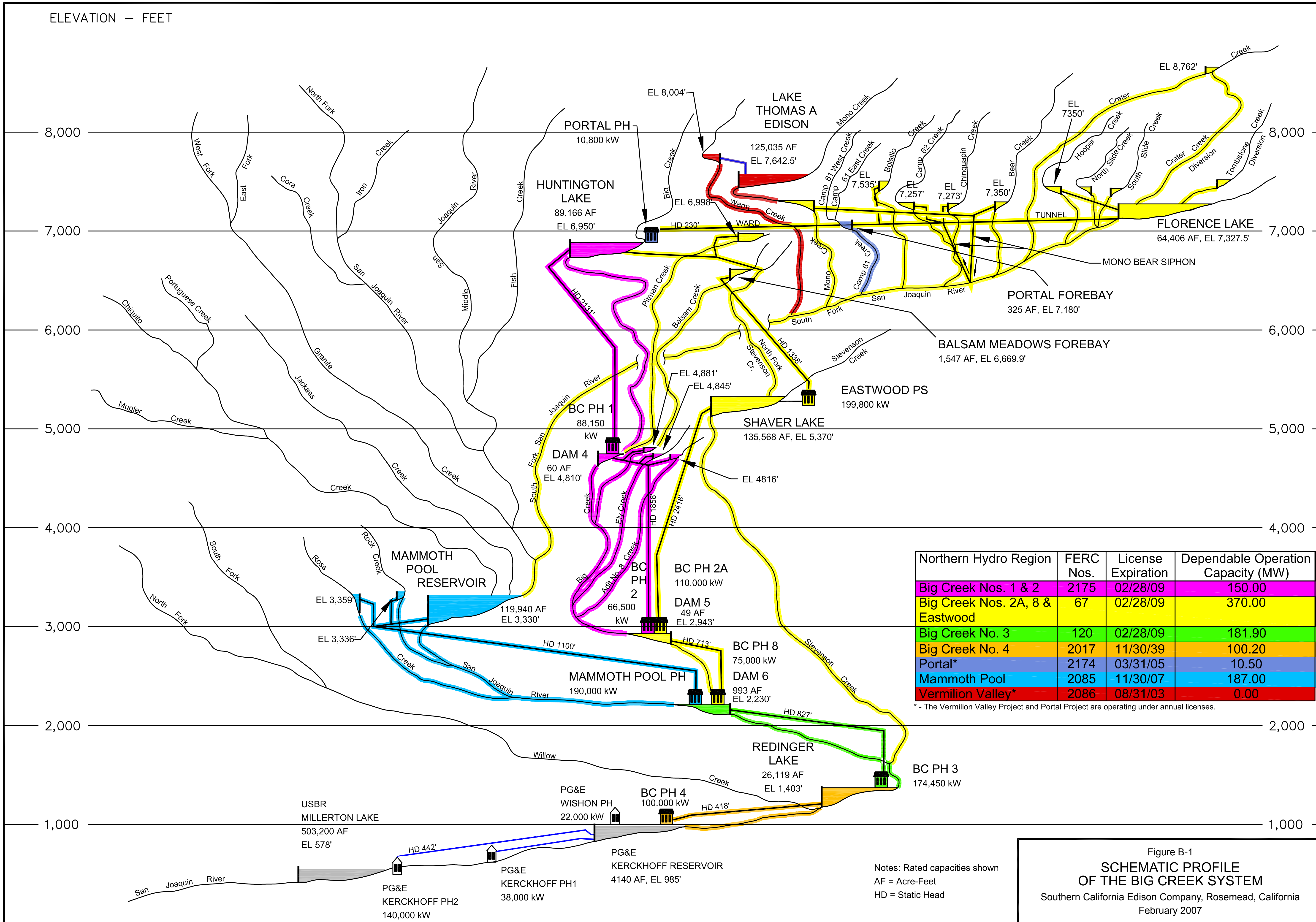
(3) Use of Generated Energy

The Big Creek Powerhouse Nos. 2A and 8 and the EPS Project operate as baseload facilities during the runoff season, and as peaking facilities the rest of the year. All energy generated, minus that necessary to operate the plant auxiliaries (energy used on site), is transmitted to SCE's electrical system. The amount of energy necessary to operate the Project auxiliaries averaged 354,830 KWh per month between 2001 and 2005. The amount of energy necessary to operate Powerhouse No. 2A auxiliaries averaged 25,982 KWh per month between 2001 and 2005, the amount of energy necessary to operate Powerhouse No. 8 auxiliaries averaged 90,265 KWh per month between 2001 and 2005, and the amount of energy necessary to operate the EPS auxiliaries averaged 238,583 KWh per month between 2001 and 2005.

(4) Plans for Future Development

SCE has no current plans for any future development of the Big Creek Powerhouse Nos. 2A and 8 and the EPS Project.

FIGURES

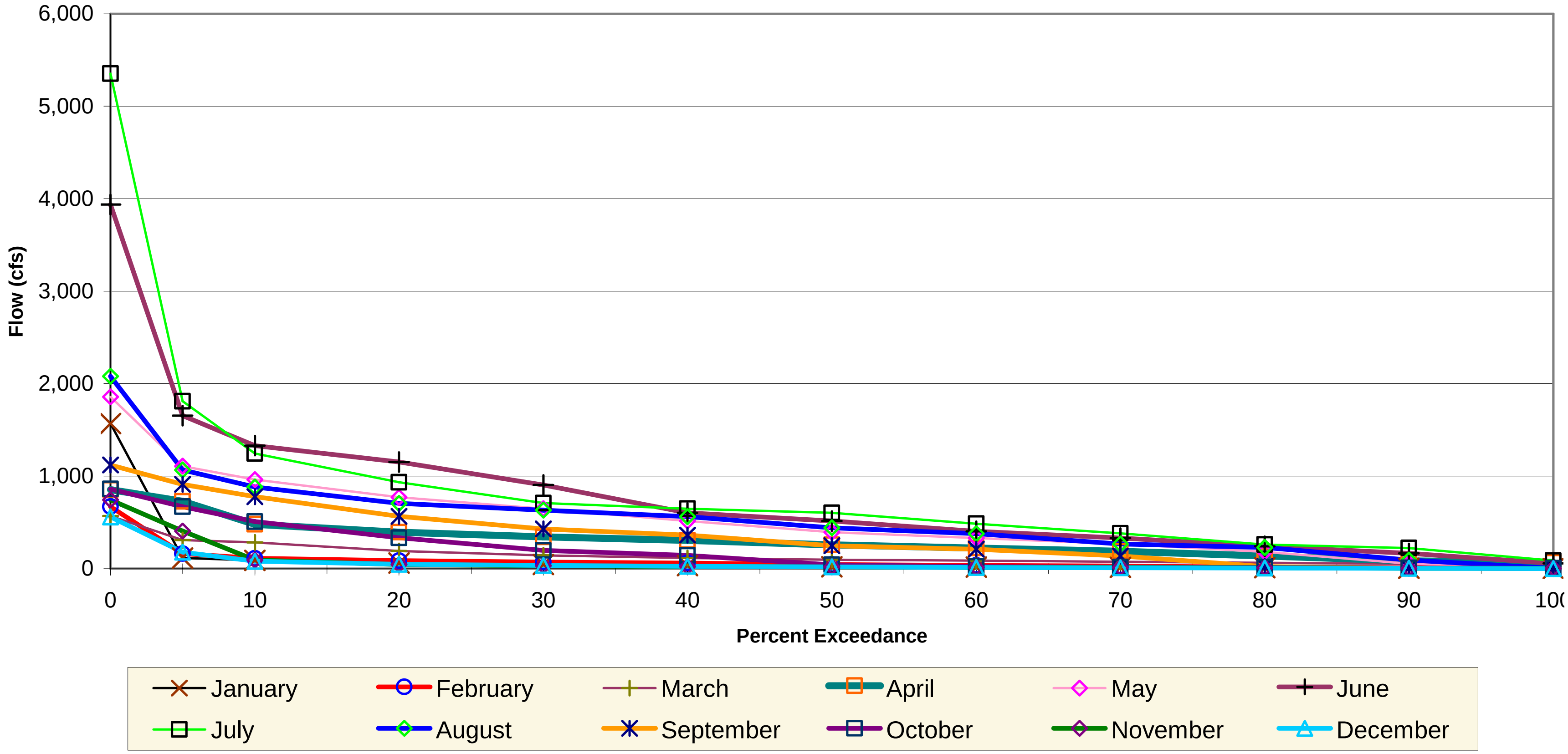


Northern Hydro Region	FERC Nos.	License Expiration	Dependable Operation Capacity (MW)
Big Creek Nos. 1 & 2	2175	02/28/09	150.00
Big Creek Nos. 2A, 8 & Eastwood	67	02/28/09	370.00
Big Creek No. 3	120	02/28/09	181.90
Big Creek No. 4	2017	11/30/39	100.20
Portal*	2174	03/31/05	10.50
Mammoth Pool	2085	11/30/07	187.00
Vermilion Valley*	2086	08/31/03	0.00

* - The Vermilion Valley Project and Portal Project are operating under annual licenses.

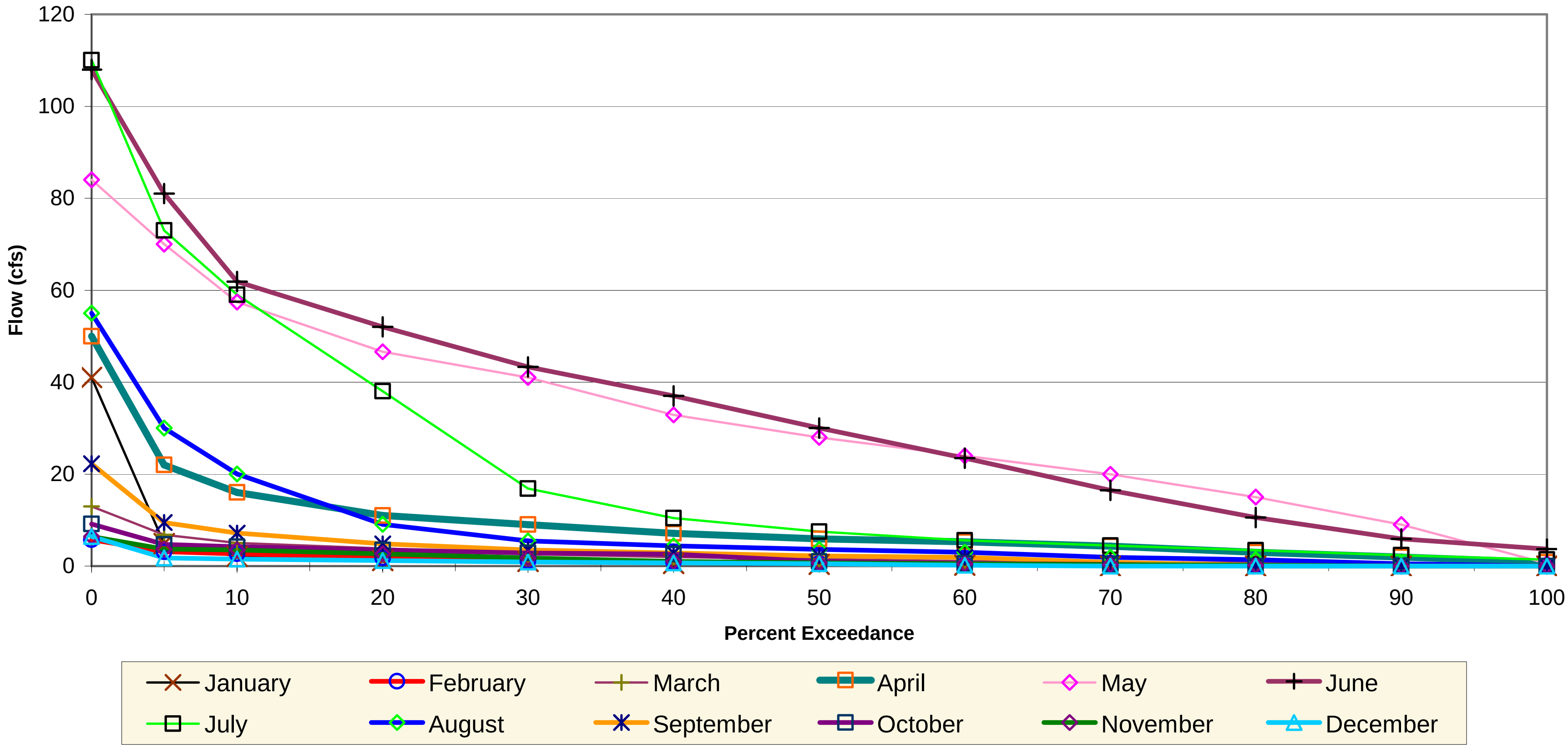
Notes: Rated capacities shown
AF = Acre-Feet
HD = Static Head

Figure B-1
SCHEMATIC PROFILE OF THE BIG CREEK SYSTEM
Southern California Edison Company, Rosemead, California
February 2007



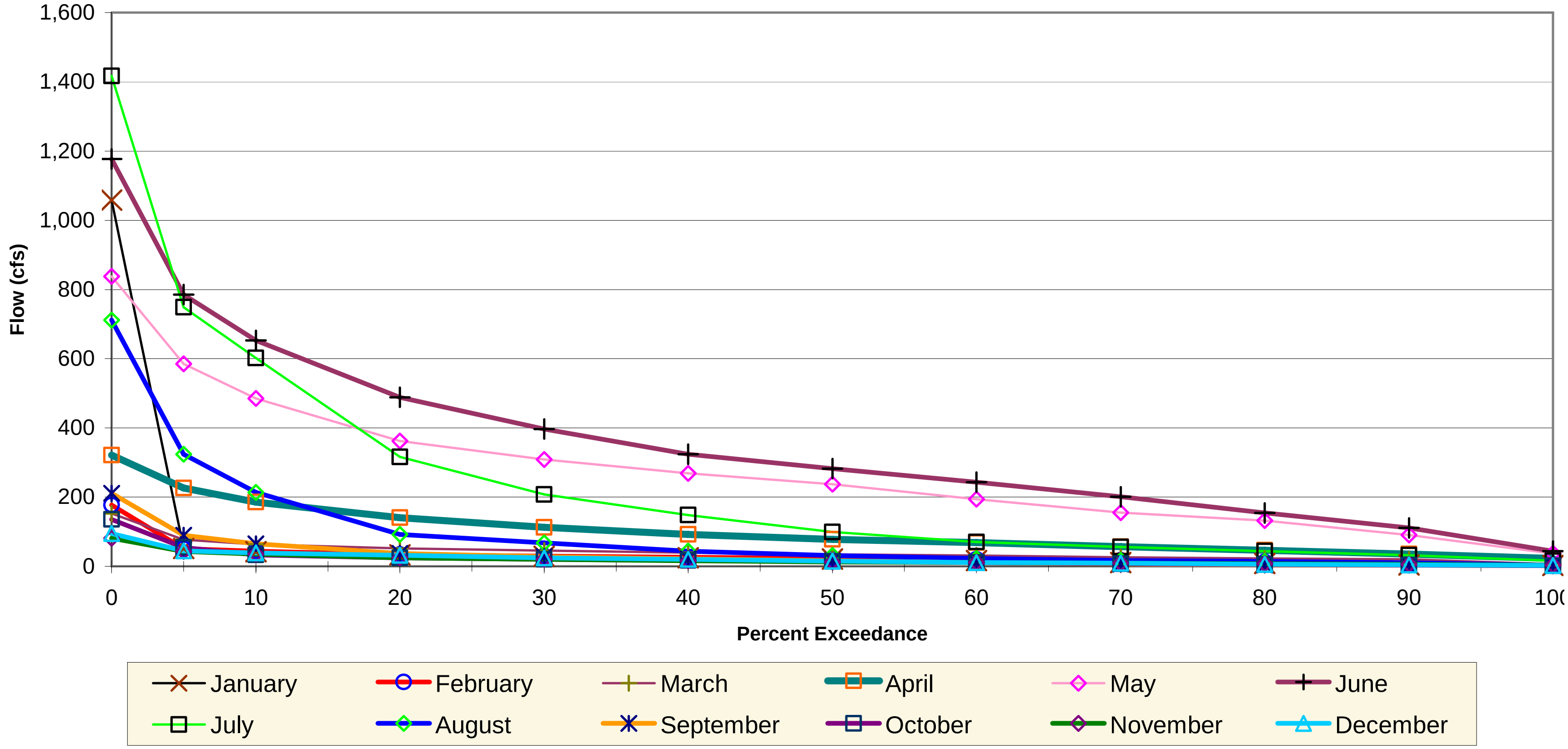
Note: Flows represent total available flow at Florence Lake and were derived by subtracting the minimum instream flow required for the South Fork San Joaquin River downstream of Florence Lake and flows in Hooper Creek below the diversion (USGS Gage No. 11230200) from the sum of the mean daily flows through Ward Tunnel (USGS Gage No. 11229500) and in the South Fork San Joaquin River below Hooper Creek (USGS Gage No. 11230215). This analysis likely overestimates available flows at Florence Lake as it includes unaccounted and ungaged accretion flow downstream of Florence Lake which include North and South Slide Creeks and Tombstone Creek. The period of record used for this analysis was October 1, 1986 to September 30, 2002.

Figure B-2. Monthly Flow Exceedance Curves of Available Flow at Florence Lake.



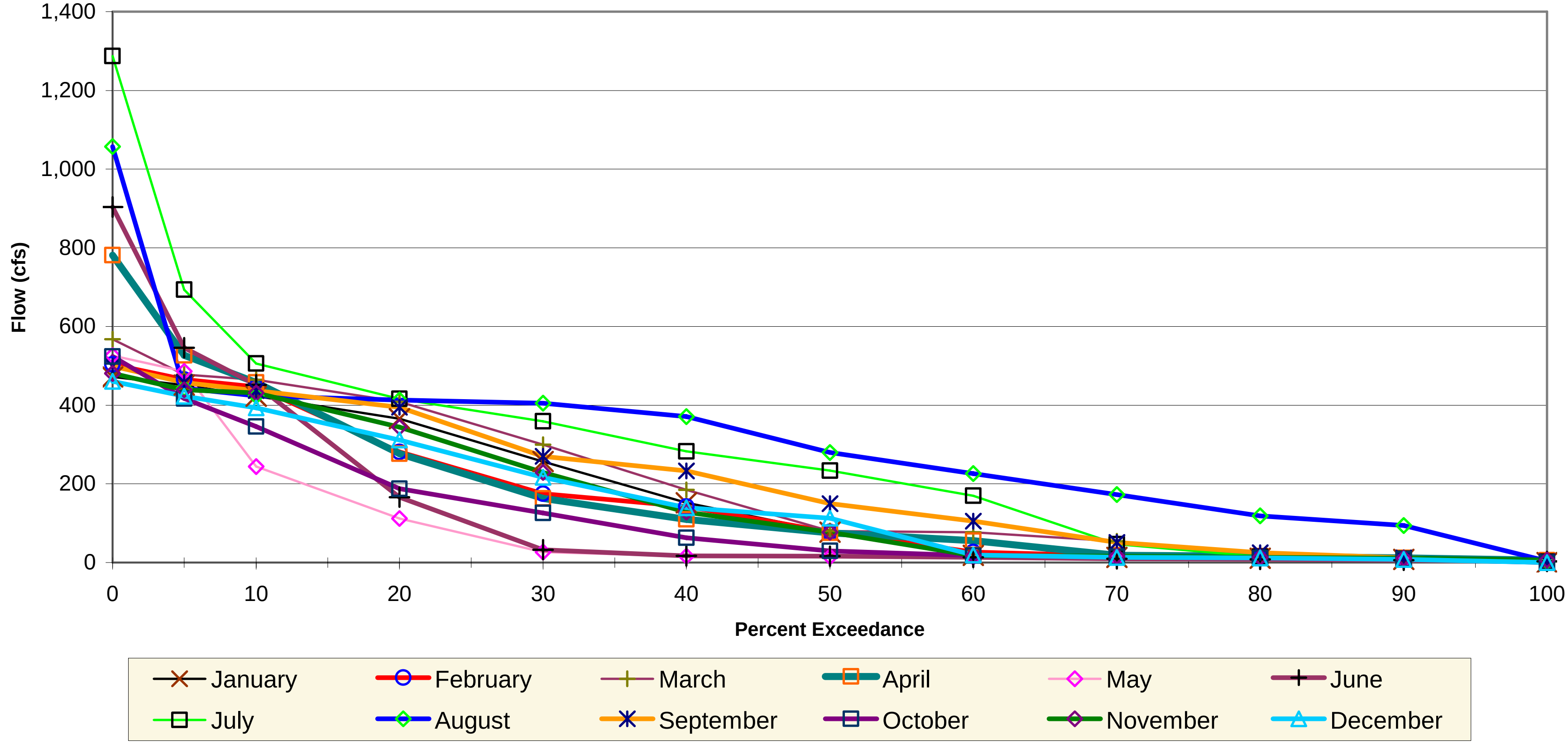
Note: Flows represent total available flow at the Hooper Creek Diversion and were derived by subtracting the minimum instream flow for Hooper Creek below the diversion recorded at USGS Gage No. 11230200 from the sum of the mean daily diversion flows recorded at SCE Gage No. 113 and the mean daily flows downstream of the diversion recorded at USGS Gage No. 11230200. The period of record used for this analysis was October 1, 1991 to September 30, 2002.

Figure B-3. Monthly Flow Exceedance Curves of Available Flow at Hooper Creek Diversion.



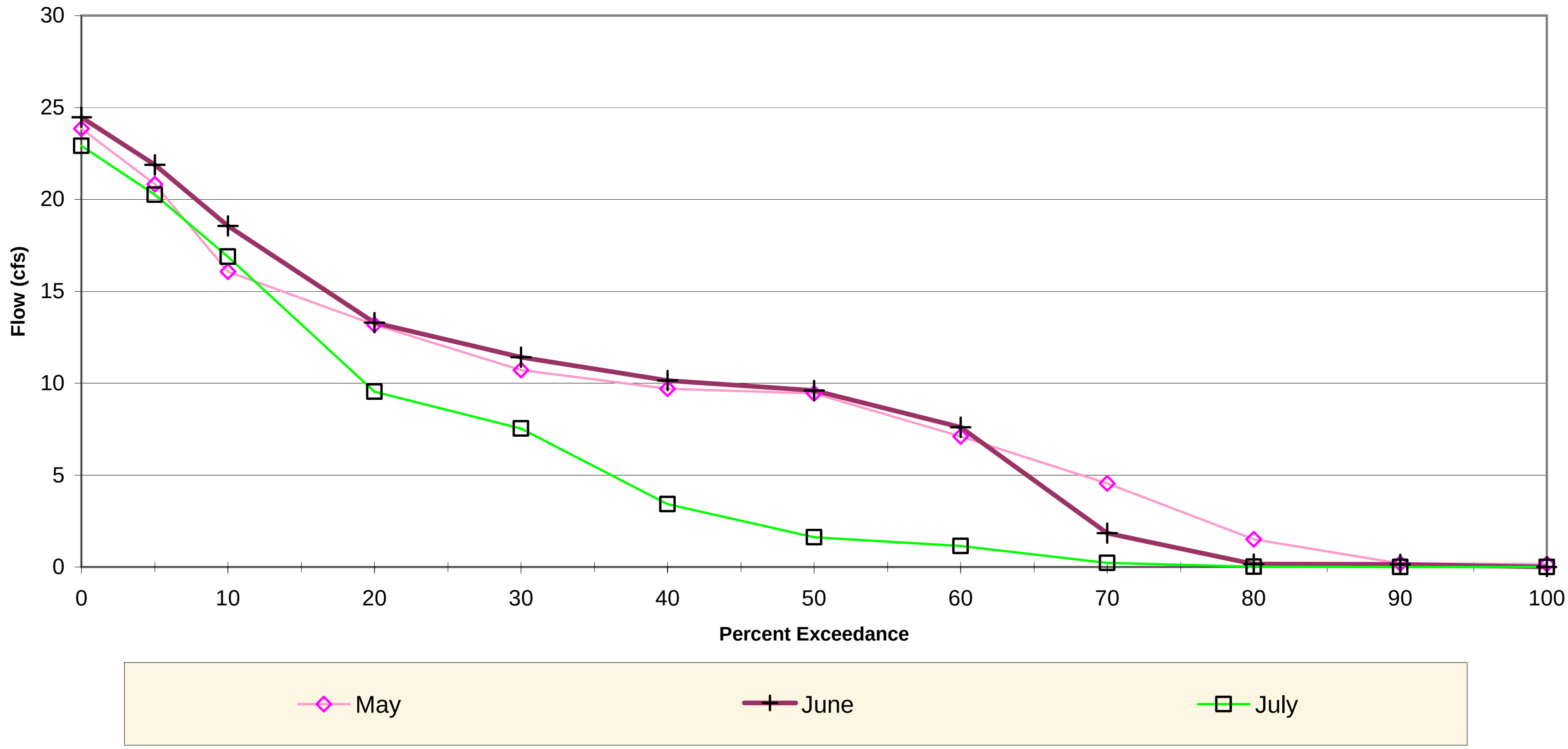
Note: Flows represent total available flow at the Bear Creek Diversion and were derived by subtracting the minimum instream flow for Bear Creek below the diversion from the mean daily flows upstream of the diversion recorded at USGS Gage No. 11230500. The period of record used for this analysis was October 1, 1982 to September 30, 2002.

Figure B-4. Monthly Flow Exceedance Curves at Bear Creek Diversion.



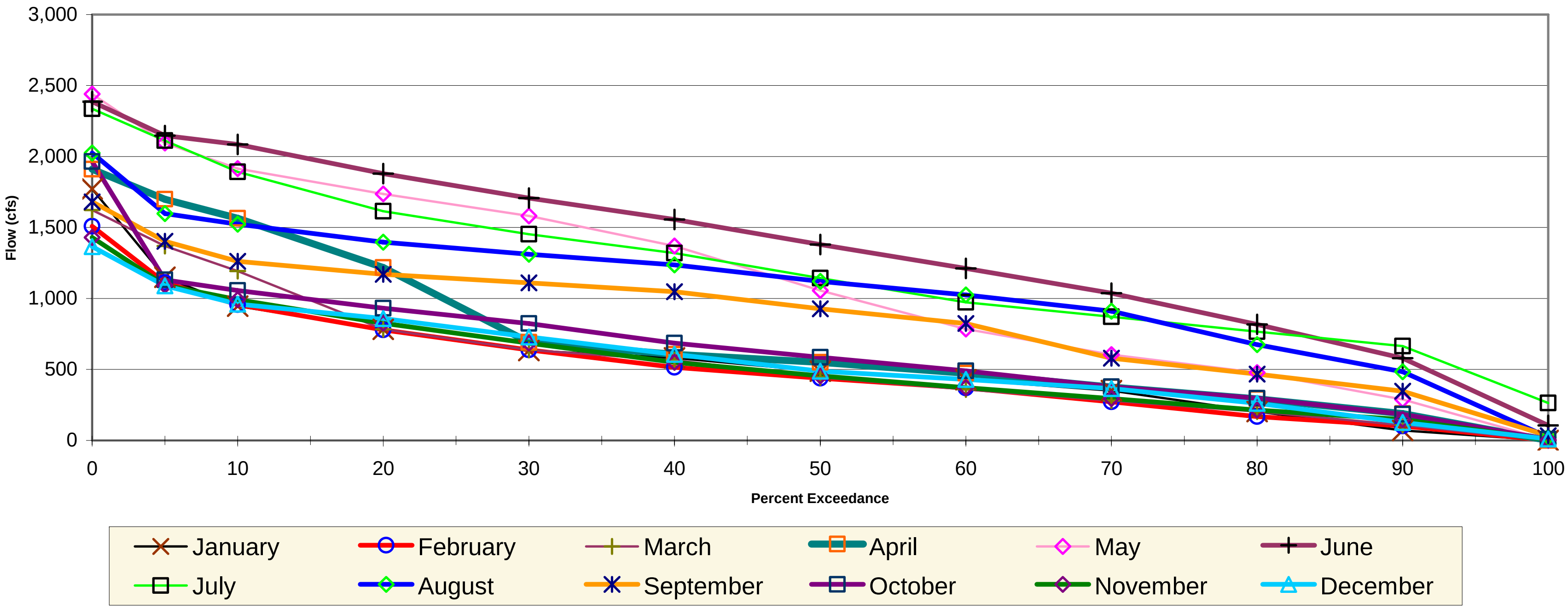
Note: Flows represent total available flow at the Mono Creek Diversion and were derived by subtracting the minimum instream flow for Mono Creek below the diversion from the mean daily flows downstream of Edison Lake recorded at USGS Gage No. 11231500. The period of record used for this analysis was October 1, 1982 to September 30, 2002.

Figure B-5. Monthly Flow Exceedance Curves at Mono Creek Diversion.



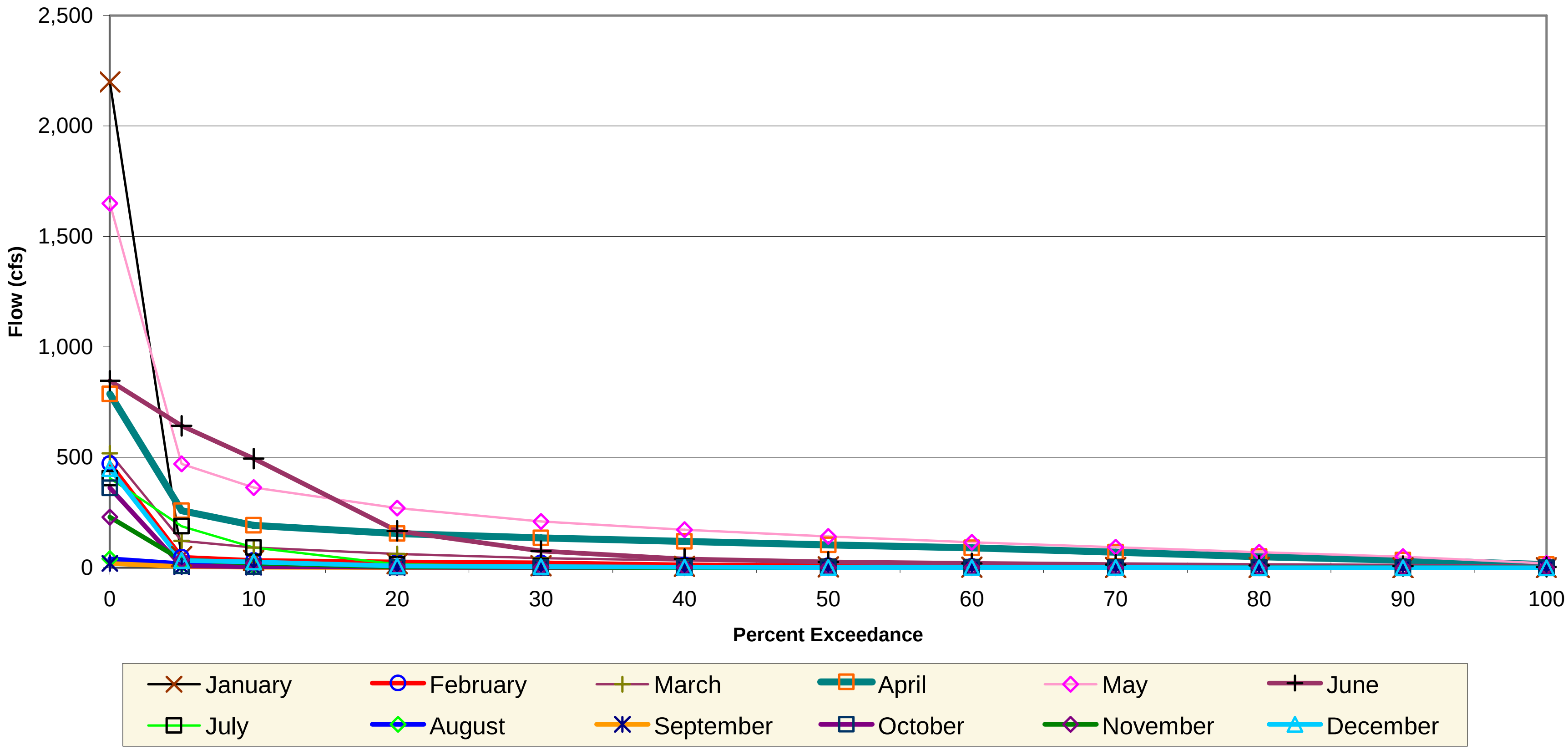
Note: Flows represent total available flow at the Bolsillo Creek Diversion and were derived by subtracting the minimum instream flow required for Bolsillo Creek downstream of the diversion from the sum of the mean daily diverted flow (SCE Gage No. 117) and the mean daily flow downstream of the diversion (USGS Gage No. 11230670). Due to the seasonal nature of operation of the diversion, sufficient data for analysis (greater than 5 years worth of data for each month) was only available for the months of May, June, and July between October 1, 1992 and September 30, 2002.

Figure B-6. Monthly Flow Exceedance Curves at Bolsillo Creek Diversion.



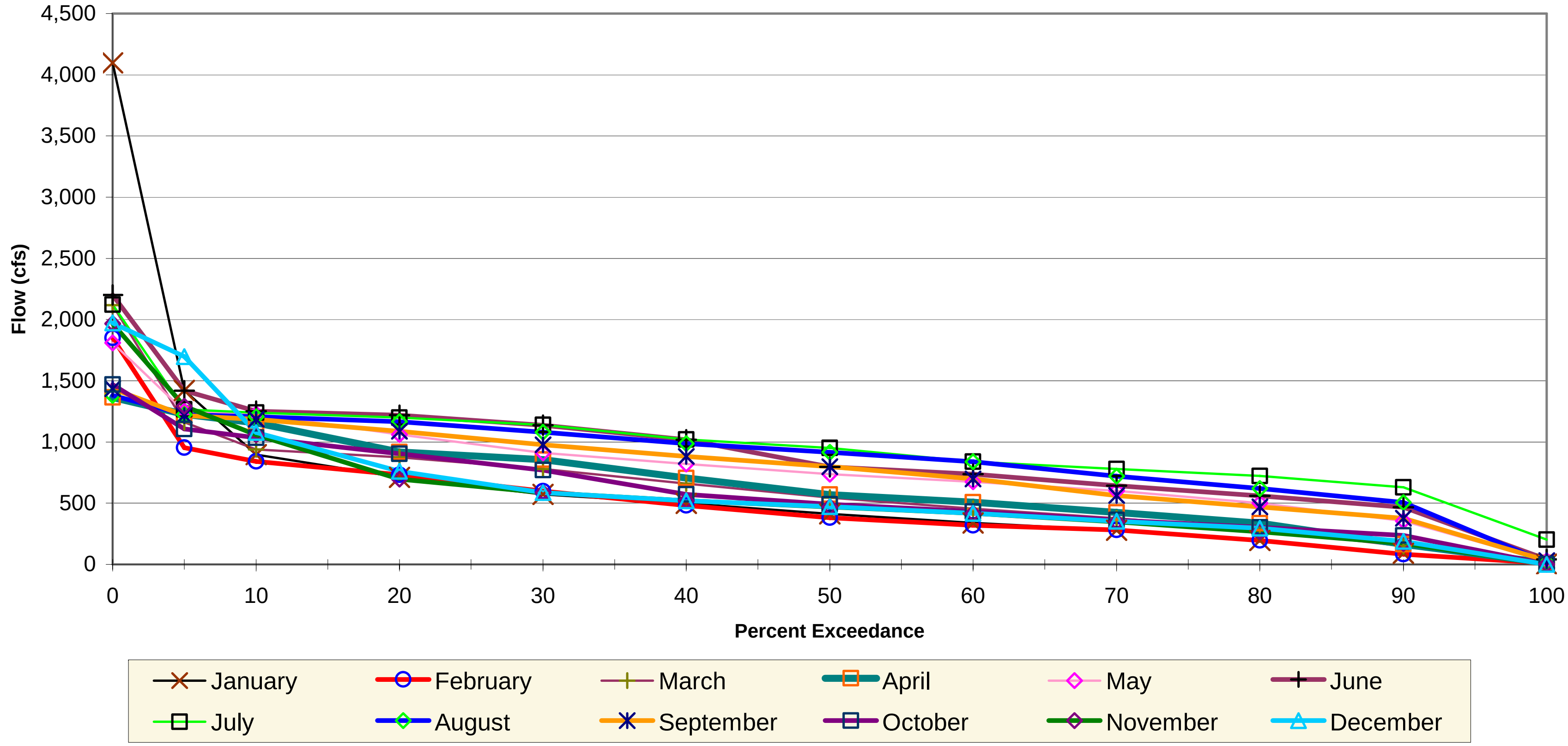
Note: The Tunnel 7 diversion transfers water from Huntington Lake to the Balsam Forebay and North Fork Stevenson Creek. The available flow at the Tunnel 7 diversion represents flow available to both FERC Project No. 2175 and FERC Project No. 67. Flow utilized for Project No. 2175 is diverted through Powerhouse No. 1. The available flow at the Tunnel 7 diversion was derived by adding the mean daily throughput flows for Powerhouse No. 1 (USGS Gage No. 11238100) and the mean daily flows through Tunnel 7 upstream of the Pitman Creek diversion. The flow data for Tunnel 7 was derived using the following methods: 1) for water year 1983, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the mean daily flow recorded at the Tunnel 7 outlet (USGS Gage No. 11239000); and, 2) for water years 1990 to 2002, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the sum of the Eastwood Powerstation throughput (USGS Gage No. 11237600) and flow in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300). The analysis for water years 1990 to 2002 overestimates available flow at Tunnel 7 since the flows recorded in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300) include ungaged inflow upstream of the outlet. The period of record used in the analysis was October 1, 1982 to September 30, 1983 and October 1, 1989 to September 30, 2002.

Figure B-7. Monthly Flow Exceedance Curves at Tunnel 7 Diversion



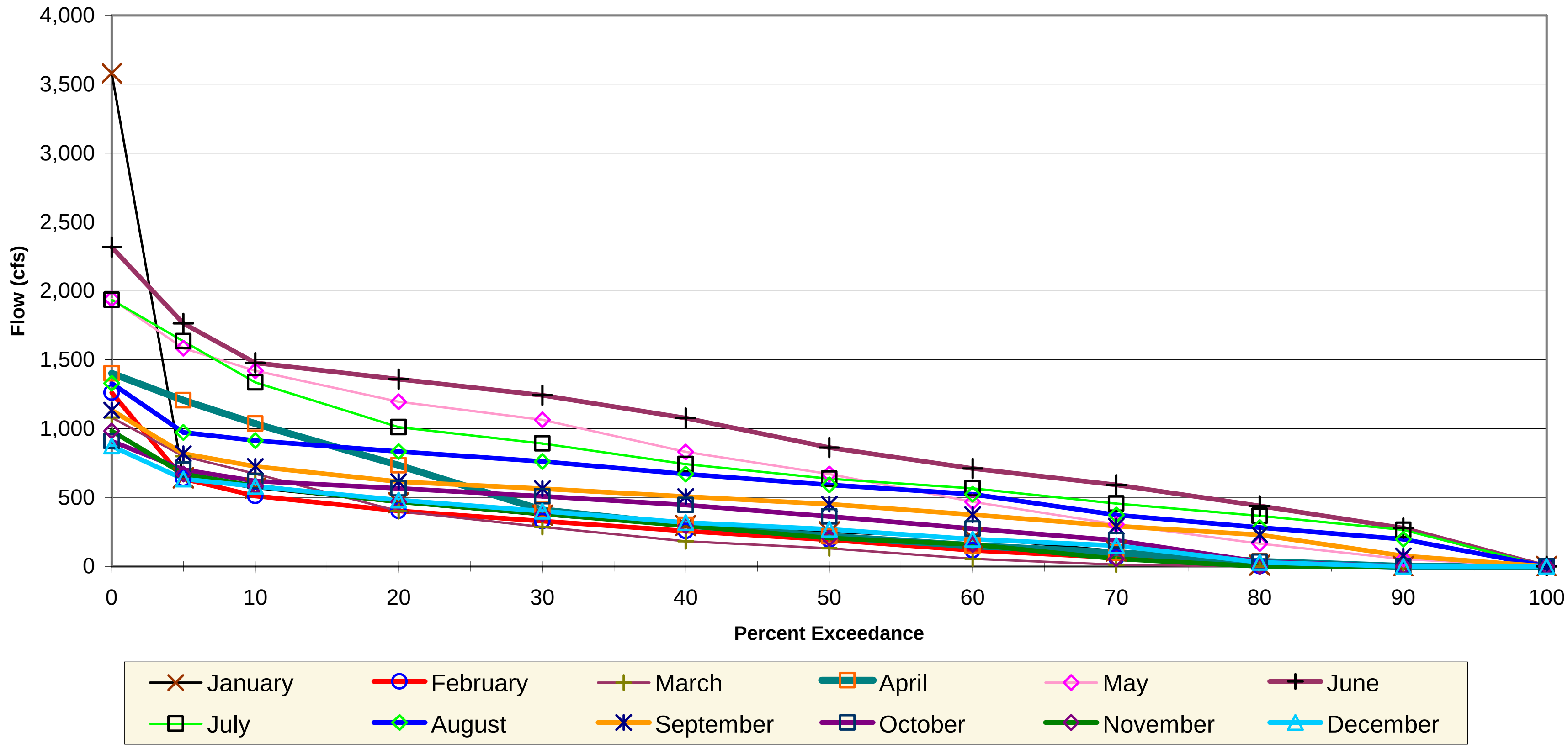
Note: Flows represent total available flow at the Pitman Creek Diversion and were derived by subtracting the minimum instream flow for Pitman Creek below the diversion from the mean daily flows upstream of the diversion recorded at USGS Gage No. 11237500. The period of record used for this analysis was October 1, 1982 to September 30, 2002.

Figure B-8. Monthly Flow Exceedance Curves at Pitman Creek Diversion.



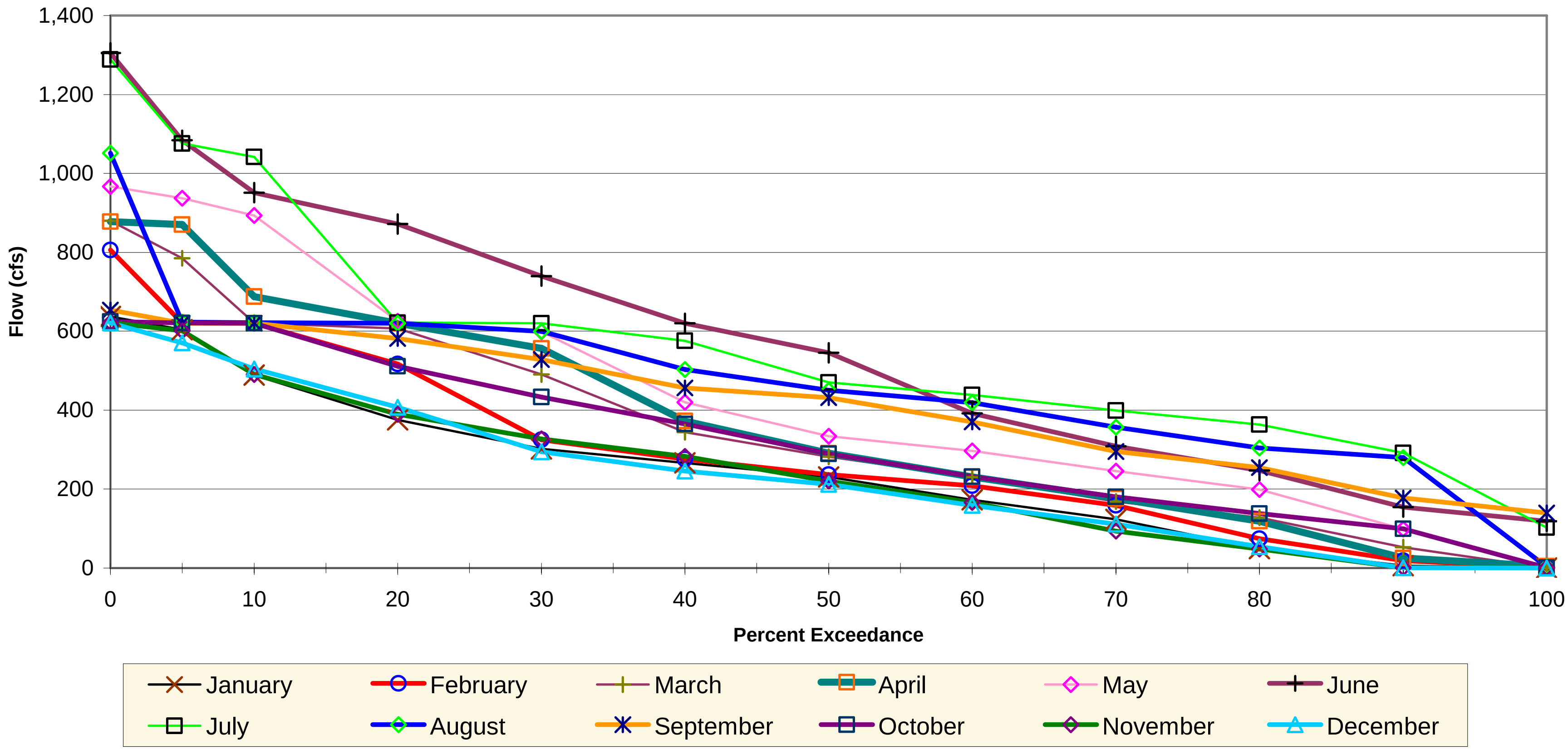
Note: Flows represent total available flow at Dam 5 and were derived by subtracting the minimum instream flow required for Big Creek downstream of Dam 5 from the sum of the mean daily flows through Big Creek Powerhouse No. 2 recorded at USGS Gage No. 11238380, Big Creek Powerhouse No. 2A recorded at USGS Gage No. 11238400, and Big Creek near the confluence with the San Joaquin River recorded at USGS Gage No. 11238500. The analysis likely underestimates available flow at Dam 5 as it does not account for flow accretion in Big Creek between Dam 4 and Dam 5. The period of record used for this analysis was October 1, 1986 to September 30, 1994 and October 1, 1995 to September 30, 2002.

Figure B-9. Monthly Flow Exceedance Curves at Dam 5.



Note: Flows represent total available flow at the Balsam Forebay and were derived by subtracting flows diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flows for Pitman Creek, Balsam Creek, and North Fork Stevenson Creek from the sum of the mean daily flows in Tunnel 7 and in Pitman Creek upstream of the diversion (USGS Gage No.11237500). The analysis assumes that there is no net increase or decrease in available water associated with pumpback between the EPS and Balsam Forebay. The period of record used for this analysis was October 1, 1989 to September 30, 2002.

Figure B-10. Monthly Flow Exceedance Curves at Balsam Forebay.



Note: Flows represent total available flow at Shaver Lake and were derived by subtracting the minimum instream flow required for Stevenson Creek downstream of Shaver Lake recorded at USGS Gage No. 11241500 from the sum of the mean daily flows through Big Creek Powerhouse No. 2A recorded at USGS Gage No. 11238400 and Stevenson Creek downstream of Shaver Lake recorded at USGS Gage No. 11241500. The period of record used for this analysis was October 1, 1986 to September 30, 2002.

Figure B-11. Monthly Flow Exceedance Curves at Shaver Lake.

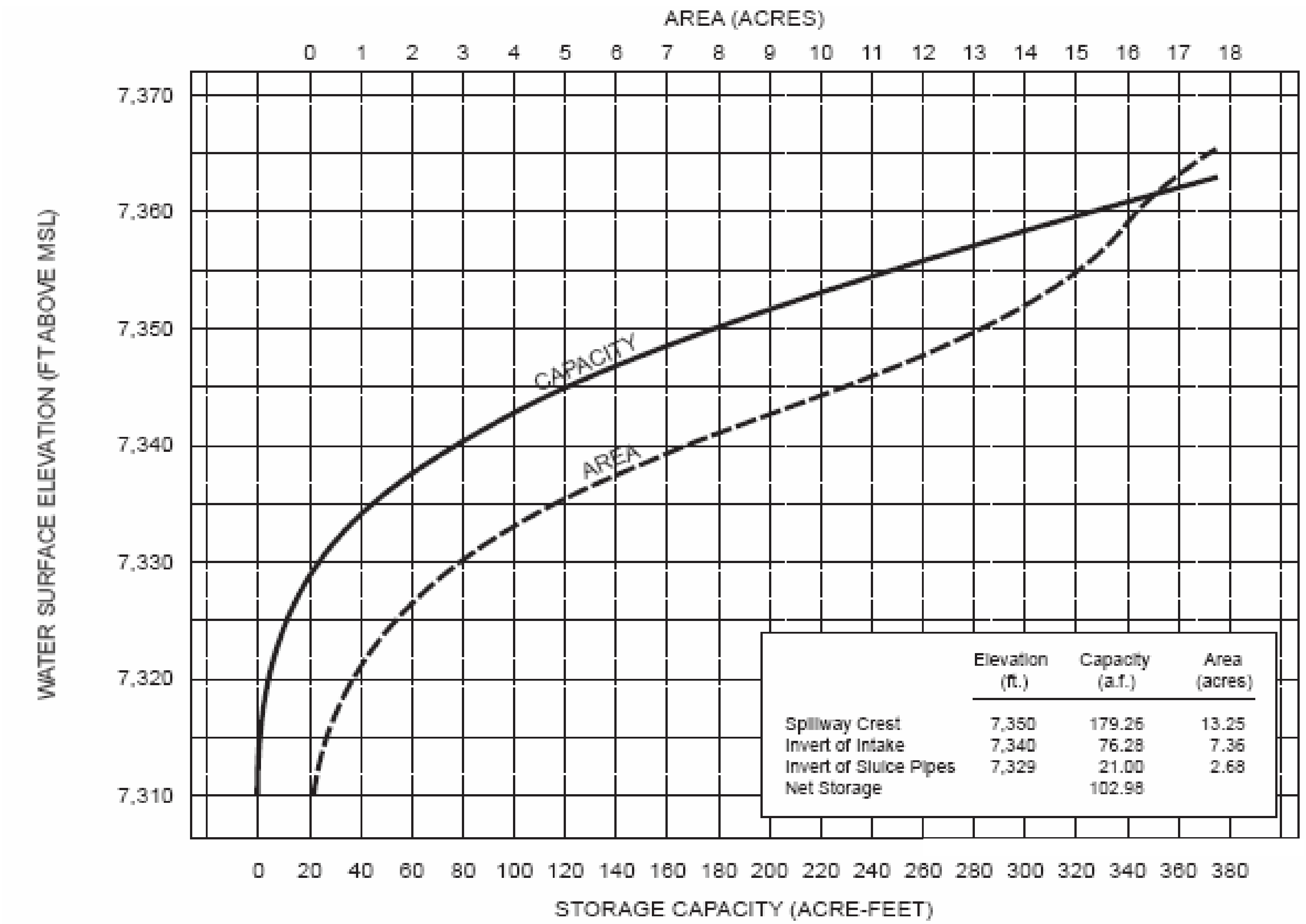


Figure B-12. Area and Capacity Curves at Florence Lake Reservoir.

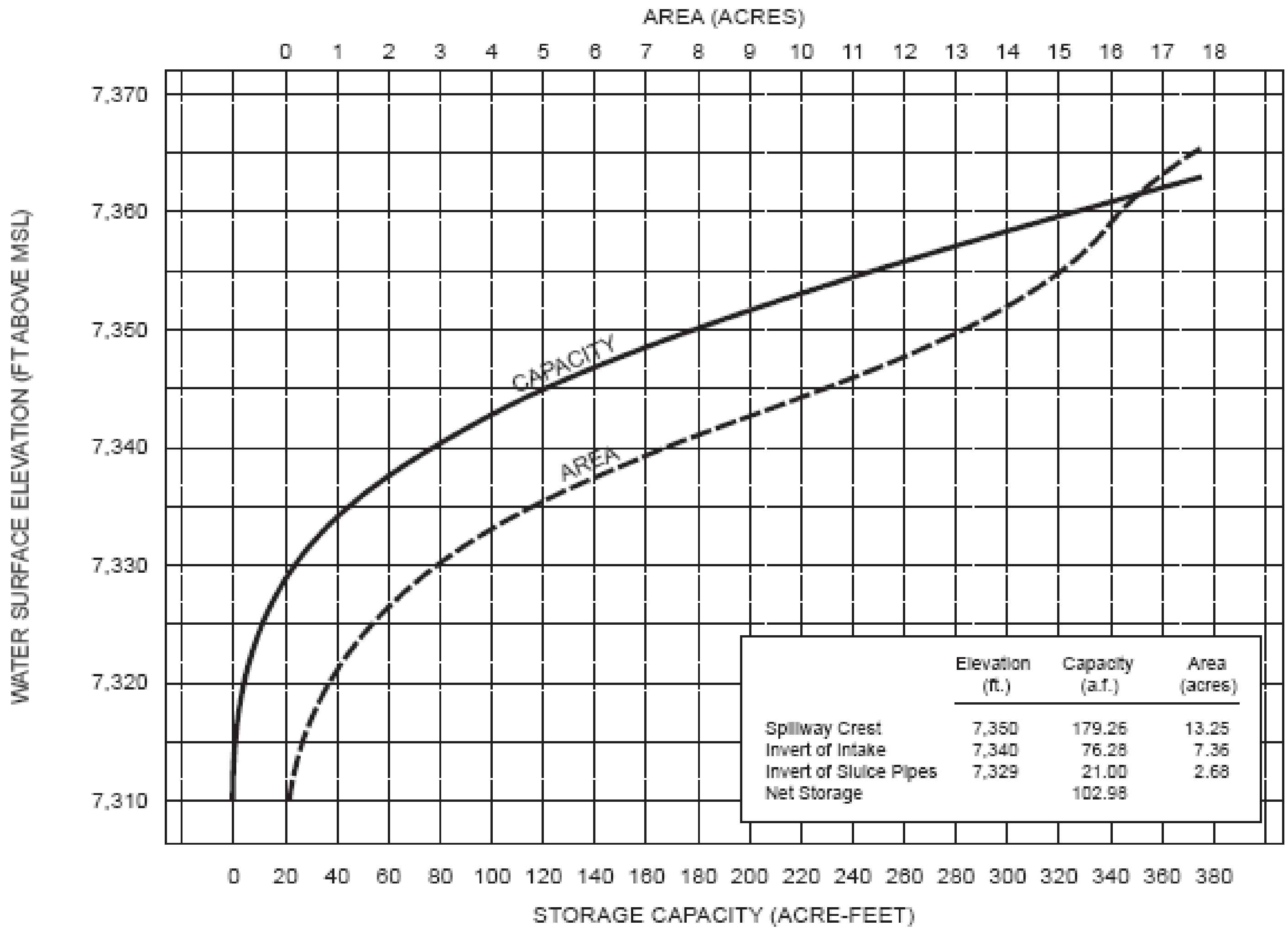


Figure B-13. Area and Capacity Curves at Bear Creek Reservoir.

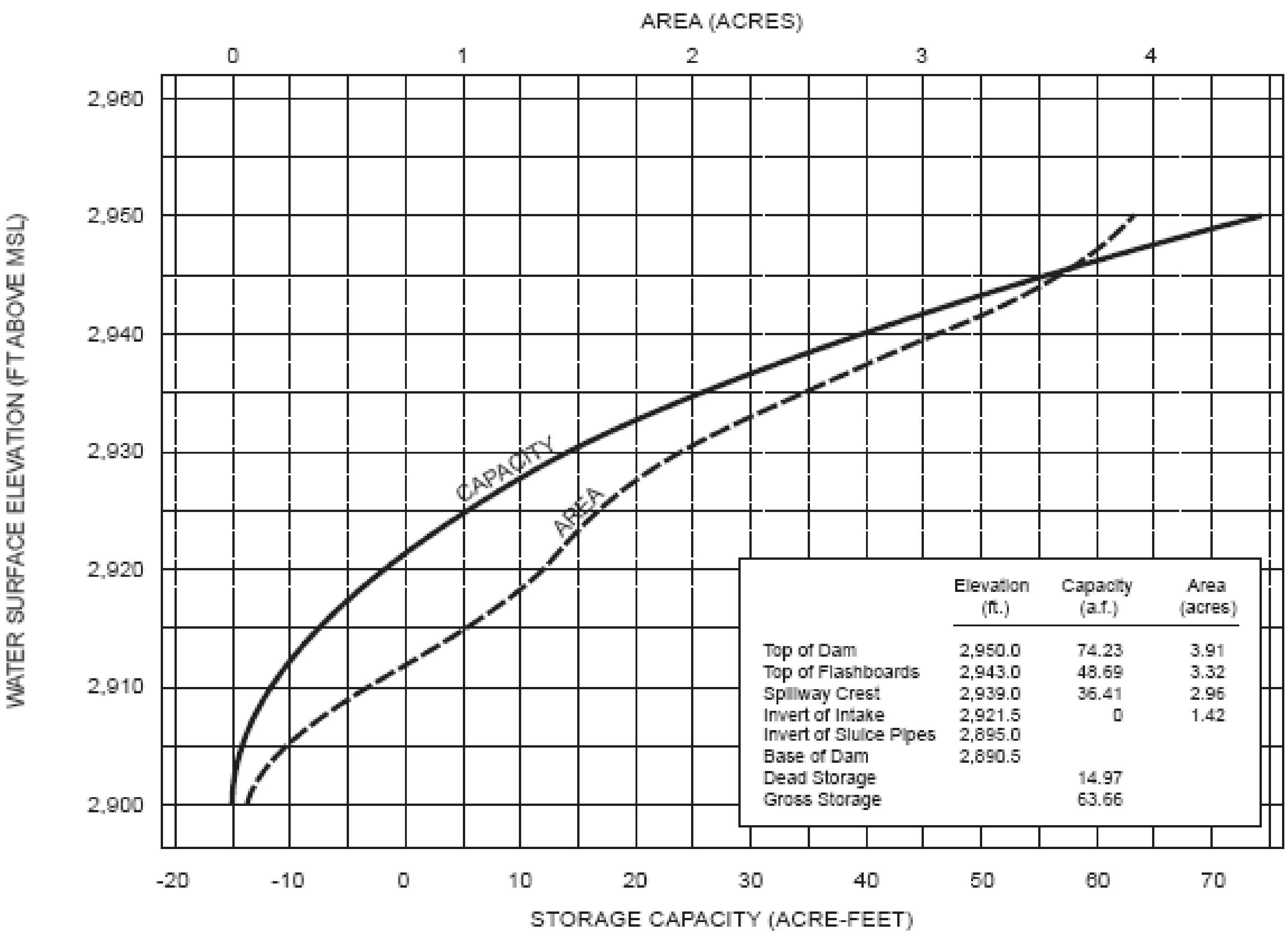
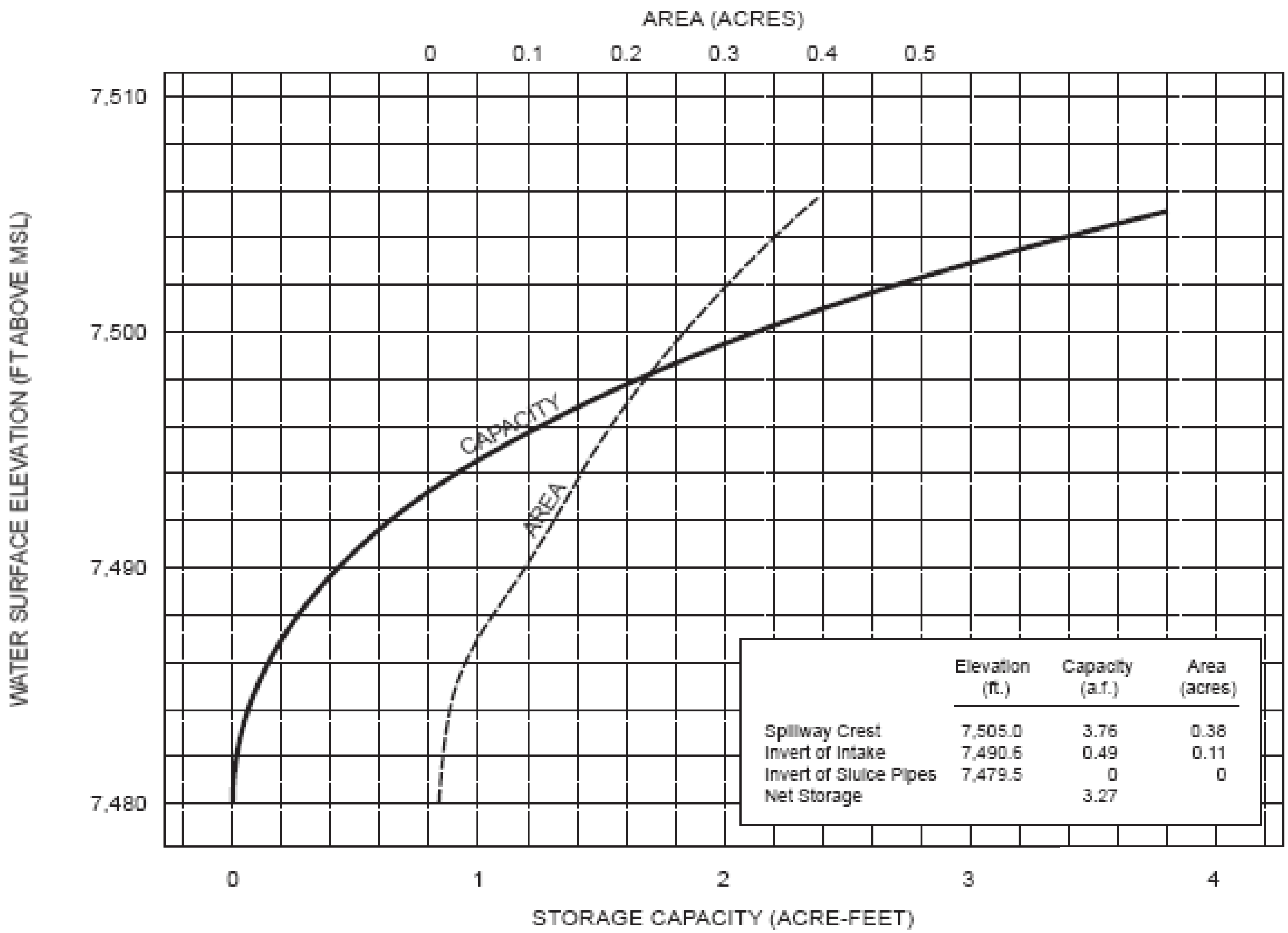


Figure B-14. Area and Capacity Curves at Powerhouse No. 8 Forebay.



	Elevation (ft.)	Capacity (a.f.)	Area (acres)
Spillway Crest	7,505.0	3.76	0.38
Invert of Intake	7,490.6	0.49	0.11
Invert of Sluice Pipes	7,479.5	0	0
Net Storage		3.27	

Figure B-15. Area and Capacity Curves at Hooper Creek Lake Reservoir.

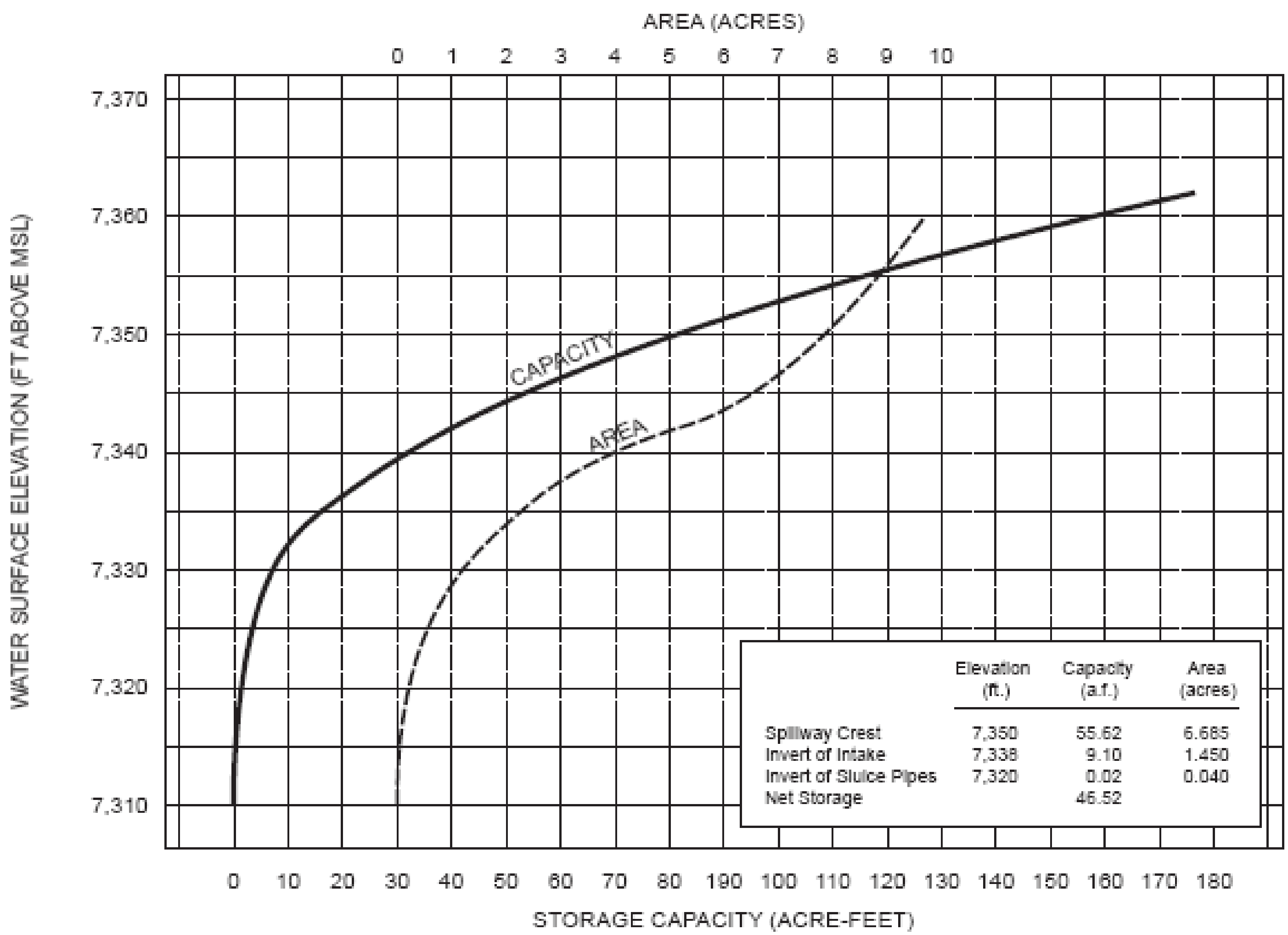
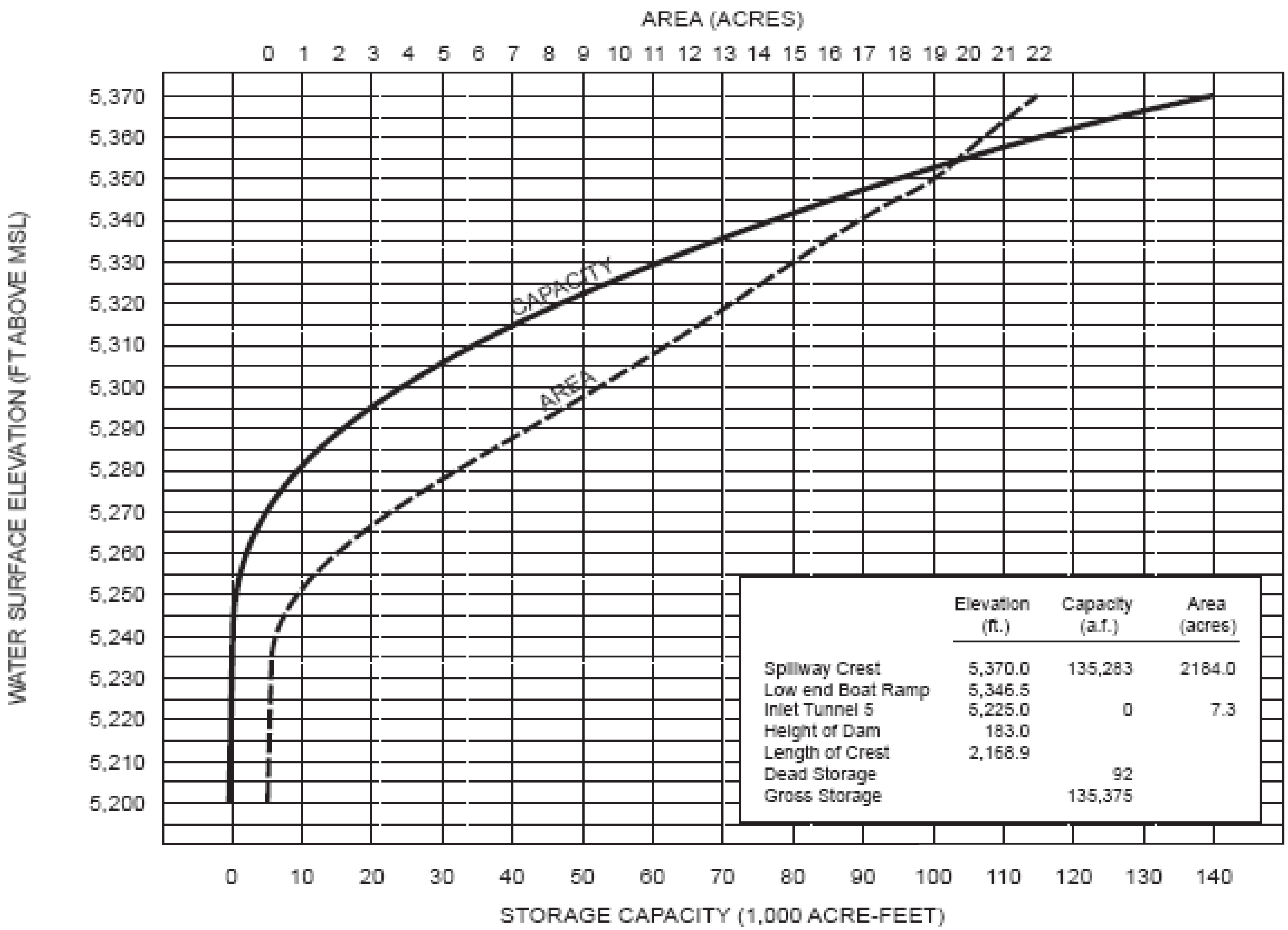
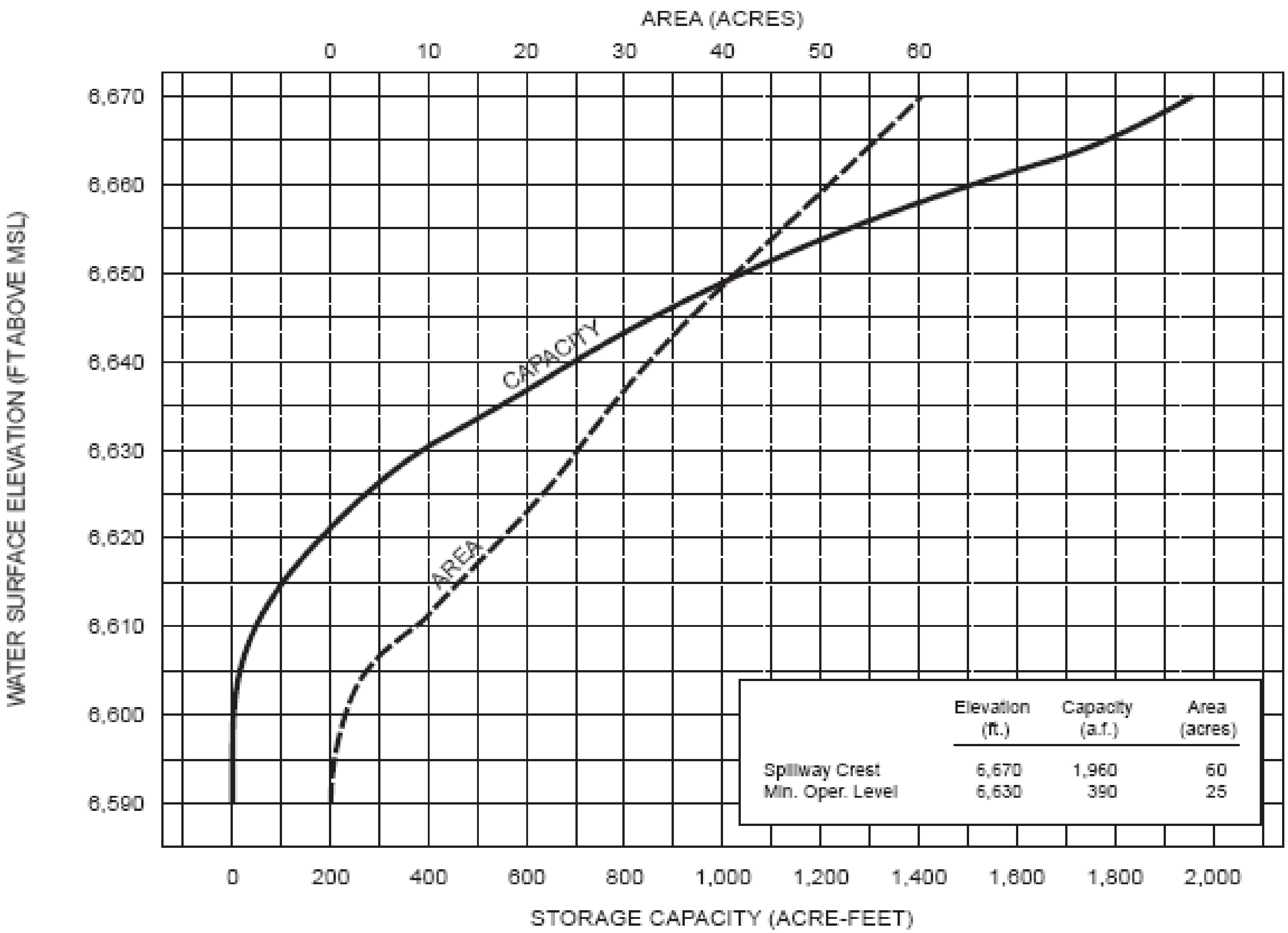


Figure B-16. Area and Capacity Curves at Mono Creek Diversion.



	Elevation (ft.)	Capacity (a.f.)	Area (acres)
Spillway Crest	5,370.0	135,283	2184.0
Low end Boat Ramp	5,346.5		
Inlet Tunnel 5	5,225.0	0	7.3
Height of Dam	183.0		
Length of Crest	2,168.9		
Dead Storage		92	
Gross Storage		135,375	

Figure B-17. Area and Capacity Curves at Shaver Lake Reservoir.



	Elevation (ft.)	Capacity (a.f.)	Area (acres)
Spillway Crest	6,670	1,960	60
Min. Oper. Level	6,630	390	25

Figure B-18. Area and Capacity Curves at Balsam Meadow Forebay.

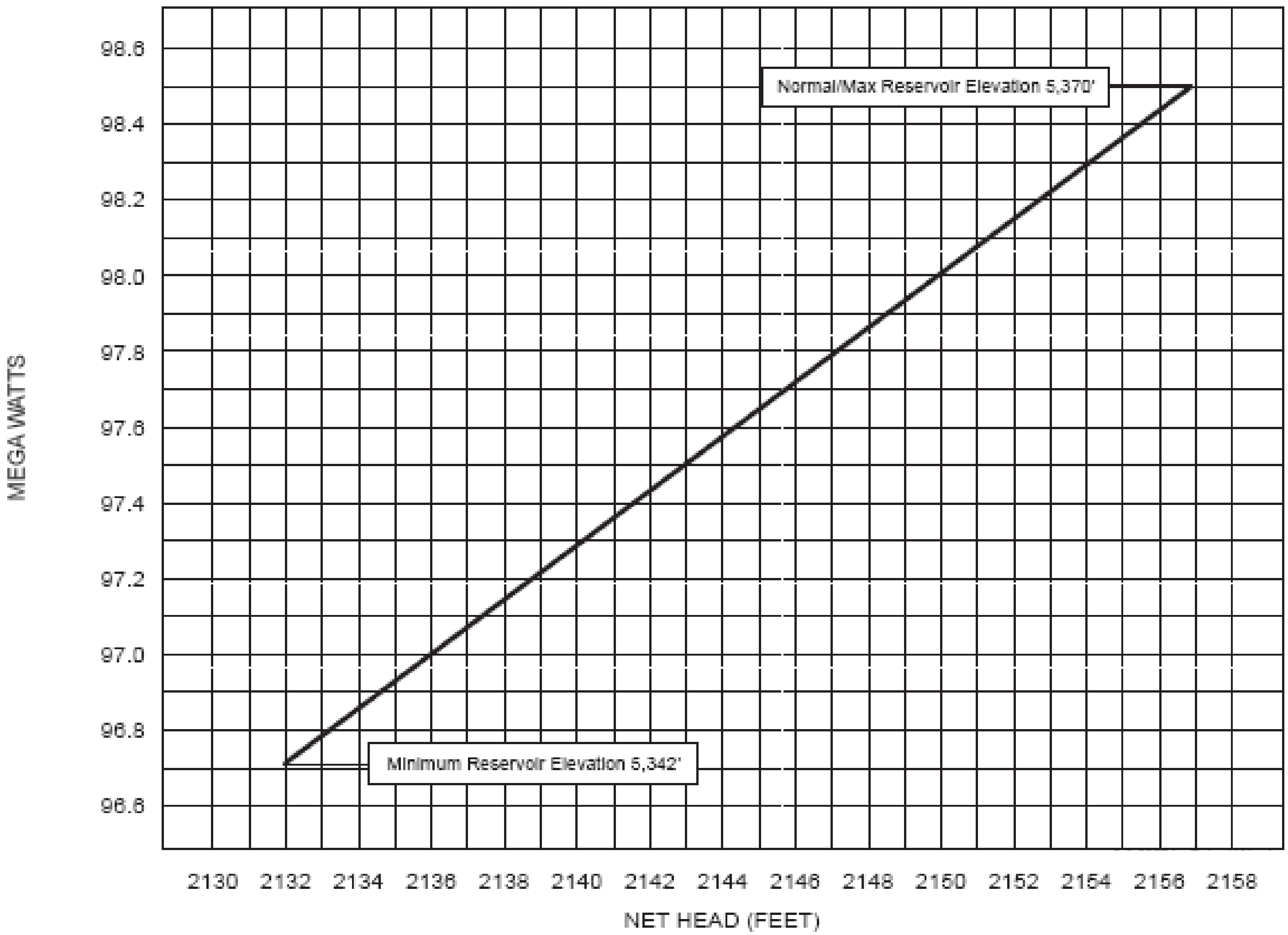


Figure B-19. Estimated Powerplant Capability Versus Head at Powerhouse No. 2A.

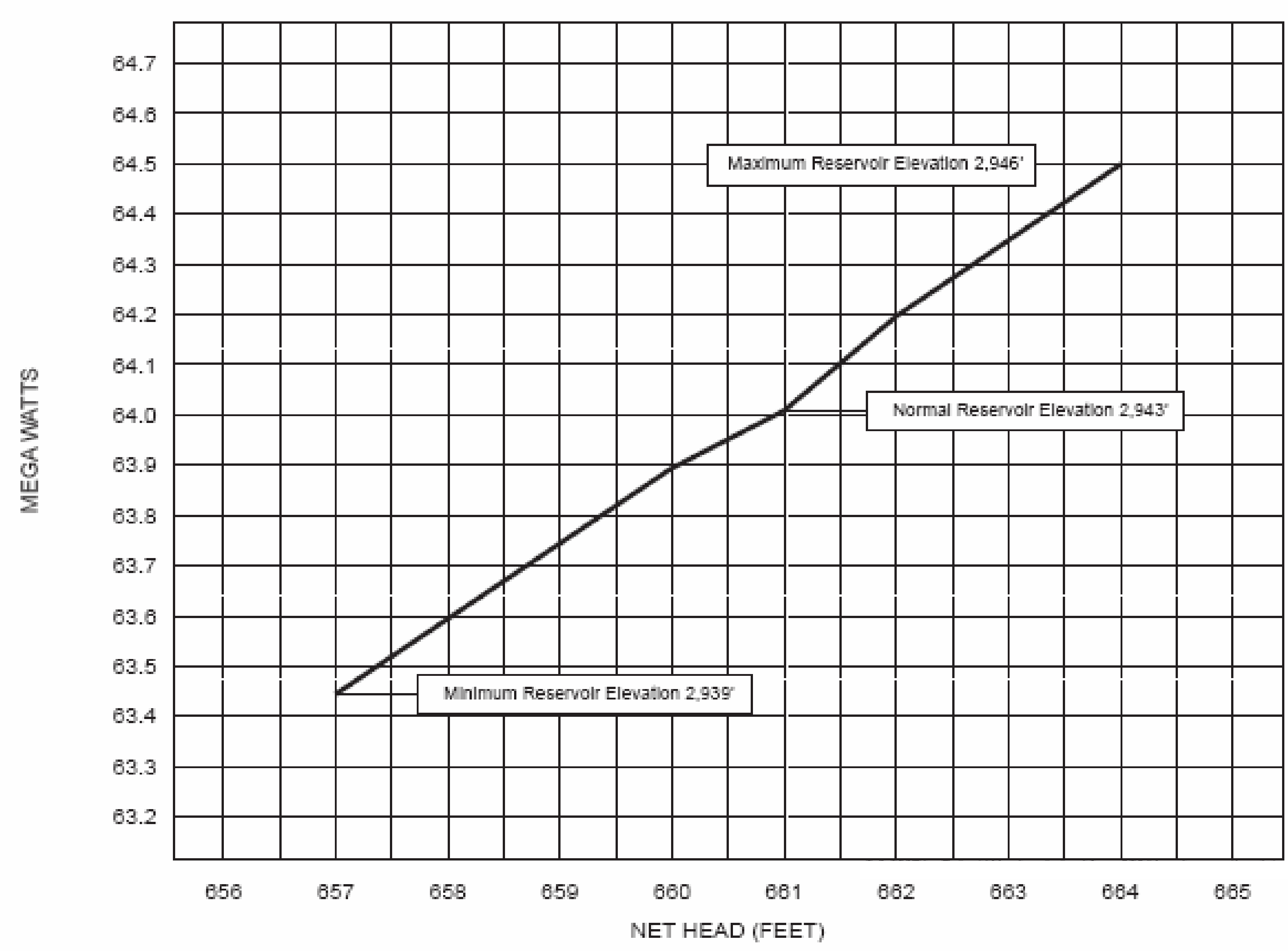


Figure B-20. Estimated Powerplant Capability Versus Head at Powerhouse No. 8.

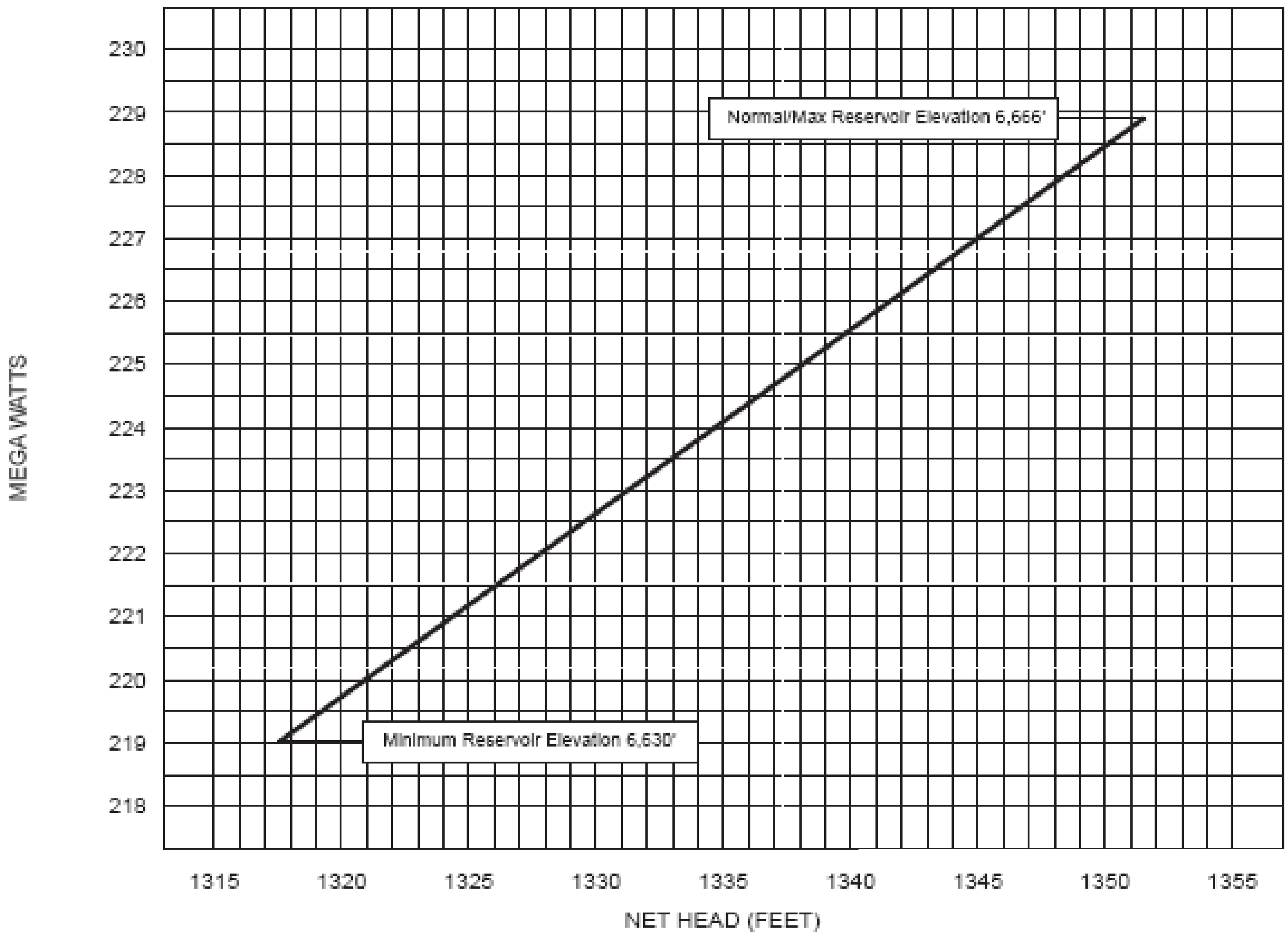


Figure B-21. Estimated Powerplant Capability Versus Head at Eastwood Power Station.

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 2A, 8 AND EASTWOOD
(FERC Project No. 67)

EXHIBIT C: CONSTRUCTION HISTORY

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit C Construction History and Proposed Construction Schedule

Exhibit C is a construction history and proposed construction schedule for the project. The construction history and schedules must contain:

> (1) If the application is for an initial license, a tabulated chronology of construction for the existing projects structures and facilities described under paragraph (b) of this section (Exhibit A), specifying for each structure or facility, to the extent possible, the actual or approximate dates (approximate dates must be identified as such) of:
>
> (i) Commencement and completion of construction or installation;
>
> (ii) Commencement of commercial operation; and
>
> (iii) Any additions or modifications other than routine maintenance; and
>
> (2) If any new development is proposed, a proposed schedule describing the necessary work and specifying the intervals following issuance of a license when the work would be commenced and completed.

(1) **Construction History**

(i) This Application is for a new license and not for an initial license. The Project was constructed between 1920 and 1987 as follows:

- Ward Tunnel was constructed between November 1920 and April 1925.
- Powerhouse No. 8 was constructed between January and August 1921. Unit 1 of Powerhouse No. 8 was installed in 1921, and Unit 2 of Powerhouse No. 8 was installed in 1929.
- Florence Lake Dam was constructed between the Spring of 1925 and August 1926.
- The Huntington-Pitman-Shaver Conduit was constructed between November 1925 and April 1928.
- Shaver Lake Dam was constructed between Spring 1926 and October 1927.
- The Mono Diversion, Bear Diversion, and the Mono-Bear Siphon were constructed between July 1926 and November 1927.
- Powerhouse No. 2A was constructed between Fall 1926 and August 1928.

- The Pitman Creek Diversion was originally constructed between 1925 to 1928. The diversion was rebuilt in 2001.
- The Crater Creek Diversion was constructed in 1944.
- The Bolsillo Creek Diversion was constructed in 1945.
- The Tombstone Creek Diversion was constructed in 1945.
- The North and South Slide Creek Diversions were constructed in 1945.
- The Hooper Creek Diversion was constructed in 1945.
- The Camp 62 Creek Diversion was originally constructed in 1948 and was rebuilt in 2001.
- The Chinquapin Creek Diversion was originally constructed in 1948 and was rebuilt in 2001.
- The Balsam Meadows Project, including the Eastwood Power Station was constructed between November 1983 and November 1987.

(ii) The commencement of commercial operation for the Project powerhouses occurred on the following dates:

- Powerhouse No. 8 Unit No. 1 commenced operation on August 16, 1921 and Unit No. 2 commenced operation on June 8, 1929.
- Powerhouse No. 2A Unit No. 1 commenced operation on August 6, 1928 and Unit No. 2 on December 21, 1928.
- The Eastwood Power Station commenced operation on December 1, 1987.

(iii) The Project has undergone the following upgrades and modifications since start-up:

<u>Big Creek 2A</u>

Shaver Lake Dam

- In 1930-31 a lower drainage gallery was drilled in the central 350 feet of the dam along the dam-to-bedrock contact.
- In 1932, a siphon groundwater extraction system was constructed in the main gallery to reduce the uplift foundation relief holes not intercepted by the lower gallery.

- Between 1965 and 1966, 69 additional relief holes were drilled into the foundation and upward through the horizontal lift joints totaling 6,000 linear feet.

- In 1968, mesh-reinforced gunite was applied to the upper 38 feet of the upstream face, and a cosmetic surfacing of gunite was applied to the downstream face.

- In 1979, a small turbine-generator was installed, utilizing a minimum flow release through the Low Level Outlet.

- In 1980, provisions to monitor existing cracks were installed in the lower gallery and at lift joints in the upper gallery for monitoring following earthquakes.

- In 1983, additional uplift relief holes were drilled from the upper gallery between stations 9+34 and 9+59.

- The gunite facing on the upper 38 feet of the upstream face was recoated with polyurethane in 1984.

- In 1987, a 48-inch Howell-Bunger valve was installed on the downstream end of the Low Level Outlet pipe.

- In 2005, forty-six post-tensioned anchors were installed in Shaver Lake Dam to maintain stability.

BC 2A Flowlines

- In 1995, a penstock expansion joint associated with Unit 2 was re-packed.

- In 1996, a leaking penstock cover plate associated with Units 1 and 2 was repaired.

Big Creek No. 2A Powerhouse

- In 1949, the Unit No. 1 generator was rewound.

- In 1950, the Unit No. 2 generator was rewound.

- In 1984, the turbine runners for Unit 2 were replaced with cast stainless steel runners and the turbine was upgraded from 68,000 HP to 69,000 HP.

- In 1985, the Unit No. 2 generator was rewound and upgraded from 44,500 kW to 55,000 kW.

- In 1987, the turbine runners for Unit 1 were replaced with cast stainless steel runners and the turbine was upgraded from 56,000 HP to 74,100 HP.

- In 1987, the Unit No. 1 generator was rewound and upgraded from 44,500 kW to 55,000 kW.

- In 1990, the Unit No. 2 generator was rewound.

Florence Lake Dam

- In 1926, the upstream faces of the arches were coated with Intertol, a coal tar preparation.

- In 1931, the upstream faces of the arches were coated with an asphaltic compound.

- In 1940, the walkway at the top of the dam was repaired by adding a linseed oil coated gunite topping to the 25 westerly and 9 easterly arches.

- In 1940, Arch 8 was repaired by removing disintegrated concrete, restoring the arch section with gunite, coating the upstream face with Asbestile, and applying aluminum paint to the upstream face.

- In 1941 and 1942, the remaining arches were repaired by removing disintegrated concrete, restoring the arch section with gunite, coating the upstream face with Asbestile, and applying aluminum paint to the upstream face.

- In 1942, the walkway at the top of the central 24 arches was rebuilt as part of the Portland Cement Association study of the Long Time Performance of Cement in Concrete.

- In 1950, instruments were installed at Arch 21 to monitor strain and deflection.

- In 1965, three foundation drainage holes were drilled about 25 feet deep immediately downstream of Arches 13, 14, 52, 53, 54, and 55.

- In 1970, Arch 13 was repaired by removing the steel facing, applying gunite coating to the upstream face followed by two coats of polysulfide rubber sealer and placing a blanket of soil-cement at the upstream base of the arch to seal the contact between the new gunite and the arch face.

- Between 1970 and 1972, spot repairs were made to the Asbestile membrane throughout the dam on a continuing basis.

- In 1971, Arch 53 was coated with polysulfide rubber.

- In 1971, foundation drainage improvements were implemented at Arches 13, 14, and 15.

- In 1971, a drain was installed through the buttress between Arches 13 and 14.
- Between 1972 and 1974, spot gunite, Asbestile, and paint repairs were made throughout the dam on a continuing basis.
- In 1975, gunite repairs were made to the buttresses and Arch 8.
- In 1976, new polysulfide coating was applied to Arch 8.
- In 1976, applied reinforced gunite to Arch 13 and reapplied Asbestile and reflective paint coatings.
- In 1976, applied aluminum paint to Arches 16 through 18 and Arches 25 through 36.
- In 1976, Arch 51 was re-coated with Asbestile to elevation 7260 feet.
- In 1977, new polysulfide coating was applied to Arch 13.
- In 1977, new aluminum paint coating was applied to Arches 37-45.
- In 1977, a minimum pool weir was installed approximately 150 feet from the intake structure.
- In 1979, a fishwater release with a Bailey valve scheme was installed at Arch 53.
- In 1980, gunite was reapplied to the counterfort buttresses 21 and 22.
- In 1981, the Asbestile coating on Angle Buttress 10 was repaired.

Camp 62 Creek Diversion

- The Camp 62 Diversion was reconstructed in 2001 with a slanted shaft to the Ward Tunnel.

Chinquapin Creek Diversion

- The Chinquapin Diversion was reconstructed in 2001 with a vertical shaft to the Ward Tunnel.

Pitman Creek Diversion

- The Pitman Creek Diversion was upgraded in 2001.

Big Creek 8

Dam 5

- In 1970, a reinforced gunite cover was placed over the intrados and spillway piers to replace concrete loss associated freeze-thaw action.

BC 8 Flowlines

- In 1924 and 1925, Penstock No. 1 was reinforced with steel bands.

Big Creek No. 8 Powerhouse

- In 1950, the Unit No. 1 generator was rewound.
- In 1955, the Unit No. 2 generator was rewound.
- In 1984, the Unit No. 2turbine was upgraded from 44,000 HP to 52,500 HP.
- In 1985, the Unit No. 1 turbine was upgraded from 30,000 HP to 36,500 HP.
- In 1986, the Unit No. 1 generator was rewound and upgraded from 27,000 kW to 30,000 kW.
- In 1986, the Unit No. 2 generator was rewound and upgraded from 31,500 kW to 45,000 kW.
- In 1992, the Unit No. 2 generator was rewound.
- In 1996, the Unit No. 2 generator was rewound.
- In 1996, the generator circuit breakers were replaced.
- In 1997, the Unit No. 2 generator was rewound.

Eastwood Power Station

Balsam Meadow Forebay Dam

- Since 1992, the outlet gate stem actuator has been repaired and the seepage collection system rebuilt with weirs added.

(2) **New Development**

This is an existing project, however new construction activities are proposed to decommission the Tombstone, North Slide, and Crater small diversions, and to construct new outlet works at the Mono Creek Diversion to allow for a larger Minimum Instream Flow release. No other construction activities are planned at this time other than those which occasionally arise during the course of routine operation and maintenance of the Project.

SCE will evaluate the likely construction approach, and access needs to determine the appropriate infrastructure modification and to complete the preliminary engineering work for the Mono Creek Diversion Dam modification. Based on this preliminary work, SCE will obtain necessary permits from resource agencies other than FERC prior to construction of the infrastructure modification. The Mono Creek Diversion Dam will require the installation of a release structure and flow measurement device. The schedule for this work is estimated as follows: preliminary engineering and permitting would be conducted in 2008; continued engineering and equipment ordering would be conducted in 2009; and the construction would begin in 2010 and possibly continue into 2011.

Decommissioning of the three small diversions would be completed within four years following issuance of the new license order. Permits would be obtained in year one, Crater Creek Diversion would be decommissioned in year two, Tombstone Creek Diversion would be decommissioned in year three, and North Slide Creek would be decommissioned in year four.

Southern California Edison Company

Before the

Federal Energy Regulatory Commission

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 2A, 8 AND EASTWOOD
(FERC Project No. 67)

Exhibit D: Project Costs and Financing

CONTAINS PUBLIC INFORMATION

February 2007

Exhibit D Project Costs and Financing

Exhibit D is a statement of costs and financing. The statement must contain:

(1) If the application is for an initial license, a tabulated statement providing the actual or approximate original cost (approximate costs must be identified as such) of:

(i) Any land or water right necessary to the existing project; and

(ii) Each existing structure and facility described under paragraph (b) of this section (Exhibit A).

(2) If the Applicant is a licensee applying for a new license, and is not a municipality or a state, an estimate of the amount which would be payable if the project were to be taken over pursuant to section 14 of the Federal Power Act upon expiration of the license in effect [*see* 16 U.S.C. 807], including:

(i) Fair value;

(ii) Net investment; and

(iii) Severance damages.

(3) If the application includes proposals for any new development, a statement of estimated costs, including:

(i) The cost of any land or water rights necessary to the new development; and

(ii) The cost of the new development work, with a specification of:

(A) Total cost of each major item;

(B) Indirect construction costs such as costs of construction equipment, camps, and commissaries;

(C) Interest during construction; and

(D) Overhead, construction, legal expenses, taxes, administrative and general expenses, and contingencies.

(4) A statement of the estimated average annual cost of the total project as proposed specifying any projected changes in the costs (life-cycle costs) over the estimated financing or licensing period if the applicant takes such changes into account, including:

(i) Cost of capital (equity and debt);

(ii) Local, state, and Federal taxes;

(iii) Depreciation or amortization;

> (iv) Operation and maintenance expenses, including interim replacements, insurance, administrative and general expenses, and contingencies; and,
>
> (v) The estimated capital cost and estimated annual operation and maintenance expense of each proposed environmental measure.
>
> (5) A statement of the estimated annual value of project power, based on a showing of the contract price for sale of power or the estimated average annual cost of obtaining an equivalent amount of power (capacity and energy) from the lowest cost alternative source, specifying any projected changes in the cost of power from that source over the estimated financing or licensing period if the applicant takes such changes into account.
>
> (6) A statement specifying the sources and extent of financing and annual revenues available to the applicant to meet the costs identified in paragraphs (e) (3) and (4) of this section.
>
> (7) An estimate of the cost to develop the license application;
>
> (8) The on-peak and off-peak values of project power, and the basis for estimating the values, for projects which are proposed to operate in a mode other than run-of-river; and
>
> (9) The estimated average annual increase or decrease in project generation, and the estimated average annual increase or decrease of the value of project power, due to a change in project operations (*i.e.,* minimum bypass flows; limits on reservoir fluctuations).

(1) Original Cost

Original cost of Project construction and obtaining land and water rights does not apply because the Big Creek 2A, 8 and Eastwood Power Station Project is not an application for an initial license and all necessary water rights and privately-owned lands have already been obtained.

(i) Not Applicable.

(ii) Not Applicable.

(2) Takeover Cost

It is the intent of SCE to continue to operate the Project upon receipt of a new license. If the Project were to be taken over at the expiration of the existing license, the following values would apply.

(i) The fair value of the Project is estimated to be $663.0 million in 2006 dollars.

The fair value of the project was determined by calculating the net benefits realized by customers from a revenue requirement perspective. The calculation nets the full capital recovery and operating costs against the energy and capacity benefits of the project. Energy benefits are defined as the value of replacement marginal-cost market energy. Capacity benefits are defined as the deferral value of a combustion turbine (CT), given the least-cost characteristics of a CT for a capacity-only product with no associated energy benefits. These values were calculated on an annual basis and present valued to determine the fair-present value of the Project.

(ii) The Net Investment of this Project was $219,234,229 as of December 31, 2006.

(iii) The severance value for the 1,173,296 MWh of annual generation is $663.0 million and equal to the fair value discussed above in D(2)(ii) (also see Attachment D-1).

(3) Cost of New Development

The costs of new development do not apply because this Application does not include any such proposals. Only upgrades to existing facilities are planned and these will be performed during routine maintenance, or as planned capital replacement, or as structural modifications consistent with any new license requirements. Infrastructure changes required to implement environmental measures are discussed below in D(4)(v) (also see Attachment D-2).

(i) Not Applicable.

(ii) Not Applicable.

(A) Not Applicable.

(B) Not Applicable.

(C) Not Applicable.

(D) Not Applicable.

(4) Cost of Financing

The annual costs for this Project include expenses for Operations and Maintenance (O&M) as well as capital improvement work. The work currently scheduled for this Project consists of plant upgrades and maintenance, not “new development.”

(i) The current SCE Cost of Capital is listed below:

Long-Term Debt	3.14%
Preferred Equity	0.75%
Common Equity	6.12%
Total Cost of Capital	10.00%

(ii) Property Taxes associated with this Project for 2005 were $2,386,974. State and Federal income taxes are computed for all of the SCE Hydro assets combined and no amount is specifically designated for this individual Project.

(iii) Depreciation for this Project for 2005 was $6,965,129.

(iv) The direct O&M expenses for this Project are $9,272,458, which is an estimated annualized value for the life of the license. Approximately $968,798 of these O&M expenses are represented by annual fees that are detailed in Exhibit H(b)(9). Additional expenses not mentioned above include Administrative and General (A&G) expenses. These expenses are calculated for all of the SCE Hydro assets combined. An approximation of A&G expenses is equal to 1.25% times the Net Plant Investment or $2,740,428 per year.

(v) The estimated capital cost and estimated annual operation and maintenance expense of each proposed environmental measure is listed in Attachment D-2 and totals $1,720,558 as an annualized value.

(5) Value of Project Power

SCE procures energy and related products to cover its “net-short” energy requirements for its electricity customers. The “net-short” position is defined as the condition when the energy required to meet customer demand exceeds the energy that SCE can provide from its owned or contracted resources.

The Project’s projected annual power value is determined by estimating the cost of replacing the energy and capacity provided by the Projects at SCE’s current forecast of the marginal cost for energy and capacity. The estimated annual amount of energy produced from the Project was derived from a 15-year annual average of historical production from 1991 to 2005.

The amount of average annual replacement energy (MWh’s) for the Project was multiplied by the marginal energy cost forecast. The dependable capacity of the Project was multiplied by the marginal capacity cost forecast. The sum of the replacement energy and capacity costs is the total cost that SCE would expect to incur to replace the power being provided by this Project. The generation marginal costs used in these calculations were obtained from SCE’s 2006 General Rate Case (GRC) filing. Since the forecast does not include information beyond 2008, it is assumed that the costs will increase according to the Gross Domestic Product (GDP) Price Index escalation. SCE used an estimate of escalation from Global Insight (formerly DRI-WEFA) for the years beyond 2008.

The Projects' forecasted power value for 2009 is $88.8 million. When the power value is escalated for the expected 44-year term of the license and discounted at the SCE cost of capital, it yields a net present value of $877.5 million in 2006 dollars. The levelized annual value of the energy benefits is $88.9 million (see Attachment D-3).

(6) Sources of Financing and Revenues

As previously discussed in Exhibit D(3), there is no major new development planned for the Projects. As such, there is no need to acquire special financing for any major capital work.

SCE previously filed a 2006 GRC with the California Public Utilities Commission (CPUC) in September 2005, which was approved in May of 2006. Included in this Rate Case filing were the generation-related O&M expenses as well as A&G expenses. The 2006 GRC filings included the expected costs for the years of 2006–2008, which are associated with the operation and maintenance of all the SCE Hydro assets, as well as the costs associated with any anticipated incremental capital additions. SCE is preparing to file a 2009 GRC Notice of Intent (NOI) with the CPUC in 2007. Assuming that the 2009 Rate case is approved, the capital and O&M expenses necessary for continued operation of the Projects will be collected through those approved rates. Those approved rates will include costs associated with license condition requirements that might be imposed upon the Projects in this license application in the years 2009-2011.

This Project is operated as a component of the entire Hydro Generation Division, which is part of the Power Production Department of SCE. The O&M expenses for this Project are therefore not wholly estimated at the division or department level, as the departmental costs are usually extrapolated from historical costs. Any financing charges required for individual projects would normally be included in the overall department budget and would not be directly attributable to the individual Project.

(7) License Application Development Cost

The cost incurred for this Project's FERC license Application through December, 2006 is approximately $14,884,000. These costs include development of the license including portions of the Amended Preliminary Draft Environmental Analysis (APDEA), which includes Projects 2085, 2175, 67, and 120 as part of the Alternative Licensing Process (ALP) started in 2000.

(8) Value of On-Peak and Off-Peak Project Power

The on-peak and off-peak power values for the Project are based upon the 2006 energy price of $49.40 per megawatt-hour (MWh) and the 2006 capacity price of $69.70 per kilowatt-year (kW-yr). In 2007, the on-peak period energy price is $56.63/MWh and the associated off-peak energy price is $42.48/MWh. The distribution of the total power value is based on the ratios of on-peak to off-peak energy and capacity values. Energy value is distributed between on- and off-peak based on ratios developed while creating hourly fundamental energy price forecasts. Capacity value is distributed based on SCE's relative loss-of-load probability factors. Both sets of factors are consistent with those presented in Phase 2 of SCE's 2006 General Rate Case.

Attachment D-4 provides the average annual Project generation for dry, normal, and wet year categories. The total generation is divided into on-peak and off-peak generation. The percentages of time that the powerhouse operated in on-peak and off-peak generation modes was calculated using hourly generation data from the years 2001 (dry), 2000 (normal), and 2005 (wet). These calculated percentages of on-peak and off–peak powerhouse operation were applied to average annual generation to determine the average generation value of on-peak and off-peak generation in megawatt-hours. This analysis was conducted for dry, normal and wet years as defined in the footnote to Attachment D-4.

(9) Effects of Changes in Project Operations

Under the Proposed Action, it is estimated that the average annual project generation will decrease by 47,867 MWh, resulting in a net reduction in the value of project power of approximately $2,509,000 (this is an annualized value in 2006$ based on the anticipated power generation over a projected 44-year license term).

ATTACHMENT D-1

FERC Project No. 67 - Fair Value

ATTACHMENT D-1

Big Creek 2A, 8 & Eastwood - Project 067 Fair Value

Revenue Requirement Net Present Value Benefit **$662,991** **(In $2006)**
(In $Thousands)

Year	Project Costs ($)	Energy Benefits ($)	Capacity Benefits ($)	Net Benefits ($)
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	12,546	61,475	27,353	76,282
2010	14,582	62,723	27,908	76,049
2011	16,708	64,064	28,504	75,860
2012	19,219	65,402	29,100	75,283
2013	20,520	66,712	29,683	75,875
2014	21,826	68,006	30,258	76,439
2015	22,890	69,283	30,827	77,220
2016	24,151	70,555	31,393	77,796
2017	25,173	71,814	31,953	78,593
2018	26,464	73,038	32,497	79,072
2019	27,339	74,361	33,086	80,109
2020	28,652	75,733	33,697	80,778
2021	29,695	77,149	34,326	81,780
2022	31,080	78,589	34,967	82,477
2023	31,965	80,072	35,627	83,734
2024	32,945	81,578	36,297	84,930
2025	33,915	83,138	36,991	86,214
2026	35,339	84,744	37,706	87,111
2027	36,484	86,372	38,430	88,319
2028	37,569	88,021	39,164	89,615
2029	38,529	89,739	39,929	91,139
2030	39,768	91,493	40,709	92,433
2031	40,858	93,265	41,497	93,904
2032	42,573	95,056	42,294	94,777
2033	43,339	96,861	43,097	96,619
2034	44,561	98,696	43,914	98,049
2035	45,875	100,552	44,740	99,417
2036	47,465	102,446	45,582	100,564
2037	48,866	104,376	46,441	101,951
2038	50,016	106,342	47,316	103,641
2039	50,945	108,345	48,207	105,607
2040	52,181	110,386	49,115	107,319
2041	53,627	112,465	50,040	108,878
2042	55,796	114,583	50,982	109,769
2043	57,159	116,741	51,943	111,525
2044	59,466	118,940	52,921	112,396
2045	61,399	121,181	53,918	113,700
2046	65,090	123,463	54,933	113,306
2047	70,162	125,789	55,968	111,594
2048	75,634	128,158	57,022	109,546
2049	81,693	130,572	58,096	106,975
2050	90,118	133,031	59,191	102,104
2051	102,631	135,537	60,306	93,211
2052	106,716	138,090	61,441	92,815
Total	**$1,953,528**	**$4,178,935**	**$1,859,369**	**$4,084,776**
NPV	**$214,488**	**$607,277**	**$270,201**	**$662,991**

(All above are $Thousands)

Assumptions:

Energy and Capacity value per Appendix D-2
Project costs are based on Revenue Requirements
SCE Cost of Capital: 10.00%
License Life: 44 years

ATTACHMENT D-2

Cost of Environmental Measures Recommended in the Proposed Action and Resulting Reduction in Annual Energy Benefits by Project for the Big Creek Nos. 2A, 8 and Eastwood Project (FERC Project No. 67)

Attachment D-2. Cost of Environmental Measures Recommended in the Proposed Action and Resulting Reduction in Annual Energy Benefits by Project for the Big Creek Nos. 2A, 8 and Eastwood Project (FERC Project No. 67).

Environmental Measures	Year(s) Implemented	Capital and One-Time Costs (2006$)	Annual Costs Including O&M (2006$)	Annualized Costs (2006$)	Reduction in Annual Energy Benefits (2006$)
WATER AND AQUATIC RESOURCES					
Implement New Minimum Instream Flow and Channel Riparian Maintenance Flow Releases	3-46[1]		$8,000	$7,225	$2,509,000
Maintain Existing and New Gaging Stations	3-46		$100,000	$90,313	
Complete Required Infrastructure Modifications (MIF releases and gaging)					
Dam 5 (core dam, install release structure and AVM gage)	4-7	$2,500,000		$156,450	
Mono Creek Diversion (core dam, install release structure and AVM gage)	4-7	$1,500,000		$93,870	
Bolsillo Creek Diversion	4-7	$100,000		$6,258	
Camp 62 Creek Diversion	4-7	$100,000		$6,258	
Decommission Small Diversions					
Crater Creek Diversion	4	$400,000		$27,679	
Tombstone Creek Diversion	5	$700,000		$45,180	
North Slide Creek Diversion	6	$25,000		$1,508	
South Slide Creek Diversion	6	$10,000		$603	
Pitman Creek Domestic Diversion	7	$25,000		$1,407	
Snow Slide Creek Domestic Diversion	7	$25,000		$1,407	
Implement Monitoring Programs					
Fish	3,10,20,30,40		$72,000	$10,334	
Temperature	8-12		$140,000	$32,301	
Flow	3-46		$140,000	$126,439	
Riparian	4,7,12,22,32,42		$75,000	$13,346	
Jackass Meadows	3,5,9,12		$75,000	$15,836	
Camp 61 Creek	4,7,12,22,32,42		$40,000	$7,118	
Implement Sediment Management Plan					
Small Diversion (pass through)	Every 3rd year, beginning 2009		$15,000	$4,901	
Dam 5 and Mono Creek (Flush)	Every 5th year, beginning 2012		$25,000	$4,148	
Dam 5, Mono Creek, and Balsam Meadows forebays (sediment removal)	Every 5th year, beginning 2012		$150,000	$24,887	
Implement Sediment Management Plan for Mono Creek	Every 2nd year, beginning 2014		$50,000	$15,587	
Implement Sediment Management Plan for Camp 61 Creek	Every 2nd year, beginning 2011		$50,000	$19,884	
Implement Large Woody Debris Measure Bear Creek Diversion	3-46		$6,000	$5,419	
Attend Annual Consultation Meeting	3-46		$500	$452	
TERRESTRIAL RESOURCES					
Implement Wildlife Habitat Enhancement	3-46		$2,000	$1,806	
Implement Management Plans					
Bald Eagle	3, 7, 12, 17, 22, 27, 32, 37, 42		$10,000	$2,234	
VELB	3-46		$13,000	$11,741	
Vegetation and Integrated Pest	3-46		$50,000	$45,157	
Implement Proposed License Articles (Mule Deer, Special-status Species, Bats)	3-46	$2,000	$6,000	$5,563	
Implement Environmental Programs (Environmental Training, ESAP, Avian Protection, Noxious Weeds, NHSSIP, Environmental Compliance)	3-46	$25,000	$2,500	$4,065	
Attend Annual Consultation Meeting	3-46		$500	$452	

Attachment D-2. Cost of Environmental Measures Recommended in the Proposed Action and Resulting Reduction in Annual Energy Benefits by Project for the Big Creek Nos. 2A, 8 and Eastwood Project (FERC Project No. 67).

Environmental Measures	Year(s) Implemented	Capital and One-Time Costs (2006$)	Annual Costs Including O&M (2006$)	Annualized Costs (2006$)	Reduction in Annual Energy Benefits (2006$)
RECREATION RESOURCES					
Implement Recreation Management Plan					
Operation and Maintenance of Recreation Facilities	3-46		$62,500	$56,446	
Rehabilitation of Existing Recreation Facilities	4-9[2]; 10-16[3], 19-23[4]	$9,200,000		$354,228	
Enhancement New Recreation Facilities/Features (Accessible Fishing Platform Jackass Mdws, and Handicapped Boat Loading Platform)	3-7	$250,000		$16,779	
Maintenance of Accessible Fishing Platform	Every 3rd Year Beginning 2012		$5,000	$1,272	
Manage Reservoir WSE	3-46		$2,000	$1,806	
Fund Fish Stocking (50% cost share)	3-7		$75,000	$24,354	
Fund Fish Stocking (50% cost share)	8-46		$75,000	$44,823	
Dissemination of Flow Information (whitewater boating)	3-46		$5,000	$4,516	
Interpretive Signs	3	$96,000		$7,143	
Prepare Report on Recreation Resources (every 6 years)	8, 14, 20, 26, 38		$100,000	$11,143	
Attend Annual Consultation Meeting	3-46		$500	$452	
LAND MANAGEMENT					
Implement Management Plans					
Transportation System Plan	3-46		$40,000	$42,941	
Fire Plan	3-46		$500	$452	
Spill Prevention Control and Countermeasure Plans	3-46		$500	$452	
Attend Annual Consultation Meeting	3-46		$500	$452	
Transportation System Plan Labor	3-46		$277,500	$250,620	
Transportation System Plan Equipment & Materials	3-46		$72,800	$65,748	
CULTURAL RESOURCES					
Implement a Historic Properties Management Plan	3-7	$243,000	$30,000	$27,823	
Implement a Historic Properties Management Plan	8-46		$30,000	$17,929	
Implement Environmental Programs (Environmental, Cultural Awareness)	3-46		$1,000	$903	
Attend Annual Consultation Meeting	3-46		$500	$452	
TOTAL PROJECT 67 COST			$1,808,800	$1,720,558	$2,509,000

[1]Assumes that geomorphic flows will only occur during wet years

[2]Years 4-9 cost = $1,800,000

[3]Years 10-16 cost = $5,400,000

[4]Years 19-23 cost = $2,000,000

ATTACHMENT D-3

FERC Project No. 67 – Total and Annual Value

ATTACHMENT D-3

Big Creek 2A, 8 & Eastwood - Project 067 Total & Annual Value

Power Present Value $877,478 (In $2006), (In $Thousands)
Power Levelized Value $88,866 (In $2006), (In $Thousands)

Year	Total Value of Power ($)	Energy Value ($)	Capacity Value ($)	Energy Price ($/MWh)	Capacity Price ($/kW-yr)	Power Escalation Factor
2006	0			49.40	69.70	2.92%
2007	0			50.41	71.13	2.05%
2008	0			51.38	72.49	1.92%
2009	88,828	61,475	27,353	52.40	73.93	1.98%
2010	90,631	62,723	27,908	53.46	75.43	2.03%
2011	92,568	64,064	28,504	54.60	77.04	2.14%
2012	94,502	65,402	29,100	55.74	78.65	2.09%
2013	96,395	66,712	29,683	56.86	80.22	2.00%
2014	98,264	68,006	30,258	57.96	81.78	1.94%
2015	100,110	69,283	30,827	59.05	83.32	1.88%
2016	101,948	70,555	31,393	60.13	84.85	1.84%
2017	103,766	71,814	31,953	61.21	86.36	1.78%
2018	105,536	73,038	32,497	62.25	87.83	1.71%
2019	107,448	74,361	33,086	63.38	89.42	1.81%
2020	109,430	75,733	33,697	64.55	91.07	1.84%
2021	111,475	77,149	34,326	65.75	92.77	1.87%
2022	113,557	78,589	34,967	66.98	94.51	1.87%
2023	115,699	80,072	35,627	68.25	96.29	1.89%
2024	117,875	81,578	36,297	69.53	98.10	1.88%
2025	120,129	83,138	36,991	70.86	99.98	1.91%
2026	122,450	84,744	37,706	72.23	101.91	1.93%
2027	124,803	86,372	38,430	73.62	103.87	1.92%
2028	127,184	88,021	39,164	75.02	105.85	1.91%
2029	129,668	89,739	39,929	76.48	107.91	1.95%
2030	132,201	91,493	40,709	77.98	110.02	1.95%
2031	134,762	93,265	41,497	79.49	112.15	1.94%
2032	137,350	95,056	42,294	81.02	114.31	1.92%
2033	139,958	96,861	43,097	82.55	116.48	1.90%
2034	142,610	98,696	43,914	84.12	118.69	1.90%
2035	145,292	100,552	44,740	85.70	120.92	1.88%
2036	148,029	102,446	45,582	87.31	123.20	1.88%
2037	150,817	104,376	46,441	88.96	125.52	1.88%
2038	153,657	106,342	47,316	90.64	127.88	1.88%
2039	156,552	108,345	48,207	92.34	130.29	1.88%
2040	159,500	110,386	49,115	94.08	132.74	1.88%
2041	162,505	112,465	50,040	95.85	135.24	1.88%
2042	165,566	114,583	50,982	97.66	137.79	1.88%
2043	168,684	116,741	51,943	99.50	140.39	1.88%
2044	171,861	118,940	52,921	101.37	143.03	1.88%
2045	175,098	121,181	53,918	103.28	145.72	1.88%
2046	178,397	123,463	54,933	105.23	148.47	1.88%
2047	181,757	125,789	55,968	107.21	151.27	1.88%
2048	185,180	128,158	57,022	109.23	154.11	1.88%
2049	188,668	130,572	58,096	111.29	157.02	1.88%
2050	192,222	133,031	59,191	113.38	159.97	1.88%
2051	195,842	135,537	60,306	115.52	162.99	1.88%
2052	199,531	138,090	61,441	117.69	166.06	1.88%

(All above are $Thousands)

Assumptions:

2007 Energy Price ($/MWh):	50.41
2007 Capacity Price ($/kW-yr):	71.13
Big Creek 2A Generation (MWh):	511,290
Big Creek 8 Generation (MWh):	305,664
JS Eastwood Generation (MWh):	356,342
Big Creek 2A Dependable Capacity (MW):	98.5
Big Creek 8 Dependable Capacity (MW):	64.5
JS Eastwood Capacity (MW):	207
2009 Power Value (In $Thousands):	$88,828
SCE Cost of Capital:	10.00%
License Life:	44 years
Power Escalation Factor:	GDP Index (Global Insight)

ATTACHMENT D-4

FERC Project No. 67 – Average On-Peak and Off-Peak Generation in MWh's for Dry, Normal and Wet Years

ATTACHMENT D-4

Average On-Peak and Off-Peak Generation in MWh's for Dry, Normal and Wet Years[1] (FERC Project No. 67)

Type of Year	Average Generation	On-Peak Generation	Off-Peak Generation
Dry	740,759	553,975	186,784
Normal	1,143,353	798,848	344,505
Wet	1,558,379	1,009,141	549,238

[1] Project 67 receives inflow primarily from the South Fork of the San Joaquin River with runoff varying from a dry year to a wet year. The determination of a dry, normal, or wet year is made with the annual runoff for the San Joaquin River downstream at Friant Dam. The decision of whether the year is dry, normal, or wet is done with a 30%-40%-30% division of annual runoff volume for 128 years, through 2005. The data used to provide the 18-year averages above are from 1988 through 2005. A longer average was not used because 1988 was the first full year of operation for Eastwood Powhouse.

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 2A, 8 AND EASTWOOD
(FERC Project No. 67)

EXHIBIT H(A) GENERAL INFORMATION

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit H(a) General Information

Exhibit H(a) describes information to be provided pursuant to 18 CFR § 16.10(a):

(1) A discussion of the plans and ability of the applicant to operate and maintain the project in a manner most likely to provide efficient and reliable electric service, including efforts and plans to:

(i) Increase capacity or generation at the project;

(ii) Coordinate the operation of the project with any upstream or downstream water resource projects; and

(iii) Coordinate the operation of the project with the applicant's or other electrical systems to minimize the cost of production.

(2) A discussion of the need of the applicant over the short and long term for the electricity generated by the project, including:

(i) The reasonable costs and reasonable availability of alternative sources of power that would be needed by the applicant or its customers, including wholesale customers, if the applicant is not granted a license for the project;

(ii) A discussion of the increase in fuel, capital, and any other costs that would be incurred by the applicant or its customers to purchase or generate power necessary to replace the output of the licensed project, if the applicant is not granted a license for the project;

(iii) The effect of each alternative source of power on:

(A) The applicant's customers, including wholesale customers;

(B) The applicant's operating and load characteristics; and

(C) The communities served or to be served, including any reallocation of costs associated with the transfer of a license from the existing licensee.

(3) The following data showing need and the reasonable cost and availability of alternative sources of power:

(i) The average annual cost of the power produced by the project, including the basis for that calculation;

(ii) The projected resources required by the applicant to meet the applicant's capacity and energy requirements over the short and long term including:

(A) Energy and capacity resources, including the contributions from the applicant's generation, purchases, and load modification measures (such as conservation, if considered as a resource), as separate components of the total resources required;

(B) A resource analysis, including a statement of system reserve margins to be maintained for energy and capacity; and

(C) If load management measures are not viewed as resources, the effects of such measures on the projected capacity and energy requirements indicated separately;

(iii) For alternative sources of power, including generation of additional power at existing facilities, restarting deactivated units, the purchase of power off-system, the construction or purchase and operation of a new power plant, and load management measures such as conservation:

(A) The total annual cost of each alternative source of power to replace project power;

(B) The basis for the determination of projected annual cost; and

(C) A discussion of the relative merits of each alternative, including the issues of the period of availability and dependability of purchased power, average life of alternatives, relative equivalent availability of generating alternatives, and relative impacts on the applicant's power system reliability and other system operating characteristics; and

(iv) The effect on the direct providers (and their immediate customers) of alternate sources of power.

(4) If an applicant uses power for its own industrial facility and related operations, the effect of obtaining or losing electricity from the project on the operation and efficiency of such facility or related operations, its workers, and the related community.

(5) If an applicant is an Indian tribe applying for a license for a project located on the tribal reservation, a statement of the need of such tribe for electricity generated by the project to foster the purposes of the reservation.

(6) A comparison of the impact on the operations and planning of the applicant's transmission system of receiving or not receiving the project license, including:

(i) An analysis of the effects of any resulting redistribution of power flows on line loading (with respect to applicable thermal, voltage, or stability limits), line losses, and necessary new construction of transmission facilities or upgrading of existing facilities, together with the cost impact of these effects;

(ii) An analysis of the advantages that the applicant's transmission system would provide in the distribution of the project's power; and

(iii) Detailed single-line diagrams, including existing system facilities identified by name and circuit number, that show system transmission elements in relation to the project and other principal interconnected system elements. Power flow and loss data that represent system operating conditions may be appended if applicants believe such data would be useful to show that the operating impacts described would be beneficial.

(7) If the applicant has plans to modify existing project facilities or operations, a statement of the need for, or usefulness of, the modifications, including at least a reconnaissance-level study of the effect and projected costs of the proposed plans and any alternate plans, which in conjunction with other developments in the area would conform with a comprehensive plan for improving or developing the waterway and for other beneficial public uses as defined in section 10(a)(1) of the Federal Power Act.

(8) If the applicant has no plans to modify existing project facilities or operations, at least a reconnaissance-level study to show that the project facilities or operations in conjunction with other developments in the area would conform with a comprehensive plan for improving or developing the waterway and for other beneficial public uses as defined in section 10(a)(1) of the Federal Power Act.

(9) A statement describing the applicant's financial and personnel resources to meet its obligations under a new license, including specific information to demonstrate that the applicant's personnel are adequate in number and training to operate and maintain the project in accordance with the provisions of the license.

(10) If an applicant proposes to expand the project to encompass additional lands, a statement that the applicant has notified, by certified mail, property owners on the additional lands to be encompassed by the project and governmental agencies and subdivisions likely to be interested in or affected by the proposed expansion.

(11) The applicant's electricity consumption efficiency improvement program, as defined under section 10(a)(2)(C) of the Federal Power Act, including:

(i) A statement of the applicant's record of encouraging or assisting its customers to conserve electricity and a description of its plans and capabilities for promoting electricity conservation by its customers; and

(ii) A statement describing the compliance of the applicant's energy conservation programs with any applicable regulatory requirements.

(12) The names and mailing addresses of every Indian tribe with land on which any part of the proposed project would be located or which the applicant reasonably believes would otherwise be affected by the proposed project.

(1) Efficient and Reliable Operation and Maintenance of Project

(i) Increased Capacity or Generation at the Project

Southern California Edison Company (SCE) currently has no plans to further increase capacity or generation at the Project.

(ii) Coordinate the Operation of the Project with any Upstream or Downstream Water Resource Projects

Project Operations

Operation of SCE's seven FERC licensed Projects in the Big Creek System (BCS) is managed from a watershed-wide perspective and on an individual project-by-project basis. The BCS consists of six major reservoirs (Thomas A. Edison, Florence, Huntington, Redinger, Shaver, and Mammoth Pool,) and nine powerhouses (Portal; Eastwood; Mammoth Pool; and Big Creek Powerhouse Nos. 1, 2, 2A, 3, 4, and 8). The operation of the BCS and the individual Projects is dependent on natural run-off and the operation of other components in the system, storage requirements of the Mammoth Pool Operating Agreement, the amount of generation required for SCE's customers, and the dispatching of energy in accordance with the California Independent System Operator requirements.

SCE operates the four Big Creek Alternative Licensing Process (ALP) Projects within the BCS in accordance with FERC license conditions, which includes MIF release requirements from diversions and impoundments.

The management of water through the BCS and specifically the four Big Creek ALP Projects routes water between Projects in a manner that best meets the operational constraints that are imposed either by contractual operating agreements (i.e., licenses, permits, etc.) or by physical limitations of the Project infrastructure. The BCS is subject to several operating constraints including the following: (1) available water supply; (2) electrical system requirements; (3) both planned and unplanned maintenance outages; (4) storage limits (including both recreation minimums and year-end carryover maximums); (5) both minimum and maximum release limits (from storage); (6) various provisions contained in water rights agreements; and (7) California Independent System Operator requirements.

Water Rights and Contractual Obligations

Each of SCE's Big Creek Hydroelectric Projects either has separate water rights or shares one or more water rights with other projects for the diversion, use, and storage of water. The majority of the water rights are for non-consumptive uses associated with the generation of power. A few locations, such as SCE's administrative offices and company housing near Big Creek No. 1 Powerhouse have minor consumptive water rights. SCE does not hold water rights for the consumptive use of water by any party other than SCE, nor does SCE sell any water rights associated with the hydropower projects to other parties.

SCE's water rights were obtained pursuant to state law and a majority of the water rights are documented by licenses and permits issued to SCE, or its predecessors, by the State Water Resources Control Board (State Water Board). Additional water rights were obtained through appropriation of water prior to the implementation of the Water Commission Act of 1914, and by prescriptive use against other parties. SCE also holds other water rights as a riparian land owner, which authorizes SCE to divert and use water on land owned by SCE.

The water rights agreements contain stipulations that stem from the senior status of certain downstream water rights holders. Generally, any water right holder with senior rights began diverting water for consumptive purposes prior to SCE or its predecessors. To protect the rights of the downstream water rights holders, SCE entered into agreements that restrict the use of water within the BCS to non-consumptive purposes, i.e., hydroelectric generation. Certain agreements limit the length of time and amount of water that SCE can store in its Project reservoirs. In a few instances, SCE's non-consumptive water use is a senior water right, and other water users hold junior water rights.

SCE operates its reservoirs consistent with the Mammoth Pool Operating Agreement (MPOA), which specifies cumulative reservoir storage constraints based on the computed natural run-off for the water year at Friant Dam. The MPOA between SCE and the U.S. Bureau of Reclamation (Bureau) specifies water storage and release requirements for the BCS reservoirs, which are upstream of Friant Dam (Millerton Reservoir) and the associated Central Valley Project water distribution system operated by the Bureau on behalf of the downstream irrigators. Millerton Reservoir is a major irrigation storage facility serving the central San Joaquin Valley agricultural community. Meetings between SCE, the Bureau, and the downstream irrigators are held following the March 1 run-off forecast each year, and periodically as needed, to coordinate and optimize hydropower production consistent with irrigation needs of the downstream agricultural users holding senior water rights and emergency flood control operations of Millerton Reservoir. The MPOA includes constraints on the annual and seasonal timing and volume of releases from SCE's reservoirs, maximum year-end storage allowed, and minimum seasonal flow from Dam No. 7 (release and diversion).

BCS Water Management

A key component of the annual water management plan for the BCS is the development of an annual run-off forecast. The annual run-off forecast is developed based on snow pack and precipitation data collected in the vicinity of the Project. This information is used along with assumptions about future median precipitation and air temperatures to produce a run-off forecast through the end of the water year (September 30). The forecast includes an estimate of both the timing and the quantity of water that will enter Project reservoirs during that run-off season. Snow pack and precipitation data are shared with the California Department of Water Resources (DWR) and the Bureau, who use it to develop individual forecasts of run-off volumes and declare water year types (critical, dry, below normal, above normal, or wet). The run-off forecast is a valuable tool for planning and ensuring compliance with the constraints of the MPOA (described above) and for planning purposes. A majority of the MPOA and other constraints are based on actual run-off volumes. The forecast also is used for directing future operational plans for: (1) instream flow release requirements; (2) reservoir recreational storage requirements; and (3) hydroelectric generation operations for the entire BCS.

The operation of the BCS is similar in all water year types in that water diverted from Project reservoirs and diversions is utilized to generate power. There are subtle differences, however, in the way that the Project is operated during different water year types and during different conditions of state energy requirements.

Some of the BCS reservoirs generally spill in wet and above normal water years and are filled to maximum capacity when spill ceases. When the BCS reservoirs stop spilling, SCE is able to manage the system with available inflows and begin managing the water to meet electric supply requirements by providing both base load and peak cycling energy. In the upper basin area, water from the upper South Fork San Joaquin River drainage is stored in Florence Lake and water from Mono Creek drainage is stored in Lake Thomas A. Edison. Water is diverted from these two lakes and various other small backcountry diversions into Huntington Lake via the Ward Tunnel and the Mono-Bear Siphon. The volumes of water that can pass through Ward Tunnel and the siphon are limited by the physical size and layout of these conduits. Water deliveries to Huntington Lake are prioritized as follows: first priority is given to water from Florence Lake; second priority is given to water from Bear Diversion and Lake Thomas A. Edison; and third priority is given to water diverted from the small diversions at Camp 61 Creek, Camp 62 Creek, Chinquapin Creek and Bolsillo Creek. The water delivered to Huntington Lake may also pass through Portal Powerhouse at the exit of the Ward Tunnel depending upon the amount of water being transported.

BCS Power Generation

The BCS has three interlinked water chains or pathways through which water may be transported and used to produce power. The three water chains are:

- Huntington Water Chain: This chain consists of Portal Powerhouse, Powerhouse No. 1, Powerhouse No. 2, Powerhouse No. 8, Powerhouse No.3, and Powerhouse No. 4.
- Shaver Water Chain: This chain consists of Portal Powerhouse, Eastwood Power Station, Powerhouse No. 2A, Powerhouse No. 8, Powerhouse No. 3, and Powerhouse No. 4.
- Mammoth Water Chain: This chain consists of Mammoth Pool Powerhouse, Powerhouse No. 3, and Powerhouse No. 4.

After passing through or bypassing the Portal Powerhouse, water entering Huntington Lake is directed to either the Huntington Chain, or the Shaver Chain. If the generation from the powerhouses of either chain is increased or decreased proportionally, the changes in load will have no effect on the MIF, or total levels of the storage reservoirs and forebays within the BCS. Changes in total loading conditions of the two chains can, however, affect Florence Lake and Lake Thomas A. Edison and can affect the amount of water leaving the project at Powerhouse No. 4. If generation from the powerhouses of either chain is changed disproportionately, the levels of Huntington Lake, Shaver Lake, and Redinger Lake can be increased or decreased.

Water from Big Creek Powerhouse Nos. 1 and 2 in the Huntington Chain joins water from the Shaver Chain, which has already passed through Eastwood Power Station and Big Creek Powerhouse No. 2A, at the Big Creek Powerhouse No. 2 and 2A Tailrace (Dam 5). Water from these two chains is then diverted through Big Creek Powerhouse No. 8, after which it joins the waters of the San Joaquin River coming from the Mammoth Chain at the Big Creek No. 8 Tailrace (Dam 6 Impoundment). Water from all three chains then continues through Big Creek Powerhouse Nos. 3 and 4.

Waters from the Middle Fork and North Fork San Joaquin River (SJR) drainages, and the South Fork SJR flows not diverted at Florence Lake, Lake Thomas A. Edison, Bear Creek Forebay, and the small backcountry diversions, are collected in Mammoth Pool Reservoir and become part of the Mammoth Chain. Mammoth Pool Powerhouse is usually run at maximum during the high flow or run-off period to prevent or delay spill at Mammoth Pool Reservoir.

For the most part, Portal Powerhouse, Eastwood Power Station, and Big Creek No. 4 Powerhouse operate independently of the other powerhouses in the BCS. Portal Powerhouse opportunistically uses water passing through the Ward Tunnel for power generation, but only operates efficiently at moderate flows through Ward Tunnel. Ward Tunnel flows outside the efficient flow range of Portal Powerhouse bypass Portal Powerhouse through the Howell Bunger (HB) valve into Huntington Lake. Eastwood Power Station generation normally occurs during the peak demand period of the day, unless water is being moved continuously from Huntington Lake to Shaver Lake to avoid spill at Huntington Lake or to increase storage at Shaver Lake for use during peak periods. Maintaining storage (water surface levels) to maintain recreational needs at Huntington Lake and above pump-back minimum water surface level in Shaver Lake are important considerations when planning operations at Eastwood Power Station. Big Creek Powerhouse No. 4 is the last power generation opportunity in the Big Creek System and therefore adjustments in the operation of the Powerhouse No. 4 will not affect other upstream powerhouses in the BCS.

Generally, the three water chains of the BCS are operated around the clock in the spring run-off period, except in dry water years. Operational flexibility is limited during normal run-off because the amount of water run-off available exceeds the combined generation and storage capacity of the project, resulting in water flowing over spillways or “spill.”

After the end of the spill period, daily unit plant load schedules are established to maximize hydro resources during system peak load periods. When spring run-off is finished, if a powerhouse does not need to operate for water management, it is run preferentially during on-peak hours. Due to the nature of the energy market and SCE's resources, it is generally beneficial for the Big Creek Projects to provide power during on-peak hours, once the spring run-off has finished. Since the BCS powerhouses discharge to reservoirs or forebays, the peaking operations generally do not cause varying flows in bypass reaches. Energy load changes on these power generation chains will not affect the water surface elevation (WSE) or instream flows, as long as adjustments are made to match reservoir inflows and outflows. A proprietary computer model used for predicting inflow is also used to plan monthly flow of water through the Project to meet the operating constraints on the system while maximizing generation during the peak load periods. In addition, computer programming of load schedules to use the most efficient units first, further enhances these operating activities and improves system integrity and efficiency. These activities can ensure the efficient use and availability of hydroelectric generation resources from these reservoir storage plants.

Market constraints and pricing, as well as transmission constraints and weather, will affect generation and operations at the Big Creek Projects. Often during the spring run-off season there is a financial disadvantage for SCE to generate energy even though to avoid generation would cause spill to occur. A simplified description of the California energy market describes the Independent System Operator (ISO) as having the role of balancing energy demand and supply in the state. The ISO takes the energy demand forecast, the transmission system constraints, and the energy that is bid into the day-ahead market to determine the acceptable energy supply. The ISO then adjusts the supply load on a real-time basis to account for changing conditions. If the ISO believes that there is a surplus of energy available beyond that necessary to supply the grid, prices in the California energy market for additional energy could be negative. This situation would require SCE to pay for contributing additional energy.

<u>Water Management for Big Creek Nos. 2A, 8, and Eastwood Project (FERC Project No. 67)</u>

The Big Creek Nos. 2A, 8 and Eastwood Project covers the largest geographical area of all seven projects in the BCS. The Project includes: (1) Florence Lake, and a number of small diversions in the high elevation backcountry or upper basin area; (2) Shaver Lake, located on Stevenson Creek; (3) Eastwood Power Station (EPS), which discharges to Shaver Lake; (4) Powerhouses 2A and 8, located along Big Creek. Powerhouses 2A and 8 and the EPS may be operated locally from the control rooms at each powerhouse or remotely from Big Creek Powerhouse No. 3 (FERC Project No. 120), which serves as the main control center for the entire BCS.

The flow of water through the Powerhouse Nos. 2A, 8 and EPS Project is dependent on natural run-off during periods of snowmelt and wet weather and the operation of other components of the BCS that are located at a higher elevation within the drainage. The Powerhouse Nos. 2A, 8 and EPS Project operate in tandem with the rest of the BCS in a parallel and stair step sequence of water chains. The EPS and Powerhouse No. 2A are in the Shaver Lake Water Chain and Powerhouse No. 8 is in both the Shaver Lake Water Chain and the Huntington Water Chain. Powerhouse No. 2A receives water from Shaver Lake and discharges to the Dam 5 impoundment on Big Creek. Powerhouse No. 8 utilizes water from the Dam 5 impoundment and discharges to the Dam 6 impoundment on the San Joaquin River. The EPS discharges to Shaver Lake and receives water from Balsam Meadow Forebay, which is filled via the Huntington-Pitman-Shaver Conduit from Huntington Lake or through water pumped back from Shaver Lake. The EPS may operate as a pump storage project in all water year types after the run-off period has ended and SCE gains control of reservoir inflows in the BCS.

The operation of all three powerhouses of Big Creek Nos. 2A and 8 and EPS are similar in all water year types, in that water being diverted into the Project from remote impoundments and diversions is utilized to generate power when the water is available. In wet water years, the Project runs at full capacity beginning in mid April to May until the end of peak run-off, which typically occurs in late July. At that time, SCE gains control of inflows and begins managing powerhouse operations to meet grid requirements by providing both base load and peak cycling energy. Project generation is greater during wet water years and water may be also bypassed around Project powerhouses at Project reservoirs and impoundments, if necessary.

In above normal water years, the Project is generally run at full capacity beginning in May until the end of peak run-off, which typically occurs in July. Some of the BCS reservoirs generally spill in above normal water years and are filled to maximum capacity until spill ceases. At that point, SCE gains control of inflows and begins powerhouse operations to meet grid requirements by providing both base load and peak cycling energy.

During dry water years, the Project may run at full capacity for a short duration in May and June. In some dry water years the Project does not run at full capacity in order to fill the reservoirs to maximum capacity. Project generation is lower in dry water years and very little water, other than dam seepage and required MIF releases, bypasses the powerhouses.

Under the Proposed Action, water management would remain generally the same as existing operations with the exception of the decommissioning of four back-country small diversions including: North Slide Creek Diversion, South Slide Creek Diversion, Tombstone Creek Diversion, and Crater Creek Diversion.

(iii) Coordinate the Operation of the Project with Other Electrical Systems to Minimize the Cost of Production

SCE optimizes the use of the Project to provide maximum generation during run-off and peak demand periods. The entire set of SCE generation facilities is coordinated through the SCE Energy Control Center to maximize generation while minimizing economic and environmental costs. SCE bids power from its retained generation facilities into markets governed by the Independent System Operator (ISO). Thus, electrical generation from the BCS and the four BC ALP Projects is coordinated with other generation throughout California.

(2) Need for the Project

The need for the Project is twofold as: (1) SCE needs the capacity of the Project to supply its customers; and (2) the value of the energy produced by the Project is greater than the costs associated with producing this energy. Continued operation of the Project will reduce the need for SCE to purchase replacement energy and capacity which would be significantly more expensive than the production costs associated with the Project. In addition, the Project contributes to the fuel diversity of SCE's energy supply and is a significant hedge against the potential impacts of the volatile natural gas market.

The environmental value of the Project mainly consists of using a non-polluting renewable fuel resource to displace other forms of generation such as gas-fired energy that creates air pollution as well as depleting non-renewable resources. The Project is, however, too large to be included as an Eligible Renewable form of energy, based on accounting regulations in California, and thus does not assist SCE in meeting the goals of California's Renewable Portfolio Standard (CA Senate Bill 1078).

(i) Costs and Availability of Alternative Sources of Power

SCE is presently unable to supply energy to its entire customer load from SCE-owned generation resources for all hours.

Load management is not currently an option to replace the Projects, as it might be able to supply capacity but cannot supply the amount of energy that these large hydroelectric facilities produce. Energy efficiency is not a viable option, in place of these facilities, because SCE is already planning on utilizing all of the available cost-effective energy efficiency programs. SCE was encouraged to, and eventually did, divest of all of its natural gas generation facilities when the California market deregulation occurred in early 1998, therefore SCE does not have any deactivated or retired plants that can be restarted to replace this capacity and energy.

SCE must therefore purchase its unmet capacity and energy requirements from the existing market. Since SCE does not currently have the necessary resources nor do we plan to develop sufficient resources to meet all our energy obligations, SCE would likely purchase "net short" customer load requirements from the market, either through bilateral transactions or through spot market purchases. It is estimated that the cost of replacement power would be approximately $88.8 million per year in 2006($) and this cost would escalate in future years. This energy is expected to be readily.

(ii) Increase in Fuel, Capital, and Other Costs

If this Project was not licensed, the replacement power could not be generated by SCE, but would be purchased from the market as discussed above. SCE would incur the costs associated with purchasing the replacement power for its customers. If firm energy contracts are purchased, the expected cost of those contracts is the same as above at approximately $88.8 million per year in 2006($) and escalating thereafter.

If contracts are structured as tolling arrangements, where SCE provides the natural gas for a generator, SCE may be required to purchase the natural gas necessary for the contracted generator to produce this energy. It is estimated that the cost to purchase the gas and replace the energy provided by the Projects would total $89.3 million. This assumes an average of 10,000 Btu/kWh heat rate for replacement energy and the gas price is based on a five-day average of NYMEX natural gas forward prices (as of December 20, 2006) plus a Southern California Gas Company transportation charge. Costs associated with the Projects not obtaining a new license would include the cost of obtaining contracts to replace the energy and capacity provided by the Projects. There may also be some additional costs in purchasing ancillary services (such as spinning reserve) if these hydro resources cannot be used for those purposes. No estimate of those costs has been provided in this filing.

(iii) Effect of Alternative Sources of Power

The Project provides a stabilizing low-cost base of generation with high reliability and, with a dependable operating capacity of 370.0 MW (98.5 MW, 64.5 MW, and 207 MW for Big Creek 2A, Big Creek 8, and Eastwood, respectively), accounts for approximately 37% of the total hydroelectric capacity for SCE's Northern Hydroelectric Division. If a new license is not granted, it will have a significant impact on SCE's total hydroelectric energy capability.

(A) The Project provides lower cost energy to SCE's customers than the cost of replacement energy. This cost savings is not specifically assigned to any one class of customers, including wholesale customers. System generation serves all customers through a diverse transmission system and with a generation mix based on many different resources such as gas, coal, nuclear, hydroelectric, and purchases from other utilities or non-utility power producers. If the resources mix shifts from low cost resources such as hydroelectric generation to higher cost resources such as gas-fired generation, the cost to all customers will increase. Without a new Project license, some of this resource shifting would occur.

(B) The generation and load projections for 2010 show that SCE hydroelectric generation will represent 6% of the supply of Utility-Retained Generation, which will enable SCE to meet approximately 5% of its load requirements. See Exhibit H(a)(3)(ii) for more detail.

(C) The Project is located near the communities of Huntington Lake and Big Creek. However, electrical service to these communities relies more on the local power grid in the area than the generation produced by the Project. The service area for power generated by the Project is predominantly the Los Angeles Basin and a portion of the central San Joaquin Valley. SCE would need to purchase replacement power from alternative power sources if a new license is not granted. Replacement power would need to be purchased from the power grid market, which would increase energy costs to SCE customers.

The costs associated with transfer of the license would be the same as the severance value described in Exhibit D(2)(iii).

(3) Need, Cost, and Availability of Alternative Sources of Power

The power produced by the Project cannot be replaced by an alternative source at a lower cost. Following the divestiture of the SCE gas-fired plants, it became necessary for SCE to purchase power during on-peak periods. Changing to an alternative source of power would increase purchased power at a higher cost than continuing operation of the Project.

(i) Average Annual Cost of Power Produced by the Project

The Project has an installed capacity of 384.80 MW and the dependable operating capacity is 370.0 MW. Table H(a)-1 presents the Project's recorded annual generation output for 15 years (1991-2005). The lowest year of generation production in the 15-year period occurred in 1992 at 631,219 MWh and the highest occurred in 1995 at 1,748,666 MWh. The average production for the 15 year period was 1,173,296 MWh.

The Project's Net Investment as of December 31, 2005 was $219,234,229 and the direct O&M expenses for this Project are $9,272,458, which is an annualized value for the life of the license. Additional Project operating expenses and capital costs are discussed in Section D(4).

Table H(a)-1 Average Project Generation Output Between 1991-2005.

Year	Production in MWH (Transmitted)			
	PH No. 2A	PH No. 8	Eastwood Powerstation	Project Total
1991	300,086	201,793	182,293	684,172
1992	332,007	185,154	114,058	631,219
1993	678,695	423,044	473,826	1,575,566
1994	404,181	227,572	271,296	903,049
1995	752,803	455,504	540,359	1,748,666
1996	644,429	378,440	487,960	1,510,828
1997	582,998	395,435	511,038	1,489,471
1998	657,541	407,609	466,379	1,531,,528
1999	520,220	299,059	329,000	1,148,279
2000	513,902	305,685	325,270	1,144,857
2001	280,088	175,005	280,924	736,017
2002	425,339	241,027	302,860	969,226
2003	494,390	279,641	362,892	1,136,923
2004	401,920	237,681	255,814	895,415
2005	680,751	372,308	441,159	1,494,218
15-Year Average:	**511,290**	**305,664**	**356,342**	**1,173,296**

(ii) <u>The Project Resources Required by SCE to Meet Capacity and Energy Requirements</u>

(A) *Energy & Capacity Resources as Separate Components of Total Resources Required*

SCE currently does not own or operate enough generation to meet all of its future projected load and energy obligations. Table H(a)-2 projects the amount of energy expected from the Utility Retained Generation (URG) in the years 2010 and 2015. This table also gives an estimate of how much of SCE's future energy needs, load in the SCE service territory will remain assuming that the Direct Access constant beyond 2006, will be met by the URG resources. Demand-side management (i.e., conservation and energy efficiency) expectations are built into the table's Load forecast.

Table H(a)-2: Expected Utility Retained Generation (URG) in 2010 and 2015

Generation Source	2010 GWH	2010 % Supply	2010 % Load	2015 GWH	2015 % Supply	2015 % Load
Utility-controlled Resources						
Nuclear	15,527	20%	18%	16,902	29%	18%
Hydro	4,775	6%	5%	4,687	8%	5%
Fossil	10,101	13%	11%	10,816	19%	11%
Must-take DWR	19,946	26%	23%	0	0%	0%
Qualifying Facility Contracts	23,581	31%	27%	23,208	40%	24%
Existing Renewable Contracts	2,438	3%	3%	2,434	4%	3%
Total URG*	76,368	100%	87%	58,047	100%	60%

Source: 2005 IEPR Alternative Case, Public Version of Form S-2, filed in CEC by SCE on April 1, 2005.
* URG less interutility contracts (i.e., Hoover, etc.)

(B) *Resource Analysis and System Reserve Margins*

The California Independent System Operator (Cal ISO) is responsible for maintaining statewide system operating reserve margins that meet the WECC required operating reserve margin requirements. The Cal ISO attempts to maintain an operating reserve of about 7%, with 3.5% as spinning reserve and 3.5% as non-spinning reserve. For a breakdown of utility-owned generation, see the above table. In addition to operating reserves, SCE will be required to provide the CAISO with documentation related to meeting the state Resource Adequacy or planning reserve margins. This Project can, and will, count towards meeting these planning reserve requirements.

(C) *Effects of Efficiency and Load Management Plans*

SCE has developed comprehensive efficiency and load reduction plans that will encourage electrical customers to decrease their load, especially during peak periods. Reference Exhibit H(a)(11).

SCE is committed to the continued development of cost effective energy efficiency and load management programs that will help the utility provide uninterrupted service to its customers. The 2005 SCE energy efficiency programs achieved over 1,372,000 MWh of net annualized energy savings and a net demand reduction of 265.2 MW.

(iii) Cost and Merits of Project Alternatives

As previously discussed in Exhibit H(a)(2)(i), SCE has very limited options regarding alternative sources of power. At the current time, the only feasible alternative is receiving energy from the wholesale energy market.

(A) *Annual Costs for Alternative Sources of Power*

The cost of replacement power in 2007 is $88.8 million per year (nominal dollars). See discussion above in Exhibit H(a)(2)(i).

(B) *Basis for Determination of Projected Annual Cost*

The projected annual cost of alternative power is determined by estimating the cost of replacing the power provided by the Project at SCE's forecast of its avoided cost of energy and capacity. As previously noted the number of MWh's needed for replacement was derived from a 15-year annual historical average. This average was then multiplied by the avoided cost of energy and capacity as forecasted by SCE in its 2006 General Rate Case (GRC) filing. Since this forecast is not available past 2008, it is assumed that the avoided cost will increase at a level consistent with other escalation assumptions as discussed above. See also Exhibit H(a)(3)(i).

(C) *Relative Merits of Each Alternative*

Forward purchases of energy are likely to be characterized by market forces. Their availability is subject to the terms and conditions specified in contracts as well as forces at work in the marketplace. The Project's availability is limited by the amount of water available to be diverted and/or stored upstream of the Project, which is governed by the precipitation available in any given year.

(iv) <u>The Effect on the Direct Providers of Alternative Sources of Energy</u>

Relicensing of the Project would have a negative effect on suppliers of alternative sources of power. It would reduce the amount of purchases made by SCE and increase the total supply of generation in the market, thus likely causing power prices to decrease.

In addition, SCE has long and short-term contracts with both public and private utilities. Generally, when utilities have different peak seasons they can exchange energy and capacity on a seasonal basis for each other's benefit. There would be minor effect to the other utilities from utilizing alternate sources of power as the overall average cost for exchange energy would increase which would create less opportunity to make exchanges.

(4) <u>Effect on Industrial Facilities</u>

The Project does not connect or otherwise provide direct electricity to any of SCE's facilities.

(5) Tribal Need for the Project on a Reservation

Applicant is not an Indian tribe nor is the Project on a Tribal reservation.

(6) Comparison of Impact on Operations and Planning of Transmission System With and Without License Renewal

(i)

Transmission and distribution lines and the associated equipment that deliver power from FERC Project No. 67 are part of SCE's transmission and distribution system and are not included in the FERC license for the Project. The Project and other hydroelectric plants in the area dependably deliver a collective total of 1,000 MW of power to serve approximately 1.2 million customers in the San Joaquin Valley and the Los Angeles basin. Removal of the 370 MW of Project generation would result in SCE's inability to adequately serve its customers in the San Joaquin Valley and Los Angeles basin areas during high load conditions. Insufficient transmission capability south of the San Joaquin Valley, and, in particular, south of the Rector Substation limits SCE's ability to import power into the region. Additional capacity would be necessary to import power to serve the San Joaquin Valley. As a result, significant transmission upgrades, in the form of new 230 kV or 500 kV transmission lines, would be necessary if the Project generation is unavailable. The new transmission lines would need to be connected to the Magunden Substation located 65 miles south of Rector and possibly the Vincent or Pardee Substations located an additional 95 miles south of Magunden, if power were imported from southern California or the southwest. Until such time that the new transmission facilities are constructed, significant involuntary load interruption in violation of established Western Electric Coordinating Council Planning Criteria would be needed during normal and outage conditions when loads are high to ensure remaining transmission facilities do not load beyond the maximum allowable limits.

(ii)

SCE's existing transmission system distributes the Project's power and utilizes the Project's power to serve local substation load. No other distribution or transmission system is currently available to transmit Project power.

(iii)

Customer load demand within the San Joaquin Valley is served by utilizing local area generation resources as well as importing power from the south. The local area generation includes Big Creek Hydro generation resources that collectively add up to over 1,000 MW. FERC Project No. 67 generation resources accounts for 370 MW of this total generation. Power from the south is imported into the San Joaquin Valley through existing 220 kV transmission facilities that originate at the SCE Vincent (Los Angeles County Acton area) and SCE Pardee (Los Angeles County Santa Clarita area) Substations. These transmission lines connect together at the SCE Magunden Substation (Kern County Bakersfield area). From the Magunden Substation, four 220 kV transmission lines run north towards the Big Creek Hydro Facilities connecting three A-Stations (Springville, Rector, and Vestal 220 kV Substation) along the way that serve the local San Joaquin Valley loads. Collectively, these four lines are limited in capacity to approximately 1,000 MW with all facilities in service and 500 to 800 MW (depending on system conditions) under loss of a single transmission line. A single-line diagram of the Big Creek System is shown in Attachment H(a)-1.

(7) Plans for Modifications

SCE has no plans at this time to modify existing Project facilities or operations to increase generation capacity.

(8) Conformance with Comprehensive Plans

The Project facilities and operations, including mitigation measures proposed in Exhibit E, are best adapted to a comprehensive plan for the San Joaquin River based on a balance between environmental protection, water supply, recreation, and the commerce and utilization of a low-cost, non-polluting source of energy. The Project, as proposed in this Application for New License, takes into account all existing and potential uses of the South Fork of the San Joaquin River, including recreation, economically viable hydroelectric generation, energy conservation in the context of the national interests in non-polluting and non-fossil fuel alternatives, public safety, and various aspects of environmental protection, including the prevention of significant detrimental impacts to fish and wildlife resources.

In addition, identification and review of the potentially relevant comprehensive plans indicate that relicensing of the Project will not conflict with the goals or objectives of any such plans. Accordingly, the Project adopts measures to ensure public safety, protect the environment, provide recreation opportunities, and operate for maximum efficiency and reliability, and thus provide the best possible overall mix of benefits.

(9) Financial and Personnel Resources

SCE's source and extent of financing and annual revenues are sufficient to meet the continuing operation and maintenance needs of the Project. For specific financial information, refer to FERC Form No. 1 which is provided to the Commission annually.

SCE has personnel resources necessary to meet license obligations for the Project. A variety of training resources and approaches are used, including classroom training, workshops, textbooks, on-the-job training, and safety training to all personnel. Safety training is conducted through a combination of regularly scheduled monthly meetings, crew meetings, on-the-job training, and special programs as needed. The training covers SCE's Occupational Safety, Health, and Fire Prevention rules and hazardous materials handling, as well as, programs mandated by governmental agencies such as the California Occupational Safety and Health Division, as well as training related to compliance with Commission license articles, and environmental and cultural protection programs.

Job knowledge and skills training programs are available for management, supervisor/administrative, clerical, and craft employees with apprenticeship training programs established for selected job classifications. Individual training needs are evaluated continually and employees are subsequently scheduled into existing programs offered within SCE or into appropriate outside training programs.

Employees are also encouraged to further their education through the educational assistance program which provides financial assistance for eligible employees who participate in job related courses, correspondence programs, and degree and/or certificate programs sponsored by accredited institutions.

(10) Notification of Expansion to Property Owners

SCE is not proposing to expand the Project to additional lands.

(11) Efficiency Improvement Program

(i) SCE is actively engaged in energy efficiency, conservation and environmentally beneficial programs. Successful program offerings include customer incentives, information and education, surveys and cooperative efforts with third-party contractors and other utilities. Some of the energy efficiency programs include:

Incentives

SCE's incentive programs include non-residential Value and Energy Stream Mapping (VESM) Advantage Plus Program, Small Nonresidential Hard-to-Reach, Express Efficiency, Standard Performance Contract, Savings by Design and the Upstream HVAC Motors Rebates Program.

SCE's residential incentive programs include Single-family Energy Efficiency Rebates, Multifamily Energy Efficiency Rebates and Appliance Recycling Programs.

Information Programs

SCE's non-residential information programs include Non-residential Energy Surveys, Building Operative Certification, and Pump Test & Hydraulic Services. SCE's Home Energy Efficiency Surveys target residential customers. Other information is disseminated to customers at Customers Technology and Applications Center technology center, located in Irwindale, California and SCE's Agricultural Technology Applications Center located in Tulare, California.

Additional information regarding energy efficiency and conservation programs is provided on SCE's website: http://sce.com.

(ii) Regulatory compliance and reporting of SCE's energy efficiency programs is tracked through collection, reporting, and verification of information on the programs' performance. The results of the performance of the programs are filed annually with the California Public Utilities Commission pursuant to Protocols and Procedures for the Verification of costs, benefits and shareholder Earnings from Demand-side Management Programs revised June 1999.

(12) Indian Tribes Affected by Project

The Project does not cross any Native American lands; therefore, no lands owned or reserved on behalf of any Native American tribe or tribal organization are affected by the Project.

SCE conducted consultations with the Native American organizations listed below. This contact list was provided by the Sierra National Forest.

Big Sandy Rancheria*
P.O. Box 337
Auberry, CA 93602

Cold Springs Rancheria*
P.O. Box 209
Tollhouse, CA 93667

North Fork Rancheria*
P.O. Box 929
North Fork, CA 93643

Dunlap Band of Mono Indians
P.O. Box 344
Dunlap, CA 93621

Picayune Rancheria*
46575 Road 417
Coarsegold, CA 93614

Table Mountain Rancheria*
23736 Sky Harbor Road
P.O. Box 410
Friant, CA 93626

Mono Nation
P.O. Box 800
North Fork, CA 93643

North Fork Mono Tribe
13396 Tollhouse Road
Clovis, CA 93611

Sierra Nevada Native American Coalition
P.O. Box 125
Dunlap, CA 93621

Bishop Tribal Council
50 Tu Su Lane
Bishop, CA 93514

Sierra Mono Museum
33103 Road 288
North Fork, CA 93643

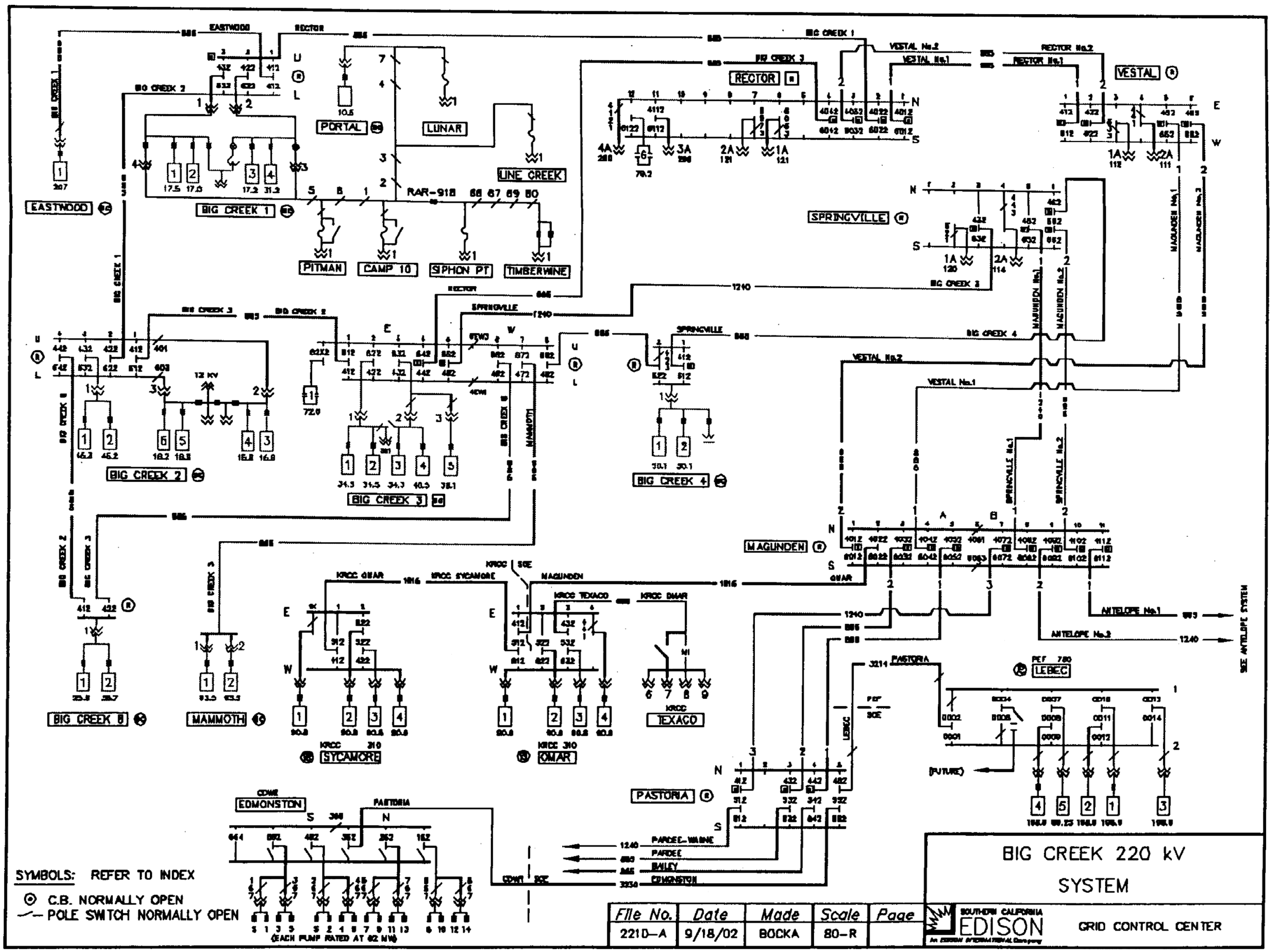
Native Earth Foundation
34329 Shaver Springs Road
Auberry, CA 93602

Michahai Wuksachi
1174 Rockhaven Ct
Salinas, CA 93906

*Federally recognized tribal organization

ATTACHMENT H(a)-1

Single Line Diagram


EASTWOOD
BIG CREEK 1
PORTAL
LUNAR
LINE CREEK
RAR-918
PITMAN
CAMP 10
SIPHON PT
TIMBERWINE
RECTOR
VESTAL
SPRINGVILLE
BIG CREEK 2
BIG CREEK 3
BIG CREEK 4
BIG CREEK 8
MAMMOTH
SYCAMORE
OMAR
TEXACO
MAGUNDEN
LEBEC
PASTORIA
EDMONSTON
SEE ANTELOPE SYSTEM
SYMBOLS: REFER TO INDEX
C.B. NORMALLY OPEN
POLE SWITCH NORMALLY OPEN
(EACH PUMP RATED AT 82 MW)
BIG CREEK 220 kV
SYSTEM
File No.
Date
Made
Scale
Page
221D-A
9/18/02
BOCKA
80-R
SOUTHERN CALIFORNIA
EDISON
GRID CONTROL CENTER

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 2A, 8 AND EASTWOOD
(FERC Project No. 67)

EXHIBIT H(B) GENERAL INFORMATION

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit H(b) General Information

Exhibit H(b) is information to be provided by an applicant who is an existing licensee. An existing licensee that applies for a new license must provide the information as specified in 18 CFR § 16.10(b):

(1) The information specified in H(a).

(2) A statement of measures taken or planned by the licensee to ensure safe management, operation, and maintenance of the project, including:

- (i) A description of existing and planned operation of the project during flood conditions;
- (ii) A discussion of any warning devices used to ensure downstream public safety;
- (iii) A discussion of any proposed changes to the operation of the project or downstream development that might affect the existing Emergency Action Plan, as described in subpart C of part 12 of this chapter, on file with the Commission;
- (iv) A description of existing and planned monitoring devices to detect structural movement or stress, seepage, uplift, equipment failure, or water conduit failure, including a description of the maintenance and monitoring programs used or planned in conjunction with the devices; and
- (v) A discussion of the project's employee safety and public safety record, including the number of lost-time accidents involving employees and the record of injury or death to the public within the project boundary.

(3) A description of the current operation of the project, including any constraints that might affect the manner in which the project is operated.

(4) A discussion of the history of the project and record of programs to upgrade the operation and maintenance of the project.

(5) A summary of any generation lost at the project over the last five years because of unscheduled outages, including the cause, duration, and corrective action taken.

> (6) A discussion of the licensee’s record of compliance with the terms and conditions of the existing license, including a list of all incidents of noncompliance, their disposition, and any documentation relating to each incident.
>
> (7) A discussion of any actions taken by the existing licensee related to the project which affect the public.
>
> (8) A summary of the ownership and operating expenses that would be reduced if the project license were transferred from the existing licensee.
>
> (9) A statement of annual fees paid under Part I of the Federal Power Act for the use of any Federal or Indian lands included within the project boundary.

(1) Information Specified in H(a)

See Exhibit H(a).

(2) Safety Measures

(i) Operation of the Big Creek Powerhouse Nos. 2A, 8 and Eastwood Power Station Project

The Big Creek Powerhouse Nos. 2A, 8 and Eastwood Powerstation Project can be controlled either locally, at each powerhouse, or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120). The local controls for Big Creek Powerhouse No. 2A are located in Powerhouse No. 2 (FERC Project No. 2175). The Eastwood Powerstation can also be remotely controlled from Big Creek Powerhouse No. 1 (FERC Project No. 2175).

A Station Order Binder is maintained at each of the Project powerhouses. This document includes individual site specific plans (Station Orders) outlining actions and considerations for high water flow events at each station and/or its associated head and tail works. The Station Orders provide for contingency planning and response to both planned and unplanned project high water flow events. This includes the potential for a single event or, when considered in aggregate, for multiple Powerhouse high water and/or flooding circumstances.

During periods of high flow, various measures are implemented to prevent water damage to infrastructure and equipment. A description of these measures for each powerhouse is provided below.

Big Creek Powerhouse No. 2A/Dam 5

The activities conducted during periods of high flow include the following:

- Monitoring the intake to Big Creek No. 8 to ensure that conditions are within the allowable differential of 5 feet;
- Monitoring the conditions at Dam 5 and pulling flashboards, as necessary, to remove trash, divert debris away from the Big Creek Powerhouse No. 8 intake, or maintain stage within the maximum spill limit of 2 feet;
- Monitoring the flow through the bearings and U-Fin tubes for plugging; and
- Monitoring the basement of Powerhouse 2A for leaks.

Big Creek Powerhouse No. 8

A condition known as spill discharge occurs when all available generation is dispatched at the Big Creek System through the Huntington, Shaver and Mammoth Pool generation chains. In spill discharge, the amount of water discharged from the upstream powerhouses exceeds the intake capacity of the downstream powerhouses, causing spill at Dam 6. During periods of spill discharge, the normal maximum loading of Unit No. 1 is increased from 480 cfs to 493 cfs and the maximum loading of Unit No. 2 is increased to 10.0 point gate opening. In addition, the Unit No. 2 station service generator is placed on the Stevenson 12 kV line at wide open load (approximately 200 kW) and the station cooling water is placed on emergency supply.

Eastwood Powerstation

The Eastwood Powerstation is situated underground, and the primary flood concern is associated with a break in a water pipe or conduit such as the high pressure penstock or the tailrace tunnel. If a break occurs on the penstock side, the controlling station or on-site supervisor sounds an alarm, trips the unit, and initiates the Gate No. 4 closing sequence. If a break occurs on the tailrace side, the controlling station or on-site supervisor sounds an alarm, trips the unit, verifies that the main sump discharge valve to Shaver Lake is open and the tie line valve is closed, initiates the Gate No. 5 closing sequence, and closes the draft tube.

The entire “Big Creek Hydroelectric System,” is operated together in a coordinated manner to maximize the hydroelectric power produced from the available water supply and to augment the operation of the federally operated Millerton Reservoir (downstream) as appropriate.

A safety/security assessment was completed for the Big Creek Powerhouse Nos. 2A, 8 and Eastwood Powerstation Project in 2003 and a critical asset vulnerability assessment was completed in 2004. Both of these assessments were updated in April 2006. Security devices have been installed to protect the Project from acts of terrorism, and the Emergency Action Plan (EAP) for each powerhouse includes response measures for emergencies related to both natural causes and acts of terrorism. A copy of the EAP is maintained at each of the Project powerhouses and at the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

(ii) Downstream Public Safety

If a potentially hazardous condition exists or dam failure is imminent, the EAP is implemented and operations personnel and the SCE Energy Control Center are contacted. The situation is communicated by Control Center personnel to SCE Hydro Generation Division Management, Pacific Gas & Electric, the U.S. Bureau of Reclamation, the California Office of Emergency Services, the California Highway Patrol, and the Fresno and Madera County Sheriffs' Departments. SCE Hydro Division management immediately notifies FERC and the California Division of Safety of Dams (DSOD). The emergency command center is immediately established at the Northern Hydro Region Office at Big Creek by SCE personnel to coordinate communications and actions of SCE personnel and each involved agency. At each step of the communications network, an assessment is made to determine whether the emergency situation requires immediate action, and who is responsible for taking such action.

(iii) Changes Affecting the Emergency Action Plan

Copies of the EAP for each powerhouse are kept at Big Creek Powerhouse Nos. 2A, 8 and Eastwood Powerstation and at the non-Project Big Creek Control Center (FERC Project No. 120). The EAPs for each of the Project powerhouses are reviewed and updated annually. SCE has no current plans to change the operation of the project or any plans for downstream development that might affect the existing Emergency Action Plans.

(iv) Monitoring Devices

Pressures near the bottom of the penstocks at each powerhouse are continuously monitored. If the pressure in the penstocks drops below a preset level from the normal operation pressure, an alarm is activated at the Big Creek Control Center at Powerhouse No. 3. The operator would acknowledge the alarm and review other system parameters such as a drop in generation or unit flow, and after evaluating the system, make a decision on whether to shut the water conveyance system down.

Water levels in the Project reservoirs and impoundments are continuously monitored by level sensors. These sensors determine whether dam failure has occurred. If water levels drop at rates faster than preset levels, an alarm is activated at the Big Creek Control Center at Powerhouse No. 3.

The Project is not staffed, although the project powerhouses and dams are visited weekly by operations personnel. All Project facilities are inspected by SCE personnel at least once a year. The California Department of Water Resources, DSOD and FERC inspect the Project on an annual basis.

The Project dams (Dam 5, Shaver Lake Dam, Florence Lake Dam, and Balsam Meadow Dam) are inspected after significant seismic events. SCE inspects any dam that is within 50 miles of an event of magnitude 5.0 or greater.

A description of the monitoring equipment associated with Shaver Lake Dam, Florence Lake Dam, and Balsam Meadow Dam is provided below. No instrumentation has been installed at Dam 5 and, as indicated in the *Eighth Five-Year Safety Inspection* dated April 2002, no significant deficiencies have been noted in the performance of the dam, so instrumentation is not considered necessary. The water level within the Dam 5 impoundment is monitored by a continuous water stage recorder and the impoundment is equipped with a rapid drawdown alarm that notifies the Big Creek Control Center if greater than the normal limits of drawdown occur.

Shaver Lake Dam

An instrumentation and monitoring system at Shaver Lake Dam was established to address concerns with dam alignment and reducing pore pressures in the foundation. The monitoring program includes regular visual inspections, deflection surveys, seepage flow, relief hole and piezometer readings, and operation of the pressure relief system.

A. Seepage/Pore Pressure

Seepage at the dam is measured in the drainage and inspection galleries by four V-notch weirs. The weirs are located at the toe of the right side of the dam and the lower drainage gallery. There are six additional toe drain leakage collection locations on the outside of the dam. Four are on the right side of the dam and two are on the left side of the dam. These leakage points collect water leaking from the groin sections on both sides of the dam. There are also 17 pipe leakage points at various station locations along the toe of the dam. The seepage is measured on a monthly basis.

Pore pressure within the underlying foundation of the dam is monitored using four piezometers. Piezometer measurements are collected on an annual basis.

Pore pressure in the foundation is also monitored by measuring water levels in relief holes that extend from the inspection gallery floor down into the rock foundation. These measurements are collected on an annual basis.

B. Dam Deflection

Deflection of the dam is monitored using 7 points located along the dam. These points are surveyed and collected on an annual basis.

C. Pressure Relief System

The pressure relief system within the dam is placed into operation when the lake level reaches elevation 5,352 feet and is kept in continuous operation whenever the water level exceeds this elevation. If vacuum in the system is lost, an alarm sounds in the Big Creek Control Center near Big Creek Powerhouse No. 3.

D. Seismic Monitoring System

A Kinemetrics K2 strong-motion recorder is located in the gatehouse for the Powerhouse 2A Tunnel, adjacent to the dam. The instrument triggers at 0.005g and digitally records the earthquake motion. After actuation, the data can be downloaded and interpreted to assess time histories and response spectra of the event.

E. Shaver Lake Water Levels

The water levels in Shaver Lake are continuously monitored at the non-Project Big Creek No. 3 Control Center (FERC Project No. 120) via telemetry.

Florence Lake Dam

A. Seepage

Seepage at various arches is measured and reported as cumulative flow. SCE has divided the leakage into three separate areas: 1) the “Frog Pond,” 2) the “Ridge,” and, 3) the “River.” The leakage data is collected on an annual basis at or near the peak reservoir storage level, which usually occurs in the month of July.

B. Seismic Monitoring System

A Kinemetrics K2 strong-motion recorder is located in the Gate House for the Ward Tunnel. When a triggering event occurs, the K2 records data into its local memory. The recorder can be set up for data transfer via phone line, radio, or satellite link; however, the data is currently downloaded onsite directly from the instrument.

C. Florence Lake Water Levels

Water levels in Florence Lake are continuously monitored using a water stage recorder that transmits the data to the Big Creek No. 3 Control Center.

Balsam Meadow Dam

A. Seepage

Seepage at the dam is measured at three 90-degree V-notch weirs that are located near the low level outlet gatehouse at the downstream toe of the dam. The weirs are located at the maximum section (toe weir), the Right Bank Spring, and the Left Bank. The current seepage monitoring system was installed in 1994. Combined leakage and minimum discharge are measured by a fourth 90-degree V-notch weir (the main weir), which is located downstream of the valve house. Flow through the main weir includes release water for minimum flow that is discharged by the low-level outlet. Seepage measurements are collected on an annual basis.

Groundwater conditions at the dam are monitored using three piezometers. The piezometers are located at approximately stations 15+00, 16+40, and 18+60, near the upstream toe of the dam. Piezometer measurements are collected on an annual basis.

B. Settlement and Alignment Surveys

A total of 48 survey monuments are present at the dam, but only 33 of these monuments are monitored regularly, since many of the upstream points are submerged much of the time. The monuments are located on three horizontal tiers on the upstream face, along the parapet wall, and on two horizontal tiers on the downstream slope of the dam. The monuments are surveyed annually.

In addition, settlement is monitored using two horizontal inclinometers that are located at station 16+50 (the maximum section of the dam), at elevation 6,600 feet and 6,635 feet. Inclinometer measurements are collected on an annual basis.

C. Dam Failure

The dam includes a failure warning system which consists of a wire across the length of the parapet wall at the dam. If electrical continuity across the wire is broken, an alarm is sounded at the Big Creek Control Center.

(v) Employee and Public Safety

Two lost-time industrial accidents have been recorded at this Project in the last ten years. These accidents consist of the following:

- May 17, 1999 - Carpal Tunnel Syndrome.
- November 18, 2005 – Broken Ribs

In the past 10 years, three public deaths and two serious injuries were recorded within the Project boundary. These incidents consisted of the following: (1) a two-victim drowning at the Jackass Meadows Campground on July 5, 1997; (2) an injury accident at Shaver Lake on July 14, 2003; (3) an injury accident at Shaver Lake on July 26, 2003; and (4) a fatal accident at the Balsam Snow Park on August 18, 2003. A Public Safety Plan on file with the FERC identifies all public safety devices installed at the Project.

(3) Project Operation and Constraints

The commencement of commercial operation for the Project powerhouses occurred on the following dates:

- Powerhouse No. 8, Unit No. 1, commenced operation on August 16, 1921, and Unit No. 2 commenced operation on June 8, 1929.
- Powerhouse No. 2A, Unit No. 1, commenced operation on August 6, 1928, and Unit No. 2 on December 21, 1928.
- The Eastwood Power Station commenced operation on December 1, 1987.

The individual ratings for the turbines and generators associated with each powerhouse are provided in Exhibit A, Section (3).

The Big Creek Powerhouse Nos. 2A, 8 and Eastwood Powerstation Project can be controlled either locally at each powerhouse or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120). The local controls for Big Creek Powerhouse No. 2A are located in Powerhouse No. 2 (FERC Project No. 2175). The Eastwood Power Station can also be remotely controlled from non-Project Big Creek Powerhouse No. 1 (FERC Project No. 120).

The Project reservoirs operate as follows:

- The Dam 5 reservoir serves as a forebay for Big Creek Powerhouse No. 8, and power generation is primarily run-of-the-river with only limited drawdown being utilized.
- Shaver Lake is normally operated between elevation 5,340 feet and 5,370 feet.
- Florence Lake is filled to the extent possible during the spring and summer and is drained in the fall and winter.
- The Balsam Meadow Forebay typically operates between the minimum pool level at elevation 6,630 feet and the maximum normal pool level at elevation 6,669.9 feet. Under normal conditions, the maximum forebay operating level is approximately 6,655 feet.

Project operation and constraints are discussed further in Exhibit B, Section (1).

(4) Project History and Upgrades

(i) The Project was constructed between 1920 and 1987 as follows:

- Ward Tunnel was constructed between November 1920 and April 1925.
- Powerhouse No. 8 was constructed between January and August 1921 and Unit 2 of Powerhouse No. 8 was installed in 1929.
- Florence Lake Dam was constructed between the Spring of 1925 and August 1926.
- The Huntington-Pitman-Shaver Conduit was constructed between November 1925 and April 1928.
- Shaver Lake Dam was constructed between Spring 1926 and October 1927.
- The Mono Diversion, Bear Diversion, and the Mono-Bear Siphon were constructed between July 1926 and November 1927.
- Powerhouse No. 2A was constructed between Fall 1926 and August 1928.
- The Pitman Creek Diversion was originally constructed between 1925 to 1928. The diversion was upgraded in 2001.
- The Crater Creek Diversion was constructed in 1944.
- The Bolsillo Creek Diversion was constructed in 1945.
- The Tombstone Creek Diversion was constructed in 1945.
- The North and South Slide Creek Diversions were constructed in 1945.

- The Hooper Creek Diversion was constructed in 1945.
- The Camp 62 Creek Diversion was originally constructed in 1948 and was modified to a slanted shaft diversion in 2001.
- The Chinquapin Creek Diversion was originally constructed in 1948 and was rebuilt in 2001.
- The Balsam Meadows Project, including the Eastwood Power Station, was constructed between November 1983 and November 1987.

A discussion of the Project upgrades and modifications since start-up is provided in Exhibit C, Section 1(iii).

(5) Unscheduled Outages

Five years of unscheduled (forced) outages, 2000 to 2005 inclusive, are listed below in Table H(b)-1:

(6) Record of Compliance

See Table H(b)-2.

(7) Actions Related to the Project Which Affect the Public

In the event of an emergency, SCE personnel, through the U.S. Forest Service and the California Highway Patrol, notify the public and the Sheriff's Office. Public safety devices (e.g., fences, locked gates, signs, grab lines, sirens) are installed where necessary to protect the public.

(8) Summary of Ownership and Operating Expenses

If the Project license were transferred, ownership and operating costs that would be reduced include:

Operation and Maintenance Costs	
(Annualized over License life)	$ 9,272,458
Depreciation (2005)	6,965,129
Property Taxes (2005)	2,386,974
A&G Expenses	
(Calculated from 2005 Net Invest)	$ 2,740,428
Total	$ 21,364,989

(9) Annual Fees

The annual fees for FERC Bill Year 2005, paid under part I of the Federal Power Act, are as follows:

Water for Power	$ 795,523
Federal Land Rents	173,275
Total	$ 968,798

Water for Power – charges for the purpose of reimbursing the United States for the costs of the administration of Part I of the Federal Power Act.

Federal Land Rents – annual fees paid for the occupancy of federal lands for reservoirs, dams, flumes, forebays, penstocks, and powerhouses.

Table H(b)-1. Unscheduled Outages - 2000 to 2005.

PH No.	Unit	Date/Time	Hours Off	Reason	Corrective Action
EPS	1	4/14/00 18:30	3.3	Faulty draft tube gate indication.	Repaired indication.
BC8	1	5/4/00 10:45	1.2	Broken shear pin.	Replaced shear pin.
EPS	1	5/14/00 10:00	2.0	Synchronizer failed.	Repaired synchronizer.
EPS	1	6/2/00 3:38	2.2	TSO valve down stream seal control valve failed.	Exercised valve.
EPS	1	6/3/00 3:45	2.2	TSO valve downstream valve failed	Exercised valve.
EPS	1	6/6/00 7:42	2.0	LCB relay blocking switch failed	Revision to switch engineered.
EPS	1	6/17/00 9:48	1.0	Speeder set too low.	Adjusted speeder.
BC8	1	7/9/00 15:04	9.1	Rodent in No.2 generator bus.	Cleaned generator bus and returned unit to service after meggar.
BC8	2	7/9/00 15:04	98.8	Rodent in generator bus.	Replaced generator PT's and cleaned generator bus.
EPS	1	8/9/00 18:19	18.5	Excitation cabinet fan failed	Installed temp. cooling
EPS	1	8/22/00 11:46	0.8	Unit relayed due to work on Ovation system.	Returned Ovation to normal.
EPS	1	9/3/00 14:03	0.9	Synchronizer failed	Repaired synchronizer.
EPS	1	9/16/00 1:00	15.0	Failed excitation auxiliary relay	Replaced relay.
EPS	1	11/27/00 9:20	7.9	Generator CB air leak.	Repaired leak
EPS	1	3/5/01 15:47	0.4	Ovation control system problem	Reset Ovation.
EPS	1	4/8/01 15:55	1.3	TSO valve seal failed to operate	Repaired operating seal water supply.
EPS	1	4/11/01 15:23	0.6	Control sequence failed.	Reset controller
BC8	1	7/13/01 4:28	13.5	Unit relayed on bus differential due to mouse in bus.	Removed mouse and inspected bus.
BC8	1	8/12/01 20:02	12.6	Loss of cooling water supply, hot bearings.	Reestablished cooling water, checked bearing operation temps..
BC8	2	8/12/01 20:08	1.9	Loss of cooling water supply.	Reestablished cooling water supply.
EPS	1	9/28/01 14:14	26.2	Failed voltage regulator firing control board.	Replaced board.
EPS	1	11/8/01 17:00	1.3	Computer logic failed	Reset logic
EPS	1	11/26/01 16:30	77.9	Gate limit indication failed, incorrect pump shutdown smoked unit brakes.	Checked indication and revised control logic against possible future.
EPS	1	2/6/02 17:17	3.6	Failed gate limit transducer.	Repaired transducer.
EPS	1	2/7/02 2:47	14.6	Failed gate limit transducer.	Repaired transducer.
EPS	1	2/8/02 19:10	3.9	Gate limit indication bad.	Adjusted span on gate limit indication.
EPS	1	3/19/02 8:40	29.0	Gov. oil pump failure.	Repaired pump unloader valve.
BC2A	1	5/6/02 22:23	16.2	Erratic governor operation.	Adjusted governor.

Table H(b)-1. Unscheduled Outages - 2000 to 2005 (continued).

PH No.	Unit	Date/Time	Hours Off	Reason	Corrective Action
EPS	1	5/26/02 15:40	1.3	TSO downstream seal not working.	Cycled seal control.
EPS	1	9/4/02 8:55	3.2	Troubleshoot pony motor.	Repaired motor
EPS	1	10/26/02 18:35	5.7	Gov. oil pump unloader valve failure.	Repaired unloader valve.
EPS	1	10/28/02 17:30	6.6	Failed speed sensing card.	Replaced card
EPS	1	10/29/02 9:28	24.9	Failed speed sensing card.	Replaced card.
BC8	1	11/11/02 20:43	5.9	Rodent in jack bus.	Removed rodent, tested unit.
BC8	1	6/19/03 3:03	13.4	Unit relayed on stator ground	Mouse in generator bus, removed same.
BC8	1	8/12/03 17:23	0.5	Loose slip ring brush.	Removed and replaced brush.
EPS	1	8/22/03 7:43	11.0	Excessive shaft seal leakage.	Adjusted shaft seal.
EPS	1	9/16/03 2:05	1.3	Pump sequence aborted	Reset sequence.
EPS	1	10/6/03 16:55	4.2	Voltage regulator won't control unit voltage.	Repaired voltage regulator control circuit.
BC8	2	3/16/04 13:19	1.9	Broken shear link	Replaced link.
BC2A	2	4/9/04 18:00	73.4	Repair excitation equipment.	Repair equipment and restart
BC8	2	5/5/04 4:05	2.0	Broken wicket gate break link	Replaced link Replaced brushes.
EPS	1	5/10/04 2:15	11.4	Faulty vibration probe	Repaired probe.
EPS	1	5/27/04 1:24	46.3	Pony motor rotor ground fault.	Removed pony motor for repairs.
EPS	1	6/19/04 4:01	15.4	Failed thrust bearing cooling coil.	Removed coil for repair.
EPS	1	7/8/04 1:41	41.2	Pony motor ground.	Removed pony motor for repairs.
BC8	1	7/30/04 9:05	2.7	Bearing temp trip relay failed.	Replaced relay.
EPS	1	8/7/04 4:53	211.1	Wiped thrust bearing.	Replaced bearing.
EPS	1	8/16/04 0:00	140.2	Wiped thrust bearing and repairs beyond original estimate.	Replaced bearing.
BC8	1	9/3/04 17:14	3.0	Tripped on high bearing temp. / c.w. flow.	Recalibrated temp. / flow indication..
BC8	2	9/4/04 6:27	2.5	Indication of high unit vibration.	Repaired indication.
EPS	1	9/30/04 19:03	2.0	Ovation control system problems	Resolved problem, tested control system.
BC8	1	10/7/04 9:19	5.7	Tripped due to human error.	Restarted unit
EPS	1	10/10/04 3:14	1.8	Problem with West draft tube gate position.	Repositioned gate.
EPS	1	11/15/04 0:00	0.3	Ovation control system problem	Resolved problem
BC2A	1	11/16/04 16:01	29.4	Penstock leak	Repacked expansion joint.

Table H(b)-1. Unscheduled Outages - 2000 to 2005 (continued).

PH No.	Unit	Date/Time	Hours Off	Reason	Corrective Action
BC2A	2	11/16/04 16:01	29.3	Penstock leak.	Repacked expansion joint.
BC8	2	01/02/05 19:17	3.5	Broken Wicket Gate Shear Links	Replaced Links
BC2A	1	01/16/05 22:18	9.5	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC2A	2	01/16/05 22:18	10.0	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC8	2	04/16/05 22:17	12.1	Control System Failed	Repaired Control System
BC2A	1	01/17/05 15:51	30.2	Cooling Water System Problems	Repaired Cooling Water System
BC8	2	01/18/05 7:32	11.4	Control System Problems	Repaired Control System
BC2A	2	01/20/05 5:05	9.0	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC2A	1	01/20/05 5:05	9.0	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC2A	2	01/28/05 6:01	1.3	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC2A	1	01/28/05 6:01	1.3	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC2A	2	02/04/05 11:34	1.4	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC2A	1	02/04/05 13:15	1.3	Loss of Temp Cooling Water Supply	Restored Temp Cooling Water Supply
BC8	1	03/04/05 5:15	4.5	Governor Speeder Problems	Adjusted Speeder
BC8	1	05/24/05 23:00	62.1	Broken Draft Tube Piping	Repaired Piping
BC8	2	05/25/05 4:26	36.1	No.1 unit broken draft tube piping flooded plant	Repaired Piping
EPS	1	05/28/05 6:12	9.5	Governor Shut Down Solenoid Valve Problems	Replace Valve
EPS	1	06/16/05 5:55	5.4	Replace P.T. Fuses	Replaced P.T. Fuses
BC8	1	08/03/05 6:33	.2	Moved Stop Logs	Moved Stop Logs
BC8	1	08/08/05 18:45	8.2	Check Vibration	Checked Vibration
BC2A	2	10/06/05 15:32	1.4	Broken High Pressure Grease Fitting	Replaced Fitting
BC8	2	11/13/05 12:17	2.1	Failed Main Guide Bearing Oil Pump Drive Belt	Replaced Belt
EPS	1	12/26/05 6:38	57.1	33kV line problems to Forebay Indication	Line Repaired

Table H(b)-2. Big Creek Hydro License & Permit Deviations (1998-2006).

Location	Description of Incident	Date(s) of Incident(s)	Date Incident(s) Reported (a)	Agency Response	Agency Ruling
2004:					
Pitman Creek Diversion	minimum flow deviation	12/1/04-12/9/04	1/6/05	FERC 2/8/05	Excused
Mono Creek Diversion	minimum flow deviation	5/1/04-5/2/04	5/28/04, 11/1/04	FERC 7/6/04, 12/2/04 CDFG 10/19/04	*Violation of license*
Bear Creek Diversion	minimum flow deviation	5/1/04-5/2/04	5/28/04, 11/1/04	FERC 7/6/04, 12/2/04 CDFG 10/19/04	*Violation of license*
2003:					
Hooper Creek Diversion	minimum flow deviation	8/1/03-8/4/03	9/2/03	FERC 10/9/03	Excused
2002:					
Bolsillo Creek Diversion	interrupted gaging record	'01-'02	11/13/02	FERC 10/16/02 FERC 11/25/02	Excused
2000:					
Camp 62/Chinquapin Diversion	interrupted gaging record	'99-'00	6/15/00, 11/2/00	FERC 9/25/00 FERC 4/2/02	Excused
Bolsillo Creek Diversion	USGS record disqualification	Spring '00	5/3/00, 6/15/00	USGS 3/23/00 FERC 4/4/00 FERC 5/12/00	Excused
Florence Lake	minimum lake deviation	12/26/99-1/17/00	3/27/00	5/10/00	Excused
1999:					
Balsam Forebay	Unauthorized spill	6/19/99	6/19/99	FERC, USFS, CDFG, SWRCB	*Violation of license*
Bear Creek	minimum flow deviation	5/2/99	6/3/99	FERC 10/7/99	Excused
1998:					
Florence Lake	minimum lake deviation	10/20/98-10/22/98	10/15/04	FERC 10/18/04 (ph)	Excused
Bolsillo Creek Diversion	minimum flow deviations	Aug & Sep '98	2/20/98	FERC 5/14/98	Excused
Mono Creek Diversion	minimum flow deviation	3/4/98	3/7/98	FERC 5/14/98	Excused
Big Creek Tunnel 7 (Stevenson Creek)	minimum flow deviation *carry-over from 1997 pending FERC response*	11/9/97, 11/10/97	12/10/97	FERC 3/6/98	Excused

(a) Date of SCE letter, not FERC "filed" date.

