APPENDIX B

DESCRIPTIONS OF THE UTILITY AND HYDROPOWER SYSTEMS

1. UTILITY SYSTEM CHARACTERISTICS

California's utility system has some key characteristics that influence how the restructured industry will operate, and in turn how owners of divested plants might change their operations from those of a large utility owner. The California electricity market has its highest overall loads during the summer air conditioning season, at which time it has large daily load swings created by warm afternoons followed by cool nights.

California's generation resources also are unique. First of all, California is the load center for the western United States. This creates the need for a large amount of imports from neighboring States. However, the physical limitations of the transmission network require that a number of in-State power plants must be running at all times to supplement these imports. As a result, the State's utilities largely import their cheapest power while running expensive plants to maintain system reliability and stability. Second, California has the largest concentration of renewable resources (other than large hydro) in any State, mainly due to a set of qualifying facility (QF) contracts called "Standard Offers" issued in the mid-1980s. In addition, California utilities operate some of the largest hydropower systems in the United States. Large amounts of utility-owned coal-fired power comes from the Rocky Mountain States, and nuclear-powered electricity is generated from both in-State and out-of-State power plants. Most of these resources are "baseloaded" (i.e., run constantly at their maximum output levels whenever available), and have either low operating costs or "must-take"[1] contractual provisions.

The State's electricity demand is expected to grow faster than new power plants will be built for the next several years. From 1990 to 1995, the peak electricity demand in California grew by a total of 2.5 percent[2]. Then between 1995 and 1998, California's growing population and economy caused peak-period electricity demand to increase by more than 6,800 megawatts (MW) or almost 14 percent. The California Energy Commission revised its latest demand forecast from 1998, now showing the State reaching a peak of 51,700 MW in 2000 instead of 2003[3]. Electricity consumption within the three utility distribution companies (UDCs) service territories (Pacific Gas

1 Must-take generation is generation that, for a variety of reasons, must be purchased by the local utility. Generally, reasons are contractual—such as the mandatory purchase by utilities of power produced by qualifying facilities (QFs) under the Public Utilities Regulatory Practices Act (PURPA)—or because of the nature of the power plant, such as nuclear plants that run at full power 24 hours per day because of physical limits that prevent rapid increases or decreases of power levels.

2 California Energy Commission Staff, *2000-2010 Demand Forecast*, P200-00-002, November 1999, Table D-9.

3 CEC, Demand Forecast, p. 25.

and Electric Company, San Diego Gas and Electric Company [SDG&E], and Southern California Edison Company [SCE]) as well as within the Sacramento Municipal Utility District (SMUD), is expected to increase at more than two percent annually between 1998 and 2010.

California's electricity supplies have not kept pace with the increase in demand. The State's power plants are aging. Older plants need to be serviced and repaired more frequently than modern facilities and, as a result, their ability to regularly and reliably produce at their full capacity is reduced. Even with improved maintenance, the reliability of California's fossil-fuel units over the next three years is uncertain, as they will have to be taken out of service to install required oxides of nitrogen (NOx) emission control devices. Under existing regulatory processes and California Independent System Operator- (ISO) determined planning process, the development of new generating and transmission capacity is likely to occur at a slow pace. If current projections are accurate, it may take between five to ten years for California to build sufficient new electric supplies to meet emerging demand.

In addition, California is and will remain heavily reliant on imports from other regions, particularly from the northwest. However, transmission constraints and demand from other western States is increasingly reducing the availability of out-of-State power. Demand in the western United States may have increased by as much as eight percent in the last year alone[4]. As a result, historical levels of imports into California from the south and northwest cannot be relied upon to be available in the future.

Almost 3,000 MW of additional generating capacity has been approved and is under construction, and over 8,000 MW of additional electricity generation within California is in the regulatory pipeline today. However, if all of this new generation is fully available by 2003—which may be an optimistic forecast—the State would still be dependent on uncertain out-of-State imports, even without considering the possibility that some of the older plants will face periodic extended outages. Likewise, although the ISO has approved the construction of approximately $800 million worth of transmission projects, and plans to propose another $200 million of projects, it will take from three to five years to restore the grid to a level that will reasonably serve California's growing demand[5].

Adding further uncertainty to California's electricity supply outlook is mounting evidence that demand for natural gas may remain high for some time, and in some regions additional gas supplies may be difficult to obtain. For example, if all 11,000 MW of proposed new gas-fired plants were built in the State, intrastate natural gas pipeline capacity would have to be doubled to supply their peak use. And, according to the American Gas Association, national supplies of natural gas in

4 Samuel A. Van Vactor , "Power Price Spikes: Aberration or Prophecy?" Economic Insight, Inc. and University of Cambridge, Presented at the Oregon Public Utility Commission Hearings, August 14, 2000.

5 California ISO, *Action Plan to Accelerate Generation, Transmission, and Demand Response in California*, August 10, 2000.

2001 will be about 16 percent below 2000 levels[6]. This is borne out in high prices. Based on NYMEX gas futures contracts at Henry Hub, natural gas prices are likely to remain above $3.30 per thousand cubic feet (mcf) through 2002[7].

2. HOW CALIFORNIA'S ELECTRICITY MARKETS FUNCTION

Most of California's electricity requirements are now met through purchases made by the utility distribution companies (UDCs) on the open market. This open market is dominated by a multi-step, short-term or "spot" market auction run by two non-profit corporations established in State law by Assembly Bill 1890 (Brulte, 1996). The UDCs regulated by the California Public Utilities Commission and still subject to the rate freeze are precluded from purchasing power outside of these two markets – with limited exceptions – until April 2002 by State law[8]. A significant portion of the State's loads are met by either municipal utilities that control their own generation resources, or through "direct-access" purchases between consumers and a specific generation resource. However, upwards of 80 percent of the State's loads are served through the spot auction markets in some fashion.

2.1 CALPX ENERGY MARKETS

The California Power Exchange (PX) Day-Ahead (DA) auction is the largest volume market for energy in California. The PX also operates a block-forward market, allowing hedging of the DA price, and an hour-ahead auction, allowing near real-time adjustments to supply and demand schedules. The results of the PX auctions are submitted as balanced schedules to the California Independent System Operator (ISO), which reconciles them with the physical characteristics of the transmission grid.

2.1.1 Day Ahead Energy Auction

The DA auction is a forward market for every hour of the next day following. Participants in the auction submit bids indicating their reservations prices for the delivery or receipt of energy at several price points in or on the border of the ISO control area. The price points inside the control area are the ISO's congestion zones, which now include three active zones (Northern California (NP15), Southern California (SP15), and a Central California region (ZP26) between them). The three major external pricing points are the Palo Verde substation in western Arizona, the northern terminus of the Pacific DC Intertie, and the Captain Jack and Malin substations in southern Oregon. Transactions may also be scheduled at other substations on the edge of the ISO control area.

---

6 California Energy Markets, "Tight Gas Supplies Risk Electric Generation," Number 580, Page 8, August 18, 2000.

7 Contracts as of August 2000.

8 CPUC-approved bilateral contracts are scheduled, but not purchased, through the PX. (CPUC Decisions D.00-09-075 and D.00-08-023)

An energy bid in the PX DA market includes a pricing point and up to 15 price-quantity pairs, representing the bidders' willingness to transact energy at different prices, submitted to the PX by 7 a.m. of the day before operations, for specified hours. The bids are "portfolio;" no specific resource (or load group) is specified. The PX evaluates these bids to find the lowest price at which the total amount that suppliers have offered is sufficient to serve the loads bid by electric service providers. This price is the Unconstrained Market Clearing Price. Winning bidders are notified of their MW responsibilities for generation and load, and must designate to the PX, in Initial Preferred Schedules, the specific resources and loads which they will use to meet these commitments. Market participants may also submit "schedule adjustment bids," of up to ten price-quantity pairs for each specific resource or load point, indicating willingness to adjust generation or load to allow reliable grid operations. The ISPs and adjustment bids are submitted to the ISO's congestion management process.

The PX auction, including possible adjustments to resolve generation and consumption with transmission-grid operations, produces a constrained market-clearing price (MCP) (or multiple prices, if there is congestion), with the same price paid to all deliveries within a congestion zone, and charged to all deliveries from a zone. The hourly MCP and the participant maximum quantities are published by 4:00 p.m. the day before the trading day.

2.1.2 Block Forward Energy Market

The PX began operations of its Block Forward Energy market in June 1999. The market is a continuously-clearing forward market for energy delivered to one of the PX within-State pricing points (at present NP15, SP15, or ZP26), in 25-MW blocks, deliverable for every peak hour in a specific month (hours ending 7 through 22, Monday through Saturday, except specific holidays). Trading is open to any party eligible to participate in the California energy markets, subject to certain security and position limits. The PX matches offers to buy and sell the block-forward contract continuously, establishing each half of the full transaction as a long or short position against the Block Forward market as a whole, at the contracted price.

Following the end of each month, the short positions (contracts to deliver energy) are charged, per MWh, the surplus of the average on-peak zonal DA Energy price over the contract price, while long positions (contracts to receive energy) are paid this surplus. A generator who sells block forwards that exactly match its planned output thus enters the DA market short its planned output; if it delivers that output in every hour it will receive the DA price, and pay the surplus of the DA price over the contract price. Thus, the contract offers a perfect hedge to a supplier. The generator is, however, free to adjust his participation in the DA market (and, for that matter, in real time), and satisfy his financial commitment to deliver energy through purchases from that market.

2.1.3 Day-Of Energy Auction

A final forward iteration in the California market design is provided by the processing of hour-ahead (HA) energy schedules, which allows generators and Energy Service Providers (ESPs) to respond to late changes in supply and demand conditions and reduce real time imbalances. The PX does not attempt to run a separate energy auction for each hour-ahead. Instead, the PX runs three late-change auctions for hourly energy, known collectively as the Day-Of market, the results of which are passed into the ISO's HA processing iteration in the same way that the results of the PX Day Ahead auctions are passed to the ISO's DA processing iteration. At 6 a.m., bids are submitted for schedule adjustments covering hours ending 11 a.m. to 4 p.m. of the operating day. Another auction closes at noon for hours ending 5 p.m. through midnight of that day. Finally, at 4 p.m. the auction closes for hours ending 1 a.m. through 10 a.m. of the following day. The rules of the Day Of market mirror those of the PX Day Ahead energy market closely, including computation of an unconstrained MCP, submission of physical schedules, computation of zonal MCPs as appropriate, and settlement based on market-clearing prices.

2.2 ISO ANCILLARY SERVICES, REAL-TIME ENERGY MARKETS, AND CONGESTION MANAGEMENT

Operation of a large electric power grid requires several “ancillary services” from generators, in addition to basic energy production. In a large interconnected system such as that which supplies most of California, the load is constantly changing throughout the day as loads at factories, commercial buildings, farms, and homes are turned on and off at various times. In addition, generators are coming on line, changing output, and going off line at various times for various reasons. Despite the complexity of the integrated system, one simple operating rule prevails: generation output must match the load at all times since there is no reserve storage of electricity in the system. Therefore, adjustment of the total generator output to match the load demand is a continuous process. If the system load is greater than the generation, voltage starts dropping and the system loses speed. If the generators pump more energy into the system than the loads demand, the voltage and the speed of the system will increase. These changes are normally very small for a well-operated system, and so go unnoticed. Daily variances in system speed might put electric clocks a few seconds off at the end of the day. That error is corrected by running the system slightly faster through the night. Provision of generation capability to match system output to load is generally referred to as “ancillary services.” The five market categories of ancillary services as defined by the ISO include:

1. Regulation up to match increasing load.
2. Regulation down to match decreasing load.
3. Spinning reserves (units on line at synchronous speed, but not heavily loaded, that can very quickly be brought up to meet sudden deficiencies in generation as could result from a generator tripping out).
4. Non-spinning reserves (units not on line but committed to be immediately available for service on very short notice of ten minutes or less).

5. Replacement reserves (units not on line that are committed to be placed into service within about an hour of notice).

The North American Electric Reliability Council (NERC) includes in its definition of ancillary services an additional category:

6. Reactive supply and voltage support (to maintain transmission line voltage and facilitate electricity transfers).

The ISO grid operations involve dispatching generation to meet loads at every point in time, taking into account the physical properties of the transmission grid. The California system accomplishes this task through two instruments. First, the ISO directly controls substantial generation within its control area that has been placed under Automatic Generation Control (AGC) through awards in the ISO's Regulation auctions[9]. Second, the ISO operates a real-time balancing-energy auction, which produces both dispatch instructions to change the generation levels of participating resources, and price signals to participants in the informal, price-taking real-time market.

To maintain reliable grid operations, the ISO must (1) place sufficient (and appropriately located) generation on AGC, and (2) ensure that there is sufficient participation in the real-time markets to meet the likely contingencies. The two tasks are accomplished jointly through the operation of the ISO's Ancillary Services (A/S) auctions, through which the ISO purchases Regulation (subdivided into Regulation Up and Regulation Down) capacity, and capacity of Spinning, Non-Spinning, and Replacement Reserves.

The ISO purchases ancillary services through a day-ahead auction following the completion of the DA congestion-management procedure, with additional purchases made in an Hour-Ahead market before the operating hour. When locational requirements cannot be satisfied even with zone-specific A/S prices, it may require generators to provide ancillary services under the terms of their Regulatory Must Run Agreements (RMRA) (if applicable).

In both DA and HA markets, the ISO evaluates bids and selects A/S capacity using a “Rational Buyer” approach. This procedure takes advantage of the cascading requirements of the services, where capacity that is qualified to provide Regulation Up is qualified to provide Spinning Reserves, capacity that is qualified to provide Spinning Reserves can provide Non-Spinning Reserves, and capacity that can provide Non-Spinning Reserves can provide Replacement Reserves. Under the Rational Buyer procedure, the ISO identifies the minimum quantities of the four services that it must procure, and purchases the set of the four services that meets or exceeds these requirements at minimum cost.

9 Automatic generation control allows a unit’s power level to be altered every four seconds to follow momentary changes in system load. Electricity supply and demand must be balanced every instant within narrow tolerances to prevent system collapse.

2.2.1 Regulation

The ISO procures enough upward and downward Regulation to respond to real-time disturbances. Capacity selected in the two auctions (one for each direction, up and down) is paid the market-clearing price, which can vary from zone to zone. In addition, the net energy delivered from Regulation action is settled at the relevant real-time ex-post price. The ISO's initial response to a system imbalance is a balancing set of AGC signals to generators providing Regulation. The ISO follows up through the operation of the formal Real-Time market, which uses the energy bids submitted to the ISO as parts of bids for Spinning, Non-Spinning, and Replacement Reserves, as well as stand-alone Supplemental Energy bids.

2.2.2 A/S Reserves

The ISO sets its purchases of reserves to secure sufficient real-time supplies to both meet expected loads and to provide an adequate margin for unplanned contingencies. Spinning and Non-Spinning requirements are set in accordance with the WSCC Minimum Operating Reserve Criteria, to five percent of expected demand (net that met by firm imports) served by hydroelectric resources, and seven percent of net expected demand served by non-hydroelectric resources, or the largest single contingency. At least half of these reserves must be Spinning. Replacement reserves are purchased based on the ISO's forecasts of unplanned outages and on the expected draw on the real-time market (taking into account the expected output of unscheduled RMR operations and other sources of uninstructed deviations).

The three A/S reserve services are arrayed in decreasing order of quality based on their technical requirements. Spinning Reserves must be provided by generators that are synchronized to the grid; a unit's Spinning Reserve capacity is limited to that which may be delivered within ten minutes of the ISO's dispatch instruction. Non-spinning Reserves have the same delivery requirement, but need not be provided by generators that are synchronized to the grid. Replacement Reserve capacity is limited to that which may deliver energy within 60 minutes of dispatch.

2.2.3 Real Time Energy Market

The ISO's Balancing Energy and Ex-post Pricing (BEEP) software operates the balancing-energy auction. It observes the balancing AGC signals, analyzes the energy bids for the hour (taking into account particular resource locations, ramp rates, and information about the expected time profile of imbalances/regulation use), and nominates a dispatch from the so-called BEEP stack of energy bids.

The primary source of the energy bids is accepted Reserve capacity. Units providing Spinning, Non-Spinning, and Replacement reserves, whether nominated by self-providing scheduling coordinators or following participation in the ISO's A/S auctions, provide a real-time energy bid, made up of price-quantity pairs indicating the levels of output they are willing to provide at different prices. Units that are not providing ancillary services may also submit similar real-time bids. The bids include incremental segments and/or decremental segments, which are offers to back the generation down.

The prices produced by the BEEP software describe the price the ISO is paying for incremental dispatch to resolve an undergeneration imbalance, or is charging for a decremental dispatch to resolve overgeneration. The same price is used to settle the instructed and uninstructed deviations between scheduled and actual generation and consumption.

2.2.4 Interzonal Congestion Management

In the California market design, forward markets produce balanced schedules matching location-specific loads and identified resources. An Interzonal Congestion Management procedure addresses inconsistencies between these schedules and the locational requirements for reliable grid operations, where resolution of such inconsistencies requires redispatch on either side of an interzonal interface to reduce electricity flows over congested paths between zones.

The ISO carries out these procedures in Day-Ahead (DA) and Hour-Ahead (HA) iterations. The ISO models the power flow and identifies potential congestion, which it reports to the scheduling coordinators along with a set of schedule adjustments that would remedy the congestion. Scheduling coordinators respond with revised schedules, which need not incorporate the proposed redispatch, and which may include adjustment bids. These adjustment bids have incremental segments, describing the price required for increases in a generator's output, and decremental segments, describing the price a generator is willing to pay to be relieved of its obligation to deliver energy. The ISO then finds sufficient decrements on the energy surplus side of the constrained interfaces, matched by sufficient increments on the deficit side, to meet the transmission constraint; the difference between the two prices is the congestion charge, which is charged to all schedules that use the constrained interface.

2.2.5 Intrazonal Congestion Management

Congestion within zones is resolved by selecting adjustment bids or, failing that, real-time energy bids for redispatch. To preserve the zonal pricing structure, the bids selected for redispatch to relieve intrazonal congestion would be paid (or charged) “as-bid”, with the cost of redispatch shared pro-rata amongst all loads in the same zone as the intrazonal congestion-management redispatch action.

3. MUST RUN CONTRACTS AND AREA RELIABILITY

Electricity, unlike any other commodity or service, must be supplied in a manner that instantaneously balances with demands and it is not readily storable[10]. These characteristics impose certain physical constraints on the generation and transmission system that limit the ability to use

10 Water can be retained behind dams within specified limits.

only economic signals in dispatching generation. These rules lead to specific generating units being designated "Must Run" (Reliability Must Run or RMR) in order to prevent: (1) the extreme consequences of an electric service interruption to highly concentrated areas; (2) overloads on generators; (3) transmission facilities overloads; (4) cascading outages; (5) voltage collapse; and/or (6) total grid blackouts.

The purpose of Reliability Must Run Agreements (RMRAs) between the ISO and specific unit owners is to ensure reliability of service to customers without overpaying. If the owner of an RMR unit failed to operate when the unit was needed, then electrical service would be jeopardized or disrupted. If the owner of a needed unit were allowed to set any price, then ratepayers might be overcharged whenever the unit was needed to maintain reliable service.

3.1 MUST RUN DESIGNATIONS

A number of the Pacific Gas and Electric Company hydroelectric generation units have been designated Must Run by the ISO. Designation as a RMR unit does not mean that the unit literally must run or operate all the time. A unit that is designated RMR by the ISO may only be needed by the ISO for a few hours each year. It means that the owner must commit to maintaining the unit and to responding on a best-efforts basis to a directive from the ISO to operate the unit. A unit is deemed RMR because in the opinion of the ISO, it is required to support either local or area reliability requirements.

The reliability criteria may cover varying regions or the entire grid. On any given day, if the ISO determines that a particular hydroelectric generation unit designated RMR is needed to assure reliability in the neighborhood of that unit, or to support the grid, then the ISO will direct that the unit produce electricity.

3.2 MUST RUN GENERAL CONTRACT TERMS

Designation as an RMR unit is not permanent, as the ISO is planning to phase out the use of RMRAs and rely entirely on purchases from the ancillary services markets. The CAISO can cancel an RMRA on 90 days notice. The owner, however, has no such right. Any Pacific Gas and Electric Company hydroelectric generation unit designated as Must Run by the ISO must enter into an RMRA even after divestiture.

Unless dispatched by the ISO, the RMR unit is under the control of its owner. If owned by Pacific Gas and Electric Company, the RMR unit must be bid into the PX until the end of the transition period. After the transition period, if Pacific Gas and Electric Company still owns the RMR unit, Pacific Gas and Electric Company may bid into the PX, enter into bilateral or multilateral sales, or engage in direct sales. The new owner of a divested unit may, immediately and without waiting for the end of the transition period, bid into the PX, make bilateral or multilateral sales, or engage in direct sales.

The owner of an RMR unit may run the unit to its permitted maximum technical limits if the owner so desires. The contract with the ISO allows the ISO to direct the owner of an RMR unit to generate under certain conditions affecting electric reliability. The conditions of the RMRA in no way allow the ISO to stop generation.

3.3 RELIABILITY MUST RUN UNIT OBLIGATIONS

The owner of an RMR hydroelectric generation unit is contractually obligated to operate and maintain the unit in accordance with good industry practice. The owner is required to notify the ISO of each forced outage, its expected duration, and when the unit is again available to generate electricity. The owner is required to perform routine and overhaul maintenance at times mutually agreed to by both the operator and the ISO.

When called upon, the owner must generate up to the maximum hourly commitment of the unit. The ISO can direct that the unit generate less than its maximum, but not less than its minimum capability. For example, the ISO might direct a unit with a maximum of 200 MW and a minimum of 50 MW to generate 100 MW. In this example, the owner could elect to generate up to the full 200 MW, but the ISO would only pay for the first 100 MW under the terms of the RMRA, and the owner would have to sell the remainder to another party.

The ISO can only dispatch an RMR unit within its operational, licensing, and contractual constraints. The ISO is also limited in the number of annual startups that can be required of any Must Run unit. The ISO is further obligated to honor unit generator constraints such as ramp-up time, minimum run time, and all other operating constraints such as the minimum flow requirements in the FERC licenses. The ISO also agrees to honor any existing contractual constraints on the operation of an RMR unit.

The ISO cannot order a RMR unit to violate any environmental restrictions placed on the unit. For example, if a hydroelectric generation unit is out of service to protect fish spawn, the ISO cannot order the unit to generate electricity. Nor can the ISO order a unit to switch generation from the off peak to the on peak if this would violate minimum flow requirements. The ISO is bound by environmental restrictions to the same extent as the unit owners.

4. PACIFIC GAS AND ELECTRIC COMPANY’S HYDRO POWER SYSTEM

Each of the 110 generating units at the 68 powerhouses that Pacific Gas and Electric Company proposes to divest generates electricity by utilizing the energy of falling water to rotate hydraulic turbines, which turn generators that produce alternating current. The water gives up its energy as it passes through the turbines and back into the stream channel or a reservoir. No significant amounts of water are consumed in the process, with some minor losses to evaporation and aquifer sideflows. Water discharged from a powerhouse is available to drive additional powerhouses as it continues on downstream to provide aquatic habitat, to provide recreational opportunities, and to provide for consumptive uses such as irrigation and municipal supplies. Hydroelectric power is renewable energy dependent upon the natural hydrological cycle to replenish stream flows and refill reservoirs.

4.1 HYDROGENERATION FACILITIES

As seen in Figure 2-2 in the Project Description, the basic components of a typical hydroelectric generation facility consist of:

- A dam and reservoir that impounds and stores stream flow;
- Conveyance facilities which may include an intake structure, canals, flumes, tunnels, pipes, and penstocks[11] to conduct water diverted from the reservoir to the powerhouse;
- Gates and valves for controlling the flow of water in the system;
- A powerhouse that contains the hydraulic turbines, generators, other electrical and mechanical equipment, and controls;
- A tailrace that channels the powerhouse discharge flow back to the stream;
- A transformer bank to increase generator output voltage to transmission levels; and
- A switchyard connecting the powerhouse to the transmission grid.

Some powerhouses are located at the base of the dam, in which case the conveyance facilities are short, consisting of only intake structures and penstocks. In other cases, the powerhouse may be located some distance downstream from the dam, or even on a different stream. For these cases, the conveyance system may include miles of tunnels, flumes or canals and intermediate reservoirs for flow re-regulation before reaching the penstock and plunging to the powerhouse.

Large storage reservoirs are filled and drawn down on a seasonal basis. A reservoir that supplies water directly to the conveyance facilities leading to powerhouses is called a “forebay.” Most of the Pacific Gas and Electric Company system forebays are small, with water levels being cycled on a daily or weekly basis in response to system load demands. The larger storage reservoirs may also be forebays, but short-term cycling of generation does not significantly affect water levels. Many of Pacific Gas and Electric Company’s powerhouses also have “afterbay” reservoirs downstream of the tailrace. Afterbays serve to smooth out rapid changes in discharge flow and dampen surges in stream flows that could endanger people or damage environmental resources. In many cases, the afterbay of one powerhouse is also the forebay for the next powerhouse in a series of reservoirs and powerhouses along a stream. On the North Fork Feather River system, water flow released from Mountain Meadows Reservoir produces electricity repeatedly through seven Pacific Gas and Electric Company powerhouses and reservoirs as it flows to Lake Oroville, and then produces

[11] A penstock is the final leg of the conveyance system consisting of a pressure pipe that usually slopes steeply to the powerhouse. Pressure progressively increases as water descends the penstock.

electricity two more times at the Department of Water Resource's Edward Hyatt and Thermalito powerhouses prior to being diverted in the Delta for the State Water Project.

The Helms Creek Pumped Storage Plant (FERC Project 2735) is unlike the typical hydroelectric generation facility in that its operation can be totally reversed from a generating mode to a pumping mode to move water from Lake Wishon back into upstream storage in Courtright Lake for re-use. In generating mode, water is drafted from Courtright Lake, passed through the powerhouse turbines, and discharged to Lake Wishon to generate up to 1,212 MW of power. In the pumping mode, the turbines become pumps, the generators become motors, the tailrace tunnel becomes an intake tunnel to draft water from Lake Wishon and pump it through the penstocks and power tunnel to Courtright Lake approximately 1,700 feet higher in elevation than Lake Wishon. Due to efficiency losses of the cycle, Helms is a net user of energy. It is economic because the pumping mode is used during off-peak hours when electric energy is less costly and electricity is generated during on-peak hours when energy and capacity values are high.

4.2 SITING OF HYDROGENERATION FACILITIES

The Pacific Gas and Electric Company hydroelectric generation facilities are mostly located on the western slopes of the Sierra Nevada and Cascade mountain ranges from the foothill zone along the eastern edge of the Central Valley and extend to the crest of the ranges. The lone exception is the small 9.2 MW Potter Valley Project in the Coastal Range on the Eel and Russian Rivers. Unlike combustion and nuclear power plants, which can be sited near load centers and transmission corridors at the choice of the developers and regulatory authorities, hydroelectric generation facilities must be sited where the resources exist. That is, they must be sited where there are sufficient stream flows, elevation differences to provide head, and economically feasible opportunities to construct dams, reservoirs and powerhouses to capture the hydro energy. Due to the heavy precipitation and steep gradients of the western slopes of the Cascades and Sierras, many such opportunities for hydropower existed that have been developed by Pacific Gas and Electric Company and its predecessors, other private and publicly-owned electric utilities, water districts, and State and Federal agencies.

Many of the best hydropower sites are located in remote, rugged, and often pristine areas far from load centers and transmission corridors. These locations required the construction of access roads, long transmission lines, and operator housing in addition to the primary hydroelectric generation facilities.

There are few sites in the mountains above the elevation of 1,000 feet suitable for large storage reservoirs due to the steep stream gradients and narrow steep-sided canyons. The major exception is Lake Almanor in an inter-range basin, with 1.13 million acre-feet (af) of useable storage capacity representing more than half of Pacific Gas and Electric Company's total useable reservoir storage capacity of 2.3 million af. The best opportunities for major water storage facilities are located in the foothill zone between the floor of the Central Valley and the 1,000-foot elevation. This zone is where most of the major water supply projects constructed by state and federal agencies and public water districts are located in California. Many of these storage facilities also have hydroelectric power developments. Notable examples are the Bureau of Reclamation's Lake Shasta with 4.55 million af of storage capacity at water surface elevation of 1,065 feet and the California Department of Water Resource's Lake Oroville with a capacity of 3.54 million af at elevation 900 feet.

4.3 HYDROLOGICAL CYCLE

Hydropower is a renewable natural resource that is dependent upon the natural annual hydrologic cycle to replenish stream flows and refill reservoirs. Water evaporated from the oceans into the atmosphere is transported eastward across California by Pacific winter storms. The coastal mountain ranges and the Cascade and Sierra mountain ranges to the east of the California Central Valley lift the flow of the moisture-laden air, causing adiabatic expansion and cooling that greatly increases precipitation over the mountainous zones (especially over the Cascades and Sierras which are much higher than the coastal mountain ranges). At the higher elevations, much of the precipitation occurs as snow where it accumulates through the winter season. Much of the rainfall runs off rapidly, but a large portion also percolates into the ground to replenish groundwater resources and springs. Streams carrying direct runoff, spring water flows, and snowmelt coalesce into rivers that flow back to the ocean to repeat the hydrologic cycle. The heavy snow pack at high elevations melts slowly in the spring and early summer, often feeding stream flows into mid-summer. The snow-pack is in effect a high-elevation storage reservoir that is of great value to Pacific Gas and Electric Company's hydroelectric power generation system. The porous volcanic rock formations of the Cascades provides another natural large reservoir that is recharged during the wet season and slowly releases the water to stream flow to benefit hydroelectric generation and other water uses throughout the dry season. Pacific Gas and Electric Company's McCloud and Pit River developments in the Shasta Region and projects in the DeSabla Region greatly benefit from such ground water storage and discharge.

4.4 EFFICIENCY OF HYDROELECTRIC GENERATION

The energy potential of water available to produce electricity is dependent upon two factors, "head" and "volume." Head is defined generally as the difference in elevation of the water surface of the forebay and the water surface of the tailrace for reaction turbines. For impulse turbines the elevation of the centerline of the turbine nozzles, rather than the tailwater elevation, is used to compute head. This elevation difference is usually referred to as "gross head." Energy losses due to friction as water flows through the system are referred to as "head losses." Head losses are subtracted from the gross head to obtain the "net head" at the turbine available for generating electricity. Volume may refer to the total volume of a body of water stored in a reservoir that is available for power production, or to the rate of flow of water in a stream or through the hydroelectric generation facilities. Stored water is usually measured in acre-feet (af)—the volume of a pond one acre in surface area with a depth of one foot (43,560 cubic feet, or 325,800 gallons).

Instantaneous flow rates for water are generally expresses in cubic feet per second (cfs), whereas water discharges over longer time spans are generally expressed in af per day, week, month, or year.

The higher the proportion of the potential and kinetic energy of the water flow that can be converted into electricity, the higher the efficiency of the conversion process and the less water needed for each kilowatt-hour (kWh) of electric energy produced. Compared to other methods of generating electricity on a commercial scale, hydropower is the most efficient method with typical overall energy conversion efficiency in the range of 75 to 85 percent compared to 30 to 50 percent energy conversion efficiency for nuclear and combustion power plants. Not all of the potential energy of stored and flowing water can be converted to electrical energy due to the efficiency losses at each step of the process. There are hydraulic head losses due to friction of water flow in the conveyance facilities, losses within the turbine converting the potential and kinetic energy of the water to mechanical rotating energy, losses in the generator to convert the mechanical energy to electrical energy, and losses in the transformers to step-up the voltage for transmission. In addition, some energy must remain in the water to enable it to flow from the powerhouse. The greatest losses usually occur in the conveyance system, especially for long tunnels and canals. Turbine losses also are significant with typical turbine efficiencies being in the range of 80 to 95 percent. Lower turbine efficiencies occur when units are operated at power levels above or below their best efficiency range or when turbines are not well maintained. Generator efficiencies are commonly on the order of 98 percent but can be much lower at low power output due to hysteresis losses in the iron core. Losses in transformers are typically low with efficiencies on the order of 98 to 99.5 percent. At low power levels, the transformer losses are also proportionately greater due to hysteresis. The efficiency ratings for all the components are multiplied together to obtain the overall efficiency. For economic reasons, it is desirable to operate hydroelectric units within their most efficient operating range and maximize operation of the most efficient units when feasible.

Pacific Gas and Electric Company turbines are primarily of two types, Francis reaction turbines and impulse turbines. The exceptions are two Kaplan units located at the Chili Bar and Merced Falls Powerhouses, and three reversible “Hitachi” pump-turbines at the Helms plant. The turbines types have distinctly different efficiency characteristics. The peak efficiency of Francis turbines is generally high, in the range of 90 to 95 percent, but their efficiency falls off rapidly for outputs above or below the peak efficiency level. For impulse or Pelton turbines, peak efficiencies are generally in the 88 to 92 percent range, but remain fairly high over a wide range of operating conditions. Kaplan turbines with adjustable vanes are very efficient with characteristically flat efficiency curves in the range of 90 to 95 percent over a broad range of flows and head conditions. The Helms pump-turbines are similar to Francis turbines. The overall pumping-generation cycle efficiency for the Helms plant is about 75 percent; i.e., about 75 percent of the pumping energy is recovered in generation. This implies that the turbine and pumping efficiencies are approximately 90 percent or greater.

The shape and peak of turbine efficiency curves can be manipulated in the design of turbines. It is common practice to design turbines with the peak operating efficiency occurring at about 80 percent of the rated unit capacity as it is expected that the units will be operated at less than their full rated capacity most of the time. This is the case for most of the Pacific Gas and Electric Company turbines. If it were known that a unit would be operated at full power most of the time, then it could be designed for peak efficiency to occur at full power output. It is feasible to modify efficiency characteristics of an existing turbine by replacing the runner with one designed to produce the desired characteristics. For at least one Pacific Gas and Electric Company powerhouse, a “low-flow” runner is provided for installation seasonally to improve efficiency during extended periods when water availability is reduced.

Impulse turbines are best suited for high head applications where the head is 1,000 feet or greater. Francis type reaction turbines work best in the range of 60 feet up to 1,000 feet. Kaplan turbines and fixed blade propeller type turbines are generally used for low head applications of less than 60 feet. These regions of application do not have fixed boundaries and there can be considerable overlap in applications. For example the Helms units rated at normal maximum gross head of 1,744 feet are substantially into the range usually reserved for impulse turbines, and nine of Pacific Gas and Electric Company’s impulse turbines are operated at heads of less than 1,000 feet.

Altogether there are 58 Francis turbines, 47 impulse turbines, two Kaplan turbines and three Hitachi pump-turbines (Helms) installed at the Pacific Gas and Electric Company powerhouses. Gross heads range from 26 feet at Merced Falls up to 2,558 feet at Bucks Creek. Eight of the impulse turbines (five powerhouses) operate at heads greater than 2,000 feet. The generating capacity of the Pacific Gas and Electric Company powerhouses, exclusive of the Helms pump-turbine units, range from 0.4 MW at San Joaquin 1-A Powerhouse up to 172 MW at James B. Black Powerhouse. The Kerckoff No. 2 Powerhouse has the largest conventional hydroelectric unit with a generating capacity of 155 MW. Pit No. 5 is the most productive powerhouse on the Pacific Gas and Electric Company system with average annual generation of 931 GWh of electrical energy. The total generating capacity of Pacific Gas and Electric Company’s conventional hydroelectric units is 2,703 MW, which produce an average of about 12,000 GWh of electricity annually. The peak flow capacity at the powerhouses ranges from 25 cfs at Phoenix up to 9,000 cfs at Helms.

The oldest Pacific Gas and Electric Company powerhouse in service is the 6.4 MW Centerville Powerhouse on Butte Creek in the DeSabla Region, which was commissioned in 1900. Although the Phoenix Powerhouse in the Motherlode Region was first commissioned in 1898, it was reconstructed in 1940. A number of the smaller units of the Pacific Gas and Electric Company system were commissioned during the first quarter of the 20th century. Many of Pacific Gas and Electric Company’s larger conventional powerhouses were constructed in the two decades following World War II to meet the needs of rapid growth in California. The early 1980s saw a spate of hydropower development as a result of oil and natural gas shortages, high energy prices, and legislation favorable to hydropower development. The 155 MW Kerckoff No. 2 came on line

1983, and the Helms Pumped Storage plant in 1984. Small new powerhouses included Volta No. 2, Toadtown, Oak Flat, Wise No. 2, and Newcastle. Newcastle, completed in late 1986, is the newest powerhouse. A number of other powerhouse additions and upgrades of existing powerhouses were planned during the early 1980s, but development became infeasible due to changing economic conditions.

4.5 ENERGY VALUE OF WATER

The energy value of a given volume of water depends on its elevation and the “head” available for power generation. Water located high in the mountains where it must fall thousands of feet before reaching the valley floor near sea level has very high energy value, whereas water at low elevations has little energy value. Comparison of Pacific Gas and Electric Company’s North Fork Kings River development and the Merced Falls Project provides a dramatic illustration of energy value. An acre-foot of water traveling from Courtright Lake at elevation 8,184 feet through the Helms, Haas, Balch, and Kings River powerhouses to Pine Flat Reservoir at elevation 905 feet would fall 7,279 feet and produce about 6,100 kWh of electrical energy. From Pine Flat Reservoir the same acre-foot of water may produce another 310 kWh of electricity passing through the Pine Flat Powerhouse and then be routed on to serve the water customers of the Kings River Conservation District. In contrast, an acre-foot of water passing through Pacific Gas and Electric Company’s low head Merced Falls Project with 26 feet of drop between the forebay and tailrace would produce only 24 kWh of electrical energy. Therefore, the energy value of a given volume of water in Courtright Lake is approximately 267 times greater than the same volume in the Merced Falls forebay.

As shown above, high heads concentrate energy in water, which permits economic hydropower development with lower flows and smaller and less costly dams, reservoirs, tunnels, penstocks, and turbines than would be required for low-head hydroelectric facilities of similar generating capacity. Because much of Pacific Gas and Electric Company’s system takes advantage of the high heads provided by the Sierra and Cascades to reduce flow requirements, very large reservoirs to supplement snowpack and ground water storage are not generally needed to operate the system year round.

4.6 BENEFICIAL ATTRIBUTES OF HYDROELECTRIC GENERATION

Hydroelectric power generation possesses a number of attributes that renders it a uniquely valuable resource with multiple non-power and power benefits. Its capability of providing a number of ancillary services in support of electric power supply grids makes it especially valuable in today’s volatile competitive market for wholesale power.

4.6.1 Reliable and Efficient Power Source

Hydroelectric generation technology is a reliable, mature industry with more than a century of innovative development. This experience is reflected in the reliability and efficiency of today’s powerhouses. Average availability of generating units is typically greater than 90 percent. Eighty to 90 percent of the potential and kinetic energy of elevated water is converted to electrical energy as it passes through the penstock and powerhouse, compared to energy conversion efficiency of only 30 to 50 percent for thermal power plants. With periodic overhauls and upgrades, some hydroelectric powerhouses have been in service for over 100 years. A number of the dams impounding water serving the generating plants have been in service even longer. Hydroelectric facilities in California are widely dispersed among the mountain and foothill regions where steep stream gradients provide the difference in elevation needed for power generation. This physical separation of the facilities provides an additional level of protection from natural disasters such as floods, earthquakes, and landslides, which are likely to affect no more than a few of the many powerhouses if such events occur. In any case, hydroelectric facilities are conservatively designed and constructed to withstand floods and earthquakes without suffering catastrophic damage. Large landslides are the greatest natural hazard for hydroelectric facilities, but are unlikely to affect more than one powerhouse in any particular event.

4.6.2 Economics

Once constructed, hydroelectric facilities have very low maintenance and operating costs compared to other types of power generation. Hydroelectric generation equipment can operate many years and sometimes for decades with only routine maintenance. Many powerhouses are remotely operated from distant control centers from which staff may operate a number of plants in the watershed region. Centralization of maintenance staffs operating from well-equipped service centers further improves labor efficiency and reduces maintenance costs. Of course, the greatest cost savings of hydroelectric power compared with other generation is the absence of any cost for fuel. The energy is provided free by nature’s elevation of water by the natural hydrological cycle of evaporation from the oceans, precipitation of rain and snow on the mountains, and runoff back to the ocean. However, there are some minor energy costs, such as payments to the Federal Energy Regulatory Commission (FERC fees) and payment of headwater benefits to upstream reservoir owners, and payments to holders of senior water rights.

The initial cost of constructing hydroelectric facilities is high compared to combustion turbine and thermal generating plants, but with amortization of these costs over time, hydroelectric power becomes increasingly more economic. Hydroelectric plants that appeared to be only marginally economic when constructed several decades ago now are very low-cost energy sources, with total cost of production (including investment) for some plants as low as one to two cents per kilowatt hour. Because most of the “cost” for hydroelectric generation is the fixed sunk cost of initial construction, the cost of operation is stabilized and unaffected by volatile prices for fuel. However, due to the large component of fixed cost, reduced production during dry years will increase the unit cost of production while wet years will reduce unit costs of production.

4.6.3 Ancillary Services

Balancing generation and load is a challenge because most thermal power plants operate best at constant loads and do not respond quickly to changes in demand. To increase load, a conventional steam plant must first increase the fuel flow and the size of the fire in the furnace to make additional steam for delivery to the turbine. This takes time, especially for older steam-drum type units that have a lot of thermal inertia due to the greater mass of their components. Nuclear plants are even less responsive and are generally operated base-loaded at full capacity. Frequently changes loads in thermal plants also increases thermal stresses in the equipment and may lead to more frequent equipment failures. Bringing a thermal plant from a cold start to full load may take several hours. Nuclear plants may take a day or more to bring to full capacity after a cold shutdown.

Providing ancillary services requires operational flexibility and agility to respond quickly to changes in load either up or down, and to come on line and to full load in a very short time. Spinning reserve requires the capability to economically operate a unit at a very low load synchronized on the system ready to crank-up to full power in a matter of minutes. Non-spinning reserve service may require a unit to come from a cold start to full power in a matter of ten minutes.

Hydroelectric generating units are especially well suited for providing ancillary services because they can change levels of output very rapidly and move from no-load condition to full power in a matter of a very few minutes. There is no warm-up time and changes in load levels do not thermally stress components to cause equipment failures. The proven reliability of hydroelectric generation assures that the ancillary service needed will be available when called for by the ISO.

The new generation of combustion turbine (CT) driven thermal power plants have faster start-up and response times than conventional steam plants, and may compete with hydroelectric generation in the ancillary services market. However, many of these CTs are combined cycle plants coupled with steam turbines for topping cycles. The steam cycles may slow the response time of these units. It remains to be seen if CTs will displace hydroelectric generation as the units of choice for ancillary services.

4.6.4 Flood Control

Hydroelectric reservoirs, even though not intended for flood control purposes, do provide incidental downstream flood control benefits by storing water during high flows for later release through the powerhouses for generation of power. The larger the reservoir, the greater the potential flood control benefits. It is in the interest of hydropower operators to capture as much of the high flows in excess of plant capacity as possible and save it for later use as needed for power generation. Typically, reservoirs are drawn down during the dry summer and fall season and refilled during the winter and spring from rainfall and snowmelt runoff. This is similar to how a flood control agency would operate except that a flood control operator would likely release water from storage immediately following a flood to prepare to receive the next high flow. A hydropower operator would be more cautious about drawing down a reservoir unless assured the reservoir could be refilled by the end of the wet season. But even if a reservoir is full at the time of a flood, especially one with a large surface area, it can substantially attenuate the flood peak by surcharge storage (water levels above the normal maximum level) during the event. The surcharge volume is drained off as the flood flow recedes. Even small reservoirs, such as many of the on-stream forebays and afterbays of the Pacific Gas and Electric system, provide some measure of flood benefits in this manner.

4.6.5 Water Supply

Hydropower reservoirs also provide incidental water supply benefits. Water is stored in reservoirs in the wet season when demand for irrigation and other consumptive uses is low and released during the dry season to provide both water supply and generation benefits. Generation and water supply functions are generally compatible. In several cases, Pacific Gas and Electric Company has partnered with water agencies to jointly develop hydropower/water supply projects with long term power purchase contracts to ensure that the electrical utility receives economical power and that the water agency receives dependable water supplies. More recently, with electric market deregulation, some water agencies not bound by long term contracts have begun directly marketing wholesale and retail power services, thus reaffirming the symbiotic relationship between hydropower and water supply.

4.6.6 Recreation

Recreation is another significant benefit of hydropower not offered by other means of electric power generation. The storage reservoirs often are attractive lakes in pristine mountainous locations providing boating, swimming, fishing and camping opportunities for outdoor enthusiasts. Access roads developed for construction and operation of the facilities also allow public access. Hydroelectric developers are required by law and the FERC licenses to allow public access to the project waters, and to develop facilities for public recreation at the licensed facilities such as picnic tables, campgrounds, and boat ramps. The leasing of recreational home sites at the lakes is an additional benefit. Fishery resources also are developed to enhance sport fishing. The planting of hatchery-raised trout and other species in project lakes and streams is funded by hydroelectric developers. Stream flow releases from reservoirs through the summer months provide flows and sport fishing in streams that might otherwise dry-up in the late summer and fall. Most of the recreational boating activity in California occurs on man-made lakes where hydropower is one of the many public benefits. Controlled summer releases of large flows into selected high gradient stream reaches provides for increasingly popular white-water boating recreation.