APPENDIX C

HYDROLOGICAL AND UTILITY SYSTEM MODELING

1. OPERATIONAL AND ECONOMIC ANALYSIS

1.1 MODELING CHANGES IN MANAGEMENT INCENTIVES

Pacific Gas and Electric Company has submitted an application to the California Public Utilities Commission (CPUC) for the sale of its hydropower generation assets, including associated lands. The hydropower generation assets proposed to auction are comprised of 26 Federal Energy Regulatory Commission (FERC) licensed hydroelectric projects and three non-jurisdictional projects with 68 powerhouses and 110 generating units totaling a normal generating capacity of 3,896 MW, including 1,212 MW at the Helms Creek Pumped Storage Project on the North Fork Kings River. Other facilities included are 174 dams, 99 reservoirs with total storage capacity of approximately 2.3 million acre feet, 76 water diversions, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipelines, and 5 miles of natural waterways and water rights associated with the facilities. Associated lands include 95,000 acres of land within FERC license boundaries and parcels encumbered by FERC licensed facilities, and 45,000 acres of other watershed lands in the vicinity of the hydroelectric facilities. These facilities and lands are mostly located on the western slopes of the Sierra and Cascade mountain ranges along the eastern side of the California Central Valley from the foothills to the crests of the mountain ranges. They extend from the Pit and McCloud rivers in the north to the Kern River in the south. The one exception is the small Potter Valley Project located in the Coastal Mountain Range on the Eel and Russian Rivers. After the proposed sale, Pacific Gas and Electric Company would retain control through power purchase contracts of 1,082 MW of hydroelectric facilities that are owned by various public water agencies.

The goal of the modeling completed by the Operations and Economics Group (OEG) of the EIR team was to identify the reasonably foreseeable changes in hydropower operations that might occur with the divestiture of the Pacific Gas and Electric Company hydropower facilities. The primary objectives were to identify and quantify any significant changes in reservoir levels, streamflow diversions, and flow releases from dams and powerhouses. A key task was separating the changes that are the result of restructuring the electricity marketplace that began in 1998 from those that might occur with transfer to new owners or other actions as a result of a Commission decision in this proceeding. Only the latter changes are subject to review in this proceeding. This analysis identifies potential changes in both electricity generation patterns and in water management practices.

For modeling purposes, he EIR preparers only considered changes in hydropower operations that will be driven by the differing management incentives associated with changes in ownership. Due to the great variety of potential ownership patterns and incentives, the modeling assessed a set of "primary" cases for comparison to baseline conditions. The primary cases are meant to reflect how a "typical" owner whose incentives differ from Pacific Gas and Electric Company's, as reflected in the baseline and "no project" cases, might alter facility operations in a predictable manner.

This analysis required integrating detailed, complex simulation models of both the electric power market and river basin hydrology. A power market model, UPLAN, was used to estimate how new owners with different incentives in the power market might change hydropower generation patterns and how these changes affect the Pacific Gas and Electric powerhouse flows, the operations of the remaining units in the WSCC, and the resulting California market prices for energy and ancillary services. Another power market simulation model, SERASYM™, assessed how these potential changes in hydropower operations would likely affect the related air emissions at other power plants in California. OASIS, a generalized program for modeling the operations of water resources systems, used the changes in power market price patterns to estimate how various water management and use parameters, such as stream and canal flows, reservoir storage, and diversions could change given physical, institutional, and legal constraints. The water operations and energy models' outputs were then melded to forecast downstream releases and powerhouse releases on a daily basis, and water supply diversions and reservoir levels on a monthly basis.

The data were then provided to the environmental specialists reviewing such topics as hydrology, water quality, biology, fisheries, cultural resources, air quality, public services, agriculture, and recreation. These specialists then determined the expected impacts under different scenarios.

1.2 BASIC ANALYTIC PREMISES

Conducting any analyses about future events requires some judgment about the likelihood of various courses of action. The proposed action almost always appears more concrete than any alternative because the decisions and milestones are more clearly specified in the proposed action. For example, the expected building and activities related to a proposed office building are more likely to be clearly delineated than other alternatives for a plot of land that is currently vacant. In the case of divestiture, the sale of the facilities is the identified action; what Pacific Gas and Electric Company would do if it did not sell the facilities is not so clearly defined. Yet through careful consideration, alternative scenarios without the specified action can be constructed and used as a baseline against which the potential impacts can be measured. This approach is the principle used in this analysis.

With this principle in mind, several basic premises are used this analysis. One basic premise is that restructuring as directed through legislation and Commission decisions has led to substantial, fundamental changes in how California's electric utility industry operates. Most generators, particularly those that establish market prices, now have to recover most of their investments through power contracts or open market sales instead of through a separate regulatory-established rate of return.

The second basic premise is that the overall process will continue. Both the Independent System Operator (ISO) and Power Exchange (CalPX) markets would continue to function much as they do now. The EIR preparers also assume that the Western Systems Coordination Council (WSCC) control area will progress toward further restructuring in general, and will add new resources at a pace projected by the various entities in the WSCC. Nevertheless, recent events in the power markets have led to a close reexamination of how these markets function and whether other policy options may be more appropriate. The Commission (I.00-08-002) and FERC have initiated analyses into recent market events. The EIR preparers cannot anticipate what policy proposals may come out of these proceedings, so they have had to assume continuation of the status quo. This assumption in no way should be considered an endorsement of the current markets or any other policy proposals.

The third basic premise is that the various policy proposals from the CalFed Bay-Delta Program will not impinge on hydroelectric power operations any further than what has already been identified in this environmental review (for example, the Battle Creek Restoration Project). The EIR preparers have not considered whether certain Pacific Gas and Electric Company controlled reservoirs may be included in the Integrated Storage Investigation. In addition, unless otherwise specified, the EIR preparers have assumed continuation of current FERC hydropower licensing conditions.

1.3 BASIC SYSTEM DATA SOURCES AND ASSUMPTIONS

The various hydrologic and market/ownership cases represent the final steps in a lengthier process to develop and refine simulations of the Pacific Gas and Electric Company hydro system within the overall western interconnected electricity system, the Western Systems Coordinating Council ("WSCC"). The modeled WSCC system includes electric loads, transmission, current and projected generators, and simulated markets and bidding behavior for electric energy and ancillary services, extending from British Columbia and Alberta in Canada southward to northern Mexico, and east to Wyoming, Colorado and New Mexico. Different levels of detail in simulating various aspects of the interconnected system and markets were evaluated and empirically tested against actual conditions, including integration/scheduling of hydro generation, transmission modeling, generator utilization and interacting energy and ancillary services markets.

For Pacific Gas and Electric Company's hydropower system, historic streamflow, powerhouse, and reservoir operation data were gathered for the 1975 to 1998 period. Each of the Pacific Gas and Electric Company hydro units was characterized in terms of monthly maximum capacity, monthly energy (varies by historic "hydro" year), run-of-river (not able to be scheduled) generation, inflows, reservoir storage, linkages between powerhouses (on the same river system), and efficiency in converting water flows to electric output. Physical and institutional operating rules, restrictions, and characteristics were collected for input to the various models. Constraints and objectives were categorized as being physical, legal, contractual or non-binding based on substantial review.[1]

Based on the above evaluations and benchmarking, adjustments and analytic decisions were made, to produce a modeling approach appropriate for the project objectives.

1.4 OPERATIONAL FLEXIBILITY WITHIN RIVER BASINS

The degree to which a new owner can change operations at any one facility depends on its operational flexibility. Table C-1 summarizes by bundle a more detailed analysis of individual facilities that analyses the ability to alter hourly, daily, weekly, and seasonal generation and water management patterns. A screening analysis was used to decide which bundles would be modeled in more detail. The river basins that were more fully modeled are shown in **bold** in Table C-1. Those bundles that are <u>not</u> highlighted are unlikely to see significant changes in operations under any ownership regime, unless they are decommissioned, because they either have little storage and operate largely as run-of-river, or they have significant unavoidable institutional constraints that will continue to limit operations under any scenario.

1 The legal, contractual and non-binding constraints are identified in Appendix D. The modeling of these constraints is discussed in detail later in this Appendix.

Table C-1
General Operational Flexibility

Bundle	System	Daily	Seasonal	Comments
1	**Hat Creek**	No	No	Upstream of and integrated with Pit River
2	**Pit River**	Yes	No	High flows relative to storage
3	Kilarc-Cow Creek	No	No	Minimal storage, run of river
4	Battle Creek	No	No	Run of river, partial decommissioning with CalFed
5	**Hamilton Branch**	No	Yes	Upstream of NF Feather River
6	**NF Feather River**	Yes	Yes	Significant storage in Almanor, Butt Valley
7	**Bucks Creek**	Yes	Yes	Integrated with NF Feather River, storage in Bucks Lake
8	Butte Creek	No	No	Minimal storage
9	Narrows	No	No	Integrated with Yuba CWA system
10	**Potter Valley**	No	Yes	Diverts from Eel to Russian River
11	**Drum-Spaulding**	Yes	Yes	Integrated with Nevada ID system, PCWA contracts
12	**Chili Bar**	Hourly	No	Integrated with Sacramento MUD system
13	**Mokelumne River**	Yes	Yes	Limited by Lodi Decree
14	**Stanislaus River**	Yes	Yes	Coordinated operations with Tri-Dam, NCPA
15	Merced Falls	No	No	Integrated with Merced ID system
16	**Crane Valley**	No	Yes	RMR contracts
17	**Kerckhoff**	Yes	No	RMR contracts
18	**Kings River**	Yes	Yes	RMR contracts, Helms pumped storage
19	Tule River	No	No	Run of river
20	Kern Canyon	No	No	Run of river

1.5 THE INFLUENCE OF MUST-RUN STATUS ON OPERATIONS

The level of potential variability of operations of the plants proposed for divestiture is significantly affected by the Regulatory Must Run (RMR) status of the individual plants. RMR plants are eligible for special contracts (i.e., ISO RMR “A” contract specially tailored to each plant) under which the plants or some individual units within the plants would be guaranteed payments that range from partial to full fixed and variable cost reimbursement in exchange for their operations being dictated by the ISO. Further, pursuant to these tariffs, the ISO has the determinative authority to classify plants as RMR, though the plant owners have some discretion as to which of the RMR contracts to accept.

Any comparison of operations before and after divestiture will vary with the RMR status of each plant. The more stringent the RMR requirements on a plant, the less variation that can arise in the plant’s operations regardless of plant ownership. At the extreme, if all of the divested plants were required to be RMR at all times, then the operation of the hydropower generation would reduce to a single commitment and dispatch outcome without permissible variation regardless of varying ownership inclinations. Table C-2 lists the 2,251.2 MW in hydropower units that are currently under an RMRA or proposed to be added by the ISO in 2001.[2]

Table C-2
Pacific Gas and Electric Company Hydro Units
Proposed for RMR in 2001 (ISO, Aug 2000)

Number	Name	Unit #	MW	1999 RMR	2000 RMR
1	Alta PH	1	1.0		
2	Alta PH	2	1.0		
3	Balch PH#1	1	34.0	A	
4	Balch PH#2	2	52.5	A	Y
5	Balch PH#2	3	52.5	A	Y
6	Chilibar	1	7.0		Y
7	Coleman	1	13.0	I	
8	Cow Creek	1	0.9		Y
9	Cow Creek	2	0.9		
10	Crane Valley	1	0.9	A	
11	Crane Valley SJPH#1	2	0.4	A	Y
12	Crane Valley SJPH#2	3	3.2	A	Y
13	Crane Valley SJPH#3	4	4.2	A	Y
14	Deer Creek	1	5.7		Y
15	Drum PH No. 1	1	13.3	I	
16	Drum PH No. 1	2	13.3	I	Y
17	Drum PH No. 1	3	13.3		Y
18	Drum PH No. 1	4	14.1		Y
19	Drum PH No. 2	5	49.5		Y
20	Dutch Flat No. 1	1	22.0	I	Y
21	Electra	1	30.0		Y
22	Electra	2	31.0		
23	Electra	3	31.0		
24	Haas PH	1	77.0	A	
25	Haas PH	2	78.0	A	Y
26	Halsey	1	11.0	I	Y
27	Helms	1	404.0	A	Y
28	Helms	2	404.0	A	Y
29	Helms	3	404.0	A	Y
30	Inskip	1	8.0	I	Y
31	Kerckhoff PH#1	1	12.7	A	Y
32	Kerckhoff PH#1	2	12.7	A	Y
33	Kerckhoff PH#1	3	12.7	A	Y

2 The capacity values shown are from the ISO's RMRAs, and may not match the listed unit capacities in other documentation.

Table C-2
Pacific Gas and Electric Company Hydro Units
Proposed for RMR in 2001 (ISO, Aug 2000)

Number	Name	Unit #	MW	1999 RMR	2000 RMR
34	Kerckhoff PH#2	1	155.0	A	Y
35	Kilarc	1	1.6		Y
36	Kilarc	2	1.6		
37	Kings River	1	52.0	A	
38	Narrows	1	12.0	I	Y
39	Newcastle	1	14.1	I	Y
40	Salt Springs	1	11.0		Y
41	Salt Springs	2	33.0		
42	South	1	7.0	I	
43	Spaulding No. 1	1	7.0	I	Y
44	Spaulding No. 2	1	4.4		Y
45	Spaulding No. 3	1	5.8		
46	Tiger Creek	1	32.0		
47	Tiger Creek	2	32.0		
48	Volta No. 1	1	9.0	I	
49	Volta No. 2	1	0.9	I	Y
50	West Point	1	16.0		Y
51	Wise No. 1	1	15.0	I	
52	Wise No. 2	1	3.0	I	Y
53	Wishon	1	5.0	A	Y
54	Wishon	2	5.0	A	Y
55	Wishon	3	5.0	A	Y
56	Wishon	4	5.0	A	Y

Agreements: A = ISO RMRA "A" in 1999
I = Informal Agreement w/ISO & Pacific Gas and Electric Company in 1999
Y = ISO RMRA in 2000

2. FUNDAMENTAL RESTRUCTURING ISSUES

2.1 DEFINING THE RESTRUCTURING BASELINE

This baseline analysis attempts to characterize how Pacific Gas and Electric Company, as the existing investor-owned utility owner of the resources proposed for divestiture, would likely operate these plants under restructuring. The analysis focuses on the different incentives that exist in the transition and post-transition periods, and how these incentives affect both market performance and Pacific Gas and Electric Company's behavior.

The analysis presented here relies, to the extent possible, on observations of how the nascent trading system is operating and, where not apparent from current power market operations, on assumptions that are conservative with respect to potential environmental impacts resulting from divestiture under a restructured regulatory regime, i.e., so as not to underestimate the possible operational changes by a new owner. Policy directives and critical dates spelled out in CPUC's *Preferred Policy Decision* and AB 1890 were used. For example, market valuation of all generation resources is assumed to occur by the December 31, 2001 deadline mandated in AB 1890. Where no guidance was given or no supporting documentation existed, the analysis assumed that the *status quo* would continue into the future to the extent that it is not changed explicitly by restructuring. An important difference in this divestiture proceeding from the initial round of sales of thermal power plants by Pacific Gas and Electric Company, Southern California Edison Co., and San Diego Gas and Electric Co. is that these sales meet fewer CPUC and state policy objectives.[3]

The cost-based rates that applied to everything but Diablo Canyon Nuclear Generating Station prior to restructuring allowed Pacific Gas and Electric Company to recover operating costs with little incentive to minimize inefficiencies, such as somewhat less than economic utilization of the hydro system. Regulation allowed informal and non-binding agreements to be made and kept with little pain to the stockholder since the costs were passed on to the ratepayer. After restructuring, neglecting the effects from stranded-cost recovery (the competition transition charge, "CTC"), reduced costs will translate directly into increased profits and less-than-economically efficient operation is paid by the stockholders. Therefore, an owner after restructuring is likely to be less tolerant of less-than-economic operation and of non-binding agreements that reduce profitability unless there are compensating factors, such as the concurrent operation of a regulated business.

California's restructured power market began operations on April 1, 1998. At that point, three important changes occurred that directly affect the current operations of Pacific Gas and Electric Company's hydropower facilities. The first was that the hour-to-hour, and in some cases minute-to-minute, direction of the operation of the power plants was transferred from Pacific Gas and

3 Pacific Gas and Electric Company divested almost all of its fossil-fueled and geothermal generation, but is still owner of the Diablo Canyon Nuclear plant and two fossil-fueled plants, as well as the State's largest hydroelectric system, which is proposed for divestiture during this phase.

Electric Company to the California Independent System Operator (ISO). The ISO directs the operation of the facilities to match statewide loads and meet reliability requirements. ISO operators tend to be less familiar with specific plant characteristics due to the much larger statewide generation portfolio that the ISO now controls. Second, Pacific Gas and Electric Company now bids its capacity to the California Power Exchange (CalPX) to meet statewide energy demands, and to the ISO to serve statewide reliability requirements. Before restructuring, Pacific Gas and Electric Company scheduled and operated its own power plants, including hydropower, to meet its own energy and reliability needs. And third, Pacific Gas and Electric Company now must recover all of its future operating and investment costs, beyond those incurred as of December 31, 1997, from the power revenues it generates from sales to the PX and ISO markets. Pacific Gas and Electric Company no longer has an assured return on its investment in generation-related assets.

These changes have important implications for how the hydropower assets are operated. Prior to restructuring, Pacific Gas and Electric Company owned or controlled most of the generation serving its loads. Recovery of these investment costs was stable from year to year, regardless how much energy each generated. “Capacity” values were being given significant attention in state utility planning studies in the early 1980s. Substantial investment was made in conservation, energy efficiency, and even peaking generation resources such as the Helms Pumped Storage plant. However, when Pacific Gas and Electric Company scheduled and dispatched its generation on a seasonal and hourly basis, it generally used only the short-run operating costs of the available resources without considering the capacity value of those resources during particular hours. Due to the similarity in operating costs of the existing natural-gas-fired steam-boiler-turbine power plants that were the last or “marginal” units being scheduled and dispatched,[4] the hourly operational costs did not vary substantially from month to month except for the varying availability and price of economy power from outside the state.[5]

The most valuable aspect of hydropower facilities is that a significant portion of water released through the turbines can be scheduled to match the time periods when it is most valuable. Under regulation, Pacific Gas and Electric Company was more likely to "peak shave", i.e., follow the daily load pattern without paying close attention to the relative economic cost differences between hours or between months. For example, Pacific Gas and Electric Company would schedule generation in August in relative proportion to expected loads in August on an annual basis to the extent feasible, because the hourly costs that Pacific Gas and Electric Company saw were roughly

4 The heat rates for most marginal fossil units varied only from 9,000 to 13,000 Btu/KWh, or less than 50 percent. Implicit capacity values in the current markets are several times this difference in many peak hours.

5 See for an estimate of month-to-month marginal costs during regulation, Richard McCann, David Mitchell, and Lon House, “Impact of Bay-Delta Water Quality Standards on California's Electric Utility Costs,” by M.Cubed before State Water Resources Control Board, Review of Standards for the San Francisco Bay/Sacramento-San Joaquin Delta Estuary, Sacramento, California: Association of California Water Agencies, October 7, 1994.

proportional among months as well. This approach approximated economic dispatch, but did not reflect the increasing value of capacity later in the summer at the same load levels.

This situation changed with restructuring. The hourly power price now reflects not only the differences in operational costs, but also the "scarcity value" of adding capacity necessary to meet reliability requirements. This scarcity value is now a significant means by which plant owners recover their investment costs in generation. The scarcity value increases at a disproportionate rate as loads rise and/or generation becomes less available. As a result, market prices rise rapidly as demand spikes or/and as more plants are unavailable.

Returning to hydropower, the market now gives clear signals as to when releasing water is most valuable. These periods are predictably concentrated around the system peak loads mostly likely to occur in July and August. Pacific Gas and Electric Company may well now be following these price signals by deferring from June generation, and scheduling its hydropower units to generate most during the peak load hours later in the summer. At least there has been an observed shift in operations in 1998 and 1999 that likely is not completely attributable to the late seasonal runoff experienced in both of those years. It is to be expected that Pacific Gas and Electric Company will respond to market signals and the result will be that hydropower generation will be delayed into the summer months as much as possible. The hour-to-hour changes will be more dramatic as Pacific Gas and Electric Company brings on the most capacity feasible during the hours when it is most valuable. Because Pacific Gas and Electric Company must recover most of its "going forward" costs from these market revenues now (i.e., it is more at risk for those costs) Pacific Gas and Electric Company is likely to operate with less tolerance for inefficiencies in its hydropower system. So, under restructuring alone, changes should include (1) less water releases during the spring and early summer than before, (2) daily ramping rates that are more rapid, particularly on days with the highest peak loads, and (3) larger disparities in daily releases between high load/value and low load/value periods (e.g., hot weekday afternoons versus cool weekend nights). These effects will occur regardless of whether the hydropower assets are divested or not. In other words, the historic operations over the last 25 years are not an appropriate measure for determining the baseline "existing" conditions.

2.2 TRANSITION VS. POST-TRANSITION PERIODS

The effects of the restructuring reforms are being phased in during a mandated "transition period."[6] The measures implemented during this transition period, particularly including the CTCs being

6 Public Utilities Code Section 368(a) provides: "The cost recovery plan shall set rates for each customer class, rate schedule, contract, or tariff option, at levels equal tot he level as shown on electric rate schedules as of June 10, 1996, provided that rates for residential and small commercial customers shall be reduced so that these customers shall receive rate reductions of no less than 10 percent for 1998 continuing through 2002. These rate levels for each customer class, rate schedule, contract, or tariff option shall remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered. The

imposed upon essentially all sales, and the simple inertia of existing plant and operating procedures, will act to moderate any sudden changes in operations.

In the post-transition period, both the IOUs and the new entrants to California's power market will have to recover their generation investments directly from sales revenue.[7] Under regulation, utility dispatchers chose which generation plant to use based on instantaneous incremental energy costs. The dispatchers could largely ignore the need to recover other longer-term costs, such as start up, labor, and capital investment. While a simplistic economic analysis might consider these "sunk," these costs in fact are a function of how often a unit is operated, cycled, and maintained. In the restructured market, plant owners will consider what prices they will need to recover these longer-term variable costs, as well as to maintain their financial status in recovering past investments, and expected market conditions. Our assumption for this analysis was that CTC will end valuation for all cases considered, so it was not included in the Baseline case, or for any other case.[8]

3. HOW OWNERSHIP INFLUENCES OPERATIONAL AND INVESTMENT DECISIONS

3.1 INTRODUCTION

In order to meet the requirements of the CEQA process the EIR preparers needed to answer the question, "How can the divestiture affect the operations of the hydro system and, in turn, impact the environment?" To do this, the EIR preparers developed a baseline case, "no project" case, and "primary" cases that define the range of operations that could be reasonably foreseen as a result of divestiture. The primary cases are not intended to represent specific likely cases, but rather a reasonable range of the results. The baseline case looks at a range of hydrological conditions, developed from the 1975 to 1998 period of record, rather than merely the hydrological conditions

electrical corporation shall be at risk for those costs not recovered during that time period. Each utility shall amortize its total uneconomic costs, to the extent possible, such that for each year during the transition period its recorded rate of return on the remaining uneconomic assets does not exceed its authorized rate of return for those assets. For purposes of determining the extent to which the costs have been recovered, any over-collections recorded in Energy Costs Adjustment Clause and Electric Revenue Adjustment Mechanism balancing accounts, as of December 31, 1996, shall be credited to the recovery of the cost." The CTC officially ends for a given IOU the earlier of March 31, 2002 or three month after full collection of CPUC adopted CTC for that IOU. Pacific Gas and Electric Company may be able to complete CTC collection prior to the maximum permitted end date, particularly if the hydropower assets are valued at a premium above book value.

7 There are exceptions to this rule: (1) plants necessary for system reliability and other services which will have contracts with the ISO; (2) utility plants which could still be regulated under performance-based ratemaking (PBR) or other special agreements such as nuclear power facilities; and (3) qualifying facilities (QFs). However, for even these facilities, a certain portion of their revenues will likely be tied to the power market and their operations will affect the revenues of other facilities.

8 The CTC introduces several confounding incentives for IOUs in bidding generation. The IOUs will want to balance generation revenues against power purchase costs to best ensure recovery of their stranded assets. AB 1890 and CPUC decisions introduced several specific exemptions to CTC recovery that further complicate these incentives. For this reason, determining the utilities' objectives in bidding resources during the transition period is extremely difficult.

for the last two years of restructuring. The baseline case, however, reflects the level of infrastructure development and energy market demand in the study year 2000. The No Project cases use the same basis assumptions as the baseline, updated to 2005. The primary cases are developed to capture the likely range of environmental impacts under different ownership scenarios in 2005. These primary cases do not represent all of the possible outcomes, but are meant to include a range of environmental impact consistent with plausible outcomes of the divestiture.

We first describe the Baseline and No Project cases. Then, each of the primary cases are defined by differing management objectives after divestiture and assumed corresponding behavior. These cases can be compared to the baseline to determine how operations might change compared to the appropriate baseline conditions.

3.2 THE INFLUENCE OF DIFFERING MANAGEMENT OBJECTIVES

3.2.1 No Project – Retention by Pacific Gas and Electric Company within Regulated Utility

In this scenario, Pacific Gas and Electric Company does not divest the assets, but rather a market value of assets is established that is credited against the Transition Cost Balancing Account. The competitive transition period ends, and the CTCs are reduced accordingly. Pacific Gas and Electric Company would recover its hydropower investment, which is set at the market value, at an established rate of return through rates. The plants' generation would be bid to minimize power costs to ratepayers in the context of an environmentally responsible "good" citizen, and operations are reviewed annually to assure the assets are used in the public interest.[9] To meet this objective, the hydropower assets would be scheduled and dispatched to best meet demand during the highest-priced hours of the year to the extent possible in keeping with its traditional environmental considerations.

However, because Pacific Gas and Electric Company generation would continue to be regulated along with its distribution and transmission assets, Pacific Gas and Electric Company would continue to observe all of its present voluntary, informal, and unenforceable ("non-binding") agreements and arrangements. Ignoring, abrogating or otherwise violating these agreements could bring political pressure to bear on Pacific Gas and Electric Company's other regulated operations, thus leaving open an avenue outside of the FERC to informally enforce them. In addition, Pacific Gas and Electric Company would observe the interim agreements that it has made in anticipation of FERC relicensing. The operations would be largely unchanged from those we see today as a result of restructuring.

If, however, regulators conclude that abiding by the non-binding agreements is costing ratepayers significant sums, they could order Pacific Gas and Electric Company to operate the hydro facilities

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9 Public Utilities Code Section 454 allows up to one percent in additional rate of return on assets for environmentally-preferable generation, as defined by the Resources Agency. Southern California Edison Company has proposed such treatment for its retained hydropower assets in A. 99-12-024.

more aggressively. For example, if regulators concluded that an informal agreement to maintain a particular reservoir level benefits few but costs ratepayers millions, they could order Pacific Gas and Electric Company to break the informal agreement. Regulators might be motivated to do so if natural gas prices reached unprecedented heights or capacity became extremely valuable.

3.2.2 The PowerMax Case - Maximizing Power Revenue Objective

In this scenario, Pacific Gas and Electric Company divests the assets, and the auction proceeds are credited against the Transition Cost Balancing Account. The competitive transition period ends, and the CTCs are reduced accordingly. Most, if not all, of the new hydropower assets owners' investments would be recovered from power market revenues. A new owner would not own more than one aggregated bundle or any other generating assets in Northern California. Each new owner would be a "price taker" that cannot readily influence market prices in a way that changes plant operations because they could not benefit from changes in prices. Capacity would be bid and operated to meet the loads during the highest-priced hours.

New or revised uses of the water may be developed to fully optimize the value of the investment. Such changes would reflect the willingness of other river or reservoir users to pay for such modifications in operations. For example, this could include greater releases during the weekend or on holidays to benefit rafting companies, or retained water in reservoirs to benefit homeowner associations along the shoreline during the early summer. In other words, whatever "obligation to serve" that carried over in the culture of the restructured Pacific Gas and Electric Company would likely be less present in a new private owner without market power. However, we have not quantitatively assessed these potential uses, as identifying them at individual locations would be speculative.

Possibly the most important change is that the existing voluntary, informal and/or unenforceable agreements that reduce potential profits may end. For example, agreements to maintain higher instream flows or reservoir levels may be ignored unless contractual or regulatory actions are taken. Potential changes include:

1. Water delivery contracts may be renegotiated or cancelled.
2. Facilities may be ramped up and down at faster rates.
3. Public and private uses of land associated with the hydro facilities that infringe on project operations or require expenditures by the facility owners may be ended.

The changes that have occurred as a result of restructuring may be accentuated to the degree permissible by the nature of the institutional arrangement now governing operations of the plants. These changes include:

1. Releasing only FERC-mandated minimum flows during off-peak hours.
2. Ramping generation up and down at physical plant limits unless specifically constrained by FERC license requirements.

3. Drawing down reservoirs more rapidly in the late summer to maximize power generation during the most valuable periods.

In other words, the facilities will be operated more closely to physical, regulatory, and contractual limits to maximize project-related profits. A special case of this scenario occurs if the plants would be owned in the smallest bundles proposed by Pacific Gas and Electric Company (the “20 bundles” case). On the Feather River and in the Crane Valley and Kerchoff systems, there may be multiple owners who may not readily coordinate their operations. Coordination agreements would have to be signed among the operators, but no agreement can foresee all circumstances, and each operator could make short-term decisions that maximize its own profit. Upstream operators may tend to generate at higher levels during the high-price hours with less regard as to how that will affect downstream facilities. As a result, more water may be spilled at the downstream dams. On the other hand, coordination agreements may be written sufficiently tightly to ensure that such events occur rarely, if at all. Also, the amount of water affected may not be sufficient to significantly impact downstream users.

3.2.3 The WaterMax Case – Ensuring Water Supply Reliability and Deliverability Objective

The applicability of this scenario varies by river basin, and only affects those that have potential water utility or purveyor buyers. For the other river basins, only the PowerMax Case is applicable. The potential buyers are segmented into two classes.

The first class of buyers currently takes delivery from Pacific Gas and Electric Company and is interested in retaining, at least approximately, current water deliveries. These agreements only differ from the Baseline case where voluntary, informal, or unenforceable agreements may be changed. For this reason, potential ownership by these entities is not considered here. The Potter Valley Project, on the Eel-Russian Rivers complex, is the major example of this class. That project is currently operated to meet Potter Valley Irrigation District water delivery requirements. Other examples include Butte Creek, Merced Falls, Tule River, and Kern Canyon.

The second class of buyers would prefer to manage these projects to meet a set of water supply objectives that may not conform with power revenue maximization. These are the ones considered here since they would change operational objectives. Because only certain river basins are likely to be purchased for this purpose, other river basins could be managed at the same time by other owners to maximize power market profits as described in the PowerMax Case. Table C-3 lists the bundles along with the water utilities and purveyors that fall into the second class and are the candidates that are most likely to buy the bundles for this purpose.

The primary management objective in the WaterMax Case would be to provide the largest, most reliable water deliveries to meet municipal and/or agricultural demands. The added supplies may be retained at reservoirs downstream of the Pacific Gas and Electric Company facilities for delivery through conveyance projects, such as the Central Valley Project, State Water Project, or East Bay

MUD's Mokelumne River facilities. These supplies may be provided even if electricity generation creates greater direct economic value. Because water utilities are almost universally local government entities, their primary objective is to meet water supply demands with great emphasis placed on political factors.[10]

Table C-3
Candidate Water Purveyor Purchasers of Pacific Gas and Electric Company Hydro Projects

Bundles	River System	Candidate	Comments
1-2	Pit River	Private water company, Westlands WD or CVP Contractors	Dry year value only when Shasta does not fill
5-7	NF Feather River	State Water Contractors	Current downstream water rights holder
11	Yuba-Bear River	Placer CWA or Nevada ID	Current water project contractor
13	Mokelumne River	East Bay MUD	Current downstream water rights holder
14	Stanislaus River	Tuolumne UD	Current contractor with conservation incentives
16	Crane Valley	Friant WUA or USBR	Downstream Friant water contractors

To achieve improved water supply reliability, the water supplier would chance a greater risk of spills during the spring of a normal to wet year by holding the most water possible until dry conditions ensue. This means that reservoirs would be held to their highest level possible through the summer and instream flows would be minimized. Nevertheless, the water supplier would attempt to maximize power-sale revenues to the extent possible within those constraints, meaning that generation capacity would still be used to the maximum extent possible during the highest-priced hours. During dry years, the water supplier would draw down the reservoir to meet water supply demands, regardless of any losses in power revenues or impacts to recreation.[11] The owner may go so far as to bypass the power turbine inlets to access a larger (deeper) portion of reservoir storage in those years. This could lead to a reduction in energy and capacity in drought conditions beyond those that occur now.

A water utility or purveyor located outside the region and essentially beyond local political influence will tend to void non-binding agreements that impinge on favorable operations or increase uncompensated costs, similar to a private power marketer. The public agency status of this class of owners will help protect such actions from judicially-imposed restraint.

10 See for a more complete discussion on water utility objectives, Richard J. McCann and David Zilberman, "Governance Rules and Management in California's Agricultural Water Districts," in *The Political Economy of Water Pricing Reforms*, ed. Ariel Dinar (New York City, New York: Oxford University Press, 2000).

11 For example, the City and County of San Francisco currently follows this practice in operating the Hetch Hetchy Project (Ron Knecht et al., *Final Report on the Feasibility of Electric System Municipalization in San Francisco*, San Francisco, California,: Economic and Technical Analysis Group, February 11, 1997).

Due to the physical and institutional differences among these entities, they would likely use different management strategies in operating each river basin to attain their objectives. For each river basin, those would translate into the following operational changes:

Pit River

Pacific Gas and Electric Company owns eleven reservoirs on the Pit and McCloud Rivers with a combined storage capacity of about 158,000 acre-feet. The largest reservoirs and their total storage capacity in acre-feet are Lake Britton (41,907), Lake McCloud (35,234), Pit 7 Forebay (34,611), Iron Canyon Reservoir (24,241), and Pit 6 Forebay (15,886). Pacific Gas and Electric Company reports licensed water rights for 19,943 acre-feet in Iron Canyon and 15,500 acre-feet in Pit 7 Forebay. Any use of these facilities for water supply would require that water be passed through Lake Shasta, a CVP reservoir on the upper Sacramento River. From there, water could be delivered downstream for irrigation use in the Sacramento Valley, or water could be released to the Delta and exported for use in the San Joaquin Valley, the Bay Area, or Southern California.

The most likely buyer of the Pacific Gas and Electric Company facilities is assumed to be a water broker who would sell water to the highest bidder, such as the State Drought Water Bank. The Bureau of Reclamation could also be another potential intermediary. Water would probably be sold only in dry years. Urban users are the most likely buyers in these markets, and Westlands Water District is also a potential buyer.

Lake Shasta, which receives flows from the Sacramento, McCloud, and Pit Rivers, usually refills entirely in normal and wet water years[12]. Only under dry conditions is additional storage upstream of Shasta of any value. In years with dry conditions, the strategy that best improves water supply reliability and provides the most value for stored water is releasing water at Pit 7 below the turbine inlets. This allows access to an additional 15,000 acre-feet of stored water. The Pit River owner would be foregoing power revenues at that time, but the dry-year value of the water supplied is assumed to be greater.

North Fork Feather River

Pacific Gas and Electric Company owns eleven reservoirs on the North Fork Feather River with a combined capacity of 1,340,486 acre-feet. Important reservoirs and their total storage capacity in acre-feet are Lake Almanor (1,142,964), Bucks Lake (105,605), and Butt Valley Reservoir (49,897). Pacific Gas and Electric Company has an obligation to release 145,000 acre-feet annually from its reservoirs upstream of the State's Thermalito Afterbay for delivery to Western Canal Water District.

[12] A water year is the 12-month period, October 1 through September 30. The water year is designated by the calendar year in which it ends. Thuse, the year ending September 30, 1995, is called the 1995 water year.

Most uses of these facilities for water supply would require that water be passed through Lake Oroville, a SWP reservoir on the lower Feather River. From there, water could be delivered downstream for irrigation use in the lower Sacramento Valley, or water could be released to the Delta and exported for use in the San Joaquin Valley, the Bay Area, or Southern California.

The most likely buyer of the Pacific Gas and Electric Company facilities is assumed to be the Department of Water Resources or State Water Contractors. The water would probably be allocated among SWP contractors according to existing entitlements and allocation criteria as modified by the Monterey Agreement.

Storage at Lake Almanor and Butt Valley Reservoir could be used to supplement storage at Lake Oroville through better coordination of system releases. In general, this implies holding Almanor and Butt Valley at higher levels during normal and wet years and not drawing them down as far during the late fall. This would increase the likelihood of winter-time spills. In dry years, these reservoirs would be drawn down further to meet water supply demands put on Oroville.

Yuba-Bear River Complex

Pacific Gas and Electric Company owns 22 storage reservoirs and seven small forebays and afterbays on the Yuba, Bear and North Fork American Rivers. Important reservoirs and their total storage capacity in acre-feet are Lake Spaulding (74,773) and Fordyce Lake (49,903). Total Pacific Gas and Electric Company storage capacity is about 151,000 acre-feet. Pacific Gas and Electric Company owns the water right to store up to 45,000 acre-feet of water in Englebright Lake, a U.S. Army Corps of Engineers reservoir on the lower Yuba River. Any use of these facilities for water supply would require that water be passed through Englebright Lake or routed down the Bear River, or through the Bear River Canal to Folsom Lake on the American River.

The Pacific Gas and Electric Company facilities are closely inter-connected with facilities owned by Nevada Irrigation District (NID) and Yuba County Water Agency, and operations are coordinated for hydropower and water supply purposes. A number of agreements and contracts are used to deliver water supply for irrigation and domestic purposes. Pacific Gas and Electric Company supplies up to 100,400 acre-feet of water under a water supply contract, and separate purchase agreements provide additional supplies to Placer County Water Agency up to a total of about 125,000 acre-feet.

The most likely buyer of the Pacific Gas and Electric Company facilities is assumed to be Placer County Water Agency (PCWA). Water would be allocated among PCWA member agencies. Existing contracts with Nevada Irrigation District and the District's own water rights would complicate transfer of additional volumes of water out of the system.

PCWA would manage the system to increase the probability of receiving full supplies in all years. This would be accomplished by holding reservoirs at higher storage levels in normal and wet years, particularly higher up the cascade, and by drawing down the reservoirs further in dry years.

Mokelumne River

Pacific Gas and Electric Company owns thirteen reservoirs on the North Fork of the Mokelumne River with a total capacity of about 225,000 acre-feet. Important reservoirs and their total storage capacity in acre-feet are Salt Springs Reservoir (141,857) and Lower Bear River reservoir (52,025). Pardee and Comanche Reservoirs, owned and operated by East Bay Municipal Utility District for municipal water supply, are downstream. Agreements with Amador Water Agency, and the Lodi Decree, a court adjudication, require certain releases, storage and deliveries from the Pacific Gas and Electric Company system.

The most likely buyer of the Pacific Gas and Electric Company facilities is assumed to be East Bay Municipal Utility District (EBMUD) or a consortium of water agencies dependent on the Mokelumne.[13] Water would be used to increase deliveries to municipal customers in the EBMUD service area, or EBMUD might use the water in an exchange or conjunctive use agreement with irrigators located downstream of Comanche Reservoir.

EBMUD would try to retain as much water storage as possible at the top of the Mokelumne cascade in Salt Springs and Lower Bear Reservoirs and the several smaller upper reservoirs. It would do this by holding those reservoirs at the highest possible monthly target levels as defined in the Lodi Decree.

Stanislaus River

Pacific Gas and Electric Company owns five reservoirs on the Middle Fork and South Fork of the Stanislaus River Basin with a combined storage capacity of about 40,500 acre-feet. Important reservoirs and their total storage capacity in acre-feet are Relief Reservoir (15,554), Pinecrest Lake (18,312), and Lyons Reservoir (6,228). New Melones Reservoir, constructed by the Army Corps of Engineers but operated by the Bureau of Reclamation as part of the Central Valley Project, is downstream. Pacific Gas and Electric Company has an agreement with the County of Tuolumne to deliver water from the Phoenix Project on the South Fork Stanislaus River for distribution by the County for consumptive use.

One potential buyer for the Pacific Gas and Electric Company facilities is Stockton East Water District. Stockton East also provides Calaveras River water and groundwater to parts of the Stockton metropolitan area. Other potential buyers include Oakdale and South San Joaquin Irrigation districts (also known as Tri-Dam), and the Tuolumne Utility District (TUD).

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13 EBMUD, AWA, Calaveras County and other local agencies have formed a Joint Power Authority to pursue acquisition of the Mokelumne system.

TUD is assumed to be the most likely buyer for South Fork facilities. The district cannot currently obtain water from Relief Reservoir on the Middle Fork Stanislaus River. Therefore, Tri-Dam is considered a more likely buyer for the Middle Fork facilities.

TUD obtains water from Pacific Gas and Electric Company by a diversion from Lyons reservoir on the South Fork of the Stanislaus River. The district serves municipal and irrigation users in Sonora, Twain Harte, Tuolumne and other developed areas in western Tuolumne County. Current arrangements with Pacific Gas and Electric Company should provide adequate water supplies in the short run. TUD has contemplated increased use of Pacific Gas and Electric Company's South Fork facilities for water supply. The district has studied the potential for enlargement of Lyon's Reservoir to meet increased demands in the future and is currently discussing changes to operations at Pinecrest Lake (Strawberry Reservoir) which would improve supply reliability.

TUD currently receives an incentive payment from Pacific Gas and Electric Company to conserve water and reduce water contract deliveries. TUD would no longer receive those conservation incentives as new owners of the facility. As such, it more likely would attempt to take its full water contract delivery, thus reducing the flows in the South Fork of the Stanislaus River. As with PCWA in the Drum system, it would also tend to hold Strawberry and Lyons Reservoirs higher in wet and normal years, and to draw them down in dry years.

Crane Valley

Pacific Gas and Electric Company owns seven reservoirs in the San Joaquin Basin, most on the North Fork Willow Creek, with a combined capacity of about 50,000 acre-feet. Bass Lake, with 45,410 acre-feet of capacity accounts for 90 percent of the total. Millerton Lake (Friant Reservoir), a water storage facility operated by the Bureau of Reclamation, is downstream. The Bureau of Reclamation may call for release of stored water from Bass Lake under specified conditions.

The most likely buyer of the Pacific Gas and Electric Company facilities is assumed to be the Bureau of Reclamation or the Friant Water Users Association. Water would be used for municipal and irrigation purposes in the Friant service area, or the water might be used for environmental restoration. FWUA and Metropolitan Water District of Southern California recently signed an agreement to facilitate a swap of FWUA's San Joaquin River supplies for MWD's Delta water supplies. FWUA would gain delivery reliability, while MWD would improve its water quality.

The Miller-Lux Agreement requires Pacific Gas and Electric Company to release up to 60% of its storage to Millerton Lake by October. However, an additional 18,000 acre-feet could be released to Millerton if owned by the FWUA. The additional water could be used to meet the recent San Joaquin River agreement between FWUA and the Natural Resources Defense Council (NRDC). In addition, this water could be introduced into the active Friant-Kern Canal water transfer market, including the proposed swap with MWD.

Special Cases Where Water Purveyors Would Not Change Operations

At least two river basins have been publicly identified as candidates to be managed primarily for water supply. However, after initial screening analysis, we found that these projects either were already operated to meet water supply objectives (Potter Valley) or simply would not be economic to operate in this mode (Kings River). We discuss each of these in turn.

Potter Valley

In The PowerMax Case, Lake Pillsbury is operated to maximize flow through the Potter Valley powerhouse. Since the operation necessary to maximize water deliveries requires maximizing flow through the Potter Valley powerhouse, these two alternatives would be virtually identical. In dry years, the system is water supply constrained and there are no additional supplies to divert. The supply is just enough to meet instream flow requirements down the Eel and Russian Rivers, water delivery demands, and the storage targets at Lake Pillsbury. In wet years, the system is capacity constrained by the size of the tunnel and powerhouse. No additional supplies could be diverted through the system in the winter because the facilities are at capacity. Thus, no operational differences exist between the PowerMax and the WaterMax Cases for Potter Valley.

Kings River

The Kings River system has substantial storage that might be used to supplement Pine Flat Reservoir if economically attractive. Courtright and Wishon Reservoirs have about 252,000 acre-feet of storage, representing more than 99 percent of the bundle storage, but much of this storage is necessary for operation of the Helms Pumped Storage facility. Given this situation, an owner who is focused on water-supply objectives, such as the Kings River Water Association, is unlikely to purchase the Helms complex because it would be too costly to forego Helm revenues to use primarily for water supply. [14] If Helms is valued at only $100 per kilowatt (compared to estimates of up to $1,000 per kilowatt for the entire Pacific Gas and Electric Company hydro system), that translates into an effective cost of $750 per acre-foot. A Kings River water supplier would place a value of about $500 per acre-foot on that storage. Given the much greater value Helms probably has as a generation facility, it is unlikely that any water purveyor would purchase the Kings River system for the primary purpose of improving water supplies.

3.2.4 Alternative – Unregulated Ownership by an Owner with Thermal Generating Assets, including PG&E Corporation

In this scenario, we assume that an owner acquires or retains a sufficient amount of the hydropower system, in conjunction with owning significant amounts of thermal generation in Northern

14 If KRWA did purchase the system, it would be to protect its current water supply situation, in which case it would fall into the first class of water utilities described above.

California, to profitably influence power market prices.[15] When the competitive transition period ends, the CTCs would be reduced accordingly. All future revenues for these generation assets will come entirely from the market at the end of the transition period. Thus, this owner would be trying to optimally recover its costs and profits from its entire generation portfolio in Northern California. It now would have an incentive to exert "market power," i.e., the ability to influence market prices to its benefit.

Market power can be exerted in several different ways. The owner could shift certain hydro facilities' generation away from the peak load hours, generating less than would be optimal under fully competitive conditions. The desired effect is to raise the price proportionately more than the reduction in generation from the owner's portfolio. A subtle form which could be difficult to detect would involve reducing generation during the "shoulder peak" hours when loads and prices are at intermediate levels, but prices still can be substantially influenced by changes in available generation resources. Hydrogeneration during hours when less than peak capacity would be used can be shifted to lower load periods through several less detectable means. These include:

1. Increasing off peak generation or fish flow releases to reduce the available amount of energy during the shoulder peak hours;
2. Using restricted ramping rates to extend the period over which output increases and decreases must occur; and
3. Maintaining higher reservoir levels and limiting reservoir fluctuations through the summer high-load period.

All of these actions can be "hidden" through various agreements, some of which can become enforceable against any ISO action by inclusion in FERC license requirements. The first two actions can lead to higher instream flows with reduced hourly and daily fluctuations. The third can benefit reservoir and stream related recreation. The owner also could do the same with its thermal generation units. A form of this strategy was performed effectively in the English power market.[16] A third approach would be to withhold hydro capacity from the ancillary services market, which could drive up prices in both the ancillary services and energy markets due to the linkage between

15 The scenario discussed here includes one in which PG&E Corporation could be able to dispose of the hydropower assets however it wishes once the assets are market valued, under the interpretation of PUC Section 377 argued by Pacific Gas and Electric Company in this proceeding. PG&E Corporation could transfer these assets to an unregulated affiliate, such as Pacific Gas and Electric National Energy Generation (NEG). The assets would be used to maximize the profits of the parent company, Pacific Gas and Electric Corporation. PG&E Corporation affiliates currently own and operate the 2,160 MW Diablo Canyon Nuclear Generating Station and are constructing the 1,079 MW Los Palomas combined-cycle plant. Other current owners of thermal generation that could fall into this category include Southern Energy, Duke Energy, and Calpine.

16 Catherine D. Wolfram, "Strategic Bidding in a Multi-Unit Auction: An Empirical Analysis of Bids to Supply Electricity in England and Wales" (paper presented at the Electricity Industry Restructuring: Second Annual Research Conference, Berkeley, California, March 14 1997).

the two. Withholding capacity will bring more higher-priced alternative generation on line and elevate the market-clearing price paid to the single owner's thermal generation.

Nevertheless, at least three caveats must be recognized. First, the number of hours in which market power can be exercised is limited and will vary with hydro and summer weather conditions. Second, after sufficient new plants have come on line to restore the load generation balance, the ability to exercise market power would decline so long as the rate of capacity additions from that point forward exceeds the rate of load growth. Third, for most of the Pacific Gas and Electric Company powerhouses, increasing instream flow releases bypassing the powerhouses would represent lost generation and revenue that would need to be made-up by the increased price received. Once increased flows are established, it would be difficult to return to the old flows if the strategy fails. To the degree that the ability and incentive to exercise market power declines, this case converges with the No Project Case.

We assume that the single owner generally would not observe the voluntary, informal, and unenforceable agreements consistent with the PowerMax Case. However, the single owner may observe selectively certain of these agreements that restrict the operations in a manner that improves the ability to exercise market power.

3.2.5 Alternative – Proposed Settlement Agreement

Pacific Gas and Electric Company jointly submitted a "Settlement Agreement for Valuation and Disposition of Hydroelectric Assets" with several parties in the proceeding on August 9, 2000. The proposed agreement calls for transferring the hydro-related assets to a new Pacific Gas and Electric Corporation affiliate, CalHydro. The proposed agreement would be for a 40-year term. The generation assets would be operated under a performance-base rate (PBR) mechanism that shares any profits or losses beyond the specified capital recovery amount 90 percent to ratepayers and 10 percent to shareholders for the first 35 years. PG&E Corporation may sell the assets to an unaffiliated entity after ten years. A target level on capital additions and operating expenditures is set initially and then adjusted to reflect actual practices. CalHydro will sign a "market-power mitigation" agreement with the ISO similar to that formulated last year as part of the proposal made to the State Legislature to transfer the hydro assets to a PG&E Corporation affiliate. However, the ISO Market Surveillance Committee believes that this agreement still allows for the potential exercise of market power by PG&E Corporation through CalHydro.[17]

From the perspective of conducting the environmental analysis, two key areas of potential impacts are addressed in the proposed settlement documents. First, water supply arrangements and many non-binding agreements are explicitly continued. This is consistent with the assumptions in the No

17 Frank Wolak, Robert Nordhaus, and Carl Shapiro, "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," (Stanford, California: Market Surveillance Committee (MSC) of the California Independent System Operator (ISO), 2000).

Project Case discussed previously. Second, the agreement calls for establishing a $70 million fund to purchase “bridging” flows at specific power plants. These are substantially increased minimum flows that continue until the expected relicensing date for those facilities. CalHydro would be compensated for the lost power generation revenues using a specified methodology spelled out in detail in the proposed settlement. However, the documents give little *a priori* guidance on how these flows regimes would be preferentially selected when available funds are less than required to purchase the entire portfolio.

PBR attempts to achieve pricing and cost recovery that mimics a competitive market. Economic theory states that purely competitive markets will lead to the most efficient resource use. Thus, we expect CalHydro to operate similarly to the regulated utility described in the No Project alternative. The possible exception to this is if the market-power mitigation agreement is not sufficiently binding, and CalHydro can operate the hydro assets to increase the profitability of Pacific Gas and Electric Corporation’s other generating assets. Due to concerns about the adequacy of the “market power mitigation” agreement with the ISO, this alternative could result in changes in operations consistent with the results of the analysis of the single owner with thermal generation assets described in Section 3.2.4 above.

We assume that all of the minimum flows can be purchased simply because we have no criteria for selecting which flows would be purchased if the funds are not sufficient. The $70 million fund is unlikely to be sufficient to accomplish this objective. For this reason, this analysis probably overestimates the environmental benefits of this alternative. Without clear guidance on which streamflows would receive the highest priorities, a more extensive analysis that uses the proposed valuation methodology is meaningless in assessing environmental impacts.

The increased minimum flows will tend to increase power market prices because less hydropower will be available during the peak load periods. These increased prices will tend to induce more investment in new generation plant, which could in turn mitigate the ability to exercise market power with the hydropower plants.

4. THE MODELING PROCESS

Since hydropower units (other than pumped storage units) have low operating costs, their participation in energy markets is based primarily on the opportunity cost for using water that would have a certain market (e.g., energy, ancillary services) value if withheld for future use. This results in hydro units with sufficient access to storage being simulated to time their generation to occur during periods of highest market prices. This timing is limited by the amount of storage and by various constraints on water releases and diversions such as to maintain minimum flows. In this study, the monthly powerhouse water use constraints provided to the UPLAN model from the OASIS model for the different powerhouses reflected these kinds of limitations, and were used to constrain UPLAN’s simulation of how these powerhouses’ generation was timed in response to power market conditions.

Thermal plants are assumed to be operated on an economic basis determined by their projected supply offers in a competitive power market. These units form the core of the supply offers projected for the Power Exchange in California, as well as for most of the WSCC. These plants' bids reflect fuel and other variable operating costs, but potentially also reflect the need to recover fixed (including capital) costs and also costs for cycling and startup, if the units are not baseloaded and thus running almost continuously. Increased revenues and elevated energy market bids that result from simulating ancillary services markets simultaneously with energy markets can provide the additional revenues needed to cover fixed, cycling and startup costs, keeping generators economically viable. All of this analysis is necessary to assess how operations of the hydropower facilities might vary under different ownership regimes, and how those variations might affect the remainder of the electricity system.

The focus of the modeling done by the Operations and Economics Group (OEG) was to identify the reasonably expected changes in hydropower operations that might occur with the divestiture of the Pacific Gas and Electric Company hydropower facilities. A key task was separating the changes that are results of restructuring the electricity marketplace in 1998 from those that might occur with transfer to new owners. This analysis identifies potential changes in both electricity generation patterns and in water management practices. Four primary cases were modeled—Baseline 2000, No Project 2005, The PowerMax Case 2005 and the WaterMax Case 2005. Additional alternatives were also modeled as needed. This first task was conducted using UPLAN, OASIS, and SERASYM™ and involved several steps as presented in Figure C-1.[18]

The first step was performed using a UPLAN model to simulate operations of the power system under market conditions and to develop an initial set of hourly market clearing prices using historical water flow data on hydro facilities. This step was performed using recorded data on how Pacific Gas and Electric Company operated hydro units under historic monthly hydro conditions. However, historical monthly operations of hydro facilities are not representative of how these facilities will be operated under restructured electricity marketplace conditions. So, this step provided an initial "seed" set of hourly market clearing prices that were passed on to the OASIS model. During this step, the UPLAN model was populated with the power system data about the existing loads and resources of the Western System Coordination Council (WSCC) interconnected system.

The second step was performed using the OASIS model. The OASIS model was used to optimize the use of water available for power generation over the year based on the market clearing prices developed in the first step. In other words, UPLAN was reporting the opportunity cost of water, which OASIS used to optimize water use over a specified period. The results from the OASIS model were revised monthly hydropower allocations, reservoir levels, and bypass flows that were

18 The UPLAN model is developed and operated by LCG Consulting. The OASIS model is developed and operated by Water Resources Management Incorporated. SERASYM is developed and operated by Sierra Energy and Risk Assessment Incorporated.

developed based on electricity market conditions. This step in essence calculated optimal operations of hydro facilities under electricity marketplace condition using the representative historical hydrology.

The third step was performed using the UPLAN model to optimize hourly dispatch of hydro resources based on monthly allocations developed during the second step. Once the reallocation of water use was performed, we used UPLAN to conduct new hydro-thermal dispatch and to calculate a revised set of market clearing prices associated with the hydro facilities operations optimized under electricity marketplace conditions. This process finalized the first iteration between models.

The next step was to compare the market clearing prices calculated in Steps 1 and 3. If we found that the market clearing prices calculated by UPLAN were much different, then we would have to perform a second iteration between the UPLAN and OASIS models. The reason for one more iteration is that different market clearing prices could potentially have additional effects on hydro allocations already calculated in OASIS.

Finally, in Step 4 we modeled air emissions. Air emissions were estimated for each case using SERASYM™ model. The hourly hydropower unit operations were directly input into SERASYM™, and the resulting emissions were calculated from the model simulations.

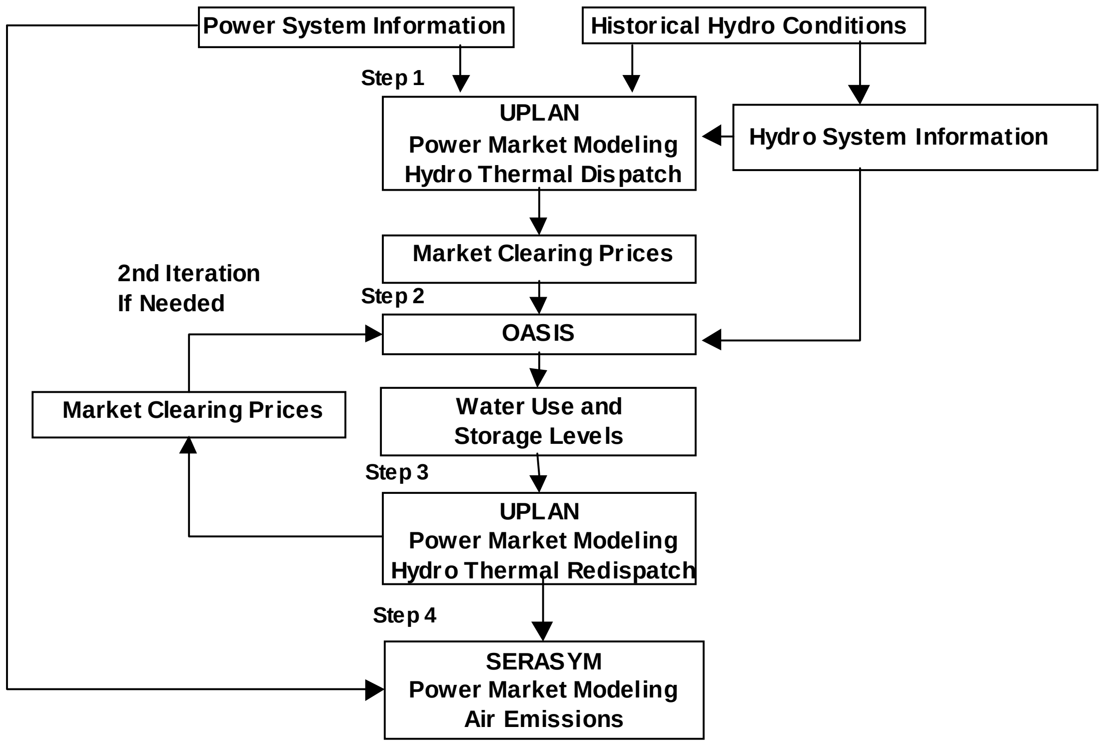
4.1 DESCRIPTION OF MODELS

4.1.1 UPLAN

UPLAN Network Power Model (UPLAN-NPM) is a state-of-the-art competitive electricity market model that simulates both the behavior of the market participants and the physical structure and dynamics of the electric system. The geographic scope of the simulation is an interconnected regional energy market, such as the WSCC, with electric loads and supply (generators) located at numerous nodes on the simulated regional transmission grid. UPLAN has been developed to evaluate utility restructuring and to forecast energy and ancillary service market prices and generator revenues under competition. It has been used to evaluate the implications of various uncertainties affecting asset valuations, market and business strategies, the potential for stranded costs, the impact of emission constraints and new entrants, and the existence of market power.

UPLAN-NPM has been applied for numerous regions within Canada and the United States, as well as many countries overseas. It has undergone extensive public review and testing, and results of

Figure C-1 Modeling Approach



benchmarking have been published in the Electricity Journal.[19] It has been extensively tested in simulating the California PX/ISO, PJM, NEPOOL and other U.S. markets, and it has been benchmarked to actual prices in the evolving markets.

UPLAN's computational objective is to simulate electricity trading that maximizes consumer surplus regarding electricity consumption and its cost, for a given set of bids that reflects (and is intended to at least recover) producer costs. This simulation reflects hourly network constraints including inter-zonal transfer limits, congestion, and voltage stability, combined with the operating characteristics and bidding strategies of individual generators. The simulation is multi-commodity in that UPLAN projects and balances concurrent markets for energy and various ancillary services. It is multi-area in that separate markets and commodity prices are established for different geographic areas (individual nodes, if desired), reflecting transmission constraints and costs that physically and economically limit power flows between areas.

A key feature is simulation of the forward market including market participants' trading behavior, with a range of options for specifying bidding strategies and constraints. This produces internally consistent projections of location-specific forward markets (bids, volumes, clearing prices) for energy and ancillary services including regulation, spinning reserves, non-spinning reserves and replacement or capacity reserves. The model simulates participants' behavior using either specified

19 "How to Incorporate Volatility and Risk in Electricity Price Forecasting," The Electricity Journal, May

bidding strategies or bids developed internally by UPLAN based on rational bidding across the different markets, since bids and projected bid acceptance into one market affect bids and projected bid acceptance into other markets. UPLAN iteratively simulates interaction among the different markets, to produce an equilibrium set of forward prices that eliminates arbitrage opportunities among the markets.

Next, UPLAN simulates the real time market to determine the hourly unit operation, power flows and market imbalance prices. This simulation uses an optimal power flow algorithm that incorporates the resources (generator bids) selected in the previous forward market simulation.. The real time simulation uses the optimal AC power flow (OPF) model and comprehensive data describing loads, generators and the transmission system. (Simpler DC power flow may alternatively be used.) The OPF simulation resolves any energy imbalance (at different nodes), voltage stability or congestion problems via security-constrained re-dispatch, determining the hourly real-time energy imbalance prices and the transmission congestion cost. Units available to provide required adjustments to the forward market schedules include units participating in the (forward) ancillary services markets, as well as units entering the imbalance market via supplemental and hour-ahead bids. The calculated real time market-clearing price depends on the energy bids associated with units providing these adjustments, and on the magnitudes of imbalance load (adjustments to the forward market) these bids are selected to address.

Besides the Forward Electricity Market Model and the real time dispatch (Optimal Power Flow Model), the UPLAN system includes the Volatility Model and the Merchant Plant Model.

The Volatility Model is used for asset valuation, bidding strategies analysis, options valuation and risk management, where uncertainties and correlations among key driving factors are critical for successful analysis. It allows systematic evaluation of volatility (unpredictable variation) in key outcomes such as market prices, due to uncertainty of key driving factors such as fuel prices, hydrological conditions, electricity demand, generator and transmission outages, and market entry. Probability distributions are provided for selected key drivers, and these distributions may be (but do not have to be) derived from historical data, such as regarding weather or hydrological conditions. Correlations among the different key drivers (such as between fuel prices and electric loads) may be specified.

To model the effects of key driver uncertainties, a Volatility Model simulation draws samples from the probability distribution for each selected driving factor using Monte Carlo methods. The resulting set of simulations produces expected values and distributions for key outcomes such as market prices and generator revenues. Running a sufficiently large set of factor combinations produces a distribution of outcomes that is stable in that the distribution is not expected to significantly change if there were to be further simulations using additional samplings of factor combinations.

2000, pp. 65-75.

The Merchant Plant Model incorporates a non-linear decomposition algorithm and is used to assess generation market entrants, including their projected profitability and impact on future prices. This includes evaluating the timing, location, size and other characteristics of new entrants (generators) that are most likely to succeed in a competitive electricity market based on projected profits, rates of return and financial risks. The Merchant Plant Model has been used to evaluate in detail the prospects and key uncertainties facing specific new plants that have been proposed. It can also simulate retirement of units that are not economically viable, after testing whether refurbishment such as to improve efficiency or emission characteristics could make them viable.

UPLAN's hydro scheduler is embedded in the Network Power Model (NPM), and is used to determine the optimal schedule for utilizing hydro resources in coordination with non-hydro generating resources, to minimize the overall costs of serving the electricity demand.[20] This "hydro-thermal coordination" takes into account the interactions and characteristics of loads, transmission, and the various components of the supply system. The general approach is to schedule storage hydro generation (from powerhouses with access to stored water whose release can be timed) when expected loads and market prices are highest. For pumped-storage hydro units, pumping is scheduled during off-peak periods with low market prices and subsequent generation is scheduled for on-peak periods. Run-of-river (non-storage) hydro generation must of course be utilized at whatever level is dictated by available water flow, which may vary over time.

When provided with the required data, UPLAN can simulate the interaction of fundamental hydrologic parameters such as water inflows, and such as reservoir and water conveyance capacities, constraints and linkages, to determine the resulting flexibilities and constraints for hydroelectric generation. Alternatively, external modeling and analysis of these fundamental hydrologic drivers and linkages (such as using the OASIS model described below) can be used to provide UPLAN with time-varying parameters defining water usage flexibilities and constraints. UPLAN then uses these parameters when integrating hydroelectric generation into the simulation of hourly operations and markets.

4.1.2 OASIS

OASIS is a generalized program for modeling the operations of water resources systems developed by Water Resources Management Incorporated (WRMI). OASIS simulates the routing of water through a system represented by nodes and arcs. The routing may account for both human control and physical constraints on the system. OASIS is completely data-driven. That is to say that one specifies the features and operating rules of the system through OASIS's input data, not by altering OASIS's source code.

20 Intermonth scheduling of hydro releases and storage was accomplished through the OASIS model, as described below.

OASIS has been used to model many of the large water storage and delivery systems in California and around the United States. Systems modeled include the Central Valley Project and State Water Project.

OASIS simulates a period of record by optimizing the operations for a single time step, then going on to the next time step. Thus a 60-year record with a monthly time step would result in 720 separate optimizations. In the first case, the model has "perfect future knowledge," where the inflows and demands are known for the entire record at the start of the run. This allows the system to respond, for example, to a flood a year before it occurs. OASIS's running from time step to time step is much more realistic in that it's more like how the operators, who are not blessed with perfect future knowledge, control the system.

In order to build new models and modify existing ones, OASIS has been designed to be flexible. For example, the modeler decides how many nodes and arcs are in the system, and how they connect. Also, your input data can come from different sources, such as time-series databases or time patterns (whose values cycle every year), or the values can be computed with Operations Control Language (OCL).

OCL frees the modeler from the constraints imposed by pre-specified rule forms. Since it is extremely difficult to foresee every type of rule that might be needed in the model, OCL allows the formulation of new rules where the form of the rule, as well as the parameter values can be specified. OCL also allows the addition of conditional ("if-then" type) logic to required operational rules.

Because OASIS simulates routing decisions through linear programming, all simulation rules are represented as either goals or constraints. The fact that rules can be modeled as goals is particularly important, because goal-seeking behavior is an efficient modeling approach that corresponds well to the way real world operators and planners think of a water resources system. For example, reservoir storage targets, instream flow requirements, and off-stream deliveries are typical goals for a water resources system. Furthermore, these goals are often in competition with each other.

The rules that are written in OCL usually look like the rules that planners, operators, and policy-makers use. For example, an agreement between water users might say that the diversion at point A plus the diversion at point B must be less than 70 percent of the flow at point C. In OCL, the modeler would write a constraint which is instantly recognizable as the mathematical form of that statement.

4.1.3 SERASYM™

SERASYM™, the chronological production costing model developed by Sierra Energy and Risk Assessment, Inc. (SERA). With SERASYM™ the user can analyze fuel requirements; economy energy purchase and sale opportunities; total, marginal or avoided costs; electric utility merger benefits; impacts of emissions limitations; or the effects of third party "Qualifying Facility" (QF) power.

Used by both gas and electric utilities, SERASYM™ has a proven track record in western United States regulatory arenas. SERASYM™ was the primary system simulation model for analyzing the environmental impacts from the previous divestitures of utility thermal plants. In particular, the air emission assumptions have been closely reviewed by the relevant air quality management agencies. In addition, SERASYM™ has been used for several siting cases at the California Energy Commission.

What SERASYM™ does:

- Monte Carlo simulation technique with variance reduction or probabilistic forced outage modeling methods
- Reliability computation plus maintenance optimization
- More than 250 separate generating units can be addressed
- Precise hourly unit-level emissions modeling, with emissions costs considered in dispatch decisions
- Hydroelectric unit modeling, including run-of-river, peaking, and pumped storage units
- Limited fuel modeling for optimizing thermal and hydro unit operation
- Energy flows between control areas with distinct hourly loads and generation
- Enforces control area import limits; limits flows on critical transmission lines
- Marginal/avoided costs by time of day
- Ramp rates and minimum up/down times observed
- Avoided cost pricing of units
- Models hourly power pool and partial requirements transactions
- Interfaces with Surplus Energy Resource Assessment Model (SERAM™ II)
- Load module to handle monthly to annual load forecasts, transactions, and demand-side planning studies

SERASYM™ simulates system operations each hour of the year. System marginal costs are calculated and reported hourly with aggregations weekly, semiannually and annually by on-, mid-, and off-peak costing periods. Results are determined based on real world constraints such as ramp rates, minimum up/down times, must-run units, endogenously determined spinning reserve requirements, and differential on- vs. off-peak economy energy or QF availability and price.

SERASYM's™ time-of-day features also allow precise definition of the amount and price of power available from individual units during user-specified time periods. In addition, these units are dispatchable.

SERASYM™ offers detailed emissions features which reflect the costs associated with NOX, ROGs, CO, CO2, and particulates emissions in utility operations. This feature allows policy makers and planners to evaluate the utility and societal costs versus the benefits of various emissions controls or required operational changes. SERASYM™ also models transmission constraints between system elements and between systems. Area generation that is overloading particular transmission lines is economically adjusted to mitigate the overloading.

Furthermore, SERASYM™ was changed to reflect the fundamental restructuring realigning the California electric market, from the introduction of a central transmission coordinator, the Independent System Operator (ISO) and power exchange market (PX). Using the new "BIGSYM" configuration, SERASYM™ accurately models the new paradigm for centralized California-wide dispatch.

5. KEY MODELING ASSUMPTIONS AND INPUTS

The modeling assumptions and other inputs for each of the models are discussed below. In some cases, the input is simply data-driven, but in other cases, judgements are made about how to capture certain effects and issues. Most importantly, each of these assumptions is a modeling representation of the actual system in place, which is necessary to create tractable, time-efficient solvable problems. The most important consideration is to compare the results among the different modeled cases, not to compare them to actual historic operations per se. The modeling results must meet a “reality” test in terms of reasonableness, but they cannot, and will never, duplicate actual outcomes, which are influenced by the accumulation and interaction of numerous unpredictable events.

5.1 MODELING OF THE CALIFORNIA POWER MARKET

5.1.1 Introduction

As required under the California Environmental Quality Act (CEQA), the Environmental Impact Report on proposed divestiture of Pacific Gas and Electric Company’s hydroelectric generating facilities seeks to identify and characterize potential environmental consequences. This required describing changes in operation of the electric supply system that can be reasonably foreseen and attributed to the divestiture, especially changes in operation of the hydroelectric facilities to be divested. Such operational changes can produce changes in reservoir levels, stream flow diversions, and water releases from dams and powerhouses, all of which potentially have environmental consequences.

Thus, as a starting point it was necessary to project in sufficient detail and realism the operation of the hydroelectric facilities after divestiture. This required modeling the integrated operation of the overall interconnected western electricity system (Western Systems Coordinating Council, or “WSCC”), including electric loads and generation at different locations, the transmission network connecting loads and generation, and the power markets providing the context and incentives for generator operating strategies. All of this required a modeling system of substantial scope, detail and sophistication. This capability was provided by the UPLAN Network Power Model, which has been developed and applied for regulatory and commercial analyses of this type for more than 17 years. For the present environmental impact analysis, UPLAN was extensively used to project operation of the Pacific Gas and Electric Company’s hydroelectric generating facilities being considered for divestiture. This modeling and analysis effort considered a range of foreseeable power market and divestiture conditions.

While a great variety of ownership patterns and operating strategies might ultimately develop for the hydro facilities in question, the present Environmental Impact Report was designed to examine a more limited set of cases. These cases were meant to reflect how far hydro facility operations might diverge from present or "baseline" operations, as well as from a future "No Project" case in which the facilities were assumed to remain as regulated assets under Pacific Gas and Electric Company ownership. The different cases represent different assumptions regarding divestiture, future owners' behavior within competitive markets, and the stringency of various constraints on use of streamflows to generate electricity. In illuminating alternative possibilities, this study is intended to take into account conditions likely to exist as a result of electric restructuring, but is not intended to evaluate the environmental or other effects of restructuring itself, which is not dependent on this divestiture.

Key Modeling Requirement One: Linking Hydroelectric Generator Operation and Water Use

A key requirement for modeling electric system operations in this study was the ability to link electric hydroelectric generator operations with physical water use, including associated flexibilities and constraints. From a business (profit) perspective, constraints on water use, whether physical, legal, or more informal, have a considerable effect on how the hydroelectric facilities could potentially be operated to produce profits under different ownership and market conditions. From an environmental perspective, these constraints limit the extent of possible changes in water use such as reservoir levels, water diversions and water releases, regardless of market conditions and business strategies. After projecting generator operations under different divestiture and market conditions, the modeling approach must permit translation of projected generator operations into water use consequences such as storage levels, amounts and timing of releases, and diversions, in order for the environmental analysis to proceed.

UPLAN met these requirements by providing a range of options, flexibilities and levels of detail for relating physical water management (hydrologic) parameters, assumptions and constraints to generator operation. For example, it was possible to have UPLAN project optimal hydro generator operations based on simulation of the power market combined with specification of many hydrologic parameters such as regarding inflows, reservoir levels, discharge rates, water-to-electricity conversion efficiencies, and physical configuration of the linked components of the overall hydroelectric system. Alternatively, it was possible to model hydroelectric system linkages outside of UPLAN. UPLAN then used the resulting calculated constraints and flexibilities on water use for generation at the different hydroelectric facilities, as a basis for projecting hydroelectric operations within overall electricity markets, under different market conditions.

Key Modeling Requirement Two: Power Market Prices and Bidding Strategies

Electric restructuring has substantially changed the system and incentives under which operation of electric generators is determined. Now, and more so after the CTC is eliminated, generators will be operated in whatever way their owners judge to provide the best mix of profit expectations and risk. Energy markets will provide the main revenue source, but potential revenues from various ancillary services markets must also be considered. The way that the hydroelectric facilities are operated will be influenced by expectations regarding prices and revenues from these markets, and by the bidding strategies that are consequently developed. The resulting hydroelectric facility operations will affect how water is stored, diverted, and released. It is especially important to note that in deregulated electricity markets prices will rise sharply in certain periods, reflecting a supply-demand balance in which supply of energy and ancillary services is stretched close to its limits. These peak prices provide important incentives affecting bidding and operating strategies for electric generators in the deregulated markets, including the hydroelectric facilities under consideration in the present study.

In turn, how these Pacific Gas and Electric Company hydroelectric facilities are operated will affect electricity market prices in northern California where the facilities are located, since the facilities provide a significant portion of the electricity supply for that region. Water storage capabilities permit a portion of the generation from these facilities to be timed on an hourly, daily or even seasonal basis. This timing will be determined by market conditions and owner strategies, as well as by constraints on water use.

UPLAN was uniquely suited to examine potential electricity market prices in deregulated markets, and their relationship to generator bidding and operating strategies. UPLAN simulates both forward and real time markets for energy and ancillary services, taking into account:

- electric loads,
- generator operating and cost characteristics,
- assumed generator bidding strategies based on costs and expected profits, taking into account potential revenues across multiple markets (energy, various ancillary services),
- transmission constraints leading to multiple geographic pricing zones, and
- the impact of reliability and security constraints on markets and generator operations.

UPLAN projected hourly market clearing prices (MCP) for each of many pricing zones, one of which is northern California, where the hydro facilities in question are located. The seasonal, daily and hourly variation of these MCP provide important signals and incentives for adjustment of hydroelectric facility operations to improve profits and risks in deregulated markets. UPLAN also permitted examination of the effect of different hydroelectric generator operating strategies and constraints on projected MCPs, on a long term (annual), seasonal, and hourly basis. While it is the resulting water use that determines the potential environmental consequences, it is the market prices that provide incentives and rationale for different operating strategies in the first place.

Key Modeling Requirement Three: Integrated Demand, Supply, and Transmission

To project future MCPs and hydro facility operations as required for this study, it was necessary to model the interconnected WSCC network in a detailed and integrated manner. UPLAN provided this capability by simulating electric loads and the operating characteristics of numerous electric generators not only in northern California where the hydro facilities in question are located, but also across the entire interconnected WSCC network stretching from southwestern Canada to northern Mexico and eastward to the eastern slopes of the Rocky Mountains. This is done because for northern California where almost all of these hydro facilities are located,[21] the electricity supply and market prices are influenced by the electricity supply/demand balance across the broader interconnected WSCC region. For many hours of the year, California utilizes considerable electricity imports, especially from hydro facilities in the Northwest and coal-fired plants to the east.

In particular, it was essential to model the transmission interconnections and power flows between the various load centers and electric generators across the overall WSCC region, and especially between northern California and other regions. While power imports play an important role in California's power supply and markets, transmission connections with other regions are neither unlimited nor cost-free. Transmission constraints can significantly limit access to imported power in certain seasons and certain hours, driving up market prices in northern California and providing important price signals for operation of the hydro facilities in question. UPLAN's transmission modeling links load centers and generators located at various nodes on the transmission grid. This was essential for projecting hydro facility operations in response to market conditions. Furthermore, the transmission configuration and the projected dynamic interaction of loads, supply and transmission under different conditions influence the value of ancillary services to support system security and reliability, services that are provided by many of the hydroelectric facilities.

Key Modeling Requirement Four: Considering Change and Uncertainty

The overall electricity system represents a physical and market context within which divestiture and its consequences would occur. Modeling and evaluation of divestiture possibilities must recognize that this context will change over time, even without divestiture, and that some future conditions are very uncertain. In this study, the time horizon for modeling and evaluating divestiture implications was only out to 2005. This short horizon limited the amount of change needing to be considered, and reduced the risk of becoming too speculative. However, even for this short time horizon the modeling and analysis must consider electric load growth and prospects for generator retirements and additions. UPLAN simulated these changes, based on input data reflecting utilities' load projections and announced retirements and additions of generators. In some cases, additional analysis must be used to complete the picture, when announcements are insufficient to produce a

21 A few of the facilities are in the central California pricing zone.

balance of future electric supply and demand. UPLAN itself can be used to calculate economic amounts and timing of further generator retirements and additions.

Future hydrologic conditions represent a type of change and uncertainty that is especially important for this study. Precipitation and the water available for hydroelectric generation vary greatly from year to year in the western United States, and there is additional variability in how water available for hydroelectric generation is distributed seasonally and geographically (among different watersheds). Combined with various physical, legal and other constraints on how water can be used for generation, this variability and uncertainty of hydrologic conditions strongly influences what kinds of hydroelectric generator operating strategies may be both attractive and feasible in response to market conditions. Furthermore, since hydroelectric generation makes an important contribution to the total electricity supply in northern California and other parts of the west, overall market conditions and opportunities will be strongly influenced by these uncertain hydrologic conditions.

Because of the importance of variable hydrologic conditions, UPLAN was used to project power market conditions and generator operations under the different hydrologic conditions that were experienced in the 24 years 1975-1998, not only in northern California, but across the WSCC. Each of these years was unique with regard to amount and distribution of precipitation, and how the hydroelectric generating facilities within, and outside of California, were operated to utilize the available water. By considering each of these 24 sets of historic conditions, a more robust and comprehensive picture is produced of the range of post-divestiture hydro operating strategies that might be attractive and feasible in some years, and of the resulting range of water use and environmental implications.

UPLAN was used to simulate each divestiture possibility 24 times, based on the historic water conditions experienced in California and across the WSCC in each the 24 historical years 1975-1998. This produced great variation in the amounts, timing, and locations of hydroelectric generation projected for this study. This in turn had substantial impacts on projected overall generating system and power market conditions, and on the resulting incentives potentially affecting operation of the Pacific Gas and Electric Company hydroelectric facilities considered for divestiture.

Additional Change and Uncertainty: Conditions of Divestiture

This study focuses especially on one kind of change and uncertainty: how the Pacific Gas and Electric Company hydro facilities would be operated under different divestiture possibilities, in response to prevailing power market conditions. For this study, fundamental drivers and linkages in Pacific Gas and Electric Company's hydroelectric system were initially modeled outside of UPLAN, varying some of the assumed water use constraints and strategies to examine different possibilities regarding divestiture and future ownership. The resulting calculated constraints and flexibilities for operating the hydro powerhouses were then used by UPLAN to project hourly operation of these and other generators in competitive WSCC power markets

5.1.2 Key Utility System Modeling Assumptions

For the environmental analysis of the proposed divestiture, there were two main objectives of LCG's modeling of the interconnected WSCC system using UPLAN.

1. To project hourly, daily and monthly power market prices under different future conditions, since these prices provide incentives for varying hydroelectric operations.
2. To project future operation of each of Pacific Gas and Electric Company's hydroelectric generating plants in response to power market conditions, under a wide range of hydrologic conditions based on historical data.

It was necessary to model the entire interconnected WSCC system stretching from southwestern Canada to northern Mexico and from the Pacific coast east to the eastern slopes of the Rocky Mountains. While the hydroelectric facilities in question are located in northern California, it is sometimes economically attractive or even physically necessary to use the extensive western transmission grid to import considerable amounts of power from other areas, often from considerable distance. Therefore, dynamics of electricity supply and demand across the entire WSCC can have a substantial impact on northern California power markets, thus influencing operating incentives and strategies for future owners of the Pacific Gas and Electric Company hydroelectric facilities. Both within northern California and across the WSCC, there will continue to be great variation in power market conditions across seasons and hours of the day, and in response to less predictable conditions, such as availability of water for hydroelectric generation.

The LCG database of plants, loads and transmission lines contains existing electric utility resources of the different North American Electric Reliability Council (NERC) regions of the United States, for use in regional analysis and power market studies. The major source of WSCC data for the present study has been the LCG database and the references cited in this section. This section summarizes the key data elements and assumptions used in LCGs modeling of the interconnected WSCC system using UPLAN, in the following order:

- Transmission
- Electric Loads
- Electric supply, general
- Fuel prices

- Power markets and bidding
- Pacific Gas and Electric Company hydro units under different divestiture cases

The greatest focus was on the future power market in northern California, where the hydro facilities in question are located. While California is currently in the lead in moving to competitive power markets, it is assumed that the entire WSCC region will increasingly function as large competitive power supply market, with a number of sub-markets that reflect transmission costs and especially periodic transmission congestion. Such a broad market situation is already being approached, especially for sales into California with its large load centers, its dependence on imports and its advanced deregulation.

Transmission Network

The WSCC represents a complex regional system with a large number of investor-owned and municipal utilities. There are now over 100 full and affiliate members in the WSCC, all linked through an extensive network of transmission lines. As of 2000, the WSCC had more than one hundred thousand miles of transmission lines. The strength of this transmission network has fostered significant coordination of operations and interchange of energy between many of the members of the WSCC.

The WSCC transmission system simulation was developed in UPLAN taking into account all major transmission lines as well as the major transmission interfaces connecting 20 different zones into which the WSCC was divided for purposes of the simulation. The zone of greatest interest for this study is the northern California zone.

A transmission interface consists of one or more lines providing the overall linkage between two adjacent geographic zones. These interfaces have been assigned power transfer constraints based on detailed WSCC load flow studies under extreme conditions, and based on operating practices. As a result, in modeling conducted for this study, the following WSCC interface capacities were assumed as shown in Table C-4.[22]

Electric Loads (Energy and Peak Requirements)

In this study, the WSCC region is divided into 20 different zones reflecting political, geographic and climatic differences, and especially, transmission constraints (Table C-4). Each zone typically includes a number of different utility service territories, and a load forecast has been developed for each utility service territory. These forecasts of annual energy requirements and peak demands were based on FERC submittals[23] where available, and otherwise were based on the annual WSCC report on loads and resources.[24]

The peak and energy forecasts for each of the major areas modeled in UPLAN for this study are presented in Table C-5. The forecast in Table C-5 includes only distribution losses, since

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22
1. Federal Energy Regulatory Commission Forms 1 and 2 and 714 and 715.
2. Western System Coordinating Council (1999) Loads and Resources Report, OE-411.
3. Western System Coordinating Council (1998) Path Rating Catalogue.
4. Energy Information Administration (1999) Form EIA 412.
5. LCG PLATO Database.

23 FERC Form 714, 1999 Filings

24 Forecasts from WSCC Loads and Resources Report, Dated December 1999.

transmission losses are subsequently calculated by the UPLAN power flow program and added automatically to the total demand at the distribution buses. These loads are spread among the various nodes in the relevant geographic regions.

Electric Supply, General

For this study, the modeled WSCC region includes a wide variety of generating plants using coal, gas, nuclear, geothermal, solar, wind, hydroelectric, and other energy sources Table C-6 shows the distribution of resources by fuel type for the WSCC region. Most of "other" consists of renewable technologies other than hydro and geothermal.

Hydroelectric, coal-fired and gas-fired plants provide most of the WSCC's electricity supply. Note that a large portion of the capacity additions projected between 2000 and 2005 are powered by natural gas, which is presently the fuel of choice for most merchant (competitive) plant additions. Projected plant additions and retirements are based on announcements, combined with judgment and analysis as required to assure that capacity additions are adequately balanced against loads Hydroelectric facilities provide a significant part of the generation available to serve the demand, especially in the Pacific Northwest and northern California. However, the amount of annual and seasonal generation available from hydroelectric facilities depends on the availability of water, which varies greatly from year to year. In projecting power markets for years 2000 and 2005, the present study considered water conditions existing over each of the historical years 1975 through 1998. This resulted in a wide range hydroelectric generation contributions to the overall power supply, both in California and over the rest of the WSCC. Table C-7 shows the total annual hydro production for the Pacific Gas and Electric Company system and for the rest of the WSCC for each water year.

For many hours of the year, the last, most costly increment of generation utilized to meet the electric loads is gas-fired, especially in California. Thus, gas-fired generation often sets the MCP, and is the main type of generation to be moved up or down in utilization, when hydro generation is decreased or increased. Thus, during peak demand periods in summers of dry years, low hydro generation translates into high levels of gas-fired generation in California.

Table C-4 Transmission Path Ratings

Interface	Maximum Flow in MW North-South East-West	South-North West-East
West of Colorado River (WOR)	9406	Not rated
East of Colorado River (EOR)	8704	Not rated
Southern California Import Transmission (SCIT)	17720	Not rated
South of Los Banos (Path 15)	2150	2700
California Oregon Interface (COI)	4880	3705
Midway to Vincent	3000	3000
South of San Onofre (SONGS)	1600	800
San Diego Simultaneous Import Limit (SIL)	2450	2450
Pacific DC Intertie	3100	3100
Intermountain DC Intertie	1920	1400
North of John Day	7900	Not rated
Northwest Colorado (TOT1A)	650	Not rated
Southwest Colorado (TOT2A)	690	Not rated
Coronado	1400	Not rated
Utah/Arizona/New Mexico (TOT2B)	820	850
Utah to South Nevada (TOT2C)	300	300
TOT2B/2C Nomogram	755	Not rated
Utah to East Nevada	245	150
Utah to East Nevada (After 2002)	400	230
Utah to Idaho (Path C)	1000	1000
West of Hatwai	2800	Not rated
Path C & Path D (Simultaneously)	1830	Not rated
Canada to Northwest	2300	1900
Montana to Northwest	2200	900
Idaho to Northwest	2400	1200
Borah West	2307	Not rated
Idaho to Nevada	550	330
Bridger West	2200	Not rated
Southeast Wyoming (TOT 3)	1424	Not rated
Southwest Wyoming (TOT4A)	810	Not rated
British Columbia to Alberta	1000	1200
IID to SoCalEdison	600	Not rated
San Diego to Mexico	408	408
Lugo to Victorville	900	1950
Midpoint to Summer	1500	400

Fuel Prices

Prices for fuels, especially natural gas, have a major impact on projected power market prices. Especially during peak load periods it is usually gas- (and sometimes oil-) fired units that provide the last, most expensive increment of generation to meet load, thus setting the market prices. This study’s natural gas and other fuel price forecasts for years 2000 and 2005 were based on the information supplied by the California Energy Commission, NYMEX future contracts, various hub delivery indices and information on fuel availability developed by LCG.

Table C-5 WSCC Load Forecast

	Energy GWh			Demand MW		
	2000	2005	2010	2000	2005	2010
California/Mexico	267609	297515	330762	54053	59120	64662
Northwest	355006	388861	425944	57085	63226	70028
Arizona/New Mexico	100109	118129	139392	20656	24677	29480
Rocky Mountain	47498	54373	62243	7841	8975	10273
Total	770222	858877	958341	139573	155961	174361

Table C-6 WSCC Generating Resources

	Available Jan 1, 2000		Available 2005	
Fuel Type	Size (MW)	Percent	Size (MW)	Percent
Coal	37308	23.0	37388	20.0
Oil	2263	1.4	2263	1.2
Gas	38754	23.9	62916	33.7
Nuclear	9216	5.7	9216	4.9
Hydro	63153	39.0	63153	33.8
Pumped Storage	3927	2.4	3927	2.1
Geothermal	3171	2.0	3317	1.8
Other	4093	2.5	4454	2.4
TOTAL	161885		186633	

Coal prices have been taken from forecasts of regional spot and long-term contract data available from FERC Form 423. For those plants for which specific fuel prices were not available in this manner, approximations have been used based on the prices for similar plants, taking into account the fuel type, plant type, method of delivery and location.

Nuclear prices are based on California Energy Commission data. Diablo Canyon fuel prices have been assumed to approximate Palo Verde fuel prices for the competitive simulation. However, nuclear fuel prices are a small part of nuclear plant costs and have no bearing on how these plants are run. Tables C-8, C-9, C-10 and C-11 display the 2000 and 2005 fuel prices for each California individual utility area and non-California WSCC geographic regions.

Table C-7 Annual Hydro Production (GWh)			
Year	Other WSCC	Pacific Gas and Electric Company	Total
1975	226816	15618	242434
1976	233245	8934	242179
1977	192803	6657	199460
1978	229354	14518	243872
1979	226538	12863	239401
1980	237266	14149	251415
1981	235981	11457	247438
1982	258106	17081	275187
1983	274361	18772	293133
1984	269558	14984	284542
1985	246018	11351	257369
1986	256630	14591	271221
1987	219358	8954	228312
1988	211067	8537	219604
1989	223352	10710	234062
1990	238309	7935	246244
1991	239382	7811	247193
1992	201298	7383	208681
1993	221144	14320	235464
1994	202362	7758	210120
1995	249006	16631	265637
1996	275115	15163	290278
1997	271431	13747	285178
1998	256489	16556	273045
Avg.	237291	12353	249645

Table C-8 Natural Gas Prices (2000$/MMBtu) Fuel Cost Case including Transportation													
Area	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Average Cost**
Northern California	2.398	2.560	2.615	2.801	3.371	4.039	3.812	4.244	4.322	4.373	4.565	4.624	3.644
Southern California	2.375	2.545	2.575	2.800	3.345	4.032	3.790	4.214	4.279	4.313	4.506	4.555	3.611
Nevada	2.530	2.675	2.665	2.807	3.343	3.960	3.672	4.115	4.242	4.332	4.535	4.633	3.626
Arizona	2.236	2.433	2.438	2.529	3.064	3.701	3.419	3.856	3.975	4.024	4.201	4.276	3.346
New Mexico	2.183	2.390	2.387	2.600	3.143	3.817	3.511	3.889	3.998	4.024	4.151	4.240	3.361
Colorado	2.185	2.370	2.360	2.651	3.195	3.872	3.582	3.972	4.070	4.098	4.242	4.320	3.410
Utah	2.229	2.411	2.408	2.589	3.126	3.773	3.492	3.924	4.027	4.078	4.260	4.339	3.388
Idaho	2.185	2.280	2.380	2.465	3.025	3.651	3.339	3.755	3.913	3.925	4.245	4.370	3.294
Oregon	2.295	2.430	2.420	2.566	3.100	3.727	3.463	3.898	4.009	4.108	4.323	4.429	3.397
Washington	2.658	2.833	2.808	2.764	3.323	3.932	3.691	4.108	4.338	4.355	4.571	4.714	3.675
Canada	2.270	2.360	2.370	2.487	3.098	3.781	3.348	3.778	3.983	4.135	4.086	4.277	3.331

Table C-9 Natural Gas Prices (2005$/MMBtu)
Fuel Cost Case including Transportation

Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Cost
Northern California	3.796	3.736	3.554	3.346	3.286	3.263	3.248	3.271	3.292	3.330	3.514	3.682	3.443
Southern California	3.753	3.693	3.513	3.306	3.247	3.226	3.212	3.234	3.254	3.292	3.473	3.640	3.403
Nevada	3.772	3.712	3.532	3.325	3.265	3.242	3.228	3.251	3.271	3.308	3.492	3.659	3.421
Arizona	3.402	3.348	3.185	2.999	2.945	2.924	2.912	2.933	2.951	2.984	3.149	3.300	3.086
New Mexico	3.422	3.367	3.204	3.016	2.962	2.941	2.929	2.950	2.968	3.001	3.168	3.319	3.104
Colorado	3.486	3.431	3.264	3.073	3.017	2.996	2.984	3.005	3.024	3.058	3.227	3.382	3.162
Utah	3.457	3.402	3.238	3.048	2.993	2.971	2.959	2.980	2.999	3.032	3.200	3.354	3.136
Idaho	3.334	3.281	3.121	2.939	2.885	2.866	2.854	2.874	2.891	2.924	3.086	3.233	3.024
Oregon	3.470	3.414	3.248	3.059	3.004	2.982	2.970	2.990	3.010	3.043	3.212	3.366	3.147
Washington	3.836	3.775	3.592	3.382	3.320	3.298	3.284	3.307	3.328	3.365	3.552	3.721	3.480
Canada	3.382	3.329	3.167	2.981	2.927	2.906	2.894	2.915	2.933	2.966	3.131	3.281	3.068

Table C-10 Other Fuel Prices (2000$/MMBtu)
Base Fuel Cost Cases – Annual

Company/Location	Coal-	Oil-F02 Cost	Oil-F02 Cost	Uranium Cost
Northern California		3.443		0.571
Southern California		3.41		
Nevada-North	1.247	3.421		
Nevada-South	1.068			
Arizona	1.4551	3.2114		0.512
New Mexico	1.333			
Colorado	1.044	3.162		
Utah	1.001	3.136		
Idaho		3.443		0.600
Montana	0.9			3.136
Wyoming	0.944	3.303		3.303
Oregon	1.071			3.162
Washington	1.477	3.48		3.068
Canada	1.23	3.068		
Mexico		3.581	3.431	3.581

Table C-11 Other Fuel Prices (2005$/MMBtu) Base Fuel Cost Cases – Annual				
Company/Location	Coal-	Oil-F02 Cost	Oil-F02 Cost	Uranium Cost
Northern California		4.443		0.565
Southern California		4.41		0.630
Nevada-North	1.247	4.421		
Nevada-South	1.068			
Arizona	1.455	4.211		0.565
New Mexico	1.333			
Colorado	1.044	4.162		
Utah	1.001	4.136		
Idaho		4.443		
Montana	0.9			
Wyoming	0.944	4.303		
Oregon	1.071			
Washington	1.477	4.48		0.662
Canada	1.23	4.068		
Mexico		4.581	4.431	

Competitive Markets and Supply Bidding

The underlying approach adopted in restructuring California's electric industry was to replace centralized optimization with a process of coordinated decentralized optimization. This new process relies on iterative market clearing and arbitrage by market participants among the various energy and ancillary service markets. Under this market-oriented approach, each participant tries to optimize the use of its generation resources among the markets. Overall optimization is achieved through a learning process, in which participants engage in standardized interactions with the ISO, the PX and other market participants, and respond to prices, transmission constraints, and other market signals. The process relies upon prompt dissemination of non-proprietary market information by the ISO.

Within this market structure, the outcomes in the various ISO and PX market prices are strongly inter-dependent. The nature of these markets, in terms of both their temporal relationship to the actual trading hour (day-ahead, hour-ahead, and real-time) and the order in which they are cleared (PX energy, followed by ISO A/S, etc.), increases the range of possibilities for arbitrage by market participants. In a market-oriented approach such as California's, description of price and quantity relationships across the markets depends on techniques such as analysis of historical data, application of behavioral models, and evaluation of assumptions regarding arbitrage among markets under equilibrium conditions.

The following discussion outlines key drivers likely to affect the relationship between energy and A/S prices in an efficient, competitive market. The supply of A/S is composed of both *infra-marginal* units, with variable operating costs *below* market energy prices, and *super-marginal* units, with variable operating costs *above* market energy prices.

Infra-marginal units, with variable operating costs below market energy prices, face an indirect opportunity cost if they provide A/S. For these units, the opportunity cost of providing A/S capacity is the foregone revenue of providing energy in the forward energy markets. For example, a given MW of a unit's capacity cannot be committed to simultaneously providing energy in the forward energy market and spinning reserves in the A/S market.

For super-marginal units, with operating costs higher than market energy prices, the costs associated with providing A/S stem from the fact that in order to provide A/S, these units must typically be already operating at minimum levels. For these units, the direct variable cost of providing A/S is a function of their variable operating costs relative to energy prices, minimum load levels, and ramping rates. Since these units have higher operating costs, there is typically less opportunity for these units to earn additional revenues from sales of energy in the real-time market. However, for hours when prices do rise in the real-time market, revenues from real-time energy sales do represent another source of revenue that can offset these units' cost of providing A/S capacity.

Sometimes generating units may be able to provide A/S at a low cost, in terms of either opportunity costs or actual operating costs. For instance, during shoulder and off-peak hours, many thermal units ramp down to minimal operating levels, with the expectation of ramping back up to provide energy later (perhaps the next day) when energy prices are higher. During these hours there are no real foregone energy opportunities for these units, yet they are operating and thus eligible to provide a range of A/S. On the other hand, units with quick startup times and low startup costs can provide A/S without having to be already operating. Combustion turbine peaking units with startup times of 5 minutes or less and relatively low startup costs are an important source of A/S, and can provide Non-spinning and Replacement Reserves without actually being in operation.

For the above reasons the variable operating cost of providing Non-spinning and Replacement reserve can be minimal and even approach zero. However, the cost of providing A/S can also be higher than would be calculated based on contemporaneous energy market opportunity costs or based on normal operating costs. For example:

- The cost of providing Upward and Downward Regulation may be increased due to required modifications to enable the unit to respond in the required manner, as well as by additional maintenance costs associated with wear and tear from actually responding, when requested.
- For hydro units with storage capacity the opportunity cost of providing A/S in a given hour may depend on the foregone opportunity for energy and A/S sales in other time periods. Optimizing use of such units requires careful consideration of how providing energy or A/S in one time period affects each unit's ability to provide energy or A/S in other time periods.

When energy and ancillary services markets are in equilibrium (eliminating arbitrage opportunities), the energy prices will be higher than in the absence of an ancillary services market, since generators will increase their energy bids to reflect the opportunity cost of foregone participation in A/S markets, in the event of selection (dispatch) in the energy market.[25]

5.2 MODELING OF THE PACIFIC GAS AND ELECTRIC COMPANY HYDRO SYSTEM

Water flows through Pacific Gas and Electric Company powerhouses may change as a result of divestiture. In particular, the timing of releases from storage reservoirs may change in response to changing price signals and changes in the configuration of the new owner's other generation assets. The possible changes in flows are a source of potential environmental impacts, and must be evaluated.

OASIS was used to develop a realistic estimate of the flows which may result from divestiture. Reservoir operations were determined by sets of rules which determine when and how much water to release. The rules included such things as constraints on minimum flow and storage, and objectives such as maximizing revenue. Thus, in order to develop realistic scenarios of future flows, we postulated a decision rule for scheduling reservoir releases and generation at powerhouses.

The decision rule was designed to achieve the primary objective of maximizing the power revenues to the owner. The decision rule was designed so that all minimum flow and other regulatory and contractual requirements are met, taking into account considerable uncertainty with regard to future flows and energy prices. Optimizing revenues under uncertainty was the most difficult issue in designing an appropriate decision rule.

Optimization models such as Pacific Gas and Electric Company's SOCRATES attempt to accomplish such an optimization. They are complex and require extensive data and involve a large computational burden. We developed a simpler and more pragmatic approach based on the following logic.

5.2.1 A Decision Rule

At any given instant, an operator is faced with a price offered for power and the decision of whether or not to commit water from storage to generation. Only if the current price is more than the expected marginal value of water saved in storage to produce power at a later time, and all other constraints can be met, will the operator be likely to choose to generate. The problem is obtaining a reasonable estimate of the marginal value of storage for future generation, given the uncertainties concerning inflows and prices.

In order to model such a decision rule, we formulated the rule as a multiple-period optimization problem which is solved within the framework of the OASIS modeling system. The optimization

25 Consider that if a generator with an operating cost of $20/MWh can make a $1/MWh profit for providing A/S, it would need an energy market price of at least $21/MWh to make energy market

was performed over a long term "forecast" of inflows, and attempts to maximize energy revenues. The solution for the first month in the optimization was implemented; storage, flows and forecasts were updated; and the problem was then solved again for the next month. The optimization, by its very nature, ensures that the minimum price at which power is generated in the first month is equal to the expected marginal value of power for the remaining months of the "forecast." The formulation of the optimization problem is discussed below.

5.2.2 Optimization Description

The optimization problem requires making several simplifying assumptions both to make the problem tractable, and to account for the use of monthly averages rather than hourly operations:[26]:

- Flows and energy prices for the current month are known with certainty;
- The distribution of energy prices over the optimization horizon is known with certainty;
- The forecasted flows used in the optimization are chosen to appropriately reflect the impact of uncertainty on the optimization;
- The highest operational priority is to meet target storages at the end of the forecast horizon;
- Operators will schedule releases through powerhouses (other than minimum flows) in the highest value time periods, i.e. they will operate optimally;
- Minimum flow requirements are always feasible, and are met as continuous flows throughout the system, even if they must be passed through powerhouses; and
- Head through each powerhouse is constant.

In addition, since the evaluation is being done using monthly flows, two additional assumptions were made:

- Flows are the same for all days of a given month; and
- Time of travel between powerhouses has little impact on scheduling - this is equivalent to assuming that each powerhouse has a forebay with sufficient storage to even out flows for release in peak hours only.

The primary constraints in the optimization ensure mass balance for water at each storage reservoir, powerhouse, or junction for each period and between periods. The mass balance constraints include constants for each inflow at each inflow point in each period. Additional constraints include the capacities of the powerhouses and reservoirs, as well as other physical limitations on

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participation worthwhile, versus $20/MWh in absence of the A/S market opportunity.

26 The analysts acknowledge that the actual amount of generation at any point in time will depend on the flow rate and head at a powerhouse, and that the monthly modeling time step may underestimate the amount of spill that may occur. The important aspect of this analysis, however, is that the results of different modeling cases are comparable with each other, and that these simplifications should not significantly affect the results given the narrow range of differences in the modeling results.

facilities. Artificial constraints (e.g. those used to piecewise linearize the power value functions for inclusion in the objective, see below) are also included.

The inflows used in the first month of the optimization are always the corresponding historical flows for that month. For June to December, December is the end of the optimization horizon. For June to September, we used the actual flows for forecasts, because we assumed that snowmelt predictions are accurate. For October through December, we made a conservative forecast by using the historical flow that was exceeded 75 percent of the time, i.e., the 25th percentile of the flow distribution.[27]

Table C-12 summarizes how the inflow for each month is expressed in each time step of the simulation. For January to May, May is the end of the optimization horizon. During January and February, we make a conservative forecast for all future months by using the historical flow that was exceeded 75 percent of the time. During March and April, we use the actual flows for forecasts, assuming that predictions are accurate. Although these assumptions could be further refined, it is believed the level of precision is appropriate for this study.

Table C-12 Monthly Inflow Assumptions

Forecast Month / Current Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Jan	Act	25%	25%	25%	25%							
Feb		Act	25%	25%	25%							
Mar			Act	Act	Act							
Apr				Act	Act							
May					Act							
Jun						Act	Act	Act	Act	25%	25%	25%
Jul							Act	Act	Act	25%	25%	25%
Aug								Act	Act	25%	25%	25%
Sep									Act	25%	25%	25%
Oct										Act	25%	25%
Nov											Act	25%
Dec												Act

The objective function includes terms which place very high value on meeting minimum flow constraints and end of period storage targets. A low value is put on keeping water in storage so as

27 The 50th percentile of the distribution is equal to the median flow.

to avoid spills, which have no value. The most relevant portion of the objective function concerns the valuation of flow through the powerhouses.

A convex value function is constructed for monthly flow through each powerhouse. That function was directly derived from the energy price information supplied by the UPLAN model. This price data was divided into energy-consumption time steps that are either off-peak or on-peak. A given step is either eight, 16, or 24 hours long. We broke all the price data into eight-hour steps. The value function was derived by sorting the 8-hour steps by price. The sorted series was then accumulated, giving a function whose slope is the marginal value of generating for one more 8-hour period during the month.

A "block" of water for a particular powerhouse was defined as the flow capacity of the powerhouse, in excess of the minimum flow through the powerhouse (if any), for an eight-hour period. The value function values the first block of water through the powerhouse as the product of the highest price for any eight-hour period in the month times the amount of water in the block times the water duty factor in units of kWh/AF. The water duty factor equals approximately the plant energy conversion efficiency times head in feet. The second block was valued using the second-highest price, and so on. For computational purposes, the value curve is represented in the optimization by a piecewise linear approximation with five segments.

Table C-13 summarizes how the price distribution for each month was expressed in each time step of the simulation. For the first month in each optimization (i.e., the current month in the simulation), the prices were taken from the corresponding month in the UPLAN output. For future months, we used a value function based upon the prices in the given month throughout all years. For example, for April we used the distribution of prices in all Aprils. For the months June through September, we decided that the prices are sensitive to the overall wetness or dryness of the year. We segregated those years whose Eight-River Index was below 15 MAF as dry years.[28] For the months June-September, each month was associated with one price distribution for dry years, and one for wet years.

28 The Eight River Index is the sum of the Sacramento and San Joaquin River Indices. The Sacramento River Index is the sum of Sacramento River at Bend Bridge, Feather River inflow to Lake Oroville, Yuba River at Smartville, and American River inflow to Folsom Lake. The San Joaquin River Index is the sum of Stanislaus River inflow to New Melones Lake, Tuolumne River inflow to New Don Pedro Reservoir, Merced River inflow to Lake McClure, and San Joaquin River inflow to Millerton Lake. The average for the Eight River Index is 18 MAF for the 1906 to 1999 period.

Table C-13 Monthly Inflow Price Distribution

Forecast Month / Current Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Jan	Act.	All	All	All	All							
		Act.	All	All	All							
Mar			Act.	All	All							
Apr				Act.	All							
May					Act.							
Jun						Act.	W/D	W/D	W/D	All	All	All
Jul							Act.	W/D	W/D	All	All	All
Aug								Act.	W/D	All	All	All
Sep									Act.	All	All	All
Oct										Act.	All	All
Nov											Act.	All
Dec												Act.

Notes: Act.: use the distribution for that month of that year

All: use the distribution for that month of all years

W/D: use the distribution for that month of all wet years or all dry years, depending on the wetness of the current year.

The appropriateness of the optimization depends on the relative reasonableness of the assumptions. Two of the more important are:

- That operators will operate optimally.
- That the inflow forecasts are chosen so as to properly reflect uncertainty. WRMI tested by simulation several different forecast assumptions in order to find the most appropriate.

To the extent that the value of the price function value for the last block of water scheduled in the first month of the optimization falls in the "flat" middle of the price distribution curve, the overall estimate of water routed for the month will represent "good" operations from the standpoint of power maximization (i.e. the total value of generation will be relatively insensitive to changes in assumptions), because the flatness of the price curve means that there will be little sensitivity to small changes in operations.

5.2.3 Watershed Schematic Diagrams

The schematic diagrams presented in Exhibit C-1 represent the physical connections through which water can be routed through the system. The schematics were developed from the figures in

Appendix C of the PEA, from SOCRATES, from figures in the USGS Water Data, and from the maps provided by Pacific Gas and Electric Company.

5.2.4 Reservoirs

The significance of reservoirs in the schematic is that water can be stored from month to month. However, many smaller reservoirs are not used to store water from month to month. Rather, their operations are used to manage water on a daily or hourly basis. Thus, the operation of smaller reservoirs is not meaningful on a monthly basis.

Most of the reservoirs with capacity of two thousand acre-feet (TAF) or less were not entered into the model as reservoirs. That is, we are not even modeling storage at these locations. For most of the reservoirs with capacity between 2 TAF and about 5 TAF, we modeled the storage capacity, but simply kept it full most of the time. The only time we modeled water being taken from storage in these reservoirs was during extreme dry periods when there was no other water to meet instream flow targets.

At a monthly time step, it is worthwhile to model storage only at the larger reservoirs. All of these reservoirs have certain operating targets in common. They are to be filled in the late spring, and drawn down to their lowest level at the beginning of winter. The model draws the reservoirs down to send water through the power plants because it seeks to maximize the revenue earned by generating power. Thus, there is an operating target to maximize power revenue, explained in more detail below. However, reservoir managers generally do not drain the reservoirs completely. Thus, we have put into the model targets preserving carryover storage at all reservoirs. These targets have higher weight than the power-generating targets.

5.2.5 Power Revenue

We chose a modeling scheme that lets the model compute the operation that maximizes power revenue. We did this by dividing the year into two optimization periods. The first is from January to May, and the second is from June to December. Within the optimization period, the model computes the operation that will maximize power revenue during that optimization period. It has no information about the revenue generated outside of the period. Targets on storage and flow outweigh the targets on generating power revenue. Therefore, these targets limit the power-generating behavior. For example, targets on storage cause the model to seek to fill the reservoirs at the end of May, rather than letting the model use all the water to generate power during the January-May optimization period.

In order to maximize the revenues from power generation, the model must have information about the varying price of power. Although the model generates results at a monthly time step, the value of power varies from day to day and within a day. Therefore, we chose a modeling method which incorporates the distribution of power within a month.

Time series of power prices were obtained from the UPLAN model. These results were given for an on-peak and off-peak period for each day. Although the length of on-peak and off-peak periods varies, all of these sub-daily periods have durations divisible by eight hours. Thus, we divided the entire month into eight-hour power periods. We sorted the prices within the month, and accumulated them to arrive at the function shown in Figure C-2.

The model revenue calculation assumes that when the managers of a powerhouse make the decision to generate power during a power period, they either decide to generate at the full capacity of the powerhouse, or they decide to generate nothing.[29] Thus, the month of August consists of 93 of these on-off type decisions (31 days times three 8-hour power periods per day). If the managers decided to generate only 10 periods during the month, they must have chosen the 10 highest-priced periods, and so forth. Thus, the more time within the month that the plant is generating, the more revenue is earned, but the lower the marginal revenue for each additional period. This relationship is clearly shown in Figure C-3.

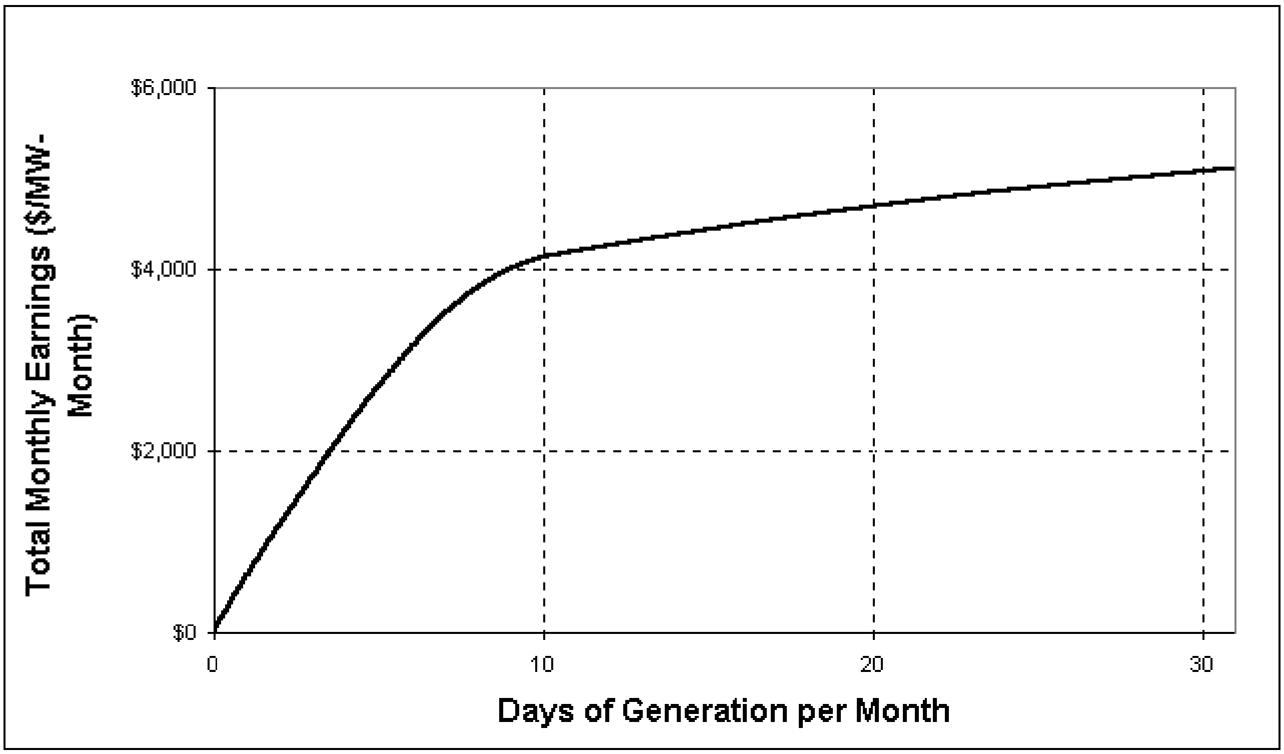

Figure C-2. Monthly Revenue per Megawatt of Capacity as a Function of Generation in a Dry-Year August

29 This assumption results in approximately the same monthly revenues as if the plant manager produced the same amount of energy during the month, but had several hours of operation at the beginning and end of the peak period at partial load. This ramping up and down over a load range is more typical of actual operations, but this difference will not affect substantially how water releases are scheduled on a monthly time step.

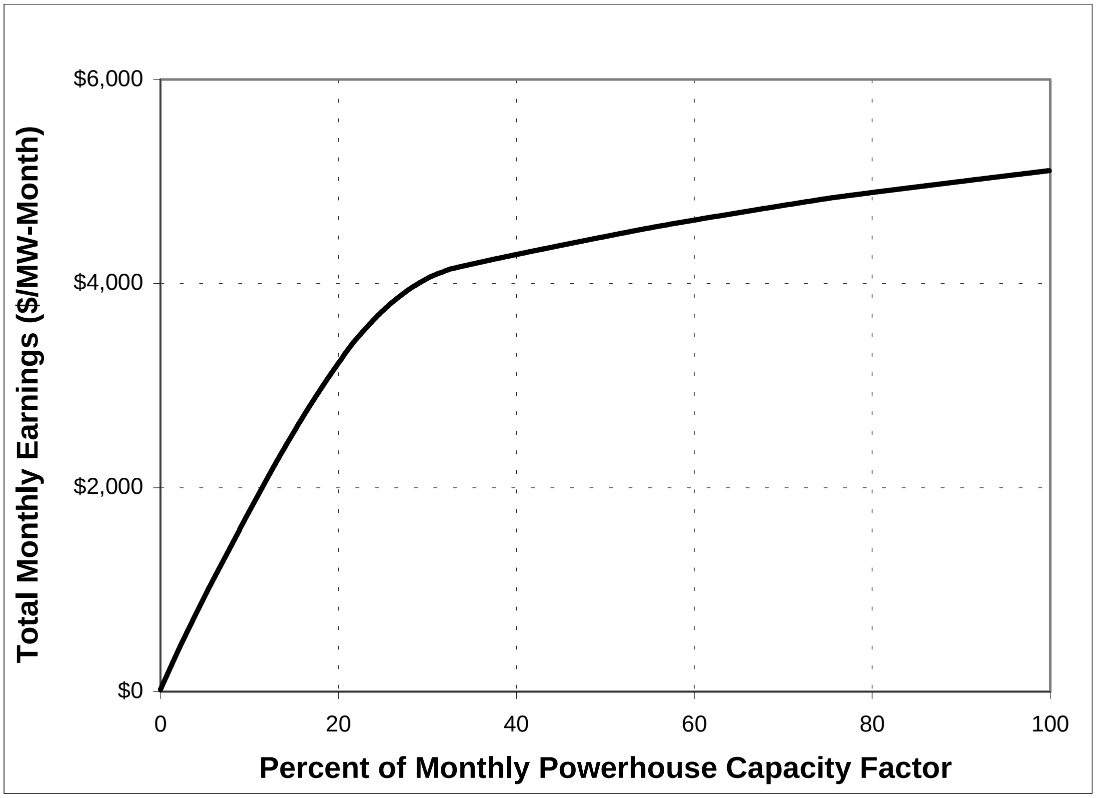

Figure C-3. Monthly Revenue per Megawatt of Capacity as a Function of Capacity Factor in a Dry-Year August

Because during each power period, the model assumes that the powerhouse generates at either full capacity or not at all, we can convert the x-axis of Figure C-2 into the percent of monthly powerhouse capacity, as shown in Figure C-3.

At each powerhouse, this percent of capacity can be multiplied by the maximum monthly flow capacity. Thus, the relationship shows how much revenue would be earned for generating at a given monthly flow.

To convert the volume of flow into energy generated, we followed the example of SOCRATES, multiplying by a constant called the "water duty." The water duty factor for each powerhouse was found in SOCRATES input.

As the model maximizes within the optimization periods, the revenue-flow function tells the relative value of power generation between months. However, we know that the real-world managers of the system do not have a perfect forecast of the future prices for the power. Therefore, we have applied the following methods.

The operation is re-simulated each month. For example, in January, the operation is simulated from January-May. In February, it is simulated from February-May, and in March, from March-May. This pattern continues until June, when optimization period ends in December. Thus, the simulation is done from June-December, July-December, August-December, and so forth. In this methodology, the simulation of the current month is preserved, while the future months will be overwritten. For example, when the model simulates March, it makes decisions for March-May. However, only the decisions for March are preserved at this point. The following month, it simulates April-May. At this point, the decision for April becomes permanent.

The information for the current month is "perfect" information, while the information for the future months is an estimate more like what the real-world operators would have available. The information referred to here are the price of power and the hydrologic inflows (hydrologic inflows will be discussed in more detail later).

For example, in March, the optimization period is March-May. When the model simulates March, it requires pricing and hydrologic information for all months March through May. However, only for March are the "true" values applied. For April and May, the model uses conservative estimates that reflect the statistics of the record.

Thus, we sorted the price information several different ways and generated many different revenue-flow functions. Firstly, there is a revenue-flow function for each specific month of the record. For example, August 1977, September 1977, and August 1978 each have their own functions. These are the "true" revenue-flow function used in the current month of simulation.

Secondly, there are revenue-flow functions that are used as estimators for future months. When developing these, we took into account how much the water manager would know about the future. During the summertime in California, water operators know whether they are expecting a dry year or a wet year. We found that the price data supplied by LCG did reflect the dryness of the water year, so we plotted the distribution of prices during all dry years separately from the distribution of prices during all wet years (We defined dry years as years when the California DWR's "eight-river index" is less than 15,000 TAF). This differentiation between year types was done for the months June-September. For October-May, we found that the prices did not reflect the dryness of the water year. Thus, for October-May, the estimate of future revenues is derived by plotting all years together.

5.2.6 Hydrologic Inflow

Pacific Gas and Electric Company supplied most of the hydrologic inflow needed to model the system. Pacific Gas and Electric Company is the primary data collection agency on most of these rivers. However, we found significant problems in these data, including gaps, lack of correlation, and flow imbalances. Often these problems arise from measurement errors. Where problems were encountered, we adjusted and replaced the data. For example, on the Drum-Spaulding system, the 1995 data was replaced with earlier water years judged to be representative.

One exception where non-Pacific Gas and Electric Company data were used is the flow of the San Joaquin River above Willow Creek. The San Joaquin River is heavily regulated by Southern

California Edison's (SCE) hydroelectric facilities, and operating policies may have changed over the years. A proper effort would include all of SCE's system in the model. However, due to limited access to hydrological data from other hydro systems such as SCE's, we only used the historical flow data. This was computed by adding the record from USGS station 11242000 (San Joaquin River above Willow Creek) to the record from USGS station 11246530 (Big Creek Powerhouse number 4). Gaps in the record at station 11246530 were filled from data from FERC Form EIA 759 supplied by LCG Consultants.

As with the price of power, real-world water managers do not usually know what will be the inflow to their system. However, due to California's climate patterns, managers have a very good prediction of what their summer inflows will be by the end of the wet season. During other months, we had to devise methods of ensuring that the model only used estimates instead of perfect forecasts. Thus, the following methods were applied:

- For the current month, the true inflow is always used.
- June-September, the true inflow is always used.
- When October-December is modeled as future months, the model uses the 25th percentile flow of record.
- When the current month is January or February, the model uses the 25th percentile flow of record.
- When the current month is March or April, the model uses the true inflow.

5.2.7 Watershed Assumptions

Exhibit C-2 presents inputs used in OASIS model for the modeling of the Pacific Gas and Electric Company watersheds.

5.3 MODELING OF AIR QUALITY IMPACTS

Potential emission impacts from electric generators in California were estimated using the SERASYM™ chronological production costing model.[30] SERASYM™ is used to simulate the operations of electric systems and to forecast, inter alia, unit-specific electric generator operations, emissions and fuel requirements. In this application the model was employed to simulate the California electric system as operated under the control of the ISO.

Two calendar years were simulated: 2000 and 2005. The amount of emissions of each of the five major criteria pollutants was estimated in each major California air basin and for the state as a whole. The five pollutants considered were NOx, SOx, reactive organic compounds (ROGs), CO and PM10. In the single 2000 case simulated, the Baseline provided emission estimates based upon the current electric system in California and the other regions of the interconnected Western Systems Coordinating Council (WSCC) grid. Three alternatives were simulated in the year 2005. Each case modeled different operational strategies for the Pacific Gas and Electric Company hydro system in the context of the forecast of the evolving mix of growing load, the addition of significant new generation, and some anticipated further emissions cleanup in existing generating units.

30 SERASYM™ is Copyrighted © 1989-2000 by Sierra Energy and Risk Assessment, Incorporated.

The database as updated for this application came from two sources. Most of the WSCC data came from the database employed in the evaluation of the impacts of the Pacific Gas and Electric Company fossil plants divestiture reported in subject Environmental Impact Report.[31] This database was updated to reflect new information about existing and putative WSCC electric generators. The key updates reflected the inclusion of all large generators that have active Applications for (siting) Certification (AFC) before the California Energy Commission (CEC) or have recently received their siting Certification from the CEC consistent with the assumptions used in the UPLAN modeling. These facilities are numerous and are nearly all comprised of highly efficient, gas fired combustion turbines with heat recovery steam boilers operating in combined cycle mode. These units are all required to be equipped with best available emission control technology and so are assumed to be considerably cleaner than the existing generation even with retrofit pollution equipment. The fact that these planned units are both much cheaper to operate and cleaner results in the reduced emissions in each of the 2005 alternative case as compared to emissions in the year 2000.

The hourly operations of all of the non-pumped storage generation of the Pacific Gas and Electric Company hydro units being considered for divestiture, outputs of UPLAN model were used for simulating the hydro impact of alternatives. The operations of the three Helms pumped storage units, also being proposed by Pacific Gas and Electric Company for auction, were modeled within SERASYM™ to reflect minimum cost operations consistent with their assumed continuing status as RMR units under the control of the ISO.

6. MODELING RESULTS

6.1 PACIFIC GAS AND ELECTRIC HYDRO SYSTEM SCHEDULING RESULTS FROM OASIS

The series of graphs presented in Exhibit C-3 summarizes resultant reservoir storage from the OASIS model runs made for the Baseline, PowerMax and WaterMax scenarios. Average end of month levels are presented for each basin modeled. In addition, storage frequency curves are presented for the months of May, August and December for the total storage in each basin. The end of May represents the approximate time when the reservoirs are usually full after the precipitation season, the end of August is about when the high recreation season comes to an end and December is the month the reservoirs might be at their lowest point in anticipation of the high runoff season. Appendix H of this EIR contains a larger set of detailed graphics and data for numerous locations in the Pacific Gas and Electric system, describing both reservoir levels and streamflows. This latter set of data was used by the environmental analysts in preparing the Environmental Impact Report.

31 Environmental Science Associates, Draft Environmental Impact Report, “Pacific Gas and Electric Company’s Application for Authorization to Sell Certain Generating Plants and Related Assets, A.98-01-008", August 5, 1998.

McCloud-Pit

In the McCloud-Pit system we discovered that the operation of the storage reservoirs would be essentially the same in both the PowerMax and the WaterMax scenarios. There is little carryover storage available in the system and that storage would be used to generate high-value energy in dry years. This generation would provide a small amount of increased water supply in those dry years. Even in WaterMax scenario, generation can take place in a price-effective manner since Shasta Reservoir, downstream of the McCloud-Pit system can provide necessary re-regulation.

As shown on figure C.3-1, in the Baseline scenario the McCloud-Pit system storage generally fills in May and then remains essentially full through July. System storage then drops to about 100,000 acre feet and remains there through December. Then storage gradually increases until it fills again in May.

In the PowerMax (and WaterMax) scenario, storage tends to fill a month later, in June. Storage decreases quickly to 72,000 acre feet by the end of September and then gradually increases to about 80,000 acre feet by the end of December.

The system storage in the PowerMax scenario is from 15,000 to 30,000 acre feet lower than in the Baseline in most months. This can easily be seen in Figures C.3-2, C.3-3, and C.3-4.

North Fork Feather River

The North Fork Feather River basin benefits from the most reservoir storage of any Pacific Gas and Electric Company basin with over 1.3 million acre feet capacity. The annual operation of the system under all three scenarios is shown on Figure C.3-5. The storage of system reservoirs is carried a little higher in the WaterMax scenario than in the Baseline, to better protect water supply against the dry years. Conversely, the reservoirs are maintained at slightly lower levels in the PowerMax scenario to reduce the likelihood of water bypassing the generators during the high runoff season.

In about 50% of Mays during in the study period, storage in the NFFR system would be near full. The other 50% of the Mays, in the Baseline ranges from full to about 950,000 acre feet in the driest year. The WaterMax scenario storage is maintained at about 1,200,000 acre feet in all but the driest year, when it also drops to about 950,000 acre feet. Storage in 50% of Mays in the PowerMax scenario, are significantly lower, reaching a low of about 750,000 acre feet in the driest year.

The pattern is similar in August where the Baseline storage and WaterMax scenario storage tend to be about the same in the wettest years with WaterMax scenario storage being slightly higher in all the rest of the years, except for the three driest. This represents the increased use of stored water to meet the demands of a water user in the driest years. NFFR reservoir storage in the PowerMax scenario tends to be from 100,000 – 200,000 acre feet lower than the other two scenarios in all years.

Potter Valley

As in the McCloud-Pit system we discovered that the operation of Lake Pillsbury would be essentially the same in both the PowerMax and the WaterMax scenarios. There is little carryover storage available in the system relative to the runoff available and that storage would be used to generate high value energy in dry years. This generation would provide a small amount of increased water supply in those dry years because the diversion to the powerhouse is the same diversion necessary to meet demands. After the water passes through the powerhouse, it can be used to meet minimum flow requirements and demands.

The goal at Lake Pillsbury is to fill the reservoir by the end of May. In 40% of the years, Lake Pillsbury does fill in May. In the remaining 60% of the years, the storage in the reservoir falls below 62 TAF only once in the Baseline and below 68 TAF only once in the PowerMax Scenario.

The pattern is similar in August where the Baseline storage and PowerMax scenario storage tend to be above 50 TAF in the wettest years with PowerMax scenario storage being slightly lower in all the rest of the years, except for the driest. This represents the increased use of stored water to generate and meet water user demands in the drier years.

Drum-Spalding

The Drum-Spalding system is a very complex system that is coordinated in its operation with the Nevada Irrigation District (NID) system of reservoirs and power plants. The operation of the combined system is governed by a contract between Pacific Gas and Electric Company and NID. In addition, Pacific Gas and Electric Company has contracts with NID and Placer County Water Agency to supply significant water supply to those two agencies for both agriculture and municipal and industrial uses. Figures C.3-6, C.3-7, C.3-8, and C.3-9 demonstrate that there is little flexibility in the system to change operations for hydrogeneration or water suppy.

In May, for all studies the reservoirs are full approximately 40% of the time. The remaining 60% of the time the reservoirs range from about 70 TAF to about 115 TAF.

The pattern is similar in August where the system storage during the wettest year is approximately 100 TAF and in the driest years the system storage is about 25 TAF. There are small variations in the operations during the years between, but the system operation is generally the same for all scenarios.

Mokelumne

The Mokelumne River basin has significant storage capacity, but flexibility is limited to wetter years. During dry years, the Lodi Decree, a court adjudication of Mokelumne River water rights governing reservoir storage levels and flow releases, allows almost no flexibility in operations. The annual operation of the system under all three scenarios is shown on Figure C.3-10. In the Baseline, storage capacity is usually filled in May, and the storage is drawn very low by December. The carryover in the reservoirs is a little higher in the WaterMax scenario than in the Baseline, to better protect water supply against the dry years. However, since the average Baseline reservoir storage is near full in May, the WaterMax scenario raises the average only a little. Conversely, the reservoirs are maintained at slightly lower levels in the PowerMax scenario to reduce the likelihood of water bypassing the generators during the high runoff season.

Figure C.3-11 shows that the PowerMax and WaterMax scenarios would change the May storage only a little. Due to higher carryover storage, the WaterMax scenario would fill the reservoirs a little more frequently. The PowerMax scenario would make almost no difference in May storage.

Figure C.3-12 shows the frequency of storage values for August. During wet years, the PowerMax scenario would result in about 10 to 20 TAF lower than the Baseline. During wet years, WaterMax scenario would see only slightly higher storage. During the dry years, the August storage is strictly limited by the Lodi Decree, so there would be very little change among the primary cases.

Figure C.3-13 shows the frequency of storage values for December. During wet years, the PowerMax scenario would result in lower carryover during most years, and WaterMax scenario would result in higher carryover. During the dry years, the December storage is strictly limited by the Lodi Decree, so there would virtually no change among the primary cases.

Stanislaus

The Stanislaus river basin has little operational flexibility. Most of the storage is in reservoirs owned by the Oakdale and South San Joaquin Irrigation Districts. Although Pacific Gas and Electric Company has contractual ability to dictate some of the release schedule from these reservoirs, a certain portion of the storage is dedicated to water supply for the irrigation districts. Figure C.3-14 shows that the average storage would change very little in any month. Figures C.3-15, C.3-16, C.3-17 show the frequency of storage values in May, August, and December, which change very little in the scenarios.

Crane-Kerckhoff

The Crane-Kerckhoff system has a fairly small storage capacity compared to the other systems in this study. However, we assumed that there is relatively high flexibility in the operation of this system. Bass Lake with approximately 45,000 AF of storage capacity is a relatively large reservoir for the small Crane Valley Project powerhouses, giving that portion of the system weekly and seasonal flexibility, although daily flexibility is constrained by long canals and small forebays. The Kerckhoff Project, dependent on releases from the upstream SCE San Joaquin River hydro system for most of its inflow, has hourly and daily flexibility using its relatively small 4,252 AF forebay. Inflow to Kerckhoff from the Crane Valley Project represents only about 4 percent of the total. Other than for hourly and daily cycling, operations at the Kerckhoff Project will reflect the water management decisions of SCE. Figure C.3-18 shows that the WaterMax scenario would lower the average storage by about 3 TAF in all months, while the PowerMax scenario would lower it by about 7 TAF in all months. Figure C.3-19 shows that the storage capacity fills in about 70 % of years in the Baseline. In the WaterMax scenario, the reservoir would fill slightly less often, while in the PowerMax scenario, the reservoir fills only in about 50 % of years. Figure C.3-20 clearly reflects the different assumptions of the scenarios. In WaterMax scenario, the carryover storage is the same as the Baseline scenario, except during the dry years, when the water is withdrawn for water supply. In the PowerMax scenario, there is a much lower carryover-storage target, so that power can be generated without less risk of spilling the water. In the wettest years, the PowerMax scenario and Baseline both exceed their carryover targets because there is no unused powerhouse capacity.

6.2 POWER MARKET SIMULATION RESULTS FROM UPLAN

6.2.1 Overview

Generator utilization and revenues, power flows and market prices in different zones of the WSCC were projected for 2000 and 2005 using methods, information and assumptions summarized in Section 5.1. For each divestiture case, UPLAN was used to model 24 sets of hydrologic conditions or “years” experienced by Pacific Gas and Electric Company and the WSCC overall, combined with electric loads, fuel prices and other electric generation resources anticipated for years 2000 and year 2005. The 24 different sets of water conditions representing historic conditions in years 1975-1998 had a significant impact on these results, reflecting the key role of hydroelectric generation in the WSCC. In addition, the different divestiture cases had a noticeable impact on projected generator utilization and revenues, and the resulting water use implications. Significantly, market prices differed little—on average less than one-half of one percent—among the primary divestiture cases. However, this was not true when the ability to exercise market power existed as analyzed in Section 6.3 below.

In simulating power markets in northern California and across the WSCC, UPLAN projected hourly operations of the powerhouses. These operations were simulated within various water use constraints, including the monthly water use schedules provided for different divestiture cases and hydrologic conditions. The water release implications of these powerhouse operations are relevant to subsequent environmental analyses.

Market clearing prices (MCP) for electric energy projected for the northern California pricing zone provided two important kinds of information. First, the MCP projected under different hydrologic and divestiture conditions provide a temporal pattern of price signals influencing how future owners of the hydro facilities might adjust operations to improve profitability. For this reason, WRMI's OASIS model was run iteratively with UPLAN to develop revised monthly hydroelectric generation schedules based on UPLAN-generated market price (see Figure C-1). The projected MCP also provide information on how power markets can be affected by the different hydrologic and divestiture conditions analyzed, under circumstances forecast for 2005 regarding electric loads, generators, fuels, and transmission.

First we describe the hydro powerhouse operations projected by UPLAN under different hydrologic and divestiture conditions. Hourly results are illustrated for certain key basins, aggregating results for the individual powerhouses within each basin. Basin-wide generation translates into water releases at the powerhouses, affecting water flows and reservoir levels in the basin on an hourly, daily and seasonal basis. More localized and/or short term water flow and storage consequences may depend on operations at specific powerhouses, depending on how storage buffers the effect of water releases, and on how water is diverted into canals, tunnels and powerhouses as opposed to natural streambeds.

Finally, we provide an overview of all-hours and on-peak market clearing prices (MCP) for electric energy, projected for the northern California pricing zone under the different hydrologic conditions and divestiture cases. These results are provided for the full set of 24 hydro years, for each case, on a daily basis.

6.2.2 Projected Hourly Powerhouse Output: Effect of Hydrologic Conditions

In some of the water basins, the Pacific Gas and Electric Company powerhouses being considered for divestiture are essentially all run-of-river plants with little or no ability to time their generation. They offer limited operational flexibility with or without divestiture. Except for certain streamflows assumed to be purchased under the Proposed Settlement Case (no longer diverted through powerhouses), these systems were modeled to continue their historic monthly patterns of generation under each of 24 sets of hydro conditions. Examples include the Kilarc, Cow Creek, Butte Creek/DeSabla, and Kern Canyon powerhouses, all of which were modeled to have slight water availability reductions (for generation) under the Proposed Settlement Case, but otherwise to operate the same across the different divestiture cases.

In contrast, powerhouses in other basins have sufficient storage to adjust operations in response to power market conditions. The greater the amount of storage relative to water inflows, the greater the time period over which generation levels can be managed, seasonally for large amounts of storage, among hours of the day for smaller amounts of storage. This flexibility is constrained by various formal and informal restrictions on water use (assumed to vary across the divestiture cases) and by control of water rights and/or upstream releases by other parties.

This Section describes some of the hourly modeling results regarding generation and water use for three of the larger components of Pacific Gas and Electric Company's hydroelectric system, in the McCloud-Pit, North Fork Feather River (NFFR) and Mokelumne basins, respectively. These three systems contribute substantially to total Pacific Gas and Electric Company hydroelectric generation, averaging about one-third, 25%, and 10% of total conventional (non-pumped) Pacific Gas and Electric Company hydroelectric generation, respectively. They also received considerable attention in analyses for the divestiture EIR, because of their size and operating flexibility. Section 6.2.2 focuses on effects of different hydrologic conditions, under the Baseline and No Project divestiture cases. The effects of the different divestiture cases are smaller, and generally do not override the effects of the different hydrologic conditions, and are discussed in Section 6.2.3.

Example UPLAN Hourly Generation/Flow Projections: McCloud-Pit System

The three systems noted above differ considerably regarding hydrology and potential for altering operations in response to ownership and market circumstances. The McCloud-Pit system has only moderate amounts of usable storage, relative to the large water flow volumes typically available for generation throughout much of the year. The porous volcanic aquifers and large springs in the region act as quasi-reservoirs, but the discharge cannot be controlled. As a result, flexibility to time generation is limited in that water often must be used or else lost (spilled, rather than diverted for generation). This means that much of the winter/spring runoff must be used rather than stored, so that generation is typically highest in winter and spring. This leaves limited potential to shift generation into the summer period to capture high market prices, as discussed in Section 5 regarding the monthly water use schedules provided for UPLAN modeling. However, there is some flexibility to time generation on an hourly basis over the course of a week.

The flow duration curves for the McCloud-Pit system in winter and summer (Figures C-5 and C-6) depict the percentage of the time that MW output (requiring water flow through powerhouses) exceeds various levels.[32] We can see that for a considerable portion of the hours in winter or summer, generation is at the maximum level, indicating water being released from storage for generation at full powerhouse capacities, typically during peak hours. At the other end of the curves, except in the wettest years a considerable number of hours are spent at the minimum generation levels, representing run-of-river generation (plants without significant water storage) plus minimum required releases at some facilities with storage. Overall, these curves indicate

[32] Water flow through turbines may contribute to or reduce (by diversion) water flow in particular reaches of natural watercourses, depending on the locations (of powerhouses and watercourses) and times considered. However, the overall pattern of generation and associated water releases is a useful, broad

- limited ability to store water from the winter to the summer, so that generation is higher in winter (November-April), and

- greater but still limited ability to store water and time generation on a daily basis within a week or month, so that minimum levels of generation (and water throughput) are projected to occur in less (usually much less) than half of the total hours

In essence, this system has high water flows and limited water storage, so that maximum (full capacity) water releases and generation occur more often than minimums. Projected basin-wide generation (and water flow through powerhouses) in the winter (November through April) is at the maximum, full capacity level between one-third of the time for the driest year to 75% of the time for the wettest year, and somewhat under half the time for an average year (Figure C-4). For the summer (May-October), this drops to a range of about 25% (driest) to about half (wettest) of the time, and about one-third of the time for an average year (Figure C-5). Note that while 1979 was an average year for the overall Pacific Gas and Electric Company hydro generation, it was somewhat on the low (dry) side for the McCloud-Pit system.

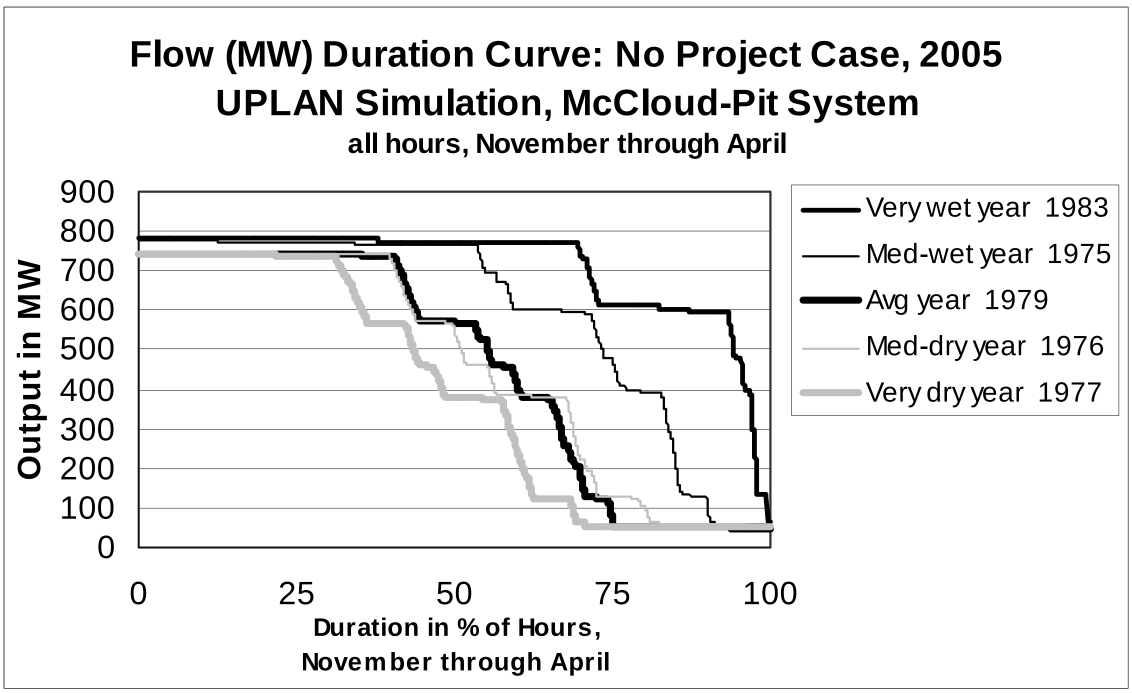

Figure C-4. McCloud-Pit System Hourly MW (Flow) Duration in Winter

No Project Case, comparing five hydro years all projected for 2005

As noted, the minimum generation level represents generation from only run-of-river plants plus required minimum releases through powerhouses from storage. In the winter this is projected to

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indicator of changes or variations in hydroelectric operations, potentially of significance for the surrounding environment.

occur about one-third of the time in the driest year, hardly at all in the wettest year, and less than 25% of the time in an average year (Figure C-4). In the summer this rises to about 40% of the time in average and dry years, and about 15% of the time in the wettest years (Figure C-5).

The value of water storage is being able to generate at highest levels during peak hours when market price are highest. Here, the peak hours are defined as 6 AM to 10 PM on weekdays. During the summer, the McCloud-Pit system is projected to generate at the maximum level for virtually all peak

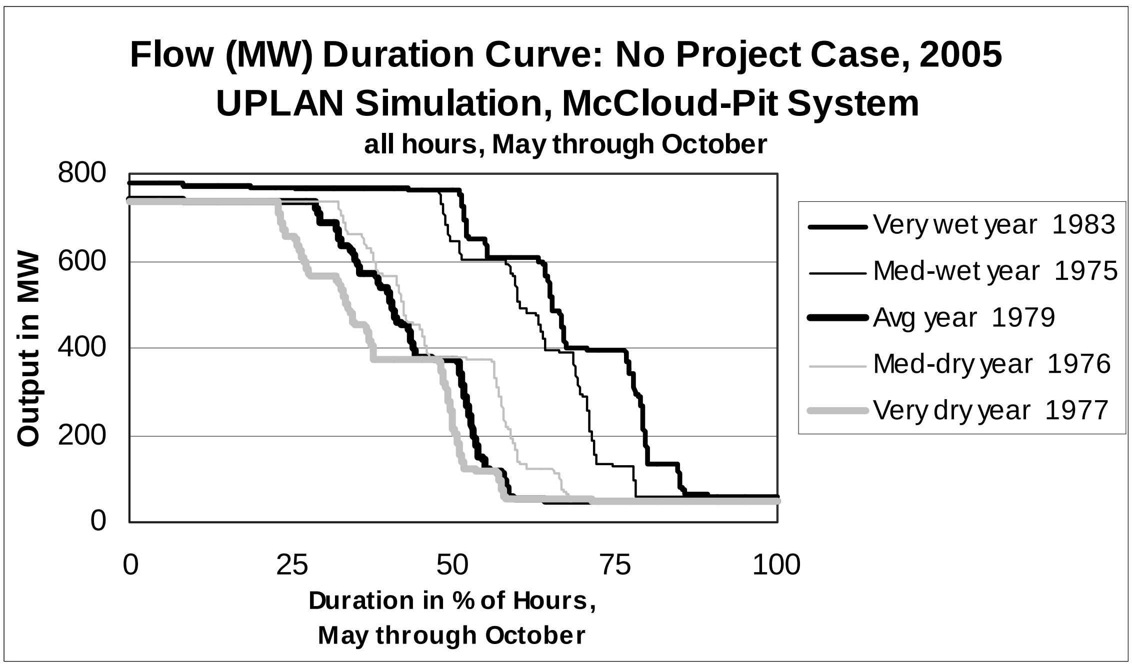

Figure C-5. McCloud-Pit System Hourly MW (Flow) Duration in Summer

No Project Case, comparing five hydro years all projected for 2005

hours during wet years, and for more than 60% of peak hours under all except the driest conditions (Figure C-6). In winter, with higher water flows (yet limited storage) these percentages rise, with maximum generation levels being reached during almost all peak hours in the wettest years and for more than 75% of peak hours in all but the driest years. Generation is not projected to fall to minimum levels during peak hours, except for a few summer hours in the driest years.

The seasonal MW (water flow) duration curves (Figures C-5 and C-6) and the high frequency of maximum generation during peak hours (Figure C-6) reflect a daily cycling pattern in which powerhouses with access to water storage time their generation (water releases) to occur during hours of the day when market prices are highest. This gives rise to a seven-day cycling pattern, with highest generation levels (often maximum levels) occurring during the high-load (high price) hours of each day (Figure C-7). This daily pattern is most pronounced in the summer due to high mid-day loads for air conditioning. Because weekdays generally have higher loads than weekends, the projected duration of high (especially maximum) generation levels is shorter on weekends, represented by the first and seventh cycles (days) in Figure C-7. Under most hydrological conditions, there is projected to be less available water and less generation towards the end of the summer and into the fall, so that the number of daily hours with high or maximum generation is projected to decline. As noted before, the minimum generation levels visible in this daily cycling pattern (Figure C-7) represent run-of-river generation (that cannot be timed) plus minimum releases for storage-based generation.

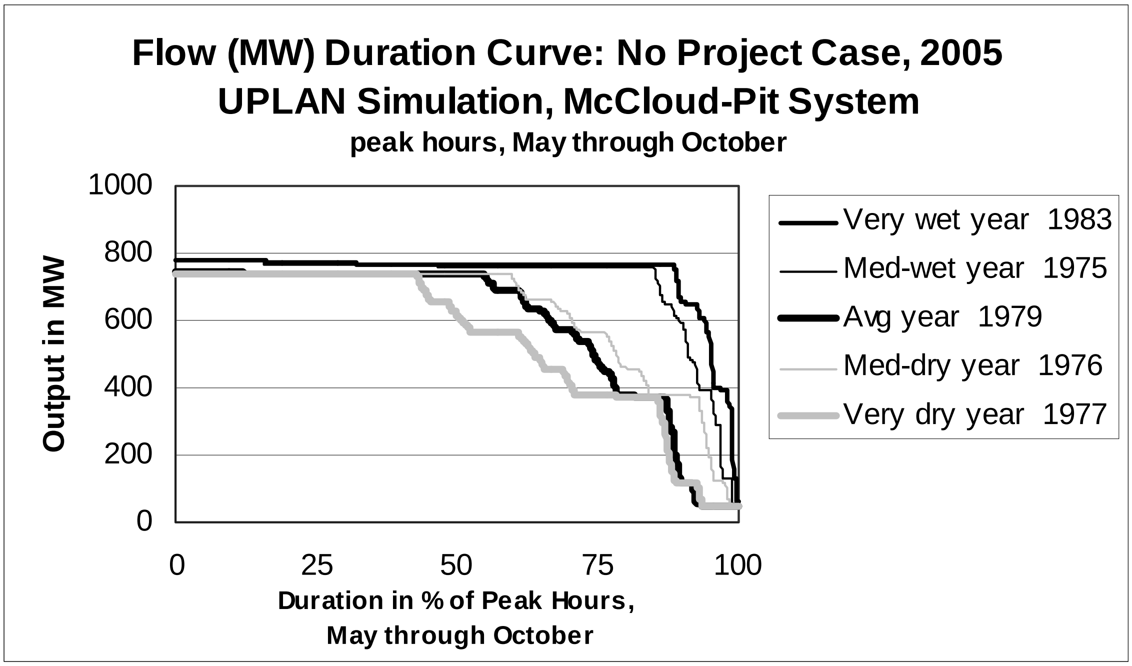

Figure C-6. McCloud-Pit System Hourly MW Duration in Summer On-Peak Hours
No Project Case, comparing five hydro years all projected for 2005

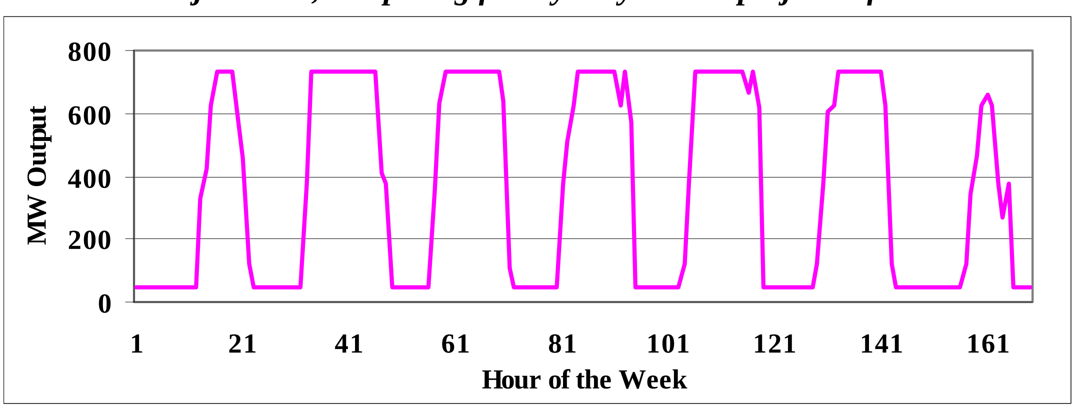

Figure C-7. McCloud-Pit System Chronological MW Output, Week of July 24, 2005
UPLAN Simulation, No Project Case for hydro year 1979 (average conditions)

During the off-peak hours, lower market prices are encountered, generation is generally is reduced to lower and often minimum levels, and water is accumulated in storage for use during the next period of high prices. However, generation during off-peak hours will exceed the minimum level when the available water exceeds the amount that can be stored for, and used during, the peak periods. This is especially influenced by the storage capacity relative to the rate of water inflows. In some off-peak hours of some months, water must be used to generate above the minimum level rather than being saved for peak (high price) periods, or else it will be lost for purposes of generation. Thus, with relatively high water flows throughout the year, projected McCloud-Pit system generation exceeds minimum levels in about two-thirds of the summer off-peak hours in wet years and about 25% to half of the summer off-peak hours in average-to-dry years (Figure C-8). In winter, with higher water flows, these percentages are even higher, 80-100% of the time for wet years, and 50-60% of the time for average-to-dry years.

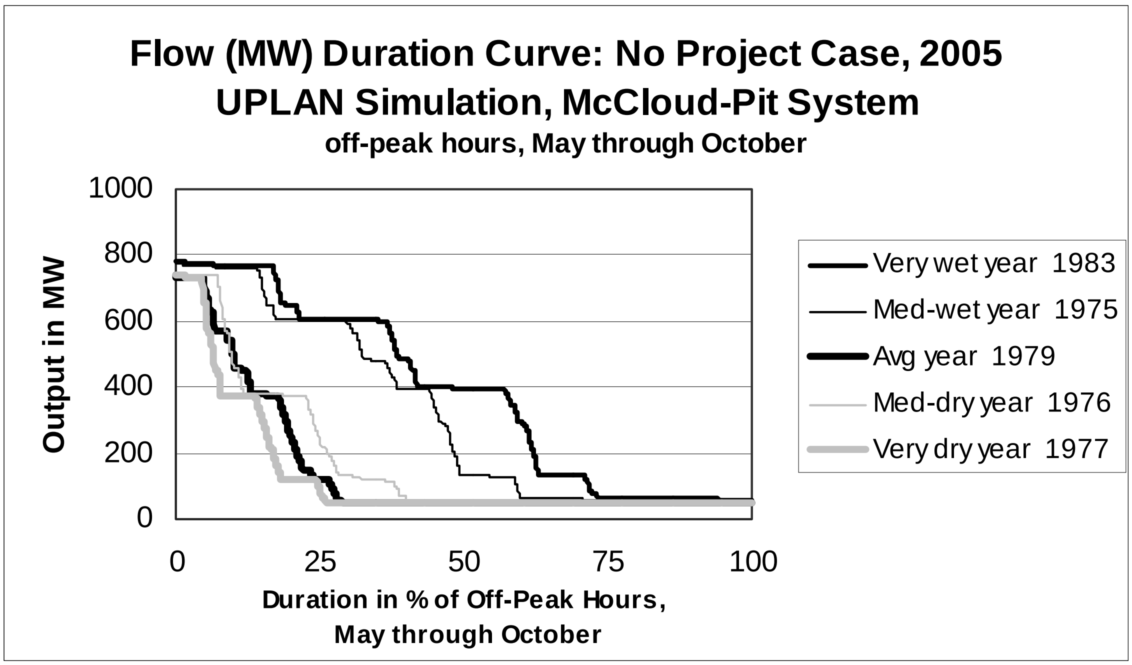

Figure C-8. McCloud-Pit System Hourly MW Duration in Summer, Off-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

Example UPLAN Hourly Generation/Flow Projections: North Fork Feather River System

The North Fork Feather River (NFFR) system experiences more seasonal and year to year variation in water availability than does the McCloud-Pit system. This results in greater variation in projected (and historic) generation across the different hydrological conditions represented by the

24 hydro years analyzed.[33] This variation is reflected in the monthly water use and generation levels provided for UPLAN modeling of the 24 different hydro years. It is also reflected in the winter and summer MW duration curves for the NFFR system across five different hydro years (Figures C-9 and C-10).

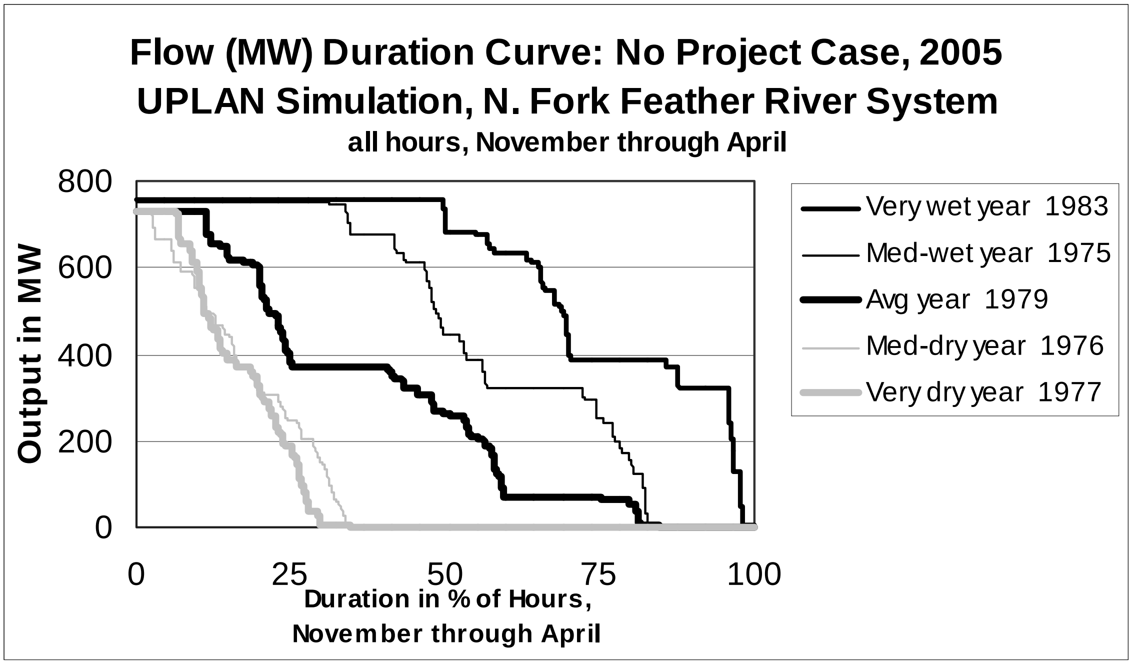

Figure C-9. NFFR System Hourly MW (Flow) Duration in Winter

No Project Case, comparing five hydro years all projected for 2005

The NFFR system accounts for the second largest portion of Pacific Gas and Electric Company's hydroelectric generation (after the McCloud-Pit). This system has both large inflows and very large amounts of storage, giving considerable ability to control levels of generation and water release on a seasonal as well as daily basis. This is reflected in the optimized monthly generation pattern provided for UPLAN modeling, in which generation levels are actually highest in later months of the year due to releases from storage, especially in drier years, although not in the wettest years. This is reflected in the MW duration curves from UPLAN modeling (Figures C-9 and C-10). Besides permitting winter-spring runoff to be stored for use in the summer, the considerable storage in this system also can be used to coordinate generation with high load (high market price) periods on a daily and hourly basis. It also provides the potential to alter operations under different market and ownership circumstances in the future. For these reasons, and because of the large amount of generation it represents (about 25% of conventional Pacific Gas and Electric

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[33] This analysis does not include any changes in FERC licensing conditions or other operating practices that may arise out of the recently proposed relicensing settlement for the Rock Creek-Cresta Project (FERC No. 1962).

Company hydro generation), the NFFR system received considerable attention in this study's evaluation of potential operating and water use changes under different divestiture cases.

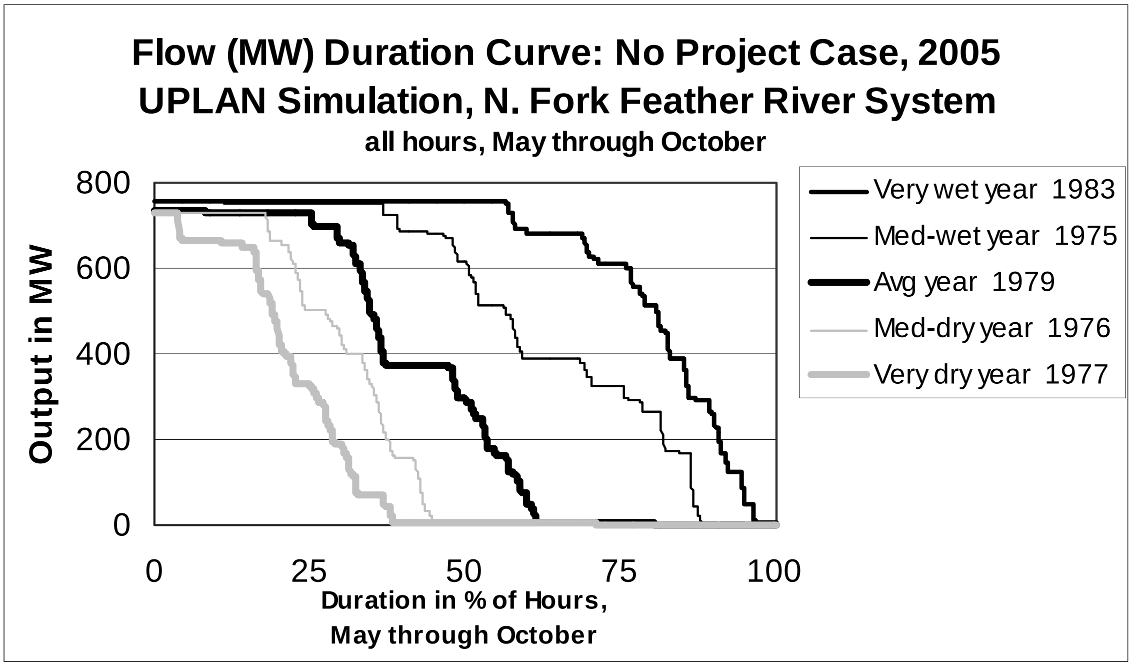

Figure C-10. NFFR System Hourly MW (Flow) Duration in Summer

No Project Case, comparing five hydro years all projected for 2005

The flow (MW) duration curves indicate that compared to the McCloud-Pit system the NFFR system is projected to operate at maximum generation levels (full capacity) for less of the time in the winter, especially in dry years. The range is from just under half of the hours in wet years to 10% or less of the hours in dry years (Figure C-9). Also in the winter, minimum generation levels (minimum water passage through powerhouses) are projected to be reached about two-thirds of the time under dry conditions (more frequently than for the Pit system) and about 5-15% of the time under average-wet conditions (similar to the Pit system). This reflects filling of storage during winter-spring runoff, rather than having to use much of the runoff for immediate generation (or else lose it). The NFFR contains little generating capacity that is fully run-of-river or that has substantial minimum required flows through powerhouses, explaining why the minimum generation level is lower than for the McCloud-Pit system.

In the summer (Figure C-10), the situation is entirely different due to the considerable storage and flexibility to manage it. For summers (May-October) of wet hydro years, maximum generation is projected to be reached about half of the time, as in McCloud-Pit system. Due to use of stored water, generation is projected to drop to the minimum level less than 10% of the time, less often than for the McCloud-Pit system.

However, in dry years less water is stored and maximum generation levels are projected to be reached for only about 5-15% of the summer hours, less than for the McCloud-Pit system. Generation is projected to drop to minimum levels more often than for the McCloud-Pit system, about 60% of the time. In essence, with its considerable storage the NFFR system has a lot of water to use for generation in the summers of wet years, but in dry years smaller amounts of stored water mean lower overall summer generation and more hours at minimum generation levels.

The considerable water storage gives the NFFR system ability to time generation for peak hours when market prices are highest, especially in average-to-wet years when storage levels are high. During the summer (May-October), the NFFR system is projected to generate at maximum capacity for 70-90% of peak hours during wet years, about half of peak hours in average years, but only 10-30% of peak hours in dry years (Figure C-11). Especially for dry years, this is a smaller percentage of peak hours at full capacity than projected for the McCloud-Pit system, and the difference between wet and dry years is considerable. In the November-April winter period when water runoff is being stored, the projected percentage of on-peak hours spent at full output capacity is lower than in summer, the opposite of what was projected for the McCloud-Pit system with its smaller storage relative to runoff. NFFR generation is rarely projected to fall to minimum levels during peak hours of average-to-wet years (winter or summer), but is projected to fall to minimum levels in about 25% to one-third of peak hours in dry years (more often in winter). This is more frequently than projected for the McCloud-Pit system.

Similar to the McCloud-Pit and other systems with usable water storage, the NFFR system is projected to operate on a daily cycling pattern, running at high or maximum output during highest load hours in the middle of the day and evening (especially on weekdays) and running at low or minimum output during off-peak hours in the early morning. (See Figure C-7 for the McCloud-Pit system.) High loads and high output are less frequent on weekends. The minimum generation level is set by run-of-river generation plus minimum water releases through powerhouses, and the maximum level is set by powerhouse capacities (water turbines, turbogenerators, water delivery). However, the duration of maximum generation levels during a week is driven by the duration of high loads during that week relative to other periods, and by availability of water to release from storage.

During off-peak hours[34] with low market prices, storage hydro generation is reduced, usually to minimum levels, to preserve water for use during high load periods. When water is used to generate above minimum levels during off-peak periods this is generally because so much water is available that the most economic option is to use some of it for generation even during off-peak hours. In the summer, off-peak generation from the NFFR system is projected to exceed minimum

[34] Here, “off-peak” includes all weekend hours, even though storage hydro may be cycled up during some high-price hours on the weekend as shown in Figure C-7.

levels roughly 80% of the time in wet years, but only about one-third of the time in a typical average year and about 10-15% of the time in dry years (Figure C-12). For wet years, above-minimum generation in summer off-peak hours is thus more frequent than was projected for the McCloud-Pit system, but for dry years

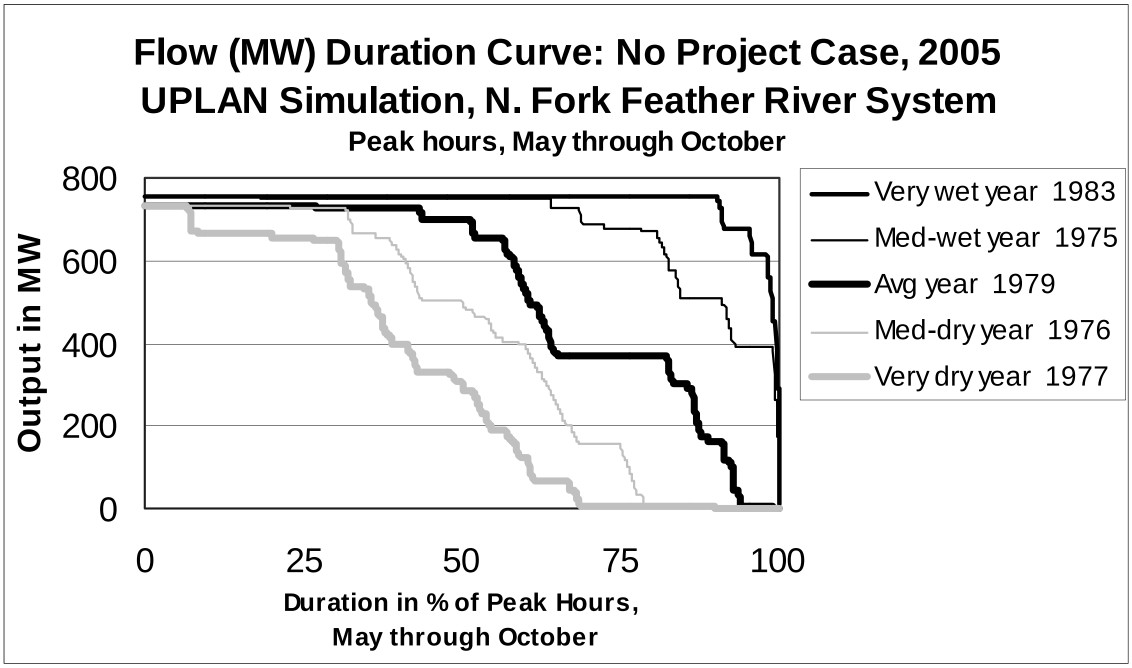

Figure C-11. NFFR System Hourly MW Duration in Summer On-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

it is less frequent (about the same for average years). This reflects abundance of stored water in summers of wet years, and unused storage in summers of dry years. In winter, the projected frequency of off-peak generation above minimum levels is about the same as in the summer under wet conditions, but under dry conditions it is rare (water would be going into unfilled storage for later use).

Example UPLAN Hourly Generation/Flow Projections: Mokelumne River System

The Mokelumne River system in the central Sierras has enough storage to provide some seasonal as well as hourly control over generation and water releases.[35] However, flexibility to time water releases and generation is constrained by the complex interconnected system of canals and tunnels, by water agreements, and because roughly a quarter of the generation comes from run-of-river

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35 This analysis does not include any changes in FERC licensing conditions or other operating practices that may arise out of the recently proposed relicensing settlement for the Mokelumne Project (FERC No. 0137).

plants with little effective storage. Since the amount of generation from run-of-river plants varies considerably by year and season, the modeled "maximum" and "minimum" generation levels also vary significantly by year and season. This is apparent in the flow (MW) duration curves for winter and summer (Figures C-13, C-14). On a percentage basis, generation in the Mokelumne River system varies among hydro years (wet versus dry conditions), about as much as it does for the NFFR system.

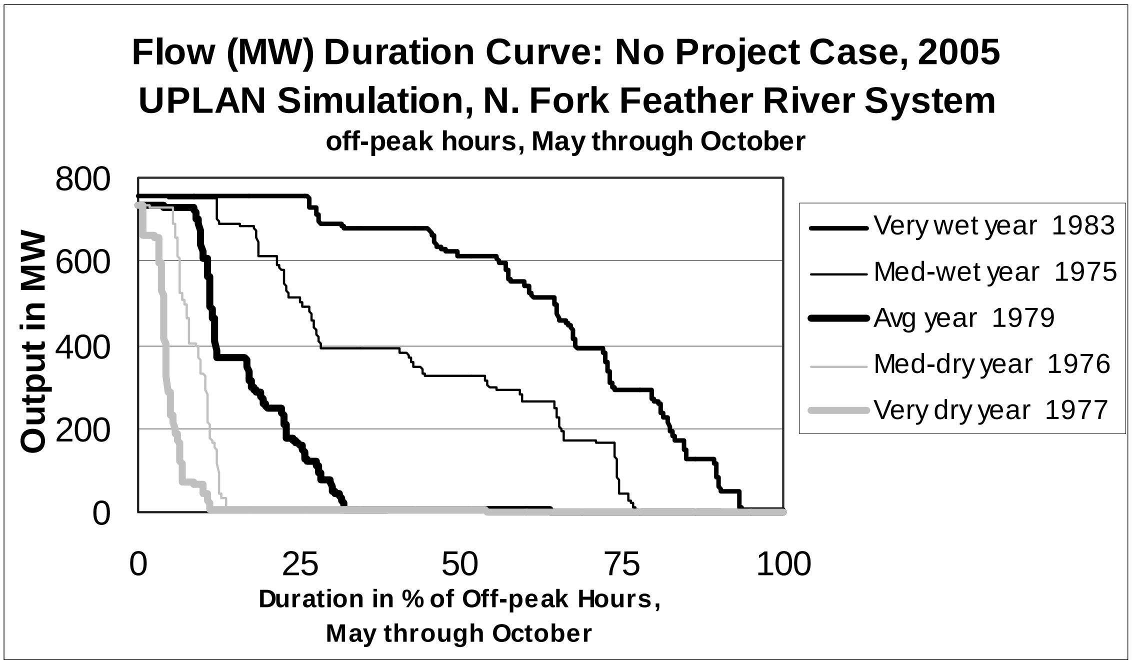


Figure C-12. NFFR System Hourly MW Duration in Summer, Off-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

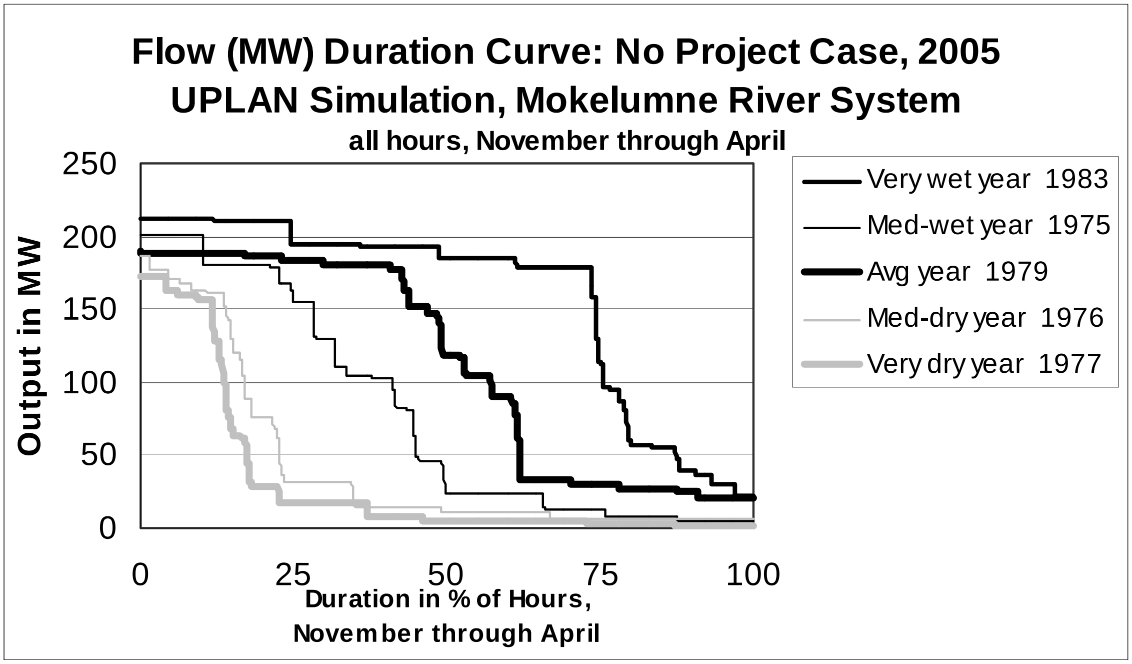


Figure C-13. Mokelumne River System Hourly MW (Flow) Duration in Winter

No Project Case, comparing five hydro years all projected for 2005

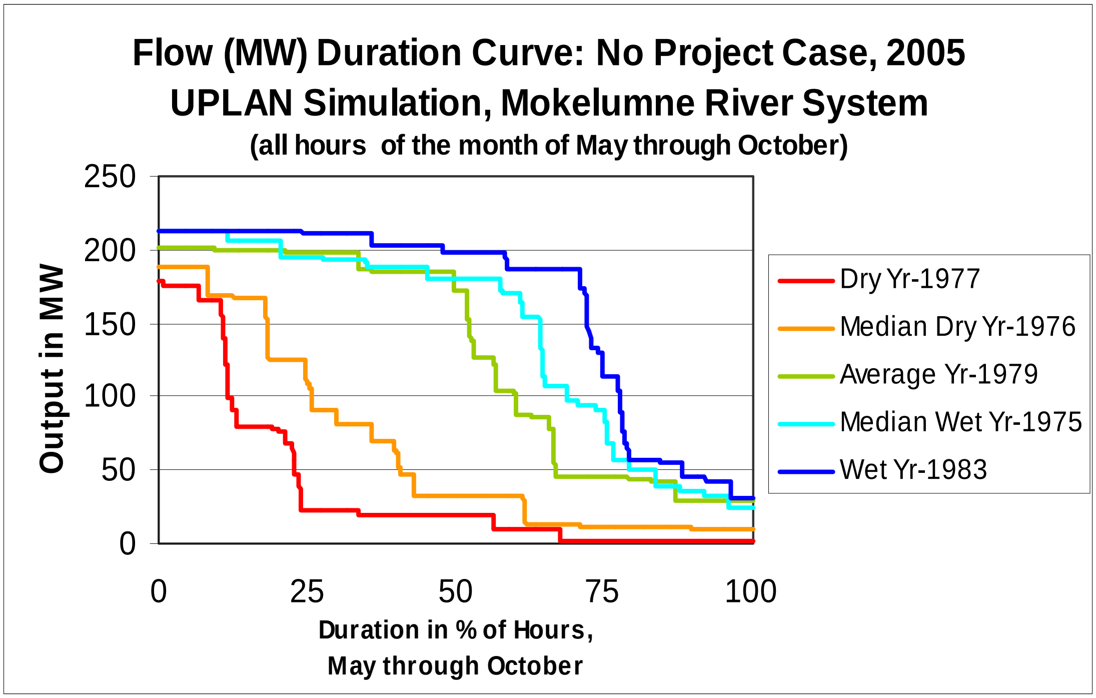


Figure C-14. Mokelumne River System Hourly MW (Flow) Duration in Summer

No Project Case, comparing five hydro years all projected for 2005

In general, projected generation levels for the Mokelumne River system are about equal in the winter and summer in the wettest years, but otherwise are somewhat higher in summer (Figures C-13, C-14). This reflects use of water from storage. The MW levels representing "maximum" and "minimum" generation vary noticeably between months and among the 24 different "hydro years." This reflects variation in run-of-river generation, which plays a larger role here than in the Pit or NFFR systems.

In the winter period, maximum (full capacity) output is projected to be attained for about 75% of the hours under wettest conditions, in somewhat less than half of the hours under average-to-wet conditions, and in only about 15% of the hours under dry conditions (Figure C-13). This is slightly more often than is projected for the NFFR system. In winter, generation is projected to drop to minimum levels about 15% of the time under the wettest conditions and almost half of the time under average-to-wet conditions, similar to what is projected for the NFFR. Under dry conditions, minimum generation levels are projected to be reached more than two-thirds of the time in winter. This is also similar to what is projected for the NFFR system, and reflects filling of storage.

In the May-October summer period (Figure C-14), the situation is altered, reflecting use of stored water. Maximum generation levels are projected to be reached in about two-thirds of the summer hours during average-to-wet years (more often than in winter) but in only about 10-20% of the hours in dry years (a little more often than in winter). This is a slightly higher frequency of reaching maximum output than is projected for the NFFR system in the same hydro years. Generation is projected to drop to minimum levels about 25% of the time in summers of average-to-wet years, but about half to 75% of the time in summers of dry years (about as often as in winter). This represents more hours at minimum generation than projected for the NFFR system, especially in the driest years. However, due to run-of-river generation, the Mokelumne minimum level is higher.

Water storage in the Mokelumne River system provides ability to time generation for peak load hours when market prices are highest. During the summer period of May-October, maximum output levels are projected to be reached in 90-100% of the peak hours during wet years, in about 75% of the peak hours in a typical "average" year, and in 25% to half of peak hours in dry years (Figure C-15). This is a slightly higher frequency than projected for the NFFR system, although the MW level representing "maximum" generation varies noticeably over time due to the influence of run-of-river generation. In the November-April winter period, water runoff is being stored and the projected frequency of attaining maximum generation during peak hours drops slightly, except in the wettest years. As with the NFFR system, the difference between wet and dry years is considerable.

Like the McCloud-Pit, NFFR and other basins with substantial water storage useable for generation, the Mokelumne River system's MW duration curves reflect an underlying pattern in which generation is cycled over the course of a week, reaching highest levels during the peak load hours of the day (especially weekdays), and dropping to minimum levels in off-peak hours, especially in early

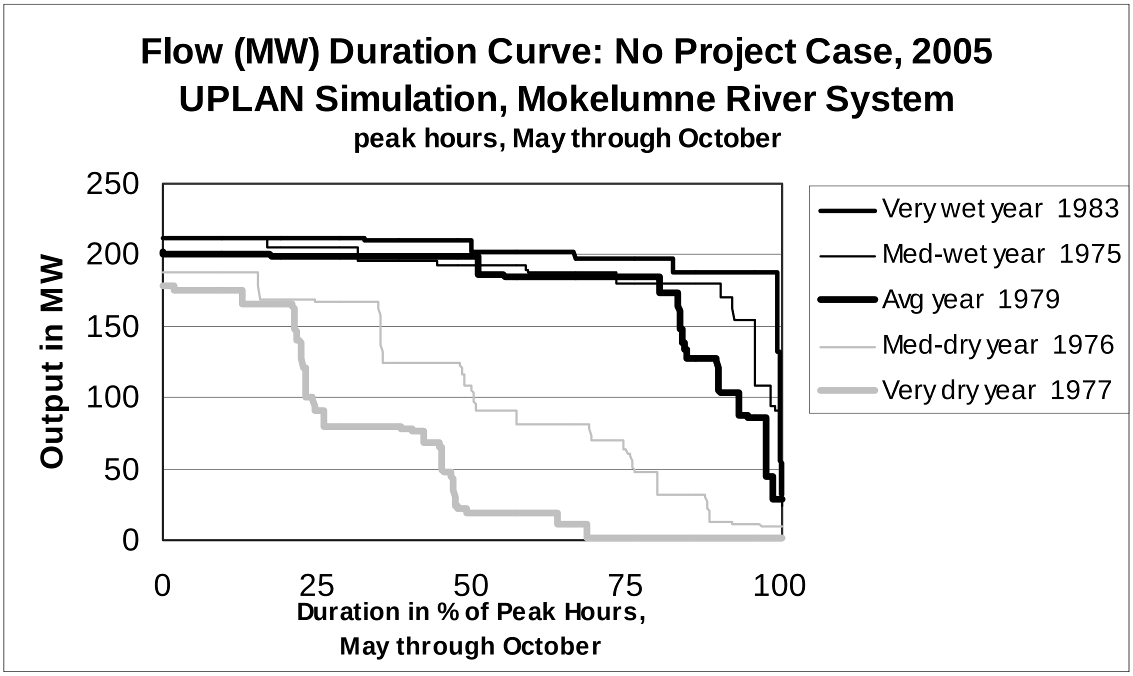


Figure C-15. Mokelumne River System Hourly MW Duration in Summer, Peak Hours

No Project Case, comparing five hydro years all projected for 2005

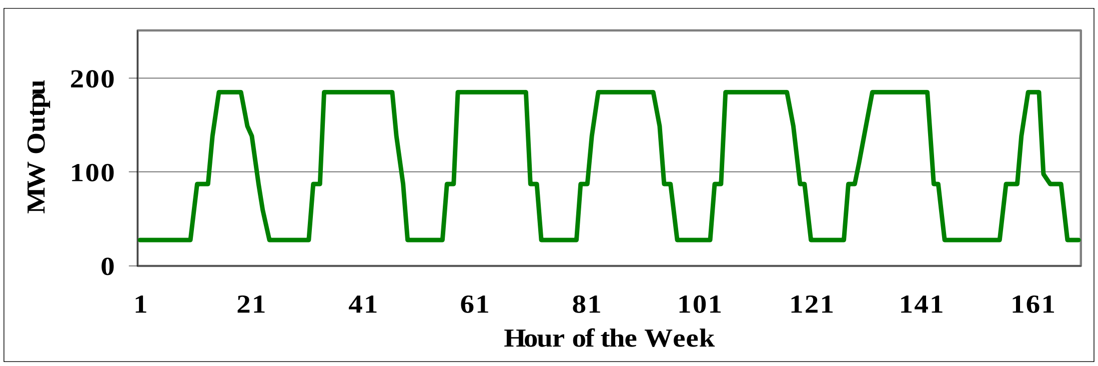


Figure C-16. Mokelumne System Chronological MW Output, Week of July 24, 2005

UPLAN simulation, No Project Case, hydro year 1979 (average conditions)

morning. Thus for an average hydro year 1979 (perhaps slightly wetter than average for this particular basin), generation projected over a mid-summer week demonstrates a pattern (Figure C-16) similar to that shown earlier for the Pit McCloud system. High generation levels are attained for few more hours during the week (Figure C-16 vs. Figure C-7), and minimum generation levels reflect a higher percentage (if not MW) of run-of-river generation.

During off-peak hours with relatively low market prices, generation is reduced to lower, usually minimum levels, to preserve stored water for use during peak hours. When water is used to generate above minimum levels during off-peak periods this is generally because so much water is available from inflows and/or storage that the most economic option is to use it for generation even during off-peak hours. In the summer period, generation from the Mokelumne River system is projected to exceed minimum levels roughly 60% of the time in wet years, about one-third of the time in a typical "average" year, and only about 10% of the time in dry years (Figure C-17). This is slightly less frequently than projected for the NFFR system, and, in dry years, is also less frequently than projected for the McCloud-Pit system. This reflects little use of storage hydro for off-peak summer generation except in wet years, although the run-of-river generation would be continuing in off peak hours, as reflected in Figure C-16. In winter when storage would be filled, the projected frequency of off-peak generation exceeding the minimum level is even lower, except under the wettest of conditions.

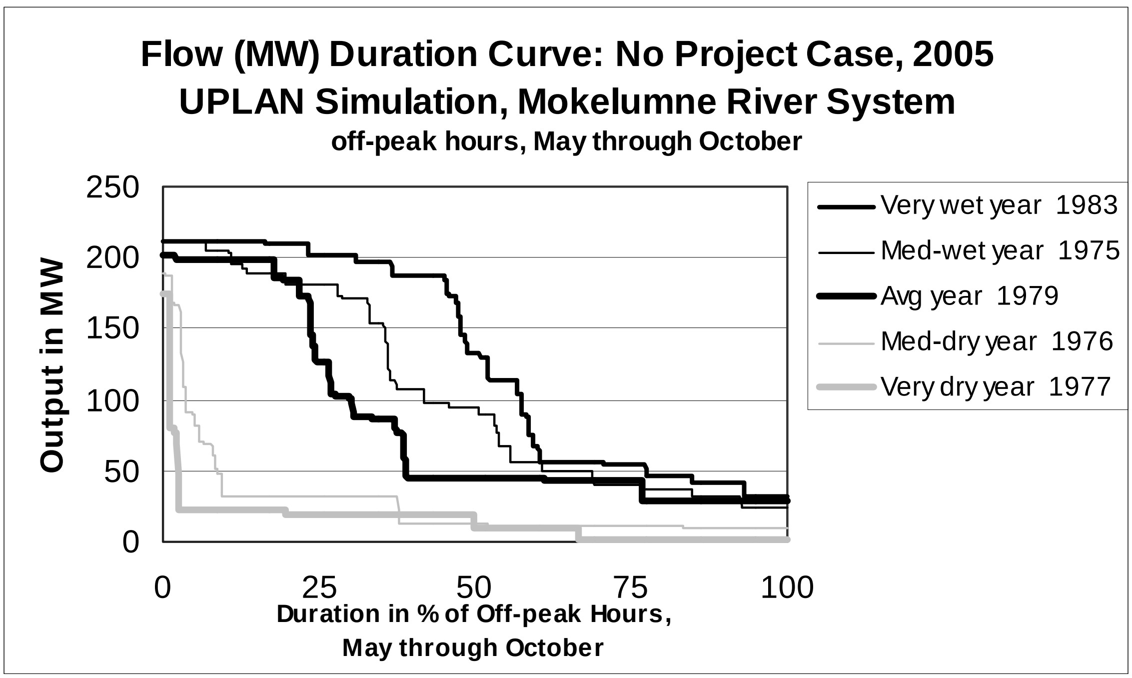


Figure C-17. Mokelumne System Hourly MW Duration in Summer, Off-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

6.2.3 Effect of Four Divestiture Cases on Projected Hydro Generation Patterns

The preceding section illustrated how patterns of water use for hydroelectric generation vary among basins due to differences in hydrology and configuration of the hydroelectric system facilities. It especially illustrated how, under the Baseline and No Project Cases, water use for generation is greatly influenced by hydrologic conditions that vary greatly from year to year in California and the

WSCC. This Section analyses the effects of four different divestiture cases on hydroelectric operations projected for 2005.

The limited impact of the divestiture cases compared to the impact of hydrologic conditions reflects physical limitations, legal/contractual restrictions, informal agreements, and ownership by others of various in-basin facilities and water rights, all of which constrain how a future owner could rationally operate the hydroelectric facilities. On the other hand, variation of hydrology, system configuration and constraints from basin to basin gives hydroelectric facilities in some basins much greater potential for varying operations after divestiture, compared to other basins. As above, the following discussion focuses on the McCloud-Pit, NFFR and Mokelumne systems. These systems provide substantial amounts of generation and a range of potentials for altering operations in the future. All three received considerable attention in this study.

Example Divestiture Case Impacts on Hourly Generation: McCloud-Pit System

While the McCloud-Pit system is the largest contributor to Pacific Gas and Electric Company's hydroelectric system and has considerable storage, modeling and analysis indicate limited potential for variation of operations across the divestiture cases. This is because usable storage is not large relative to large water flows that persist into the summer more than in the other basins. While there is potential to time generation for the peak load hours on a daily basis, there is much less potential to store water or vary water use strategies on a longer term basis. Also, there are fewer water use agreements and practices considered subject to variation in the future, compared to some of the other basins.

The result is that across the four divestiture cases analyzed, there is little variation in projected frequency of achieving different MW output (or water release) levels. The impact of the divestiture cases is largest in summer (May-October), but even then it is small, for either wet (Figure C-18) or critically dry (Figure C-19) years. The main effects are a moderate reduction in generation under the Proposed Settlement Case due to assumed purchase of streamflows (no longer diverted for generation), and increased summer (but not winter) generation under The PowerMax Case (maximize profits) in wet years. The impact on projected frequency of maximum and minimum generation levels is very minor, mainly consisting of somewhat over 10% increase in frequency of reaching maximum generation levels under the PowerMax Case, in summers of wettest years.

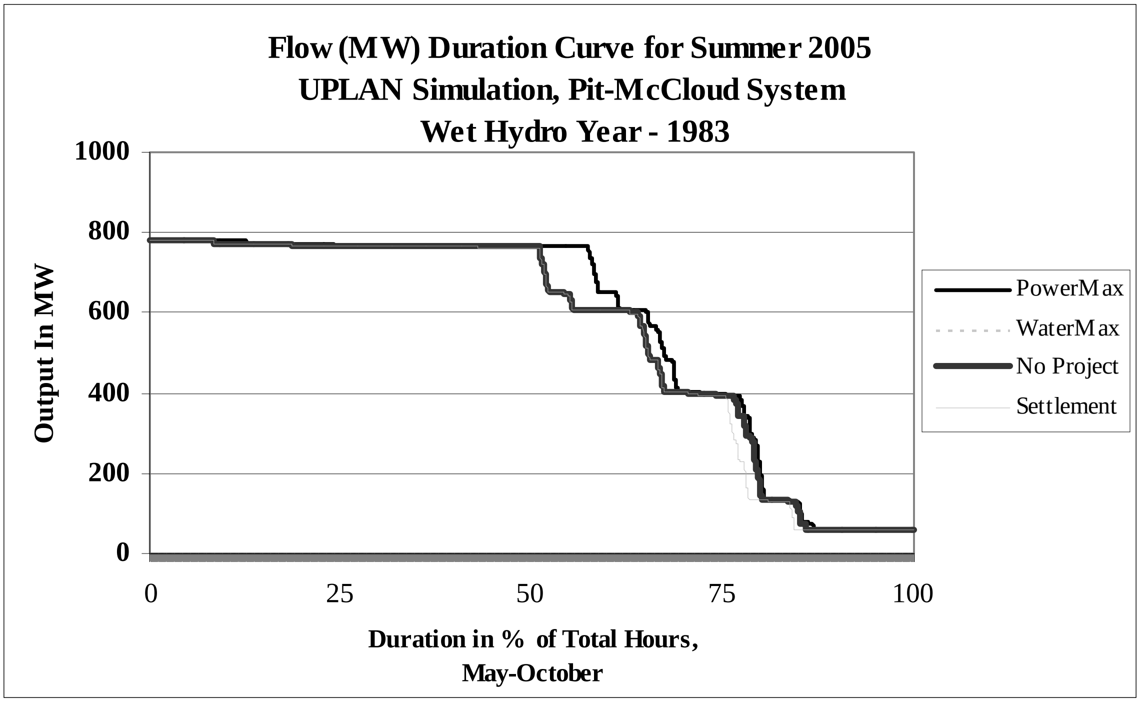


Figure C-18. McCloud-Pit System: Effect of Divestiture Cases on Hourly MW Duration in Summer, Wet Hydro Conditions (1983)

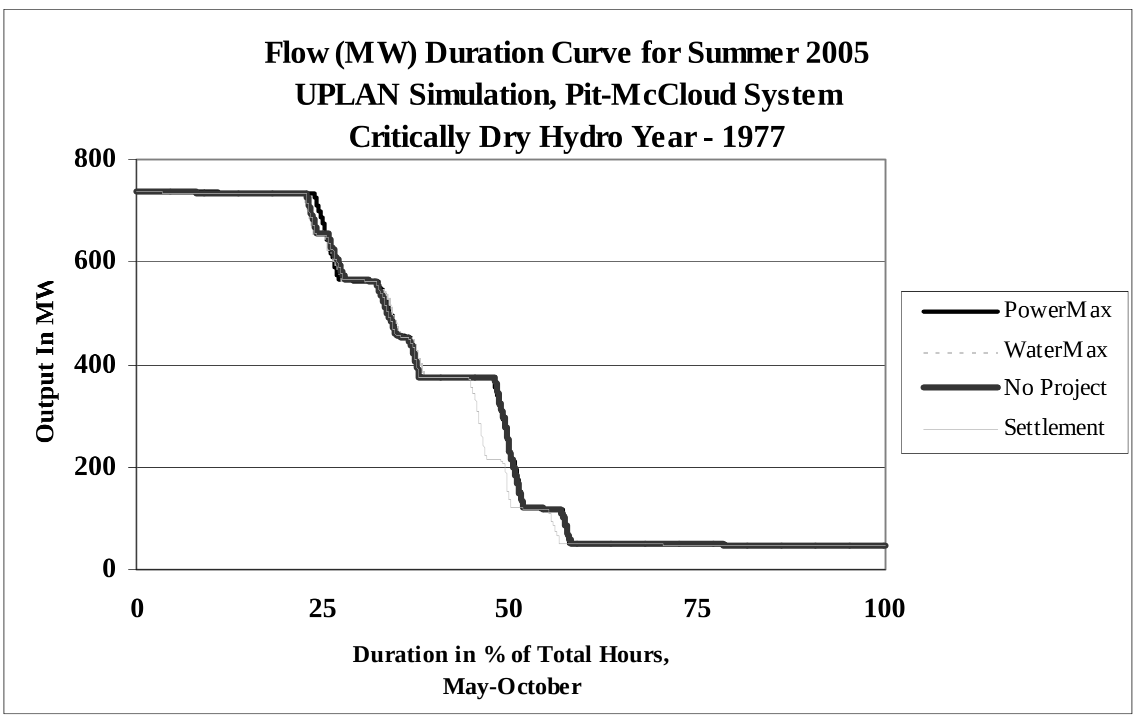


Figure C-19. McCloud-Pit System: Effect of Divestiture Cases on Hourly MW Duration in Summer, Critically Dry Hydro Conditions (1977)

Example Divestiture Case Impacts on Hourly Generation: NFFR System.

Of all of the water basins and groups of hydroelectric facilities analyzed in this study, the North Fork Feather River (NFFR) system accounted for the greatest impact of divestiture cases on projected hydroelectric operations. This reflects the large amounts of both generation and storage, combined with considerable flexibility.

The purchase of streamflows assumed under the Proposed Settlement Case reduces water projected to be available for generation. This slightly reduces the projected frequency with which maximum generation levels are reached, mainly in the summer and under dry conditions. However, the biggest impacts come from the PowerMax and the WaterMax Cases.

The PowerMax Case represents heightened efforts to time generation for periods of highest market prices, observing legally binding water use constraints but not the informal constraints that were assumed to continue under the No Project Case. For winter, the result is lower generation levels and lower frequency of high generation hours, somewhat under dry conditions (Figure C-20) but especially under wet conditions (Figure C-21). This represents keeping more water in storage for use in the summer. The impact on frequency of reaching maximum or minimum generation levels is modest, mainly a decrease in projected frequency of reaching maximum MW output levels.

In summer, the PowerMax Case results in higher generation levels using stored water, taking advantage of peak loads and high market prices. Compared to the No Project Case, the projected frequency of reaching maximum output levels more than doubles under the driest conditions (Figure C-22), and increases slightly under the wettest conditions, where the frequency would already be high (Figure C-23). The PowerMax Case has little impact on the projected frequency of dropping to minimum generation levels in summer under the driest conditions, moderately reduces the frequency under average water conditions (not shown), and reduces the frequency to zero under wet conditions.

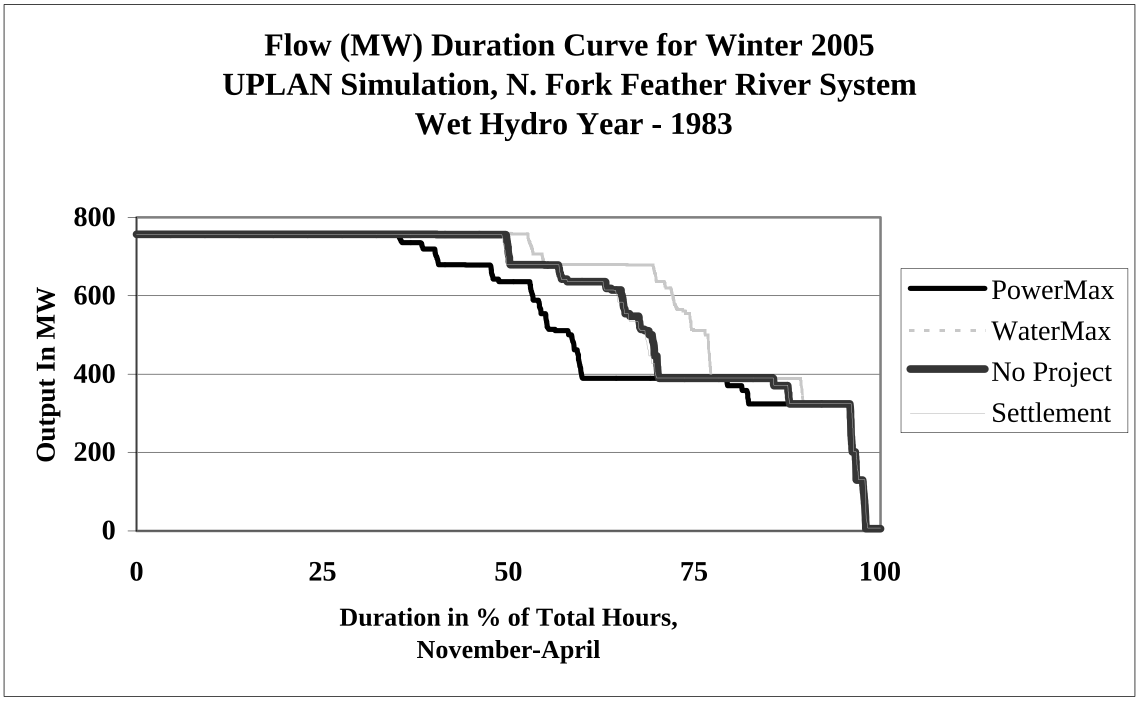


Figure C-20. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Winter, Wet Hydro Conditions (1983)

The WaterMax Case represents revised commercial priorities that emphasize reliability and profitability of water deliveries. It had a great impact on projections for the NFFR system, with its large storage and flexibility. In winter under wet conditions, the revised monthly schedules of water use for generation result in increased generation and especially, increased frequency of attaining high and maximum generation levels (Figure C-20). This presumably reflects holding reservoirs at higher levels going into wet winters, increasing the potential of both spills and high generation in winter/spring. In the summers under wet conditions, the WaterMax Case entails lower projected generation levels, and in particular, a substantial increase in projected frequency of low and even minimum generation levels (Figure C-21). These results are less pronounced under average (rather than wet) water conditions.

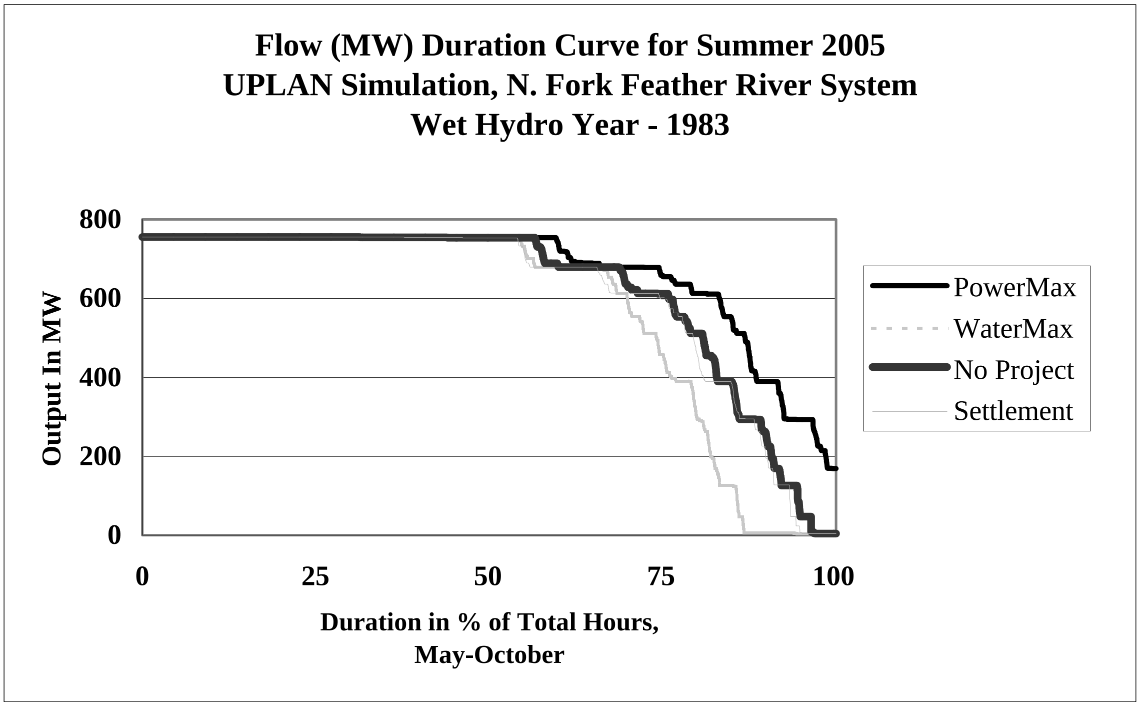


Figure C-21. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Summer, Wet Hydro Conditions (1983)

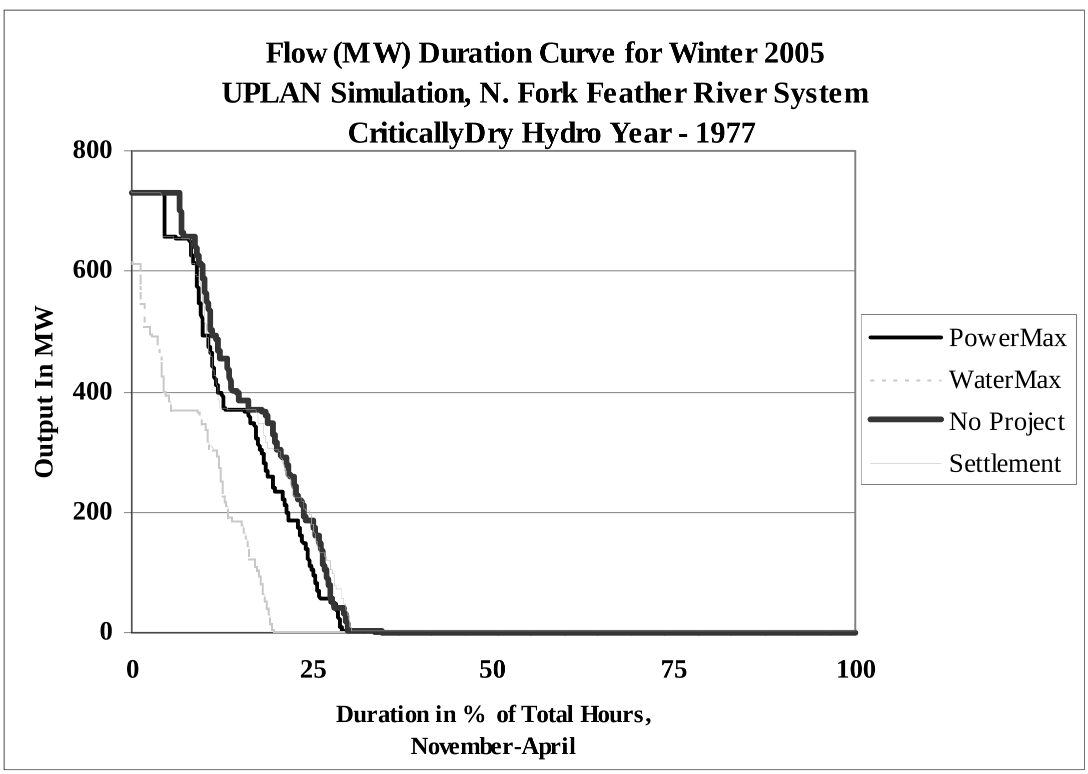


Figure C-22. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Winter, Critically Dry Hydro Conditions (1977)

Under critically dry conditions the impact of the WaterMax Case is quite different. Winter generation levels are decreased, reflecting extreme drawdown of reservoirs the previous year, so that early winter generation is very low. Minimum generation levels are projected to occur more frequently in the winter, and maximum generation levels are not even projected to be reached, as water is added to the depleted reservoirs (Figure C-22). However, under the driest conditions (Figure C-23) and also under somewhat less dry conditions (not shown), the WaterMax Case is projected to result in much higher summer generation levels than the No Project Case, as water is withdrawn from reservoirs for water deliveries (also used for generation). This leaves low water levels in reservoirs and consequent low end-of year ("winter") generation. Under the WaterMax Case, maximum generation levels are projected to be reached about 25% of the time in summer under critically dry conditions, much more often than under the No Project Case. Minimum generation levels are projected to occur less than (instead of more than) half of the time.

Example Divestiture Case Impacts on Hourly Generation: Mokelumne System

Modeling of the Mokelumne River system powerhouses shows a slightly greater impact of the divestiture cases than for the McCloud-Pit system, but less than for the NFFR system. Greater water use restrictions and lesser amounts of storage help account for this lower response, reducing the flexibility for altering operations under different future conditions. In addition, the proposed Settlement Agreement does not identify any streamflows potentially to be purchased from this system. A separate relicensing settlement agreement is pending for Project 137, but this agreement is not reflected in the modeling presented here. The greatest divestiture case impact on modeled operations for the Mokelumne River powerhouses was a slight elevation of hourly generation levels projected for the winter (especially, end-of-year months) under the PowerMax Case (maximize profits, only binding constraints remain). This is illustrated for an average year (Figure C-24), but also occurred for other years. It results in a slightly increased frequency of attaining maximum generation levels and a slightly decreased frequency of falling to minimum generation levels, relative to the No Project Case. In addition, the minimum and maximum generation levels are themselves increased due to slightly higher run-of-river generation. The divestiture cases have very little impact on projected summer generation patterns for the Mokelumne River system, as illustrated for an average year in Figure C-25.

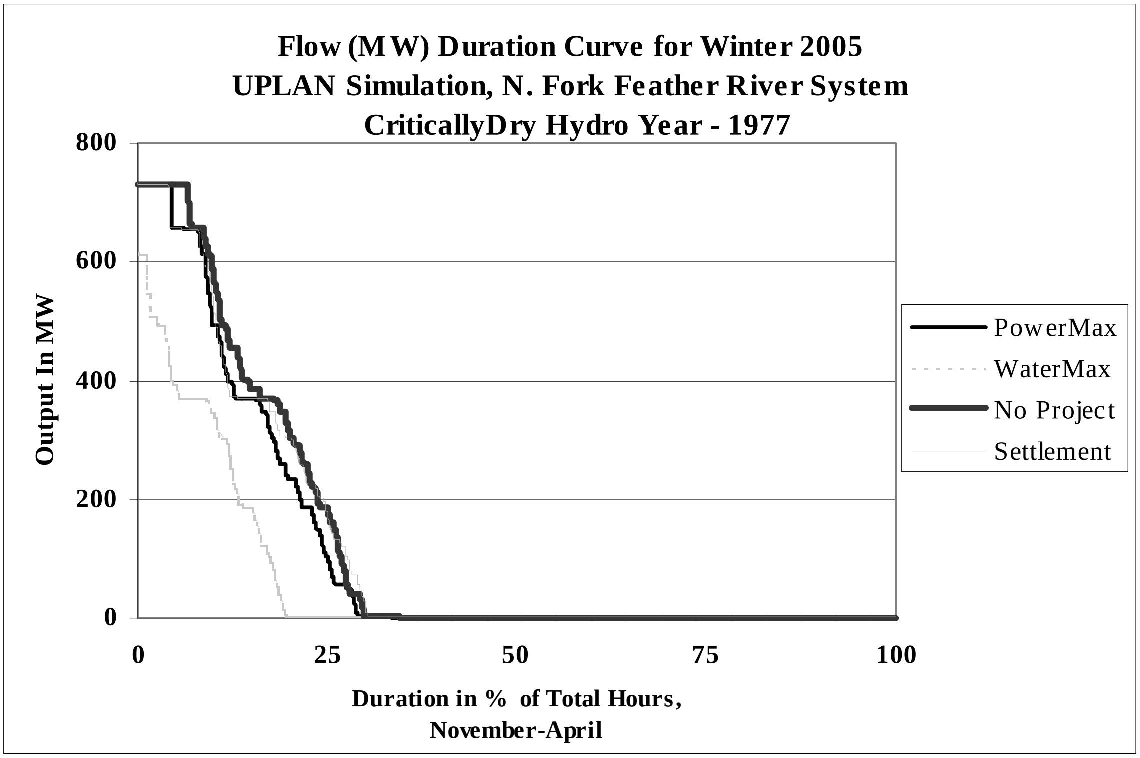


Figure C-23. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Summer 2005, Critically Dry Hydro Conditions (1977)

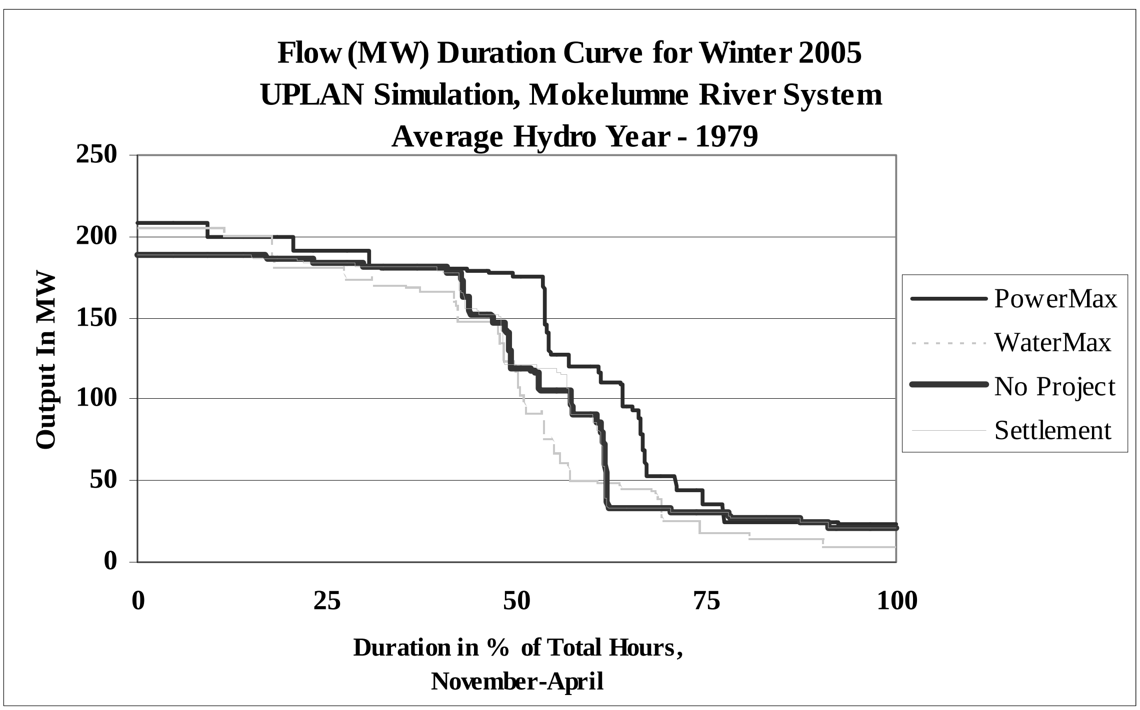


Figure C-24. Mokelumne System: Effect of Divestiture Cases on Hourly MW Duration in Winter, Average Hydro Conditions (1979)

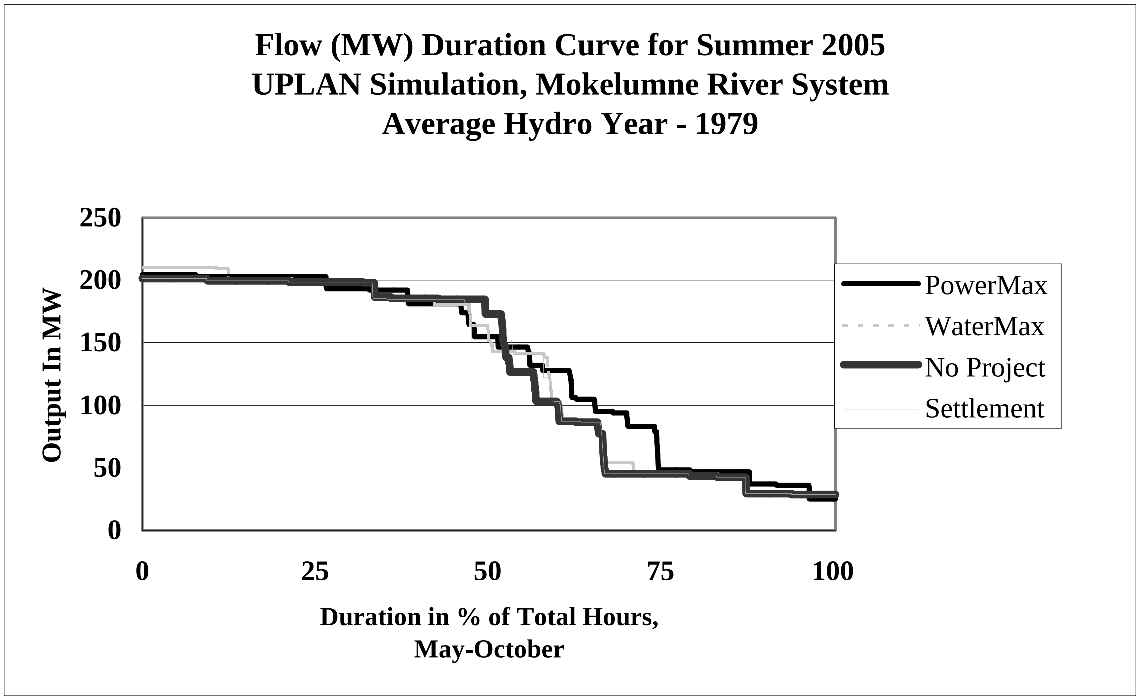


Figure C-25. Mokelumne System: Effect of Divestiture Cases on Hourly MW Duration in Summer, Average Hydro Conditions (1979)

Example Divestiture Case Impacts on Hourly Generation: Chili Bar

Pacific Gas and Electric Co. currently operates Chili Bar under an informal agreement with the commercial rafting operators. Pacific Gas and Electric Company notifies the rafting operators when it will not be meeting specified release targets during the rafting season. These targets generally call for power generation to ramp up starting by 9 AM, and for weekend releases similar to weekday releases. This operation requires coordination with the Sacramento Municipal Utility District to provide sufficient water from upstream storage.

In modeling the Pacific Gas and Electric Company hydropower system after divestiture, a reasonable expectation is that a new owner might not honor such an agreement, and instead would operate to maximize power revenues. With such a management objective, the new owners generally would operate to meet summertime peak loads, which occur in the afternoon and early evening. Thus, releases would occur later in the day, and at substantially lower levels during the weekends. The PowerMax Case was modeled based on this presumption.

Exhibit C-4 shows expected typical hourly Chili Bar operations for the months of July and August for weekdays and weekends under the PowerMax Case assumptions. Six different water-year type conditions that range from critically dry (1977) to extremely wet (1983) are shown. Note that under all but the wettest conditions, the weekend flows never top 1,200 cfs before noon in July or August.

6.2.4 Market Clearing Prices – Effect of Hydro Conditions

Hydroelectric generation plays a substantial role in overall power supply not only in California, but also across the WSCC. The great year to year variations in precipitation, runoff and resulting hydroelectric generation have a large impact on western power markets. In wet years low-cost energy from hydroelectric generation is abundant in the spring during runoff and persists at high levels into the summer. In dry years when less hydroelectric generation is available, especially into the summer, higher cost thermal generation sources must be called upon more frequently, driving up market prices.

California imports considerable amounts of electricity from other parts of the WSCC, including considerable hydroelectric generation from the Pacific Northwest. Generally a wet or dry hydro year in northern California where the Pacific Gas and Electric Company hydroelectric plants are located corresponds to a wet or dry year in the Pacific Northwest as well. Thus, a dry hydro year as modeled and evaluated in this study typically means high market prices in northern California not only because of low levels of hydroelectric generation in California, but because of low levels of hydroelectric generation across the WSCC.

This study considered a large range of hydro conditions, represented by 24 different historical years of data. In the UPLAN modeling, this range of conditions translated into a range of market clearing prices (MCPs) projected for 2005 in northern California (Figure C-26). Great variation among the 24 sets of water conditions produced considerable variation in MCP projected for the northern California pricing zone. The annual average (all-hour) prices differed by just over \$10/MWh (about 25%) between the wettest and driest of the historical hydro conditions simulated, and the average price for on-peak hours in August (over 300 hours altogether) differed by almost \$20/MWh, or over 30%. The price difference between MCP projected for more typical wet versus dry years are about \$5/MWh for all annual hours, and about \$10/MWh for the average peak hour prices in August. The lowest MCPs of the year, typically experienced in the spring when hydroelectric generation is high and loads are low, vary less across different hydro conditions On the other hand, the highest MCPs of the year, during summer peak load periods when hydro generation is more limited, vary about \$20/MWh between wettest and driest conditions.

Peak load hours give rise not only to the highest MCPs but also the greatest differences between wet versus dry conditions. The highest MCPs occur during on-peak summer hours (weekdays, 6AM to 10 PM) with high air conditioning loads, and this is also when MCPs are projected to vary the most across different hydro conditions (Figure C-27). The association of critically dry hydro conditions with great elevation of the very highest summer MCPs especially stands out on the left side of Figure C-27. However, wet versus dry hydro conditions are projected to make almost as great a difference in the peak hour MCPs during the winter (Figure C-28). It would be expected that storage-based hydro generation would have the greatest impact on peak (versus off-peak) MCPs, since this generation would generally be timed to coincide with peak loads.

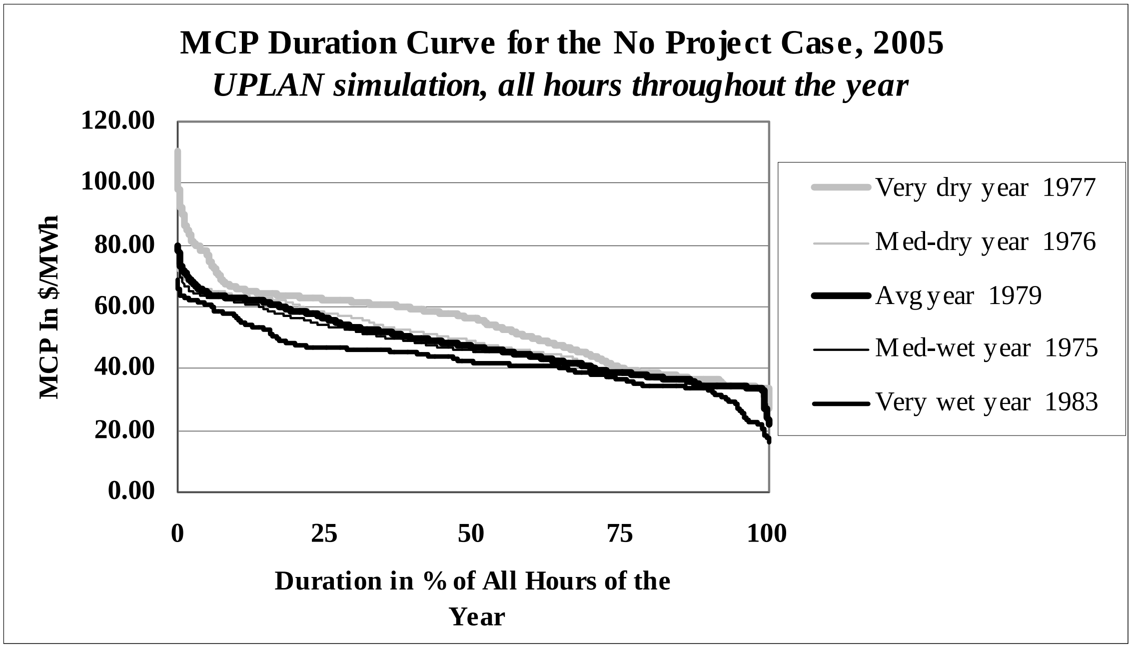


Figure C-26. Projected All Year Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions (For 2005, in year 2000$)

During off-peak hours, dry versus wet conditions have less of an impact on projected MCPs for northern California, especially in the winter (Figure C-29). In summer, differences in hydro conditions are projected to have a larger impact on off-peak MCPs, especially the highest off-peak MCPs of the summer (Figure C-30). Then, the difference between wettest and driest conditions is roughly $10/MWh. These highest off-peak MCPs would generally occur in mid to late summer, when water for generation is scarce in dry years.

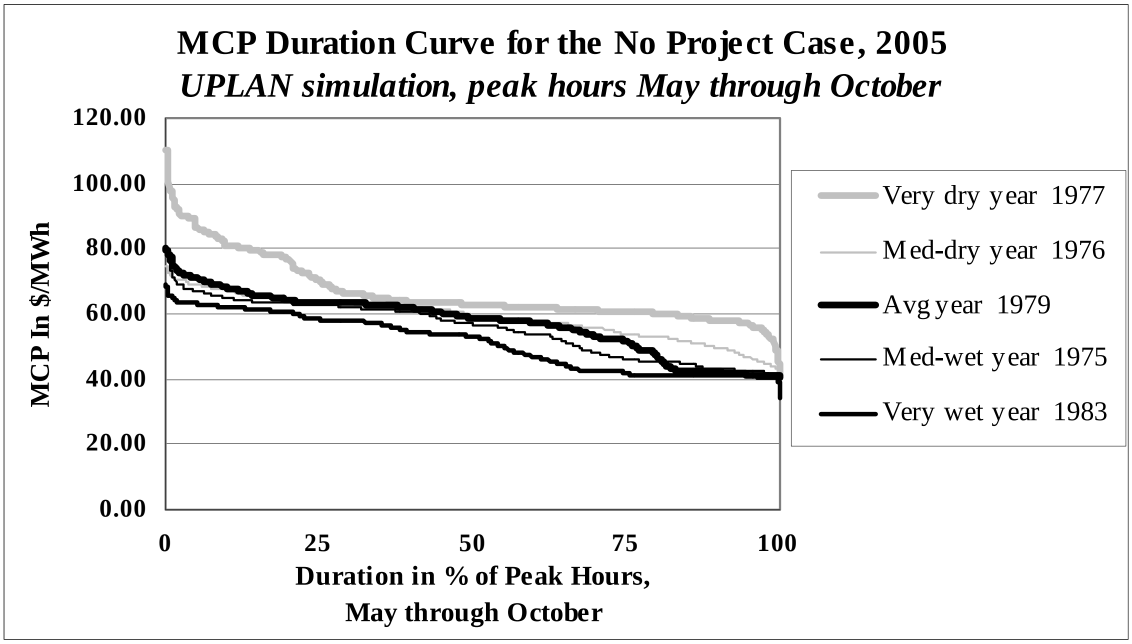


Figure C-27. Projected Summer On-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions ***(For 2005, in year 2000 $)***

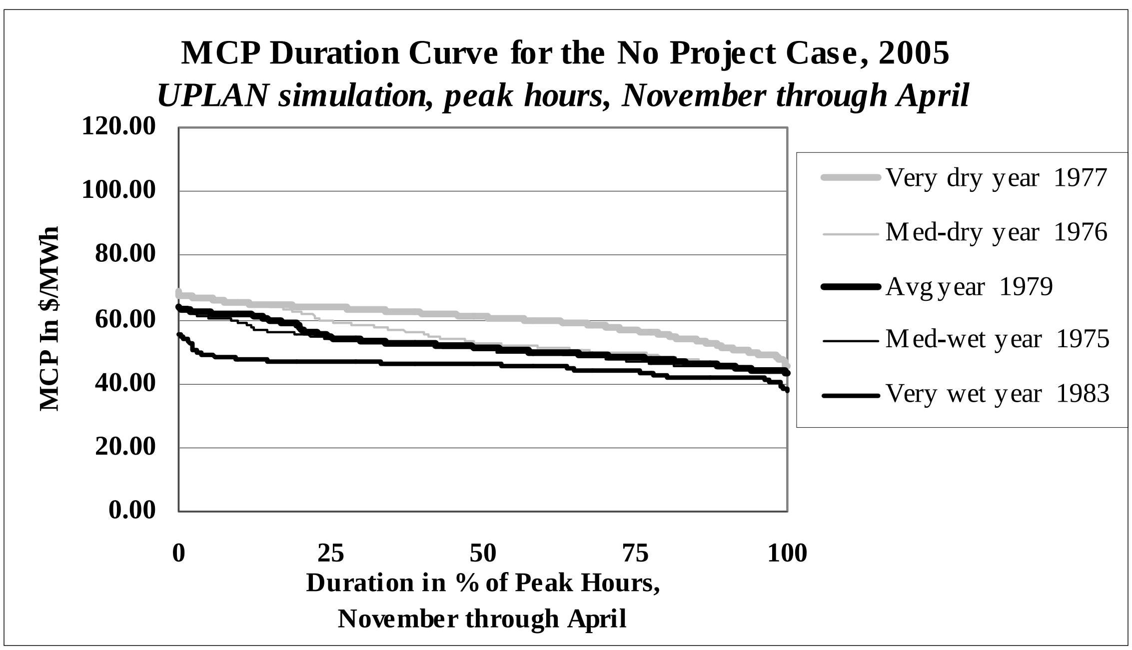


Figure C-28. Projected Winter On-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions ***(For 2005, in year 2000 $)***

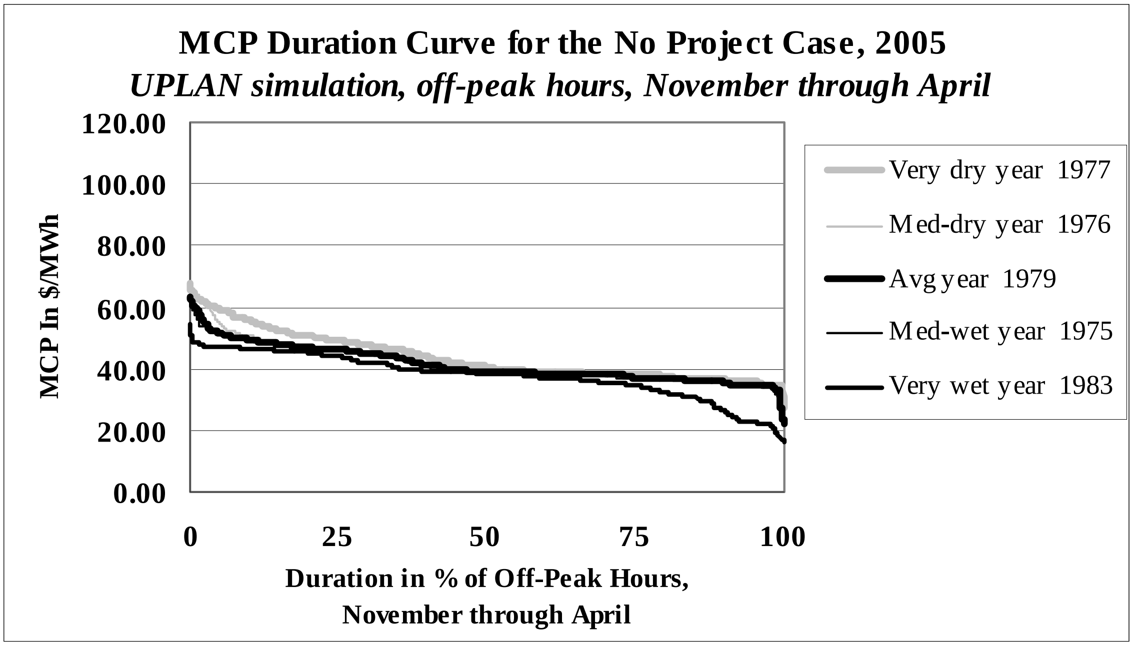


Figure C-29. Projected Winter Off-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions ***(For 2005, in year 2000 $)***

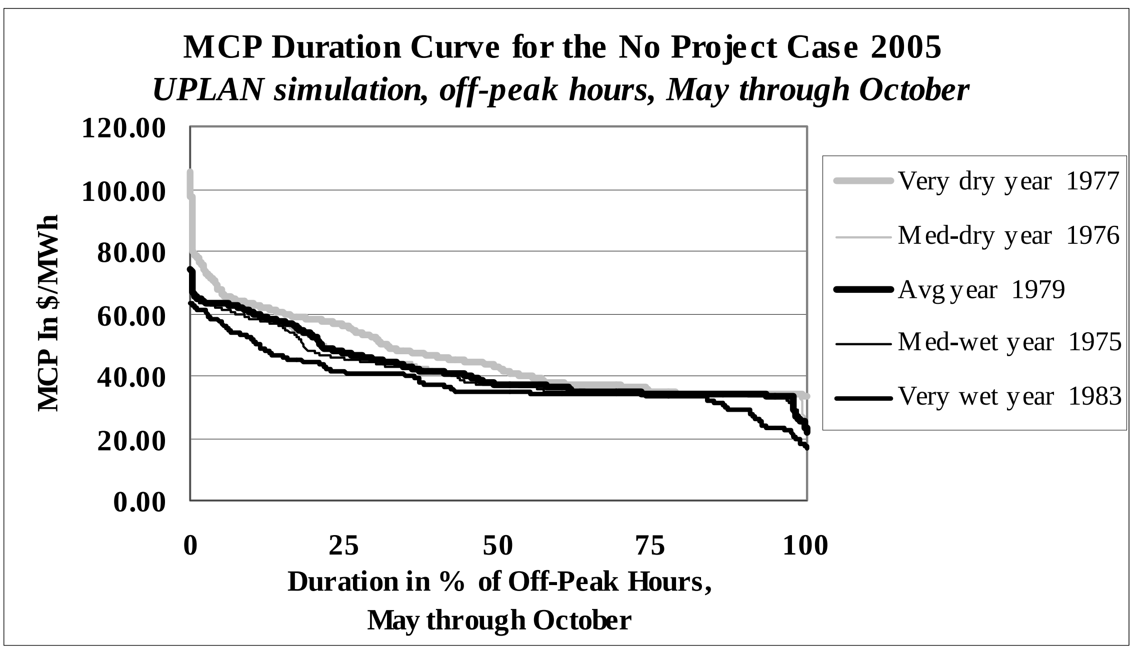


Figure C-30. Projected Summer Off-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions ***(For 2005, in year 2000 $)***

6.2.5 Market Clearing Prices – Effect of Divestiture Cases

For each divestiture case and each hydro year simulated, UPLAN projected hourly market clearing prices for each pricing zone (defined by transmission constraints) in the WSCC. With the exception of a very few powerhouses in the central California pricing zone, all Pacific Gas and Electric Company hydro facilities in question are in the northern California zone. UPLAN's MCP projections were used iteratively with runs of WRMI's OASIS model to develop optimized month to month schedules of water use for electric generation under the different divestiture cases and hydrologic conditions. UPLAN incorporated these schedules as constraints in simulating WSCC power markets and generator operations on an hourly basis.

As noted above, great variation among the 24 sets of water conditions produced considerable variation in MCP projected for the northern California pricing zone. In contrast, for any one set of hydro conditions, the difference in MCP across the four different divestiture cases analyzed was very small, generally in the range of 0.1% to 0.3% for annual average prices and somewhat less than twice that for August peak prices. Figure C-31 shows the MCP distribution for summer during a critically dry year (1977), and Figure C-32 shows the same distribution for an "average" year (1979). The similarity among the cases is evident from these charts.

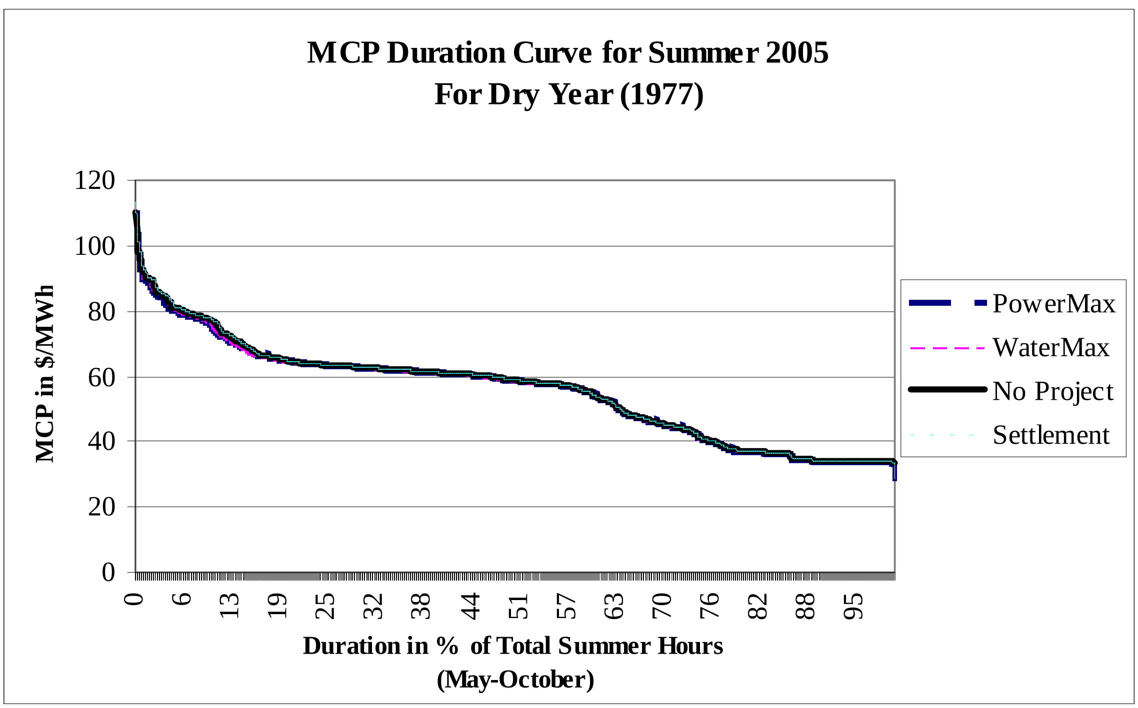


Figure C-31. Projected Summer Market Prices for Electric Energy in Northern California, Critically Dry Conditions, 1977 ***(For 2005, in year 2000 $)***

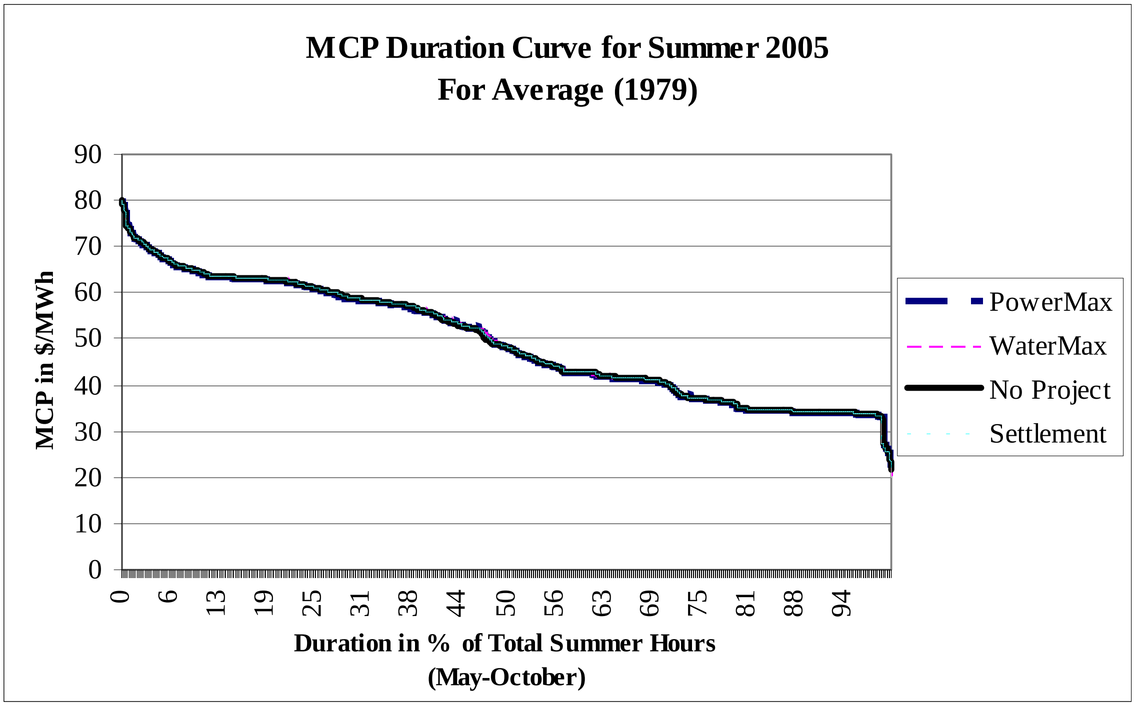


Figure C-32. Projected Summer Market Prices for Electric Energy in Northern California, Average Conditions, 1979 ***(For 2005, in year 2000 $)***

Occasionally, a greater difference was produced across divestiture cases. The greatest observed differential was for peak hour prices in August under 1977 hydro conditions, the driest of the 24 hydro years analyzed. Here, the WaterMax Case made substantially more water available for generation in mid-summer for the NFFR system while, simultaneously, the Proposed Settlement Case significantly (not greatly) reduced water available for generation, to maintain streamflows. These opposite impacts produced a 2.2% difference in projected on-peak MCPs for northern California in that month, between these two divestiture cases (simulated for year 2005). However, for the entire simulated year, under critically dry 1977 hydro conditions, the difference in yearly average on-peak MCP was only 0.35% between these two cases.

There are three basic reasons why different divestiture cases analyzed have a limited impact on projected MCP for northern California.

- Although the Pacific Gas and Electric Company hydroelectric system is large and makes a substantial contribution to electricity supply in northern California, most of the supply comes from other sources, including those outside of California.
- As noted previously, the extent to which operations of the Pacific Gas and Electric Company hydroelectric facilities could be varied by future owners is limited by physical conditions regarding water supply and configuration of the facilities, by various agreements and regulations constraining water use, and by other parties' ownership of water rights and/or water facilities (including powerhouses) in the basins involved.

- Under all divestiture cases modeled it is assumed that future owners will operate the facilities to maximize the coincidence of whatever generation is available with highest electric loads and prices, within the applicable physical, legal and other constraints.

The pattern of MCP differences across the four divestiture cases that were modeled is illustrated by the monthly average prices shown in Table C-14. Average prices are shown both for all hours of each month and for peak hours only, averaged over all 24 hydro years that were simulated. The prices are lowest in spring due to low electric loads and abundance of water for hydroelectric generation. Prices (especially peak prices) rise dramatically in mid-summer as loads rise and water supply dwindles, then drop in the fall. Overall, the prices in the second half of the year (July and later) are higher than those in the earlier half, making it worthwhile to store water for generation in the last half of the year, where possible.

The PowerMax Case assumes more aggressive maximization of profits from electric generation, by discontinuing non-binding water use constraints and saving more water for generation in the last half of the year (especially July through fall) when prices are high. This results in very minor increases in projected MCP over much of the spring (relative to the No Project Case), followed by MCP declines (also very minor) in summer-fall. This modest trend can be seen in both all-hours monthly average prices and in on-peak monthly average prices. When averaged over all 24 hydro years, the WaterMax Case, "water deliveries", tends to reverse this trend.[36] Averaged over 24 hydro years simulated, this case results in more water running through the turbines during the first half of the year in certain watersheds, and less in late summer and especially in fall, after summer water deliveries have been made. The Proposed Settlement Case removes some water from generators to enhance natural streamflows, and so results in a slight increase in MCP across all months.

Under wet hydro conditions (hydro year 1983), projected MCPs are lower due to greater amounts of low-cost hydroelectric generation, and the price rise in the summer is softened by the continued availability of water (Table C-15). The PowerMax Case has the same general effect on projected MCP for this single hydro year as for all 24 years combined. That is, more water is held in storage during spring runoff, during which time the projected MCP is very slightly higher than under the No Project Case. Then, in the latter half of the year with its higher market prices, hydro generation is increased relative to the No Project Case, and the MCP drops very slightly. The WaterMax Case (water deliveries) also has a similar effect on projected MCP for this single wet year as for all 24 hydro years averaged. More water is run through the turbines during spring runoff, slightly lowering projected MCP. By the fall, less water (and hydro generation) is available and projected MCP rise slightly above the No Project Case level. Finally, the Proposed Settlement

36 An important aspect to keep in mind about the WaterMax Case, as discussed in Section 3.2.3, is that it is highly improbable that all of the river basins that might be bought by entities with a water supply objective actually would be purchased with this purpose in mind. For this reason, no conclusions can be drawn about how this scenario might affect MCPs.

Case again has the effect of making slightly less water available (diverted) for generation, producing an MCP slightly higher than under the No Project Case, for all months under these wet (1983) hydro conditions.

Table C-14

Projected Northern California MCP for 2005, Average Over 24 Hydro Years

Monthly Average MCP, Hydro Years 1975-1998 Combined
In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	47.99	48.04	1.001	47.97	0.999	48.01	1.000
2	45.95	45.96	1.000	45.94	1.000	45.97	1.000
3	42.87	42.91	1.001	42.83	0.999	42.89	1.000
4	43.95	43.97	1.001	43.90	0.999	43.97	1.000
5	40.35	40.19	0.996	40.31	0.999	40.39	1.001
6	42.86	42.89	1.001	42.75	0.998	42.91	1.001
7	53.78	53.64	0.997	53.79	1.000	53.86	1.001
8	55.93	55.80	0.998	55.98	1.001	55.97	1.001
9	52.10	52.04	0.999	52.11	1.000	52.14	1.001
10	48.93	48.84	0.998	49.11	1.004	48.97	1.001
11	48.97	48.90	0.999	49.13	1.003	49.00	1.001
12	48.79	48.81	1.000	48.88	1.002	48.81	1.000
Yr.	47.73	47.69	0.999	47.75	1.000	47.76	1.001

Monthly Avg.On-Peak MCP, Hydro Years 1975-1998 Combined
In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	53.87	53.96	1.002	53.85	1.000	53.90	1.001
2	50.99	50.97	1.000	50.97	1.000	51.00	1.000
3	47.38	47.41	1.001	47.35	0.999	47.40	1.000
4	49.72	49.76	1.001	49.67	0.999	49.74	1.000
5	45.03	44.68	0.992	44.98	0.999	45.07	1.001
6	48.44	48.49	1.001	48.28	0.997	48.52	1.002
7	63.57	63.43	0.998	63.55	1.000	63.66	1.001
8	66.53	66.40	0.998	66.52	1.000	66.58	1.001
9	61.41	61.39	1.000	61.42	1.000	61.45	1.001
10	56.78	56.68	0.998	57.09	1.005	56.85	1.001
11	56.11	56.06	0.999	56.34	1.004	56.14	1.001
12	55.09	55.16	1.001	55.25	1.003	55.13	1.001
Yr.	54.60	54.56	0.999	54.63	1.001	54.64	1.001

Table C-15
Projected Northern California MCP for 2005, Wet Hydro Year (1983)

Monthly Average MCP, Hydro Year 1983 (wet)
In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	44.11	44.21	1.002	44.15	1.001	44.21	1.002
2	41.83	41.95	1.003	41.88	1.001	41.97	1.003
3	37.76	38.24	1.013	37.57	0.995	37.69	0.998
4	38.53	38.73	1.005	38.50	0.999	38.57	1.001
5	36.13	36.18	1.001	36.15	1.000	36.19	1.002
6	37.40	37.13	0.993	37.39	1.000	37.49	1.002
7	48.10	48.09	1.000	48.09	1.000	48.11	1.000
8	50.25	50.14	0.998	50.55	1.006	50.28	1.001
9	47.95	47.82	0.997	48.02	1.001	48.05	1.002
10	44.74	44.72	0.999	44.84	1.002	44.79	1.001
11	43.23	43.18	0.999	43.32	1.002	43.24	1.000
12	42.69	42.59	0.998	42.71	1.001	42.71	1.001
Yr.	42.75	42.77	1.000	42.78	1.001	42.79	1.001

Monthly Average On-Peak MCP, Hydro Year 1983 (wet)
In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	47.46	47.57	1.002	47.46	1.000	47.55	1.002
2	46.31	46.31	1.000	46.25	0.999	46.31	1.000
3	42.81	43.29	1.011	42.78	0.999	42.82	1.000
4	41.99	41.98	1.000	41.97	1.000	41.98	1.000
5	40.99	40.95	0.999	40.99	1.000	40.99	1.000
6	41.97	41.97	1.000	41.97	1.000	41.97	1.000
7	56.97	56.94	0.999	56.99	1.000	56.98	1.000
8	59.34	59.25	0.998	59.64	1.005	59.41	1.001
9	56.41	56.37	0.999	56.45	1.001	56.48	1.001
10	51.32	51.28	0.999	51.41	1.002	51.37	1.001
11	47.59	47.51	0.998	47.63	1.001	47.60	1.000
12	46.25	46.28	1.001	46.26	1.000	46.26	1.000
Yr.	48.30	48.33	1.001	48.34	1.001	48.33	1.001

Very different MCP results are produced under year 1977 hydro conditions, the driest over the 24 hydro years simulated (Table C-16). First, with low hydroelectric generation across the west, projected MCP for 2005 are much higher, and they peak dramatically in the mid-summer (refer to Table C-16 and the left side of Figure C-27). In these stressed electricity supply circumstances, the PowerMax Case reduces projected mid-summer prices (especially on-peak) by making more water available for generation in mid-summer (and less in the fall). However, the WaterMax Case has a greater impact, by making even more water available for generation in mid-summer (and even less available in the fall), mainly through changes in the NFFR system operations. This leads to average and on-peak MCP being 1-1.5% percent lower than under the No Project Case in June-

August. For most hydro conditions simulated, the Proposed Settlement Case produces slight increases in projected MCP due to reduced water diversions for generation, but in the critically dry summer conditions under hydro year 1977, the Proposed Settlement Case has a greater effect, increasing MCP by about 0.5% above the No Project Case level. It is these opposite effects of the WaterMax Case (water deliveries) making more water available for generation in the dry summer and the Proposed Settlement Case making less water available that produces the greatest observed MCP differential among divestiture cases, 2.2% for on-peak prices in August under 1977 hydro conditions. For other times of the year and under other hydro conditions, the MCP impact across the different cases is much less, as noted earlier.

Table C-16

Projected Northern California MCP for 2005, Critically Dry Hydro Year (1977)

Monthly Average MCP, Hydro Year 1977 (dry)

In $/MWh, UPLAN Projection year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	51.06	51.08	1.000	50.93	0.997	51.05	1.000
2	51.17	51.17	1.000	51.16	1.000	51.19	1.000
3	47.66	47.65	1.000	47.70	1.001	47.69	1.001
4	53.67	53.63	0.999	53.64	1.000	53.69	1.000
5	49.34	49.40	1.001	49.33	1.000	49.36	1.000
6	51.56	51.50	0.999	51.16	0.992	51.61	1.001
7	62.90	62.44	0.993	62.25	0.990	63.18	1.004
8	63.33	62.53	0.987	62.45	0.986	63.55	1.003
9	54.46	54.63	1.003	54.36	0.998	54.47	1.000
10	52.55	52.67	1.002	52.72	1.003	52.56	1.000
11	53.30	53.23	0.999	53.63	1.006	53.37	1.001
12	51.54	51.43	0.998	51.93	1.008	51.54	1.000
Yr.	53.57	53.47	0.998	53.46	0.998	53.63	1.001

Monthly Average On-Peak MCP, Hydro Year 1977 (dry)

In $/MWh, UPLANr Projection for M21year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	58.89	58.97	1.001	58.66	0.996	58.84	0.999
2	59.46	59.45	1.000	59.43	1.000	59.48	1.000
3	54.56	54.54	1.000	54.62	1.001	54.59	1.001
4	63.41	63.39	1.000	63.40	1.000	63.43	1.000
5	58.61	58.73	1.002	58.61	1.000	58.64	1.000
6	60.57	60.47	0.998	59.93	0.989	60.62	1.001
7	76.45	75.73	0.991	75.69	0.990	76.96	1.007
8	77.72	76.47	0.984	76.44	0.984	78.14	1.005
9	64.33	64.63	1.005	64.20	0.998	64.33	1.000
10	61.68	61.93	1.004	62.08	1.007	61.70	1.000
11	62.69	62.67	1.000	63.24	1.009	62.77	1.001
12	59.76	59.65	0.998	60.37	1.010	59.77	1.000
Yr.	63.20	63.07	0.998	63.07	0.998	63.29	1.002

6.3 Analysis of Alternative: An Owner with Thermal Plants with the Potential to Exercise Market Power

California's electric market has experienced an extraordinary summer, leading the Commission to open an investigation into the wholesale market where the question of anticompetitive behavior and the possibility of the exercise of undue market power, among other things, are being addressed.[37] Some parties in Pacific Gas and Electric Company's hydroelectric divestiture proceeding have also served testimony regarding the potential to operate the hydroelectric assets in ways that could constitute the exercise of market power. Even Pacific Gas and Electric Company has specifically attempted to address this possibility by including a "market power mitigation" agreement with the ISO in its Proposed Settlement.[38] Given the experience of this summer, the Commission needs to better understand the potential for the owner or owners of the hydroelectric generating assets to exercise undue market power. In addition, the Commission needs to understand the ability of other market participants (not necessarily an owner of a hydroelectric or other generating facility) to exercise market power.

Attempts to exercise market power could lead to hydroelectric system operations that deviate from the operations modeled in this EIR for the No Project, PowerMax, and WaterMax scenarios, and such deviations could have significant adverse environmental effects. The preparers of this EIR have therefore conducted a screening-level analysis of the potential to exercise market power with various combinations of the Pacific Gas and Electric Company hydropower assets and thermal generating capacity participating in California electricity markets.[39] This section describes the rationale, methods, and results from this screening-level Market Power Analysis.

6.3.1 Study Approach and Scope

Department of Justice guidelines characterize market power to a seller (such as an electric generator) as "…the ability *profitably* to maintain prices above competitive levels for a significant period of time"[40] (emphasis added). This analysis has considered three ways in which market power in conjunction with ownership of hydro facilities might be exercised in California power markets.

- First, the owner could shift certain hydro facilities' generation away from the peak load (high market price) hours, generating less in these hours than would be optimal (most profitable) under fully competitive conditions. This would be profitable if it increased market prices enough so that net

37 I. 00-08-002.

38 Settlement Agreement for Valuation and Disposition of Hydroelectric Assets, Appendix D, "The ISO-PG&E Corporation Market Power Mitigation Agreement."

39 As discussed in Section 3.2.4, this scenario would not be limited solely to ownership by PG&E Corporation affiliates. Other current owners of thermal generation that could fall into this category include Southern Energy, Duke Energy, and Calpine.

40 U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, Issued April 2, 1992 and revised April 8, 1997.

income increases for the owner's other generating facilities outweighed the net income losses for the shifted hydro generation.

- Second, the owner could withhold generation at some of its non-hydro facilities, particularly gas-fired thermal power plants in California. In the time periods affected, these facilities would then generate less than would be optimal (most profitable) under fully competitive conditions. Again, this would be profitable if it increased market prices enough so that net income increases for the owner's other facilities (including hydro) outweighed the losses for the withheld generation.

- Third, hydro capacity might be withheld from participation in ancillary services (AS) markets, driving up prices in both A/S and energy markets.

While the exercise of market power is generally considered to entail the ability to profitably raise market prices for a *significant* period of time, the relevant market may itself be discontinuous in time. This is especially true for electric generation, because demand and also other relevant circumstances such as availability of generation, fuel and transmission can vary considerably over seasons, days, and hours, while electricity cannot be readily stored and must be generated to meet current requirements. This means that the circumstances of supply and demand vary greatly over time, but with similar circumstances repeating themselves in both unpredictable and predictable (such as seasonal, and daily) ways. Because of this, investigating whether there is significant potential for exercising generation market power in conjunction with hydro facility ownership requires considering a wide and complex range of interacting factors such as:

- electric loads;
- hydrologic conditions;
- ownership of hydro and other generating facilities; and
- the amount of competing (under different ownership) generation that is available in those time periods and conditions for which there is reason to believe that market power might be exercised.

All of the above factors have been considered in the market power analysis presented here. However, because the analysis was brief, the breadth of factor combinations analyzed was limited. The different factors considered are outlined below.

Loads

A single load forecast has been considered for California and the WSCC, for the modeling period consisting of calendar year 2005. However, since this forecast involves 8,760 individual hourly loads at each load center, it actually represents a range of load conditions.

Hydrological Conditions

Four separate yearly sets of hydrologic conditions have been considered, based on historic water conditions in "hydro years" 1976 (dry), 1977 (critically dry), 1979 (average), and 1998 (wet). The different hydrologic conditions reflect very different amounts of water being available for electric generation over the course of a year at the Pacific Gas and Electric Company hydro facilities, over the rest of California, and across the overall WSCC. This affects power markets and potential for exercising market power in California. Figure C-33 indicates how these years stand in relationship to other historical hydro years between 1975 and 1998, in terms of hydroelectric generation in California and across the WSCC. Note that a wet or dry year in northern California is usually, but not always, a wet or dry year for the WSCC overall. In addition, within each hydro year, water availability for hydro generation varied seasonally, creating a still greater diversity of conditions

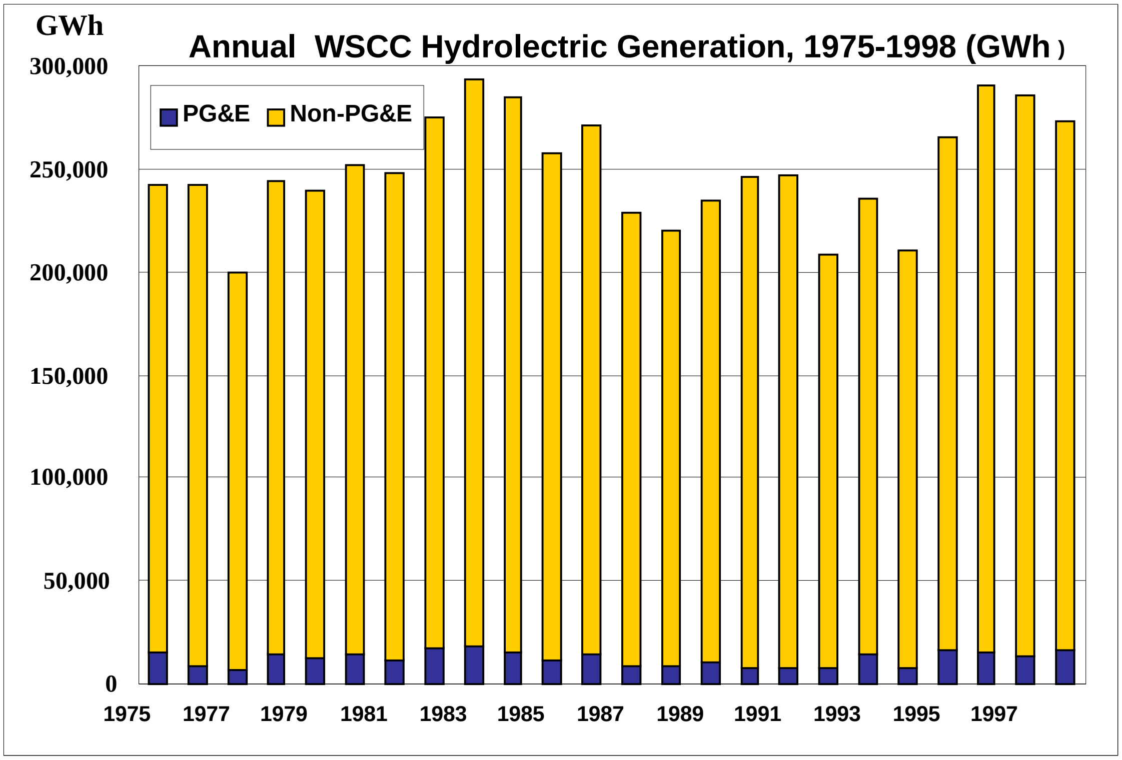


Figure C-33. Annual Hydroelectric Generation: Pacific Gas and Electric Company vs. WSCC Overall

affecting hydroelectric generation and power markets. Of these four hydro years, 1979 (average conditions) was analyzed most extensively. Hydro year 1998 was selected because it was among the wettest in the 24-year hydrology, and those hydrologic conditions appear to have been included in the recent analysis of market power potential associated with Pacific Gas and Electric Company hydro facilities.[41]

41 By analyzing 1998 hydro year conditions, the results presented here can be compared with the ORA analysis by Laurence Kirsch in ORA Testimony, Chapter VI-Market Power Implications Of Hydro Power Divestiture (March 2000), who relied upon a different methodology that was also used in James Bushnell, “Water and Power: Hydroelectric Resources in the Era of Competition in the Western U.S.,” (PWP-056r, Program on Workable Energy Regulation (POWER), University of California Energy Institute, Berkeley, CA, July 1998) and Severin Borenstein, James Bushnell, and Frank Wolak, “Diagnosing Market Power in California’s Deregulated Wholesale Electricity Market,” (PWP-064, Program on Workable Energy Regulation (POWER), University of California Energy Institute, Berkeley, CA, March 20) to analyze market power issues in the WSCC.

Ownership

Six separate groups ("portfolios") of Pacific Gas and Electric Company hydroelectric facilities have been considered when analyzing the effects of shifting output from hydroelectric or thermal facilities to increase net income for the owners' overall portfolio of generating assets. The six hydro portfolios are identified in Table C-17. Helms and the other Kings River powerhouses are not included among the portfolios considered in this analysis.[42] Potential alterations of output patterns for a large pumped storage facility such as Helms are complex and in many ways differ from those associated with shifting output at storage hydro facilities. For example, the amount and not just timing of output may be adjusted substantially, and it is nontrivial to establish what constitutes "normal" operation of pumped storage facilities in newly competitive markets.

Table C-17
Basin-Specific Groups of Hydroelectric Plants
Considered to Be Owned and Operated as Part of Asset Portfolios

	MW Capacity		MW Assumed Able to be Scheduled (Shifted On- or Off-Peak)	
Group	Total MW in Portfolio	Share of PG&E Total	Total MW in Portfolio	Share of PG&E Total Hydro MW Assumed Able to be Scheduled
1. North Fork Feather River (NFFR)	734	18.8%	728	20.6%
2. NFFR plus McCloud-Pit	1502	38.6%	1417	40.2%
3. Group 2 plus Crane-Kerckhoff	1724	44.2%	1592	45.1%
4. Group 3 plus Mokelumne	1939	49.8%	1748	49.6%
5. Group 4 plus South Yuba (Drum)	2141	55.0%	1874	53.1%
6. Group 5 plus Stanislaus	2241	57.5%	1965	55.7%

This analysis also considered generic and specific amounts of thermal generating capacity that might hypothetically be part of combined thermal-hydro generating portfolios. Such portfolios are used to examine if market power might be exercised under various conditions. Clearly, any actual opportunities for exercising market power would depend on what specific combinations of hydro and thermal plant ownership develop, which is presently speculative.

42 Kirsch's analysis found that control of Helms and the Kings River system played a significant role in the ability to manipulate market prices. The analysis presented here does not review the exercise of market power through the Helms pumped storage facility.

Other Generation

The amount of other generation competing in northern California power markets has a major impact on the potential for exercising market power via owning hydroelectric facilities plus thermal plants. A higher level of generator market entry by the simulation time horizon of 2005 generally reduces the potential for exercising market power, because greater availability of moderately priced generation can reduce market price increases achievable through withholding generation. This analysis considered two different levels of generation market entry in California out to 2005. Assuming proposed projects come on line as announced produces the “Proposed” market entry scenario, resulting in projected in-state generating capacity increasing by just over 11,000 MW between 2000 and 2005, with virtually all additions being gas-fired. The “Proposed” market entry scenario for 2005 was used for modeling all cases (except the “Moderate” market scenario described below) in the Draft Environmental Impact Report (EIR).[43] Assuming delays in bringing proposed projects on line, the “Moderate” market entry scenario results in generator additions that increase total generating capacity in California by about 5600 MW between 2000 and 2005, with about 97% of the added capacity being gas-fired (Table C-18 & C-18a).

Table C-18
Projected California In-State Generating Capacity
With Two Market Entry Scenarios for 2005

Fuel Type	Year 2000		2005 “Moderate”		2005 “Proposed”	
	Amount (MW)	Share	Amount (MW)	Share	Amount (MW)	Share
Geothermal	2364	4.9%	2510	4.7%	2510	4.2%
Gas	25660	53.3%	31114	57.9%	36682	61.9%
Nuclear	4310	9.0%	4310	8.0%	4310	7.3%
Oil	750	1.6%	750	1.4%	750	1.3%
Other	3380	7.0%	3380	6.3%	3380	5.7%
P. Storage.	3108	6.5%	3108	5.8%	3108	5.2%
Hydro	8540	17.8%	8540	15.9%	8540	14.4%
Total	48112	100%	53712	100%	59280	100%

Due to transmission constraints and costs, it is generating capacity in California that has the greatest bearing on northern California power markets and the potential exercise of market power, especially during peak load conditions. However, WSCC generation from outside of California also plays a significant role in California power markets. Modeling for this analysis includes a forecast increase in WSCC generating capacity outside of California between 2000 and 2005 that amounts to almost 8,000 MW. This has some impact on the potential for exercising market power in northern California power markets, and if a lesser amount of WSCC capacity additions should materialize, the potential for market power in northern California might be higher. As with the

43 To the extent that new generation is proposed by existing generators, their potential ability to exercise market power could be enhanced by delaying the completion of such new generation.

forecasted California additions, the modeling analyses of the other cases assumes entry of the entire portfolio of proposed new generation.

All of these factors (loads, hydrologic conditions, ownership, other generation and market entry) played a role in the analysis. Certain circumstances have been identified under which there may be potential for exercising market power associated with ownership of hydroelectric generating facilities in California. By clarifying how certain combinations of conditions produce elevated potential for market power, we can ultimately focus on the dynamics underlying the most relevant conditions, and can evaluate the frequency with which such conditions might occur. For there to be significant potential for market power, the right conditions would have to occur frequently enough, and to be sufficiently predictable by would-be practitioners of market power. Nevertheless, this analysis is intended only to assess the potential for exercising market power, rather than the likelihood of such exercise.

Table C-18a
New California Power Plants Included in Modeling Analysis Forecasts for 2005

Plant Name	Company	Size	Fuel Type	2005 Scenario Primary Cases MPA "Proposed"	2005 Scenario MPA "Moderate"
Los Medanos	Calpine	500	Gas	X	X
Salton Sea	Cal Energy	49	Geo	X	X
Las Palomas	PG&E NEG	1,048	Gas	X	X
Sutter	Calpine	500	Gas	X	X
Chula Vista	Duke	49	Gas	X	X
Telephone Flat	Cal Energy	48	Geo	X	X
Delta Energy Center	Calpine	880	Gas	X	X
Fourmile Hill	Calpine	49	Geo	X	X
Sunrise	Texaco	320	Gas	X	X
ElkHills	Sempra	500	Gas	X	X
Otay Mesa	PG&E NEG	510	Gas	X	X
Mountain View 1	Thermo-Ecotek	528	Gas	X	X
High Desert	Inland	680	Gas	X	X
Nueva Azela	Sunlaw	550	Gas	X	
Three Mountain	Ogden Power	500	Gas	X	
Metcalf Energy Center	Calpine	600	Gas	X	
Blythe	Summit	520	Gas	X	
Midway 2	ARCO	500	Gas	X	
Contra Costa	Southern	530	Gas	X	
Moss Landing	Duke	1,090	Gas	X	
Pastoria	Pastiori	750	Gas	X	
Mountain View 2	Thermo-Ecotek	528	Gas	X	
Total Capacity (MW)				11,229	5,661

The analysis has focused on short-term variations in hydroelectric and thermal unit operations that might constitute exercise of market power, through reducing output and increasing net income, compared to what would be expected under fully competitive conditions.[44] By “short term,” we mean alteration of the pattern or amount of generator output across the hours within an individual month. It could be expected that over such a short time horizon, owners would have considerable ability to anticipate key drivers of market prices, such as water conditions, generator availability (including outages), fuel prices, and, to a lesser extent, loads. Such anticipation would increase the likelihood that conditions favorable to exercise of market power might actually be foreseen and exploited. This analysis implicitly assumes that the owners in question do in fact anticipate these short-term (within-month) conditions. Reduced ability to anticipate these conditions would mean less potential for exercise of market power.

This analysis has considered two ways of altering hydro output to raise market prices and potentially increase net income for an overall generation portfolio, and two ways of withholding thermal generation to achieve the same result. These screening-level analyses help to identify the conditions under which it could be profitable to exercise market power. The two ways of altering hydro output that were investigated are

- A “baseload” strategy shifts output from storage hydro facilities (whose output in any month is limited, but can be timed) away from the typical, competitive “peaking” strategy of concentrating output in peak (high load, high price) hours. Instead, the output is the same in every hour of a month (but still varying month to month due to changing water supply).

- “Inverting”, under which generation at storage hydro facilities is shifted even further away from the peaking pattern, so that output is higher in off-peak hours than in peak hours.

These two strategies were simulated for each of the six progressively larger groups or “portfolios” of Pacific Gas and Electric Company hydro facilities identified in Table C-17. Such generation shifting is only possible for “storage hydro” plants with sufficient water storage that they can time their output, at least over the course of a day. The amount of hydroelectric generating capacity having this timing flexibility, and thus being simulated to shift output, is shown for each of the six portfolios in Table C-17.

For thermal units, two kinds of generation withholding behavior were analyzed:

- Entire generating units were assumed to be made unavailable (effectively, placed on outage) over an entire month. While an entire calendar year was simulated, each of 12 months was evaluated as a separate time interval over which generation might be withheld in this manner, to evaluate the potential for profiting from such withholding of output under different conditions.

- A selected cycling thermal generator having some impact on projected market prices was assumed to withhold part of its output in various hours of the month, and the effect on market prices and net income for overall hydro-thermal portfolios was analyzed.

44 A key assumption is that the baseline, competitive situation being simulated (in this case the PowerMax Case from the CEQA study) does in fact represent optimal competitive behavior in the absence of market power, so that any deviation producing significantly greater income with less generation, over a significant period of time, does in fact represent exercise of market power.

6.3.2 Results: Shifting Hydro Generation

WSCC power markets were simulated over the 12 months of projected year 2005, under several different sets of hydrologic conditions. Two different strategies for shifting hydro generation strategies were simulated as described earlier, the "baseload" and "inverted" strategies. This resulted in changes in projected peak and off-peak market clearing prices (MCP) for electric energy in the northern California pricing zone, compared to the baseline prices projected under the PowerMax Case.

The PowerMax Case optimally allocated each powerhouse's generation over the months of a year and then over the different hours of a month, assuming fully competitive conditions and treating each powerhouse as separate profit center and not as part of a portfolio that could potentially exercise market power. Only "hard" (binding) water use constraints were assumed, giving somewhat greater flexibility of water use and generation timing than would be available under additional, informal (nonbinding) water use agreements currently being observed. Starting from the PowerMax Case, "baseload" and "inverted" generation shifting were simulated for each of the six hydro portfolios listed in Table C-17, for the combinations of conditions shown in Table C-19.

Table C-19
Combinations of Conditions for Which Hydro Strategies "Baseload" and "Inversion" Were Analyzed

Water Conditions (Hydro Year)	Market Entry by 2005 (M, P = Moderate, Proposed)	Strategy Analyzed for Each Month (B, I = baseload, inverted)
1976 (dry)	M, P	B, I
1977 (critically dry)	M, P	B, I
1979 (average)	M, P	B, I
1998 (wet)	M, P	B

Based on the resulting increase in on-peak MCP, the "breakeven" amount of thermal capacity that the owner would have to own was calculated and plotted. This is the amount of thermal capacity that, if running during all peak hours of a given month, would experience a net income increase (relative to the PowerMax Case) that would exactly offset the income decrease for the hydro part of the portfolio due to generation shifting. Thus the hypothetical hydro-thermal portfolio would break even. Owning additional thermal capacity would result in an income increase, relative to the PowerMax Case.[45]

Since the objective of shifting hydro generation is to increase MCP during peak hours, it would make sense to own thermal generation running during peak hours, since hydro generation is

45 For this analysis the "peak hours" run from 6 AM to 10 PM seven days a week, compared to only five days a week as used to graph duration curves for hourly hydro generation and market prices (MCP) in the presentations on the primary cases above.

actually *increased* in off-peak hours (which should generally lower off-peak prices). Gas-fired thermal units in California would be most likely to run in peak, as opposed to off-peak, hours.

Shifting hydro generation away from peak hours reduces projected income for hydro facilities whose generation is shifted. This is only partly offset by income increases at other, run-of-river (non-storage) hydro facilities in the same portfolio, due to their limited generation. However, if the owner also owns other capacity that is running during peak hours, such as thermal units, then income from the overall portfolio are projected to increase under some of the conditions that were analyzed.

Table C-20 illustrates how applying this "baseload" shifting strategy for a hydro portfolio assumed to consist (only) of Pacific Gas and Electric Company's North Fork Feather River system of powerhouses (734 MW) has the following consequences when simulated for summer months under hydro year 1979 (average) water conditions.

- The hydro portfolio alone experiences operating losses since it generates less during peak hours with high market prices (while generating more during off-peak hours).
- The resulting increase in the peak MCP varies among the four months. This reflects a diversity of supply/demand conditions that would be even greater if considering more months, more hydro years, or individual hours.
- For three of the four months, most notably August, the "baseload" strategy drives up peak MCP substantially more under "Moderate" market entry than under "Proposed" market entry. This likely reflects the much tighter supply situation under lower market entry, especially during summer peak hours.
- The amount of thermal (or other) generating capacity that an owner would have to have running on-peak to offset hydro losses varies considerably among months (and hours within a month). This reflects the way that MCP responds much more to hydro shifting in some months (and in some hours) than others. Among only four months and two market entry scenarios displayed in Table C-20, the amount of thermal (or other) capacity the hydro owner would need to have running in all peak hours of the month in order to offset the hydro income losses ranges from under 600 MW to over 40,000 MW. If considering individual hours, the variation would be even greater.

Table C-20
Effect of the "Baseload" Hydro Strategy for a Portfolio Assumed to Include Feather River Hydro Plus Thermal Generating Capacity
Hydro year 1979, Summer Months

Month	Proposed Market Entry by 2005			Moderate Market Entry by 2005		
	Income Loss, Hydro ($1000)	Increase in Peak MCP, $/MWh	Thermal MW Needed to Break Even	Income Loss, Hydro ($1000)	Increase in Peak MCP, $/MWh	Thermal MW Needed to Break Even
June	916	0.48	3976	987	0.13	15817
July	2583	0.36	14466	2864	0.85	6793
August	2563	0.57	9066	2538	9.09	563
Sept.	2418	0.11	45795	2226	0.32	14492

This specific example represents one of several situations in these simulations where this sort of simplistic exercise of market power could plausibly succeed. By considering more sophisticated strategies for altering hydro output focused on narrower sets of hours and circumstances, the potential rewards could be increased. However, in the real world it would always be necessary for the would-be practitioner of market power not only to own the appropriate portfolio of assets but also to anticipate the occurrence of favorable conditions with sufficient accuracy. For this reason, these results must be viewed in the context of being plausible, but not necessarily likely, situations when market power could be exercised effectively. Nevertheless, these plausible situations do include likely ones as a subset.

The “breakeven” amount of thermal capacity that the owner would have to own was calculated and plotted for a variety of circumstances. This is the amount of thermal capacity that, if running during all peak hours of a month, would experience an income increase (relative to the PowerMax case) sufficient to exactly offset the income decrease for the hydro part of the portfolio due to generation shifting. Thus, the hypothetical hydro-thermal portfolio would break even. Owning additional thermal capacity would result in an income increase, relative to the PowerMax case.

Table C-21 summarizes results from simulating the “baseload” shifting strategy under different water conditions (hydro years) and market entry scenarios, for different hypothetical hydro portfolios. This table identifies those months (entire months, not individual hours) for which the strategy was found to pay off after thermal capacity ownership exceeded levels that could realistically be attained. This occurred most frequently in summer months when projected MCP are high, supply is tight, and shifting hydro generation away from peak hours can produce substantial increases in the MCP. However it also occurred in some winter/spring months. As discussed below, a key driver is the shape of the generation supply curve, affecting how much the marginal bid (and the MCP) rise for a particular change in supply. This varies by hour, season, and in response to many factors such as hydrologic conditions and market entry.

The simulated consequences of the “inverted” strategy were similar to those for the “baseload” strategy. While the “inverted” strategy can shift more hydro generation away from peak hours, this is limited by the fact that only so much hydro generation from powerhouses can be moved into the off-peak hours, and also by the fact that any hydro generation remaining in the peak hours can benefit from the increased peak MCP.

Some of the results summarized in Table C-21 are depicted in Figures C-35 to C-37. Four key observations are as follows.

- Even on a month-long basis (not targeting selected hours), the “baseload” strategy can be successful in certain conditions, especially in the summer (see Figures C-35, C-36, and C-37), but also potentially also in other seasons (Figure C-37).

- The financial consequences of such a strategy vary considerably across months, hydro conditions, market entry conditions, and the amount of assumed hydro ownership. This suggests the need to better understand the fundamental drivers of the potential for market power. It also suggests that in the real world it might be challenging to anticipate the occurrence and duration of conditions conducive to exercising market power.

- Under a particular combination of conditions, a smaller hydro portfolio (Feather only) sometimes required the smallest amount of thermal capacity in order for hydro shifting to succeed. However, under some conditions it was the largest hydro portfolio analyzed that performed best, and sometimes it was an intermediate portfolio. This again hints at the complexity of the underlying conditions influencing the potential for exercising market power. However, which hydro portfolio was considered was generally much less important than the how various other factors combined and interacted, making the MCP more or less sensitive to hydro shifting.

- Although not directly tested, hydro shifting might succeed even without thermal ownership, if the peak MCP could be increased sufficiently, and if the owner had enough other hydro generation (within or outside of the 6 portfolios considered here) still running in peak hours and thus benefiting. Simulated mid-summer conditions under Moderate market entry and 1979 hydro conditions suggest such a possibility (Figure C-34 and Table C-21).

Table C-21
Conditions Under Which Ownership of Realistic Amounts of Thermal Capacity Made Month-Long "Baseload" Hydro Shifting Pay Off

Hydro Year and Market Entry Scenario	Hydro Portfolio (1)	Months in which the "Breakeven" On-Peak Thermal Capacity is in the Following MW Ranges	
		<1500 MW	<4000 MW
1976, Proposed	1		May
	2		March, May
	4		January, March, May
	6		March, May
1976, Moderate	1		
	2		
	4		
	6		
1977, Proposed	1		
	2		
	4	August	August
	6	August	August
1977, Moderate	1		July, August
	2		July, August
	4		July, August
	6		July, August
1979, Proposed	1		March
	2		March
	4		March, April
	6		March, April
1979, Moderate	1	August	May, August
	2	August	May, August
	4	August	May, August
	6	August	May, August
1998, Proposed	1		
	2		
	4		April
	6		April
1998, Moderate	1		June
	2		June
	4		June
	6		June

(1) Hydro portfolios: 1 = Feather, 2 = Feather+Pit, 4 = #2 plus Crane/Kerckhoff and Mokelumne, 6 = #4 plus S. Yuba and Stanislaus.   (Portfolios 3 and 5 produced intermediate results.)

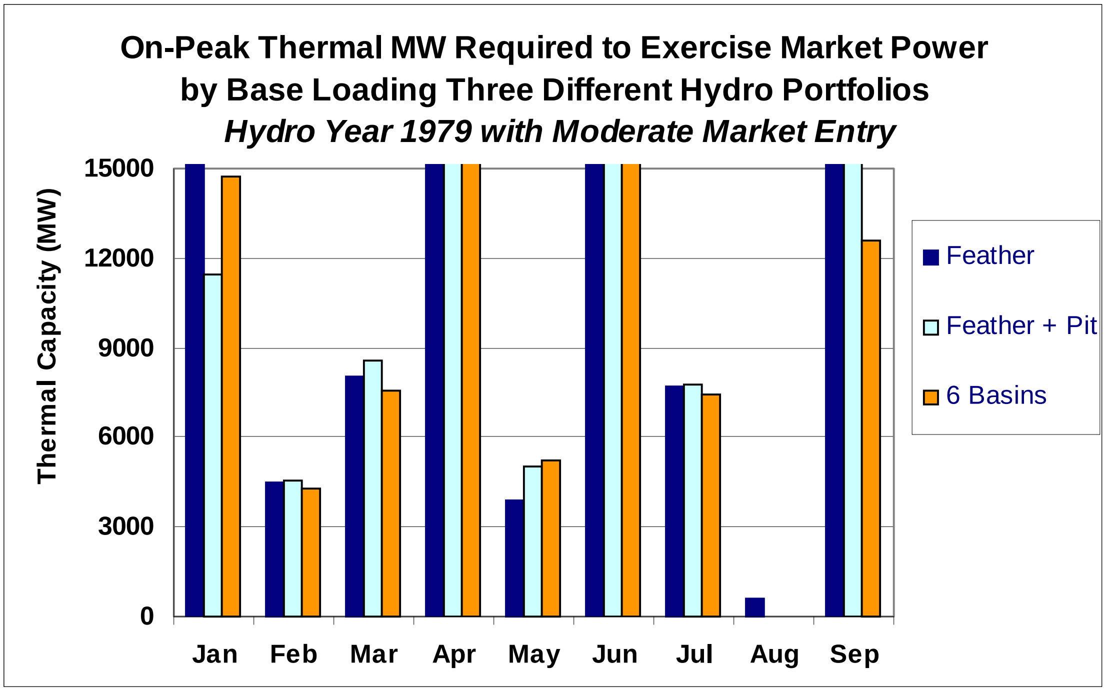


Figure C-34. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1979 (average) with "Moderate" market entry***

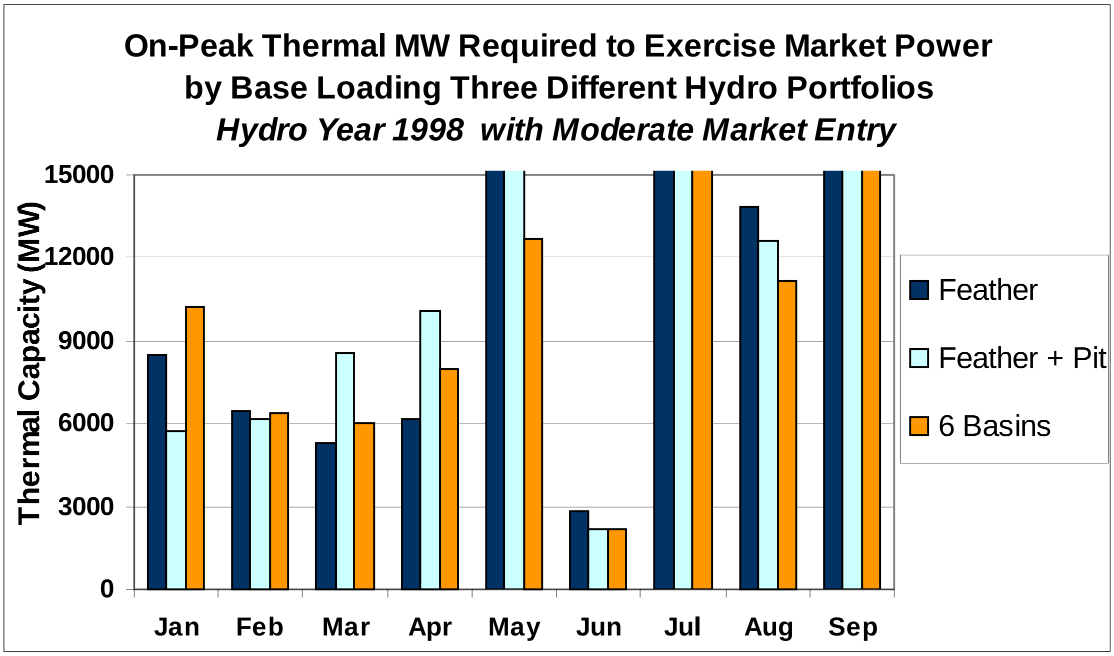


Figure C-35. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1998 (wet) with "Moderate" market entry***

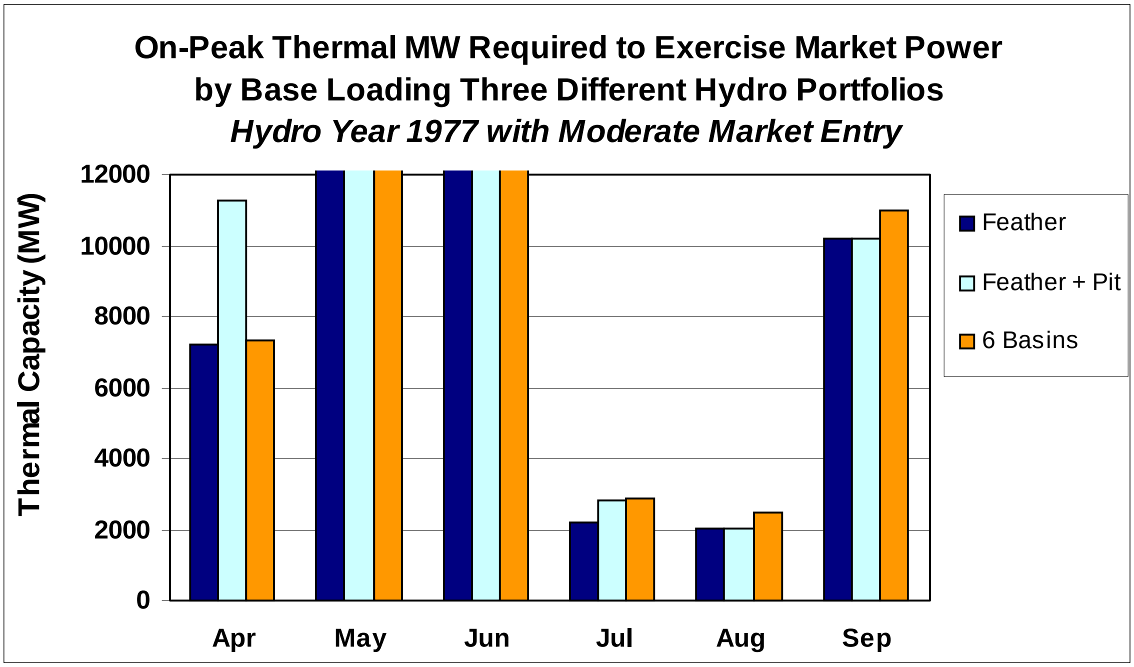


Figure C-36. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1977 (critically dry) with "Moderate" market entry***

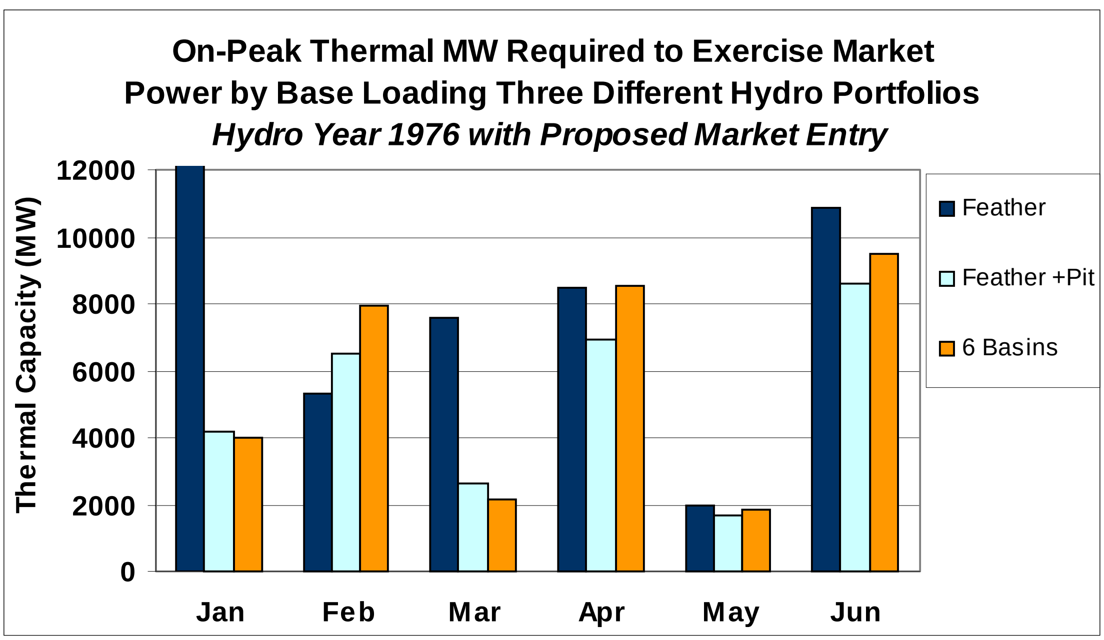


Figure C-37. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1976 (dry) with "Proposed" market entry***

Changes in market prices due to shifting hydro generation not only affect producer revenues and income, they also affect consumers' payments. We have developed a preliminary, illustrative estimate of the increase in electric energy costs for the combined customers of Pacific Gas and Electric Company, SCE, and SDG&E when moving from the original PowerMax Case to the "baseload" hydro shifting strategy simulated for Hydro Portfolio 2 (Feather and Pit systems). The estimate was made for the month of August 2005 with 1979 hydro conditions and Moderate market entry, circumstances previously depicted in Table C-20 and Figure C-34.

The additional cost to consumers was estimated under three different PX price cap levels, assuming no elasticity of electricity demand within this price range (Table C-22). The price increases (and some off-peak price decreases) over the month combine with the projected customer loads (Figure C-38) to produce the overall estimated increase in consumer costs for electric energy. The actual simulation such as depicted in Figures C-35 to C-39 assumed the $750 price cap.

Table C-22
Additional Pacific Gas and Electric Company, SCE and SDG&E Customer Payments for Electric Energy Due to Simulated Hydro Shifting (Base Loading) in the Month of August
Feather + Pit shifted, 1979 hydro conditions, Moderate market entry

Cap $/MWh	Additional Payment $Million
750	287.24
500	182.4
250	77.5

As previously suggested, an interaction of factors determines when and how hydro generation shifting has the potential to drive up MCP sufficiently to produce potential for exercising market power. We gain further insight into how this occurs by considering the hourly patterns of both hydro generation and MCP. Storage hydro whose output can be timed is generally expected to cycle its output, to high levels during high load (high market price) hours of the day and week, and down to low or minimum (minimum water passage) levels during off peak hours. This is illustrated for the "PowerMax" case in Figure C-38. Such clear cycling is especially likely during the summer, when loads, market prices and the value of water (for generation) are all highest. In contrast, the "baseload" strategy assumes that storage hydro facilities produce the same MW level of output in each hour of a month (Figure C-39). Since the MCP is substantially higher during the peak hours (Figure C-40), the cycling output pattern produces higher expected hydro generation income, under the original the PowerMax Case.

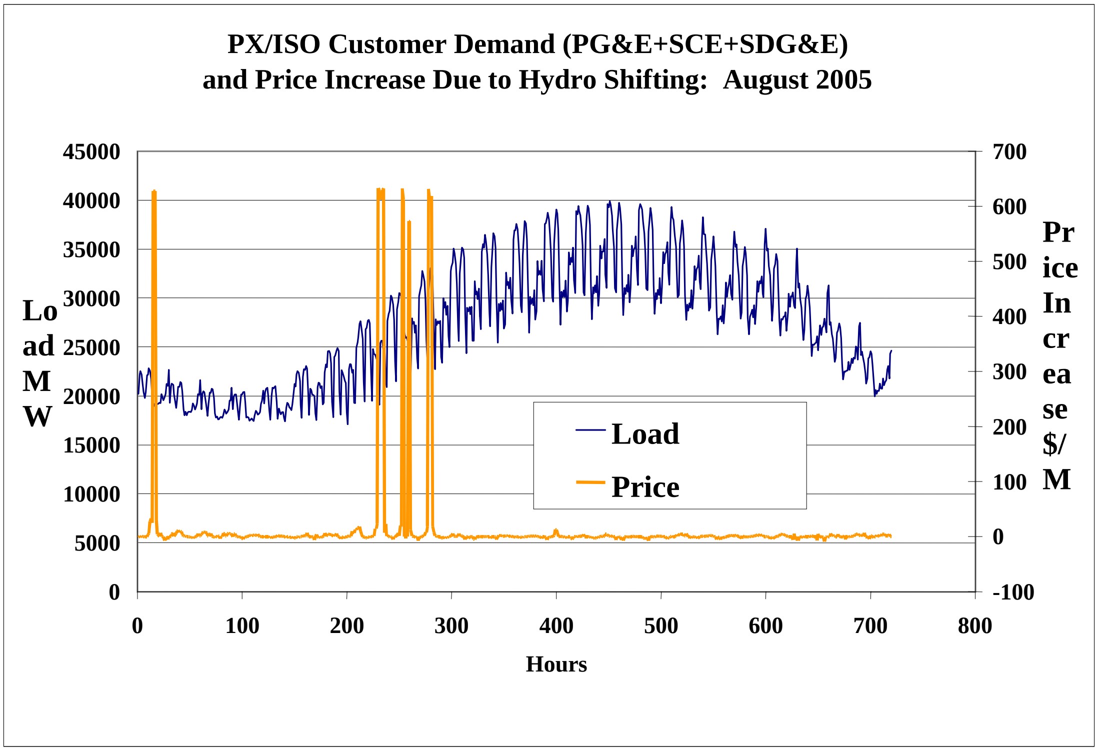


Figure C-38. Hydro Shifting: Customer Loads and Price Increases Translate into Increased Consumer Cost for Electric Energy

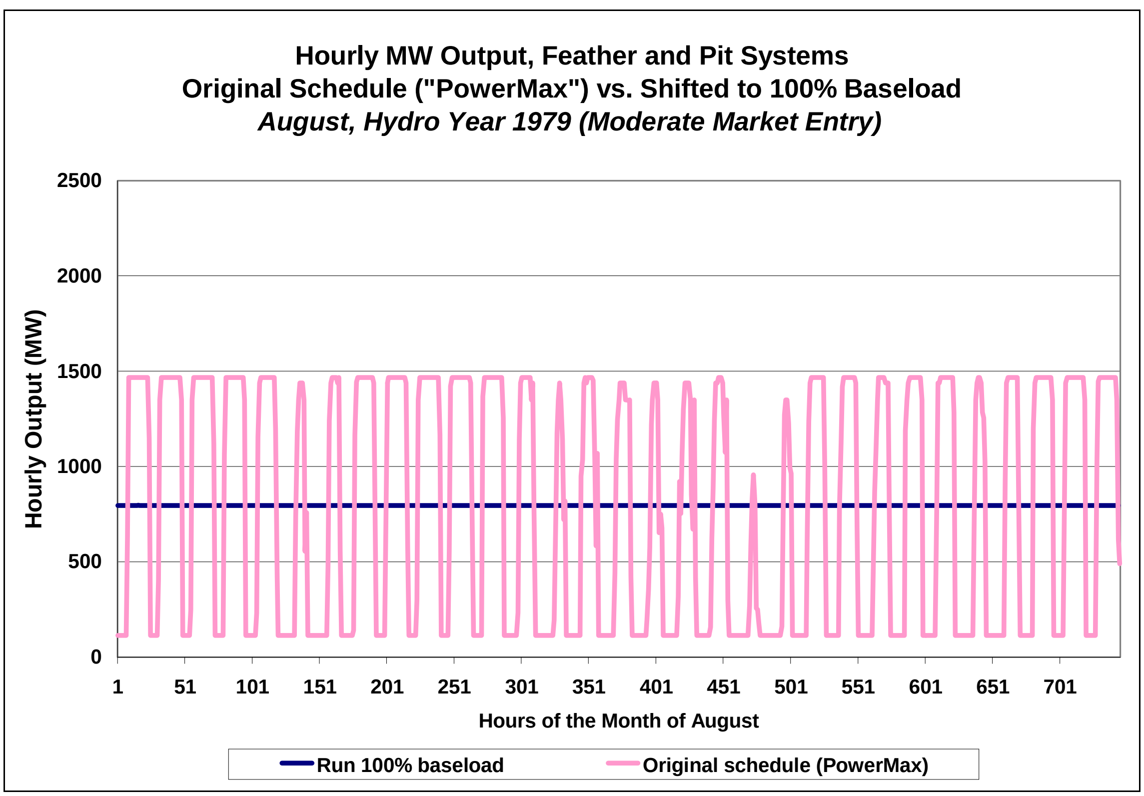


Figure C-39. "Baseload" Strategy Shifts Hydro Output from Cycling to Flat

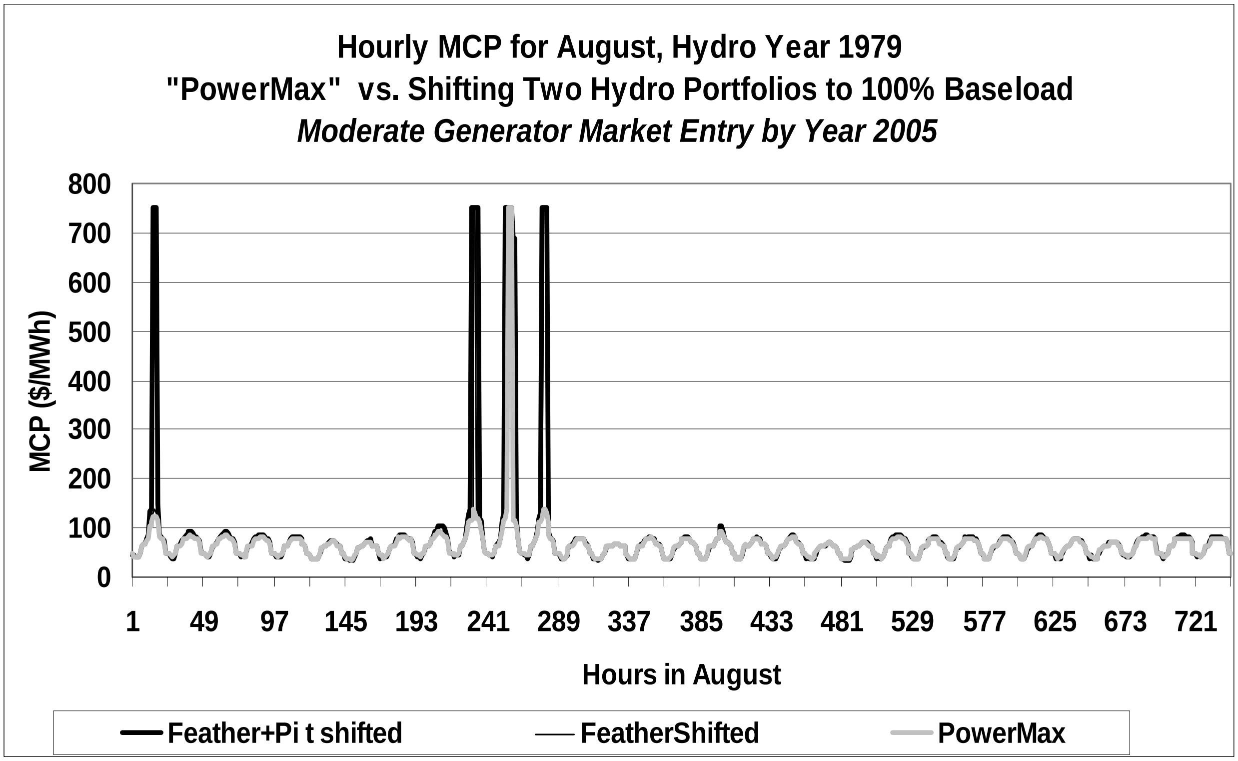


Figure C-40. In the Summer, Projected MCP Cycles Daily, Occasionally Spiking

Under the original competitive conditions (the PowerMax Case) MCP is projected to cycle not only daily during August, but on one day to spike at very high levels, reaching the mandatory cap. This reflects the combined effect of the underlying drivers, such as projected loads, the availability of water for hydro generation, and the availability of generators and transmission, in a relatively tight overall generation supply situation. Such price spikes represent an important revenue source for generators. Under the "baseload" strategy with hydro generation shifted away from peak hours, the peak MCPs are slightly elevated on many days. Further, the duration of the original price spike is increased and there are three additional days with price spikes. This can be seen in Figure 40, but more clearly in Figure C-41 that focuses on a single week. Such elevation of the MCP explains why under this particular set of conditions the "baseload" hydro shifting strategy was simulated to be successful when combined with ownership of only a small amount of thermal capacity.[46]

46 This strategy would be effective with an even smaller amount of thermal capacity if the hydro owner could reliably focus the release-shifting strategy to the days when generation resources are more scare and price spikes more likely, rather than for the entire month as shown here.

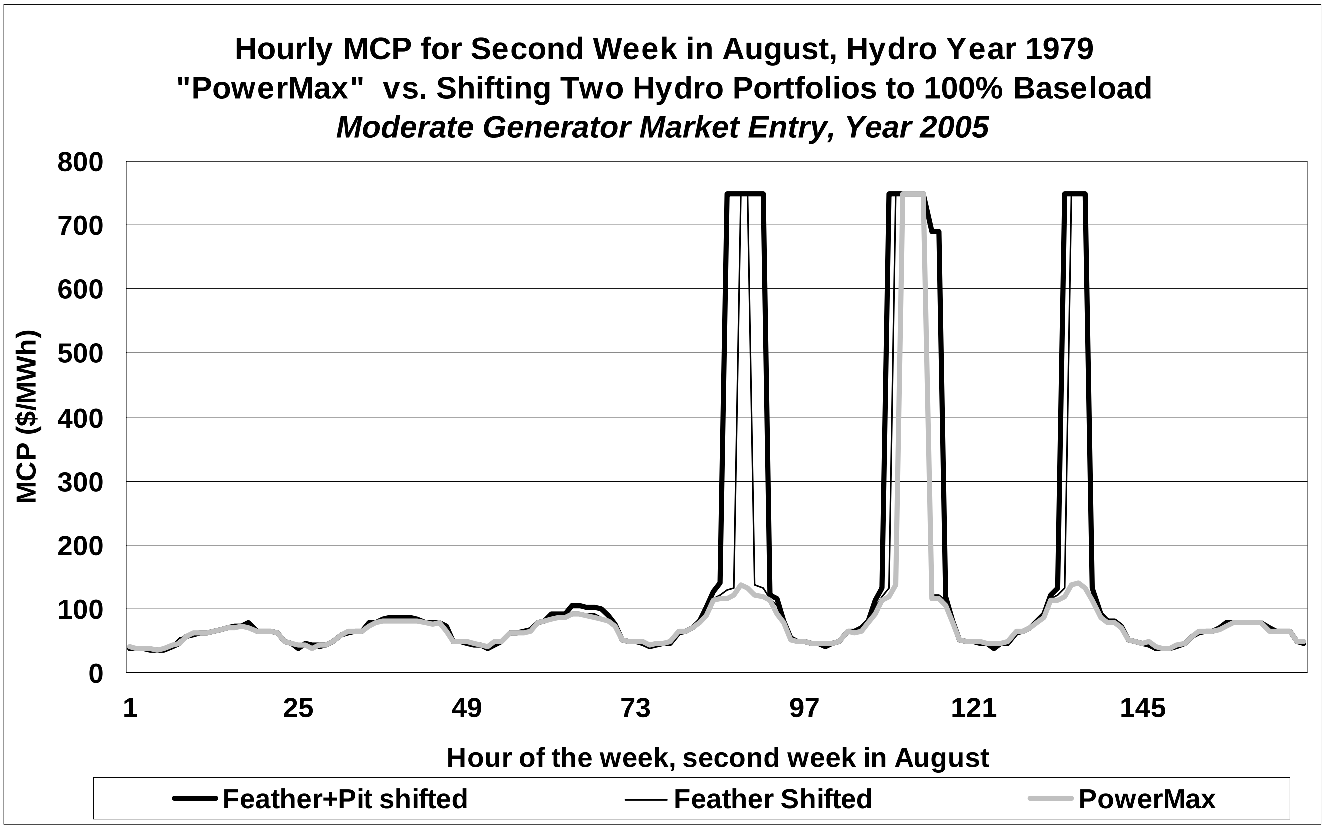


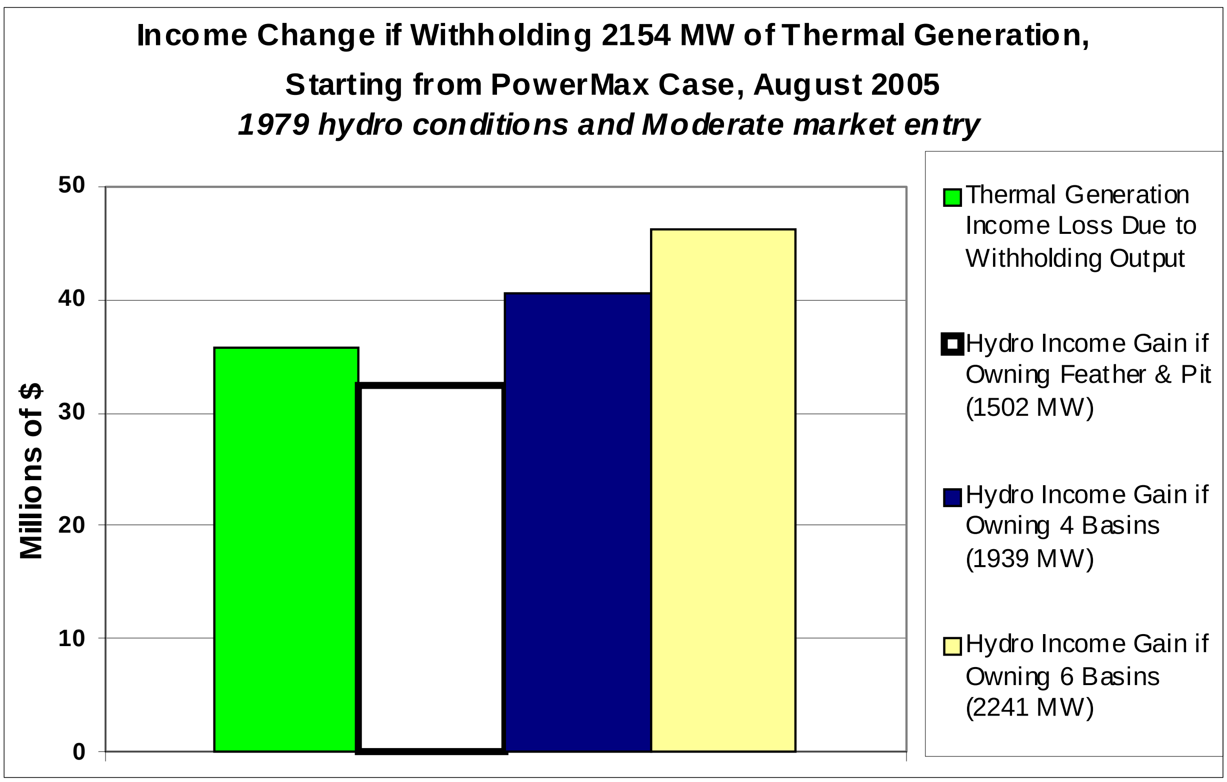
Figure C-41. Shifting Hydro Generation: More (and Longer) Projected Price Spikes

6.3.3 Results: Withholding Thermal Generation

The second general kind of market power strategy analyzed is withholding of thermal generation to increase the MCP. This could pay off if the owner has sufficient generation still in the market, including hydro, to benefit from the increased MCP. The strategy pays off if this remaining generation obtains an income increase outweighing the loss due to withholding generation. A wide range of amounts and types of thermal capacity could be considered as candidates for such generation withholding, over a wide range of time periods and conditions. Gas-fired cycling units that run mostly during peak and shoulder peak hours at narrow profit margins may be the best candidates. This analysis simulated the impact of a substantial amount of gas-fired capacity being held off-line for an entire month at a time. This test helps to identify conditions under which a withholding strategy is especially promising. In practice, withholding strategies would likely be more refined to increase chances for success, such as by focusing on a narrower set of hours or withholding only portions of a plant's output. In this screening test, the actual units simulated to act in this fashion were Moss Landing 6 and 7 and Morro Bay 3 and 4, all owned by Duke Energy, totaling about 2,200 MW.[47] This behavior was simulated for five sets of hydro conditions, as follows:

- hydro year 1977 (critically dry) under "proposed" market entry,
- hydro year 1979 (average) under both "proposed" and "moderate" market entry, and
- hydro year 1998 (wet) under "proposed" and "moderate" market entry

As illustrated in Figure C-42, when combined with ownership of certain hydro portfolios (Feather + Pit or larger), this thermal withholding was simulated to "pay off" in August 2005, under hydro year 1979 conditions and Moderate market entry. Among the other months in which the projected capacity factor for these four thermal units combined reached at least the 10% range, a positive payoff was simulated for two of the months. As summarized in Table C-23, the hypothetical strategy illustrated in Figure C-42 would not quite pay off if the overall generation portfolio included the four thermal units plus the Feather and Pit systems, but would pay off if additional hydro capacity was added to the portfolio. For the month in question, the amount of generation from the Feather and Pit systems is about 60% of the amount of withheld thermal generation. It is likely to be generation from storage hydro that benefits most from withholding thermal generation,



47 These units were selected because they represent a large amount of existing gas-fired capacity under common ownership in northern California. Their selection is for illustrative purposes and is not intended to suggest that Duke Energy is more or less likely to attempt to exercise market power than are any other owners of generation participating in California power markets.

since storage hydro generation would be concentrated in peak hours, unlike run-of-river hydro generation.

Figure C-42. Owning Enough Hydro Can Make Withholding Thermal Generation Pay Off

Table C-23
Elements Contributing to Overall Benefits of Withholding Thermal
Generation in the Previous Example

Change in Income if Withholding Generation from Selected Thermal Units While Also Owning Different Hydro Systems
August, Hydro Year 1979 - - "Moderate" market entry

Assets	Income change, $1000
Morro Bay 3	-5374
Morro Bay 4	-5648
Moss Landing 6	-15104
Moss Landing 7	-9629
Feather	16173
Pit	16171
Mokelumne	4262
Crane/Kerckhoff	3987
South Yuba	3652
Stanislaus	2134
NET TOTAL	**10624**

A second, more focused thermal generation withholding strategy was also analyzed. Under the Moderate market entry scenario with 1998 (wet) hydro conditions, a gas-fired, cycling generator in northern California was assumed to decrease its output by 30 MW in selected hours during the first week in August, 2005. The actual unit selected was part of Southern Energy Company's approximately 3,000 MW thermal generation portfolio in northern California.[48] This 30 MW of generation represents about one percent of the owner's overall generation portfolio in northern California. If not withheld it would have been profitable, generating at a marginal cost below the MCP for the hours in question. The result of withholding was an increase in projected MCP for those hours when the generation was withheld, more so in some hours than in others. Since hydro year 1998 represents wet conditions, it is quite possible that a similar strategy would produce greater increases in MCP under average or dry water conditions.

Backing off by 30 MW during peak hours in August reduces thermal unit's profits. The projected incremental fuel cost for this 30 MW of generation is about $981 per hour. An MCP of $70/MWh

48 As with the previous thermal withholding example, particular thermal generating capacity was selected for this illustration because the selected plant and its owner (in this case Southern Energy) represent large amounts of existing gas-fired capacity in northern California. This selection is for illustrative purposes and is not intended to suggest that Southern Energy is more or less likely to attempt to exercise market power than are any other owners of generation participating in California power markets.

would yield a positive income for running this 30 MW, with hourly revenues exceeding the hourly fuel cost by about $1100. (The MCP projected for various peak hours in August often exceeded $70.) However, if the MCP rises sufficiently due to withholding the 30 MW and if the owner has sufficient generating assets still producing in that hour, then the owner may increase overall income despite directly losing the revenues from running this 30 MW.

In fact, results indicated that in some hours merely owning a thermal plant portfolio the size of Southern Energy's was sufficient to make the withholding pay off, even without hydro ownership. For example, in hour 16 of August 5, the 30-MW reduction in output caused the MCP to increase by $0.99, so that lost income from withholding the 30 MW was more than offset by increased income at the 1,183 MW of remaining Southern Energy Company generation simulated to be sold into the market for that hour (Figure C-43).

For hour 17 of August 3 the 30-MW withholding produced a somewhat smaller MCP increase of $0.46/MWh. The original competitive MCP under the PowerMax Case was $76/MWh, so that the generator's owner needed to recoup about $1,300 ($2,280 revenues minus $980 of avoided fuel cost) from the rest of its portfolio, to break even. This is calculated to require having over 2,800 MW in the market for that hour and thus benefiting from the elevated MCP. Since the owner's thermal portfolio was simulated to be producing 1,510 MW (after the withholding), the owner would need about 1,300 MW of additional assets generating in that hour, in order to benefit from withholding. Adding the 734 MW Feather River portfolio is thus insufficient, but adding the larger 1,502 MW Feather + Pit portfolio is sufficient to make the withholding pay off, assuming that all hydro units are producing at full capacity in these peak hours (which may not be the case).

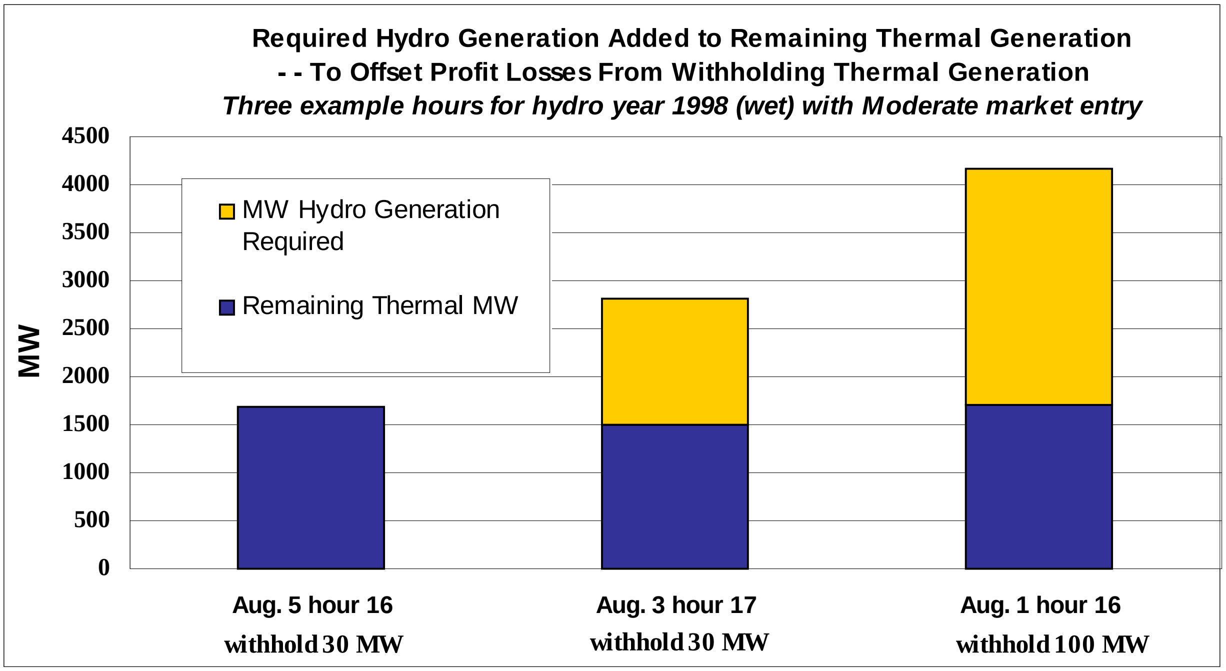


Figure C-43. Owning Enough Hydro Plus Thermal Generation Can Make Hourly Withholding of Thermal Generation Pay Off

A third hour provides additional insight. In hour 16 of August 1, withholding 30 MW produced no change in MCP, withholding 75 MW produced a $0.33/MWh increase in MCP, and withholding 100 MW produced a $1.08 increase. The latter withholding would pay off if in addition to projected thermal generation still in the market, the owner had at least 2,460 MW of hydro generation in that hour. This is somewhat more than the 2,241 MW represented by the 6-basin hydro portfolio number 6 (Table C-17). Larger withholding amounts might cause very large increases in MCP relative to the resulting income losses, so that smaller generation portfolios might be required for the strategy to be profitable. However, very large MCP responses to withholding might be viewed as symptomatic of a general shortage of capacity, rather than that of a market power problem. Clearly the potential for using a combined hydro-thermal generating portfolio to exercise market power varies considerably over the range of conditions analyzed to date and requires much more analysis.

6.3.4 Results: Market Power via Ancillary Services

One key aspect of hydroelectric generation is the ability to provide regulation, one of the "ancillary services" (A/S) required for reliable delivery of electricity. The opportunity for a generator to participate in markets for several ancillary services produces an opportunity cost for foregoing that participation by selling into the energy market. These "opportunity prices" can increase energy market bids and prices, relative to what would be expected in the absence of AS markets. Prices in the different markets rise or fall to levels that remove arbitrage between the markets, so that participants in the forward markets develop bids reflecting indifference to which market they are ultimately selected for.

The EIR preparers have investigated whether market power can be exercised by the owner of a hydro portfolio by withholding capacity from the regulation market in order to induce higher prices in both the energy and A/S markets. This withholding should increase the market price for regulation services, thus increasing the opportunity price for regulation, which in turn is reflected in increased energy bids (and prices). These higher energy and A/S prices can enable other units owned by the same supplier to recoup and even surpass the revenues lost due to the hydro portfolio not participating in the regulation market.

For illustration the EIR preparers simulated August 2005, with 1979 (“average”) hydro conditions and Proposed generator market entry. The EIR preparers assumed that a single owner controls the bidding strategy for a hydro portfolio consisting of the Feather River system, and compare two cases -- this portfolio’s participation versus non-participation in the ancillary service market for regulation. Table C-24 shows results for the first fifteen days of the month.

The significant revenue differences between the cases illustrate the value of proactive, strategic participation in all markets, to achieve better income prospects than provided by seeking maximum returns from energy markets alone. Another observation is that the greatest profit from withholding capacity in the AS market is projected for days with moderate, rather than highest loads. During these lower load days the hydro facilities tend to represent a larger fraction of the regulation market, and with fewer other units available to provide regulation up service, the price is higher.

Table C-24
Market Power Through Withholding Ancillary Services
Hydro Year 1979 (Average) With "Proposed" Generation Market Entry

Day	Daily Revenue ($)			Price Impact of Non-participation (withholding Impact		MW of Generation Required to Offset Lost Income Due to Nonparticipation in AS market Generation Owned to Have Market Power MW
	Participate In PX & AS	Participate In PX Only	Lost Income by Not Participating In AS	Price Increase in Regulation Market $/MW/Day	Price Increase in the PX Market $/MW/Day	
1	1564392	1280762	283631	45.57	-0.22	6254
2	1603992	1304058	299934	38.3	-6.52	9438
3	1481050	1190291	290759	32.68	10.34	6759
4	1423389	1154806	268583	67.96	20.36	3041
5	1297498	1058329	239169	78.11	17.30	2507
6	777867	621960	155907	85.14	30.67	1346
7	880288	710612	169675	73.99	24.03	1731
8	1434968	1200949	234020	66.09	9.15	3110
9	1561656	1316405	245250	46.29	13.94	4072
10	1603798	1338533	265265	24.74	9.27	7800
11	1609542	1339376	270166	64.86	9.22	3647
12	1512107	1255623	256484	59.95	-7.74	4913
13	1065417	886199	179218	101.77	25.13	1412
14	695597	585013	110583	100.56	47.53	747
15	1129055	935929	193126	116.79	26.03	1352

Of the days analyzed, August 14 shows the greatest opportunity for profiting from market power by withholding capacity from the regulation up market. Figure C-44 shows how this withholding strategy is projected to alter the pattern of utilization for the Feather River hydro system, and Figure C-45 shows the resulting impact on prices in the energy and regulation up markets.

The complex hourly patterns of energy market prices projected under original case are slightly altered by the simulated hydro portfolio nonparticipation in the regulation up market (Figure C-46). While Figure C-46 illustrates the absolute magnitudes of the energy prices, the change in hourly prices that is produced by withholding capacity from the AS market for regulation up is shown more clearly in Figure C-47. At the extremes, the price change ranges from a decrease of 6% to an increase of 10%, in different hours.

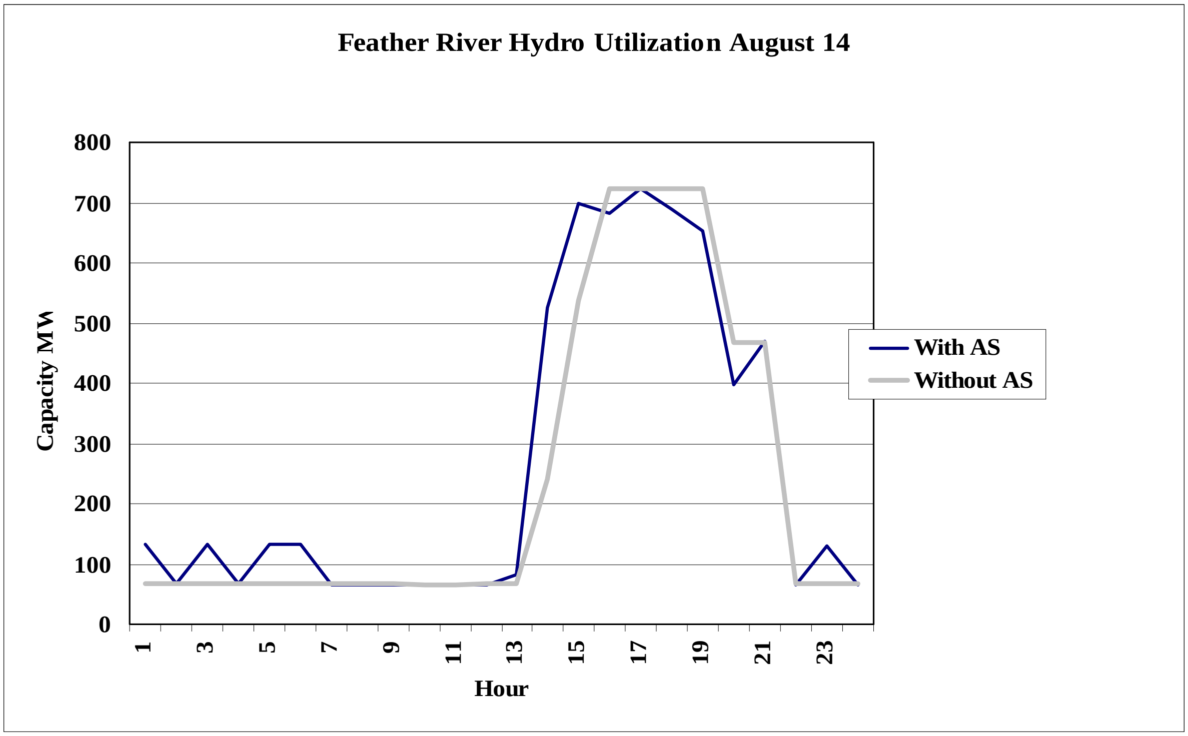


Figure C-44.   Hourly Operation of the Feather River "Portfolio" With vs. Without AS Market Participation

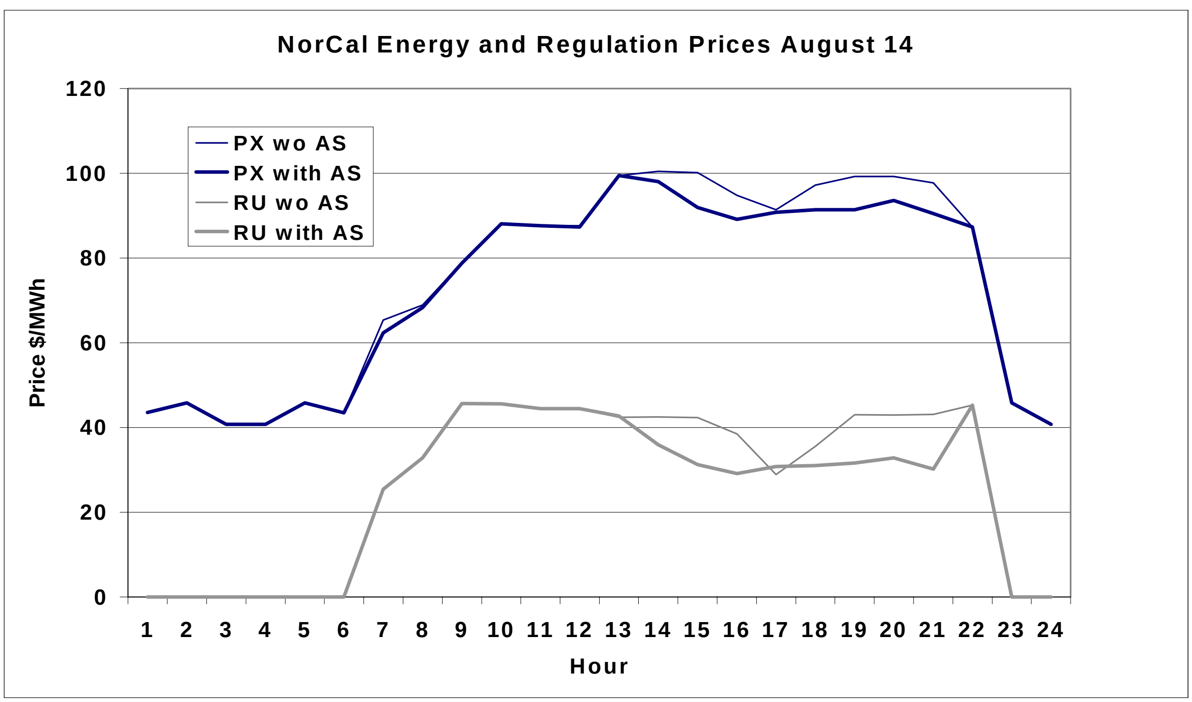


Figure C-45. Energy ("PX") and Regulation Up ("RU") Prices With vs. Without Feather River Portfolio Participation in AS Market

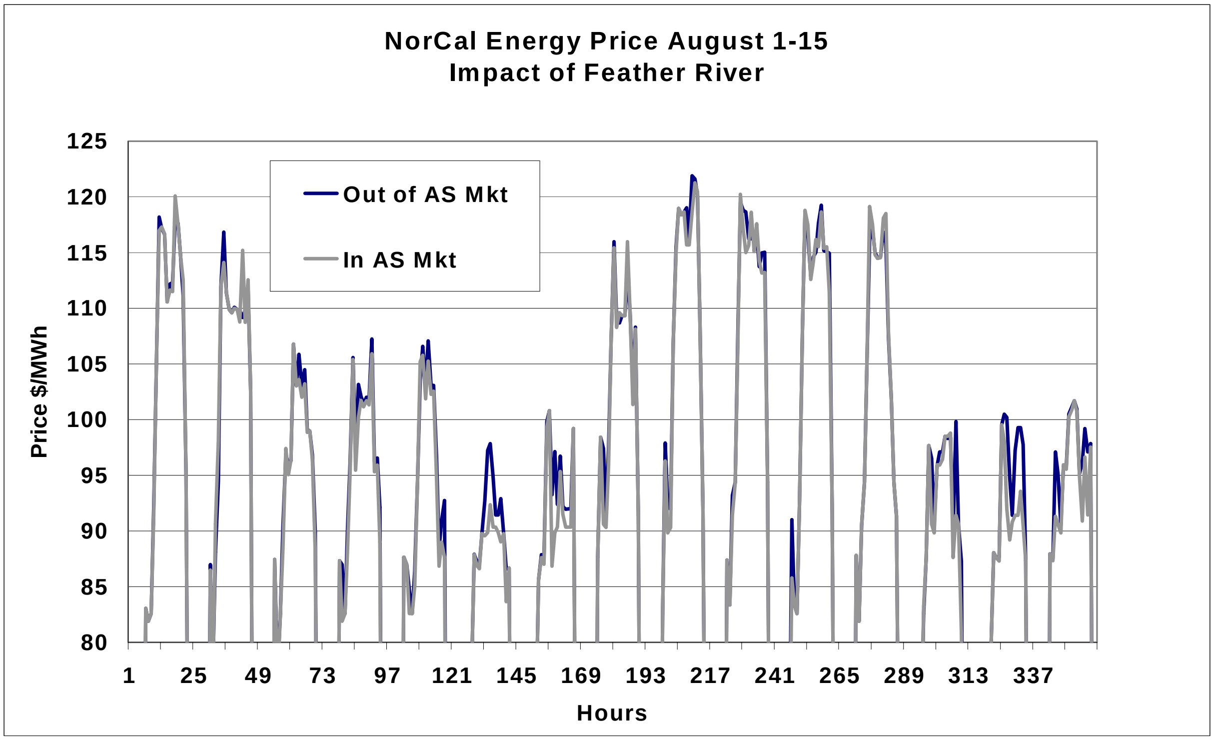


Figure C-46. Feather River Portfolio Non-Participation in Ancillary Services Market: Tweaking an Already-Complex Energy Market Price Pattern

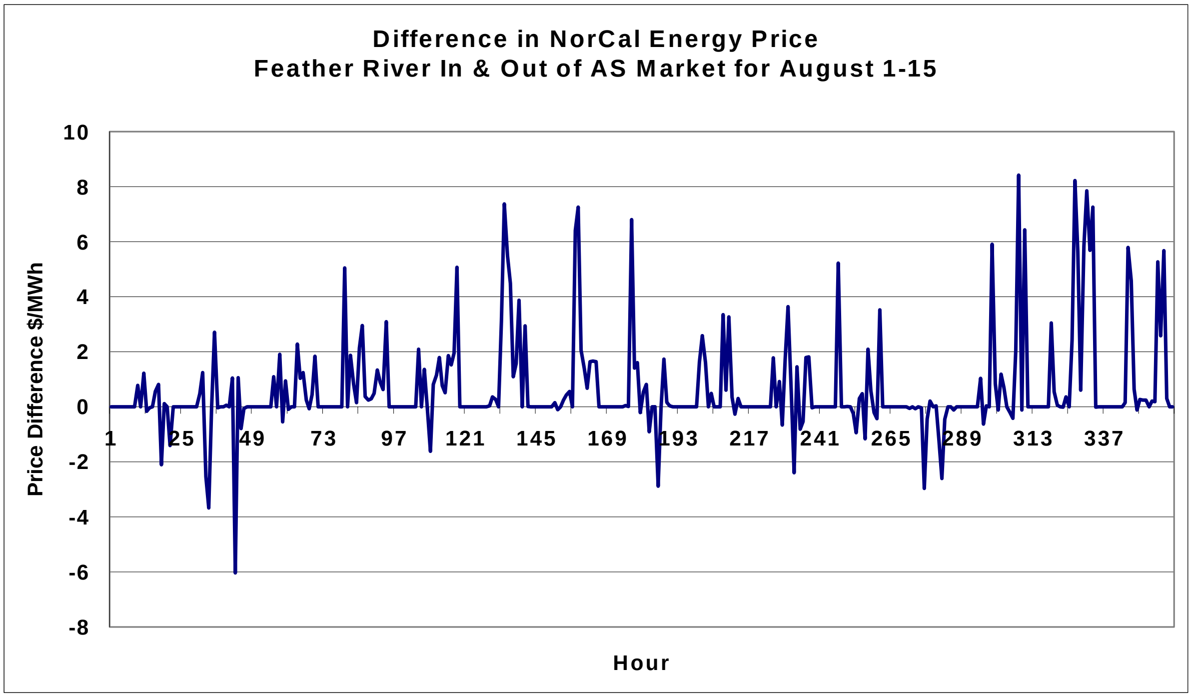


Figure C-47. Change in Hourly Energy MCP Due to Feather River Portfolio Non-Participation in Ancillary Services Markets

1979 (average) hydro conditions, "Proposed" market entry

The preceding cases illustrate opportunities for exercising market power that may exist through strategic utilization of the interaction of the multi-commodity markets for energy and ancillary services. If these opportunities are indeed highest during off-peak days, while hydro dispatch shifting described earlier provides additional market power opportunities especially during peak load conditions, there may be an attractive set of profitable, integrated market power strategies combining the two approaches. While the AS market strategy alone produced a small change in the simulated pattern of hydro generation (Figure C-44), the combined strategy could have a larger effect.

6.3.5 A Key Driver: Generation Supply Curves and Their Steep Points

This analysis indicates that under some conditions there is credible potential for exercising market power by shifting or withholding generation to increase energy and/or A/S market prices in California. This potential appears to vary dramatically across different seasons, hours, hydro conditions, and other circumstances. A key driver of this potential and its variation is the generation supply curve, including its shape and variation across time and changing conditions. The hourly supply curve represents the amount of additional MW of supply that is available for each step upwards in the $/MWh energy price, in that hour. If the curve rises steeply, as it does under certain conditions, then withholding supply can produce a large increase in the MCP, enhancing the prospects for exercising market power.

An understanding of this phenomenon can be obtained by examining supply curves for California. As an example, The EIR preparers have plotted a California supply curve[49] from the year 2005 simulation under 1976 hydro conditions and Moderate market entry, before any hydro generation shifting (Figure C-48). This curve represents the in-state generation supply for hour 12 (12 noon) of August 8, illustrating how certain parts of the supply curve give a steep increase in MCP for a given increase in supply (MW). When the system is at such points, potential practitioners of market power could achieve the greatest increase in MCP for a given amount of generation shifting or withdrawal.

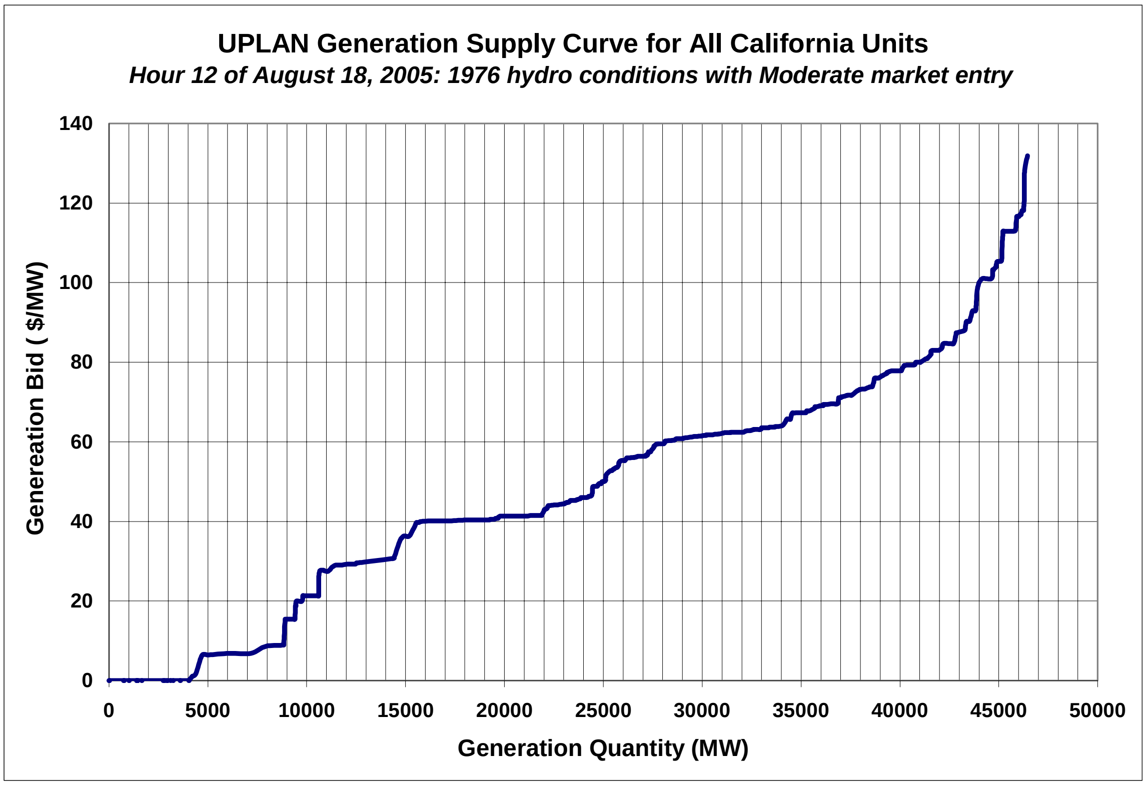


Figure C-48. UPLAN-Simulated Supply Curve for Generation Located In California

For example, in Figure C-48, if the load is at 22,000 MW, an additional 6,000 MW of supply (required if 6,000 MW is withdrawn or shifted) is associated with an MCP increase from roughly $40 to $60 (per MW, for this hour). Withdrawing 6,000 MW loses 6,000 MW X $40/MWh or $240,000 in revenues, which might represent a much smaller profit loss, depending on the operating costs and profit margin. On the other hand, any 12,000 MW of generation that remains in the market after such an MCP increase would receive a $240,000 increase in revenues (12,000 MW X {$60-$40}/MWh), the profit implications of which would also depend on operating costs.

49 The curve includes generating units located in California, but excludes out-of-state generators that also make a contribution to the simulated (and actual) supply of electric energy consumed in California.

The supply curve in Figure C-48 represents a particular hour, under particular conditions regarding loads, generator market entry and water supply. Under other conditions, the curve would change, shifting to the right or left under different water (hydro generation) conditions, and changing shape somewhat depending on the additions, retirements, or short-term commitment status of thermal generators.

The EIR preparers have also analyzed several actual supply curves from the California Power Exchange (CalPX) and observed similar pronounced bid (price) increases in certain parts of the curves. Figure C-49 shows one such PX supply curve, for noon of August 12, 1999. As in UPLAN-simulated supply curves, there are certain parts of the curves where price rises steeply for an increase in supply, such as at the supply level just above 34,000 MW.[50]

This analysis has observed that the potential for profitably exercising market power can vary considerably across seasons, hours, hydro conditions, loads, and generator market entry, not to mention other factors not analyzed, such as fuel prices. This variation is especially influenced by the location and size of the “steep” parts of the supply curve, and by what combination of conditions is being experienced by the market at any point in time.

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50 Note that unlike the supply curve extracted from the UPLAN simulation (Figure C-48), the PX supply curve in Figure C-49 includes generation originating from outside of California. In fact, the UPLAN simulation includes markets and generation across the WSCC, including out-of-state generation imported into California. Also note that the length in MW of the relatively flat lower section of the curve (zero or very low $/MW) depends especially on hydro and coal generation, which in the PX supply come significantly from outside of California. (Water supply was above average in 1999 and below average in 1976.)

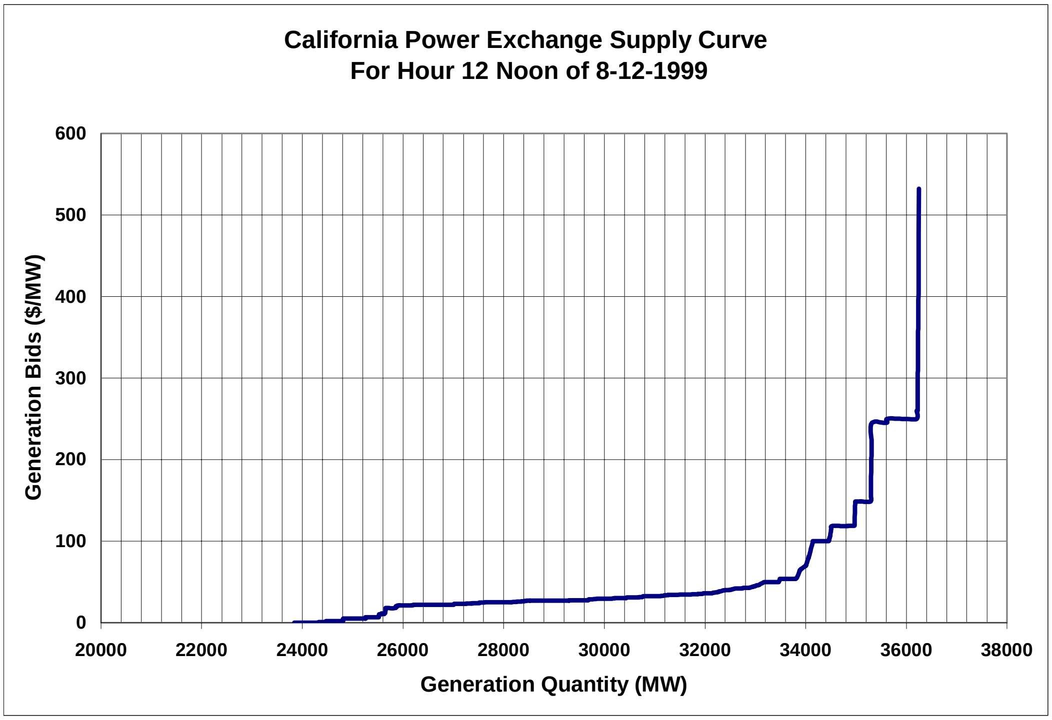

Figure C-49. California Power Exchange Generation Supply Curve for an Actual Peak Hour in August 1999.

6.3.6 Implications of the Market Power Analysis

This analysis covered a limited set of conditions that might be conducive to the exercise of market power, but it suggests the following key observations. The results indicate that under a range of conditions, a single owner with a portfolio of thermal plants in California could use those resources differently than might be the case in a competitive market to enhance portfolio profits through manipulation of market prices. In general, realistically achievable (in the real world) amounts of hydro and/or thermal plant ownership can confer an ability to exercise market power. The potential for profitably exercising market power appears to vary greatly over different hydrologic conditions, seasons and individual hours, and other circumstances that combine and interact. The projected ability to exercise market power by driving up market prices also strongly depends on what amount of new generator market entry is assumed or expected for the future. The dependence of the ability to exercise market power on these variables suggests that in the real world it might be challenging to anticipate the occurrence and duration of conditions conducive to exercising market power. Since efforts to profitably exercise market power would affect the patterns of utilizing hydroelectric and thermal power plants, they could have environmental consequences.

6.4 AIR EMISSION MODELING RESULTS FROM SERASYM™

The air emission modeling results from SERASYM™ are discussed in detail in Section 4.14 (Air Quality) of the Draft EIR. The SERASYM™ modeling was conducted in a manner consistent with the UPLAN modeling discussed previously.

7 ANALYSIS OF ALTERNATIVES NOT MODELED

7.1 MAXIMIZE POWER MARKET PROFITS IN THE 20 BUNDLE GROUPS

The effects on hydroelectric operations, as a result of changing from 16 river basin bundle owners wherein each owns all the Pacific Gas and Electric Company facilities on a single river system to 20 new owners wherein each owns one of the 20 bundles as proposed by Pacific Gas and Electric Company in their Application, would be small. All owners in this situation are assumed to be price takers.[51] A new operating agreement would be needed only on the North Fork Feather River between the Bucks Creek Project: Bundle 7, and Bundle 6 consisting of the Upper North Fork, Rock Creek-Cresta, and Poe projects. For these alternative cases each owner would own only one bundle and no other generation facilities. The owners would not be able to exert market power to influence market prices and would be "price takers" maximizing revenue by selling power and ancillary services into the high priced period of the market to the extent feasible. The 16-bundle alternative differs from the 20-bundle Pacific Gas and Electric Company proposal as follows:

- Shasta Watershed Region: Pacific Gas and Electric Company Bundle 1 (Hat Creek 1 & 2 Project) would be combined with Bundle 2, (Pit 1, Pit 3,4 &5, and McCloud-Pit Projects) to be a single bundle.
- DeSabla Watershed Region: Pacific Gas and Electric Company Bundles 5 (Hamilton Branch), 6 (Upper NFFR, Rock Creek-Cresta, and Poe Projects), and 7 (Bucks Creek Project) would be a single bundle.
- Kings Crane – Helms Watershed Region: Pacific Gas and Electric Company Bundle 16 (Crane Valley Project) would be merged with Bundle 17 (Kerckhoff 1 & 2) to be a single bundle.

All other bundles are the same for both cases. The potential operating effects of disaggregating the 16 bundles into the 20 Pacific Gas and Electric Company proposed bundles are discussed below.

7.1.1 PIT RIVER

Hat Creek 1& 2 (FERC License No. 2661)

Separating the 17 MW Hat Creek 1 & 2 project from the other Pit River projects would have no effect on operations. Hat Creek flows are diverted from Cassel Pond to flow through the Hat Creek 1 Powerhouse and then discharged to Baum Lake. Flows are diverted from Baum Lake to flow through the Hat Creek 2 Powerhouse and then discharged back to Hat Creek, which flows into the Pit River at Lake Britton. The small project forebays provide combined storage capacity of only 677 acre-feet, less than a one-day water supply for the Hat Creek powerhouses. Year-round large spring-fed inflows to the forebays must be used for generation or spilled since more than several hours of inflow cannot be stored. Therefore, the Hat Creek Project has very little flexibility and must be operated essentially run-of-river whether operated by an independent owner or by the owner of the rest of the Pit River facilities. Even so, some hourly variation in generation is possible for the Hat Creek 2 Powerhouse by drafting and refilling the 629 AF forebay (Baum Lake).

The 48 acre-foot capacity of the forebay for Hat Creek 1 is too small to permit any significant cycling. The peak flow capacity through the Hat Creek 2 Powerhouse of 580 cfs is small (17.5 percent) compared to the 3315 cfs flow capacity of the downstream Pit 3 powerhouse. More significant is that Hat Creek outflow discharges to the large 42,000 AF capacity Lake Britton (Pit 3 forebay) which absorbs and smoothes-out any daily or hourly variation of flows from Hat Creek such that it is unnecessary to make any changes in the operation of Pit 3 and the other downstream Pit River powerhouses as a result of variation in flows from the Hat Creek Project. An operating agreement would not be required.

7.1.2 NORTH FORK FEATHER RIVER

Hamilton Branch (unlicensed)

The separation of the 4.8 MW Hamilton Branch Project from the Feather River ownership bundle would have no effect on the hydroelectric operations of the rest of the river system. The project is the uppermost step of the Feather River "Stairway of Power," a series of Pacific Gas and Electric Company and Department of Water Resources powerhouses utilizing most of the flows and available head of the North Fork Feather River (NFFR) for power generation. The project impounds Goodrich Creek and Duffy Creek in the 24,000 acre-foot Mountain Meadows Reservoir. Water released from the reservoir flows down Hamilton Branch where a maximum flow of 200 cfs is diverted to the Hamilton Branch Flume, which conveys the flow to the penstock and Hamilton Branch Powerhouse. The powerhouse discharges the flow back to Hamilton Branch near its entry into Lake Almanor, which has 1.1 million acre-feet of storage capacity. Flows up to approximately 2200 cfs are diverted from Lake Almanor through a tunnel to the 40 MW Butt Valley Powerhouse, the next step down the Stairway of Power.

Several observations are made in assessing the potential effects of separating the ownership of the Hamilton Branch Project from the rest of the NFFR projects. The controlled maximum inflow rate to Lake Almanor from Hamilton Branch is only about 9 percent of the maximum controlled outflow to Butt Valley Powerhouse. There are several other tributaries inflowing to Lake Almanor including the main stem of the NFFR. The average annual inflow to Lake Almanor through Hamilton Branch Powerhouse is about 90,000 acre-feet, only 8.2 percent of the storage capacity of Lake Almanor and about 12.6 percent of the average annual diversion to Butt Valley Powerhouse. The annual inflow to Mountain Meadows Reservoir is approximately four times its storage capacity, indicating that water must be released through the powerhouse and power generated throughout much of the year and that the reservoir should be drawn down to minimum levels by the beginning of the wet

51 There should be no difference between 5 or 16 owners to the extent that owners of any one administrative watershed unit also would be price takers who cannot influence overall market prices significantly.

season to minimize potential spill. Therefore the project has limited seasonal operating flexibility and insufficient storage capacity to withhold water from downstream water users.

Mountain Meadows Reservoir is very shallow with a large, 5,746 acre surface area and, subject to the typically warm, dry California summer weather. This leads to rapid evaporation during the summer months. If not drawn down, more than half the reservoir could be lost to evaporation. To best utilize the total reservoir capacity, this reservoir must be drawn down quickly early in the summer, thus limiting its flexibility to meet late summer operational objectives.

Hourly operational flexibility is constrained by a relatively long canal that is best operated at a steady flow and with changes in flow made only gradually. This precludes marketing of ancillary services requiring rapid changes in generation.

During the summer and fall months, the project has flexibility of power dispatch for daily and longer cycles. However, any variation in outflows would be masked by the very large capacity of Lake Almanor such that downstream projects would not see any effects.

In conclusion, the Hamilton Branch Project is a relatively small contributor to the NFFR hydroelectric system that lacks sufficient storage capacity to withhold inflows to Lake Almanor on a seasonal basis. Manipulation of generation and flows to maximize revenues in the summer and fall months would be unnoticed by the downstream hydro projects because the great storage capacity of Lake Almanor would smooth-out any variations in flows from Hamilton Branch Project. An operating agreement between the different owners would not be required.

Bucks Creek Project (FERC No. 619)

Ownership of the 65 MW Bucks Creek Project by a different entity than the Bundle 6 NFFR projects could negatively affect hydroelectric operations and productivity at Cresta and Poe Powerhouses in the absence of coordination of operations. Historically, Bucks Creek has been operated in coordination with Rock Creek-Cresta and Poe powerhouses to maximize total generation and avoid any unnecessary spills.

The Bucks Creek Project is a branch flight of steps on the NFFR “Stairway of Power.” Its primary storage reservoir is Bucks Lake with a capacity of 105,327 acre-feet. Other storage capacity includes Lower Bucks Lake at 5,819 acre-feet, Three Lakes at 606 acre-feet, and Grizzly Forebay at 1,109 acre-feet. The reservoirs usually fill by May or June in average to wet years. Runoff impounded in Bucks Lake and Three Lakes is released to Lower Bucks Lake and thence released through a tunnel to pass through the 18.8 MW Grizzly Powerhouse[52] and into Grizzly Forebay.

[52] The Grizzly Powerhouse is part of FERC License No. 619, but is owned by the City of Santa Clara. It is operated, maintained and dispatched for Santa Clara by Pacific Gas and Electric Company under the terms of a detailed agreement. Thus, Bucks Creek already is operated essentially in a coordinated fashion with the City of Santa Clara facility.

Grizzly Forebay receives inflows from Grizzly Creek in addition to discharge from the Grizzly Powerhouse. From Grizzly Forebay water is diverted at flow rates up to the maximum of 384 cfs to the Bucks Creek Powerhouse located one mile upstream of Cresta Reservoir where the flow is discharged to the NFFR. Other inflows to Cresta Reservoir include up to 3,300 cfs from Rock Creek Powerhouse discharge, instream flows of the NFFR, and several significant tributaries including Chambers Creek, Jackass Creek, Milk Ranch Creek, Bucks Creek, and Rock Creek. The maximum flow capacity of Cresta Powerhouse is about 3,800 cfs and the minimum instream flow release required at Cresta Dam is less than 50 cfs (50 cfs less Grizzly Creek inflow downstream of Cresta Dam). It is readily apparent that the sum of the inflows might easily exceed the sum of the maximum diversion to Cresta Powerhouse and the minimum stream flow requirement to cause spill at Cresta Dam if the excess flow cannot be stored in Cresta Reservoir.

The capacity and operation of Cresta Reservoir is also important to assess the potential effects of separate ownership of the Bucks Creek Project. Cresta Reservoir is a small afterbay/forebay relative to the large flows with an original capacity of 4,140 acre-feet that has been reduced 40 to 50 percent by sediment deposits. The deposits do not affect normal reservoir operations. The reservoir is generally not drawn down more than 10 feet from the normal maximum level and is operated at or near full much of the time to maximize the head at Cresta Powerhouse. Therefore, there may be little or no storage capacity available in Cresta Reservoir to receive and mitigate increased discharge from the Bucks Creek Powerhouse. If Bucks Creek Project discharge were to be suddenly increased, then flow diversion to Cresta Powerhouse would need to be increased, or discharge from Rock Creek Powerhouse decreased, by an equal amount to avoid spill. If Cresta were to be already operating at maximum capacity and the forebay full, spill could occur. Under such conditions, spill might also occur at the downstream Poe Dam because the Poe reservoir has only 1,203 acre-feet of capacity and also is usually operated at or near full capacity. In effect, the Bucks Creek owner would be generating and making money at the expense of the owner of the downstream projects by forcing spill of water that, with water management coordination, might also have generated power at Cresta and Poe powerhouses. Also, unscheduled releases from Bucks Creek Powerhouse could interfere with the flexibility of Cresta and Poe Powerhouses to provide ancillary services.

Despite the potential for spill and some loss of generation benefits if Bucks Creek were separately owned and operated without coordination with the downstream projects, such spills would be most likely to occur during the high run-off winter and spring months when Cresta and Poe were operating at full capacity and already spilling excess water. Then the additional spill caused by adding Bucks Creek flows would represent a loss only if the Bucks Creek reservoirs did not fill completely and the spilled water could have been saved for use in the dry season. The economic penalty of the occasional small spills that might occur would be a relatively small percentage of the total generation value. However, if such spills occurred during the recreation season, sudden surges in flows below the Cresta and Poe dams could increase the level of risk for recreationists.

(Sudden flow changes are recognized risks for recreationists using the river below the dams and warning signs are posted at most access points.)

Also, it is noted that the Cresta and Poe components of the NFFR hydro system were constructed after Bucks Creek such that Cresta and Poe are sized to accommodate the Bucks Creek discharge, which represents less than 10 percent of the annual inflow to Cresta Reservoir. Therefore, minimal coordination efforts on the part of new owners would be required to ensure the system is operated in the most efficient and economic manner for the benefit of all.

An operating agreement would be required.

7.1.3 KINGS CRANE – HELMS WATERSHED REGION

Crane Valley Project (FERC License No. 1354)

The 28.7 MW Crane Valley Project consists of five small powerhouses connected in series by diversions and canals located along the North and South forks of Willow Creek, a tributary of the San Joaquin River. The primary storage capacity for the system is the 45,410 acre-foot Crane Valley Reservoir (Bass Lake). The combined capacity of 5 other small reservoirs and forebays in the system is less than 600 acre-feet. Water is diverted from Bass lake to the 0.9 MW Crane Valley Powerhouse and then sequentially through the San Joaquin #3 (4.2 MW), San Joaquin #2 (3.2 MW), San Joaquin #1A (0.4 MW), and the finally the 20 MW A.G. Wishon Powerhouse. The A.G. Wishon Powerhouse discharges a maximum flow of 235 cfs to the 4252 acre-foot Kerckhoff Reservoir on the main stem of the San Joaquin River, the forebay for the 38 MW Kerckhoff 1 Powerhouse and the 155 MW Kerckhoff 2 Powerhouse (FERC License No. 96).

Average annual flow through the Kerckhoff powerhouses is approximately 1.6 million acre-feet. The Crane Valley Project delivers approximately 85,000 acre-feet of water annually to Kerckhoff Reservoir, only 5.3 percent of the total volume passed through the Kerckhoff powerhouses. The balance of the water volume for Kerckhoff comes from the San Joaquin River, which is controlled by the upstream Big Creek and Mammoth Pool projects owned by Southern California Edison (SCE). On an instantaneous basis the A.G. Wishon discharge of 235 cfs represents only 3.4 percent of the 6,835 cfs combined flow capacity of Kerckhoff 1 and 2.

In summary, the relatively large storage capacity provided by Bass Lake for the Crane Valley Project might allow an owner flexibility to vary operations on a weekly and seasonal basis such that timing of generation and water discharge could be manipulated to maximize revenues. But, due to the physical constraints of the system, including small forebays and a number of long canals, changing flows requires careful coordination of operations at all the powerhouses to avoid spilling at the small reservoirs or canals. There are also recreational constraints and the Miller-Lux Agreement with the Corps of Engineers on the operation of Bass Lake, leaving a new owner with limited flexibility to modify operations to be significantly different than the current operation by

Pacific Gas and Electric Company. Due to these constraints and the very small contribution in flows the project makes to the Kerckhoff Project, the EIR preparers conclude that operation of the Crane Valley Project by a different owner would have negligible impact on Kerckhoff operations, even in the absence of an operating agreement between the owners. An operating agreement with the Kerckhoff Project would not be required.

7.2 UNBUNDLE TO FERC LICENSE LEVEL. MAXIMIZE POWER MARKET PROFITS IN THE 29 BUNDLE GROUPS

The effects on hydroelectric operations, as a result of changing from the Pacific Gas and Electric Company 20 bundle plan wherein each owner has one of the 20 bundles to 29 new owners wherein each owns one bundle consisting of one of the 26 FERC licensed project, or one of the three unlicensed projects, would be significant. The alternative for 29 bundles would require new inter-project operating agreements on the Pit River (Pacific Gas and Electric Company Bundle 2), the Feather River (Pacific Gas and Electric Company Bundles 6, 7 and 8), and the NF Kings River (Pacific Gas and Electric Company Bundle 18). For these cases each owner would own only one license bundle or unlicensed plant and no other generation facilities. The owners would not be able to exert market power to influence market prices and would be "price takers" maximizing revenue by selling power and ancillary services into the high priced period of the market to the extent feasible.

For the larger projects on the Pit, NF Feather and NF Kings rivers, effective participation in the ancillary market would require agreements that would go beyond just requiring operating cooperation for efficient use of the water resources. To efficiently market ancillary services, business alliances that would be virtual partnerships would be needed for the plant groups identified by Pacific Gas and Electric Company as Bundles 2, 6, and 18. For example, the Poe Project could be operated as a run-of-river facility with no operating agreements. In that case, Poe would likely be able to market only energy as it would have no control over the level or timing of generation. However, with operational coordination and business alliances with the upstream owners, ancillary services could be optimally marketed as a unified system including Poe with the upstream plants to maximize the economic benefits for all the owners and perhaps the ratepayers as well. For Pacific Gas and Electric Company Bundles 2, 6, and 18, the whole is definitely worth more than the sum of its parts.

The small unlicensed Lime Saddle and Coal Canyon projects included by Pacific Gas and Electric Company in Bundle 8 would require a complex operating agreement between the two projects to ensure fulfillment of the existing water contracts. Coal Canyon is 100 percent dependent on Lime Saddle for water. There is no apparent benefit to be gained by dividing this small system into its two components. However, there is no operational need for them to remain bundled with the licensed DeSabla-Centerville Project as proposed by Pacific Gas and Electric Company. To minimize potential conflicts and adverse impacts, Lime Saddle and Coal Canyon should be considered as one package. Exhibit C-5 shows the relationships among the projects within a river basin.

7.2.1 Shasta Regional Bundle

Pacific Gas and Electric Company Bundle 1

Hat Creek 1 & 2, FERC License No. 1354: No operating agreement required

As discussed in the 20-bundle scenarios, unbundling the Hat Creek 1 & 2 Project from the other Pit River facilities would have no impact on downstream operations. An operating agreement would not be required.

Pacific Gas and Electric Company Bundle 2

Pit 1 Project, FERC License No. 2687: No operating agreement required

The 61 MW Pit 1 Project is the uppermost Pacific Gas and Electric Company hydroelectric development on the Pit River system. The only storage is the small forebay, which has 1,159 acre-feet of usable capacity. The project diverts water from Fall River through a tunnel and penstock to the Pit 1 Powerhouse located on the Pit River. A maximum flow of 1900 cfs is discharged from the powerhouse to the river, which then flows three miles downstream to Lake Britton with 42,000 acre-feet of storage capacity, the forebay for the Pit 3 Powerhouse (FERC License No. 233). Because of the small capacity of Pit 1 forebay, the project must be operated as a run-of-river facility, although some dispatch flexibility on an hourly basis is possible. Any hourly variations in the flows discharged would be dampened out by the relative large capacity of Lake Britton such that the variations would have no effect on the operation of Pit 3 and other powerhouses downstream. Operating agreements between Pit 1 Project and the downstream projects would not be required.

If the **smallest bundle is a FERC licensed project**, the following projects highlighted in bold Italics would require a new operating agreement with the upstream or downstream owner.[53]

Pit 3, 4, 5 Project (FERC License No. 233) and McCloud-Pit Project (FERC License No. 2106): Operating Agreement Required

The 325 MW Pit 3, 4, 5 Project consists of the 70 MW Pit 3 Powerhouse, the 95 MW Pit 4 Powerhouse and the 160 MW Pit 5 Powerhouse along with, penstocks, tunnels, and forebays/afterbays linked in hydraulic series. Pit 5 Powerhouse discharges up to 3,580 cfs into the Pit 6 Reservoir (FERC License No. 2106), which has a storage capacity of 15,605 acre-feet. Also, the James B. Black Powerhouse (FERC License No. 2106), receiving flows from the McCloud River and Iron Canyon Creek, discharges up to 2,000 cfs into Pit 6 Reservoir for a maximum

53 The tables and notes are from Pacific Gas and Electric Company's Rebuttal Testimony of 6/23/00 by witness Norman F. Sweeny.

controlled inflow of 5,580 cfs. In addition to the powerhouse discharges, there are the Pit River instream flow and several tributaries adding inflow to the reservoir.

The flow capacity of the 80 MW Pit 6 Powerhouse is 6,470 cfs. At that flow, the Pit 6 Powerhouse would drain the reservoir in only 29 hours, indicating that despite its apparent large capacity, the reservoir is not large enough to be classified as a seasonal storage facility due to the high volumes of inflows and outflows. Up to 55 percent of the Pit 6 flow capacity may be provided by the Pit 5 discharge. In some cases, operation of the James Black Powerhouse might be curtailed, forcing spill at McCloud Dam in efforts to mitigate for excessive discharge from Pit 5 Powerhouse.[54]

It is evident from the fact that total inflow could easily exceed the capacity of Pit 6 Powerhouse that coordinated water management of the reservoir inflows is necessary to maximize generation and minimize spills at Pit 6 and Pit 7. The need for coordinated operation will be most urgent during the winter and spring months when the runoff flows are high. A water management operating agreement between the owner of McCloud-Pit Project and the owner of Pit 3, 4, 5 Project will be necessary for planned efficient operation of Pit 6 and the downstream Pit 7 components of the McCloud-Pit Project.

7.2.2 DeSabla Regional Bundle

Pacific Gas and Electric Company BUNDLE 5

Hamilton Branch Project (No FERC License): No Operating Agreement Required

As discussed in the 20-bundle scenario, alternative operations at Hamilton Branch would have no impact on downstream operations. An operating agreement is not required.

Pacific Gas and Electric Company BUNDLE 6

Upper North Fork Feather River (FERC License No 2105), Rock Creek-Cresta Project (FERC License No. 1962), and Poe Project (FERC License No. 2107): Operating Agreement(s) Required

The Upper North Fork Feather River (UNFFR) Project consists of the 41 MW Butt Valley Powerhouse, 75 MW Caribou No. 1 Powerhouse, 120 MW Caribou No. 2 Powerhouse, 125 MW Belden Powerhouse, 1.3 MW Oak Flat Powerhouse, Lake Almanor, Butt Valley Reservoir, Belden Forebay, and associated dams, tunnels and penstocks. Significant water storage capacity is provided by the 1.1 million acre-foot Lake Almanor and the 50,000 acre-foot Butt Valley Reservoir. Water flows from Lake Almanor through the Butt Valley Powerhouse into Butt Valley Reservoir and thence through the Caribou 1 and 2 powerhouses into the small 2,421 acre-foot Belden Forebay. From the forebay, water is diverted to the Belden Powerhouse that discharges a

54 A prudent operator of the combined licenses would allow spill at the relatively low-head Pit 6 Dam in preference to spilling the high-head McCloud water, which would have almost eight times the energy value per unit volume.

maximum flow of 2,410 cfs into Rock Creek Reservoir, the forebay for the Rock Creek Powerhouse. Oak Flat is a small energy recovery unit operating on the minimum required stream flow release at Belden Dam. It has no effect on water storage or the operation of any other generating units.

The Rock Creek-Cresta Project consists of the 112 MW Rock Creek Powerhouse, 70 MW Cresta Powerhouse, 4,400 acre-foot Rock Creek Reservoir, 4,140 acre-foot Cresta Reservoir, and associated dams, tunnels, and penstocks. Water is diverted from Rock Creek Reservoir through the Rock Creek Powerhouse with a maximum flow capacity of about 3,300 cfs and is discharged to the Cresta Reservoir. From Cresta Reservoir flow is diverted through the Cresta Powerhouse at flows up to 3,800 cfs and then discharged to the Poe Reservoir (FERC License No. 2107). In addition to the discharge from Belden Powerhouse, Rock Creek Reservoir receives significant inflows from instream flow of the NFFR, East Branch North Fork Feather River (EBNFFR), Yellow Creek, and several smaller tributaries. Most years the volume of these inflows may at times during wet winter and spring months exceed the diversion capacity of the Rock Creek Powerhouse, allowing the Rock Creek and downstream powerhouses to operate at full capacity without inflow from the UNFFR Project. Historically during these periods, Pacific Gas and Electric Company has curtailed the operation of the UNFFR Project by storing inflows in Lake Almanor and Butt Valley Reservoir and shutting down operation of the two Caribou powerhouses and Belden Powerhouse. However, during the dry season, Rock Creek and the downstream powerhouses are dependent upon flows from Belden for most of their generation. On average, approximately 50 percent of the annual generation at Rock Creek Powerhouse is from the Belden discharge. At Cresta Powerhouse about 81 percent of the annual generation is from discharge from Rock Creek Powerhouse with the balance of flows coming from the Bucks Creek Powerhouse and tributary side flows.

It is readily apparent that an operating agreement is required between the UNFFR Project and the Rock Creek-Cresta Project to ensure continuation of coordinated efficient operation, particularly during the high runoff months when UNFFR Project operations must be curtailed and water held at Lake Almanor and Butt Valley Reservoir to minimize spills at Rock Creek Dam and the other downstream facilities.

Poe Project (FERC License No. 2107) Operating Agreements Recommended but Not Essential

The 120 MW Poe project consists of the Poe Powerhouse, the 1204 acre-foot Poe Forebay and the Poe Tunnel and Penstock. The maximum flow capacity of Poe Powerhouse is 3900 cfs. On average, about 95 percent of the generation at Poe is from water discharged through the Cresta Powerhouse, with the balance of flow coming from several small tributaries entering the NFFR between Cresta Dam and Poe Dam. Poe Powerhouse discharges into Lake Oroville operated by the Department of Water Resources (DWR). Due to the large storage capacity of Lake Oroville (3.6 million acre-feet) discharge flow rates from Poe have no short-term effects on operations by DWR. With virtually no storage capacity in its small forebay, Poe is essentially a run-of-river project almost entirely dependent upon the flow releases from the Cresta Powerhouse. With the storage constraint, flow discharged from Cresta must be immediately routed on through the Poe Powerhouse or spilled.

Poe could operate in the run-of-river mode as a price taker without any operating agreements with the upstream owners. The Poe generation pattern would mimic that of Cresta Powerhouse with only a slight delay. The generation at Poe would be subject to the decisions of the upstream owners in their quest to maximize revenues for themselves. This could serve the Poe owner quite well if the upstream owners engage in sound water management and marketing practices. At minimum, the Poe owner would need water management information from the upstream owners in order to schedule operations and maintenance. However, the Poe owner might be better served by the negotiation of agreements with the upstream owners that would allow him a voice in the decision making for marketing strategy and managing the water resources, to share watershed data, and to participate jointly with the other owners in the ancillary services market. A coordinated operating agreement would likely improve resource-use efficiency and project revenues.

Pacific Gas and Electric Company BUNDLE 7

Bucks Creek Project (FERC No. 619)

The need for an operating agreement between Rock Creek-Cresta Project and the Bucks Creek Project is discussed in the 20-bundle scenario. The new owner of Poe might also wish to engage in an operating agreement with the Bucks Creek Project as well as with the Rock Creek-Cresta Project.

Pacific Gas and Electric Company BUNDLE 8

DeSabla-Centerville Project (FERC License No. 803), Lime Saddle Project (Unlicensed) and Coal Canyon Project (Unlicensed): No Operating Agreement Required for DeSabla Centerville Project. Operating Agreement Required Between Lime Saddle and Coal Canyon

Separation of the licensed DeSabla-Centerville project from the unlicensed Lime Saddle and Coal Canyon projects would require no operating agreements because there is no hydrologic linkage. Lime Saddle diverts flows from the West Branch Feather River (WBFR) well downstream of the Hendricks Head Dam diversion to the DeSabla Centerville Project. However, the Lime Saddle and Coal Canyon projects are intimately intertwined both hydrologically and contractually such that separate ownership would require a complex agreement.

Water is diverted from the WBFR to the Upper Miocene Canal and conveyed several miles to the 154 acre-foot Kunkle Reservoir,[55] forebay for the 2 MW Lime Saddle Powerhouse. Maximum flow through the Lime Saddle Powerhouse is 87 cfs discharged directly to the Middle Miocene

Canal which conveys the flow several miles further to the 0.9 MW Coal Canyon Powerhouse. Water is distributed along the way to three private buyers from the Lime Saddle Penstock and to 11 buyers from the Middle Miocene Canal and Coal Canyon Forebay. After the remaining water (about 47 cfs maximum) passes through Coal Canyon Powerhouse, it enters the "Powers Canal" and is sold to the California Water Company for municipal use in the City of Oroville.

Coal Canyon Powerhouse is dependent on Lime Saddle discharge for its entire water supply, and there is a long-term obligation to supply water to the California Water Company. These constraints require that the operations of the canals and two powerhouses be fully coordinated. Also, the other water customers, even though they may have contracts with Pacific Gas and Electric Company that allow termination with relatively short notice, have grown to view their contracts as "water rights" and would likely protest long and loudly if terminated.[56] Therefore, an operating agreement between different owners of the Lime Saddle and Coal Canyon components would be necessary to ensure meeting all the commitments of Miocene Canal system. A superior solution would be to maintain these two small projects under a single ownership.

7.2.3 Motherlode Regional Bundle

Pacific Gas and Electric Company BUNDLE 14

Spring Gap-Stanislaus Project (FERC License No. 2130) and Phoenix Project (FERC License No. 1061. Operating Agreement is Not Recommended

The 98 MW Spring Gap-Stanislaus Project is located primarily on the Middle Fork Stanislaus River (MFSR), but receives inter-basin water transfers from the South Fork Stanislaus River (SFSR). The project consists of the Spring Gap component which includes the 7.5 MW Spring Gap Powerhouse located on the MFSR at Sand Bar Reservoir, the Philadelphia Diversion on the SFSR upstream of the Phoenix Project, and the Philadelphia Ditch connecting the two. Up to 59 cfs are diverted from the SFSR to the Spring Gap Powerhouse and discharged to Sand Bar Reservoir. The Stanislaus component includes an 11-mile long tunnel connecting the diversion at Sand Bar Reservoir to the forebay, the small 320 acre-foot Stanislaus Forebay, the penstock, and the 91 MW Stanislaus Powerhouse. Up to 830 cfs of flow are released from the forebay through the Stanislaus Powerhouse and discharged to the New Melones Reservoir, but diversions from Sand Bar Reservoir are constrained by the 525 cfs capacity of the long tunnel. Tri-Dam's Donnells, Beardsley, and Sand Bar projects are located on the MFSR upstream of the Stanislaus Powerhouse. In addition the project includes two storage reservoirs: Relief Reservoir (15,554 acre-feet) on the MFSR upstream

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55 Kunkle Reservoir may also receive some inflow from the Wilinor Canal of Thermalito Irrigation District shown on the watershed map.

56 In the late 1980s, Pacific Gas and Electric Company attempted to impose higher fees and to better regulate the volume of water actually diverted by these customers, but met strong resistance. (Larry Harrison, co-author of this report, was Pacific Gas and Electric Company project manager during that period.)

of the Tri-Dam projects, and Strawberry Reservoir (Pinecrest Lake) (18,312 acre-feet) on the SFSR upstream of the Phoenix Project.

The Phoenix project is located entirely in the SFSR basin. The project consists basically of the 2 MW Phoenix Powerhouse, the 6,224 acre-foot Lyons Reservoir and the Main Tuolumne Canal. In addition to conveying water from the reservoir to the powerhouse, there are several diversions from the canal to the Tuolumne Utility District (TUD) for irrigation and domestic uses. A maximum flow of 25 cfs passes through the Phoenix Powerhouse and is discharged to Phoenix reservoir (not part of the FERC project) for irrigation and domestic use. The project is more of a water supply project than it is a power project. The Phoenix Project and its water clients also benefit from storage in Strawberry Reservoir. Water rights issues are complex. There are current agreements limiting diversions from the SFSR to the MFSR via the Philadelphia Ditch, which are proposed to be incorporated into the Spring Gap-Stanislaus FERC license upon future relicensing.

An operating agreement between new owners for the projects is unnecessary in view of 1) an interface between the projects exists only in regards to diversion rights to the SFSR flows and the Strawberry Reservoir storage, 2) current diversion agreements to protect the interests of the consumptive water users on the SFSR, 3) likely FERC action to issue license conditions to License No. 2130 limiting SFSR water export, 4) existing adjudicated water rights to the SFSR flows, and 5) SFSR exports provide only seven percent of Stanislaus Powerhouse flows and less than 19 percent of the average annual generation of the Spring Gap-Stanislaus Project. An operating agreement between new owners of the projects would add little benefit to either party and might introduce conflicts with established practices and water rights.

7.2.4 Kings Crane Helms Watershed Region

Pacific Gas and Electric Company BUNDLE 18

Helms pumped Storage Project (FERC License No. 2735), Haas-Kings River Project (FERC License No. 1988), Balch Project (FERC License No. 175) Operating Agreements Required

The 1,212 MW Helms Pumped Storage Project is the uppermost power development on the Kings River. It utilizes the water stored in the two uppermost reservoirs: Courtright Reservoir with a usable storage capacity of 119,000 acre-feet, and Wishon Reservoir with useable capacity of 89,000 acre-feet. Power is generated when water from the higher Courtright Reservoir is passed through the Helms units and discharged to Lake Wishon. In pumping mode, Helms moves water from Lake Wishon back to Courtright for use during the next generating cycle. Helms Creek and other small tributaries inflowing to Courtright add to the water available for generation through the Helm units. The two reservoirs also supply water to two downstream projects, the Haas-Kings River Project, and the Balch Project. Courtright and Wishon Reservoirs were built as part of the original Haas-Kings River development in the 1950s to store water for use in the conventional hydroelectric generating plants. The two reservoirs are now uniquely licensed to both the Helms and the Haas-

Kings projects. Reservoir operations must be closely coordinated between the Helms pumped storage operations, conventional hydro generation, and the consumptive water needs of the Kings River Water Association at Pine Flat Reservoir. Overdraft of Courtright and Wishon would curtail Helm operations. In the converse, filling both reservoirs to capacity would block Helms operations by leaving no space to move water back and forth between the reservoirs.

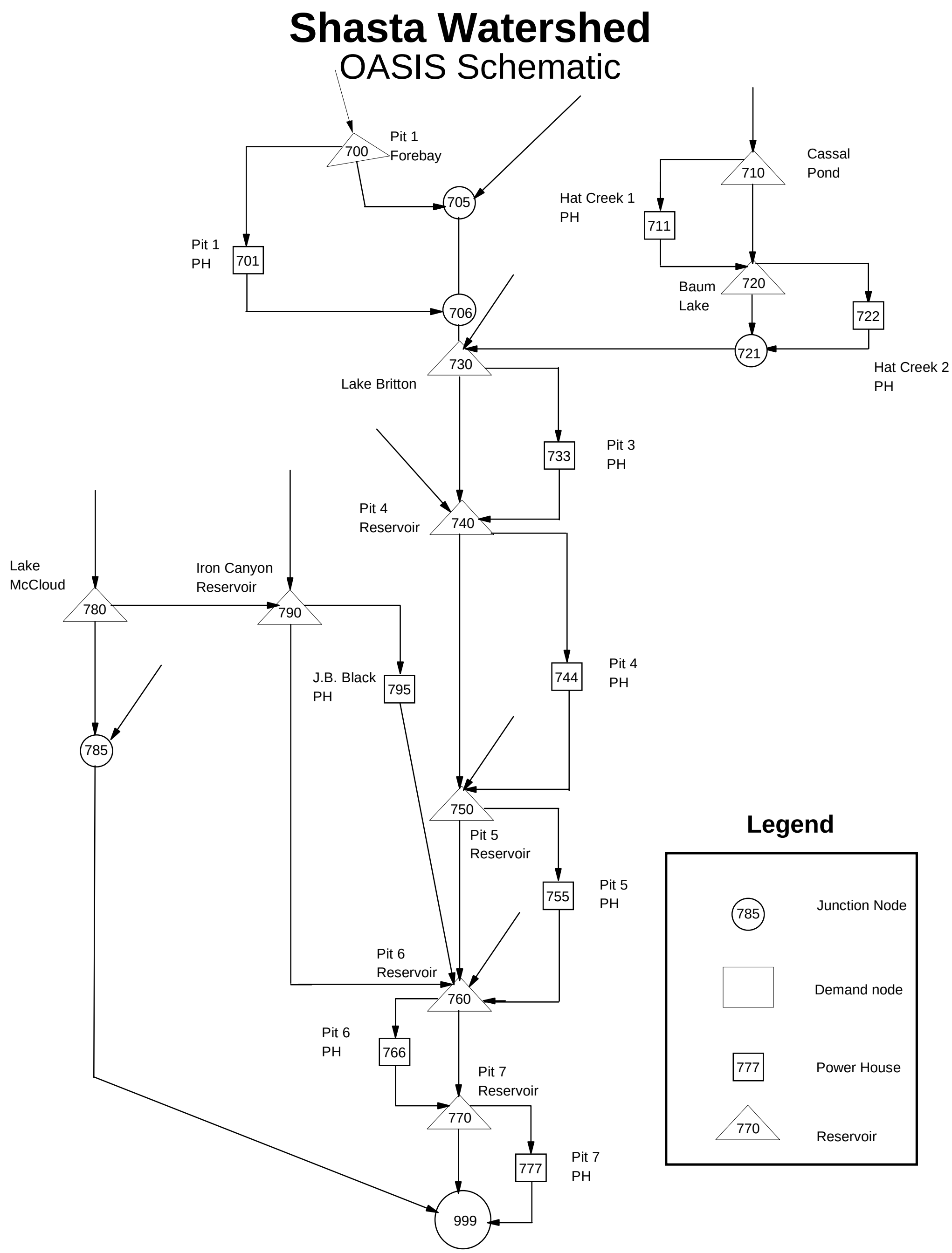
The KRWA water agreement limits Pacific Gas and Electric Company's carry-over storage rights to 60,000 acre-feet in the reservoirs shared by FERC Licenses 2735, 0175 and 1988 upstream of the Pine Flat Reservoir under certain drought year conditions. Separating the Helms Project from the rest of Bundle 18 is inconsistent with the terms of the KRWA agreement because the agreement looks at the upstream storage as a single unit. Separation of the licenses would require renegotiation of these agreements with separate owners, and allocation of the storage rights among the licensed projects. Such allocation would reduce the flexibility to meet the contractual requirements most efficiently.

The Balch Project separates the Haas and Kings River components of License No. 1988. Water is diverted from Lake Wishon through the 144 MW Haas Powerhouse at flows up to 825 cfs and discharged to the 1260 acre-foot Black Rock Reservoir, the forebay for the Balch 1 and 2 powerhouses. Water is routed from Black Rock Reservoir through the 34 MW Balch 1 Powerhouse and 105 MW Balch 2 Powerhouse at a maximum combined flow of 843 cfs and discharged to the 317 acre-foot Balch Afterbay. Flow is then diverted at up to 990 cfs to the 52 MW Kings River Powerhouse and discharged into Pine Flat Reservoir, operated by the United States Army Corps of Engineers. Flow is increased somewhat moving downstream by side flows from several small tributaries. The small size of the Black Rock Reservoir and Balch Afterbay provide virtually no storage capacity. Once water is released from Lake Wishon, it must be routed on through the Haas, Balch and Kings River powerhouses or spill will occur. All four conventional powerhouses must be operated in concert to make efficient use of the water.

Also, during spring snowmelt and other high runoff periods, the tributary inflows downstream of Lake Wishon may be sufficient to provide much or all the flow capacity of the Balch and Kings River powerhouses. Any additional flow released from Lake Wishon through Haas Powerhouse at these times might be spilled and wasted. The high heads on the NF Kings River, over 2,000 feet at Haas and at Balch, make the energy value per unit of the water very high.

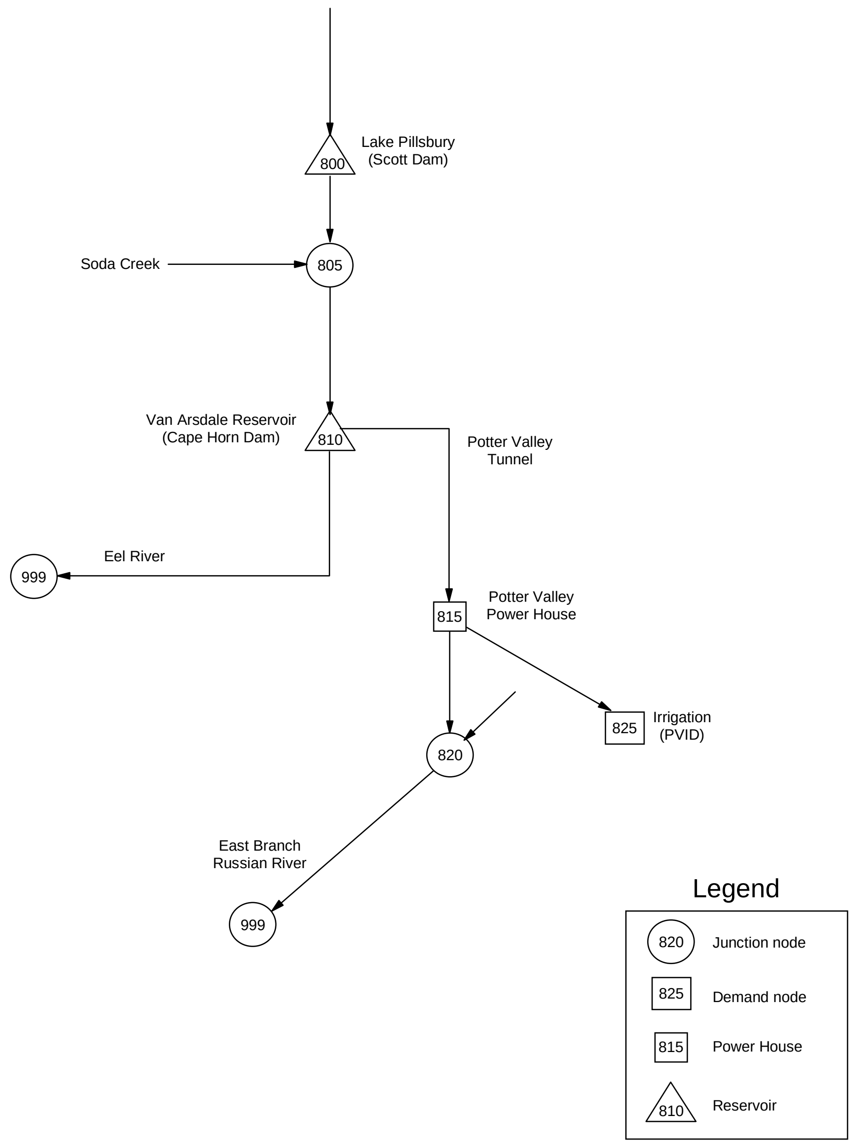
The above described constraints and high value of the water would demand comprehensive operating agreements between the owners of all three projects on the NF Kings River to make efficient use of the hydro resources.

EXHIBIT C.1 OASIS SCHEMATICS



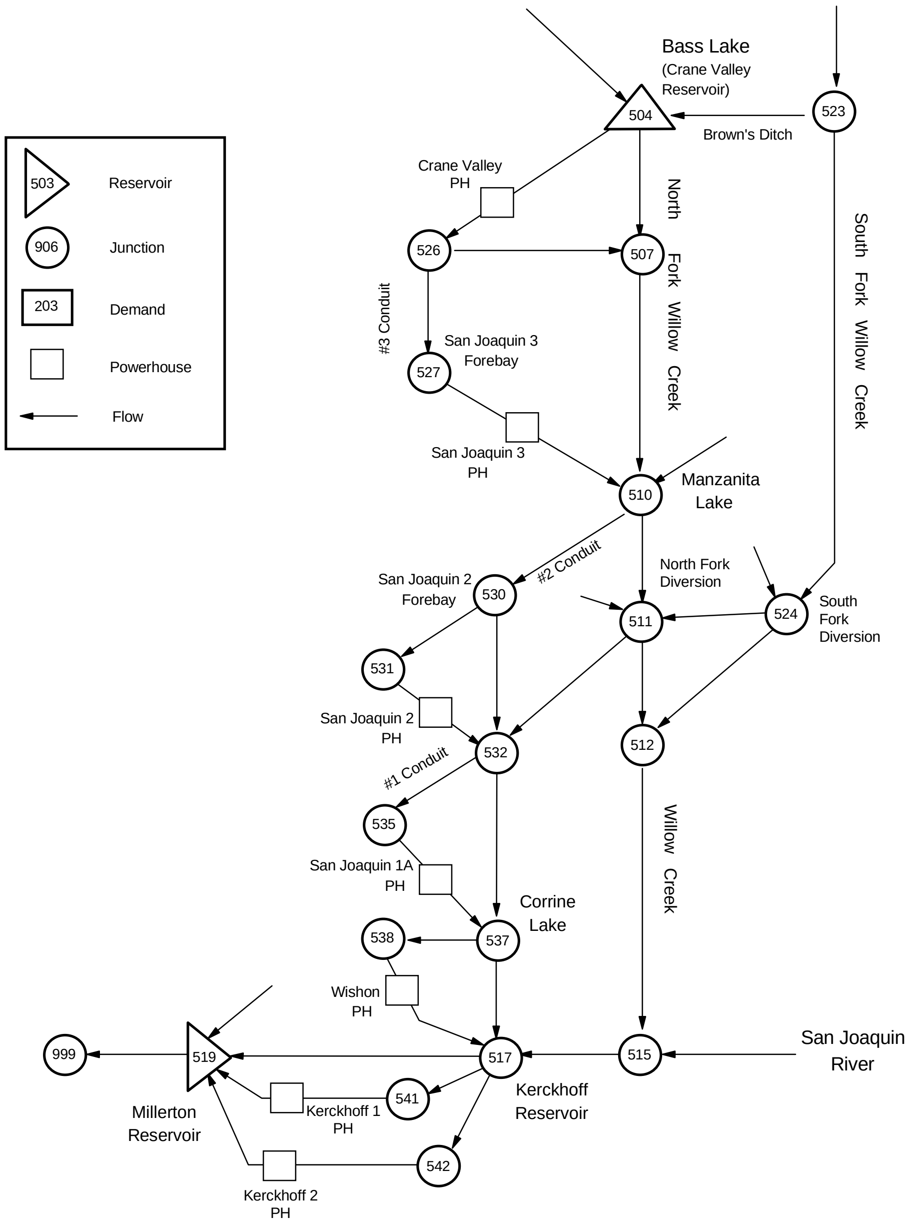
Potter Valley Project

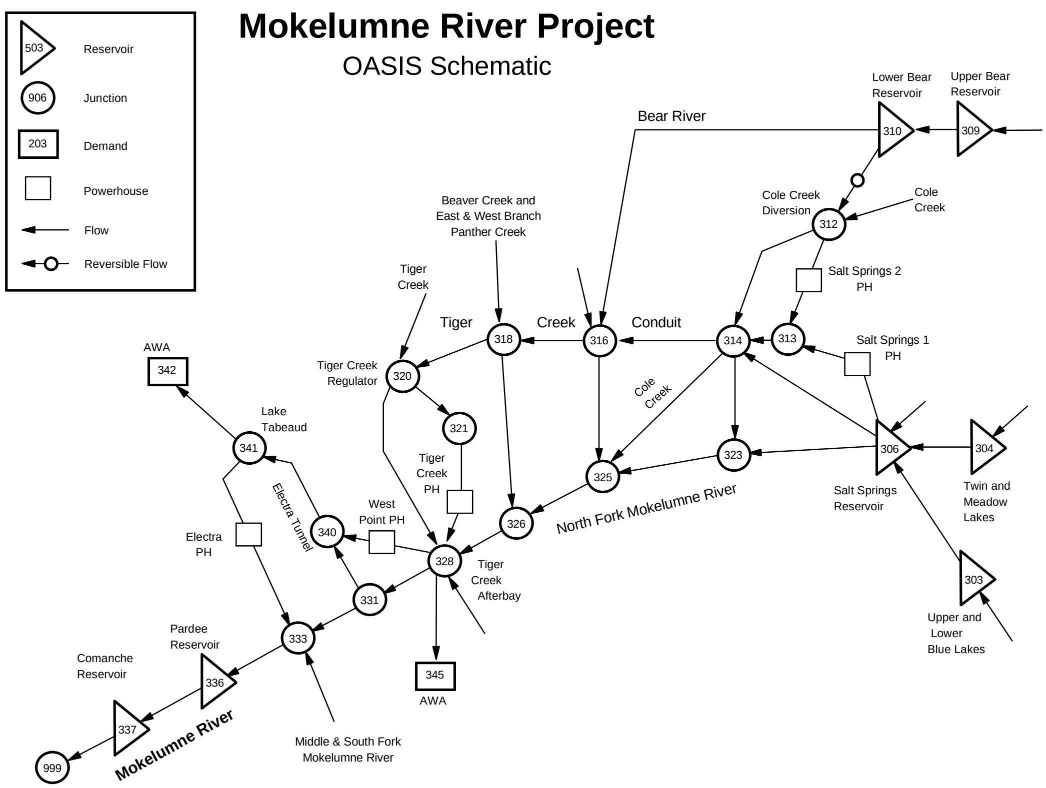
OASIS Schematic



Crane Valley and Kerckhoff Projects

OASIS Schematic

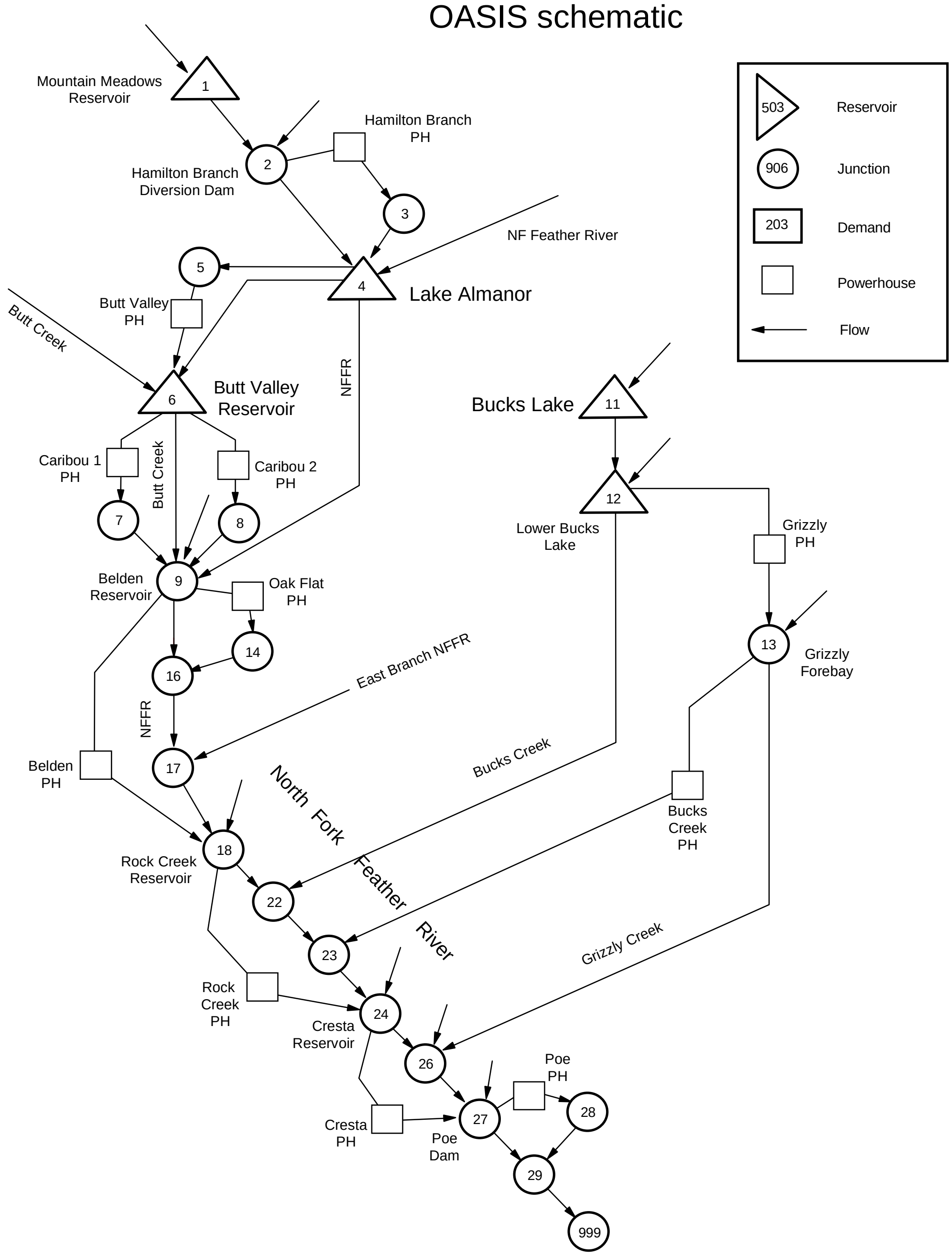


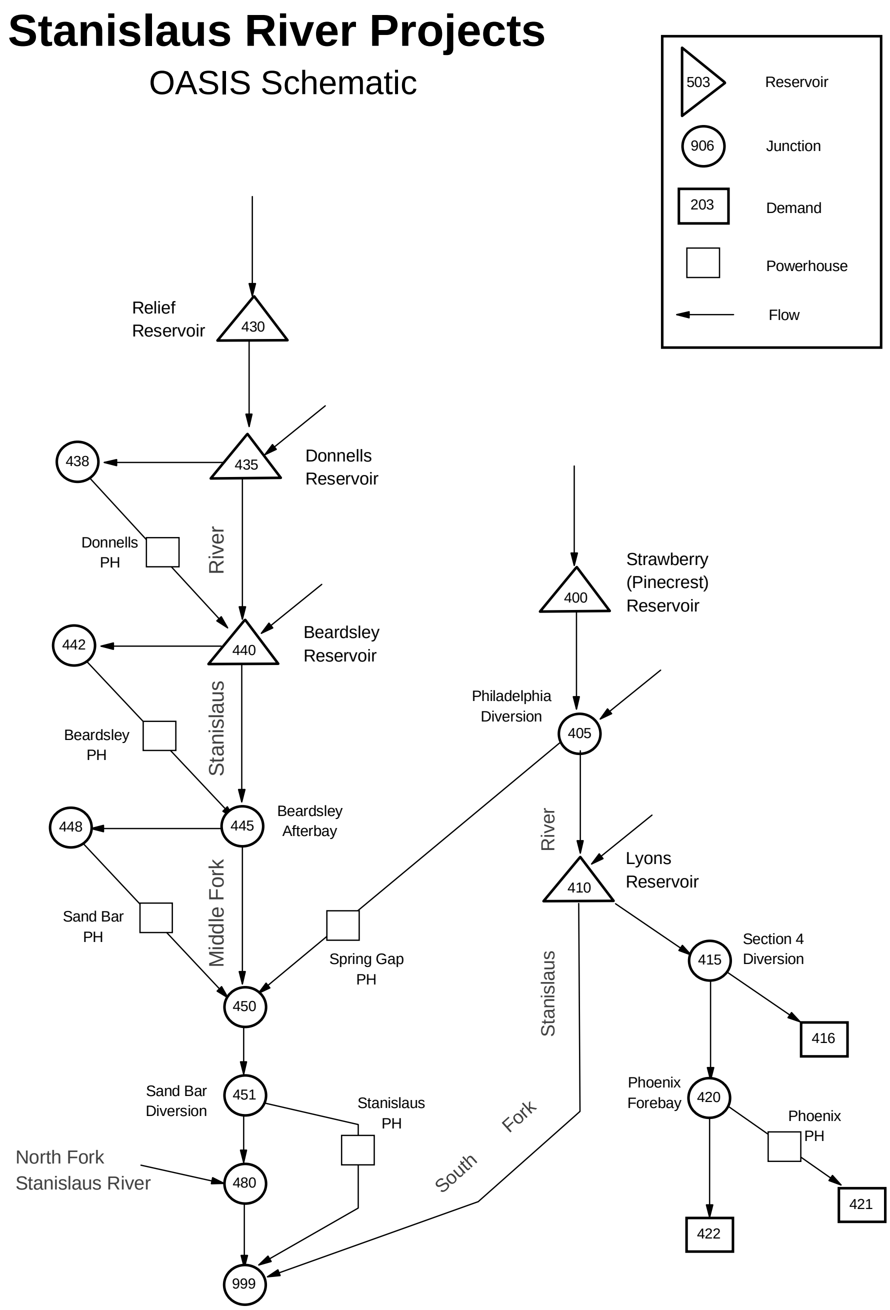


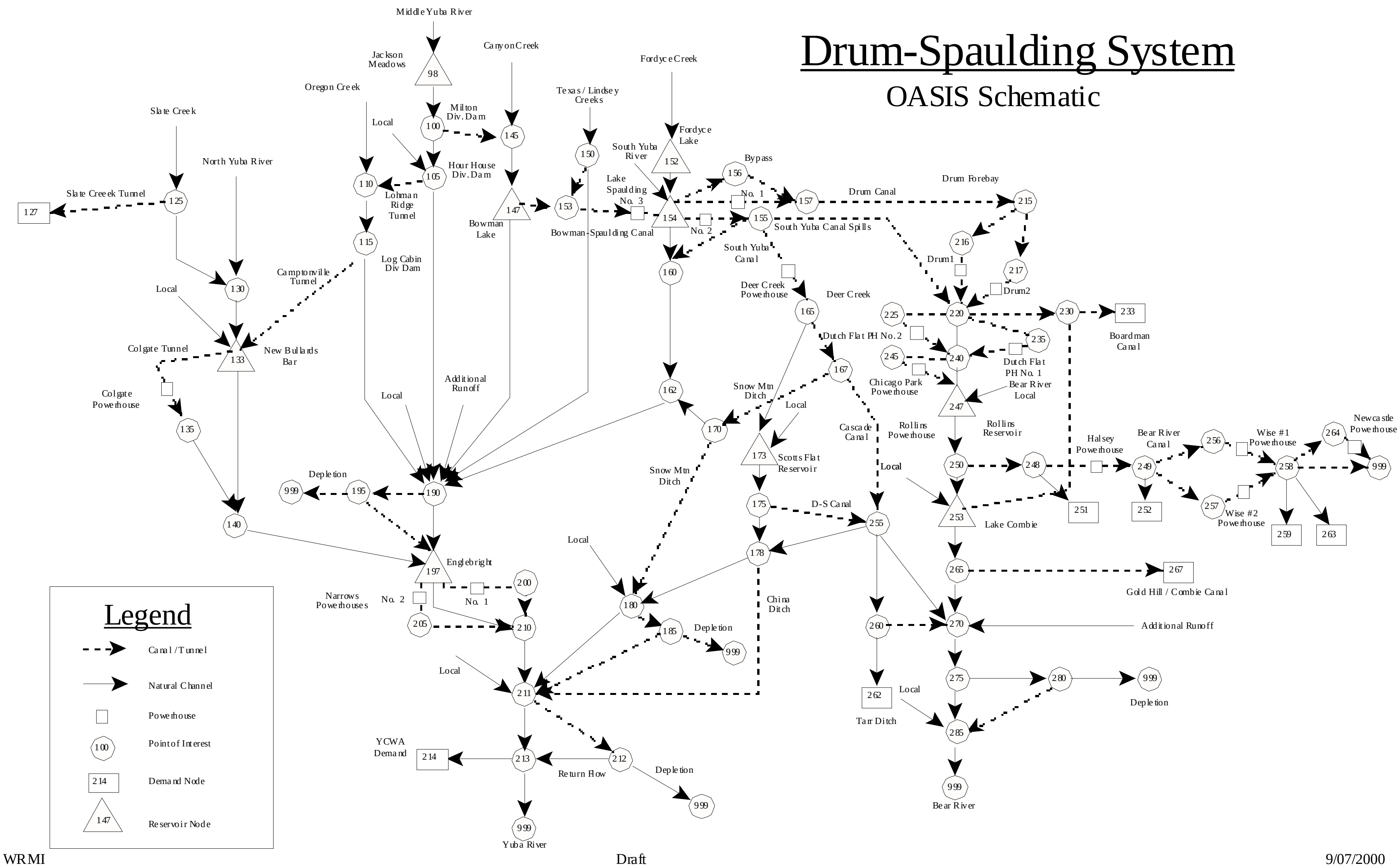
Mokelumne River Project
OASIS Schematic
503 Reservoir
906 Junction
203 Demand
Powerhouse
Flow
Reversible Flow
Lower Bear Reservoir
Upper Bear Reservoir
Bear River
310
309
Cole Creek Diversion
Cole Creek
312
Beaver Creek and East & West Branch Panther Creek
Tiger Creek
Salt Springs 2 PH
Tiger Creek Conduit
318
316
314
313
Salt Springs 1 PH
AWA
342
Tiger Creek Regulator
320
Cole Creek
Lake Tabeaud
321
341
323
306
304
325
Salt Springs Reservoir
Twin and Meadow Lakes
Tiger Creek PH
Electra Tunnel
West Point PH
326
North Fork Mokelumne River
Electra PH
340
328
Tiger Creek Afterbay
303
331
Upper and Lower Blue Lakes
Pardee Reservoir
333
Comanche Reservoir
336
345
AWA
337
Mokelumne River
999
Middle & South Fork Mokelumne River

North Fork Feather River Projects

OASIS schematic




Stanislaus River Projects
OASIS Schematic
503
Reservoir
906
Junction
203
Demand
Powerhouse
Flow
Relief Reservoir
430
435
Donnells Reservoir
438
Donnells PH
440
Beardsley Reservoir
442
Beardsley PH
445
Beardsley Afterbay
448
Sand Bar PH
450
451
Sand Bar Diversion
Stanislaus PH
480
North Fork Stanislaus River
999
Middle Fork Stanislaus River
400
Strawberry (Pinecrest) Reservoir
405
Philadelphia Diversion
Spring Gap PH
410
Lyons Reservoir
South Fork Stanislaus River
415
Section 4 Diversion
416
420
Phoenix Forebay
Phoenix PH
421
422


Drum-Spaulding System
OASIS Schematic
Middle Yuba River
Jackson Meadows
Canyon Creek
Fordyce Creek
Oregon Creek
Texas / Lindsey Creeks
Slate Creek
Milton Div. Dam
Local
Fordyce Lake
South Yuba River
North Yuba River
Hour House Div. Dam
Bypass
Lake Spaulding No. 3
Drum Forebay
Slate Creeek Tunnel
Lohman Ridge Tunnel
No. 1
Drum Canal
Bowman Lake
No. 2
South Yuba Canal Spills
Bowman-Spaulding Canal
South Yuba Canal
Drum1
Log Cabin Div Dam
Camptonville Tunnel
Drum2
Deer Creek Powerhouse
Deer Creek
Boardman Canal
Colgate Tunnel
New Bullards Bar
Dutch Flat PH No. 2
Dutch Flat PH No. 1
Additional Runoff
Chicago Park Powerhouse
Bear River Local
Colgate Powerhouse
Snow Mtn Ditch
Rollins Powerhouse
Rollins Reservoir
Newcastle Powerhouse
Cascade Canal
Halsey Powerhouse
Bear River Canal
Wise #1 Powerhouse
Depletion
Scotts Flat Reservoir
Wise #2 Powerhouse
D-S Canal
Lake Combie
Englebright
Narrows Powerhouses
China Ditch
Gold Hill / Combie Canal
YCWA Demand
Return Flow
Tarr Ditch
Yuba River
Bear River
Legend
Canal / Tunnel
Natural Channel
Powerhouse
Point of Interest
Demand Node
Reservoir Node
WRMI
Draft
9/07/2000

SAN JOAQUIN RIVER SYSTEM (CRANE VALLEY AND KERCHKHOFF))

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Bass Lake	45.41 TAF	PEA p A-1-117	0.6 TAF	ENVDEF_ATT2-1	fill in late spring	historical operation
					Release stored water for US Bureau of Reclamation. Assumed that the storage releases are required every year. Target maximum storage as a percent of Bass Lake capacity: Sep 30 – 60% Oct 31 – 50 % Nov 30 – 50 % Dec 31 – 50 %	Contract: Miller and Lux et al, with San Joaquin Light & Power Company, June 14, 1909.
					Do not release storage below the Miller-Lux-mandated drawdown	historical operation
					Keep reservoir high during July and August for recreational users	historical operation
					Releases to the river only possible when the river spills	FERC license
					Do not draw storage below 5.9 TAF (FERC minimum).	ENVDEF_ATT2-1

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE

Crane Valley	165 CFS	PEA p 13-49	70	SOCRATES	See target on North Fork Willow Creek below Crane Valley PH	
San Joaquin #3	164 CFS	PEA p 13-50	300	SOCRATES		
San Joaquin #2	148 CFS	PEA p A-1-119	228	SOCRATES		
San Joaquin #1A	167 CFS	PEA p 13-50	27	SOCRATES		
Wishon	235 CFS	PEA p 13-50	1040	SOCRATES		
Kerckhoff #1	1735 CFS	PEA p 13-52	267	SOCRATES	From May 15 to June 30 If Millerton < 545 ft 462 CFS from Kerckhoff 2 OR 400 CFS from Kerckhoff 1 If Millerton > 545 ft 846 CFS from Kerckhoff 2 OR 400 CFS from Kerckhoff 1	FERC-issued "Order Establishing Permanent Flow Release Regime." April 22, 1993 Historical Millerton elevation from CDEC Assume that Bass Lake is not operated to maintain this flow.
Kerckhoff #2	5100 CFS	PEA p 13-52	366	SOCRATES	See Kerckhoff #1	

CANALS, PIPES, TUNNELS

	CAPACITY		OPERATING TARGETS	
LOCATION	VALUE	SOURCE	VALUE	SOURCE
San Joaquin #3 Ditch	160 CFS	PEA p 13-50		
San Joaquin #2 Ditch	160 CFS	PEA p 13-50		
San Joaquin #1 Ditch	210 CFS	PEA p 13-50		
North Fork Diversion	150 CFS	SOCRATES		
South Fork Diversion	105 CFS	SOCRATES		

	CAPACITY		OPERATING TARGETS	
LOCATION	VALUE	SOURCE	VALUE	SOURCE
Brown's Ditch	95 CFS	SOCRATES		

STREAMS

	OPERATING TARGETS	
LOCATION	VALUE	SOURCE
South Fork Willow Creek below Brown's Diversion	4 CFS (voluntary release)	PEA p 13-49
North Fork Willow Creek below Crane Valley PH	1 CFS (voluntary release)	PEA p 13-50
San Joaquin River below Kerckhoff Dam	25 CFS in dry years 15 CFS in wet years Dry year is when unimpaired inflow to Millerton is less than 534 TAF	"Fishery Agreement between Pacific Gas and Electric Company and the State of California Relating to FERC Project No. 96, Kerckhoff 2 Project" June 19, 1981 Unimpaired Millerton inflow from California DWR.

Changes for alternative scenarios:

<u>PowerMax</u>

- set the end-of-December storage target lower than the Miller-Lux drawdown: 10 TAF.
- removed the voluntary instream flow targets on Willow Creek.

<u>WaterMax</u>

- *During dry years*, set the end-of-December storage target lower than the Miller-Lux drawdown: 16 TAF during a dry year that follows a wet year, and 7 TAF during a dry year that follows a dry year.
- removed the voluntary instream flow targets on Willow Creek.

PIT RIVER SYSTEM

BASELINE-2000 AND NO PROJECT A-2005 SCENARIOS

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Pit #1	3.212 TAF	ENVDEF_ATT2-1	N/A		Not operated as a Reservoir in OASIS	N/A
Cassel Pond	0.048 TAF	Overview of PG&E Hydro Facilities and Operations	N/A		Not operated as a Reservoir in OASIS	N/A
Baum Lake	0.630 TAF	Overview of PG&E Hydro Facilities and Operations	N/A		Not operated as a Reservoir in OASIS	N/A
Lake Britton	41.9 TAF	ENVDEF_ATT2-1	0.030 TAF	USGS Water-Data Report	**20.5 TAF** Top of tunnel to Pit #3 power plant **UPPER RULE** 41.91TAF 4/1 – 12/31 34.6 TAF 1/1 – 3/31 **LOWER RULE** 32.0 TAF All Year	ENVDEF_ATT2-1 ENVDEF_ATT2-1 Historic Operation
Pit # 4	1.970 TAF	ENVDEF_ATT2-1	N/A		Not operated as a Reservoir in OASIS	N/A
Pit # 5	0.327 TAF	Overview of PG&E Hydro Facilities and Operations	N/A		Not operated as a Reservoir in OASIS	N/A

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Pit #6	15.9 TAF	ENVDEF_ATT2-1	0.280TAF		**4.00 TAF** Top of penstock to Pit #6 power plant **UPPER RULE** 15.5 TAF All year **LOWER RULE** 12.0 TAF All Year	ENVDEF_ATT2-1 Historic Operation
Pit # 7	34.6 TAF	ENVDEF_ATT2-1	0.310 TAF		**11.5 TAF** Top of penstock to Pit #7 power plant **UPPER RULE** 34.0 TAF All Year **LOWER RULE** 30.0 TAF All Year	ENVDEF_ATT2-1 Historic Operation
McCloud	35.2 TAF	Overview of PG&E Hydro Facilities and Operations	0.003 TAF	USGS Water-Data Report	**10.0 TAF** Invert of tunnel to Iron Canyon Reservoir. **Upper Rule:** 32.0 TAF All year **Lower Rule**: 16.6 TAF All Year	HydroCEQA22_ED_Oral_ Mcubed_003 Historic Operation
Iron Canyon	24.4 TAF	ENVDEF_ATT2-1	0.044 TAF	USGS Water-Data Report	**0.56 TAF** Top of tunnel to J. B. Black power plant **Upper Rule**: 13.0 TAF 10/31 11.0 TAF 11/30	ENVDEF_ATT2-1 Historic Operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					9.0 TAF 12/31 9.0 TAF 3/31 15.0 TAF 4/30 20.0 TAF 5/31 20.0 TAF 8/31 15.0 TAF 9/30 **Lower Rule**: 7.0 TAF 10/31 6.0 TAF 11/30 5.0 TAF 12/31 4.0 TAF 5/31 7.0 TAF 6/30 10.0 TAF 7/31 10.0 TAF 8/31 6.5 TAF 9/30	Historic operation

PIT RIVER SYSTEM

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Pit #1	2065 cfs	SOCRATES	360	SOCRATES	200 cfs Minimum release through the Powerhouse to the Pit River below Pit #1	Voluntary action requested by CDF&G et al
Hat Creek # 1	548 cfs	SOCRATES	182	SOCRATES		
Hat Creek #2	690 cfs	SOCRATES	169	SOCRATES		
Pit #3	3315 cfs	SOCRATES	264	SOCRATES		
Pit # 4	4000 cfs	SOCRATES	312	SOCRATES		
Pit # 5	3880 cfs	SOCRATES	496	SOCRATES		
Pit #6	7620 cfs	SOCRATES	132	SOCRATES		
Pit # 7	8350 cfs	SOCRATES	170	SOCRATES	150 cfs Minimum release through the Powerhouse to the Pit River below Pit #7	PEA Vol. 3 p 5-58
J. B. Black	2165 cfs	SOCRATES	1041	SOCRATES		

PIT RIVER SYSTEM

MINIMUM FLOWS

	VALUE	SOURCE
STREAM REACH		
Pit River below Pit #1 Powerhouse Discharge	500 cfs	PES Vol 3 page 5-50
Hat Creek below Cassel Pond	2 cfs	PES Vol 3 page 5-45
Hat Creek Below Baum Lake	8 cfs	PES Vol 3 page 5-56
Pit River Below Lake Britton	150 cfs	PES Vol 3 page 5-53
Pit River Below Pit #4 Dam	150 cfs	PES Vol 3 page 5-54
Pit River Below Pit #5 Dam	120 cfs measured below Nelson Creek	PES Vol 3 page 5-55
Pit River Below Pit #7 Dam	150 cfs	PES Vol 3 page 5-58
McCloud River Below McCloud Dam	50 cfs May through November 40 cfs December through April	PES Vol 3 page 5-57
McCloud River Below at AH-DI-NA, near McCloud	170 – 210 cfs depending on time of year and water year type	PES Vol 3 page 5-57
Iron Creek below Iron Canyon	3 cfs	PES Vol 3 page 5-57

PIT RIVER SYSTEM

POWERMAX SCENARIO

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Pit #1	3.212 TAF	ENVDEF_ATT2-1	N/A		Not operated as a Reservoir in OASIS	N/A
Cassel Pond	0.048 TAF	Overview of PG&E Hydro Facilities and Operations	N/A		Not operated as a Reservoir in OASIS	N/A
Baum Lake	0.630 TAF	Overview of PG&E Hydro Facilities and Operations	N/A		Not operated as a Reservoir in OASIS	N/A
Lake Britton	41.9 TAF	ENVDEF_ATT2-1	0.030 TAF	USGS Water-Data Report	20.5 TAF Top of tunnel to Pit #3 power plant Upper Rule 41.91TAF 4/1 – 12/31 34.6 TAF 1/1 – 3/31 Lower Rule 26.2 TAF All Year	ENVDEF_ATT2-1 ENVDEF_ATT2-1 ENVDEF_ATT2-2
Pit # 4	1.970 TAF	ENVDEF_ATT2-1	N/A		Not operated as a Reservoir in OASIS	N/A
Pit # 5	0.327 TAF	Overview of PG&E Hydro Facilities and Operations	N/A		Not operated as a Reservoir in OASIS	N/A

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Pit #6	15.9 TAF	ENVDEF_ATT2-1	0.280TAF		4.00 TAF Top of penstock to Pit #6 power plant **Upper Rule** 15.89 TAF All year **Lower Rule** 7.5 TAF All Year	ENVDEF_ATT2-1 Full Assumes enough water over the top of penstock inlet to prevent vortex.
Pit # 7	34.6 TAF	ENVDEF_ATT2-1	0.310 TAF		**11.5 TAF** Top of penstock to Pit #7 power plant **Upper Rule** 34.6 TAF All Year **Lower Rule** 18.0 TAF All Year	ENVDEF_ATT2-1 Full Assumes enough water over the top of penstock inlet to prevent vortex.
McCloud	35.2 TAF	Overview of PG&E Hydro Facilities and Operations	0.003 TAF	USGS Water-Data Report	**10.0 TAF** Invert of tunnel to Iron Canyon Reservoir. **Upper Rule:** 28.0 TAF All year **Lower Rule**: 16.6 TAF All Year	HydroCEQA22_ED_Oral_Mcubed_003 Provides space to minimize spills from minor flood events. Assumes enough water over the top of tunnel to prevent vortex.
Iron Canyon	24.4 TAF	ENVDEF_ATT2-1	0.044 TAF	USGS Water-Data Report	**0.56 TAF** Top of tunnel to J. B. Black power plant **Upper Rule**: 23.7 TAF All year	

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					Lower Rule: 4.0 TAF All Year	

PIT RIVER SYSTEM

POWERMAX SCENARIO

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Pit #1	2065 cfs	SOCRATES	360	SOCRATES		
Hat Creek # 1	548 cfs	SOCRATES	182	SOCRATES		
Hat Creek #2	690 cfs	SOCRATES	169	SOCRATES		
Pit #3	3315 cfs	SOCRATES	264	SOCRATES		
Pit # 4	4000 cfs	SOCRATES	312	SOCRATES		
Pit # 5	3880 cfs	SOCRATES	496	SOCRATES		
Pit #6	7620 cfs	SOCRATES	132	SOCRATES		
Pit # 7	8350 cfs	SOCRATES	170	SOCRATES	150 cfs Minimum release through the Powerhouse to the Pit River below Pit #7	PEA Vol. 3 p 5-58
J. B. Black	2165 cfs	SOCRATES	1041	SOCRATES		

PIT RIVER SYSTEM

POWERMAX SCENARIO

MINIMUM FLOWS

	VALUE	SOURCE
STREAM REACH		
Pit River below Pit #1 Powerhouse Discharge		PES Vol 3 page 5-50
Hat Creek below Cassel Pond	2 cfs	PES Vol 3 page 5-45
Hat Creek Below Baum Lake	8 cfs	PES Vol 3 page 5-56
Pit River Below Lake Britton	150 cfs	PES Vol 3 page 5-53
Pit River Below Pit #4 Dam	150 cfs	PES Vol 3 page 5-54
Pit River Below Pit #5 Dam	120 cfs measured below Nelson Creek	PES Vol 3 page 5-55
Pit River Below Pit #7 Dam	150 cfs	PES Vol 3 page 5-58
McCloud River Below McCloud Dam	50 cfs May through November 40 cfs December through April	PES Vol 3 page 5-57
McCloud River Below at AH-DI-NA, near McCloud	170 – 210 cfs depending on time of year and water year type	PES Vol 3 page 5-57
Iron Creek below Iron Canyon	3 cfs	PES Vol 3 page 5-57

PIT RIVER SYSTEM

SETTLEMENT SCENARIO (IDENTICAL TO NO PROJECT A 2005 SCENARIO EXCEPT AS FOLLOWS)

MINIMUM FLOWS

	VALUE	SOURCE
STREAM REACH		
Pit River below Pit #1 Powerhouse Discharge Fall River below Pit 1 Forebay	500 cfs 121 cfs (Bypasses Pit 1 Powerhouse)-nonbinding	A. 99-09-053,Settlement Agreement, Appendix G
Hat Creek below Cassel Pond	13 cfs	
Hat Creek Below Baum Lake	52 cfs	
Pit River Below Lake Britton	200cfs	A. 99-09-053,Settlement Agreement, Appendix G
Pit River Below Pit #4 Dam	200 cfs	A. 99-09-053,Settlement Agreement, Appendix G
Pit River Below Pit #5 Dam	250 cfs measured below Nelson Creek	A. 99-09-053,Settlement Agreement, Appendix G
Pit River Below Pit #7 Dam	150 cfs	
McCloud River Below McCloud Dam	125 cfs All Year	
McCloud River Below at AH-DI-NA, near McCloud	170 – 210 cfs depending on time of year and water year type	
Iron Creek below Iron Canyon	5 cfs	A. 99-09-053,Settlement Agreement, Appendix G

YUBA-BEAR SYSTEM (DRUM-SPAULDING)

BASELINE-2000 AND NO PROJECT A-2005 SCENARIOS

RESERVOIRS

<table>
<tr><th></th><th colspan="2">CAPACITY</th><th colspan="2">DEAD STORAGE</th><th colspan="2">OPERATING TARGETS</th></tr>
<tr><th>RESERVOIR</th><th>VALUE</th><th>SOURCE</th><th>VALUE</th><th>SOURCE</th><th>VALUE</th><th>SOURCE</th></tr>
<tr><td rowspan="2">Jackson Meadows</td><td rowspan="2">69.2 TAF</td><td rowspan="2">SOCRATES</td><td rowspan="2">2.5 TAF</td><td rowspan="2">USGS</td><td>Normal Year Minimums:
21 TAF 6/1 – 9/30
10 TAF 10/1 – 5-31

Dry Year Minimums:
21 TAF 6/1 – 9/30
3 TAF 10/1 – 5/31</td><td>Consolidated Contract between Nevada Irrigation District and Pacific Gas and Electric Company, Dated July 12, 1963</td></tr>
<tr><td>Operating Targets
Norm Yr: Dry Yr:
39 TAF 28 TAF 10/31
32 TAF 25 TAF 11/30
32 TAF 20 TAF 12/31
37 TAF 14 TAF 1/31
40 TAF 14 TAF 2/29
45 TAF 20 TAF 3/31
58 TAF 28 TAF 4/30
65 TAF 40 TAF 5/31
60 TAF 35 TAF 6/30
55 TAF 33 TAF 7/31
53 TAF 30 TAF 8/31
50 TAF 28 TAF 9/30</td><td>Historical operation</td></tr>
<tr><td>Bowman Lake</td><td>68.988 TAF</td><td>United States G.S.</td><td>1 AF</td><td>USGS</td><td>Upper Rule:
68.5 TAF All Year

Lower Rule
6 TAF 10/31
4.5 TAF 11/30
3 TAF 12/31
1 TAF 1/31 – 9/30</td><td>Historical operation</td></tr>
</table>

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					Operating Targets Norm Yr: Dry Yr: 45 TAF 25 TAF 10/31 41 TAF 24 TAF 11/30 35 TAF 23 TAF 12/31 35 TAF 20 TAF 1/31 35 TAF 16 TAF 2/29 35 TAF 20 TAF 3/31 38 TAF 35 TAF 4/30 55 TAF 45 TAF 5/31 65 TAF 40 TAF 6/30 60 TAF 35 TAF 7/31 55 TAF 32 TAF 8/31 50 TAF 30 TAF 9/30	Historical operation
Fordyce Lake	49.903 TAF	SOCRATES	3 AF	USGS	Upper Rule: 7 TAF 10/31 15 TAF 11/30 25 TAF 12/31 25 TAF 1/31 30 TAF 2/29 35 TAF 3/31 40 TAF 4/30 45 TAF 5/31 49.9 TAF 6/30 49.9 TAF 7/31 30 TAF 8/31 15 TAF 9/30 Lower Rule: 5 TAF All Year	Historic operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					Operating Targets Norm Yr: 4 TAF 10/31 8 TAF 11/30 10 TAF 12/31 15 TAF 1/31 19 TAF 2/29 25 TAF 3/31 40 TAF 4/30 49 TAF 5/31 38 TAF 6/30 26 TAF 7/31 15 TAF 8/31 8 TAF 9/30	Historical operation
Lake Spaulding	74.8 TAF	SOCRATES	5 AF	USGS	Upper Rule: 74.8 TAF All Year Lower Rule: 20 TAF 10/31 25 TAF 11/30 25 TAF 12/31 20 TAF 1/31 20 TAF 2/29 20 TAF 3/31 30 TAF 4/30 40 TAF 5/31 50 TAF 6/30 50 TAF 7/31 40 TAF 8/31 30 TAF 9/30	Historical operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					Operating Targets Norm Yr: 20 TAF 10/31 17 TAF 11/30 15 TAF 12/31 30 TAF 1/31 35 TAF 2/29 40 TAF 3/31 50 TAF 4/30 60 TAF 5/31 74.8 TAF 6/30 60 TAF 7/31 50 TAF 8/31 40 TAF 9/30	Historical operation
Scott's Flat	49 TAF	SOCRATES	1 AF	USGS	Upper Rule: 49 TAF All Year Lower Rule: 35 TAF 10/31 38 TAF 11/30 41 TAF 12/31 48 TAF 1/31 48 TAF 2/29 48 TAF 3/31 48 TAF 4/30 48 TAF 5/31 47 TAF 6/30 42 TAF 7/31 37 TAF 8/31 34 TAF 9/30	Historical operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Rollins Reservoir	65.988 TAF	SOCRATES	5 TAF	USGS	Upper Rule: 65.988 TAF All Year Lower Rule: 35 TAF 10/31 37.5 TAF 11/30 45 TAF 12/31 65 TAF 1/31 65 TAF 2/29 65 TAF 3/31 65 TAF 4/30 65 TAF 5/31 65 TAF 6/30 62.5 TAF 7/31 60 TAF 8/31 45 TAF 9/30	Historical operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
New Bullards Bar	961.3 TAF	USGS	233.92 TAF	USGS	Upper Rule (Flood Control): 791.3 TAF 10/31 791.3 TAF 11/30 791.3 TAF 12/31 791.3 TAF 1/31 791.3 TAF 2/29 791.3 TAF 3/31 891.3 TAF 4/30 961.3 TAF 5/31 961.3 TAF 6/30 961.3 TAF 7/31 961.3 TAF 8/31 961.3 TAF 9/15 905.3 TAF 9/30	New Bullards Bar Reservoir North Yuba River, California Reservoir Regulation For Flood Control, June 1972 Department of the Army Sacramento District, Corps of Engineers Sacramento, California
					Lower Rule: 500 TAF 10/31 550 TAF 11/30 560 TAF 12/31 605 TAF 1/31 675 TAF 2/29 695 TAF 3/31 725 TAF 4/30 750 TAF 5/31 730 TAF 6/30 660 TAF 7/31 580 TAF 8/31 560 TAF 9/15 540 TAF 9/30	Historical operation
					Carryover Target 500 TAF 12/31	Historical operation
Englebright	70.0 TAF	SOCRATES	50.0 TAF	SOCRATES	Upper Rule: 70 TAF All Year Lower Rule: 60 TAF All Year	Historical operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Rollins Reservoir	65.988 TAF	SOCRATES	5 TAF	U.S.G.S.	Upper Rule: 65.988 TAF All Year Lower Rule: 35 TAF 10/31 37.5 TAF 11/30 45 TAF 12/31 65 TAF 1/31 65 TAF 2/29 65 TAF 3/31 65 TAF 4/30 65 TAF 5/31 65 TAF 6/30 62.5 TAF 7/31 60 TAF 8/31 45 TAF 9/30	Historical operation
					Maximum release from Rollins is 879 cfs until storage in the reservoir reaches the spillway elevation	PG&E Dispatcher's Operations Manual

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
New Bullards Bar	961.3 TAF	U.S.G.S	233.92 TAF	U.S.G.S.	Upper Rule (Flood Control): 791.3 TAF 10/31 791.3 TAF 11/30 791.3 TAF 12/31 791.3 TAF 1/31 791.3 TAF 2/29 791.3 TAF 3/31 891.3 TAF 4/30 961.3 TAF 5/31 961.3 TAF 6/30 961.3 TAF 7/31 961.3 TAF 8/31 961.3 TAF 9/15 905.3 TAF 9/30 Lower Rule: 500 TAF 10/31 550 TAF 11/30 560 TAF 12/31 605 TAF 1/31 675 TAF 2/29 695 TAF 3/31 725 TAF 4/30 750 TAF 5/31 730 TAF 6/30 660 TAF 7/31 580 TAF 8/31 560 TAF 9/15 540 TAF 9/30	New Bullards Bar Reservoir North Yuba River, California Reservoir Regulation For Flood Control, June 1972 Department of the Army Sacramento District, Corps of Engineers Sacramento, California Historical operation
					Carryover Target 650 TAF 12/31	Historical operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Englebright	70.0 TAF	U.S.A.C.E.	14.5 TAF	PG&E Dispatcher's Operating Manual	Upper Rule: 70 TAF All Year Lower Rule: 60 TAF All Year Storage prevented from going below 27.5 TAF for Marina Operations.	Historical operation
					Maximum release from Englebright is 4285 cfs (Flow through Narrows PH 1 + Narrows PH 2) until storage in the reservoir reaches the spillway elevation	PG&E Dispatcher's Operating Manual

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Spaulding #1	750 CFS	SOCRATES	121	SOCRATES		
Spaulding #2	200 CFS	SOCRATES	254	SOCRATES		
Spaulding #3	310 CFS	SOCRATES	256	SOCRATES		
Deer Creek	110 CFS	SOCRATES	612	SOCRATES		
Drum #1	643 CFS	SOCRATES	1004	SOCRATES		
Drum #2	530 CFS	SOCRATES	1150	SOCRATES		
Dutch Flat #1	490 CFS	SOCRATES	507	SOCRATES		
Dutch Flat #2	600 CFS	SOCRATES	516	SOCRATES		

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Chicago Park	1070 CFS	SOCRATES	384	SOCRATES		
Halsey	495 CFS	SOCRATES	270	SOCRATES		
Wise #1	390 CFS	SOCRATES	390	SOCRATES		
Wise #2	80 CFS	SOCRATES	450	SOCRATES		
Newcastle	392 CFS	SOCRATES	325	SOCRATES		
Narrows #1	800 CFS	PG&E Dispatcher's Operations Manual	192	PG&E Dispatcher's Operations Manual		
Narrows #2	3485 CFS	PG&E Dispatcher's Operations Manual	192	PG&E Dispatcher's Operations Manual		

CANALS, PENSTOCKS, PIPES, ETC

	CAPACITY		OPERATING TARGETS	
CONDUIT	VALUE	SOURCE	VALUE	SOURCE
Milton-Bowman Tunnel	400 CFS	SOCRATES		
Lohman Ridge Tunnel	839 CFS	Historic Records		
Camptonville Tunnel	1090 CFS	Historic Records		
Slate Creek Tunnel	863 CFS	Historic Records	Timeseries Demand	California Department of Water Resources, HEC 3 Model of the Yuba River
Colgate Tunnel	4200 CFS	Historic Records		

	CAPACITY		OPERATING TARGETS	
CONDUIT	VALUE	SOURCE	VALUE	SOURCE
Bowman-Spaulding Canal	300 CFS	SOCRATES		
South Yuba Canal	247 CFS	Historic Records	Pacific Gas and Electric Company to deliver up to the following quantities. Normal Yr Dry Yr 4.4 TAF Jan 3.2 TAF Jan 4.1 TAF Feb 2.8 TAF Feb 4.4 TAF Mar 3.2 TAF Mar 5.4 TAF Apr 2.3 TAF Apr 5.6 TAF May 4.2 TAF May 6.3 TAF Jun 4.4 TAF Jun 6.5 TAF Jul 5.6 TAF Jul 6.5 TAF Aug 5.6 TAF Aug 6.3 TAF Sep 5.2 TAF Sep 6.2 TAF Oct 4.8 TAF Oct 4.7 TAF Nov 3.3 TAF Nov 4.6 TAF Dec 3.4 TAF Dec	Yuba-Bear Consolidated Contract between Nevada Irrigation District and Pacific Gas and Electric Company dated July 12, 1963.
Drum Canal	740 CFS	Placer County Water Agency		
Narrows #1 Penstock	800 CFS	Pacific Gas and Electric Company Dispatcher's Operations Manual		
Narrows #2 Penstock	3485 CFS	Pacific Gas and Electric Company Dispatcher's Operations Manual		
Boardman Canal	40 CFS	Placer County Water Agency		
Bear River Canal	490 CFS	Placer County Water Agency		

CANALS, PENSTOCKS, PIPES, ETC

	CAPACITY		OPERATING TARGETS	
CONDUIT	VALUE	SOURCE	VALUE	SOURCE
Milton-Bowman Tunnel	400 CFS	SOCRATES		
Lohman Ridge Tunnel	839 CFS	Historic Records		
Camptonville Tunnel	1090 CFS	Historic Records		
Slate Creek Tunnel	863 CFS	Historic Records	Timeseries Demand	California Department of Water Resources, HEC 3 Model of the Yuba River
Colgate Tunnel	3510 CFS	PG&E Dispatchers Operations Manual		
Bowman-Spaulding Canal	300 CFS	SOCRATES		
South Yuba Canal	126 CFS	PG&E Dispatcher's Operations Manual	PG&E to deliver up to the following quantities. Normal Yr Dry Yr 4.4 TAF Jan 3.2 TAF Jan 4.1 TAF Feb 2.8 TAF Feb 4.4 TAF Mar 3.2 TAF Mar 5.4 TAF Apr 2.3 TAF Apr 5.6 TAF May 4.2 TAF May 6.3 TAF Jun 4.4 TAF Jun 6.5 TAF Jul 5.6 TAF Jul 6.5 TAF Aug 5.6 TAF Aug 6.3 TAF Sep 5.2 TAF Sep 6.2 TAF Oct 4.8 TAF Oct 4.7 TAF Nov 3.3 TAF Nov 4.6 TAF Dec 3.4 TAF Dec	Yuba-Bear Consolidated Contract between Nevada Irrigation District and Pacific Gas and Electric Company dated July 12, 1963.
Drum Canal	850 CFS	SOCRATES		
Narrows #1 Penstock	800 CFS	PG&E Dispatcher's Operations Manual		
Narrows #2 Penstock	3485 CFS	PG&E Dispatcher's Operations Manual		

	CAPACITY		OPERATING TARGETS	
CONDUIT	VALUE	SOURCE	VALUE	SOURCE
Boardman Canal	40 CFS	Placer County Water Agency		
Bear River Canal	490 CFS	Placer County Water Agency		

STREAMS

	OPERATING TARGETS	
REACH	VALUE	SOURCE
Minimum flow below Jackson Meadows	5 CFS All Year	FERC #2266, Article 32
Minimum flow below Milton Diversion Dam	3 CFS All Year	FERC #2266, Article 32
Minimum flow below Hour House Diversion Dam	2 CFS 1/1 – 3/31 3 CFS 4/1 – 10/31 2 CFS 11/1 – 12/31	FERC #2266, Article 32
Minimum flow below Log Cabin Diversion Dam	Minimum of natural flow or 8 CFS 1/1 – 4/14 12 CFS 4/15 – 6/15 8 CFS 6/16 – 12/31	Yuba River Watershed Model Memorandum Report dated January 1985, Table 5 “Required Fish Flows”, DWR-Division of Planning
Minimum flow below New Bullards Bar	Minimum of 5 CFS or natural inflow	Yuba River Watershed Model Memorandum Report dated January 1985, Table 5 “Required Fish Flows”, DWR-Division of Planning
Minimum flow below Bowman Lake	2 CFS 1/1 – 3/31 3 CFS 4/1 – 9/30 2 CFS 10/1 – 12/31	FERC #2266. Article 32
Diversion from Texas/Lindsey Creeks to Bowman-Spaulding Canal	Minimum of natural flow or 30 CFS from July through November.	Consolidated Contract between Nevada Irrigation District and Pacific Gas and Electric Company, Dated July 12, 1963
Minimum flow below Fordyce Lake	5 CFS All Year	FERC #2310, Article 39
Minimum flow below Spaulding	5 CFS All Year	FERC #2310, Article 39

	OPERATING TARGETS	
REACH	VALUE	SOURCE
Flow from Spaulding to Drum Canal	The minimum amount of water required to leave Spaulding is equal to the Amount of NID water entering Spaulding. This is because NID is not allowed to store water at Lake Spaulding.	Consolidated Contract between Nevada Irrigation District and Pacific Gas and Electric Company, Dated July 12, 1963
Minimum flow from South Yuba Canal to Bear River	5 CFS All Year	Yuba River Watershed Model Memorandum Report dated January 1985, Table 5 "Required Fish Flows", DWR-Division of Planning
Minimum flow on South Yuba River below at Lang's Crossing	5 CFS All Year	FERC #2310, Article 39
Minimum flow below Deer Creek Power House	10 CFS 1/1 – 6/30 3 CFS 7/1 – 9/30 10 CFS 10/1 – 12/31	Yuba River Watershed Model Memorandum Report dated January 1985, Table 5 "Required Fish Flows", DWR-Division of Planning
Minimum flow below Scott's Flat Reservoir	10 CFS 1/1 – 6/30 3 CFS 7/1 – 9/30 10 CFS 10/1 – 12/31	Yuba River Watershed Model Memorandum Report dated January 1985, Table 5 "Required Fish Flows", DWR-Division of Planning
Minimum flow below Narrows Power houses on Yuba River	700 CFS 1/1 – 3/31 1000 CFS 4/1 – 4/30 2000 CFS 5/1 – 5/31 1500 CFS 6/1 – 6/30 450 CFS 7/1 – 9/30 700 CFS 10/1 – 12/31	FERC # 2246, Article 402
Minimum flow on Yuba River below YCWA demand	245 CFS 1/1 – 6/30 70 CFS 7/1 – 9/30 400 CFS 10/1 – 12/31	Yuba River Watershed Model Memorandum Report dated January 1985, Table 5 "Required Fish Flows", DWR-Division of Planning
Minimum flow on Bear River below Drum Afterbay	Dependent upon precipitation at Lake Spaulding. Dry Years: 5 CFS All Year Normal Years: 5 CFS 1/1 – 2/29 10 CFS 3/1 – 9/30 5 CFS 10/1 – 12/31	FERC #2310, Article 39
Minimum flow on Bear River below Dutch Flat Afterbay	5 CFS 1/1 – 4/30 10 CFS 5/1 – 9/30 5 CFS 10/1 – 12/31	FERC #2266, Article 32

	OPERATING TARGETS	
REACH	VALUE	SOURCE
Minimum flow on Bear River below Bear River Canal diversion	Dependent upon precipitation at Lake Spaulding Dry Years: 15 CFS 1/1 – 4/30 40 CFS 5/1 – 10/31 15 CFS 11/1 – 12/31 Normal Years: 20 CFS 1/1 – 4/30 75 CFS 5/1 – 10/31 20 CFS 11/1 – 12/31	FERC #2266, Article 33
Minimum flow on Bear River below the Gold Hill/Combie Canal diversion	8 CFS All Year	
Minimum flow below Camp Far West Reservoir + Camp Far West Irrigation District Demands	10 CFS 1/1 – 3/31 25 CFS 4/1 – 4/30 65 CFS 5/1 – 5/30 75 CFS 6/1 – 6/30 60 CFS 7/1 – 8/30 30 CFS 9/1 – 9/30 10 CFS 10/1 – 12/31	Bear River Watershed Model Memorandum Report dated April 1985, Table 4 “Required Fish Flows”, DWR-Division of Planning

POWERMAX SCENARIO-2005 (ELIMINATE NON-BINDING AGREEMENTS)

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Jackson Meadows	69.2 TAF	SOCRATES	2.5 TAF	U.S.G.S.	Norm Yr: 65 TAF 5/31 40 TAF 12/31 Dry Yr : 40 TAF 5/31 20 TAF 12/31	
Bowman Lake	68.2 TAF	SOCRATES	1 TAF	U.S.G.S.	Norm Yr: 55 TAF 5/31 42 TAF 12/31 Dry Yr : 45 TAF 5/31 23 TAF 12/31	
Fordyce Lake	49.903 TAF	SOCRATES	3 TAF	U.S.G.S.	All Years: 49 TAF 5/31 28 TAF 6/30 6 TAF 12/31	
Lake Spaulding	74.8 TAF	SOCRATES	5 TAF	U.S.G.S.	All Years: 60 TAF 5/31 74.8 TAF 6/30 23 TAF 12/31 The Spaulding No. 2 Power House operating rule was removed. The rule operated Spaulding No. 2 to meet the Nevada Irrigation District requirements at Deer Creek, Boardman Canal requirements at Alta and fish requirements. Without the rule the above requirements are still met, but they do not all need to be met with flows through Spaulding No. 2 Power House.	

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Englebright	70.0 TAF	U.S.A.C.E.	14.5 TAF	PG&E Dispatcher's Operating Manual	Upper Rule: 70 TAF All Year Lower Rule: 60 TAF All Year Storage allowed to go down to dead storage rather than held at 27.5 TAF for the Marina operations.	Historical operation
					Maximum release from Englebright is 4285 cfs (Flow through Narrows PH 1 + Narrows PH 2) until storage in the reservoir reaches the spillway elevation	PG&E Dispatcher's Operating Manual

WATERMAX SCENARIO-2005 (WATER SUPPLY OBJECTIVES)

A fictitious demand node was added to estimate the additional water available in the system that could be delivered. This demand node is located on the Bear River Canal and competes directly with the Newcastle Power House for water supply. Any delivery made would reduce the amount of water available for generation at the Newcastle plant.

MOKELUMNE RIVER SYSTEM

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Blue Lakes	12.4 TAF	SOCRATES	0	SOCRATES	Fill in late spring	Historical operation
Twin/Meadow Lakes	6.9 TAF	SOCRATES	0	SOCRATES	Fill in late spring	Historical operation
					Do not draw below 1.2 TAF	PEA p 11-45
Upper Bear Reservoir	7.3 TAF	SOCRATES	0.5 TAF	SOCRATES	Fill in late spring	Historical operation
Lower Bear Reservoir	52.0 TAF	SOCRATES	2.1 TAF	SOCRATES	Fill in late spring	Historical operation
					Maximum storage is reduced to 42.8 from Nov-Mar due to removal of flashboards.	ENVDEF_ATT2-1
					Do not draw below 3.3 TAF	PEA p 11-45
Salt Springs Reservoir	141.9 TAF	SOCRATES	5.0 TAF	SOCRATES	Fill in late spring	Historical operation
					Maximum storage is reduced to 131.44 from Nov-Mar due to removal of flashboards.	ENVDEF_ATT2-1
Tiger Creek Afterbay	2. 6 TAF	SOCRATES	2.1 TAF	SOCRATES		
All reservoirs combined					During Dry Years, keep storage above these levels: Sep 30 - 30 TAF Oct 31 - 18 TAF Nov 30 - 18 TAF Dec 31 - 15 TAF Jan 31 - 10 TAF	PEA Errata March 29,2000 Attachment 2. Communications with Ed Horciza, Pacific Gas and Electric Company hydrologist (retired)

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					During Normal Years, keep storage above these levels: May 31 - 130 TAF Jun 30 - 112 TAF Jul 31 - 94 TAF Aug 31 - 76 TAF Sep 30 - 58 TAF Oct 31 - 40 TAF Nov 30 - 30 TAF Dec 31 - 20 TAF	
					During Dry Years, release storage above these levels: Jul 31 - 94 TAF Aug 31 - 76 TAF Sep 30 - 58 TAF Oct 31 - 40 TAF Nov 30 - 30 TAF Dec 31 - 20 TAF	

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Salt Springs 1	700 CFS	SOCRATES	181	SOCRATES		
Salt Springs 2	220 CFS	SOCRATES	1755	SOCRATES		
Tiger Creek	625 CFS	PEA p 11-45	968	SOCRATES		
West Point	675 CFS	PEA p 11-45	250	SOCRATES		

Electra	1130 CFS	PEA p 11-45	1020	SOCRATES	See targets on North Fork Mokelumne River below Electra Diversion	

CANALS, PIPES, TUNNELS

	CAPACITY		OPERATING TARGETS	
LOCATION	VALUE	SOURCE	VALUE	SOURCE
Bear River Tunnel	800 CFS	PEA p 11-41		
Tiger Creek Conduit	550 CFS	PEA p 11-43	*Nov-Mar* 120 CFS	Dispatcher's Operations Manual
Tiger Creek Conduit -- Diversion from Cole Creek	200 CFS	Dispatcher's Operations Manual		
Tiger Creek Conduit -- Diversion from Bear Creek	550 CFS	Dispatcher's Operations Manual		
Tiger Creek Conduit -- Diversion from Panther Creek	70 CFS	Dispatcher's Operations Manual		
Electra Diversion	800 CFS	SOCRATES		
Electra Tunnel	875 CFS	SOCRATES		
AWA diversion from Lake Tabeaud			12.5 TAF per year	Communication with AWA
AWA diversion from Tiger Creek Afterbay			1.0 TAF per year	Communication with AWA

STREAMS

	OPERATING TARGETS			
LOCATION	VALUE			SOURCE
Below Lower Blue Lake		*Dry Year*	*Normal Year*	PEA p 11-43
	Nov-Apr	2 CFS or natural flow	2 CFS or natural flow	
	May-Oct	7.5 CFS	15 CFS	
	Maximum 70 CFS (to minimize erosion)			Dispatcher's Operations Manual
Below Meadow Lake	*Nov-Apr*	2 CFS		PEA p 11-43
	May-Oct	5 CFS		
	Jun-Aug	50 CFS Maximum		Dispatcher's Operations Manual
Bear River below Lower Bear Reservoir		*Dry Year*	*Normal Year*	PEA p 11-43
	Nov-Apr	2 CFS	2 CFS	
	May-Oct	2 CFS	4 CFS	
Cole Creek below Cole Creek Diversion	2 CFS or natural flow			PEA p 11-43
Cole Creek below Tiger Creek Conduit	2 CFS or natural flow			PEA p 11-43
North Fork Mokelumne River below Salt Springs Tailrace		*Dry Year*	*Normal Year*	PEA p 11-43
	Nov-Apr	20 CFS	20 CFS	
	May-Oct	20 CFS	30 CFS	
Bear River below Tiger Creek Conduit	4 CFS			PEA p 11-44
Beaver Creek and East and West Branch Panther Creeks (combined) below Tiger Creek Conduit		*Dry Year*	*Normal Year*	PEA p 11-44 (note: natural flow not considered here because PG&E did not provide records of natural flow in these streams)
	Nov-Apr	3.5 CFS	3.5 CFS	
	May-Oct	3.5 CFS	5 CFS	
Tiger Creek below Tiger Creek Regulator		*Dry Year*	*Normal Year*	PEA p 11-44
	Nov-Apr	5 CFS	5 CFS	
	May-Oct	5 CFS	10 CFS	
North Fork Mokelumne River below Bear River		*Dry Year*	*Normal Year*	PEA p 11-44
	Nov-Apr	20 CFS	20 CFS	
	May-Oct	20 CFS	40 CFS	
North Fork Mokelumne River below Tiger Creek Afterbay		*Dry Year*	*Normal Year*	Pacific Gas and Electric Company and State of California, Agreement relating to FERC project no. 137 – (Mokelumne River Project), April 19, 1978
	Nov-Apr	10 CFS	10 CFS	
	May-Oct	10 CFS	18 CFS	
North Fork Mokelumne River below Electra Diversion		*Dry Year*	*Normal Year*	PEA p 11-45
	Nov-Apr	10 CFS	10 CFS	
	May-Oct	10 CFS	15 CFS	

	OPERATING TARGETS	
LOCATION	VALUE	SOURCE
	(combined flow of stream and Electra Powerhouse) *Dry Year* / *Normal Year* *Jan* 200 CFS 300 CFS *Feb* 200 CFS 200 CFS *Mar* 200 CFS 200 CFS *Apr* 200 CFS 200 CFS *May* 300 CFS 300 CFS *Jun* 300 CFS 300 CFS *Jul* 300 CFS 500 CFS *Aug* 300 CFS 500 CFS *Sep* 300 CFS 500 CFS *Oct* 200 CFS 500 CFS *Nov* 200 CFS 500 CFS *Dec* 200 CFS 500 CFS	PEA Errata March 29,2000 Attachment 2. Communications with Ed Horciza PG&E hydrologist, retired.

Changes for alternative scenarios:

PowerMax

! Decreased storage-carryover targets on Lower Bear Reservoir and Salt Springs Reservoir. The carryover targets are of lower priority than the storage releases mandated by the Lodi Decree, so the change is only effective during normal years.

WaterMax

! Increased the storage-carryover targets on Lower Bear Reservoir and Salt Springs Reservoir. The carryover targets are of lower priority than the storage releases mandated by the Lodi Decree, so the change is only effective during normal years.

NORTH FORK FEATHER RIVER SYSTEM

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Mountain Meadows Reservoir	24.0 TAF	SOCRATES	0	Historical operation	Fill in late spring	Historical operation
					Draw down to 10 TAF at end of July	Historical operation
					Maximum storage is decreased to 5.0 TAF from Nov-Jan due to removal of flashboards. Flashboards are slowly raised in Feb and Mar.	Dispatcher's Operations Manual
Lake Almanor	1143.0 TAF	ENVDEF_ATT2-1	8.9 TAF	ENVDEF_ATT2-1	Fill in late spring	Historical operation
					Do not draw below 500 TAF	PEA p 7-54
					Do not draw below 800 TAF until September	PG&E has identified this as an informal commitment.
Butt Valley Reservoir	49.9 TAF	SOCRATES	8.0 TAF	Historical operation	Keep reservoir high at all times for powerhouse intakes.	Historical operation Dispatcher's Operations Manual
					Fill in late spring	Historical operation
Bucks Lake	105.6 TAF	SOCRATES	4.2 TAF	Historical operation	Fill in late spring	Historical operation
					Dry Year: do not draw below 4.7 TAF *Normal Year*: do not draw below 21.2 TAF	FERC license No. 619
					Do not draw below the elevation on June 1 minus 15 feet.	FERC license No. 619
					Keep reservoir storage below 75 TAF Nov-Mar	Historical operation Dispatcher's Operations Manual

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
					Maximum storage is decreased to 101.9 TAF from Nov-Mar due to removal of flashboards.	Dispatcher's Operations Manual
Lower Bucks Lake	5.8 TAF	SOCRATES	0	Historical operation		
All reservoirs combined					Ensure that the total release of stored water is at least 145 TAF from the summer peak to the end of October.	State of California Department of Water Resources, Agreement on Diversion of Water from the Feather River. January 17, 1986. Historical operation.

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Hamilton Branch	200 CFS	SOCRATES	288	SOCRATES		
Butt Valley	2140 CFS	SOCRATES	243	SOCRATES		
Caribou 1	1110 CFS	SOCRATES	859	SOCRATES		
Caribou 2	1515 CFS	SOCRATES	972	SOCRATES	No generation when Butt Valley Reservoir contains less than 30 TAF	Dispatcher's Operations Manual
Oak Flat	150 CFS	SOCRATES	112	SOCRATES	*Sep-Apr* 60 CFS *May-Aug* 140 CFS	PEA p 7-55
Beldon	2350 CFS	SOCRATES	613	SOCRATES		
Rock Creek	3300 CFS	SOCRATES	448	SOCRATES		

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Cresta	3800 CFS	SOCRATES	230	SOCRATES		
Poe	3900 CFS	SOCRATES	384	SOCRATES		
Grizzly	395 CFS	SOCRATES	638	SOCRATES		
Bucks Creek	384 CFS	PEA p A-1-54	2050	SOCRATES		

CANALS, PIPES, TUNNELS

	CAPACITY		OPERATING TARGETS	
LOCATION	VALUE	SOURCE	VALUE	SOURCE
Prattville Tunnel	0 CFS	SOCRATES and review of historical data	Flows through the tunnel cannot bypass the powerhouse.	Dispatcher’s Operations Manual

STREAMS

	OPERATING TARGETS	
LOCATION	VALUE	SOURCE
Hamilton Branch Feather River below Mountain Meadows Reservoir.	2 CFS	PEA p 7-73
Hamilton Branch Feather River below Hamilton Branch Diversion Dam	4 CFS	PEA p 7-73
North Fork Feather River below Lake Almanor Dam	35 CFS	PEA p 7-54
Bucks Creek below Lower Bucks Lake Dam	*Apr-Nov* 3 CFS *Dec-Mar* 1 CFS	PEA p 7-59
Grizzly Creek below Grizzly Forebay	*Apr-Nov* 4 CFS *Dec-Mar* 2 CFS	PEA p 7-59
North Fork Feather River below Oak Flat Powerhouse	See target on Oak Flat Powerhouse	
North Fork Feather River below Rock Creek Dam	*May-Oct* 100 CFS *Nov-Apr* 50 CFS	PEA p 7-62
North Fork Feather River below Cresta Reservoir	50 CFS	PEA p 7-62
North Fork Feather River below Poe Dam	25 CFS	PEA p 7-65
North Fork Feather River at Big Bar USGS Gage upstream of Poe Powerhouse	50 CFS	PEA p 7-65 FERC License No. 2107, Article 26

Changes for alternative scenarios:

<u>PowerMax</u>

! lowered the end-of-year targets at Almanor and Bucks Lake.

! removed the requirement that Almanor remain above 800 TAF until September.

<u>WaterMax</u>

! increased the end-of-year targets at Almanor, Bucks Lake, and Butt Valley Reservoirs.

! created a conceptual demand downstream of the system. This target delivery was 900 TAF during dry years and nothing during normal years. This demand outranks the storage-carryover targets.

EEL RIVER SYSTEM (POTTER VALLEY)

BASELINE-2000 AND NO PROJECT A-2005 SCENARIOS

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Lake Pillsbury	80.599 TAF	SOCRATES	10.0 TAF	SOCRATES	November 1 – April 1 raise radial gates. This reduces storage capacity to 59.469 TAF	Safety of Dams
					Maximum release to the river is 400 cfs until storage reaches spillway. Rating curves were used to vary the allowable release based on reservoir storage level	PG&E Rating Curve for Pillsbury Needle Valve dated 1/29/81.
					18 TAF 1/31 35 TAF 2/29 45 TAF 3/31 65 TAF 4/30 80.6 TAF 5/31 75 TAF 6/30 65 TAF 7/31 55 TAF 8/31 50 TAF 9/30 40 TAF 10/31 31 TAF 11/30 27 TAF 12/31	historical operation

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Potter Valley	325 CFS	PEA p A-1-72	350	SOCRATES		

CANALS, PENSTOCKS, PIPES, ETC

	CAPACITY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE	SOURCE
Potter Valley	331 CFS	PEA p A-1-73		

STREAMS

	OPERATING TARGETS	
Reach	VALUE	SOURCE
Eel River below Scott Dam	See Appendix A 100cfs Dec-May, Norm 60 cfs June-Nov, Norm 40 cfs year-round, Dry 20 cfs year-round, Crit.	FERC License #77, Article 38 PEA, C-6-21
Eel River below Cape Horn Dam	See Appendix A Complex flow schedule: 5 – 100 cfs Normal years 5 – 75 cfs Dry years 5 cfs year-round Critical years	FERC License #77, Article 38 PEA, C-6-23
East Branch Russian River below Potter Valley Power House	See Appendix A 20 to 75 cfs (See Schedule)	FERC License #77, Article 38 PEA, C-6-22

POWERMAX SCENARIO-2005 (ELIMINATE NON-BINDING AGREEMENTS)

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE

Lake Pillsbury	80.599 TAF	SOCRATES	10.0 TAF	SOCRATES	November 1 – April 1 raise radial gates. This reduces storage capacity to 59.469 TAF	Safety of Dams
					70 TAF 5/30 All Years 40 TAF 12/31 Normal Yrs 32 TAF 12/31 Dry Yrs 25 TAF 12/31 Crit Yrs	To Optimize Power Revenues.

STANISLAUS RIVER SYSTEM

RESERVOIRS

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
Relief Reservoir	15.55 TAF	USGS Water Resources Data for California, Water Year 1994	0	USGS Water Resources Data for California, Water Year 1994	Fill in late spring	Historical operation
Donnells Reservoir	64.7 TAF	USGS Water Resources Data for California, Water Year 1994	2.1 TAF	USGS Water Resources Data for California, Water Year 1994	Fill in late spring	Historical operation
					Maintain the following storage rather than meet the higher Sand Bar target flow. *Jan* 35.6 TAF *Feb* 32.7 TAF *Mar* 29.2 TAF *Apr* 36.3 TAF *May* 51.3 TAF *Jun* 64.5 TAF *Jul* 64.5 TAF *Aug* 60.1 TAF *Sep* 56.3 TAF *Oct* 52.8 TAF *Nov* 47.6 TAF *Dec* 41.3 TAF	Tri-Dam Project Contract dated July 9, 1952 with revisions and notes to July 9, 1958
Beardsley Reservoir	98.5 TAF	USGS Water Resources Data for	0	USGS Water Resources Data for	Fill in late spring	Historical operation

	CAPACITY		DEAD STORAGE		OPERATING TARGETS	
RESERVOIR	VALUE	SOURCE	VALUE	SOURCE	VALUE	SOURCE
		California, Water Year 1994		California, Water Year 1994	Maintain the following storage rather than meet the higher Sand Bar target flow. *Jan* 77.9 TAF *Feb* 73.7 TAF *Mar* 68.4 TAF *Apr* 80.5 TAF *May* 106.9 TAF *Jun* 111.6 TAF *Jul* 109.7 TAF *Aug* 106.0 TAF *Sep* 104.1 TAF *Oct* 100.4 TAF *Nov* 93.8 TAF *Dec* 85.6 TAF	Tri-Dam Project Contract dated July 9, 1952 with revisions and notes to July 9, 1958
Strawberry Reservoir	18.3 TAF	SOCRATES	0	SOCRATES	Fill in late spring	Historical operation
Lyons Reservoir	6.2 TAF	SOCRATES	1	SOCRATES	Fill in late spring	Historical operation

POWERHOUSES

	CAPACITY		WATER DUTY		OPERATING TARGETS	
POWERHOUSE	VALUE	SOURCE	VALUE (MWh/TAF)	SOURCE	VALUE	SOURCE
Donnells	760 CFS	SOCRATES	1260	SOCRATES		
Beardsley	660 CFS	SOCRATES	196	SOCRATES	No generation when Beardsley Reservoir contains less than 21.6 TAF	Dispatcher's Operations Manual
Sand Bar	650 CFS	SOCRATES	300	SOCRATES		
Spring Gap	59 CFS	PEA p 11-52	1428	SOCRATES		
Stanislaus	525 CFS	SOCRATES	1282	SOCRATES		
Phoenix	25 CFS	PEA p 11-52	900	SOCRATES		

CANALS, PIPES, TUNNELS

	CAPACITY		OPERATING TARGETS	
LOCATION	VALUE	SOURCE	VALUE	SOURCE
Tuolomne Ditch	52 CFS	PEA p A-1-108		
Section 4 Ditch				
Columbia Ditch				

STREAMS

	OPERATING TARGETS	
LOCATION	VALUE	SOURCE
South Fork Stanislaus River below Philadelphia Diversion	*Nov-Apr* 3 CFS *May-Oct* 6 CFS	PEA p 11-49 FERC License 2130, Article 28
South Fork Stanislaus River below Lyons Reservoir	2 CFS	PEA p 11-50 FERC License 1061, Article 404
Middle Fork Stanislaus River below Relief Reservoir	*Dry Year* / *Normal Year* *Nov-Apr* 5 CFS / 5 CFS *May-Oct* 5 CFS / 10 CFS	PEA p 11-50 FERC License 2130, Article 25
	Keep flow below 150 CFS Jul-Sep to protect a horse crossing	Dispatcher's Operations Manual
Middle Fork Stanislaus River below Donnells Reservoir	*Dry Year* / *Normal Year* *Nov-Apr* 5 CFS / 5 CFS *May-Oct* 5 CFS / 10 CFS	Tri-Dam Project Contract dated July 9, 1952 with revisions and notes to July 9, 1958
Middle Fork Stanislaus River below Beardsley Afterbay	*Dry Year* / *Normal Year* *Nov-Apr* 25 CFS / 25 CFS *May-Oct* 25 CFS / 50 CFS	Tri-Dam Project Contract dated July 9, 1952 with revisions and notes to July 9, 1958
Middle Fork Stanislaus River above Sand Bar Diversion	314.3 TAF/year if storage in Donnells and Beardsley is above the critical level, 106.1 TAF/year if storage in Donnells and Beardsley is below the critical level.	Tri-Dam Project Contract dated July 9, 1952 with revisions and notes to July 9, 1958
Middle Fork Stanislaus River below Sand Bar Diversion	*Nov-Apr* 25 CFS *May-Oct* 50 CFS	PEA p 11-50 FERC License 2130, Article 27, Order 9/14/97

Changes for alternative scenarios:

PowerMax

! Lowered the storage target on Strawberry Reservoir which keeps the reservoir high for recreational interests. This allows more freedom to generate power when it is most profitable.

WaterMax

! Lowered the storage target on Strawberry Reservoir which keeps the reservoir high for recreational interests. The end-of-the-year carryover targets were higher than the base.

! Increased delivery targets from the Tuolomne Ditch. We did not assume any increased deliveries from New Melones Reservoir or below.

EXHIBIT C.3 RESERVIOR STORAGE LEVELS

Figure C.3-1 Total Pit-McCloud System Storage Average End of Month Level

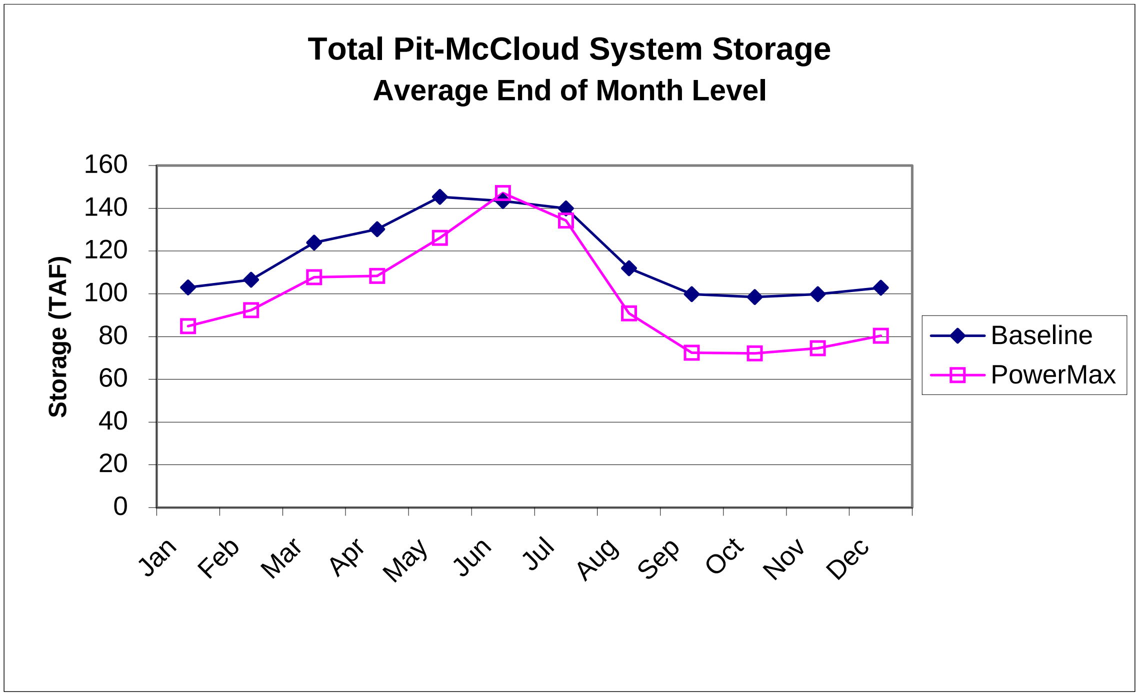


Figure C.3-2 Total Pit-McCloud System Storage End of May

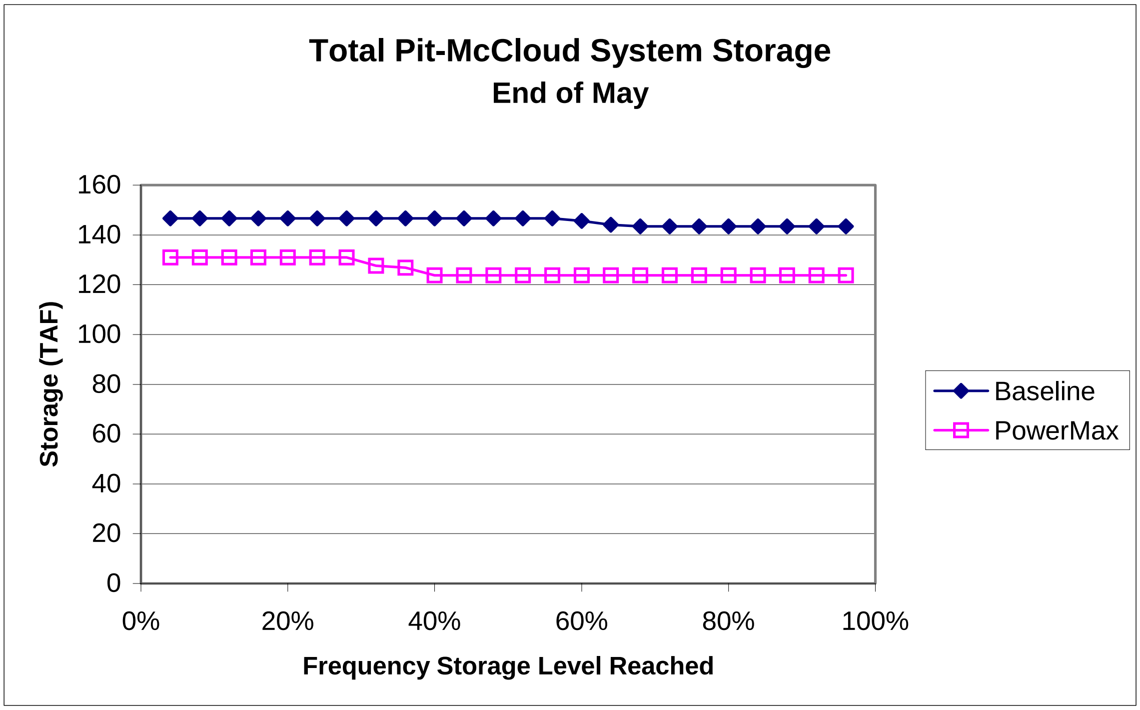


Figure C.3-3 Total Pit-McCloud System Storage End of August

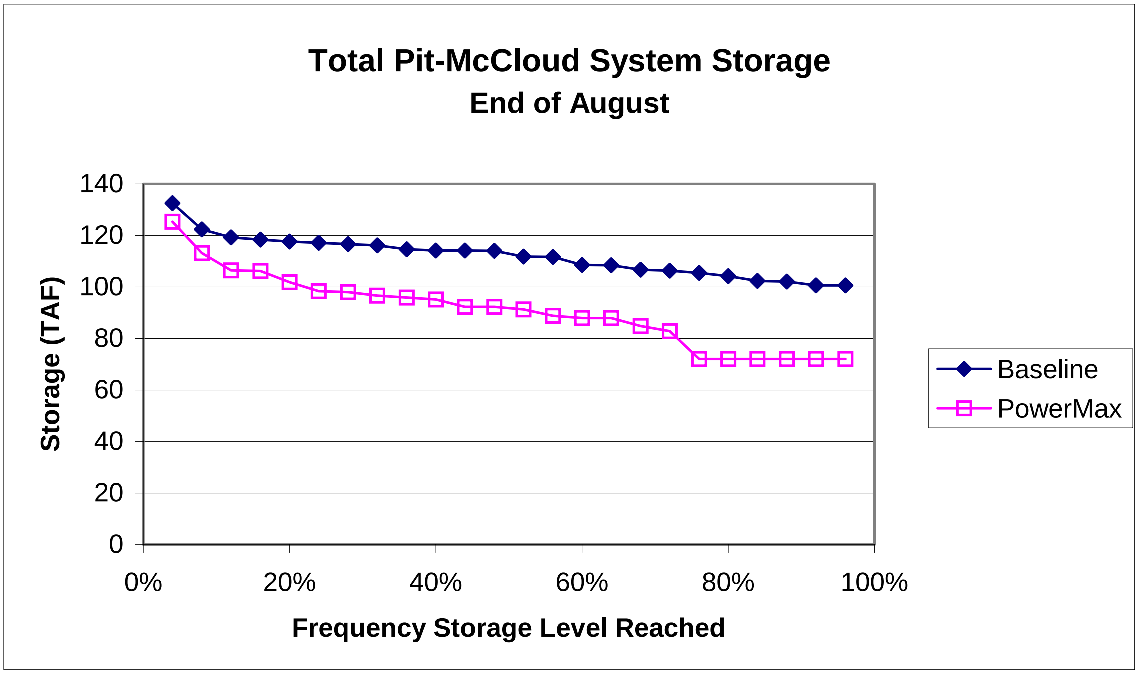


Figure C.3-4 Total Pit-McCloud System Storage End of December

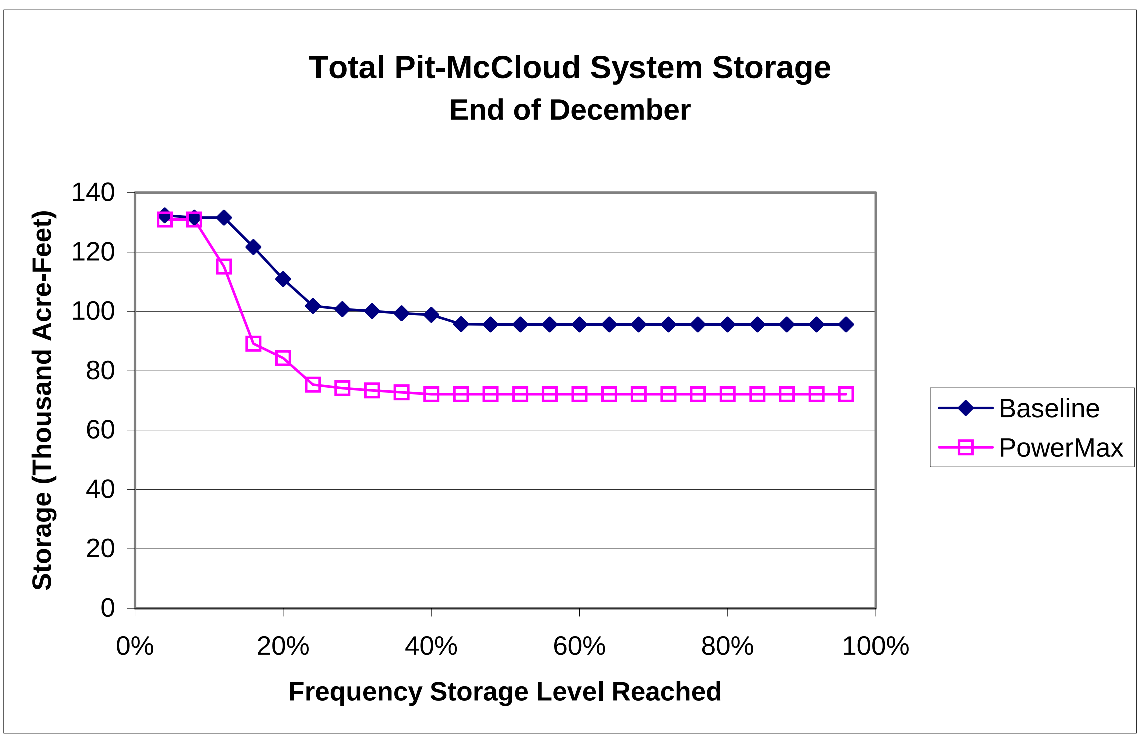


Figure C.3-5 Total NF Feather River Average End of Month Level

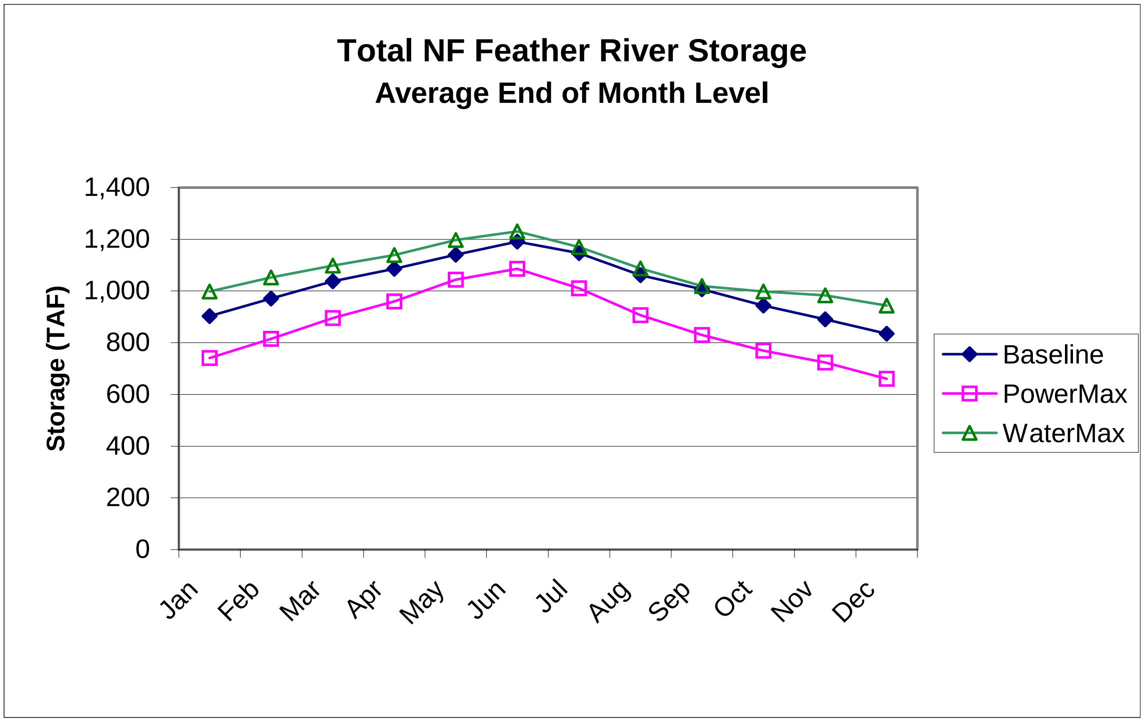


Figure C.3-6 PG&E Drum-Spaulding Storage Average End of Month Level

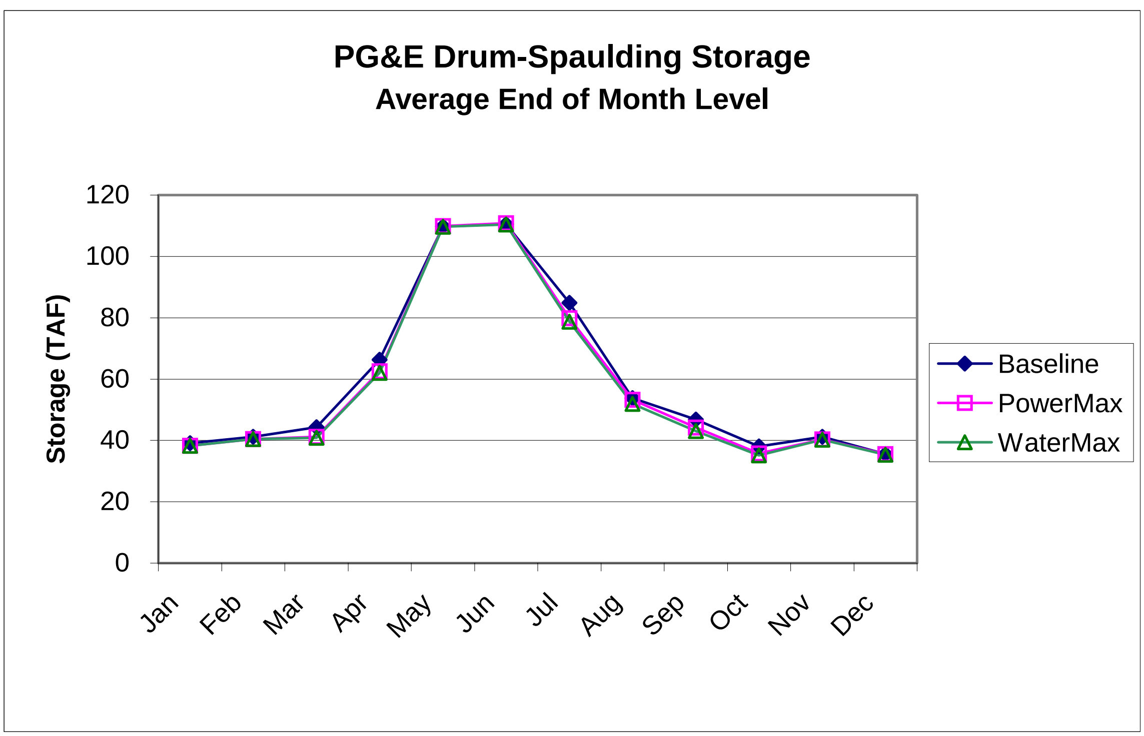


Figure C.3-7 PG&E Drum-Spaulding Storage End of May

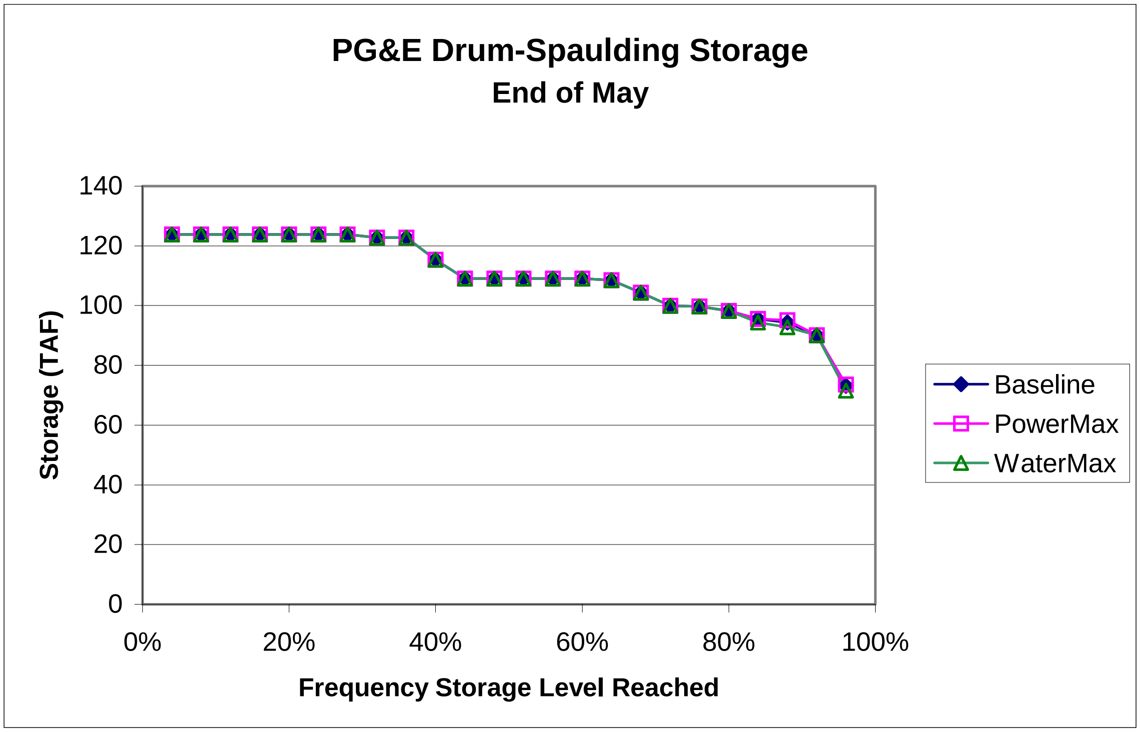


Figure C.3-8 PG&E Drum-Spaulding Storage Average End of August

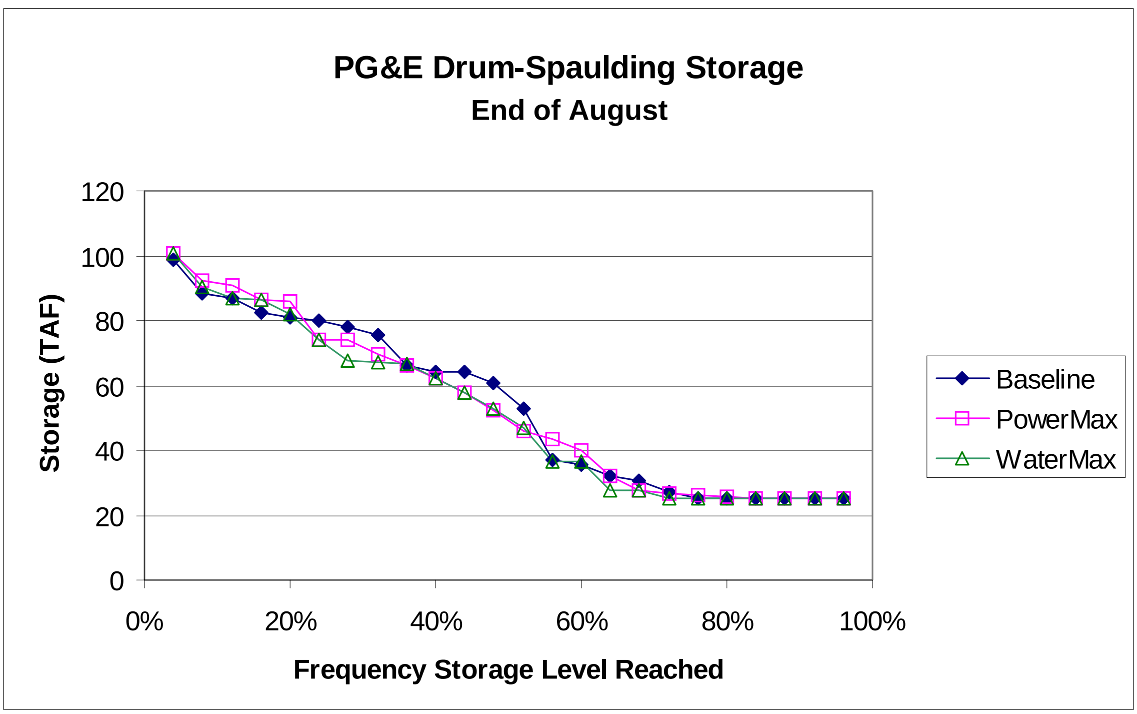


Figure C.3-9 PG&E Drum-Spaulding Storage Average End of December

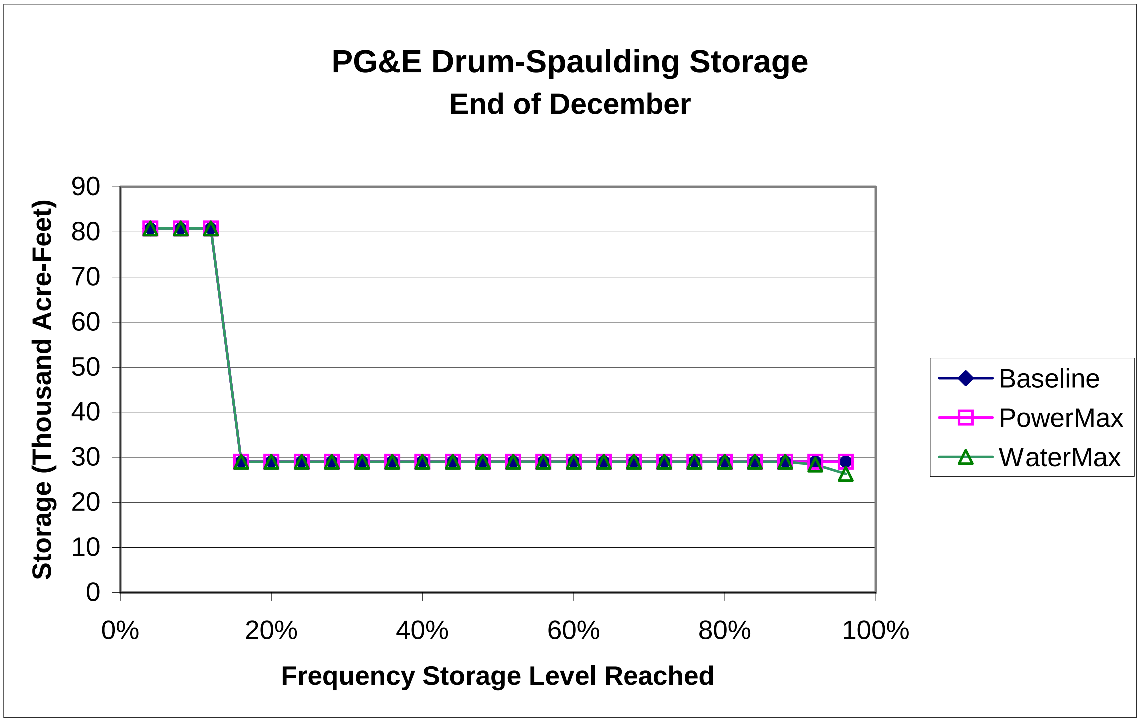


Figure C.3-10 Total Mokelumne River Storage Average End of Month Level

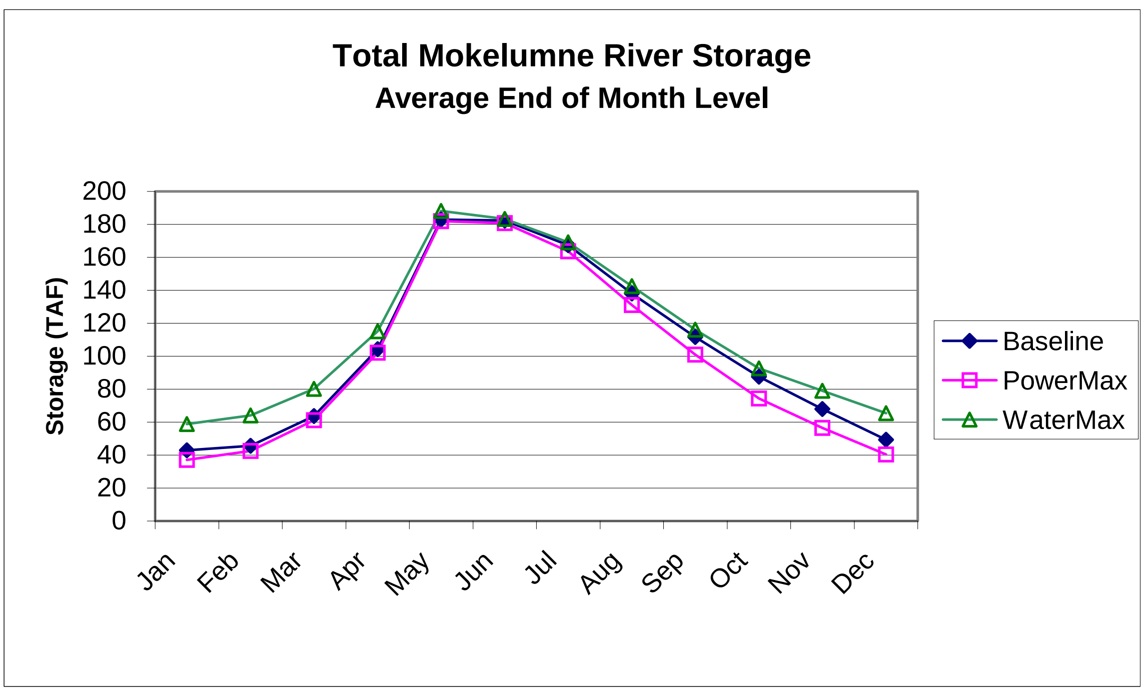


Figure C.3-11 Total Mokelumne River Storage End of May

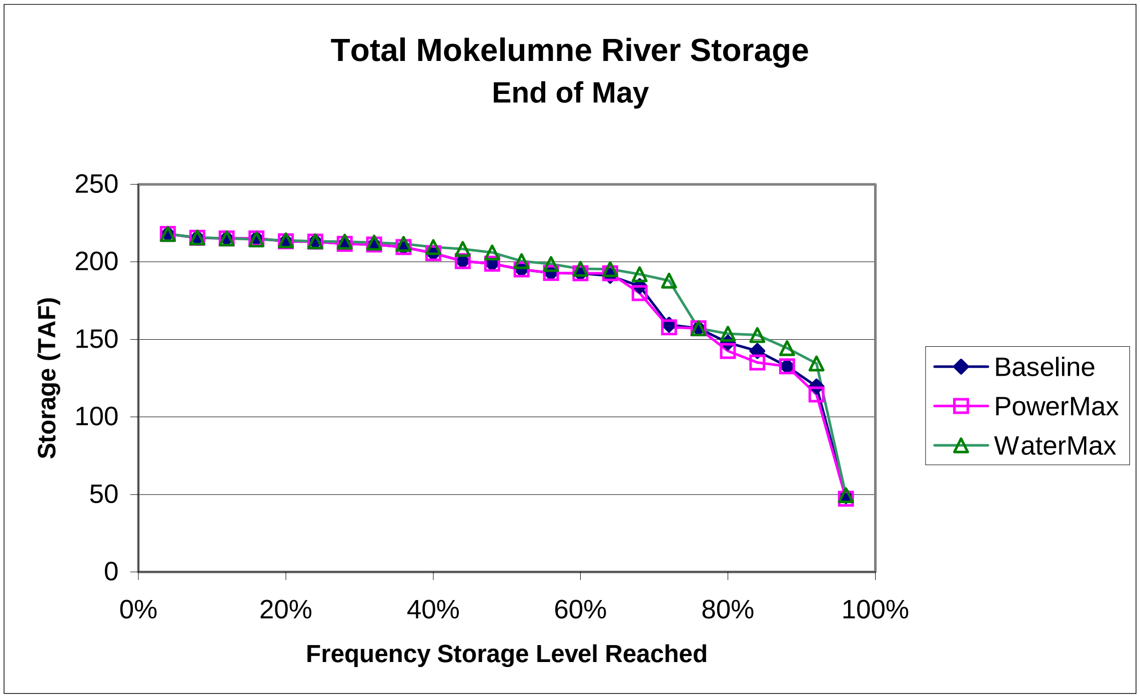


Figure C.3-12 Total Mokelumne River Storage End of August

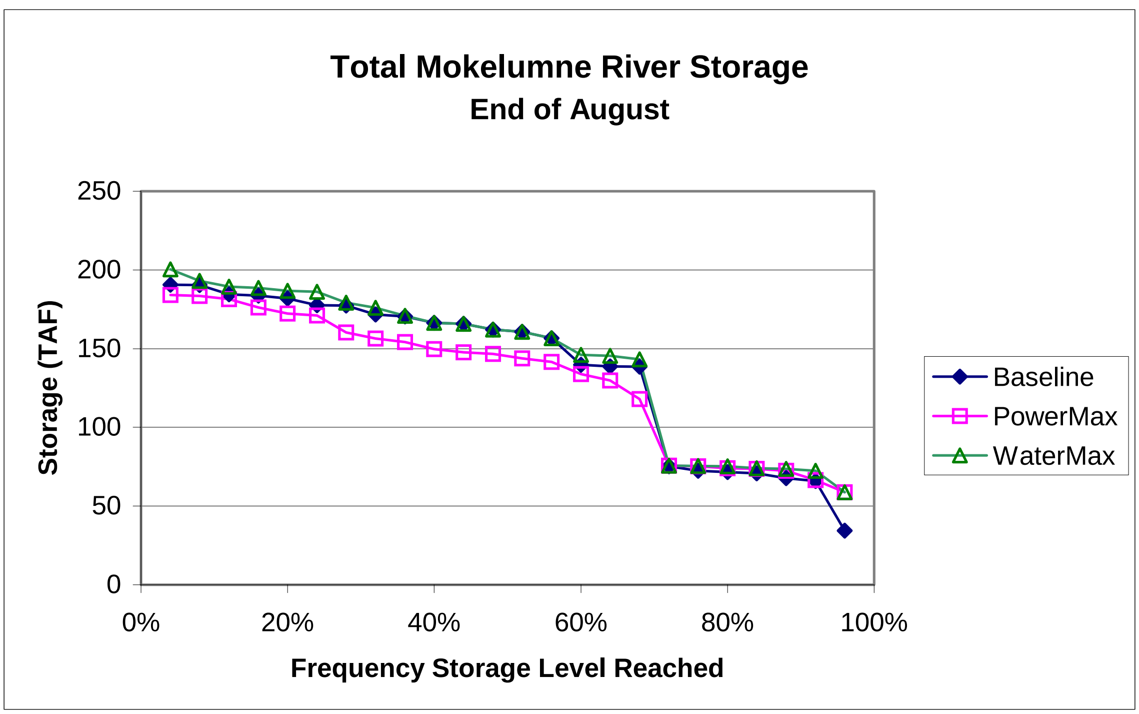


Figure C.3-13 Total Mokelumne River Storage End of December

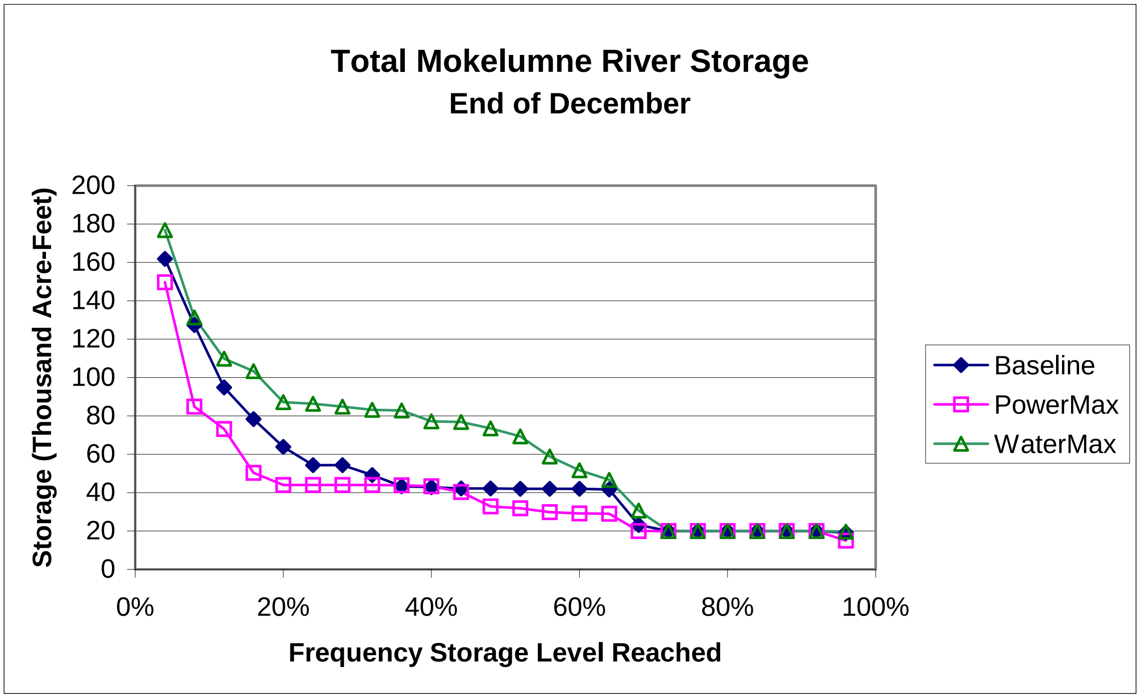


Figure C.3-14 Total Stanislaus River Storage Average End of Month Level

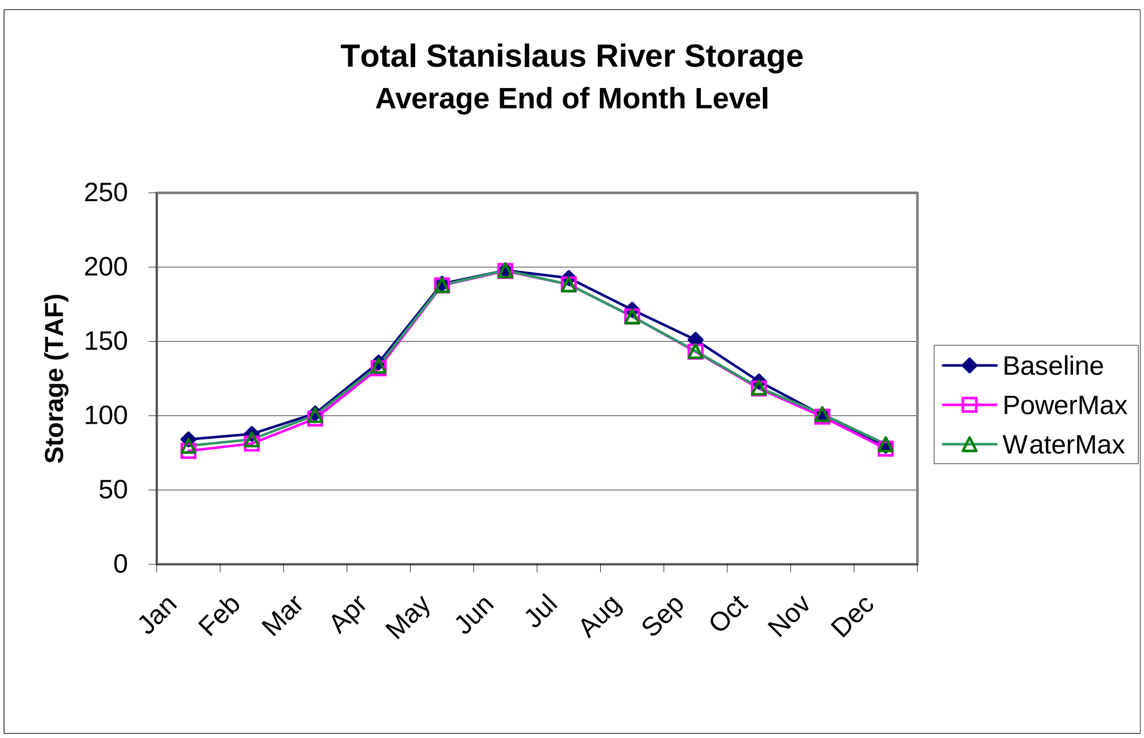


Figure C.3-15 Total Stanislaus River Storage End of May

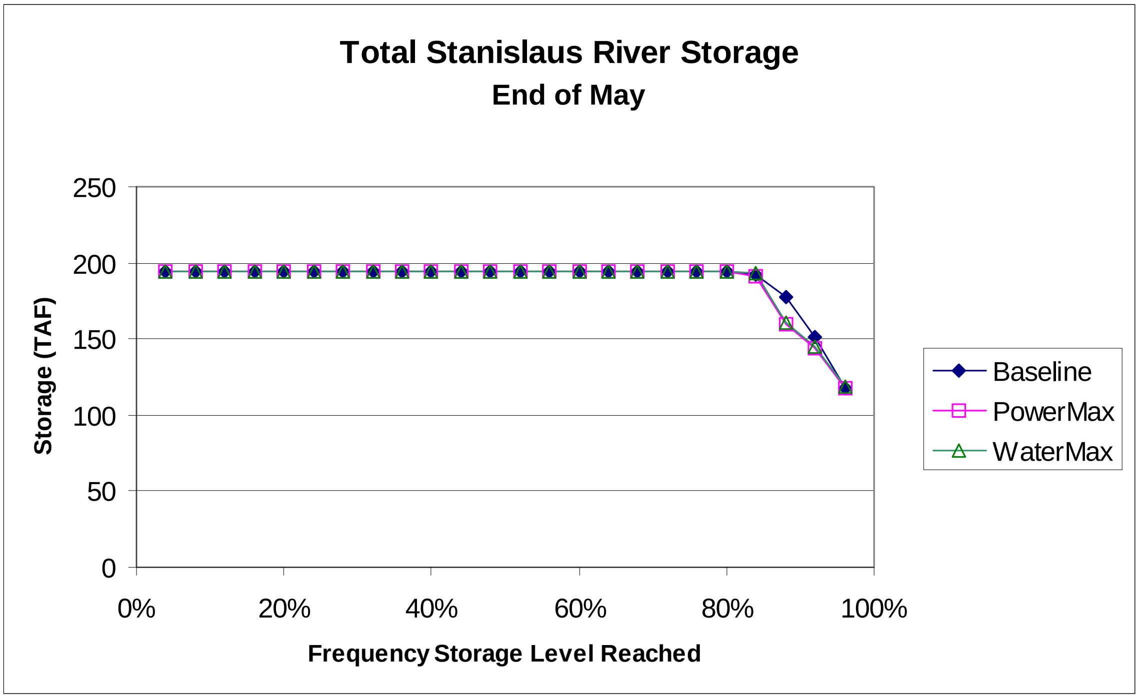


Figure C.3-16 Total Stanislaus River Storage Average End of August

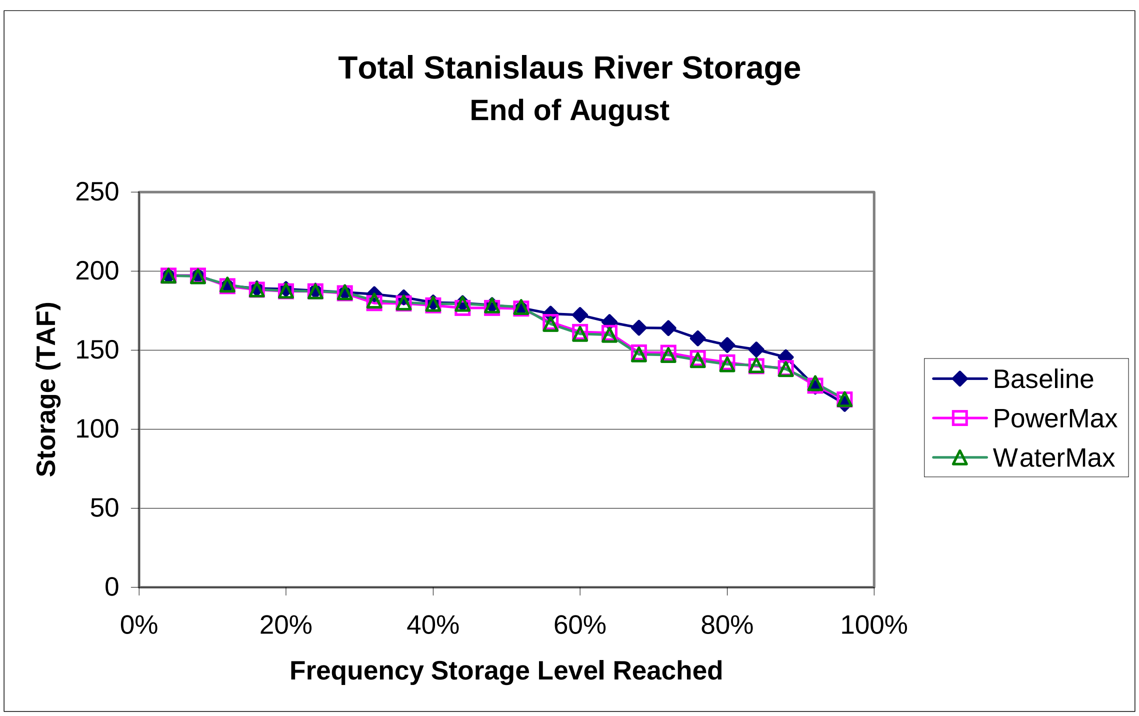


Figure C.3-17 Total Stanislaus River Storage Average End of December

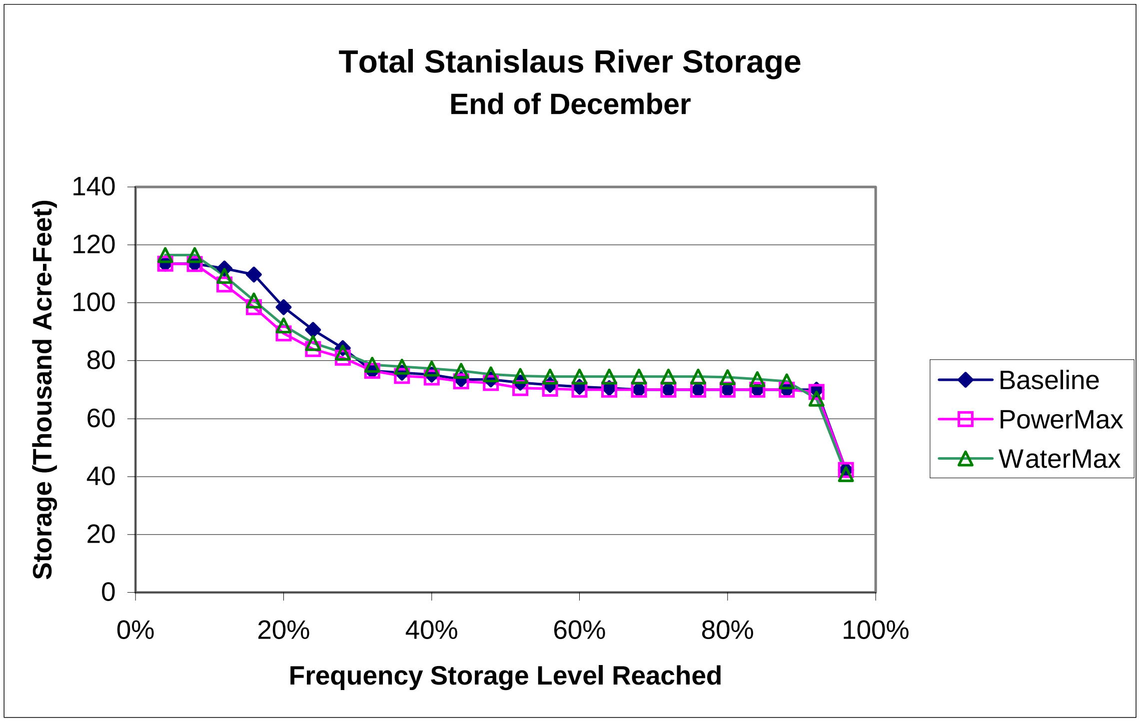


Figure C.3-18 Total Crane-Kerckhoff System Storage Average End of Month Level

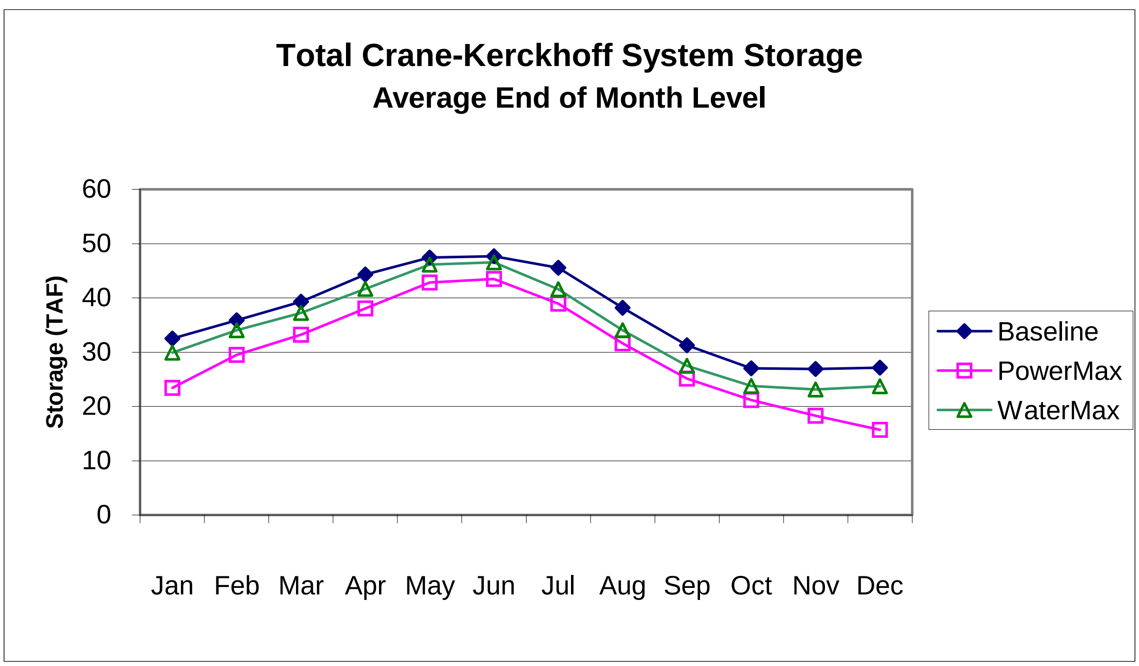


Figure C.3-19 Total Crane-Kerckhoff System Storage End of May

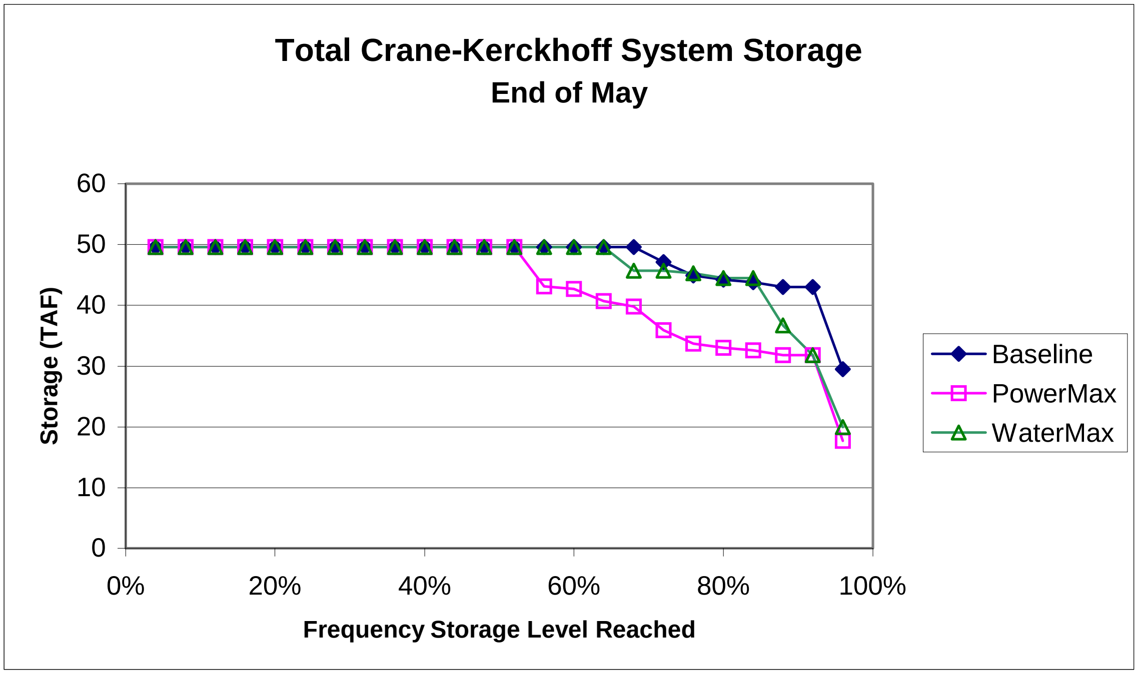
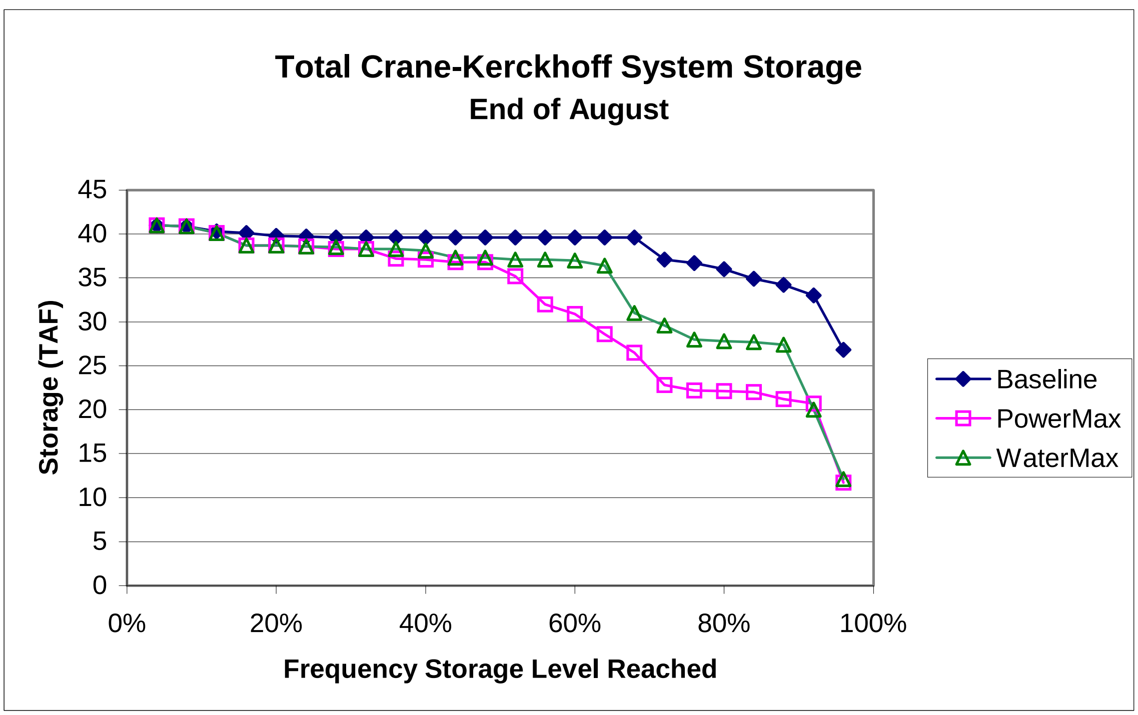


Figure C.3-20 Total Crane-Kerckhoff System Storage End of August



Chili Bar Weekday July Power Flows under Different Water-Year Conditions

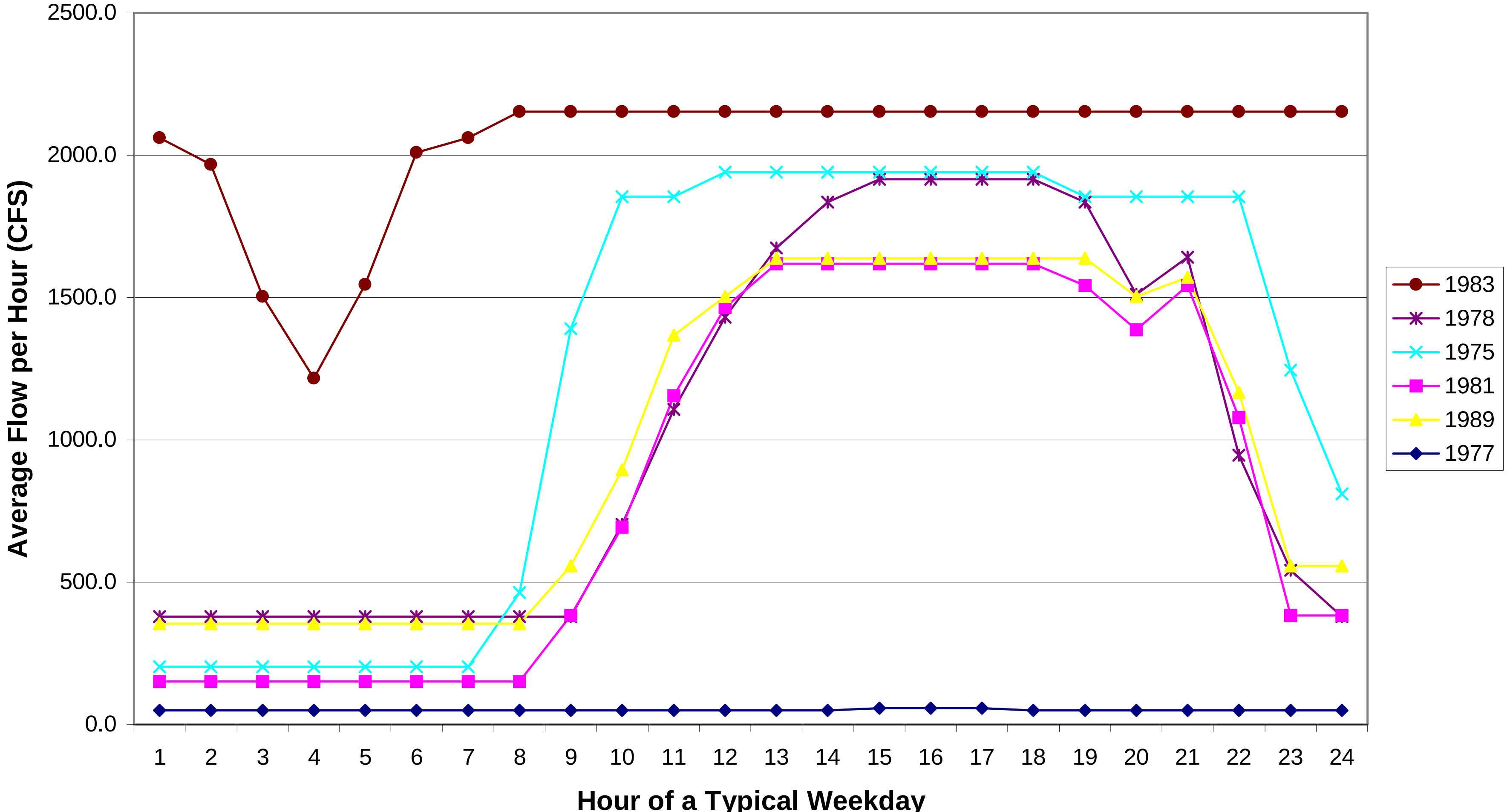


Exhibit C.4 Powerhouse Releases at Chili Bar under the PowerMax Scenario

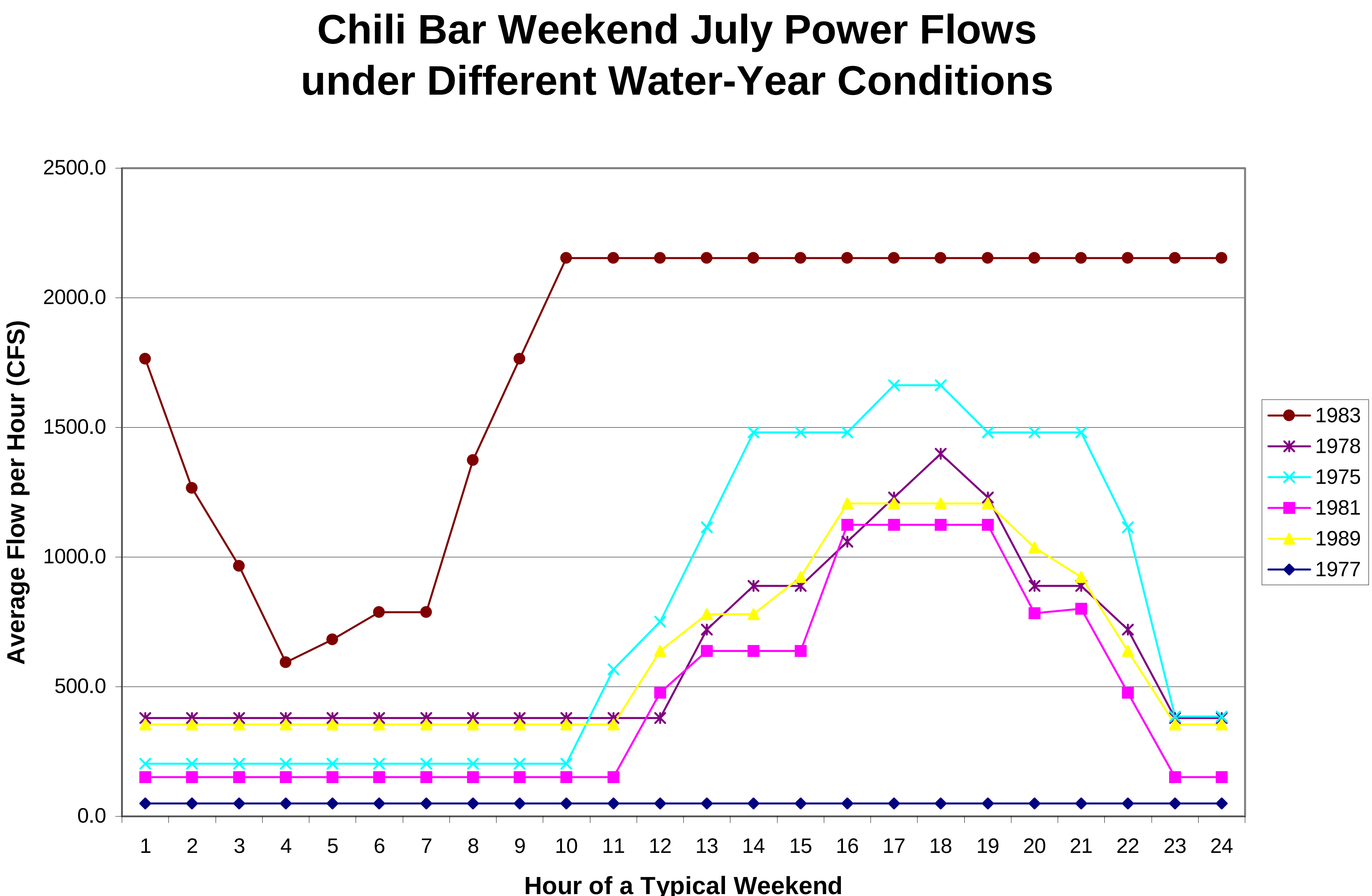


Exhibit C.4 Powerhouse Releases at Chili Bar under the PowerMax Scenario

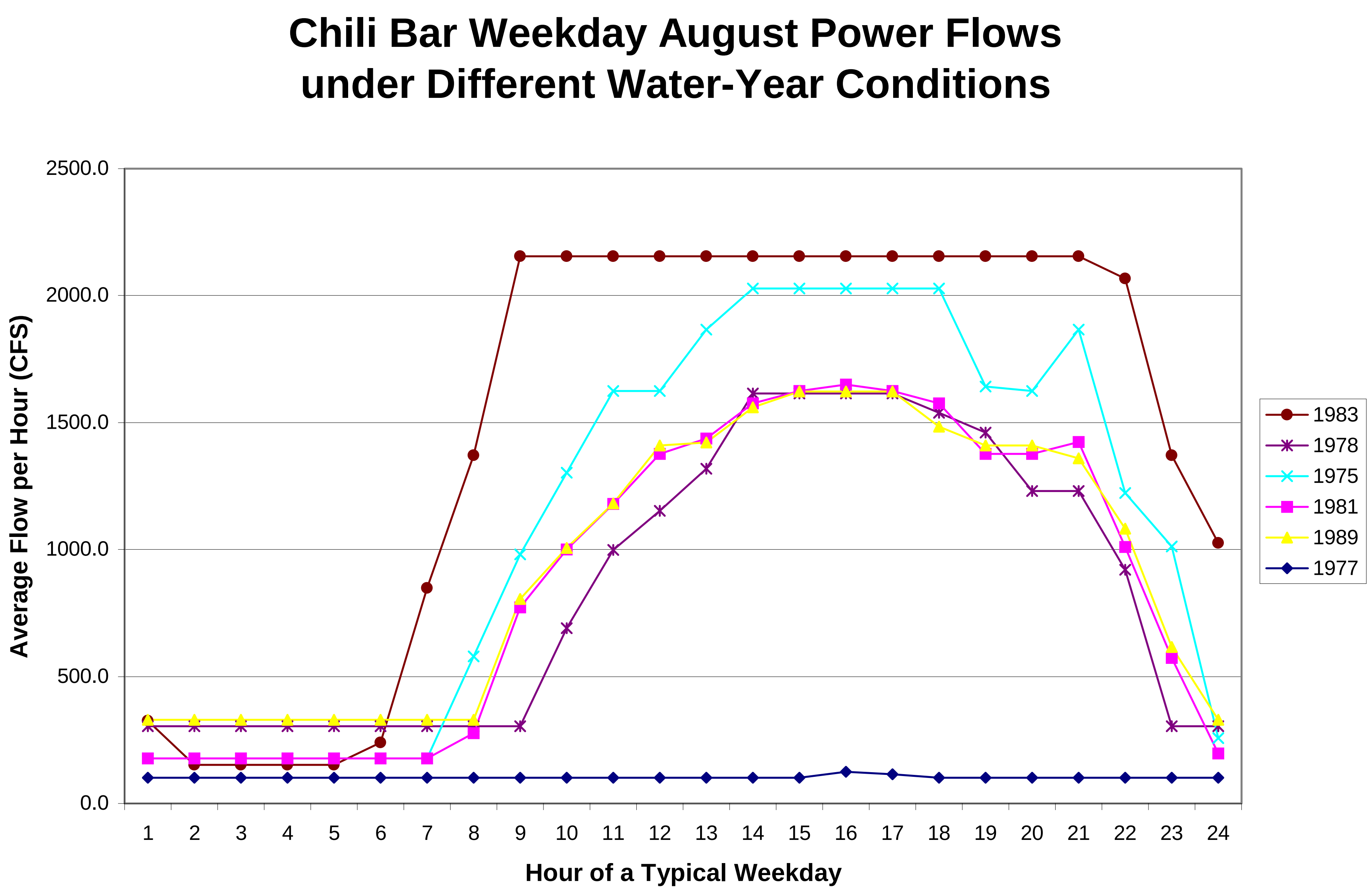


Exhibit C.4 Powerhouse Releases at Chili Bar under the PowerMax Scenario

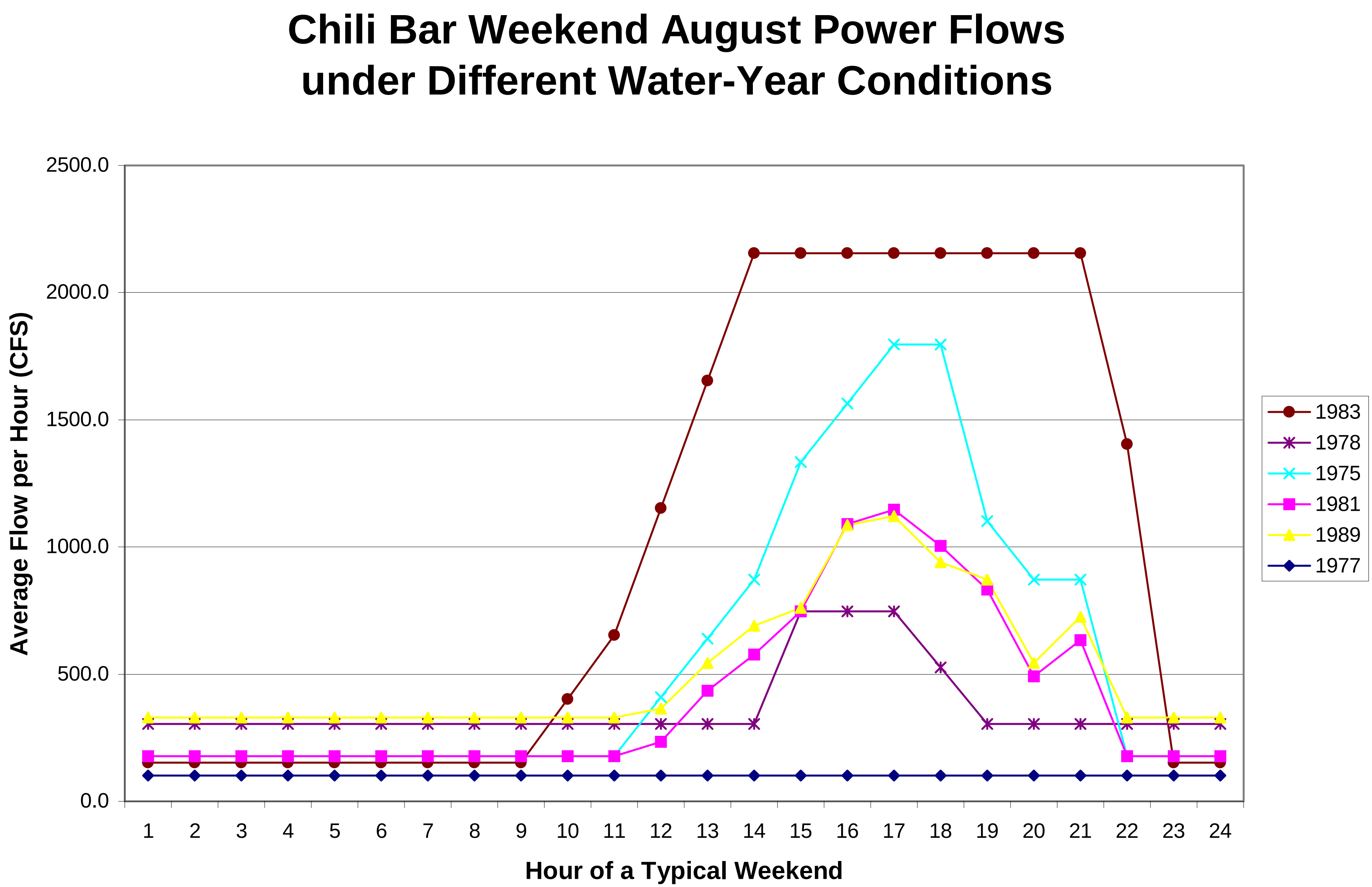


Exhibit C.4 Powerhouse Releases at Chili Bar under the PowerMax Scenario

EXHIBIT C.5

Table C.5-1 Hydrological Linkage -- Operating Efficiencies, Shasta Regional Bundle

Bundle No.	FERC License Powerhouses	No. of Units	Capacity (MW)	Hydrological Linkage with Upstream Facility
A	**Shasta Watershed**	28	809.9	
1	FERC No. 2661 (Hat Creek Project)			
	Hat Creek No. 1	1	8.5	0
	Hat Creek No. 2	1	8.5	64 percent
2	**FERC No. 2687 (PIT PROJECT)**			
	Pit No. 1	2	61	0
	FERC No. 0233 (Pit 3, 4, & 5 Project)			
	Pit No. 3	3	70	52 percent[i]
	Pit No. 4	2	95	91 percent
	Pit No. 5	4	160	94 percent
	FERC No. 2106 (McCloud-Pit Project)			
	James B. Black	2	172	0
	Pit No. 6	2	80	67 percent+22 percent[ii]
	Pit No. 7	2	112	94 percent
3	FERC No. 0606 (Kilarc Cow Creek Project)			
	Kilarc	2	3.2	0
	Cow Creek	2	1.8	0
4	FERC No. 1121 (Battle Creek Project)			
	Volta No. 1	1	9	0
	Volta No. 2	1	0.9	92-100 percent
	South	1	7	61 percent
	Inskip	1	8	70 percent
	Coleman	1	13	80 percent

[i] 21 percent of water comes from Hat 2 Powerhouse. Pit 1 forebay at 2,451 AF is too small to affect Pit 3,4,5 operations as the much larger 41,877 AF Lake Britton (Pit 3 forebay) would levelize any cycling of Pit 1.

[ii] 67 percent of water comes from Pit 5 Powerhouse and 22 percent from James Black PH.

Table C.5-2 Hydrological Linkage – Operating Efficiencies DeSabla Regional Bundle

Bundle No.	FERC License Powerhouses	No. of Units	Capacity (MW)	Hydrological Linkage with Upstream Facility
B	**DeSabla Watershed**	25	763.4	
5	No FERC License			
	Hamilton Branch	2	4.8	0
6	***FERC No. 2105 (Upper North Fork Feather Project)***			
	Butt Valley	1	41	9 percent[i]
	Caribou No. 1	3	75	82 percent
	Caribou No. 2	2	120	Share Forebay
	Oak Flat	1	1.3	93 percent[ii]
	Belden	1	125	93 percent
	FERC No. 1962 (Rock Creek Cresta Project)			
	Rock Creek	2	112	84 percent[iv]
	Cresta	2	70	92 percent[iii]
	FERC No. 2107 (Poe Project)			
	Poe	2	120	95 percent
7	***FERC No. 0619 (Bucks Creek Project)***			
	Bucks Creek	2	65	0[v]
8	FERC No. 0803 (De Sabla Centerville Project)			
	Toadtown	1	1.5	0
	DeSabla	1	18.5	49 percent
	Centerville	2	6.4	99 percent
	No FERC License			
	Lime Saddle	2	2	0
	Coal Canyon	1	0.9	100 percent

[i] Water comes from Hamilton Branch. 9 percent contribution to Butt Valley not significant enough to require a coordination agreement. The large Lake Almanor storage capacity would levelize any irregular releases from Mountain Meadows Reservoir.

[ii] Fishwater release from Belden Forebay. Water inflows to the forebay from Caribou Nos. 1 & 2 powerhouses and from NFFR Main Stem. Oak Flat and Belden powerhouses have the same dependency upon the upstream facilities since they both draft water from the Belden Forebay.

[iii] Eight percent of water comes from upstream Bucks Creek/Grizzly project. Releases from Bucks Creek Project are too small to significantly impact operations at Cresta and Poe throughout most of the year. However, if Cresta and/or Poe are at full capacity without Bucks Creek inflow, then release of water from Bucks Creek that might otherwise be stored in Bucks Lake or the smaller Bucks Project reservoirs would spill past Cresta and Poe with a loss of generation. Coordination agreements between the owners of Cresta, Poe and Bucks Creek projects would be needed.

iv Because the Rock Creek – Cresta and Poe projects depend on releases from the UNFFR Project for 84 percent of their inflow. Also, during the high flow season, when inflows from the East Branch NFFR and other local tributaries are high, discharge from the UNFFR Project must be curtailed and water stored in Lake Almanor and Butt Valley Reservoirs to reduce or prevent spill at Rock Creek, Cresta and Poe dams. Coordination agreements would be required if the projects are sold to different new owners.

v Grizzly Powerhouse under the Buck Creek Project license is owned by the City of Santa Clara but is operated by Pacific Gas and Electric Company for them. The new agreement will be needed between the City of Santa Clara and a new owner of the rest of the Bucks project to coordinate operations and operating services.

Table C.5-3 Hydrological Linkage – Operating Efficiencies
Drum Regional Bundle

Bundle No.	FERC License Powerhouses	No. of Units	Capacity (MW)	Hydrological Linkage with Upstream Facility
C	**Drum Watershed**	21	218.2	
9	FERC No. 1403 (Narrows Project)			
	Narrows No. 1	1	12	0[i]
10	FERC No. 0077 (Potter Valley Project)			
	Potter Valley	3	9.2	0
11	FERC No. 2310 (Drum-Spaulding Project)			
	Spaulding No. 3	1	5.8	0
	Spaulding No. 2	1	4.4	72 percent
	Spaulding No. 1	1	7	Share Forebay
	Deer Creek	1	5.7	55 percent
	Alta	2	2	7 percent[ii]
	Drum No. 1	4	54	98 percent
	Drum No. 2	1	49.5	Share Forebay
	Dutch Flat No. 1	1	22	43 percent [iii]
	Halsey	1	11	98 percent
	Wise No. 1	1	14	95 percent
	Wise No. 2	1	3.1	Share Forebay
	Newcastle	1	11.5	83 percent
12	FERC No. 2155 (Chili Bar Project)			
	Chili Bar	1	7	0 [iv]

[i] Shares water from forebay w/YCWA Narrows 2. Transfer of the existing coordination agreements, including any informal agreements necessary for coordinated operation, between Pacific Gas and Electric Company, YCWA and the US Army Corps of Engineers to a new owner of Narrows 1 will be required.

[ii] Alta receives water from Drum Forebay that comes from Spaulding 1 Powerhouse. Transfer of the existing coordination agreements, including any informal agreements necessary for coordinated operation, between Pacific Gas and Electric Company, NID and PCWA a new owner of the Drum-Spaulding Project will be required.

[iii] Shares water from forebay w/NID Dutch Flat 2

[iv] Chili Bar operations must be coordinated with the operation of upstream SMUD projects. Transfer of the existing coordination agreement, including any informal agreements necessary for coordinated operation, between Pacific Gas and Electric Company and SMUD to a new owner of the Chili Bar Project will be required.

Table C.5-4 Hydrological Linkage – Operating Efficiencies
Motherlode Regional Bundle

Bundle No.	FERC License Powerhouses	No. of Units	Capacity (MW)	Hydrological Linkage with Upstream Facility
D	**Motherlode Watershed**	12	318	
13	FERC No. 0137 (Mokelumne Project)			
	Salt Springs	2	44	0
	Tiger Creek	2	58	90 percent
	West Point	1	14.5	86 percent
	Electra	3	98	89 percent
14	***FERC No. 2130 (Spring Gap-Stanislaus Project)***			
	Spring Gap	1	7	0
	Stanislaus	1	91	7 percent [iii]
	FERC No. 1061 (Phoenix Project)			
	Phoenix	1	2	0[i]
15	FERC No. 2467 (Merced Falls Project)			
	Merced Falls	1	3.5	0[ii]

[i] Phoenix receives some water diverted from Pinecrest Lake (FERC 2130) A coordination agreement is needed between different owners of the Spring Gap-Stanislaus and Phoenix projects to ensure Phoenix receives adequate water supply from Pinecrest Lake to serve its downstream water customers.

[ii] 100 percent of water comes from upstream MID hydroelectric projects

[iii] Interbasin diversions from the SF Stanislaus River upstream of Lyons Reservoir to the MF Stanislaus River via the Philadelphia Ditch and Spring Gap Powerhouse represent only 7 percent of the flow though the Stanislaus Powerhouse, which is unlikely to seriously impact Stanislaus operations even if not coordinated through an operating agreement. However, Stanislaus operations must be coordinated with the upstream Tri-Dam hydro facilities. Pacific Gas and Electric Company's existing operating agreements with Tri-Dam will need to be transferred to the new owner of the Spring-Gap Stanislaus Project.

Table C.5-5 Hydrological Linkage – Operating Efficiencies Kings Crane Helms Regional Bundle

Bundle No.	FERC License Powerhouses	No. of Units	Capacity (MW)	Hydrological Linkage with Upstream Facility
E	**Kings Crane–Helms Watershed**	24	1786.6	
16	FERC No. 1354 (Crane Valley Project)			
	Crane Valley	1	0.9	0
	San Joaquin No. 3	1	4.2	98 percent
	San Joaquin No. 2	1	3.2	100 percent
	San Joaquin No. 1A	1	0.4	89 percent
	A.G. Wishon	4	20	71 percent
17	FERC No. 0096 (Kerckhoff Project)			
	Kerckhoff No. 1	3	38	4 percent[1] Share Forebay
	Kerckhoff No. 2	1	155	
18	***FERC No. 2735 (Helms Pumped Storage*** Project)			
	Helms Pumped Storage	3	1212	0
	FERC No. 0175 (Balch Project)			
	Balch No. 1	1	34	82 percent[2] Share Forebay
	Balch No. 2	2	105	
	FERC No. 1988 (Haas-Kings River Project)			
	Haas	2	144	16 percent[3]
	Kings River	1	52	100 percent[4]
19	FERC No. 1333 (Tule River Project)			
	Tule River	2	6.4	0
20	FERC No. 0178 (Kern Canyon Project)			
	Kern Canyon	1	11.5	0[5]
	Entire System	110	3896.1	

[1] 90 percent of water comes from upstream SCE hydroelectric projects. Crane Valley project contributes only 4 percent of the Kerckhoff flows, not large enough to affect operations to require a coordination agreement.

[2] Water comes from Haas Powerhouse afterbay. (100 percent from Haas indicated by Pacific Gas and Electric Company testimony is in error; Rancheria Creek, Long Meadow Creek and Teakettle Creek are tributaries, which provide measurable inflow to Balch forebay, entering the NFKR downstream of Wishon Dam.) The Balch Project physically separates the Haas and Kings components of the Haas-Kings River Project. The water flow is Haas to Balch to Kings and then to the Corps of Engineers Pine Flat Reservoir. Coordination agreements are required if the Balch and Haas-Kings River projects have different owners.

The upstream storage reservoirs, Courtright and Wishon, are part of the FERC No. 1988 Haas-Kings River license. The reservoirs are also the forebay and afterbay of the Helms Pumped Storage Project and included in its license, FERC No. 2735. The Helms pumped storage operations imposes certain minimum reservoir levels and requires that the reservoirs not be completely filled to allow space for moving water back and forth between the reservoirs during the pumping and generating modes of operation. The pumped storage operation of Helms is virtually superimposed upon normal storage reservoir operations, resulting in a number of rules to coordinate the two different operational objectives. Therefore, if the Hass-King River and Helms projects were sold to different new owners, operations coordination agreements would be necessary. The Balch owner would also need to be included in the agreements since Balch is dependent on releases from Lake Wishon for most of its flow.

[3] Water comes from Lake Wishon, the Helms Powerhouse afterbay; however, the contribution to Lake Wishon of the net flow through Helms (natural inflow to Courtright Lake) represents only about 16 percent of the the flow released to Haas Powerhouse.

[4] Water comes from Balch Powerhouse afterbay

[5] 100 percent of water comes from upstream SCE hydroelectric projects.