Appendix D

Hydropower in the CALVIN Model

Randall S. Ritzema

Department of Civil and Environmental Engineering

University of California, Davis

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Abstract

California water system operators use hydropower extensively to capture and manage energy and provide economic returns to system operation. This attachment outlines efforts to include economic values for hydropower in the latest version of CALVIN, a large-scale optimization model of California's intertied system. The methods for efficiently representing the non-linearity of hydropower in CALVIN's network flow algorithm are presented, along with initial test results, data documentation, and suggested improvements.

1.1 Hydropower in California

California's water system is physically and institutionally complex. System entities operate the extensive network of reservoirs, rivers, canals, and diversions, as well as pumping and power plants with varying levels of coordination to meet a wide array of urban, agricultural, and environmental needs. Operational criteria for this system include water supply quantity and quality for urban and agricultural demands, flood control, minimum instream flow requirements, wetland requirements, and hydropower. Because most facilities were developed primarily for water supply and flood control, hydropower typically serves a lesser purpose in system operations. Although often institutionally subordinate, hydropower nonetheless provides large economic returns to facility operations, and is thus an important criterion to consider when assessing economically driven management alternatives.

The California Energy Commission (CEC) lists 386 licensed hydropower facilities in the state, ranging from the 1495-MW Castaic facility to local installations of less than 100 kW (CEC, 2001). In 1999, California produced 41,617 GWhr of hydropower, or approximately 15% of the power consumed by the state during that year (CEC, 2002). Such an extensive list reflects

California's varied topography, because hydropower depends on one essential ingredient — falling water. Within the United States, only Washington State exceeds California's hydropower generation potential (U.S. Department of Energy [DOE], 2002), although only a fraction of this potential is being utilized. The elevation difference, or "head," needed to drive turbines can originate through natural or synthetic means. Most facilities that capitalize on naturally falling water capture runoff from mountainous areas and are located in the wetter northern region of the state and throughout the Sierra Nevada and Coast mountain ranges. Typically, greater heads and lower storage capacities characterize higher elevation facilities, and most of the larger storage facilities are located at lower elevations.

Some hydropower facilities are designed to use synthetic head created from pumped water. For example, energy used to pump State Water Project water over the north side of the Tehachapi Mountain range in Southern California is partially recovered on the southern side of the range through a series of hydroelectric facilities, offsetting the costs of delivering water to Southern California demands. Pumped storage facilities, such as San Luis Reservoir, are another major example.

Different operational criteria apply to various hydropower facilities, depending on their physical and institutional flexibility. Because wholesale electricity prices follow diurnal, seasonal, and annual cycles, operators of "peaking" plants seek to utilize a reservoir's storage capacity by releasing water when wholesale electricity prices are highest, maximizing economic returns. Hydropower facilities with little or no storage or reservoirs, where downstream demands are the primary operational consideration ("base load" plants), may not have this flexibility, and must release water in nonpeak periods. Several storage facilities in California advantageously use an afterbay by pumping water from the afterbay into the reservoir in non-peak hours and releasing water from the reservoir in peak hours. This generates revenue through the electricity price differential.

The State Water Project (SWP) and the federal Central Valley Project (CVP) extensively augment their water supply systems with hydropower plants. Utility companies such Pacific Gas & Electric and Southern California Edison, as well as several municipal utility districts, operate hydropower facilities as an integral component in their power supply systems. In addition, irrigation districts may generate power for local consumption or for sale to the wholesale market.

1.2 Hydropower in CALVIN (Phase I)

CALVIN is an optimization model of California's entire intertied water supply system and includes 90% of the urban and agricultural water demands in the state. This highly complex system is governed by physical capacities, connections, and constraints, as well as by an extensive array of agreements, contracts, and regulations. Because of the size and complexity of the system, a fairly simple modeling approach was needed — an approach that would characterize the system with sufficient accuracy, yet allow analysis to remain tractable. HEC-PRM, a network flow optimization package from the

U.S. Army Corps of Engineers Hydrologic Engineering Center (HEC), was chosen as CALVIN's engine because of its flexibility and scalability. However, although a network flow algorithm (a simplified form of linear programming) greatly reduces computational requirements compared to other approaches, it also requires mathematical relationships between model elements to be linear. This linear stipulation required alternative methods of representing the non-linearity of most hydropower facilities. The iterative method included in HEC-PRM (discussed later in this attachment), is computationally burdensome and ultimately rendered analysis of a large-scale system such as CALVIN intractable.

Because of these computational difficulties, only eight fixed-head facilities (easily represented linearly) were included in the first phase of CALVIN's development (Jenkins et al., 2001, Appendices G and H). In this attachment, we report our efforts to include variable-head hydropower in CALVIN in the second phase of model development. Characterization of all 386 plants was difficult because of time and data limitations, so facility selection criteria were used to narrow the list of facilities included.

1.3 Criteria for Inclusion in CALVIN (Phase II)

Only plants with generating capacities greater than 30 MW were considered, with the exception of a few fixed-head facilities for which ample data were available. Parameters for several small powerplants on the California Aqueduct, for example, were easily obtained from DWRSIM (California Department of Water Resources [CDWR], 1996) and were therefore included.

In addition, only facilities within the boundaries of the first phase of CALVIN's development were modeled. CALVIN uses rim inflows from DWRSIM and several other planning models. Historical unimpaired hydrology and powerplant parameter data above these inflows are either unavailable or extremely difficult to reconstruct. Omission of these upstream facilities, however, is typically of little importance from the perspective of the management of California's intertied system. As discussed earlier, these upstream facilities are higher in elevation and are typically low-storage systems, making system operation relatively inflexible and reducing the potential for applying alternative management strategies. Implementing these two criteria reduced the list of facilities to be included in CALVIN from 386 to 32.

2. Hydropower Modeling Methodology

2.1 Hydropower Equation

Equation 1 is the instantaneous hydropower equation and shows that the economic benefit from hydropower at any point in time is a function of the price of electricity, the unit weight of water (62.4 lb/ft^3), the flow rate through the system, the head, the efficiency with which the turbine converts the water's energy to electrical power, and a unit conversion factor. Integrating this function over a given time period results in the total economic benefit over that period.

$$B_t = p_t c \gamma Q_t H(S_t) e \quad (1)$$

Figure 1 illustrates how a reservoir storage system translates into these hydropower parameters. The head is considered to be the elevation difference between the surface of the reservoir and the tailwater below the power plant. It is this elevation difference that creates a "pressure" difference across the turbine. The elevation of the reservoir surface depends on the amount of water stored behind the dam, necessitating a relationship between storage and elevation that translates storage into head.

The conversion factor and the specific weight of water are considered constant. With a few exceptions, efficiency is also assumed to be fixed (although efficiency technically varies with flow rate and head, it remains fairly constant over a normal operating range).

Because CALVIN is a monthly time step model, average monthly values for p_t, Q_t, and $H(S_t)$ are substituted into the equation. This requires the use of an average electricity price, entailing assumptions of how the facility will be operated (for peaking or base load management, for example). All facilities use an average monthly price in CALVIN (see Table 1), regardless of their typical operation.

Substituting these parameters into Equation 1 results in the modified monthly benefit equation (Equation 2) used in CALVIN (in the cases where efficiency is considered constant):

$$B_m = p_m c \gamma Q_m H(S_m) e \text{, for month } m \quad (2)$$

The non-linearity of the hydropower function arises predominantly from $H(S_m)$. Power plants where storage head is a significant portion of the total head (known as variable-head facilities) exhibit highly nonlinear benefit functions. Conversely, in facilities with small storage head to total head ratios, benefits are roughly proportional to flow rate. $H(S_m)$ is constant for facilities with little or no storage capacity (fixed-head facilities), and the economic benefit becomes a linear function of flow rate.

2.2 Data Sources

Parameters for hydropower facilities in the SWP and the CVP were gleaned from the hydropower postprocessor within DWRSIM. The postprocessor provided “power factors” for variable-head plants at various storage levels and “flow factors” for fixed-head plants. These factors combine several of the hydropower parameters into a single coefficient, which gives monthly estimates of energy generation when multiplied by the flow rate. These power and flow factors were easily assimilated in CALVIN, and 18 of the 32 plants represented in CALVIN use DWRSIM parameters.

Physical parameters were used to build individual representations of the remaining facilities. $H(S_m)$ functions were calculated using published storage and elevation data and estimated average tail water elevations. A default overall constant efficiency of 85% was assumed for facilities where efficiencies were unknown.

3. Four Methods for Representing Hydropower

HEC-PRM employs a cost-minimization algorithm, requiring that benefits be modeled as linear or convex piecewise linear penalty functions. These penalties are equivalent to the unrealized loss of benefit from *not* operating the system at maximum capacity; i.e., at maximum head (storage) and release (see Figure 2 and Equation 3). CALVIN balances these hydropower “penalties” with other costs in the system and suggests operations that minimize overall costs to the entire system.

$$P_m = B_{\max,m} - B_m \qquad (3)$$

Four different methods were used in generating hydropower penalty functions, based on facility configuration, data availability, and computational considerations. Two methods were used for fixed-head facilities, and two for variable-head plants with penalty functions expressing varying degrees of non-linearity.

3.1 Unit cost on flow (UC): Fixed-head, constant efficiency

For fixed-head facilities with an assumed constant efficiency, penalty functions are a simple linear function (see example in Figure 3). All facilities with unit costs on flow are based on DWRSIM power factors. The x-intercept represents the flow capacity of the plant.

3.2 Piecewise linear cost on flow (PWL): Fixed head

DWRSIM lists several large non-storage facilities where head is a function of flow because of head losses at varying flow rates. These plants exhibit a slightly nonlinear convex penalty function. To capture this non-linearity, a least-squares approach was utilized to fit a three-piece linear approximation to the nonlinear function (see Figure 4). A Visual Basic macro utilized the Solver function in Microsoft Excel to choose breakpoints along the nonlinear penalty that maximized the coefficient of determination of the piecewise linear fit. The only facilities modeled with this method were the Castaic and Warne power plants in Southern California.

Additionally, flow–power factor relationships were provided by DWRSIM for the Nimbus and Keswick power plants. These data sets were incorporated directly into piecewise linear penalties in CALVIN, and did not require the least-squares approximation described above.

3.3 Iterative variable head (IVH): Variable head

The nonlinear nature of variable-head (i.e., storage) hydropower necessitates the application of algorithms that can approximate non-linearities with linear relationships. HEC-PRM has incorporated an iterative algorithm for hydropower that successively interpolates within a family of penalty curves, with each curve representing a specific storage level. Figure 5 graphically displays a set of storage penalty curves for Shasta Reservoir in the SWP system.

The HEC-PRM solver completes an initial iteration. Average reservoir and release rates for a given month are used to approximate power generation benefits using the penalty from the closest storage level. The solver then calculates the rate of change of the penalty per unit of storage based on the adjacent storage curves. The solver updates the network matrix with the new storage values and completes another iteration. This process continues until the solver no longer finds a solution with a lower total cost. See Appendix B of HEC (1993) for details.

This method, although it yields satisfactory results for systems with relatively few hydropower plants, quickly becomes computationally infeasible as hydropower facilities are added (see the Test Results section below). Another method was needed to represent variable-head facilities to complement the limited usability of the iterative algorithm.

3.4 Storage and Release Penalties (SQ): Variable Head

Variable-head hydropower plants increase their energy generation as storage and release levels increase. The SQ method approximates a nonlinear variable-head hydropower penalty function through the sum of independent linear storage and release penalties.

The first step is to generate a nonlinear penalty surface that represents all possible combinations of storage levels and releases for a given month using power factors and the nonlinear hydropower equation. Minimum operating flows and maximum flow capacities dictate a range of possible flow values through the power plant; minimum operating storage levels and maximum storage capacities or flood pools bracket possible storage values. Minimizing the operating range for storage and releases provides a better linear approximation. Dividing the operating ranges of storage and releases into 50 and 25 increments, respectively, provides 1,250 points on the penalty surface.

Figure 6 displays the penalty surface for Shasta Reservoir for the month of January. At low release rates, little variation is seen in the penalty function between low storages and high storages. However, that differential increases as flow rates increase.

For DWRSIM facilities, a best-fit polynomial curve was generated using the storage/power factor pairs given in the DWRSIM code. This polynomial relates average monthly storage values in CALVIN to a specific power factor. Storage and release ranges translate into a penalty matrix, using Equation 4 (a variation of the hydropower equation in DWRSIM's formulation):

$$B_m = 10\, p_m (PF) Q \qquad (4)$$

where B_m is the monthly benefit in K\$, p_m is the electricity price in cents/kWh, PF is the power factor, and Q is the release rate in taf/mo.

Non-DWRSIM facilities use another variation on the hydropower equation. Published storage and elevation data were used to generate a best-fit polynomial curve. Any storage level can be converted to a reservoir elevation, and $H(S_m)$ is then found by subtracting the average tail water elevation. Equation 5 calculates the monthly generation benefit:

$$B_m = p_m e Q_m H(S_m) c \qquad (5)$$

where e is the assumed efficiency, and c is a factor of 0.0102368 (k\$-kW-h-cents^{-1}-taf^{-1}-ft^{-1}), which incorporates the specific weight of water from the hydropower equation and a unit conversion.

The second step of the SQ method uses a least-squares approach to fit a piecewise planar surface to the 1,250 points on the nonlinear penalty surface to give a linear approximation to the penalty function, using the formulation shown in Equation 6:

$$P_m = P(S_m) + P(Q_m) \tag{6}$$

A Visual Basic macro initializes an optimization routine in Excel that maximizes the coefficient of determination (R^2 value) of the piecewise planar surface. The decision variables of the routine are the two breakpoints in the piecewise storage curve, along with the slopes and y-intercepts of the three lines in the storage curve and the single release line. The optimized R^2 value indicates how well the planar surface "fits" the nonlinear surface. R^2 values for SQ facilities range from 0.963 to 0.9999+ (see Table 4).

Figure 8 displays how a piecewise planar approximation of the penalty curve (meshed surface) for Shasta Reservoir compares to the nonlinear penalty surface (solid surface). The methods are very similar if operated in the midrange of possible storage and release values, but diverge near the extremes.

To complete the piecewise linear penalty, an additional segment is needed. The end point at the lowest storage level (S = 212 taf in Figure 7) is at the minimum operating pool. The dead pool for Lake Shasta, however, is 116 taf. Below a storage level of 212 taf, the plant would be unable to generate power. Theoretically, the penalty function should jump vertically to the maximum level at the minimum operating pool, and then extend horizontally at that maximum penalty level to the dead pool (see Figure 9, line "A"). Simply extending a segment from the minimum operating pool to the maximum penalty at dead pool (Figure 9, line "B") would greatly underestimate the penalty for storage operations in this range. A compromise penalty segment is shown as line "C," where the end point of the penalty function located at the dead pool is placed at twice the maximum penalty level. Although there is a risk of overestimating penalties using the C penalty segment, this approach is necessary to maintain a convex penalty function.

As noted earlier, SQ penalty functions fit nonlinear penalty surfaces more accurately where storage head is a small proportion of the total head of the facility. Thus, the R^2 value reflects the linearity of the facility in consideration. Representing variable-head facilities with the SQ method over the IVH method sacrifices some accuracy but permits feasibility of large-scale systems analysis by reducing computational time.

4. Test Results

Because the effectiveness of the IVH and SQ variable-head methods for a large-scale model was uncertain, two tests were performed on a portion of the CALVIN model. Run times and realistic, justifiable operations were the performance indicators for the two methods.

4.1 Test 1: IVH method

Test 1 was used to discern the sensitivity of CALVIN to varying degrees of detail in the IVH representation of variable-head hydropower. Using only the Upper Sacramento Valley region of the CALVIN model (region 1) for this test enhanced the interpretability of the results. An unconstrained model run for region 1 from the CALVIN CALFED**.** study provided a basis for comparison.

Shasta and Clair Engle reservoirs were modeled with HEC-PRM's iterative algorithm, but all other facility representations remained unchanged from the unconstrained "base case." DWRSIM power factor/storage paired data translated directly into a family of storage-based penalty curves (see Figure 9).

Subsequent runs changed the number of storage curves used for the two reservoirs, as described in Table 2. In a similar manner to the PWL method described above, a piecewise linear curve fitting a best-fit polynomial line of the storage/power factor relationship mimicked the linear interpolation that HEC-PRM performs (see Figure 10). The breakpoints of the best-fit piecewise linear approximation indicate which storage levels should be used for different numbers of storage curves. The points shown in Figure 10 translate the original 13 storage levels from DWRSIM into the 6 storage levels shown in Figure 11. By varying the number of segments in the piecewise linear approximation, families of varying numbers of storage penalty curves can be generated and tested.

Test results show little difference among runs 2 through 5, as Table 3 shows. Incorporating the IVH method, even on only two reservoirs on a small portion of the entire system, causes a marked increase in run time. Results indicate that the model run times are relatively insensitive to the number of storage penalty curves used on a fixed number of variable-head facilities, but are highly sensitive to the number of facilities modeled with the iterative algorithm. These results suggest the necessity of minimizing the number of facilities represented with the IVH algorithm.

4.2 Test 2: Comparing the SQ and IVH methods

An earlier combined run of the Upper Sacramento Valley and Lower Sacramento Valley & Bay Delta regions of CALVIN (regions 1 and 2) from the CALFED modeling effort provided a base case for this test. This confined the test to a smaller geographical region while still capturing a significant portion of the state's generating capacity, because most of the hydropower capacity in the state is located north of the Delta.

In the first run, flow ("fixed-head") penalties were placed on Keswick, Nimbus, Thermalito Diversion, and Thermalito Fore/Afterbay. Whiskeytown, New Bullards Bar, Folsom, and Englebright reservoirs utilized the SQ representation for variable-head hydropower. Shasta, Oroville, and Clair Engle reservoirs, the largest and most nonlinear facilities in the region, were modeled using the IVH algorithm. In the second run, Shasta, Oroville, and Clair Engle were converted to the SQ method.

Initial run time results showed the substantial computational "savings" of using the SQ method for variable-head facilities. Run 1 lasted 17.9 h; run 2 lasted 10.7 h. This time differential would be expected to increase as the remaining regions to the south of the Delta are included in statewide CALVIN runs.

Variable-head storage and release comparisons between the runs show the mixed effectiveness of the SQ method (see Figures 12 through 14). Shasta is the largest reservoir in the state, and the R^2 value for Shasta and that of smaller Clair Engle are 0.958 and 0.963, respectively. Test results reveal that the IVH and SQ methods differ little for Shasta and Clair Engle operations. An average monthly storage level of 3.581 maf for Shasta under the SQ representation exceeds the IVH storage by only 51 taf. Similarly, SQ average monthly storage for Clair Engle differs from the IVH storage by 55 taf (see Figure 13). Similar average storages are consistent with only slight variations in average monthly releases for both reservoirs. The SQ method appears to be an acceptable alternative for the IVH representation for Shasta and Clair Engle, despite their size and the non-linearity of their hydropower penalty functions.

In contrast, the operation of Lake Oroville differs sharply between the two variable-head methods. The average storage level for the SQ representation exceeds the IVH method by 435 taf, with much larger differences occurring in the months from July to November (see Figure 14). Releases follow a similar disjointed pattern, where large releases are offset by as much as 5 months. These results support the conclusion that reservoir size or the degree of non-linearity of the hydropower function are not necessarily the factors that determine the effectiveness of the SQ approximation. The residuals between the SQ linear approximation and the nonlinear penalty function are typically positive at higher storage values and lower release rates, where the system tends to operate variable-head facilities for most of the year. Economic values of storage, then, tend to run higher for most of the year. In portions of the system where hydropower facilities are well connected to other supplies, the system may have the flexibility to re-operate reservoirs and groundwater basins to maximize the storage of the SQ facility, even if the value of storage on that reservoir is not significantly higher. This appears to be the case with Lake Oroville in the test runs.

As reflected in Figure 15, total regional surface storage increases under the SQ representation. Average monthly surface storage in the SQ run is almost 11.5 maf, compared to 10.9 maf in the IVH run. Of the 538 taf difference, 435 taf is due to the disparity in Oroville storage.

Figure 16 shows how small differences in values of hydropower generation can dramatically affect operations. Oroville attempts to maximize hydropower production by reserving storage until a release is necessary. In this north-of-Delta analysis, these releases occur mainly in December as a large pulse through the Delta. Smoother operations can be expected if downstream demands (south-of-Delta) are allowed access to the water.

Marginal values on storage capacity expansion vary slightly between the two representations. Differences of the nonzero marginal value of storage range from $0.27 per acre-ft expansion for Clair Engle reservoir to $0.37 per acre-ft for Oroville reservoir.

5. Hydropower Facilities

Table 4 lists all the hydropower facilities included in CALVIN in this phase of model development. These power plants either have greater than 30 MW of generating capacity or were previously modeled in the DWRSIM hydropower postprocessor.

With the exception of Castaic Lake, the largest facilities are located north of the Delta, in regions 1 and 2 of the CALVIN model (see Lund, 2002 for regional descriptions). Power plants in Southern California are mainly comprised of high-head facilities on the Los Angeles Aqueduct or energy recovery plants on the SWP system. Along with the CDWR and the U.S. Bureau of Reclamation (USBR), operators include several irrigation districts, urban utilities, and conservation districts.

Almost all fixed-head facilities (shown in Table 5) utilize DWRSIM representations, except for the Hetch Hetchy and Los Angeles Aqueduct systems. Flow factors from DWRSIM translate directly into piecewise linear penalty functions for Keswick, Thermalito Fore/Afterbay and Diversion Dam, and Nimbus power plants. A flow/head relationship gleaned from DWRSIM's code was used to generate three-segmented piecewise linear penalties for the Castaic and Warne power plants. Data for the Los Angeles Department of Water and Power (LADWP) plants were difficult to obtain; models of the San Francisquito and Gorges facilities use heads reported in Jenkins (2001) and an assumed overall efficiency of 0.85.

Table 6 lists the 15 variable-head power plants included in CALVIN, how they are represented, and their data sources. Three of the largest power plants on Shasta reservoir, Clair Engle reservoir, and Lake Oroville utilize the IVH algorithm, because test results indicate susceptibility to operational distortion with the storage/release penalty method. Storage levels were taken directly from storage- and power-factor paired data in DWRSIM.

Flood pool levels for many of the SQ reservoirs (which are modeled as monthly upper bounds on storages in CALVIN) aided in narrowing operational storage ranges, increasing the fit of the piecewise planar approximation. Furthermore, minimum instream flows directly downstream of the New Don Pedro and New Exchequer facilities served as operational lower bounds. Where institutional or regulatory constraints were not imposed, physical capacities were used in determining storage and release ranges.

Each of the DWRSIM-based SQ models translated the model's paired data into a best-fit polynomial, allowing storage and release ranges to be evenly discretized. Maximum flow rates and minimum and maximum operating pools also came directly from DWRSIM data.

Parameters for the Colgate and New Narrows power plants were derived from the Bookman-Edmonston study (2000) on the Yuba River, and from CDWR's Bear River study . These planning studies were based on HEC-3 and HEC-5 simulations. Physical parameter data on Pine Flat, Colgate, and New Exchequer were obtained from personal contacts at several irrigation districts and water agencies (Klein, 2002; Richards, 2002; Yuba County Water Agency [YCWA], 2002).

Because data on physical parameters were sparse, hydropower parameters for the Hetch Hetchy system and the New Don Pedro power plant were derived using published operational data. Regression analysis utilized known parameters gleaned from sources such as USBR (1987) to derive the unknown parameters (namely efficiency and average tail water elevation).

Further documentation will be available on the future CALVIN CEC disk, and can be ordered through Jay Lund in the Civil and Environmental Engineering Department of the University of California, Davis. (http://cee.engr.ucdavis.edu/faculty/lund)

6. Potential Improvements

6.1 Pump/storage facility representation

The Castaic, Hyatt, and Gianelli power plants, which are several of the largest in the state, are pump/storage facilities, although CALVIN treats them as conventional hydroelectric plants. In actuality, operational criteria are based on daily energy price fluctuations. Difficulties in capturing diurnal operations in a monthly time step model are exacerbated by the limitations of CALVIN's network flow solver. Representation of pump/storage facilities may be possible, although it may involve operational assumptions that may limit the efficacy of such an approach. It may be possible to represent diurnal pumped storage energy generation value as a function of monthly storage, which partially determines peak-generation capacity for such plants.

6.2 Capacity values on storage

CALVIN currently models the economic benefit of power generation, but excludes system reliability considerations. In reality, reservoir operators are compensated for maintaining water in storage and excess turbine capacity, both of which are held in reserve in case of emergency (such as when several power plants shut down concurrently). A more accurate depiction of the true economic benefit of hydropower would include values of generating capacity.

6.3 Electricity pricing

Most of the large storage facilities with means of regulating inflows or releases (through forebays or afterbays) are operated as peaking plants. CALVIN uses an average monthly wholesale price, eliminating the distinctions between peaking, intermediate, and base load plants. Such an approach potentially underestimates the economic benefit from peaking facilities and overestimates benefits from base load plants. Further thought is needed to discover ways of representing price differentials without relying heavily on operational assumptions.

6.4 Including upstream facilities currently outside the boundaries of CALVIN

Although limited in storage capacity, a number of large hydropower systems exist above the boundaries of the CALVIN model. Some examples include Southern California Edison's Big Creek system on the Upper San Joaquin River, which has a combined generating capacity of 1 GW, and Pacific Gas & Electric's 810-MW Shasta watershed system. Including these upstream facilities, although adding to CALVIN's robustness, presents formidable modeling obstacles. Historical unimpaired hydrology data are largely unavailable. Modeling these systems may be possible, but access to privately held hydrologic data is necessary for the sake of accuracy.

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Table 1. Wholesale electricity prices used in CALVIN (cents/kWh).

January	February	March	April	May	June	July	August	September	October	November	December
2.0	2.0	2.0	1.8	1.8	1.8	3.0	3.0	3.0	2.6	2.6	2.6

URS (2002)

Table 2. IVH test run descriptions.

Run 1	Unconstrained combined regions 1 and 2 model. No variable-head hydropower.
Run 2	IVH variable-head method applied to Shasta and Clair Engle reservoirs, using DWRSIM power factors. Shasta: 13 storage curves; Clair Engle: 10 storage curves.
Run 3	IVH method. Both Shasta and Clair Engle: 6 storage curves.
Run 4	IVH method. Both Shasta and Clair Engle: 26 storage curves.
Run 5	IVH method. Both Shasta and Clair Engle: 5 storage curves.

Table 3. IVH test results.

Run	Number of hydropower iterations	Time (h)
1	n/a	3.7
2	15	10.6
3	16	10.9
4	20	12.9
5	17	10.6

Table 4. CALVIN hydropower facilities.

Name	Location	Operator	Capty. (MW)	CALVIN region
Shasta	Shasta Res.	CVP[a]	629	1
Spring Creek	Spring Creek Tunnel	CVP	180	1
Judge Francis Carr	Clear Creek Tunnel	CVP	154.4	1
Trinity	Trinity R., Clair Engle Res.	CVP	140	1
Keswick	Sacramento R. below Shasta	CVP	117	1
Hyatt	Feather R., Oroville complex	SWP	644.25	2
Colgate	New Bullards Bar Res.	YCWA	325	2
Folsom	American R., Folsom Res.	CVP	198.7	2
Thermalito	Feather R., Oroville complex	SWP	115	2
New Narrows	Yuba R., Englebright Res.	YCWA	49	2
Nimbus	American R.	CVP	13.5	2
Thermalito Divers.	Feather R., Oroville complex	SWP	3	2
Gianelli	San Luis/ Cal. Aqueduct	SWP, CVP	424	3
New Melones	Stanislaus R., New Melones Res.	CVP	300	3
Don Pedro	Tuolumne R., Don Pedro Res.	TID[a],MID[b]	203.2	3
Dion R. Holm	Tuolumne R., Cherry Lake	HHW&P[c]	156.8	3
R C Kirkwood	Tuolumne R., Hetch Hetchy Res.	HHW&P	121.9	3
Moccasin	Tuolumne R.	HHW&P	103.6	3
New Exchequer	Merced R., Lake McClure	MID[d]	94.5	3
O'Neill	San Luis/Cal. Aqueduct	CVP	25.2	3
Pine Flat	King's R., Pine Flat Res.	KRCD[e]	190	4
Castaic	Off Cal. Aqueduct, Castaic Lake	SWP, LADWP[I]	1247	5
Devil Canyon	Cal. Aqueduct	SWP	280	5
William E. Warne	Pyramid Lake	SWP	78.2	5
San Francisquito 1	Los Angeles Aqueduct	LADWP	75.5	5
San Francisquito 2	Los Angeles Aqueduct	LADWP	47	5
Control Gorge	Inyo, Owens River	LADWP	38	5
Middle Gorge	Mono Basin	LADWP	38	5
Upper Gorge	Mono Basin	LADWP	36	5
Mojave Siphon	Cal. Aqueduct	SWP	32.4	5
Drop 4	All American Canal	IID[f]	18.05	5
Alamo	Cal. Aqueduct	SWP	17	5

a. Turlock Irrigation District.
b. Modesto Irrigation District.
c. Hetch Hetchy Water & Power.
d. Merced Irrigation District.
e. King's River Conservation District.
f. Imperial Irrigation District.

Table 5. Fixed-head hydropower facilities.

Name	CALVIN link name	Method	Data source
Keswick	D5_D73	PWL	DWRSIM
Thermalito Fore/Afterbay	SR-7_C25	UC	DWRSIM
Nimbus	D9_D85	PWL	DWRSIM
Thermalito Div. Dam	C23_C25	UC	DWRSIM
Moccasin	C44-C88	UC	SFPUC (2002)
O'Neill	ONeill PWP_D712	UC	DWRSIM
Castaic[a]	Cast PWP_D887	PWL	DWRSIM
Devil Canyon	Devil PWP_C129	UC	DWRSIM
Warne	Warne PWP_SR-28	PWL	DWRSIM
San Francisquito 1&2	Owens 2 PWP_C122	UC	CALVIN CALFED
Gorges[b]	Owen1 PWP_C114	UC	CALVIN CALFED
Mojave Siphon	Mojave PWP_SR-25	UC	DWRSIM
Drop 4	AAC PWP_C151	UC	CALVIN CALFED
Alamo	Alamo PWP_D868	UC	DWRSIM

a. See note on Table 4.
b. Includes Upper, Middle, and Control Gorge plants.

Table 6. Variable-head hydropower facilities.

Name	Reservoir	Release	Method	R^2 value	Data source
Shasta	SR-4	SR-4_D5	SQ	.958	DWRSIM
Spring Creek	SR-3	SR-3_D5	SQ	0.995	DWRSIM
Carr	SR-3	D94&D40_ SR-3	SQ	0.999+	DWRSIM
Trinity	SR-1	SR-1_ D94&D90	SQ	0.963	DWRSIM
Hyatt[a]	SR-6	SR-6_C23	IVH	N/A	DWRSIM
Colgate	SR-NBB	SR-NBB_C27	SQ	0.996	USGS (1994), Bookman-Edmonston (2000), YCWA (2002)
Folsom	SR-8	SR-8_D9	SQ	0.986	DWRSIM
New Narrows	SR-EL	SR-EL_C28	SQ	0.999	DWR (YUBA)
Gianelli[a]	SR-12	Gianelli PWP_D816	IVH	N/A	DWRSIM
New Melones	SR-10	SR-10_D670	SQ	0.963	DWRSIM
Don Pedro	SR-81	SR-81_D662	SQ	0.965	SFPUC (2002), Lund (1999)
Holm	SR-LL-LE	SR-LL-LE_SR-81	SQ	0.999+	SFPUC (2002), USBR (1987)
Kirkwood	SR-HHR	SR-HHR_C44	SQ	0.997	USBR (1987), SFPUC (2002), USGS (1994)
New Exchequer	SR-20	SR-20_D642	SQ	0.963	USGS (1994), Klein (2002)
Pine Flat	SR-PF	SR-PF_C51	SQ	0.965	USGS (1994), Richards (2002)

a. Castaic, Gianelli, and Hyatt powerplants are actually pump/storage facilities. Water released at peak periods of the diurnal cycle can be pumped from the afterbay back into the reservoir in off-peak times. Models of these three plants at this time use the DWRSIM representations of these facilities because pumped/storage behavior is difficult to represent in CALVIN's network flow algorithm.