5.0 Decision Support System

5.1 Background and Overview

The INFORM DSS is a planning and management tool for the Northern California river and reservoir system described in Chapter 2 (and Figure 10). The system encompasses five rivers (Trinity, Sacramento, Feather, American, and San Joaquin), five major reservoirs (Clair Engle Lake, Shasta, Oroville, Folsom, and New Melones), 10 hydropower plants, the Sacramento-San Joaquin (Bay) Delta, and the water export system to southern California, including the San Luis reservoir. Water uses include water supply (to domestic, agricultural, and industrial sites), energy generation, minimum instream flow targets, and delta environmental and ecosystem requirements. Appendix G includes various project and demand data.

An agreement between the US Department of the Interior, Bureau of Reclamation, and the California Department of Water Resources (1986) provides for the coordinated operation of the state (State Water Project--SWP) and federal (Central Valley Project--CVP) facilities. This Agreement of Coordinated Operation (COA) aims to ensure that each project obtains its share of water from the Delta and protects other beneficial uses in the Delta and the Sacramento Valley. The coordination is structured around the necessity to meet the in-basin use requirements in the Sacramento Valley and the Delta, including Delta outflow and water quality requirements.

The INFORM DSS modeling framework has been described in Chapter 2 (Figure 11). The DSS includes multiple interconnected modeling layers designed to support decisions associated with four temporal scales, several objectives, and a number of federal and state decision making agencies. More specifically, the INFORM DSS includes models for long range planning (monthly resolution/one-two year horizon), mid range management (daily resolution/several months horizon), short range management (hourly resolution/one day horizon), and near real time operation (hourly dispatching of each hydropower turbine and hydraulic outlet). The INFORM DSS also includes an assessment model which replicates the system response under various inflow scenarios, system configurations, and policy options. In this Chapter, the DSS models are described in detail, including typical case studies. The models are discussed in the order they were developed, starting with the near real time operational models (highest resolution/shortest horizon), continuing with the short and mid range management models (intermediate resolution/horizon), and ending with the long range planning models (lowest resolution/longest horizon). This model development order is necessary because each model in the DSS structure is build upon information generated by the preceding model.

5.2 Near Real Time Operations: Turbine Load Dispatching Model
In hydropower plants with many turbines, the turbine load dispatching problem for an individual plant can be expressed as follows: Given a total outflow discharge $Q'$ and a certain reservoir storage $S$, determine the discharge $q_j$ through each turbine $j$ and the spillway flow rate $s$ such that $\Sigma q_j + s = Q'$ and total power $P$ is maximized. Namely, the problem calls for allocating the total discharge among the turbines in a way that maximizes power generation. This mode of operation is also attractive from a water management standpoint because it implies that a given power generation level is achieved at the least possible outflow (water conservation).

In what follows, mathematical formulation of this problem is presented and the solution method implemented in the INFORM DSS is outlined.

The formulation uses the following notation:

$q_j$ discharge of turbine $j$, $j = 1, \ldots, n$;

$[q_j^{\text{min}}, q_j^{\text{max}}]$ discharge operational range for turbine $j$;

$p_j$ power load of turbine $j$;

$[p_j^{\text{min}}, p_j^{\text{max}}]$ power operational range of turbine $j$;

$Q'$ total discharge target for the entire hydro-plant including spillway outflow, if any;

$s$ spillway (or other outlet) discharge;

$p_j = g_j(H_n, q_j)$ turbine power generation function relating power generation ($p_j$) to discharge ($q_j$) and net hydraulic head ($H_n$);

$H = f(S)$ reservoir forebay elevation ($H$) versus storage ($S$) relationship;

$H_{ls}(Q)$ hydraulic loss function;

$t = r(Q)$ tailwater elevation ($t$) versus total outflow ($Q$) curve;

$H_n$ net hydraulic head.

The objective of the load dispatching problem is to find $\{q_j \text{ and } p_j, j = 1, \ldots, n\}$ that

$$\text{maximize } P = \sum_{j=1}^{n} p_j$$

subject to

$$Q' = \sum_{j=1}^{n} q_j + s$$
An efficient way to handle the various nonlinearities and discontinuities of the above-stated problem is to reformulate it in multistage form and solve it via dynamic programming. The multistage formulation is as follows:

\[
\text{Maximize} \quad J = \sum_{j=1}^{n} p_j(q_j, H_n)
\]

subject to

\[
X_{j+1} = X_j + q_j, \quad j = 1, \ldots, n,
\]
\[
X_1 = 0, \quad X_{n+1} = Q^*
\]
\[
H_n = f(S) - r(Q^*) - H_b(Q^*),
\]
\[
p_j^{\text{min}} \leq p_j \leq p_j^{\text{max}} \quad \text{or} \quad p_j = 0,
\]
\[
q_j^{\text{min}} \leq q_j \leq q_j^{\text{max}} \quad \text{or} \quad q_j = 0.
\]

Clearly, if the discharge target \(Q^*\) is higher than \(\sum q_j^{\text{max}}\), the problem is trivial, and the optimal solution would be to load the turbines at full capacity and pass the excess flow through the spillway or some other outlet structure.

In the previous formulation, the individual turbine discharges \((q_j)\) constitute the control variables and the cumulative discharges \((X_i)\) constitute the state variables. Each stage \(j\) represents a different turbine, and the performance index maximizes the total plant power. This problem is in a typical, one-dimensional, dynamic programming form, and can be solved by the traditional backward DP procedure (Bellman and Dreyfus, 1962).

An equivalent formulation that also maximizes plant operational efficiency would be to minimize the total plant discharge \(Q\) for a given plant power generation \(P^*\). This problem can also be formulated in the same way and solved using dynamic programming.

The load dispatching problem can be solved for various combinations of plant discharge \((Q)\) and reservoir level \((H)\) to define the best efficiency plant power function.
P(Q,H). This function determines the maximum possible power that can be produced by outflow Q and head H and is used by the short range reservoir management model to represent the power generation function in the reservoir management process. The computations to obtain P(Q,H) are performed only once in an off-line mode. Updating of P(Q,H) is necessary only if turbine characteristics change.

Various reservoir and hydropower plant data used by the turbine load dispatching model are included in Appendix G. Specifically, the appendix contains Tables and Figures with storage versus elevation data, discharge versus tail water level data, and turbine characteristic curves (i.e., power versus discharge versus net hydraulic head relationships) for Trinity, Shasta, Oroville, and Folsom.

Model results are presented in Figure 66 at the end of this section. This Figure depicts the plant generation curves derived by the optimization procedure described in this section. The curves provide the maximum power output that a plant can generate for a particular combination of reservoir level and total discharge.

5.3 Short Range Reservoir Management

The purpose of this model is to find the most suitable hourly release schedule within a particular day. The short range model uses the power functions generated by the turbine load dispatching model for each power plant, and must satisfy the daily release target decided by the mid range control model (discussed next). The short range model incorporates all release requirements (pertaining to water supply, flood control, environmental protection, etc.) as well as all power requirements such as dependable capacity commitments. In addition to generating optimal schedules, the model is used in an off-line mode to generate the relationship between daily release, reservoir level, and energy generation to be used by the mid range management model.

Denoting R the total daily release volume specified by the mid range reservoir management model, the objective of the short range model is to determine the hourly discharges \{u(t), t = 0, ..., 23\} for each reservoir that

\[
\minimize J_s[R,H(s(0))] = \sum_{t=0}^{23} F[u(t)] - P[u(t), H(S(t))]
\]

subject to

\[
S(t+1) = S(t) - u(t) + w(t) - L(t), \quad t = 0, ..., 23 , \quad S(0) = \text{known},
\]

\[
R = \sum_{t=0}^{23} u(t),
\]

\[
u(t) - \Delta u_{\text{min}} \leq u(t+1) \leq u(t) + \Delta u_{\text{max}}, \quad t = 0, ..., 23,
\]

\[
P_{\text{min}}(t) \leq P[u(t), H(S(t))] \leq P_{\text{max}}(t), \quad t = 0, ..., 23,
\]
\[ u^{\min}(t) \leq u(t) \leq u^{\max}(t), \quad t = 0, \ldots, 23, \]
\[ S^{\min}(t) \leq S(t) \leq S^{\max}(t), \quad t = 0, \ldots, 23, \]

where \( t \) is the time index (in hours); \( F[u(t)] \) is the flood damage or cost associated with hourly discharge \( u(t) \) including both turbine and spillway outflow; \( P[u(t), H(S(t))] \) is the best efficiency plant power function discussed earlier; \( H(S(t)) \) is the elevation versus storage relationship; \( S(t) \) is reservoir storage at the beginning of hour \( t \); \( w(t) \) is the inflow (characterized by ensemble forecasts); \( L(t) \) is reservoir loss or gain due to water diversions and surface precipitation and evaporation if the latter are significant; \( P^{\min}/P^{\max} \) are power generation constraints; \( u^{\min}/u^{\max} \) are hourly release constraints reflecting water supply, environmental, ecological, flood control, and other operational requirements; \( S^{\min}/S^{\max} \) are storage constraints; and \( \Delta u^{\min} \) and \( \Delta u^{\max} \) are operational limits on release decreases and increases from hour to hour.

The previous formulation accounts for different reservoir management objectives through various means. These are discussed in the following comments:

1. The objective function (or performance index) \( J \) aims to minimize flood damage and maximize energy generation. Although both terms are present in \( J \), they are usually active during different hydrologic events. Specifically, during low, normal or moderate flows, flooding is not a concern, and the model aims to maximize energy generation (or, equivalently, minimize the negative of \( P[J] \)). During such times, low flow, water supply, and other operational requirements (such as dependable capacity constraints) are enforced through the release and power constraints (\( u^{\min}/u^{\max}, \Delta u^{\min}/\Delta u^{\max}, \) and \( P^{\min}/P^{\max} \)). On the other hand, during high floods when significantly higher volumes \( R \) must be released, all available hydro turbines run at full gate, and the model is concerned with regulating spillway outflows to mitigate flood damage (\( F[J] \)).

2. If the inflow forecast over the next 24 hours is probabilistic, the storage constraints in the above formulation must also be converted in a probabilistic form, reflecting the requirement that the storage bounds \( S^{\min}/S^{\max} \) should not be exceeded by more than a certain tolerance level. Furthermore, in this case, the performance index aims to optimize a statistic of \( J \) such as the mean value or a certain percentile of its distribution. However, inflow forecast uncertainty over 24 hours may not translate to considerable uncertainty of reservoir storage, and the previous probabilistic considerations may not be necessary.

3. If hourly power sale prices are available, this model can be used to optimize total economic gains or losses by replacing function \( P[u(t), H(S(t))] \) in the performance index by function \( G[P[u(t), H(S(t)), t] \) which represents the economic gain associated with power generation \( P[u(t), H(S(t))] \) in hour \( t \). Alternatively (but not equivalently), one could determine the hourly power generation which minimizes the sum of square
deviations from an hourly target power demand sequence \( \{ P^*(t), t = 0, 1, \ldots, 23 \} \). Namely, in this case, the objective would be to

\[
\min J_s[R, H(s(0))] = \sum_{t=0}^{23} F[u(t)] - (P^*(t) - P[u(t), H(S(t))])^2.
\]

This procedure recognizes the need to generate more power during the peak generation period, but does not explicitly maximize economic gains.

4. The above-formulated problem is solved by the Extended Linear Quadratic Gaussian (ELQG) control method to be discussed in Section 5.5. However, in cases where daily inflow and outflow is a small fraction of reservoir storage, the problem can be considerably simplified assuming that reservoir level remains constant. This problem does not include the storage dynamical equation and associated constraints \( (S_{\min}/S_{\max}) \) and is solved via a one dimensional dynamic programming scheme.

5. Repeated solution of the short range problem for various combinations of initial reservoir levels \( H(S(0)) \) and \( (R-I) \) yields the daily energy generation (or energy revenue) function \( E[H(S(0)), R-I] \), the daily flood damage function \( F[H(S(0)), R-I] \), and the daily spillage function \( S_r[H(s(0)), R-I] \), where \( (R-I) \) is the daily release minus the daily inflow. These functions are computed once, in an offline mode, and are used by the mid range control model to represent the benefits and costs associated with particular combinations of reservoir levels, daily releases, and inflow forecasts. If the daily inflow is not appreciable relative to reservoir storage and release, the previous functions are derived in terms of the daily release \( R \), not the difference \( R-I \).

Results from the short range management model for Trinity, Shasta, Oroville, and Folsom are presented in Figures 67 and 68 at the end of this Chapter. Figure 67 shows the daily energy generation functions obtained through the optimization process described earlier. These functions are used by the mid range management model to translate daily release volumes into daily energy generation. Figure 68 depicts typical examples of 24-hour power generation sequences that correspond to each point of the daily generation functions.

### 5.4 Mid Range Reservoir Management

The mid range management model has a time resolution of one day and a time horizon of several months. The link with the short range control model are the daily energy generation, flood damage, and spillage functions, which ensure that the benefits and consequences associated with daily decisions are realizable in an hourly sense. The mid range model also uses the seasonal forecasts provided by the forecasting component. The purpose of the model is to (1) assess the relevant operational tradeoffs and (2) determine the reservoir releases associated with the tradeoff regions that might interest the management authorities.
The mathematical formulation of the mid range management problem is similar to that of the short range model, except that it applies to daily quantities and has a control horizon that extends over several months. The objective is to determine the daily release sequences \( \{u(t), t = 0, ..., N-1\} \) that

\[
\begin{align*}
\text{minimize} & \quad J_M[H(S(0))] = \sum_{t=0}^{N-1} F_t[H(S(t), u(t) - w(t)] - E[H(S(t)), u(t) - w(t)] \\
& \quad + S_p[H(S(t)), u(t) - w(t)] + c(t) [S(t) - S^{max}(t)]^2 + c(N) [S(N) - S^{max}(N)]^2
\end{align*}
\]

subject to

\[
\begin{align*}
S(t + 1) &= S(t) - u(t) + w(t) - L(t), \quad t = 0, ..., N - 1, \quad S(0) = \text{known}, \\
E_{\min}(t) &\leq E[H(S(t)), u(t) - w(t)] \leq E_{\max}(t), \quad t = 0, ..., N - 1, \\
u_{\min}(t) &\leq u(t) \leq u_{\max}(t), \quad t = 0, ..., N - 1, \\
S_{\min}(t) &\leq S(t) \leq S_{\max}(t), \quad t = 0, ..., N,
\end{align*}
\]

where \( t \) is the time index (in days); \( N \) is the length of the control (and forecast) horizon; \( F_t[\ ] \) is the daily flood damage or cost function associated with initial reservoir level \( H(S(t)) \), daily release \( u(t) \), and inflow forecast \( w(t) \); \( E[\ ] \) is the daily energy generation function; \( S_p[\ ] \) is the daily spillage function; \( S(t) \) is reservoir storage at the beginning of day \( t \); \( L(t) \) is reservoir loss or gain due to water diversions and surface precipitation and evaporation if the latter are significant; \( E_{\min}/E_{\max} \) are energy generation requirements based on energy contracts; \( u_{\min}/u_{\max} \) are daily release constraints reflecting water supply, environmental, ecological, flood control, and other operational requirements; \( S_{\min}/S_{\max} \) are storage constraints reflecting flood control and recreational requirements, and \( \{c(t), t = 0, 1, ..., N\} \) are coefficients penalizing storage deviations away from its maximum levels \( S_{\max}(t) \). The following comments clarify various aspects of the mid range reservoir management model formulation.

1. The daily inflow process \( \{w(t), t=0, 1, ..., N-1\} \) is characterized by forecast ensembles and is thus probabilistic. This inflow characterization is necessary in the mid range model in light of the significant magnitude and uncertainty associated with seasonal inflows. In view of this, the performance index is a random variable, and the objective of the optimization is to minimize its mean or a certain percentile. Furthermore, the storage constraints are understood in a probabilistic sense,

\[
\begin{align*}
\text{Prob}[S_{\min}(t) \leq S(t)] &\geq \pi_{\min}(t), \quad t = 0, ..., N, \\
\text{Prob}[S(t) \leq S_{\max}(t)] &\geq \pi_{\max}(t), \quad t = 0, ..., N,
\end{align*}
\]
where $T_i^{\text{min}}$ and $T_i^{\text{max}}$ are user defined probabilistic levels for keeping the reservoir storage respectively higher and lower than $S_i^{\text{min}}$ and $S_i^{\text{max}}$ at prescribed reliabilities.

2. The mid range objective function aims to minimize flood damage and spillage (i.e., spillway releases in excess of turbine capacity), maximize energy generation, and maintain reservoir levels as high as possible while meeting water supply and environmental flow requirements. Clearly, these objectives cannot be fully met all at the same time. For this reason, the model is intended first to assess the tradeoffs among the various water uses. Tradeoffs are important information that management authorities can use to select management options in a dynamic fashion. For example, in any given season, a key decision is the portion of reservoir storage that should be reserved for flood control versus energy generation and other purposes. Clearly, more flood control storage would reduce the risk of flood damage. However, it would also draw reservoir levels down and could potentially compromise energy generation and other water uses (e.g., water supply and low flow augmentation) in the ensuing dry season. On the other hand, if the inflow forecast reliably indicates a drier than normal climate, the risks of reducing flood control storage would be small, and the impact to the other water uses less significant. Similar considerations apply to generating more energy versus keeping reservoir levels higher for use in future seasons. Thus, deriving and studying tradeoffs provides an insightful appreciation of the inter-relations among water uses and establishes a holistic perspective of water management.

In the INFORM DSS, tradeoffs are quantified by gradually increasing the reliability parameters and the coefficients $c(t)$. The relationships of various quantities (e.g., flood risk, energy generation, terminals storage, risk of not meeting water supply and low flow requirements, etc.) are then examined and compared. After reviewing this information, the management authorities can decide on an acceptable compromise between benefits and risks. Once a decision is made, the INFORM DSS determines the associated release and storage sequences and is ready to activate the short range management model to refine the daily release volumes into consistent hourly decisions. This process is intended to be sequential and be reevaluated adaptively as time progresses and as more accurate information is collected on the state of the system, the hydrology, and the demands.

3. The above-stated problem is solved by the extended linear quadratic Gaussian control method developed by A. Georgakakos and associates (described in the next section and the cited references), a method suitable for multidimensional and uncertain reservoir systems. The mid range management problem is formulated and solved for each individual reservoir, and it could thus be solved using a one dimensional dynamic programming algorithm. However, for consistency with the basin-wide reservoir coordination that is carried out at the long range planning model, the mid range reservoir management problem is solved using ELQG, a dynamic optimization algorithm suitable for multi-reservoir uncertain systems. ELQG is an explicitly stochastic optimization method, determining releases that optimize with respect to the entire
forecast ensemble, not with respect to individual traces. ELQG is described in detail in the following section, long range planning, where it is more generally and uniquely applicable.

Results from the mid range control model for Folsom and Oroville are included in Figures 69, 70, 71, and 72. These Figures present example model runs with a 90-day forecast and management horizons. The reservoir management purpose for these runs is to determine releases that meet the minimum and maximum release requirements while maintaining (1) reservoir levels as high as possible and (2) the probability of spillage less or equal to 10%. The graphs indicate that the model accomplishes this objective by keeping reservoir levels near the top of the conservation storage with 90% of the traces being within the pre-specified storage limits. The INFORM DSS can be used to generate operational tradeoffs by varying the reliability levels and other parameters (e.g., minimum and maximum release levels and storages) and running the model to explore the impacts that these changes might have on the system’s performance relative to its various objectives (e.g., the reliability of meeting water supply and environmental flow targets, energy generation, and flood protection requirements).

5.5 Long Range Planning

The long range planning model has a time resolution of one month and a time horizon of one to two years. In contrast to the preceding DSS models, the long range planning model represents the entire Northern California River and reservoir system and aims to assess applicable planning tradeoffs and develop coordinated planning strategies.

The long range planning model includes comprehensive simulation and optimization routines described next.

5.5.1 System Simulation Model

The simulation model for the Northern California river and reservoir system was developed based on input received by the California Department of Water Resources, the US Bureau of Reclamation DWR, and the US Army Corps of Engineers in the form of personal discussions, email communications, water balance and demand spreadsheets, and internal agency technical reports. The entire system is divided into 6 sub-systems based on hydrological network location and functionality. These subsystems are as follows (Figure 10):

- Trinity River System (Clair Engle Lake, Trinity Power Plant, Lewiston Lake, Lewiston Plant, JF Carr Plant, Whiskeytown, Clear Creek, and Spring Creek Plant);
- Shasta Lake System (Shasta Lake, Shasta Power Plant, Keswick Lake, Keswick Plant, and the river reach from Keswick to Wilkins);
• Feather River System (Oroville Lake, Oroville Power Plants, Thermalito Diversion Pond, Yuba River, and Bear River);
• American River System (Folsom Lake, Folsom Plant, Natoma Lake, Nimbus Plant, Natoma Plant, and Natoma diversions);
• San Joaquin River System (New Melones Lake, New Melones Power Plant, Tulloch Lake, Demands from Goodwin, and Inflows from the main San Joaquin River); and
• Bay Delta (Delta Inflows, Delta Exports, Coordinated Operation Agreement--COA, and Delta Environmental Requirements).

The model formulation and associated assumptions for each subsystem are fully described next.

5.5.1.1 Trinity Sub-system

The Trinity River System includes Clair Engle (or Trinity) Lake, Trinity Power Plant, Lewiston Lake, Lewiston Plant, JF Carr Plant, Whiskeytown, Clear Creek, and Spring Creek Plant. The Clair Engle Lake is operated to meet the minimum and target flows in the Trinity River, and the monthly target storage for Whiskeytown reservoir. This system is described by the following water balance equations:

Whiskeytown:

\[ S_{WH}(k+1) = S_{WH}(k) + I_{WH}(k) - \text{EVP}_{WH}(S_{WH}(k),k) + R_{JF}(k) - R_{CC}(k) - R_{SC}(k) \]

Clair Engle Lake (Trinity):

\[ S_{CL}(k+1) = S_{CL}(k) + I_{CL}(k) - \text{EVP}_{CL}(S_{CL}(k),k) - R_{CL}(k) \]

\[ R_{CL}(k) = R_{LE}(k) + R_{JF}(k) \]

where

\( k \) is the time step in months;

\( S_{WH}, I_{WH}, \) and \( \text{EVP}_{WH} \) are respectively the storage, inflow, and evaporation loss of Whiskeytown;

\( R_{CC} \) is the minimum river flow requirement for Clear Creek;

\( R_{SC} \) is the target flow for Spring Creek plant;

\( R_{JF} \) is the flow through JF Carr plant;

\( R_{LE} \) is the minimum river flow requirement for Trinity River; and
SCL, ICL, EVPCL, RCL are respectively the storage, inflow, evaporation loss, and release of Clair Engle Lake.

5.5.1.2 Shasta Lake Sub-system

The Shasta Lake System includes Shasta Lake, Shasta Power Plant, Keswick Lake, Keswick Plant, and the river reach from Keswick to Wilkins. The Shasta Lake is operated to meet the minimum and the target flow at Wilkins on the Sacramento River and share (if specified) the water supply in the Delta. The dynamical response of Shasta Lake and flow at Wilkins are described by the following equations:

**Shasta Lake:**

\[
S_{SH}(k+1) = S_{SH}(k) + I_{SH}(k) - EVP_{SH}(S_{SH}(k), k) - R_{SH}(k);
\]

\[
R_{SH}(k) = R_{KE}(k) - R_{SC}(k) + Q_{DISH};
\]

\[
R_{KE}(k) = \max[R_{KE}^{\min}(k), Q_{Wilk}^{\min}(k) - R_{CC}(k) - I_{Wilk}(k)];
\]

**Flow at Wilkins:**

\[
Q_{Wilk}(k) = R_{CC}(k) + R_{KE}(k) + I_{Wilk}(k);
\]

where

\(S_{SH}, I_{SH}, EVP_{SH}, R_{SH}\) are respectively the storage, inflow, evaporation loss, and release of Shasta Lake;

\(R_{KE}\) is the release of Keswick reservoir;

\(R_{KE}^{\min}\) is the minimum Keswick release requirement;

\(Q_{Wilk}^{\min}\) is the minimum river flow requirement at Wilkins;

\(I_{Wilk}\) is the local inflow between Keswick and Wilkins; and

\(Q_{DISH}\) is Shasta’s share of the Delta demand.

5.5.1.3 Feather River Sub-system

The Feather River System includes Oroville Lake and power plants, Thermalito Diversion Pond, Yuba River, and Bear River. The inflows from Yuba and Bear are combined in the simulation model. The flow contributions to the Delta from both rivers are lumped into an aggregate quantity called *Sacramento Accretion*. The Oroville Lake is operated to meet the demand associated with Thermalito and the Feather River minimum and target flow requirements, and share (if specified) the water demand of the Bay Delta. The system dynamics of Oroville Lake and flow downstream of Thermalito on the Feather River are described by the following equations:
**Oroville Lake:**

\[
S_{OR}(k+1) = S_{OR}(k) + I_{OR}(k) - EVP_{OR}(S_{FO}(k),k) - R_{OR}(k);
\]

\[
R_{OR}(k) = D_{TH}(k) + \max(Q_{TH}^{\text{min}}(k),Q_{TH}^{\text{TGT}}(k)) + Q_{D\text{OR}};
\]

**Flow at Thermalito:**

\[
Q_{TH}(k) = R_{OR} - D_{TH}(k);
\]

where

\(S_{OR}, I_{OR}, EVP_{OR}, R_{OR}\) are respectively the storage, inflow, evaporation loss, and release of Oroville Lake;

\(D_{TH}\) is the demand from Thermalito;

\(Q_{TH}^{\text{min}}\) and \(Q_{TH}^{\text{TGT}}\) are the minimum and target flow requirement downstream of Thermalito; and

\(Q_{D\text{OR}}\) is the Oroville share of the Delta demand.

### 5.5.1.4 American River Sub-system

The American River System includes the Folsom Lake, Folsom Plant, Natoma Lake, Nimbus Plant, Natoma Plant, and Natoma diversions. The Folsom Lake is operated to meet the demands of the Natoma reservoir and the minimum and the target flow requirements on the American River, and share (if specified) the water demands of the Delta. The dynamics of Folsom Lake and the flow downstream of Nimbus are described by the following equations:

**Folsom Lake:**

\[
S_{FO}(k+1) = S_{FO}(k) + I_{FO}(k) - EVP_{FO}(S_{FO}(k),k) - R_{FO}(k);
\]

\[
R_{FO}(k) = \max(Q_{NI}^{\text{min}}(k),Q_{NI}^{\text{TGT}}(k)) + DPM_{FO}(k) + D_{FS}(k) + Q_{D\text{FO}};
\]

where

\(S_{FO}, I_{FO}, EVP_{FO}, R_{FO}\) are respectively the storage, inflow, evaporation loss, and release of Folsom Lake;

\(DPM_{FO}\) is the demand for Folsom pumping;

\(D_{FS}\) is the demand for Folsom South Canal;

\(Q_{NI}^{\text{min}}\) and \(Q_{NI}^{\text{TGT}}\) are the minimum and target flows downstream of Nimbus; and

\(Q_{D\text{FO}}\) is Folsom’s share of the Delta demand.
5.5.1.5 San Joaquin River Sub-system

The San Joaquin System includes New Melones Lake, New Melones Power Plant, Tulloch Lake, Demands from Goodwin, and the inflows from the main San Joaquin River. The New Melones is operated to meet the demands at Goodwin and the minimum and the target flow requirement downstream. The system dynamics of New Melones Lake, Tulloch Lake, and the river flow at Vernalis are described by the following equations:

New Melones:
\[ S_{NM}(k+1) = S_{NM}(k) + I_{NM}(k) - EV_{NM}(k) - R_{NM}(k); \]

Tulloch:
\[ S_{TU}(k+1) = S_{TU}(k) + R_{NM}(k) - R_{TU}(k); \]
\[ R_{TU}(k) = D_{CUP}(k) + D_{OIID/SSJD}(k) + \max(Q_{GO}^{min}(k), Q_{GO}^{TGT}(k)); \]
\[ R_{NM}(k) = R_{TU}(k) + (S_{TU}^{TGT}(k+1) - S_{TU}(k)); \]

Flow at Vernalis:
\[ Q_{VE}(k) = \max(Q_{GO}^{Min}(k), Q_{GO}^{TGT}(k)) + I_{ISJR}(k); \]

where
\[ S_{NM}, I_{NM}, EV_{NM}, R_{NM} \] are respectively the storage, inflow, evaporation loss, and release of the New Melones Lake;
\[ S_{TU}, R_{TU} \] are the storage and release of Tulloch;
\[ D_{CUP} \] and \[ D_{OIID/SSJD} \] are the demands at Goodwin;
\[ S_{TU}^{TGT} \] is the target storage of Tulloch Lake;
\[ Q_{GO}^{min} \] and \[ Q_{GO}^{TGT} \] are the minimum and target flows downstream of Goodwin;
\[ Q_{VE} \] is the river flow at Vernalis; and
\[ I_{ISJR} \] is the inflow from Jan Joaquin above the Stanislaus junction.

5.5.1.6 Bay Delta

The Delta receives inflows from the Sacramento River, San Joaquin River, and several local streams. In addition to the consumptive use inside the Delta and the environmental constraints, the Delta provides storage for exporting water to the south part of California through pumping. Under normal hydrological conditions, the Delta inflows can meet
the Delta demands and the water export targets. However, during dry water years, extra water has to be released from the upper major reservoirs to meet the Delta demands. The required extra water is shared by the large reservoirs in the Sacramento River basin (Clair Engle Lake, Shasta, Oroville, and Folsom). The shared percentage and operation rules in the simulation follow the Agreement of Coordinated Operation (COA) but can also be modified by the program user.

**Delta Inflows:**

The local Delta inflows include:

- Sacramento Valley Accretion: $I_{SV}(k)$;
- Freeport Treatment Plant: $I_{FT}(k)$;
- Eastside Stream: $I_{ES}(k)$;
- Miscellaneous Creeks Inflow: $I_{MC}(k)$;
- Yolo bypass: $I_{VB}(k)$; and
- Transfer Inflow: $I_{TI}(l)$.

**Freeport Flow:**

$$Q_{FP}(k) = Q_{CC}(k) + Q_{KE}(k) + Q_{NI}(k) + Q_{TH}(k) + I_{SV}(k) + I_{FT}(k).$$

**Total Delta Inflow:**

$$I_{DE}(k) = Q_{FP}(k) + Q_{VE}(k) + I_{ES}(k) + I_{VB}(k) + I_{TI}(k) + I_{MC}(k).$$

**Delta Exports:**

The Delta water exports are determined jointly by the US Bureau of Reclamation (USBR) and the State Department of Water Resources (DWR). Federal exports include:

- CCWD Diversion, DCCWD;
- Barker Slough, DBS;
- Federal Tracy Pumping, DFTPP;
- Federal Banks on-peak, DFBON;
- Federal Banks off-peak, DFBOFF;
- Federal Banks Pumping total, DFPPTOT;
- Federal Banks PP CVC, DFBPPCVC;
- Federal Banks PP Joint, DFBPPJNT; and
• Federal Banks PP Transfer, DFBPPTR;

The total federal pumped water is estimated as follows:

\[ D_{FPPTOT}(k) = D_{FTP}(k) + D_{DFBON}(k) + D_{DFBOFF}(k) + D_{FBPP}(k) + D_{FBPPCVC}(k) + D_{FBPPINT}(k) + D_{FBPPTR}(k) \]

The total federal planned export is the sum of the federal pumped water and the CCWD diversion:

\[ D_{FEXTOT}(k) = D_{FPPTOT}(k) + D_{CCWD}(k) \]

State water exports include:

• NBA Diversion, DNBA;
• State Banks PP, DSBPP; and
• State Tracy PP, DSTPP.

The total state export is computed as the sum of the previous components:

\[ D_{SEXTOT}(k) = D_{NBA}(k) + D_{SBPP}(k) + D_{STPP}(k) \]

The total planned export from both federal and state is computed as follows:

\[ D_{EXTOT}(k) = D_{SEXTOT}(k) + D_{FEXTOT}(k) + D_{SE}(k) \]

**Delta Coordinated Operation Agreement (COA):**

The Delta COA is described using the following notation:

• Required Delta Outflow, QminDlt;
• Delta Consumptive Use, Ddlt;
• Combined required reservoir release, QRES:

\[ QRES(k) = \max(0, D_{DR}(k) + D_{EXTOT}(k) + Q_{min}^{dir}(k) - I_{SV}(k) - Q_{VE}(k) - I_{FI}(k) - I_{ES}(k) - I_{MC}(k) - I_{VB}(k)) \]

Total Federal Storage Withdrawal, DSFTOT:

\[ DS_{FTOT}(k) = (R_{CC}(k) - I_{WH}(k)) + (R_{KE}(k) - I_{SH}(k)) + (R_{FO}(k) - I_{FO}(k)) \]

• Total State Storage Withdrawal, DSSTOT:

\[ DS_{STOT}(k) = (R_{OR}(k) - I_{OR}(k)) \]

• Computed Delta Outflow, QDlt:
\[ Q_{\text{Dr}}(k) = Q_{\text{FP}}(k) + I_{\text{YB}}(k) + Q_{\text{VE}}(k) + D_{\text{Dr}}(k) - D_{\text{EXTOT}}(k) + I_{\text{ES}}(k) + I_{\text{MC}}(k); \]

- Estimated Excess Outflow, QESTOT:
  \[ Q_{\text{ESTOT}}(k) = (Q_{\text{Dr}}(k) - Q_{\text{min}}^{\text{Dr}}(k)); \]

- Un-stored Flow for Export, QUFE:
  \[ Q_{\text{UFE}}(k) = \begin{cases} D_{\text{EXTOT}}(k) + Q_{\text{ESTOT}}(k) - (DS_{\text{FTOT}}(k) + DS_{\text{STOT}}(k)), & \text{if } DS_{\text{FTOT}}(k) + DS_{\text{STOT}}(k) < D_{\text{EXTOT}}(k) \\ 0, & \text{otherwise} \end{cases} \]

- Estimated in-basin use of storage withdrawal, Qinbasin:
  \[ Q_{\text{INBSN}}(k) = \max(0, DS_{\text{FTOT}}(k) + DS_{\text{STOT}}(k) - D_{\text{EXTOT}}(k)) \]

- USBR Allowable Export, MAX DFEXTOT:
  \[ D_{\text{DFEXTOT}}^\text{max}(k) = \begin{cases} D_{\text{DFEXTOT}}(k), & \text{if } Q_{\text{Dr}}(k) > Q_{\text{Dr}}^{\text{min}}(k), \\ 0.55Q_{\text{UFE}}(k) + DS_{\text{FTOT}}(k), & \text{if } Q_{\text{UFE}}(k) > 0 \\ DS_{\text{FTOT}}(k) - 0.75Q_{\text{INBSN}}(k) & \text{otherwise} \end{cases} \]

- USBR Monthly COA Account, QFCOA:
  \[ Q_{\text{FCOA}}(k) = \begin{cases} 0, & \text{if } Q_{\text{Dr}}(k) > Q_{\text{Dr}}^{\text{min}}(k), \\ D_{\text{DFEXTOT}}^\text{max} - D_{\text{DFEXTOT}}(k), & \text{otherwise} \end{cases} \]

- Accumulated COA(k), SCOA:
  \[ S_{\text{SCO}}(k + 1) = S_{\text{SCO}}(k) + Q_{\text{FCOA}}(k) \]

- Adjusted Delta Outflow, QDlta:
  \[ Q_{\text{Dlta}}(k) = Q_{\text{FP}}(k) + I_{\text{YB}}(k) + Q_{\text{VE}}(k) + D_{\text{Dr}}(k) - D_{\text{DFEXTOT}}^\text{max}(k) + I_{\text{ES}}(k) + I_{\text{MC}}(k) + I_{\text{YB}}(k) \]

- Adjusted Excess Outflow, QESTOTA:
  \[ Q_{\text{ESTOTA}}(k) = (Q_{\text{Dlta}}(k) - Q_{\text{Dr}}^{\text{min}}(k)) \]

- Rio Vista Flow, QRV:
  \[ Q_{\text{RV}}(k) = \begin{cases} 0.87Q_{\text{FP}}(k) - 0.333 \times 2632 - 1000, & \text{if } \text{XChannelGate} = 1, \\ 0.7Q_{\text{FP}}(k) - 0.333 \times 2632 - 2050, & \text{if } \text{XChannelGate} = 0, \\ 0.5(0.87Q_{\text{FP}}(k) - 0.333 \times 2632 - 1000 + 0.7Q_{\text{FP}}(k) - 0.333 \times 2632 - 2050), & \text{otherwise} \end{cases} \]

**Bay Delta Environment:**

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The Delta environmental conditions are simulated based on the following notation and relationships:

- X Channel Gates, XGopt;
- Cross Delta Flow, Qxdlt:
  \[
  Q_{\text{xdlt}}(k) = \begin{cases} 
  0.133Q_{\text{fp}}(k) + 829, & \text{if } X\text{ChannelGate} = 1, \\
  0.293Q_{\text{fp}}(k) + 2090, & \text{if } X\text{ChannelGate} = 0, \\
  0.213Q_{\text{fp}}(k) + 1460, & \text{otherwise}
  \end{cases}
  \]
- Antioch Flow, QAN:
  \[
  Q_{\text{an}}(k) = 0.8(Q_{\text{ve}}(k) + 2/3D_{\text{dl}}(k) - D_{\text{extot}}(k) + Q_{\text{xdr}}(k))
  \]
- QWEST:
  \[
  Q_{\text{west}}(k) = Q_{\text{an}}(k)/0.8 + I_{\text{es}}(k)
  \]
- Computed Delta/Inflow Ratio (%), DI%:
  \[
  \text{DI}\%(k) = (Q_{\text{extot}}(k) - \text{CCWD})/I_{\text{de}}(k)
  \]
- X2 Location (km from GG), X2:
  \[
  X2(k) = 122.2 + 0.3287X2(k-1) - 17.65\log(Q_{\text{dr}}(k))
  \]
- Supplemental project water, QSup:
  \[
  Q_{\text{sup}}(k) = D_{\text{ftot}}(k) + D_{\text{stot}}(k) - D_{\text{extot}}(k)
  \]

**South Delta Formulation:**

The exports south of the Delta are simulated based on the following notation and relationships:

- Delta Mendota Canal, DDM;
- Federal Dos Amigos, DFDA;
- Federal O\text{N}e\text{il} to Dos Amigos, DFODS;
- San Felip Demands, DSF;
- Cross Valley Demands, DCV;
- Federal South Exports in O\text{N}e\text{il}, DFEXO;
- Federal South Exports in San Luis, DFEXSL;
• Federal San Luis Pumping, QFSL:
\[ Q_{\text{FSL}}(k) = D_{\text{DM}}(k) + D_{\text{FDA}}(k) + D_{\text{FODA}}(k) + D_{\text{FPPTOT}}(k) - D_{\text{FEXO}}(k) - 0.47 \text{Evp}_{\text{Oneil}} \]

• Federal Storage in San Luis, SSLF:
\[ S_{\text{SLF}}(k+1) = S_{\text{SLF}}(k) + Q_{\text{FSL}}(k) - D_{SF}(k) - 0.47 \text{Evp}_{\text{Oneil}} \]

• South Bay Demand, DSB;

• State Dos Amigos Demand, DSDA;

• State San Luis Pumping, QSSL:
\[ Q_{\text{SSL}}(k) = D_{\text{SEXTOT}}(k) - D_{\text{SI}}(k) - D_{\text{SDA}}(k) - 0.53 \text{Evp}_{\text{Oneil}} \]

• State Storage in San Luis, SSLS:
\[ S_{\text{SSLS}}(k) = S_{\text{SSLS}}(k) + D_{\text{SSL}}(k) - 0.53 \text{Evp}_{\text{Oneil}} \]

The previous relationships provide the means to simulate the month-by-month response of the Northern California system to a particular set of inflows, demands, and operational policies.

### 5.5.2 Simulation Model Validation

To determine the validity of the INFORM DSS system simulation model described in the previous section and to demonstrate its utility in relation to other commonly used models, a comprehensive comparison with CALSIM (reference) was performed. CALSIM is also a monthly model but includes considerable detail with respect to withdrawals occurring at the various reaches of the Trinity, Sacramento, Feather, American, Yuba, and San Joaquin Rivers. The INFORM DSS simulation model includes a more aggregate system representation but is the basis for a more advanced system optimization model to be described in the next section. The purpose of the comparison presented herein is to investigate whether the two simulation models yield consistent results under the same hydrologic and demand conditions and reservoir release policies.

#### 5.5.2.1 Comparison Set-up

The model comparison included the following steps:

(i) CALSIM and its necessary computational accessories (databases and auxiliary programs) were acquired (reference site) and rendered operational at the Georgia Water Resources Institute computer facility;

(ii) CALSIM was run using data from the CALSIM 2001 Level-of-Development Benchmark Study;
(iii) The CALSIM hydrologic (inflows, evaporation coefficients, etc.) and demand sequences were aggregated to the spatial aggregation level used by INFORM DSS;

(iv) INFORM DSS was run using the previous sequences and the CALSIM reservoir releases;

(v) CALSIM and INFORM DSS simulation results were finally compared to assess consistency with respect to major reservoir storages, river node flows, and the X2 location.

An example of the spatial aggregation performed on the CALSIM sequences for use by the INFORM DSS is provided in Figure 73, depicting a section of the American River. Specifically, the Figure shows that INFORM represents inflows to the Folsom reservoir and demands taken out of Natoma, while CALSIM includes a more detailed representation of inflows and demands. The aggregation process is described in the Figure. Similar spatial aggregations were performed for all other reaches of the northern California reservoir system.

5.5.2.2 Model Comparison

CALSIM and the INFORM DSS simulation model were compared with respect to river node flows, the X2 location (interface of saline and fresh water), and major reservoir storages. These quantities are compared in the following series of Figures showing the two model sequences. Figures 74, 75, and 76 depict model results for the Delta outflow, Delta X2 location, and major reservoir storages, respectively. CALSIM and INFORM results for the first two quantities are identical. Furthermore, with the exception of Oroville, all CALSIM and INFORM storage sequences also coincide. The discrepancy for the Oroville storage was traced to be due to an error in the CALSIM code. During certain months in the sequence (primarily Septembers), CALSIM adds random quantities in the Oroville water balance equation. The end-of-period reservoir storage calculated by the model in these months differs from the value that would be obtained by adding/subtracting the net inflows/outflows from the beginning-of-period storage.

Notwithstanding this discrepancy, which will hopefully be corrected in future CALSIM versions, the comparison results confirm that the INFORM simulation model is consistent with CALSIM and can be used to represent the response of the Northern California system at the same accuracy level.

In view of the above conclusion, it is recommended that CALSIM and INFORM DSS be used in a manner that re-enforces their individual utility. Namely, the planning process can benefit as follows: First, the INFORM DSS can be employed to generate long range planning tradeoffs and associated reservoir release policies based on seasonal hydro-climatic forecasts. Second, the INFORM DSS policies and forecasts can be used by
CALSIM to develop a more detailed spatial representation of the system processes (inflows, withdrawals, returns) that are more meaningful to individual stakeholders.

5.5.3 System Optimization Model

The optimization model is described by the system dynamics, various constraints, performance index, and optimization method.

5.5.3.1 System Dynamics

System dynamics refers to the system simulation model described in Section 5.5.1. However, the optimization algorithm requires expressing the simulation model equations in state space form. This can be accomplished by assembling the water balance relationships for the major system reservoirs and the equation for the X2 location as follows:

\[
\begin{align*}
S_{CL}(k+1) &= S_{CL}(k) + I_{CL}(k) - EVP_{CL}(S_{CL}(k),k) - R_{CL}(k); \\
S_{OR}(k+1) &= S_{OR}(k) + I_{OR}(k) - EVP_{OR}(S_{FO}(k),k) - R_{OR}(k); \\
S_{SH}(k+1) &= S_{SH}(k) + I_{SH}(k) - EVP_{SH}(S_{SH}(k),k) - R_{SH}(k); \\
S_{FO}(k+1) &= S_{FO}(k) + I_{FO}(k) - EVP_{FO}(S_{FO}(k),k) - R_{FO}(k); \\
S_{NM}(k+1) &= S_{NM}(k) + I_{NM}(k) - EVP_{NM}(S_{NM}(k),k) - R_{NM}(k); \\
X2(k) &= 122.2 + 0.3287 X2(k-1) - 17.65 \log(Q_{DH}(k));
\end{align*}
\]

where

\[
\begin{align*}
Q_{DH}(k) &= Q_{FP}(k) + I_{VB}(k) + Q_{VE}(k) + D_{HR}(k) - D_{EXTOT}(k) + I_{ED}(k) + I_{MC}(k); \\
Q_{FP}(k) &= R_{CL}(k) + R_{SH}(k) + R_{OR}(k) + R_{FO}(k) - D_{TH}(k) + I_{SV}(k) + I_{FT}(k); \\
Q_{VE}(k) &= R_{NM}(k) - D_{CU}(k) - D_{DSSJID}(k) + I_{SR}(k).
\end{align*}
\]

In the previous equations, the two-letter subscript includes the first two letters of the reservoir name; \(k\) is the discretization time interval corresponding to one month; \(S(k)\) is reservoir storage at the beginning of the month; \(EVP(S(k))\) is the net evaporation loss which is a function of reservoir surface area and therefore storage; \(R(k)\) is the release volume during period \(k\); \(I(k)\) is the local inflow volume; \(X2(k)\) is the X2 location at time \(k\); and \(Q_{DH}\) is the delta outflow computed as a function of the flow at Freeport, flow at Yolo Bypass, flow at Vernalis, total Delta demand, total exports from Delta, East Side streams inflow, and inflow from miscellaneous creeks. The terms in the expressions for \(Q_{FP}\) and \(Q_{VE}\) have been defined in the description of the simulation model (Section 5.5.1 and subsections therein).

These equations can be compiled into one vector equation as follows:

\[
S(k+1) = f(S(k),u(k),\xi(k),k);
\]
where \( S(k) \) is the state vector, \( u(k) \) is the vector of controllable releases, \( \xi(k) \) is the vector of uncertain inputs, \( f[k] \) is the state transition (vector) function relating the previous quantities, and \( N \) is the simulation horizon. An important feature of the above equation is that the quantities of its right side pertain only to time period \( k \). Namely, there are no time-lagged quantities involved. This represents the system state equation and is a standard form necessary for the application of dynamic optimization (decision) methods.

The state and control vectors are defined as follows:

\[
S(k) = \begin{bmatrix} S_1(k) \\ S_2(k) \\ S_3(k) \\ S_4(k) \\ S_5(k) \\ S_6(k) \end{bmatrix} = \begin{bmatrix} S_{CL}(k) \\ S_{SH}(k) \\ S_{OR}(k) \\ S_{FO}(k) \\ S_{NM}(k) \\ X_{d}(k-1) \end{bmatrix}, \quad u(k) = \begin{bmatrix} u_1(k) \\ u_2(k) \\ u_3(k) \\ u_4(k) \end{bmatrix} = \begin{bmatrix} R_{CL}(k) \\ R_{SH}(k) \\ R_{OR}(k) \\ R_{FO}(k) \end{bmatrix},
\]

where the initial state vector \( S(0) \) is presumed known. The state transition vector function is defined as shown below:

\[
f(k) = \begin{bmatrix} f_1(k) \\ f_2(k) \\ f_3(k) \\ f_4(k) \\ f_5(k) \\ f_6(k) \end{bmatrix} = \begin{bmatrix} S_{CL}(k) + I_{CL}(k) - EVP_{CL}(S_{CL}(k),k) - R_{CL}(k) \\ S_{SH}(k) + I_{SH}(k) - EVP_{SH}(S_{SH}(k),k) - R_{SH}(k) \\ S_{OR}(k) + I_{OR}(k) - EVP_{OR}(S_{OR}(k),k) - R_{OR}(k) \\ S_{FO}(k) + I_{FO}(k) - EVP_{FO}(S_{FO}(k),k) - R_{FO}(k) \\ S_{NM}(k) + I_{NM}(k) - EVP_{NM}(S_{NM}(k),k) - R_{NM}(k) \\ 122.2 + 0.3287 X_{d}(k-1) - 17.65 \log(Q_{d}(k)) \end{bmatrix}.
\]

Finally, the uncertain inputs associated with each transition equation comprise the input vector \( \xi(k) \):

\[
\xi(k) = \begin{bmatrix} f_1(k) : I_{CL}(k) \\ f_2(k) : I_{SH}(k) \\ f_3(k) : I_{OR}(k) \\ f_4(k) : I_{FO}(k) \\ f_5(k) : I_{NM}(k) \\ f_6(k) : I_{d}(k) \end{bmatrix},
\]

where \( I_{d}(k) \) represents all uncertain inflows to the Bay Delta.

The previous equations summarize the system dynamics. In decision systems terminology, \( S \) is the state vector; \( u \) is the control vector; and \( \xi \) is the input vector. As
discussed next, these quantities are subject to various constraints imposed by physical or operational requirements.

5.5.3.2 Constraints

Generally, the storage and release variables for all reservoirs are constrained to be within certain feasible ranges:

\[ S^\text{min}(k) \leq S(k) \leq S^\text{max}(k) , \quad k = 1, 2, \ldots, N, \]
\[ R^\text{min}(k) \leq R(k) \leq R^\text{max}(k) , \quad k = 0, 1, \ldots, N - 1 . \]

In these relationships, the upper and lower storage limits delineate the extent of reservoir conservation storage and can vary seasonally. The lower release limits represent existing environmental and water supply requirements, aggregated along the river reaches downstream of each reservoir. The upper release limits are determined based on hydro generation and spillway capacities.

In view of the system uncertainties, however, the reservoir storage constraints are more properly expressed in a probabilistic form:

\[ \text{Prob}[S^\text{min}_i(k) \leq S_i(k)] \geq \pi^\text{min}_i(k) , \]
\[ \text{Prob}[S_i(k) \leq S^\text{max}_i(k)] \geq \pi^\text{max}_i(k) , \]

where \( \pi^\text{min}_i \) and \( \pi^\text{max}_i \) are user-specifiable reliability levels. These levels, similar to the upper and lower storage and release limits, can vary seasonally but are usually constant.

The goal of the optimization algorithm is to identify release sequences for all reservoirs \( \{u'(k), i = 1, 2, \ldots, 5; k = 0, 1, \ldots, N-1\} \) such that system objectives and constraints are met successfully. The element of the optimization formulation that brings this to bear and also measures the success of the various operational alternatives is the performance index discussed next.

5.5.3.3 Performance Index

The optimization procedure aims to maximize system-wide benefits, while meeting all environmental and water supply demands. A performance index, \( J \), that can achieve this objective is as follows:

\[ J = \mathbb{E} \left\{ \sum_{k=0}^{N-1} [P_h(S(k)) + P_{\text{hrg}}(S(k)) + P_{\text{urrg}}(u(k)) + P_{\text{spl}}(u(k),S(k)) + P_{\text{hp}}(S(k))] \right. \]
\[ \left. + P_h(S(N)) + P_{\text{hp}}(S(N)) \right\} , \]

where
\[
P_H(S(k)) = \sum_{i \in \text{Reservoirs}} \alpha_{H_i} \left[ \frac{[H_i^{\text{max}} - H_i(S_i(k))]^2}{1 + e^{\frac{H_i^{\text{max}} - H_i(S_i(k))}{T_H}}} + \frac{[H_i^{\min} - H_i(S_i(k))]^2}{1 + e^{\frac{H_i^{\min} - H_i(S_i(k))}{T_H}}} \right],
\]

\[
P_{\text{trg}}(S(k)) = \sum_{i \in \text{Reservoirs}} \alpha_{\text{trg}} \left[ \frac{H_i(S_i(k)) - H_i^{\text{trg}}(k)}{H_i^{\text{max}} - H_i^{\min}} \right]^2,
\]

\[
P_{\text{utrq}}(u(k)) = \sum_{i \in \text{Reservoirs}} \alpha_{\text{utrq}} \left[ \frac{[u_i(k) - u_i^{\text{trg}}(k)]^2}{[u_i^{\text{max}}(k) - u_i^{\text{min}}(k)]^2} \right],
\]

\[
P_{\text{sp}}(u(k), S(k)) = \sum_{i \in \text{Reservoirs}} \alpha_{\text{sp}} \mathcal{SP}_i(u_i(k), S_i(k)),
\]

\[
P_{\text{hp}}(S(k)) = \sum_{i, j \in \text{Reservoirs}} \alpha_{ij} \left[ \frac{H_i(S_i(k)) - H_i^{\text{min}}(k)}{H_i^{\text{max}} - H_i^{\min}} - \frac{H_i(S_i(k)) - H_{ij}^{\text{min}}(k)}{H_i^{\text{max}} - H_{ij}^{\min}} \right]^2.
\]

In the above, \( \mathbb{E}\{ \cdot \} \) denotes expectation of the quantity in the brackets with respect to the joint probability distribution of the reservoir inflows.

There are five penalty terms in the performance index to be minimized through the optimization algorithm. The first term \( P_H(S(k)) \) uses barrier functions (one for each reservoir) to enforce elevation (or equivalently) storage constraints. In this term, \( H_i^{\text{min}}(k) \) and \( H_i^{\text{max}}(k) \) are the lower and upper elevation limits for the \( i \)th reservoir, \( H_i(S_i(k)) \) is the elevation versus storage function, and \( T_H \) is a barrier parameter. Their most important feature is that they are everywhere analytical (with continuous first and second derivatives) and yet delimit with desirable accuracy the conservation storage regions. Namely, inside the \([ H_i^{\text{min}}(k), H_i^{\text{max}}(k) ]\) range, they vanish, while outside of it, they impose a quadratic penalty the severity of which is controlled by the weighing coefficients \( \alpha_{H_i} \). The value of \( \alpha_{H_i} \) should be high enough to ensure that these constraints have priority over other performance index terms. Parameter \( T_H \) controls the smoothness of the transition over \( H_i^{\text{min}}(k) \) and \( H_i^{\text{max}}(k) \), and requires some experimentation. (A value of \( T_H = 0.002 \) has been found to work well.)
The second term $P_{\text{trg}}(S(k))$ penalizes departures from a target level. In this case, the target level is the top of the conservation storage zone. This choice promotes water conservation as well as hydropower generation efficiency. In addition, purely quadratic state and control terms improve the convergence speed of the optimization algorithm to be discussed later.

Similar to the second term, the third term $P_{\text{trg}}(u(k))$ penalizes releases away from some target value. This term is useful if a certain release target pattern is provided. An example is provided in the case studies.

The fourth term, $P_{\text{spl}}(u(k), S(k))$, aims at minimizing spillage. Spillage is defined as the portion of the release which is larger than the turbine capacity. Minimizing spillage is consistent with the long-term goal of maximizing energy generation and conserving water.

The last term $P_{\text{iv}}(S(k))$ aims to operate the system reservoirs in a fairly uniform manner and avoid extreme level fluctuations where some system reservoirs are fully depleted while others remain full.

Penalty parameters $\alpha$ are used to introduce priorities in the performance index terms. These parameters should be determined such that the first term of the performance index is dominant. The rest of the terms are adjusted based on the priority of the operating objective. The logic is to determine feasible sequences guaranteed to minimize the other terms.

It is noted that energy generation terms can also be included in the performance index. However, optimizing long term energy generation is consistent with maintaining high reservoir levels (water conservation) and minimizing spillage, which are also achieved by the previous index terms. To be sure, energy generation terms will have to be included in the short range models for hydropower operations scheduling.

5.5.3.4 Optimization Method

The optimization problem formulated in the previous section is solved using the Extended Linear Quadratic Gaussian (ELQG) control method which was originally introduced by Georgakakos and Marks, 1987, and further developed by Georgakakos 1989, 1991, 1993, Georgakakos et al., 1995a, and Georgakakos and Yao, 1995, Georgakakos et al., 1997a,b,c, and Yao and Georgakakos, 2001. ELQG is an iterative optimization procedure starting from an initial control sequence $\{u(k); k = 0, 1, 2, .., N-1\}$ and subsequently generating increasingly better sequences until convergence. Convergence is achieved when the value of the performance index cannot be reduced any further. ELQG is reliable, computationally efficient, and especially suited for uncertain, multi-reservoir systems. A more detailed account of the ELQG optimization algorithm and features is provided next.
The elements of the optimization problem (system dynamics, constraints, and performance index) are summarized below:

- **System Dynamics:**
  
  \[ S(k+1) = f[S(k), u(k), \xi(k), k], \quad k = 0, 1, ..., N-1, \]

- **Constraints:**
  
  \[
  \begin{align*}
  \text{Prob}[H_i \text{min}(k) \leq H_i(S(k))] & \geq \pi_i \text{min}(k), \\
  \text{Prob}[H_i(S(k)) \leq H_i \text{max}(k)] & \geq \pi_i \text{max}(k), \\
  u_i \text{min}(k) & \leq u_i(k) \leq u_i \text{max}(k), \\
  i & = 1, 2, ..., 6; \quad k = 0, 1, ..., N.
  \end{align*}
  \]

  These are associated with the system reservoirs and are expressed in a probabilistic form due to the uncertain inputs.

- **Performance Index:**
  
  \[
  \text{Minimize} \quad J = E \left\{ \sum_{k=0}^{N-1} g_k[S(k), u(k)] + g_N[S(N)] \right\},
  \]

  where \( S(k), u(k), \) and \( \xi(k) \) are the state, control, and uncertain input vectors defined in the previous section, \( \pi_i \text{min} \) and \( \pi_i \text{max} \) are reliability parameters, \( g_k \) is a function including all performance index terms associated with period \( k \), and \( g_N \) is a function including terms associated with the terminal time \( N \). (As before, bold type indicates vector or matrix quantities.)

  The Extended Linear Quadratic Gaussian (ELQG) optimization procedure starts with an initial control sequence \( \{ u^0(k), \ k = 0, 1, ..., N-1 \} \) and the corresponding mean state vector sequence \( \{ \bar{S}^0(k), \ k = 0, 1, ..., N \} \):

  \[
  \begin{align*}
  \bar{S}^0(k+1) &= f[\bar{S}^0(k), u^0(k), \bar{\xi}(k), k], \\
  \bar{S}^0(0) &= S(0) = \text{known}, \\
  k &= 0, 1, ..., N-1,
  \end{align*}
  \]

  where \( \bar{\xi}(k) \) represents the mean vector of the uncertain input \( \xi(k) \). The next step is to define a perturbation system model valid in the neighborhood of the nominal state and control sequences:

  \[
  \begin{align*}
  \Delta S(k) &= S(k) - \bar{S}^0(k), \quad k = 0, 1, ..., N, \\
  \Delta u(k) &= u(k) - u^0(k), \quad k = 0, 1, ..., N-1, \\
  \Delta \xi(k) &= \xi(k) - \bar{\xi}(k), \quad k = 0, 1, ..., N-1.
  \end{align*}
  \]
This model describes the dynamic relationship of the state, control, and input vector perturbations, and, to a first order approximation, it has the following form:

\[
\Delta S(k+1) = A(k) \Delta S(k) + B(k) \Delta u(k) + C(k) \Delta \xi(k),
\]

\[
\Delta S(0) = 0,
\]

\[k = 0, 1, ..., N-1,\]

where the matrices \(A(k), B(k),\) and \(C(k)\) represent the gradient matrices of the state transition function with respect to the state, control, and input vectors respectively:

\[
A(k) = \nabla_{S(k)} f(k) = \begin{bmatrix}
\frac{d f_1(k)}{d S(k)} \\
\frac{d f_2(k)}{d S(k)} \\
\vdots \\
\frac{d f_d(k)}{d S(k)}
\end{bmatrix},
\]

\[
B(k) = \nabla_{u(k)} f(k) = \begin{bmatrix}
\frac{d f_1(k)}{d u(k)} \\
\frac{d f_2(k)}{d u(k)} \\
\vdots \\
\frac{d f_d(k)}{d u(k)}
\end{bmatrix},
\]

\[
C(k) = \nabla_{\xi(k)} f(k) = \begin{bmatrix}
\frac{d f_1(k)}{d \xi(k)} \\
\frac{d f_2(k)}{d \xi(k)} \\
\vdots \\
\frac{d f_d(k)}{d \xi(k)}
\end{bmatrix}.
\]

The performance index can also be expressed in terms of the perturbation variables as follows:

\[
J = E \left\{ \sum_{k=0}^{N-1} \left[ \frac{1}{2} \Delta S^T(k) Q_{SS}(k) \Delta S(k) + q_1^T(k) \Delta S(k) + \frac{1}{2} \Delta u^T(k) R_{uu}(k) \Delta u(k) + r_u^T(k) \Delta u(k) + \Delta u^T(k) Q_{us}(k) \Delta S(k) \right] \right. \\
\left. + \frac{1}{2} \Delta S^T(N) Q_{SS}(N) \Delta S(N) + q_2^T(N) \Delta S(N) \right\},
\]

where \(Q_{ss}(k), q_1(k), R_{uu}(k), r_u(k), Q_{us}(k)\) are coefficient matrices defining a quadratic approximation of the original performance index. These matrices include the first and second partial derivatives of the \(g_s[\cdot]\) and \(g_u[\cdot]\) functions with respect to the state and control variables evaluated at the nominal sequences.

The perturbation control problem defined above is next solved to generate an optimal control sequence \(\Delta u^*(k), k = 0, 1, ..., N-1\). This constitutes the optimization direction which defines a new nominal control sequence according to the following relationship:

\[
u^\text{new}(k) = u_0^0(k) + \alpha \Delta u^*(k),
\]

\[k = 0, 1, ..., N-1,\]

where \(\alpha\) is the optimization step size. Some important features of the ELQG solution process are summarized below:

- The ELQG iterations are (1) analytically-based (the optimization directions are obtained by Riccati-like equations), (2) reliable (the iteration process is
guaranteed to converge if the problem has a feasible solution), and (3) computationally efficient (convergence is fast). In fact, in the neighborhood of the optimum, it can be theoretically shown that the method converges at a quadratic rate.

- Control constraints are not included in the performance index as penalty terms but are handled explicitly through a Projected-Newton procedure. This has important computational efficiency implications as it allows for many constraints to enter or exit the binding control set at the same iteration. The optimization direction is then obtained in the space of the binding constraints.

- State (or, equivalently, elevation) constraints are handled through the barrier penalty functions discussed in the previous section. This approach has proven to be reliable and computationally efficient. Handling of the state constraints requires the characterization of the state probability density. This is accomplished by developing a linear approximation of the true feedback laws as a by-product of the analytical computation of the optimization direction. These feedback law approximations are used within the state dynamical equation and to generate state variable traces corresponding to each member of the inflow forecast ensemble. The state variable traces characterize fully the joint probability density of the state vector and are used to convert the state probabilistic constraints into deterministic equivalents.

The ELQG iterations continue until the value of the performance index can not be reduced any further. At this point the process terminates, and the current nominal control sequence becomes the solution of the optimization problem. Under convexity conditions (which are usually valid), this solution is globally optimal. (Convexity can be tested by starting the optimization process from different initial control sequences and verifying that the process converges at the same optimal sequence.)

As indicated earlier, the optimization model is applied sequentially, where only the first element of the control sequence is actually implemented. The system is then monitored, new values for the state variables are recorded, new forecast ensembles are generated, and the optimization cycle is repeated at the beginning of the next time period (i.e., at the beginning of the next month). In this way, the model always uses the most recent system information and continually updates its policies to the current demands, storage availability, and hydrologic conditions (adaptive management).

ELQG is unique in that it is the only optimization method that can handle large reservoir systems with an explicit account of uncertainty. More details on this method can be found in the above-cited and in forthcoming references.

5.5.3.5 Long Range Planning Case Study
The case study was performed in March 2006 using real forecasts with a nine-month forecast and management horizon. More specifically,

- Inflow forecast ensembles (112 traces) were generated by the procedures described in Sections 3 and 4 at five locations (Clair Engle Lake, Shasta, Oroville, Folsom, and Yuba) from March 1, 2006, through November 30, 2006 (9 month forecast horizon);
- Historical monthly average values are used for locations where forecasted inflows are not available (Appendix G; Table G-3);
- Monthly reservoir parameters and constraints (max, min, and target storages, and evaporation rates) are recorded in Appendix G, Table G-4;
- Minimum river flow requirements are shown in Appendix G, Table G-5; and
- Base monthly demands at all locations are as reported in Appendix G, Table G-6.

The forecasted inflow sequences are shown on Figure 77. Figure 78 presents comparisons of the forecasted inflow means versus the corresponding historical means for Trinity, Shasta, Oroville, and Folsom. The Figure shows that the forecasted means for March, April, and May are higher than the historical means for all locations, indicating a wet spring season. (It is noted that these results preceded the spring 2006 flooding of the Sacramento River.)

Using the forecasted inflows, tradeoffs are generated by the long range planning model by gradually varying the demand targets at all locations from 80% to 120% of the base demands. Figure 79 depicts the tradeoffs between a) reservoir carry over storage versus demand target level and b) energy generation versus demand target level. As expected, reservoir carryover storage decreases with increasing demands. Depending on the risk level that the management authorities are willing to assume in the next year, this tradeoff can be used to determine water allocations for this year. The energy generation versus demand tradeoff shows that, initially, energy generation increases with increasing demand targets. However, as reservoir releases increase to meet downstream demands, reservoir levels fall, generation efficiency decreases, and energy generation eventually falls (tradeoff point 5; 120% of base demand targets). Overall, these results imply that, under the forecasted inflows and current storage levels, the system could meet up to 10-15% more than the base demand targets. Demands beyond this level would result in reservoir draw downs, water supply deficits, and energy generation losses.

The reservoir and other system sequences corresponding to all tradeoff points are saved in the DSS database. Selected reservoir elevation, release, and energy generation sequences are shown in Figures 80 and 81. Figure 82 shows the X2 location sequences for tradeoff points 3 (100% of base demand targets) and 5 (120% of base demand targets). At tradeoff point 3, due to wetter than normal forecasts, the X2 is located less than 80 km from the Golden Gate Bridge in all scenarios. (The distance of 80
km was used as an upper limit for this state variable.) At tradeoff point 5, however, the X2 location begins to exceed 80 km at the end of November, 2006, for some scenarios. The probability that this might happen can be estimated by the proportion of the traces exceeding 80 km in each month. Finally, Delta outflow sequences are plotted on Figure 83, indicating that the low flow period extends from June to October.

It is noted that the INFORM long range planning model can additionally derive other types of tradeoffs. For example, by establishing a range of minimum Delta outflows or maximum X2 distance limits, one can assess the impacts on other system variables and outputs such as reservoir storages, water supply allocations, and energy generation. Tradeoff information is an important DSS output and can be useful in planning water allocations and reservoir releases with quantitative appreciation of the associated risks.

Once the management authorities decide on the most preferable policy, the INFORM DSS determines the associated reservoir releases and water allocation targets and passes them to the mid range model for operational implementation.

### 5.6 Scenario and Policy Assessment Models

The scenario and policy assessment models are part of the INFORM decision support system, their main purpose being to provide a quantitative and consistent procedure to assess the benefits and risks associated with particular hydrologic scenarios, demand levels, forecasting schemes, and management policies. The assessment process operates in a sequential fashion simulating the system response as it would have occurred under the conditions specified.

The scenario and policy assessment process is depicted on Figure 84 and consists of the sequential, day by day, or month by month, application of the mid range management or long range planning model over a pre-specified simulation horizon. Each assessment first requires selecting the

(a) hydrologic scenario, assessment horizon, and time resolution (i.e., daily or monthly) over which the assessment will be carried out,

(b) demand target levels (i.e., water supply and low flow requirements, energy commitments, and flood management risk thresholds) and management policies, including COA terms, water year characterization rules, and reservoir regulation attributes (i.e., heuristic or adaptive; focused on individual reservoirs or system-wide), and

(c) the inflow forecasting model and forecast horizon (i.e., deterministic or ensemble based; statistical, hydrologic, or hydro-climatic).

After selecting these parameters, the assessment is carried out as follows: First, future inflows are forecasted based on the scheme selected. Next, the mid range management (or the long range planning) model is activated to develop release and
generation schedules for all system reservoirs and hydropower plants. The releases for the first day (or the first month) of the control horizon and the daily (or monthly) inflows (unknown up to this time) are applied, and the system response (reservoir levels, releases, spillage, water supply deficits, energy generation and shortages, flood damage if any, and Delta conditions) is simulated and recorded. This process is repeated for the next day (or month) until the end of the assessment horizon. At the conclusion of the assessment process, several criteria are used to measure system performance, including statistics of water supply deficits, energy generation, flood damage, violation of low flow requirements, reservoir draw downs, Delta X2 location, Delta outflow, and other quantities relevant to system management.

The following sections present assessments pertaining to mid range management and long range planning.

5.6.1 Mid Range Scenario and Policy Assessment Examples

This section describes three assessments with the following attributes and scope:

- The assessments aim to evaluate the response of Trinity, Shasta, Oroville, and Folsom over a 15 year horizon in daily time steps;
- The assessments are carried out over the historical reservoir inflows from 1981 to 1995;
- The mid range management model is run sequentially for each day of the assessment horizon;
- The management objectives are to (a) avoid flooding, (b) pass as much of the release as possible through the plant turbines and avoid spillage (energy generation), (c) meet the applicable minimum flow requirements (water supply and environmental/ecological flows), and (d) maintain high reservoir levels (water conservation and energy generation);
- Inflow forecasts have a forecast horizon of 90 days and are generated by either a Perfect Forecast scheme, which assumes that the upcoming 3 month inflows are perfectly known, or a Historical Analog scheme; The historical analog approach, described in Appendix H, identifies historical periods where inflows exhibited similarity with recently observed inflows and develops a forecast ensemble with the inflow sequences that materialized following these historical periods. These forecasting schemes are used here to establish benchmarks for the more elaborate forecasting schemes to be used in the following Chapter (integrated assessments);
- The assessments differ by the forecasting scheme and the way forecasts are used by the mid range management model; More specifically, the first assessment uses perfect forecasts (one 90-day sequence identical to the forthcoming inflows); The second assessment employs the historical analog forecast scheme with 10
ensemble members but only uses the mean ensemble sequence (i.e., one 90-day sequence representing the conditional ensemble mean) to drive the mid range management model; Lastly, the third assessment also generates historical analog forecasts but uses the full forecast ensemble to drive the mid range management model; In the third case, storage constraints are expected to be met at 90% reliability, while the first and second cases are essentially deterministic.

The results of these assessments are summarized in Figures 85, 86, 87, and 88, and Table 26. Figure 85 displays the Trinity elevation and release sequences associated with the three assessment runs. Figures 86, 87, and 88 show the same information for Shasta, Oroville, and Folsom respectively. These Figures illustrate that reservoir levels and releases differ significantly for each assessment, underscoring the importance of forecast information in the management process.

More specifically, comparing first the deterministic and stochastic historical analog forecast cases (corresponding respectively to the blue and red lines in the figures), one observes that the deterministic case maintains consistently higher reservoir levels but also causes more frequent and more severe spills. This holds true for all reservoirs and occurs because the deterministic HA forecast model communicates (to the management model) information only on the ensemble mean and not the possible extremes. In view of this, the management model cannot anticipate potentially high flows and maintains high reservoir levels, causing more frequent and more severe spills. This is illustrated in Table 26 which shows that the spillage, maximum release, and flood damage associated with the deterministic historical analog model are always higher than (or equal to) those of the stochastic model. Thus, ignoring forecast uncertainty in the management process leads to increased flood risks and, eventually, higher flood damage.

Second, comparing the perfect forecast case with the other two, one can appreciate the value of forecast information for reservoir management. When forthcoming inflows are predicted with good precision, the management model guides the reservoir to meet all objectives more effectively. Thus, high reservoir levels are maintained throughout the assessment horizon, more hydropower is generated, while spillage and flood damage are minimized. When forecast information is imperfect (as in all real world applications), system performance depends critically on forecast precision and reliability. In this regard, narrower and more reliable forecast ensembles lead to better performance. A third desirable forecast attribute is long lead time. In the case of the perfect forecast assessment, system performance would improve further if the forecast lead time extended longer than three months.

While forecast precision, reliability, and long lead time are all necessary attributes for good system performance, they are not also sufficient. The second critical factor for good system performance is the implementation of an adaptive management system that can fully utilize the forecast information and derive dynamic, risk based management policies. Yao and Georgakakos, 2001 illustrate this aspect, demonstrating
that even the best possible forecasts lead to inferior performance if they are coupled with static and heuristic regulation schemes. More specifically, they show that static regulation rules cannot take full advantage of inflow forecasts, leading to less energy generation and inability to balance reservoir management objectives during wet and dry climatic periods.

In Chapter 6, assessments will also be performed with the forecast schemes described in Chapters 3 and 4, and the results will be compared with the baseline results presented in this section.

5.6.2 Long Range Scenario and Policy Assessment Examples

This section discusses four long range assessments with the following attributes and scope:

- The assessments aim to evaluate the response of the entire Northern California system described in Section 5.5.1;
- The assessments are carried out over the historical hydrology from 1970 to 1995 (26 years), in monthly time steps;
- The long range planning model is run sequentially for each month of the assessment horizon;
- The management objectives are to (a) meet water demands and the minimum required flows, (b) meet the Delta requirements associated with the X2 location and the Delta outflow, (c) generate as much energy as possible, and (d) maintain high reservoir levels; The objectives of the assessments are to (a) quantify the capacity of the system to meet increasing demands, (b) assess the potential impacts on other water uses, and (c) evaluate the effectiveness of adaptive forecast-management schemes as a means to mitigate the adverse impacts of increasing stresses;
- Inflow forecasts have a forecast horizon of 3 months and are generated by either a Perfect Forecast scheme, or a Historical Analog scheme forecasting the mean of a 10 member ensemble; These two forecast schemes are selected to provide a range of system performance, the expectation being that most other forecast schemes of interest should yield intermediate performance;
- The assessments differ by the forecasting scheme (previous two options) and by two water demand target levels; The demand targets are determined as a function of the base demands reported in Table G-6 (Appendix G) and as a function of the river index; More specifically, the forecasted inflows, along with the observed inflows up to the current month are used to compute the river index as stipulated by the COA (Appendix I); Based on the river index, the water demands and minimum flow requirements reported in Table G-6 are adjusted according to agreed upon rules; The adjusted demands and minimum flows are
subsequently multiplied by 0.5 or 0.6 (two options) and used as targets in the simulations.

The results of these assessments are summarized on Figures 89 through 94 and Tables 27, 28, 29, and 30. More specifically, Figure 89 shows the simulated reservoir level sequences of Trinity, Shasta, Oroville, Folsom, and New Melones for all four scenarios. Figures 90 and 91 display the release and energy generation sequences for the same five reservoirs. Figure 92 presents the target south exports sequences, the south exports sequences that were actually met, and the deficits incurred, if any. Finally, Figures 93 and 94 depict the simulated sequences of the X2 location and Delta outflow. The tables include statistics on (a) reservoir levels, releases, net evaporation, and inflows (Table 27), (b) energy generation and spillage (Table 28), (c) water demands and associated deficits (Table 29), and (d) maximum X2 location distance (Table 30). The results support the following observations:

**System Capacity to Meet Water Demand Targets:** The 0.5 water demand scenario can be fully met throughout the assessment horizon, without causing violation of any other system requirement (such as minimum flows, Delta environmental conditions, etc.). To meet this water demand scenario, however, reservoir levels fluctuate markedly on seasonal and inter-annual basis. The 0.6 water demand scenario, on the other hand, begins to experience water supply deficits (Delta demand and south exports) and fails to keep the Delta X2 location less than 80 km from the Golden Gate Bridge during the 1991-1992 dry years. This scenario also leads to greater reservoir fluctuations including five to six years of full conservation storage depletion. On average, reservoir levels are 10 to 20 feet lower than those of the 0.5 demand scenario. Scenarios of higher water demands would lead to more frequent and more severe water shortages and failures to meet other system requirements. Thus, the water stress that uses up the system capacity to meet its objectives is estimated to be between 50% and 60% of the base demands (Tables G-5 and G-6).

**Value of Forecast Information:** The results associated with the two forecasting schemes (Perfect Forecasts and Deterministic Historical Analog) show that better forecast information improves system performance and mitigates the impacts of increasing water stress. More specifically, the Perfect Forecast scenario (three months lead time) leads to higher reservoir levels, more energy generation, and increased capacity to meet water demands and the Delta environmental requirements. This is particularly evident at the 0.6 water demand scenario where the Perfect Forecast case practically avoids water supply deficits and maintains the Delta X2 location less than 80 km from the Golden Gate Bridge in all years.

**Need for Reservoir Coordination in Planning and Management:** An interesting observation can be made by comparing the results of the long range planning and the mid range management assessments. The two assessments share a common simulation period from 1981 to 1995. The main difference between the assessments is that the mid range assessment manages the reservoirs individually and does not include potential
interactions that might arise as part of the need to meet Delta demands and environmental conditions. To a certain extent, this approach reflects current practices which during flood periods focus on individual reservoir management (daily or sub-daily operations), while for purposes of long range planning consider the entire system (monthly operations). The assessments show that this incompatibility between planning and management may compromise system performance and lead to potential failures. This can be seen by the different reservoir level sequences generated by the two assessments. More specifically, mid range management objectives and the need to fully use forecast information, occasionally cause significant reservoir draw downs. From the mid range management model standpoint, this is an appropriate operational strategy. Long range planning, on the other hand, concerned with inter-annual droughts and system-wide demands, imposes additional reservoir storage requirements and results in different inter-annual storage sequences. Thus, from a long range planning standpoint, significant reservoir draw downs imply increased drought risks. This incompatibility between mid range management and long range planning can be addressed by expanding the mid range management scope to include a system wide, rather than an individual reservoir, perspective.
<table>
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<th>Perfect Forecasts</th>
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<td></td>
<td></td>
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<td>Deterministic</td>
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<td><strong>Folsom</strong></td>
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### Table 27. Long Range Assessment: Reservoir Statistics

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<th>Folsom</th>
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### Table 28. Long Range Assessment: Hydropower and Spillage Statistics

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<th>Scenarios</th>
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<th>Trinity</th>
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<th>Oroville</th>
<th>Folsom</th>
<th>New Melones</th>
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### Table 29. Long Range Assessment: Water Supply Statistics

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### Table 30. Long Range Assessment: Maximum X2 Location Statistics

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Figure 66. Plant Power Generation as Function of Hourly Discharge and Reservoir Level:  a) Trinity, b) Shasta, c) Oroville, d) Folsom
Figure 67. Plant Daily Generation as Function of Daily Release and Reservoir Level:  a) Trinity, b) Shasta, c) Oroville, d) Folsom
Figure 68. Typical Hourly Power Generation Schedules: a) Trinity, b) Shasta, c) Oroville, d) Folsom
Figure 69. Mid Range Model Example Run for Trinity; 3-month forecast horizon from 1/1/1981
Figure 70. Mid Range Model Example Run for Shasta; 3-month forecast horizon from 1/1/1981
Figure 71. Mid Range Model Example Run for Oroville; 3-month forecast horizon from 4/1/1981
Figure 72. Mid Range Model Example Run for Folsom; 3-month forecast horizon from 1/1/1965
Aggregated INFORM inputs:

Net Folsom Inflow = I300 + I8 - D8 - D300
Net Natoma Demands = I9 - D9 - GS56 + I302 - D302

Figure 73. American River Spatial Aggregation
Figure 74. Delta Outflow Comparisons

Figure 75. X2 Location Comparisons
a) Trinity

b) Shasta
c) Oroville

Storage Sequence - Oroville

Storage (TAF)

Storage Sequence - Folsom

Storage (TAF)

d) Folsom
Figure 76. Reservoir Storage Comparisons:  a) Trinity, b) Shasta, c) Oroville, d) Folsom, and e) New Melones
Figure 77. Long Range Inflow Forecasts from March 1, 2006
Figure 78. Long Range Inflow Forecast vs. Historical Means
Figure 79. Planning Tradeoffs: a) Carry over Storage vs. Demand; b) Energy Generation vs. Demand
Figure 80. Reservoir Storage and Release Sequences associated with Tradeoff Point 3
Figure 81. Energy Generation Sequences associated with Tradeoff Point 3
Figure 82. X2 Location Sequences associated with Tradeoff Points 3 and 5
Figure 83. Delta Outflow associated with Tradeoff Point 3
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Figure 85. Mid Range Assessments: Trinity Elevation and Release Sequences
Figure 86. Mid Range Assessments: Shasta Elevation and Release Sequences
Figure 87. Mid Range Assessments: Oroville Elevation and Release Sequences
Figure 88. Mid Range Assessments: Folsom Elevation and Release Sequences
Figure 89. Long Range Assessments: Reservoir Elevation Sequences
Figure 90. Long Range Assessments: Reservoir Release Sequences
Figure 91. Long Range Assessments: Energy Generation Sequences
Figure 92. South Export and Deficit Sequences
Figure 93. X2 Location Sequences
Figure 94. Delta Outflow Sequences