OPTIMAL SHORT–TERM UNIT COMMITMENT FOR HYDROPOWER SYSTEMS USING DYNAMIC PROGRAMMING

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Abstract: A mathematical model using dynamic programming approach is applied to an optimal unit commitment problem. In this study, the units are treated as stages instead of as state dimension, and the time dimension corresponds to the state dimension instead of stages. A considerable amount of computer time is saved as compared to the normal approach if there are many units in the basin. A case study on the Lower Colorado River Basin System is presented to demonstrate the capabilities of the optimal scheduling of hydropower units.

Key Words: optimal unit-commitment, hydropower systems, dynamic programming

1. INTRODUCTION

Optimal unit commitment model determines which generating units should be committed, and what loads should be placed on each unit to maximize efficiency, while satisfying system load demands, system reliability requirements and operational and security constraints. Depending on the size of the system and prevailing circumstances, a large number of variables may be involved in the problem, with a high percentage constrained to integer values. Mathematically, this is a nonlinear, nonconvex, high dimensional, and large-scale optimization problem over mixed integer variables.

Lowery(1966), Pang et al.(1976), Lauer et al.(1982), Van den Bosch et al.(1985), Snyder et al.(1991), Peterson et al.(1995) developed various kinds of solution techniques to solve optimal unit commitment problem. Yi(1998, 1999) developed optimal unit commitment model using mixed integer programming (MIP) technique and combined MIP technique respectively. The MIP model that consists of three sub-models (PLANT_DY_W, PLANT_GO_W, and PLANT_ST_W) suffers from certain disadvantages. The sub-models PLANT_GO_W and PLANT_ST_W of the MIP model use water release schedule obtained from the first sub-model PLANT_DY_W. However, a discrepancy may exist between unit commitment schedule obtained from PLANT_DY_W and the other two sub-models since they use different sets of constraints. Even though combined MIP model can solve this problem, it is a computationally intensive approach with a large number of integer variables and constraints requiring an extensive computational effort which is not suitable for real-time unit commitment scheduling. New approach using dynamic programming technique is developed to handle these problems in this study.

2. PROBLEM FORMULATION

To apply dynamic programming to the unit commitment problem, the problem should satisfy the following general format for DP problems. First, the problem should be formulated in sequential stages. For the unit commitment problem, if a unit is designated as a stage, a sequential decision process can be applied without difficulty. Secondly, the variables of the problem should be separated into state variables and decision variables. State variables are dependent variables, since their values are determined by the independent decision variables and the state variables for the previous stage.

In applying dynamic programming to the unit commitment problem, there are two approaches to formulating the problem. First, the units are treated as the state dimension and the time dimension is treated as stages. Secondly, the units are treated as stages instead of as state dimension, and the time dimension corresponds to the state dimension instead of stages. By using the second approach, the number of state variables can be reduced for this short-term unit scheduling problem. A considerable amount of computer time is saved as compared to the first approach if there are many units in the entire basin. An additional advantage of the second approach is that if it becomes necessary to add more units later by building new hydroelectric powerplants in the basin, they are easily added by simply increasing the number of stages and the state dimensions remains the same.

In this study, the unit commitment problem is formulated as follows: Suppose there are a total of N units associated with all hydroelectric powerplants in the basin. State variable $x1_{i\tau}$ is defined as the accumulated amount of generation from unit 1 through unit $i-1$, at τ th schedule change. The corresponding decision variable $g_{i\tau}$ is defined as the amount of generation from unit i, at τ th schedule change. State variable $x2_i$ is defined as the accumulated daily releases from unit 1 through unit $i-1$. The corresponding decision variable Q_i is defined as the releases from unit i. The final state variable $x3_{i\tau}$ is defined as the accumulated assigned power capacity from unit 1 through unit $i-1$, at τ th schedule change. The corresponding decision variable $c_{i\tau}$ is defined as the assigned power capacity to unit i, at τ th schedule change. This formulation is expressed in state equations (1) through (3).

$$x1_{i+1,\tau} = x1_{i\tau} + g_{i\tau} \tag{1}$$

$$x2_{i+1} = x2_i + Q_i \tag{2}$$

$$x3_{i+1,\tau} = x3_{i\tau} + c_{i\tau} \tag{3}$$

for $i = 1, \ldots, N$

for all $\tau \in \mathrm{T}$

where $g_{i\tau}$ = generation from unit i, at τ th schedule change in MW; Q_i = daily releases from unit i in cfs; and $c_{i\tau}$ = capacity of unit i, at τ th schedule change in MW. [T = the set representing the number of times the generation shape or capacity requirement changes].

Even though the actual accumulation process may not occur in this step by step manner, it can be viewed in this way for computational purposes. Here, the subscript τ represents the number of times that unit commitment changes should occur. Unit commitment changes occur in the following cases.

• If the required increase or decrease of plant release from the water driven plants is greater than a given deadband.

• If the required increase or decrease of plant generation from the generation driven plants is greater than a given deadband.

• If the required increase or decrease of plant capacity from either water or generation plants is greater than a given deadband.

• If a unit was running in the previous hour, and that unit becomes unavailable at the present hour

• If a unit was down in the previous hour, and that unit becomes a '*must run*' unit at the present hour.

Other than these cases, the unit schedule is assumed to be the same as in the previous hour. By calculating a unit schedule for only these hours, the number of state variables can be reduced from 2 × 24 + 1 to 2 × (number of hours when unit commitment change should occur) + 1.

The third criterion for using DP is that a system state equation must be defined which relates the state variable for stage $i+1$, with the state and decision variable for the previous stage. Basically, the state equation transforms state x_i, which is acted upon by decision u_i, into state x_{i+1}. This assumes that all other inputs and outputs are constant and deterministic. In this study, the state equations are written as equations (1) through (3).

The fourth requirement in conforming to the general format is to have an objective function which is separable. That is, the objective function should be composed of individual objective functions for each stage which are functions of the state and/or decision variables for that particular stage only. There is no restriction on the structure of these individual objective functions. They can be highly nonlinear, or even discontinuous. In this study, the objective of the model is to maximize total generation from water driven hydroelectric powerplants and to minimize water requirements from generation driven plants at the same time. The objective function for stage i is expressed as follows:

$$\max \sum_{i \in A(p)} (BW_i + BG_i)$$

if unit i belongs to water driven plants

$$BW_i = \sum_{\tau \in T} (g_{i\tau} - P2_\tau \cdot b_{i\tau}^2) - P1 \cdot a_i^2 \qquad (4)$$

if unit i belongs to generation driven plants

$$BG_i = -E \cdot \sum_{\tau \in T} [(Q_{i\tau} \cdot H_g \cdot 8.45 \times 10^{-5}) - P2_\tau \cdot b_{i\tau}^2]$$

where BW_i = daily basin generation from unit i at a water driven plant in MWh; LL = daily basin generation from unit i at a generation driven plant MWh; E is assumed average efficiency; $Q_{i\tau}$ = flow through unit i at τ th schedule change in cfs; H_g = gross head for generation driven plant g in ft; $P1$ = penalty coefficient; and $P2_\tau$ = penalty coefficients at τ the schedule change; a_i = difference between daily unit flows calculated from unit generation and real daily unit flows given in equation (5); and $b_{i\tau}$ = difference between assigned unit capacity calculated from unit generation and actual assigned unit capacity as given in equation (12). Trial and error methods are obtain suitable penalty coefficients $P1$ necessary to and $P2_\tau$ values.

A difficulty with this formulation is that there are three different state variables calculated using separate state equations, but which are actually closely related. That is, the sum of hourly releases over 24 hours for unit i calculated from the generation ($g_{i\tau}$) should equal the daily releases for the unit i (Q_i). Also, the assigned capacity converted from generation ($g_{i\tau}$) should equal the directly calculated assigned capacity ($c_{i\tau}$). To encourage the equality of these variables, quadratic penalty terms a_i^2, and $b_{i\tau}^2$ are introduced into the objective function.

$$a_i^2 = (RC_i - Q_i)^2 \quad \text{for all } i \in A(p), \text{ for all } p \in P \tag{5}$$

where RC_i is converted daily unit flow from generation for unit i in MW. RC_i can be obtained as follows:

$$RC_i = \sum_{t=1}^{24} \left(SNF_i \cdot OL_{it} + \frac{GL_{it} \cdot (BP_i - SNF_i)}{HZ_i} + SN_i \cdot OU_{it} + \frac{GU_{it} \cdot (CF_i - SN_i)}{C_i} \right) C_i \cdot GEN_{it} \quad \text{for all } i \in A(p), \text{ for all } p \in P \tag{6}$$

where SNF_i is hourly speed no load flow for unit i in cfs; BP_i is hourly break point flow for unit i in cfs; SN_i is hourly speed no load flow for upper segment for unit i in cfs; CF_i is hourly capacity flow for unit i in cfs; SNF_i, BP_i, SN_i and [illegible] are calculated from flow slope curve for each unit. OL_{it} and OU_{it} are unitless binary variables representing the status of generating: below rough zone, and above rough zone, respectively, at time t for unit i. Parameters GL_{it}, and GU_{it} are generations supplied by generator below and above rough zone at time t for unit i in MW, respectively. Parameters OL_{it}, OU_{it}, GL_{it} and GU_{it} are calculated from state variable $g_{i\tau}$ as follows; Decision variable $g_{i\tau}$ is calculated using state equations (1). Hourly unit generation is calculated as follows:

$$p_{it} = \frac{g_{i\tau}}{\Delta t_t} \quad \text{for } i \in A(p), \text{ for all } p \in P; \ \text{for all } t \in T(\tau), \text{ for all } \tau \in \mathrm{T} \tag{7}$$

where p_{it} = hourly unit generation for unit i at hour i; Δt_t = length of time interval at where the unit schedule does not change; set $T(\tau)$ is defined as a set of hours when unit schedule changes.

If hourly generation p_{it} is greater than 0, then the unit should generate in either upper or lower rough zone. Otherwise, a large penalty value is assigned to the corresponding decision variable $g_{i\tau}$ to avoid the rough zone.

$$\begin{aligned} &\mathit{if}\ p_{it} \geq LL \cdot C_i \\ &\mathit{and}\ p_{it} \leq LZ_i \\ &\mathit{then}\ GL_{it} = p_{it} \\ &OL_{it} = 1 \end{aligned} \tag{8}$$

$$\begin{aligned} &\mathit{elseif}\ p_{it} \geq HZ_i \\ &\mathit{and}\ p_{it} \leq C_i \\ &\mathit{then}\ GU_{it} = p_{it} \\ &OU_{it} = 1 \end{aligned} \tag{9}$$

$$\text{for all } g_{i\tau}, \text{ for all } p \in P; \ \text{for all } g_{i\tau}, \text{ for all } \tau \in \mathrm{T}$$

where LL = percentage of capacity used for low generation level; C_i = capacity limit for unit G in MW; LZ_i = low rough zone limit for unit i in MW; and HZ_i = high rough zone limit for unit i in MW.

If hourly generation p_{it} is less than 0, then the unit should motor.

$$\begin{aligned} &\mathit{if}\ p_{it} < 0 \\ &\mathit{then}\ OM_{it} = 1 \end{aligned} \quad \text{for all } i \in A(p), \text{ for all } p \in P; \ \text{for all } t \in T(\tau), \text{ for all } \tau \in \mathrm{T} \tag{10}$$

where OM_{it} is unitless binary variables representing the motoring status.

If hourly generation p_{it} is 0, then the unit should be down.

$$\begin{aligned} &if\ p_{it} = 0 \\ &then\ OL_{it} = 0 \\ &OU_{it} = 0 \\ &OM_{it} = 0 \end{aligned} \tag{11}$$

for all $i \in A(p)$, for all $p \in P$

for all $t \in T(\tau)$, for all $\tau \in \mathrm{T}$

The deviation term $b_{i\tau}^2$ from equation (4) is calculated as follows:

$$b_{i\tau}^2 = (c_{i\tau} - GG_{i\tau})^2 \tag{12}$$

for all $i \in A(p)$, for all $p \in P$

for all $\tau \in \mathrm{T}$

where $GG_{i\tau}$ is converted assigned unit capacity from generation in MW as follows:

$$GG_{i\tau} = \sum_{t=t1}^{t2} (OL_{it} + OU_{it} + OM_{it}) \cdot C_i \tag{13}$$

for all $i \in A(p)$, for all $p \in P$

for all $\tau \in \mathrm{T}$

The final requirement for the general format is that all additional constraints in the problem must be separable. That is, each constraint must be associated with an individual stage only.

Several other constraints are required for completion of the DP model besides equations (1) to (3). First, unit generation $g_{i\tau}$ should be greater than the minimum motoring range and less than the unit capacity during its continuation.

$$-MT \cdot C_i \cdot \Delta t_t \le g_{i\tau} \le C_i \cdot \Delta t_t \tag{14}$$

for all $i \in A(p)$, for all $p \in P$

for all $t \in T(\tau)$, for all $\tau \in \mathrm{T}$

where MT is percentage of generator capacity required for motoring set for each turbine unit.

Second, daily releases from unit Q_i should be maintained greater than 0 and less than its releases capacity during the day.

$$0 \le Q_i \le \sum_{t \in T} \left((SN_i + (CF_i - SN_i) + CT_i \cdot C_i) \cdot \Delta t_t \right) \tag{15}$$

for all $i \in A(p)$, for all $p \in P$

Third, assigned capacity $c_{i\tau}$ should be maintained within required minimum and maximum ranges.

$$0 \le c_{i\tau} \le C_i \cdot \Delta t_t \tag{16}$$

for all $i \in A(p)$, for all $p \in P$

for all $t \in T(\tau)$, for all

There are also constraints related to state variables which should be considered during the optimization. The DP model is formulated as units from generation driven plants are treated first as stages, and then units from water driven plants are treated as stages later as follows:

$$\left.\begin{aligned} &i = 1 \\ &\vdots \\ &i = Ng \end{aligned}\right\} \textit{for generation driven plants}$$

$$\left.\begin{aligned} &i = Ng + 1 \\ &\vdots \\ &i = N \end{aligned}\right\} \textit{for water driven plants}$$

First, all state variables should be maintained within their minimum and maximum ranges which can be calculated from their corresponding decision variables.

$$\sum_{n=1}^{i} g_{\min,n\tau} \le x1_{i\tau} \le \sum_{n=1}^{i} g_{\max,n\tau}$$

for $i = 1, \ldots, N$ (17)

$$x2_i = 0$$
$$\text{for } i = 1, \ldots, Ng \tag{18}$$

$$\sum_{n=1}^{i} Q_{\min,n} \le x2_i \le \sum_{n=1}^{i} Q_{\max,n}$$
$$\text{for } i = Ng + 1, \ldots N \tag{19}$$

$$\sum_{n=1}^{i} c_{\min,n\tau} \le x3_{i\tau} \le \sum_{n=1}^{i} c_{\max,n\tau}$$
$$\text{for } i = 1, \ldots, N \tag{20}$$
$$\text{for all } \tau \in \mathrm{T}$$

where $g_{\min,n\tau}, Q_{\min,n}$, and $c_{\min,n\tau}$ are minimum values of decision variables $g_{n\tau}$, Q_n, and $c_{n\tau}$, respectively; $g_{\max,n\tau}, Q_{\max,n}$, and $c_{\max,n\tau}$ are maximum values of decision variables $g_{n\tau}$, Q_n, and $c_{n\tau}$, respectively; N is total number of units from all plants; Ng is total number of units from generation driven plants.

Secondly, total generation level for water driven plants must be maintained within a band of a rough generation schedule which is developed using the generation shape. If a unit i is the final unit (stage) N_w from the final water driven plant in the basin:

$$x1_{\min,Ng+1,\tau} + (GS_t - BD)\cdot\Delta t_t \le x1_{NW+1,\tau} \le x1_{\max,Ng+1,\tau} + (GS_t + BD)\cdot\Delta t_t \tag{21}$$
$$\text{for all } t \in T(\tau), \text{ for all } \tau \in \mathrm{T}$$

where GS_t is the water driven plant generation schedule at hour t in MW; BD is the basin generation schedule deadband in MW set by scheduler; and $x1_{i\tau}$ is the total generation level up to the final water driven plants unit i at τ th schedule change in MW.

Third, a total generation requirement for generation driven plants must be maintained.

$$p \in P \tag{22}$$
$$\text{for all } g \in G, \text{ for all } \tau \in \mathrm{T}$$
$$\text{for } t = 1, \ldots, 24$$

where $x1_{Ng+1,\tau}$ = the total generation level from the final unit for generation driven plants in the basin at τ th schedule change; GR_t = hourly plant generation requirement for generation driven plant at time t in MW.

Fourth, the plant release from water driven plant should be satisfied at the final unit of each water driven plant.

$$x2_{\min,i} = x2_{\max,i} = \sum_{j=1}^{nw} SF_{wj}\cdot 24\times 10^3 \tag{23}$$
$$\text{for } i = Ng + \sum_{j=1}^{nw} N_{wj} + 1$$
$$\text{for all } w \in W, \text{ for all } g \in G$$

where N_g is the final unit from generation driven plants; $x2_{Ng+1}$ is assumed 0, since tracking daily release for generation driven plants is not necessary; N_{wj} is number of units from j -th water driven plant; SF_{wj} is scheduled releases from j-th water driven plant in 1,000 cfs;

Also, capacity requirements should be satisfied for all plants.

$$x3_{N\tau} \ge CR_t\cdot\Delta t_t \tag{24}$$
$$\text{for all } i \in A(p), \text{ for all } p \in P$$
$$\text{for all } t \in T(\tau), \text{ for all } \tau \in \mathrm{T}$$

where $x3_{N\tau}$ = the total capacity level from the final unit N for all plants in the basin at τ th schedule change; CRt = hourly capacity requirement for all hydroelectric powerplants in the basin at hour t in MW.

3. OPTIMIZATION PROCESS

Optimization process using DP is as follows.

(1) Decide and initialize unit status. Read from the data file as to whether unit belongs to set $A(p)$, $R(p)$ or $N(p)$. Set $A(p)$ indicates set of units that are available in plant p, $R(p)$ indicates set of units that must run in plant p, and $N(p)$ indicates set of units that must generate in plant p. It is assumed that all available *must run* units are motoring and no units are running in generation mode at the first hour. *Available* generators that may only generate are *must generate* units initially and *available* generators that must run are the *must run* units initially.

(2) Calculate unit flow constants for all plants in the basin based on starting head.

(3) Tailbay levels are calculated considering the releases effects from the plants.

(4) Capacity flow for tailbay effects and speed no load flow for upper segments are recalculated.

(5) Calculate the beginning and the length of time intervals that generation schedule, capacity requirement schedule does not change. If unit was running in the previous hour, ant that unit becomes *unavailable* at present hour or if unit was down in the previous hour, and that unit becomes *must run* unit at present hour, then the beginning and the length of time interval again need to change.

(6) From the state equations, get the decision variables.

(7) Start the 24 hours time loop.

(8) From the decision variable which represents the unit generation, decide where the unit belongs at that hour. If the unit is available at that hour, the unit can generate either upper or lower rough zone. Also the unit can motor or down. If the unit does not belong to any of these, this decision variable is not feasible and we need to get another decision variable by giving it a penalty value.

(9) In case of an increase of flow is required from the water driven plants or increase of generation is required from the generation driven plants or increase of capacity is required from either water or generation driven plants at the hour, the following conditions should be considered. If unit was generating at the previous hour, it cannot be down or motoring. If unit was motoring at the previous hour, it cannot be down. If unit was down at the previous hour, it can be in any mode.

(10) In case of a decrease of flow is required from the water driven plants or decrease in generation is required from the generation driven plants or decrease in capacity is required from either water or water driven plants at the hour, the following conditions should be considered. If unit was generating at the previous hour, it can be in any mode. If unit was motoring at the previous hour, it cannot generate. If unit was down at the previous hour, it cannot motor or generate.

(11) The following two conditions apply to either case of 9 and 10. If unit could only generate it cannot motor. If unit should run, it cannot be down.

(12) If there are not enough changes in flow, generation, or capacity requirement, unit schedule is assumed as same as the previous hour.

(13) Consider the minimum up and down time of each unit.

(14) Go to next hour and use the previous value of unit status.

4. CASE STUDY

A case study on Lower Colorado River basin is presented to demonstrate the capabilities of the optimal short-term unit commitment models using dynamic programming.

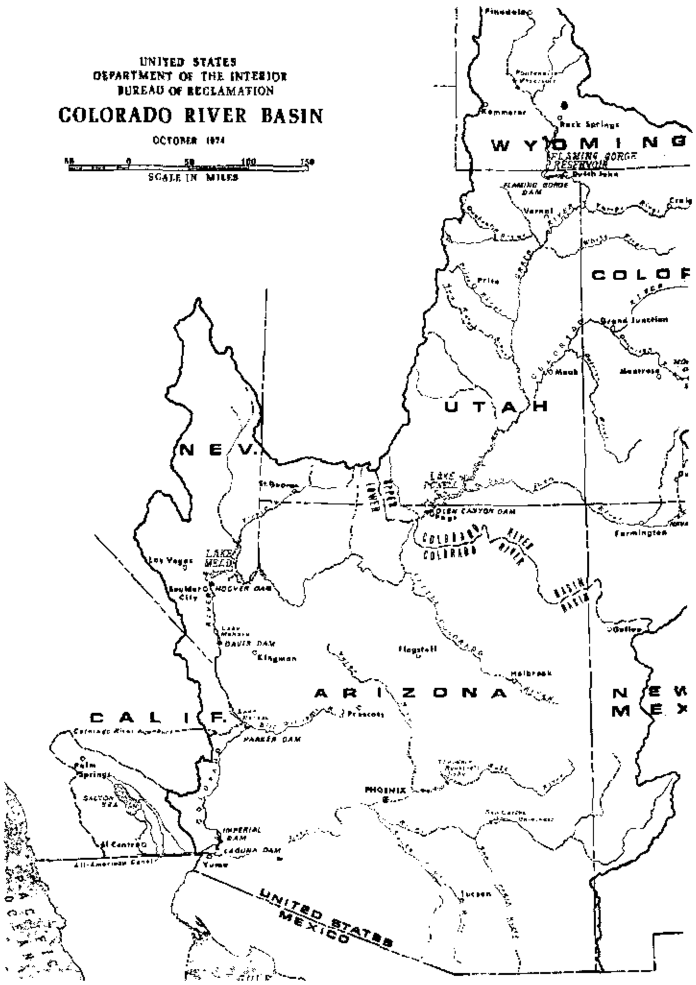

Fig. 1. Colorado River Basin Map

4.1 Lower Colorado Basin

The Colorado River Basin drains nearly 250,000 square miles in seven western states before entering Mexico and then the Gulf of California (Fig. 1). The Colorado River basin has been politically divided into two subbasins, Upper and Lower basins, for administrative purposes. The boundary between the two subbasins is known as Lee Ferry or Compact Point. The Lower Colorado River hydroelectric power plants generate about 5 billion kilowatt-hours of energy per year with an installed capacity of about 1,700 megawatts. Three major dams in the northern portion of the river control the Lower Colorado River. Hoover Dam is the northernmost dam in the Lower Colorado River. Lake Mead is created by Hoover Dam with content over 27,300,00 acre-ft. The powerplant at Hoover Dam has 19 turbines for a total generating capacity of approximately 2,000 MW. Davis Dam lies 67 miles downstream from Hoover Dam. Lake Mohave is created by Davis Dam

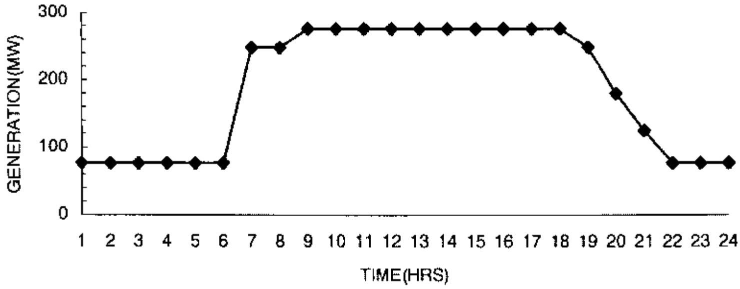

Fig. 2. Generation Shape for Davis and Parker Powerplant

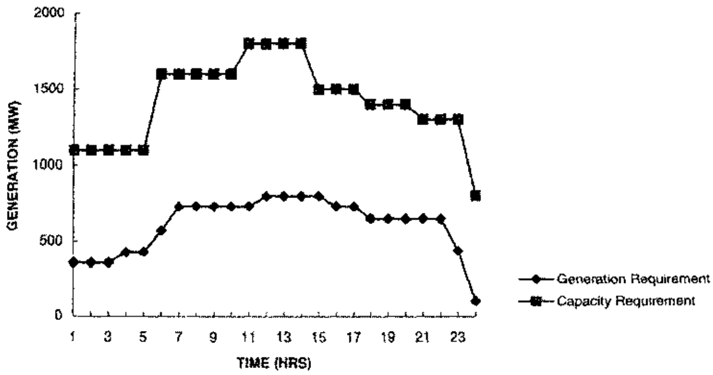

Fig. 3. Generation and Capacity Requirement

and has a capacity of over 1,800,000 acre-ft. The powerplant at Davis Dam has 5 turbines and a total generating capacity of approximately 240 MW. Parker Dam is 88 miles downstream from Davis Dam. Lake Havasu which is created by Parker Dam has a maximum content of about 600,000 acre-ft. The powerplant at Parker Dam has 4 turbines and a total generating capacity of approximately 120 MW. The main purpose of Hoover Dam operation is generating power and it is classified as generation driven plant. In Hoover Dam, the regulation of Lower Colorado River is one of the important objects. The regulation schedule is changed very often during the day, it forces the unit schedule of Hoover to change frequently. The main purpose of Davis and Parker Dam is meeting various water demands from downstream and they are classified as water driven plants.

4.2 Application to Lower Colorado River Basin

The optimization of the Lower Colorado Powerplants, Hoover, Davis, and Parker, is implemented using dynamic programming (DP). The historical data used consists of a 24 hour generation and capacity schedule and total 24 hour releases for Davis and Parker Powerplants from April 17, 1988. The generation and capacity schedule come directly from the operation of the generators on that day. Fig. 2 shows the generation shape for Davis and Parker powerplants. Fig. 3 shows the generation schedule and capacity schedule for all three plants. The model is required to produce the exact generation schedule, capacity at or above the capacity schedule, and water releases approximately equal to the required releases.

4.3 Results

CSUDP, a generalized dynamic programming solver, developed by Labadie (1988) at Colorado State University is used to solve the DP model. DP model has 27 states variables with 26 stages. Dynamic Programming with Successive Approximation (DPSA) technique is used to handle 27 dimensional problem. A discretization value of 20 is used for state variables $x1_{i,t}$, and $x3_{i,t}$. A discretization value of 1,000 is used for state variable $x2_i$. A splicing option is available such that after a complete solution over all stages, a tightened corridor is defined around the current solution and a new interval is selected. The use of splicing option can significantly reduce the execution time, but there is a danger in missing the global optimal solution. It took 7 minutes and 28 seconds on Pentium III PC. A comparison was done between the MIP model, combined MIP model that is already developed by Yi(1998, 1999), and DP Model to compare the results generated from three different types of models. Fig. 4 shows the comparisons of the average efficiency of the three models. Table 1 and Table 2 show the optimal schedules for three powerplants in the basin from the result of DP model. In these tables, the negative sign means the unit is in the motoring state. Because MIP model uses a bigger deadband of rough generation schedule than other optimization models, MIP model gives the highest basin efficiency. The first sub-model PLANT_DY_W of MIP model cannot find a feasible release schedule when a deadband of rough generation schedule, DB, is set to 5 MW. So, 15 MW is used for sub-model PLANT_DY_W of MIP model. DP model and combined MIP use 5 MW as a deadband of rough generation schedule. Combined MIP model is a computationally intensive approach. A large number of integer variables and constraints requires a large computational efforts. Also, it showed the lowest efficiency among three models. The performance of DP model is consistently high. DP model gives high efficiency and it is 1.8 % higher than efficiency without optimization. DP model is robust and can generate optimal solution with a smaller deadband of rough generation schedule. Also,

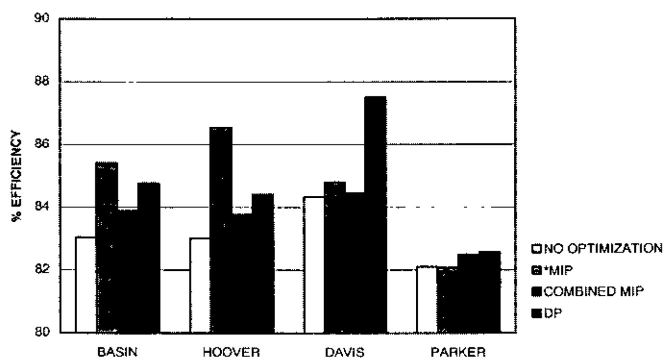

Fig. 4. Basin and Powerplants Efficiency

Table 1. Hoover Powerplant Unit Commitment

	TURBINE UNITS (MW)																
HRS	N1	N2	N3	N4	N5	N6	N7	N8	A1	A2	A3	A4	A5	A6	A7	A8	A9
1	-3.9	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.8	104.9	130.0	0.0	0.0
2	-3.9	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.8	104.9	130.0	0.0	0.0
3	-3.9	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.8	104.9	130.0	0.0	0.0
4	-3.9	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	0.0	64.5	126.6	110.8	130.0	0.0	0.0
5	-3.9	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	0.0	64.5	126.6	110.8	130.0	0.0	0.0
6	-3.9	-3.9	-3.9	127.2	-3.9	0.0	0.0	0.0	0.0	0.0	65.0	64.4	127.0	85.2	104.4	0.0	0.0
7	-3.9	-3.9	-3.9	60.0	-3.9	0.0	0.0	0.0	0.0	129.7	90.0	64.8	127.0	130.0	130.0	0.0	0.0
8	-3.9	-3.9	-3.9	60.0	-3.9	0.0	0.0	0.0	0.0	129.7	90.0	64.8	127.0	130.0	130.0	0.0	0.0
9	-3.9	-3.9	-3.9	59.7	64.3	0.0	0.0	0.0	44.8	90.1	64.9	64.9	127.0	85.2	130.0	0.0	0.0
10	-3.9	-3.9	-3.9	59.7	64.3	0.0	0.0	0.0	44.8	90.1	64.9	64.9	127.0	85.2	130.0	0.0	0.0
11	-3.9	-3.9	-3.9	59.7	64.3	0.0	0.0	0.0	44.8	90.1	64.9	64.9	127.0	85.2	130.0	0.0	0.0
12	-3.9	-3.9	-3.9	59.9	65.0	0.0	0.0	0.0	44.9	113.4	65.0	65.0	127.0	130.0	130.0	0.0	0.0
13	-3.9	-3.9	-3.9	59.9	65.0	0.0	0.0	0.0	44.9	113.4	65.0	65.0	127.0	130.0	130.0	0.0	0.0
14	-3.9	-3.9	-3.9	59.9	65.0	0.0	0.0	0.0	44.9	113.4	65.0	65.0	127.0	130.0	130.0	0.0	0.0
15	-3.9	-3.9	-3.9	59.9	65.0	0.0	0.0	0.0	44.9	113.4	65.0	65.0	127.0	130.0	130.0	0.0	0.0
16	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	129.7	116.4	98.4	127.0	130.0	130.0	0.0	0.0
17	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	129.7	116.4	98.4	127.0	130.0	130.0	0.0	0.0
18	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	44.6	115.6	106.0	127.0	130.0	130.0	0.0	0.0
19	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	44.6	118.8	102.8	127.0	130.0	130.0	0.0	0.0
20	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	44.6	126.8	94.8	127.0	130.0	130.0	0.0	0.0
21	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	44.6	128.4	93.2	127.0	130.0	130.0	0.0	0.0
22	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	44.9	122.0	97.6	127.0	130.0	130.0	0.0	0.0
23	-3.9	-3.9	-3.9	-3.9	0.0	0.0	0.0	0.0	0.0	44.9	122.0	97.6	127.0	130.0	130.0	0.0	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.0	127.0	118.0	130.0	0.0	0.0

DP model is the fastest model of the three. Since Parker Powerplant loads units low or motors, all unit commitment models show low efficiency for Parker Powerplant. The advantages of DP model to other models are as follows:

- Better basin operating efficiency
- Fastest execution time.
- Robust performance.
- Because DP model is developed using C language, it can be ported to other environment without problems.
- DP model is easy to update and modify when system structure is changed. Adding and removing units are as easy as adding and removing stages.
- Adding more units will affect the computation time linearly compared to other optimization techniques which will affect the computation time exponentially.
- DP model can handle nonlinear constraint directly such as flow slope curves.
- DP model can handle conditional constraints without any modifications.

5. CONCLUSIONS

Optimization models use mathematical programming techniques to find preferred alternatives which meet specified constraints and

Table 2. Davis and Parker Powerplant Unit Commitment from DP Model

	TURBINE UNITS(MW)								
HRS	D1	D2	D3	D4	D5	P1	P2	P3	P4
1	0.0	0.0	0.0	0.0	48.0	0.0	0.0	21.4	0.0
2	0.0	0.0	0.0	0.0	48.0	0.0	0.0	21.4	0.0
3	0.0	0.0	0.0	0.0	48.0	0.0	0.0	21.4	0.0
4	0.0	0.0	0.0	0.0	48.0	0.0	0.0	21.0	0.0
5	0.0	0.0	0.0	0.0	48.0	0.0	0.0	21.0	0.0
6	0.0	0.0	15.2	15.2	48.0	0.0	0.0	14.2	0.0
7	0.0	48.0	48.0	48.0	48.0	23.9	6.4	28.0	0.0
8	0.0	48.0	48.0	48.0	48.0	23.9	6.4	28.0	0.0
9	0.0	48.0	48.0	48.0	48.0	28.0	28.0	28.0	-0.8
10	0.0	48.0	48.0	48.0	48.0	28.0	28.0	28.0	-0.8
11	0.0	48.0	48.0	48.0	48.0	28.0	28.0	28.0	-0.8
12	0.0	48.0	48.0	48.0	48.0	13.9	28.0	28.0	1.6
13	0.0	48.0	48.0	48.0	48.0	13.9	28.0	28.0	1.6
14	0.0	48.0	48.0	48.0	48.0	13.9	28.0	28.0	1.6
15	0.0	48.0	48.0	48.0	48.0	13.9	28.0	28.0	1.6
16	0.0	48.0	48.0	48.0	48.0	14.5	28.0	28.0	1.6
17	0.0	48.0	48.0	48.0	48.0	14.5	28.0	28.0	1.6
18	0.0	48.0	48.0	48.0	48.0	3.0	28.0	28.0	12.0
19	0.0	48.0	48.0	48.0	48.0	3.4	28.0	28.0	0.0
20	0.0	11.2	48.0	46.4	48.0	0.0	13.2	27.2	0.0
21	0.0	0.0	0.0	48.0	48.0	0.0	6.6	28.0	0.0
22	0.0	0.0	0.0	0.0	48.0	0.0	0.0	27.8	0.0
23	0.0	0.0	0.0	0.0	48.0	0.0	0.0	27.8	0.0
24	0.0	0.0	0.0	0.0	48.0	0.0	0.0	27.8	0.0

maximize or minimize some specified set of objectives. Optimization techniques have been criticized that identifying and expressing all objectives or/and constraints of real systems in a quantitative form is not always possible. Because even small real systems can have quite large constraints and variables that may require excessive computational resources, some simplifying assumptions on model structure are used to reduce the size of a model. In this study, however, most operating and system constraints such as total generation requirement constraint, spinning reserve requirement constraint, spinning water requirement constraint, and water release requirements constraint, rough zone avoidance constraints, minimum up and down time constraints, and unit outage mode constraints are included in the DP model clearly and explicitly. Total computational requirements are small and fast enough to be applied to real system.

The expected benefits from implementing the unit commitment model are as follows. The unit commitment model can provide operators and dispatchers with flexibility to meet the many constraints presented to them while improving efficiency. A 1.8% basin efficiency increase was obtained using DP model. A 1.8 % increase in average basin efficiency will result in an estimated increase in revenues of 3 million dollars per year. Also increased spinning reserve capacity can be obtained. Spinning reserves can be shifted quickly between plants in the basin as needed for generation or additional security changes. The maintenance of units can be scheduled easily. The scheduler can program the unit mode such as available, unavailable, available as generator, must run units easily in advance. Finally, by setting the tailbay levels, environmental constraints can be dealt with in better way.

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