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# Hydropower Reservoirs Operation: A Time Decomposition Approach

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In this paper, a framework for operation of hydropower reservoirs in Iran is discussed. A time decomposition approach, which breaks down the operation optimization problem to long, mid and short-term planning stages, is developed. Stochastic dynamic programming models are developed for long-term and mid-term optimization and a deterministic dynamic programming model is developed for short-term optimization of two hydropower-reservoirs (a parallel system). An economic analysis of the benefits and cost of the operation are incorporated in all three stages of planning by developing economic cost functions. The developed algorithm is applied to the Karoon and Dez river-reservoir systems in the southwest of Iran. The results of this study have shown the significant value of the developed models and their relational framework in providing more flexibility and adaptability in using methods and tools for decision-making in real world situations.

## INTRODUCTION

Among energy production methods, electricity is the most environmentally sound energy production method and has been given more attention in recent years. The development of hydropower electricity generation, which has high efficiency (compared with thermal and hydrothermal units) and negligible environmental pollution, is one of the major concerns in planning for the sustainable development of this sector of the economy.

Hydropower units often operate as part of a larger system. Performance of a hydropower reservoir in supplying water demands might only affect local users downstream of the reservoir, but the power generation has regional effects on the power network. Operation of hydropower reservoirs depends on different parameters that are mostly region specific. Different optimization models, ranging from monthly to hourly time scales, have been developed. Tejada-Guilbert et al. [1] developed a monthly optimization model, in which the power generation costs in a hydropower plant were considered. Yeh et al. [2] developed a procedure for economic optimization of hydrothermal power system operations in China. This procedure consists of three models for long-term (monthly), mid-term (daily) and short-term (hourly) planning. In these models, some limitations in the operation of power networks, including the variation of transmission losses with hydroelectric and thermal plant loadings, have been considered.

Georgakakos et al. [3] formulated an optimal control model that can be used to determine the dependable power capacity of a hydropower system. The model structure consists of a turbine load allocation module and a reservoir control module and allows for a detailed representation of hydroelectric facilities. In the reservoir control module, the value of power generated in hydropower plants is assigned, based on power generation-cost curves for thermal plants.

Peng and Buras [4] developed optimal operation policies for a hydropower system, which consists of nine reservoirs in Maine, USA, using a nonlinear programming technique. Different objectives of stakeholders were also considered. By generating synthetic inflows, the expected values and probability distribution of decision variables were estimated and analyzed.

Considering the hourly variations of the electrical load and the limitations of thermal units for short-term changes in generation, hydropower units play a significant role in supplying the higher valued (price) peak loads. Therefore, operation planning for hydropower reservoirs is more focused on peak generation, although the ability to shift from one unit to another increases the power network reliability.

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In this study, a time decomposition approach, which consists of monthly, weekly and hourly models, is developed for hydropower reservoir operations management. For this purpose, the decision-making process for the operation management of hydropower reservoirs in Iran is considered as a basis for developing the proposed models. Furthermore, variations in the hourly value of hydro-generation is considered as the main criteria, which links the monthly, weekly and hourly models. The proposed algorithm is applied to the Karoon and Dez river-reservoir systems in the southwest of Iran.

## TIME DECOMPOSITION APPROACH

In addition to the variations in load and the economic benefits of short-term optimization of hydropower reservoir operation, the optimization procedure and optimal operation policies should be in line with the organizational decision-making structure, which is responsible for the management of hydropower reservoirs and appurtenant facilities. This is an important step in advancing the optimization models from theory to practice, particularly at the level of actual operators of river-reservoir systems.

In Iran, the Ministry of Energy is responsible for the water and hydropower energy supply. Two main divisions of this Ministry, namely Water and Power Management, make decisions about the quantity and timing of releases from reservoirs and power generation rates through a sequential decision-making process, as follows:

- The Water Management Division (WMD) decides how much water should be released in the coming month, based on water demand and forecasted inflow to the reservoirs. They also estimate the monthly power generation of hydropower units;
- At the beginning of each week, the Power Management Division (PMD) decides how much power should be generated in each hydropower unit, considering WMD's total predicted power generation and the plans for hydrothermal coordination. Instream requirements, flood control and other water supply issues are also considered;
- The operators of the dams and the appurtenant facilities are responsible for the real-time operation of hydropower reservoirs, following the decisions and operating policies defined by WMD and PMD on a daily time scale. In case of emergency situations, such as breakdown in the national electricity network or severe flood, the WMD and PMD could change their decisions and the operators follow these decisions in the real-time operation of reservoirs and power plants.

It seems apparent that in the above process, the weekly decisions are an important link between the water and power management divisions. The daily decisions are also important in creating the link between planners/decision-makers and the operators. Based on the above process and considering the time variations of power load and value, a time-decomposition approach is developed in this study (Figure 1).

In this flowchart, the higher level outputs (policies) impose constraints on the lower level models. As seen in Figure 1, optimization of hydropower reservoir operations consists of four steps:

- ☐ Long-term planning (strategy): Optimization of reservoir operation on a monthly time scale in the planning time horizon,
- ☐ Mid-term planning (strategy and tactic): Optimization of reservoir operation on a weekly time scale for a single month time horizon,
- ☐ Short-term planning (tactic): Optimization of reservoir operation on an hourly time scale using a one week planning horizon,
- ☐ Real-time operation: Unit commitment scheduling on an hourly time scale.

Based on the above classification, the strategic decisions refer to how much water should be released and how much power should be generated on a monthly time scale. Similarly, tactic decisions refer to the volume of water release and the power generation on an hourly time- scale. In the next sections of the paper, the framework developed for long, mid and short-term planning models for multi-purpose hydropower storage projects is presented.

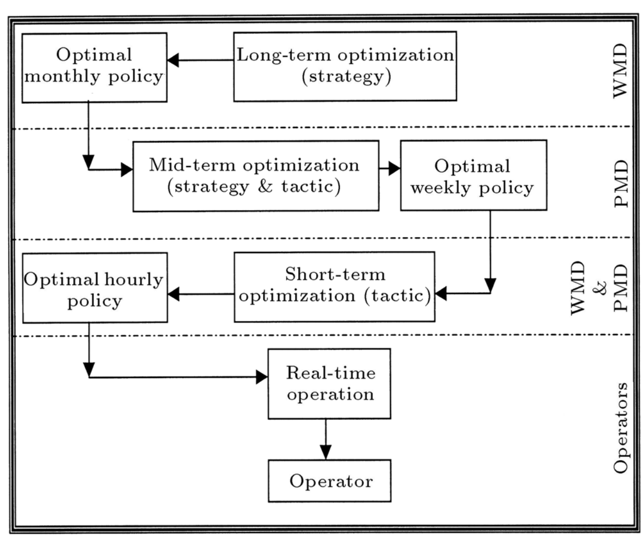


**Figure 1.** Flowchart of the time decomposition approach for optimizing the hydropower reservoirs operation.

## LONG-TERM PLANNING MODEL

The main objective in the long-term planning of hydropower storage projects is to maximize the net benefits of the system operations. Reservoirs usually satisfy different objectives such as: Supplying different water demands, flood control, supplying power loads and supplying instream flows.

Conflicts between water supply objectives and keeping enough head in the reservoirs for efficient power generation is the main issue in the long-term planning models. In this study, the stochastic model, known as Demand Driven Stochastic Dynamic Programming (DDSP), for hydropower reservoir operation optimization, is applied. DDSP is an extension of the Bayesian Stochastic Dynamic Programming (BSDP) model developed by Karamouz and Vasiliadis [5]. In BSDP, a discrete Markov Process describes the transition of an inflow from one period to the next. In addition, in BSDP, Bayesian Decision Theory (BDT) is used to develop and continuously update, prior to posterior probabilities, to capture the natural and forecast uncertainties. The stochastic model, developed by Vasiliadis and Karamouz [6], is extended for a two hydropower-reservoirs system (parallel system). More details about the objective function and constraints added to the DDSP model are presented in the following sections.

The following constraints are added to the DDSP model, in order to incorporate power generation constraints:

- A mass balance equation is modified to separate releases from a power plant and other outlets:

$$S_{j,t+1} = S_{j,t} + I_{j,t} - R_{j,t}, \tag{1}$$

$$R_{j,t} = Q^P_{j,t} + Q^B_{j,t} + Q^S_{j,t}, \tag{2}$$

where:

| | |
|---|---|
| $R_{j,t}$ | total releases from reservoir $j$ in month $t$, |
| $S_{j,t}$ | water storage at the beginning of month $t$ in reservoir $j$, |
| $I_{j,t}$ | volume of inflow to reservoir $j$ in month $t$, |
| $Q^p_{j,t}$ | water discharge from turbines of reservoir $j$ in month $t$, |
| $Q^B_{j,t}$ | water discharge from bottom outlets of reservoir $j$ in month $t$, |
| $Q^S_{j,t}$ | water discharge from spillways of reservoir $j$ in month $t$. |

- Spinning reserve requirement: The hydropower plants have less loading and unloading limitations compared with thermal plants. Therefore, in case of emergency situations, such as shutdown in some of the hydro or thermal plants and breakdown in the electricity network, hydropower plants can be loaded in a short time to supply the load of the system in that specific time. So, a part of the capacity of the hydropower plants, which is called the spinning reserve, is usually unloaded to supply the power loads in emergency situations. For this purpose, the following relation is included in the model:

$$\sum_{j=1}^{2}(PGT_{j,t} - PG_{j,t}) \geq SP_m$$

$$m = t - \left[\frac{t-1}{12}\right] \times 12, \tag{3}$$

where:

| | |
|---|---|
| $PGT_{j,t}$ | power generation capacity of power plant $j$ in month $t(t = 1, \ldots, T)$, |
| $SP_m$ | spinning reserve of the system in month $m(m = 1, \ldots, 12)$, |
| $PG_{j,t}$ | power generated in hydropower plant $j$ in month $t$. |

- Maximum power generation capacity in different units considering the installed capacity, $Cap_j$, of each power plant and monthly plant factor, $PF_{j,t}$:

$$PGT_{j,t} = Cap_j \cdot PF_{j,t}. \tag{4}$$

- Power generation equations on a monthly time scale by using the following information:
  - Elevation-volume curve,
  - Discharge-elevation curve for each turbine,
  - Reservoir release-tailwater elevation curve,
  - Turbine efficiency curve.

In this study, the power generation functions of the Karoon and Dez power plants are estimated, based on a multiple regression analysis of the historical reservoir operation records. The following relations are fitted with a 99% correlation coefficient:

$$PG_{1,t} = (E_{1,t} - 372)^* {Q^p_{1,t}}^* \alpha,$$

for the Karoun reservoir, (5)

$$PG_{2,t} = (E_{2,t} - 175)^* {Q^p_{2,t}}^* \beta,$$

for the Dez reservoir, (6)

where $E_{j,t}$ is the water level in reservoir $j$ at the beginning of month $t$ and $\alpha$ and $\beta$ are constants for different elevation ranges, which are estimated based on the regression analysis. In defining different elevation ranges in Equations 5 and 6, historical records of headwater and tailwater elevation, turbine discharge, and efficiency were considered.

In order to estimate the cost of operation, $\lfloor C\left(R^C_{1,t}, R^C_{2,t}, PG_{1,t}, PG_{2,t}\right)\rfloor$, it should be noted that the relative importance and priority of water supply and power generation objectives are not at the same level. Many social and political issues should be considered in supplying water demands. Therefore, the cost of shortages in allocating water to different users, such as agricultural, cannot, or should not, be replaced by power generation benefits. In this study, for simultaneous optimization of the water supply and power generation in a two-reservoir system, the cost function for estimating operation loss is formulated as follows:

$$C(R_{1,t},R_{2,t},PG_{1,t},PG_{2,t})=\sum_{j=1}^{2}\text{Loss}_{j,t}^{\text{Water}}+\sum_{j=1}^{2}\text{Loss}_{j,t}^{\text{Power}}, \tag{7}$$

where:

| | |
|---|---|
| $R_{j,t}$ | total release from reservoir $j$ in month $t$, |
| $\text{Loss}_{j,t}^{\text{water}}$ | losses associated with water shortage in supplying the demands or excessive water release from reservoir $j$ in month $t$, |
| $\text{Loss}_{j,t}^{\text{power}}$ | losses associated with supplying power loads in reservoir $j$ in month $t$. |

Because water prices are highly subsidized in the study area, the water charge cannot be used to represent the actual costs and benefits of the operation of the system. In this study, a more realistic cost function was used to reflect the marginal cost of water shortages and possible flood damage, as well as the realistic cost of a power shortage (not meeting the targeted power load). For this purpose, the present value of the monthly cost of the reservoir operation is estimated by considering the present value of the initial investment and the cost of maintenance and operation. In order to estimate the present value of initial investment, the age of the dam and its appurtenant facilities are considered. The historical series of an indicator, showing the discount rate (cumulative discount index) for concrete dams in Iran and the rate of depreciation, are utilized (Iranian Ministry of Energy [7]). The cost associated with unit volume of water release in each month for each reservoir, $P_{j,t}^{w}$, is, then, estimated as:

$$P_{j,t}^{w}=\frac{\text{Cost}_{j,t}}{R_{j,t}}, \tag{8}$$

where $\text{Cost}_{j,t}$ is the present value of the monthly cost of operation of reservoir $j$. Then, three different situations are considered for defining loss function for the water supply:

- Normal situation: When the reservoir satisfies demand with no deficit or surplus. In this case, the cost of operation is considered to be zero;

- High-flow situation: When reservoir release is more than demand. In this case, the cost is estimated as the economic cost of any unused release in that time period. The costs associated with releases that are larger than the carrying capacity of the downstream river are penalized, based on historic records of flood damage:

$$\text{Loss}_{j,t}^{\text{water}}=P_{j,t}^{w}\times(R_{j,t}-D_m)$$

$$\text{when}\quad 1<\frac{R_{j,t}}{D_m}\leq 1+\delta, \tag{9}$$

$$\text{Loss}_{j,t}^{\text{water}}=P_{j,t}^{w}\times(R_{j,t}-D_m)\times(1+H')$$

$$\text{otherwise}, \tag{10}$$

where $D_m$ is the monthly demand and $H'$ is the percentage cost increase due to flooding in the downstream river. In the study area, $H'$ and $\delta$ are estimated to be 30% and 5%, respectively, based on flood damage analysis;

- Low-flow situation: When the reservoir release is less than demand (shortage). In this case, the cost of the water shortage is estimated, based on the economic cost of water that is not supplied, or should be supplied, from other sources, such as groundwater. When the shortages increase, costs should be penalized, due to damage associated with agricultural products and other users of the water resources system:

$$\text{Loss}_{j,t}^{\text{water}}=P_{j,t}^{w}\times(D_m-R_{j,t})$$

$$\text{when}\quad \omega\leq\frac{R_{j,t}}{D_m}\leq 1, \tag{11}$$

$$\text{Loss}_{j,t}^{\text{water}}=P_{j,t}^{w}\times(D_m-R_{j,t})\times(1+H'')$$

$$\text{otherwise}, \tag{12}$$

where $\beta$ is the lower bound of release-demand ratio and $H''$ is the percent of cost increase due to severity and duration of shortages. $H''$ and $\omega$ should be estimated based on the sensitivity of water users to shortages, which are estimated to be 20% and 0.7%, respectively.

Figure 2 shows the economic cost function estimated, based on the above relations. As seen, the costs associated with shortage are much higher than for flood. Therefore, the reliability of the water supply to different demands is expected to increase with this cost function.

The second part of Equation 7 is the cost function associated with power generation. The electric power

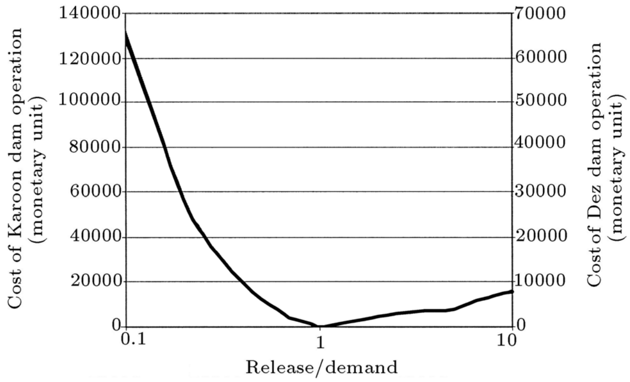


**Figure 2.** Real cost function developed based on economic analysis.

load is highly sensitive to short-term decisions. Therefore, different methods for aggregation of the long-term strategies to short-term policies (tactics) should be selected carefully. Separating peak and firm power generation is not considered in most of the long-term operation models developed by different researchers.

In this study, in order to have a better estimate of losses due to power shortages, the values of power generated at different hours are estimated and the difference between the maximum economic benefits that could be gained and the benefits that are actually provided, based on power generation, is estimated. Although no loss is actually incurred, the power cost-function is a reflection of an opportunity gain that is lost. It should be noted that the deficits in supplying loads are provided by thermal units, which have a significantly higher cost. Table 1 shows the classification of the value of power generation in different hourly classes in each month. As can be seen in this table, the cost of no energy production during low-load hours is much less than no production during high-load hours. Classification of the value of power generation in Table 1 is based on the load of the system and is defined as follows:

- □ Very high load hours ($k = 1$),
- □ High load hours ($k = 2$),
- □ Medium load hours ($k = 3$),
- □ Low load hours ($k = 4$),
- □ Very low load hours ($k = 5$).

The first two classes ($k = 1, 2$) cover about 220 hours each month, so the power generated will have a high value (peak generation). The third class has a medium value ($k = 3$) and the hydropower generation would have a very low value (firm generation) in the last two classes, ($k = 4$ and 5). In order to create a tendency to produce more energy by hydro-plants in peak hours, the following relations are used to classify the monthly loads into the hourly classes shown in Table 1:

$$PL_{j,1,t}^{\text{hourly}} = \begin{cases} PGT_{j,1,t}^{\text{hourly}} & \text{if } PL_{j,k,t}^{\text{hourly}} > PGT_{j,1,t}^{\text{hourly}} \\ PL_{j,t}^{\text{hourly}} & \text{otherwise} \end{cases} \tag{13}$$

$$PL_{j,k,t}^{\text{hourly}} = \begin{cases} PGT_{j,k,t}^{\text{hourly}} & \text{if } \left(PL_{j,t} - \sum_{m=1}^{k-1} PL_{j,m,t}^{\text{hourly}}\right) > PGT_{j,k,t}^{\text{hourly}} \\ PL_{j,t} - \sum_{m=1}^{k-1} PL_{j,m,t}^{\text{hourly}} & \text{otherwise} \end{cases}$$

$$(k = 2, \ldots, 5) \tag{14}$$

where:

$PL_{j,t}$ total power load that should be supplied by reservoir $j$ in month $t$,

$PL_{j,k,t}^{\text{hourly}}$ estimated power load that should be supplied by reservoir $j$ in hourly class $k$ in month $t$,

$PGT_{j,k,t}^{\text{hourly}}$ power generation capacity of reservoir $j$ in hourly class $k$ in month $t$.

Similar relations are used to determine monthly power generation in each of the above hourly classes. For this purpose, it is assumed that the hydro generation in each month first satisfies the load in very high load hours ($k = 1$), then, the rest satisfies the high load hours ($k = 2$) and so on. The cost of not supplying the loads in each month is then estimated, using the

**Table 1.** Classification of the hourly value of power generation in a month.

| Load Classification | Duration (Hours) | Value (Monetary Unit/Kwh) |
|---|---|---|
| Very high load hours | 80 | 83 |
| High load hours | 140 | 74.6 |
| Medium load hours | 60 | 70 |
| Low load hours | 260 | 56 |
| Very low load hours | 180 | 55 |

following equation:

$$\text{Loss}_{j,t}^{\text{power}} = \begin{cases} \sum_{k=1}^{5} \left(PL_{j,k,t}^{\text{hourly}} - PG_{j,k,t}^{\text{hourly}}\right) \times P_{k,t}^{\text{hourly}} & \text{if } PG_{j,k,t}^{\text{hourly}} < PL_{j,k,t}^{\text{hourly}} \\ 0 & \text{otherwise} \end{cases} \quad (15)$$

where:

$P_{k,t}^{\text{hourly}}$ actual price (value) of power (indicating the costs of operation and maintenance) in hourly class $k$ in month $t$ (monetary unit/MWh),

$PG_{j,k,t}^{\text{hourly}}$ power generated in hourly class $k$ in month $t$ in reservoir $j$ (MWh),

$PL_{j,k,t}^{\text{hourly}}$ power load in hourly class $k$ in month $t$ in reservoir $j$ (MWh).

By using this equation, the energy production during peak hours in month $t+1$ is given more priority compared to firm energy production in month $t$. In other words, higher priority is given to the peak energy production. Therefore, in month $t$, a lower energy level than firm energy could be provided to ensure peak energy production in month $t+1$ and a better inter-year distribution of power generation is expected.

The idea behind this cost function is that if the water price were estimated, based on the Marginal Cost Method, then, this cost function could show the economic cost to the system. Another capability that is considered in this extended model is that a part of the water supply costs to agricultural demands, which can be replaced by the benefit of power generation, are incorporated.

Considering the time decomposition approach shown in Figure 1, the outputs of the long-term planning model consist of water and power demands that are planned to be supplied by monthly releases from the reservoirs. Therefore, the Water Management Division (WMD) can decide on how much power can be supplied in the coming month.

## MID-TERM PLANNING MODEL

The mid-term planning model has a structure similar to the long-term model. The only differences are in the accuracy of constraints and forecasts. Because the planning horizon is shorter (four weeks), the model is capable of further decompositions and more realistic simulation. In this study, the long-term DDSP model is modified for weekly optimization. The governing probabilities are estimated from the historical and forecasted weekly inflows, assuming that the weeks are independent of each other and the inflows and forecasts follow a first-order Markov Process. More details about the formulation of the probabilities can be found in Vasiliadis and Karamouz [6].

The long-term operating policies that define the monthly release from the reservoir and power generation are considered as a constraint for the mid-term model. For this purpose, a weekly model is formulated to find the optimal operating policies within each month. The water storage in the reservoir at the beginning and at the end of the month are assumed to be constant and equal to the values estimated by the long-term planning model.

The cost function and hourly power generation classification in the weekly model are the same as the monthly model. Therefore, in week $t$, a lower energy level than firm energy could be provided to ensure peak energy production in week $t+1$. So, a better inter-month distribution of power generation is provided by this model.

As noted earlier, the weekly loads that are planned to be supplied by the hydropower reservoirs, are estimated by the Power Management Division (PMD). For this purpose, the PMD decision-makers take into account the system load forecasts and the estimated monthly power generation by the reservoirs provided by the long-term planning model. Therefore, the relationship between monthly and weekly models creates a link between the PMD and WMD decision-makers and planners.

## SHORT-TERM PLANNING MODELS

The purpose of the short-term optimization model is to determine the optimal operating policies on an hourly time scale for a weekly time horizon. In this study, a deterministic dynamic programming model is developed for short-term optimization of hydropower-reservoir systems (parallel system). More precise economic objective functions are applied in the short-term optimization model by incorporating the value of peak and off-peak generation. For this purpose, the hourly values of power generation on different days of the week are used for estimating the loss of power deficits.

Estimation of future power loads is a primary step for hydropower development planning and operation management studies. In addition to annual and monthly variation of power loads, the load distribution in weekly and daily scales must also be considered to determine the type of load that the hydropower project could carry and to estimate the benefits of the system operation. The demand for electricity usually varies from a minimum in the early hours of the morning to peak loads in the late morning and/or early evening. Previous studies have shown that load distribution in summer has a closer correlation with air temperature and it is easier to predict load fluctuations in this season [8].

Besides meeting power loads, the system should have enough capacity to supply the expected peak load plus additional reserved energy in case of breakdown and necessary maintenance shutdown. Rangarajan et al. [9] defined reliability in a hydropower system in terms of the system's adequacy and security. Adequacy relates to the existence of sufficient energy within the system to satisfy the power loads or system operational constraints. Security refers to the ability of the system to respond to disturbances such as power network breakdowns within the system.

In this study, in order to consider both aspects of reliability, the following formulation is used:

- Equations 3 and 4 are applied on an hourly time scale to satisfy the security of the power system by satisfying the spinning reserve requirement;
- The loss function of the model is formulated to satisfy adequacy by supplying the hourly loads of the system:

$$\mathrm{Loss}_{d,h}^{\mathrm{short}} = \begin{cases} \sum_{j=1}^{2} \left[\left(PL_{d,h}^{\mathrm{short}} - PG_{d,h,j}^{\mathrm{short}}\right) \times P_{d,h}^{\mathrm{short}}\right] & \text{if } PL_{d,h}^{\mathrm{short}} > PG_{d,h,j}^{\mathrm{short}} \\ 0 & \text{otherwise} \end{cases} \tag{16}$$

where:

| | |
|---|---|
| $PL_{d,h}^{\mathrm{short}}$ | load in hour $h$ of day $d$, |
| $PG_{d,h,j}^{\mathrm{short}}$ | power generation of plant $j$ in hour $h$ of day $d$, |
| $P_{d,h}^{\mathrm{short}}$ | hourly value of power in hour $h$ of day $d$, |
| $\mathrm{Loss}_{d,h}^{\mathrm{short}}$ | loss of short-term power generation in hour $h$ of day $d$. |

As seen in the above formulation, the hourly model is considerably more detailed than the long-term and mid-term planning models. The objective function in this model is:

$$\text{Minimize } Z = \sum_{j=1}^{2}\sum_{d=1}^{7}\sum_{h=1}^{24} \mathrm{Loss}_{d,h}^{\mathrm{short}}(PG_{d,h,j}^{\mathrm{short}}, PL_{d,h}^{\mathrm{short}}, P_{d,h}^{\mathrm{short}}). \tag{17}$$

Other constraints of the model, such as the power generation equations, are the same as the long-term planning model, but are modified for an hourly time scale.

### Case Study: Karoon and Dez River-Reservoir System

The Karoon and Dez drainage basins are located in the southwest of Iran and carry more than one fifth of the surface water supply of the country (Figure 3). The combined area of these basins includes about 67000 square kilometers of foothills and the Khuzestan plain. Two reservoirs have been constructed on the Karoon and Dez rivers, which are named after the rivers. The total storage capacity of the Karoon and Dez reservoirs is 2900 and 3340 Million Cubic Meters (MCM), respectively. The two rivers are joined at a location called Band-e-Ghir, some 40 kilometers north of the city of Ahwaz (the capital of the strategic border province of Khuzestan), which forms the so-called "Great Karoon River". This river passes Ahwaz and reaches the Persian Gulf some 120 Kilometers South of Ahwaz. The average annual streamflow to the Dez and Karoon reservoirs is about 8.5 and 13.1 billion cubic meters, respectively. The power generation capacity of the Karoon and Dez power plants is 1000 and 520 Megawatts, respectively. The total power generation capacity of these power plants is more than 75 percent of the current total hydropower generation capacity in the country.

The two rivers downstream of the Karoon and Dez dams supply water for domestic, industrial and agro-industrial demands. The total irrigation network downstream of the Dez and Karoon dams is estimated at 250,000 hectares (1 hectare = 10000 square meters). The total water demand for the existing cropping mix is about 5260 million cubic meters. Low irrigation efficiency within agricultural lands, large amounts of water loss along the transfer channels and a high evaporation rate are the main reasons for the high agricultural water demand in this region. The total water demand from the Dez and Karoon rivers for all purposes is estimated as 9120 million cubic meters.

## RESULTS

The monthly operation of the Karoon and Dez reservoir systems over a 19 year period (1978-96) is simulated using the optimal policies obtained from the long-term planning model. For this purpose, a general streamflow forecasting model (Auto-Regressive Integrated Moving Average (ARIMA) model, with non-seasonal parameters $(p, d, q)$ and seasonal parameters $(P, D, Q)$ and a seasonality of twelve, for forecasting monthly inflow to the reservoirs), was developed, considering the required transformation of data and comprehensive statistical analysis. Seasonal and non-seasonal parameters were calculated and inflow forecast time series were generated by going back in time and forecasting three months at a time from the beginning of the operation. The ARIMA $(1,0,1)(1,0,1)_{12}$ and ARIMA $(1,0,1)(1,1,1)_{12}$ models were selected as the best forecasting models for the streamflows entering the Karoon and Dez reservoirs, respectively.

Figures 4 and 5 show the comparison between

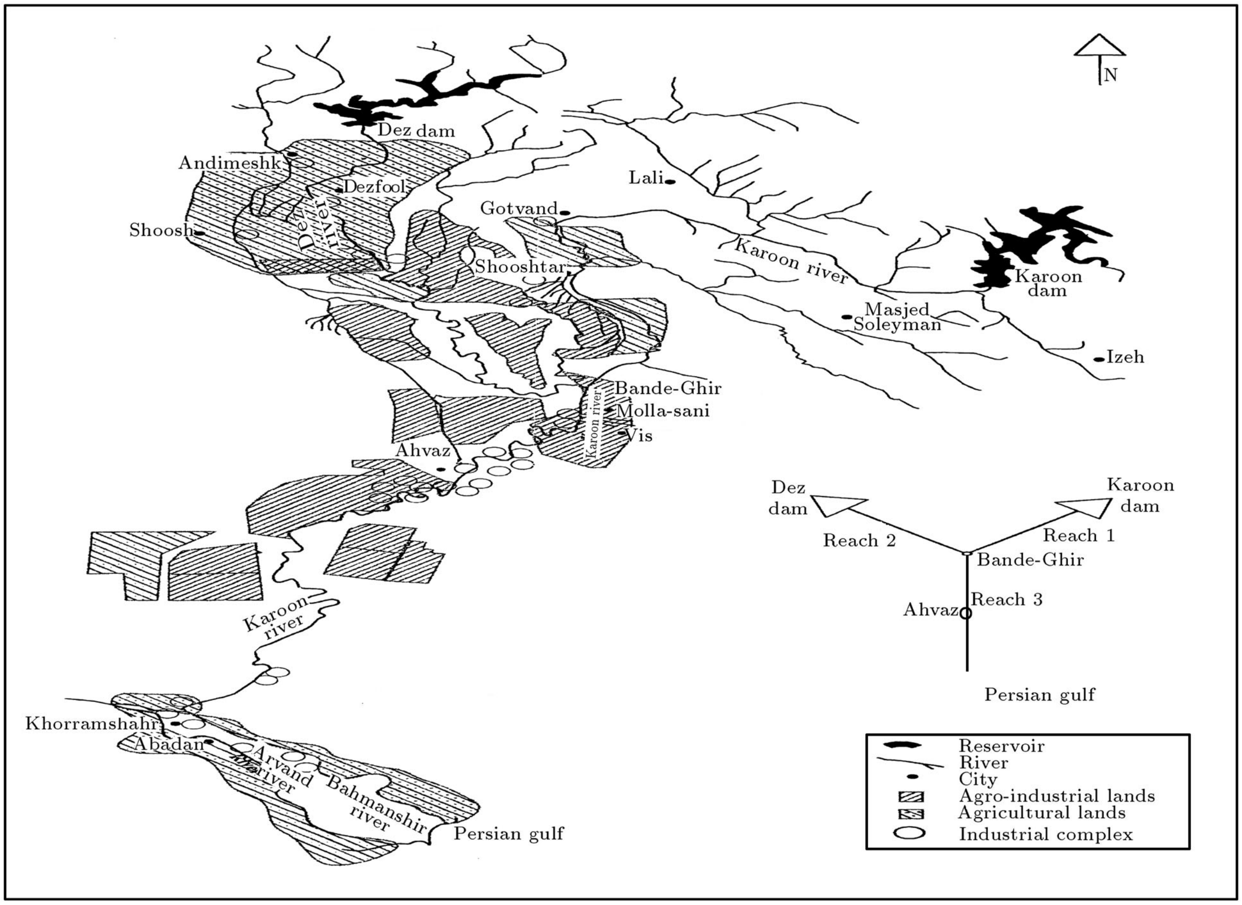


**Figure 3.** Karoon and Dez reservoirs and the study area in the southwest part of Iran.

the time series and the average monthly simulated power generation of the Karoon and Dez reservoirs and the power loads. The selected power loads are higher than the actual loads of the system, in order to develop operation policies, which provide more power. The long-term results of the DDSP model, with economic cost function, show that the model has

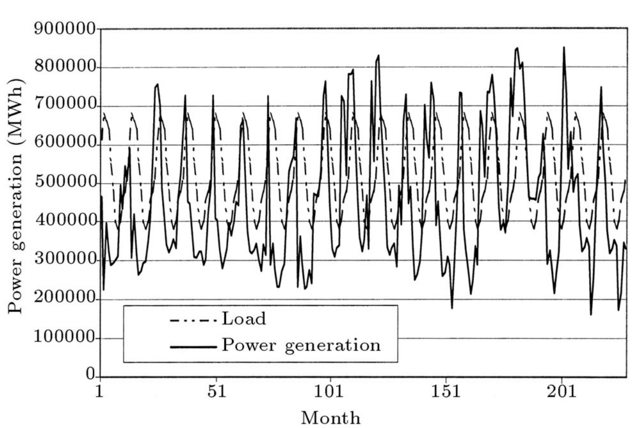


**Figure 4.** Comparison between simulated monthly power generation of Karoon and Dez reservoirs based on DDSP policies and power loads.

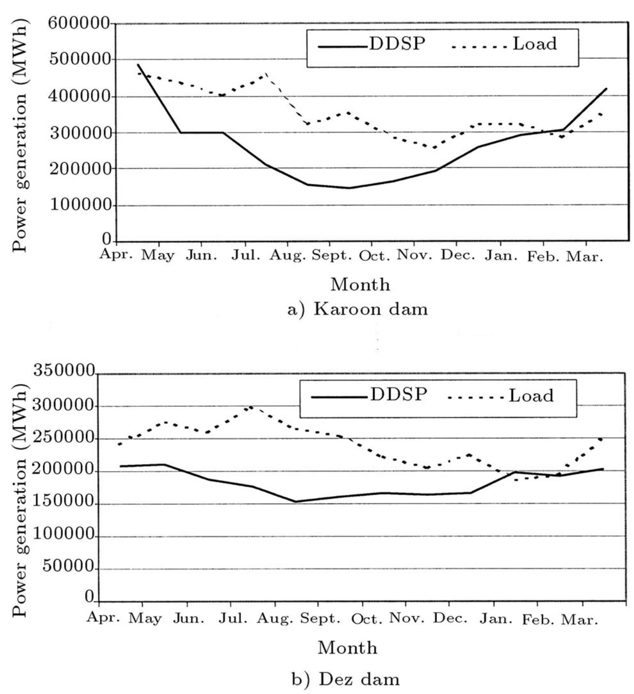


**Figure 5.** Comparison between average monthly power generation of Karoon and Dez power plants based on DDSP policies and power loads.

resulted in higher power generation compared with historical records. The long-term average improvement of power generation has been about 10 percent.

Table 2 shows the results of a monthly planning model for the water supply. As seen, the model has been able to provide all of the water demands from October through April. Application of economic cost function has been effective in supplying water demands that have a higher priority (compared with power generation) in the study area. Overall, more than 97 percent of the water demands are met.

The operation of the system on weekly and hourly time scales is also simulated, using the optimal policies developed by the mid- and short-term models. As an example, Table 3 shows the results of the long-term model for a specific month (September 1995). Table 4 shows the results of the mid-term (weekly) model in September 1995. As seen in this table, the mid-term model has been able to supply all power demands with available water. In order to have a better estimate of the capabilities of the weekly model, the year 1995 is simulated, based on the optimal policies of this model. Results of the model for this year can be summarized as follows:

- Monthly model constraints:
  - Reservoir storage at the end of the month: In the month of April, the end of the month storage has not been reached due to the floods, which were not detected in the streamflow forecasts;
  - Monthly power generation: In the months of June and July, the power generation based on the weekly policies, has resulted in about 8 percent shortage in monthly power generation;
  - Monthly water supply: In the months of June and July, a 15 and 12 percent decrease in the water supply (compared with the values estimated by the long-term model) occurred.
- Weekly constraints:
  - Power load in each week: In 80 percent of the weeks, the model has been able to supply the weekly loads. The shortages mainly occurred in the months of June and July, when the total monthly power generation by the long-term model is not achieved.

Results of the weekly model in the year 1995 show that the weekly model has adequately supplied water and

**Table 2.** Results of DDSP model in supplying water demands in Karoon and Dez river-reservoir system.

| Month | DDSP | Demand |
|---|---|---|
| April | 1010.05 | 1010.05 |
| May | 1032.71 | 1050.91 |
| June | 814.3 | 817.47 |
| July | 1085.63 | 1096.98 |
| August | 1116.3 | 1242.51 |
| September | 1075.28 | 1127.56 |
| October | 772.51 | 772.51 |
| November | 207.32 | 207.32 |
| December | 77.36 | 77.36 |
| January | 100.03 | 100.03 |
| February | 276.76 | 276.76 |
| March | 640.92 | 640.92 |
| Total | 8209.17 | 8420.38 |

April is first month of solar calendar.

**Table 3.** Assumptions for mid-term planning including results of the long-term model in September 1995.

| Reservoir | Karoon | Dez |
|---|---|---|
| Reservoir storage at the beginning of the month (MCM) | 1523.2 | 962 |
| Reservoir storage at the end of the month (MCM) | 1912.2 | 1073.5 |
| Forecasted inflow in the first week of the month (MCM) | 130.75 | 40.1 |
| Forecasted inflow in the second week of the month (MCM) | 135 | 45.3 |
| Forecasted inflow in the third week of the month (MCM) | 140.25 | 49.7 |
| Forecasted inflow in the fourth week of the month (MCM) | 137 | 52.5 |
| Reservoir release during the month (MCM) | 154 | 76.1 |
| Power load in the first week (MWh) | 14340 | |
| Power load in the second week (MWh) | 14467.1 | |
| Power load in the third week (MWh) | 14628.7 | |
| Power load in the fourth week (MWh) | 15507.4 | |
| Total water demand (MCM) | 180 | |

**Table 4.** Results of the mid-term model in September 1995.

| Reservoir | Karoon | Dez |
|---|---|---|
| Reservoir storage at the end of the first week (MCM) | 1616.69 | 984 |
| Reservoir storage at the end of the second week (MCM) | 1712.56 | 1009.8 |
| Reservoir storage at the end of the third week (MCM) | 1815.34 | 1039.4 |
| Reservoir storage at the end of the fourth week (MCM) | 1912.2 | 1073.5 |
| Power generated in the first week (MWh) | 10002 | 4338.5 |
| Power generated in the second week (MWh) | 10111 | 4356 |
| Power generated in the third week (MWh) | 10105 | 4524 |
| Power generated in the fourth week (MWh) | 10774 | 4732 |

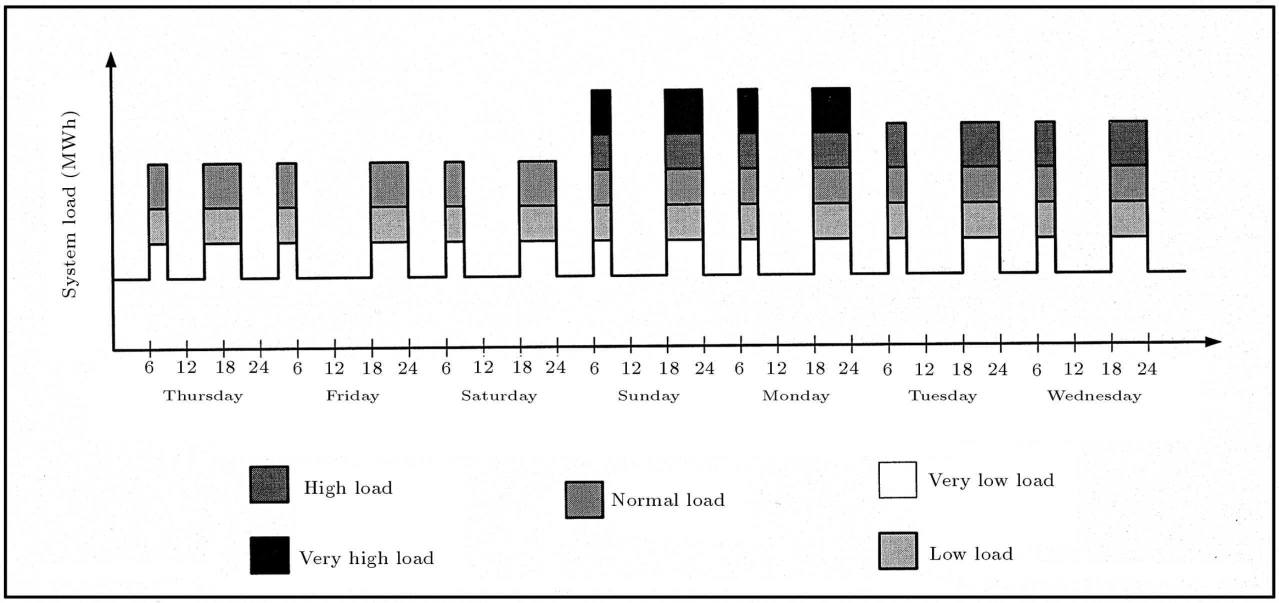


**Figure 6.** The weekly load pattern used in the case study.

power demands, while it has also satisfied the long-term model constraints. The results also show that the weekly model has failed to meet the demands and constraints of the long-term model, when the errors in the inflow forecasts have been significant.

In the short-term model, the weekly load pattern shown in Figure 6 is used. Figure 7 shows the results of the short-term model for the first week of September 1995. Considering the high load for this week, the system was not able to provide the total power load, due to limited water that could be released, based on optimal policies of the mid-term model. The hourly variation of the power value (price) is shown in Figure 8. The highest power load occurs in early evening and is higher than power plant capacity. The hourly variation of the power generated by the system shows that peak loads in the late evening hours, which provide more economic benefits, are supplied with higher efficiency.

To better understand the capabilities of this model, the hourly operation of the Karoon and Dez reservoirs is also optimized in the year 1995. Results of the short-term model for this year show that in 87 percent of the times, the peak loads have been supplied. Table 5 shows the summary of the results of the short-term model for the year 1995. As can be seen in this table, the model has been able to supply the medium, low and very low load hours more than 90 percent of the time. Overall, the results of the model show that the load pattern has been followed by the model and the expensive energy needed in the very high load hours has been supplied by the hydropower plants.

## COMPUTATIONAL REQUIREMENTS

The classical SDP usually has two state variables for each reservoir. In the DDSP model, which is developed in this study for two parallel reservoirs, seven state variables are used, as follows:

- Two for inflow,
- Two for storage levels,
- Two for inflow forecast,
- One for the month showing the variation in demand from month to month.

Therefore, DDSP is significantly more complicated compared to the classical SDP. In the dynamic programming model used for hourly scheduling, only one state variable is needed for each reservoir but the number of discrete storage levels should be very high to approximate the continuum of hourly variations in reservoir levels. In this study, 100 levels were selected and the run-time was about two hours. For DDSP, ten storage levels and five inflow forecast levels were used. The computational time on a Pentium 3, 800 MHz computer, was about 36 hours.

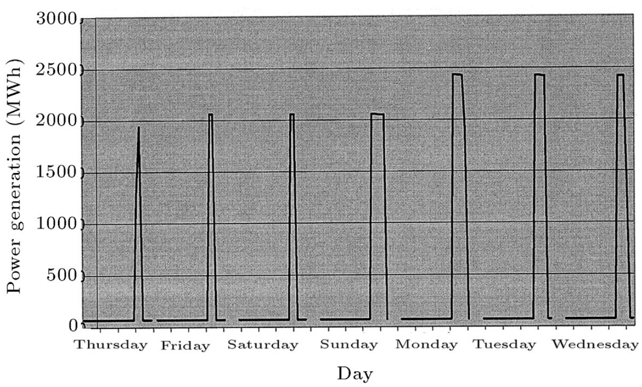


**Figure 7.** The total hourly power generation of Karoon and Dez reservoirs based on optimal policies of short-term model for the first week of September 1995.

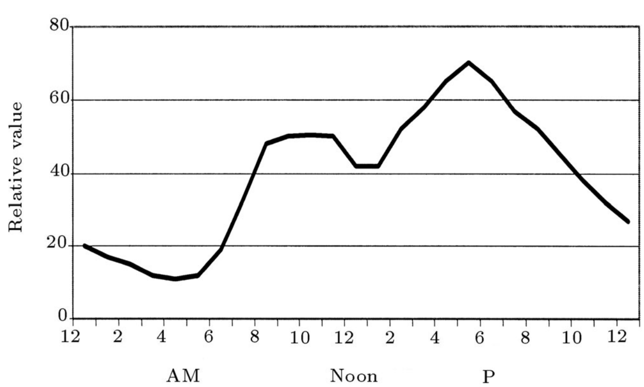


**Figure 8.** Relative hourly value of power generation used in the case study.

**Table 5.** Results of the short-term model in 1995.

| Power Load | Percent of the Time That the Load is Supplied |
|---|---|
| Very high load hours | 87 |
| High load hours | 72 |
| Medium load hours | 92 |
| Low load hours | 90 |
| Very low load hours | 91 |

## SUMMARY AND CONCLUSION

In this paper, the decision-making framework for operation of hydropower reservoirs in Iran is considered as a basis for formulating a set of reservoir operation optimization models. A temporal decomposition approach is employed, including long, mid and short-term planning models. The main objective of these models was to create more flexibility in the decision-making process. The Demand Driven Stochastic Dynamic Programming Model (DDSP) is developed for operation of two hydropower-reservoirs in a parallel system for long and mid-term planning. In the long and mid-term models, the inflow/forecast uncertainties are incorporated in developing optimal operation policies. In short-term scheduling, the inflow uncertainties do not have a major effect on power generation estimation. Therefore, a deterministic dynamic programming model is formulated for hourly operation of the two reservoirs.

The benefits and costs of reservoir operation are incorporated at all planning levels through economic cost functions. For this purpose, the annual reservoir costs are estimated and used for determining cost associated with the water supply. The hourly variation of power value (price) is also considered in determining the cost of reservoir operation associated with the deficits in supplying energy demands.

The approach was applied to the Karoon and Dez river-reservoir systems in southwest Iran. Results of this study show that the developed framework provides a flexible tool for the system operation. The optimal DDSP policies produce a 10 percent larger power generation compared with historical records. Also, more than 97 percent of the water demands are supplied.

The mid-term model (weekly) incorporates the uncertainties associated with weekly inflow and develops the weekly operation policies that can be used for real-time operation. The short-term model (hourly) determines the optimal schedule of hourly reservoir releases that maximize the power generation benefits.

Overall, the developed models provide acceptable levels of reliability for water and power supply in a large-scale system. Furthermore, application of economic cost function enables the decision-maker to analyze the economic costs and benefits of the system by changing the price of water and the peak and off-peak power supply.

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