Quantification of Short-Term Hydropower Generation Flexibility

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ABSTRACT

The main goal of the current research is to quantify hydropower generation flexibility in a system of ten multi-objective reservoirs on the Federal Columbia River Power System (FCRPS). At a given time step, the flexibility in electricity supply (F(t)) is defined as the remaining capacity after satisfying the scheduled production plan. The scheduled production plan includes the sum of future electricity demand and existing obligatory electricity sales resulting from open market sales of electricity. The time-varying flexibility metric is expressed in energy units (MWh). Estimating the flexibility helps the energy producers to address potential negative shocks in energy supply (e.g., due to shocks in wind/solar energy or increased regulatory constraints). To quantify the flexibility, we use a hydraulic routing model to simulate the maximum capacity in energy production at any given time period, given the initial (e.g., current) forebay elevation level in the reservoirs and conditioning on the operational and regulatory constraints. The maximum hydropower generation capacity depends on the given inflows. In this study, we defined the maximum and minimum flexibility, and tested the proposed framework on a ten reservoir system on the Columbia River in the Pacific North-West in the USA.

Keywords
Electricity supply, hydropower reservoir operation, maximum and minimum flexibility

1.0 Introduction

Spatial and temporal variation of water disturbution has obligated to construct reservoirs. If the main objective of a reservoir is hydropower generation, the water managers would like to have much water level in the reservoir to generate more power (Xu and Ito, 1997). Hydropower optimization with deterministic inputs is not realistic because of stochastic nature of inputs such as inflow, energy demands, energy price, etc. (Simonovic and Srinivasan, 1993). That is why we should consider risk in the reservoir operation. Figure 1 shows a schematic figure of various sources of uncertainity in hydropower reservoir operation. Uncertainty on energy prices usually should be incorporated in long-term models (Olivares, 2008), so for the short-term operation we consider it as a deterministic parameter. Many researchers including Bashiri-Atrabi et al. (2015), Loaiciga and Marino (1986), and Sharifi et al. (2014; 2016) dealt with probability and uncertainity in reservoir operation.

Flexibility in a power system is defined in various ways. Menemenlis et al. (2011) defined the flexibility as "one that enables the utility to quickly and inexpensively change the system's configuration or operation in response to varying market and regulatory conditions". In this study flexibility is defined as the remaining capacity after satisfying the scheduled production plan. It should be noted that this is an additional flexibility relative to the initial amount available from storage.

2.0 Methods

In this study, to calculate the maximum and minimum flexibility we first calculated shifted data including mean, mean + STD (standard deviation), and mean – STD based on historical inflow data of Grand Coulee (GCL) and Lower Granite (LWG) reservoirs. After calculation of these data, we used an optimization model with different objective functions to calculate the minimum and maximum flexibility in our system. Figure 2 shows a flowchart of calculation of maximum and minimum flexibility in this research.

2.1 Quantification of flexibility

The flexibility of the system at each time step is expressed as the difference between the maximum hydropower capability and the demand. The minimum and maximum flexibility of the system is calculated by Eqs. (2) and (3).

$$F(t)=P(t)-D(t) \tag{1}$$

$$\text{Min } \sum_{i=1}^{I}\sum_{t=1}^{T}F(t)^2 \tag{2}$$

$$\text{Max } \sum_{i=1}^{I}\sum_{t=1}^{T}F(t) \tag{3}$$

where t = time, T = total number of periods of short-term operation (14 × 24 hr), i = reservoir id (i = 1, …, 10), F(t) = flexibility at period Δt, P(t) = hydropower capability, and D(t) = demand. The hydropower capability at each reservoir is expressed as

$$P(t) = \eta\rho g Q(t)H_n(t) = \gamma Q(t)H_n(t) \tag{4}$$

where $\gamma = \eta\rho g$, η = the efficiency of the reservoir to produce the power (in this stydy $\eta = 0.75$), ρ = the water density, g = the acceleration due to gravity, Q(t) = the turbine flow, and $H_n(t)$ = the net head, which is calculated as

$$H_n(t) = Hf(t)-H_{tail}(t) \tag{5}$$

here $Hf(t)$ = the forebay elevation, and $H_{tail}(t)$ = the tail water level.

Inequalities (6)-(12) are constraints on reservoir forebay elevation, turbine flow, outflow, and tailwater elevation.

- Forebay elevation

$$Hf_{i_{\min}} \leq Hf_i(t) \leq Hf_{i_{\max}} \tag{6}$$

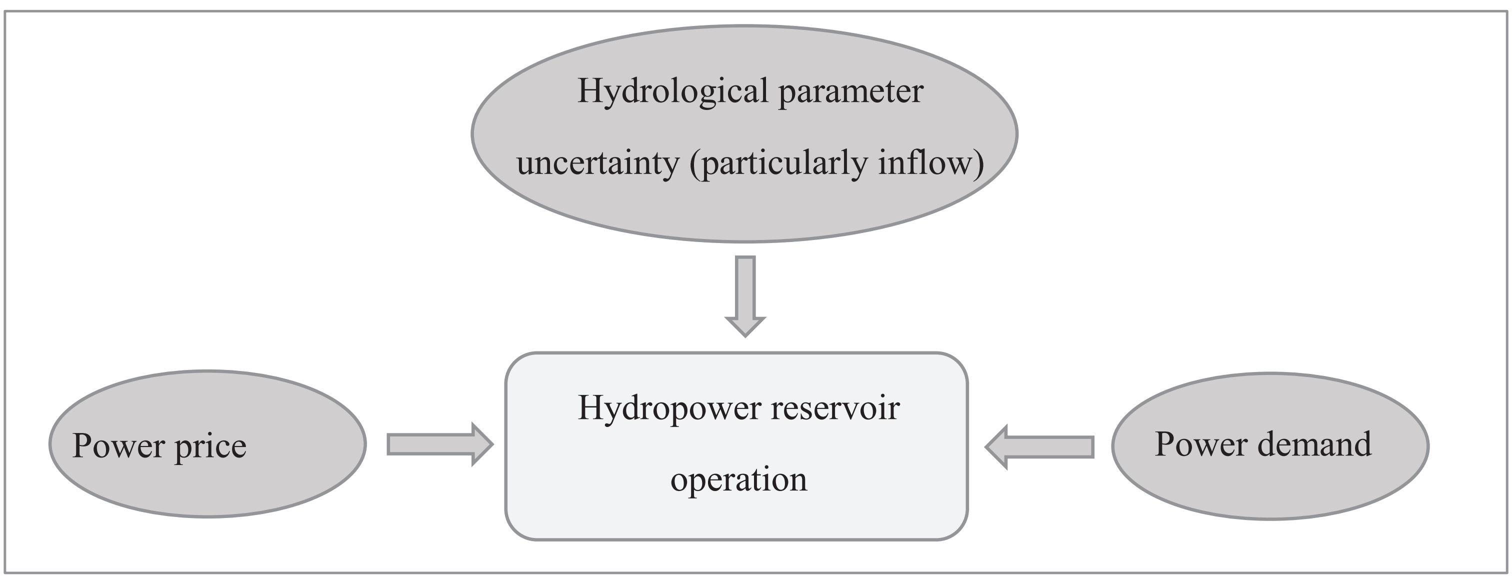

Figure 1. Schematic diagram of sources of uncertainty for quantification of flexibility.

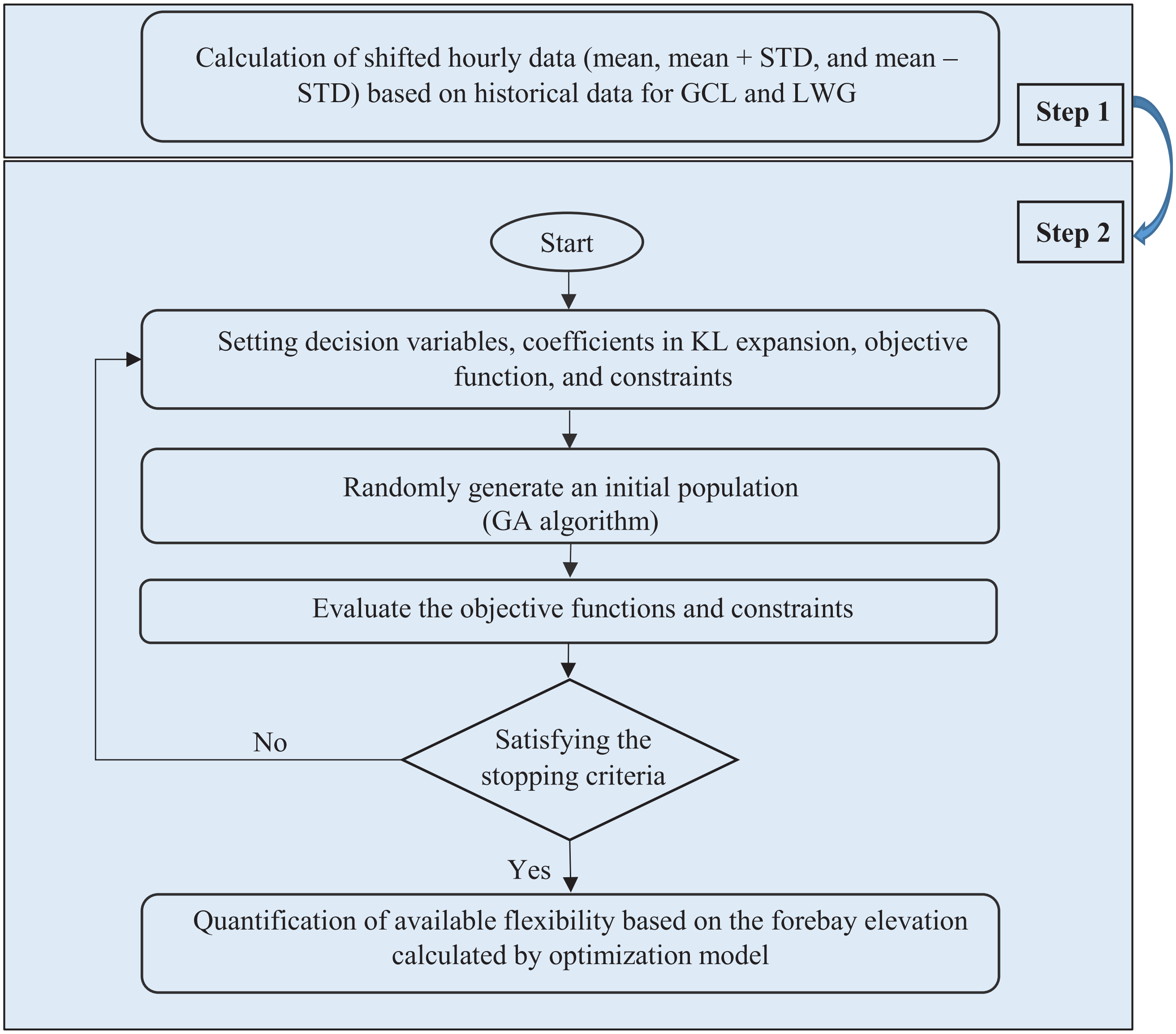

Figure 2. Flow chart of the proposed model for quantification of flexibility.

where $Hf_{\min}$ = minimum allowed forebay elevation, and $Hf_{\max}$ = maximum allowed forebay elevation.

- Turbine flow

$$Q_{turb\text{-}\min_i} \leq Q_{turb_i}(\mathrm{t}) \leq Q_{turb\text{-}\max_i} \tag{7}$$

where Q_{turb} = turbine flow, $Q_{turb\text{-}\min}$ = minimum turbine flow, and $Q_{turb\text{-}\max}$ = maximum turbine flow.

- Ramping limits for outflow

$$|Q_{out_i}(t) - Q_{out_i}(\mathrm{t}+1)| \leq Q_{out\text{-}allowed}(t) \tag{8}$$

- Ramping limits for forebay elevation

$$\begin{cases} H_{r,i}(t) - H_{r,i}(t+1) \leq H_{ramp_{down},i}(t) \\ \text{if} \\ H_{r,i}(t) - H_{r,i}(t+1) > 0 \\ \\ H_{r,i}(t+1) - H_{r,i}(t+1) \leq H_{ramp_{up},i}(t) \\ \text{if} \\ H_{r,i}(t) - H_{r,i}(t+1) < 0 \end{cases} \tag{9}$$

where $H_{ramp_{up}}$ and $H_{ramp_{down}}$ = are allowed ramping rate when reservoir level is increasing and decreasing, respectively.

• Ramping limits for tailwater elevation: This limit is only applied when tailwater elevation is decreasing.

$TW_{r,i}(t)$ - $TW_{r,i}(t+1) \leq TW_{ramp\_down,i}(t)$

if

$TW_{r,i}(t)-TW_{r,i}(t+1) > 0$ *(10)*

where TW_{ramp_down} = is allowed ramping rate for tail water.

• Output

$N_{d\_min,i} \leq N_{d,i}(t) \leq N_{d\_max,i}$ *(11)*

where N_d = is power output, $N_{d\text{-}min}$ = is minimum required output, and $N_{d\text{-}max}$ = is maximum output limit.

• Constraints on end-of-optimization forebay elevation

$H_{r,i}(T) \geq H_{tar,i}$ *(12)*

where $H_{r,i}(T)$ = the forebay elevation at the end of optimization, and H_{tar} = the target forebay elevation at the end of the optimization.

3.0 Study Area

The Bonneville Power Administration (BPA), the US Army Corps of Engineering, and the US Bureau of Reclamation are jointly managing FCRPS. Figure 3 shows a map of the study area, which consists of ten dams. Flood control, irrigation, power generation, navigation, recreation, and municipal water supply are purposes of FCRPS operation (Karimanzira et al., 2016). Among these, hydropower generation is the most important objective of reservoir operation by BPA. In this study the operation period is two weeks from August 25th to September 8th. Hourly turbine

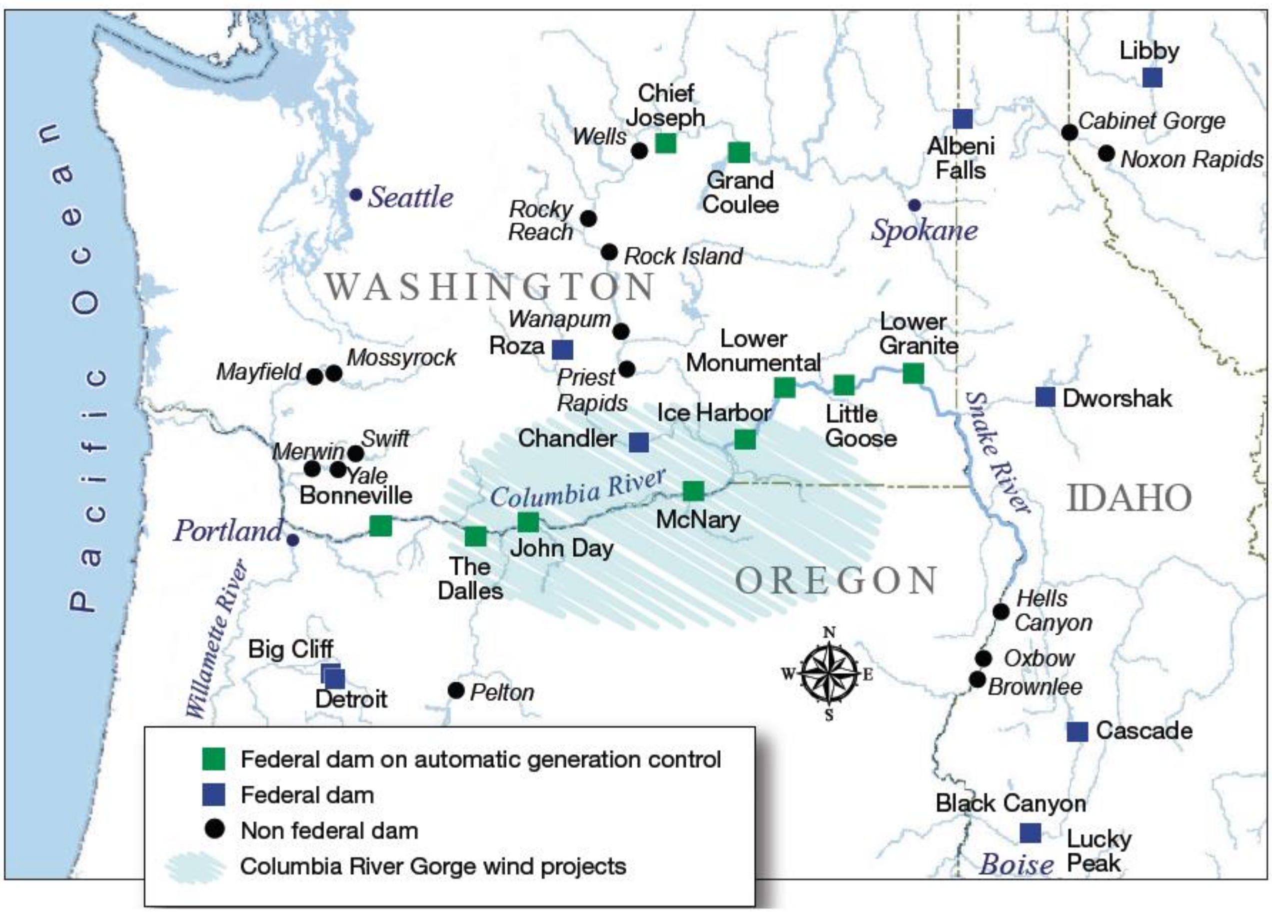

Figure 3. 10 big dams on Columbia River (green squares on the map) (adapted from Bonneville Power Administration Fact sheet, 2016).

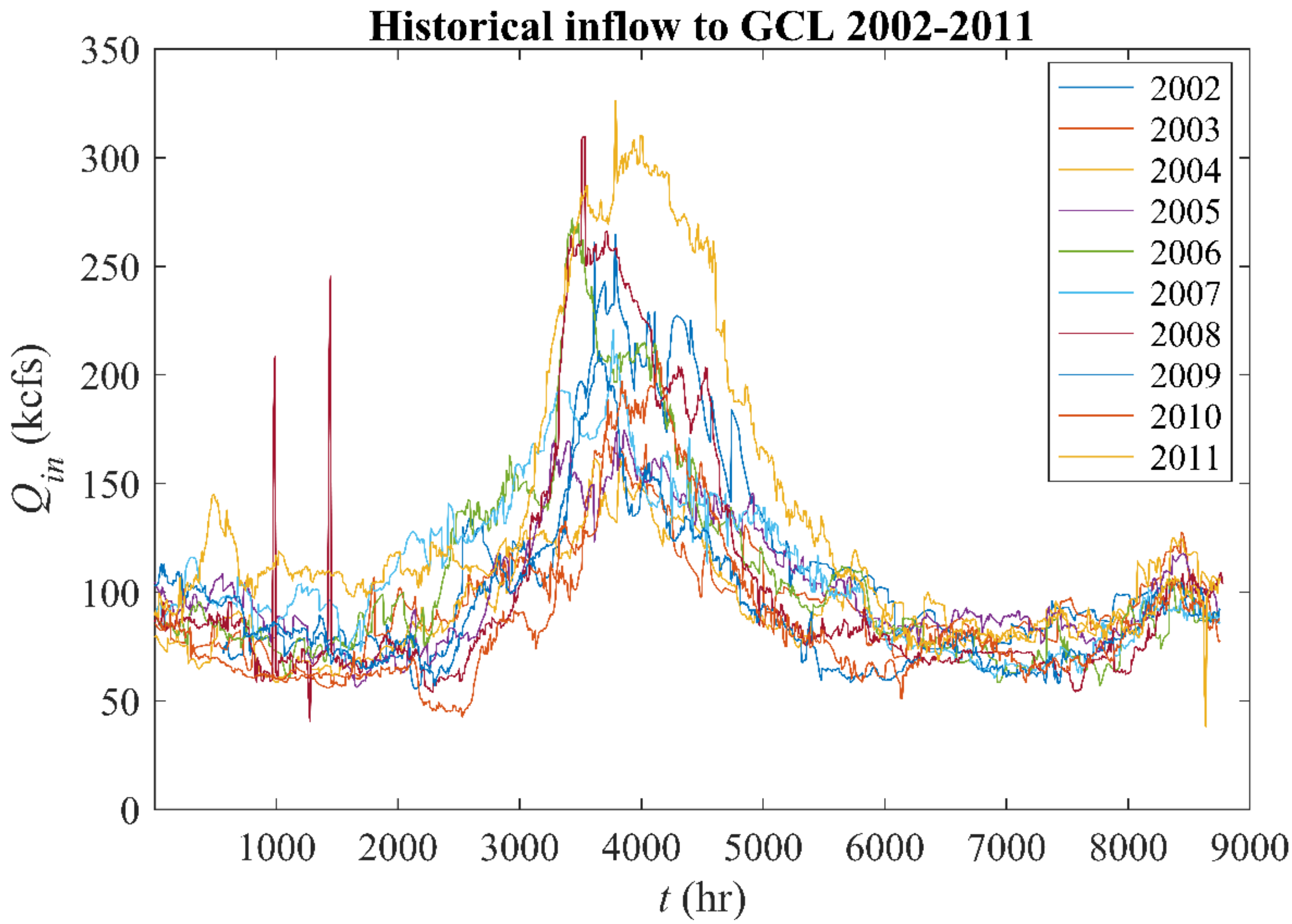

Figure 4. Six hourly Reservoir inflow to GCL reservoir (US Army Corps of Engineers, Northwestern Division).

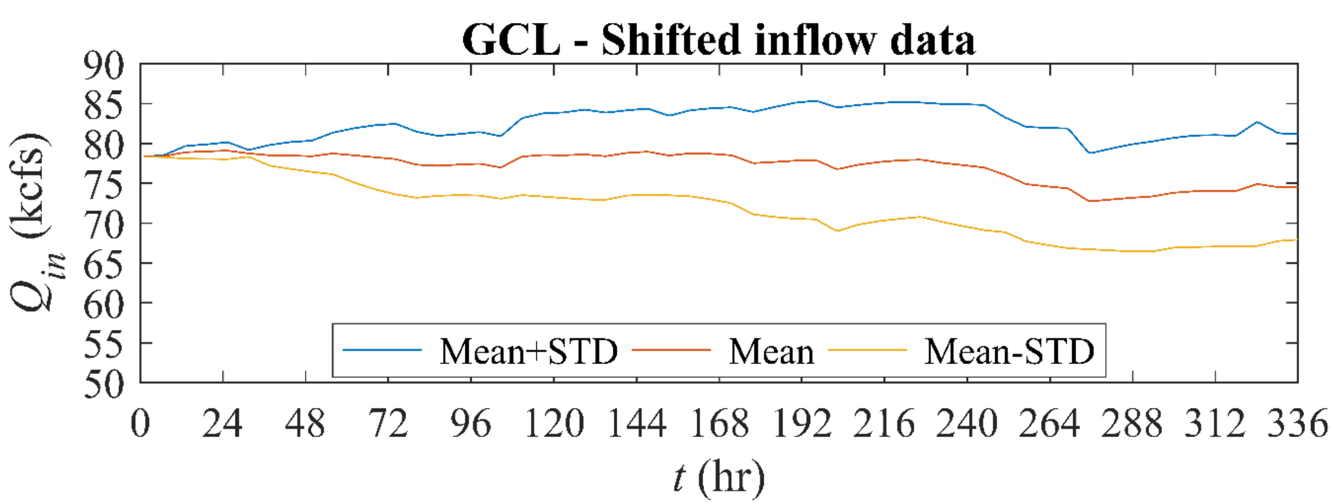

Figure 5. Hourly shifted data of GCL reservoir for 14 day.

outflows are the decision variables in this study. Six hourly inflow data of GCL and LWG reservoirs for these 14 days from 2002 to 2011 are used in this model.

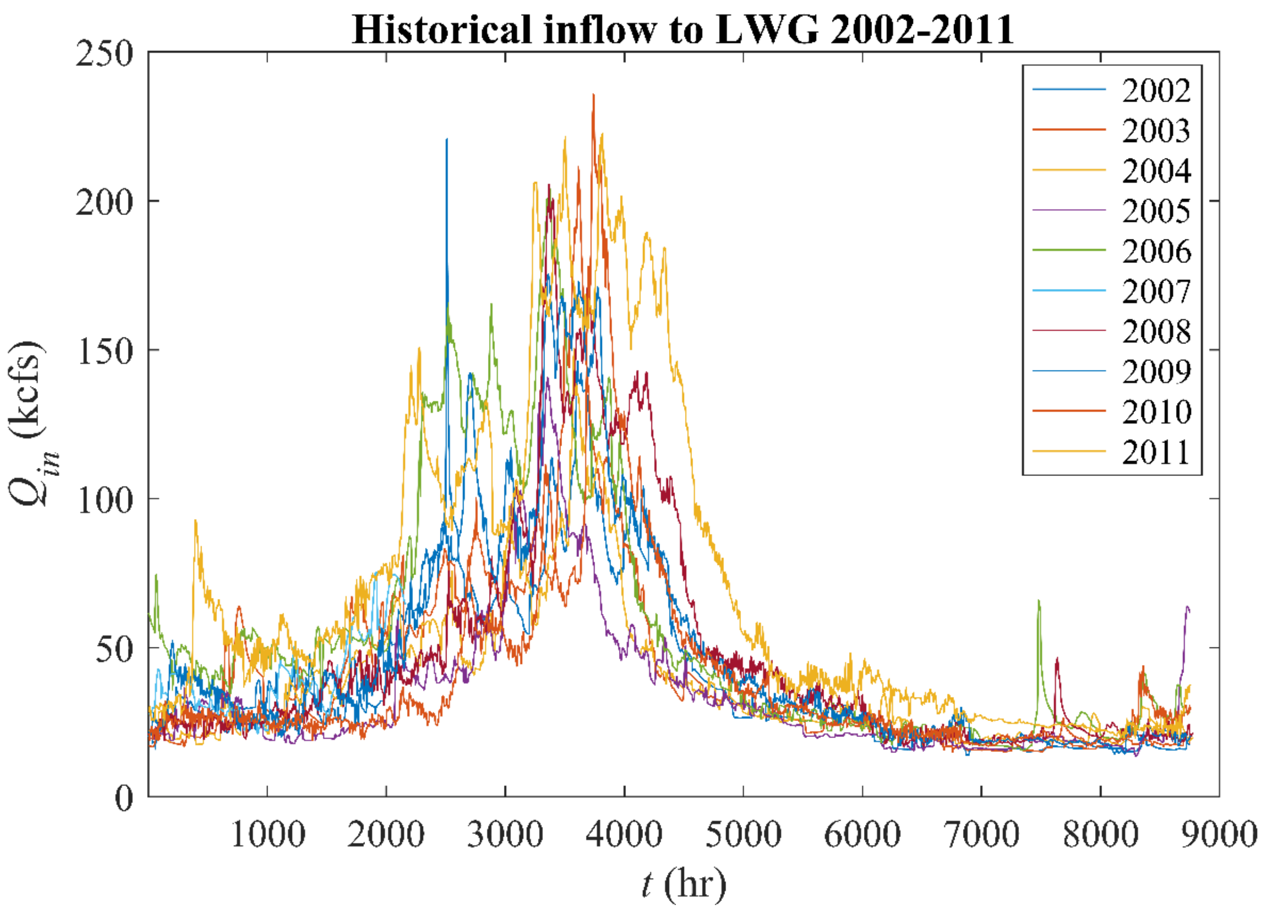

Figure 6. Six hourly Reservoir inflow to LWG reservoir (US Army Corps of Engineers, Northwestern Division).

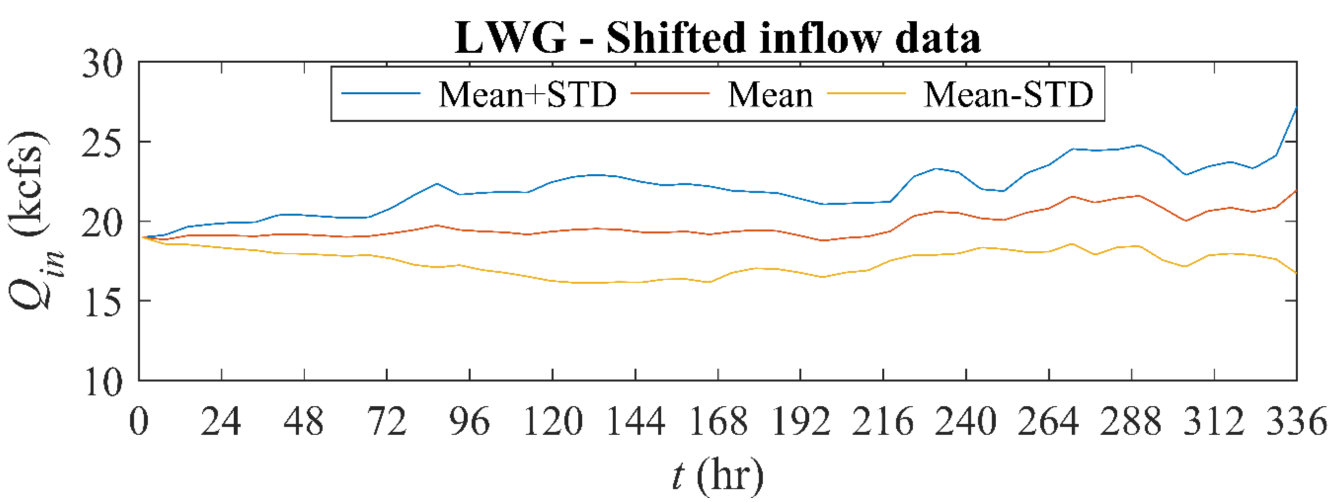

Figure 7. Hourly shifted data of LWG reservoir for 14 days.

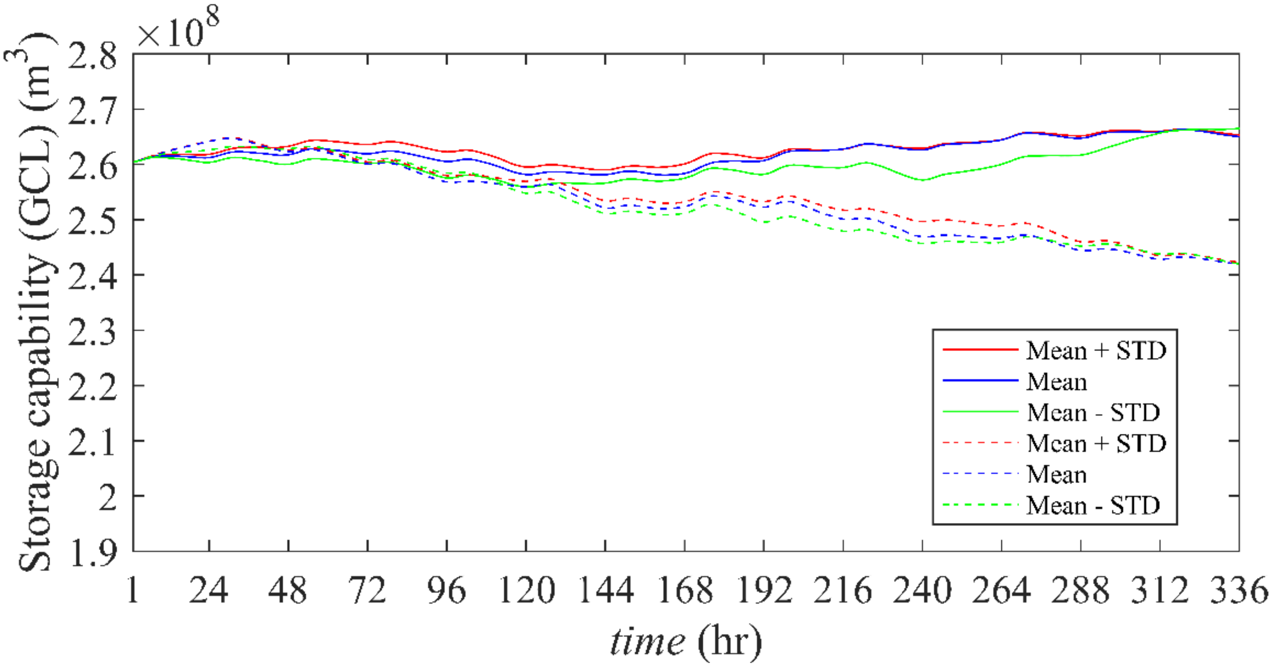

Figure 8. Storage capability of the GCL reservoir for maximum and minimum flexibility with shifted data.

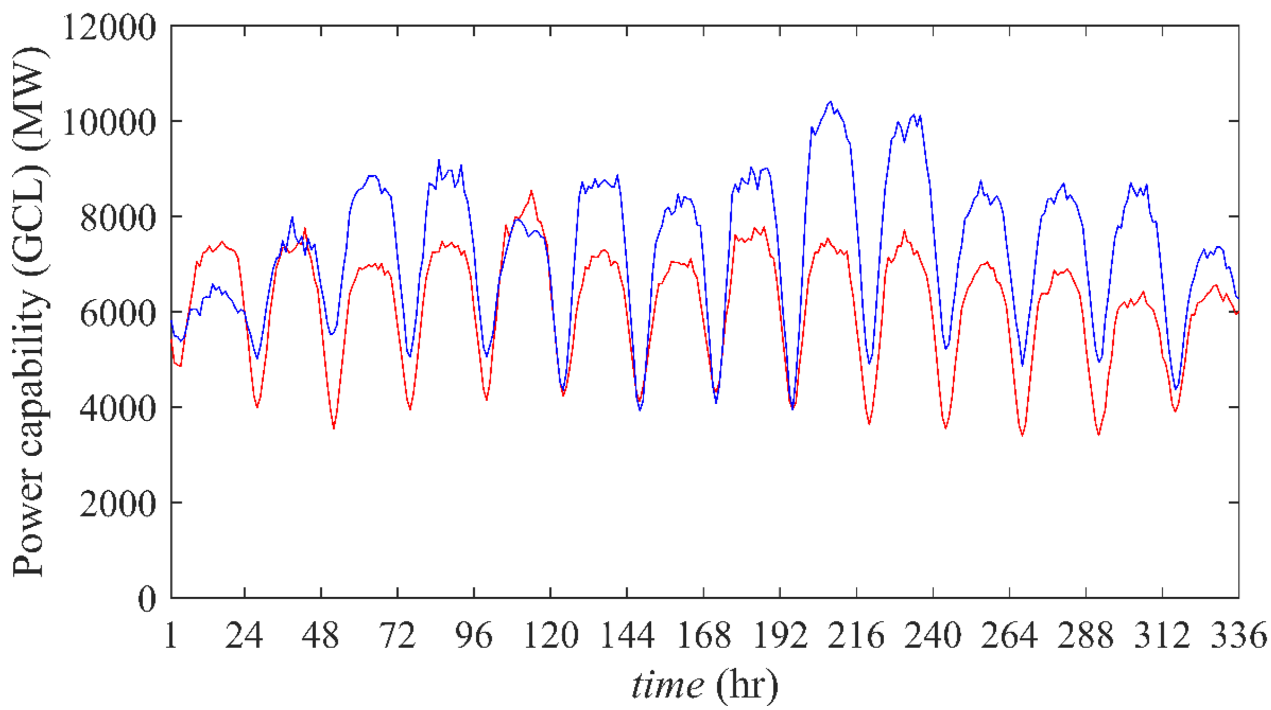

Figure 9. Maximum and minimum power capability of the system with mean inflow data.

4.0 Results and Discussion

In this study, the authors focus on the short-term management of hydropower production for forecast horizons of up to 14 days, for the FCRPS in the Columbia River basin. We first collected the 6 hourly data for the same days over 10 different years form 2002-2011 and then shifted the amounts (added or subtracted a

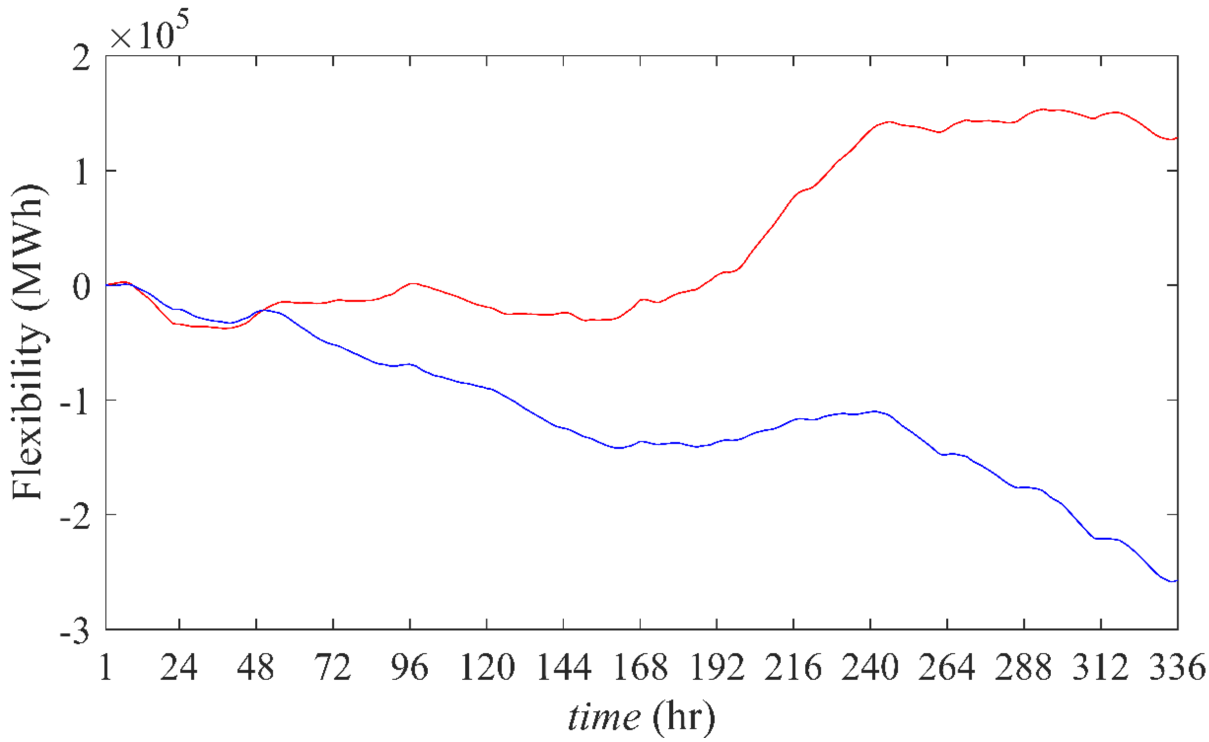

Figure 10. Additional flexibility of the system with mean inflow data.

constant) in order for them to start at the same level. Then, we used a cubic spline interpolation to calculate the hourly data and used them in lieu of inflow forecasts. Figures 4 and 6 show the historical 6 hourly data from 2002 to 2011 for GCL and LWG reservoirs. The mean, mean + STD, and mean – STD values of inflow to these reservoirs are shown in Figures 5 and 7.

The optimization problem for a forecast horizon 14 days with hourly time steps is used for a ten reservoirs system.

GCL maximum and minimum flexibilties are shown in Figure 8. The solid and dashed lines show maximum and minimum flexibilties using different inflow data, respectively. In addition, Figure 9 and 10 show the maximum and minimum power capability and cumulative flexibility in the system using the mean inflows and assumed demands.

5.0 Conclusion

In this study, we quantified the minimum and maximum flexibility using an optimization method. To this end, we used shifted data to start at the same level. We considered flexibility as the remained value of power in the system after satisfying the demand. We applied this model on a ten reservoirs system in Columbia River in Northwest of the USA, using hourly data. For the future plan we will consider the uncertainty for the both inflows and demands to calculate the maximum and minimum flexibility.

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