Research paper

Hydropower flexibility valuation tool for flow requirement evaluation

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ABSTRACT

Timing of generation is becoming more and more valuable. This creates greater potential tension between environmental and power system objectives since both systems require their own flow patterns. Identifying win–win outcomes in this context requires being able to discuss the value of flexibility across stakeholder groups. This research proposes a two-stage optimization method to understand hydropower flexibility to meet both environmental and power system requirements. The tool simulates the two-settlement market process in the U.S. by maximizing revenues from both the day-ahead and real-time markets, subject to plant operational limits, regulatory flow and ramping requirements, and uncertainties associated with water availability and market prices. The model is formulated as linear programming problems and solved using IBM ILOG CPLEX optimizer. By examining a range of flow requirements, ramping constraints, and storage capacities, the proposed tool shows how to make more informed decisions to weigh the cost of specific flow requirements in the context of the overall license requirements. Results from the case study show that revenue is more sensitive to the ramping constraints than the minimum flow constraints. We also demonstrate that removing flow constraints in a dry month increases monthly revenue by up to 118%, as opposed to only 1% in a wet month. In addition, our results suggest that using a learning-based water flow forecast results in an increase of monthly revenue up to 6.4% compared with persistence forecast.

1. Introduction

More than 200 hydropower facilities are coming up for relicensing in the United States (U.S.) in the next ten years (Kotchen et al., 2006; Uria Martinez et al., 2021). The Federal Energy Regulatory Commission (FERC) hydro relicensing process requires a hydropower project to develop an Environmental Analysis (EA) or Environmental Impact Statement (EIS) as per the requirements of National Environmental Policy Act (NEPA) (Federal Energy Regulatory Commission (FERC), 2004). FERC may impose alternative operating schedules for a hydropower based on the environmental impact and the value of the hydropower. However, the value of a hydropower plant is evaluated based on multiplying total generation and average annual energy prices and ignores the flexible nature of operation of a hydropower plant (Federal Energy Regulatory Commission (FERC), 2004). For example, ramp rate limit or minimum instream flow requirement, which may

impact the flexibility of a hydropower project, is not captured in FERC's analysis in any meaningful way. This research proposes a tool that can evaluate the true value of a hydropower plant by accurately representing the tradeoffs between the environmental flow requirements and the power system value.

The value of hydropower flexibility has increased because of the need for fast ramping generation in power systems (Goutte and Vassilopoulos, 2019). Increase in wind, PV energy generation has put power system operators such as CAISO to look for cleaner alternatives to meet the sharp ramp of demand during evening hours which is often referred as *duck curve* (CAISO, 2016). The dynamics in generation and demand mismatch and the constraints on transmission and distribution networks create market opportunities resulting in temporal and spatial fluctuations of electricity prices (Durvasulu and Hansen, 2018). During the evening ramping hours, the value of energy is higher than the average. FERC's existing techniques to estimate the value of hydropower only considers the total generation and average price that results in misleading evaluation of these hydropower assets that are critical resources to meet these ramping challenges.

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Therefore, more accurate presentation of hydropower's value is becoming critical in the licensing process.

Most of the constraints for a dam are fixed but the environmental flow constraints are fixed during the FERC relicensing process (Federal Energy Regulatory Commission (FERC), 2004). These environmental constraints will be more important considerations as increased droughts and floods with climate change continue to be an issue (Viers, 2011). There are even cases of operating hydropower dam removal (e.g., Elwha River Hydropower) for the purpose of environmental restoration (Gowan et al., 2006). FERC licensing process needs a tool that can: (1) accurately represents the link between flexibility and revenue; (2) effectively communicates tradeoffs between environmental flow requirements and power system value to diverse stakeholders; and (3) is easily portable to the many hydropower projects that are coming up for standardized re-licensing. Existing tools used to assess the value of flexibility during re-licensing are simple and often only consider the average energy or capacity price to estimate the value of a hydropower plant. A tool with medium complexity that is capable of representation the value of flexibility under multiple scenarios, and effectively communicate the trade offs between flow requirements and power value and yet be simple enough to be portable is required for the relicensing process (Stoll et al., 2017).

The literature has many studies that evaluate the revenue of a hydropower plant taking advantage of the flexibility, for example a unique market participation techniques optimized for day-ahead (DA) and real-time (RT) markets have been developed to maximize revenue (Gu et al., 2014). Similarly, there are works that optimize the operation of hydropower plants with a reservoir to optimally bid into competitive markets and maximize their revenue (Lino et al., 2004). A review paper that investigated most of the bidding and market revenue optimization works show that a lot of progress has been made in modeling a price maker and price taker models for revenue and cost optimization (Steeger et al., 2014). These techniques are successful in improving the revenue for hydro projects based on real flow data, but fail to take the environmental constraints into consideration which is an essential step for the FERC relicensing.

Hydropower operators utilize tools that advice their daily operations and also used for long term planning to maximize their revenue (Mai et al., 2013). Tools developed based on these studies often consider the cascaded operation of multiple hydropower projects on the same river or stream to meet the collective objectives of environmental stewardship, flood control, water supply, and power, but are too complex to evaluate a wide variety of scenarios during a licensing process. Most of these studies improve the revenue for a hydropower plant through market participation but the complexity of such tools can hinder the commutation with stakeholders who lack the expertise in utility operations (Ilak et al., 2014; Lohndorf and Minner, 2010; Villar and Rudnick, 2002).

There are several commercial tools available for production cost modeling (PCM) such as PLEXOS (Papadopoulos et al., 2014) and PROMOD (ABB, 2015), which focus on the accurate representation of the power system, but miss out on the hydrology representation. These tools serve best for operational modifications, but do not serve the environmental flow constraints estimation. Detailed hydrological models like the Water Use Optimization Toolset (Gasper et al., 2014), which are representative of the watershed models have detailed water inflows and outflows. There are tools that evaluate the investment strategy to reduce risk and plan the dispatch and bidding strategy to mimic a physical system in a real market (Fernandes et al., 2018). A tool that was developed as a price-maker model with other generating assets was used to perform an analysis of the true value

of hydropower by evaluating the effect on emissions (Gallego-Castillo and Victoria, 2020). Most of these tools perform well with one or more aspects of hydropower modeling, but are not set up for FERC re-licensing evaluation because none of them can cover the environmental constraints and flexibility aspect that can be ported to evaluate the revenue for any hydropower asset.

We developed a tool that incorporates a two-stage optimization that incorporates the day-ahead and real-time market like all the revenue improvement tools mentioned earlier, but in addition to that this tool has the ability perform the two-stage market optimization under multiple environmental flow and market scenarios. This ability of optimizing operation under various environmental flow constraints and yet be portable and open source makes this tool unique and very useful for small hydropower operators going into relicensing process. This tool incorporates temporal differences in power pricing and hydropower plant generation considerations into a hydropower flexibility valuation tool that can facilitate communication among parties in FERC negotiations. This ability would enable more accurate and precise valuation reports in proceedings (Stoll et al., 2017). The benefit of this tool over the existing tools and studies: (1) a simple yet capable tool to improve communication across stakeholders involved in the proceeding; (2) enhance the information present in the alternative scenarios of varied flow constraints, ramping, and reservoir storage limits; and (3) evaluate trade-offs between the economic and environmental impacts of flow requirements, thereby improving environmental well-being while also balancing revenue and the grid's need for clean energy generation at certain times.

The contributions of this study include: (1) Developing an optimization model to maximize the economic revenues within environmental bounds and flexibility requirements under electricity price variability and water inflow uncertainty, (2) Demonstrating the proposed tool by case studies of a hypothetical hydropower plant as a generic example of the FERC re-licensing process, (3) Sensitivity analysis by a range of scenarios to take into account flow requirements, ramping requirements, and reservoir sizes, and (4) Demonstrating the economic benefits of using forecasts in hydropower plant scheduling to address the inflow uncertainty in a competitive electricity market.

The remainder of this paper is structured as follows. Section 2 gives the mathematical formulation of the proposed model and input data. Section 3 presents the results. Section 4 further discusses on the results and provides insights from our discoveries.

2. Methods and data

2.1. Hydropower flexibility valuation tool

The study developed a Hydropower Flexibility Valuation Tool (HFVT) that incorporates temporal differences in power pricing and hydropower plant generation considerations to facilitate communication among parties in FERC licensing negotiations. The HFVT does not scope resource mix changes (e.g. PV, wind). Instead, it evaluates hydropower flexibility in terms of minimum flow, reservoir storage limit, ramping limits, etc. This is done by quantifying the value of one operational regime relative to other operational regimes. This HFVT employs an optimization model to allocate generation within the bounds of environmental flow requirements to maximize revenue from electricity market participation (Fig. 1). The tool also can compare multiple scenarios, as defined by a conceptually intuitive set of inputs to assess outcomes across scenarios.
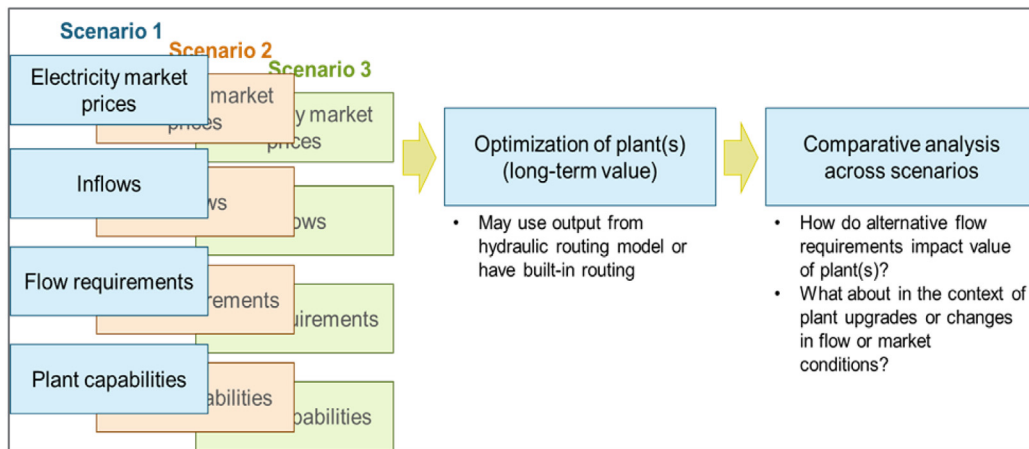
Fig. 1. The HFVT enables more accurate valuation of an individual hydropower plant, which can compare multiple scenarios as defined by a conceptually intuitive set of inputs to assess outcomes across scenarios.
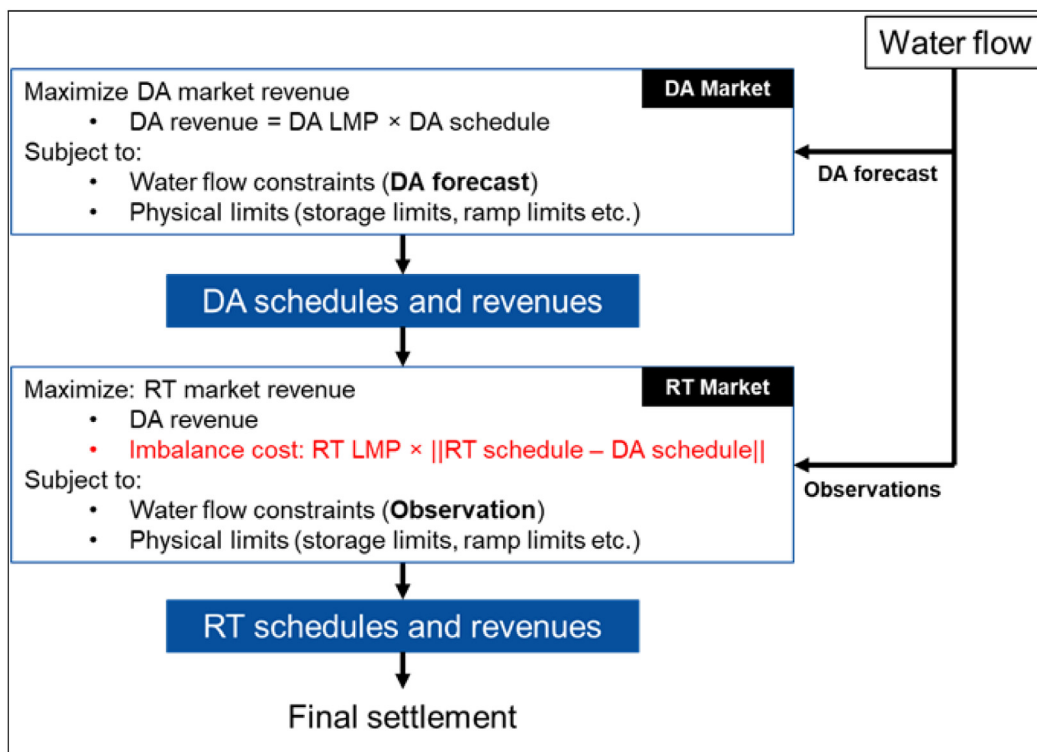

Fig. 2. Process flow of the two-stage revenue optimization model showing how the model feeds inputs through subroutines. In the first stage, the decision to participate in the DA market is optimized first based on a forecasted flow. In the second stage, the decision about RT market participation is optimized based on forecast error and observed flow.

2.2. Tool optimization model structure

The tool's optimization model is currently designed to consider a single reservoir and corresponding power plant. It captures basic characteristics of each, such as reservoir storage, hydropower plant limitations, and operational considerations such as flow requirements. In this single-reservoir system, the tool is designed to evaluate multiple scenarios encapsulating differences in electricity market prices, water inflows, flow requirements, and plant capabilities using a two-stage optimization method (Fig. 2). Primary inputs to the tool include: (1) hourly forecast of flow; (2) hourly observed flow; and (3) hourly DA and RT electricity prices. Other input data that form the technical constraints to the optimization include the power efficiency and power-generation rule as well as the ramping rate.

The tool is designed to evaluate and compare multiple scenarios. For each scenario, the tool maximizes the plant revenue by optimizing electricity generation within a set of boundary conditions that include factors such as water inflow, reservoir storage, plant capabilities, and environmental flow requirements or operational regimes. For example, if the FERC requirements allow the reservoir drawdown by certain number of feet, the model can be utilized to understand the revenue difference for the different reservoir drawdown limit. The tool can be used to optimize sub-daily decisions based on providing it input from an external operations or hydraulic routing model, or multi-day operations can be simulated within the tool. The model considers two dispatch horizons corresponding to DA and RT market bidding. Different price and water profiles can also be used to compare across water

year type or expectations about future electricity market conditions. Based on implementing multiple scenarios, the tool enables users to compare revenue estimates across multiple scenarios, assessing how changes in boundary conditions (e.g., environmental flow requirements, plant upgrades) impact potential revenue.

This model is designed to reflect competitive electricity markets with a two-settlement system consisting of a DA forward market and RT spot market. This model implements a two-stage optimization method to provide accurate assessment of revenue difference caused by environmental flow constraints, which are included in both stages of optimization. Energy producers or buyer participates in the DA energy market to buy or sell electricity one day before the operating day. Energy producers or buyer participates in the RT energy market to buy or sell electricity during the operating day. For example, in the CAISO, the DA market closes at 10 am one day prior to real time, and the imbalance caused by uncertainties are corrected in the RT market. The DA market clears once per day, whereas the RT market clears every five minutes. For our tool, the market clearing price is defined as the price where the demand for electricity by consumers is equal to the electricity that can be generated at that price (i.e., it is the price when market equilibrium is achieved). Market operators collect bids from market participants and clear the markets using unit-commitment and economic-dispatch models, which give the locational marginal prices (LMPs) for energy at each node. The revenue of a hydropower plant comes from selling energy to the electricity market, which includes forward transactions in the DA market and delivery of electricity in the RT market.

In this two-stage revenue optimization method, the decision to participate in the DA market is optimized first based on a forecasted flow. The first stage objective function in the first stage (e.g. DA market) aims to maximize the total revenue generation of hydropower plant during the planning horizon considering environmental flow, physical limit constraints (e.g., storage limits, ramp limits). The model assumes that if the hydro-power participates in the DA market, it will also participate in the RT market.

In the second stage, the decision about RT market participation is optimized based on forecast error and observed flow. The second stage objective function aims to minimize imbalance energy cost caused by deviation of actual generation from RT schedule while maximizing the revenue for monthly operations on an hourly timestep. The plant operator determines the optimal operating schedules by maximizing total revenue based on hourly water inflow. Because of forecasting errors of water flow, the DA schedules usually differ from the RT schedules, which are settled by imbalance costs based on RT prices.

Water flow is translated into generation by approximating the hydropower conversion efficiency relationship using piecewise linear curve fitting. The optimization model has three types of linear variables: hourly reservoir water release, hourly reservoir water storage, and hourly water spillage.

Environmental flow can be applied in the model to allow comparison of multiple potential environmental flow or operational regimes. Examples of the types of environmental flows that can be simulated include minimum instream flows, ramping rate limits, hydropower output limits, and storage constraints. The regulatory requirements on stream releases can be defined as are reservoir operating ranges and targets, as well as license and contract requirements under different water availability conditions (e.g., wet, normal, dry). These include minimum instream flow requirements, water rights, and reservoir-release capacities. A reservoir's hourly water-balance constraints determine flow release based on minimum and maximum water-storage requirement by hour. Ramping rate limits are determined by maximum hourly flow variations.

Environmental flow requirements are usually determined through stakeholder negotiation and there are a variety of ways these are determined. Most methods rely on some forms of hydrologic and/or bathymetric model combined with considerations of life history, ecological, and other environmental (such as cultural and recreational) requirements to support a desired environmental outcome. Parties involved in this process might include tribes, U.S. Fish and Wildlife Service, National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NOAA-NMFS), state fish and game and water quality entities, environmental non-governmental organizations, citizen groups, and more. When disagreements exist among stakeholders in a FERC licensing process, FERC will make a determination as to what the environmental flow should be (or if there should be one at all). Note that the focus of this paper is to develop a generic tool to aim the decision-making process of FERC licensing under environmental flow requirements, and the determination of these constraints per se are out of our scope. Interested readers are referred to relevant literature, such as in Cameron and Pracheil (2022).

2.3. Optimization model

The planning horizon of this model is defined by T (e.g., daily, weekly or monthly) with each individual period indexed by $t = 1, \ldots, T$. This optimization model is developed for an hourly time-step. It is assumed that reservoir storage, flow release and bypass decision can vary hourly.

2.3.1. First-stage optimization: DA schedule

The first stage optimization model aims to identity a day-ahead schedule based on a 24-h forecast flow defined by S_t^{DA}. The first stage optimization model has following linear variables: hourly reservoir water release (Q_t^{DA}), hourly reservoir water storage (R_t^{DA}), and hourly water spillage (P_t^{DA}). The notations used in this manuscript are listed in Table 1. The objective is to maximize the total revenue from DA market given water flow forecasts and is defined by Eq. (1).

$$\max : \sum_{t \in \mathcal{T}} \psi_t(Q_t^{DA}) c_t^{DA} \tag{1}$$

where coefficient c_t^{DA} represent day-ahead market price during hour t. The model assumes that hydro operation is subject to the regulatory flow release constraints, hourly water balance constraints, ramping rate constraints, and hydropower output limits of turbines. These constraints are described below:

Regulatory reservoir water level and flow constraints: The regulatory constraints on stream releases are reservoir operating ranges and targets, as well as license and contract requirements under different weather conditions. These include instream flow requirements, water rights, and reservoir release capacities. The reservoir's lower and upper bounds of storage is defined by Eq. (2). The reservoir water storage requirement may vary by weather conditions and upstream or downstream requirement. This time specific reservoir's lower and upper bounds of storage at t is defined by Eq. (3). Regulatory flow requirement constraints are defined by Eqs. (4) and (5). Constraints (4) define minimum and maximum flow requirements. Constraints (5) define minimum and maximum flow requirements at time period t depending on weather conditions.

$$U^{min} \leq R_t^{DA} \leq U^{max} \qquad \forall t \in T \tag{2}$$

$$V_t^{min} \leq R_t^{DA} \leq V_t^{max} \qquad \forall t \in T \tag{3}$$

$$W^{min} \leq Q_t^{DA} \leq W^{max} \qquad \forall t \in T \tag{4}$$

$$L_t^{min} \leq Q_t^{DA} \leq L_t^{max} \qquad \forall t \in T \tag{5}$$

Water balance constraints: Reservoir water balance during period t is defined by Eq. (6).

$$R_t^{DA} - R_{t-1}^{DA} = S_t^{DA} - Q_t^{DA} - P_t^{DA} \qquad \forall i \in I, \forall t \in T \qquad (6)$$

Ramping constraints: Maximum hourly up-ramping and down-ramping rates is defined by Eqs. (7) and (8).

$$Q_t^{DA} - Q_{t-1}^{DA} \leq \mathcal{Q}_t^{max} \qquad \forall i \in I, \forall t \in T \qquad (7)$$
$$Q_{t-1}^{DA} - Q_t^{DA} \leq \mathcal{Q}_t^{max} \qquad \forall i \in I, \forall t \in T \qquad (8)$$

Water spill rate constraints: Spillways provide added flexibility of operations given variations in water inflow. However, the spill rate is subject to constraints, and depends on the downstream requirement. Water hourly spill rate is defined by Eqs. (9) and (10).

$$P_{t-1}^{DA} - P_t^{DA} \leq \mathcal{P}_t^{max} \qquad \forall t \in T \qquad (9)$$
$$P_t^{DA} - P_{t-1}^{DA} \leq \mathcal{P}_t^{max} \qquad \forall t \in T \qquad (10)$$

Non-negativity constraint: Constraints Eq. (11) are a non-negativity constraint on the continuous decision variable.

$$R_t^{DA}, Q_t^{DA}, P_t^{DA} \geq 0 \qquad \forall t \in T \qquad (11)$$

2.3.2. Second-stage optimization: RT schedule

Given DA schedules $P_t^{DA}, Q_t^{DA}, R_t^{DA}$, the real-time schedules are revised based on the observed water flow availability S_t^{RT}. The objective function should consider imbalance energy cost incurred by deviation from the DA schedule due to forecast errors.

$$\max : \sum_{t \in \mathcal{T}} \left[c_t^{DA} \cdot \psi_t(Q^{DA}) - c_t^{RT} \cdot \| \psi_t(Q^{DA}) - \psi_t(Q^{RT}) \| \right] \qquad (12)$$

Similar to the DA optimization problem, the real-time schedules are subject to the following constraints:

$$U^{min} \leq R_t^{RT} \leq U^{max} \qquad \forall t \in T \qquad (13)$$
$$V_t^{min} \leq R_t^{RT} \leq V_t^{max} \qquad \forall t \in T \qquad (14)$$
$$W^{min} \leq Q_t^{RT} \leq W^{max} \qquad \forall t \in T \qquad (15)$$
$$L_t^{min} \leq Q_t^{RT} \leq L_t^{max} \qquad \forall t \in T \qquad (16)$$

$$R_t^{RT} - R_{t-1}^{RT} = S_t^{RT} - Q_t^{RT} - P_t^{RT} \qquad \forall i \in I, \forall t \in T \qquad (17)$$

$$Q_t^{RT} - Q_{t-1}^{RT} \leq \mathcal{Q}_t^{max} \qquad \forall i \in I, \forall t \in T \qquad (18)$$
$$Q_{t-1}^{RT} - Q_t^{RT} \leq \mathcal{Q}_t^{max} \qquad \forall i \in I, \forall t \in T \qquad (19)$$

$$P_{t-1}^{RT} - P_t^{RT} \leq \mathcal{P}_t^{max} \qquad \forall t \in T \qquad (20)$$
$$P_t^{RT} - P_{t-1}^{RT} \leq \mathcal{P}_t^{max} \qquad \forall t \in T \qquad (21)$$

$$R_t^{RT}, Q_t^{RT}, P_t^{RT} \geq 0 \qquad \forall t \in T \qquad (22)$$

Eqs. (13)–(16) represent regulatory reservoir water level and flow constraints (similar as Eqs. (2) through (5)). Eq. (17) represent water balance constraints. Eqs. (18) to (19) represent ramp rate constraints. Water hourly spill rate constraints are defined by Eqs. (20) and (21). Eq. (22) defines non-negativity constraint.

2.4. Solution approach

The objective function (12) in the second stage optimization model contains an absolute value terms and forms a nonlinear optimization problem. This objective function is reformulated by replacing the absolution value terms using an additional variable to handle the non-linearity of the problem. The term $c_t^{RT} \cdot$

Table 1
Notations used in the optimization model.

Name	Definition
Sets	
T:	Set of time period
Model parameters	
c_t^{DA}	Day ahead market price at period t
c_t^{RT}	Real time market price at period t
S_t^{DA}	Forecast flow at period t
S_t^{RT}	Observed flow at period t
U^{min}:	Minimum storage capacity
U^{max}:	Maximum storage capacity
V_t^{min}:	Minimum storage requirement at period t
V_t^{max}:	Maximum storage requirement at period t
$\mathcal{Q}_t^{max}$:	Maximum ramping rate at period t
$\mathcal{P}_t^{max}$:	Maximum spilling rate at period t
L_t^{min}:	Minimum turbine discharge at period t
L_t^{max}:	Maximum turbine discharge period t
W^{min}:	Minimum flow requirement t
W^{max}:	Maximum flow requirement t
Decision variables	
Q_t^{DA}	First stage reservoir water release at period at t
R_t^{DA}	First stage reservoir water storage at period t
P_t^{DA}	First stage water spillage at period t
Q_t^{RT}	Second stage reservoir water release at period at t
R_t^{RT}	Second stage reservoir water storage at period t
P_t^{RT}	Second stage water spillage at period t

$\| \psi_t(Q^{DA}) - \psi_t(Q^{RT}) \|$ is replaced by a new variable (A_t) and the objective function is formulated by Eq. (23).

$$\max : \sum_{t \in \mathcal{T}} \left[c_t^{DA} \cdot \psi_t(Q^{DA}) - A_t \right] \qquad (23)$$

Since the absolute value terms is replaced by A_t, constraints (24) are added to the second stage optimization model to ensure we do not lose any information by doing this substitution.

$$- c_t^{RT} \left[\psi_t(Q^{DA}) - \psi_t(Q^{RT}) \right] \leq A_t \leq c_t^{RT}$$
$$\times \left[\psi_t(Q^{DA}) - \psi_t(Q^{RT}) \right] \qquad \forall t \in T \qquad (24)$$

The term $\psi_t(Q^{DA})$ and $\psi_t(Q^{RT})$ in the objective function is power generation function at time t at constant elevation head and depends on released water flow (Q^{DA}, Q^{RT}) through the turbine. This function can be approximated by assuming linear relationship between water discharge and power generated. The resulting optimization model is solved via the IBM CPLEX commercial solver (via Python API).

2.5. Input data

Primary input data used in this study is described in this section.

2.5.1. Case study hydropower plant configuration

A hypothetical bypass reach hydropower plant (shown in Fig. 3) with a 27.43 m wide dam is assumed over the Trinity river, in proximity of the United States Geological Survey (USGS) stream gauge # 11523200 (USGS, 2021).

Although the selected location is in the mountain valley, for simplicity, the surface area across the reservoir depth is assumed to be uniform (i.e., rectangular prism) with minimal impact to the neighborhood and set to 6110.753 m². This location is in the
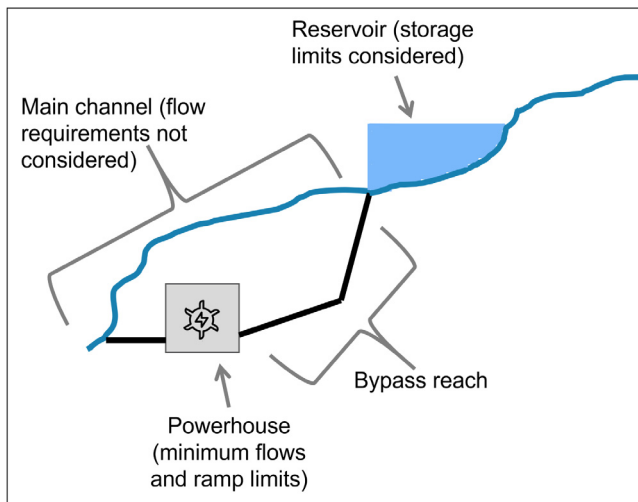
Fig. 3. Bypass reach hydropower configuration.

North of Coffee Creek, near Trinity Center, CA, USA as shown in Fig. 4.

The design flow rate for the hydropower plant is set to 20.61 m^3/s (728 cubic feet per second) - the 70th percentile of the daily median flow rate measured by the mentioned stream gauge as shown in Fig. 5. With this design flow rate, the plant is assumed to operate a 18.3 megawatt (MW) vertical shaft Francis turbine requiring 106.7 m head at 85% efficiency. Assuming a 7.62 m (25 ft) reserve, the maximum water height behind the dam will be 114.32 m (106.7 + 7.62) or 375 ft. Since the surface area across the reservoir depth is assumed to be uniform with minimal impact to the neighborhood and set to 6110.753 m^2, the maximum reserve is therefore (114.32 m × 6110.753 m^2 =) 698 581.28 m^3.

2.5.2. DA and RT electricity price

DA and RT electricity price was collected for the year 2020 from CAISO (CAISO, 2021). These DA and RT electricity prices represent wholesale prices. This market price consists of generation and delivery cost from particular grid locations called nodes. The selected node in this study is ANTLER_6_N001.

2.5.3. Observed flow data and inflow forecasts

The flow rate recorded by the USGS stream gauge # 11523200 in the year 2020 is considered as the observed flow data. This is shown in Fig. 6 and roughly reveals first six months (January–June) of wet season and later six months of dry (July–December) season.

Inflow forecasts are necessary for hydropower operators and water managers to make dispatch decisions that account for future conditions. Therefore, by having improved forecasts, it is possible that the decision-makers can better satisfy both power market and environmental objectives. This study considered three forecast scenarios: (1) "Perfect foresight" which assumes that the power plant operator has the perfect foresight into the future and the DA forecasts used in the DA market equal exactly the observations in the RT market; (2) "Persistence forecast" which uses recently observed flow values as an estimate of future flows; and (3) "HydroForecast" (Kratzert et al., 2019) which uses a long short-term memory (LSTM) based neural network to generate 0 to 10 day ahead probabilistic (Klotz et al., 2022) water-flow forecasts at an hourly forecast step. The persistence forecast used in this scenario was created by averaging all instantaneous United States Geological Survey (USGS) gage (11523200 Trinity River above Coffee Creek near Trinity Center, California) observations of

streamflow taken within the 24 h proceeding the forecast issue time. That average value is applied as the forecast value for all steps in the issued forecast. A comparison between the inflow forecasts and observations are shown in Fig. 7.

The forecasts in the "HydroForecast" scenario are produced using a learning-based model from Kratzert et al. (2019) and Klotz et al. (2022). The prediction model (Kratzert et al., 2019) used in HydroForecast (Kratzert et al., 2019) has four types of model inputs: (1) multiple weather forecasts from the NOAA's global forecast system and the European Centre for Medium-Range Weather (ECMWF); (2) near real-time observations of the land surface such as snow cover, vegetation growth, and day and night land surface temperature, which are primarily derived from satellites operated by the U.S. National Aeronautics and Space Administration (NASA); (3) characteristics of the drainage basin such as elevation, slope, and land cover; and (4) in situ streamflow (Nearing et al., 2021) observations from the USGS. These inputs are observed at up to an hourly frequency and aggregated over the entire drainage basin. At each time step (in our case each hour or day), the model takes in new inputs, updates a set of internal states it maintains representing the hydraulic conditions of the basin, and then outputs a prediction for the current time step. The model outputs the full probabilistic range of values for each model time step, which can be useful to users in managing risk and using this information in downstream models. This scenario takes the day-ahead median of HydroForecast's probabilistic prediction as the input to the DA scheduling model and does not use forecast values beyond 24 h ahead.

3. Results

Scenarios implemented in the tool are defined by several factors, including (1) operational mode (including environmental flow considerations); (2) minimum flow and ramping constraints; (3) hydropower plant configuration (including reservoir and powerhouse); and (4) hydrology and market (including inflow forecasting, inflow observations, and electricity price signals). Four examples are provided herein to demonstrate functionality within each of the aforementioned categories. In each of the four examples only a small set of parameters are varied to demonstrate the effect of those parameters. In real applications (e.g., as part of FERC proceedings), scenarios may be constructed and compared that utilize functionality across each of these categories.

3.1. Impact of operational mode on revenue

The example demonstrating operational mode considerations in building a scenario examines the effect of varying operational regimes on revenue. The three scenarios represent the span of flexibility a hydropower plant may have, from "no flow constraints" to "natural variability", with a scenario in between called "constrained flow" representing a realistic set of environmental flow requirements, as shown in Table 2. The minimum flow constraints are set to reflect the wet and dry seasons from Fig. 6.

Fig. 8 shows how the operational modes from Table 2 impact the monthly revenue for year 2020. It can be observed that the monthly revenue follows the discharge rate pattern from Fig. 6 irrespective of flow constraints. This is expected since the water discharge rate is driving the generation efficiency, total generation, and hence the revenue being earned. For any given month, the total revenue decreases as the operational mode changes from "no flow constraints" to "flow constraints", and then to "natural variability". This is a direct consequence of the operational modes that drive the gradual lack of head room availability and
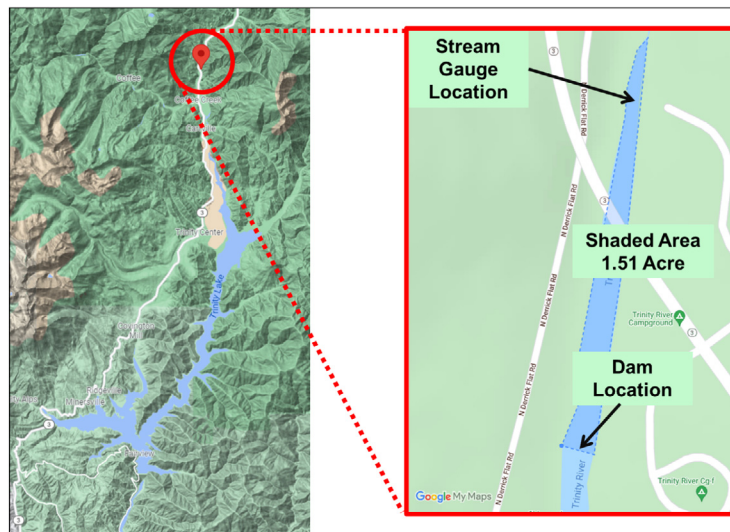
Fig. 4. Google map showing the location of the stream gauge and hypothetical hydropower plant.
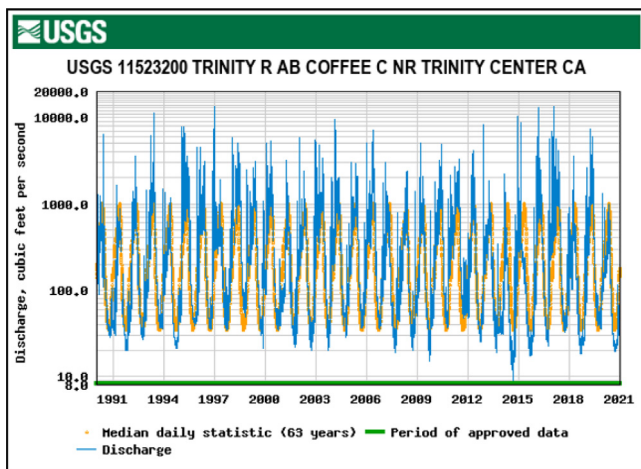

Fig. 5. Historical water flow rate (cubic feet per second) measured by the USGS stream gauge # 11523200.
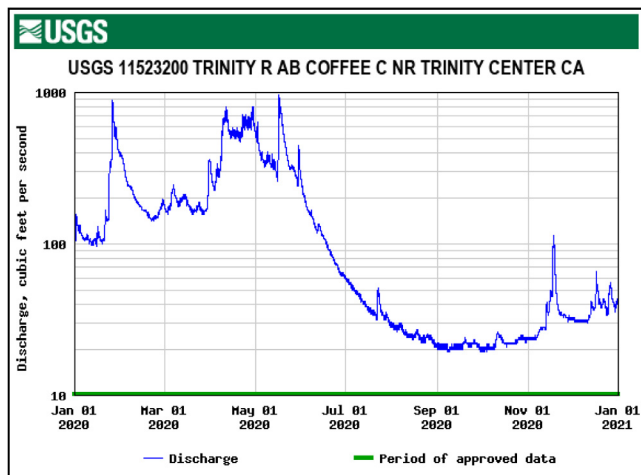

Fig. 6. Water flow rate (cubic feet per second) in 2020, measured by the USGS stream gauge # 11523200. From the month of July, reduction of flow rate below 100 cubic feet per second can be noticed.

Table 2

Operational mode comparing three different scenarios: "no flow constraints", "constrained flow", and "natural variability". Matrix of flow constraints represent the flow constraints for each month, January–December.

Scenario name	No flow constraints	Flow constraints	Natural variability
Monthly minimum flow constraint (m^3/s)	None	[1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	None
Maximum storage requirement (m^3)	51,189	51,189	None
Maximum hourly up-ramping and down-ramping rates	None	±10% of hourly reservoir water release	None
Maximum water spill-rate fluctuation	None	±100% of hourly water spillage	None
Forecasting method	UpstreamTech	UpstreamTech	UpstreamTech

water discharge flexibility for the bypass reach hydropower plant. However, monthly revenue variation across operational modes is more noticeable during the dry season than the wet one. For example, a comparison between the "No flow constraints" and "Flow constraints" scenarios indicates that after the removal of flow constraints, the monthly revenue only increases by 1% in April, which is the wettest month, as opposed to 118% in August, which is one of the driest months. Imposing a minimum flow constraint during an already low water flow in the dry season affects the water discharge required for hydropower generation more severely than in the wet season.

3.2. Impact of minimum flow and ramping constraints on revenue

HFVT is used to understand the impact of minimum flow and ramping constraints. Three monthly minimum flow and hourly ramping constraints were applied. Three hourly ramping constraints and three sets of monthly minimum flow constraints are presented in Table 3. While "no ramping constraints" offer the greatest flexibility in hydropower generation ramp rate, "10%" offers the least flexibility. The minimum flow constraints are selected based on historical flow at different months in the studied region and agrees with the wet and dry season from Fig. 6. Notice
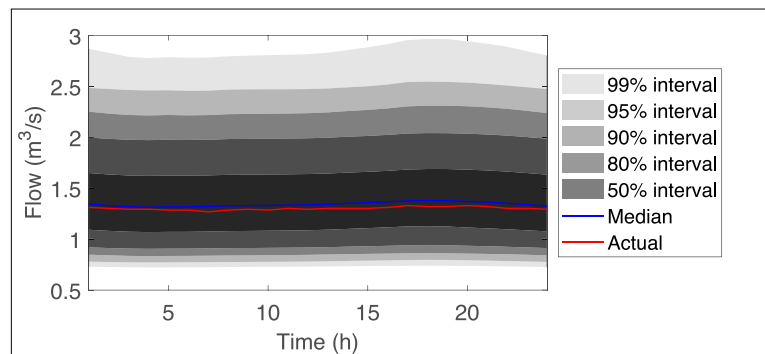
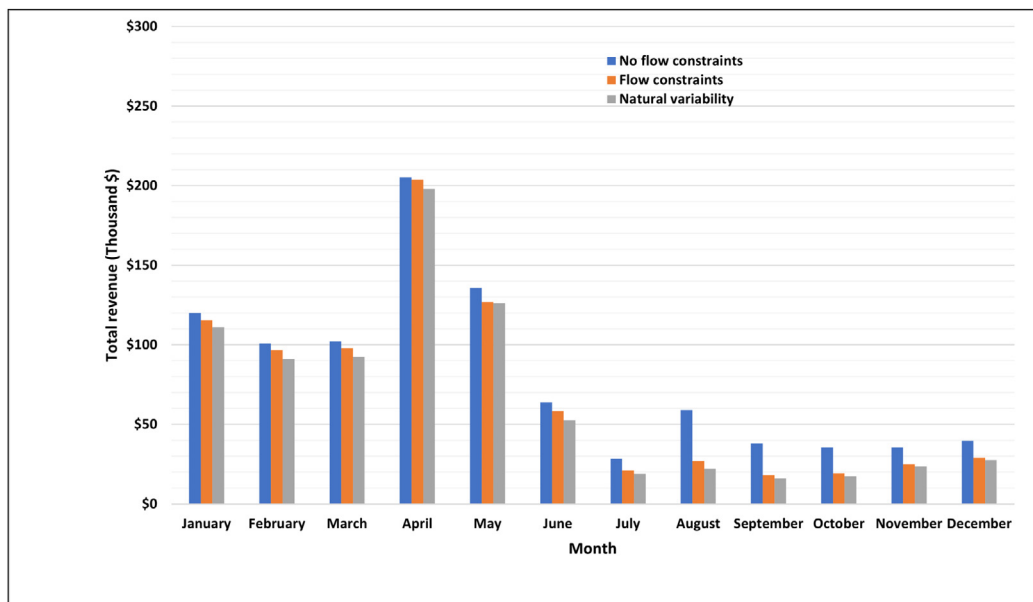**Fig. 7.** Comparison between probabilistic inflow forecasts and observations from July 10, 2020.

Fig. 8. The impact that flow constraints will have on monthly revenue.

Table 3
Operational mode comparing minimum flow and ramping constraints.

Monthly [Jan., Feb., …Dec.] minimum flow constraint (m³/s)	Hourly ramping constraints
Min. flow constraints set-1 = [0.85, 0.85, 0.85, 0.85, 0.85, 0.85, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	10%
Min. flow constraints set-2 = [1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	50%
Min. flow constraints set-3 = [2.72, 2.83, 2.83, 2.83, 2.83, 1.73, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	No ramping constraints

the increase in the wet season minimum flow constraints from set - 1 to set - 3.

First the impact of ramping constraints on hourly discharge rate is shown in Fig. 9. In this analysis, natural flow scenarios were varied by applying different ramping constraints. Sub-daily differences in operations among the scenarios vary in a manner consistent with expectations: water flow under the "no ramping constraints" varies the most in response to price fluctuations; "10% ramp rate" scenario varies the least; and "natural variability" is not responsive to prices as shown in Fig. 9.

The impact of ramping and minimum flow constraints is further investigated for annual revenue. Fig. 10 shows the annual revenue under different minimum flow and ramping constraints. For any ramping constraint, the annual revenue gradually decreases with the increase in the wet season minimum flow constraints. This is consistent with our findings in Fig. 8. Second, the annual revenue increases as the ramping constraints are relaxed. This reflects the direct consequence of ramping constraints on the generation ramping while responding to RT electricity price. Overall, annual revenue is found to be more sensitive to ramping constraints than the minimum flow constraints. For a given ramping constraint, the annual revenue generally decreases with an increase in the minimum flow constraints. Relaxing maximum ramping rates from 10% to 50% increase annual revenues by approximately 5%, and an additional 2% increase can be obtained by removing the ramping constraints.

3.3. Impact of hydropower plant configuration on revenue

The results demonstrating the effect of hydropower plant configuration focus on reservoir storage limits. The four cases considered are: "no inter-day storage", "baseline storage", "increased reservoir capacity by 100%", and "increased reservoir capacity by 200%" as shown in Table 4. In the reservoir storage examples,
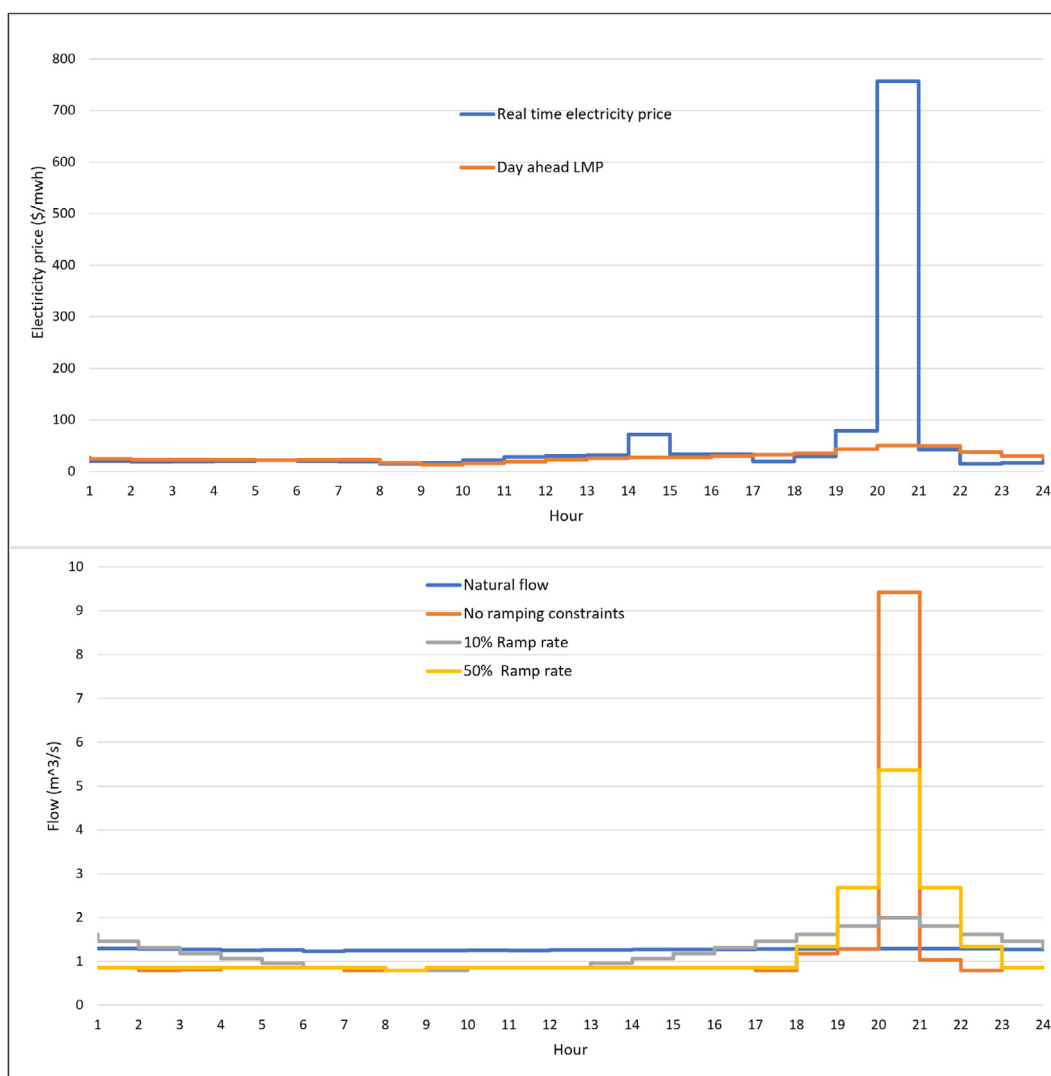
Fig. 9. Daily hourly RT electricity price (top) and water flow (bottom) for four flow scenarios: (1) Natural flow; (2) no ramping constraints; (3) 10% ramp rate; and (4) 50% ramp rate for July, 10th, 2020.

Table 4
Input data utilized economic impact of reservoir/storage size and constraints.

Scenario name	No storage	Baseline storage	Increased reservoir capacity by 100%	Increased reservoir capacity by 200%
Maximum storage requirement (m^3)	None	698 581.28	698 581.28 × 2	698 581.28 × 3
Maximum hourly up-ramping and down-ramping rates	±50% of hourly reservoir water release	±50% of hourly reservoir water release	±50% of hourly reservoir water release	±50% of hourly reservoir water release
Maximum water spill-rate fluctuation	±100% of hourly water spillage	±100% of hourly water spillage	±100% of hourly water spillage	±100% of hourly water spillage
Monthly minimum flow constraint (m^3/s)	[1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	[1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	[1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]	[1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]

only minimum and maximum storage are varied among scenarios and there are no changes in ramping rates or spill rate variability among scenarios (Table 4). Reservoir storage capacity can enable hydropower plants to have flexibility that improves both market participation and the ability to meet environmental flow objectives. This analysis isolates only the reservoir capacity, holding environmental flows constant. Given this setup, it is expected, and observed, that increasing reservoir storage increases revenue as observed in Fig. 11. While the monthly revenue pattern follows Fig. 6, variation across reservoir capacity impacts is wider during the wet season as opposed to the dry season's operational mode impact shown in Fig. 8. Finally, the value of reservoir storage
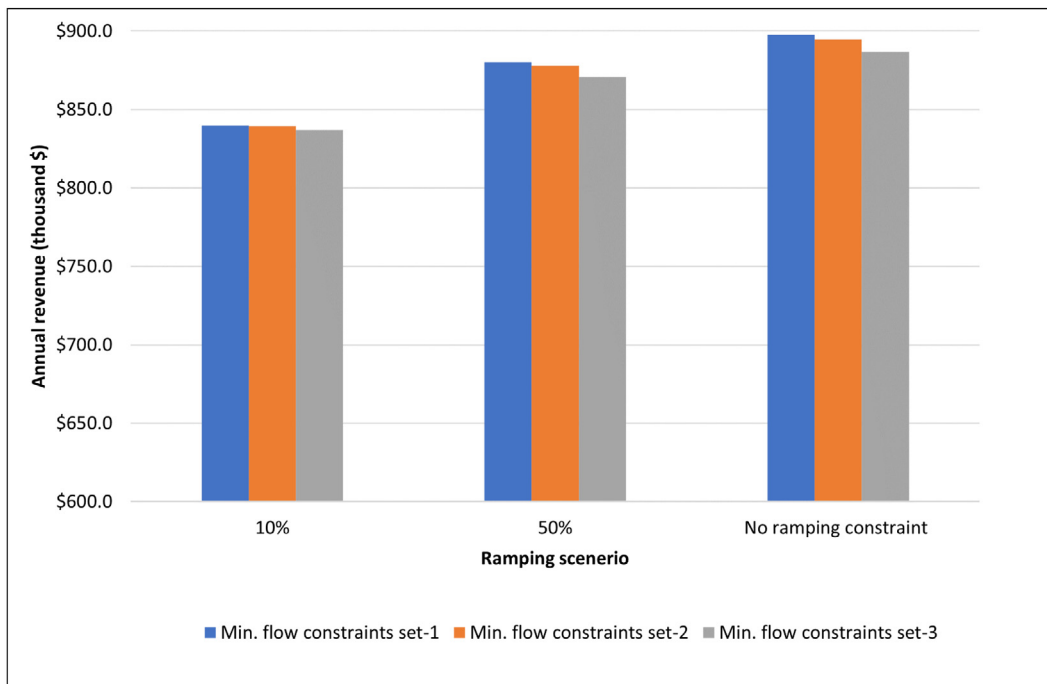
Fig. 10. Economic impact of different operational mode varied by minimum flow and ramping constraints.
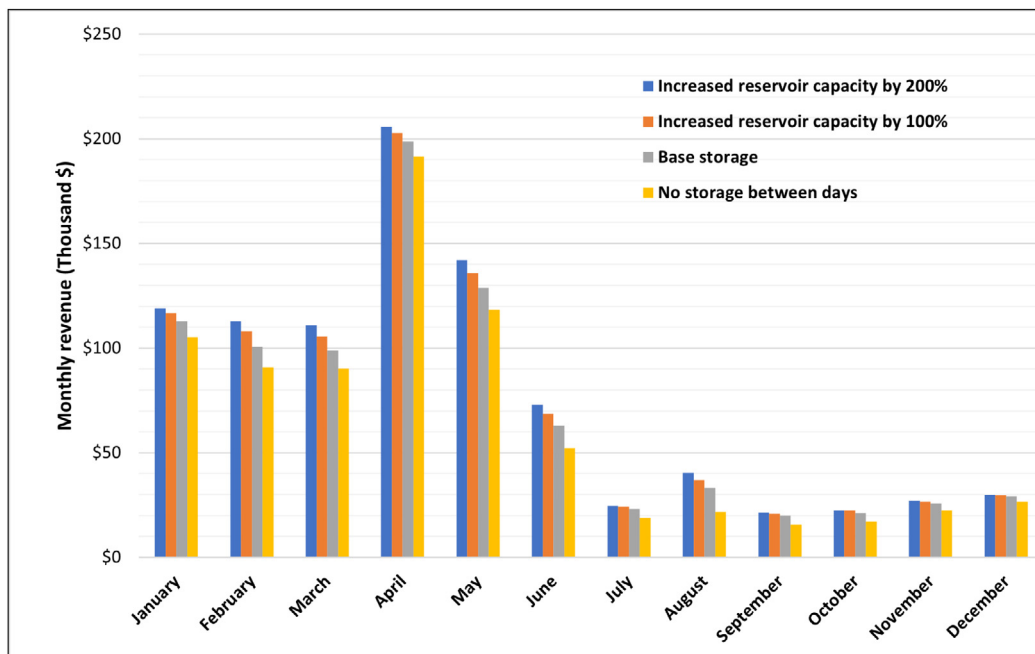

Fig. 11. Economic impact of different storage requirements.

is the greatest in the spring runoff months of April and May, which is when the CAISO electricity market has abundant cheap hydropower.

3.4. Impact of hydrology and market on revenue

Inflow forecasts are necessary for hydropower operators and water managers to make dispatch decisions that account for future conditions. Therefore, by having improved forecasts, it is possible that the decision makers can better satisfy both power market and environmental objectives. In this section, we present monthly revenue for three forecast scenarios assuming maximum

reservoir storage capacity of 51,189 m^3, maximum ramping rate of 10%, and monthly minimum flow constraint (m^3/s) from January to December to be [1.42, 1.42, 1.42, 1.42, 1.42, 1.42, 0.79, 0.57, 0.54, 0.54, 0.65, 0.85]. Consistent with this expectation, it is seen that the highest revenue case is the one that uses "perfect foresight", as shown in Fig. 12. Perfect foresight, however, is not possible in the real world. Of the two potential forecasts tried, HydroForecast (Kratzert et al., 2019) results in higher revenue up to 6.4% compared to "persistence forecast" depending on the month. This is expected, because HydroForecast, is a more sophisticated forecast model than persistence. While the monthly revenue pattern follows Figs. 6, 8, and 11, no clear pattern on
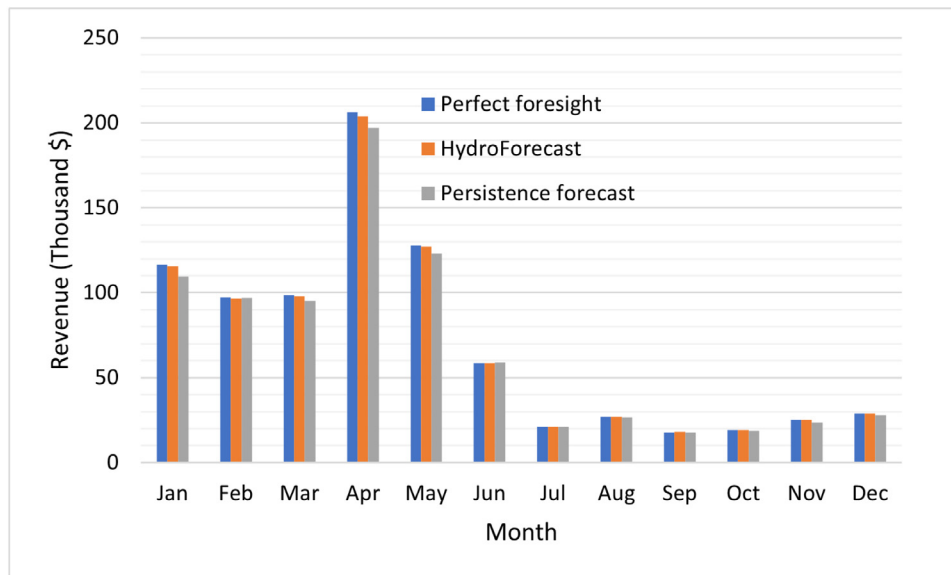
Fig. 12. Monthly revenues for each forecast scenario.

relative performance of different forecast scenario is observed for a given month. In part, it depends on forecast accuracy across different water conditions and events.

4. Discussion and conclusion

Timing of generation is becoming more and more valuable. This creates greater potential tension between environmental objectives, which require their own flow patterns, and the power system requirements for electricity, which are encapsulated in LMPs. Identifying win–win outcomes in this context requires being able to discuss the value of flexibility across stakeholder groups. The intent of the hydropower flexibility valuation tool is to aid in these discussions through providing a straightforward framework that represents how power markets function and dispatch decisions are made and enables building scenarios that are relevant to different stakeholders.

The tool is designed to consider different constraints that would be reflected in a project's license agreement (e.g., minimum flow requirements, maximum ramping, pulse flows, etc.) and physical capabilities (e.g., maximum plant ramping rate, rough zones, etc.). This functionality has been demonstrated for a hypothetical bypass reach hydropower plant participating in CAISO through varying the following: (1) operational mode of the plant (represented here by varying flow considerations and operational regime); (2) hydropower plant configuration (represented here by varying reservoir size); and (3) hydrology and market (represented here by varying inflow forecast). While a scenario, or set of scenarios, used in a real-world example would likely include modifications to more than one of these buckets. Here they are demonstrated separately to isolate the impact of each. It has been observed that monthly revenue (1) irrespective of the scenarios, follows the same pattern as seen in the stream gauge data record, (2) is more sensitive to flow constraints in the dry season, (3) is more sensitive to storage constraints in the wet season, and (4) is not much sensitive across forecast techniques. Furthermore, annual revenue is more sensitive to ramping constraints than the flow constraints.

The results conform to intuition about the impacts of specific changes to revenue. They also point to the fact that often times the differences in revenue are not that large. And, there may be ways to make up for the difference. For example, while adding

minimum flow constraints reduces revenue, it will likely not reduce revenue to the same degree as conditions that limit a plant's flexibility. Therefore, there may be combinations of modifications that are revenue neutral or positive while adding environmental flow requirements.

This tool leaves scenario definition to the stakeholders involved in the licensing proceeding. That is, it does not recommend a set of flow requirements that are likely to produce an improved environmental outcome. This is still left to the stakeholders engaged in the licensing proceeding. This flexibility valuation tool is highly adaptable across power system and environmental contexts because the information required to set up simulations are relatively straightforward to assemble (e.g., flow, price signals, plant capabilities, and flow requirements). Yet, the identification of specific "win–win scenarios" will depend on more information than just what is contained in this tool. It will require understanding how flow regime impacts aquatic species wellbeing, which is not part of this tool. Therefore, future work will need to link models and tools that relate environmental outcomes with flow to this flexibility valuation tool. These environmental to flow relational models are likely to be more regionally specific given that aquatic species and environmental biomes vary significantly between river systems. The role of this flexibility valuation tool is to be an integrator between these regionally-specific environmental considerations and the power systems that a given hydropower plant is connected to. Additional work would be needed to implement this tool in practice. For example, functionality must be created for it to be implemented in different types of electricity markets (e.g., vertically integrated and competitive) and for different contract types (e.g., main stem, bypass reach, cascade of facilities). These practical cases require additional modifications to our model. One example is to model cascade hydropower systems, which consist of a series of hydropower plants along a river. A key consideration is the hydraulic continuity condition of plants along the same river, and this is usually satisfied by adding constraints to account for the time water needs to travel from an upstream hydropower plant to a downstream one (Apostolopoulou et al., 2018; Qiu et al., 2020).

Code availability

The input data and source code is available for this paper at https://github.com/IdahoLabResearch/HFVT.

CRediT authorship contribution statement

Mohammad Roni: Development and implementation of the model, Preparing results, Writing – original draft. **Thomas Mosier:** Conceptualization, Scoping the study, Writing, Preparing the final manuscript. **Binghui Li:** Development and implementation of the model, preparing results, Writing – original draft. **S.M Shafiul Alam:** Data collection, Review and writing. **Venkat Durvasulu:** Writing – review & editing. **Beth Lawson:** Conceptualization, Scoping the study, Validate modeling results. **Dave Steindorf:** Conceptualization, Scoping the study, Validate modeling results. **Brenda Pracheil:** Writing – review & editing. **Vishvas Chalishazar:** Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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