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Bugs Buy Steady Releases from Hydropower Producers to Encourage More Synergistic Reservoir Management

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BUGS BUY STEADY RELEASES FROM HYDROPOWER PRODUCERS TO ENCOURAGE MORE SYNERGISTIC RESERVOIR MANAGEMENT

by

Moazzam Ali Rind

A thesis submitted in partial fulfillment
of the requirements for the degree

of

MASTER OF SCIENCE

in

Civil and Environmental Engineering

Approved:

David E. Rosenberg, Ph.D. Major Professor	Bethany T. Neilson, Ph.D. Committee Member
Theodore Kennedy, Ph.D. Committee Member	D. Richard Cutler, Ph.D. Interim Vice Provost of Graduate Studies

UTAH STATE UNIVERSITY
Logan, Utah

2022

ABSTRACT

Bugs Buy Steady Releases from Hydropower Producers to Encourage more Synergistic Reservoir Management

by

Moazzam Ali Rind, Master of Science

Utah State University, 2022

Major Professor: Dr. David E. Rosenberg
Department: Civil and Environmental Engineering

Many dams that generate hydropower have downstream ecological costs. To encourage more synergistic management, we suggest a program for Glen Canyon dam, Arizona where ecosystem managers are provided a budget needed to buy days of steady releases from hydropower producers and compensate producers for lost hydropower revenue. Steady releases let aquatic invertebrates lay and hatch eggs and mature to feed endangered, native fish of the Grand Canyon, yet these steady releases decrease hydropower revenues that support environmental monitoring programs. To help identify a program budget and promising transactions, we developed a linear optimization model that quantified tradeoffs between monthly hydropower revenue and days of steady releases. We found the 2018 experiment of steady releases for 8 weekend days per summer month reduced hydropower revenues by $300,000 (June) to $600,000 (August). If provided with a fixed budget, ecosystem managers could potentially use that budget to purchase a larger number of days of steady releases in different summer and shoulder months while sustaining hydropower income. Smaller monthly release volumes maintain tradeoff curve shape; thus, under our proposal managers can purchase a similar number of days of steady releases for lower cost during months with lower volume releases compared to months with higher release volumes. Reducing the gap between weekday on- and off-peak energy prices flattens tradeoff curves; thus, with the same budget ecosystem managers can purchase more days of steady releases during months or times of year when the gap between on and off-peak is small compared to large. Widening the offset between the steady release and minimum release on other days preserved tradeoff curve shape and position. Next steps would include 1) updating model values with the proprietary GTMax SL model used by the Western Area Power Administration and 2) engage and share this information with the Glen Canyon Dam Adaptive Management program.

(63 pages)

PUBLIC ABSTRACT

Bugs Buy Steady Releases from Hydropower Producers to Encourage more Synergistic Reservoir Management

Moazzam Ali Rind

Hydropower generated from dams has significant economic value, however, that value is achieved at the cost of native ecosystem devastation. Here, we have estimated loss in hydropower revenue due to inclusion of the steady low flow days –Bug Flow Experiments. We developed a linear optimization model and constraint method that restrict the number of steady low flow days while maximizes the hydropower revenue generation. The results suggested that increase in release volume will benefit both the objectives (win-win scenario), energy price differential between on- and off-peak periods controls the position and shape of tradeoff curves, and offset release does not have impact on the tradeoffs. Monthly results of the model helped us devise a program where hydropower producers are compensated for the steady low flow days. The program allocates funds and provides opportunities for ecosystem managers to pay hydropower producers revenue loss from the steady low flow days (escape from the win-lose scenario). In other words, the ecosystem managers are empowered to make decision about when and how many steady low flows days to buy against compensating the hydropower producers. This study is an initial effort and next steps would include a) improve results by adding information from the GTMax SL model used by the Western Area Power Authority and b) engagement with more organizations: National Park Service, Bureau of Reclamation, and Glen Canyon Dam Adaptive Management program.

DEDICATION

I dedicate this work to my late father Mr. Moula Bux Rind. Without his encouragement, guidance, and support, I would have never traveled and completed my degree aboard. Also, the role of my loving and compassionate mother Seema Rind cannot be overlooked in this journey.

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I also want to acknowledge the consultation from Dr. Jack Schmidt during different phases of the research. His knowledge and experience kept us motivated throughout the study. Moreover, interest and collaboration from folks at Western Area Power Administration (WAPA): Stanley Calyton Palmer and Craig Ellsworth has been keen in completion of this work. I am thankful to my friends and colleagues at Utah State University who provided me support and feedback on my work whenever I reached out. Lastly and most importantly, I thank Michaella Whitney to be there for me throughout, and helped me with my thesis writing and formatting.

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CHAPTER

1. Introduction

Many dams that generate hydropower have downstream ecological costs (Poff et al., 2007; Carpenter et al., 2011) that researchers are trying to identify and mitigate (Bunn and Arthington, 2002; Poff and Zimmerman, 2010; Vörösmarty et al., 2010; Liermann et al., 2012). To encourage more synergistic management, we suggest a program for Glen Canyon dam, Arizona where ecosystem managers buy days of steady releases from hydropower producers and compensate producers for lost hydropower revenue. Days with steady releases can help downstream aquatic invertebrates lay and hatch eggs, increase insect diversity, and grow to become food for endangered, native fish of the Grand Canyon (Nakano and Murakami, 2001; Baxter et al., 2005; Kennedy et al., 2016). To help identify a program annual budget and promising transactions, we answer four questions about the win-lose tradeoffs between hydropower revenue and number of days with steady releases:

a. How is monthly hydropower revenue impacted by number of days of steady releases on weekends and weekdays?

b. What factors control the shape and position of the tradeoff curve?

c. How do tradeoffs vary across months?

d. How can tradeoff results be used to suggest an appropriate budget for an ecosystem manager including the number and timing of days to purchase steady releases from hydropower producers?

Below, section 2 reviews the prior hydropower optimization and aquatic ecosystem literature plus shares experiences of release experiments at Glen Canyon dam to enhance downstream ecosystems. Section 3 describes a linear programming model and constraint method to estimate tradeoffs at Glen Canyon dam between hydropower revenue and days of steady releases. Estimates include scenarios that vary monthly release volume, weekend offset release, weekday on- and off-peak energy prices, and price type (market and contract). Sections 4 and 5 validate the model and present results. Section 6 describes a program where ecosystem managers can purchase additional days of steady releases from hydropower producers and compensate the producers for the lost hydropower revenue. Section 7 presents limitations. A final section concludes.

2. Literature Review

Typically, a hydropower objective to maximize revenue is a non-linear function (Yoo, 2009) that depends on the power generation release, reservoir storage level, turbine efficiencies, and operations in relationship to design efficiencies. Hydropower releases fluctuate through the day according to varying contracted energy demands and prices. There are two types of energy prices: contract and market prices. At Glen Canyon Dam, contract price is the fixed price between the hydropower producer, Western Area Power Authority (WAPA), and distribution companies for a contracted energy generation amount over the contract period. Market price is the price to purchase or sell energy on the open market. WAPA purchases energy at the market price when generated energy is less than the contracted amount.

Commonly, dynamic or nonlinear programing has been preferred to solve energy generation problems because multiple sub decisions are required to reach the ultimate optimal decision or the release, reservoir level, and turbine efficiency variables are multiplied together (e.g. Yakowitz, 1982; Ko et al., 1992; Tilmant et al., 2002). Nonlinear optimization problems are computationally intensive (Hochbaum, 2007), therefore, researchers have approximated nonlinear objectives with various linearization techniques.

Yoo (2009) used successive linear programming to maximize the annual energy production at Yongdam dam in South Korea. To avoid iterations, he considered weighted constant values of the storage water level and the water volume released for hydropower generation in the objective function to linearize the problem. Similarly, Wang et al., (2015) linearized the hydropower objective in their multi-objective mixed integer programming model by assuming a constant reservoir level and hydropower generation as primarily flow-dependent. The assumption of constant reservoir head is case specific and usually applied for large reservoirs (Magilligan and Keith, 2005; Loucks and Beek, 2017). Lee et al. (2008) used a first-order linear approximation for transformation of a non-linear hydropower function into linear objective.

To serve both human and freshwater ecosystem requirements, researchers identified and defined environmental flows—change in quantity, quality and timing of flows to favor ecosystems (Baron et al., 2002; Richter et al., 2003; Tharme, 2003; Arthington; 2012; Null and Lund, 2012; Pegram et al., 2013; Richter, 2014; Hart, 2016). For instance, Postel and Richter (2003) showed that ecological health is dependent on flow quantity and timing instead of constant minimum amount of water. Lane and Rosenberg (2020) recommended modifications in water rights law to improve in-stream flow conditions. Many researchers have used mathematical models to better understand and optimize water systems for environmental flows (Horne et al., 2016).

Rheinheimer et al. (2015) developed a linear programming model to maintain downstream cold water temperatures for Chinook salmon below Lake Spaulding, California. Their model determined the amount of water required from different stratified reservoir layers to maintain downstream river temperature. They modeled the reservoir as two completely mixed thermal layers (i.e. warm and cold pools) and the release decisions were made prior to, and independent from, temperature management decisions. These assumptions converted a non-linear problem with both quality (thermal layer selection) and quantity (release hydrograph) decisions into a linear problem with only the quality decision. Richter and Thomas (2007) described a framework to help evaluate the ecological benefits of dam re-operation. Young et al. (2000), Xevi and Khan (2005), Shafroth et al. (2010), Alemu et al. (2011), and Adams et al. (2017) presented a decision support system which considered both human and ecological objectives. These optimization models are rarely used by managers (Horne et al., 2016) and there is art to translate ecological knowledge into operations because of limited information about long-term effects of ecological flows (Harman and Stewardson, 2005). To overcome, researchers engaged managers earlier in the process and explored alternatives that balance competing water management and environmental objectives (Kareiva et al., 2000; Langsdale et al., 2013; Acreman et al., 2014; Richter, 2014; Poff et al., 2016; Alafifi and Rosenberg, 2020).

Glen Canyon Dam releases water to the Colorado River and Grand Canyon. The Grand Canyon attracts millions of visitors each year because of its unique geology and spectacular scenery (DOI, 2017). It is one of the most studied geologic landscapes in the world and home to numerous native endemic species (NPS, 2018). Glen Canyon Dam releases follow typical hydropeaking operations—high day-time releases and low night-time releases to meet contracted energy demands (Topping et al., 2003). This artificial variation in flows creates an unsuitable environment for aquatic organisms (Ward and Stanford, 1979; Moog, 1993) that require their eggs to stay wet throughout the incubation period for days to weeks' time (Stevens et al., 1997; Kennedy et al., 2016). Many hydropeaking dam sites across the Western United States have little insect diversity (Kennedy et al., 2016; Carlisle et al., 2017).

Aquatic invertebrates (e.g. Stoneflies, Mayflies, Caddisflies, and Midges) construct the major part of the Colorado River food web in the Grand Canyon (Kennedy et al., 2016) that varies throughout the canyon (Cross et al., 2013). Just below the dam, the food web is dominated by non-native invertebrates and rainbow trout are in abundance because release water temperatures are cold. At downstream locations, the river temperature as well as food web variety increase, hence, higher populations of native fish species. Mackey and Marsh (2009) discussed causes of degrading population of native fish in various river systems. The human developments (e.g. dams, canal, diversion, industrialization and urbanization) have destroyed native ecosystems and significantly modified natural river systems. The existing river systems have altered river water temperature, flows, sediment transport, and water quality regimes that favors non-native fish to native fish.

Mihalevich et al., (2020) developed a model to estimate water temperature of Colorado River in the Grand Canyon. They found that short-wave radiation dynamics and hydropeaking flows controlled river temperatures over space and time. Lately, it has been observed that native fish populations in downstream locations of the canyon are increasing. The possible reasons are variable flow regimes, increasing water temperature, the lowering of Lake Mead, and emergence of the Pearce Ferry rapid as a barrier between non-native lake fish and upstream native fish (Ragowski et al., 2018; Kegerries et al., 2020). These changes also favor non-native fish (Rahel and Olden 2008).

Starting in 1990's, there have been numerous efforts to learn and restore the natural river ecosystem of the Grand Canyon. For instance, controlled floods during 2008 restored geomorphic processes (Robinson and Uehlinger, 2008; Cross et al., 2011). Since 1996, High-Flow Experiments (HFE) were conducted to mimic the natural annual pre-dam flood flows required for sediment transport and restoration of downstream sand bars. In the latest Bug flow Experiments, reservoir releases during weekend were kept steady and low while hydropeaking continued on weekdays.

The idea for steady low weekend flows was to keep aquatic invertebrate eggs wet. Further, energy demands on weekends are lower (Førsund, 2015), and weekend steady flows affect hydropower revenues less (USBR, 2016). From 2018 to 2020, weekend steady low flows were implemented during summer months of each year at Glen Canyon dam (hereafter referred to as Bug Flow Experiments). The concept was included in the preferred alternative of the long term experimental and monitoring program (LTEMP, 2016). Ploussard and Veselka (2019) used the proprietary GTMax SL model to estimate the overall hydropower revenue loss from 2018 Bug Flow Experiment as approximately $165,000. May and June showed profit while July and August showed losses. In the 2019 Bug Flow Experiment, they found that losses increased to $327,000 (Ploussard and Veselka, 2020). Their work highlighted the need to quantify the tradeoff between hydropower revenue and ecosystem objectives and identify how the monthly release volume, weekend offset release, and market and contract energy prices influence the tradeoff. Furthermore, there exist an opportunity to define a program where tradeoff information can help hydropower and ecosystem managers work more synergistically.

3. Methods

We quantified tradeoffs between hydropower revenue and number of days of steady releases from Glen Canyon dam with a linear optimization model. The model had five inputs: inflows to Lake Powell (cfs), monthly evaporation (ac-ft), initial reservoir storage (ac-ft), contract, and market energy prices ($/MWh). The model was setup in the General Algebraic Modeling System (GAMS; Hozlar, 1990). One objective function maximized hydropower revenue. The second objective, number of days of steady releases, was programmed as a constraint whose limit varied in scenarios from 0 to 31 days.

Temporal resolution: To set the model's temporal resolution, we analyzed the monthly hydrograph observed at Lees Ferry gage (station id: USGS 09380000) from August 2018 (observed, Fig. 1). While we had hourly release data (744 hours per month), we found that days grouped into 3 day types—Saturday, Sunday, and weekday—by release and energy pricing patterns. For example, August energy pricing data (Appendix, Fig. S1) showed two periods in a day: 1) off-peak (pLow) from midnight to 8 a.m. and 2) on-peak (pHigh) from 8 a.m. to midnight (Saturday-Sunday-Weekday model, Fig. 1). These groupings reduced daily release decisions from twenty-four to two. This assumption of two periods per day was valid in pricing data of different months of 2014 (Palmer, personal communication, 2019). We also tested different number of periods, e.g. three and four, and periods' lengths to compare against observed hydrograph; we found monthly estimates of hydropower revenue from two periods per day assumption reasonable. Thus, 744 hourly release decisions per month (i.e. 24 hours per day * 31 days per month = 744) reduced to 6 sub-daily decisions (3 day types * 2 periods).

WAPA contracted with the power companies and rural electric utilities for a long-term and fixed price. If demand exceeds electricity generation—either because demand increases, or generation drops from a bug flow release, disruption in power generation, or droughts that limit hydropower generation—WAPA bought electricity from private companies at the market rate, but sold the additional purchased energy at the lower contract price. The market price is higher than the original contract price and decided by factors like energy demand and consumers' willingness to pay.

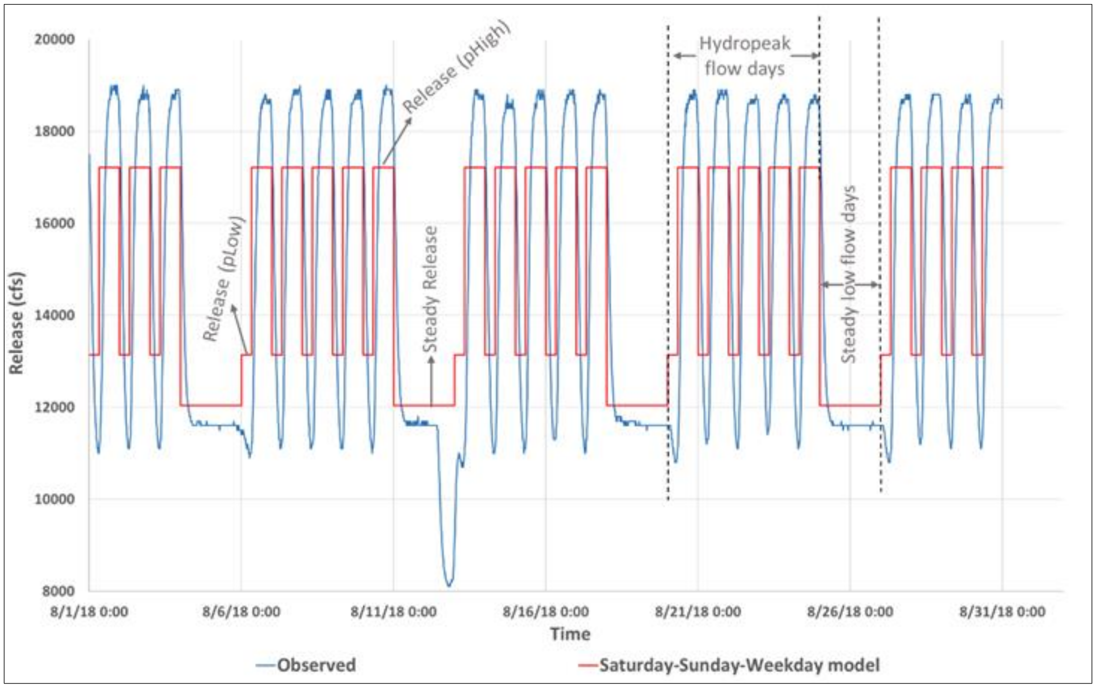

Fig. 1 Comparison between hourly hydrograph observed at Lees Ferry gage during August 2018 (blue color) and the modeled hydrograph with two periods per day: pLow and pHigh (red color).

We estimated contract energy prices of different periods using the weighted average method. For instance, we used the fifteen minute hydrograph data from the Lees Ferry gage and averaged the releases to get hourly values. We then calculated the energy generation at hourly timescale using the hydropower generation formula (Eq. 2) provided by WAPA (Palmer, personal communication, 2019). Using the hourly pricing from WAPA (e.g. Fig. S 1, Appendix), the hydropower revenue generated per hour was estimated. Finally, division of a period’s total monthly hydropower revenue by total number of hours of a period in the month gave the average energy price of the period. For example, for August 2018, the estimated weighted average energy prices for off- and on-peak periods on a weekday were $49.7/MWh and $79/MWh, respectively. The contract energy price for on-peak Saturday was unknown, hence we used average of on- and -off peak weekday periods i.e. $64.4/MWh. Sunday is priced as off-peak, which means both periods of Sunday equals off-peak Saturday equals off-peak weekday price. The most recent pricing data we found was from 2014.

The contract energy prices for different day types (weekday, Saturday, Sunday) remain same throughout the month; likewise, we modeled releases for different day types as constant over the month. This assumption further reduced the number of required release decisions to four. The monthly hydrograph is defined by:

- pLow on a weekday,
- pHigh on a weekday,
- pHigh on a hydropeak Saturday, and
- Steady release during steady low flow day.

Moreover, depending on the number of steady low flow days, some of the release decisions are replicated over different day types. For example, the hydrograph for current Bug Flow Experiment (red, Fig. 1) has steady low flow days on all weekends. There is no hydropeaking on Saturday. For that case, there are three release decisions (pLow, pHigh, and steady release). Furthermore, there are two possible flow patterns (*Flowpattern*) on any day type: steady or hydropeak flows. Fig. 1 shows a typical hydrograph that has both steady and hydropeak flow days (red color). The model has three day types and contract energy prices only; thus, we have used Saturday-Sunday-Weekday model and Contract price model names interchangeably.

The area under the observed and Saturday-Sunday-Weekday model hydrographs are the same; even though the traces do not overlay perfectly (Fig. 1). In the Saturday-Sunday-Weekday model, the higher base flow, lower peaks during the weekdays, and higher steady release during weekends are due to the selected lengths of the periods. The period's lengths (hrs) were decided from hourly energy pricing data and validation results.

We now present the linear optimization model formulation – decision variables, objectives, and constraints (Fig. 2).

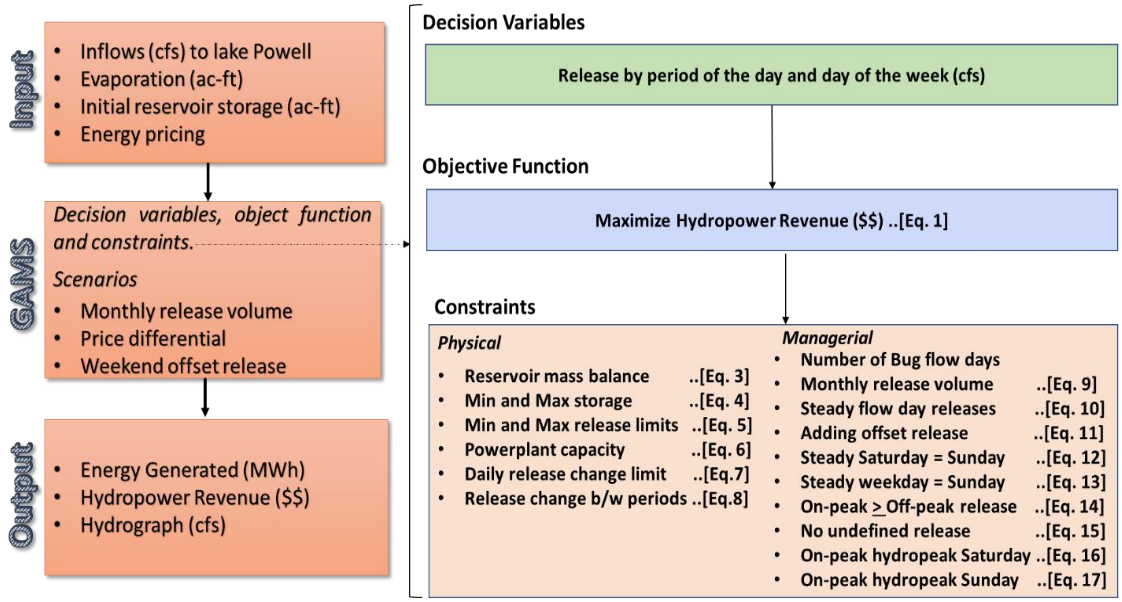

Fig. 2 Saturday-Sunday-Weekday model formulation.

Decision variables: The model decides the release ($Release_{\text{Flowpattern,d,p}}$ [cfs]) per period *p* (pLow and pHigh) for each day type *d* (Saturday, Sunday, and weekday) for a *Flowpattern* (steady and hydropeak). The steady flow pattern has constant release over the day and the hydropeak pattern has variable releases for the periods of the day (red color, Fig. 1). The number of steady and hydropeak flow pattern days depends upon number of steady low flow days. In addition, the release decisions control a set of state variables that contains hydropower energy generated from releases ($Energy\_Gen_{Flowpattern,d,p}$ [MWh]), monthly release volumes (*Released_Vol* [ac-ft]), and the end of the month reservoir storage (*Storage*[ac-ft]).

We introduced a variable “$\text{Revenue}_{\text{Flowpattern,d,p}}$” for hydropower revenue generated from different flow patterns on a day type *d* (Sunday, Saturday, and Weekday) within a period *p* (pHigh and pLow). The parameter “$\text{Energy\_Price}_{\text{price,d,p}}$” controls the price type (contract and market) on a day type *d* within a period *p* to be used.

Objective functions*:* The model has two competing objectives: 1) maximize aquatic invertebrate’s suitability represented by the number of days of steady low flow ($Num\_Days_{\text{Flowpattern,d}}$), and 2) maximize total monthly hydropower revenue [$$]. We quantified the tradeoff between the two objectives by maximizing hydropower revenue while constraining the days of steady low releases to different values.

$$Max.\ hydropower_Revenue = \sum\nolimits_{\text{Flowpattern,d,p}} Energy_Gen_{\text{Flowpattern,d,p}} * Energy_Price_{\text{Price,d,p}} * Num_Days_{\text{Flowpattern,d}} \quad \ldots [1]$$

Here, *Energy_Price* represents price type (contract or market) of energy during a period of the day and *Num_Days* is to include number of days of each day type with specific flow pattern during a month. The $Energy\_Gen_{\text{Flowpattern,d,p}}$ was calculated by (Palmer, personal communication, 2019):

$$Energy\_Gen_{\text{Flowpattern,d,p}} = Release_{\text{FlowPattern,d,p}} * Duration_{\text{p}} * 0.03715 \qquad \ldots[2]$$

Duration is length of period in hours and 0.03715 MWh/cfs is typical energy generation per 1 cfs of release. Which means on average 0.03715 MWh of hydropower was generated by one cfs release during July 2014. The information we received from WAPA used the same factor for energy generation during each months of 2014.

Constraints: The model has physical and managerial constraints. Physical constraints include:

a) Reservoir mass balance. The mass balance was applied at the reservoir and it was applied on monthly time scale (Eq. 3):

$$Storage = Initstorage + Inflow - Released\_vol - evap \qquad \ldots[3]$$

Where, *Initstorage* is initial reservoir storage [ac-ft], *Inflow* is monthly volume inflow to the reservoir [ac-ft]. The inflow volume is the product of average discharge inflow [cfs] converted into [ac-ft/hr] (i.e. 1 cfs = 0.083 ac-ft/hr), duration of periods [hrs], and number of day in a month. *Released_vol* is total volume of water released in the month [ac-ft], and *evap* is volume of water evaporated during the month [ac-ft].

b) Reservoir storage limits. Storage should not go below a minimum storage volume *minstorage* [ac-ft] or exceed maximum storage capacity *maxstorage* [ac-ft].

$$minstorage \leq Storage \leq maxstorage \qquad ...[4]$$

The minimum live storage required for hydropower generation was 4 million acre feet [MAF] (3490 ft msl) and the maximum live storage of Glen Canyon Dam was 25 MAF (3710 ft msl).

c) Release limits. During any period *p* on any day type *d*, reservoir releases should not go below a minimum release [cfs] or exceed a maximum release [cfs]. The minimum release was 8,000 cfs (approx. minimum required for hydropower generation) and maximum release was the turbine capacity at Glen Canyon Dam i.e. 31,500 cfs.

$$MinRel \leq Release_{\text{FlowPattern,d,p}} \leq maxRel \qquad \forall FlowPattern,d,p \qquad ...[5]$$

d) Maximum Energy Generation limit. During any time period, the energy generated should not exceed maximum generation capacity [MWh] of the turbines.

$$Energy\_Gen_{\text{FlowPattern, d, p}} \leq 1320 \times Duration_{\text{p}} \qquad \forall FlowPattern,d,p$$

...[6]

Where, 1,320 MW is the maximum hydropower generation capacity at Glen Canyon Dam (USBR, 2019).

e) Allowable change in release between periods. The maximum allowable change between periods is defined in the Long Term Experimental Management Plan (LTEMP, 2016) as 8,000 cfs. Which means between any two periods the change in release should not exceed *Daily_RelRange* (i.e. 8000 cfs).

$$Release_{\text{FlowPattern,d, ``pHigh''}} - Release_{\text{FlowPattern,d, ``pLow''}} \leq Daily\_RelRange$$

$$\forall FlowPattern,d \qquad ...[7]$$

f) Allowable change in release between periods of neighboring days. Release change between on-peak periods of current day and off-peak period of next day should not exceed *Daily_RelRange* (i.e. 8000 cfs).

$$Release_{\text{FlowPattern,d, “pHigh”}} - Release_{\text{FlowPattern,d+1, “pLow”}} \leq Daily\_RelRange \quad \forall FlowPattern \qquad \text{...[8]}$$

The managerial constraints include:

g) Total monthly release volume. The total release volume is input to the model and the model is required to make release decisions which sum up to the given release volume.

$$TotMonth\_volume = \sum_{\text{Flowpattern,d},p} Release_{\text{Flowpattern,d,p}} * Convert * Duration_{\text{p}} * Num\_Days_{\text{Flowpattern,d}} \qquad \text{…[9]}$$

Convert is a conversion factor from cfs to ac-ft per hour (i.e. 1 cfs = 0.083 ac-ft/hr).

h) Same on- and off-peak release on steady flow days. On a steady flow day, the model should make same releases during both on- and off-peak periods.

$$Release_{\text{“Steady”, d, “pHigh”}} = Release_{\text{“Steady”, d, “pLow”}} \qquad \text{…[10]}$$

i) Add weekend offset release. In the original Bug Flow Experiment, the releases on steady weekend days and weekday low periods were the same (zero offset). This experimental design provided greatest egg-laying benefits at Lees ferry while sites far downstream in the canyon saw progressively smaller benefits. The hydropeaking wave changed its shape while passing downstream and it was predicted that with zero offset eggs laid on weekdays at father downstream sites can be desiccated. This occurs due to locations further downstream having elevated weekday low flows due to the overlap of the wave released each day. Whereas, with a 48 hour long low bug flow, the discharge level at the dam and the downstream sites are the same. This means that eggs laid at downstream sites during weekday minimum flows will dry out during the weekend. To address this situation, offset releases were introduced to create more favorable egg-laying sites throughout the canyon (Kennedy, personal communication, 2021). The offset release were based on results of egg laying optimization models that sought to maximize egg laying benefits canyon wide (especially at downstream locations where native fish populations are high). Still, the offset release concept is in experimental phase, where 1000 cfs (H1000) offset was tested in 2018, and 750 cfs (H750) during 2019-2020.

$$Release_{\text{“Steady”, “Sunday”, “pLow”}} = Release_{\text{“Hydropeak”, “Weekday”, “pLow”}} + Weekend\_Rel \qquad \ldots[11]$$

Where, *Weekend_Rel* is pre-defined offset release value [cfs]

j) Same flows on steady Saturdays and Sundays.

$$Release_{\text{“Steady”, “Saturday”, p}} = Release_{\text{“Steady”, “Sunday”, p}} \qquad \forall p \qquad \ldots[12]$$

k) Steady weekday release equals the release on steady Saturday and Sunday.

$$Release_{\text{“Steady”, “Weekday”, p}} = Release_{\text{“Steady”, “Sunday”, p}} \qquad \forall p \qquad \ldots[13]$$

l) On-peak release on a Hydropeak day should be equal to or greater than off-peak release.

$$Release_{\text{“Hydropeak”, d, “pHigh”}} \geq Release_{\text{“Hydropeak”, d, “pLow”}} \qquad \forall d \qquad \ldots[14]$$

m) No release during undefined day type. This constraint ensures that when a particular day type and flow pattern (e.g. hydropeak Saturday) is not required in a hydrograph, the flow during that day type and pattern is zero.

$Release_{\text{FlowPattern, d, p}} = 0$ … [15]

n) On-peak hydropeak Saturday release equals 2000 cfs less than on-peak hydropeak weekday. It was observed that pre-bug flow experiment hydrograph had ~2000 cfs lower release during on-peak Saturday and Sunday in comparison to on-peak weekday. The possible reason can be lower hydropower demand on weekend.

$Release_{\text{“Hydropeak”, “Saturday”, “pHigh”}} = Release_{\text{“Hydropeak”, “Weekday”, “pHigh”}} - 2000$ …[16]

o) On-peak hydropeak Sunday release equals 2000 cfs less than on-peak hydropeak weekday.

$Release_{\text{“Hydropeak”, “Sunday”, “pHigh”}} = Release_{\text{“Hydropeak”, “Weekday”, “pHigh”}} - 2000$ … [17]

Constraints n and o (Eq. 16 and 17) introduce a pre-Bug Flow Experiment hydrograph in the Saturday-Sunday-Weekday model. The idea was to simulate the pre-bug flow hydrograph during hydropeaking Saturdays and Sundays. The releases during hydropeaking Saturdays and Sundays were approximately 2000 cfs less in comparison to weekday i.e. ~1000 cfs lower on-peak and ~1000 cfs lesser off-peak (Fig. S 1, Appendix). We considered on-peak Saturday and Sunday to be 2000 cfs less than on-peak Weekday and kept the off-peak weekend the same as off-peak weekday. The consideration might cause small errors (under estimation) in hydropower revenue of Saturdays because on-peak energy price is greater than off-peak price; whereas Sundays will have the same price for both periods, hence no error is expected there. Without these two constraints, the model was expected to generate maximum possible hydropower revenue by saving water during *hydropeak* Saturdays and Sundays (minimum release). Nevertheless, the minimum release would have created energy deficit and forced WAPA to purchase energy from market.

The constraint method varied the number of steady low flow days from 0 to 31, then maximized monthly hydropower revenue for each number of steady low flow days. For example, if there are 10 steady flow days in a month (e.g. August) that starts on a Monday, then the model will place 8 steady days on the weekends first (i.e. Sundays followed by Saturdays), because contract energy prices on Sunday are lowest, followed by Saturday, and then place the remaining two steady days on weekdays. In this scenario, all the *hydropeak* days are placed on weekdays. In contrast, scenario with zero steady low flow days means both weekends and weekdays will be *hydropeak* flow days.

Market-Contract price model variant: Adding a market price requires different model setup; we call this version a Market-Contract price model. We introduced "$Nobugflow\_Rel_{d,p}$" parameter that has observed pre-bug flow releases from 2017, 2016, and 2015 (Fig. S 2 to S 4, Appendix). The Market-Contract price model follows the logic that energy generation from $Nobugflow\_Rel_{d,p}$ is priced at contract price and any extra or deficit energy is priced at market price (Fig. 3). We differentiate a scenario of zero days of steady releases from scenarios with 1 or more days of steady releases. A zero steady low flow day will have pre-bug flow releases with contract price only, while other scenarios have market price too (Section S1, Appendix). We couldn't find the market prices for August 2018; the market price was assumed \$5/MWh higher than the contract price.

Weekday-Weekend model variant: To identify the importance of unique Saturday pricing, we observed that power distribution companies such as Rocky Mountain Power (https://www.rockymountainpower.net/savings-energy-choices/electric-vehicles/utah-ev-time-of-use-rate.html) use a weekend and weekday pricing template. There are two day types (weekend and weekday). Saturday and Sunday have the same prices. The Appendix, Section 4 further compares the Weekday-Weekday and Saturday-Sunday-Weekday models.

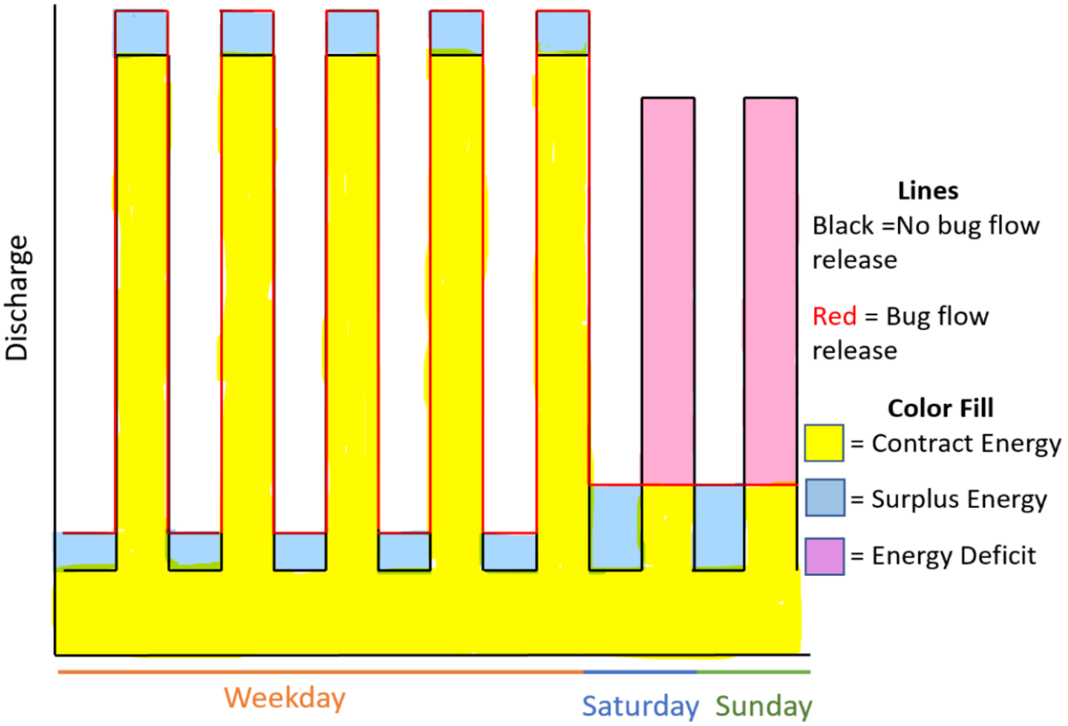

Fig. 3 Weekly hydrograph for no bug flow (black line) and bug flow i.e. Saturday and Sunday steady flows (red line). The yellow filled portion is contract energy priced at contract price, the blue filled portion is surplus energy sold by WAPA at market price, and the pink filled portion is energy deficit which WAPA has to purchase at market rate. Refer Table S 1 for revenue generation from possible hydrographs.

Scenarios: We ran the Saturday-Sunday-Weekday model for the following scenarios:

- Monthly release volume varied from 0.71 and 0.95 MAF.

- On-peak weekday contract energy price decreased from $79 (base case) to $64.4 to $49.7 per MWh.
- Offset release increased from 0 to 1000 cfs (H0 to H1000) (2nd study objective).
- Contract energy prices, initial reservoir storage, monthly inflows, and reservoir evaporation were varied from values observed in April to September of 2018 (3rd study objective).

4. Validation

The Saturday-Sunday-Weekday model was validated for August 2018 against observed and hourly data. The observed scenario has 15-min observed hydrograph at Lees Ferry gage (https://www.gcmrc.gov/discharge_qw_sediment/station/GCDAMP/09380000) and daily Glen Canyon power plant energy generation acquired from United States Bureau of Reclamation website (https://www.usbr.gov/rsvrWater/HistoricalApp.html). The hourly scenario was designed to apply the hourly energy pricing from WAPA.

In the model validation runs, flow volume for the observed, hourly, and Saturday-Sunday-Weekday models were identical (Table 1; Fig. S 5, Appendix). Energy generation varied by only 4.2% in comparison to observed (Table 1; Fig. S 6, Appendix). The possible reasons for surplus energy generation were: an assumption that reservoir head remains constant throughout the month and an outdated energy generation formula (Eq. 2). We were unsuccessful to acquire up-to-date energy generation formula and details of the given formula from WAPA. Validation over different months of 2018 shows that the energy generation error varied from 2.8% (July) to 9% (October; Table S

2, Appendix). We couldn't find monthly revenue generated by WAPA during 2018, hence we only validated our model against the observed energy generated.

Table 1 Validation summary statistics August 2018

Scenario	Flow volume (Ac-ft/ Month)	Energy Generated (MWh)	Revenue generated (Million $)	% Error in Energy generated relative to observed
Observed	914,428	392,938		
Hourly	914,428	409,289	$27.2	4.2%
Saturday-Sunday-Weekday model	914,428	409,289	$27.6	4.2%

Note: Energy prices used in Saturday-Sunday-Weekday model are given in Table S1 in appendix

5. Results

Colored traces in Fig. 4 show tradeoffs between hydropower revenue (x-axis) and the number of steady low release days (y-axis) for release volumes of 0.72 to 0.94 maf per month. The red dot on the upper right corner is the ideal point (maximize both objectives). Hydropower revenues increase as the number of steady low flow days (movement along y-axis) increases to eight steady flow days (win-win situation). Each steady low flow day on a Sunday adds $56,160, and each steady flow day on a Saturday creates additional $3,932 to the hydropower revenue. The counter-intuitive increase came from relaxing constraints n and o (Eq. 16 and 17) that bind the on-peak *hydropeak* Saturday and Sunday releases to their observed values. The increase means that the current hydrograph of Bug Flow Experiment (all weekends being steady low flow days) with contract prices generates more revenue than the pre-Bug Flow Experiment hydrograph (zero steady low flow days).

After eight steady low flow weekend days, the tradeoff curves change direction and are more intuitive to interpret. Hydropower revenues decrease with additional steady low flow days. The magnitude of loss (or slope) for converting each weekday into steady low flow day was $64,420. Here, constraints e and f bind that limit change in release between periods. The model has to increase releases on off-peak and steady flow days. These increases reduce hydropower revenue. Each additional 0.11 MAF release volume adds an extra ~$3.5 million in monthly hydropower revenue (tradeoff curves pushed right and outward). The slopes on 0.74 maf per month tradeoff differed because constraints e and f (Eq. 7 and 8) did not bind with the lower monthly flow volume. The release scenarios of 0.72, 0.83, and 0.94 MAF per month with zero steady flow days generate the same breakeven revenue as with 16, 12, and 12 steady flow days.

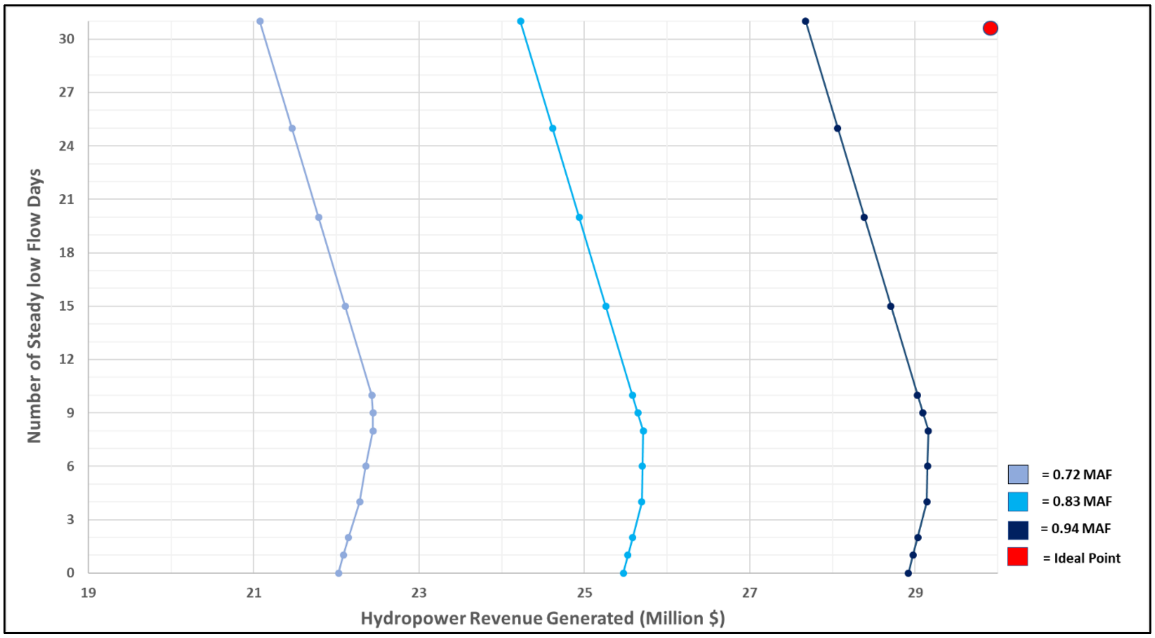

Fig. 4 Tradeoffs between number of steady low flow days and Hydropower revenue from Saturday-Sunday-Weekday model in August, with contract prices, and zero offset. Trace color indicates specific monthly release volume scenario.

Modeled releases show that the number of steady low flow days controls the on- and -off peak releases (Fig. 5). Until eight steady low flow days, the model saved water during off-peak releases on *hydropeak* days and steady low flow releases. The saved water is released during on-peak weekday periods to maximize overall hydropower revenue (high contract energy price of on-peak weekday). Above eight steady low flow days, the allowable release change between periods constraints becomes binding, hence we see simultaneous increase in the peak and base releases.

The difference between weekday on- and off- peak prices controls the position and slopes of the curves (Fig. 6). Decreasing the price differential ($29.3/MWh to $14.7/MWh to $0/MWh) moved curves left towards less hydropower revenue. Decreasing price differentials made the tradeoffs more vertical. The $0/MWh price differential curve between 4 and 8 steady flow days is not perfectly vertical because the on-peak Saturday price is higher than on-peak weekday and Sunday prices.

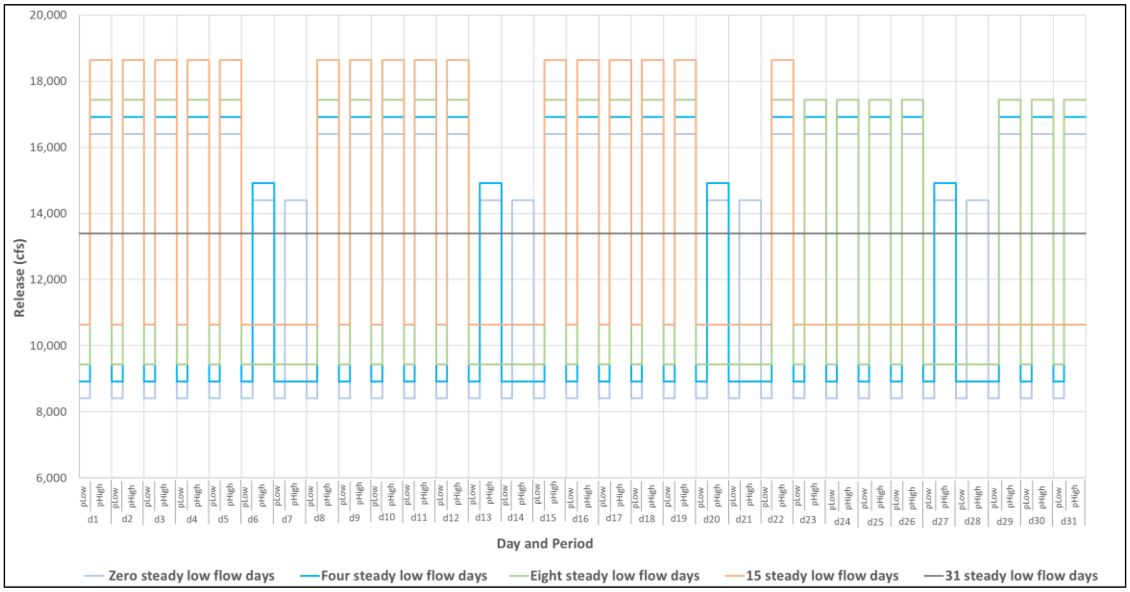

Fig. 5 Monthly hydrographs from Saturday-Sunday-Weekday model for different steady low flow day scenarios (color) with 0.83 MAF monthly release volume and zero offset release. d1 is a Monday

An increase in offset releases slightly decreased hydropower revenue (Fig. S7, Appendix). For the remainder of this analysis, we use only the single offset release of H1000 or 1000 cfs differential release between off-peak weekday and steady releases.

Between 0 and 4 steady low flow days, hydropower revenues increased by $20,000 (March) to $48,000 (July) with additional steady low flow day. Between 4 to 8 steady low flow days, there is slight decrease in hydropower revenues and above eight steady flow days, hydropower revenues decrease by $30,000 (March) to $70,000 (July) per day of weekday steady release added (Table S3, Appendix).

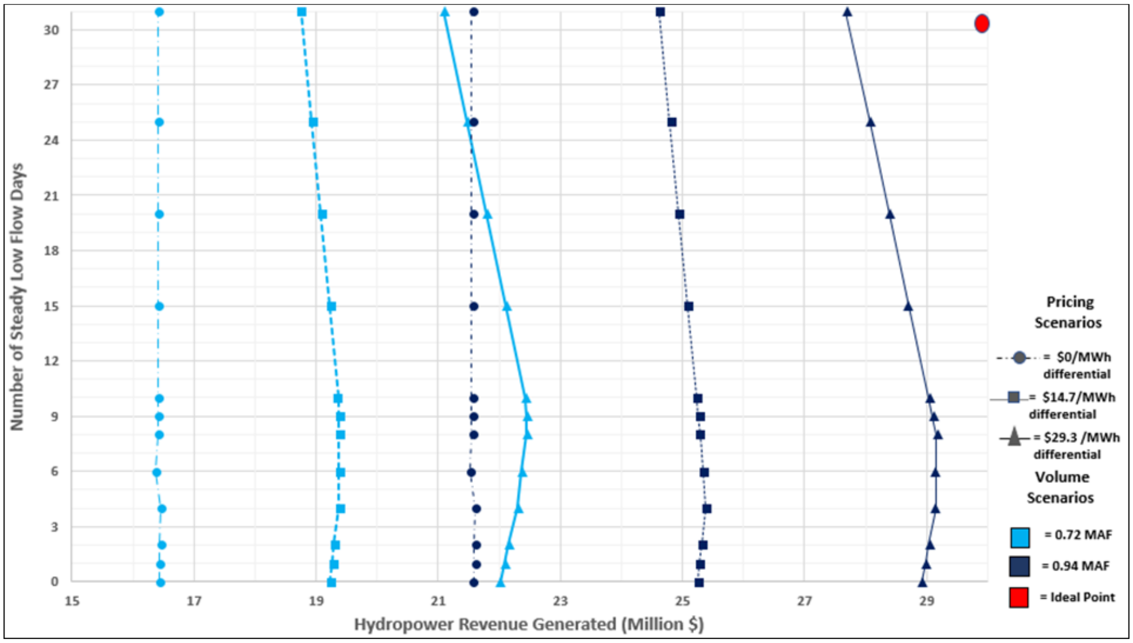

Fig. 6 Tradeoffs of three price differential scenarios (circle, square, and triangle markers) and two monthly volume scenarios (sky and dark blue) for August 2018.

Adding a market price shifts the tradeoff curves left to lower revenue in comparison to the Saturday-Sunday-Weekday model with contract prices (orange vs blue, Fig. 7). Each added day of steady released reduced revenue. There is no longer a breakeven point.

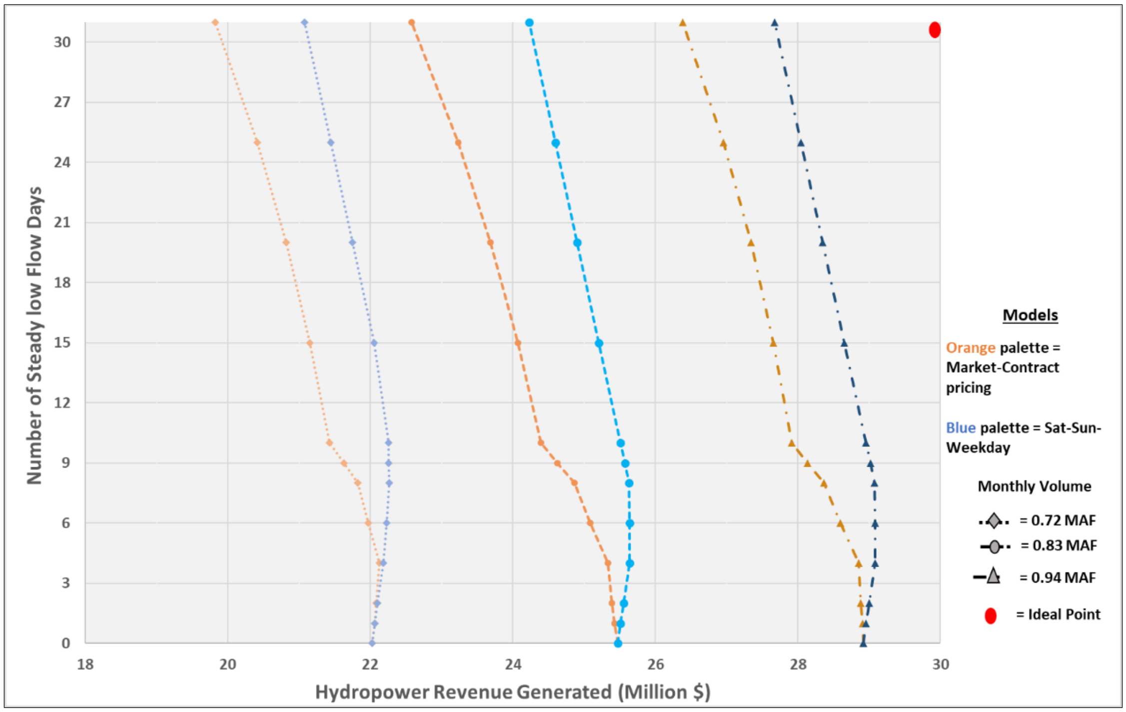

Fig. 7 Comparison of tradeoffs with contract (blue) and market (orange) prices for different release volumes (line types and symbols) in August 2018 with 1000 cfs offset.

6. Program for bugs to buy days of steady releases

Additional days of steady releases let aquatic invertebrates lay and hatch eggs and reduce hydropower revenue. How to escape the win-lose tradeoff and increase the number of days of steady release *and* sustain hydropower revenue?

We suggest a program to allow bug advocates and ecosystem managers to buy days of steady releases from hydropower producers. We suggest purchase prices ($/day) by converting the tradeoff curves in Fig. 7 into hydropower revenue loss per added day of steady release (Table 2). This conversion shows that the current bug flow experiment of 8 steady flow days per month from May to August results in $300,000 (June) to $600,000 (August) per month in lost hydropower revenue. We suggest to give the $300,000 to $600,000 per month amount to ecosystem managers as a budget. Managers can then use the budget and their ecosystem expertise to purchase days of steady releases from hydropower producers during alternative months when revenue loss is lower. For example, an ecosystem manager can substitute 8 weekend days of steady releases in August that reduce hydropower revenue by $610,000 (existing experiment) for:

- Eight days of steady weekend releases in April and 8 days of steady weekend releases in June that cost $600,000.
- Eight days of steady weekend and 7 additional days of steady weekday releases in April for $530,000 or in September for $520,000.
- Six days of steady weekend releases in May and 6 days of steady weekend releases in July that cost $600,000.
- Many other combinations.

More generally, ecosystem managers can purchase days of additional steady releases in shoulder months where hydropower revenues are lower and bug flows are not presently implemented (e.g. March, April, September, and October). Like a bank account, we suggest ecosystem managers carry over unspent money to a next accounting period.

The payments convert the left-sloping, market-contract tradeoff curves (Fig. 7, orange) into vertical lines of constant revenue that intercept the x-axis at the revenue generated with zero days of steady releases ($Revenue_0$)(Table 2, Column 2). For any month and monthly release volume:

$$\text{Revenue}_0 = \text{Hydropower\_Revenue}_n + \text{Payment\_for\_SteadyRelease}_n \quad \text{... [18]}$$

Here, $Hydropower\_Revenue_n$ is the modeled hydropower revenue with n days of steady releases (Fig. 7, orange line) and $Payment\_for\_SteadyRelease_n$ is the difference (Table 2). As the number of days of steady releases increase, hydropower revenue declines and payments increase. The payments sustain hydropower revenues and allow for more synergistic management of hydropower and downstream aquatic ecosystems.

The $300,000 to $600,000 monthly budget is almost two orders of magnitude *lower* than monthly Glen Canyon Dam hydropower revenues. Environmental non-governmental organizations or another branch of the Federal government can fund the budget for steady flows. Having these organizations fund the budget can help escape a negative feedback wherein Lake Powell drawdown lowers hydropower generation, decreases hydropower revenue, and reduces money deposited into a basin fund to support bug and other flow experiments.

Table 2 Cumulative hydropower revenue loss (Million $) per added day of steady release in 2018 with 0.83 MAF release volume, H1000 (offset release), and market and contract energy prices.

Month	**Revenue at Zero Steady days**	**Number of Steady Flow Days**						
		4	**6**	**8**	**9**	**15**	**30**	**31**
March	$19.9	$0.19	$0.38	$0.37	$0.41	$0.68	-	$1.81
April	$18.6	$0.03	$0.18	$0.31	$0.36	$0.53	$1.3	-
May	$18.4	$0.09	$0.27	$0.43	$0.6	$1.02	-	$2.09
June	$20.1	$0.03	$0.14	$0.29	$0.47	$0.93	$1.8	-
July	$25.3	$0.09	$0.33	$0.55	$0.8	$1.61	-	$3.11
August	$25.5	$0.14	$0.39	$0.61	$0.85	$1.4	-	$2.89
September	$23.6	$0.1	$0.29	$0.27	$0.3	$0.52	$1.51	-
October	$21.8	$0.18	$0.39	$0.52	$0.56	$0.87	-	$2.12

**Blue color represents profit.*

7. Discussion and Limitations

We found that reducing the number of monthly release decisions from 744 (hourly) down to 4 (day type and period) resulted in a 2.3 to 7.7% error in monthly energy generation from March to September 2018. Minimizing the number of release decisions helped us maintain a linear model formulation, cut computational time, and explore different scenarios of monthly release volumes, price differentials, offset releases, pre-bug flow hydrograph, breakeven analysis, and market prices. These analyses informed the number, prices, and timing of days of steady releases for ecosystem managers to buy from Glen Canyon dam hydropower producers. Purchase of days of steady releases can convert a win-lose tradeoff between hydropower revenue and days of steady releases into more synergistic management.

We found hydropower revenue decreased in all months as days of weekend steady release were added. Ploussard and Veselka (2019) reported smaller financial losses of $210,000 and $135,000 for July and August 2018 and gains of $19,000 and $160,000 for May and June. Our model validated monthly release volume and energy generated so we believe differences were due to different financial assumptions. For example, Ploussard and Veselka (2019) used energy sale (market) and purchase prices from 2019 and 2018 that were 25% and 50% lower than the 2014 prices we used. Our model maximized hydropower revenue by releasing a specified monthly water volume whereas GTMax SL used energy demand, sale price, and purchase price profiles for every hour of a representative week. The Ploussard and Veselka's (2019) work suggests the monthly budget for ecosystem managers to buy days of steady releases can be lower than $300,000.

The ecological benefits of an additional steady flow day depend on river temperature, sediment transport, and aquatic invertebrate's growth. This information is constantly evolving. A program for ecosystem managers to buy days of steady releases gives managers flexibility to adapt the number and timing of purchases to evolving information.

The Market-Contract price model presented here is only one possible way to estimate energy deficit and approximate lost revenues from steady flow days. The hydrograph assumed in this study may differ for higher release volumes. Market prices may differ from the values we used.

Lake Powell's level is falling due to annual releases that are larger than inflows. This drop lowers energy head, efficiency, and energy generation and affects energy pricing, WAPA, its customers, and ecosystem managers (Arellano at CRWUA, 2022). To overcome, WAPA introduced the Deliverable Sales Amount (DSA) where WAPA is only responsible to deliver electricity they can generate and sell. Consumers purchase shortfalls from alternative providers. The effects of Lake Powell draw down on ecosystem managers depend on DSA energy prices. If DSA energy prices decrease, then we expect the tradeoff curves for hydropower revenue and days of steady releases to shift left and have shallower slope such as in Fig. 7. If DSA prices increase, the curves may shift right and have steeper slopes. A shallower slope means ecosystem managers can purchase more days of steady releases for the same fixed budget.

At least three conditions may trigger a partial or full switch of Glen Canyon dam releases from the hydropower penstocks to the lowest level river outlets and change the hydropeaking regime to one with longer periods of steady releases that allow aquatic invertebrates to lay and hatch eggs.

1. Non-native fish in Lake Powell get entrained in the existing penstocks, pass through, and threaten native, endangered fish populations in the Grand Canyon. This event may trigger before Lake Powell reaches its minimum power pool elevation of 3,490 feet.
2. Summertime Lake Powell levels fall below approximately 3,525 feet. This drop is thought to release water with temperature greater than 18 ^{o}C through the existing penstocks. These high water temperatures make outcomes for native, endangered fish of the Grand Canyon highly uncertain (Wheeler et al, 2021).
3. Lake Powell's level falls below the minimum power pool elevation. Managers can no longer release water through the penstocks and generate energy.

Lastly, we recommend next steps to:

- Update results with the proprietary GTMax SL model.
- Consider scenarios where Glen Canyon dam releases water through both the hydropower penstocks and low level river outlets.
- Apply to other flow experiments such as high flows (LTEMP, 2016).
- Further engage people at Western Area Power Authority, National Park Serve, Reclamation, and Glen Canyon Dam Adaptive Management program.

8. Conclusions

For many dams, days of steady releases allow invertebrates to lay and hatch eggs but reduce hydropower revenues. To encourage more management synergy, we suggested a program for Glen Canyon dam, Arizona where ecosystem managers buy days of steady releases from hydropower producers and compensate producers for lost hydropower revenue. We used a linear optimization model with three day types (Saturday, Sunday, and weekday) to quantify tradeoffs between hydropower revenues and number of days of releases. We validated the model against energy generation data for August 2018 and ran for scenarios of monthly release volumes, price differential, offset release, and market-contract prices.

We found that steady low flow days on weekends with contract energy price increased the hydropower revenue (win-win). In contrast, steady low flow days on weekdays caused loss of hydropower revenue (win-lose). Reducing the price differential between weekday on- and -off peaks moved the curves left and straightened the curves into flat vertical lines. The use of market prices decreased hydropower revenue.

We found the 2018 experiment of steady releases for 8 weekend days per summer month reduced hydropower revenues by $300,000 (June) to $600,000 (August). Ecosystem managers can use that budget to purchase a larger number of days of steady releases in different summer and shoulder months while sustain hydropower income. Larger monthly release volumes added ~$3.5 million in hydropower revenues for each added 0.11 MAF per month while allowing the purchase of the same number of days of steady releases. The price differential between weekday on- and -off peaks controlled the position and shape of tradeoff curves, and the offset release did not produce significant impacts on tradeoffs. Reducing the gap between weekday on- and off-peak energy prices flattens tradeoff curves; with the same budget ecosystem managers can purchase more days of steady releases. Widening the offset between the steady release and minimum release on other days preserved tradeoff curve shape and position.

We see next steps to 1) update program values with the proprietary GTMax SL model used by the WAPA and 2) engage more people from WAPA, National Park Serve, Reclamation, and Glen Canyon Dam Adaptive Management program. The work will have a larger impact when it gets into the hands of the Federal servants who have the awesome responsibility to plan and manage a large, unique, and critical piece of our nation’s infrastructure, Glen Canyon Dam.

9. Data Availability Statement

The data, models, and code used in this study are available in the GitHub repository (Rind and Rosenberg, 2022).

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APPENDICES

ENGINEERING SIGNIFICANCE

Hydropower objective to maximize revenue is a non-linear function that depends on multiple decisions: power generation release, reservoir storage level, turbine efficiencies, and operations in relationship to designed efficiency. Here, we have linearized the hydropower objective by assuming monthly release volume, energy prices, turbine efficiencies, and constant hydrograph shape of day types (Saturday, Sunday, and Weekday) over the month. The framework presented here produce acceptable results and it can be used to improve resolution of conflict between reservoir and ecosystem managers. In addition, bugs buy steady low flow days from hydropower producers is one of its kind program where both stakeholders (ecosystem and hydropower managers) can optimize their resources usage i.e. ecosystem managers can buy maximum number of steady low flow days with available funds and hydropower producers are paid for revenue loss.

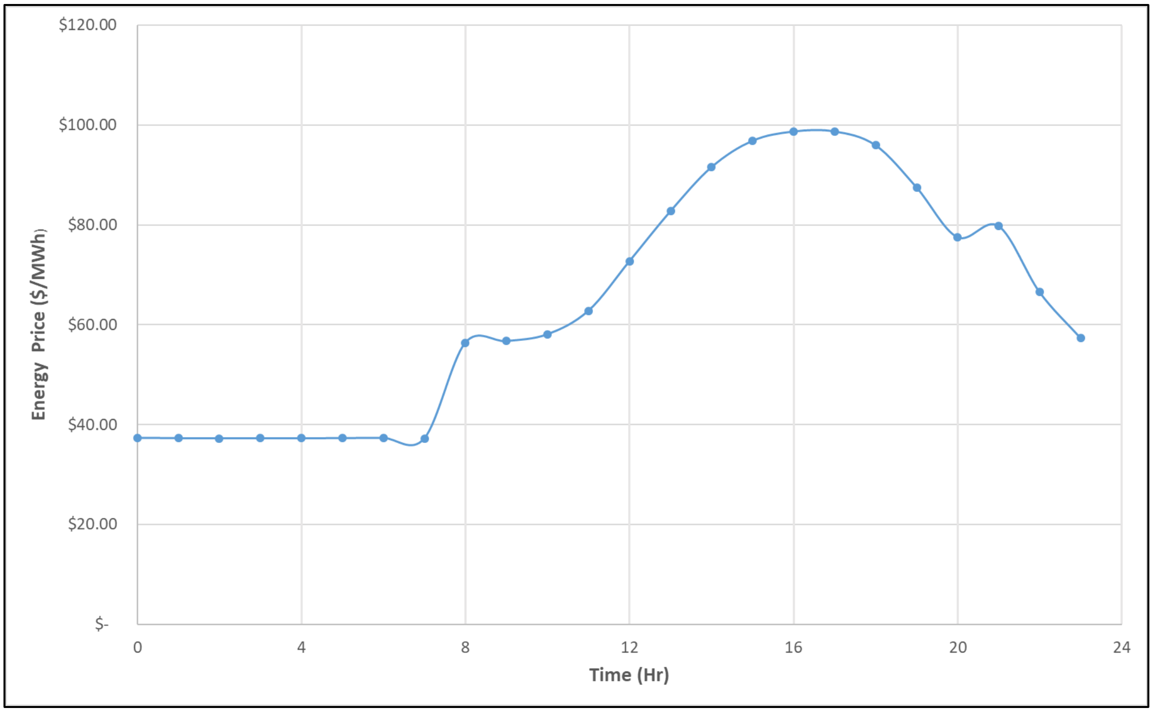

Fig. S 1 Hourly Energy prices from WAPA for the month of August.

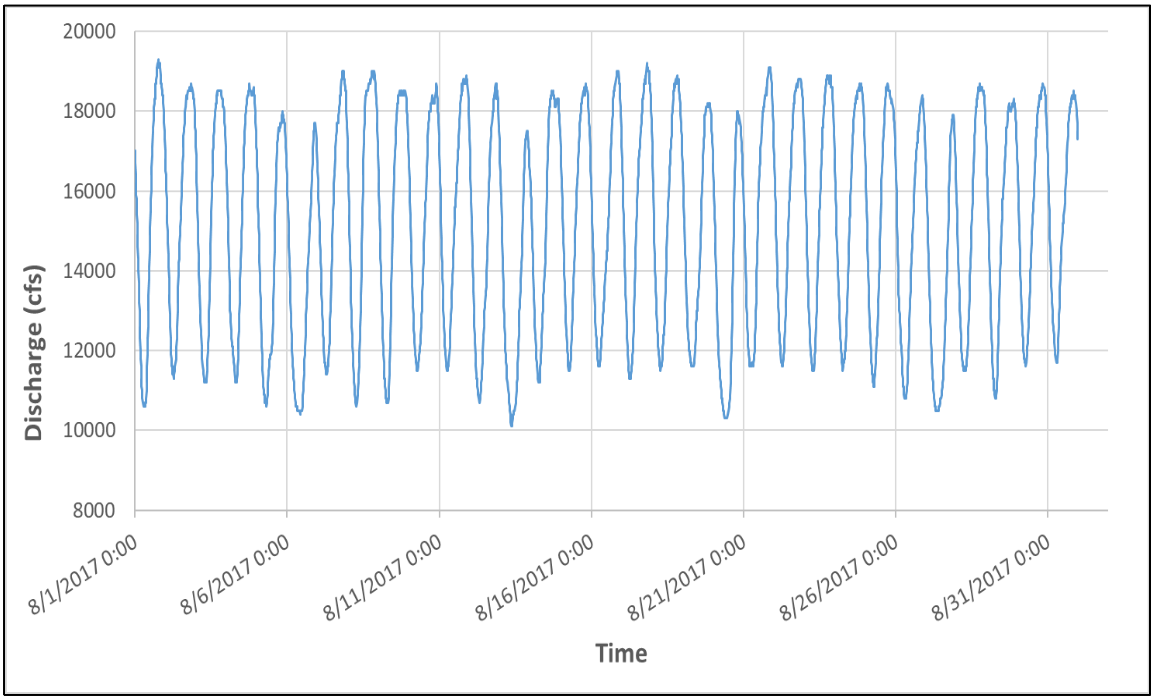

Fig. S 2 Pre-Bug Flow Experiment observed hydrograph (USGS 09380000). August 5, 6, 12, 13, 19, 20, 26, and 27 were weekends during 2017. Total monthly volume was ~0.94 Ac-ft.

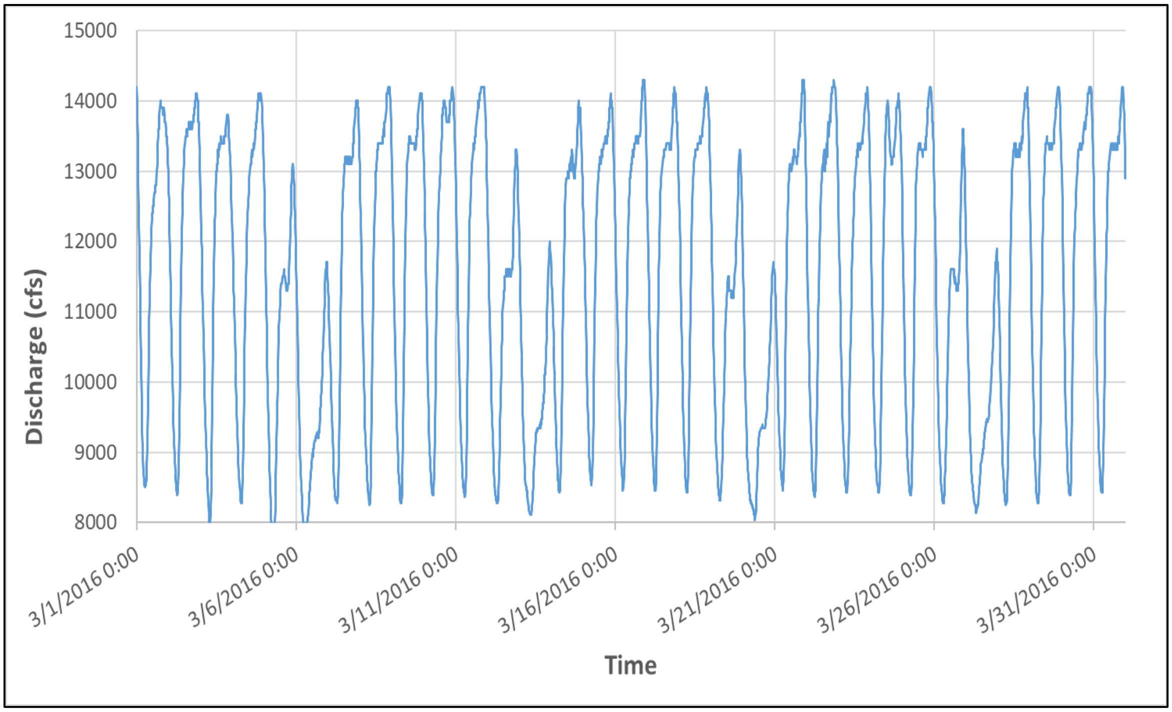

Fig. S 3 Pre-Bug Flow Experiment observed hydrograph (USGS 09380000). March 5, 6, 12, 13, 19, 20, 26, and 27 were weekends during 2016. Total monthly volume was ~0.72 Ac-ft**.**

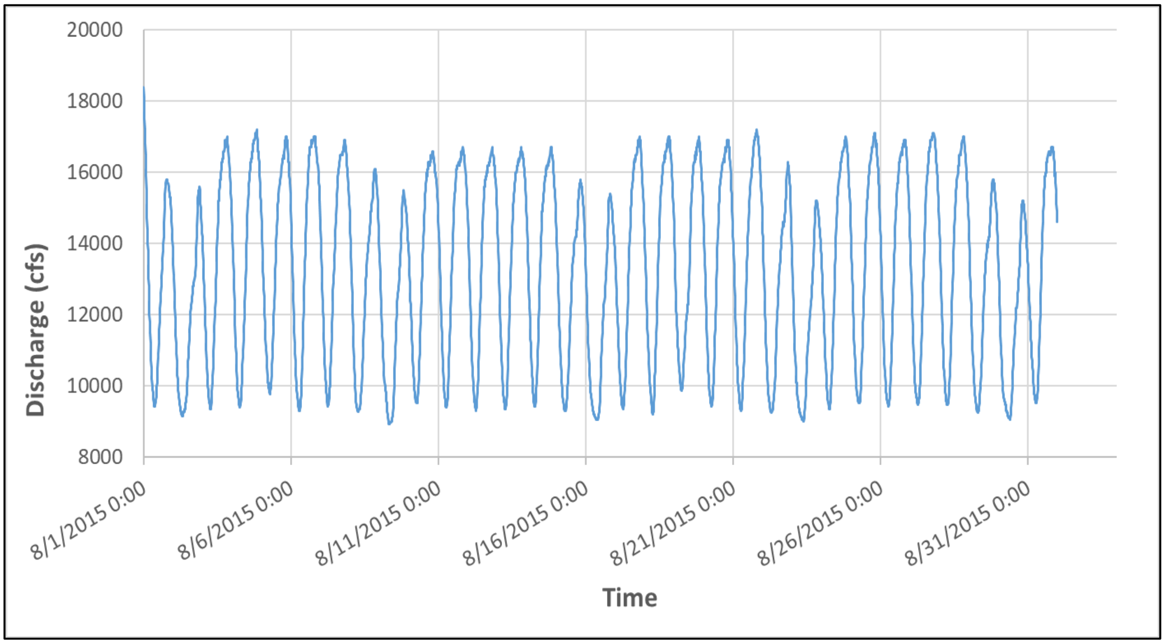

Fig. S 4 Pre-Bug Flow Experiment observed hydrograph (USGS 09380000). August 1, 2, 8, 9, 15, 16, 22, 23, 29 and 30 were weekends during 2015. Total monthly volume was ~0.83 Ac-ft.

Section S 1: Additional Equations in Market-Contract Price Model.

Addition of possible hydrographs (Fig. 3) in the base model requires inclusion of following models:

I. Zero steady low flow day Model:

The model is assumed to have a complete hydropeaking hydrograph i.e. all day types (Saturday, Sunday, and weekday) has *Hydropeak* flow pattern and contract energy price. Equation 19 estimates the hydropower revenue for the zero steady low flow day case. The model decided minimum releases during Saturdays and Sundays (lower energy price) and increased releases during weekday to maximize the hydropower revenue. The model generates maximum possible hydropower revenue from a release volume.

$$\text{Revenue\_ZeroSteadyDays}=\sum\nolimits_{Hydropeak,d}[\{\sum\nolimits_{p}(Release_{Hydropeak,d,p} \times Duration_{\,p} \times 0.03751 \times Energy\_Price_{d,contract,p})\} \times Num\_Days_{Hydropeak,d} \qquad \forall \text{ d, p} \quad \text{...[19]}$$

II. Number of steady low flow days Model:

Two hydropower estimation equations with both contract and market prices were identified that covered all the possible combinations of flow patterns, day type, and periods (Fig. 3). Table S1 further discuss the combinations, provides logic about considered hydrographs and revenue generation, and specifies the equations used for hydropower revenue calculations. We simulated the pre-Bug Flow Experiment releases for on-peak hydropeaking Saturdays and Sundays. In other words, the model only makes release decisions on steady flow days. Releases for *hydropeak* days are input to the model. The defined hydrograph reduced energy deficit during on-peak *hydropeak* Saturdays and Sundays. The model would have released minimum without simulated on-peak weekend releases (low contract energy prices on weekend) and created deficit. On the flip side, with more steady low flow days, there will be higher energy generation during on- and off- peak *hydropeak* weekday (surplus energy).

For example, the assumed weekly hydrograph for a bug flow release in comparison to pre-Bug Flow Experiment hydrograph (no steady flow days) (Fig. 3) illustrate that weekends are steady low flow days. With Bug Flow Experiment, there will be higher releases (surplus energy generation) during *hydropeak* weekdays in comparison to pre-Bug Flow Experiment releases. The energy generation from no bug flow uses contract prices (yellow filled, Fig. 3) and the surplus energy (i.e. difference between energy from bug flow and no bug flow) using market prices (blue filled, Fig. 3). In terms of energy, WAPA will generate surplus energy (blue shaded, Fig. 3) in addition to contracted energy (yellow filled, Fig. 3). For weekends, the on-peak energy generation will be lower than no bug flow (i.e., loss in revenue (pink shaded, Fig. 3)), but off-peak energy generation is assumed to be greater than no bug flow (blue shaded, Fig. 3) i.e. additional hydropower revenue. The loss in energy was priced at market price because WAPA has to purchase that energy from open market to fulfil their contracts. Whereas, the surplus energy during off-peak can be sold at market price.

Table S 1 Combinations between Daytype, Flowpattern, and Periods. Logic behind hydropower revenue calculation and equation used for the combination. The combinations are for cases with steady low flow day but not applied to zero steady low flow day.

Daytype	Flowpattern	Period	Revenue logic	Equation
Weekday	*Hydropeak*	pHigh	Bug flow release is greater than no bug flow. No bug flow energy (contract) is priced at contract price and surplus energy sold by WAPA at market Price.	Eq. 21

		pLow	Bug flow release is greater than no bugflow. Revenue template similar to Weekday *Hydropeak pHigh*.	Eq. 21
	Steady	pHigh	Bug flow release is less than no bug flow. The bug flow energy is priced as contract price and the deficit energy (no bug flow minus bug flow) will be purchased by WAPA at market price.	Eq. 22
		pLow	Bug flow release is greater than no bug flow. Revenue template is similar to Weekday *Hydropeak* pLow.	Eq. 21
Saturday	*Hydropeak*	pHigh	Bug flow release will be greater than no bug flow release. Revenue template will be similar to Weekday *Hydropeak pHigh*.	Eq. 21
		pLow	Bug flow release is greater than no bug flow. Revenue template similar to Weekday *Hydropeak pLow*.	Eq. 21
	Steady	pHigh	Bug flow release is less than no bug flow. Revenue template is similar to Weekday *Steady* pHigh.	Eq. 22
		pLow	Bug flow release is greater than no bug flow. Revenue template is similar to Weekday *Steady* pLow.	Eq. 21
Sunday	*Hydropeak*	pHigh	Bug flow release is greater than no bug flow. Revenue template is similar to Saturday *Hydropeak* pHigh.	Eq. 21
		pLow	Bug flow release is greater than no bug flow. Revenue template is similar to Saturday *Hydropeak pLow*.	Eq. 21
	Steady	pHigh	Bug flow release is less than no bugflow. Revenue template is similar to Saturday *Steady* pHigh.	Eq. 22
		pLow	Bug flow release is greater than no bugflow. Revenue template is similar to Saturday *Steady* pLow.	Eq. 21

Equation 20 sums the hydropower generated from different combinations of number of study low flow days and calculates the total hydropower revenue with steady flow days.

Revenue_Bugflows = $\sum_{flowpattern,d,p} Revenue_{Flowpattern,d,p}$ ... [20]

Two possible equations for Number of steady low flow days model:

I. Surplus Energy :

Equation 21 is valid for all the cases in Table S1 expect on-peak (*pHigh*) steady release on any day type (Saturday, Sunday, Weekday). WAPA will generate surplus energy and that energy will be sold at market price.

$$Revenue_{\,Flowpattern,d,p} = [\{Nobugflow\_Rel_{\,d,p} \times Energy\_Price_{\,d,Contract,p} + (Release_{Flowpattern,d,p} - Nobugflow\_Rel_{\,d,p}) \times Energy\_Price_{d,Market}\} \times Duration_{\,p} \times 0.03751] \times Num\_Days_{Flowpattern,d}$$

∀ Flow pattern, d,p except combinations Flowpattern ={Steady}, d={Weekday, Saturday, Sunday} and p={pHigh} ...[21]

II. Deficit Energy :

Equation 22 is only applicable to pHigh steady release during day type (Saturday, Sunday, Weekday). WAPA will generate less energy than the target and buy the shortfall energy at market price.

$$Revenue_{\,Flowpattern,d,p} = [\{Release_{Flowpattern,d,p} \times Energy\_Price_{d,Contract,p} - (Nobugflow_{\,d,p} - Release_{Flowpattern,d,p}) \times Energy\_Price_{d,Market,p}\} \times Duration_{\,p} \times 0.03751] \times Num\_Days_{Flowpattern,d}$$

∀ Flowpattern = {Steady}, d= {Weekday, Saturday, Sunday} and p= {pHigh} ... [22]

Note: Energy price can be market or contract price (two sets).

Section S 2: Validation

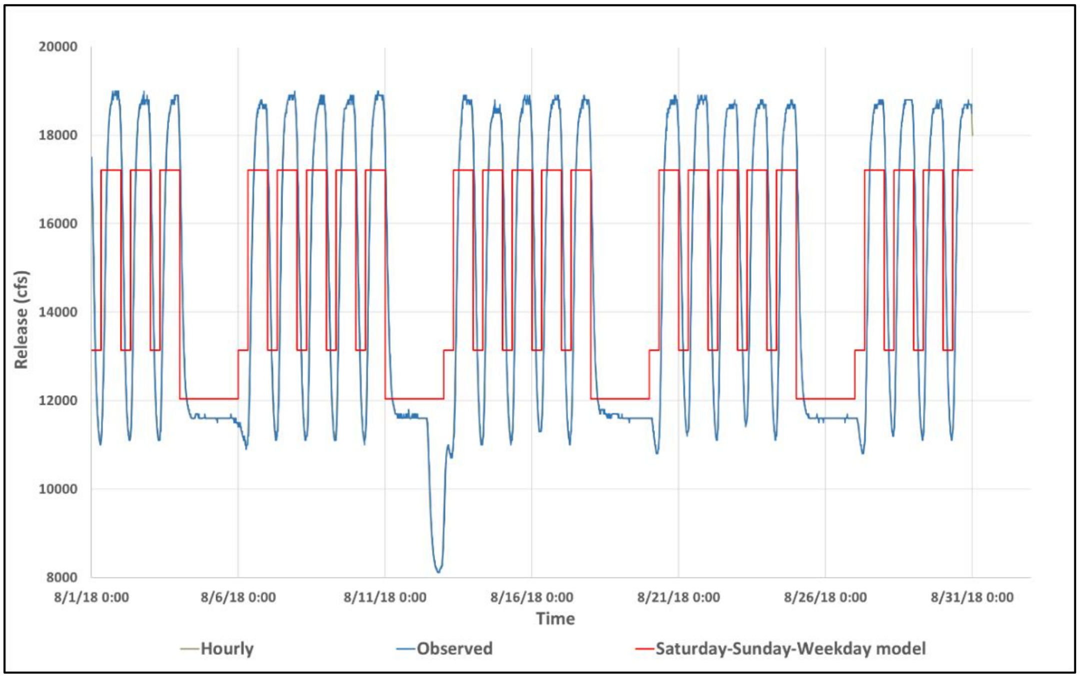

Fig. S 1 Releases for August 2018: Observed vs hourly vs Saturday-Sunday-Weekday. Here, observed and hourly hydrographs overlap.

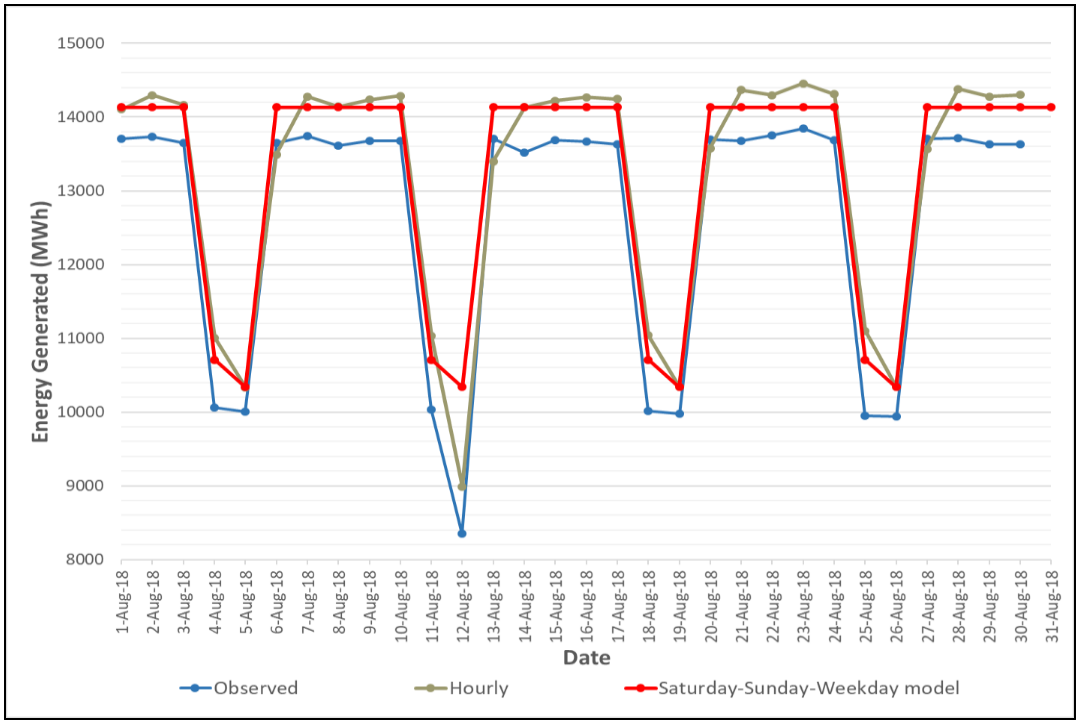

Fig. S 2 Daily energy generation: observed vs hourly vs Saturday-Sunday-Weekday model.

Table S 2 Validation results for different months of the year with contract price model.

<table>
<tr><th colspan="7">March 2018</th></tr>
<tr><th>S.No</th><th>Scenario</th><th>Released volume (Ac-ft/ Month)</th><th>Energy Generated (MWh)</th><th>% Error in Energy generated relative to observed</th><th>Revenue generated ($)</th><th>Energy Prices used ($/MWh)</th></tr>
<tr><td>1</td><td>Observed</td><td>838,771</td><td>363,797</td><td></td><td></td><td></td></tr>
<tr><td>2</td><td>Hourly</td><td>838,771</td><td>375,426</td><td>3.2%</td><td>$19,497,014</td><td>Hourly prices by WAPA</td></tr>
<tr><td>3</td><td>Weekend-Weekday model</td><td>838,771</td><td>375,426</td><td>3.2%</td><td>$19,497,050</td><td>Weekday On-peak= 58.643 & Off-peak = 44.37 and Weekend =44.37</td></tr>
<tr><td>4</td><td>Saturday-Sunday-Weekday model</td><td>838,771</td><td>375,426</td><td>3.2%</td><td>$19,787,571</td><td>Sunday, off-peak Saturday & Weekday = 44.37, on-peak Saturday =51.5, and on-peak Weekday= 58.643</td></tr>
<tr><th colspan="7">April 2018</th></tr>
<tr><td>1</td><td>Observed</td><td>740,527</td><td>318,194</td><td></td><td></td><td></td></tr>
<tr><td>2</td><td>Hourly</td><td>740,527</td><td>331,453</td><td>4.2%</td><td>$15,548,812</td><td>Hourly prices by WAPA</td></tr>
<tr><td>3</td><td>Weekend-Weekday model</td><td>740,527</td><td>331,453</td><td>4.2%</td><td>$15,548,840</td><td>Weekday On-peak= 55.05 & Off-peak = 38.24 and Weekend =38.24</td></tr>
<tr><td>4</td><td>Saturday-Sunday-Weekday model</td><td>740,527</td><td>331,453</td><td>4.2%</td><td>$15,805,642</td><td>Sunday, off-peak Saturday & Weekday = 38.24, on-peak Saturday =46.70, and on-peak Weekday= 55.05</td></tr>
<tr><th colspan="7">May 2018</th></tr>
<tr><td>1</td><td>Observed</td><td>731,979</td><td>318,486</td><td></td><td></td><td></td></tr>
<tr><td>2</td><td>Hourly</td><td>731,979</td><td>327,627</td><td>2.9%</td><td>$15,759,215</td><td>Hourly prices by WAPA</td></tr>
</table>

3	Weekend-Weekday model	731,979	327,627	2.9%	$15,759,222	Weekday On-peak= 57.16 & Off-peak = 35.96 and Weekend =35.96
4	Saturday-Sunday-Weekday model	731,979	327,627	2.9%	$15,993,079	Sunday, off-peak Saturday & Weekday = 35.96, on-peak Saturday =46.56, and on-peak Weekday= 57.16
June 2018						
1	Observed	784,406	343,202			
2	Hourly	784,406	351,093	2.3%	$18,308,079	Hourly prices by WAPA
3	Weekend-Weekday model	784,406	351,093	2.3%	$18,308,089	Weekday On-peak= 63.52 & Off-peak = 37.70 and Weekend =37.70
4	Saturday-Sunday-Weekday model	784,406	351,093	2.3%	$18,708,916	Sunday, off-peak Saturday & Weekday = 37.70, on-peak Saturday =50.61, and on-peak Weekday= 63.52
July 2018						
1	Observed	880,790	383,680			
2	Hourly	880,790	394,233	2.8%	$25,694,899	Hourly prices by WAPA
3	Weekend-Weekday model	880,790	394,233	2.8%	$25,694,908	Weekday On-peak= 80.08 & Off-peak = 46.55 and Weekend = 46.55
4	Saturday-Sunday-Weekday model	880,790	394,233		$26,150,218	Sunday, off-peak Saturday & Weekday = 46.55, on-peak Saturday =63.31, and on-peak Weekday= 80.08

August 2018						
1	Observed	914,428	392,938			
2	Hourly	914,428	409,289	4.2%	$27,235,815	Hourly prices by WAPA
3	Weekend-Weekday model	914,428	409,289	4.2%	$27,235,936	Weekday On-peak= 79 & Off-peak = 49.70 and Weekend = 49.70
4	Saturday-Sunday-Weekday model	914,428	409,289	4.2%	$27,641,618	Sunday, off-peak Saturday & Weekday = 49.70, on-peak Saturday =64.35, and on-peak Weekday= 79
September 2018						
1	Observed	693,733	288,363			
2	Hourly	693,733	310,508	7.7%	$18,918,733	Hourly prices by WAPA
3	Weekend-Weekday model	693,733	310,508	7.7%	$18,918,852	Weekday On-peak= 70.01 & Off-peak = 52.19 and Weekend = 52.19
4	Saturday-Sunday-Weekday model	693,733	310,508	7.7%	$19,241,731	Sunday, off-peak Saturday & Weekday = 52.19, on-peak Saturday = 61.1, and on-peak Weekday= 70.01
October 2018						
1	Observed	653,338	268,334			
2	Hourly	653,338	292,428	9.0%	$16,679,721	Hourly prices by WAPA
3	Weekend-Weekday model	653,338	292,428	9.0%	$16,679,743	Weekday On-peak= 65.24 & Off-peak = 47.17 and Weekend = 47.17
4	Saturday-Sunday-Weekday model	653,338	292,428	9.0%	$16,924,578	Sunday, off-peak Saturday & Weekday = 47.17, on-peak Saturday = 56.20, and on-

						peak Weekday= 65.24

Table S 3 Change in hydropower revenue per additional steady low flow day added in 2018 with 0.83 MAF release volume, H1000 (offset release), and contract energy price ($ 1000).

Month	0 and 4 steady low flow days	4 to 8 steady low flow days	Above 8 steady low flow days
March	$20	-$0.6	-$30
April	$23	-$1.2	-$35
May	$30	-$1	-$44
June	$37	-$1.5	-$54
July	$48	-$1.6	-$70
August	$42	-$1.4	-$61
September	$25	-$1	-$37
October	$26	-$0.8	-$38

To further evaluate the impact of constant monthly reservoir head assumption, we looked through reservoir elevation data and found that storage level dropped ~6.5 ft within August 2018. Which means a ~69 MW power generation cut would be expected if one assumes the releases and turbine efficiency remains same. It’s difficult to estimate exact MWh reduction because the storage level drop was gradual over the month. One of the possible estimation can be by assuming that all reduction equals to 10 days with reduced storage level. Which means MWh reduction will be 69*10*24 = 16,560 MWh. This means time period with lowered storage level can improve the estimation. The model results (August, Table S 2) show noticeable surplus energy generation (an additional ~17,000 MWh in comparison to observe). The exact cause of this surplus energy requires further daily storage level information and details about the energy generation formula (Eq. 2). The generation formula was provided by WAPA with minimum details and the generation per flow rate multiplication factor remained constant for different months. In reality, the factor need to be adjusted with changes in reservoir elevation (Table S 4, Appendix).

Table S 4 Elevation change during months of 2018 and impact on hydropower production.

S.No.	**Month**	**Elevation difference (Start-End) in ft**	**Change in hydropower production (MW)**
1	March	3.7	32
2	April	2.8	19
3	May	2.3	19
4	June	1.6	15
5	July	6.0	46
6	August	6.5	69
7	September	4.6	34
8	October	1.7	12

* *Red shows decrease, and blue is for increase.*

Section S 3: Offset Releases

The offsets releases did not impact hydropower revenues (Fig. S 7).

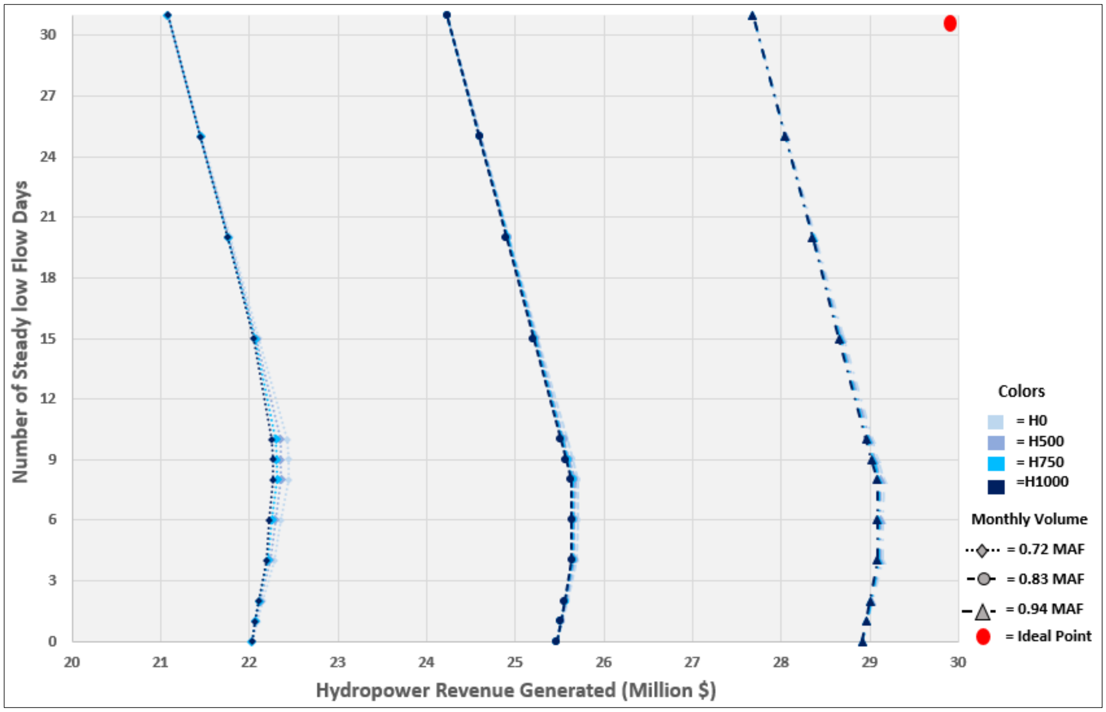

Fig. S 3 Tradeoffs of four offset release scenarios (light to dark blue) and three monthly release volumes (marker shape). The results are from contract price model.

Section S 4: Weekend-Weekday Model

Here, the energy price and releases for Saturday and Sunday were the same. The weekend-weekday model generated less hydropower revenue than the Saturday-Sunday-Weekday model because Saturday and Sunday releases and prices were lower. These reductions shifted the tradeoff curve left compared to the Saturday-Sunday-Weekday model (Fig. S 8).

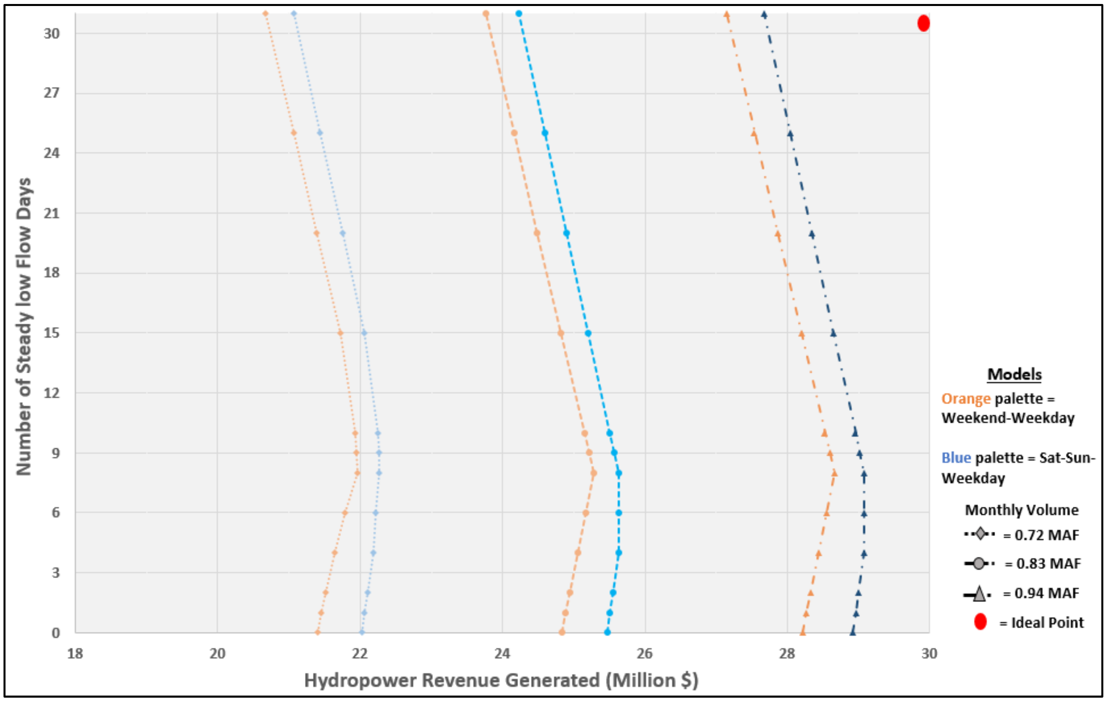

Fig. S 4 Comparison of tradeoffs from Weekend-Weekday and Saturday-Sunday-Weekday models. Each color is representing results from specific models. Different line types and marker symbol shows monthly release volumes. The results are for August 2018 with 1000 cfs offset release.