Supporting Information for:

Bugs Pay for Days of Steady Reservoir Releases to Reduce Hydropeaking-Ecosystem Conflict

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Introduction

The information in this document shares the contract prices, market prices, hydropeaking value estimated from the 2 prices, and observed hydrographs at Lees Ferry Gage. We also share equations for the Saturday-Sunday-Weekday and Market-Contract price models. We share the model structure that includes input data, decision variables, constraints, outputs, and scenarios. We also share results from model validation across different months, results from price differential and offset scenarios, and change in hydropeaking value per additional steady low flow day. Last, we discuss elevation change and its expected impact on hydropower production.

Text S1. Contract and market energy prices.

We received weekday hourly energy contract prices for the months of 2014 from the Western Area Power Authority (WAPA)(Palmer, personal communication, 2019). As an example, Figure S1 shows weekday August 2014 contract prices. We transformed the hourly price data into prices for each day type and period. First, we averaged the 15-minute hydrograph data from the Lees Ferry gauge to get hourly release values. We then used the hydropower generation formula (Supplementary, Eq. S1) to calculate hourly energy generation. We multiplied the estimated hourly energy generation by the hourly energy price (Supplementary, Figure S2) to estimate hydropeaking value generated per hour. Finally, we divided the monthly hydropeaking value for each high and low flow period of each day type by the number of hours for each period of each day type. This division estimated the average energy price for each day type and period. August is the month with the highest energy prices. We used weekday peak- and off-peak contract prices to generate contract prices for Saturdays and Sundays, and market energy prices for all day types.

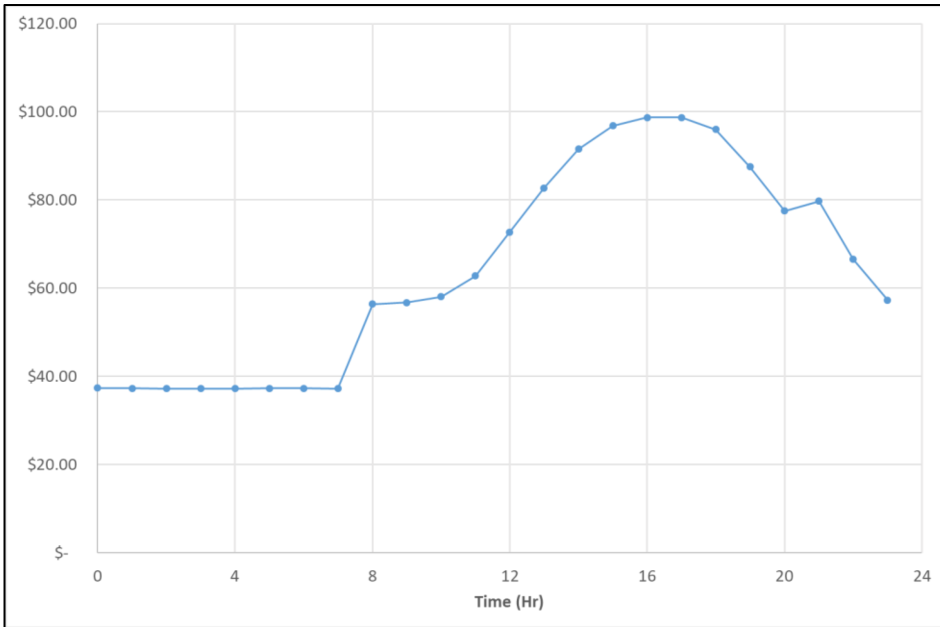

Fig. S1. August hourly contract energy prices.

We generated market energy prices by adding $30/MWh to contract prices for all days and periods. We compared our market prices to the prices used in a different dataset to estimate the impacts on hydropower of flows to disrupt small mouth bass spawning (Bair and Yackulic, 2024; Yackulic et al, 2024). Within that data, weekday market prices surged to $300/MWh for a few hours a week in August and September (Figure S2). However, when those surge prices were averaged across the 80 weekday on-peak hours per week, prices were less than our market prices (Figure S3).

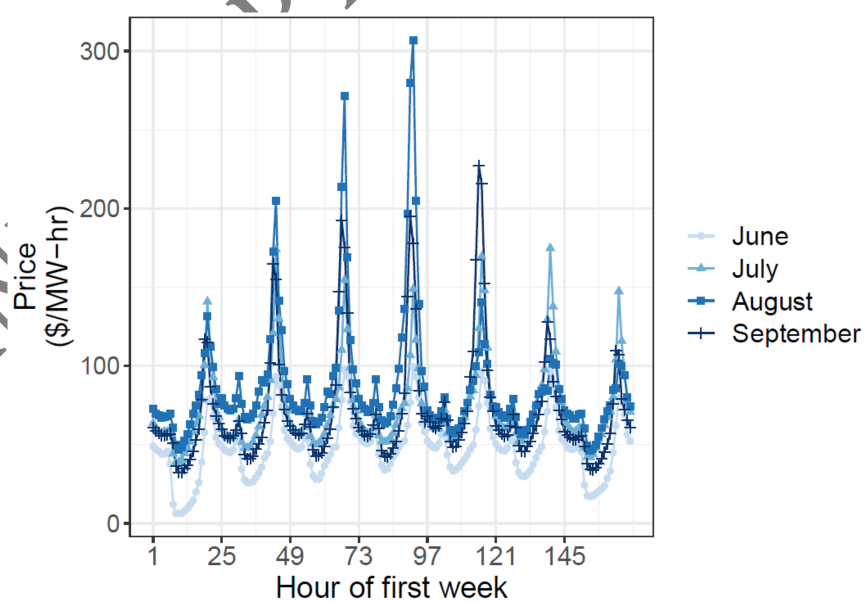

Fig. S2. Time-series of prices in 2024 for the first week of June, July, August, and September (estimated from Bair and Yackulic, 2024; Yackulic et al, 2024).

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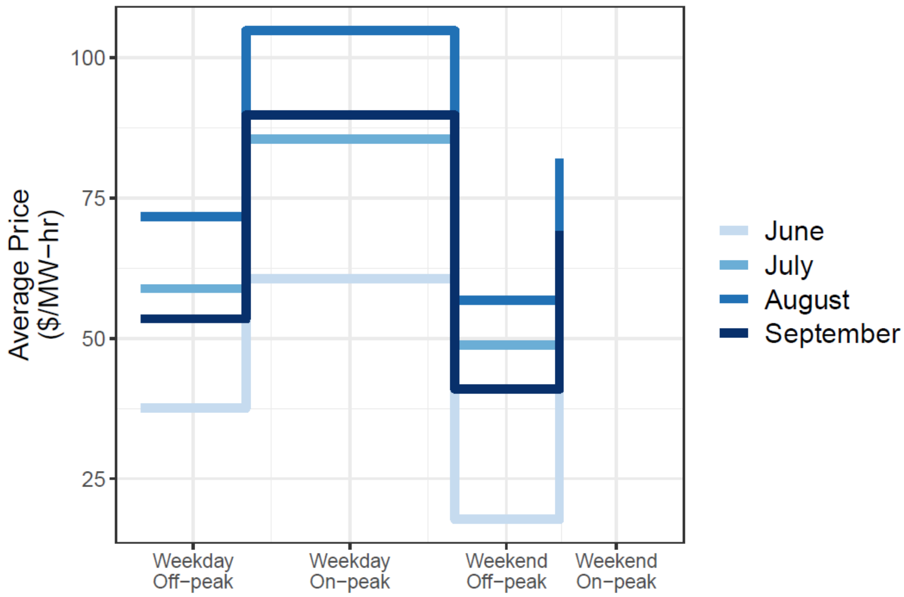

Fig. S3. Period average prices in 2024 for the first week of June, July, August, and September (estimated from Bair and Yackulic, 2024; Yackulic et al, 2024).

Text S2. Observed hydrographs at Lees Ferry Gage.

We looked through multiple monthly hydrographs across various pre-bug flow years and observed a similar pattern for operations—weekday on and off-peak periods and slightly lower peaks during weekend. Here, we present a few pre-bug flows observed hydrographs of August (Figure S4–S6) from different years with various monthly flow volumes.

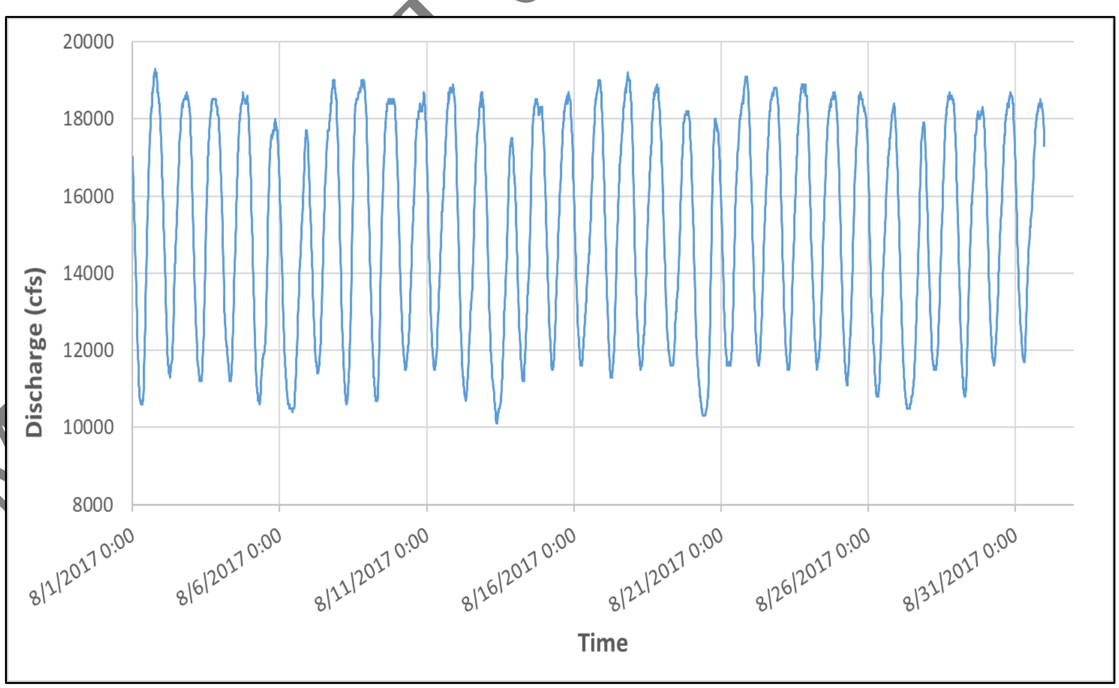

Fig. S4. Pre-bug flow observed hydrograph (USGS 09380000). August 5, 6, 12, 13, 19, 20, 26, and 27 were weekends in 2017. Total monthly volume was ~0.94 Ac-ft.

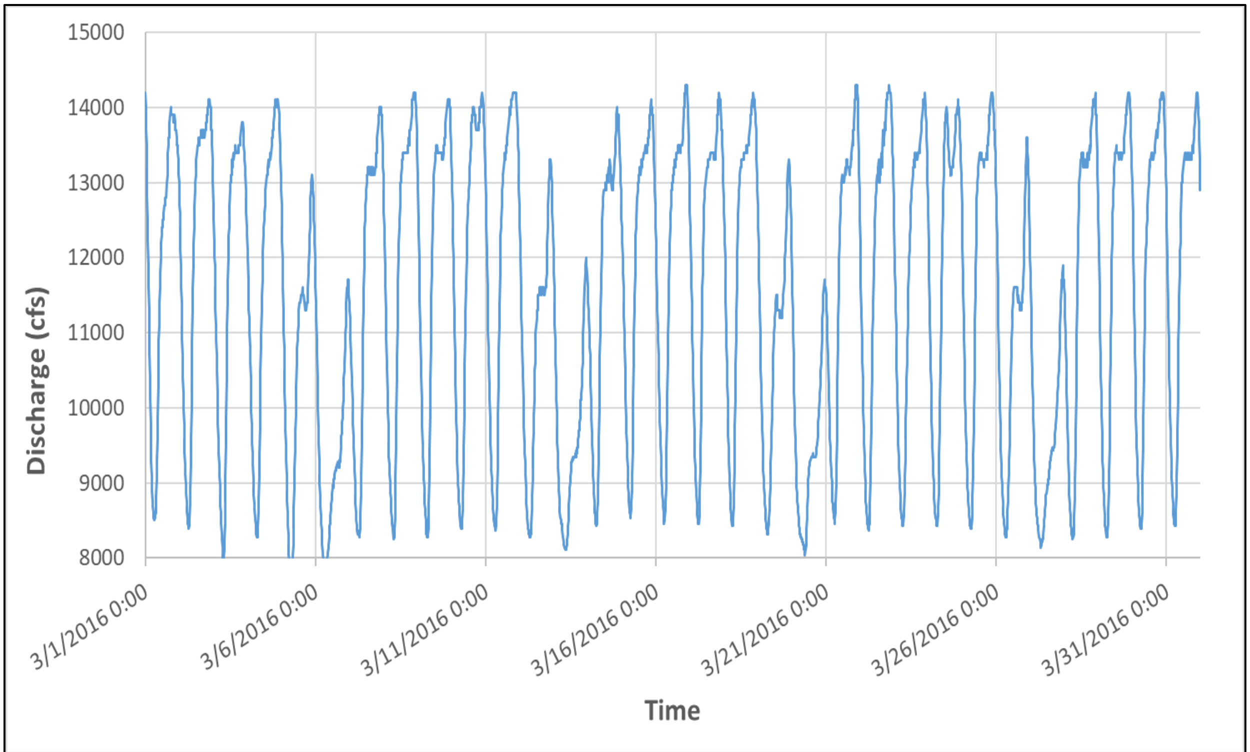

Fig. S5. Pre-bug flow observed hydrograph (USGS 09380000). March 5, 6, 12, 13, 19, 20, 26, and 27 were weekends in 2016. Total monthly volume was ~0.72 Ac-ft**.**

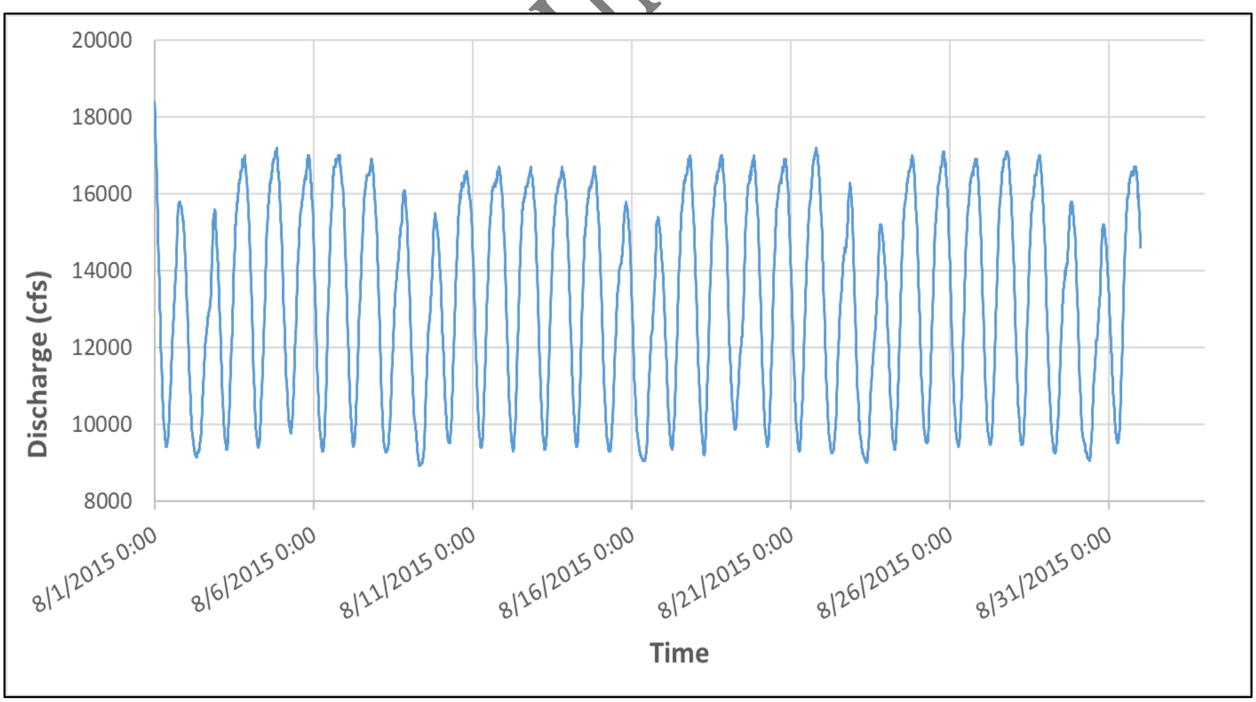

Fig. S6. Pre-bug flow observed hydrograph (USGS 09380000). August 1, 2, 8, 9, 15, 16, 22, 23, 29, and 30 were weekends in 2015. Total monthly volume was ~0.83 Ac-ft.

Text S3. Model formulation.

The model structure includes input data, decision variables, constraints, outputs, and scenarios (Fig. S7).

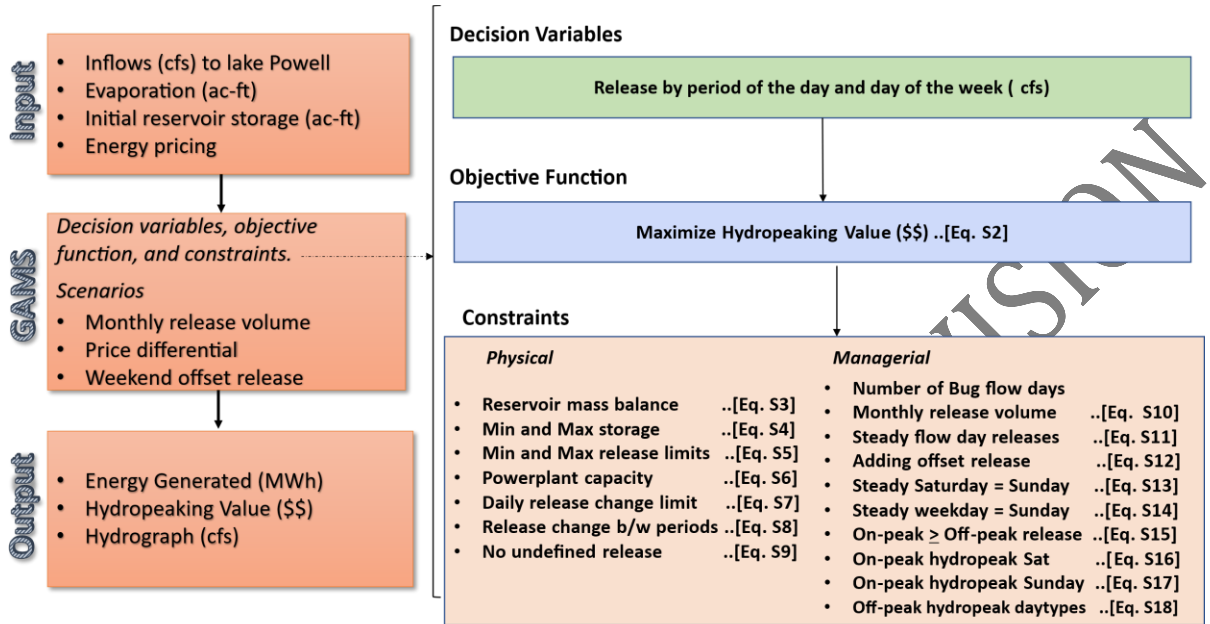

Fig. S7. Model structure.

The energy prices and observed hydrographs supported the assumption of 2 weekly flow patterns *f* (*hydropeak* or *steady*), 3 day types *d* (*Sunday*, *Saturday, and Weekday*), and 2 periods *p* per day (*on-peak* or *off-peak*). This grouping reduced 744 hourly flow values for a month (24 hours per day * 31 days per month = 744 hours per month) into 12 sub-daily characteristic releases, $Release_{f,d,p}$ [cfs]. Here, 2 flow patterns *p x* 3 day types *d* x 2 periods *p* = 12 characteristic releases per month.

We introduced and calculated the state variable energy generation ($Energy\_Gen_{f,d,p}$ [MWh per month]) for each flow pattern *f*, day type *d*, and period *p*:

$$Energy\_Gen_{f,d,p} = Release_{f,d,p} * Duration_{p} * 0.03715, \quad \forall f, d, p. \qquad \text{(eq. S1)}$$

Where *Release* was defined previously, $Duration_p$ is the duration of each period *p* [hr], and 0.03715 is the typical energy generation coefficient [MW-hr per 1 cfs of release].

As discussed in the main text, we opted to maximize hydropeaking value using the constraint method. The objective function was:

$$\text{Hydropeaking Value} = \sum_{f,d,p} Energy\_Gen_{f,d,p} * Price_{d,p} * Num\_Days_{f,d} \qquad \text{(eq. S2)}$$

Here, $Price_{d,p}$ [$/MW-hr] represents the energy price type during each day type *d* and period of the day *p*. Specifying the number of days ($Num_Days_{f,d}$) for each flow pattern *f* and day type *d* allowed the model to vary the number of steady low flow days per month from 0 to 31 and define the order that day types *d* switched from a hydropeak to steady flow pattern (e.g., first

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Sundays, then Saturdays, then Weekdays). In all cases, $\sum_{f,d} Num\_Days_{f,d}$ equals the number of days in the month. 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 the first 4 steady days on Sundays first because contract energy prices on Sunday are lowest, then next 4 steady flow days on Saturdays, and the remaining 2 steady days on weekdays. The 21 remaining days of the month fall on weekdays have a flow pattern of *hydropeak* (Table A1):

Table A1. Number of days per month for each flow pattern *f* and day type *d* for a month with 31 days and 10 days of steady low releases.

Day type	Flow pattern	
	Steady	Hydropeak
Sunday	4	0
Saturday	4	0
Weekday	2	21

In contrast, a scenario with zero steady low flow days per month means the model will decide releases for all weekends and weekdays with flow pattern *hydropeak* while the number of days for flow pattern *steady* are zero (Table A2).

Table A2. Number of days per month for each flow pattern *f* and day type *d* for a month with 31 days and 0 days of steady low releases.

Day type	Flow pattern	
	Steady	Hydropeak
Sunday	0	4
Saturday	0	4
Weekday	0	23

Equations S1 and S2 are subjected to physical and managerial constraints. Physical constraints include:

a. **Reservoir mass balance**. The mass balance was applied at the reservoir on a monthly time scale.

$$Storage = Initstorage + Inflow - Released\_vol - evap \quad \text{(eq. S3)}$$

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 inflow [cfs] converted into [ac-ft/hr] (i.e., 1 cfs = 0.083 ac-ft/hr), duration of periods [hrs], and number of days in a month. *Released_vol* is the total volume of water released in the month [ac-ft], and *evap* is the 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 the maximum storage capacity *maxstorage* [ac-ft].

$$minstorage \leq Storage \leq maxstorage \quad \text{(eq. S4)}$$

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The minimum live storage required for hydropower generation at Glen Canyon Dam was 4 million-acre feet [MAF] (3490 ft msl), and the maximum live storage 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 the maximum release was the turbine capacity at Glen Canyon Dam, i.e., 31,500 cfs.

$$MinRel \leq Release_{f,d,p} \leq maxRel \qquad \forall f,d,p \qquad \text{(eq. S5)}$$

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

$$Energy\_Gen_{f,d,p} \leq 1320 \times Duration_{p} \qquad \forall f,d,p \qquad \text{(eq. S6)}$$

The maximum hydropower generation capacity of Glen Canyon Dam is 1,320 MW (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. The change in release between any two periods should not exceed *Daily_RelRange* (i.e., 8000 cfs).

$$Release_{f,d,pHigh} - Release_{f,d,pLow} \leq Daily\_RelRange \qquad \forall f,d \qquad \text{(eq. S7)}$$

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).

$$Release_{f,d,pHigh} - Release_{f,d+1,pLow} \leq Daily\_RelRange \qquad \forall f,d \qquad \text{(eq. S8)}$$

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

$$Release_{f,d,p} = 0 \qquad \text{(eq. S9)}$$

The managerial constraints include:

h. **Total monthly release volume**. The sum of releases for all flows patterns, day types, and periods must equal the specified monthly release volume.

$$TotMonth\_volume = \sum_{f,d,p} Release_{f,d,p} * Con * Duration_{p} * Num\_Days_{f,d} \qquad \text{(eq. S10)}$$

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

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

$$Release_{Steady,d,pHigh} = Release_{Steady”,d,pLow”} \qquad \forall d \qquad \text{(eq. S11)}$$

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j. **Add offset release** as the difference between the steady low Sunday release and weekday low hydropeaking release. This offset was added because with zero offset (H0, 0 cfs), downstream sites saw progressively smaller benefits due to the weekday peak releases converging to a high flow value. Eggs laid on weekdays were still desiccated when the trough of the weekend steady low release passed downstream (Kennedy, personal communication, 2021). The offset release value was based on the results of egg-laying optimization models that sought to maximize canyon-wide egg-laying benefits (especially at downstream locations where native fish populations are high). The offset releases are still experimental. A 1000 cfs (H1000) offset was tested in 2018, and 750 cfs (H750) during 2019-2020.

$$Release_{\text{Steady,Sunday,pLow}} = Release_{\text{Hydropeak,Weekday,pLow}} + Offset\_Rel \qquad \text{(eq. S12)}$$

Where *Offset_Rel* [cfs] is a pre-defined offset release value.

k. **Same flows on steady Saturdays and Sundays**.

$$Release_{\text{Steady,Saturday, p}} = Release_{\text{Steady,Sunday,p}} \qquad \forall p \qquad \text{(eq. S13)}$$

l. **Steady weekday release equals the release on steady Saturday and Sunday**.

$$Release_{\text{Steady,Weekday,p}} = Release_{\text{Steady,Sunday p}} \qquad \forall p \qquad \text{(eq. S14)}$$

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

$$Release_{\text{Hydropeak d,pHigh}} \geq Release_{\text{Hydropeak,d,pLow}} \qquad \forall d \qquad \text{(eq. S15)}$$

n. **On-peak hydropeak Saturday release equals 2,000 cfs less than on-peak hydropeak weekday** to follow the pre-bug flow hydrograph where there was ~2,000 cfs lower release during on-peak Saturdays and Sundays in comparison to on-peak weekdays. This difference may be that there was lower hydropower demand on weekend.

$$Release_{\text{Hydropeak,Saturday,pHigh}} = Release_{\text{Hydropeak,Weekday,pHigh}} - 2000 \qquad \text{(eq. S16)}$$

o. **On-peak hydropeak Sunday release equals 2,000 cfs less than on-peak hydropeak weekday**.

$$Release_{\text{Hydropeak,Sunday,pHigh}} = Release_{\text{ Hydropeak,Weekday,pHigh}} - 2000 \qquad \text{(eq. S17)}$$

Constraints n and o (Eq. S16 and S17) mimic a pre-Bug Flow Experiment hydrograph (e.g., Fig S2, S3, and S4). Without constraints n and o, the model was expected to generate the maximum possible hydropeaking value by saving water during *hydropeak* Saturdays and Sundays (minimum release). Nevertheless, the minimum release would have created an energy deficit and forced WAPA to purchase energy from the market.

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p. **Same off-peak releases for hydropeak day types.** Off-peak releases were assumed identical across hydropeaking day types (Saturday, Sunday, and weekday). The consistent off-peak energy prices supported the assumption.

$$Release_{\mathrm{Hydropeak,Saturday,pLow}} = Release_{\mathrm{Hydropeak,Sunday,pLow}} = Release_{\mathrm{Hydropeak,Weekday,pLow}} \quad \text{(eq. } S18\text{)}$$

Text S4. Additional equations for market-contract price model.

Adding a market price to the Saturday-Sunday-Weekday model represents the situation where generation is less than the contracted amount and hydropower producers must purchase water at the market price to supply the energy deficit. This case required two sub-models:

I. Sub-model for zero days of steady low flow

This sub-model has a hydropeaking flow pattern on all day types (Saturday, Sunday, and weekday) and all periods. Flows for all days and periods for the steady flow pattern are zero. This sub-model generates the maximum possible hydropeaking value.

$$\text{Revenue\_ZeroSteadyDays} = \sum\nolimits_{\mathrm{d,p}} (Release_{Hydropeak,d,p} \times Duration_p \times 0.03751 \times Energy\_Price_{d,contract,p}) \times Num\_Days_{Hydropeak,d} \quad \text{(eq. } S19\text{)}$$

II. Sub-model when the number of steady low flow days is greater than zero

This sub-model uses combinations of contract and market prices to calculate hydropeaking value when the number of days of steady flow is greater than zero (main text, Figure 3).

We used observed releases ($\mathrm{Observed\_Rel}_{d,}$) as a reference to decide the case of either surplus or deficit energy.

$$\mathrm{SurplusDeficitEnergy}_{\mathrm{flowpattern},d,p} = \{\mathrm{MinimumRelease}_{\mathrm{flowpattern},d,p} \times Energy\_Price_{d,contract,p} + (Release_{\mathrm{flowpattern},d,p} - \mathrm{Observed\_Rel}_{d,p}) \times Energy\_Price_{d,\mathrm{Market},p}\} \times Duration_p \times 0.03751 \times Num\_Days_{Hydropweak,d} \quad \text{(eq. S20)}$$

The *MinimumRelease* refers to the lower value of the observed or modeled releases in *flowpattern* on day type *d* and period *p* (eqs. S21 and S22).

$$MinimumRelease_{\mathrm{flowpattern},,} \leq Release_{\mathrm{flowpattern},d,p} \quad \forall\, flowpattern,\, d,\, p \quad \text{(eq. S21)}$$

$$MinimumRelease_{\mathrm{flowpattern},,} \leq Observed\_Rel_{d,p} \quad \forall\, flowpattern,\, d,\, p \quad \text{(eq. S22)}$$

Here, releases up to the *MinimumRelease* are valued and sold at the contract price (first term in eq. S20). When the *Release* is greater than the *Observed_Rel*, the difference is positive, valued, and sold at the market price (positive value of second term in eq. S20; surplus energy). When the *Observed_Rel* is greater than the *Release*, the difference is negative, valued, and purchased at the market price (negative value of second term in eq. S20; deficit energy).

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Text S5. Model validation.

We compared sub-daily releases from Saturday-Sunday-weekday model against observed (i.e., 15-min hydrograph) and averaged hourly datasets (e.g., Fig. S8). The release volume was identical across the hydrographs. Next, we compared daily energy generation (MWh) from the hydrographs (e.g., Fig. S9). The hourly scenario was designed to directly apply the energy pricing from WAPA. We validated the model for months of 2018 and the results are gathered in Table S1.

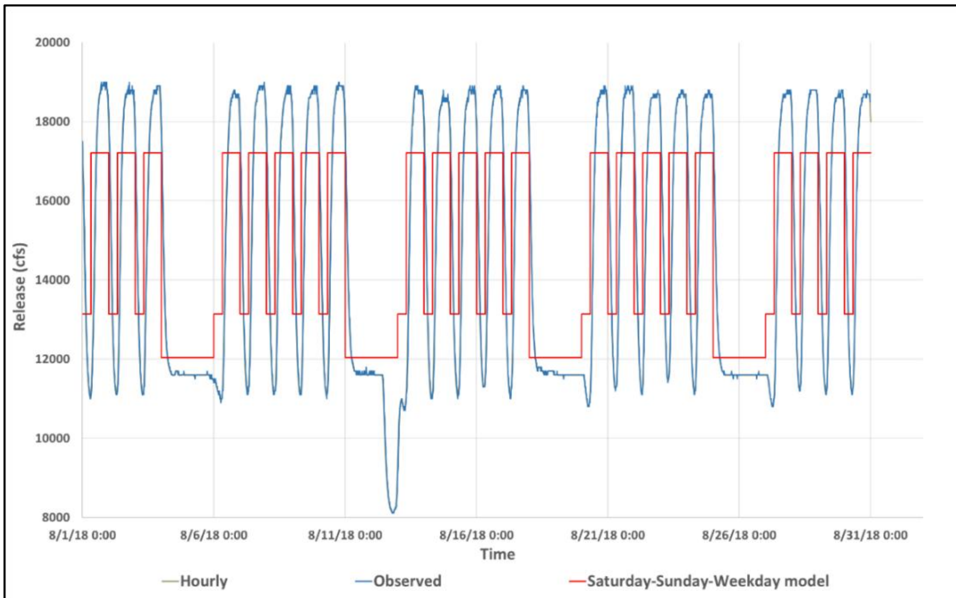

Fig. S8. Releases for August 2018: Observed (blue) vs Saturday-Sunday-Weekday (red).

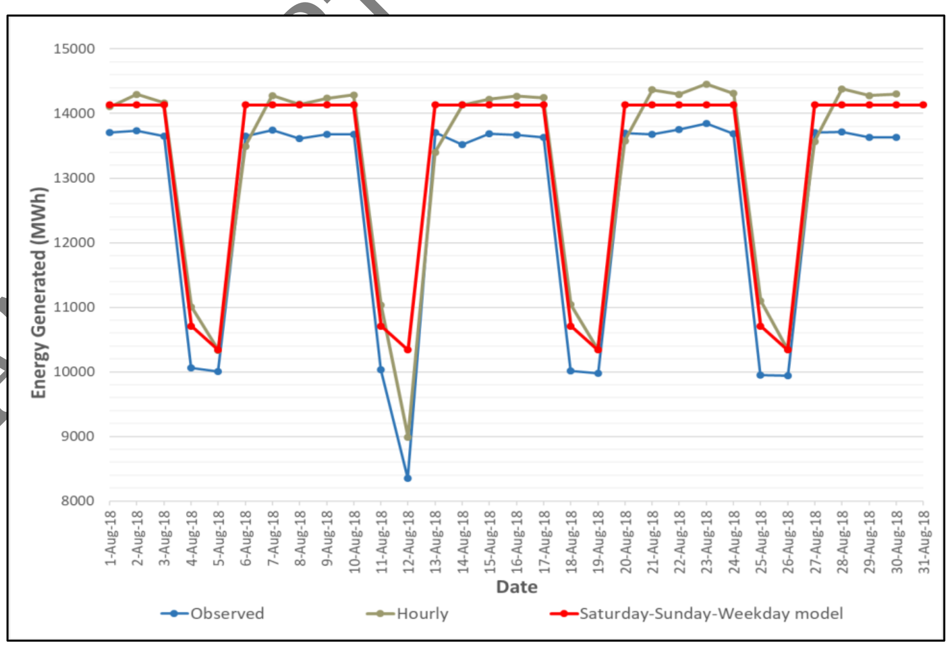

Fig. S9. Daily energy generation: observed (blue) vs hourly (green) vs Saturday-Sunday-Weekday model (red).

Table S1. Validation results for months of the year with contract price model.

Scenario		Released volume (Ac-ft/ Month)	Energy Generated (MWh)	% Error in Energy generated relative to observed	Hydropeaking value ($)	Energy Prices used ($/MWh)
March 2018						
1	Observed	838,771	363,797			
2	Hourly	838,771	375,426	3.2%	$19,497,014	Hourly prices by WAPA
3	Weekend-Weekday model	838,771	375,426	3.2%	$19,497,050	Weekday On-peak = 58.643 & Off-peak = 44.37 and Weekend = 44.37
4	Saturday-Sunday-Weekday model	838,771	375,426	3.2%	$19,787,571	Sunday, off-peak Saturday & Weekday = 44.37, on-peak Saturday = 51.5, and on-peak Weekday = 58.643
April 2018						
1	Observed	740,527	318,194			
2	Hourly	740,527	331,453	4.2%	$15,548,812	Hourly prices by WAPA
3	Weekend-Weekday model	740,527	331,453	4.2%	$15,548,840	Weekday On-peak = 55.05 & Off-peak = 38.24 and Weekend = 38.24
4	Saturday-Sunday-Weekday model	740,527	331,453	4.2%	$15,805,642	Sunday, off-peak Saturday & Weekday = 38.24, on-peak Saturday = 46.70, and on-peak Weekday = 55.05
May 2018						
1	Observed	731,979	318,486			
2	Hourly	731,979	327,627	2.9%	$15,759,215	Hourly prices by WAPA
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

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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-	914,428	409,289	4.2%	$27,641,618	Sunday, off-peak Saturday & Weekday = 49.70, on-

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	Weekday model					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

Text S7. Releases, price differential, offset, and elevation scenarios.

The number of steady low flow days controlled the on- and off-peak releases (Fig. S10). Until 8 steady low flow days, the model reduced off-peak releases on *hydropeak* days and steady low flow releases. The saved water was released during on-peak weekdays to maximize overall hydropeaking value.

We found that the energy price differential between on- and off-peak weekday periods determines the position and shape of the tradeoff curves for hydropeaking value and number of days of steady low flows (Fig. S9). Reduction in the price differential moved the tradeoff curves left towards lower hydropeaking value (darker to lighter blue, Fig. S11). The reduction in the price differential also made tradeoff curves more convex (closer to a vertical line; triangles to rectangles to circles in Fig. S9). In addition, we also tested impacts of different offset releases on the tradeoff curves and found minimal changes (Fig. S12).

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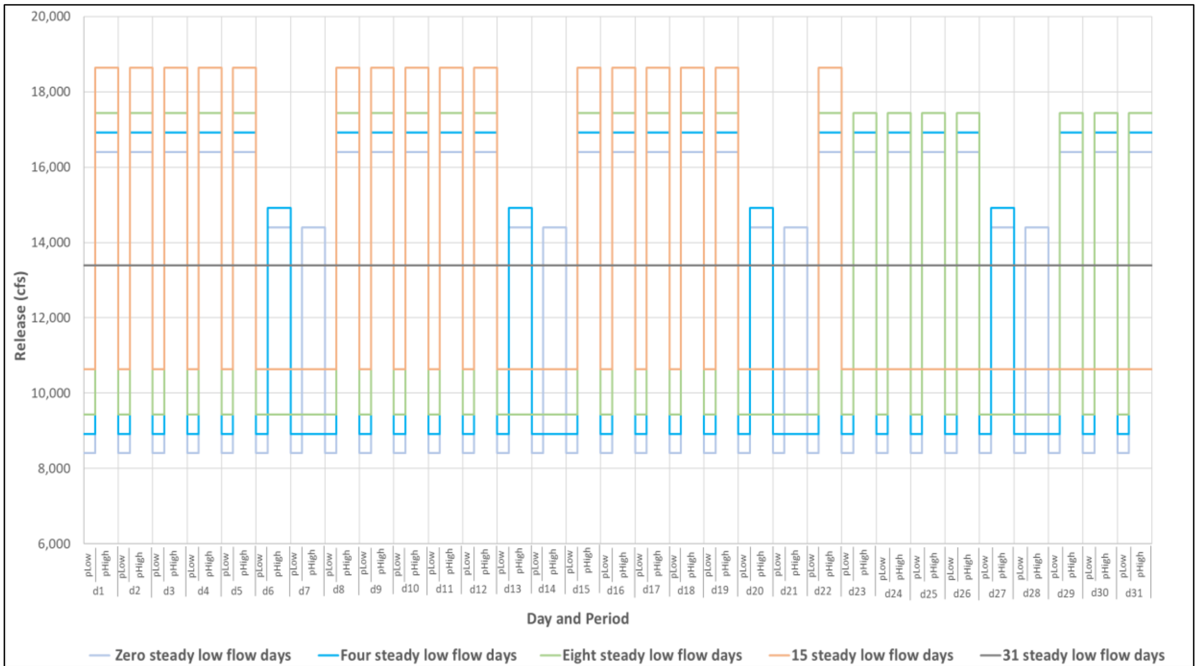

Fig. S10. Monthly hydrographs from Saturday-Sunday-Weekday model for monthly release volume of 0.83 MAF, zero offset release, and scenarios of different number of days of steady releases. d1 is a Monday.

We also estimated the effects of elevation changes on energy production (Table S2). In these estimates, we assumed a constant turbine efficiency (0.9) across depths in the power equation for the hydropower plant. The change in energy generation due to elevation change was less than 70 MWh per month (0.02% of observed energy generated in Table S1).

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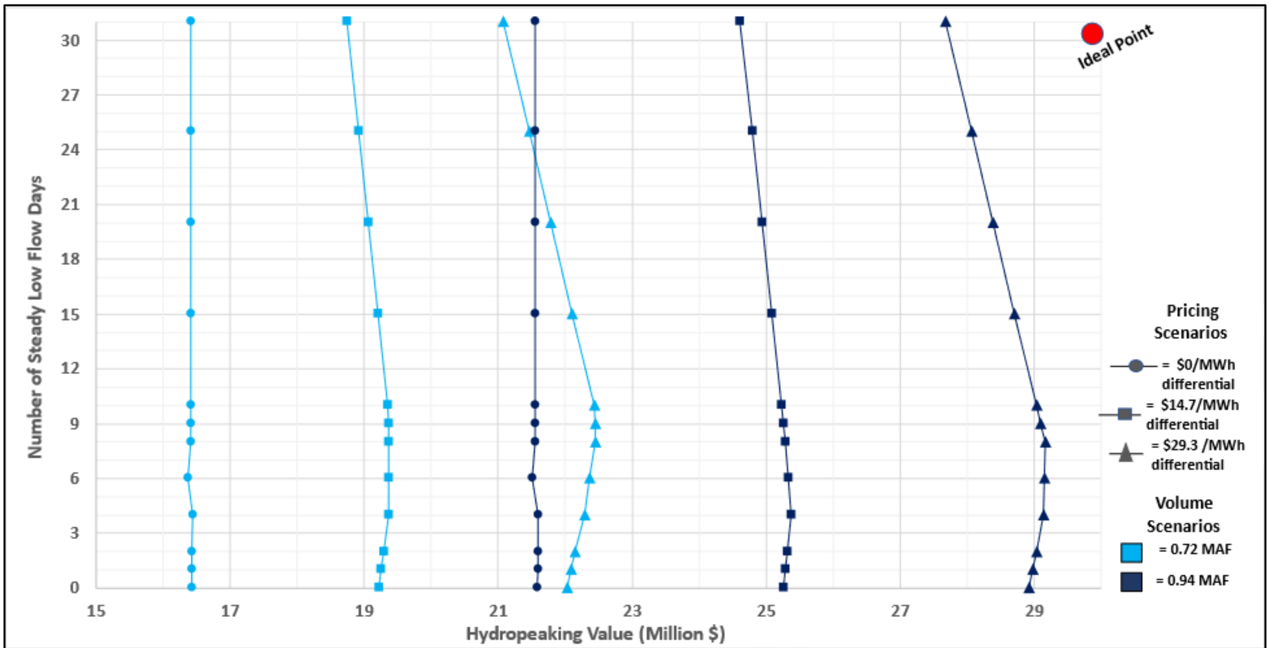

Fig. S11. Tradeoffs of 3 price differential scenarios (circle, square, and triangle markers) and two monthly volume scenarios (sky and dark blue) for August 2018. Saturday-Sunday-Weekday contract price model was used.

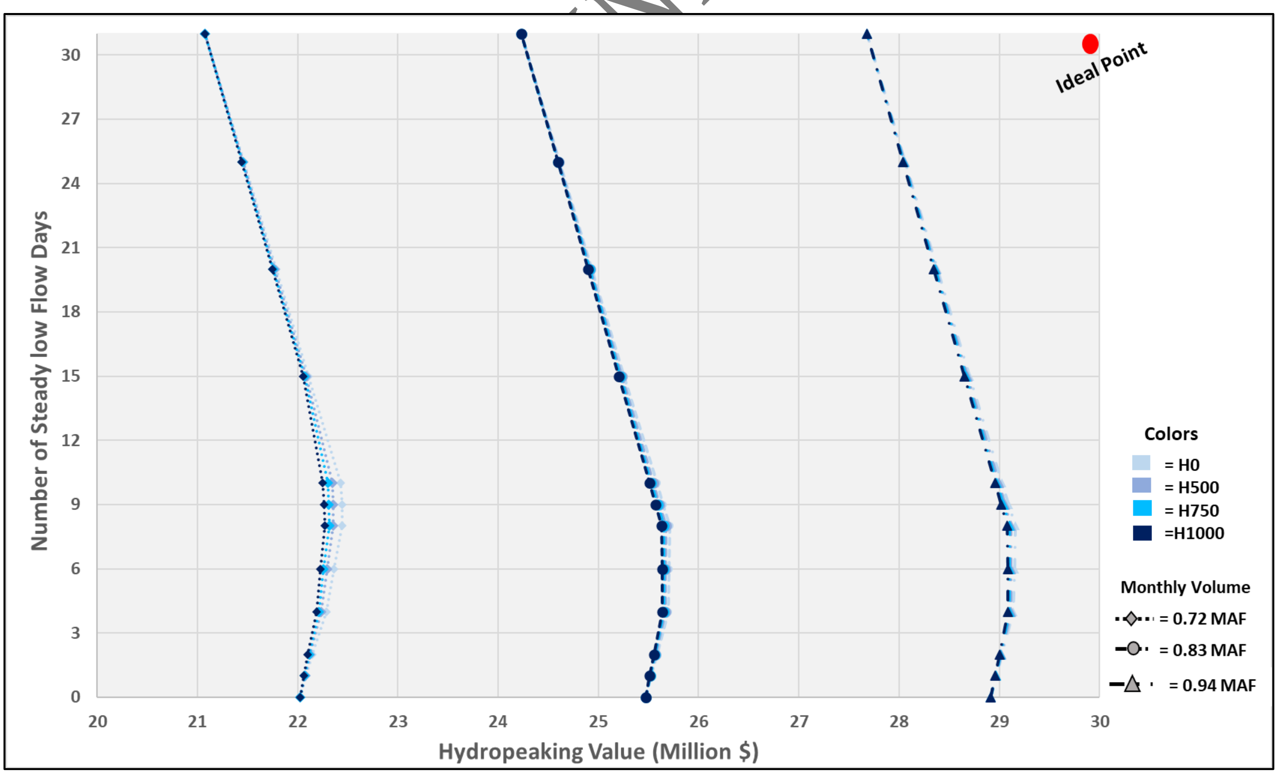

Fig. S12 Tradeoffs for 4 offset release scenarios (light to dark blue) and 4 monthly release volumes (marker shape) using the Saturday-Sunday-Weekday contract price model.

Table S2. Elevation change during the months of 2018 and change in hydropower generation. Negative values indicate a decrease; positive values indicate an increase.

Month	Elevation change (feet)	Change in energy production (MWh)
March	-3.7	-32
April	-2.8	-19
May	+2.3	+19
June	-1.6	-15
July	-6.0	-46
August	-6.5	-69
September	-4.6	-34
October	-1.7	-12

Finally, we computed the change in hydropeaking value using the Saturday-Sunday-Weekday model for each additional day of steady low flow across various months in 2018 (Table S3).

Table S3. Change in hydropeaking value ($1000) per additional steady low flow day added in 2018 with 0.83 MAF release volume, H1000 (offset release), and contract energy price. Positive values show an increase; negative values a decrease).

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

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