Net Revenue and Downstream Flow Impact Trade-offs for a Network of Small-Scale Hydropower Facilities in California

Supplemental Information

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SI.1: Drainage Area and River Elevation

Figures S1 and S2 depict the drainage area of the North Yuba River, where the 36 proposed hydropower facilities would be located, and the drainage area of the Feather River, which encompasses the North Yuba drainage area.

Figure S1: Drainage area of the Feather River, which includes the North Yuba River drainage area.
Figure S2: Drainage area of the North Yuba River, where the 36 proposed hydropower facilities would be located.

Figure S3: Cross-section of elevation and mileage along the Yuba River of each proposed hydropower facility’s forebay and afterbay.
SI.2: Summary Statistics for Goodyear Bar Flows on Yuba River

Table S1: Average, maximum, and minimum flows of Yuba River at Goodyear Bar by month in 2015, 2016, and 2017, which represent dry, typical, and wet hydrological years.

| Year | Month | Average Flow (m$^3$/s) | Maximum Flow (m$^3$/s) | Minimum Flow (m$^3$/s) |
|------|-------|-------------------------|-------------------------|------------------------|
| 2015 | 1     | 9.1                     | 12.8                    | 7.7                    |
|      | 2     | 25.5                    | 156.6                   | 7.3                    |
|      | 3     | 8.6                     | 11.6                    | 7.1                    |
|      | 4     | 7.1                     | 12.4                    | 5.7                    |
|      | 5     | 5.7                     | 9.3                     | 4.6                    |
|      | 6     | 3.5                     | 4.8                     | 2.7                    |
|      | 7     | 2.6                     | 4.2                     | 2.1                    |
|      | 8     | 2.0                     | 2.3                     | 1.9                    |
|      | 9     | 2.0                     | 2.2                     | 1.9                    |
|      | 10    | 2.2                     | 3.3                     | 2.0                    |
|      | 11    | 2.8                     | 6.2                     | 2.1                    |
|      | 12    | 11.2                    | 72.8                    | 2.4                    |
| 2016 | 1     | 31.8                    | 314.3                   | 5.6                    |
|      | 2     | 27.2                    | 64.8                    | 21.0                   |
|      | 3     | 75.5                    | 320.0                   | 21.7                   |
|      | 4     | 47.4                    | 70.8                    | 32.6                   |
|      | 5     | 40.0                    | 64.3                    | 26.7                   |
|      | 6     | 16.6                    | 33.7                    | 8.1                    |
|      | 7     | 6.2                     | 8.5                     | 4.6                    |
|      | 8     | 4.1                     | 4.8                     | 3.6                    |
|      | 9     | 3.4                     | 3.7                     | 3.2                    |
|      | 10    | 10.7                    | 60.9                    | 3.2                    |
|      | 11    | 12.9                    | 34.0                    | 7.1                    |
|      | 12    | 49.2                    | 407.8                   | 7.7                    |
| 2017 | 1     | 88.4                    | 685.3                   | 17.5                   |
|      | 2     | 149.1                   | 549.3                   | 31.7                   |
|      | 3     | 62.3                    | 165.9                   | 41.1                   |
|      | 4     | 88.3                    | 157.7                   | 57.5                   |
|      | 5     | 95.8                    | 153.2                   | 64.8                   |
|      | 6     | 56.5                    | 88.6                    | 26.6                   |
|      | 7     | 14.8                    | 27.6                    | 8.9                    |
|      | 8     | 7.3                     | 9.1                     | 5.8                    |
|      | 9     | 5.7                     | 7.4                     | 5.3                    |
|      | 10    | 5.1                     | 7.3                     | 4.7                    |
|      | 11    | 25.5                    | 225.7                   | 4.7                    |
|      | 12    | 10.4                    | 21.7                    | 7.0                    |
SI.3: Model Formulation

We construct an optimization that maximizes net revenues subject to river network, environmental impact, and technology constraints. In maximizing net revenues, we assume that the small hydropower units are price takers in the aggregate, so their operations do not influence electricity or ancillary service prices.

Table S2: Variables, parameters, and sets used in profit-maximizing model formulation.

| Variable | Definition |
|----------|------------|
| $a_{S_i,j,t}$ | Provided ancillary services (MWh) |
| $c_{i,t}$ | Inflow into, i.e., charging of, forebay reservoir ($m^3/s$) |
| $f_{d_{i,t}}$ | Forebay depth (m) |
| $h_{i,t}$ | Net head (m) |
| $i_{n,t}$ | Total inflows ($m^3/s$) |
| $o_{u_{i,t}}$ | Outflows net of natural flows ($m^3/s$) |
| $p_{i,t}$ | Electricity generation (MWh) |
| $p_{i,t,TOTAL}$ | Total electricity generation, including dispatch of committed regulation up and down reserves (MWh) |
| $q_{i,t}$ | Water discharge from turbine ($m^3/s$) |
| $v_{i,t}$ | Forebay reservoir volume ($m^3$) |
| $x_{i,t}$ | Binary variable indicating provision of up (1) or down (0) ancillary services |
| $z$ | Total profits |

Variables for Piecewise Linear Approximations

- $f_{d_{i,t,fdz}}$ ZONE: Forebay depth in forebay depth zone of operation (m)
- $h_{i,t,hz}$ ZONE: Net head in net head zone of operation (m)
- $q_{i,t,qz,hz}$ ZONE: Water discharge from turbine in turbine discharge zone of operation ($m^3/s$)
- $u_{i,t,fdz}$ FD: Binary variable indicating forebay depth zone of operation
- $u_{i,t,hz}$ H: Binary variable indicating net head zone of operation
- $u_{i,t,qz,hz}$ Q: Binary variable indicating discharge zone of operation

Parameter | Definition |
|----------|------------|
| $AMP_{j,t}$ | Ancillary mileage price, only applicable to regulation reserves ($/MWh) |
| $AS_{i,j}^{MAX}$ | Maximum ancillary service provision (MW) |
| $ASMM_{j,t}$ | Ancillary service mileage multiplier, which equals the sum of automatic generation control signals over each time interval and is only applicable only to regulation reserves (MWh/MWh) |
| $ASNE_{j}$ | Ancillary service net energy, i.e., amount of provided reserves deployed in each time interval (MWh/MW) |
| $ASPF_{j,t}$ | Ancillary service price ($/MWh) |
| $ASR_{j}$ | Ancillary service performance, which we assume equals 0.9 |
| $AST_{i}$ | Ancillary service response time |
| $C_{i,t}^{ELIG}$ | Binary parameter indicating whether hydropower operations are permitted(1) or not (0) |
| $F_{i,t}^{CASC}$ | Cascading flows ($m^3/s$) |
| $F_{i,t}^{TRIB}$ | Tributary flows ($m^3/s$) |
| $FD_{i}^{MIN}$ | Minimum forebay depth (m) |
| Parameter | Definition |
|-----------|------------|
| FD<sub>i</sub> | Maximum forebay depth (m) |
| FL <sub> UPPER </sub> | Upper limit on flows immediately downstream from each unit, expressed as a fraction of natural flows |
| FL<sub>i</sub> <sub> LOWER </sub> | Lower limit on flows immediately downstream from each unit (m<sup>3</sup>/s) |
| FV | Unit conversion from flow to volume |
| H<sub>i</sub> <sub> MIN </sub> | Minimum net head (m) |
| LMP<sub> i </sub> | Locational marginal price ($/MWh) |
| P<sub>i</sub> <sub> MAX </sub> | Maximum electricity generation (MWh) |
| OUT<sub>i</sub><sub>,t</sub> | Net outflows from prior optimization horizon (m<sup>3</sup>/s) |
| Q<sub>i</sub> <sub> MAX </sub> | Maximum turbine discharge (m<sup>3</sup>/s) |
| RR<sub>i</sub> | Ramp rate (MWh) |
| TL<sub>i</sub> | Temporal lag in flows from adjacent upstream unit |
| V<sub>i</sub> | Initial forebay reservoir volume (m<sup>3</sup>) |
| V<sub>i</sub> <sub> MIN </sub> | Minimum forebay reservoir volume (m<sup>3</sup>) |
| VOM<sub>i</sub> | Variable operation and maintenance costs of generator i ($/MWh) |

**Parameters for Piecewise Linear Approximations**

| Parameter | Definition |
|-----------|------------|
| FD<sub>i</sub>,<sub>fdz</sub> | Maximum forebay depth in forebay depth zone (m) |
| H<sub>i</sub>,<sub>hz</sub> | Maximum net head height in net head zone (m) |
| PF<sub>i</sub>,<sub>qz</sub>,<sub>hz</sub> | Electricity generation at maximum turbine water discharge in turbine water discharge zone (MWh) |
| Q<sub>i</sub>,<sub>qz</sub>,<sub>hz</sub> | Maximum turbine water discharge in turbine water discharge zone (m<sup>3</sup>/s) |
| VF<sub>i</sub>,<sub>fdz</sub> | Forebay reservoir volume at maximum forebay depth in forebay depth zone (m<sup>3</sup>) |

**Set**

| Symbol | Definition |
|--------|------------|
| fdz | Forebay depth zone; fdz ∈ FDZ |
| hz | Net head height zone; hz ∈ HZ |
| i | Hydropower units; i ∈ I |
| j | Ancillary services; j ∈ J |
| J<sub>DOWN</sub> | Down ancillary services, i.e., offers of decreased electricity generation; subset of J |
| J<sub>UP</sub> | Up ancillary services, i.e., offers of increased electricity generation; subset of J |
| qz | Turbine water discharge zone; qz ∈ QZ |
| t | Time intervals; t ∈ T |

**Objective Function**

Our model maximizes net revenues, or electricity generation and ancillary service revenues minus variable operation and maintenance costs:
$$z = \sum_{i,t} \left( p_{i,t} \cdot LMP_t - p_{i,t}^{TOTAL} \cdot VOM_i \right) + \sum_{j} \left( a_{s,i,j,t} \cdot (ASP_{j,t} + ASR_j \cdot ASMM_{j,t} \cdot AMP_{j,t}) \right) \quad \forall i \in I, j \in J, t \in T$$

where $i, j,$ and $t$ index hydropower units, ancillary services, and time, respectively; $z =$ total net revenues [$] ; $p =$ electricity generation [MWh]; $LMP =$ locational marginal price, or the price received per unit of electricity generation [$/MWh] ; $p^{TOTAL} =$ total electricity generation accounting for the deployment of provided regulation reserves [MWh]; $VOM =$ variable operation and maintenance (VOM) costs [$/MWh]; $as =$ ancillary service provision [MWh]; $ASP =$ ancillary service price, or the price received per unit of ancillary services provided [$/MWh]; $ASR =$ ancillary service performance, which we assume equals 0.9 ; $ASMM =$ ancillary service mileage multiplier, or the sum of the absolute automatic generation control signal for each time interval [MWh/MWh]; and $AMP =$ ancillary service mileage price [$/MWh]. Total electricity generation ($p^{TOTAL} [\text{MWh}]$) equals electricity generation plus deployed ancillary services:

$$p_{i,t}^{TOTAL} = p_{i,t} + \sum_{j} (a_{s,i,j,t} \cdot ASNE_j) \quad \forall i \in I, j \in J, t \in T$$

where $ASNE =$ deployed ancillary services per unit of provided ancillary services [MWh/MWh].

### Electricity Generation and Reserve Provision Constraints

Electricity generation plus up reserve, e.g., regulation up and spinning reserve, provision by each unit cannot exceed each unit’s maximum generation capacity:

$$p_{i,t} + \sum_j a_{s,i,j,t} \leq P_{MAX} \quad \forall i \in I, j \in J^{UP}, t \in T$$

where $P_{MAX} =$ maximum electricity generation [MWh]. Down reserve, e.g. regulation down, provision cannot exceed electricity generation:

$$\sum_j a_{s,i,j,t} \leq p_{i,t} \quad \forall i \in I, j \in J^{DOWN}, t \in T$$

Ancillary service provision cannot exceed a maximum limit ($AS_{MAX}^{MAX} [\text{MWh}]$), which is limited by each unit’s ramp rate ($RR$ [MWh]) and the ancillary service’s response time ($AST$):

$$a_{s,i,j,t} \leq AS_{i,j}^{MAX} = RR_i \cdot AST_j \quad \forall i \in I, j \in J, t \in T$$

Finally, each unit is limited to providing up or down ancillary services at any given time:

$$\sum_j a_{s,i,j,t} \leq AS_{i,j}^{MAX} \cdot x_{i,t} \quad \forall i \in I, j \in J^{UP}, t \in T$$
\[
\sum_{j} a_{i,j,t} \leq A_{i,j}^{\text{MAX}} \times (1 - x_{i,t}) \quad \forall \ i, j \in D^{\text{DOWN}}, t \in T
\]

where \( x \) = binary variable indicating provision of up reserves.

To approximate the nonlinear dependence of electricity generation on net head height and water discharge through the turbine, we use linear piecewise approximations of both dependences. Specifically, we divide the nonlinear relationship into segments, then use binary variables to indicate which segment is active. Only one net head segment and one water discharge segment can be active at any given time:

\[
\sum_{hz} u_{i,t,hz}^H = 1 \quad \forall \ i, t \in T, hz \in HZ
\]

\[
\sum_{qz} u_{i,t,qz,hz}^Q = u_{i,t,hz}^H \quad \forall \ i, t \in T, hz \in HZ, qz \in QZ
\]

where \( hz \) and \( qz \) index net head and discharge segments, \( u^H \) = binary variable indicating which net head segment is active, and \( u^Q \) = binary variable indicating which discharge segment is active. Note that discharge segments exist for each head segment, allowing for electricity generation at varying discharge levels for a given net head height. Positive variables representing net head segment is active, and are constrained by minimum and maximum values:

\[
H_{i,hz-1} \times u_{i,t,hz}^H \leq H_{i,hz} \times u_{i,t,hz}^H \leq H_{i,hz} \times u_{i,t,hz}^H \quad \forall \ i, t \in T, hz \in HZ
\]

\[
Q_{i,qz-1,hz} \times u_{i,t,qz,hz}^Q \leq Q_{i,qz,hz} \times u_{i,t,qz,hz}^Q \leq Q_{i,qz,1,hz} \times u_{i,t,qz,hz}^Q \quad \forall \ i, t \in T, hz \in HZ, qz \in QZ
\]

where \( H \) = maximum net head height in a segment, and \([m]\) \( Q \) = maximum water discharge in a segment \([m^3/s]\). The total net head height \( (h_{ZONE} [m]) \) and water discharge \( (q_{ZONE} [m^3/s]) \) equal the sum of the net head and discharge values in each linear segment:

\[
h_{i,t} = \sum_{hz} h_{i,t,hz}^{ZONE} \quad \forall \ i, t \in T, hz \in HZ
\]

\[
q_{i,t} = \sum_{qz,hz} q_{i,t,qz,hz}^{ZONE} \quad \forall \ i, t \in T, hz \in HZ, qz \in QZ
\]

Finally, electricity generation varies linearly with water discharge based on the minimum and maximum water discharge and electricity generation values in the active segment:

\[
p_{i,t} = \sum_{hz,qz} \left( u_{i,t,qz,hz}^Q \times PF_{i,qz-1,hz} + \frac{PF_{i,qz,hz} - PF_{i,qz-1,hz}}{Q_{i,qz,hz} - Q_{i,qz-1,hz}} \right) 
\]

\[
\times \left( q_{i,t,qz,hz}^{ZONE} - u_{i,t,qz,hz}^Q \times Q_{i,qz-1,hz} \right) \quad \forall \ i, t \in T, hz \in HZ, qz \in QZ
\]
where \( PF \) = electricity generation at the maximum discharge level in each segment [MWh]. Note that this relationship also captures the role of net head on generation through \( PF \), which varies with discharge and net head.

**Forebay Reservoir Constraints**

Several constraints relate forebay reservoir operations to electricity generation. The stored water volume in the forebay reservoir \((v [m^3])\) varies with water added to the reservoir \((c [m^3/s])\), water discharged from the turbine \((q [m^3/s])\), and the volume in the prior period:

\[
v_{i,t} = v_{i,t-1} + (c_{i,t} - q_{i,t}) \cdot FV \quad \forall i \in I, t > 1
\]

\[
v_{i,t} = V_i + (c_{i,t} - q_{i,t}) \cdot FV \quad \forall i \in I, t = 1
\]

where \( FV \) = a scalar to convert from volume per second to volume, and \( V_i \) = stored water volume in the first time interval of the optimization. Total water discharge through the turbine is constrained by the stored volume in the prior time interval and inflows not stored in the reservoir:

\[
q_{i,t} \leq \frac{(v_{i,t-1} - V_{MIN})}{FV} + (i_{n,t} - c_{i,t}) \quad \forall i \in I, t > 1
\]

\[
q_{i,t} \leq \frac{(V_i - V_{MIN})}{FV} + (i_{n,t} - c_{i,t}) \quad \forall i \in I, t = 1
\]

where \( i_{n} \) = total inflows to the hydropower unit, and \( V_{MIN} \) = the minimum water volume that can be stored in the forebay reservoir. Water added to and taken from the reservoir is limited by maximum values:

\[
c_{i,t} \leq i_{n,t} \cdot C_{i,t}^{ELIG} \quad \forall i \in I, t \in T
\]

\[
q_{i,t} \leq Q_{i}^{MAX} \quad \forall i \in I, t \in T
\]

where \( C_{i,t}^{ELIG} \) = a binary parameter that indicates whether turbine operations are permitted (1) or not (0), and \( Q^{MAX} \) = maximum turbine discharge rate. We set \( C_{i,t}^{ELIG} \) to zero, and thereby prohibit hydropower operations, when natural flows are less than minimum flow requirements that vary by hydropower unit.

Stored water volume in the forebay reservoir varies with the forebay head height in a nonlinear relationship. To include this relationship in our linear program, we use a piecewise approximation in which we divide the nonlinear relationship into segments, then use binary variables to indicate which segment is active. Only one linear segment can be active at once:

\[
\sum_{fdz} u_{i,t,fdz}^{FD} = 1 \quad \forall i \in I, t \in T, fdz \in FDZ
\]

where \( fdz \) indexes the linear segments, or zones, of the linearized relationship, and \( u_{i,t,fdz}^{FD} \) = the binary variable indicating which segment is active. Positive variables representing the forebay depth \((fdz^{ZONE} [m])\) in each segment can only be nonzero in the active segment:
where \( FD = \) maximum forebay depth in each segment \([\text{m}]\). The total forebay depth equals the sum of these segment forebay depths:

\[
f_{d_{i,t}} = \sum_{f_{dz}} f_{d_{i,t,f_{dz}}} \quad \forall i \in I, t \in T, f_{dz} \in \text{FDZ}
\]

Finally, the model calculates the forebay reservoir stored volume based on the slope of the relationship between forebay depth and stored volume in the active segment:

\[
v_{i,t} = \sum_{f_{dz}} \left( u_{i,t,f_{dz}}^{FD} \cdot VF_{i,f_{dz}} - u_{i,t,f_{dz}}^{FD} \cdot FD_{i,f_{dz}} - 1 \right) \quad \forall i \in I, t \in T, f_{dz} \in \text{FDZ}
\]

where \( VF = \) forebay reservoir volume at the maximum forebay depth in each segment \([\text{m}^3]\). Note that forebay depth can only vary between the minimum \((FD_{MIN} [\text{m}])\) and maximum \((FD_{MAX} [\text{m}])\) values:

\[
FD_{i,t}^{MIN} \leq f_{d_{i,t}} \leq FD_{i,t}^{MAX} \quad \forall i \in I, t \in T
\]

Forebay head height drives the total net head:

\[
h_{i,t} = H_{i,t}^{MIN} + (f_{d_{i,t}} - FD_{i,t}^{MIN}) \quad \forall i \in I, t \in T
\]

where \( H^{MIN} = \) minimum net head, i.e., the net head when the forebay depth equals its minimum value, and \( FD_{MIN} = \) minimum forebay head. Net head can also only vary between minimum \((H^{MIN} [\text{m}])\) and maximum values:

\[
H_{i,t}^{MIN} \leq h_{i,t} \leq (FD_{i,t}^{MAX} - FD_{i,t}^{MIN}) + H_{i,t}^{MIN} \quad \forall i \in I, t \in T
\]

**River Network Constraints**

The final set of constraints link flows between hydropower units. First, inflows to each hydropower unit are composed of natural cascading flows \((F_{CASC} [\text{m}^3/\text{s}])\), natural tributary flows \((F_{TRIB} [\text{m}^3/\text{s}])\), and nonnatural flows caused by water discharges from the adjacent upstream hydropower unit \((out [\text{m}^3/\text{s}])\):

\[
in_{i,t} = F_{i,t}^{CASC} + F_{i,t}^{TRIB} + out_{i-1, t-TL_i} \quad \forall i \in I, t > TL_i
\]

\[
in_{i,t} = F_{i,t}^{CASC} + F_{i,t}^{TRIB} + OUT_{i,t} \quad \forall i \in I, t \leq TL_i
\]

where \( TL = \) temporal lag of water discharges from the adjacent upstream turbine reaching the current turbine. Note that water discharges from turbines from the prior optimization horizon are passed in as parameters. For the first unit in the series of hydropower units, inflows depend only on natural cascading and tributary flows:
\[ in_{i,t} = F_{i,t}^{\text{CASC}} + F_{i,t}^{\text{TRIB}} \quad \forall \, i = 1, t \in T \]

Net outflows track the difference in total outflows from natural flows:
\[ out_{i,t} = in_{i,t} + q_{i,t} - c_{i,t} - F_{i,t}^{\text{CASC}} - F_{i,t}^{\text{TRIB}} \quad \forall \, i \in I, t \in T \]

With respect to limiting environmental impacts, net outflows cannot increase natural flows beyond a certain factor (\(FL_{\text{UPPER}}\)):
\[ out_{i,t} \leq (F_{i,t}^{\text{CASC}} + F_{i,t}^{\text{TRIB}}) \ast FL_{\text{UPPER}} \quad \forall \, i \in I, t \in T \]

Additionally, total outflows cannot be less than a minimum flow requirement:
\[ in_{i,t} + q_{i,t} - c_{i,t} \geq FL_{i,t}^{\text{LOWER}} \ast C_{i,t}^{\text{ELIG}} \quad \forall \, i \in I, t \in T \]
SI.4: Distribution of Prices

Figure S4 provides histograms of electricity and reserve prices from 2015 through 2017. All prices are for the day-ahead market in the CAISO NP15 zone, which includes our study system. Electricity prices are significantly greater than reserve prices, and regulation up and down prices are similar.

Figure S4: Histograms of prices from 2015 through 2017 for electricity (LMP), regulation up (RU), regulation down (RD), regulation up mileage (RMU), and regulation down mileage (RMD).
SI.5: Flow Constraints on Electricity Generation

Insufficient flows impose significant constraints on potential electricity generation on hydropower facilities (Figure S5). Consequently, even during periods with high electricity prices, such as the summer of 2015, no electricity generation occurs.

Figure S5: Maximum achievable capacity factors based on whether flows exceed minimum flow requirements at each facility (bars) by month across years. A value of 0 indicates flows never exceeded minimum flow requirements for a facility, so it could not generate electricity that month. A value of 1 indicates flows were sufficient for maximum electricity generation throughout the entire month for a facility.
SI.6: Daily Generation Profile of Hydropower Facilities

Under no maximum flow constraints, electricity generation by hydropower facilities peaks two times per day, in the late morning and early evening (Figure S6). This trend is less clear in 2015 than 2016 or 2017 because of insufficient flows for generation in much of 2015. This daily generation profile mirrors daily electricity price profiles (Figure S7), in which electricity prices peak in the late morning and early evening.

Figure S6: Total annual generation by each hydropower facility (lines) by hour of day in each year.
Figure S7: Average electricity prices (LMPs) by hour of day in each year.
SI.7: Change in Monthly Net Revenues with Maximum Flow Constraints

As with annual net revenues, imposing maximum flow constraints results in negligible decreases in monthly net revenues across hydropower facilities (Figure S8).

Figure S8: Monthly net revenues across hydropower facilities in 2015 (upper left), 2016 (upper right), and 2017 (bottom) without maximum flow constraints (“None”) and with maximum flow constraints (“0.05”, “0.5”, and “1”) across years.
Figure S9 depicts the combined daily generation profile of all hydropower facilities. Note that under maximum flow constraints, particularly the most stringent (0.05), the daily generation profile flattens as generation shifts from peak to off-peak hours. This occurs because the maximum flow constraint limits generation that can occur on peak hours, leading to hydropower facilities instead generating on off-peak hours. The largest change in the generation profile occurs in 2015, the dry hydrological year, when low flows in that year result in tighter constraints on discharges than in high flow years. For instance, if natural flows exceed the maximum discharge capacity of a facility (which occurs more in wet than dry hydrological years), then the maximum flow constraints do not limit the facility’s discharges and generation.
SI.9: Reservoir Use under Maximum Flow Constraints

By limiting discharges during peak price periods, imposing maximum flow constraints decreases use of storage reservoirs across facilities (Figure S10). From no maximum flow constraint to the 0.05 constraint scenario, reservoir use as measured by mileage decreases by 60% to 90%, with the largest decrease in the driest hydrological year, 2015, and the smallest increase in the wettest year, 2017. Expressed as a ratio relative to fully charging and discharging all facilities’ reservoirs once per day, reservoir use ranges from 0.5 to 2.5 from 2015 through 2017 under the 0.05 maximum flow constraint scenario, versus ranging from 3 to 6.5 under no flow constraint. Thus, even with flow constraints, reservoirs in the aggregate are charged and discharged regularly, but much less than without flow constraints.

Figure S10: Reservoir use, i.e., mileage, measured as the sum of the absolute value of changes in stored water between each time interval (left) and the ratio of that use to fully charging and discharging the reservoir each day (right) summed across hydropower facilities by year without maximum flow constraints (“None”) and with maximum flow constraints (“0.05”, “0.5”, and “1”).