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Net revenue and downstream flow impact trade-offs for a network of small-scale hydropower facilities in California

Michael Craig[1], Jin Zhao[2], Gia Schneider[2], Abe Schneider[2], Sterling Watson[2] and Greg Stark[1]

[1] National Renewable Energy Laboratory, 15013 Denver West Parkway, Golden, CO 80401, United States of America
[2] Natel Energy, 2401 Monarch Street, Alameda, CA 94501, United States of America

E-mail: Michael.Craig@nrel.gov

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Abstract

Deployment of small-scale hydropower, which generally ranges in capacity from 1-10 MW, may partly depend on its ability to mitigate environmental concerns while generating sufficient revenues. In this paper, we quantify net revenue and downstream flow impact trade-offs of a cascading series of 36 small-scale hydropower facilities under consideration for development in Northeast California. To do so, we develop a net-revenue-maximizing optimization model that determines hydropower operations while capturing key technical and river network constraints. We find that significantly constraining maximum discharges from each facility largely eliminates downstream flow impacts but negligibly changes the 36 facilities' combined operations and net revenues. Thus, we find a negligible trade-off between net revenues and downstream impacts in our study system, suggesting small-scale hydropower can contribute to decarbonization efforts while limiting local environmental impacts on downstream flows at little economic cost.

1. Introduction

In the United States, large-scale hydropower, which we loosely define as hydropower with an installed capacity of 50 MW or more, is the dominant hydropower technology. Total installed capacity of large-scale hydropower is 50 GW, or roughly 63% of total hydropower capacity (US Energy Information Administration 2017). Large-scale hydropower generates electricity without emitting greenhouse gases or local air pollutants, and can provide a flexible, dispatchable electricity source to balance variable and uncertain wind and solar generation with demand. However, significant expansion of the technology is challenged by several factors, including market uncertainty, low wholesale electricity prices, litigation risk, and concerns about environmental impacts (e.g., deforestation, changes in local habitat). Additionally, operations of large-scale facilities have the potential to kill fish and alter short- and long-term (e.g., hourly and seasonal) flow, temperature, and sediment regimes, which collectively affect water quality, wildlife, and ecosystems (Baxter 1977, Bunn and Arthington 2002, Trussart *et al* 2002)—issues that can be reduced and often avoided with small-scale hydro deployment, as discussed below. Nonetheless, these impacts have contributed to opposition to new construction, hindered licensing and relicensing by the US Federal Energy Regulatory Commission of existing facilities, and motivated several large dam removals (Kosnik 2005, 2008, 2010a, Abbasi and Abbasi 2011, US Army Corps of Engineers 2018, US National Park Service 2018). For these and other reasons, since 2000 hydropower capacity in the United States has grown less than 2% (Johnson and Hadjerioua 2015).

To reduce downstream impacts, large-scale hydropower can shift its operational profile from peaking or load-following, in which hydropower stores water for increased generation during high demand or price periods, toward run-of-river, in which hydropower uses available flows rather than stored water for generation. This shift aims to better approximate natural flows by avoiding large swings in downstream flows. Several papers have assessed the extent to which such an operational shift affects electricity generation and revenues

(Kotchen *et al* 2006, Jager and Bevelhimer 2007, Beilfuss 2010, Ziv *et al* 2012, Kern *et al* 2012). (Kern *et al* 2012) quantified net revenues under different operational strategies for large-scale hydropower in the PJM Interconnection, a deregulated electricity market in the United States. They found that shifting from revenue-driven operations to run-of-river operations results in more natural flow regimes but large (up to 15%) revenue reductions. (Beilfuss 2010) assessed trade-offs between flows and electricity generation among three large hydropower facilities in Mozambique during a 97-year period. They found that re-creating natural flows requires large reductions in electricity generation and firm capacity except during high flow months. (Jager and Bevelhimer 2007) conducted a retrospective analysis of large hydropower facilities in the United States that changed their licenses from peaking to run-of-river operations. For most facilities, they found that change reduces generation efficiency and flows during peak demand periods.

Overall, these papers indicate that decreasing environmental impacts through operational changes may significantly reduce electricity generation and revenues for large-scale hydropower. However, alternate hydropower technologies exist that may not face such trade-offs. In particular, this paper focuses on small-scale hydropower, which is often defined as ranging in capacity from 1–10 MW (Paish 2002, Kosnik 2010b, International Renewable Energy Agency 2012, Kelly-Richards *et al* 2017). Small-scale hydropower has a total installed capacity in the United States of only 6 GW (US Energy Information Administration 2017), but substantial resources exist for additional deployment (Johnson and Hadjerioua 2015).

While small-scale hydropower can have similar types of environmental impacts as large-scale hydropower (discussed above), small-scale hydropower entails smaller reservoirs and requires less flows for electricity generation than large-scale hydropower (Bakken *et al* 2012). Consequently, small-scale hydropower can disrupt the local environment and downstream flows of a given river less than large-scale hydropower (Egré and Milewski 2002, Bakken *et al* 2012). However, small-scale hydropower can be deployed in streams that are too small for large-scale hydropower development. In these cases, small-scale hydropower operations can affect a large fraction of natural flows and incur large changes in downstream flows, analogous to large-scale hydropower on large rivers (Abbasi and Abbasi 2011, Pang *et al* 2015, Kelly-Richards *et al* 2017). Limiting small-scale hydropower operations might mitigate such impacts on downstream flows, but how such operational changes might affect net revenues remains unclear (Kelly-Richards *et al* 2017). In areas with strict environmental impact regulations, this trade-off between revenues and downstream flow impacts might inform the potential for small-scale hydropower deployment.

To understand how mitigating downstream impacts of small-scale hydropower affects its electricity generation and revenues and, in turn, growth potential, we quantify net revenue and downstream flow impact trade-offs of a cascading series of 36 small-scale hydropower facilities under consideration for development in Northeast California. To do so, we develop a net-revenue-maximizing optimization model that determines hydropower operations while capturing key technical and river network constraints. With this model, we then quantify economic and environmental trade-offs by comparing electricity generation and net revenues without and with maximum flow constraints that limit downstream flow increases resulting from hydropower operations to as little as 5%.

2. Methods

2.1. Study system

We quantify trade-offs between downstream impacts and net revenues for a series of 36 small-scale hydropower facilities under consideration for development in Northeast California. We assume the facilities are owned and operated by a single entity. Development of the facilities would require new construction of small dams and impoundment areas, impacts of which are outside the scope of our analysis. Each facility uses one of two hydroEngine models developed by Natel Energy (Natel Energy 2018). The hydroEngines are Linear Pelton impulse turbines, which direct water jets into buckets to turn an attached wheel and turbine. Their design allows the hydroEngines to increase their power output from zero to their maximum capacity or vice versa within a few minutes and to generate electricity at low head and discharge levels.

The 36 facilities primarily differ in their net head heights, power capacities, and reservoir storage. The former two parameters primarily vary by hydroEngine type (table 1). Total power capacity across facilities equals 33.5 MW. With respect to reservoir storage, all 36 facilities have 2 m deep forebay reservoirs. These reservoirs have storage capacities of 700–49,000 m^3, or 0.02–0.77 MWh of potential generation. Summed across facilities, total stored potential generation equals 8.82 MWh. Due to the cascading nature of the 36 facilities, reservoir discharges from each facility may be used for generation not only at that facility (quantified above), but also at downstream facilities. Accounting for this potential downstream generation yields storage generation potentials of 0.59–5.98 MWh across facilities and 87 MWh summed across facilities.

Table 1. Mean (across facilities) and range of values of key facility parameters by hydroEngine type.

Hydro engine type	Number of facilities	Maximum turbine discharge [$m^3 s^{-1}$]	Average (min–max) net head height [m]	Average (min–max) power output at max head height [MW]
1	32	8.1	17.2 (16.2–18.4)	1.0 (0.93–1.06)
2	4	10	6.9 (6.5–7.2)	0.5 (0.46–0.51)

To leverage historic flow data and ground our analysis in the real world, we use the Yuba River in Northeast California as our study system. We model the 36 hydropower facilities in series over a 36-km stretch of the river with a total elevation drop of roughly 750 m (see supplemental information (SI) (available online at stacks.iop.org/ERC/1/011001/mmedia) section SI.1 for elevations and drainage area). We obtain 15-min flow data from Goodyear Bar, the nearest available location on the Yuba River, from the US Geological Survey (US Geological Survey 2018). Because Goodyear Bar is downstream from the farthest downstream facility (by roughly 0.3 km), we obtain facility-specific flows by scaling down flows at Goodyear Bar based on the ratio of each facility's drainage area to Goodyear Bar's drainage area. This ratio varies from 0.23 to 0.92. To capture a range of hydrological conditions, we conduct our analysis using flow data from 2015, 2016, and 2017, which represent dry, typical, and wet meteorological years, respectively (SI.2).

2.2. Optimization model

To quantify trade-offs between net revenues and downstream impacts, we determine electricity generation and ancillary service provision by each hydropower facility using a net-revenue-maximizing optimization model that limits downstream flow impacts and captures cascading flows among facilities, reservoir options, and nonlinear electricity generation and volume relationships (SI.3). Net revenues equal energy and ancillary service revenues, including mileage payments (Hinman 2015, California ISO 2016), minus variable operation and maintenance (VOM) costs, which equal \$24/MWh for all facilities. Given the small total installed capacity of the hydropower facilities (33.5 MW) relative to the total installed capacity in the California Independent System Operator (CAISO) (more than 50,000 MW) (California ISO 2018), we assume that the facilities are price takers, i.e., they do not affect electricity or ancillary service prices. Consequently, we optimize operations using historic, day-ahead, hourly energy and ancillary service prices from CAISO's northern zone (NP15) for 2015 through 2017 (California ISO 2017) (SI.4). To balance computational requirements with optimizing operations given water traversal times from the first to last facility (15 h) and reservoir storage potential (up to 1.3 h of operations), we run our model over a 15 h window plus a 2 h look-ahead period.

To constrain downstream flow impacts, we enforce maximum flow constraints at each hydropower facility. These constraints limit each facility's discharges to increasing natural downstream flows, i.e. flows prior to deployment of the hydropower facilities (see section 2.1), by 5% to 100%. In other words, in the 100% scenario, each facility's discharges can result in downstream flows that are up to double natural flows. Throughout our analysis, we also include a minimum flow constraint at Goodyear Bar of 2.8 $m^3 s^{-1}$. This constraint approximates statutory requirements, which are not available for Yuba River. To translate this minimum flow constraint to facility-specific constraints, we scale it down using the same approach as when scaling flows.

Because the 36 facilities are arrayed in series on the Yuba River, discharges from upstream facilities alter flows at downstream units. To capture this dynamic, for each facility we divide inflows into 'cascading' and 'tributary' flows, or flows that can and cannot be affected by the adjacent upstream facility. Tributary flows equal the difference between adjacent facilities' portion of Goodyear Bar flows because that difference indicates flows entering the river between adjacent facilities. Cascading flows vary with facility operations (discharges and reservoir inflows) in our model. Our model also includes traversal times (up to 15 h) of cascading flows between facilities.

To account for the nonlinear dependence of electricity generation on discharge levels and head heights and of forebay reservoir volume on forebay reservoir depth, we include all three relationships using piecewise linear approximations with two segments in our model (Borghetti *et al* 2008). Our model also includes constraints on electricity generation, reserve provision, and ramping applicable to all generation technologies, e.g., maximum generation limits. To capture the deployment of provided regulation up and down reserves, our model also accounts for increases or decreases in electricity generation caused by the provision of regulation up and down reserves, respectively, in each time interval by assuming a net energy ratio of 10%. For instance, 10 MW of provided regulation up reserves incurs 1 MWh of electricity generation in an hour and associated VOM costs.

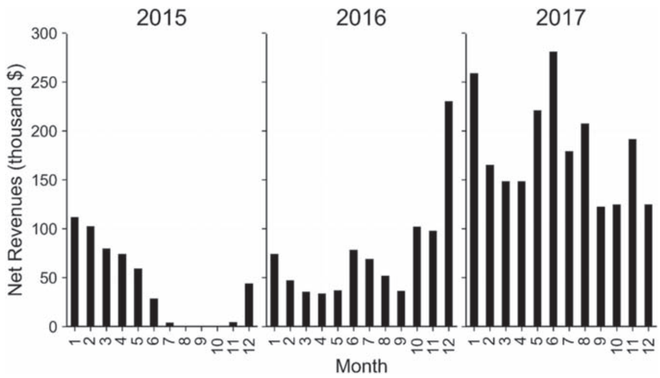

Figure 1. Net revenues among hydropower facilities by month in each year.

Table 2. Annual net revenues, electricity generation, and regulation up provision among hydropower facilities.

Year (hydrological conditions)	Annual net revenue (million $)	Annual electricity generation (GWh)	Annual regulation up provision (GWh)
2015 (dry)	0.5	55	0.1
2016 (typical)	0.9	93	0.1
2017 (wet)	2.2	142	0.1

3. Results

We first provide operations and net revenues of the hydropower facilities with only minimum flow requirements based on environmental regulations. We then test the sensitivity of those results to adding various maximum flow constraints. Throughout our analysis, we optimize operations across electricity generation and regulation up provision for computational efficiency and because results differ negligibly when optimizing instead across electricity generation and regulation down reserves.

3.1. Operations and net revenues with minimum flow requirements based on environmental regulations

In each year, the hydropower facilities primarily provide electricity generation (55–142 GWh annually across years) rather than regulation up reserves (0.1 GWh across years) (table 2). Optimizing for electricity generation and regulation down provision yields similar results, with hydropower facilities almost exclusively providing electricity generation (55–142 GWh annually across years) rather than regulation down provision (0.1–0.2 GWh across years). Because of increased available resources, electricity generation is greatest in 2017, the wet hydrological year, and least in 2015, the dry hydrological year. Differences in electricity generation and prices drive differences in net revenues, which equal $0.5, $0.9, and $2.2 million in 2015, 2016, and 2017, respectively.

Net revenues vary significantly across months in each year (figure 1), reflecting insufficient prices for profitable operations in some periods and insufficient water availability for operations in other periods. In 2015, the dry meteorological year, monthly net revenues are lowest in the summer (July–September) despite high electricity prices because of river flows less than minimum requirements (SI.5). In other years, net revenues are highest in winter (2016) and late spring through early summer (2017).

To take advantage of high electricity prices, electricity generation by hydropower facilities peaks in the late morning and early evening (SI.6). Two factors drive this daily generation profile. First, each hydropower facility has a small reservoir in which they can store water, allowing them to shift their generation to high price hours. Second, low overnight and midday prices often do not exceed facilities' VOM costs, resulting in less generation in those hours than in high price periods.

Although it maximizes net revenues, this daily generation profile of peak electricity generation in the late morning and early evening results in large increases and decreases in downstream flows (figure 2). For instance, in 2016, hydropower facilities increase natural flows by up to 2 to 11 times, significantly altering downstream conditions. Across years and facilities, the 85th percentile of downstream flow changes ranges up to an increase of 55%, such that even greater flow increases occur in 15% of time periods. Increases in downstream natural flows are greater in 2015, the dry hydrological year, than in 2016 or 2017 because of low natural flows. Despite complying with the minimum flow requirement, the minimum and 15th percentile of downstream flow changes across years and facilities range up to decreases of 98% and 53%, respectively.

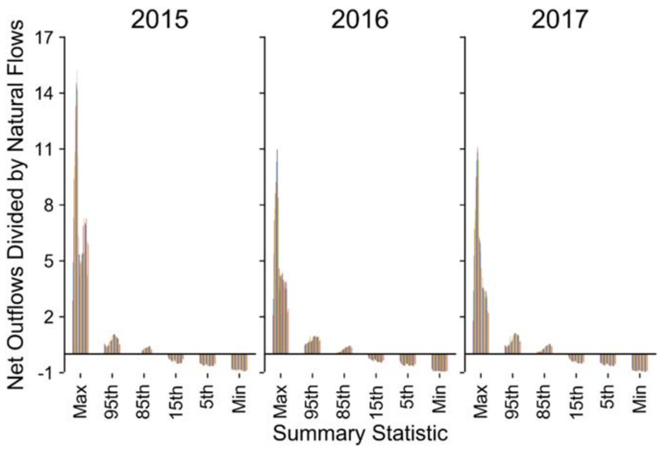

Figure 2. Summary statistics for net outflows, which equal total outflows minus natural flows at each facility, divided by natural flows for each hydropower facility (bars) in each year. Summary statistics are maximum; minimum; and 95th, 85th, 15th, and 5th percentiles. A value of 1 indicates facility operations double downstream flows, and a value of −1 indicates operations eliminate downstream flows (which is prevented by the minimum flow requirement).

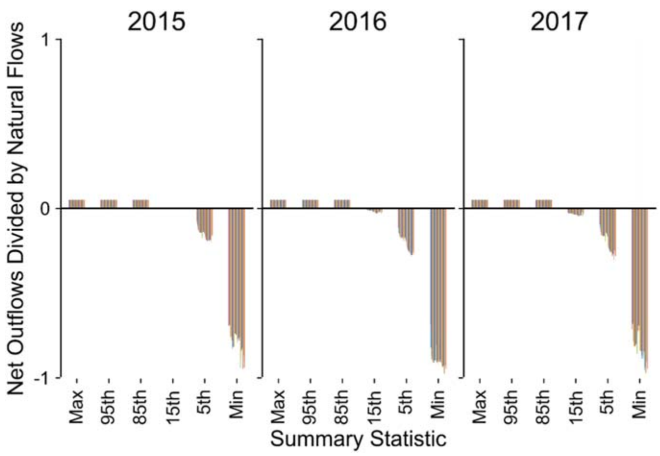

Figure 3. Summary statistics for net outflow divided by natural flows for each hydropower facility (bars) in each year under the 0.05 maximum flow constraint. Summary statistics are maximum; minimum; and 95th, 85th, 15th, and 5th percentiles. A value of 1 indicates facility operations double downstream flows, and a value of −1 indicates operations eliminate downstream flows (which is prevented by the minimum flow requirement).

3.2. Operations and net revenues with minimum and maximum flow constraints

To quantify economic and environmental trade-offs, we compare electricity generation and net revenues from the prior section, i.e., without maximum flow constraints (‘None’ scenario), to those with maximum flow constraints. We test maximum flow constraints that limit turbine discharges to up to 5%, 50%, and 100% more than natural flows (‘0.05’, ‘0.5’, and ‘1’ scenarios, respectively). These constraints effectively limit downstream flow increases (figure 3), e.g., by reducing maximum increases in downstream flows from up to 1,600% (figure 2) to up to 5%. The maximum flow constraints also mitigate downstream flow decreases resulting from facility operations. For instance, across years and facilities, the 15th percentile of downstream flow changes decreases from an increase of up to 53% to an increase of up to 5%, and the 5th percentile of downstream flow changes decreases from a decrease of up to 67% to a decrease of up to 32%. Fewer benefits occur for the largest downstream flow reductions.

Despite significantly mitigating downstream flow increases and decreases, maximum flow constraints have a negligible effect on electricity generation or net revenues across years (figure 4). In the 0.05 scenario, in which hydropower operations cannot increase natural flows by more than 5%, annual net revenues decrease by less than 4% across years. However, this decrease is within the optimality gap of our model (5%), so we cannot state net revenues would actually change under maximum flow constraints. Monthly net revenues also change negligibly with maximum flow constraints (SI.7).

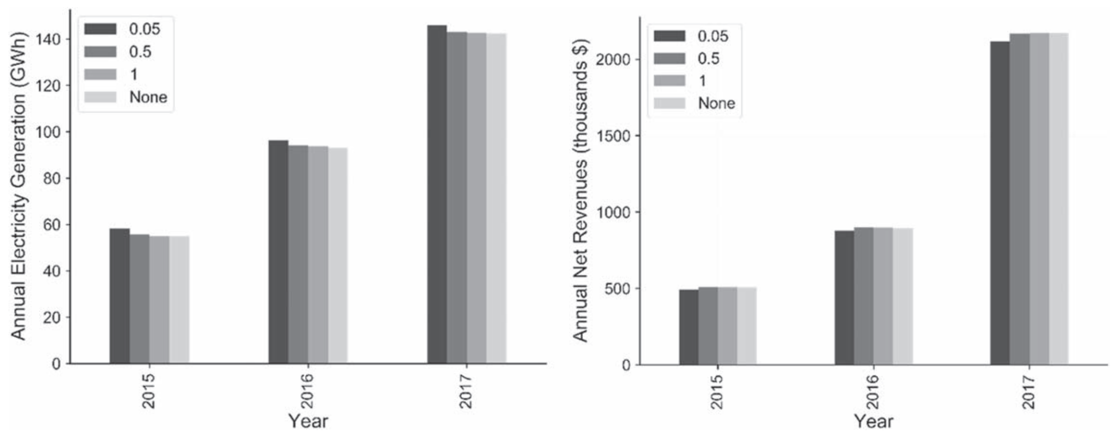

Figure 4. Annual electricity generation (left) and net revenues (right) among hydropower facilities without maximum flow constraints ('None') and with maximum flow constraints ('0.05', '0.5', and '1') in each year.

Contrary to net revenues, imposing maximum flow constraints increases electricity generation by up to 6% across years, although these changes are also within our model's optimality gap, except in 2015 under the 0.05 maximum flow constraint. Maximum flow constraints drive increased electricity generation by shifting generation from peak to off-peak hours or by flattening facilities' daily generation profiles (SI.8). For instance, imposing the 0.05 maximum flow constraint in 2015 increases total generation from 1.6 to 1.9 GWh at 2 p.m. PST (an off-peak hour) and decreases total generation from 3.1 to 2.7 GWh at 7 p.m. PST (a peak hour). Increased generation with maximum flow constraints does not translate to increased net revenues because increased generation occurs in lower price periods. By shifting generation from peak to off-peak hours, imposing maximum flow constraints also reduces reservoir discharge at peak price periods, which decreases the use of storage reservoirs among facilities (SI.9).

Although total net revenues of all hydropower facilities decrease under maximum flow constraints, net revenues increase for upstream facilities and decrease for downstream facilities (figure 5). Further, from no constraint to the 0.05 maximum flow constraint scenario, per-facility changes in net revenues, which vary from −14% to 28% across years and facilities, greatly exceed changes in total net revenues, which are less than 4%. Without maximum flow constraints, the interconnected nature of the hydropower facilities, which we capture through temporally lagged cascading flows between facilities, results in upstream facilities discharging water so it reaches downstream facilities at high price periods. However, constraining maximum flows limits the ability of downstream facilities to generate electricity during high price periods, disincentivizing upstream facilities to operate in that behavior. Consequently, because of maximum flow constraints, upstream facilities operate in a manner that increases their net revenues at the expense of downstream facilities' net revenues. Thus, the interconnected nature of the small-scale hydropower network mitigates net revenue reductions caused by maximum flow constraints, resulting in negligible overall net revenue reductions.

4. Discussion

Deployment of small-scale hydropower might partly depend on its ability to earn revenues while minimizing downstream impacts. To assess this trade-off, we quantified electricity generation and net revenues for a proposed deployment of 36 small-scale hydropower facilities in series in Northeast California without and with maximum flow constraints. From dry to wet hydrological years, we found that the hydropower facilities primarily generated electricity rather than provide reserves, and they accrued \$0.5–\$2.2 million in annual net revenues without maximum flow constraints. Electricity generation by the hydropower facilities peaked in the late morning and early evening, resulting in significant increases and decreases to natural flows. Under maximum flow constraints that limited natural flow increases from hydropower operations to as little as 5%, we found negligible changes in electricity generation or net revenues but substantial mitigation of downstream flow changes. Relative to no maximum flow constraints, annual net revenues decreased by less than 4% under maximum flow constraints across years. Notably, this decrease is within our model's optimality gap and therefore not clearly different than net revenues without maximum flow constraints. Thus, we found a negligible trade-off between net revenues and downstream impacts for our study system.

The large inter-annual variability in net revenues (from \$0.5–\$2.2 million) we document has several implications for small-scale hydropower development. First, reducing variable O&M costs would likely reduce

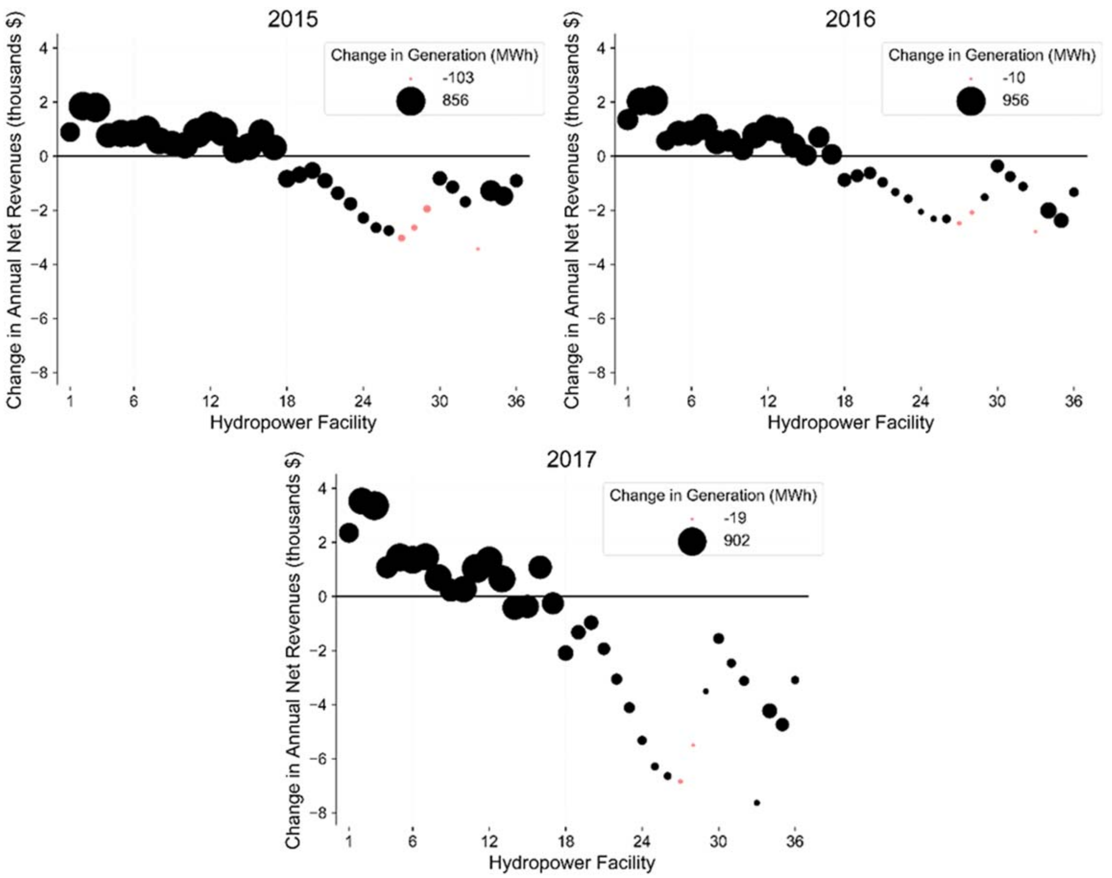

Figure 5. Change in annual net revenues for each hydropower facility in each year from no maximum flow constraints to the 0.05 maximum flow constraint scenario. Points are scaled based on the magnitude of each facility's change in electricity generation and colored based on whether each facility's generation increased (black) or decreased (pink) between the same two scenarios. Hydropower facility 1 is the farthest upstream.

this variability by enabling more periods of profitable operation by the facilities, although inter-annual variability in hydrological conditions will still lead to inter-annual variability in net revenues. Consequently, small-scale hydropower developers would need to be able to tolerate periods with low revenues, which could make securing financing and servicing debts more difficult. To mitigate such periods, developers could leverage a portfolio that includes technologies with complementary revenue profiles, i.e. technologies that earn high revenues when small-scale hydropower earns little revenues (Street *et al* 2009). Large inter-annual variability also necessitates longer monitoring of potential development locations. If net revenues didn't significantly fluctuate inter-annually, one or less than one year of stream flow and market price data would yield a fair estimate of annual operations and revenues. Conversely, in our study system, net revenues vary inter-annually by more than a factor of four, indicating long-term data collection might be necessary to estimate long-term revenues.

The main driver of negligible declines in net revenues under strict maximum flow constraints is the interconnected nature of the 36 hydropower facilities. Although total net revenues slightly decrease, per-facility net revenues increase for upstream facilities and decrease for downstream facilities. These competing changes largely cancel out, resulting in negligible changes in total revenues. Net revenue changes differ for upstream versus downstream facilities because maximum flow constraints limit the peaking behavior of downstream facilities, which in turn allows upstream facilities to operate in a manner that increases their own net revenues. Large-scale hydropower is typically not deployed with as many facilities in close proximity, which likely explains why our results differ from prior literature showing large trade-offs between net revenues and downstream impacts for large-scale hydropower (Kotchen *et al* 2006, Jager and Bevelhimer 2007, Kern *et al* 2012).

Our results have several insights for policymakers. In our study system and assuming a single owner of 36 cascading small-scale hydropower facilities, we demonstrate small-scale hydropower can reduce their downstream flow impacts at negligible economic cost. This indicates a potential economic and environmental win-win that policymakers can exploit, although future research should explore the sensitivity of our results to other regions and to splitting ownership of the cascading facilities across multiple entities (Faria *et al* 2009). When considering policies related to small-scale hydropower, policymakers should also carefully weigh how small-scale hydropower operations affect the rest of the power system. While we focus here on small-scale hydropower's immediate downstream flow impacts, its environmental impacts will also differ depending on whether it displaces other zero-emission technologies, e.g. large-scale hydropower, versus fossil fuels. Depending on which technologies it displaces and on the results of future research on economic and environmental trade-offs in other regions, small-scale hydropower could make a large contribution to reducing environmental impacts of the power system, since ample opportunity for small-scale hydropower development exists in the United States (Johnson and Hadjerioua 2015).

Several opportunities exist for future research. First, rather than conduct a detailed analysis for a single study system, future research could use a simplified model to assess trade-offs for several potential small-scale hydropower sites across the United States. Second, other small-scale hydropower technologies exist with different characteristics than the Linear Pelton turbines studied here (Paish 2002, Kelly-Richards *et al* 2017). These alternate characteristics might lead to different economic and environmental trade-offs. Third, future research should grapple with how uncertain factors might affect small-scale hydropower planning and operations. For instance, long-term weather variability might alter hydrological conditions, which in turn might affect net revenues and trade-offs of small-scale hydropower. Although we include dry, typical, and wet hydrological years in our analysis to improve the robustness of our results, climate change might result in wetter and drier hydrological years than tested here (US Global Change Research Program 2017). Other sources of uncertainty that future research should capture include policy changes that constrain (e.g., environmental requirements) or incentivize (e.g., deployment subsidies) small-scale hydropower. Finally, future research should explore how small-scale hydropower design and operation can enable stream restoration, such as by reducing energy in flood flows in conjunction with creating habitat, e.g. by adding large woody debris. Such research would extend our results, which indicate that small-scale hydropower operations can limit downstream flow impacts at little economic cost, from streamflow impact mitigation to stream restoration.

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ORCID iDs

Michael Craig https://orcid.org/0000-0002-3031-5041

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