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Assessing climate change impacts on California hydropower generation and ancillary services provision

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Abstract

Climate change is expected to significantly reshape hydropower generation in California. However, the impact on the ability of hydropower to provide reserve capacity that can provide on-demand, back-up electricity generation to stabilize the grid in the case of a contingency has not been explored. This study examined the impact of climate change-driven hydrologic shifts on hydropower contributions to generation and ancillary services. We used projections from four climate models under Representative Concentration Pathways (RCP) RCP4.5 and RCP8.5 to evaluate the impact of climate change conditions, comparing the future period 2046–2055 to the baseline 2000–2009, and observed a net increase of inflow into large hydropower units in northern California. However, as extreme events yield greater spillage, increased overall inflow did not necessarily yield increased generation. Additionally, higher winter generation and summer reservoir constraints resulted in decreases in the spinning reserve potential for both RCP scenarios. We also examined a regionally downscaled "long drought" scenario under RCP8.5 to assess the impact of an extended dry period on generation and spinning reserve bidding. The long drought scenario, developed as part of the California 4th Climate Assessment, involves rainfall congruent with 20-year historical dry spells in California under increased temperatures. In addition to decreased generation, the long drought scenario yielded a 41% reduction in spinning reserve bidding tied to a decline in reservoir levels. The decreased spinning reserve bidding from hydropower may require increased reliance on other electricity resources that can provide the same dynamic support to maintain grid stability under climate change.

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1 Introduction

Climate change is projected to shift the temporal and spatial availability of water across the globe (IPCC 2013). Shifts in regional hydrology may have significant impacts on electricity generation dispatch, electric grid reliability, and regional emissions (Hardin et al. 2017). In California, where hydroelectric capacity mainly resides in the Sierra Nevada, inflow to reservoirs has historically been regulated by the melting snowpack. The slow release of water, peaking in spring, allows for hydropower plants to deliver important load-following and peak support throughout the year and most critically during summer when electricity demand is high (CAISO 2008).

Hydropower also provides key ancillary services (FERC 2001). Ancillary services refer to functions that power plants (e.g., hydropower facilities) provide to maintain the reliability and resilience of electricity service against sudden disruptions and unexpected imbalances in the system (CAISO 2006). In California, hydropower's main contribution to ancillary services is spinning reserve, which refers to capacity that can be engaged to provide generation in the event of a loss of transmission or generation capacity, or unexpected load (or net load) fluctuations to the electricity system to maintain the ability of the system to meet electricity demand (CAISO 2017). In order to participate in the spinning reserve market, hydropower plants are required to provide the committed capacity within 10 min and be able to stay online for 2 h (CAISO 2006). Capacity accepted into the spinning reserve market will only be called upon in the case of a contingency or unexpected system fluctuation that requires additional power to balance the load. When spinning reserves are called, the dispatch time may vary depending on the type of disturbance and the rate of recovery of the system. This means that only a portion of pledged resources will actually be required to dispatch power and in the case where resources are not dispatched, revenue can be earned without loss of water storage. Hydropower has historically provided roughly 50–65% of California's spinning reserve depending on reservoir conditions (CAISO 2017). Hydropower services for generation and ancillary services become increasingly important as the percentage of variable renewable generation grows in order to ensure a balanced grid (Chang et al. 2013).

However, projected temporal and spatial shifts in hydrology under climate change conditions may jeopardize these services. Simulations of climate warming have projected seasonal shifts in runoff, decreased snowpack, and increased winter runoff (Stewart et al. 2005; Vicuna and Dracup 2007). Under this new regime, reservoirs are expected to reach capacity sooner in the year, and the increased fill rate may result in increased spilling for reservoirs with limited storage capacities. In winter, increased inflow may yield greater hydropower generation, but in summer, reduced inflow may yield decreased generation due to greater reservoir constraints (Vine 2012).

Understanding the impact of these hydrologic changes on ancillary service bidding is important for predicting and preparing for future changes in hydropower. In general, hydropower spinning reserve bidding is highly dependent on bid commitments that a hydropower plant makes towards providing bulk generation and the constraints of reservoir conditions. Inflow into California reservoirs can vary greatly between years and between different seasons. As reservoir conditions vary throughout the year and from year to year, the potential for a given hydropower plant to provide ancillary services varies with them. Periods of high and low water reservoir conditions both result in decreased spinning reserve bidding. During periods where generation bids dominate due to high reservoir conditions, fewer hydropower units will bid into the spinning reserve market as the two are inversely related. Alternatively, during the

recent 2012–2017 drought, California relied on natural gas to provide load-following, peaking, and ancillary services in the absence of hydropower potential (CAISO 2008; U.S. Energy Information Administration 2014). Decreased hydropower participation in generation and spinning reserve markets can drive up electricity prices and increase the use of natural gas plants and imports to satisfy load and reserve requirements, respectively (CAISO 2017).

2 Background

Several studies have examined the potential impact of climate change on hydropower within California (Madani et al. 2014; E. P. Maurer et al. 2007; Medellín-Azuara et al. 2008; Null and Viers 2012; Vicuña et al. 2011); however, these studies did not examine the subsequent impact on ancillary service bidding. Comparing these studies, we observed that some regions in California are more susceptible to climate forcing, resulting in higher magnitudes of change. Madani et al. (2014) found that high elevation hydropower with low reservoir capacities and high hydraulic heads are sensitive to small shifts in runoff, leading to large impacts on hydropower operations under climate change. Vicuña et al. (2011) found that northern and southern California hydropower experience different degrees of warming and changes in precipitation, with southern California experiencing greater annual reduction in runoff. Additionally, Diffenbaugh et al. (2015) found that there is an increased risk of drought in California under climate change.

Although projections for total runoff changes vary between studies and climate scenarios (Cayan et al. 2008; Edwin P. Maurer and Duffy 2005; Zhu et al. 2005), a shift towards earlier runoff is predicted in all scenarios due to more precipitation falling as rain rather than snow (Hayhoe et al. 2004; Knowles et al. 2006). Whereas snowfall results in a relatively slow release of water as the snowpack melts, rain events produce greater runoff over a short period of time, which is more likely to trigger reservoir spillage (Georgakakos et al. 2012). A shift towards earlier runoff and an increased risk of spillage may result in greater constraints on reservoirs during summer when hydropower serves a pivotal role in supporting peak load demand (Null and Viers 2012; Tarroja et al. 2016).

However, the impacts of climate change on regional hydrology do not directly translate to impacts on hydropower. Hydropower units have a range of flexibility to capture, store, and dispense water. Systems with large storage capacities may see little to no impact from increased runoff during winter and spring (Vicuna et al. 2008), as they have the ability to manage the increase in inflow. On the other hand, systems with small storage capacities and high hydraulic heads are sensitive to small shifts in runoff, and experience higher rates of spillage, leading to decreased generation potential especially during summer (Madani et al. 2014).

Data on the contribution of individual hydropower plants to ancillary services are limited, which has resulted in a lack of studies on the impact of climate change on these services (CAISO 2017; Electric Power Research Institute 2013; Federal Energy Regulatory Commission 2001; Loose 2011). In general, hydropower plants associated with large reservoirs fully participate in ancillary service markets, whereas plants with small reservoirs have limited participation, and run-of-the-river have none (Gaudard and Romerio 2014). Available data for the hydropower units owned by the Bureau of Land Reclamation support this generalization (U.S. Bureau of Reclamation n.d.). Restrictions for participating in ancillary services include outflow constraints, reservoir capacity, and pricing versus operating costs (Electric Power Research Institute 2013). Reservoir conditions, which can change daily, seasonally, and

annually, affect participation in ancillary services. CAISO market reports indicate that high hydropower production in spring can result in reduced ancillary market participation in summer (CAISO 2008).

Previous studies examining future hydropower participation in ancillary services mostly focus on new management and market strategies to increase hydropower participation in ancillary service markets (Deng et al. 2006; Doorman and Nygreen 2002; Ehsani et al. 2009; Gaudard and Romerio 2014). These studies present hourly bidding strategies that optimize simultaneous participation in multiple markets to maximize revenue, however, all but one ignore projected future climate conditions. Gaudard and Romerio (2014) discusses the potential impacts of climate change on hydropower dispatch, but does not model climate forcing changes to ancillary service market participation.

While the topic of climate change impacts on hydropower generation has been investigated in the literature, the majority of these studies have typically assessed hydropower generation at the monthly timescales (Null and Viers 2012; Tanaka et al. 2006; Vicuna et al. 2008). Few studies have resolved the impacts of climate change on hydropower to the temporal resolution necessary for interfacing with the electric grid, which requires hourly or shorter timescales (Guégan et al. 2012; Tarroja et al. 2016). Neither of these studies model climate impacts on bidding into ancillary service markets. Guégan et al. (2012) investigates projected climate impacts on electricity demand and pricing, partnering these changes to updated hydrologic conditions to determine the impact on future hydropower revenue from generation. Tarroja et al. (2016) examines the impact of dispatched hydropower generation under climate change conditions on grid performance and GHG emissions. While it discusses the resulting change in reservoir levels due to projected future inflows under climate change, the impact on the reserve capacity available to provide additional grid support through ancillary services is not quantified.

This study aims to use higher temporal resolution analyses at the hourly and daily timescales to capture the impact of climate change on ancillary service provisions, as there is a current gap in understanding how climate change impacts may influence ancillary service participation assuming historical market strategies. In particular, this study seeks to evaluate how changes in reservoir conditions under projected future inflow will translate to changes in operational capacity available for providing ancillary services. To this end, the study pairs a networked reservoir model with a high-resolution, multi-market bidding optimization for the grid to understand the simultaneous impacts of future reservoir constraints on different markets. Additionally, we will test the impact of a projected extreme condition of a "long drought" on available ancillary service provisions.

3 Methodology

An overview of the general methodology is provided in Fig. 1.

3.1 Scope

We investigated climate change impacts on hydropower by comparing the historical baseline of 2000–2009 to the years 2046–2055 as projected by Representative Concentration Pathways (RCP) RCP4.5 and RCP8.5. We accomplished this by identifying changes in hydropower generation and participation in ancillary service markets.

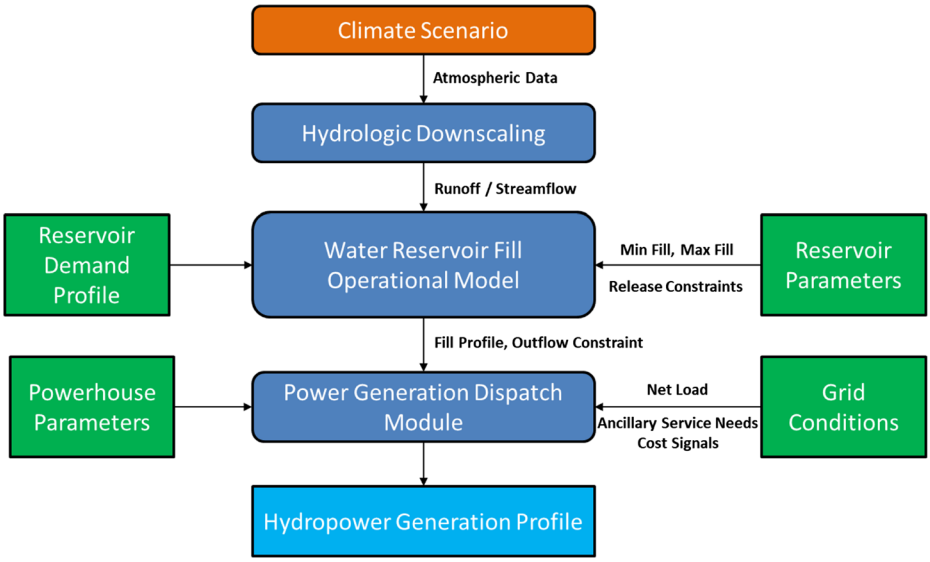

Fig. 1 Flowchart of the methodological framework

We considered hydropower plants identified as "large hydropower" by the California Energy Commission (CEC) for this analysis (California Energy Commission 2017). "Large hydropower" plants tend to have a capacity greater than 30 MW and generate electricity on the scale of 10^5 MWh or greater annually. If a hydropower unit had significant data gaps preventing the calculation of inflow and reservoir profile matching, we did not model the hydropower unit. Some large hydropower plants were ultimately not included in this analysis due to 1) significant gaps in reservoir data (less than 60% for either inflow or reservoir storage for the calibration period or little or no data for both total inflow and outflow through the reservoir for the historical period) and/or 2) incongruence between historical water data and historical electricity generation (i.e., a clear correlation between inflow, modeled outflow, and calculated generation could not be drawn). A complete list of the hydropower plants included in this study can be found in online resource 1.

Hydropower units were categorized as "dispatchable" or "non-dispatchable," based on the size of the most proximate reservoir. In general, the term "dispatchable" refers to power plants that are capable of ramping their output up or down in response to a load signal. Hydropower units with large reservoirs are able to time the release of water through their turbines to correspond to electricity demand on the grid, making them dispatchable. Run-of-the-river plants with small or no reservoirs do not have the same flexibility and their electricity generation is more strongly tied to the flow of the river on which they are situated. For this study, dispatchable hydropower units were assumed to 1) have a large enough storage capacity to retain inflow and dispatch it with demand beyond the daily timescale, 2) manage outflow throughout the day to respond to changes in electricity demand, and 3) participate in ancillary service markets. For this study, the minimum dispatchable capacity for the applied reservoir model to adequately simulate reservoir level dynamics was found to be 16 thousand acre-feet (TAF). Hydropower units with reservoirs that did not meet the above limitation or did not have associated reservoirs were considered non-dispatchable and it was assumed that generation potential varies directly with changes in inflow.

Hydropower units identified as being downstream from another hydropower unit were assumed to directly receive the outflow of that hydropower unit. Dispatch decisions were made for the first hydropower unit and the results from the first unit were the input for the next in the series. The downstream unit then dispatches this inflow based on its own reservoir demands and constraints.

3.2 Historical data

Historical data were retrieved from the California Data Exchange Center (Department of Water Resources 2017), the United States Geological Survey (USGS) (USGS Water Resources 2017), and Pacific Gas and Electric Company (PG&E). Water data are temporally resolved at the daily timescale. Available USGS gauges for inflow, outflow, and reservoir data were determined from USGS schematics (US Geological Survey California Water Science Center 2011). The following parameters were taken from historical data for each hydropower unit: total reservoir capacity, hydraulic head, power capacity, instream water demands, water delivery constraints, and minimum/maximum flow constraints. Many of these values were taken directly from Null and Viers 2012 and Tarroja et al. (2014).

In cases where inflow data were unavailable or incomplete, inflow was calculated as follows:

$$Q_{in} = dS + Q_{out,tot} \tag{1}$$

This calculation assumes that inflow must be accounted for either by a change in storage (dS) or outflow ($Q_{\mathrm{out,tot}}$) from the reservoir. This equation was derived from assumptions previously made by Pacific Gas and Electric Co (PG&E) for its management of its hydropower reservoirs and the results of the reservoir model with the calculated inflow were validated against known historical generation data.

3.3 Reservoir model

The reservoir model applied in this analysis was previously used by Tarroja et al. (2014) and was designed to be applied to hydropower units with a large storage capacity. Reservoir dispatch is resolved at the day scale and is based on previous monthly reservoir model work (van Beek et al. 2011; Haddeland et al. 2006; Hanasaki et al. 2006).

The modeling of the California reservoir system is accomplished by creating simple models of each individual reservoir. The individual reservoir model takes inputs of daily-resolved inflow and demand, initial fill level, minimum and maximum reservoir levels, as well as constraints for minimum environmental flows and maximum release flows for flood control. This model uses these inputs to determine daily-resolved water releases from each of these reservoirs, using a rule-based algorithm to minimize spillage while satisfying reservoir demand, reservoir capacity, and flood control constraints. The objective of minimizing spillage is supported by Null and Viers (2012).

Reservoir operation was simulated using baseline data for a historical period of 2000 to 2009. The base inflow is perturbed using gridded runoff to simulate projected climate change conditions for the different future scenarios (See Section 3.5). The parameters for each reservoir are maintained to be common between all of the analysis scenarios. To compose the reservoir system, information on the hydrologic connections between different reservoirs (i.e., common rivers) are used to link the individual reservoirs as appropriate, with output from one reservoir influencing input into downstream reservoirs. The reservoirs considered in the

system are presented visually in Fig. 2, with a list of reservoirs and their parameters available in online resource 1.

A complete description of the model and previous applications can be found in Tarroja et al. (2014) and Tarroja et al. (2016), respectively.

3.4 Power generation model

We evaluated power generation from non-dispatchable and dispatchable hydropower units using different approaches. Generation from non-dispatchable hydropower was assumed to be a direct function of inflow and is resolved at the daily scale, in line with water flow data available, as verifiable assumptions about hourly operations for these facilities could not be drawn:

$$P_i = \eta * \min\left(P_{cap}, \rho g h * \max\left(0, \dot{Q}_{in} - \dot{Q}_s\right)\right), \tag{2}$$

Where:

- η = efficiency of hydropower unit (assumed to be 90%)
- P_{cap} = rated capacity of corresponding hydropower unit
- h = hydraulic head of corresponding hydropower unit

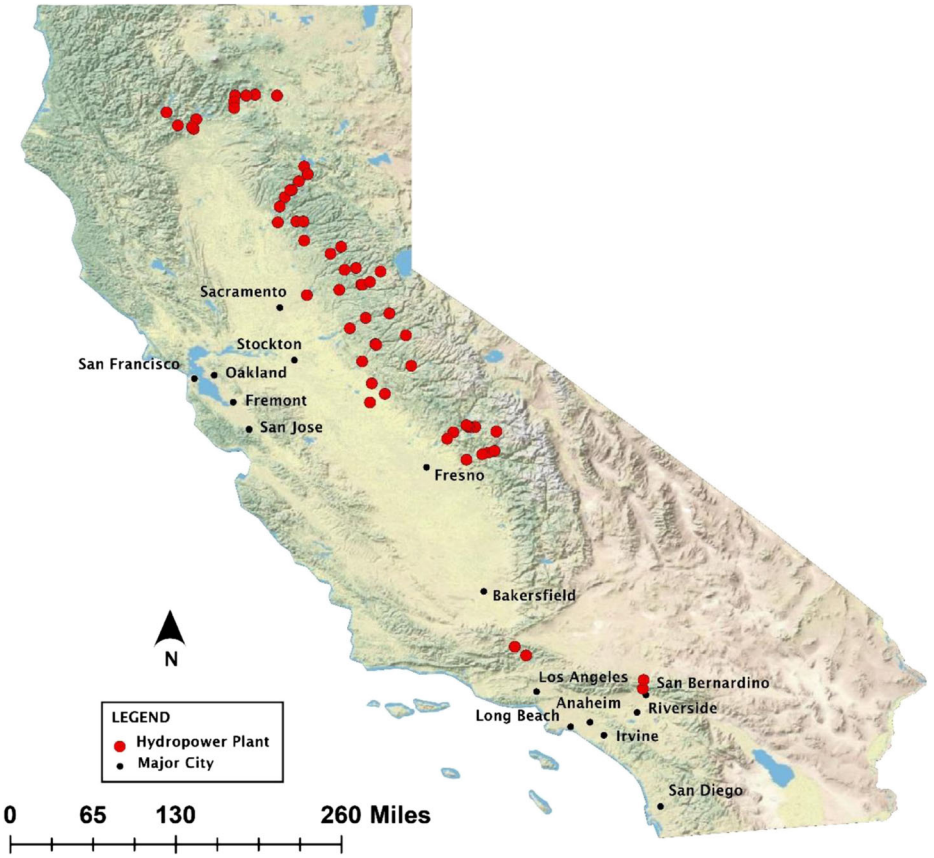

Fig. 2 Map of hydropower plants in study. Copyright (c) 2013 National Geographic Society, i-cubed

- $\dot{Q}_{in}$ = inflow
- $\dot{Q}_s$ = auxiliary water demands such as instream requirements and water deliveries

In contrast, dispatchable hydropower units consider inflow through the turbines to be the outflow from the reservoir model to account for auxiliary water demands. The equation for the dispatchable units is the same except Q_{in} (inflow) is replaced by Q_{res}, where Q_{res} is total outflow from the reservoir.

Dispatchable hydropower units were assumed to be dispatchable at the hourly timescale and participate in spinning reserve markets, requiring an optimization based on price. This optimization problem is described in Section 3.4.1. All hydropower units were modeled as fixed head units since the fill vs. head profiles for each reservoir were unavailable. The hydraulic head used for each reservoir can be found in online resource 1.

3.4.1 Bidding optimization module

We assumed dispatchable hydropower participated simultaneously in the energy market and ancillary service markets for spinning reserve throughout the day. The bidding optimization model prompts the hydropower unit to select the optimal service based on price and under a set of constraints.

The optimization acts to maximize water reservoir revenue for each day:

$$\min\left(-\sum\left(R_{\text{gen}}(t) + R_{SP}(t) + R_{\text{reg}}(t)\right)\right) \tag{3}$$

Where $R_{\text{gen}}(t)$, $R_{\text{SP}}(t)$, and $R_{\text{reg}}(t)$ are the revenues in dollars from providing generation, spinning reserve, and frequency regulation respectively, calculated at each hour t within a given day. The bid commitments for generation, spinning reserve, and regulation are the optimization variables.

Generation revenue is calculated from the hydropower unit generation bid (P_{gen}) during a given hour in MWh and data on the market clearing price (MCP) as a function of net load (P_{NL}) in $/MWh.

$$R_{\text{gen}}(t) = P_{\text{gen}}(t) \cdot MCP(P_{NL}(t)) \tag{4}$$

Spinning reserve revenue is calculated from the hydropower unit spinning reserve bid (P_{SP}) in MW and the price of spinning reserve (C_{SP}) in $/MW.

$$R_{SP}(t) = P_{SP}(t) \cdot C_{SP}(t) \tag{5}$$

Regulation revenue is calculated from the hydropower unit regulation bid (P_{reg}) in MW and the price of regulation service (C_{reg}) in $/MW.

$$R_{\text{reg}}(t) = P_{\text{reg}}(t) \cdot C_{\text{reg}}(t) \tag{6}$$

Historical data regarding the market-clearing price, net load, prices of spinning reserve, and regulation on an hourly basis were obtained from the CAISO OASIS database for the year 2014 (CAISO n.d.). The data were used for the per-unit service prices in this analysis.

The optimization process takes place within the following constraints. First, the total bid from a hydropower unit must not exceed the total power capacity of that unit:

$$P_{\text{gen}} + P_{SP} + P_{\text{reg}} \leq P_{\text{cap}} \tag{7}$$

Second, the total outflow calculated by the power generation module over the day must be equal to the daily outflow calculated by the water reservoir model for the corresponding unit:

$$\mathrm{sum}(Q_{\mathrm{out}}(t)) = Q_{\mathrm{day}} \tag{8}$$

The outflow calculated by the power generation module is related to the bids during each hour which correspond to physical releases of water. Note that generation and frequency regulation are the only services which release water from the reservoir; spinning reserve is a contingency service which does not release water unless called upon to respond to a contingency.

$$Q_{\mathrm{out}}(t) = \frac{P_{\mathrm{gen}}(t) + P_{\mathrm{reg}}(t)}{\eta \rho g h} \tag{9}$$

Third, the maximum spinning reserve bid is limited by the amount of water stored at any given time. A hydropower unit cannot bid to provide more spinning reserve at a given hour than the amount of energy available to discharge, which is directly related to the amount of water stored:

$$P_{SP}(t) \leq \eta \rho g h \cdot V_{\mathrm{available}}(t) \tag{10}$$

Where $V_{\mathrm{available}}$ is the difference between the volume of water stored and the minimum water storage level for the corresponding reservoir.

We obtained price curves for spinning reserves from the CAISO OASIS Database (CAISO n.d.). This study did not modify electricity demand between historical and future scenarios. We also did not make assumptions for changes in spinning reserve markets. Currently, the electricity markets are under rapid transformation and the value of spinning reserve is subject to change in the future, but how that change will occur is abstract at this point in time.

Power generation was validated using annual generation data for each hydropower unit obtained from the CA almanac (California Energy Commission 2017) and directly from PG&E. The aggregate generation profile was also verified compared to available historical data. The aggregate error for each historical year is in online resource 1.

3.5 Climate and hydrological models

This study utilizes projected streamflow and runoff obtained from the variable infiltration capacity (VIC) model forced with the localized constructed analogs (LOCA) downscaled (1/16° spatial resolution) Climate Model Intercomparison Project Phase 5 (CMIP5) simulations (Liang et al. 1994; Pierce et al. 2014; Brekke, Brekke et al. 2014). There are several RCP scenarios designed to reflect pathways of future atmospheric greenhouse gas concentrations based on different global emission levels and numerous general circulation models (GCMs) that simulate the corresponding climate impacts. The computational requirements for our analysis required that we select a limited number of RCPs and GCMs. We, therefore, sought to select models that perform well for modeling California given a set of accepted metrics and that also best encapsulate the range of potential shifts projected under each RCP. This analysis considers the models, CanESM2, CNRM-CM5, HadGEM2-ES, and MIROC5, under RCP4.5 and RCP8.5. These models were selected based on a number of weighted metrics following the methodology established in Tarroja et al. (2016) to examine a range of possible climatic outcomes classified by the CEC as mid-range, "cool/wet," "warm/dry," and a complement (Kravitz 2017). These GCMs have also been confirmed by the California Climate Change

Technical Advisory Group as performing well for the California region in their analysis to inform which GCMs should be applied for water resource planning (Climate Change Technical Advisory Group 2015). RCP 4.5 and RCP 8.5 were selected in order to capture the differences, if any, in projected hydrological conditions between the midrange concentration pathways and business-as-usual pathways.

The hydropower units taken from the Tarroja et al. (2014) study relied on routed inflow data using the Variable Infiltration Capacity (R-VIC) hydrological model (Liang et al. 1994). The remainder of the inflow vectors were perturbed using gridded runoff obtained from the CMIP5 models. We applied a bias correction to convert changes in runoff to future inflow changes, with negative values calculated for future inflow to zero. The bias correction method is as follows:

$$I_f = I_h + \propto \left(R_f - R_h\right), \tag{11}$$

Where:

I_f = future inflow

I_h = historical inflow

$\propto$ = (mean (I_h)) / (mean (R_h))

R_f = future runoff

R_h = historical runoff

We conducted a follow-up analysis to determine how hydropower may respond to longer droughts projected under climate change. This analysis uses a long-drought scenario derived from LOCA projections (Kravitz 2017; Pierce et al. 2014). Developed for the California 4th Climate Assessment, the long-drought scenario provides a California-specific (i.e., regionally downscaled) long-drought scenario under RCP8.5 in which rainfall is consistent with a 20-year dry spell in the historical record, but under increased temperatures. A 10-year period within an identified 20-year drought during the latter half of the twenty-first century was selected, and runoff was derived using the HadGEM2-ES model. Similar to other simulations, the long-drought simulations are available at 1/16° spatial resolution. Inflows were calculated using the same bias correction method used for the other scenarios.

4 Results and analysis

4.1 Hydropower generation trends under climate change

4.1.1 Impact of hydrology shifts on generation and spillage under climate change conditions

Under RCP4.5 and RCP8.5, the magnitude and timing of runoff and the resulting inflow into hydropower units shifted for the years 2046–2055 compared to the historical baseline. Winter inflow increased for all scenarios, while the scenarios for RCP4.5 and RCP8.5 were split on trends of summer inflow into hydropower units, with HadGEM2-ES (including the long drought) and MIROC5 showing a decrease and CanESM2 and CNRM-CM5, a slight increase. Winter inflow increased due to greater runoff during those months, tied to more precipitation falling as rain, as well as earlier snowmelt driven by higher temperatures.

This result was influenced both by spatial and temporal changes in runoff and by hydropower units downstream from another reservoir. In the latter case, while the upper reservoir

experienced decreased inflow during the summer, the reservoir drew from its storage to meet water demands, resulting in outflows resembling historical levels. These outflows then became inflow inputs to the connected hydropower unit. Therefore, while the inflow into these units may not have shown a decline in summer inflow, the net impact on the system was lower reservoir levels in the upstream reservoir.

Increased inflow through hydropower units did not always result in increased generation. When total inflow increases, water releases may exceed maximum output through turbines, requiring use of spillways. Spillage increased for all scenarios, leading to a more subdued generation response to increased precipitation and resulting reservoir inflow. For the long drought scenario, although average and median inflows decrease, peak inflow increases. Like the RCP4.5 and RCP8.5 scenarios, there are several events with higher than historical runoff, resulting in reservoirs being above their capacity to retain or utilize the inflow (see online resource 1 for comparison of spillage and seasonal analysis).

4.1.2 Shifting monthly generation trends for all scenarios

We investigated average generation as a percentage of peak generation to compare overall trends across models and RCP scenarios (Fig. 3). The average generation for each month across the 10-year period was divided by the highest average monthly value. Historically, hydropower tends to peak in May, with generation maintaining around 90–95% of peak generation through August. Generation tends to decrease in fall, reaching a minimum around November and staying low through February, at which point it begins increasing again.

For all scenarios, except the long drought, there is an increase in generation as a percentage of peak from January through April. Peak generation still occurs around May for all scenarios, but there is a greater decline in summer generation under the climate change scenarios. Lower percentages compared to peak generation persist through December. RCP8.5 shows the greatest decline with output dropping 25% below peak generation by August for all models.

For RCP4.5 and RCP8.5 averages, this shift is the result of higher winter and spring inflow followed by summer inflow around or below historical levels: peak generation increases while generation during summer remains around the historical average or slightly lower, resulting in a lower ratio. Water lost by spillage more than offsets is the increased inflow during winter and spring. Not enough of this inflow is retained into summer to overcome the relatively lower summer inflow values, and generation appears lower in the summer compared to peak.

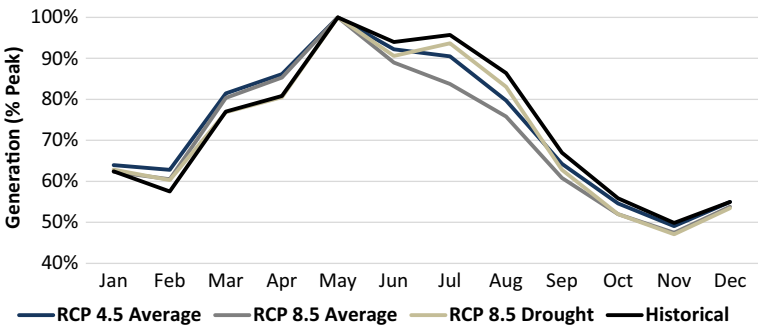

Fig. 3 Average monthly generation compared to the annual peak for historical (baseline) and all RCP8.5 simulations

Overall, a greater portion of a given year's hydropower generation is produced earlier in the year, and less is produced during the summer.

For the long drought scenario, the months between January and May follow the historical trend and the reduction observed during the summer is less pronounced than the other scenarios. This trend is related to the reduction in peak generation compared to the baseline and an overall reduction in runoff.

4.2 Future ancillary service trends under climate change conditions

4.2.1 Spinning reserve bidding for all scenarios

In addition to spinning reserve bidding being secondary to generation bids in terms of price, spinning reserve bids occur after reservoir outflow demand is satisfied, and therefore, under flood and drought conditions, reservoir level constraints may restrict spinning reserve bidding. Spinning reserve potential decreased across all years for all scenarios. For RCP4.5 and RCP8.5, the average decrease in spinning reserve bidding was relatively uniform across seasons and models at −18 to −12% compared to the historical average. The long-drought scenario had the greatest decrease at −41% below historical.

Comparing spinning reserve and generation bidding can help identify the relative contribution of generation bid changes and increased operational constraints on decreased spinning reserve participation. We examined the change in the frequency of days when hydropower units are constrained and the magnitude of these constraints for the climate change scenarios (Figs. 4, 5, 6 and 7).

For Figs. 4, 5, 6 and 7, each point represents the average bid of all participating hydropower plants for a given day in terms of how much of their rated capacity is committed to each service—

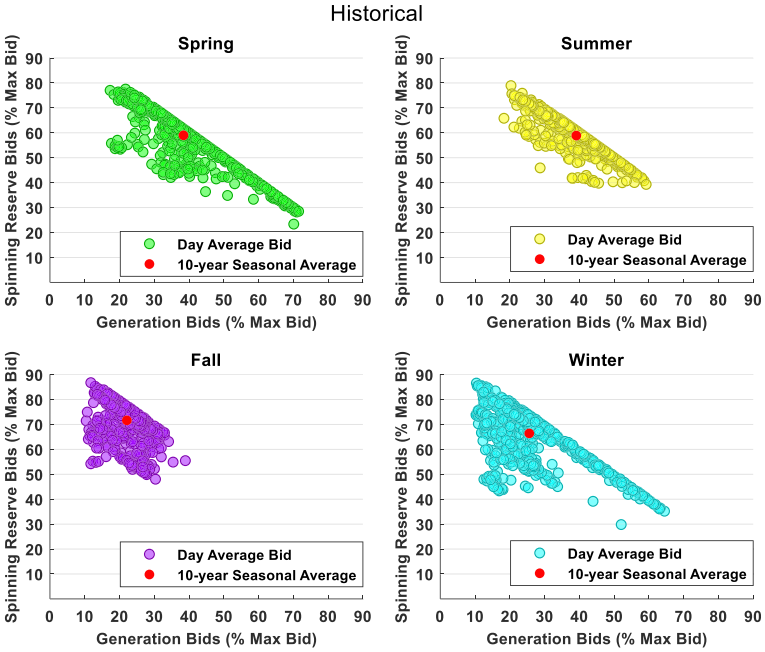

Fig. 4 Historical daily average spinning reserve bids versus generation bids

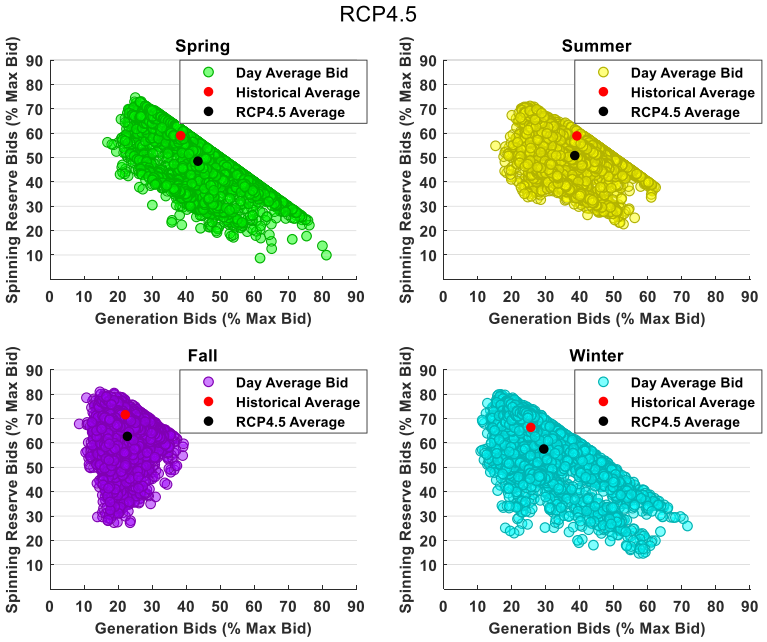

Fig. 5 RCP4.5 daily average spinning reserve bids versus generation bids

generation or spinning reserve. The values are normalized by the power capacity of the plants. Days across the 10-year period for all models are plotted by season. The upper bound of Fig. 4 characterizes days where outflow and bidding constraints did not prevent any hydropower units

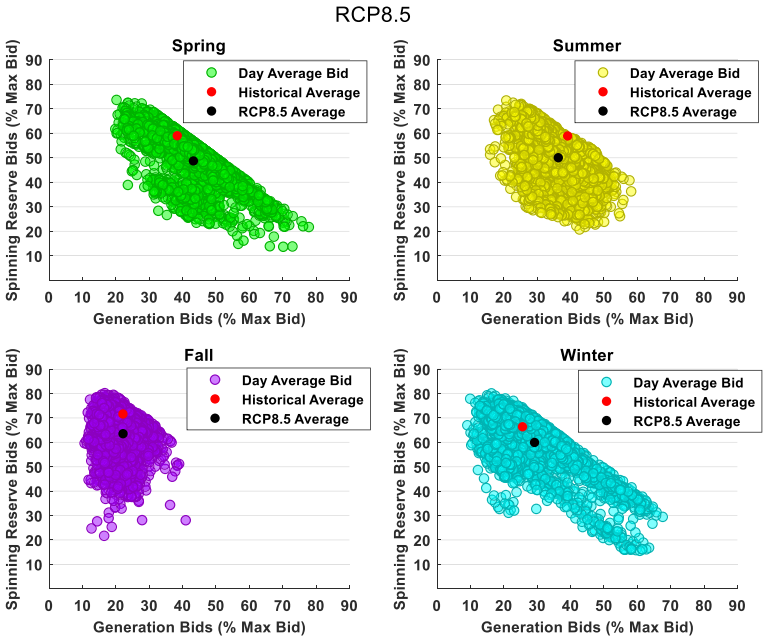

Fig. 6 RCP8.5 daily average spinning reserve bids versus generation bids

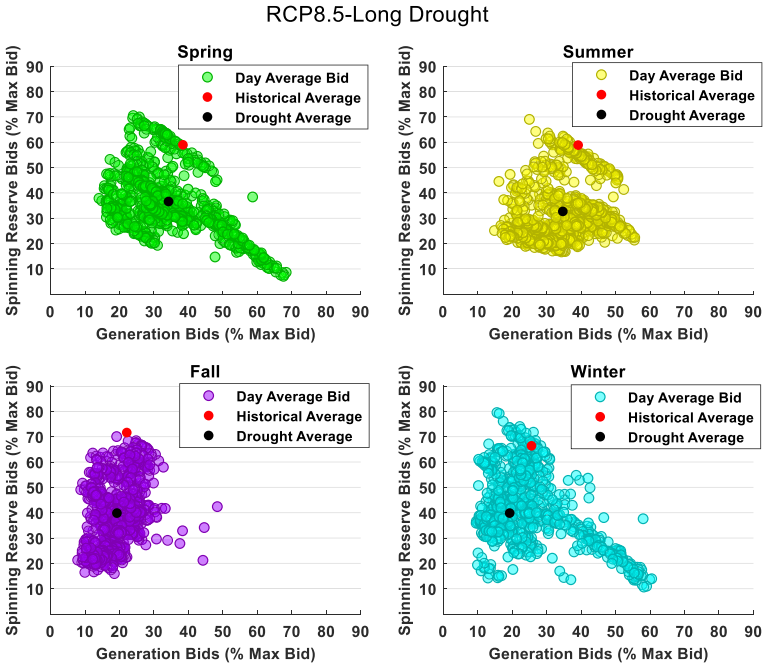

Fig. 7 RCP 8.5 Long Drought daily average spinning reserve bids versus generation bids

from full participation (100% of maximum bid) in the markets (e.g., 70% of available capacity bid for providing generation, 30% for spinning reserve). Days falling below this line are characterized by a fraction of the available hydropower being limited in their participation in the spinning reserve market, such that their total bid (generation + spinning reserve) that day was lower than their rated power capacity. The average across all days for the historical baseline is plotted in red and the average across all days for the given RCP is plotted in black.

The average generation bids for both RCPs (Figs. 5 and 6) are greater compared to the historical average (Fig. 4), due to increased inflow during winter and early spring. While all models under RCP4.5 show a net increase in generation bids, for RCP8.5, this average is skewed by the "wetter" models (CanESM2 and CNRM-CM5) and the trend is not consistent between all models (online resource 1). Nevertheless, all models show increased generation during the winter and spring.

For the long-drought scenario under RCP8.5, there was a sharp increase in days where one or more reservoirs experience constraints on bidding into spinning reserve markets, see Fig. 7. There are also numerous days where most reservoirs have reservoir level constraints, resulting in average overall spinning reserve bids being 41% lower than the historical average. Balancing the decrease in inflow while maintaining historical water demands not only decreases water releases for generation but it also decreases the reservoir storage available to bid into the spinning reserve market. Even for days where most dispatchable hydropower units are running at high part load, a large portion demonstrate reduced capacity to bid into the spinning reserve market due to low reservoir levels.

All future scenarios, Figs. 5, 6 and 7, have an increase in the number of constrained days, especially in summer, where increased constraints due to low reservoir levels result in decreased spinning reserve potential. These scenarios also show an increase in days where more hydropower units simultaneously experience reservoir constraints that limit to their spinning reserve potential, leading to spinning reserve bids that fall below the historical minimum.

5 Conclusions

This study examined the potential climate change impacts on hydropower generation and its contribution to ancillary services. This was accomplished by modeling the historical behavior of large hydropower units. The CMIP5 climate model projections were used to perturb historical inflow into hydropower units to evaluate shifts in hydropower operations in terms of electricity generation and spinning reserve bidding.

1. Winter and spring runoffs are projected to increase, leading to increased chance of reservoir spillage and lost generation potential. Increased inflow into hydropower units when storage is already high can overwhelm the capacity to hold and dispense water in correspondence with demand, leading to increased spillage. This risk is greater for small reservoirs with high minimum storage constraints. Inflow into reservoirs earlier in the year lowers the probability that the water can be retained into the summer when hydropower supports peak electricity demand. Overall, average annual generation increased for the scenarios with a large increase in inflow, but for scenarios where inflow was at or slightly above historical, spillage led to a net decrease in generation.
2. Temporal shift in runoff leads to increased generation earlier in the year and decreased generation in the summer compared to the annual peak. The temporal shift in inflow resulted in a subsequent shift in the timing of generation bids, with a greater percentage of the year's bids occurring earlier in the year and a smaller percentage occurring during summer compared to the historical baseline. This shift in generation has planning implications as high inflow during winter may give an overly generous idea of water available for generation in summer, if assuming the historical trend.
3. Spinning reserve bidding potential is projected to decrease. All scenarios, except the long drought, experienced increased generation bidding during winter and spring, leading to decreased spinning reserve bidding. Reservoirs also experienced increased reservoir constraints due to spilling and minimum storage requirements, leading to greater limitations on spinning reserve bidding. These two factors led to a net decrease in spinning reserve potential. For the long-drought scenario, the spinning reserve bidding potential is even further constrained by much lower reservoir levels.

The hydrological shifts predicted under climate change conditions lead to greater dispatch constraints which in turn result in decreased hydropower participation in the spinning reserve market. A large decrease in hydropower potential for spinning reserve support may put the system at risk for instability, and may require new flexible capacity to balance the high penetration of variable renewable generation planned for California. If this additional flexible capacity is met through fossil fuel plants, it may undermine the state's objective to reduce emissions from these resources.

6 Discussion

While this analysis focused on quantifying climate change impacts on the contribution of hydroelectric power plants to generation and spinning reserve markets for the electric grid, there are additional insights and implications that are worthy of discussion.

First, changes in seasonal and yearly bidding into generation and spinning reserve markets affect the potential for earning revenue. While the potential for spinning reserve bidding decreased for all scenarios, there is an increase in generation bidding during winter and spring for the RCP4.5 and RCP8.5 scenarios, indicating that there is an opportunity recuperate lost revenue from the reduction in spinning reserve bidding from increased revenue from the energy market. Nevertheless, under the long drought scenario, bidding into both markets declined, suggesting overall declines in hydropower revenue.

By understanding the potential impacts of climate change conditions on reservoirs and revenue, strategies for mitigation and adaptation can be explored. As highlighted in this analysis, reservoir operators may need to manage fluctuating periods of higher and lower runoffs in order to ensure water demands are met under climate change scenarios. Reservoir operators may adapt to changing hydrological conditions by changing their bidding strategies for the different electric grid markets in order to offset lost revenue from spillage events and guard against less summer bidding as well as drought periods when revenue yields may decrease across the year. The potential for recuperation will depend on market pricing and each reservoir's flexibility to change when and how water is dispatched.

Reservoirs and their associated power plants also may be physically modified to mitigate the potential loss of revenue tied to increased spill events and uncertainty surrounding projected changes to inflow. Hydropower plants expected to see periods of higher inflow during peak generation periods may increase their power capacity and/or expand reservoir capacity. Additionally, there is opportunity for constructing new reservoirs in areas where there is confidence of hydropower potential. The mitigation potential of these strategies must be weighed against environmental and economic costs associated with construction and expansion.

Lastly, this analysis assumed historical demands for water utilization; however, water demands may change in the future in response to increased population and changing environmental conditions. For example, as temperatures rise, environmental flow requirements may increase to ensure proper water quality and temperature. These changes may further limit hydropower contributions to the electric grid.

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