CLIMATE CHANGE ALTERS INTERREGIONAL ELECTRICITY MARKET DYNAMICS ON THE U.S. WEST COAST

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ABSTRACT

Joy Hill: Climate Change Alters Interregional Electricity Dynamics on the U.S. West Coast
(Under the direction of Gregory Characklis and Jordan Kern)

Power systems and markets are influenced by hydrometeorological variability, including temperature-driven changes in electricity demand and water availability impacts to hydropower. The U.S. Pacific Northwest (PNW) meets over 55% of its regional electricity demand with hydropower, a majority of which is produced within the Federal Columbia River Power System. California relies on hydropower produced in-state and imported electricity the PNW to meet demand, leaving California vulnerable to West Coast wide hydrologic variability. As hydroclimate changes across this region, a combination of forces may work in tandem to make West Coast power markets even more susceptible to reliability and price risk. A warmer climate is expected to shift the timing of streamflow earlier in the year and increase summer cooling demand. In this work, we investigate how climate change could alter interregional electricity market dynamics on the West Coast, including the possibility that hydroclimate changes in one region (e.g. PNW) could compound price and reliability risks in another (e.g. California) and vice versa. Power system metrics (generation, demand, market prices) are analyzed for multiple combinations of downscaled Global Climate Models (GCMs), Representative Concentration Pathways (RCPs), hydrologic models and timescales. We find that under static grid conditions, climate change across the West Coast could cause higher average annual wholesale prices and reduced reliability. We find that

hydroclimatic risks for the PNW power system are largely driven by changes in streamflow, while risks for the California system are driven by changes in summer air temperatures, particularly extreme heat waves increasing peak system demand. In addition, we find that climate change conditions in the PNW (including altered timing and amounts of hydropower exports to California) have little impact on reliability and prices in the California market -- unless compounded by climate change conditions in California. However, climate conditions in California have a significant impact on outcomes in the PNW, especially when compounded with shifts in the timing of PNW hydropower generation.

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LIST OF ABBREVIATIONS

PNW	Pacific Northwest
Mid-C	Mid-Columbia Market
CAISO	California Independent System Operator
GCM	Global Climate Model
RCP	Representative Concentration Pathway
CMIP5	Coupled Model Intercomparison Project Phase 5
VIC	Variable Infiltration Capacity
PRMS	Precipitation Runoff Modeling System
CAPOW	California and West Coast Power System Model

CHAPTER 1: INTRODUCTION

Bulk electric power systems and wholesale power markets are influenced by hydrometeorology (Kern et al., 2020; Su et al., 2020; S. W.D. Turner et al., 2019). Extreme air temperatures (heat waves and cold snaps) increase electricity demands for cooling and heating, respectively, and hydrologic conditions control the availability of water for hydropower production and cooling at thermal power plants (Bartos & Chester, 2015; Schaeffer et al., 2012; Van Vliet et al., 2012; Van Vliet, Sheffield, et al., 2016; Van Vliet, Wiberg, et al., 2016). By influencing supply and demand for electricity on the grid, uncertainty in hydroclimate and extreme events can negatively affect physical reliability and environmental performance of power systems and significantly influence market price dynamics. For example, combined heat-waves and droughts tend to create scarcity on the grid and result in higher wholesale prices, greater greenhouse gas emissions, and lower reliability (Rübbelke & Vögele, 2011; Tarroja et al., 2016; Sean W.D. Turner, Hejazi, et al., 2017; Voisin et al., 2016).

Given the current vulnerabilities of power systems to hydroclimatic uncertainty and extremes, there is growing concern about the future impacts of climate change on power systems operations (Bartos & Chester, 2015; Förster & Lilliestam, 2010; Hamlet et al., 2010; S. W.D. Turner et al., 2019; SW.D. Turner, Hejazi, et al., 2017). Previous investigations have focused on the potential impacts of climate change on streamflow dynamics and the timing and amount ofhydropower production available globally (Hamududu & Killingtveit, 2012; S W.D. Turner, Hejazi, et al., 2017; S W.D. Turner, Ng, et al., 2017) and over specific regions

(Bartos & Chester, 2015; Craig et al., 2020; Ganguli et al., 2017; Hamlet et al., 2010; Kern & Characklis, 2017; Kopytkovskiy et al., 2015; Totschnig et al., 2017). Several previous studies have also investigated the impacts of higher air temperatures and altered streamflow dynamics on cooling water resources and the useable capacity of thermal power plants (Förster & Lilliestam, 2010; Pechan & Eisenack, 2014; Van Vliet, Sheffield, et al., 2016); and many other studies have examined the potential impacts of a warming climate on electricity demand (Auffhammer et al., 2017; McFarland et al., 2015; Perera et al., 2020), with an overall consensus that summer cooling demand may increase while winter heating demands are reduced.

However, relatively few previous studies have examined the potential for climate change to impact electricity supply and demand simultaneously, especially at granular (daily and hourly) timescales (S. W.D. Turner et al., 2019; Voisin et al., 2018). Turner et al. 2019 examined the potential climate change impacts to system reliability (i.e. the ability to meet electricity demand) in the Pacific Northwest (PNW) region of the United States (U.S.) under two future climate scenarios, finding the frequency of potential power shortfall events to increase. They also examined the potential change in seasonality of these events, finding summer shortfalls more likely and winter shortfall events less likely to occur under a 2030s forecasted climate. However, these impacts were evaluated for a single forecasted year (2035), and the study did not consider the impacts of climate change on regional imports/exports of electricity.

A relatively unexplored area of research is how projected changes in regional hydroclimate (precipitation, timing of streamflow, temperatures, etc.) could manifest in large interconnected power systems spanning diverse climatic zones and wholesale electricity markets. In particular, there has been little attention paid to the potential for changes in hydroclimate in one region to adversely affect the performance of other adjacent power systems and wholesale markets. Failure to consider the impacts of climate change on interregional flows of electricity may overlook the potential for increased resource sharing (if one regional system is scarce and the other has excess supply) or the potential for "cascading" impacts that reduce reliability across the entire system.

In the U.S., there is perhaps no region more at risk from these effects than the West Coast. Hydropower accounts for 55% of installed capacity in the PNW (BPA, 2018) (a large fraction of which is part of the region's Federal Columbia River Power system jointly managed by the U.S. Army Corps of Engineers and Bonneville Power Administration), and 18% of installed capacity in California (California Energy Commission, 2017), most of which is located in the Sierra Nevada Mountains. There are significant interdependencies between the PNW and California electric grids, with California importing significant amounts of hydropower from the PNW to help meet the state's electricity load (Public Generating Pool, 2017). Furthermore, in times of relatively low demand and a surplus of renewable energy, California also exports power to the PNW.

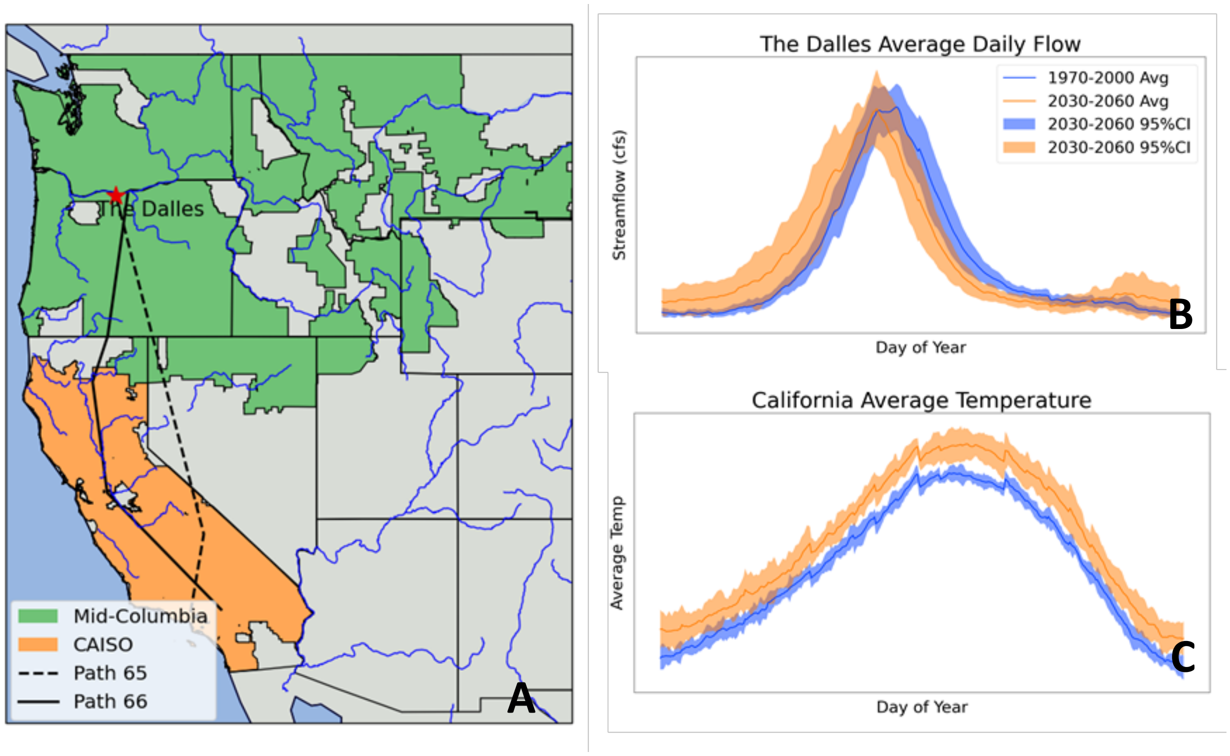

Figure 1. Map of study domain, with the Mid-Columbia (Mid-C) wholesale electricity market in the Pacific Northwest and California Independent System Operator (CAISO) wholesale electricity market in California (Panel A) Time series of average and 95% confidence intervals of The Dalles daily streamflow (Panel B) and temperatures averaged across California (Panel C).

With such a large share of electricity demand being met with hydropower, the impact of climate change on the timing and amount of streamflow and hydropower production on the West Coast has been the subject of numerous previous studies (Boehlert et al., 2016; O'Connell et al., 2019; Rupp et al., 2017; S. W.D. Turner et al., 2019). Most projections show a decrease in summer water availability for hydropower and an increase over the wet season (October to May) (see Figure 1), as well as greater variability overall, leading to more frequent "tail events" (periods of either extremely high or low flows) (Boehlert et al., 2016; Hamlet et al., 2010; Rupp et al., 2017).

In addition to altered hydropower production, both California and the PNW's demands for electricity (heating and cooling) are expected to change as temperatures increase (Auffhammer et al., 2017; Hamlet et al., 2010) (Figure 1). In particular, summer cooling demands across the West Coast will most likely increase (Auffhammer et al., 2017) and winter heating demands in the Pacific Northwest are expected to decline (Hamlet et al., 2010). Notably, the combined impacts of climate change may lead to a damaging mismatch in the timing of hydropower generation (supply) and demand. Lower summer streamflow across the West Coast could reduce the availability of hydropower during the highest demand period of the year, leaving the grid vulnerable to disruptions in reliability (North American Electric Reliability Corporation, 2020; S. W.D. Turner et al., 2019).

Nonetheless, the potential impacts of climate change on these interlinked power systems have been explored in isolation, either analyzing the impacts in the PNW or California independently (Madani et al., 2014; Tarroja et al., 2016; S. W.D. Turner et al., 2019). No study to date has focused on the impacts of a changing hydroclimate across both of these interconnected power systems, despite the reliance of California on out-of-state resources (including hydropower produced in PNW) to meet increasing summer demand (Penn, 2020). In this study, we characterize the potential for hydroclimatic changes across the entire U.S. West Coast to cause price and reliability risks. In addition, for the first time, we quantify the impacts of a changing hydroclimate in the PNW on the California grid and vice versa through a controlled experiment to isolate the individual and combined effects of climate change in both regions on system reliability and market prices. We force 10 bias-corrected down-scaled Global Climate Models, calibrated with two RCPs and four hydrologic models, through the California and West Coast Power System (CAPOW) model, a newly developed open-source power system simulation software spanning systems in the

PNW and CA (Su et al., 2020). We simulate system performance under four hydroclimate scenarios: hindcast (1970-2000 conditions), combined climate change forcings (2030-2060 conditions in both regions), and two additional scenarios in which climate impacts are activated in one region at a time (e.g., future climate conditions triggered in the PNW while hindcast conditions remain in CA and vice versa). Using this controlled experimental approach, we are able to identify the role of intra- and extra-regional climate change on these two major West Coast power markets. Our results provide insights about the potential role of climate change on system dynamics, which should prove valuable for multiple stakeholders (independent system operators, utilities and utility commissions) in making long term planning and investment decisions based on estimates of future reliability and market prices.

CHAPTER 2: METHODS

2.1 Hydroclimate Data

The dataset containing hydroclimate data for both the hindcast (1970-2000) and forecast (2030-2060) periods include daily time series of temperature and wind speeds at 17 weather stations within NOAA'S Global Historical Climatological Network (GHCN), solar irradiance at 6 NREL National Solar Radiation Database (NSRDB) sites, and unregulated streamflow from 108 streamflow gauges across the West Coast. For a comprehensive list of hydrometeorological sites used within the model, see Su et al. 2020. Down-scaled time series of temperature, wind speed, and solar irradiance are obtained from forcings of two Representative Concentration Pathways (RCPs 4.5 and 8.5) and 10 Global Climate Models (GCMs) from the Coupled Model Intercomparison Project Phase 5 (CMIP5) for both PNW and CA, with selection of GCMs informed by Rupp et al. (2013) (Rupp et al., 2013). Streamflow time series are a function of GCM, RCP, and hydrologic model calibration. Streamflow data in the PNW sets exist for 160 climate change model configurations (the 2 RCPs mentioned above x 10 GCMs x 2 different downscaling methods x and 4 hydrologic model calibrations) (Rupp et al., 2017). After comparison of annual streamflow and hydropower metrics, we removed one of the downscaling methods considered, which has been shown to be the lowest contributor of hydrologic variation compared to RCP, GCM, or hydrologic modeling choice (Chegwidden et al., 2019). Thus, in total, we utilize 80 permutations of hindcast and forecasted streamflow conditions in the PNW. For the streamflow sites in California, the climate scenario dataset includes just one hydrologic modeling calibration (VIC) and is obtained from bias-corrected, downscaled (BCSD) projections from the National Center for Atmospheric Research (NCAR) CMIP5 dataset (Maurer, E. Brekke, L., Pruitt, T., Duffy, 2007).

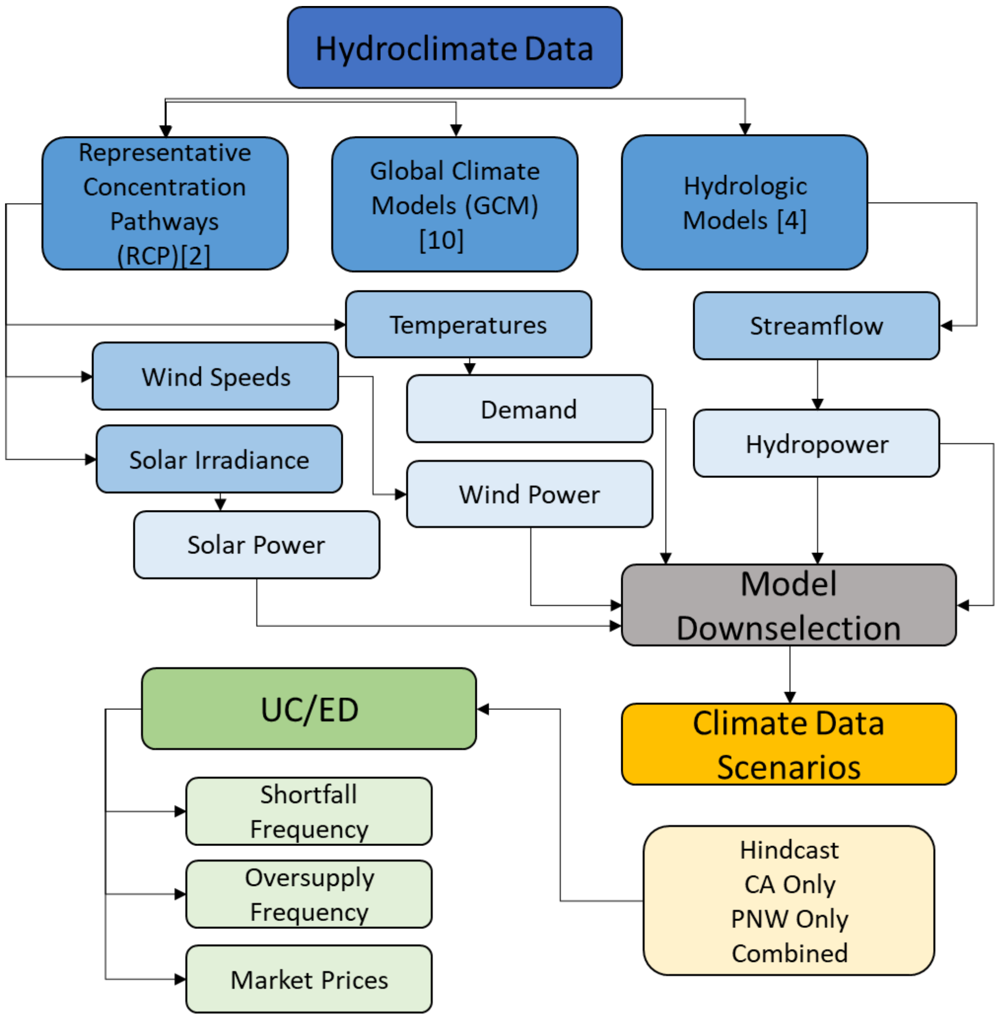

Figure 2. Modelling framework used in this work. To start, a set of ten Global Climate Models (GCM) are forced with two Representative Concentration Pathways (RCP) to produce 20 unique combinations of temperatures, wind speeds, and solar irradiance. We use four hydrologic model calibrations for the PNW streamflow sites, giving us a total of 80 independent modelling configurations (20 for California). Lists of GCMs, RCPs and Hydrologic models can be found in Table A1.

The streamflow dataset for PNW was then translated into a “modified” form used in planning studies by the U.S. Army Corps of Engineers and Bonneville Power Administration (Bonneville Power Administration, 2011), which accounts for irrigation and evaporation losses (both of which are kept at 2010 historical levels). A few sites within the set of streamflow gauges did not have representative streamflow time series for hindcast and forecast climate change scenarios. Daily flows at these sites were calculated using linear regressions, or substitution of neighboring sites’ streamflow time series if available.

2.2 Power Systems Modelling

The study domain covered in this work spans representations of the two major wholesale electricity trading hubs across the U.S. West Coast, including the Mid-Columbia (Mid-C) market serving most of Washington and Oregon, and the region spanning the territory of the California Independent System Operator (CAISO), which manages the majority of California’s electricity system including a wholesale market (see Figure 1).

The power system simulation model used in this work, CAPOW, aggregates the system topology into five interconnected zones, one in the PNW (representing the Mid-C market) and four across California (collectively representing CAISO). Transmission constraints within each zone are not explicitly modeled. Each representative zone has a unique set of generation resources (hydropower, variable renewable energy, natural gas, etc.) and unique hourly demand profiles. Capacity within each market is kept at 2016 grid levels and no long-term changes in demand (other than those caused by climate change) are modeled. This is likely an unrealistic assumption about what the future capacity of the West Coast grid will look like (as the region builds out capacity to meet future increases in demand and renewable energy targets), but in this work we choose to evaluate current system performance in order to isolate climate-driven impacts to power system outcomes in the Mid-C and CAISO.

Bulk power system operations for each major market (CAISO and Mid-C) are simulated separately. Daily power flows between the two markets (along Western Electricity Coordinating Council (WECC) Paths 65 & 66) and from other adjacent regions are simulated statistically using multivariate regression. Regression models are fitted to historical interregional power flow time series data, with primary independent variables including demand, hydropower availability, and renewable energy availability in each region (Su et al., 2020).

The full suite of hydrometeorological data (daily time series of temperature, wind speeds, solar irradiance, and streamflow) is passed through the first stage of the CAPOW power simulation model, which simulates generation (hydropower, solar and wind power) and demand across the five zones. Multivariate regressions are used to simulate daily peak demand, wind and solar power, which are then disaggregated to an hourly time step using historical profiles. A majority of hydropower generation in the PNW is modeled using a mechanistic hydrologic mass balance, adapted from the U.S. Army Corps of Engineer's HYSSR model of the Federal Columbia River Power System, and a ResSim model of operations of federal dams in the Williamette River Basin. In California, where hydropower simulation models are not as readily available, hydropower generation was simulated using a rule-based approach parameterized using a differential evolution algorithm. Daily hydropower generation simulated across each zone is restricted to a single 24-hour period, thus our model does not allow for operational shifting in the timing of dispatched generation.

The second stage of CAPOW is a unit commitment and economic dispatch (UC/ED) model that simulates market operations in both regions. The UC/ED model is structured as an iterative, mixed integer linear program formulated to meet the objective of minimize the cost of meeting demand for electricity. The model dispatches generation by minimizing the cost of meeting demand for electricity and operating reserves. More detail on the mathematical formulation of CAPOW, as well as validation of every stage of the model can be found in a separate paper by the authors (Su et al., 2020). Appendix A provides a schematic of the model work flow within CAPOW.

2.3 Overview of 80 GCM-RCP-Hydrologic Model Configurations

Figure 3 displays statistical measures of daily "net demand" for the Mid-C system (Box A) and CAISO (Box B) for every unique combination of RCP and GCM (distinguished by color and marker shape). Net demand in this work is calculated as simulated daily demand minus any available hydropower, solar and/or wind power generation. It thus serves as a proxy for scarcity and the need for power supply from thermal generation. In the Mid-Columbia region, simulated values of "negative" net demand indicate days in which generation exceeds demand (due to an abundance of simulated hydropower).

Note there are four datapoints for each color and shape combination, representing the four hydrologic modelling calibrations within the Mid-C streamflow dataset. Due to the larger number (80) of climate model configurations for the Mid-C, and its greater dependency on hydropower to meet demand, values of daily net demand in the Mid-C system encompass a much larger envelope of possible values than for the CAISO system. Box B displays only 20 unique combinations of RCP-GCM due to a single hydrologic model calibration within the CAISO streamflow sites.

In both zones, variability in values of daily net demand (i.e. median, 5th and 95th percentiles) are driven by the choice of RCP and GCM. Given the significant difference in expected average temperature increases under RCP4.5 vs RCP8.5 forcings, it was expected that RCP8.5 scenarios would result in overall higher median values of net demand. This is generally the case for simulated net demand in CAISO In the Mid-C system however, there is not a clear signal between RCP forcing and median net demand. This is due to: 1) higher variance in regional precipitation projections across climate scenarios (compared to more consistent temperature projections, with RCP8.5 being consistently hotter than RCP4.5); and 2) the PNW region's generation mix being dominated by hydropower, meaning hydrology significantly effects net demand. In both regions, choice of GCM is a large contributor to variability in simulated daily net demand. Finally, exploring variation in streamflow (and hydropower production) in the Mid-C under four unique hydrologic modelling calibrations allows us to explore an even further range of uncertainty in system outcomes.

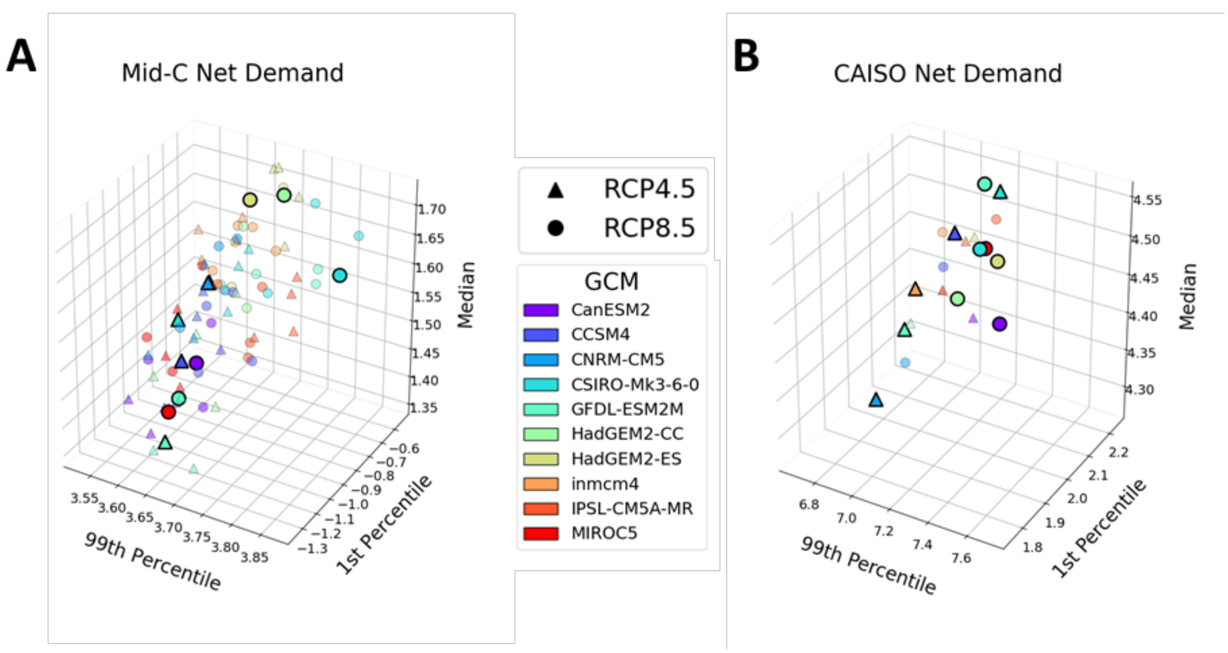

Figure 3. Daily net demand statistics under future climate conditions (2030-2060) in the Mid-C market (Box A) and CAISO (Box B) across all 80 combinations of RCP, GCM, and hydrologic modelling choice in the Mid-C, and 20 combinations of RCP and GCM in CAISO.

2.4 Scenario down-selection

Due to the computational resources required to run the CAPOW model (approximately 8 h for one simulated year using eight cores and 40 GB memory), an 11-member subset of the original 80 GCM-RCP-hydrologic model configurations was selected for more detailed analysis, with selection based on daily net demand metrics in the Mid-C and CAISO markets. Table 1 lists the 11 configurations of GCM-RCP-hydrologic model selected, and their corresponding ranking in terms of 99^{th} and 1^{st} percentiles of daily net demand (with 1 being highest and 80 lowest). The 11 configurations were selected manually to achieve diversity across these metrics and to capture the tails of the net demand distribution), as well as a relatively balanced allocation across RCP, GCM, and hydrologic model calibration.

Table 1. Model selection ranking, discussion of RCP, GCM, hydrologic model diversity. Ranking is according to initial subset of 80 scenarios, with 1 being the highest and 80 lowest ranked.

Modelling Configuration			**PNW Net Demand**		**CA Net Demand**	
RCP	GCM	Hydrologic	99^{th} Percentile Rank	1^{st} Percentile Rank	99^{th} Percentile Rank	1^{st} Percentile Rank
4.5	GFDL-ESM2M	VIC-P3	40	79	71	24
4.5	CSIRO-Mk3-6-0	PRMS-P1	72	44	27	18
4.5	CCSM4	PRMS-P1	53	66	54	13
4.5	inmcm4	VIC-P1	64	23	78	15
4.5	CNRM-CM5	VIC-P3	57	32	69	60
8.5	GFDL-ESM2M	VIC-P2	38	74	68	1
8.5	HadGEM2-CC	VIC-P2	22	5	32	65
8.5	HadGEM2-ES	VIC-P3	52	3	5	74
8.5	CSIRO-Mk3-6-0	VIC-P1	2	49	17	57
8.5	CanESM2	PRMS-P1	39	61	2	79
8.5	MIROC5	VIC-P1	43	76	24	52

2.5 Experimental Setup and Performance Metrics

For each of the 11 aforementioned selected GCM-RCP-hydrologic model configurations, we create time series of key power system inputs (supply and demand) across two time periods of 31 years: 1) 1970-2000, the “hindcast” period; and 2) 2030-2060, the “forecast” period. Each of the 11 GCM-RCP-hydrologic model configurations is then explored via simulation under 4 separate scenarios: 1) 1970-2000 hindcast data applied to both regional power markets (PNW and CA); 2) hindcast data in CA + climate change forecasts in the PNW (referred to as “PNW only” in the remaining sections of this paper); 3) hindcast data in PNW + climate change forecasts in CA (“CA only”); and 4) climate change forecasts in both regions (“Combined”). In this manner, we are able to identify the individual and combined effects of regional climate change in the PNW and CA on power market outcomes.

We evaluate simulated system performance using two key metrics: wholesale market prices and hourly reliability, or ability to meet demand with existing installed system capacity (static 2016 grid). While system reliability is important for maintaining the functionality of the grid and ensuring consistent service, market prices are an important component of power system operations for several stakeholders, including power producers and sellers and new or existing investors. High market prices signal a need to procure additional capacity, while low market prices suggest new investment is less valuable and/or not necessary (unless mandated by state policy). CAPOW calculates the hourly market price in each of the 4 zones within CAISO territory and calculates the zonal average using historical price weights. Daily prices are simply the average across each 24-hour simulation period. In the PNW, there is only one zone and thus one hourly price calculated. Hours in which systems fail to meet demand (i.e. supply “shortfalls”) are priced at $1000/MWh, based on evidence in both markets of prices trading at this level, even as recently as August 2020 in CAISO and 2018 in the Mid-C (Micek, 2020; U.S. Energy Informaton Administration, n.d.). Note that we do not account for the potential for adaptation to scarcity (high prices) in real-time markets using demand response, increased interregional imports, or lower available reserves. Furthermore, our model does not account for sub-daily storage capacity recently added to the CAISO market and surrounding WECC areas, which would provide further adaptation potential. For each of the 11 GCM-RCP-hydrologic model configurations and 4 controlled experiment scenarios tested, we track the frequency of shortfalls greater than 100 MW in magnitude to assess reliability risk. For each model configuration, we also track hours of the year in which there is an oversupply (generation exceeds projected demand) event. These hours are set at $0/MWh. In reality, oversupply events can depress prices even below zero, meaning generation operators would *pay* to sell their electricity (Amelang & Appunn, 2018). Although oversupply prices may benefit wholesale power buyers temporarily, increased frequency of these events may lead to depressed investment in new capacity.

CHAPTER 3: RESULTS & DISCUSSION

3.1 Impacts to Reliability on an Annual Timescale

Figure 4 displays the frequency of annual shortfall events (y-axis) and the average shortfall amount (MW) (x-axis) for all 11 GCM-RCP-hydrologic model configurations and 4 controlled experiment scenarios in the Mid-C market. When climate change conditions are triggered for the PNW alone ("PNW Only" scenario), all 11 GCM-RCP-hydrologic model configurations experience a higher frequency of potential shortfall events, relative to hindcast conditions; at the same time, in 6 out of 11 configurations the average shortfall magnitude declines. This result confirms findings from (S. W.D. Turner et al., 2019), which found hourly PNW shortfall events under 2 GCM-RCP-hydrologic simulations to be more frequent but less severe Adding in climate change conditions in California (i.e. triggering the "Combined" scenario) results in a further increase in the frequency of shortfall events for all 11 GCM-RCP-hydrologic model configurations, suggesting a compounding impact on reliability in the Mid-C market. Within the "combined" scenario, the three highest average frequency of shortfall events occurs under RCP8.5 climate forcings (GCMs: CSIRO-Mk3-6-0, HadGEM2-ES, and HadGEM2-CC). These three model configurations all fall within the "extremes" of the 80-member set of daily net demand rankings listed in Table 1. Underlying greater potential for extreme net demand values in these model configurations are forecasts of very low summer streamflows in the PNW (using full natural flows at the Dalles, OR as a proxy). In addition, these three configurations represent three out of the four biggest increases in summer temps among the 11-member subset (with CanESM2 RCP8.5 forecasting the highest summer temperatures).

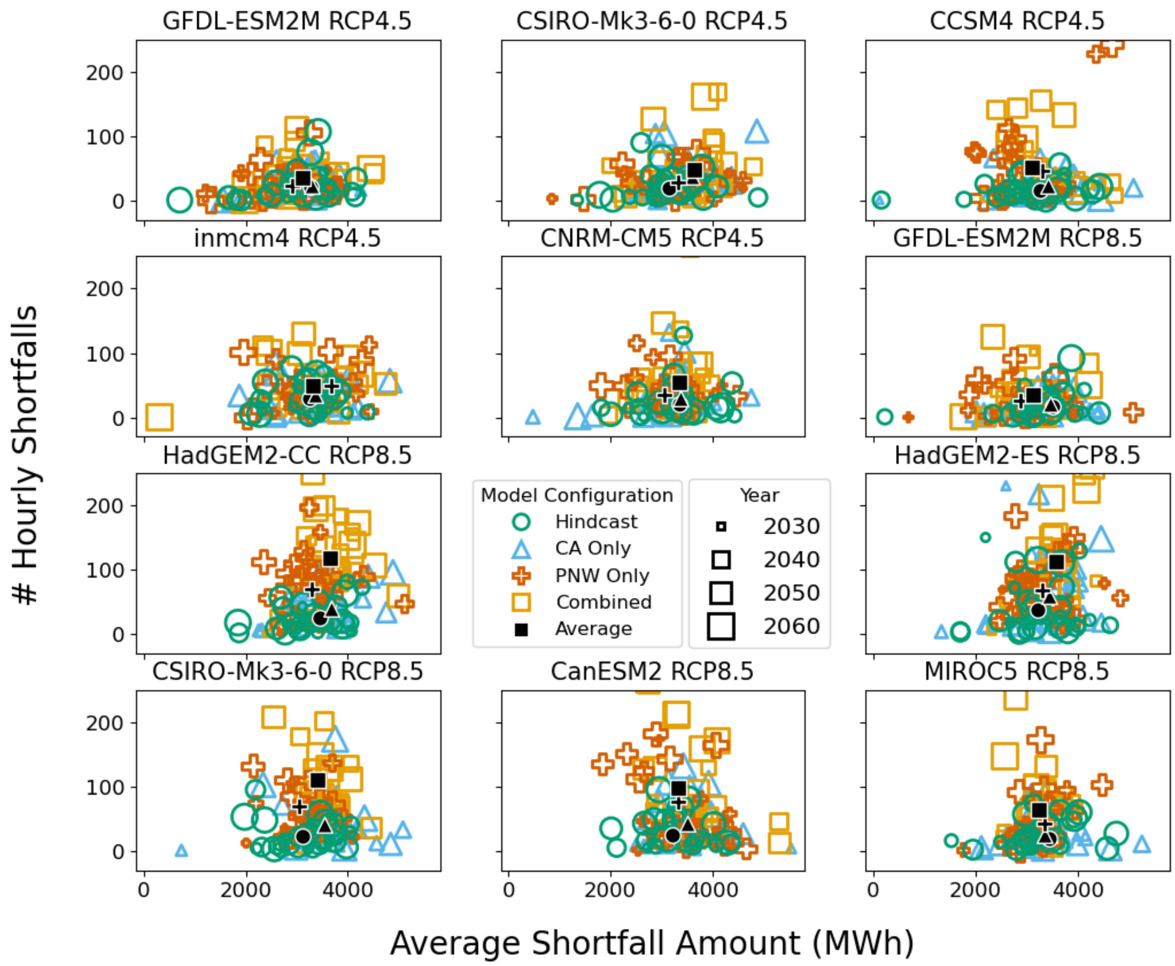

Figure 4. Comparison of yearly reliability in the Mid-C system across 11 GCM-RCP configurations and 4 controlled experiment scenarios, which are distinguished by marker color and shape. Marker size indicates the modelling year within the simulation period (either 1970-2000 or 2030-2060, with larger markers indicating a later year). Finally, black solid markers indicate the average (number and magnitude) for each scenario across the 31-year period. Note: the y-axis has been truncated to better show the spread in average values, thus some high frequency years are cut out of the plot for the following scenarios and model configurations: PNW Only (CanESM2 RCP8.5 (1 year), CSIRO-Mk-3-6-0 RCP8.5 (1), inmcm4 RCP4.5 (1)) and Combined (CanESM2 RCP8.5 (3), CSIRO-Mk-3-6-0 RCP8.5 (2), HadGEM2-CC RCP8.5 (2), CNRM-CM5 RCP4.5 (1), HadGEM2-ES RCP8.5(2)).

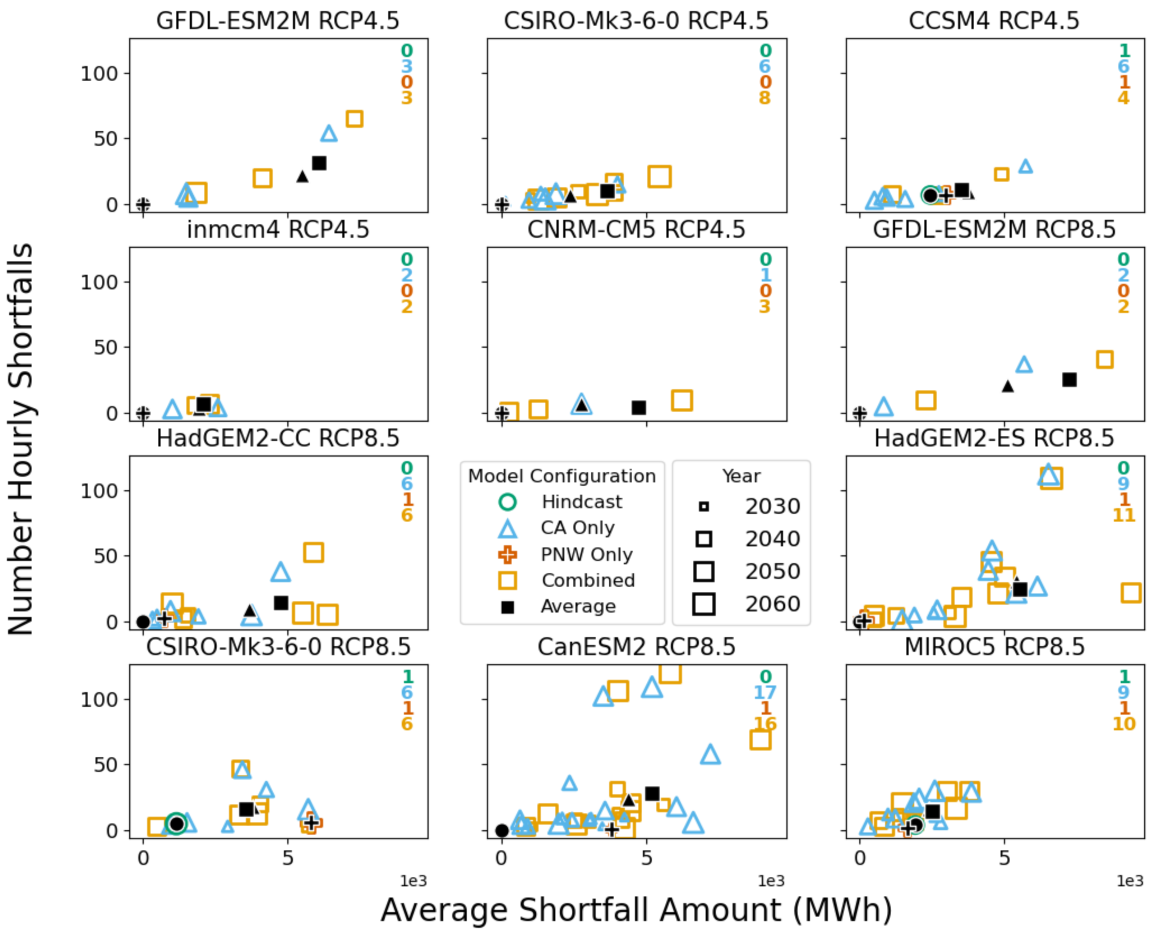

Figure 5. Comparison of yearly reliability in the CAISO system across 11 GCM-RCP configurations and 4 controlled experiment scenarios, which are distinguished by marker color and shape. Marker size indicates the modelling year within the simulation period (either 1970-2000 or 2030-2060, with larger markers indicating a later year). Numbers in each top right corner of the 11 subplots counts the number of years (out of 31) in which there is at least one potential shortfall event greater than 100 MW. Finally, black solid markers indicate the average (number and magnitude) for each scenario across the 31-year period.

Overall, shortfall events are much less frequent in the CAISO market (Figure 5), regardless of model configuration (panel) and scenario (colors). Note, however, that the upper bounds on the magnitude of potential events is much higher than in the Mid-C market. The CAISO system under hindcast conditions experiences almost no potential physical shortfall events across each model configuration and scenario 31-year span. Relative to hindcast conditions, the frequency of shortfalls increases across every GCM-RCP-hydrologic model configuration when climate change is applied to California alone (the "CA Only" scenario) and when climate change is applied in both regions simultaneously. In terms of the frequency of shortfalls, the most vulnerable model configuration for the CAISO market is CanESM2 RCP8.5, which is the 2nd (of 80) highest ranked model configuration in terms of 99th percentile daily net demand annually, and 1st overall across summer months (June-September). This model configuration has the highest frequency of potential shortfall events across the 31-year modelling period, as well as the highest number of years with at least one physical shortfall above 100 MW (16 out of 31). Note that climate change conditions in PNW alone seem to have a negligible impact on CAISO reliability, despite the potential for climate change in the PNW to alter the timing and amount of hydropower that is delivered into the CAISO market. We explore this lack of effect in greater detail in a later section of the paper.

We also analyze the frequency of coincident shortfalls, or hours in which both the Mid-C and CAISO markets fail to meet demand with existing generation resources (Table 2). Coincident shortfall events are potentially more damaging than shortfall events in one market alone, because neither system would be able to rely on the other for electricity imports and would be forced to reduce demand across both markets or buy from other regions. Under hindcast conditions, there are no instances of coincident shortfalls under any GCM-RCP-hydrologic model configuration. A PNW Only climate change scenario triggers a small number of coincident shortfalls, while CA Only and Combined climate change scenarios contribute significantly more. Even so, these remain extremely rare events. Even under the most severe case (the HadGEM2-ES model, run for an RCP8.5 scenario using the VIC-P3 hydrologic model calibration) the maximum number of coincident shortfalls is 72 hourly occurrences over 31 modeling years. The timing of these potential coincident blackout events is shown in Figure 6, which displays a histogram of day-of-year for these events. Most potential coincident blackouts occur in late summer, when seasonal hydropower production in both zones is typically at a minimum (regardless of climate scenario). This indicates that these combined shortfall events are caused by the incidence of extremely high summer air temperatures as opposed to altered streamflow dynamics (this also explains the significant increase in coincident shortfalls under RCP8.5 configurations, in which projected temperature increases are much greater and consistent).

Table 2. Frequency of hours experiencing potential coincident physical shortfall events across Mid-C and CAISO markets under 11 GCM-RCP-hydrologic model configurations and three controlled experiment scenarios.

Model Configuration	CA Only	PNW Only	Combined
GFDL-ESM2M RCP4.5 VIC-P2	5	0	13
CSIRO-Mk3-6-0 RCP4.5 PRMS-P1	3	0	0
CCSM4 RCP4.5 PRMS-P1	2	6	3
inmcm4 RCP4.5 VIC-P1	1	0	6
CNRM-CM5 RCP4.5 VIC-P3	4	0	8
GFDL-ESM2M RCP8.5 VIC-P3	0	0	25
HadGEM2-CC RCP8.5 VIC-P2	17	2	29
HadGEM2-ES RCP8.5 VIC-P3	46	0	72
CSIRO-Mk3-6-0 RCP8.5 VIC-P3	18	0	29
CanESM2 RCP8.5 PRMS-P1	20	1	69
MIROC5 RCP8.5 VIC-P1	15	1	48

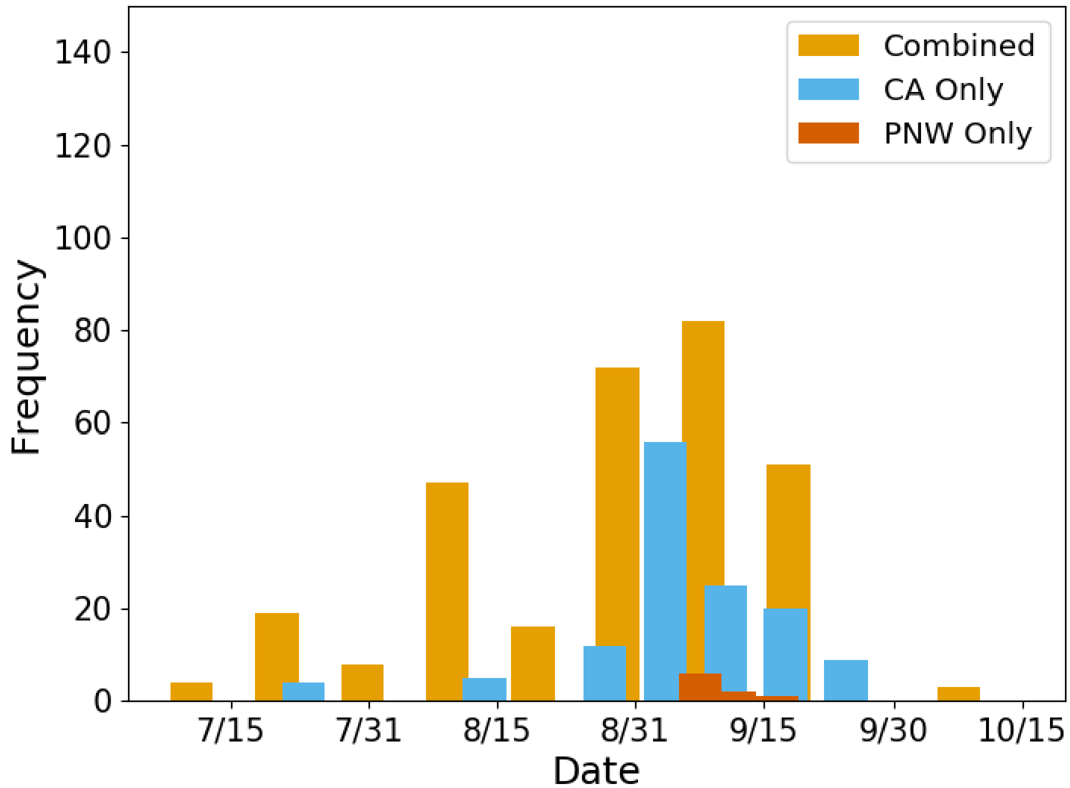

Figure 6. Timing of potential coincident shortfall events across both the Mid-C and CAISO systems across all 11 GCM-RCP-hydrologic model configurations and the four controlled experiment scenarios. There are no coincident shortfalls under hindcast climate conditions.

3.2 Impacts to Mid-C Market Prices

Figure 7 shows distributions of average annual wholesale prices in the Mid-C market. The highest prices tend to occur under RCP8.5 model configurations with climate change triggered for both regions simultaneously (Combined scenarios), which experience the largest decline in summer hydropower, the largest increase in summer demand, and thus the highest frequency of shortfall events priced at $1000/MWh. Looking especially at the RCP8.5 scenarios, the three climate change scenarios (CA Only, PNW Only and combined) significantly impact both the expected value of average annual prices in the Mid-C and the range of average annual prices experienced. Not only are prices higher on average under forecast climate change conditions, but also much more volatile within each model configuration. Increased variation in expected annual prices represents a growing risk for customers and utilities and their investors, both of whom may have to absorb part of this increased risk.

For 7 out of 11 model configurations (GCM-RCP-hydrologic) tested, triggering the four climate change scenarios (CA Only, PNW only, and then both regions combined) results in increases in median and interquartile prices, relative to hindcast conditions. The magnitude of increases in median and interquartile prices relative to hindcast conditions is less severe for the CA Only scenario and most severe for the combined scenario. This suggests that, in most cases, market prices in the Mid-C market will be most profoundly impacted by the effects of climate change in the Pacific Northwest, including higher summer temperatures and shifts in streamflow dynamics, given the system's dependency on hydropower to meet demand But climate change in California also has a clear impact on supply and demand (and thus prices) in the Mid-C market as well, as evidenced by the CA Only and Combined scenarios. In fact, for 4 out of 11 model configurations, triggering climate change in California alone (CA Only scenario) causes a greater increase in Mid-C prices than PNW Only conditions.

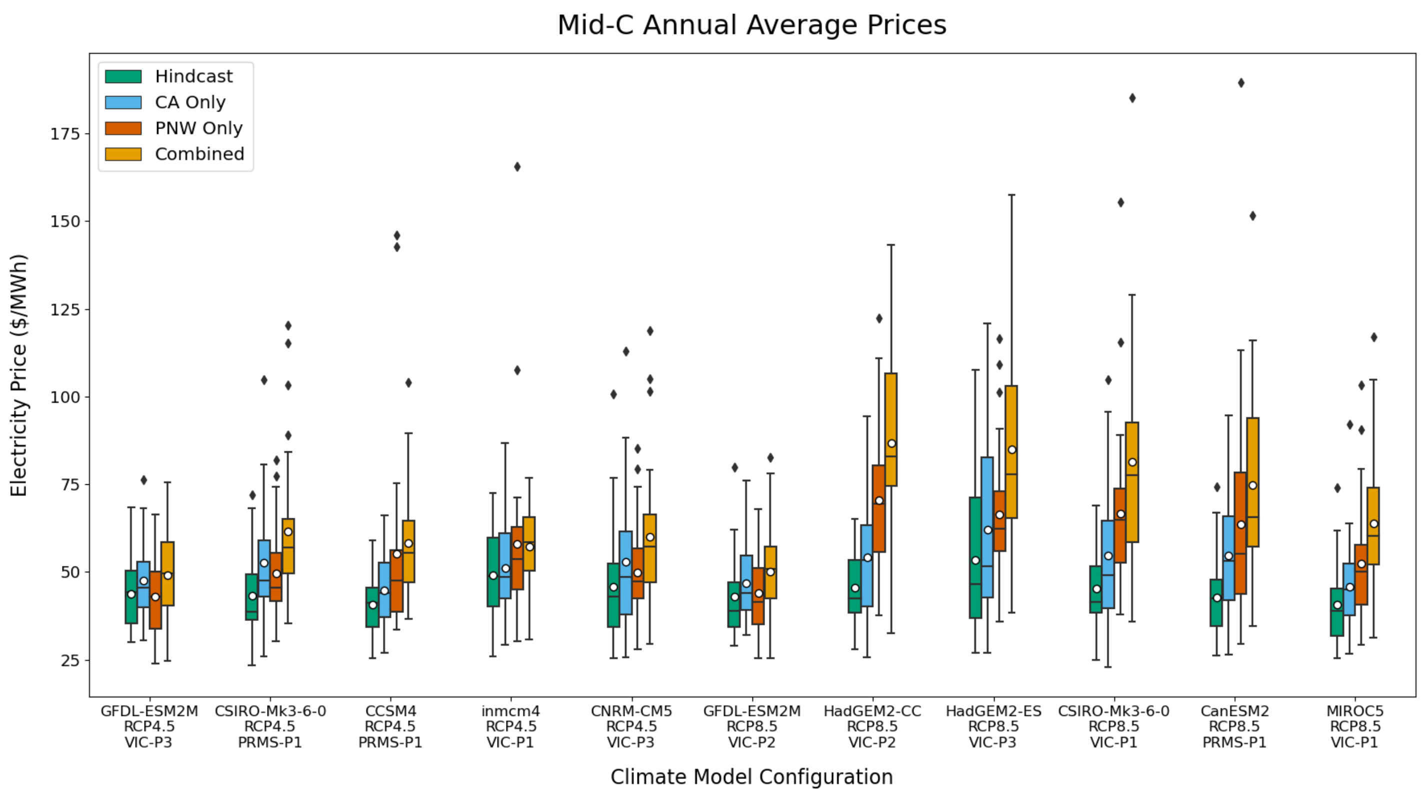

Figure 7. Distributions of Mid-C annual wholesale prices across 11 GCM-RCP-hydrologic configurations and four climate data scenarios. Each boxplot describes the distribution of average annual prices across 31 modeling years.

The underlying reason why (in some cases) the effects of climate change in California appears capable of having a greater impact on the Mid-C market than climate change in the PNW alone boils down to late summer streamflow dynamics. In the Mid-C system, the months with the highest frequency of shortfall events are August and September (shortfalls are priced at \$1000/MWh in the UC/ED model, easily an order of magnitude higher than average wholesale prices). In these post-snowmelt months, dams along the Columbia River produce comparatively little hydropower, and demand for electricity is higher due to warmer temperatures, resulting in greater resource scarcity on the grid. The four GCM-RCP-hydrologic model configurations (GFDL-ESM2M RCP4.5, CSIRO-Mk3 RCP4.5, CNRM-CM5 RCP4.5, and GFDL-ESM2M RCP8.5) that exhibit muted effects on prices under the PNW Only scenario compared to CA Only have a relatively low frequency of August and September potential shortfall events. This is due to higher than average August and September streamflow (Figure 8), translating to a greater availability of hydropower and an enhanced ability to meet demand for electricity during these typically dry months.

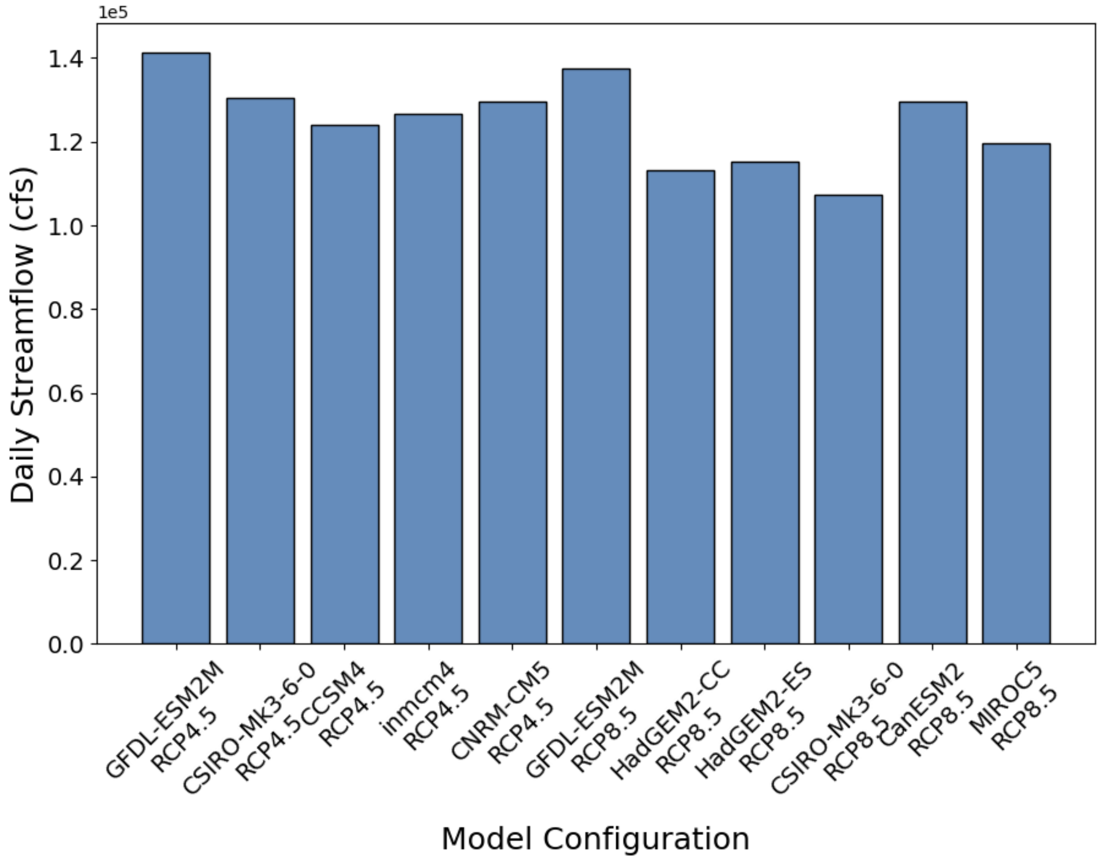

Figure 8. Average Daily Discharge at the Dalles Dam in Oregon in August and September, typically the driest months in the PNW. The Dalles is an important dam for hydropower decision-making, and thus serves as a suitable proxy for streamflow conditions in the PNW.

More nuanced dynamics between demand, generation and system performance metrics emerge from analysis of key state variables on a monthly timescale. Figure 9 visualizes monthly dynamics for one configuration, CanESM2 RCP8.5 PRMS-P1. Under the PNW Only and Combined scenarios, panel A shows shifts in monthly streamflow and hydropower, with decreases in summer months (the largest occurring in June and July) and increases in spring. Panel B shows increased demand in those same summer months, and decreased demand in winter. Note that shifts in the timing of hydropower generation is an order of magnitude higher (in MWh) than temperature-driven impacts to system demand, despite average temperature increases as high as 4.5°C in summer. Thus, we find shifts in hydrology within the PNW are likely to be the main driver of altered market dynamics in the Mid-C.

Given the size of the shift in streamflow and hydropower that occur in June and July, it may seem reasonable to expect these months to exhibit the largest climate change-caused increases in wholesale prices. However, Figure 9 shows that Mid-C prices in September experience the largest increase (panel C). September is typically a period of scarcity in the Mid-C market, even at baseline, because streamflows and hydropower production are minimal. We find that relatively small decreases in September streamflows caused by climate change, in concert with even smaller increases in demand, are enough to cause a significantly higher frequency of potential shortfall events (panel D). Due to our valuation of shortfall events at $1000/MWh, a higher frequency of shortfall events tends to be the major driver of large increases in prices in annually as well. This suggests that, even though the largest hydrologic shifts in the PNW may in traditional snowmelt months (i.e. June and July), the most *consequential* shifts could be more subtle effects that occur during months when the grid is already stressed. This phenomenon is largely consistent across all RCP8.5 model configurations under PNW Only and Combined climate change scenarios.

Figure 9 also provides further evidence that climate change impacts in California (namely, higher demand in the CAISO market) have an significant effect on Mid-C prices. For example, under the CA Only scenario, Mid-C prices increase in August and September relative to hindcast conditions (this result in consistent across all 11 model configurations). Under a Combined scenario, higher CAISO load works in tandem with shifts in PNW hydropower production to *increase* the volume of dispatched exports from the Mid-C into CAISO during August and September, when the PNW grid is already experiencing relative scarcity. This further increases the frequency of shortfall events and higher prices, and explains the substantial difference in late summer prices shown between PNW Only and Combined.

The effects of climate change in the PNW also increase the potential for spring oversupply events (priced at $0/MWh) to occur in the Mid-C market (panel E). Across all 11 model configurations, the frequency of April oversupply events is higher under climate change scenarios, and February and March oversupply events increase for most configurations (see Figure 9 for results for under CanESM2 RCP8.5 PRMS-P1). Increases in the frequency of oversupply events lowers average prices across the spring months, though to a much lesser extent than the potential increase in summer prices caused by more frequent shortfalls. Nonetheless, oversupply events represent important risks for generators. They can cause physical curtailment of wind and solar, leading to declining revenues (Su et al., 2017).

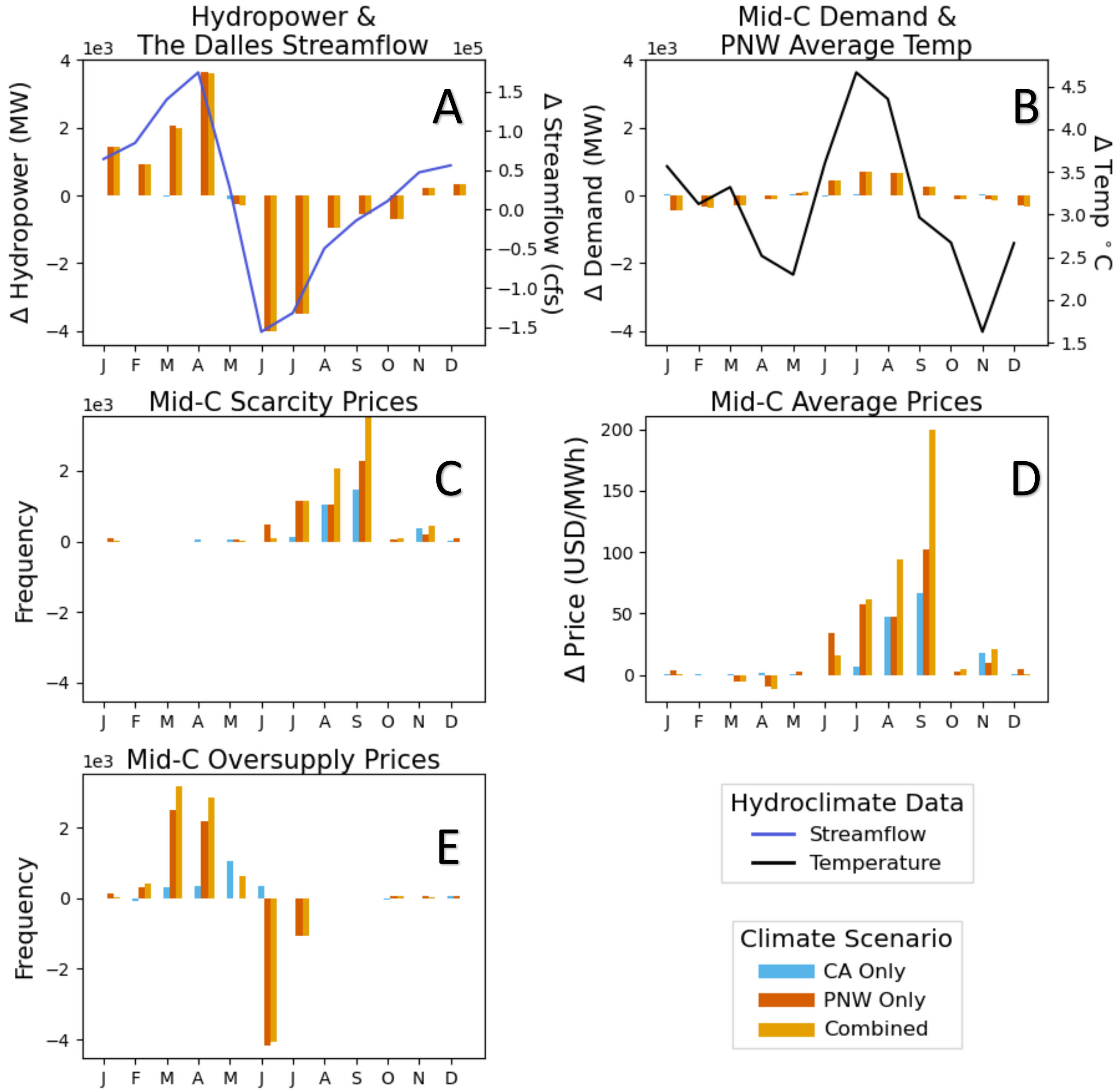

Figure 9. Changes in Mid-Columbia monthly system metrics under the CanESM2 RCP8.5 PRMS-P1 model configuration (color coded by scenario relative to hindcast conditions). These key metrics include: hydropower generation and streamflow at the Dalles (A), Mid-C demand and average PNW temperatures(B), scarcity price events (C), average Mid-C prices (D) oversupply price events (E).

3.3 Impacts to CAISO Market Prices

Figure 10 shows distributions of average annual prices in the CAISO market for the 11 GCM-RCP-hydrologic model configurations and 4 controlled experiment scenarios. A key difference is visible between these results and those for the Mid-C market (Figure 7). Namely, extra-regional climate change (i.e. in this case the PNW Only scenario) appears to have a very modest impact on the distribution of market prices in a neighboring market (CAISO). This is clear from the similarities between the distributions of prices under the PNW Only and hindcast scenarios, as well as similarities between the CA Only and Combined scenarios. It is somewhat expected that price effects in the CAISO system would be driven more by climate change in California; however, it does contrast sharply with the Mid-C results, which showed sensitivity to climate change in an adjacent region (California). This result is all the more surprising, because it appears to refute our original hypothesis that the most likely mechanism for climate change to influence interregional power market dynamics is for altered streamflow in the PNW to disrupt the delivery of hydropower south into the CAISO market.

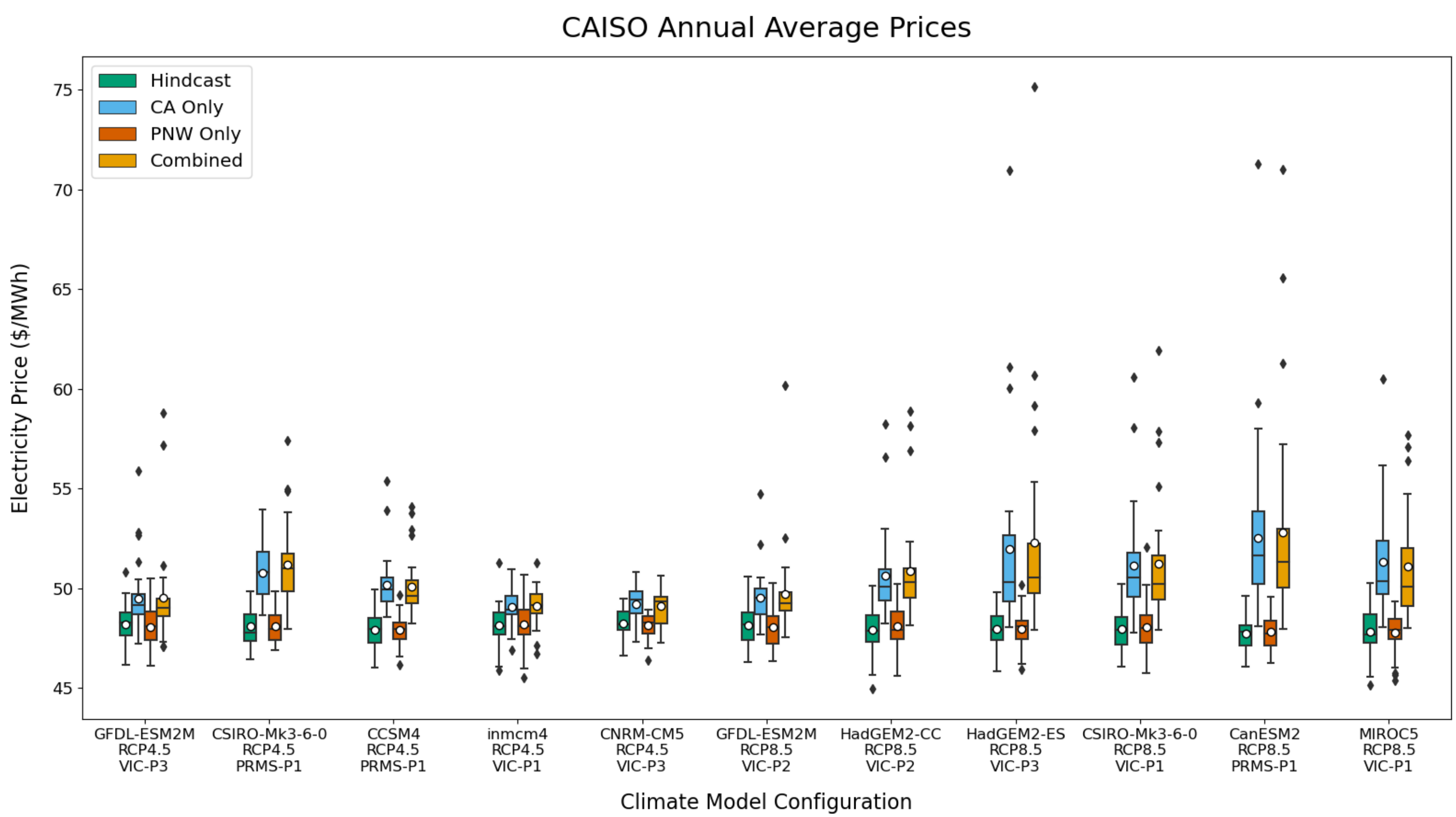

Figure 10. Distributions of CAISO average annual wholesale prices across 11 GCM-RCP-hydrologic configurations and four climate data scenarios. Each boxplot describes the distribution of average daily prices across 31 modeling years.

However, zooming in to sub-annual scales provides a more complex story about the role of climate change in the PNW on the CAISO market. Under a PNW Only scenario, CAISO prices in November-April decrease relative to hindcast conditions for a majority (8 out of 11) model configurations. This is due to an increase in available hydropower from the PNW during these months, made available by increased precipitation falling as rain in winter and earlier spring snowmelt. Consequently, a greater portion of CAISO demand is met with lower cost hydropower imports from the PNW, and prices decline. These decreases in spring and winter prices are balanced by corresponding increases in August and September prices under a PNW Only scenario, which result from less PNW hydropower being available in CAISO. Figure 11 provides an example of these dynamics for the CanESM2RCP8.5 PRMS-P1 model configuration.

Figure 11 also demonstrates the much stronger influence of intra-regional climate change on the CAISO market, specifically increased demand caused by higher air temperatures. Temperatures across California increase by 2.8°C on average in the CanESM2 RCP8.5 PRMS-P1 configuration, with the largest increases in temperature occurring in late summer. This increases electricity demand within CAISO from March to October (and decreases it slightly demand over winter months). Note that under the CA Only climate scenario, even without a change in the timing and amount of hydropower produced in the PNW, this increase in CAISO demand (combined with a shift in the time of hydropower production in California) "pulls" more power from the Mid-C market, especially in late summer. However, even increased hydropower imported from the Mid-C market is not sufficient to offset the increases in CAISO summer demand driven by hotter temperatures, which are roughly an order of magnitude larger. As a result, average CAISO summer prices increase dramatically. These results are largely consistent across all 11 model configurations, despite wide variability in Mid-C hydrology.

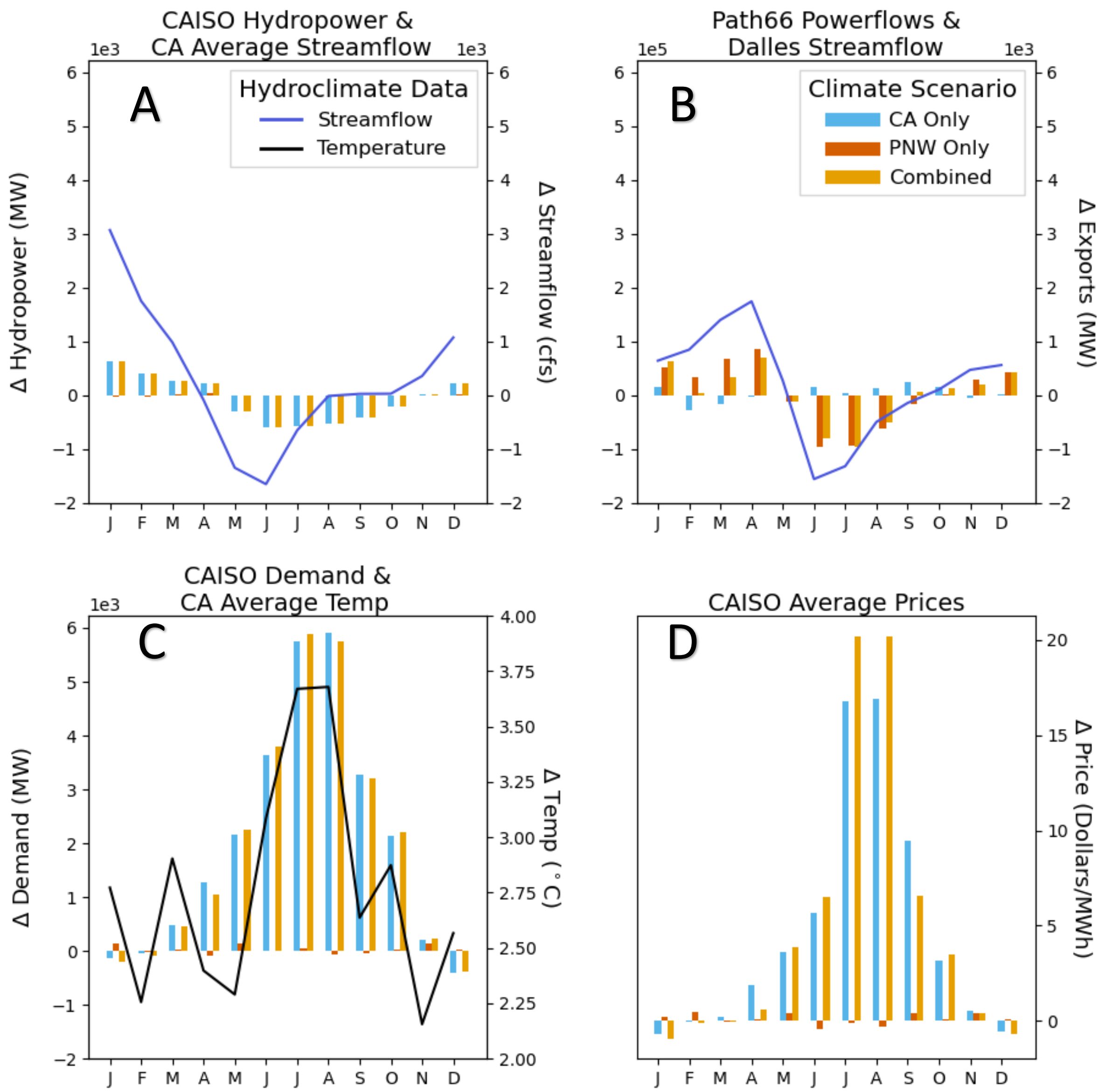

Figure 11. Changes in monthly state variables for the CanESM2 RCP8.5 model configuration, including: CAISO hydropower production (A), WECC Path 66 flows (B), CAISO electricity demand (C), and CAISO average wholesale prices (D). Panel A also visualizes monthly changes in streamflow at the Dalles, OR and Panel C shows monthly changes in average temperatures across the CAISO system. Changes are shown for three climate data scenarios relative to hindcast conditions.

3.4 Daily system dynamics

The impacts of regional climate change on system reliability and market price dynamics can be further explored by zeroing in on individual modelling years. Figure 12 shows one year of daily generation in the Mid-C (panels A and B) and CAISO (panels C and D) markets for a HadGEM2-CC RCP8.5 VIC-P2 model configuration, one of the worst in terms of vulnerability to increased shortfall potential in the Mid-C. This configuration also has the lowest overall forecasted hydropower generation of Mid-C configurations. For each respective system, the top panels (A and C) show generation under a PNW Only scenario, and the bottom panels (B and D) show generation under a Combined scenario. The data shown in Figure 12 correspond to the year 1993 for hindcast conditions and the year 2053 for all climate change data.

Panel A shows the daily generation mix in the Mid-C market under a PNW Only scenario (i.e. climate change conditions are applied in the PNW while hindcast conditions are applied in California). The average daily price is \$69.51/MWh, with prices over the summer months (June, July, August and September (JJAS)) reaching an average of \$140.70/MWh. These prices are close to the average experienced over the entire 2030-2060 simulation period for the PNW Only scenario under this model configuration (this can be considered a representative average year). Panel B shows the effects on the Mid-C market from triggering climate change conditions in California, in addition to the PNW Only scenario. The average price in the Mid-C system increases to \$120.51 and the average JJAS price increases to \$280.35/MWh. This additional stress in the Mid-C market is caused by a significant increase in September temperatures in California (+5.8°C compared to average hindcast conditions, and +2.9°C compared to the 2030-2060 average for HadGEM2-CC RCP8.5) which dramatically increases late summer electricity demand in CAISO (panel D). This leads to an increase in Mid-C exports during JJAS (+16.9% compared to the PNW Only scenario) and a higher frequency and magnitude of shortfall events in the Mid-C market (panel B). Considering this model configuration has the largest declines in Mid-C hydropower under forecasted climate conditions, any increases to dispatched exports into CAISO during times of extreme summer load will dramatically increase prices. This example demonstrates our consistent finding that extreme summer temperatures in California show an ability to further deteriorate outcomes on the PNW grid.

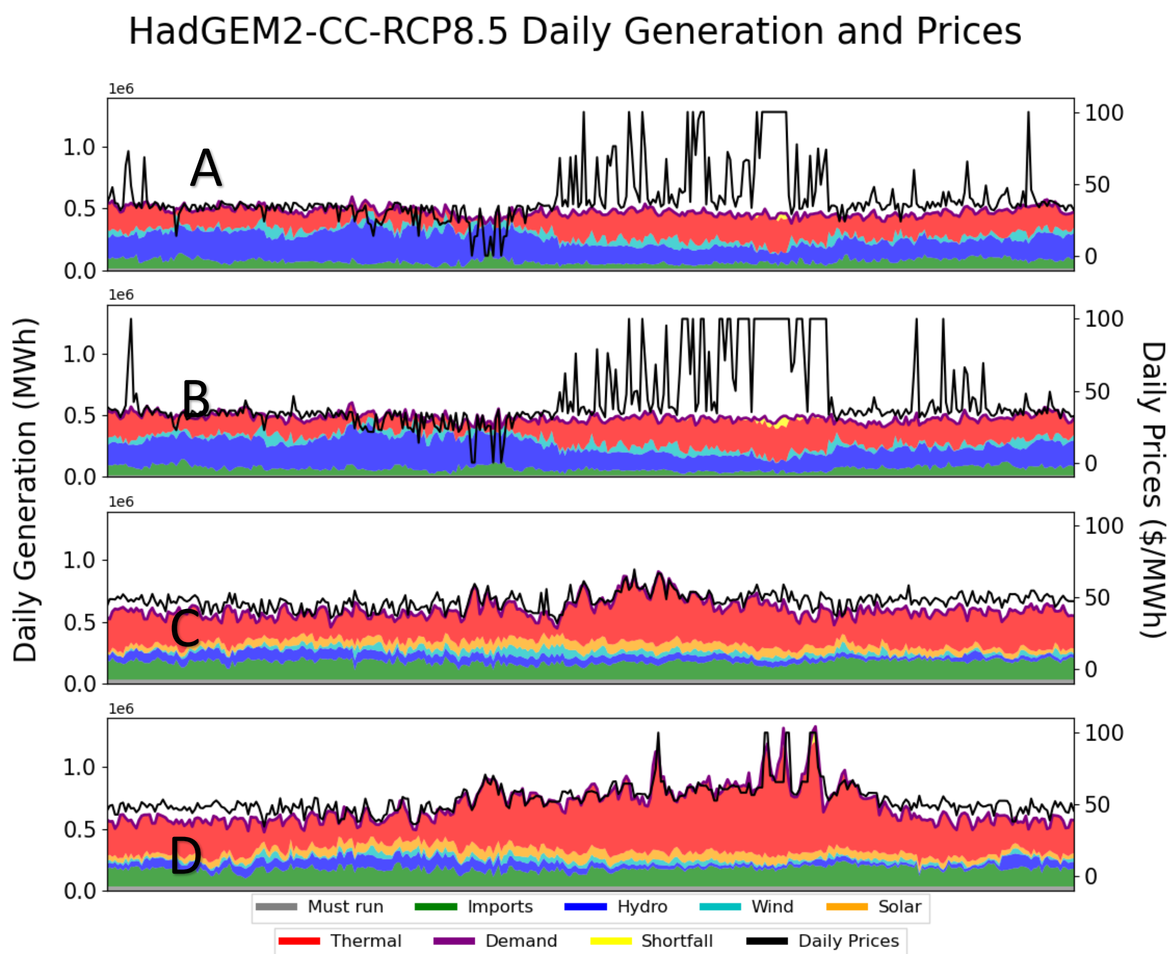

Figure 12. One year of daily generation and prices for the Mid-Columbia market (panels A and B) and the CAISO market (panels C and D) for two climate data scenarios: PNW Only (panels A and C) and Combined (panels B and D). This is a modelling year within the HadGEM2-CC RCP8.5 VIC-P2 model configuration. Note: In order to better visualize daily prices, any values above $100/MWh have been capped at this price.

3.5 Study limitations and future work

This work has a number of limitations and critical modeling assumptions, the primary one being we do not consider additional capacity expansion but instead analyze the impacts of climate change on 2016 grid resources in both the Mid-C and CAISO markets. Therefore, this work is not meant to serve as predictor of future market prices, per se, but rather an analysis of the impacts of climate change *in isolation* on existing power system reliability and prices. Future work should include both an exploration in future grid conditions and potential climate-driven vulnerabilities to supply and demand.

CAPOW simulates power flows between markets statistically based on historical data. In many cases, we thus assume that even in times of scarcity in the Mid-C market, power producers in the PNW would continue to export electricity into California. Furthermore, we assume imports from other regions within WECC (the Southwest for example) would continue at historical volumes. Ultimately, this dynamic would depend on established power trading agreements, and future work should explore the sensitivity of our results to altered trading structure and constraints.

Furthermore, our model does not price shortfall events according to the magnitude of an event (i.e. not meeting demand by 100 MW or 10000 MW results in the same hourly price). Although Figures 4 and 5 visualize the frequency and average magnitude of potential physical shortfall events above 100 MW, CAPOW prices unmet reserves at $1000/MWh as well. August and September potential shortfall events are more frequent, but the events with highest magnitudes occur in June and July, when temperatures are highest across both systems and demand is highest. Thus, our choice to make no distinction in the valuation of shortfall events influences our finding that the highest price increases from climate change tend to occur in August or September. It should be noted that system planners consider the magnitude of potential shortfall events just as if not more important than the frequency. The magnitude of shortfall events would inform capacity expansion. Another key assumption that may bias our findings is the restriction of daily simulated hydropower to a single 24-hour period within the UC/ED model. In reality, operators may decide to shift hydropower generation outside of this operational window to avoid costly reliability shortfalls. Future work should attempt to model the day-to-day shifting of hydropower generation in this region, especially during times of scarcity. Another related area of exploration is the addition of long-duration (12-24 hours) seasonal storage of hydropower, giving the operators greater resource flexibility to meet peak late summer demands.

CHAPTER 4: CONCLUSIONS

Impacts of climate change on interconnected, hydropower-dependent power markets are examined in this work. Changes in system reliability (the ability to meet hourly demand with existing generation) and wholesale market prices are analyzed for both the Mid-Columbia and CAISO systems using an open-source power simulation software, CAPOW, and an expansive set of climate model configurations, including 10 GCMs, 2 RCPs, and 4 hydrologic model calibrations. We are able to isolate the impacts of climate change in one of these markets on the dynamics of the other by way of a controlled experiment, in which forecasted climate conditions are applied to one system's generation and demand at a time.

Overall, we find that, without significant capacity expansion or demand-side management, both the Mid-Columbia and CAISO systems would become more vulnerable to an increased frequency of potential shortfall events under forecasted climate conditions, both of which exhibit more severe outcomes under RCP8.5 forcings. We find that CAISO is at risk for reduced reliability when forecasted climate change conditions in California are applied, but climate impacts in the PNW show little potential for affecting reliability and prices in the CAISO system. This is an unexpected finding, given the potential for climate change in the PNW to alter the timing and magnitude of hydropower production in the Mid-C market and CAISO's reliance on that imported power. Instead, we find that changes in CAISO demand (driven by warmer temperatures) to be a significantly larger influence than any shift in hydrology and hydropower production. In contrast, impacts to reliability and prices in the Mid-C market are more strongly influenced by shifts in hydrology rather than temperature-driven changes to electricity demand. We also find that the risk of simultaneous blackout (loss of load) events could increase across both systems, especially under an RCP8.5 future, but remain a relatively rare event.

In both markets, prices are higher on average under combined climate change conditions relative to hindcast conditions, which is largely driven by increased frequency of scarcity price events ($1000/MWh) over summer months. Prices in both markets under the combined climate scenario are overall more volatile and the within model configuration variability (across the 31-year modelling period) increases compared to hindcast conditions. In the Mid-C, volatility of annual prices also increases dramatically under the PNW Only scenario, especially for RCP8.5 forcings. For the CAISO market, the CA Only or PNW Only scenario has little impact on market prices for RCP4.5 forcings, but the CA Only scenario causes annual prices to be more volatile for the RCP8.5 model configurations.

We also find the Mid-Columbia system to be potentially more vulnerable to oversupply events under forecasted climate change conditions due to the shift in hydropower generation away from summer to spring, when electricity demand is relatively low. In contrast, $0/MWh hourly price events are quite rare. An increased frequency of oversupply events further contributes to the within year volatility of market prices, which is risky for stakeholders/investors. The compounded impact of reduced hydropower generation in summer when prices are higher and increased generation when demand is low and the system is more susceptible to oversupply is particularly problematic for hydropower producers, who assess the financial viability of continued investment (such as physical upgrades, FERC re-licensing, etc.) on forecasted returns based on market prices.

The results of this study can provide useful insights into how forecasted climate change conditions may impact the reliability and market price dynamics of two interconnected power systems in the U.S. Although our work does not consider capacity expansion, these findings can be used as a tool to inform long-term system planning. Policymakers, utilities, power producers and other important stakeholders should consider the implications of climate-driven changes to key power system metrics not only in their respective markets & regions, but also analyze the possible additional vulnerabilities due to climate impacts in other regions.

APPENDIX A: LIST OF GCMS, RCPS AND HYDROLOGIC MODELS

Global Climate Models	CanESM2 CCSM4 CNRM-CM5 CSIRO-Mk3-6-0 GFDL-ESM2M HadGEM2-CC HadGEM2-ES Inmcm4 IPSL-CM5A-MR MIROC5
Representative Concentration Pathways	RCP4.5 RCP8.5
Hydrologic Models	VIC-P1 VIC-P2 VIC-P3 PRMS-P1

APPENDIX B: CAPOW WORKFLOW

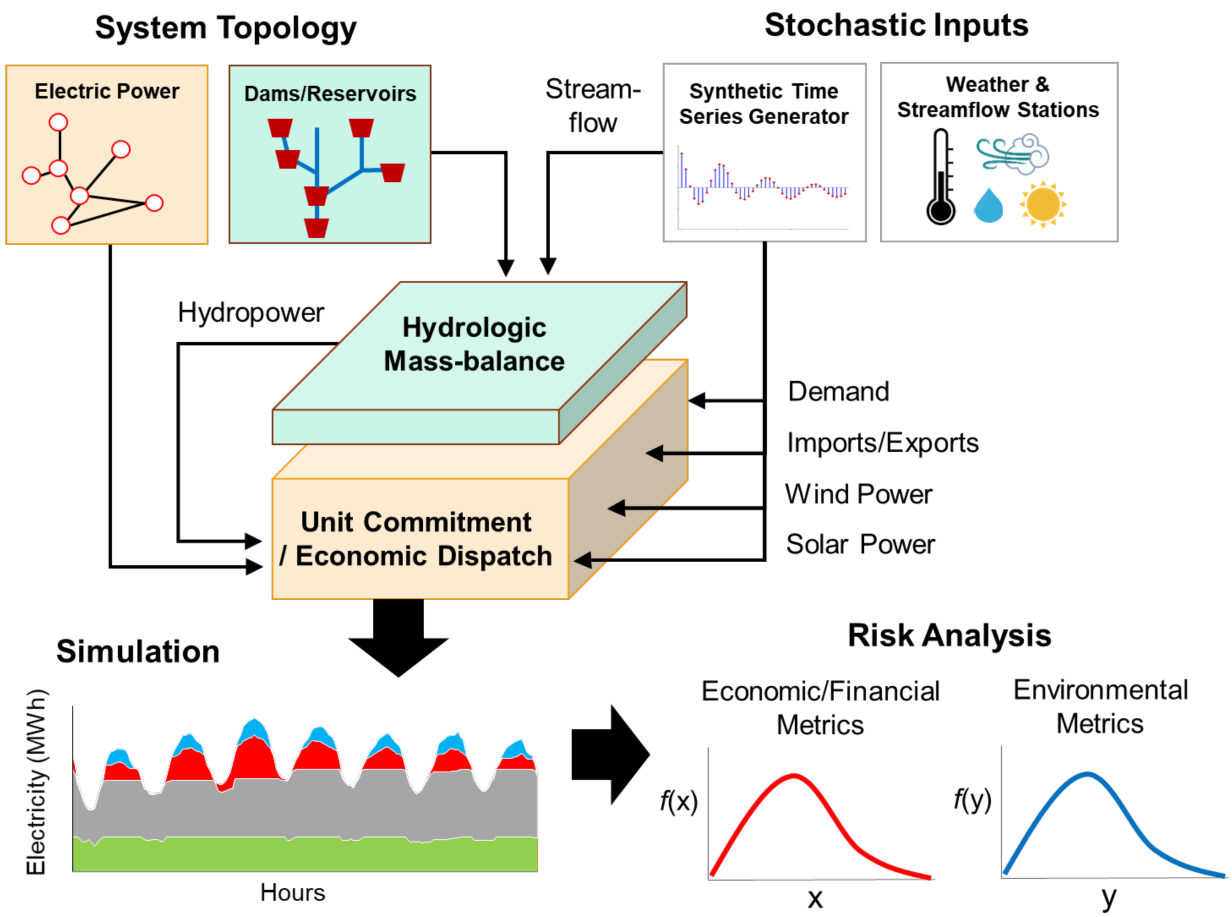

Figure B1. Schematic showing model workflow of CAPOW, as described in Su et. al 2019. In this work, stochastic representatives of historical data are replaced with hydroclimate data described in Section 2.1 (Su et al., 2020).

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