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Climate Influences on Capacity Expansion Planning with Application to the Western U.S.

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Abstract

Electric power system planners utilize a variety of planning tools to inform decisions concerning generation and transmission additions to the electric grid, the need for operational changes, and to evaluate potential stressors on the system. Numerous factors contribute to the planning process including projected fuel and technology costs, policy and load profiles. There is also a growing recognition of the interdependency of the electric grid with other natural and engineered systems. Here we explore how future climate change and hydropower operability might influence decisions related to electricity capacity expansion planning and operations. To do so we assemble a multi-model framework. Specifically, water resource modeling is used to simulate climate impacts on future water supply for thermoelectric and hydropower generation. Separately, temperature impacts on electricity load are evaluated. Together, these climate factors spatially constrain a capacity expansion model that projects generation and transmission additions to the grid. The projected new capacity-builds are then evaluated on their operations, reliability, and cost under average and extreme climate conditions using production cost modeling. This coupled framework is demonstrated on the electric grid in the Western U.S., supporting capacity expansion planning by WECC, the North American Electric Reliability Corporation (NERC) regional entity responsible for reliability assurance of the Western Interconnection. This region was selected in part because the West is unique in that it has high potential for renewable penetrations and is experiencing large retirements/displacements of baseload resources, primarily coal, leading to possible operational challenges in terms of changing resource mix and the need for resource flexibility. Toward this challenge, planning scenarios encompass a range of alternative energy, climate and drought futures. In this context we explore answers to two strategic questions: 1) How does changing climate influence electricity expansion planning (generation and transmission) and future operations, including type and capacity of new builds, system reliability, cost and environmental impacts? 2) How does the representation of hydropower in the modeling framework influence the evaluation of bulk power system operations ? Results indicate that climate has a measurable influence on recommendations concerning the capacity, type and location of new generation and transmission additions, with up to 17 GW additional capacity needed by 2038 to meet peak loads (~6.6% increase over capacity-builds based on historical climate). The extent of additional infrastructure needs is strongly influenced by future water availability for hydropower and the potential deployment of demand response technologies. Systems designed for future climate conditions were found to maintain high system reliability under a range of electricity and water availability scenarios (including significant drought), with minimal system curtailments. Additional capacity needs due to higher load tend to increase cumulative 20-year investment and operating costs by $5–$17 billion and generation costs increase by 9 to 19%. Finally, changing the representation of hydropower flexibility has a relatively small influence on capacity expansion in the Western Interconnection through 2038, but hydropower flexibility impacts generation costs to a similar extent as climate.

Contents

1. Introduction

Changing climate will influence the way our electricity grid looks and operates in the future. Climate will influence loads, increasing summer peak demand while likely decreasing winter loads (Dirks et al 2015; Sathaye et al. 2013; Allen et al. *2016;* Auffhammer et al. 2017*)*. Increasing temperatures will reduce the capacity of transmission lines (Bartos et al 2016; Sathaye et al. 2013), transformers and substations (Sathaye et al. 2013) while also reducing the efficiency of power conversion and steam cycle cooling (Chuang and Sue 2005; Durmayaz and Sogut 2006; Ibrahim et al. 2014). Climate change will affect river flows causing alterations in operations at thermoelectric plants due to limited water supply or elevated river temperatures (Bartos and Chester 2015; Van Vliet et al. 2012; Miara et al 2017; Miara et al. 2018; Henry and Pratson 2016; Henry and Pratson 2019). Changes in snowpack extent and timing of spring melt will influence when hydropower production is available and overall generation capacity (Zhou et al. 2018; Turner et al. 2017a; Van Vliet et al. 2016; Kao et al. 2015; Hamududu and Killingtveit 2012; Vicuna et al. 2011). The changing climate will also impact the availability of water for new development and thus challenge the siting of new thermoelectric generation (Roy et al. 2012; Sovacool and Sovacool 2009).

Traditional electricity system planning has relied on capacity expansion modeling where technology, market, policy, social, cultural and environmental assumptions constrain the least-cost solution for reliability assurance which includes system adequacy, stability, flexibility, resilience and others. Informed planning is critical as capital expenditures for new electricity generation and transmission infrastructure have multi-decadal life expectancies (e.g., EIA 2018a), consistent with the timeframe over which climate effects are projected to intensify (IPCC 2014; Schaeffer et al. 2012). This convergence provides a clear need for including climate change impacts into long-term capacity expansion planning. Although the potential importance of climate and water considerations has been recognized (Buras 1979) they are still not necessarily part of planning practice (NAERC 2015).

Recent studies have begun to consider climate related stressors in electricity systems planning across multiple domains, using a variety of approaches. Climate related impacts on the demand of Macedonia's energy system were explored utilizing capacity expansion modeling configured to evaluate both damages and benefits of adaptation (Taseska et al. 2012). Similarly, national energy system adaptation pathways for Brazil were assessed while climate change impacts on the availability and efficiencies of hydropower and thermoelectric power were addressed through adjusted capacity factors (de Lucena et al. 2010). Multi-model studies of capacity-builds in Brazil (Lucena et al, 2018) and Columbia (Arango-Aramburo, 2019) demonstrate the sensitivity of simulated capacity expansion decisions to both climate change and model structure and assumptions. Webster and others (2013) explored climate impacts on capacity expansion decisions for the Electric Reliability Council of Texas, where restrictions were established through arbitrary limits on water withdrawals and CO_2 emissions at thermal power plants. They found that simultaneous restriction of CO_2 emissions and water withdrawals required a different mix of energy technologies and higher costs than one would plan to reduce either CO_2 or water alone. The Global Change Assessment Model (GCAM), a technologically-detailed integrated model of the economy, energy, agriculture, water, and climate, has been used to assess global power capacity-builds under climate-influenced hydropower scenarios (Turner et al., 2017b) and has also been extended to model the electricity-water nexus at the state level in the U.S. (Liu et al. 2015). This analysis was extended by including climate related physical water constraints which projected increased cost of electricity generation, early retirement of water-intensive technologies and increased investment in low-water use technologies (Liu et al. 2019). Parkinson and Djilali (2015) demonstrated a robust optimization approach to capacity planning under climate change for the electricity system in British Columbia (BC), Canada. The coupled electricity-hydroclimate framework co-optimized system operations and capacity additions for a system consisting of eight major hydropower stations, which service more than 90 % of BC's annual electricity demand, and other ancillary services. Sridharan et al. (2019) evaluated capacity expansion plans in Eastern Africa where considering the impact of climate change on hydropower would impact regional prices and operations with adjacent countries.

Here we build upon and extend this past body of work by introducing climate-informed production cost modeling as a means of examining the operations, reliability and cost of projected capacity expansion plans. A multi-model framework is constructed that borrows key elements from the work of Miara et al. (2019) that integrates climate-driven hydrological, thermal power plant, and capacity expansion modeling. These tools are loosely coupled and accommodate detailed spatial representation over a large geographic extent. In this study, we expand this framework to include representation of hydropower, in both the hydrologic and capacity expansion modeling, and for the first time include production cost modeling to evaluate short-term operations of the capacity expansion plans under significant drought conditions.

We focus on the Western Interconnection, which relies on hydropower to provide 25% of its generation, albeit with significant sub-regional diversity. Simulated grid operations using a current infrastructure have shown sensitivity to long-term changes in water availability and extreme drought (Voisin et al. 2018) although alleviated with sub-regional diversity and power flows (Voisin et al. 2020). In this context we explore answers to two strategic questions: 1) How does changing climate influence electricity expansion planning (generation and transmission) and future operations, including type and capacity of new builds, system reliability, cost and environmental impacts? 2) How does the representation of hydropower in the modeling framework influence the evaluation of bulk power system operations? While results are specific to the Western Interconnection, they still provide general insight into the integration of water and climate into capacity expansion planning and their potential to influence capital investment decisions.

2. Methods

2.1. Study Scope

Grounding the modeling framework in a real-world context is crucial for the developed product to address problems important to industry. Here we teamed with the Western Electricity Coordinating Council (WECC) which promotes bulk power system reliability and security in the Western Interconnection. WECC's footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between (Figure 1). The WECC region includes 258 GW of total electric generation capacity including 71 GW of hydropower for a population of over 80 million (WECC 2018). Due to limitations in model geographical scope as described below, our analysis is limited to the U.S. portion of the WECC service area, which includes 225 GW total generating capacity and 49 GW of hydropower.

Core to WECC's mission is reliability planning and resource assessment. Of growing concern to WECC is understanding how changes in future climate and water availability might affect investment and dispatch decisions and grid reliability in the Western Interconnection; how climate and water impacts change under alternative climate projections and electric system drivers; and how the role of hydropower might change under future climate and water conditions. Measures of interest include reserve shortages, unserved energy, locational marginal zonal electricity prices, generation cost, average electricity price, Greenhouse Gas emissions, transmission path usage and expansion needs, and capacity/generation by generator type and zone. The target horizon for the assessment is the year 2038, selected based on input from WECC and represents an 18-20 year horizon.

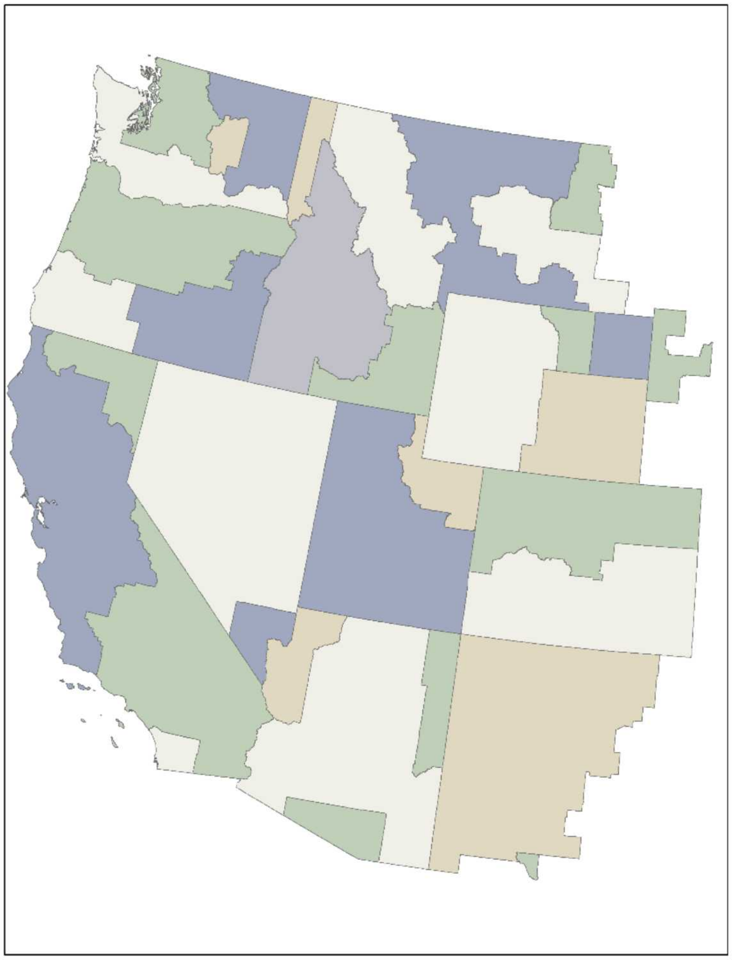

Figure 1. Map showing the U.S. portion of the Western Electricity Coordinating Council (WECC) with the variously shaded areas representing the ReEDS model Balancing Areas (BAs).

2.2. Scenario Description

WECC planning is comprised of different areas of focus: near-term (0-5 years), planned (5-10 years), and long-term (10-20 years). The focus of this study pertains to long-term. The ultimate goal of WECC long-term planning is to inform strategic choices for planners and other stakeholders in a 20-year planning horizon (i.e. 2038). To address uncertainties in climate, resource demands, policy, technology and other electricity system drivers, a scenario planning approach is used. Four electricity expansion scenarios and four alternative future climate projections were adopted, with additional scenarios to explore the range of possible hydropower dispatch in greater detail. The four electricity scenarios are intended to span a range of alternative infrastructure development pathways, including:

- Reference-case (REF) using demand and fuel prices from the 2018 U.S. Energy Administration (EIA) Annual Energy Outlook (AEO) (EIA 2018b) and technology costs from the 2018 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) Mid-Cost Case (NREL 2018);
- Low variable-generation (renewables) cost case (LOW.VG.COST) that adjusts wind and solar technology cost projections to use the 2018 ATB Low-Cost Case (NREL 2018);
- High variable-generation (renewables) cost case (HIGH.VG.COST) that adjusts wind and solar technology cost projections to use the 2018 ATB High-Cost Case (NREL 2018); and
- High-electrification scenario (ELEC) with higher electricity demand based on transportation and building electrification aligned with the NREL Electrification Futures Study (EFS) (NREL 2020) High Technology Adoption, Moderate Technology Advancement case with moderate demand flexibility.

Four alternative climate futures are used to assess potential impacts of changes in temperature and water supply on electricity demand, thermoelectric power plant operations, and hydroelectric generation. Impacts are taken relative to a fixed future for each electricity scenario where the climate is implicitly assumed to remain constant at historical conditions. The four climate projections were selected to capture a broad range of future temperature and precipitation trends in the Western U.S. This was achieved with two climate scenarios for each of the moderate (RCP4.5) and extreme (RCP8.5) emissions pathways. For RCP4.5, we use IPSL-CM5A-LR and GFDL-ESM2M climate model data, and for RCP8.5 we use IPSL-CM5A-LR and MIROC-ESM-CHEM data. Throughout, these scenarios are referred to as IPSL45, GFLD45, IPSL85, and MIROC85.

From these four climate scenarios three representative “drought” years were selected for driving the production cost modeling. These include a year with significant drought, a historic drought year and an average climate year (see Section 3.1.3). These are complimented by three projected future load conditions, high, medium and baseline.

Finally, two additional scenarios allow an expanded assessment of hydropower dispatch outcomes by adjusting the flexibility of dispatchable (not run-of-river) hydropower. These scenarios, HIFLEX and LOFLEX, are selected to bookend the likely range of hydropower flexibility within the existing non-pumped storage hydropower fleet. HIFLEX allows power output at dispatchable facilities to span the full range from zero to the maximum generating capacity and ramp from zero to maximum output within 1 hour, while LOFLEX requires fixed output across monthly or seasonal durations and halves default ramp rates. Due to differences in temporal resolution of grid operations and planning models described in Section 2.3.3, LOFLEX is implemented such that output is constant across each month in hourly operations modeling and each season in planning modeling.

2.3. Multi-Modeling Platform

Here we describe a multi-model framework that explicitly incorporates climate related factors into long-term capacity expansion planning and grid operations. The framework integrates three elements:

hydrologic modeling, capacity expansion modeling, and production cost modeling (Figure 2). Analyses begin by establishing model drivers and assumptions corresponding to each electricity and climate scenario (e.g., Section 2.2). Hydrologic modeling (VIC-MOSART/WM) then determines for each climate and hydrology scenario the monthly availability of hydropower across the Western Interconnection as well as estimated changes to cooling water availability for thermal generators. Given estimated water availability, temperature-sensitive loads, and generation technology costs, capacity expansion modeling using the Regional Energy Deployment System (ReEDS) determines the least-cost future power sector capacity-build that meets WECC system reliability and other requirements. Projected capacity-builds for the year 2038 at the balancing area spatial level are then downscaled into a future generator database for the Western Interconnection implemented into the PLEXOS electricity production cost model, which determines the least-cost hourly operation of the system under load and reserve requirements as well as detailed generator operating constraints. Together, this modeling platform explores climate impacts on infrastructure planning, operation, and reliability at high spatial, temporal, and process resolution. Below we describe each model framework component.

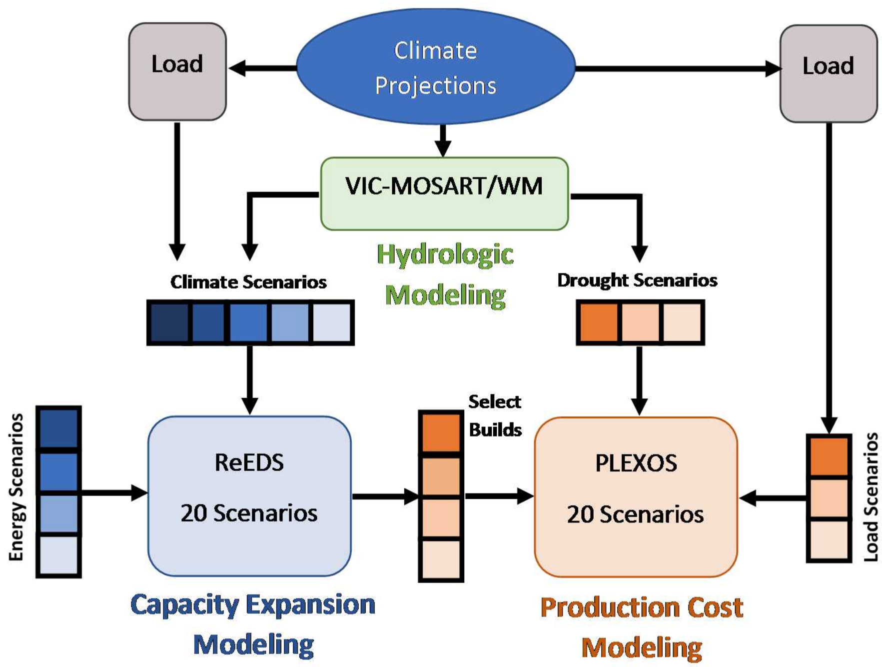

Figure 2. Schematic of the multi-model simulation framework.

2.3.1. Hydrologic modeling for long term trends and drought

Hydrological modeling is performed at two separate junctures of this study. First, it is used to support the capacity expansion modeling in ReEDS (see Section 2.3.2) where hydrological simulations are used to generate long-term seasonal projections of hydropower availability and thermal cooling water availability commensurate with the four climate scenarios selected. Second, the hydrological modeling is used to force the production-cost modeling performed in PLEXOS under significant drought and average year conditions (see Section 2.3.3). In this study, all hydrological simulations are conducted using VIC-MOSART-WM. The Variable Infiltration Capacity model (VIC) (Liang et al. 1994) provides spatially distributed runoff at one eighth degree grids and at a daily temporal resolution (Brekke et al. 2013).

Runoff are routed to streamflow using the Model for Scale Adaptive River Transport with Water Management (MOSART-WM) (Voisin et al., 2013). The WM (Water Management) component of this model enhances the MOSART river routing (Li et al. 2011) with human water demands and regulation by reservoirs.

***Input to ReEDS**:* Projections of long-term change in hydropower and thermal cooling water availability for ReEDS are created by first driving MOSART-WM with VIC runoff derived from downscaled, bias-corrected climate projections (Reclamation, 2013) for each of the selected GCMs (Section 2.2). We then extract simulated, regulated river flows for grid cells associated with power plant locations. These are aggregated to annual flows and standardized by expressing as a ratio to long-term average flow conditions. The ReEDS model develops incremental infrastructure expansion at the scale of Balancing Authorities (Bas), which is an intermediate scale smaller than the entire system (Figure 1). Within each BA load must be balanced at all times, providing the desired scale for resources adequacy and reliability studies. For each BA, standardized stream flow time series are combined as a weighted average, with weighting based on total nameplate capacity of plants occupying each grid cell. The resulting time series for each BA is referred to as the Water Scarcity Grid Impact Factor (WSGIF) (Voisin et al., 2016). In this work, the WSGIF is computed separately for hydropower and thermal facilities, and the time series of WSGIFs are smoothed with a Loess spline and rebased to the a 30-year time slice centered on 2018, resulting in trends (% difference from baseline) in hydropower generation and thermal plant capacity projected to 2038. These annual time series of generation constraints inform the capacity expansion modeling.

Input to PLEXOS: To provide drought scenarios for electricity production cost modeling, monthly estimates of energy availability are required for all non-fixed hydropower plants included in PLEXOS. To convert monthly simulated flow to hydropower availability, a statistical approach is adopted. Using monthly, plant-level generation data (EIA 2018a) as the predictand, a linear flow-power model is trained for each plant and calendar month. This approach provides flexibility in the conversion of flow to power by month, and therefore it accommodates seasonal changes in reservoir storage levels (affecting hydraulic head) and spilled (non-powered) releases for compliance with environmental regulations. These linear models provide adequate, flow-driven seasonal power projections at both plant and regional scales. A year with significant drought and an average year are selected from the 800 years simulated in the hydrological model for future use. These years are selected using a measure of WSGIF which typically ranges from 0.3 to above 4 in highly variable regions, with the typical median value around 1.9. We use the WSGIF to select an average year as well as a number of drought years that are not only the most extreme overall across the West, but are also significant within each of the major reserve regions the Western Interconnection.

2.3.2. Capacity expansion modeling

ReEDS is an electric sector capacity expansion model for the contiguous U.S. that minimizes the cost of investment and operation for electricity generation, transmission, and storage through a future year up to 2050 (Cohen et al. 2018). Since its inception in 2003 it has been used in a multitude of analyses exploring future renewable energy deployment, policies, and climate-water impacts (Miara et al. 2019; Cole et al. 2018; DOE 2016; DOE 2019; Cole et al. 2019; Frazier et al 2019; Mai et al 2019).

ReEDS is formulated as a deterministic linear program optimization, and the 2018 version employed for this analysis executes in 2-year solution time steps through a 2038 end year, chosen to align with current WECC system planning studies (Cohen et al. 2018). The model is executed for the contiguous U.S. to preserve any cross-interconnect electricity relationships, but this analysis focuses specifically on results within the Western Interconnection. The WECC region is resolved into 35 BAs for which load and generation resources are resolved, and these BAs are connected by an aggregated transmission system with capacity and flow constraints. The generating fleet composition is initialized using the ABB Velocity Suite (2017) database, which also includes data for known construction and retirements. As demand and corresponding capacity and reserves needs rise over time, the model represents economic competition between a suite of generation and storage technologies and can expand transmission capacity to accommodate system needs. While this analysis uses PLEXOS for detailed study of electricity system operation, ReEDS employs a reduced-form dispatch within each model year to better represent electricity cost and value streams. This dispatch formulation balances supply and demand in four chronological time slices in each season (morning, afternoon, evening, night) along with a time slice for the average of the 40 highest summer demand hours, which allows ReEDS to better capture capacity needs at peak demand. This chronological intra-annual time resolution incorporates consistent load and renewable generation profiles, opportunities for diurnal energy arbitrage, and curtailment reduction by storage systems. Variability of wind and solar resources is assessed by capacity credit calculations using 8760-hourly data, statistical estimations of curtailments, and published relationships between variable renewable deployment and operating reserve requirements due to forecast error. This structure updates variable generator characteristics to align with the time-varying generation portfolio, allowing for a detailed regional look at electric sector investment decisions under a broad range of scenarios.

Climate change impacts are endogenously represented in ReEDS in several ways. For temperature impacts, the model uses heating and cooling degree data, following the approach detailed in Miara et al. 2019, to represent temperature impacts on electricity load and power system performance. Electricity load impacts use regressed sensitivities of load to temperature based on Sullivan and others (2015) and McFarland and others (2015), accounting for differences in temperature sensitivity across regions and time-of-day. Transmission capacity and power generation capacity and efficiency are also reduced for thermal generators during summer afternoon time slices using relationships developed by ICF (1995) and Jaglom and others (2014)), though previous work finds these relationships to have little effect on capacity expansion results (Steinberg et al. 2020).

Changes to water availability for thermal cooling and hydropower in the Western Interconnection utilize VIC-MOSART-WM model output (Section 2.3.1), with results aggregated to ReEDS spatial and temporal resolution. Thermal cooling water availability impacts are applied as constraints on surface water availability that limit the quantity of water withdrawn across the thermal generating fleet for each season and BA (Miara et al. 2019). Availability and cost of alternative sources of water (e.g., groundwater, wastewater) are provided by Tidwell and others (2014). These constraints then limit electricity generation potential according to reduced water availability. Similarly, seasonal energy availability for hydropower is adjusted over time with the changes to hydropower water availability assessed by VIC-MOSART-WM.

Climate change impacts on future wind and solar resource availability are not represented in ReEDS. These effects are subject to ongoing research and could potentially be implemented in the model for future scenario analysis (Craig et al. 2018, Stengel et al. 2010).

Hydropower flexibility sensitivity scenarios are implemented in ReEDS using the existing hydropower modeling formulation that differentiates between dispatchable and non-dispatchable hydropower using data from the TEPPC 2024 Common Case (WECC 2013). For the HIFLEX scenarios, minimum fractional output for dispatchable hydropower is set to zero, along with full flexibility within the seasonal energy limits across time-slices in each season. For LOFLEX scenarios, minimum fractional output for dispatchable hydropower is set to one, requiring fixed output across all time slices in a season at the maximum allowable value within seasonal energy limits.

ReEDS is used to project infrastructure in the Western Interconnection through 2038 for all combinations of electricity and climate scenarios (see Section 2.2), along with a set of baseline simulations assuming historic climate conditions for each electricity scenario. Climate impacts are applied after 2020 to maintain consistent historic climate conditions. The resulting 20 simulations that serve as the basis of the generation capacity and transmission results are discussed in Sections 3.1.1 and 3.2.1. ReEDS also projects capacity expansion for HIFLEX and LOFLEX variations on each electricity scenario with historic climate, as discussed in Section 3.3.1. A subset of these projections is then used in detailed grid operations modeling as discussed below.

2.3.3. Grid operation modeling under climate warming and significant drought

Production cost modeling simulates optimal operations of a power system by minimizing generation cost, including energy and reserve provision. We use PLEXOS software to simulate hourly operation of the alternative electric-system capacity-builds determined by ReEDS for the year 2038. The simulation includes the Texas and Eastern Interconnections, but we focus our analysis on the Western Interconnection (interaction among the interconnections is limited). We downscale the ReEDS-determined 2038 BA-level capacity mix to establish a unique location and facilitate plant-level unit commitment decisions in hourly operations. One exception to this procedure is the existing hydropower fleet, which is not taken from ReEDS but is instead taken from plant-level models used in O'Connell and others (2019) so that the plant-level capacities and baseline monthly flows are consistent with the drought scenarios. We use a direct current-optimal power flow in the production cost model transmission solution with transmission aggregated to 35 balancing authorities (BA) in the Western Interconnection registered with WECC. We simulate 2038 operations in 6-month partitions, where the second 6-month partition repeats simulations of the last two days from the first partition as a look-back to capture unit commitment decisions that depend on the previous days. The model first solves a monthly solution, which is approximated by a load duration curve using 40 load steps. This monthly timestep allows the monthly hydropower generation "budget" determined by hydrology models (Section 2.3.1) to be optimized over the course of the month, accounting for variations in load and other resources. In this way, the monthly optimization determines daily hydropower budgets for use in the daily simulations. Daily simulations are chronological, hourly simulations with 24 hours of look-ahead into the next day. The look-ahead period is solved at four-hour resolution.

We use PLEXOS to simulate the operation of four 2038 ReEDS capacity-builds (HIGH.VG.COST, HIGH.VG.COST.IPSL85, LOW.VG.COST, and LOW.VG.COST.GFDL45, described later). For each ReEDS capacity-build, we simulate three load scenarios: baseline, medium, and high load. The baseline load is the same as the ReEDS historic climate load for the year 2038. The medium and high loads are based on projections from the IPSL85 climate scenario, which was the warmest of the four climate scenarios, using the same air temperature drivers as in ReEDS. For a medium load, we adjust the load according to the change in BA-level, seasonal cooling degree days for the climate year 2038. For the high load, we calculate the same for the 2050 climate year. While the load is adjusted using the load-temperature sensitivities used in ReEDS, the ReEDS timeslice sensitivities are smoothed over a 7-hour window to obtain hourly temperature sensitivities.

In PLEXOS, hydropower flexibility scenarios are implemented by adjusting the more dispatchable hydropower generation that uses monthly energy budgets (supplied by hydrology modeling) in the HIGH.VG.COST and LOW.VG.COST electricity scenarios with historic climate. To create an inflexible fleet (LOFLEX), we adjust the minimum stable level of each unit for each month to be equal to the monthly energy budget divided by the number of hours per month. Therefore each unit will run at a constant output (minimum stable). To create a highly flexible fleet (HIFLEX), we adjust the minimum stable level to 0 MW so that generators can turn all the way down and we adjust the ramp rate to 100% of capacity in one hour. Therefore each unit can ramp from 0 to maximum capacity at any time, while still limited by the monthly energy budgets. These two bounds are likely physically unrealistic for most generators but allow us to study the value and impact of hydropower flexibility.

3. Results

3.1. Simulated Climate Impacts

3.1.1. How does climate influence electricity demands?

A general increase in temperatures, with a resulting increase in electricity load, is projected across the West for all four climate scenarios albeit with some important variations (**Error! Reference source not found.**). All models show considerable variability across regions. The greatest increases in temperature are seen in the case of IPSL85 and MIROC85 with an increase of approximately 3.2 and 3.4 C° respectively by mid-century relative to long-term historical conditions. Scenarios for the more moderate Representative Concentration Pathway, IPSL45 and GFDL45, register a smaller increase at 2.2 and 2.3 C° respectively.

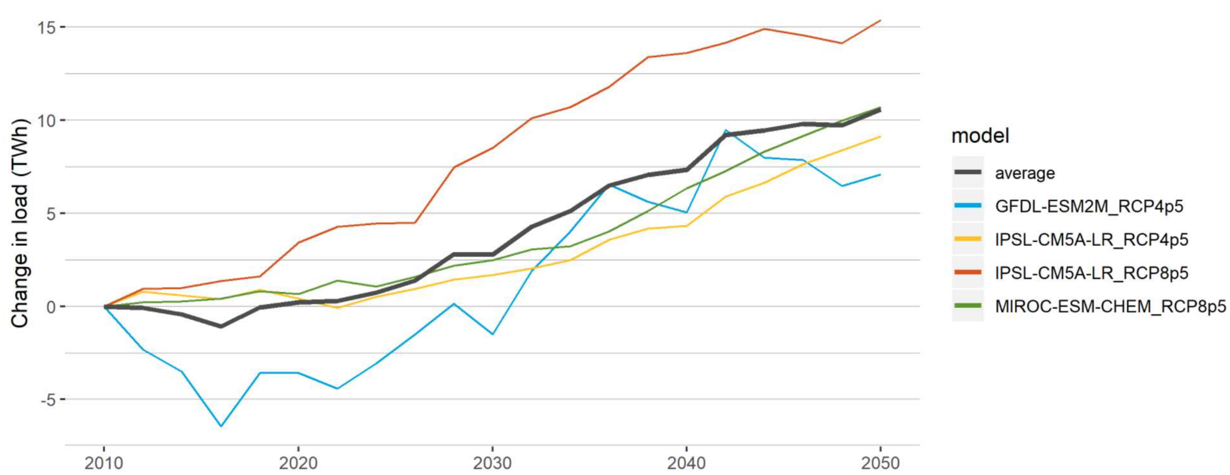

Figure 3 Average change in cooling degree days across WECC for different GCMs and RCPs.

Projected increasing temperatures impact electricity demand. Figure 4 shows the change in cooling degree days on a summer day for each year from one of the warmer models, IPSL85, after smoothing the annual variations, demonstrating that each of the 35 WECC balancing areas (BAs) have a unique warming pattern. Figure 5 shows the resulting annual and summer load values aggregated from BAs to approximate regional transmission operators (rto). Overall, average load growths range from 1 to 10%. A majority of the load growth due to climate occurs in the rto3 (AZNM) and rto4 (CAISO) regions in the IPSL85 model. Further, the most significant differences are between the 2010 climate and the 2038

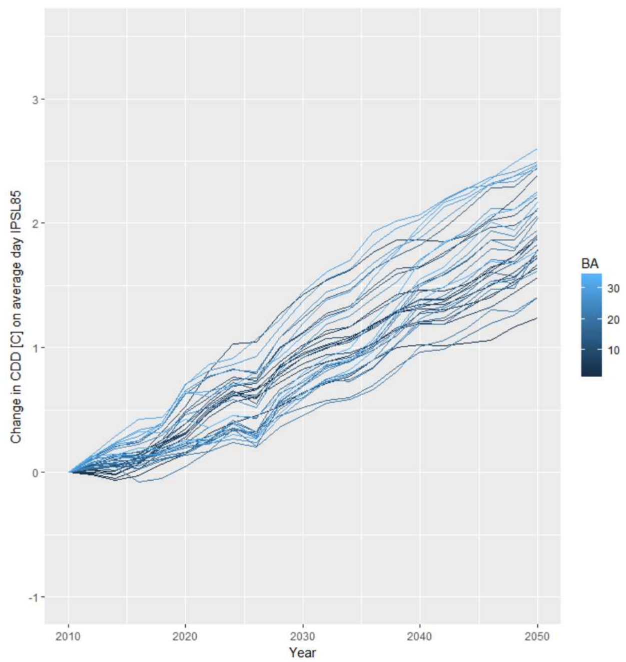

Figure 4. Change in cooling degree days for a summer day across different BAs in the WECC (IPSL85).

climate; the 2050 climate load increase from 2038 is smaller.

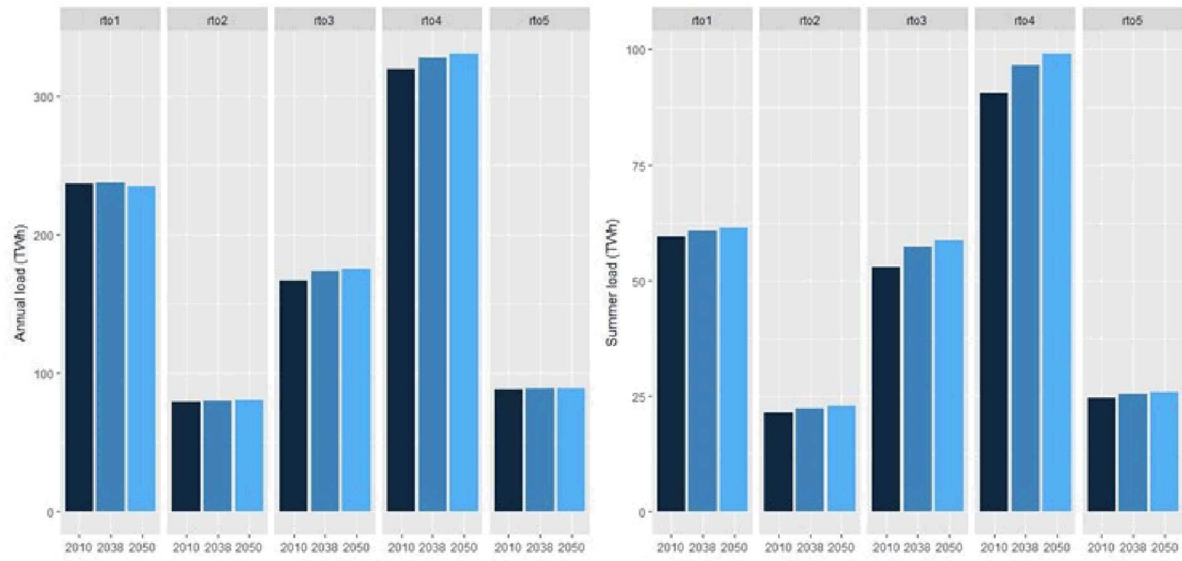

Figure 5. Projected annual (left) and summer (right) load growths for different rto areas within the WECC using the IPSL85 climate projection.

3.1.2. How does climate influence the water supply constraint for capacity expansion planning?

Impacts of climate change on water availability and annual hydropower are displayed in Figure 6 Projected changes (%) by balancing area in average streamflow at hydropower plant locations (weighted by plant capacity) between 2018 and 2038 across the Western U.S., highlighting significant divergence in the streamflow trends across the four GCMs selected (results compare 2038 against 2018 after smoothing is applied). RCP4.5 scenarios are associated with relatively moderate impacts, while RCP8.5 scenarios manifest deep reductions in hydropower availability in the Southwest (IPSL85), and in Nevada and California (MIROC85). Wetter conditions in the Pacific Northwest under this scenario mean the net impact on hydropower availability is marginal. Seasonal results for summer and winter (see Supplemental Information) show that hydro availability is generally trending down in summer and up in winter—reflecting the models' tendency to generate drier summer and wetter winter conditions. Summer hydropower availability is reduced across nearly all regions in three out of four scenarios (GFDL45 projects modestly increased summer hydro availability). Summer conditions in the Pacific Northwest under MIROC85 are also drier, although wetter conditions in winter mean the net annual impact is a modest increase in hydro.

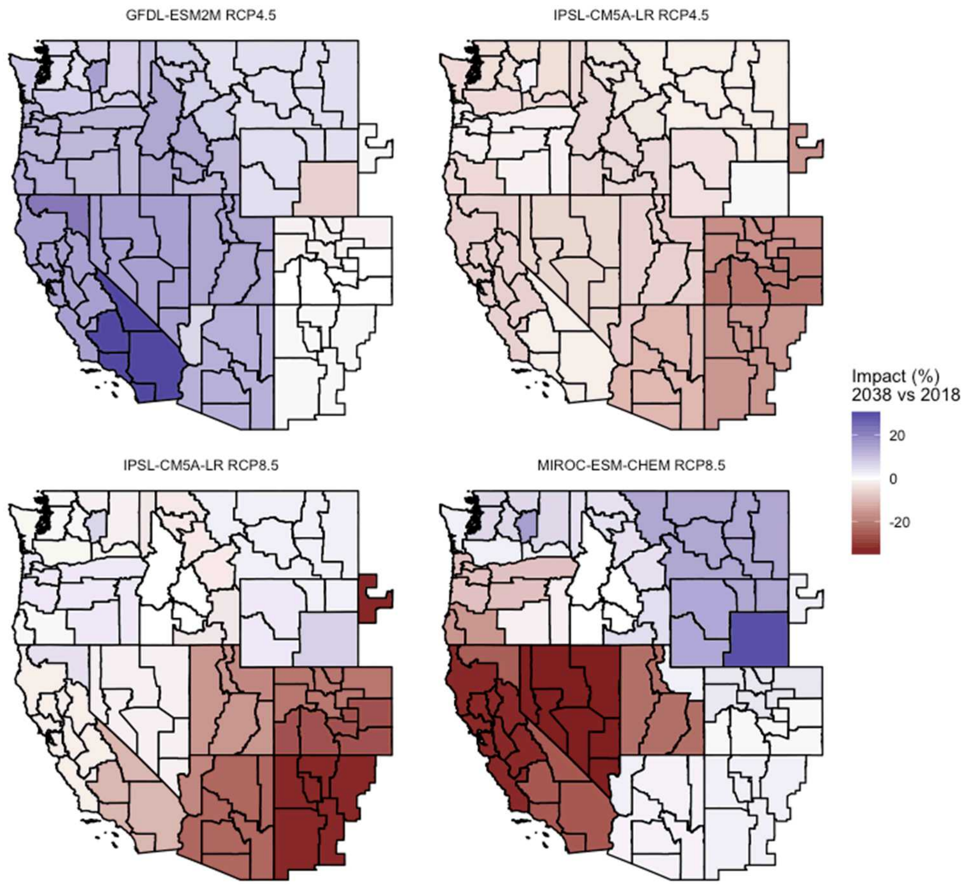

Figure 6 Projected changes (%) by balancing area in average streamflow at hydropower plant locations (weighted by plant capacity) between 2018 and 2038 across the Western U.S.

3.1.3. How do drought events limit water supply for grid operations?

Production cost modeling (PLEXOS) is employed to evaluate operations of the ReEDS projected capacity-builds under alternative climate futures. To do this WSGIF time series were used to select years of average and significant drought conditions (Figure 7). The year 2053 from the IPSL85 climate simulation is the overall driest of the 800 water years drawn from ten GCM projections. The year 2090 from the IPSL85 climate scenario (average year) represents the 45th percentile of all years for the Western Interconnection as a whole. It also exhibits approximately median water conditions within each of the major river basins. To complement the significant drought and average year, the 1977 drought was selected for comparison so as to provide perspective of the driest historical year as measured by the WSGIF calculated across the Western Interconnection. These three years form the basis of the average conditions and drought scenarios used in later phases of analysis (Section 3.2.2).

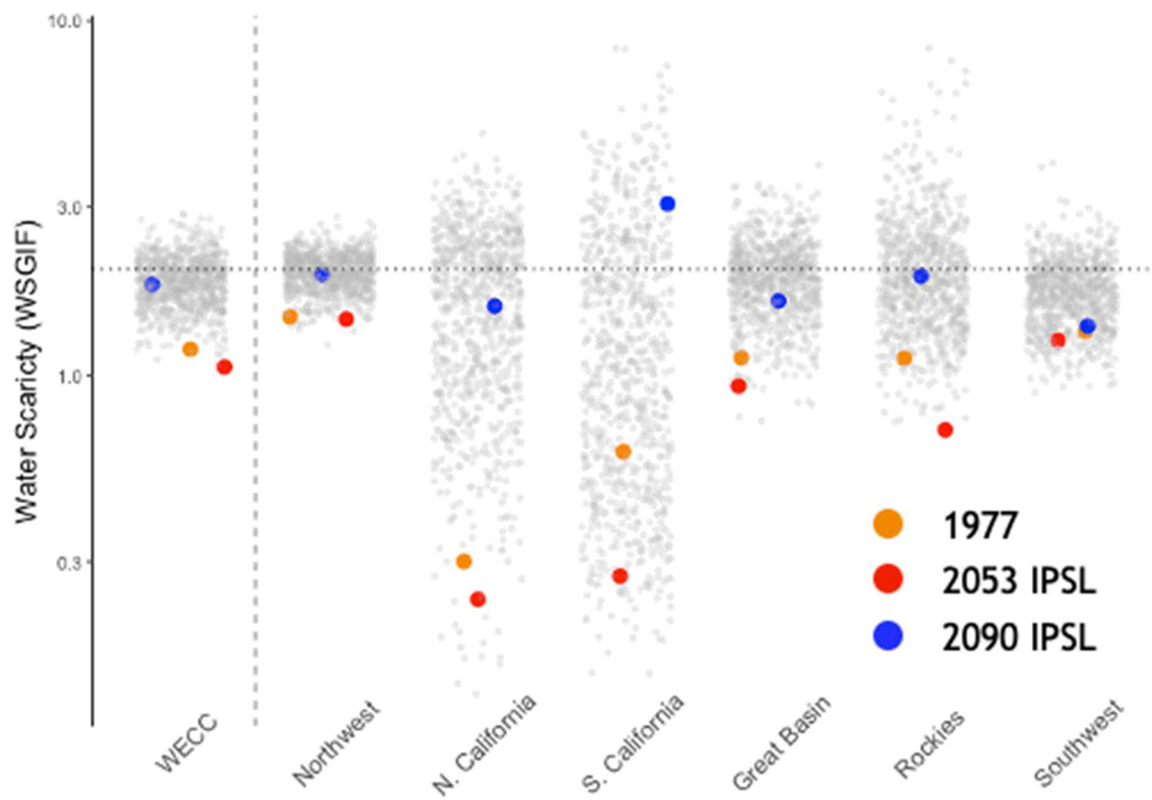

Figure 7. Water Scarcity Grid Impact Factor (WSGIF) calculated for different subregions, years and climate models to identify extreme and average years for further analysis.

Impacts on hydropower generation associated with each selected year are shown in Figure 8, aggregated to the county scale. The spatial distribution of impacts on hydropower are similar for the historical drought (1977) and the projected drought (2053 IPSL85). The IPSL85 model drought is marginally more severe, leading to sharper losses in hydropower in the Columbia River Basin (northwest) and in the Colorado River Basin where Nevada meets Arizona. These droughts reduce total annual hydropower in the Western Interconnection by approximately 5 – 10%.

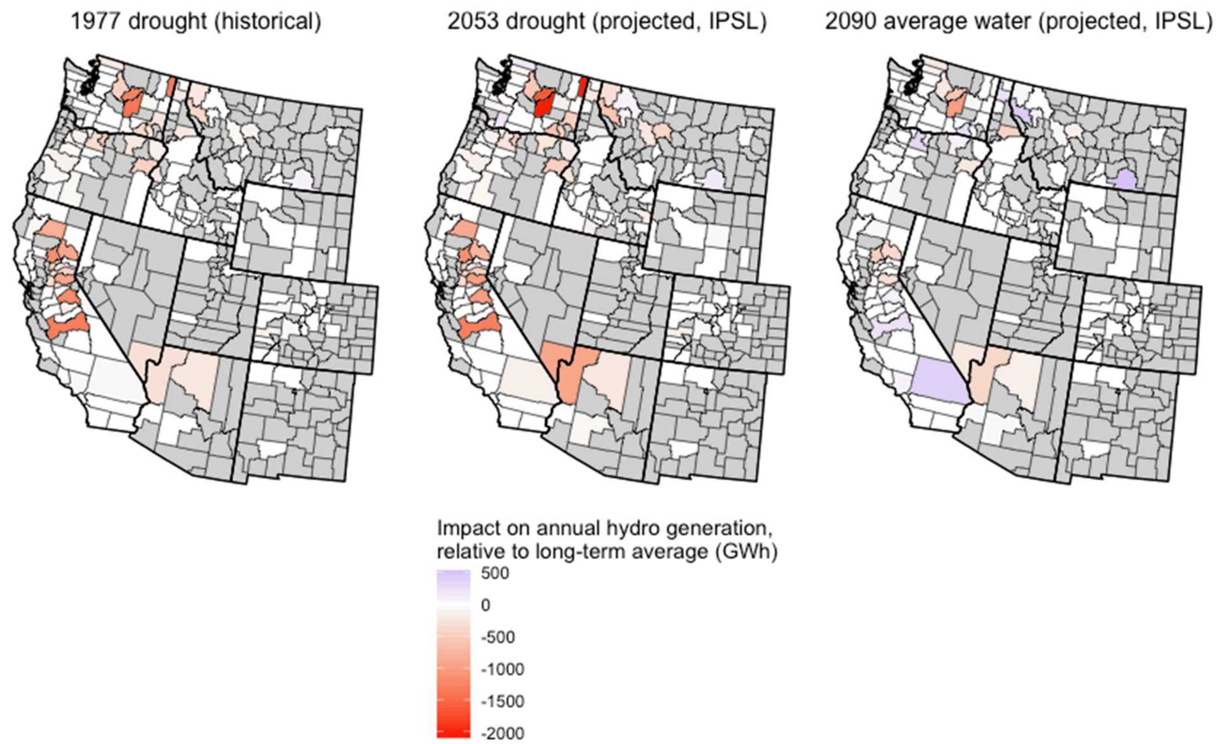

Figure 8. Drought years and average year hydropower generation relative to long-term historical average (aggregated to US counties)

3.2. Electricity sector results

3.2.1. How does climate impact projected capacity expansion and transmission expansion planning (total capacity change, mix, location)?

In the West , climate-impacts on both temperature and precipitation have long-term impacts on electric sector outcomes (Figure 9). Higher average air temperatures reduce heating loads in some subregions, but system-wide, the associated electricity demand reduction is offest by higher cooling loads. The resulting increase in electricity demand drives greater generating capacity needs in many scenarios due to climate effects, up to nearly 17 GW system-wide in 2038 for the IPSL85 climate and HIGH.VG.COST electricity scenario (~6.6% increase over historic climate case). Additional capacity needs from climate impacts largely consist of photovoltaic (PV) and natural gas-based technologies, and both Gas-Combustion Turbine (CT) and Gas-Combined Cycle (CC), despite substantial differences in generation technology costs and assumptions about electrification. This consistent result arises because temperature impacts on load are higher in peak demand periods in the summer, and the increased peak demand relative to other time periods drives PV and gas-based technologies that provide energy and capacity at peak. Solar resources coincide well with these higher demands, while Gas-CC provides dispatchable energy and capacity when PV is unavailable. Gas-CT is deployed primarily for resource adequacy purposes. Battery technology costs assumptions do not result in utility-scale battery deployment in these scenarios, but batteries could supply similar services as Gas-CT if cost-competitive.

A different trend is evident with the GFDL45 scenarios as they do not consistently deploy more PV and gas-based resources because GFDL45 precipitation levels indicates greater water availability for hydropower generation (Figure 6 Projected changes (%) by balancing area in average streamflow at hydropower plant locations (weighted by plant capacity) between 2018 and 2038 across the Western U.S.). Given hydropower's large contribution to electricity mix in the Western Interconnection, additional hydropower availability in this scenario is able to meet temperature-induced increases in electricity demand, largely offsetting the need for additional generating capacity. Though hydropower capacity is constant, an additional 27–28 TWh electricity from hydropower reduces the net climate effect on capacity to 1.4 GW (~1% increase over historic climate case) or less in these scenarios, with ELEC.GFDL45 having a net reduction in capacity. However, the technology-specific impact of additional hydropower is inconsisent across scenarios, with additional PV still economic in the LOW.VG.COST.GFDL45 scenario but gas-based capacity being slightly greater in other GFDL45 scenarios. Hydropower could play an important role in responding to future climate impacts on the Western Interconnection, but its relationship to other technology impacts is uncertain due to the inherent uncertainty in future water availability.

Climate impacts are also lower in the ELEC cases relative to the other electricity scenarios, with the net change in capacity being -8.5–5.0 GW (-6 to 3% change over historic climate). A key reason is the assumption that some fraction of electrified demand (largely transportation demand) is flexible and controllable in response to electricity system needs. While the magnitude of and mechanisms behind flexible electrified load is highly uncertain, this result demonstrates that flexible load could help mitigate climate impacts on the Western Interconnection, allowing system planners to avoid new investments to meet increased load. In some modeled scenarios, system capacity for the Western Interconnection in 2038 is actually lower with flexible electrified load. In higher-temperature scenarios where more generation capacity is required, PV investment is preferred over gas-based capacity, with some additional investment in storage to provide flexibility.

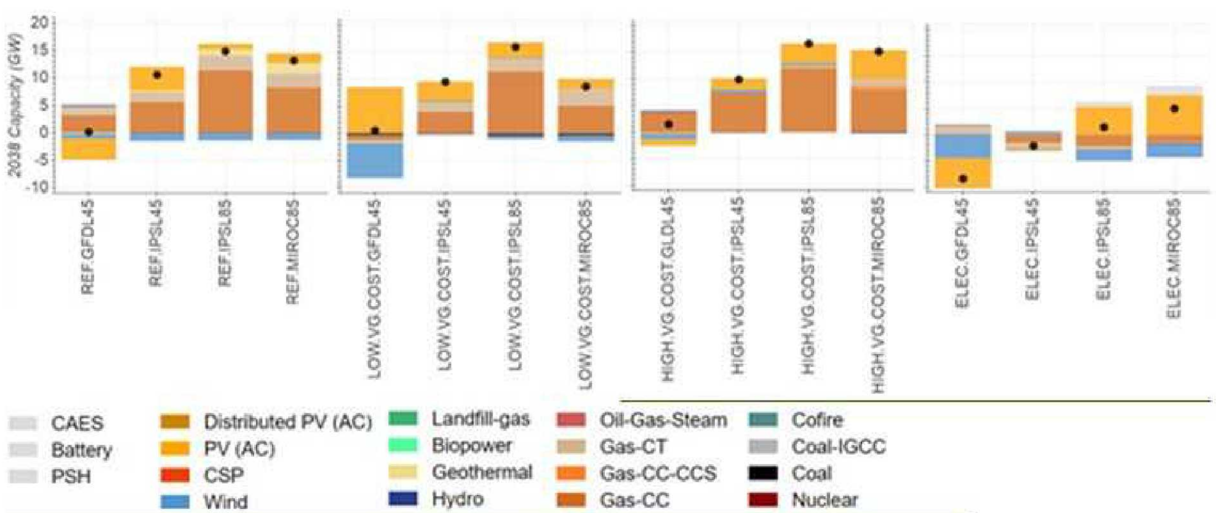

Figure 9. Climate impacts on Western Interconnection *capacity for each climate scenario relative to the corresponding electricity scenario without climate change impacts. Circles on plot represent net effect.*

While system-wide changes in capacity expansion illuminate relationships between climate change, supply-side competition, and demand effects, subregion specific changes in generating capacity are more nuanced. These effects are discussed for a subset of electricity and climate scenarios in Figure 10 and Figure 11, which show climate effects on capacity for several technology-region-electricity-climate combinations at the NERC subregion level. The GFDL45 and IPSL85 climate scenarios are discussed primarily in this section because these bound climate impacts on capacity in the Western Interconnection for all but the ELEC scenario.

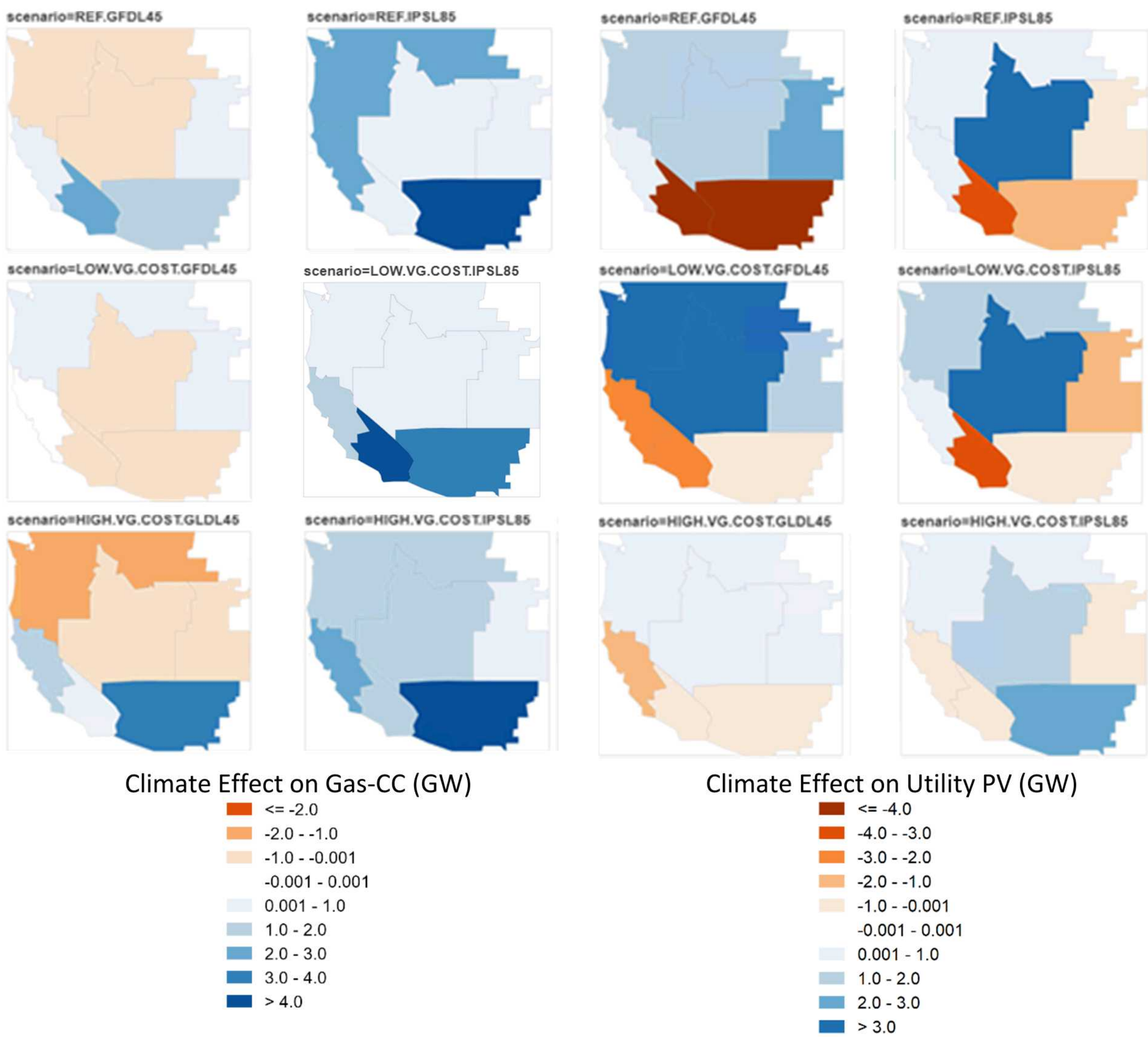

Figure 10. Climate impacts on 2038 Gas-CC and Utility PV capacity by NERC subregion within WECC for the GFDL45 and IPSL85 climate scenarios relative to the REF, LOW.VG.COST, and HIGH.VG.COST scenarios without climate change impacts.

Figure 10 shows climate effects on Gas-CC (left panels) and PV (right panels) for all but the ELEC scenario under GFDL45 and IPSL85. For either technology, a system-wide increase (or decrease) does not necessarily mean an increase (or decrease) is observed across all regions, and there are often regions where the direction of change is opposite between the two technologies. For instance, the system-wide result in REF.GFDL45 of less PV and more Gas-CC is driven largely by results in the Desert Southwest and Southern California, with other regions such as the Pacific Northwest and Great Basin having additional

PV and less Gas-CC. Throughout, any climate-induced increase in PV tends to occur in the Pacific Northwest or Great Basin regions with climate effects often reducing PV capacity in areas with better PV resource, suggesting these regions must prioritize flexibility in response to climate induced load.

These results begin to highlight the complex interplay involved in regional climate impacts on the electric sector. Water availability, fuel and technology costs, transmission constraints, and even local policy can interact with regional differences in climate to generate variability in how climate change could influence regional electric sector outcomes.

Consistent with system-wide outcomes, the ELEC scenario has relatively small sub-regional climate impacts on Gas-CC deployment, but sub-regional PV effects are highly variable (Figure 11). While GFDL45 has less PV overall, there are small increases in the Pacific Northwest and Desert Southwest regions. In contrast with other electricity scenarios under most climate futures, PV capacity is greater in the Desert Southwest in all ELEC climate variations. This result suggests that flexible demand able to respond to system needs facilitates additional PV adoption and mitigates the competition between PV and Gas-CC observed in other scenarios. Conversely, PV in the Great Basin is often lower, and other subregions have inconsistent effects across climate scenarios. Sub-regional variability in PV outcomes for the ELEC scenario demonstrates the increased uncertainty introduced by demand flexibility and how it could both mitigate and confound expected climate effects on electricity planning.

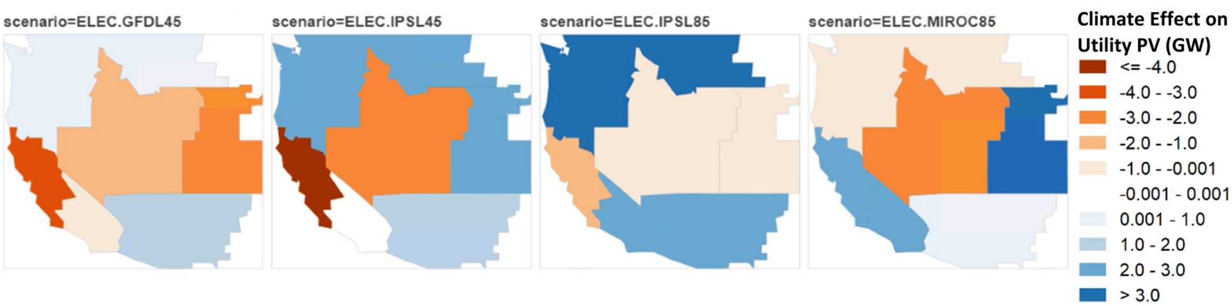

Figure 11. Climate impacts on 2038 Utility PV capacity by NERC subregion within WECC for each climate scenario relative to the ELEC scenario without climate change impacts.

With no direct climate impacts on wind resource potential, climate effects on regional wind deployment are small for most electricity-climate scenario combinations, with Figure 12 demonstrating low-magnitude impacts in REF alongside the LOW.VG.COST scenario, the only electricity scenario with consistently large climate impacts on wind deployment. While the LOW.VG.COST scenario has the greatest wind deployment before applying climate impacts, climate effects create a load shape with a greater peak-to-base load difference, which deviates from typical wind profile shapes in the central plains where wind is typically stronger in off-peak times. Climate effects sometimes result in increased in wind capacity in the Desert Southwest and California with LOW.VG.COST, but only the IPSL45 scenario (see SI) has an increase in wind capacity elsewhere.

Climate Effect on Wind (GW)

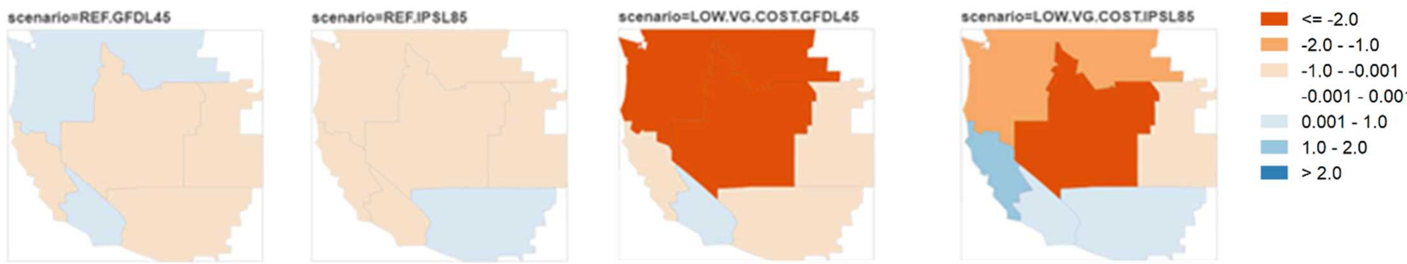

Figure 12. Climate impacts on 2038 wind capacity by NERC subregion within WECC for the GFDL45 and IPSL85 scenarios relative to the REF and LOW.VG.COST scenarios without climate change impacts.

The bulk electricity transmission system also responds to climate impacts and the resulting generating capacity outcomes. Figure 13 shows total bulk transmission system capacity in the Western Interconnection in 2038 for all scenarios. Climate impacts on transmission capacity are relatively small throughout, with a maximum change of approximate 3 GW (1.6%). The direction of change is inconsistent, even for a given electricity scenario. The LOW.VG.COST scenario typically builds additional transmission with climate impacts, as does REF aside from the GFDL45 climate future. HIGH.VG.COST has higher transmission investment with climate impacts, though the magnitude never exceeds 0.8 GW. Outcomes are mixed in ELEC, consistent with the range of generating capacity outcomes. Transmission impacts are often related to variable renewable penetration, with scenarios having greater PV with climate change often having larger increases in transmission builds. The GFDL45 scenario often has reduced transmission needs as an indirect consequence of increased hydropower availability.

Transmission impacts at the NERC subregional level (Figure 14) are typically 1–2 GW or less, and impacts are highly variable across scenarios. For instance, climate impacts on transmission in the great basin are very sensitive to electricity scenario, with notable transmission increases in LOW.VG.COST and REF but reductions in HIGH.VG.COST and ELEC. This result is consistent with variability in great basin PV and wind deployment, and it also reflects observed changes in power flows from the great basin region to the desert southwest, particularly the BA containing Las Vegas in summer time periods. The direction of climate impact on transmission capacity is also variable for the Pacific Northwest. However, for a given electricity scenario, the direction of climate impacts is most often the same across the four climate scenarios. Some regions also have minimal climate impacts on transmission in these scenarios, namely the Rocky Mountain and Northern California regions.

Climate impacts on transmission are variable both system-wide and within individual regions, with the important result that this uncertainty can be considered in long-term transmission planning to have a better understanding of the range of possible grid outcomes.

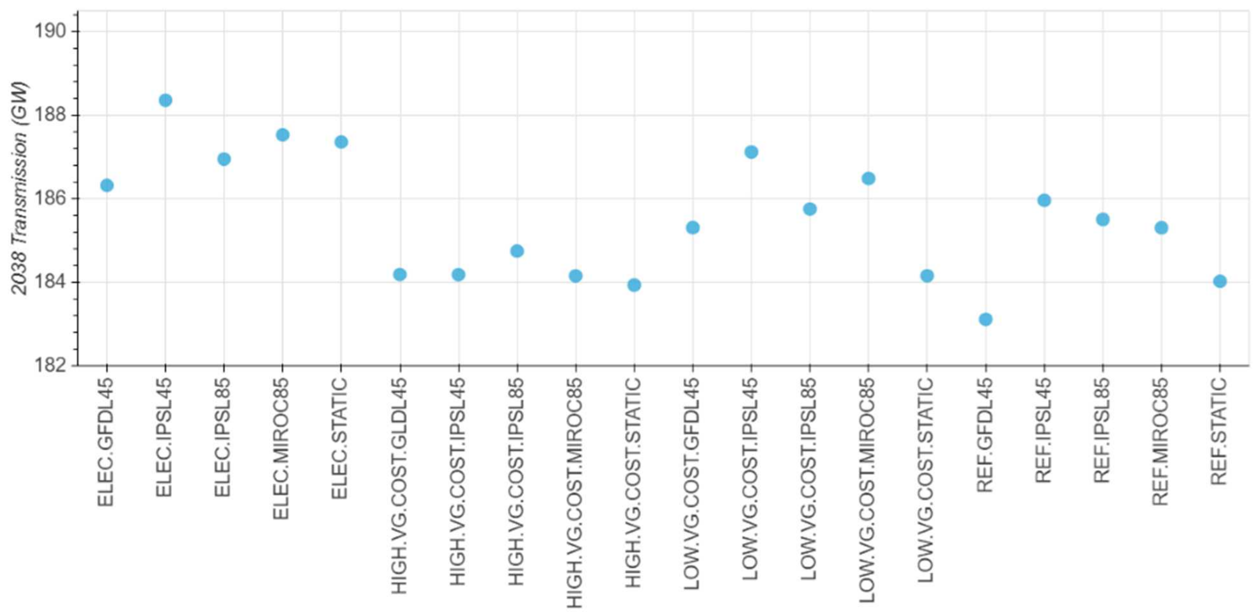

Figure 13. Transmission capacity in the Western Interconnection in 2038 for climate and reference scenarios.

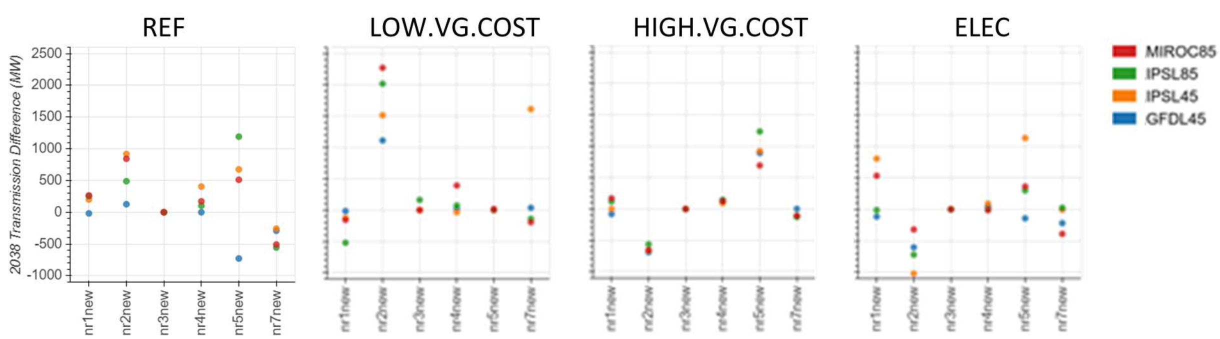

Figure 14. Differences in NERC regional transmission expansion by WECC region where the transmission capacity begins, for each climate scenario relative to the corresponding scenario without climate impacts. [nr1=northwest, nr2=great basin, nr3=rocky mtn, nr4=norcal, nr5=socal, nr7=desert southwest.

3.2.2. How does climate impact projected operations and reliability of the electric grid?

PLEXOS simulations were performed to explore climate impacts on system operations in the Western Interconnection. We explore operational changes from two angles. To understand the sensitivity of a given infrastructure to climate conditions, we explore how different capacity-builds from ReEDS perform under drought and heat compared to their performance under 'normal' water conditions and without adjusting electricity loads for climate. This highlights how different power systems adapt to climate. We refer the baseline condition for PLEXOS as IPSL 2090 water conditions and 2038 load unadjusted for warming. To understand the importance of climate foresight in the infrastructures, we also compare the performance of climate-informed ReEDS build outs to build outs that are not climate informed.

Because of the large number of scenarios only a subset of cases were simulated and analyzed. To select bounds on possible future infrastructure and climate impacts, we chose the HIGH.VG.COST.IPSL85 and

LOW.VG.COST.GFDL45 scenarios, all in the 2038 year, along with the HIGH.VG.COST and LOW.VG.COST infrastructures under historic climate. These cases exhibit some of the greatest and most diverse differences in capacity-builds between climate and historical climate driver (Figure 9). The installed capacity and total generation of each of the four capacity builds for the baseline condition (average water year and baseline load) are shown in Figure 15 and Figure 16.

First, we explore how consideration of climate (climate foresight) in the four capacity-builds impacts the response of grid operations to drought and heat. We found that the HIGH.VG.COST scenarios compensated for drought and increased load almost entirely with Gas-CCs (Figure 17; upper left). This result is consistent with studies that examine drought for historical infrastructures dominated by thermal generation (Gleick 2016; O'Connell et al. 2019). The LOW.VG.COST scenarios, with higher renewable penetration, compensated for drought and heat with Gas-CCs and also curtailed less wind and solar and had more Gas-CT, and Coal generation in 2038 operations (Figure 17; lower left). The HIGH.VG.COST.IPSL85 capacity-build from ReEDS has similar drought- and heat-forced generation changes to the HIGH.VG.COST scenario except that even in the baseline conditions (average water and baseline load), the additional solar capacity compared to no climate foresight means that there is more solar generation (and some wind and Gas-CT) and less Gas-CC generation (Figure 17; upper right). The LOW.VG.COST.GFDL45 capacity-build from ReEDS behaves similar to the LOW.VG.COST capacity-build but the LOW.VG.COST.GFDL45 capacity-build has less wind and more solar, so compared to the LOW.VG.COST baseline condition, its generation mix reflects the same in all conditions (less wind, more solar, Figure 17; lower right).We focus further analysis on the differences in generation between historic climate and the drought- and heat-forced operation for the HIGH.VG.COST and LOW.VG.COST scenarios without climate foresight.

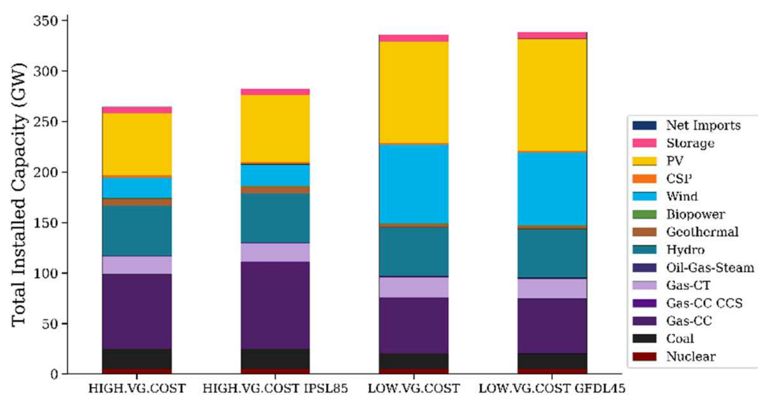

Figure 15 The installed capacity for the HIGH.VG and LOW.VG scenarios (with and without climate foresight) after translation of the ReEDS zone level capacities into individual power plant capacities for PLEXOS.

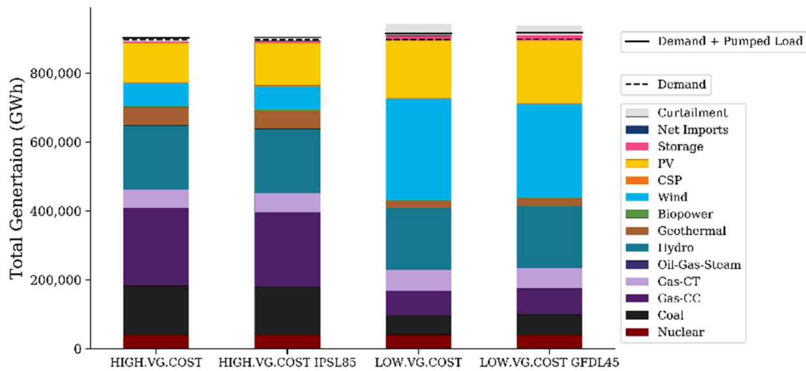

Figure 16 The generation for the HIGH.VG and LOW.VG scenarios (with and without climate foresight in ReEDS) using baseline load and IPSL85 2090 water ("average") conditions for PLEXOS operations.

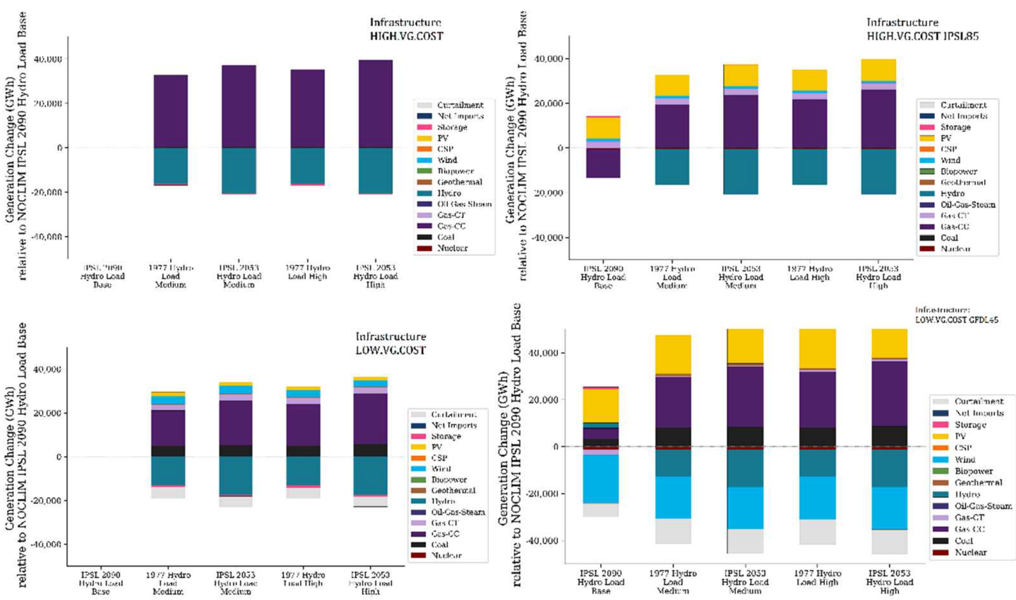

Figure 17: The change in generation relative to the no-foresight build out under baseline hydrology and load are shown under five different drought and heat conditions for each of the four infrastructures modeled in PLEXOS. The top two rows are relative to HIGH.VG.COST without climate foresight and the bottom two rows are relative to LOW.VG.COST without climate foresight.

Changes by generation type can be further delineated at the regional level, presented here by Regional Transmission Operator (RTO) region (Figure 18). Change in hydropower availability are mostly within Bonneville Power Administration (BPA) (rto1) and the California Independent System Operator (CAISO) (rto4). Changes in load are largely in Arizona-New Mexico (AZNM) (rto3) and CAISO. Compensation for these changes occurs in all regions, though minimally in the Rocky Mountain Power Pool (RMPP) (rto5). In the HIGH.VG.COST system, loss of hydropower in BPA (rto1) is directly offset by increased Gas-CC output in BPA. Gas-CC usage increases in AZNM and CAISO as well to compensate the loss of hydropower availability and increased load. In the LOW.VG.COST system, the same drought and load stressors are compensated for by a larger mix of generation types and in a more spatially distributed way.

Under the range of climate drivers for both drought and temperature-adjusted load, we observe that the variable renewable energy curtailment in the HIGH.VG.COST scenario remains near zero. The LOW.VG.COST scenarios, however, have moderate curtailment that decreases under drought and heat conditions (Table 1**Error! Reference source not found.**). Curtailment can be reduced under drought and heat conditions because springtime load is higher in some regions, allowing wind and solar that would otherwise be curtailed in the spring to be used.

Table 1: Curtailment of variable renewable energy (VRE) and photovoltaics (PV) (PLEXOS results) under the two LOW.VG.COST infrastructures (ReEDS results). Note that VRE curtailment under drought and heat scenarios (1977 Drought Load Medium, IPSL 2053 Drought Load Medium, 1977 Drought Load high, and IPSL 2053 Drought Load High) was the same for all four scenarios, while a range is provided for PV curtailment as it did vary with drought and heat conditions.

VRE cost assumptions in ReEDS build-out	Climate foresight in ReEDS build-out	VRE curtailment		PV curtailment	
		Historic climate conditions	Heat/drought scenarios	Historic climate conditions	Heat/drought scenarios
LOW.VG.COST Infrastructure scenarios	Historic climate	3.6%	3.1%	4.9%	3.9-4.0%
	GFDL45	3.0%	2.5%	5.6%	4.3-4.5%

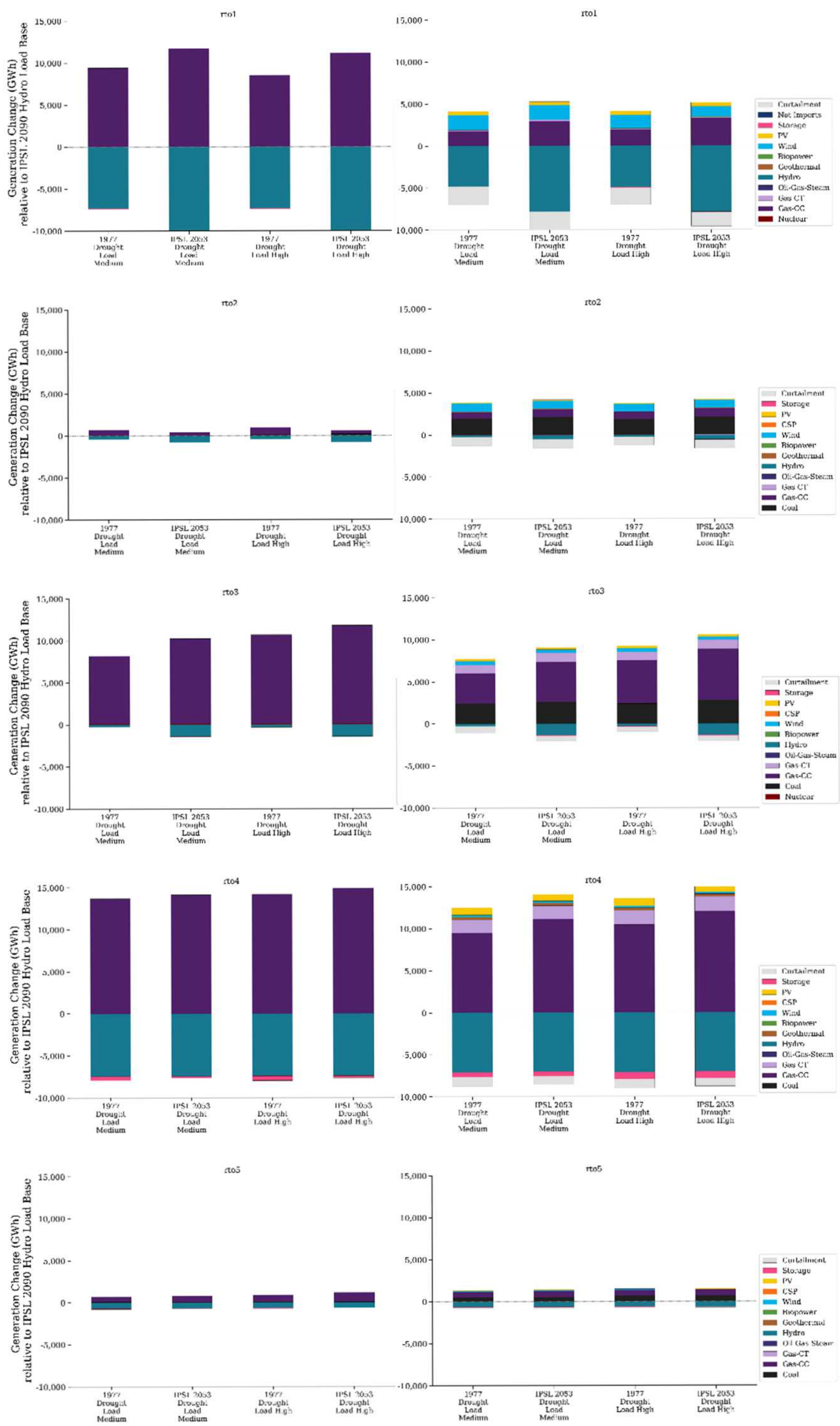

Figure 18: The change in generation under drought and heat drivers compared to average climate (IPSL85 2090) conditions for HIGH.VG.COST (left column) and LOW.VG.COST (right column) scenarios by region (rto).

Next, we explore how climate impacts hourly grid operations under increased load and drought conditions. Impacts on different components of the generation fleet can be observed in duration curves of fleet-level capacity factor. We define fleet-level capacity factor here as generation divided by available capacity for all generators of four generator types (Coal, Gas-CT, Gas-CC, Hydro). Duration curves show the hourly capacity factors sorted from highest to lowest, allowing us to examine the hourly operation at a high level. In the HIGH.VG.COST scenarios only the Gas-CC fleet capacity factor is impacted by drought and temperature-adjusted load in most hours; coal capacity factor is relatively high already in the baseline scenario (2090 'average' hydro availability and baseline load) and does not change under these scenarios (Figure 19). In the LOW.VG.COST scenarios, the Coal and Gas-CT fleet are impacted by drought and load as well (Figure 20). Coal and Gas-CC impacts occur in most hours of the year, while Gas-CT's are affected only during times of lower fleet-wide capacity factor.

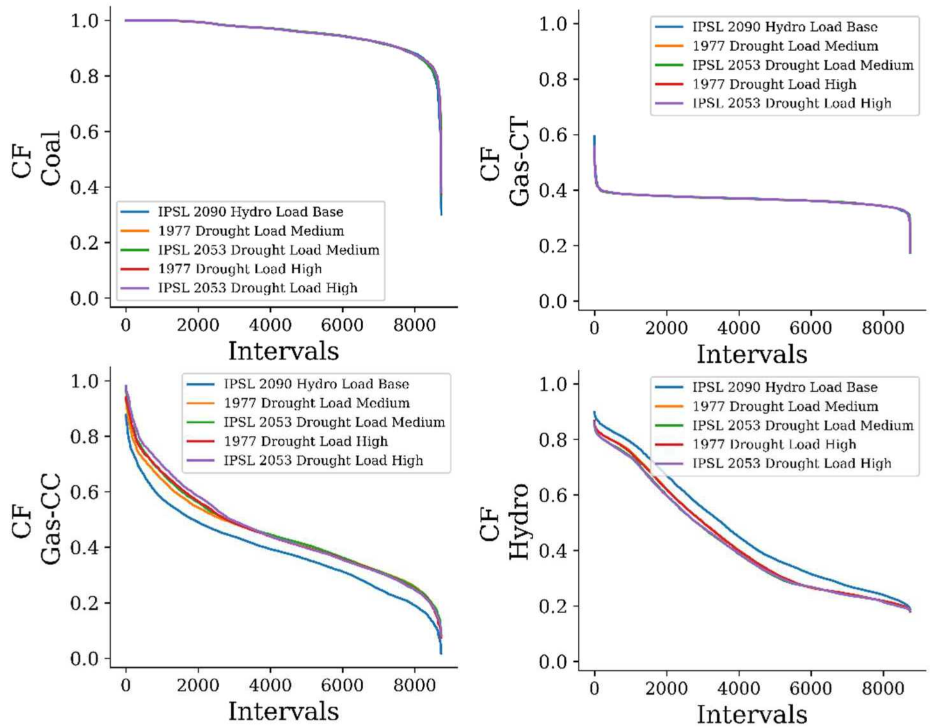

Figure 19: Duration curves of fleet-wide capacity factor for each of the four major non-variable generation types in the HIGH.VG.COST system.

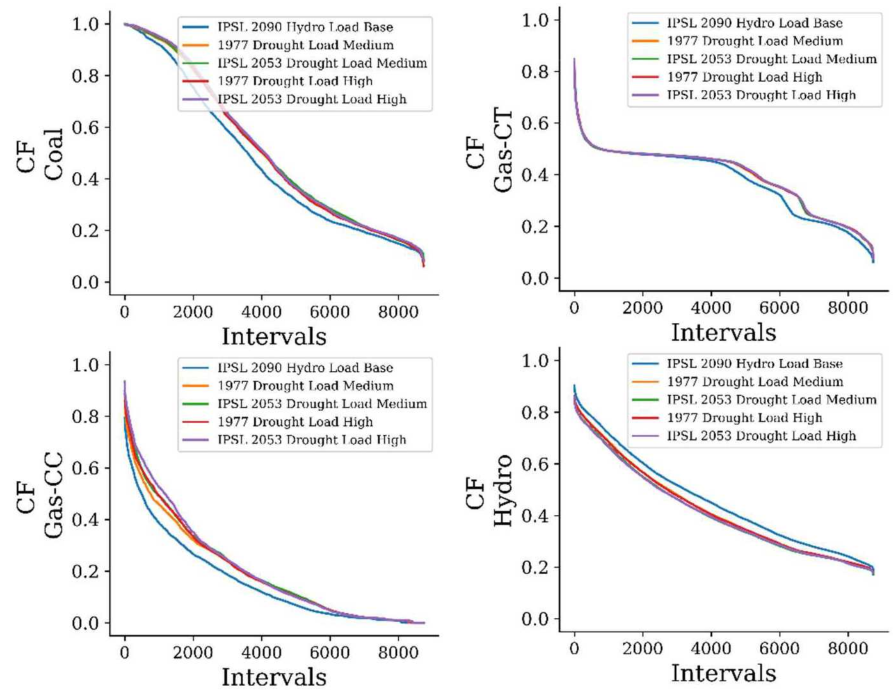

Figure 20 Duration curves of fleet-wide capacity factor for each of the four major non-variable generation types in the LOW.VG.COST system.

We further examine the seasonal changes using hourly chronological results, focusing on differences in hourly dispatch between two scenarios that are exemplary of the trends observed in Figure 19 and Figure 20.The difference between Gas-CC generation in the baseline scenarios and the drought and high load scenarios are highest in the summertime (Figure 21). In the HIGH.VG.COST drought/heat scenario the increased (negative in this figure) Gas-CC generation happens in the spring as well as the summer, while in the LOW.VG.COST scenario reduced curtailment instead makes up the additional generation in the spring. The LOW.VG.COST system has more differences in coal generation than the HIGH.VG.COST system, especially in the summertime.

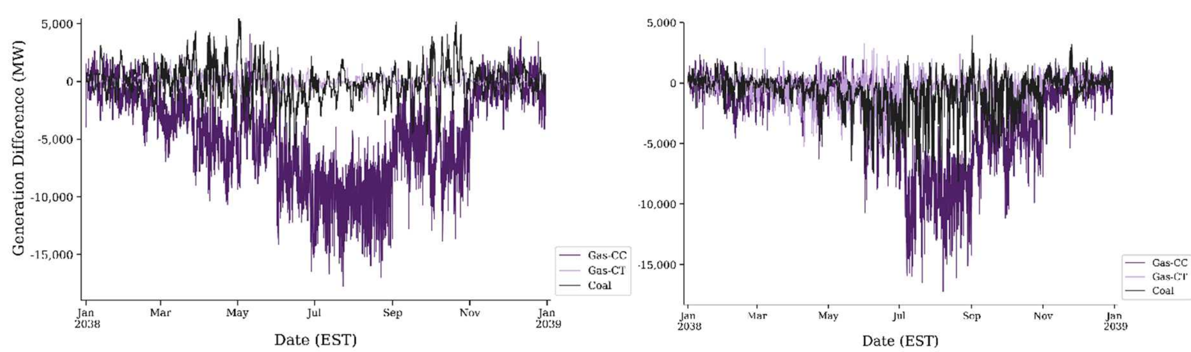

Figure 21: Left: Hourly thermal generation in HIGH.VG.COST baseline (IPSL85 2090 and baseline load) condition minus generation in HIGH.VG.COST climate-forced drought of IPSL85 2053 and high load. Right: Hourly thermal generation in LOW.VG.COST baseline (IPSL85 2090 and baseline load) condition minus generation in LOW.VG.COST climate-forced drought of IPSL85 2053 and high load.

There is a small decrease in storage (mostly pumped hydropower) used in CAISO for all drought/heat scenarios compared to the historic climate scenario (see Figure 18). The change is persistent through climate scenarios, so it is interesting to investigate though small. In the HIGH.VG.COST scenario, storage usage is variable between the two scenarios (baseline IPSL 2090 water and baseline load versus climate forcing IPSL85 water and high load), but is generally higher in the historic climate scenario (positive in Figure 22). In the LOW.VG.COST scenario storage is relatively equal between the historic and climate-forced scenarios in all seasons except the summer, when generation from storage is reduced in the drought and high load scenarios. One reason for this seasonal change is that the increase in thermal generation online requires less storage to handle hourly changes in load and VRE.

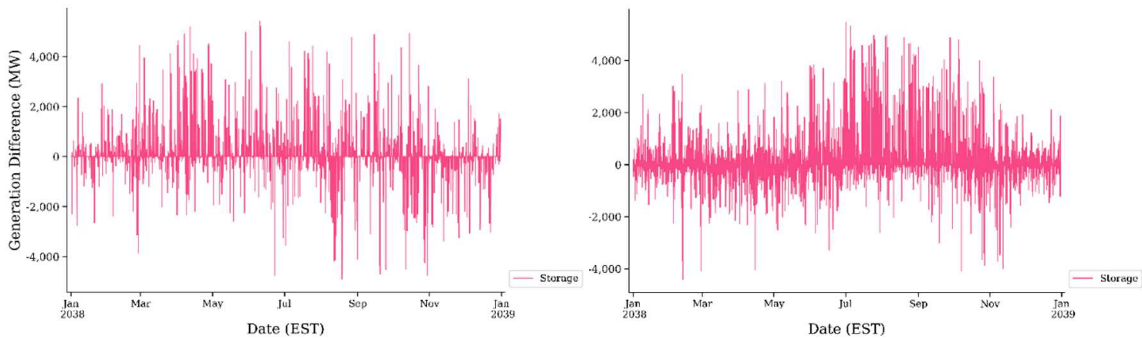

Figure 22 Left: Hourly storage discharge in HIGH.VG.COST baseline (IPSL85 2090 and baseline load) condition minus discharge in HIGH.VG.COST climate-forced drought of IPSL85 2053 and high load. Right: Hourly storage discharge in LOW.VG.COST baseline (IPSL85 2090 and baseline load) condition minus discharge in LOW.VG.COST climate-forced drought of IPSL85 2053 and high load.

Hourly dispatch stacks provide insight into exactly how the system is operating during the times when climate causes the largest differences in generation. The period of July 11-17 (Figure 23) is an example of consistently higher Gas-CC generation. .

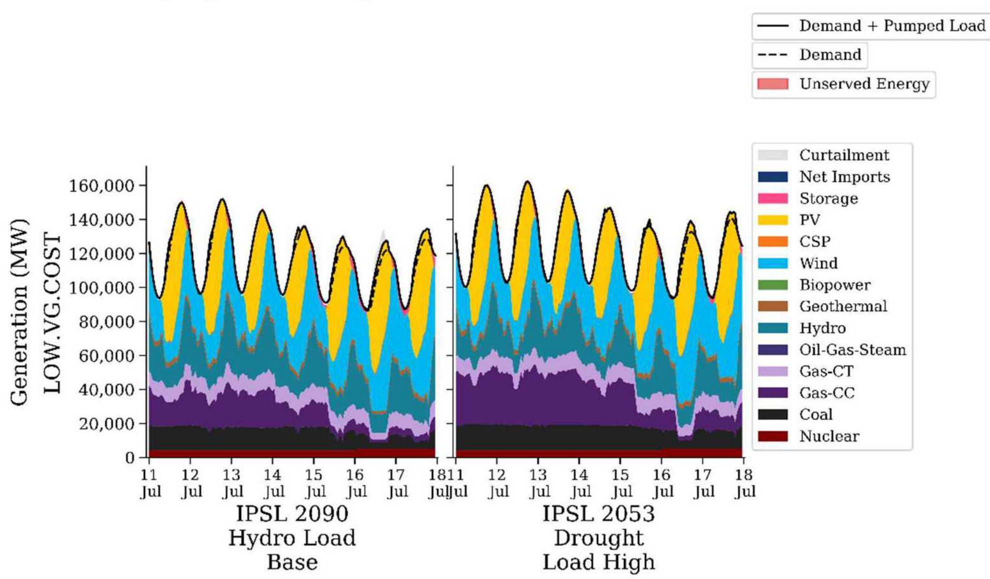

Figure 23: Example dispatch stack for LOW.VG.COST baseline scenario and climate-forced drought and heat scenario.

Finally, reliability is assessed by calculating unserved load throughout each annual simulation. Over 99.999% of load is met in the PLEXOS simulations of the Western Interconnection. There are small amounts of unserved load in two modeled scenarios; this unserved load occurs during two hours in late July. This unserved load is an artifact of the model, in reality, grid operations would respond to meet load. Over 99.96% of reserves are met in the PLEXOS simulations. These metrics indicate that, *under the assumptions of the production cost model*, climate drivers and drought scenarios do not reduce grid reliability under a range of future possible conditions. Note that this production cost model assumes that operation is optimized throughout the entire Western Interconnection and that the system has perfect foresight into the load, wind, and solar generation one day ahead. This is also an hourly production cost model, and additional insight in short term operation could be obtained from subhourly market simulations, but we do not expect subhourly simulations to significantly change the impact of the relatively longer term drivers of drought and warming temperatures under climate.

We can also assess the available thermal capacity after generation needs are met as a measure of the ability of the system to respond to further stressors. Figure 24 shows the available capacity after outages are accounted for and generation needs are met by thermal generator type for each of the four infrastructures in one of the more severe operational scenarios: IPSL 2053 Hydro and High Load. The Gas-CC availability is most variable and depends on climate foresight. The duration curve shows that during all hours the Gas-CC capacity available is higher in the HIGH.VG.COST IPSL85 build-out which incorporates IPSL85 climate foresight compared to the build-out with no foresight. This additional buffer persists during the more constrained hours. In the LOW.VG.COST scenarios, Gas-CC availability varies less between GFDL45 and no climate foresight scenarios, but we did not simulate the LOW.VG.COST scenario under the IPSL85 driver, which was warmer and wetter than GFDL45 and drove a higher capacity build out (Figure 9).

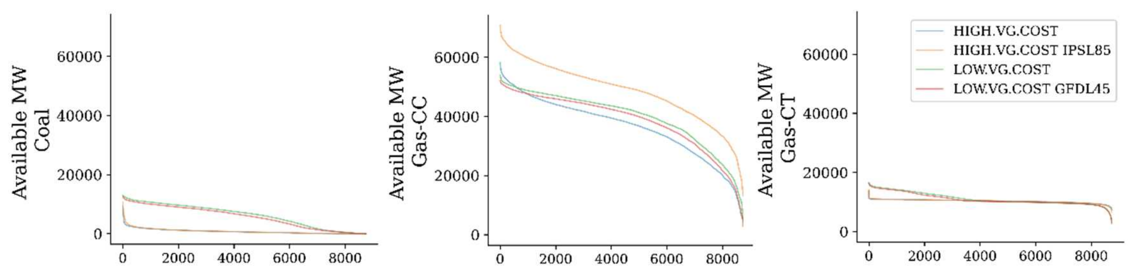

Figure 24: Duration curves of available capacity (after meeting generation needs) of major thermal generation types in the operational scenario which has a drought from IPSL 2053 and the high load case.

Like available thermal capacity, curtailed PV and wind can also be a source of flexibility. In the HIGH.VG.COST scenarios curtailment was negligible, but in the LOW.VG.COST scenarios there were 2,000 to 3,000 hours with some curtailment (Figure 25).

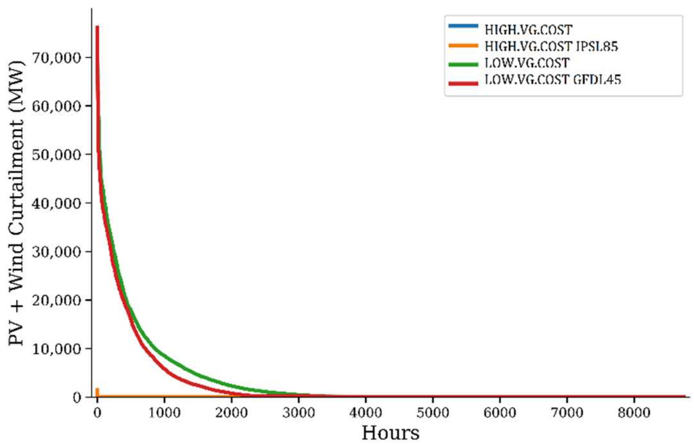

Figure 25: Curtailment duration curves for each infrastructure in the operational scenario which has IPSL 2053 drought and high load case. Note that HIGH.VG.COST curtailment is negligible.

3.2.3. How does climate impact projected system wide costs?

The system-wide economic impact of these climate scenarios over the period of 2018 to 2038 is shown by Figure 26, which uses the ReEDS capacity-builds to calculate a present value of all investment and operating costs for the Western Interconnection . The left panel shows total costs for the historic climate scenarios, while the right panel then shows climate impacts on costs across climate-forced scenarios relative to the corresponding historic climate electricity scenario.

Total costs are similar across REF and the VG.COST scenarios, while higher electricity demand in ELEC leads to higher baseline costs. Climate impacts on system costs reflect the combined influence of temperature, water availability, and demand flexibility. Costs are slightly lower in the ELEC scenario for all climate futures relative to ELEC.HISTORIC, demonstrating the value of demand flexibility even when in opposition to temperature-induced load growth. Climate effects reduce system costs under the GFDL45 case for all electricity scenarios due to the increased availability of low-cost hydropower reducing both fuel costs and capital costs for new capacity to meet higher electricity demand. For all other electricity-climate scenarios, temperature-induced generation capacity needs drive costs higher by up to \$5–\$17 billion. Ultimate climate impacts on total long-term system costs are thus uncertain, with the outcome dependent on technology innovation in addition to climate trends.

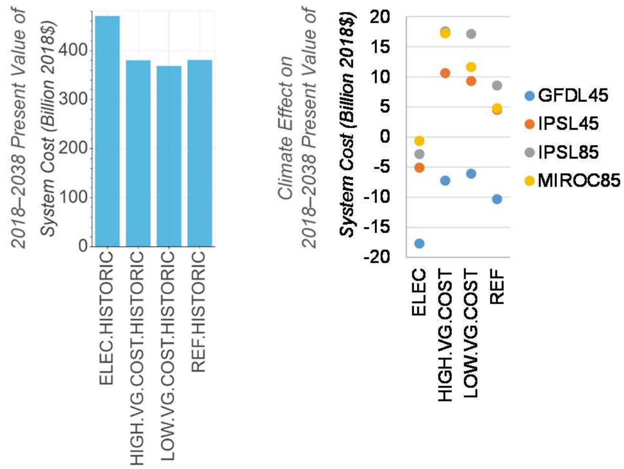

Figure 26. Present value of all 2018–2038 Western Interconnection *costs without climate impacts, along with the change in cost results with climate impacts.*

Figure 27 presents a competitive electricity price metric over time from 2020 to 2038 for all twenty ReEDS simulations. Competitive electricity price trends are driven primarily by the electricity scenario, with relatively little variation across climate scenarios for a given electricity future. Prices are typically determined by the cost of the marginal generating technology, typically natural gas, so these trends largely follow natural gas prices in each scenario. Across all years and scenarios, climate effects range from -2.9–3.3 2018$/MWh.

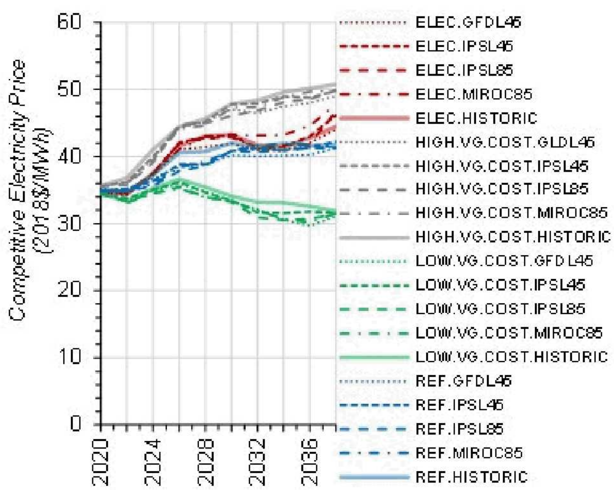

Figure 27. Change over time of the ReEDS competitive electricity price metric, as a load-weighted average across BAs.

Operating costs from hourly 2038 simulations in PLEXOS also reveal economic impacts of future climate and drought conditions. PLEXOS production costs include only the generation costs such as fuel costs, variable O&M, and start-up costs. Figure 28 shows the production costs by generator type for each infrastructure under the baseline conditions (water availability according to IPSL 2090 and baseline load unadjusted for heat). The HIGH.VG.COST scenario with climate foresight using IPSL85 is about 2% less expensive to operate than that without climate foresight mostly because of the increase in wind and solar capacity and generation. The LOW.VG.COST scenario with climate foresight using GFDL45 is about

4% more expensive to operate mostly because of the decrease in wind capacity and associated net decrease in VRE generation (though solar generation increases). In production cost modeling simulations, drought and heat increase production cost predictably by increasing thermal generation (Figure 29). In the lower renewable (HIGH.VG.COST; Figure 29 upper left) scenarios, fuel costs for natural Gas-CC make up the majority of the cost increase. In the high renewable (LOW.VG.COST; Figure 29 lower left) systems, Gas-CC and Coal comprise the fuel cost increase. The magnitude of the cost increase in LOW.VG.COST is smaller than in the HIGH.VG.COST infrastructure because the natural gas prices are lower due to price response to reduced electric sector demand, and because much of the system responds to load and drought stress by decreasing wind and PV curtailment. The right panels of Figure 29 follow the trends described in the right panels of Figure 17 based on the differences in the build-outs with climate foresight. Table 2 shows the generation costs for each scenario. The generation cost implications of climate foresight in the build-out, holding operational conditions static, are -2 to +4% (Table 3). The generation cost increase from drought and heat, holding the infrastructure static, ranges from 9–19%; the highest cost increases as a percent of historic-climate costs are in the LOW.VG.COST scenarios, while the highest cost increases in absolute terms are in the HIGH.VG.COST scenarios. Table 4 provides the generation cost changes due to operational conditions (drought and heat) for each ReEDS capacity-build simulated in PLEXOS.

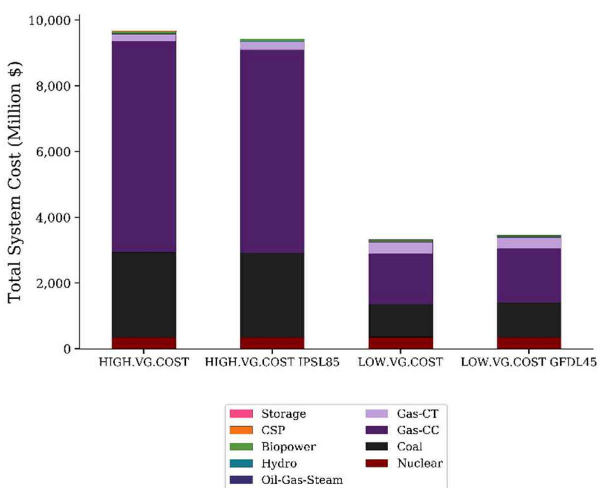

Figure 28: Total generation cost by generator type under baseline condition (which is IPSL85 2090 climate hydro and baseline load) operation.

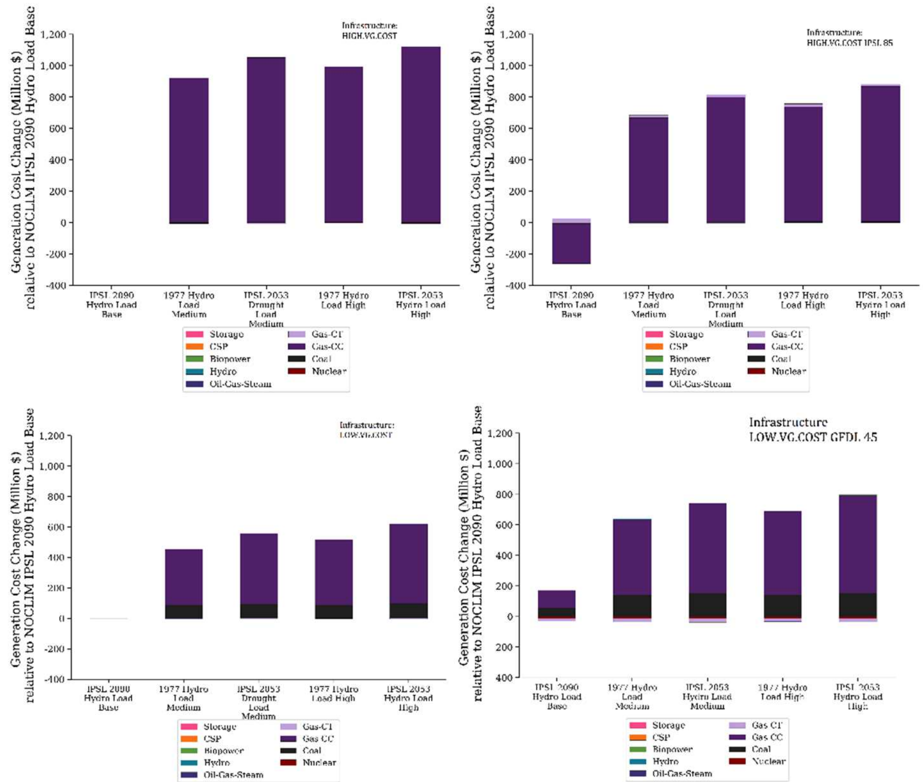

Figure 29 The change in generation cost relative to the no-foresight build out under baseline hydrology and load are shown under five different drought and load conditions for each of the four infrastructures modeled in PLEXOS. The top two rows are relative to HIGH.VG.COST without climate forcing and the bottom two rows are relative to LOW.VG.COST without climate forcing.

Table 2: The generation cost for each PLEXOS simulation including all combinations of four infrastructures and five drought/heat conditions.

Infrastructure	Operational condition for drought and heat				
	IPSL 2090 Hydro, Base Load	1977 Hydro, Load Medium	IPSL 2053 Hydro, Load Medium	1977 Hydro, Load High	IPSL 2053 Hydro, Load High
HIGH.VG.COST	9,674	10,593	10,720	10,663	10,790
HIGH.VG.COST IPSL85	9,437	10,356	10,486	10,428	10,554
LOW.VG.COST	3,319	3,773	3,872	3,836	3,939
LOW.VG.COST GFDL45	3,463	3,923	4,025	3,978	4,082

Table 3: Generation cost changes from PLEXOS operational model. Generation cost changes are relative to the operation modeled in PLEXOS under the same conditions compared to a build-out that did not have climate foresight.

VRE cost assumptions in ReEDS build-out	Climate foresight	Absolute change in PLEXOS generation cost due to climate foresight in ReEDS build-out (Million $)	Relative change in PLEXOS generation cost due to climate foresight in ReEDS build-out (%)
HIGH.VG.COST	Historic climate versus IPSL85	-234 to -236	-2.2 to -2.4%
LOW.VG.COST	Historical climate versus GFDL45	142 to 154	3.6 to 4.3%

Table 4: Generation cost changes due to drought and heat conditions from PLEXOS operational model. Generation cost changes are relative to the operation of the same infrastructure under baseline conditions for PLEXOS (i.e. IPSL 2090 water availability and 2038 baseline load without climate warming).

VRE cost assumptions in ReEDS build-out	Climate foresight in ReEDS build-out	Absolute change in generation cost due to drought/heat from PLEXOS (Million $)	Relative change in generation cost due to drought/heat from PLEXOS (%)
HIGH.VG.COST	historic climate	919-1,116	9-12%
	IPSL85	919-1,117	10-12%
LOW.VG.COST	Historic climate	453-620	14-19%
	GFDL45	460-618	13-18%

We explore the generation cost changes further by regional transmission operator (RTO, or “rto” in figure labels) for the HIGH.VG.COST and LOW.VG.COST capacity-builds (Figure 30). Note that the related climate-forced capacity-builds are similar (not shown). Regional cost changes in Figure 30 reflect generation changes in Figure 18, except highlighting that cost changes mostly reflect natural gas prices through Gas -CC usage and incorporating differences in natural gas prices from the LOW.VG.COST and HIGH.VG.COST scenarios.

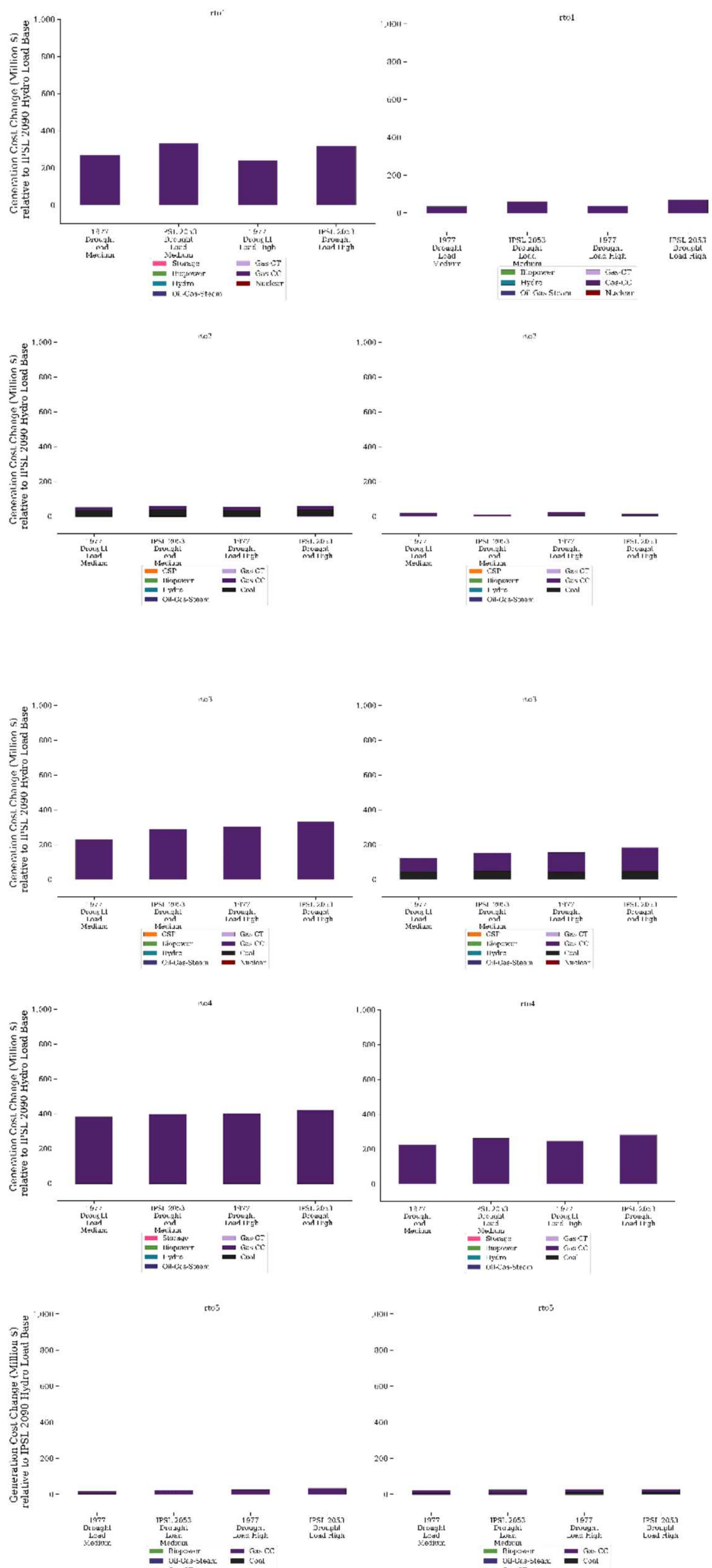

Figure 30 The change in generation cost under climate drivers compared to average climate and baseline load conditions for HIGH.VG.COST (left column) and LOW.VG.COST (right column) scenarios by region (rto).

3.2.4. How does climate impact projected electricity-related emissions and water demand?

While not as resolved as PLEXOS, the reduced-form dispatch in ReEDS demonstrates long-term trends in other environmental outcomes such as CO_2 emissions and water use. Figure 31 shows system-wide CO_2 emissions per year throughout 2020–2038 for all electricity-climate scenarios. In this time frame, the climate scenarios have relatively little impact on CO_2 emissions, with only the LOW.VG.COST scenario having climate scenarios deviating more than 6% from the historic climate case in a given year. While higher temperatures increase demand, CO_2 emissions are often lower due to some combination of (1) additional hydropower generation in wetter climate conditions, or (2) displacement of coal generation by additional Gas-CC and PV built to supply growing peak demands. This result is significant for the Western Interconnection and can be partially attributed to its relatively low emissions intensity today, as other systems might instead see higher CO_2 emissions due to increased electricity demand under climate change.

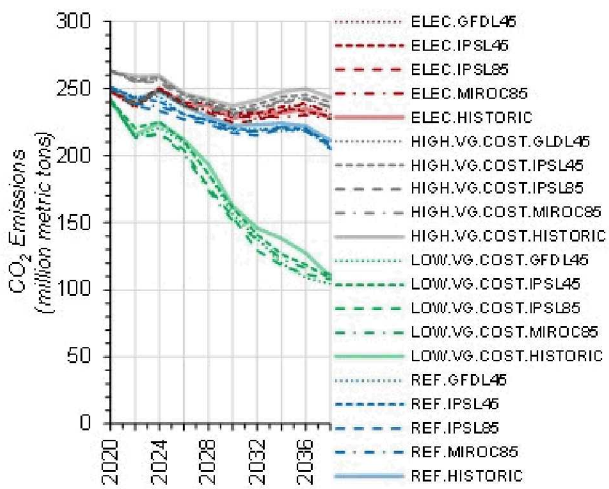

Figure 31. Change over time of CO_2 emissions in the Western Interconnection *using the ReEDS operating solution.*

ReEDS also endogenously accounts for power sector water withdrawal and consumption, which is reported for this study in Figure 32. Water withdrawals fall abruptly in the near-term (~74%) due to announced nuclear plant retirements, with a further reduction in LOW.VG.COST scenarios because these scenarios result in additional coal retirements from low utilization. Water consumption trends are determined by future deployment and use of Gas-CC, which uses recirculating cooling in the model[1]. HIGH.VG.COST and ELEC have higher water consumption than REF scenarios beyond 2030 due to greater Gas-CC usage, and LOW.VG.COST has lower consumption (~40% decrease) due to limited Gas-CC growth and additional coal retirements.

As with CO_2 emissions, climate impacts do not have substantial effects on aggregate water system outcomes. Additional hydropower and displaced coal generation can reduce water use, but water consumption can increase in scenarios with additional Gas-CC capacity. Assuming once-through cooling is not installed with new capacity, power sector water withdrawals in the Western Interconnection

[1] New capacity may use dry cooling as well, but the least-cost optimization rarely if ever chooses this option due to higher costs and reduced plant efficiency.

should fall as large once-through cooled plants retire, while water consumption outcomes could depend on the relative competitiveness of Gas-CC with wind and PV technologies.

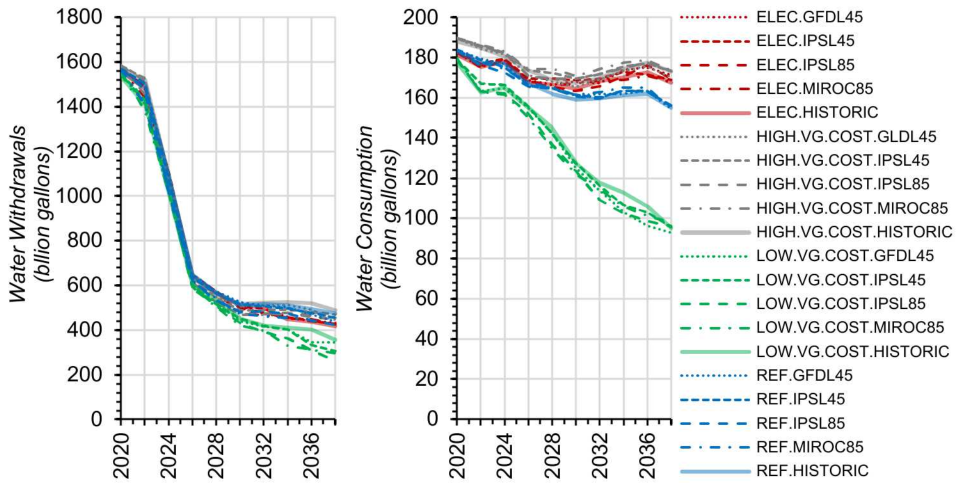

Figure 32. Change over time of water withdrawal and consumption in the Western Interconnection *from the ReEDS operating solution.*

3.3. How Does the Representation of Hydropower in the Modeling Framework Influence Electricity Expansion Planning and Dispatch Optimization Results?

3.3.1. Projected impacts on capacity/transmission expansion

We assess the effect that varying hydropower flexibility as described in Section 2.3.2 has on electric sector investment decisions for each of the four electricity scenarios under historic climate conditions. Cross-sensitivity scenarios combining flexibility and climate variations is outside the scope of this work but could be considered for future work to understand relationships between hydropower operability and climate variations when making planning decisions.

The effect of varying hydropower flexibility depends on the electricity scenario as shown in Figure 33, which is plotted on a similar scale as Figure 9 for comparison. In 2038, net impacts on capacity are small for all flexibility scenarios, but technology-specific effects in LOW.VG.COST and ELEC have a similar order of magnitude as climate effects. Changing hydropower flexibility has relatively limited impact on the generating capacity in the REF and HIGH.VG.COST scenarios, except for a reduction in PV and overall capacity in the REF.LOFLEX scenario. ELEC.LOFLEX also has less PV deployment, suggesting that hydropower flexibility is helpful for PV integration in the Western Interconnection. PV deployment is greater in ELEC.HIFLEX than the reference ELEC scenario, further supporting this inference. However, the LOW.VG.COST scenario includes additional PV and less wind and natural gas regardless of the direction of varying hydropower flexibility. Inspection of capacity differences for LOW.VG.COST across all years shows that the direction of impacts on both technology-specific and net capacity deployment is highly variable across years, so the results for LOW.VG.COST in Figure 33 are not representative of typical behavior over time. This observation implies that the effect of hydropower flexibility on future investments in the Western Interconnection could be less certain in a future with very high renewable penetration. As variable renewable penetration grows, inflexible hydropower that cannot respond to variations in electricity demand can actually displace much or all of the remaining Gas-CC generation supplying base and intermediate load in lower demand periods, which could indirectly create opportunities for more PV generation to meet higher daytime loads.

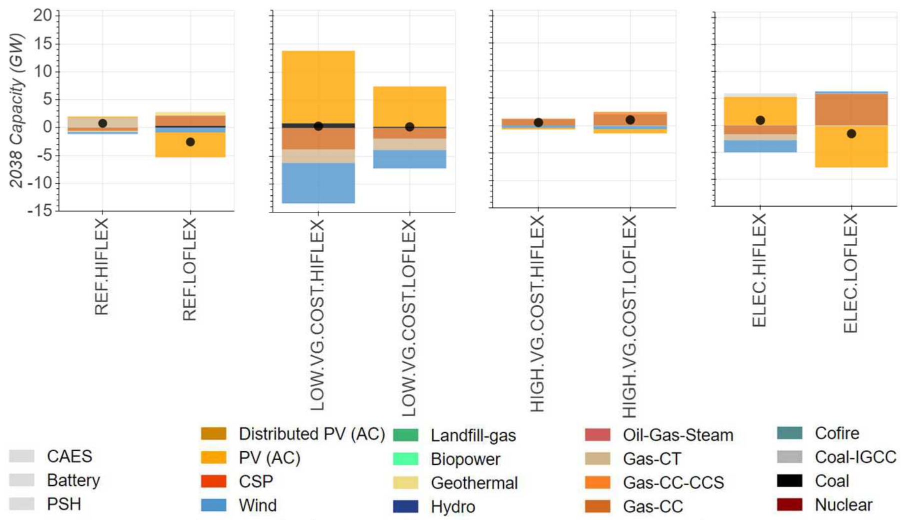

Figure 33. Impacts of varying hydropower flexibility on 2038 capacity in the Western Interconnection *for each flexibility scenario relative to the corresponding electricity scenario with reference flexibility. Circles on plot represent net effect.*

As with climate impacts, changes to the capacity mix are not necessarily consistent across all NERC subregions within WECC. Figure 34 shows sub-regional changes in utility PV capacity in 2038 for all flexibility sensitivity scenarios relative to the corresponding electricity scenario with default flexibility, and Figure 35 includes the same results for 2038 Gas-CC and wind capacity but only for the LOW.VG.COST and ELEC scenarios.

In the REF electricity scenarios, changing hydropower flexibility in either direction corresponds to less PV deployment in the Desert Southwest, which is an unexpected indirect result demonstrating the complexity of inter-regional interactions. With high hydropower flexibility, system-wide PV capacity is similar to REF with default flexibility because flexible hydropower helps facilitate PV deployment in other regions. PV impacts are also regionally disparate in the ELEC scenario, with the PV increase in HIFLEX primarily in the Rocky Mountain and Southwest regions and the decrease in LOFLEX largely in the Great Basin. Large quantities of assumed flexible demand in the ELEC scenario adds another dimension of complexity around the effect of hydropower flexibility on PV construction. Additional PV in both LOW.VG.COST flexibility scenarios is located throughout the Pacific Northwest, Great Basin, and Rocky Mountain regions, demonstrating broad regional effects relative to other electricity scenarios. PV impacts with HIGH.VG.COST are small in all regions for HIFLEX, but there are some variations in PV deployment in the southern regions despite limited system-wide impacts.

Gas-CC and wind deployment is not impacted greatly by varying hydropower flexibility in the REF and HIGH.VG.COST scenarios, and impacts are typically smaller than those on PV in ELEC and LOW.VG.COST. REF and HIGH.VG.COST have a relatively large fraction of Gas-CC capacity relative to load, so Gas-CC is able to adjust dispatch in response to changes in hydropower flexibility with smaller impacts on the overall capacity expansion. Additional Gas-CC in ELEC.LOFLEX is spread throughout the northern NERC subregions, while reductions in other scenarios are often concentrated in Southern California.

Reductions in wind capacity often occur in the Great Basin region, but these impacts remain less than 2 GW per region except for in the LOW.VG.COST.HIFLEX scenario.

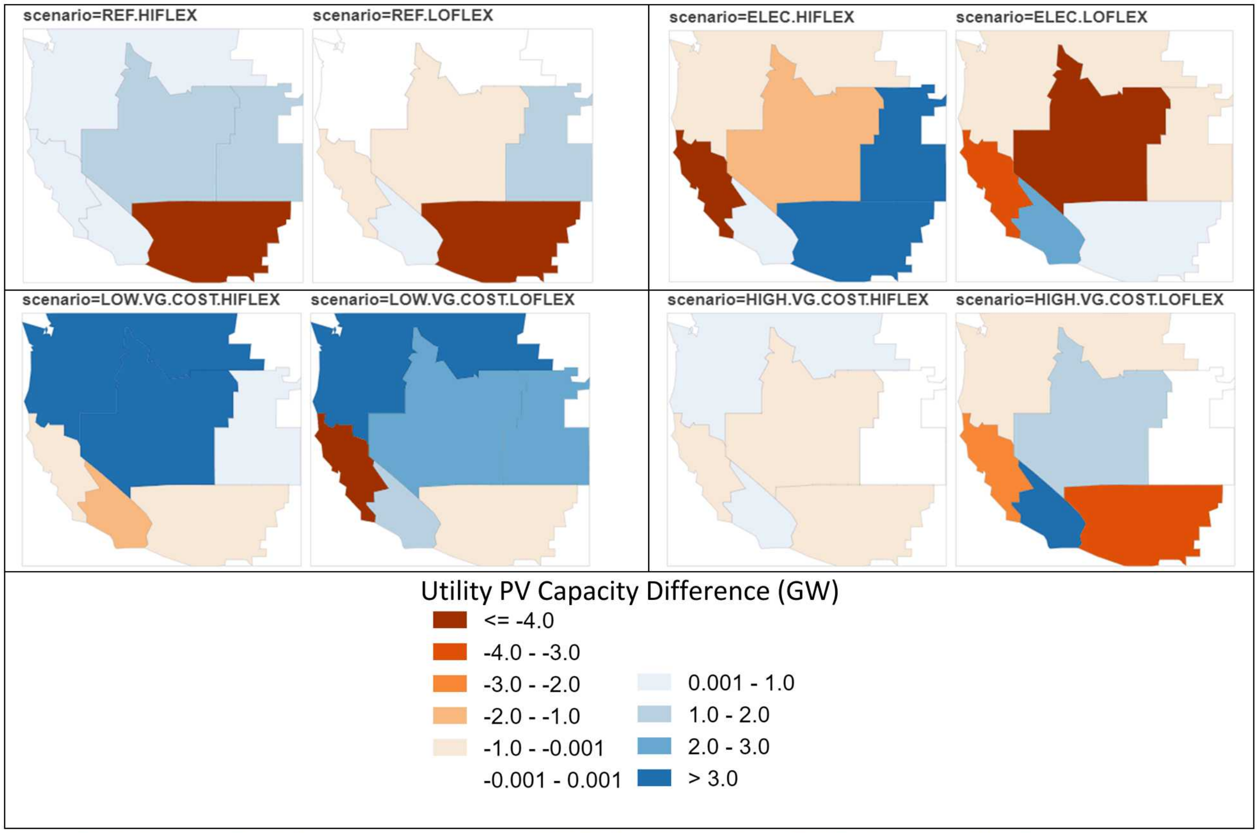

Figure 34. Hydropower flexibility scenario impacts on 2038 Utility PV capacity by NERC subregion within the Western Interconnection relative to corresponding scenarios reference flexibility.

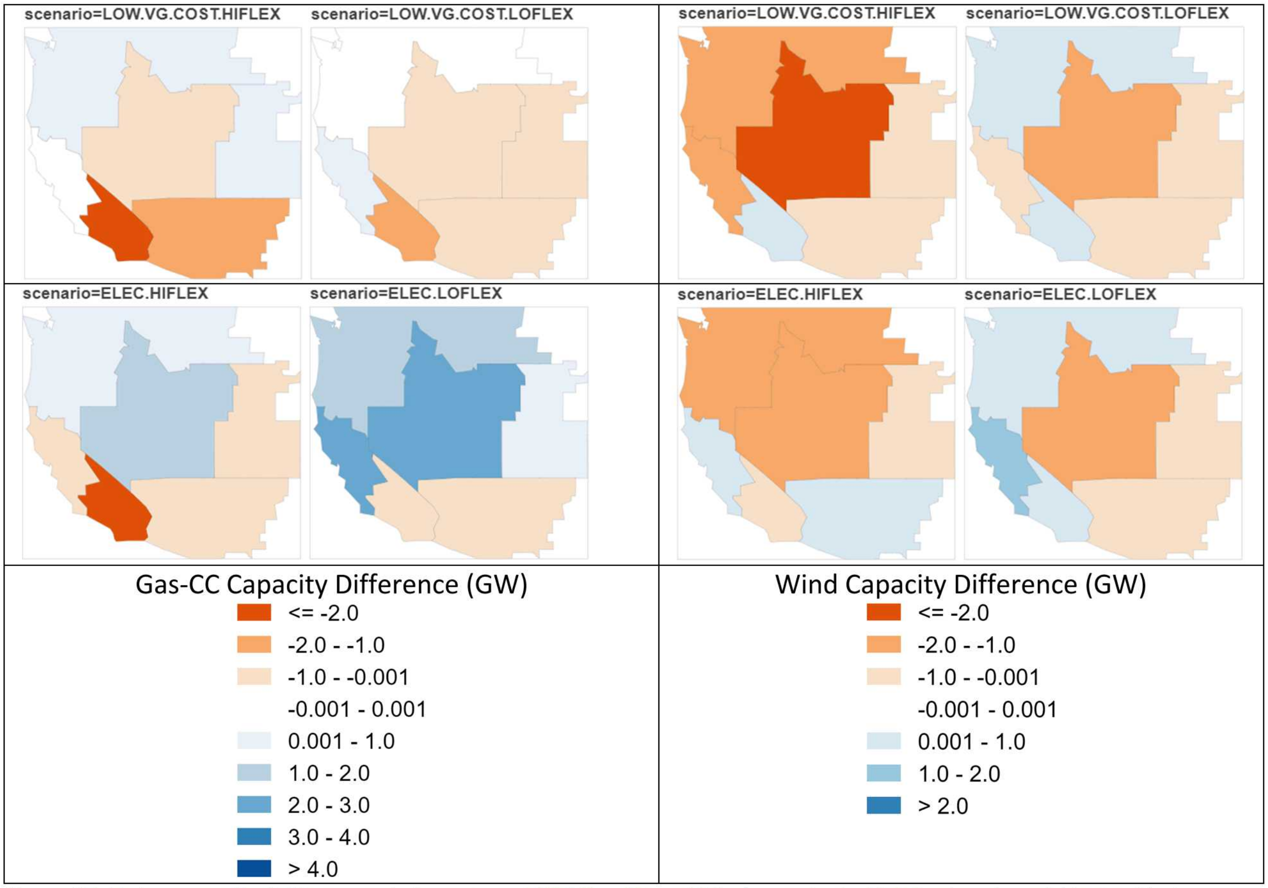

Figure 35. Hydropower flexibility scenario impacts on 2038 Gas-CC and Wind capacity by NERC subregion within the Western Interconnection *for the LOW.VG.COST and ELEC scenarios relative to corresponding scenarios reference flexibility.*

Varying hydropower flexibility has little impact on transmission capacity expansion in most scenarios (Figure 36 and Figure 37), with the key exceptions being those with changes to system-wide or regional PV deployment. For example, 2038 WECC transmission capacity is about 1 GW lower in REF.HIFLEX, and this change is centered in the southern regions where PV deployment is lower. An approximately 2 GW increase in transmission capacity in LOW.VG.COST.LOFLEX relative to LOW.VG.COST.HISTORIC corresponds to higher PV capacity in that region, but this effect is not seen with LOW.VG.COST.HIFLEX. In ELEC scenarios, high hydropower flexibility corresponds to more PV and transmission, and vice versa, making this relationship somewhat robust but still subject to other interregional grid relationships.

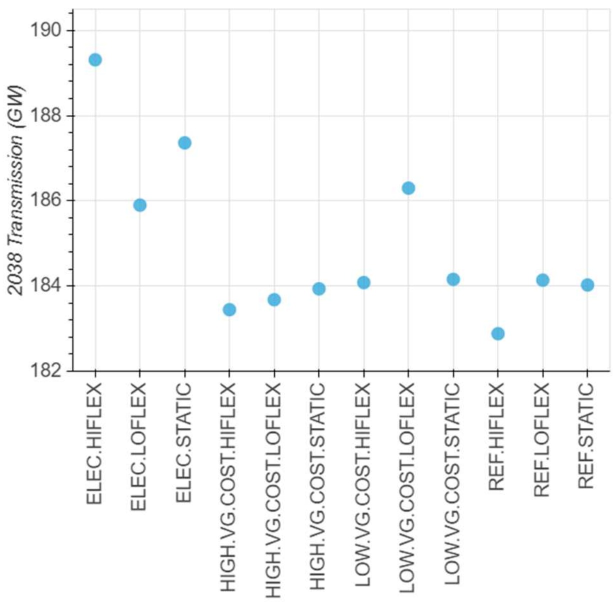

Figure 36. 2038 transmission capacity in the Western Interconnection *for flexibility and reference scenarios.*

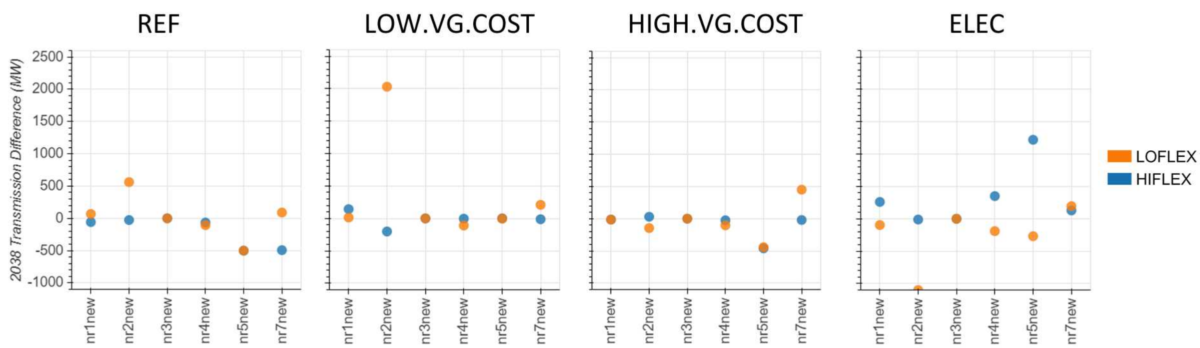

Figure 37. Differences in NERC regional transmission expansion by WECC subregion where the transmission capacity begins, for each flexibility scenario relative to the corresponding scenario with reference flexibility. [nr1=northwest, nr2=great basin, nr3=rocky mtn, nr4=norcal, nr5=socal, nr7=desert southwest.

3.3.2. Projected impacts on operation

We compare the 2038 generation in the LOFLEX and HIFLEX hydropower fleets to reference flexibility conditions for the HIGH.VG.COST and LOW.VG.COST scenarios using PLEXOS simulations. These scenarios all assume average hydrologic conditions (i.e., IPSL85 year 2090) and reference load to isolate the impacts of varying hydropower flexibility. Figure 38 shows hourly net load (here calculated from total generation minus wind and PV generation each hour) and hydro dispatch during one week in July for the LOW.VG.COST scenario to demonstrate hourly operation under different hydropower flexibilities.

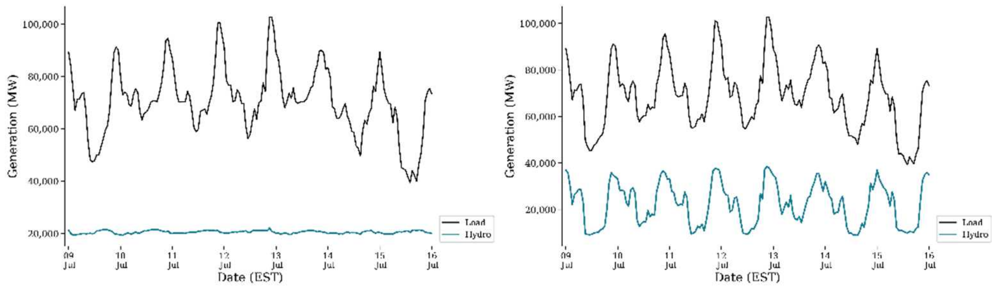

Figure 38: Net load and hydro for LOW.VG.COST showing impact of hydropower flexibility on hourly dispatch. Left: LOFLEX hydro. Right: HIFLEX hydro.

The impact of changing hydropower flexibility on the LOW.VG.COST fleet is that an inflexible hydropower fleet significantly increases curtailment and Gas-CC generation (Figure 39 and Figure 40). The high flexibility case has the opposite effect but to a much lesser extent because the baseline hydropower fleet is already highly flexible. In the HIGH.VG.COST case, the increase in Gas-CC generation under low flexibility assumptions is about the same quantity as the Gas-CC generation change in the LOW.VG.COST case, but more storage is utilized and less coal is utilized as well. The associated generation cost changes in the LOW.VG.COST scenarios are +17% for low flexibility and –2% for high flexibility (Figure 41 and Figure 42). In the HIGH.VG.COST scenarios the change in generation cost are +4% for low flexibility and there is a less than 1% difference for high flexibility, demonstrating the increased importance of flexibility with higher VRE penetration. The LOW.VG.COST scenario has a higher relative change in cost as a percentage because the generation costs are lower in a high-renewable system, but the magnitude of the cost changes are similar.

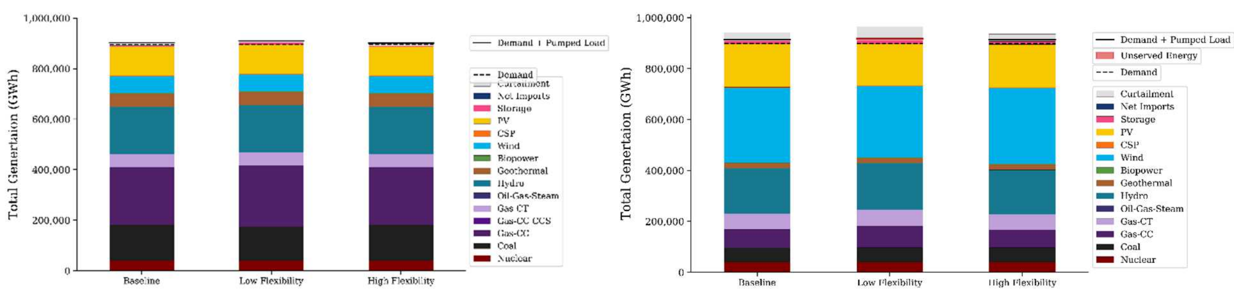

Figure 39: Generation by type for HIGH.VG.COST (left) and LOW.VG.COST (right) IPSL85 2090 Hydro, Baseline load, under varying hydropower flexibility.

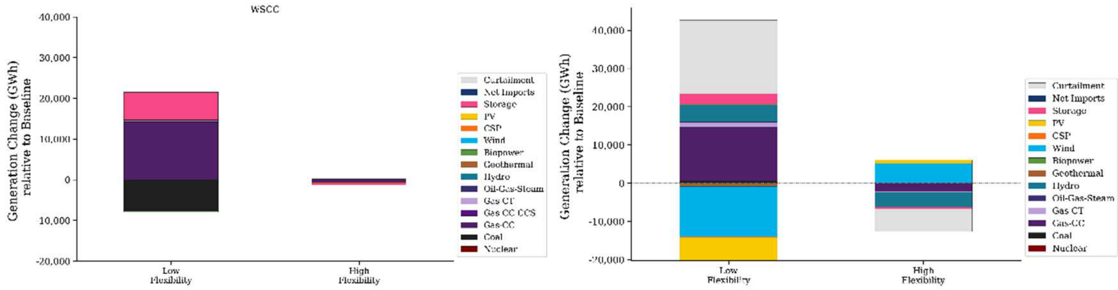

Figure 40: Change in generation relative to baseline hydropower flexibility assumptions for HIGH.VG.COST (left) and LOW.VG.COST (right) system.

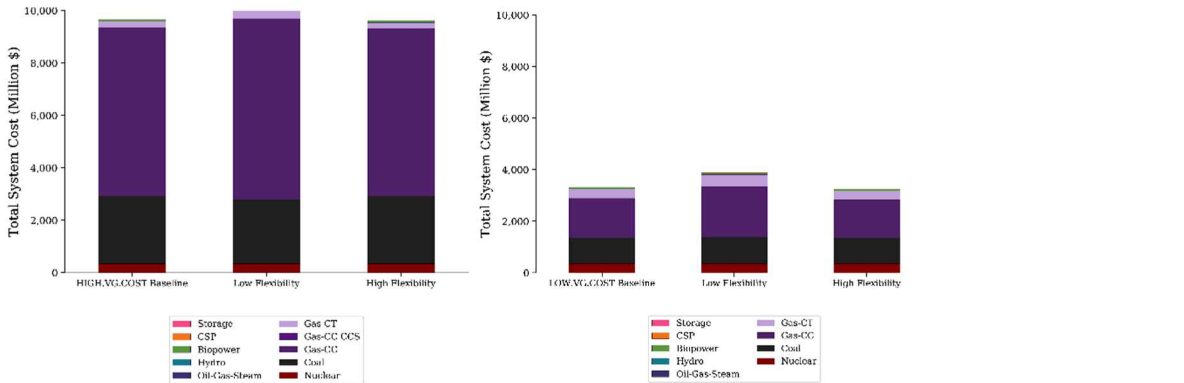

Figure 41: Generation cost by type for HIGH.VG.COST (left) and LOW.VG.COST (right) IPSL 2090 hydro, baseline load, under varying hydropower flexibility.

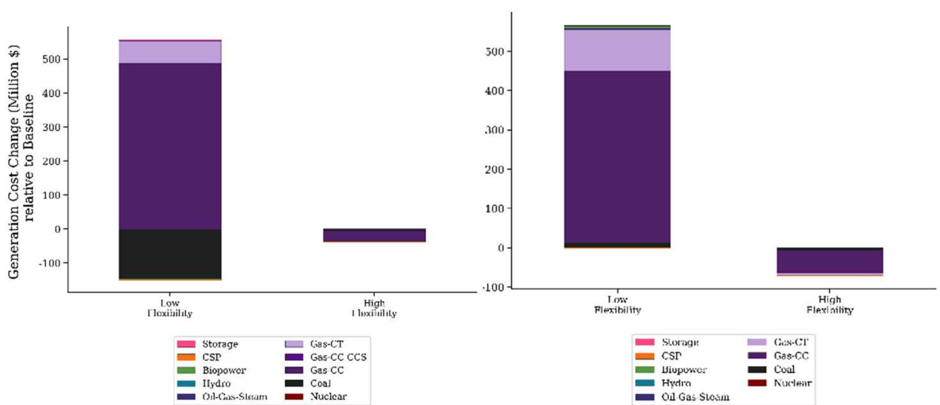

Figure 42: Change in generation cost for HIGH.VG.COST (left) and LOW.VG.COST (right) system relative to baseline hydropower flexibility cost assumptions.

4. Summary

Climate change has the potential to impact decisions associated with electricity capacity expansion planning and operations. Here we support long-term planning of the Western Electricity Coordinating Council. To do so we develop a multi-model framework consisting of hydrologic, capacity expansion and production cost modeling. The framework is used to simulate and analyze a range of future scenarios that differ according to assumptions concerning evolving power sector technology, climate and flexibility in hydropower dispatch. Below, we review results in the context of our two guiding questions: 1) How does changing climate influence electricity expansion planning (generation and transmission) and future operations including type and capacity of new builds, system reliability, cost and environmental impacts?, and 2) How does the representation of hydropower in the modeling framework influence the evaluation of operations and reliability studies?

To inform the analysis, four different climate scenarios were utilized that encompass a range of possible futures in terms of temperature and precipitation change in the Western Interconnection. The average temperature over the Western U.S. increase by approximately 2 to 3 °C by mid-century under these projections depending on the emissions pathway. These changes drive an increase in cooling degree days and a reduction in heating degree days. Considerable variability exists between different regions in the West, but these effects lead to an increase in annual electricity load of 3–15 TWH on average. Trends in precipitation vary substantially across the four climate scenarios. The RCP45 emissions pathway leads to a uniformly wetter future across the Western Interconnection under GFDL (11% increase in precipitation by mid-century) and uniformly drier future under IPSL (5% decrease in precipitation). Although the system-wide precipitation changes are less intense under RCP85, this emissions pathway leads to intense drying trends in particular locations across the West over the next two decades—namely California/Nevada under MICO85, where decreasing precipitation leads to an approximate 25-30% reduction in flows, and the Southwest under IPSL85, where flows are reduced by approximately 20%. In the most undesirable case, projected changes to water supply threaten to reduce total hydropower production in the Western Interconnection by roughly 5-10%.

These ***changes in climate are seen to impact capital investment decisions*** in generation and transmission projects. Across modeled climate futures, higher electricity demand due to higher temperatures drives up to 17 GW additional generating capacity in Western Interconnection through 2038 (~6.6% increase over corresponding historical capacity-build). Capacity needs are driven by more rapidly growing peak load requirements, which typically favor flexible technologies or those available during higher-load daytime periods, such as PV and gas-based generation. This response could be mitigated by increased water availability for hydropower; however, there is considerable uncertainty how future water availability will evolve. While the magnitude of and mechanisms behind flexible electrified load is also highly uncertain, this analysis motivates further investigation on how additional demand-side flexibility could mitigate climate impacts on capacity requirements. Transmission capacity expansion also tends to increase by 1–2 GW when accounting for future climate changes, 1% or less change across the Western Interconnect. There is also variation across regions in climate impacts on generating and transmission capacity expansion, with local resource availability, fuel and technology costs, transmission constraints, and policy interacting with climate change to influence regional electric sector outcomes.

Climate change was seen to impact system operations. At a regional level, our drought scenarios encounter variability in hydropower generation primarily in the Pacific Northwest while increased load due to climate occurred in the Southwest. These dynamics required load balancing across regions, which was achieved in the hourly production cost modeling simulations. Importantly, resource expansions that are high in thermal and low in renewable generation respond to changes in climate mostly through usage of Gas-CC across the Western Interconnection, while resource expansions that are high in renewables have a more diverse set of responses both in type of generation and in regional mix of generation types. Though all systems are reliable (have nearly zero unserved energy and reserve), those high in renewables may be more resilient in uncertain futures due to their diversity.

Only high renewable capacity-builds have significant curtailment (up to 5.5% of PV), and curtailment decreases slightly under climate scenarios because increased load can utilize otherwise surplus variable generation in the springtime (up to 1% decrease in PV curtailment).

System reliability was observed to remain robust under our drought scenarios with over 99.999% of load being met in the PLEXOS simulations of the Western Interconnection. We note that this reliability assessment is limited to the assumptions of the production cost model and to the number of scenarios analyzed (20). When climate foresight was used in ReEDS in a highly thermal fleet (HIGH.VG.COST IPSL85), the operational model in PLEXOS showed that there was more spare thermal capacity available after meeting load. When climate foresight was used in ReEDS in a highly renewable fleet (LOW.VG.COST GFDL45), the change in thermal capacity was smaller but we noted that significant curtailment existed as a source of flexibility for parts of the year.

Climate was seen to impact long-term system investment and operating costs reflecting the combined influence of temperature, water availability, and demand flexibility. Additional capacity needs due to higher load tend to increase costs, but increased water availability for hydropower and flexible demand can reduce system costs and actually lead to a net cost reduction in Western Interconnection under climate change. Absent these benefits, climate effects increase system costs by $5–$17 billion. Production cost modeling shows that generation costs increase under the climate scenarios analyzed by 9 to 19%. The magnitude of the cost changes are highest in the high thermal (HIGH.VG.COST) scenarios but as a percentage changes are higher in the high renewable fleet (LOW.VG.COST) relative the lower generation costs of a high renewable fleet (up to 19%). The impact of climate foresight on the operational costs was smaller: -2 to +4% change in operation costs relative to the same conditions in an infrastructure without climate foresight.

Long-term projections of ***CO2 emissions, and water use are driven primarily by the future electricity scenario***, with relatively little variation across climate scenarios for a given electricity future. A key exception is a high variable renewable penetration scenario, where climate effects tend to slightly reduce CO2, and water use by the mid-2030s because climate-induced capacity tends to displace additional fossil-fueled.

Changing the representation of hydropower flexibility has a relatively small influence on net capacity expansion in the Western Interconnection through 2038. However, higher hydropower flexibility corresponds to additional PV deployment in some future electricity scenarios, while lower hydropower flexibility corresponds to reduced PV deployment in other scenarios. An increase in PV sometimes corresponds to additional transmission needs as well. **In production cost modeling, hydropower flexibility has a significant impact on production costs**, as hourly simulations show that increased need for flexibility in the system is met by increased deployments of Gas-CC generation in all systems and by additionally curtailing wind and PV in high renewable systems. The change in generation cost is -2 to +17% in the high renewable system (LOW.VG.COST), and up to 4% increase in the high thermal system (HIGH.VG.COST)..

Finally, two important limitations are noted. First, analyses here do not endogenously represent climate impacts and planning and operational decisions within Canada and Mexico. Thus we do not consider any changes to Mexican or Canadian load, hydropower, or other electricity supply and demand conditions in response to the scenarios in this analysis, which in reality could affect cross-border electricity flows and system needs within the United States. Integration of these regions is a priority for future efforts.

Second, climate change impacts are expected to accelerate at/after mid-century; that is, beyond the 2038 time horizon of this study (Brekke et al. 2014). This is important as what is built in 2038 will be affected by climate post 2050. In fact, different decisions might be made if a multi-decadal legacy of infrastructure is considered.

5. Acknowledgements

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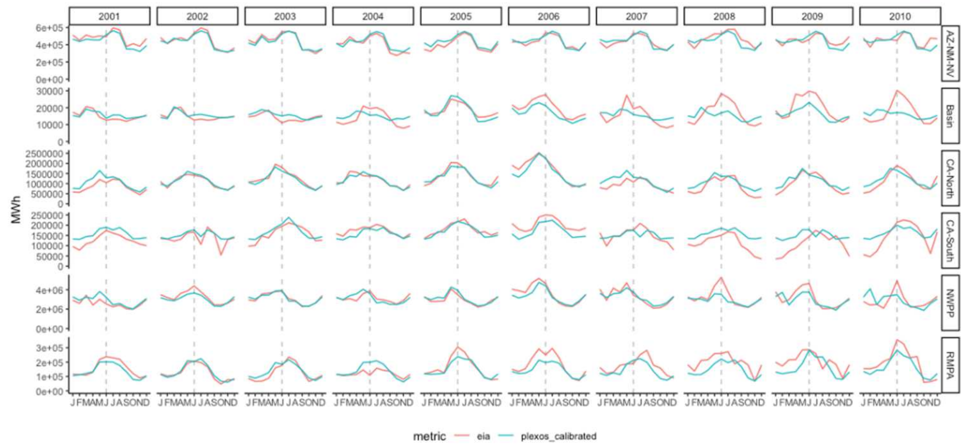
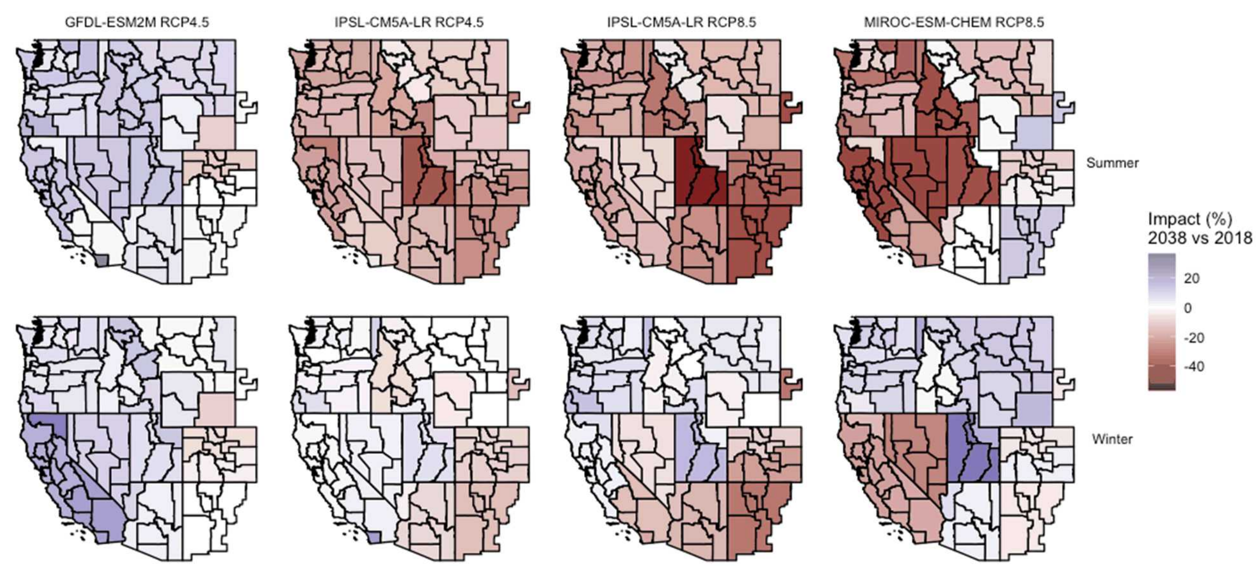
Supplemental Information

1. Calibration and validation of plant-level flow to generation model



Note: calibration performed on years 2001 – 2006 monthly generation (validation on 2007 – 2010).

2. Seasonal trends in water availability for hydro generation



3. Baseline Results without Consideration of Climate

1.1. Demands

1.2. Flows, disruptions to hydropower and thermoelectric power generation

1.3. Capacity expansion

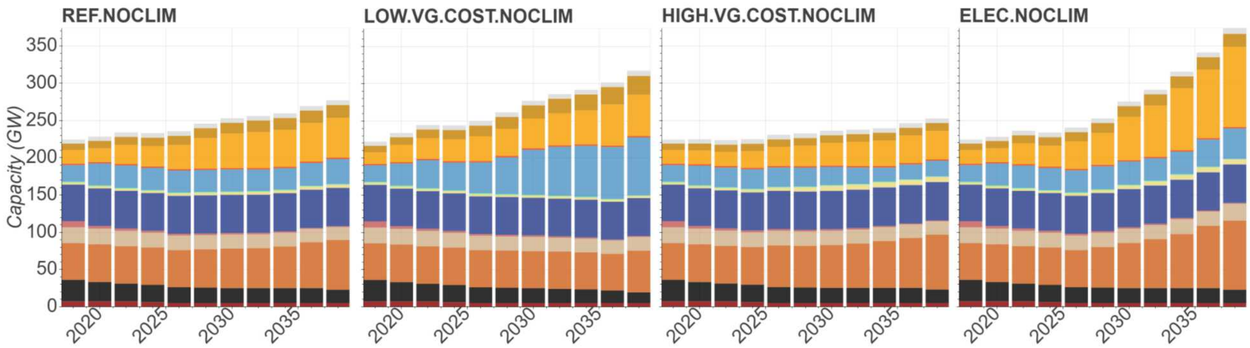


Figure 43. Capacity expansion in the Western Interconnection *through 2038 for each of the electricity system scenarios without climate change impacts.*

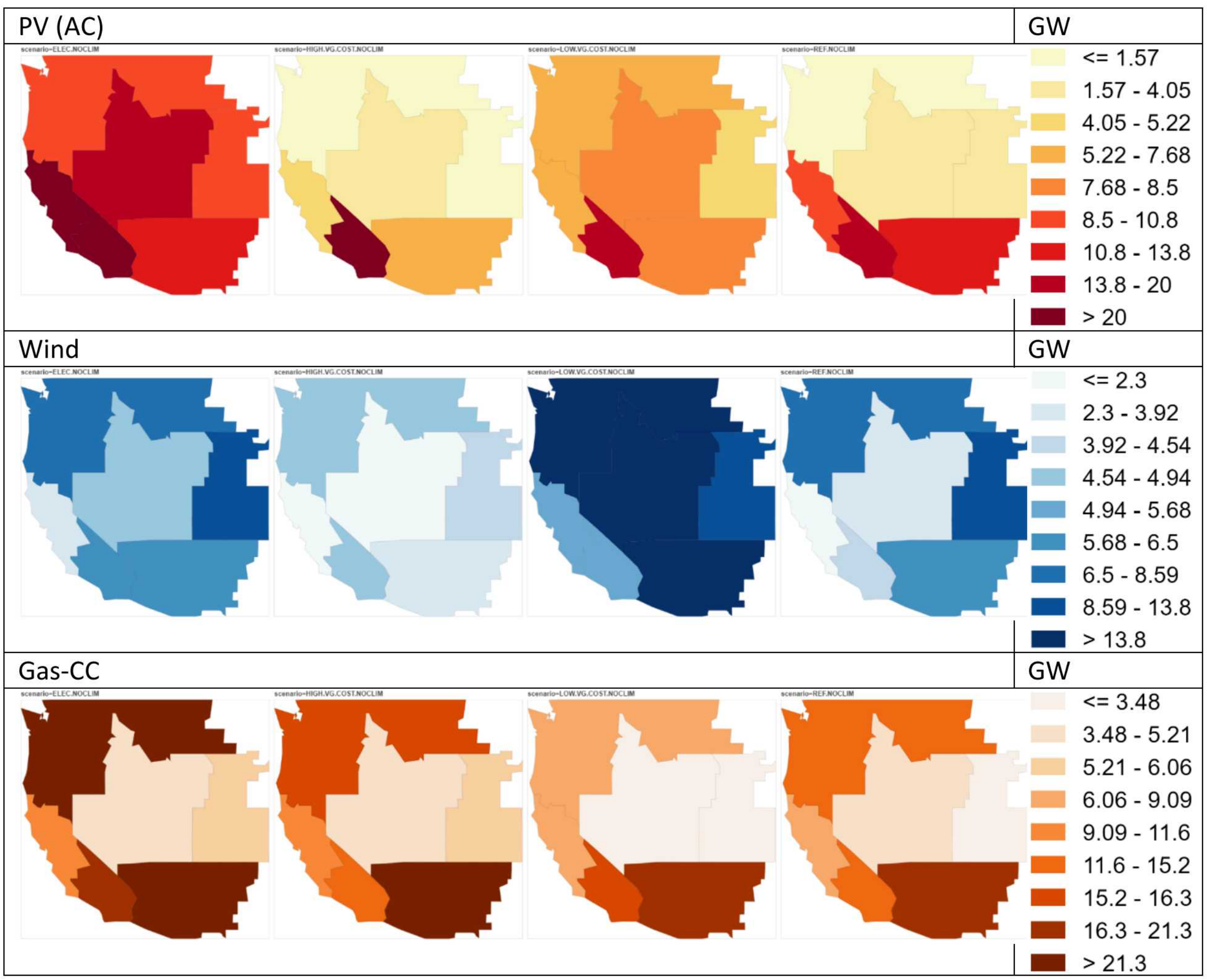
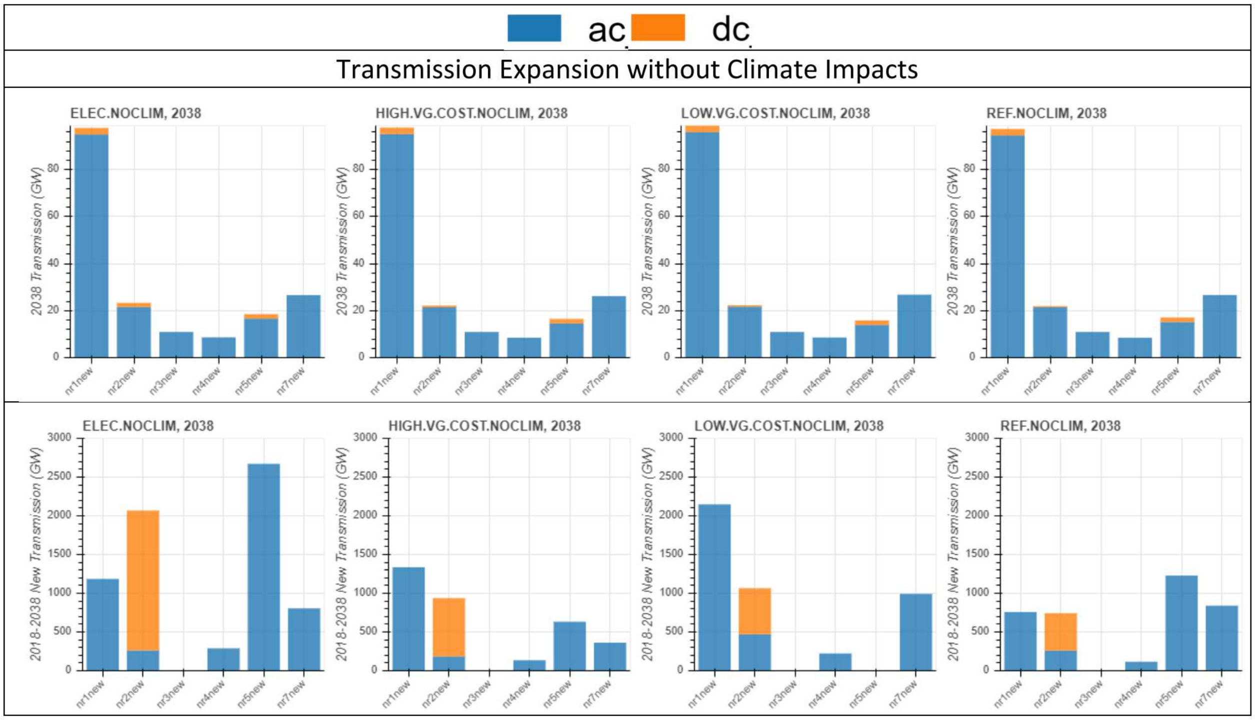
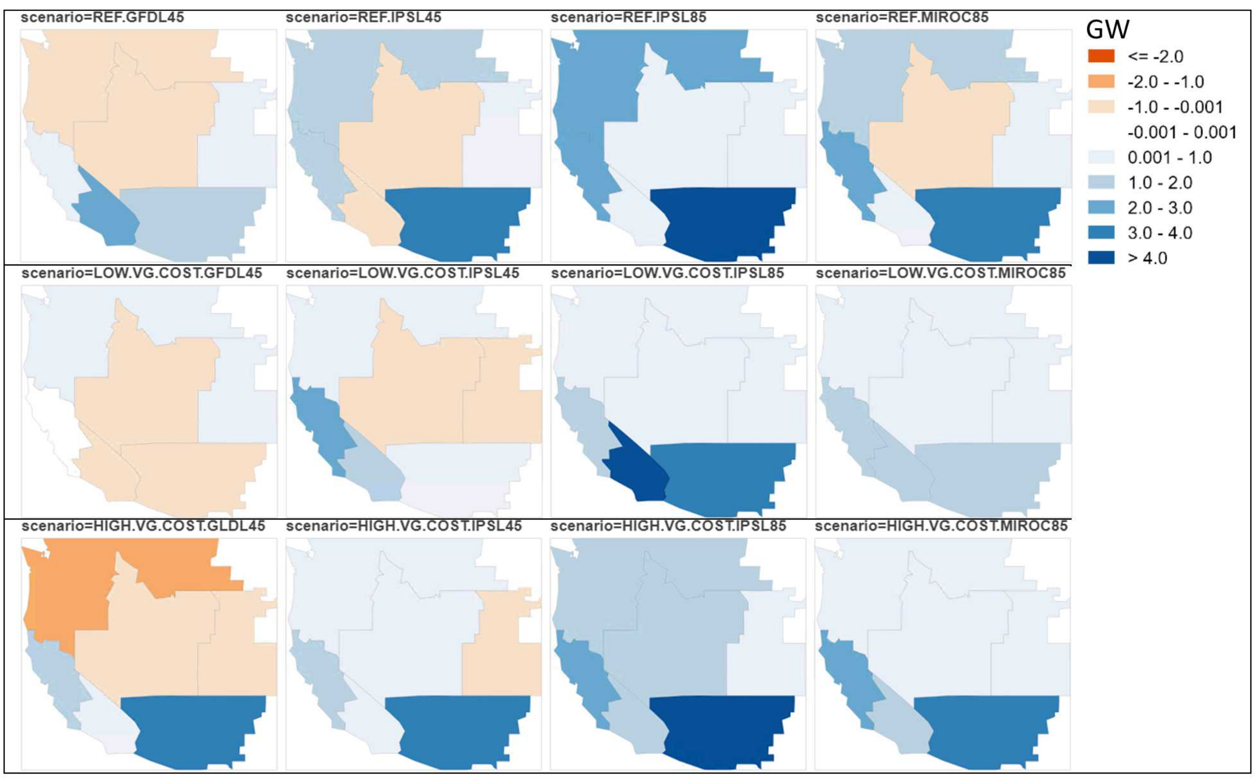


Figure 44. 2038 capacity of utility PV, Wind, and Gas-CC by NERC subregion within WECC for each of the electricity system scenarios without climate change impacts.





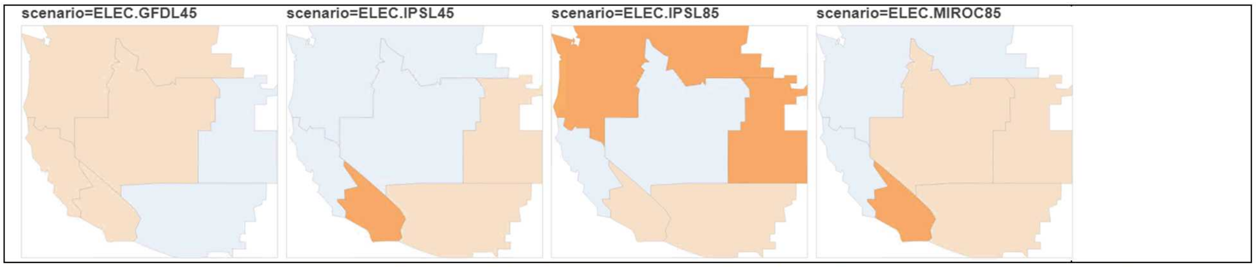


Figure 45. Climate impacts on 2038 Gas-CC capacity by NERC subregion within WECC for each climate scenario relative to the corresponding electricity scenario without climate change impacts.

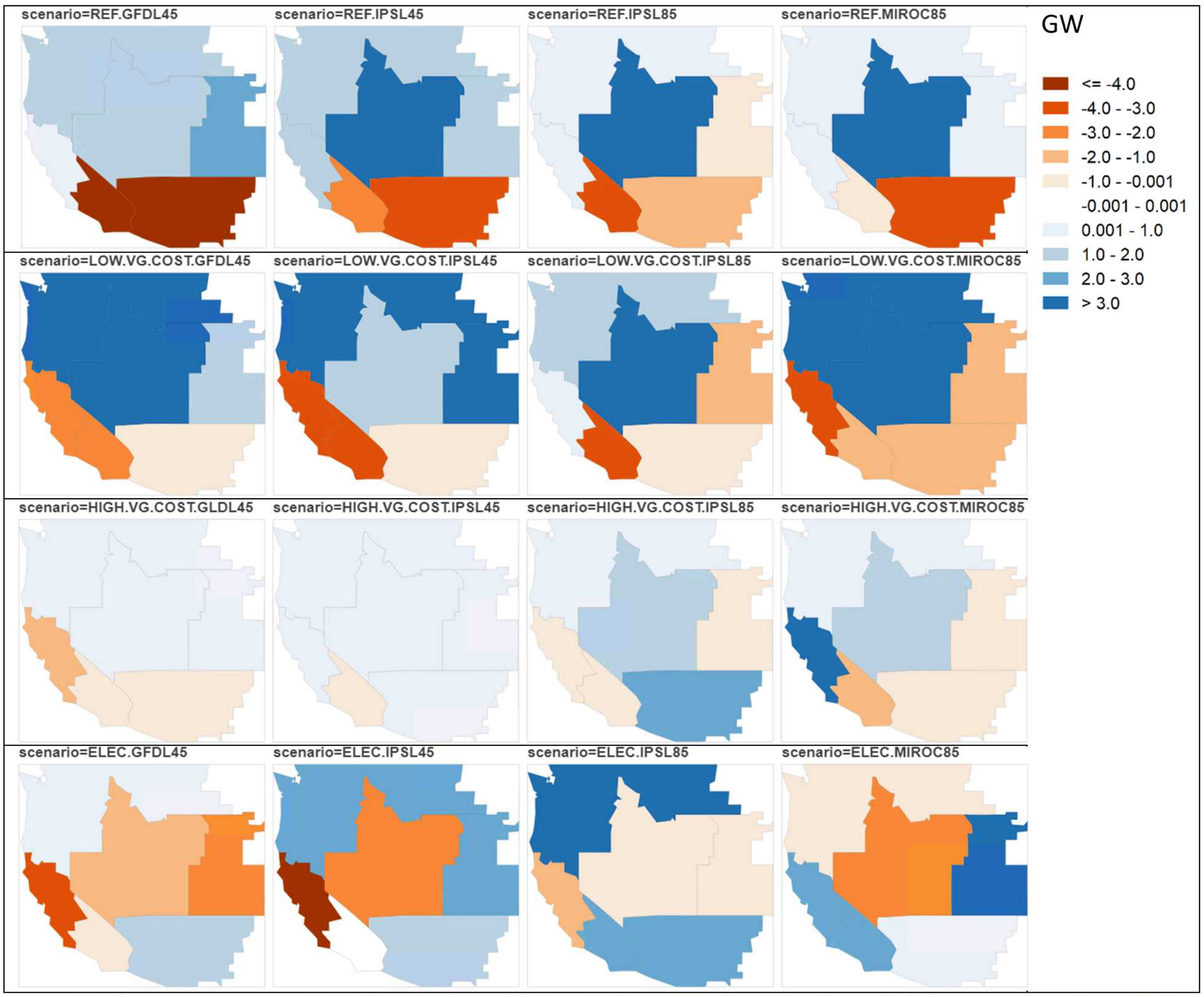


Figure 46. Climate impacts on 2038 Utility PV capacity by NERC subregion within WECC for each climate scenario relative to the corresponding electricity scenario without climate change impacts.

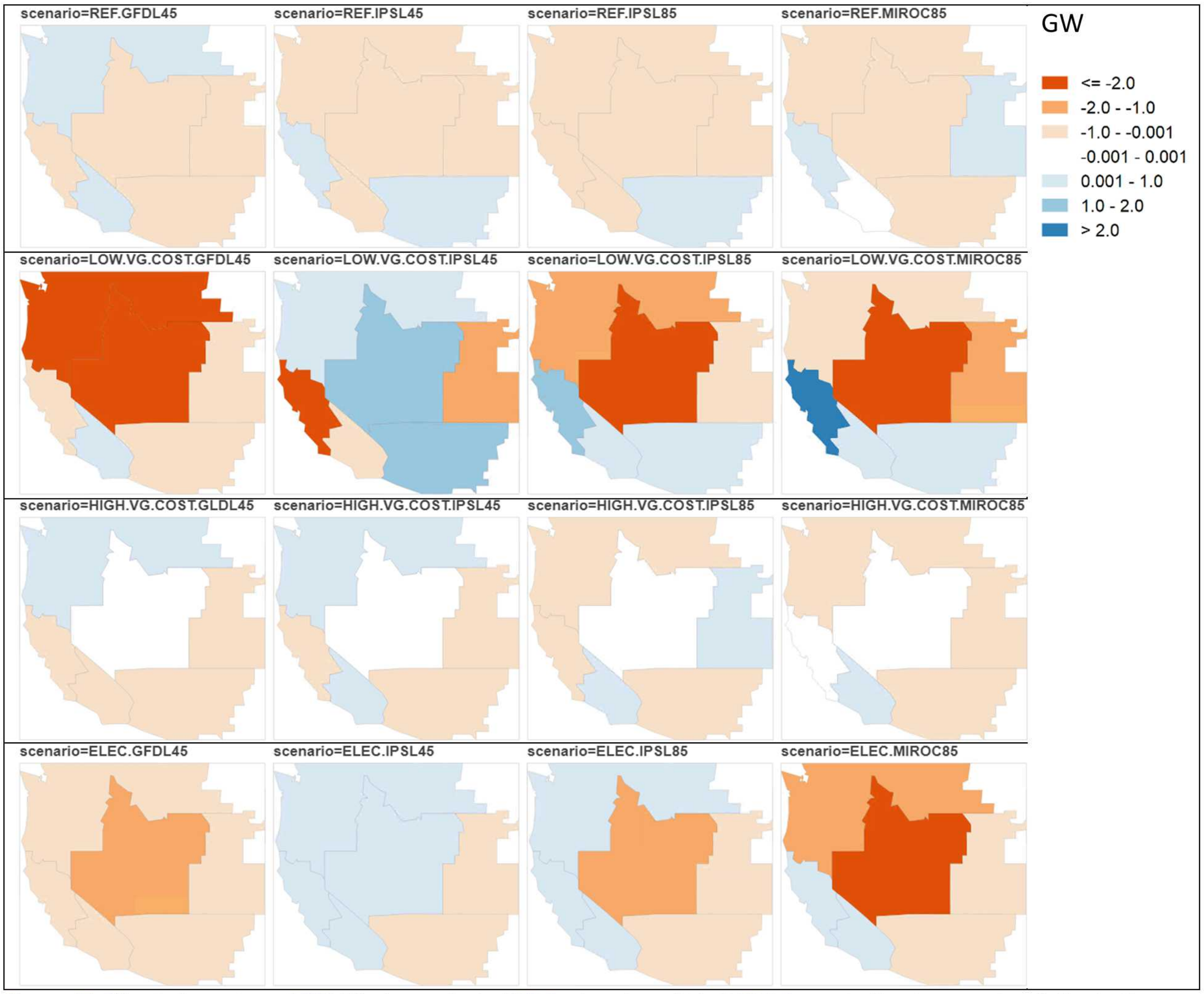
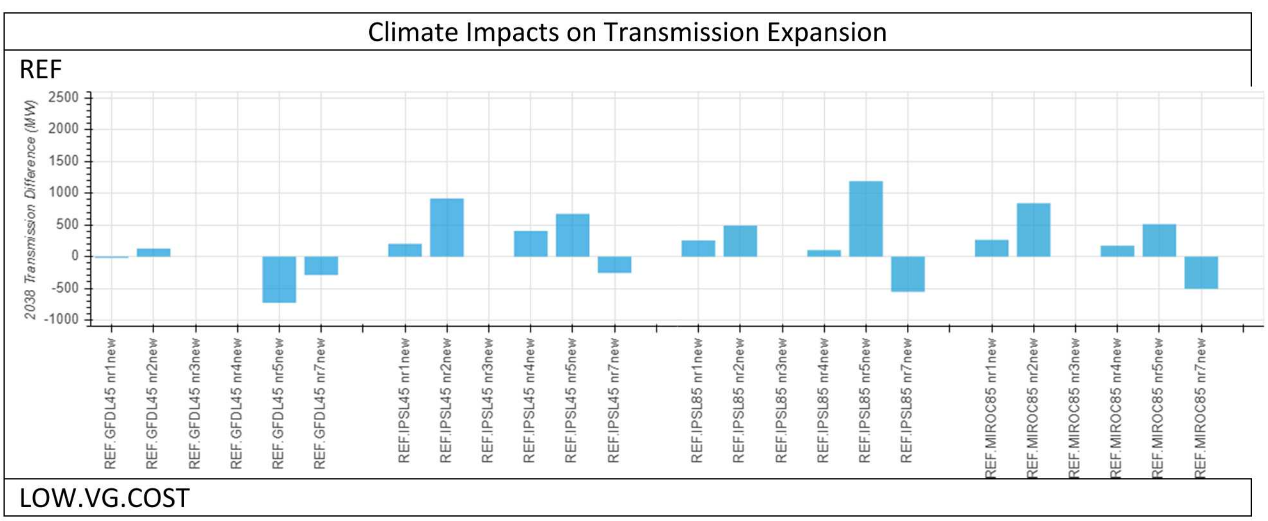


Figure 47. Climate impacts on 2038 Wind capacity by NERC subregion within WECC for each climate scenario relative to the corresponding electricity scenario without climate change impacts.

Transmission capacity and location (or combined discussion with above)



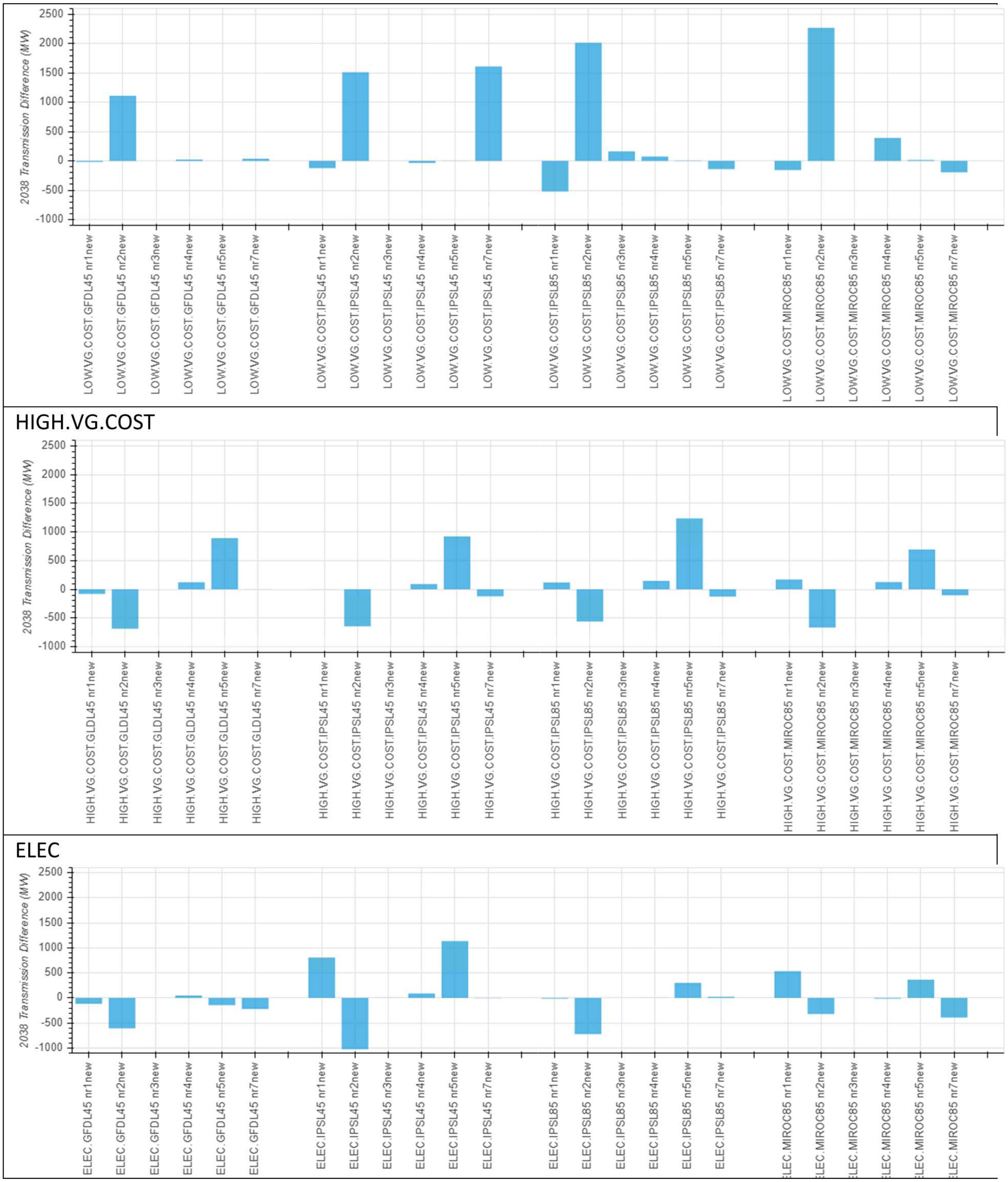


Figure 48. NERC regional transmission expansion by WECC subregion, including total transmission capacity in 2038 without climate impacts, new transmission capacity through 2038 without climate impacts, and the changes to 2038 transmission due to climate impacts. [nr1=northwest, nr2=great basin, nr3=rocky mtn, nr4=norcal, nr5=socal, nr7=desert southwest.

2. Additional Results from Hydropower Flexibility Sensitivity

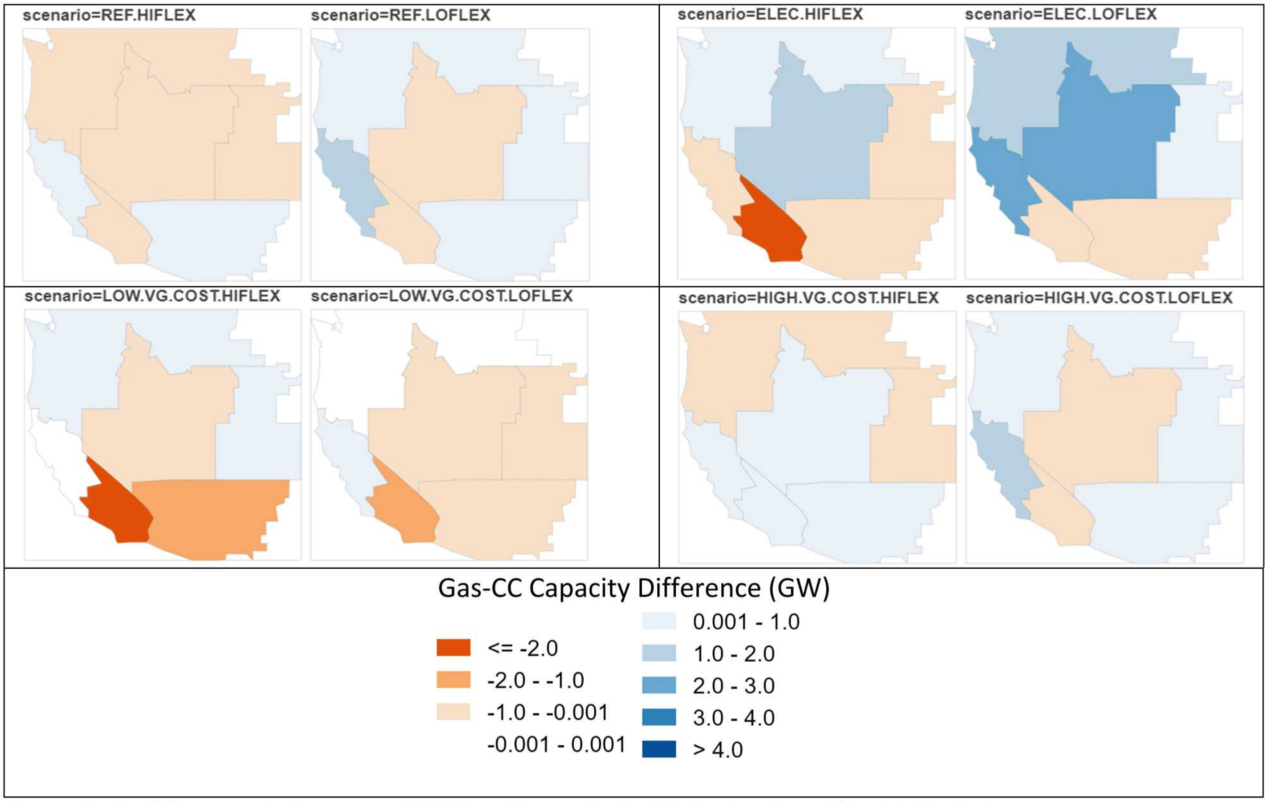
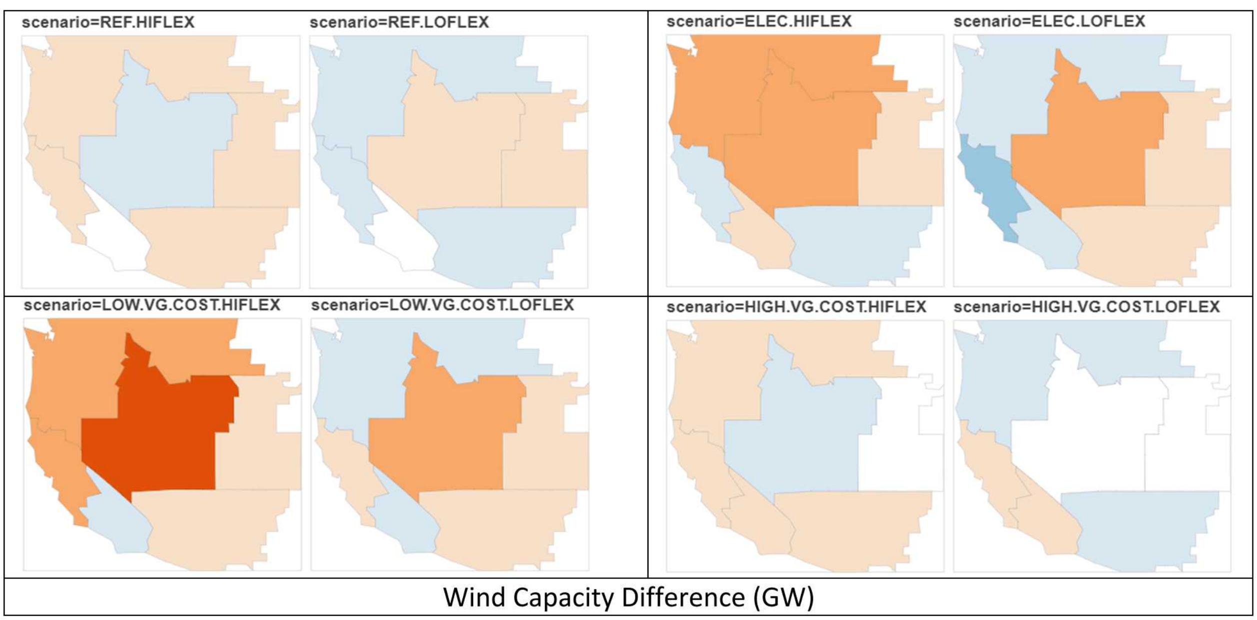


Figure 49. Flexibility scenario impacts on 2038 Gas-CC capacity by NERC subregion within WECC relative to corresponding scenarios reference flexibility.



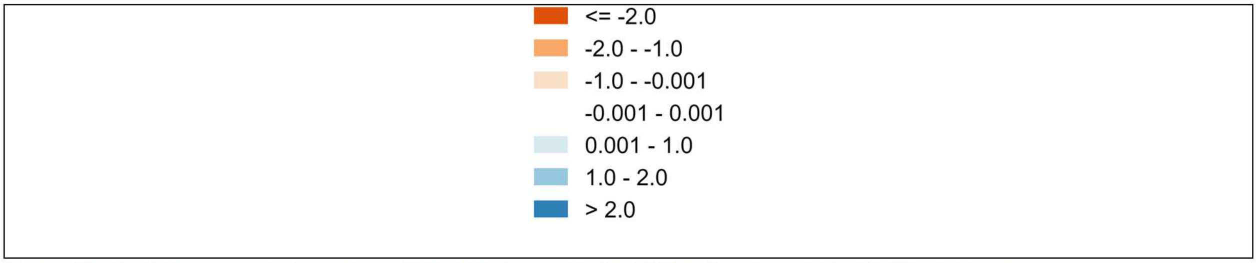


Figure 50. Flexibility scenario impacts on 2038 Wind capacity by NERC subregion within WECC relative to corresponding scenarios reference flexibility.