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Holland & Knight References (4 of 11)

The attached document is the fourth of 11 separate uploads that contain the references cited in Holland & Knight's DEIR Comment Letter.

Additional submitted attachment is included below.

1 Introduction

Clean energy transitions are underway globally, propelled by declining renewable technology costs [1] and sparked by policies mandating significant greenhouse gas (GHG) reductions and high shares of renewable electricity [2–4]. Recent studies charting possible pathways to achieve these ambitious mandates have laid out the technology choices, estimated the scale and rate of technology adoption, and compared system costs [5–7]. Yet few have accounted for natural resource constraints, barriers, impacts in implementing the pathways—and, in particular, where low-carbon infrastructure should be developed to avoid and minimize ecological and social impacts.

Ecological studies have begun to reveal the unintended impacts of large-scale solar and wind development [8, 9]. The media and scholars have noted the rise of "green vs. green" conflicts when siting renewable energy infrastructure in sensitive landscapes, such as the desert southwest in the United States [10]. To help alleviate these conflicts and potential trade-offs, studies are needed to assess the possible land use constraints and ecological impacts of energy infrastructure needed for a deeply decarbonized national or sub-national economy [11–14].

Addressing this gap requires integrating land conservation values into the energy planning process and evaluating both the environmental and system cost implications of siting policies and energy procurement standards. One of the key challenges in this integration is tackling a mismatch of spatial scales: energy policies are regional or national, but project implementation is local and must address local resource values. Planning can help bridge policy and implementation by also bridging this divide in spatial scales. Currently, renewable energy planning relies on electricity capacity expansion models, which simulate future investments in generation and transmission infrastructure given assumptions about energy demand, technology costs and performance, resource availability, and policies or regulations (e.g., GHG emissions targets). These capacity expansion models are highly spatially aggregated, but the renewable resource assumptions that serve as important inputs to these models must come from highly spatially-explicit analyses. These spatial analyses usually remove areas legally protected from development, but do not include the detailed spatial datasets that can account for many other ecologically sensitive areas where development is likely to trigger conflicts with resource management agencies, environmental organizations, and local communities [15, 16]. Other resource assumptions used in capacity expansion planning studies can also be overly conservative by applying uniform discounts on resource availability, with the unintended impact of underestimating low-impact and low-conflict siting options. In terms of evaluation and comparison of portfolios, capacity expansion model outputs are also typically too spatially coarse to provide information on possible siting impacts of portfolios.

We address these gaps and challenges by developing an approach to support policy and regulatory design that achieves multiple objectives—protection of natural and working (agricultural and rangelands) lands and decarbonization of the electricity sector for the state of California. California is the second state in the U.S. to pass legislation that sets a policy of supplying 100% of electricity from renewable energy and zero-carbon resources by 2045 (Senate Bill 100)—reinforcing and complementing an earlier goal to reduce GHG emissions by 80% below 1990s levels by 2050 (Executive Order S-3-05). To guide energy policy and regulations in support of climate commitments, utility regulators and energy planners use an electricity sector capacity expansion model, RESOLVE [17]. We develop a planning framework using RESOLVE that quantifies—using regionally-consistent, detailed, spatially-explicit datasets—how siting constraints to avoid impacts on natural and working lands in the Western United States are likely to affect technology choices, amount of generation and transmission capacity, system costs, and environmental impacts of pathways that achieve climate targets (Executive Order S-3-05). This study expands on related existing studies [11, 12] by examining the implications of the geographic availability of renewable resources in the Western Interconnection for import to California and examining pathways to achieving California's ambitious renewable and zero-carbon electricity policy by mid-century.

We first estimate the quantity and quality of onshore wind, solar, and geothermal energy potential under four levels of environmental siting considerations in 11 states in the Western United States. We use these environmentally-constrained resource estimates as inputs in RESOLVE. With these inputs, RESOLVE creates land-constrained optimal electricity generation portfolios that achieve the economy-wide GHG target of 80% below 1990 levels by 2050, and puts California on a path to meeting SB 100 as these scenarios deliver 102-110% renewable or zero-carbon electricity by 2050. We examine a high electrification pathway—a more likely and most cost-effective pathway for California—that relies predominantly on wind, solar PV, and storage technologies to meet most energy end uses [18]. In order to compare possible environmental impacts due to land conversion from infrastructure development, we use a geospatial site suitability model and a geospatial site selection model (ORB [11] and MapRE in conjunction with the RESOLVE model to identify each portfolio's spatial build-out of generation sites and transmission corridors and estimate the area of natural and working lands impacted. We examine how California's current resource availability assumptions, along with other variables such as lower battery costs, higher behind-the-meter solar photovoltaic (PV) adoption, and access to other states' renewable resources (states closest to California or all states in the Western Electricity Coordinating Council) affect outcomes such as California's generation portfolios' technology mix, the location and extent of environmental impacts, and system costs.

2 Methods

2.1 Methods overview

The methodological workflow is comprised of five key steps (Fig. 1). Step 1 (Section 2.2) consists of spatial environmental data gathering (representing ecological, agricultural, cultural, and other natural resource values). In this step, we constructed four Environmental Exclusion Categories and designed four different levels of siting protections for wind, solar, and geothermal power plants. The second step uses the Environmental Exclusion Categories, along with spatial data on socio-economic and technical siting criteria for renewable energy, to identify suitable sites for development of each technology (Section 2.3). The purpose of Step 2 is to identify potential locations of future wind, solar, and geothermal power plants and to construct a supply curve based on these locations. This forms the list of candidate supply-side power generation resources which will be available as inputs to the capacity expansion model. The supply curve is comprised of renewable energy resources and their associated attributes including location, size (MW), capacity factor, and estimated annual energy production. For this second step, we applied the Optimal Renewable Energy Build-out (ORB) framework [12], which is a suite of spatial modeling tools that perform site suitability and site selection analyses for planning the spatial build-out of new wind, solar, and geothermal technologies. The ORB framework includes the Renewable Energy Zoning Tools developed under the MapRE (Multi-criteria Analysis Planning Renewable Energy) Initiative [19], which were used in this study to create maps of suitable areas and subdivide them into smaller, utility-scale project-sized areas. We refer to these project-sized areas as Candidate Project Areas. After removing existing renewable energy power plants from the identified Candidate Project Areas, we created wind and solar supply curves by aggregating the amount of generation capacity and spatially-averaging the capacity factor (CF) per RESOLVE Zone. A RESOLVE Zone is the spatial unit with which the capacity expansion model, RESOLVE, aggregates the generation supply characteristics, including cost, generation potential, generation temporal profiles, and transmission availability.

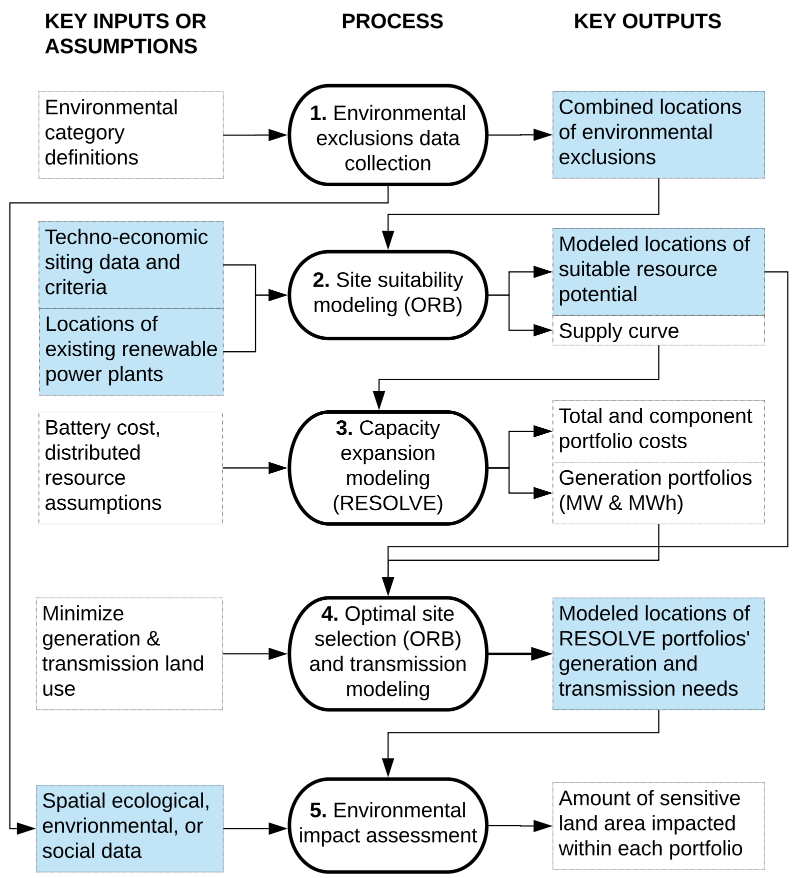


Figure 1: Flow diagram of key methodological inputs, processes, and outputs. Blue boxes indicate spatially-explicit inputs or outputs. RESOLVE and Optimal Renewable energy Build-out (ORB) are the two main models used in the study.

In Step 3, we modify the supply curve inputs and assumptions of RESOLVE, an electricity sector capacity expansion model used by the state of California for energy planning (Section 2.4). From the environmentally constrained supply curve, RESOLVE selects certain quantities of candidate resources to create generation portfolios. These differ in their input assumptions, but all satisfy the emissions reduction target of 80% reductions below 1990s levels by 2050. By varying assumptions in ORB (Step 2) and RESOLVE (Step 3), we explored the outcomes of 1) applying different Environmental Exclusion Categories to resource availability (Siting Levels 1, 2, 3, and 4, Section 2.5.1); 2) expanding geographic availability of renewable resources in the Western U.S.(*In-State*, *Part West*, and *Full West* Geographic cases; Section 2.5.2); 3) relaxing existing constraints on renewable resource assumptions in RESOLVE (*Constrained* and *Unconstrained* Resource Assumption cases, Section 2.5.3); 4) reducing battery costs (Battery cost sensitivity, section 2.5.4); and 5) increasing behind-the-meter PV adoption (Distributed Energy Resources sensitivity, section 2.5.4). By varying these input assumptions, RESOLVE generated 61 generation portfolios.

In Step 4, the ORB model then takes the output portfolios of the RESOLVE model and determines optimal siting locations, in contiguous development zones of 1 to 10 km^2, for utility-scale renewable power plants that will collectively generate the amount of electricity energy specified in each portfolio (Section 2.6). The site selection process is based on maximizing resource quality and minimizing distance proximity to existing and planned transmission corridors. The resulting modeled project locations are used to assess the overall environmental impacts of each portfolio in the fifth and final step of the analysis (Section 2.7). In step 5, we perform a "Strategic Environmental Assessment" by calculating the area of overlap between Selected Project Areas and sets of general and specific environmental metrics. These metrics include the Environmental Exclusion Categories used in the site suitability analysis in Step 2, as well as 10 ecological metrics (e.g., Audubon Important Bird Areas, wetlands, eagle habitat) capturing focal species and habitat in recent power plant siting cases, and agricultural lands and rangelands.

2.2 Step 1. Environmental exclusions definitions and data collection

The gathering and compiling of environmental data for this study was informed by conventions established in prior work [12, 15, 20–26]. Following prior studies, we aggregated environmental data into four categories. These data types, which we refer to as Environmental Exclusion Categories, range from low to moderate and high levels of protection for lands with high conservation value and intactness. The definitions of the four Environmental Exclusion Categories are as follows (see Supporting Information [SI] Tables 10–13 and the full spreadsheet linked here for an exhaustive list of individual datasets in each Category):

- **Environmental Exclusion Category 1 (Legally protected)**: Areas with existing legal restrictions against energy development. (Examples: National Wildlife Refuge, National Parks)
- **Environmental Exclusion Category 2 (Administratively protected)**: Areas where the siting of energy requires consultation or triggers a review process to primarily protect ecological values, cultural values, or natural characteristics. This Category includes areas with existing administrative and legal designations by federal or state public agencies where state or federal law requires consultation or review. This Category includes tribal lands, as these areas are subject to the authority of Tribes, or nations, to determine if utility-scale renewable energy development is an appropriate or allowable use. Lands owned by non-governmental organizations (NGOs) that have conservation obligations also included in this Category. Multiple-use federal lands such as Forest Service lands without additional designations were not included in this Category, although in some prior studies they have been. (Examples: Critical Habitat for Threatened or Endangered Species, Sage Grouse Priority Habitat Management Areas, vernal pools and Wetlands, tribal lands)
- **Environmental Exclusion Category 3 (High conservation value)**: Areas with high conservation value as determined through multi-state or ecoregional analysis (e.g., state, federal, academic, NGO) primarily characterizing the ecological characteristics of a location. This category may also include lands that have social, economic, or cultural value. Prime

farmlands as determined by U.S. Department of Agriculture (USDA) are also included in this Category. Despite their conservation value, these lands typically do not have formal conservation protections. (Examples: Prime Farmland, Important Bird Areas, big game priority habitat, The Nature Conservancy Ecologically Core Areas)

- **Environmental Exclusion Category 4 (Landscape Intactness)**: Lands with potential conservation value based on their contribution to intact landscape structure. This Category includes lands that maintain habitat connectivity or have high landscape intactness (low habitat fragmentation). Again, despite their conservation value, these lands typically do not have formal conservation protections. (Examples: landscape intactness, wildlife corridors)

As a guiding principle for the environmental and land use data compilation, we strove for consistency with prior work. Where prior work included transparent peer review, public stakeholder processes, and agency adoption of the final work product, these products were prioritized for accurate incorporation into this study. However, there were many land use types that did not fit neatly into categories, where treatment varied in prior studies, and where discretionary judgment was applied. These areas are described briefly below, with further Supporting Information and a comparison of datasets included in other similar studies found in Supporting Information [SI] Tables 10–13.

Studies vary in their treatment of the following area types: protected areas identified in different versions of PAD-US (the Protected Areas Database of the U.S. created by the U.S. Geological Survey and Conservation Biology Institute), multiple-use public lands (e.g., state and national forests), critical habitat, big game habitat, and species-related information. This study fills gaps in prior studies (e.g., improving west-wide treatment of wetlands, important habitat for non-listed species, Audubon Important Bird Areas, tribal lands, agricultural lands, county zoning ordinances, landscape intactness). Although we considered including a least-conflict land category such as that identified in A Path Forward, and that identified in the TNC Site Wind Right study, we decided not to include such a layer, as the intent of this study is to conduct scenario analysis and not to provide direct siting guidance. We did, however, include data that were used to inform the identification of least conflict areas. See Supporting Information (Tables 10–13 and the full spreadsheet linked here) for more detailed descriptions of data, rationale for their categorization, and their sources.

The draft list of data layers and categorization decisions were subjected to several rounds of review, and comments were incorporated from the following: The Nature Conservancy (TNC) state chapters, the TNC Site Wind Right project team, and several peer NGOs. After review and refinement, we converged on a final list of more than 250 data layers for Categories 1, 2, 3, and 4 (SI Tables 10–13). For each Category, the constituent data layers were aggregated into a single layer. These aggregated layers were later applied in the site suitability analysis (Step 2, Section 2.3) and in the strategic environmental assessment (Step 5, Section 2.7).

2.3 Step 2. Renewable resource assessment (ORB)

2.3.1 Site suitability modeling

The purpose of site suitability modeling is to identify areas that would be suitable for large-scale terrestrial renewable energy development, based on several siting criteria. The result of site suitability modeling is a spatial dataset representing wind and solar resource potential areas in the form of vector polygons and associated attributes. Attributes include Candidate Project Area size

(km^2), potential capacity (MW), and capacity factor (modeled from irradiance and wind speed). These attributes are necessary components for constructing a generation "supply curve," which is an important input for the capacity expansion model, RESOLVE.

Technical and economic data inputs For this study, site suitability modeling of wind and solar potential closely followed methods described in several previous studies [11, 12, 19]. To identify technically and economically suitable areas for renewable energy development, we used spatial datasets that capture technical (e.g., competitive wind resource locations), physical (e.g., slope, water bodies), and socio-economic or hazardous (e.g., densely populated areas, military zones, railways, airports, mines, flood zones) siting considerations. We used the National Renewable Energy Lab (NREL)'s WIND Toolkit metadata, which reports annual average capacity factor per point location, for the basis of economically and technically viable wind locations in the U.S. [27]. We did not apply a capacity factor threshold for solar PV suitability, but allowed RESOLVE to select solar capacity from each RESOLVE Zone based on capacity factors generated from NREL's System Advisor Model (SAM) [28]. A list of RESOLVE Zones can be found in the RESOLVE User Manual as Figure 7: In-state transmission zones in RESOLVE. A more complete list can be found in the RESOLVE "User interface" workbook, "REN_Candidate" sheet [17]. For feasible geothermal locations, we relied on the Western Renewable Energy Zone's study of resources in the Western U.S. [21], which is also the source for RESOLVE's current geothermal resource availability inputs. We modeled the geothermal facilities' footprint using the appropriate buffer radius assuming 25.5 MW km^{-2} and the capacity (MW) in the attribute table. See SI Table 6 for sources of all non-environmental input datasets. Although we modeled suitable sites for geothermal, the amount of geothermal potential in the RESOLVE Base case supply curve was significantly lower compared to potential estimates for wind and solar (SI Figs. 14B–15B). Thus, while we show geothermal findings in the results figures, we focus on discussion of wind and solar results.

We did not include offshore wind and concentrating solar power (CSP). Offshore wind resources were not included primarily to maintain consistency with assumptions in existing versions of the RESOLVE model, in which offshore wind has not yet been incorporated. Secondarily, the publicly available data for offshore wind along the Pacific Coast is not yet well enough characterized and vetted in stakeholder processes for incorporation at the time of the study. Although CSP is included in the supply curve for existing versions of RESOLVE, its estimated capital costs are too prohibitive for new capacity to be selected under any scenario.

Identification of suitable sites and Candidate Project Areas In order to create resource potential maps, we used Stage 1 of the MapRE (Multi-criteria Analysis for Planning Renewable Energy) Zoning Tool [19], which uses raster-based algebraic geoprocessing functions and siting assumptions specified for each dataset and technology (SI Table 6). MapRE Zone Tools are the graphical user interface version of the ORB tools and are part of the ORB suite of siting tools. We created a single 250 meter resolution raster of areas that satisfy techno-economic siting criteria for each technology (i.e., suitability map). For each technology, we removed the Environmental Exclusion Categories (section 2.2) from the techno-economic suitability map to create four Siting Levels (SL) of suitable areas that meet both techno-economic and environmental siting criteria (see Section 2.5.1 for a full description of Siting Levels). In order to simulate potential project locations within suitable areas identified, we used Stage 2 of the MapRE Zoning Tool, or the "project creation stage," to create Candidate Project Areas (CPAs) by subdividing suitable areas into smaller, utility-scale project-sized areas. Solar potential project areas ranged from 1 km^2 to 7 km^2 (or about 30–270 MW), with the vast majority of solar CPAs designed to be 4 km^2 or to accommodate approximately 120 MW of solar capacity. Wind CPAs ranged from 1 km^2 to 10 km^2 (or about 6.1–61 MW), with the vast majority of wind CPAs designed to be 9 km^2 or to accommodate approximately 55 MW of wind capacity. We eliminated CPAs less than 1 km^2, as these parcels would typically be considered too small for commercial utility-scale renewable energy development.

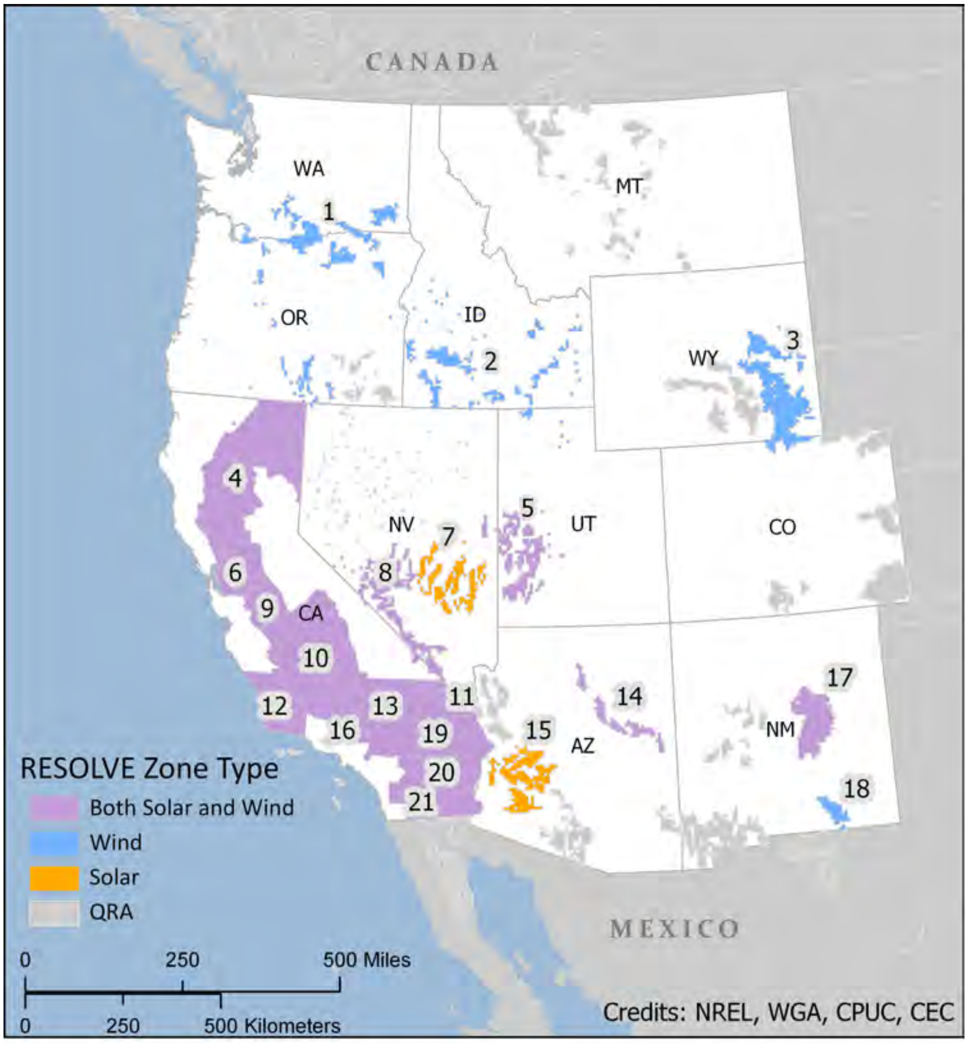
Creation of candidate supply curves for capacity expansion modeling To create supply curves for RESOLVE, we summarized site suitability results for each RESOLVE Zone. Each row in the supply curve table corresponds to an area within which resources and their attributes have been aggregated or averaged (i.e., RESOLVE Zones in this study). From this supply curve, RESOLVE selects certain quantities of candidate resources in a capacity expansion optimization. Within California, RESOLVE Zones are comprised of one or more Super Competitive Renewable Energy Zones, regions identified in previous California renewable energy planning processes and studies [20, 29] (Fig. 2). Outside of California and within the Western Electricity Coordinating Council (WECC) states, RESOLVE Zones are collections of various Qualifying Resource Areas (QRA) [21] specific to each technology (Fig. 2).

To generate these RESOLVE-specific supply curves, we spatially averaged capacity factors (CF) across all CPAs (CFs are from resource datasets listed in SI Table 6) and calculated the megawatts (MW) of potential generation capacity for each technology (assuming 6.1 MW km^{-2} for wind [30], 30 MW km^{-2} for solar PV [31], and 25.5 MW km^{-2} for geothermal [31]), for each RESOLVE Zone or state, and for each Siting Level (see Section 2.5.1 for explanation of Siting Levels). These Zone- and state-specific MW and CF values formed the basis for the supply curve inputs for RESOLVE. See SI Figures 14, 15 for plotted supply curves. We made modifications to the supply curve to account for wind capacity that can be accessed via existing transmission lines. RESOLVE assumes that 500 MW and 1500 MW of wind potential in New Mexico and Pacific Northwest RESOLVE Zones, respectively, can utilize existing transmission infrastructure (and thus have lower system costs). Because CPAs represent all suitable sites for energy development, in order to avoid over-estimating candidate wind resources, we subtracted these 500 MW and 1500 MW of "existing transmission" candidate resource capacity amounts from the total capacity in all wind Candidate Project Areas in the New Mexico and Pacific Northwest RESOLVE Zones. This meant that the sum of CPAs in New Mexico RESOLVE Zones and the "existing transmission" resources in New Mexico should equal the total available CPAs identified for New Mexico. The "existing transmission" resources in RESOLVE are additional, non-spatial resources, with no associated project footprint. As such, RESOLVE treats them as additional to the CPAs. When selected by RESOLVE, these resources must be assigned to a spatial footprint. This subtraction essentially completes this assignment.

Because the existing policy assumptions and the version of RESOLVE currently being used in California energy planning do not include Montana and Colorado, the supply curve inputs for the RESOLVE capacity expansion model and all subsequent steps do not include Montana and Colorado wind, solar, or geothermal resources.

2.3.2 Accounting for existing power plant footprints

The results of the above site suitability modeling steps include maps of possible locations for wind and solar development. For many of these possible locations, however, there are wind and solar power plants that have already been constructed. Existing power plants must be removed from



Map Label	RESOLVE Zone	Map Label	RESOLVE Zone	Map Label	RESOLVE Zone
1	Pacific Northwest Wind	8	Southern Nevada Wind and Solar	15	Arizona Solar
2	Idaho Wind	9	Central Valley North Los Banos	16	Tehachapi
3	Wyoming Wind	10	Westlands	17	New Mexico Wind and Solar
4	Northern California	11	Mountain Pass El Dorado	18	New Mexico Wind
5	Utah Wind and Solar	12	Greater Carrizo	19	Southern California Desert
6	Solano	13	Kramer Inyokern	20	Riverside East Palm Springs
7	Southern Nevada Solar	14	Arizona Wind and Solar	21	Greater Imperial

Figure 2: RESOLVE Zone names and locations for solar-only, wind-only, and both technologies. Other Qualifying Resource Areas (QRA) that were not used to create RESOLVE Zones are also shown in grey.

the CPAs and supply curve in order to ensure that the supply curve only contains undeveloped future candidate projects. By removing existing projects, we enable RESOLVE to optimize future capacity expansion investment decisions and avoid overestimating the resource potential.

For existing wind facilities, we used a combination of Ventyx/ABB wind farm boundaries and theU.S.Wind Turbine Database (USWTD) to fill in gaps in both datasets (SI 7). We selected only turbines greater than 1 MW (or with no MW data but built after the year 2000) for removal as existing projects. In order to account for re-powering potential, for older, smaller wind turbine models, we assumed that existing wind turbines smaller than 1 MW or with online dates prior to the year 2000 could be re-powered. This increased the candidate wind resource potential significantly in some areas with existing wind turbines (e.g., the Tehachapi region of California). The remaining

>1MW turbines were buffered using 1200 meters. This was the distance that best approximated the Ventyx wind farm boundaries in the locations where turbines and farm boundaries overlapped. Because substantially large regions of several Ventyx "wind farms" did not contain turbines (as verified by overlaying the USWTD points and visual inspection of recent satellite imagery), we clipped the Ventyx wind farm boundary feature classes to the buffered USWTD extent (creating the "corrected Ventyx boundaries" polygons), which effectively removes areas in the Ventyx dataset that do not have existing wind turbines. However, we also found that the Ventyx wind farm boundary did not encompass all existing wind turbines in the USWTD, so we isolated these turbines without wind boundaries and created wind farm boundaries for them using a 750-m buffer radius (creating the "additional USWTD boundaries" polygons). Finally, we merged the corrected Ventyx and additional USWTD polygons to have a gap-filled existing wind turbine footprint dataset. These areas with existing wind turbines were removed from the candidate wind project areas.

For solar resource potential, we used the TNC solar array footprint dataset for within California [32] and the USGS national solar array footprint datasets for all other states in the study [33] (SI Table 7). These existing solar projects were removed from the candidate solar project areas.

2.4 Step 3. Capacity expansion modeling (RESOLVE)

2.4.1 Overview of RESOLVE

The capacity expansion modeling was carried out using Energy and Environmental Economics' (E3) RESOLVE model, developed for the California Energy Commission (CEC) Deep Decarbonization in a High Renewables Future study [18]. The CEC study evaluates long-term scenarios that achieve a 40% reduction in economy-wide greenhouse gas (GHG) emissions by 2030 and an 80% reduction by 2050, relative to 1990 levels. The RESOLVE model determines the resource portfolios necessary for the electric sector to reliably serve loads without exceeding a sectoral carbon budget consistent with meeting these goals.

RESOLVE uses linear programming to identify optimal long-term generation and transmission investments in an electricity system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable renewable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electricity system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities enable it to select from among a wide range of potential new resources. For this study, the options for new investments are limited to those technologies that are commercially available today. This approach ensures that the GHG reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. A more detailed description of the RESOLVE model structure and operations, along with a publicly available version of the model used in the state's Integrated Resource Plan (IRP) process, are available on the California Public Utilities Commission (CPUC) website [17]. Because this study was designed to look at the entire state of California's electricity demand on the 2050 timeframe, the CEC version of the model was the appropriate choice.

2.4.2 Key assumptions

The inputs and assumptions used in this analysis are generally consistent with those used in the CEC study, but certain parameters were updated to allow modeling of the specific scenarios for this study. In the case of renewable and storage costs, values were updated to include the latest available data on the costs of resources.

Electricity Demand The electricity demand forecast is consistent with the "high electrification" scenario from the CEC Deep Decarbonization study, which achieves California's long-term emission goals through extensive electrification of space and water heating loads in buildings and a heavily decarbonized electricity sector. The demand forecast from the CEC Deep Decarbonization study incorporates findings from recent studies regarding impacts of climate change on California's electricity sector, including a lower average availability of hydroelectric generation available to meet California demand in 2050, and higher average temperatures, which result in lower heating demands in buildings and higher air-conditioning demands. After exploring ten "mitigation" scenarios, the Deep Decarbonization study identified the "high electrification" scenario as one of the lower-cost, lower-risk mitigation scenarios. The "high electrification" scenario assumes high levels of energy efficiency and conservation, renewable electricity, and electrification of buildings and transportation, with reliance on biomethane in the pipeline to serve mainly industrial end uses. It also assumes a transition of the state's buildings from using natural gas to low-carbon electricity for heating demands. More details on the assumptions behind this scenario can be found in the CEC publication [7].

RESOLVE Base resource potential The RESOLVE model contains a list of candidate resources also referred to as the supply curve. The supply curve is a list of resource potentials identified in zones, often referred to simply as "resource potential." The current versions of RESOLVE contain resource potential estimates, which are referred to here as the "RESOLVE Base" case [20, 21]. In most scenarios, the "RESOLVE Base" resource potential estimates only assume Categories 1 and 2 lands to be protected in California and west-wide; however, characterization of Category 2 lands outside of California is incomplete. All other lands (outside of the techno-economic-environmental screens) are assumed available for renewable energy development in the "RESOLVE Base" scenarios. However, there are differences in the Category definitions and their underlying datasets between the current study and the "RESOLVE Base."

The resource potential values developed for the CPUC IRP RESOLVE model used only 5% of the total solar technical potential from the California RESOLVE zones, reflecting concerns about the level of conversion to industrial land use associated with developing the full potential in any given resource area. In the CEC study and this analysis, this assumption was expanded to 20% of the technical potential due to the increase in demand for clean electricity in 2050 relative to 2030. The estimated resource potential in the CEC study for all other supply-side resources is consistent with the amounts assumed in the CPUC RESOLVE model. For creating Siting Level portfolios constrained by the Environmental Exclusion Categories, these RESOLVE Base resource potential values were replaced by estimates derived from the site suitability analysis (Section 2.3.1).

The existing versions of the RESOLVE model currently being used by state agencies in California, do not include any wind or solar resource potential in Colorado or Montana. Colorado resources are not included because Colorado is not well electrically interconnected to export power to California. Montana resources were not included because the geographic scope was limited to what were considered the most economically attractive and feasible resources at the time. For this study, we addressed a broader geographic extent and longer timeframe than prior studies, and thus we did complete a site suitability analysis and resource potential assessment for Colorado and Montana. However, for consistency with existing RESOLVE model conventions in state energy planning forums, we did not incorporate Montana or Colorado zones into the supply curve. RESOLVE Zones are currently being used in California energy planning, and so we retain the RESOLVE Zone convention for consistency.

Existing or Baseline Resources In addition to candidate future resources, the RESOLVE model also includes a list of baseline resources (for all renewable and conventional technologies, including nuclear and hydropower; this is the list of contracts included in the RESOLVE model User Interface workbook, within the sheet called "REN_Existing Resources." This list represents commercial projects that are existing and under development—including projects with online dates in the past and in the future. This list of contracts was incorporated into the site selection process, and hence removed from the future candidate resource potential.

Resource Cost Assumptions Each candidate resource in the RESOLVE model supply curve has capital cost attributes. Capital costs for solar, wind, batteries, etc. are updated periodically. For this study, capital costs for solar, and battery storage resources were updated to reflect recent cost estimates from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) [34] and Lazard's Levelized Cost of Storage studies [35]. Table 2 shows the capital cost differences among the three versions of the model.

Table 2: Capital cost assumption comparisons between different RESOLVE versions

Capital Cost Comparison (2016 $/kW)						
Technology	CPUC IRP 2020	CPUC IRP 2050	CEC Study 2020	CEC Study 2050	This Study 2020	This Study 2050
Solar PV – 1-axis Tracking	$1,862	$1,692	$1,862	$1,692	$2,108	$1,916
Li-Ion Battery (4 hr duration)	$2,135	$1,407	$2,427	$1,874	$1,013	$815

The solar PV costs in this study are higher than the costs assumed in the CPUC IRP and the CEC study because of differences in data sources used as the basis for the capital cost assumptions. Previous capital cost assumptions were based on 2016 estimates provided by Black & Veatch as part of the IRP process. The latest cost assumptions are based on estimates from NREL's ATB [34]. Forecasted battery costs for this study are lower than 2016 forecasts in the CPUC IRP and the CEC studies because of cost updates in the Lazard study used as the basis for the capital cost assumptions.

Transmission Assumptions For California zones, RESOLVE assumes a limited transmission capacity is available per zone. Beyond this available capacity, a cost is assumed for building additional transmission capacity. See Table 3 for resources able to be accommodated per transmission zone.

There are two forms of transmission costs associated with resources in the supply curve. First, for all resources (in-state and out-of-state), there is the $/kW-yr cost of transmission upgrades within CAISO once the Full Capacity Deliverability Status (FCDS) limit for the resource's associated transmission zone is exceeded (Table 24 of the RESOLVE Inputs and Assumptions [17]). Second, for the out-of-state resources, there are 2,000 MW of existing transmission capacity into California from the "Existing Northwest" (from the Pacific Northwest) and "Existing Southwest" (from New Mexico) transmission zones. Beyond this cost-free existing transmission capacity, there is a $/kW-yr cost for delivery to the California border (Table 25 of the RESOLVE Inputs and Assumptions document [17]). These transmission costs are in addition to the other costs associated with each resource, resulting in an all-in fixed $/kW-yr resource vintage cost. See RESOLVE model Inputs and Assumptions documentation for more information [17].

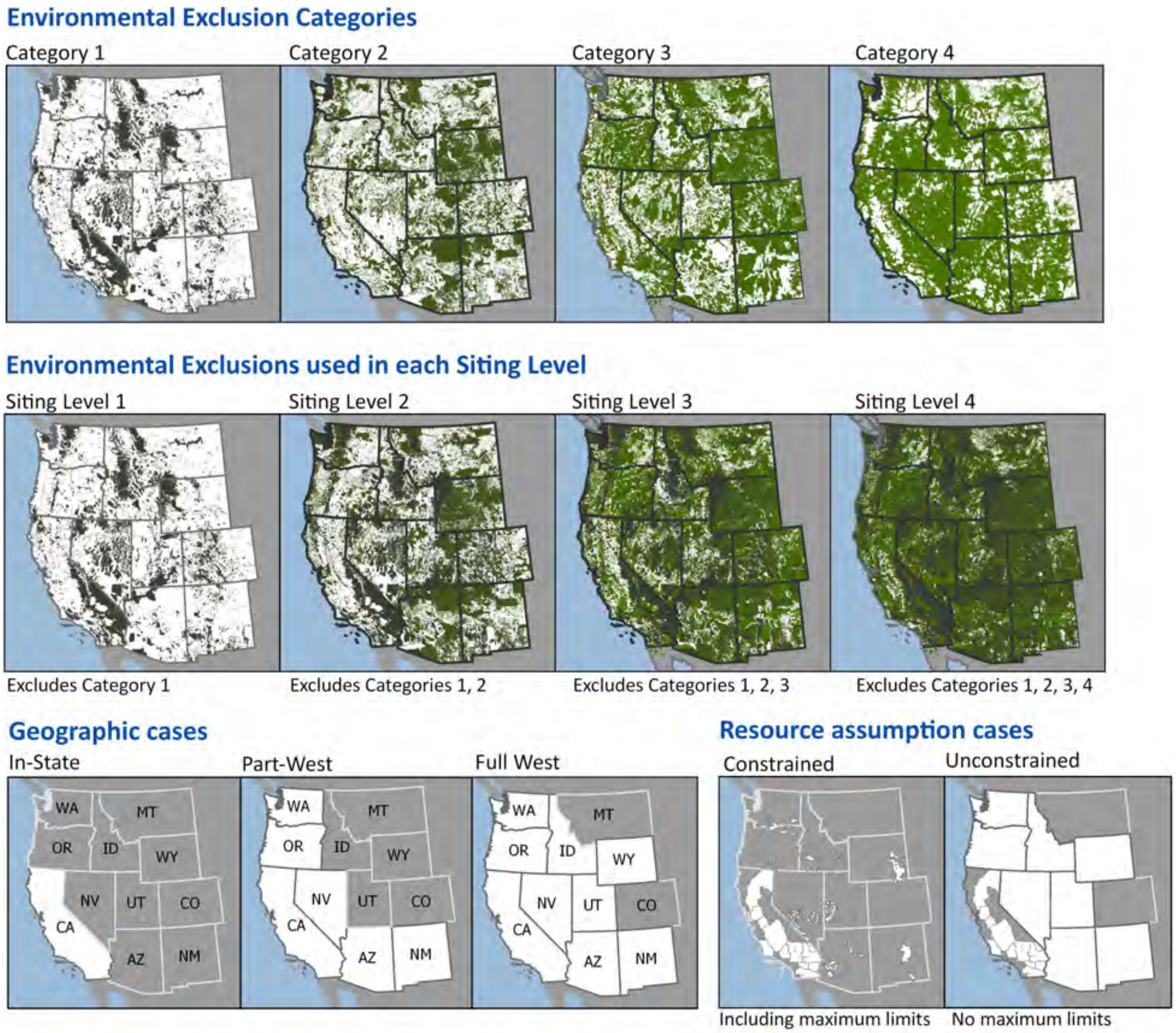
2.5 Description of cases and sensitivity assumptions

We developed several cases and modified sensitivity assumptions in order to understand the impact of the following changes: 1) applying different Environmental Exclusion Categories to resource availability (Siting Levels, Section 2.5.1); 2) expanding geographic availability of renewable resources in the Western U.S. (Geographic cases, Section 2.5.2); 3) relaxing existing constraints on renewable resource assumptions in RESOLVE (Resource Assumption cases, Section 2.5.3); 4) reducing battery costs (Battery cost sensitivity, Section 2.5.4); and 5) increasing behind-the-meter PV adoption (Distributed Energy Resources sensitivity, Section 2.5.4). See Fig. 3 for summary of cases and sensitivities examined. *Constrained* cases were identified as the core cases for this study because they are most closely aligned with existing models being used in California state planning. We refer to a case as a modification of a single assumption (e.g., Siting Level 1), whereas a scenario is a combination of cases or a set of assumptions that generate a specific result (e.g., Siting Level 1, *Full West* Geography, *Constrained* resource assumptions, base case DER, and battery cost assumptions; see sections below for an introduction and explanation of example case names).

2.5.1 Environmental Siting Levels for candidate resources

Using the Environmental Exclusion Categories (Section 2.2) and the technical and economically suitable areas (Section 2.3.1), we created four supply curves, which are referred to as Siting Levels (SL) 1, 2, 3, and 4 (Fig. 3). All Siting Levels use the same set of technical and economically suitable areas, but are additive in their use of the Environmental Exclusion Categories. That is, Siting Level 1 excludes only land area datasets in Category 1; Siting Level 2 excludes land area datasets in Categories 1 and 2; Siting Level 3 excludes land area datasets in Categories 1, 2, and 3; and Siting Level 4 excludes datasets in Categories 1, 2, 3, and 4. As such, as the Siting Level increases, more land is protected from development (Fig. 3). As described in Section 2.3.1, we created candidate resource supply curves for each of these Siting Levels using the land area in each RESOLVE Zone or state by converting km^2 to MW of capacity for each technology and calculating spatially-specific average capacity factors for each Siting Level. These supply curves were further modified to create *Constrained* and *Unconstrained* cases, as introduced and explained in Section 2.5.3 below. We compare these Siting Levels with the unmodified RESOLVE supply curve, which we refer to as the RESOLVE Base case (Section 2.4.2).

To ensure consistency with the representative RESOLVE resource temporal profiles for wind and solar generation, we adjusted the site suitability supply curve potential values using the average CF of the temporal profiles. The adjustments to capacity were necessary to ensure that the amount of energy generated by the resource (assuming load profiles and average capacity factors in RESOLVE) will match the expected energy based on the supply curve. To do this, we calculated the amount of generation (MWh) using the resource potential and the average CF for each RESOLVE Zone



Battery Cost sensitivity cases

	Cost in 2050 ($/kWh-yr)
Base battery cost	$29.89
Low battery cost	$22.67

Distributed Energy Resources sensitivity cases

	GWh	GW	% of technical potential in CA
Base DER	49,207	24.7	19.2%
High DER	65,966	33.2	25.7%

Figure 3: Summary of assumptions for the following cases and sensitivities examined: Siting Levels, Geographic cases, Resource Assumption cases, Battery Cost and Distributed Energy Resources sensitivity cases. Siting Levels (row 2) use the Environmental Exclusion Categories (row 1) cumulatively as indicated by the corresponding color in the maps of the Categories. The three Geographic cases (row 3) include resources identified within states indicated in white in addition to 1.5 GW and 0.5 GW of wind resources in the Pacific Northwest and New Mexico, respectively (see Table 3 for more details regarding Geographic cases). The *Constrained* Resource Assumption cases restrict resource potential to within RESOLVE Zones and apply the RESOLVE Base as the maximum limit in each zone. The *Unconstrained* cases expand resources to the rest of the state and do not impose maximum limits except for New Mexico Wind in the Part West Geography.

estimated from the site suitability analysis. We then divided this value by 8760 hours and the RESOLVE temporal profiles' average CF for that zone to calculate an adjusted site suitability potential (MW). For example, if a 100 MW solar resource has a 25% capacity factor in the supply curve, but a 22% capacity factor based on the resource's generation profile, the associated capacity with that resource in RESOLVE becomes 113 MW (i.e. (25%)/(20%)*100 MW). See Figure 15 for the unadjusted supply curve values and Figure 14 for the adjusted values. For the most part, the adjustments did not result in significant changes to the original resource values.

2.5.2 Geographic cases

Three Geographic cases—also referred to as Geographies—were constructed for the analysis, representing different potential for imported out-of-state resources to meet California's need for clean electricity (Fig. 3). The *In-State* case restricts renewable resource availability to within California's borders while allowing up to 2,000 MW of out-of-state wind resources delivered to California using existing available transmission capacity (see Transmission Assumptions in Section 2.4.2). This allowance was made in order to most closely reflect existing market conditions. In the *Part West* case, RESOLVE has access to renewable resources in five other states with strong electrical ties to California. In this case, New Mexico wind resource is Constrained at 3,000 MW based on the capacity of an existing 500-kV dual-circuit HVDC transmission line. In the *Full West* case, RESOLVE has access to renewable resources across eight other states in the Western Interconnection. The *Part West* and *Full West* cases would require changes to markets and policies to allow for import of electricity at the quantities in the 2050 portfolios. Table 3 shows the zones and the maximum available resources allowed in each Geography.

Table 3: RESOLVE resources available by Geographic cases

Resource		Geographic cases	
Resource Zone	In-State	Part West	Full West
California Solar	X	X	X
California Wind	X	X	X
California Geothermal	X	X	X
Existing Northwest Transmission Wind	Constrained at 1500 MW	Constrained at 1500 MW	Constrained at 1500 MW
Existing Southwest Transmission Wind	Constrained at 500 MW	Constrained at 500 MW	Constrained at 500 MW
Utah Solar	-	-	X
Southern Nevada Solar	-	X	X
Arizona Solar	-	X	X
New Mexico Solar	-	-	X
Pacific Northwest Wind (new transmission)	-	-	X
Idaho Wind	-	-	X
Utah Wind	-	-	X
Wyoming Wind (new transmission)	-	-	X
Southern Nevada Wind	-	X	X
Arizona Wind	-	X	X
New Mexico Wind (new transmission)	-	Constrained at 3000 MW	X
Pacific Northwest Geothermal	-	X	X
Southern Nevada Geothermal	-	X	X

2.5.3 *Constrained* and *Unconstrained* sensitivity cases

The publicly-available RESOLVE model used in the California Public Utilities Commission's (CPUC) Integrated Resource Planning (IRP) process assumes that out-of-state development is limited to "Qualifying Resource Areas" (QRA) identified by Black and Veatch through the 2009 Western Renewable Energy Zones study [21]. This assumption stands as the current policy default. As explained in Section 2.3.1, these QRAs have been reclassified as "RESOLVE Zones". As previously explained (Section 2.4.2), the CPUC RESOLVE model "discounts" solar resources estimates within California by 95% and the CEC RESOLVE model discounts it by 80%. For example, if a resource assessment identified 100 GW of solar in a particular RESOLVE Zone, the CEC version of the RESOLVE model assumes 20 GW of that solar will be available for development, as reflected in the supply curve. For the *Constrained* assumptions case, we maintained these current (RESOLVE Zone and solar discount) resource assumptions. For the *Constrained* case, we also restricted non-California resource potential estimates to within these RESOLVE Zones for each Siting Level and used the lower of the two following values: the site suitability resource estimates within RESOLVE Zones and the default RESOLVE "discounted" Base case resource potential values (Figs. 2, 3).

To understand how these current resource assumptions affect cost and generation mix, we developed an *Unconstrained* sensitivity case in which the supply of out-of-state resources is not limited to RESOLVE zones, but rather is based on a "wall-to-wall" estimate of technical potential across the entire state for each of the Siting Levels (Fig. 3). Additionally, the *Unconstrained* case uses the site suitability resource potential estimates directly for all solar RESOLVE Zones, thus removing RESOLVE's "discounted" base case resource potential as the upper limit.

As an example of how the *Constrained* and *Unconstrained* cases were developed for the present study, consider the Westlands RESOLVE Zone in central California. Within the Westlands RESOLVE Zone, the default RESOLVE Base solar potential in the existing model is 28.1 GW. The site suitability analysis for this study identified a much greater solar resource potential—210 GW—under *Unconstrained* assumptions in Siting Level 3 (which assume no development on high conservation value lands). Thus, for Westlands, we assumed 28.1 GW of solar potential in the *Constrained* case and 210 GW of solar potential in the *Unconstrained* case for SL 3 (SI Fig. 14). Again, potential values are options for the capacity expansion model to select from in creating an optimal generation portfolio—not all candidate renewable resources may be chosen.

As an example of how the *Constrained* and *Unconstrained* assumptions differ for regions outside of California, consider that in Siting Level (SL) 1, the estimated amount of wind resource potential within the New Mexico RESOLVE Zone is 36.1 GW (SI Fig. 15B). Looking beyond the RESOLVE Zone, the amount in the entire state of New Mexico is 190 GW (SI Fig. 15B) while the default RESOLVE Base potential is 34.6 GW (SI Fig. 14B). Thus, for New Mexico, we assumed 34.6 GW of wind potential in the *Constrained* assumptions case and 190 GW of wind potential in the *Unconstrained* assumptions case (SI Fig. 14).

2.5.4 Battery cost and distributed energy sensitivity cases

Along with the cases considered above, we considered two additional sensitivities: high behind-the-meter PV distributed energy resource (High DER) and low battery cost.

High DER sensitivity A high behind-the-meter (BTM) PV adoption forecast was developed for the High DER sensitivity analysis, using the relationship between the High BTM PV and Mid BTM

PV forecasts from the 2016 CEC Integrated Energy Policy Report (IEPR) [36]. A capacity factor of 22.7% is assumed for the DER resource. Table 4 below shows the forecast for the Base and High DER cases.

There are several publicly available DER forecasts that were considered (LBNL technical potential, NREL technical potential, IEPR). The IEPR High DER forecast is widely considered a realistic optimistic forecast, assuming faster customer adoption rates and continued falling costs. It includes more residential solar tied to Title 24 (high penetration assumes 90% of new houses built after 2020 install rooftop solar). Other publicly available forecasts may include additional considerations such as major policy changes, new incentives, and technological disruption. Because we do not have control over policies or market forces, we chose to use the forecast that assumes fulfillment of current policy mandates with expected increased adoption rates and does not assume major disruptive changes.

The RESOLVE model treats BTM PV resources as a demand modifier, reducing the total demand that will be met by the optimized resource portfolio. Assuming a projected demand of 400 TWh year^{-1} in 2050, the high BTM PV sensitivity case reduces demand by about 5%. Using NREL's estimate for technical potential of rooftop PV in California of 128.9 GW [37], the High DER scenario assumes the installation of about 25.7% of technical potential and is about 35% greater than the Base BTM assumptions (Table 4). The NREL technical potential study does not consider limits such as how much rooftop solar the distribution system can accommodate before needing upgrades, nor does it consider load balancing costs. These and other integration challenges are why economic potential typically tends to be less than the technical potential for a resource, as is the case here.

For more detail about the High DER assumptions, see the IEPR California Energy Demand Updated Forecast 2016, and the independent 2018 Distribution Working Group Forecast Report by Itron, which confirms the robustness of the IEPR forecast. The amount of BTM PV assumed in the model is separate from, and additional to the 40 GW of distributed solar that is available for RESOLVE's optimization as a supply-side candidate resource. It should be noted that the supply-side distributed solar in RESOLVE is characterized with the cost and generation profiles of a typical parking lot and warehouse rooftop solar array.

Table 4: Behind-the-meter PV forecast generation (GWh) and capacity (GW) assumptions for the base case and high distributed energy (High DER) sensitivity

BTM PV	2020	2025	2030	2035	2040	2045	2050
Base DER (GWh)	11,578	19,084	30,499	35,071	39,782	44,562	49,207
Base DER (GW)	5.82	9.60	15.3	17.6	20.0	22.4	24.7
High DER (GWh)	12,432	22,770	38,440	45,391	52,332	59,268	65,966
High DER (GW)	6.25	11.5	19.3	22.8	26.3	29.8	33.2

Low Battery Cost sensitivity We also explored the effect of an optimistic battery cost forecast by assuming 25% reduction in the levelized cost of battery storage through the modeled period [35] (Table 5).

2.6 Step 4. Site selection and transmission modeling

Table 5: Battery cost assumptions: All-In Fixed Cost, 4 hr Li-Ion Battery

Cost (2016 $/kWh-yr)	2020	2025	2030	2035	2040	2045	2050
Base Battery Cost	$38.08	$31.21	$29.88	$29.88	$29.88	$29.88	$29.887
Low Battery Cost	$27.48	$23.53	$22.67	$22.67	$22.67	$22.67	$22.67

2.6.1 Generation site selection

The RESOLVE model selected an amount of generation from each spatially coarse RESOLVE Zones. In this step, we spatially disaggregated the generation and assigned each MWh to locations within each RESOLVE Zone by selecting CPAs to meet each portfolio's technology-specific generation requirements. This site selection step is necessary because impacts to natural and working lands vary significantly by location, and power plants have specific siting requirements that make them more likely to be sited in some areas over others. This approach models the possible build-out of infrastructure and enables a "strategic environmental assessment" of each portfolio, enabling comparison of portfolios by their modeled overall impact on natural and working lands (Section 2.3.1).

Attribute calculations We calculated the following set of attributes for each CPA, with details for specific calculations described in subsequent paragraphs: generation land area, Euclidean distance to the nearest existing or planned transmission line or the interconnection/gen-tie distance (i.e., transmission line to interconnect the new generator with the grid), gen-tie land area, adjusted gen-tie land area (see explanation below), total land area (generation and gen-tie), estimated generation capacity (MW), area-weighted average capacity factor (CF), area-weighted average CF adjusted using RESOLVE assumptions, annual average generation in MWh, the average total (generation and gen-tie) land use efficiency in MWh km^{-2}, and distance to the nearest "RPS executed" wind or solar power plant. We performed these attribute calculations for each CPA after removing other technologies' selected CPAs to account for changes in land area due to removal of previously selected CPAs. For example, if a CPA was selected as the site of a future wind project to fulfill the generation requirements of a portfolio, then that CPA was removed from the solar resource potential.

We then calculated gen-tie paths distances for each CPA. We assumed developers of selected CPAs would need to permit and develop interconnection corridors to the nearest existing transmission line >69 kV (data from the California Energy Commission and Ventyx/ABB) or an interstate planned transmission line in "advanced development" (SI Table 7). As in the ORB study [12], Euclidean distances from each CPA to the nearest transmission line were multiplied by a rule-of-thumb factor of 1.3 [12] in order to account for the additional length required due to topography and other environmental or social right-of-way constraints. Gen-tie Euclidean distances were then multiplied by an average transmission corridor width of 76 meters to estimate gen-tie land area. Since the sizes of CPAs span a large range and to avoid systematically reducing the total land use efficiency (MWh km^{-2}) of smaller CPAs as a result of a fixed interconnection area, we applied a correction factor to the gen-tie area using the ratio of the CPA area (as small as 1 km^2) to the largest possible CPA area (10 km^2 for wind and 7 km^2 for solar). This correction results in a fixed generation-to-interconnection area ratio for CPAs of different sizes that are the same distance from the nearest transmission line and have the same capacity factor. Note, however, that the least-cost gen-tie paths modeled after the generation site selection step (Section 2.6.2), not these adjusted

Euclidean distance gen-tie areas, are the areas that are finally reported in the results section as transmission land use requirements.

Wind and solar average CFs per RESOLVE Zone in the RESOLVE Base case differ from the area-weighted average CFs estimated from site suitability renewable resource CFs (see Section 2.4 for an explanation). Thus, to achieve consistency with existing RESOLVE CFs for both wind and solar, we scaled the average CF per CPA using an adjustment factor calculated as the ratio of the RESOLVE Base CF to the average site suitability CF of each RESOLVE Zone in Siting Level 1. This approach assumes that SL 1 resource assumptions are the most similar to the RESOLVE Base resource assumptions. We applied this RESOLVE Zone and technology-specific adjustment factor to each CPA across all Siting Levels, which maintains relative variation in CFs geographically and between Siting Levels.

Selection process Due to the relatively fewer areas of spatial overlap between CPAs of different technologies across the study region (primarily as a result of not including concentrating solar power and constraining resource areas to RESOLVE Zones outside of California) and the significantly lower availability of wind resources compared to solar resources, we did not perform site selection using an integer optimization program as per the approach in the ORB study [12]. Instead, we implemented a sequential selection approach that chooses CPAs based on their potential candidacy as a planned or commercial project (based on proximity) and total (generation and estimated transmission interconnection) land use efficiency (in MWh km^{-2}). By choosing based on total land use efficiency, we effectively select sites by prioritizing those with highest resource quality (highest capacity factor) and those closest to existing transmission infrastructure (reducing gen-tie costs), which are key siting criteria used by developers as they both lower development costs per unit of generation.

The sequence of steps were as follows for each case: 1) select geothermal CPAs, 2) remove selected geothermal CPAs from available wind CPAs, 3) select wind CPAs, 4) remove selected wind and geothermal CPAs from available solar CPAs, 5) select solar CPAs. The selection process for each technology simply involved ranking the CPAs by their total land use efficiency from highest to lowest, and selecting from this ranked "supply curve" the number of CPAs that would meet the expected amount of technology-specific generation as per the RESOLVE portfolio for each scenario or sensitivity case. Due to CPAs having discrete areas and sizes, CPAs selected at the margin will not meet the RESOLVE expected generation target exactly, but will exceed the target. That is, the decision to select a CPA is discrete—and marginal CPAs are not sized to precisely meet the RESOLVE generation target. Lastly, because the underlying spatially explicit site suitability dataset or Candidate Project Areas for out-of-state RESOLVE Zones used to create the RESOLVE Base supply curve do not exist in the public domain and the methods to replicate the process of creating the site suitability dataset are also not publicly available, we used Siting Level 1 CPAs to select project areas for all RESOLVE Base cases.

We made two exceptions to the CPA selection heuristic above—the first for allowing co-location of wind and solar resources in California, and the second to account for inadequate existing power plant footprint data in California. In the first exception, we did not remove selected wind CPAs from available solar CPAs before selecting solar CPAs—but only for the *Unconstrained* assumptions cases. This assumes that areas where selected wind and solar CPAs overlap, solar panels can be constructed between wind turbines. We made this exception in order to allow the maximum capacity to be selected in RESOLVE Zones where there is significant potential for both wind and solar energy—

specifically, in the Tehachapi RESOLVE Zone in California. Because the site suitability analysis and supply curve creation steps could not account for the overlap of wind and solar CPAs, if the capacity expansion optimization does select the maximum amount of resource capacity in RESOLVE Zones with significant enough technology overlap, there would be an insufficient number of CPAs to meet the RESOLVE generation target for solar (i.e., this zone would be over-subscribed or have too much development). While this condition was only true in the *Unconstrained* assumptions case in the Tehachapi RESOLVE Zone in Siting Levels 3 and 4, for consistency, we made this exception for all *Unconstrained* cases.

The second exception was to address the fact that despite using the most recent and best available wind farm and turbine and solar array footprint data, we found that these datasets did not entirely encompass the renewable energy projects in the CPUC's database of Renewable Portfolio Standard (RPS) executed projects, which are point locations (SI Table 7). To address this issue, we identified all "RPS executed" projects locations that do not overlap with existing power plant footprint data and then labeled all CPAs within 2.5 km of these project locations to prioritize them in the site selection process (i.e., select these labeled CPAs first, in order of their land use efficiency, before selecting non-labeled CPAs). This approach assumes that proximity to these executed project locations is an adequate proxy for whether the CPA has already been developed or should be considered for development potential. Since these additional RPS executed project locations meant that we did not adequately account for the spatial footprints of existing power plants in California, we calculated more representative "selected" generation to model. We did this by subtracting the MWh estimated from existing power plants with footprint data (using RESOLVE's CFs) from RESOLVE's "baseline" and "selected" resources for California, or the "total" resource portfolio, for wind and solar and modeled the spatial build-out using these "net" selected resources. For other states and RESOLVE Zones, we used RESOLVE's "selected" resources directly, without further modification.

2.6.2 Gen-tie corridor modeling

Through the selection process described above, wind and solar resources selected by RESOLVE (total MWh per Zone) were assigned spatial project footprints. The approach generally assigned new renewable capacity to sites that were simultaneously economically attractive (having high capacity factor and low capital cost) and land use efficient (low total land area for the amount of generation, including straight-line-distance estimated gen-tie area).

Once the new resources were assigned to spatially explicit locations, it was possible to more accurately model the gen-tie route for connecting the Selected Project Areas to the existing transmission system. This then allowed a more accurate estimate of gen-tie area requirements and enabled a footprint-based strategic environmental assessment for modeled transmission projects. We modeled future gen-tie paths by performing a least cost path analysis. This analysis requires the following three inputs, described in detail below: a cost surface, a source dataset, and a destination dataset.

Cost surface The cost surface is comprised of WECC environmental data and topographic slope information (SI Table 6). The WECC environmental data was used because these layers were intentionally designed for the siting of linear features such as transmission lines [22]. We used a weighted sum to combine the slope and environmental risk layers into a cost surface, assigning the following levels of influence to the two layers: 66% slope, 34% environmental risk, per methods described in the EPRI GTC paper [38]. We intentionally set WECC Environmental Risk Category

4 values to “null” so that no gen-tie paths would be modeled across areas where development is prohibited [22].

Source dataset The source dataset was a combination of the existing and planned transmission lines (Ventyx and CEC existing transmission, planned transmission lines in advanced stages of permitting; see SI Table 7 for existing and planned energy infrastructure data sources).

Destination dataset The destination dataset was composed of wind and solar project areas that had been selected in the prior step for being economically attractive and in close proximity to existing transmission (estimated using Euclidean distance).

The resulting least cost path dataset contains drawn gen-tie lines for each Candidate Project Area or group of Candidate Project Areas (Fig. 25). We enabled the “each-zone” option so that shared interconnection paths would be identified for groups of projects. The final least cost gen-tie paths were included with the Selected Project Areas in the later step, strategic environmental assessment. In this way, we were able to assess the total impact of a new wind or solar project including the interconnection line, beyond just the area impacted by wind turbines or solar panels.

It should be noted that terrain multiplier criteria (such as landcover type, rolling hills, mountains) identified in the WECC TEPPC Transmission Cost Report [39] were not included, nor were other layers such as weighted values for residential and non-residential building densities, utility corridors, open land, forest, roads, mines, and quarries (identified in EPRI-GTC transmission line siting methods 2006). These could be added in future analyses.

2.7 Step 5. Strategic environmental assessment

We conducted a land-area-based strategic environmental assessment using the modeled generation, gen-tie, and bulk transmission spatial build-out of portfolios created in Step 4 (Section 2.6). The purpose of the strategic environmental assessment is to anticipate the impact of energy development on lands with conservation value, and to examine whether siting protections can be effective in reducing development in areas with high conservation value. For bulk transmission lines with polyline spatial data, we approximated polygon corridor footprints using the average corridor width for each line reported in the BLM Record of Decision for each utility Right-of-Way Management Plan (see SI Table 8 for widths). For each infrastructure type (generation, gen-tie, bulk transmission) and each scenario, we calculated the amount of land area that overlaps with the four Environmental Exclusion Categories, 10 other environmental metrics, and the area-weighted average housing density. Ecological and landscape metrics included critical habitat for sensitive and listed species, sage grouse habitat, Important Bird Areas, wetlands, big game corridors, eagle habitat, and wildlife linkages [40]. Working lands metrics include all agricultural land (crop and pasture land), prime farmland, and rangelands [41]. For rangelands, we used the only known publicly available rangelands extent maps for the U.S. created by Reeves and Mitchell [41] and chose the map created using the National Resources Inventory (NRI) definition of rangelands mapped using the 2001 LANDFIRE landcover dataset. We use the rangelands definition adopted by the Natural Resources Conservation Service’s NRI program, which states that rangelands are, “land on which the climax or potential plant cover is composed principally of native grasses, grass-like plants, forbs or shrubs suitable for grazing and browsing, and introduced forage species that are managed like rangeland” [41]. Several environmental metrics are comprised of datasets that are also used in Environmental Exclusion Categories 2-4. See SI Table 9 for the underlying datasets, sources for each metric, and whether a metric was also included in an Environmental Exclusion Category.

The metrics for the strategic environmental assessment were chosen to represent two types of impacts—specific and generalized. The specific metrics (e.g., sage grouse habitat and wildlife linkages) were intended to explore areas of focus in current public discourse in energy planning forums. Thus, several specific metrics were chosen to explore trends and implications to key species. In contrast, the generalized metrics (e.g., impacts to Environmental Exclusion Category 3 lands) are meant to explore overall impacts to natural and working lands for a given resource portfolio.

3 Results

3.1 Site suitability

Site suitability results show significant solar PV potential, with the highest quantity and quality in the southwestern states (Fig. 4, SI Figs. 14A–15A). Onshore wind resources are spread throughout the Western U.S., with few remaining undeveloped resources in California but large concentrations of high-quality resources in New Mexico and Wyoming as well as along the Oregon-Washington border (Fig. 4, SI Figs. 14B–15B). About 30 GW and 20 GW of wind potential were identified in Montana and 5.8 GW and 3 GW of wind potential were identified in Colorado under Siting Levels 3 and 4, respectively. The resources for these two states were not included in the capacity expansion analysis.

In the *Constrained* scenarios, land protections appear to reduce resource potential, but significantly more resources are available when areas outside of the RESOLVE Zones are considered in the *Unconstrained* scenarios. Additionally, RESOLVE maximum limits in the *Constrained* scenarios were effective at reducing solar resource potential (SI Fig. 14A) in several of the Northern California RESOLVE Zones across all Siting Levels, several Southern California RESOLVE Zones for SL 1-2, and almost all other states' Zones for SL 1-4 (except Nevada under SL 4). For many states, wind and solar resources outside of RESOLVE Zones are several times greater than those within the Zones, and for states like Nevada, Arizona, and Utah, almost all wind resources are outside of RESOLVE Zones in Siting Levels 2-4 (SI Fig. 15B). This is notable for more protective scenarios, since expanding beyond the Zones can counteract the effect of land use exclusions in Siting Levels 3 and 4. Between SL 2 and 3, wind resources are reduced from 96 GW to 25 GW in the *Constrained* case and 328 GW to 95 GW in the *Unconstrained* case (SI Fig. 15), such that it is possible to develop the same amount of wind resources while achieving SL 3 if we include resources outside of RESOLVE Zones.

Although we modeled suitable sites for geothermal, the geothermal potential in the RESOLVE Base case supply curve and identified under Siting Levels 1-4 was significantly lower compared to potential estimates for wind and solar (SI Figs. 14B–15B). Thus, while we include geothermal findings in the figures, we focus on discussion of wind and solar results.

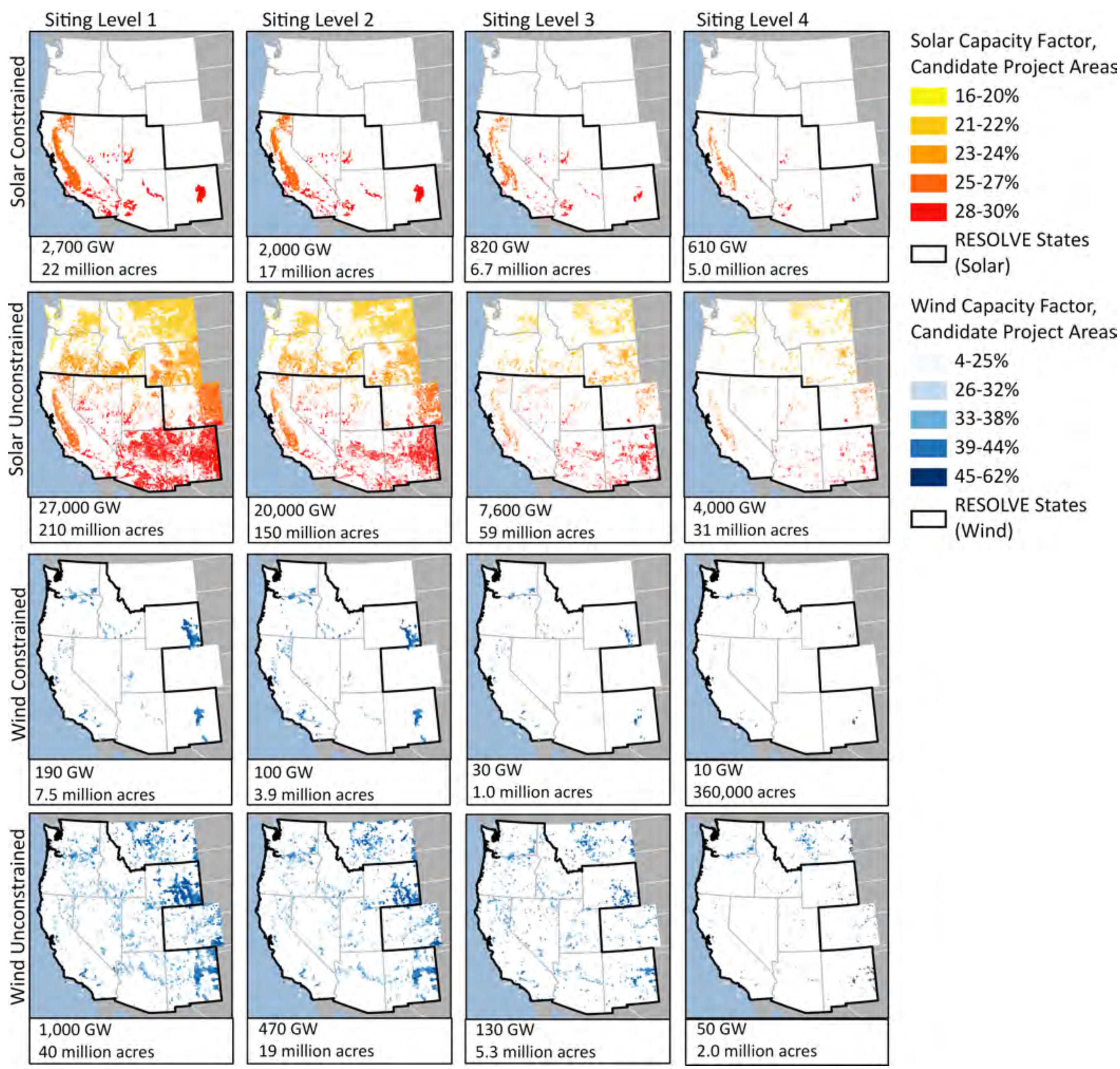


Figure 4: Site suitability maps showing solar and wind Candidate Project Areas for Siting Levels 1–4. Black outlines indicate states that were used to build supply curves for RESOLVE capacity expansion modeling. Total resource potential (summing all colored areas across all states) is indicated in text labels within each subfigure. (Note: RESOLVE supply curve potential is less than the total resource potential reported here for the state-wide maps due to some states not being included in RESOLVE. For RESOLVE supply curve potential, see Figs. 14 and 15). For context, any given 2050 portfolio typically requires no more than 180 GW of total capacity.

3.2 Selected capacity, economic costs, and spatial build-out

3.2.1 Technology mix and total resource cost of RESOLVE portfolios

We used the environmentally-constrained supply curves in the RESOLVE model to generate a resource portfolio (i.e., generation mix) for each Siting Level, as well as to explore the sensitivity of the results to higher levels of distributed energy resources (DERs) in the form of rooftop solar, lower battery costs, and removal of the spatial (i.e., RESOLVE Zone) and solar discount constraints on resource availability. In total, we produced a total of 61 different resource portfolios or scenarios, all compliant with GHG emissions reductions of 80% below 1990 levels and that generate 102%–110% renewable and zero-carbon electricity by 2050 based on retail sales.

RESOLVE optimizes the generation mix to minimize the total cost of each portfolios. We present the results in terms of the annual levelized cost of serving load in California. These cost numbers reflect not only the costs of the portfolio selected by RESOLVE, but also the continuing costs of existing resources expected to remain in service in 2050 and resources already reflected in utility plans. As an input to the model, existing and planned resource costs (totaling $64.5 billion) are not subject to cost-optimization and do not vary across scenarios. We refer to these as "unmodeled" costs. They are included in the final annual cost estimates to provide a sense of scale for the modeled costs that result from RESOLVE's optimization.

Effects of Geography Geographic availability of resources affects not only the generation mix, but also the total generation capacity required from wind, solar, and geothermal sources (102–145 GW in *Full West* vs. 135–181 GW in *In-State*; Fig. 5A). Less overall capacity and significantly greater wind capacity is selected in the *Part* and *Full West* Geographies. Grid storage decreases dramatically with increasing geographic availability of resources (declining from 50 GW to 9 GW of storage in the RESOLVE Base case, and 67 GW to 45 GW in Siting Level 4). As more wind is available, less battery storage is required (Fig. 5D). By allowing more wind resources to be selected, increasing geographic availability reduces solar capacity in California by 30%–60% for *Part West* and by 50%–70% for *Full West* (range spans resource assumption cases and Siting Levels; Fig. 6).

Across all scenarios examined—including the unmodified RESOLVE Base case—the total annual costs in 2050 ranged from roughly $97 billion to $125 billion (Fig. 5B), or between $0.24 and $0.30 per kilowatt-hour of retail sales (by comparison, California's average rate in 2018 is about $0.16 per kWh). In the RESOLVE Base case sceanrios, which all use resource availability assumptions consistent with those developed for the California Energy Commission study [7], the annual cost of generation reduces as more out-of-state resources are made available ($109 billion In-State, $105 billion in *Part West*, and $97 billion in the *Full West*; Fig. 5B). Increasing the resource availability through regional energy procurement or trade significantly reduces cost.

Effects of Siting Levels Siting Level constraints affect the generation mix as well as the total generation capacity. The amount of (available and selected) wind capacity decreases with increasing Siting Levels in the *Part West* and *Full West* scenarios. Utility-scale and distributed solar capacity increase due to increasing protections (Fig. 5A). By limiting wind availability, increased siting protections also increase the need for more battery storage, with about a 30% (*In-State*), 70% (*Part West*), and 450% (*Full West*) increase in storage between RESOLVE Base case and Siting Level 4 (Fig. 5D). The sharp rise in battery storage between Siting Levels 2 and 3 in the *Full West* Geography closely tracks the steep decline in selected wind capacity.

Siting Level constraints also affect the geographic distribution of selected capacity across states. The most dramatic redistribution is seen in Siting Levels 3 and 4 in the *Full West* Geography

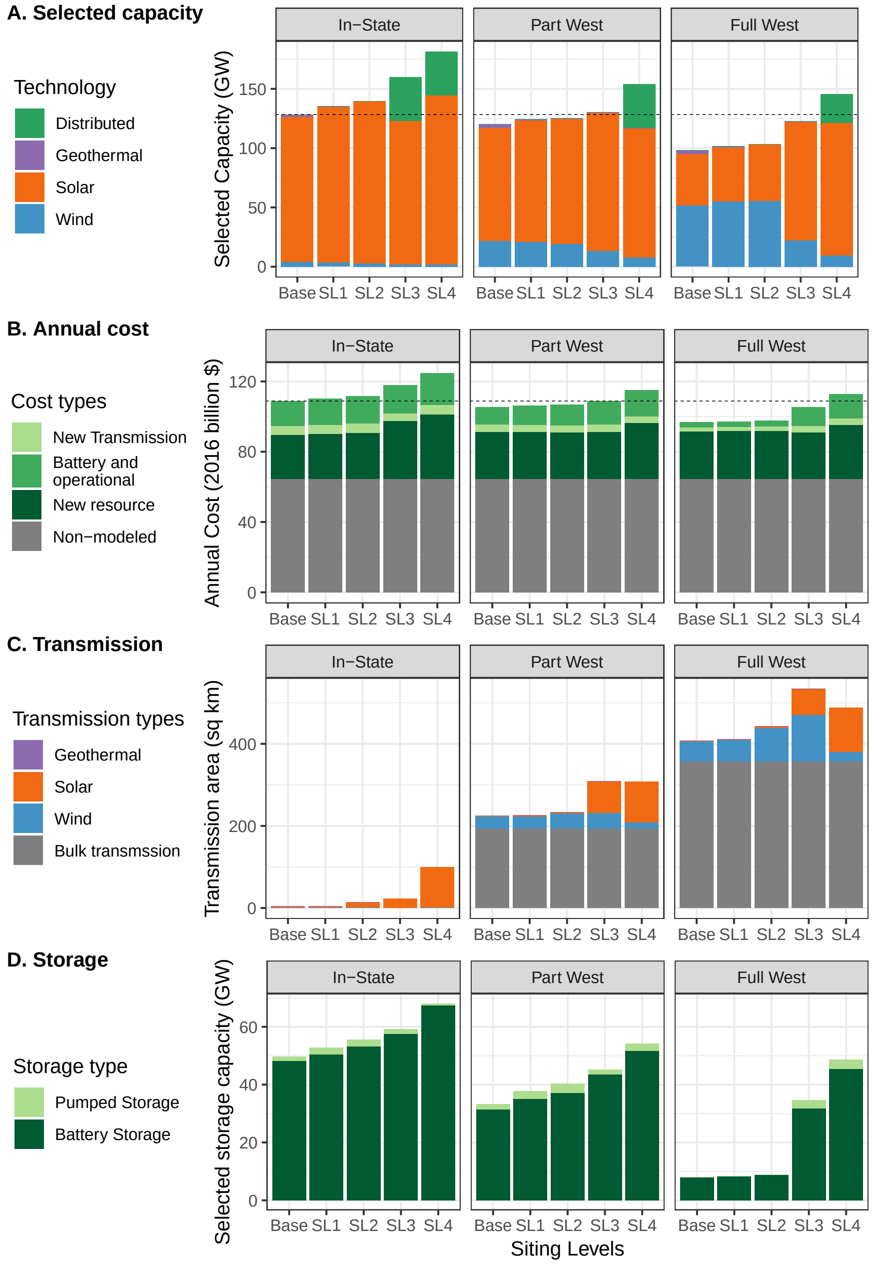


Figure 5: Selected installed capacity of distributed resources, geothermal, solar, and wind by 2050 summed across all RESOLVE Zones (A), total resource cost in 2050 (B), gen-tie and planned bulk transmission land area requirements (C), and pumped and battery storage capacity requirements (D) for the three Geographies (*In-State*, *Part West*, and *Full West*) and four Siting Levels (1-4). As a comparison with business-as-usual, the dotted horizontal line across all three Geography panel plots indicates the value of the *In-State* Base case.

with reduced wind capacity in New Mexico and Wyoming replaced by increased solar capacity in California, Arizona, Nevada, and Utah (Fig. 6).

Siting Levels are also a key determinant of the total cost of RESOLVE portfolios. All else equal, applying more protective siting assumptions increases the total resource cost to meet California's demand. For the *Constrained In-State* scenarios, the total cost increases from $109 billion in the

RESOLVE Base case to \$125 billion under Siting Level 4, an increase of \$16 billion (Fig. 5B) or 14.5% (Fig. 7A). However, the marginal impact of the application of each successive level of environmental restriction can vary widely. Again for the *Constrained In-State* scenarios, Siting Levels 1 and 2 have modest incremental annual costs impacts (\$1.4 billion and \$1.3 billion, or 1% and 2.5%, respectively), while the incremental impacts of the SL 3 and 4 are more significant (\$6.5 billion and \$6.8 billion, or 8% and 14.5%, respectively; Figs. 5B and 7A). This same pattern holds true across the Geographies, with one notable exception: in *Part West*, the marginal impact of achieving Siting Level 3 is only \$2.0 billion or about 3% (Figs. 5B and 7A).

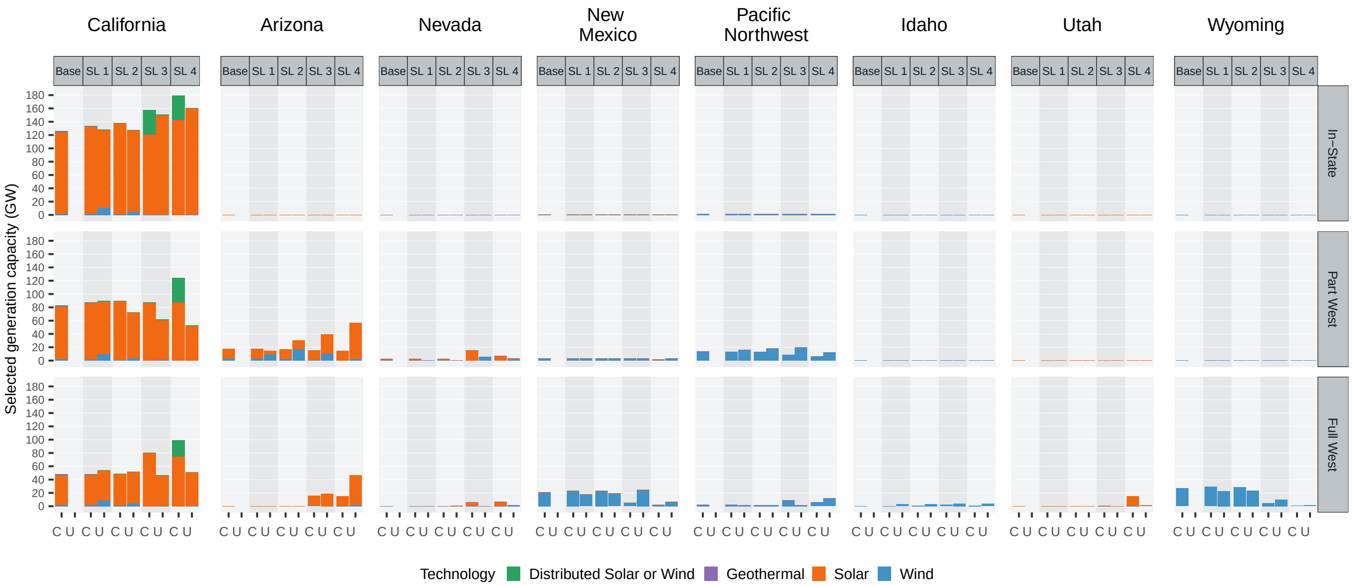


Figure 6: Selected installed generation capacity of distributed resources, geothermal, solar PV, and wind by 2050 for each RESOLVE Zone (or state) for the three Geographic cases (*In-State*, *Part West*, and *Full West*), the four Siting Levels (1-4; grouped bars), and the *Constrained* and *Unconstrained* resource sensitivity assumptions (C and U, respectively, as the x-axis labels). The Pacific Northwest includes Washington and Oregon.

The interaction of Geography and Siting Levels While increasing siting protections increases total costs, expanding geography reduces total costs. Trends for these two assumptions can be combined to produce portfolios that satisfy both land use and cost objectives, to achieve siting protections at lower cost. Generally, we find that procuring renewable electricity from more western states can offset most, but not all, of the cost increase associated with increasing land protections. Results show that under *Constrained* assumptions, the Base case *In-State* incurs nearly the same cost as Siting Level 3 in the *Part West* Geography and is actually 3.1% more expensive than Siting Level 3 in the *Full West* Geography (Fig. 7B). Under *Unconstrained* assumptions, it is actually more cost effective to obtain Siting Level 3 protections in the out-of-state scenarios than the Base case *In-State*. The *Unconstrained* Base case *In-State* is 2% more expensive than Siting Level 3 in *Part West* and is 8% more expensive than Siting Level 3 in the *Full West* Geography. Under the RESOLVE Base case assumptions in the *Constrained* case, *In-State* has a total annual cost of \$109 billion, compared to an annual cost of \$113 billion in Siting Level 4 in the *Full West* Geography, or only about 3.7% cost increase to achieve the most protective Siting Level (Fig. 7B). In the

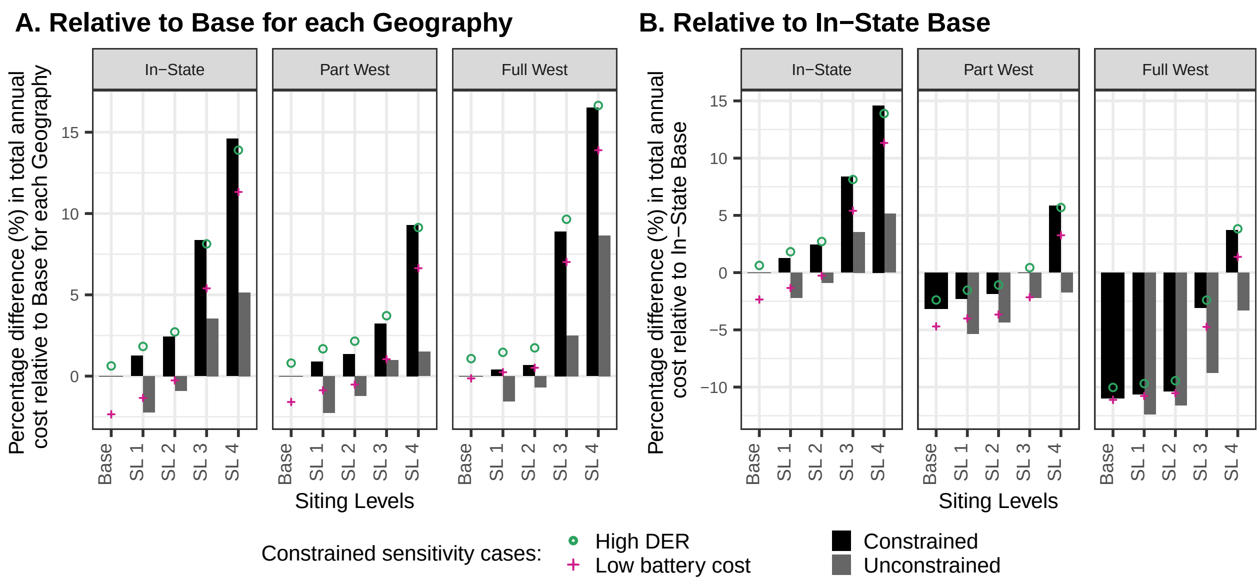


Figure 7: Percentage total resource cost differences relative to the RESOLVE Base within each Geographic case (A) and relative to *In-State* RESOLVE Base (B) for all Siting Levels (x-axis) and *Constrained* and *Unconstrained* Resource Assumption cases. High DER and Low Battery cost sensitivities are shown only for the *Constrained* scenarios. Percentages are calculated using the total resource cost, including the $65 billion in non-modeled costs. For percentage calculations using only modeled costs, see SI Fig. 16.

Unconstrained scenarios, it is actually less expensive to choose Siting Level 4 in the *Part* and *Full West* Geographies (by 2% and 3%, respectively) compared to the RESOLVE Base case in the *In-State* Geography (Fig. 7B).

Effects of *Constrained* vs. *Unconstrained* resource assumptions By expanding resource potential beyond the RESOLVE Zones for other western states and expanding solar resource availability to full technical potential within California (by removing the 80% discount factor for solar resources), the *Unconstrained* portfolios have lower overall generation capacity requirements, increased share of wind capacity, and more evenly distributed capacity across states (Fig. 8). Generally, we find more dramatic differences between *Unconstrained* and *Constrained* assumptions for Siting Levels 3 and 4 compared to Siting Levels 1 and 2 (Fig. 8). *Unconstrained* scenarios allow access to more low-impact, high-quality wind resources outside of RESOLVE Zones and solar resources within California in the more protective Siting Levels 3 and 4, which dampens the effect of increasing land use protections on capacity requirements and loss of wind potential. Specifically, by including resources outside of RESOLVE Zones in the supply curve, RESOLVE is able to select more wind capacity in New Mexico, the Pacific Northwest, and Wyoming under the more protective Siting Levels 3 and 4 in the *Full West* Geography (Fig. 6). As an example of impacts on geographic distribution, in Arizona, a state that does not see much development in the *Constrained* scenarios, there is significantly more wind development under Siting Levels 1–3 and more solar development in Siting Level 4 in the *Part West* Geography (Fig. 6). However, more abundant, higher-quality resource availability in the *Unconstrained* scenarios also causes RESOLVE to select far less commercial distributed solar or wind resources compared to the *Constrained* scenarios. In California, this lack of distributed resources is partially made up by more utility-scale solar.

Results indicate that impacts of *Unconstrained* assumptions on the generation mix and total capacity requirements translate into system cost savings, with greater cost savings in the more protective Siting Levels. These cost reductions are modest for Siting Levels 1 and 2 (under \$5 billion annually) but become significant under the more protective Siting Levels 3 and 4 (Fig. 7). For Siting Level 4, increased resource availability leads to savings of \$10 billion annually in the *In-State* Geography (or a 5% cost increase as opposed to 14.5% in the *Constrained* case), and \$8 billion annually in the *Part West* (1.2% vs 9% cost increase) and *Full West* cases (8% vs. 16.5% cost increase; Figs. 5B, 7). These cost savings are partially achieved through the concentration of resource development in the highest quality resource zones. The most extreme example is the *Unconstrained*, *In-State*, Siting Level 4 scenario, in which the model selects 143 GW of solar in the Westlands Zone, where development had previously been constrained at 28 GW in that zone (Fig. 9, SI Fig. 23). In the *Part* and *Full West* Geographies, these cost savings are due to more availability of low-impact and high-quality wind in Wyoming, New Mexico, and the Pacific Northwest, particularly for Siting Level 3 (Fig. 6).

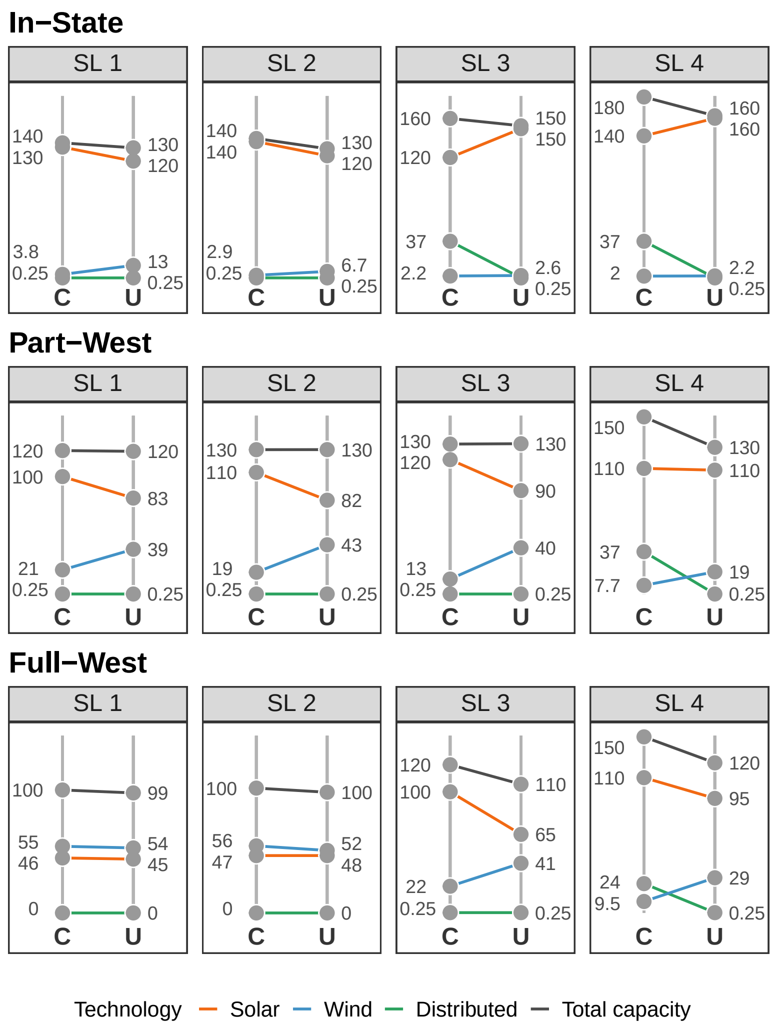


Figure 8: Slope plots comparing *Constrained* and *Unconstrained* resource assumption sensitivity results (C and U, respectively, as the x-axis labels) for selected technology-specific generation capacity (colored lines) and total generation capacity (grey lines) across the four Siting Levels (SL) and three Geographies (*In-State, Part West, Full West*). Numerical labels indicate the amount of selected capacity in gigawatts (GW).

Key cost drivers The annual costs in the various scenarios are primarily driven by two factors: the quality of the solar resources available to the model and the resources available to balance or complement the solar resources. In every case, the model relies heavily on utility-scale solar photovoltaic (PV) resources to meet the increasing demand for carbon-free electricity, reflecting the substantial declines in the price of solar panels in the last decade. The predominance of solar is especially pronounced for the scenarios in which new development is kept *In-State*, as environmental and political restrictions, as well as limited wind resource potential, have sharply limited the potential for new on-shore wind development throughout California. For these *In-State*, *Constrained* scenarios, the model selects 122–142 GW of utility-scale solar for construction by 2050, roughly 10–15 times the existing resources represented in the model (11.3 GW), while only selecting 2–5 GW of wind generation (Fig. 5A). The addition of this much solar to the system requires resources to supply energy to the system during hours with little solar production, i.e., overnight and during winter storms. The model achieves this through a combination of wind and battery resources as determined by the supply curve, given geographical, transmission capacity, and environmental limits. Though battery costs have dropped in recent years, and these improvements are expected to continue in the future, the modeling results indicate that wind generation is generally preferred over battery storage options when sites are available. If generation resources are limited to *In-State* development, balancing the 122 GW to 180 GW of solar requires between 48 GW and 68 GW of battery storage to shift the solar generation to match load (Fig. 5D). If California can take advantage of west-wide wind resources, specifically those high-quality resources in New Mexico and Wyoming, the model will divide the resource build roughly evenly between wind and solar resources (selecting 61 GW of wind generation and 56 GW of solar generation in the *Full West* base case; Fig. 5A) and reduce the amount of battery storage (falling from 48 GW in the *In-State* RESOLVE Base case to 8 GW in the *Full West* RESOLVE Base case; Fig. 5D).

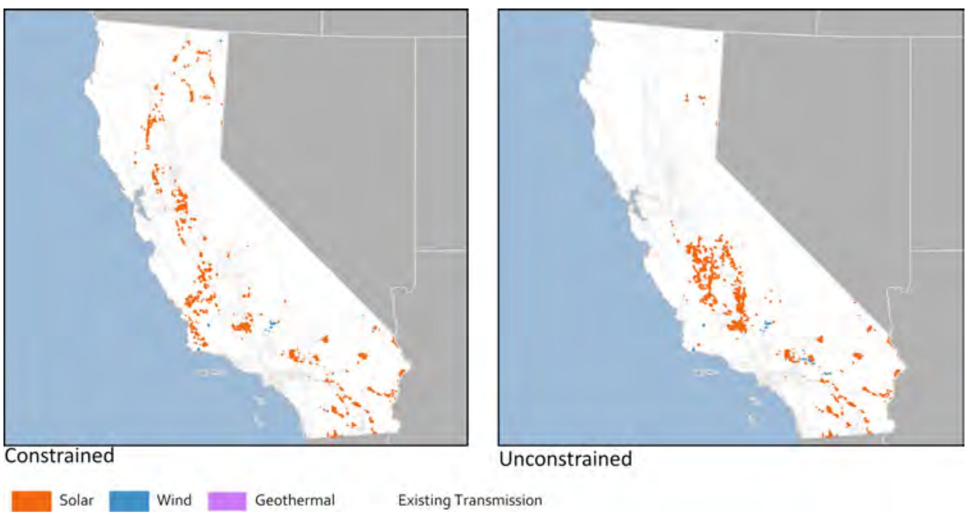


Figure 9: Example Selected Project Areas for *Constrained* and *Unconstrained* assumptions for the *In-State* Siting Level 3 Base scenario.

This trade-off between wind generation and battery storage is most obvious in the *Full West* scenarios. As the more protective Siting Levels are applied, there is a dramatic reduction in the wind resources: moving from Siting Level 2 to 3 reduces the total selected wind potential in Wyoming and New Mexico from 52 GW to just under 9 GW. While the model selects all available wind in the *Constrained* Siting Level 3 scenarios, the reduction in the total wind resource available forces the model to select more solar (increasing from 47 GW to 100 GW) and battery (increasing from 9 GW to 32 GW) resources. This increase in battery storage is a key driver of increased cost.

Effects of lower battery cost and higher behind-the-meter PV adoption Overall, sensitivity analyses increasing the amount of behind-the-meter (BTM) solar PV distributed energy resources (High DER sensitivity case) and reducing battery storage costs (Low Battery Costs sensitivity case) do not significantly alter the generation mix, the distribution of selected capacity between states (SI Fig. 17–20), or the total resource costs (Figs. 7).

Lowering battery costs decreases the overall cost of the portfolio (Fig. 7) but does not cause major shifts in the resource builds between scenarios, nor does it cause the quantity of batteries selected by the model to differ significantly (SI Fig. 17–20). This indicates that the quantity of batteries selected is determined more by the mix of other resources available to the optimization rather than the battery cost. Perhaps the most significant effect of lower battery costs is that no additional pumped hydro storage is selected in any Geography or Siting Level (SI Fig. 17). In scenarios where reducing battery costs changed overall generation mix (*Part* and *Full West*), the effect is a slight increase in solar capacity and a decrease in wind capacity, but with little or no effect on the total selected capacity. The reduction in wind capacity is observed most noticeably in the Pacific Northwest RESOLVE Zone under the Base and Siting Level 1 cases in the *Part West* Geography but is also seen in Wyoming and New Mexico for Siting Levels 1 and 2 (Fig. 18B). Lower Battery Costs do have a larger effect on distribution of selected solar capacity between RESOLVE zones within California. The most significant changes are in the *Part West* case—solar capacity increases in Riverside East Palm Springs and reduces in Greater Imperial in the Base and Siting Level 1 cases (SI Fig. 21).

Increasing BTM DER resources installed by homeowners and businesses by about 35% by 2050 (Table 4) reduced selected utility-developed capacity by about 4-7%—primarily solar capacity in California—across most Siting Levels and Geographic cases (SI Figs. 17A–20A) but had only minor impacts on the geographic distribution of selected resources (SI Figs. 17–20). While the utility costs are lower in the High DER scenarios than in the base cases, the total cost of resources (including the $2.2 billion USD incremental cost of the DER resources borne by homeowners and businesses) generally goes up. However, in scenarios where only lower quality solar resources were available due to more environmental protections (Siting Levels 3 and 4 for the *In-State* Geography, Siting Level 4 in the *Part West* Geography), the total resource cost for the High DER sensitivities are lower than the Base case scenarios (Figs. 5B, 7). In the *In-State* Geography, High DER assumptions reduce Northern California solar in Siting Levels 3 and 4 and reduce Central Valley North Los Banos and Greater Carrizo wind in SL 1 and 2 (SI Fig. 21). In the *Part West* and *High DER* scenarios, Solano and Northern California experience reduced solar development in Siting Levels 3 and 4, respectively, while Riverside East Palm Springs have lower solar capacity in SL 1 and 2.

3.2.2 Transmission requirements

Overall, transmission area and length requirements increase as generation land protections increase and Geography expands—both in absolute transmission area (Fig. 5C) and percentage of total (generation and transmission) infrastructure area (SI Table 18). The land area requirements from the planned bulk inter-state transmission lines exceed that of the total modeled gen-tie lines in the *Part* and *Full West* cases (Fig. 5C). Compared to *Unconstrained* scenarios, *Constrained* scenarios require less gen-tie transmission area, regardless of Geography, except for Siting Level 4 in the *In-State* Geography (Fig. 5C). This is due to more selected wind capacity in the *Unconstrained* scenarios, which we expect to have more transmission requirements given that wind is typically more heterogeneous in quality (more dispersed) and have lower total land use efficiencies.

As expected, among the Geographic cases, *In-State* requires the least amount of additional transmission corridor area, while *Full West* requires the most (Fig. 5C). In the *Part* and *Full West* Geographies, wind dominates total transmission area requirements for Base and Siting Levels 1 and 2 despite comprising a much lower fraction of overall generation capacity. The large selected solar capacity for the same Siting Levels require very little additional transmission area. Although solar generation capacity is not significantly higher in Siting Levels 3 and 4, the solar gen-tie transmission area tends to increase dramatically compared to Siting Levels 1 and 2 (Fig. 5C). In *Part* and *Full West* cases, most of these solar gen-tie transmission requirements are disproportionately due to development primarily in Nevada and secondarily in California (Fig. 10, Fig. 25). Wind transmission requirements are disproportionately greater in Arizona, Nevada, and New Mexico in the *Part West* case and in Idaho and the Pacific Northwest in the *Full West* case, particularly for Siting Level 3 (Fig. 10, Fig. 25).

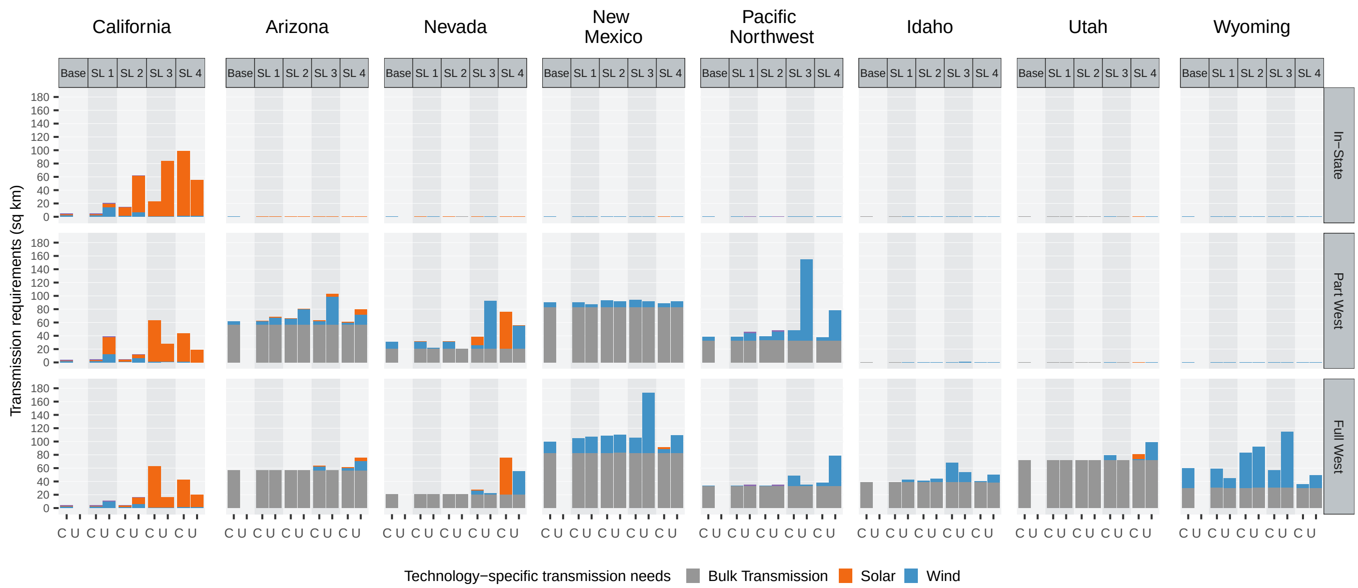


Figure 10: Gen-tie and planned bulk transmission area requirements for each RESOLVE Zone (or state) for the three Geographic cases (*In-State*, *Part West*, and *Full West*), the four Siting Levels (grouped bars), and the *Constrained* and *Unconstrained* resource sensitivity assumptions (C and U, respectively, as the x-axis labels). Gen-tie areas are modeled using least cost analysis. Pacific Northwest includes Washington and Oregon.

3.2.3 Selected Project Areas

For the *In-State* Geography, increasing Siting Levels causes site selection to shift away from Southern California toward Northern California (Fig. 11). As the geographic extent expands from *In-State* to *Part West*, wind development tends to shift from California toward New Mexico and to the Oregon-Washington border, to the maximum extent possible within the constraints of the model since the 3,000 MW transmission limit in New Mexico is binding in the *Part West* Geography. Within the *Part West* Geography, solar distribution continues to shift northward as Siting Levels become more protective, and wind experiences a smaller shift away from New Mexico wind and toward the Pacific Northwest. The *Part West* case includes two new long-distance high-voltage transmission lines, SunZia and Southline, with a total distance of 1,200 km to deliver wind power from New Mexico to California.

Expanding the Geography from *Part West* to *Full West*, new Selected Project Areas occur in Wyoming and New Mexico to the maximum extent possible within the constraints of the model. The 3,000 MW transmission limit for New Mexico wind is lifted in the *Full West* Geography, and additional development occurs in New Mexico as a result, up to 24,000 MW. However, with increasing levels of siting considerations, selected Wyoming and New Mexico wind resources becomes smaller and more dispersed. In the more protective Siting Levels, New Mexico and Wyoming wind resources tend to be replaced by smaller wind resources in the Pacific Northwest and Idaho. The *Full West* scenario includes additional new long-distance high voltage transmission lines, TransWest Express, Gateway South, Gateway West, Boardman to Hemingway, and SWIP North with a total distance of 5,356 km to deliver wind power from Wyoming and Idaho to California.

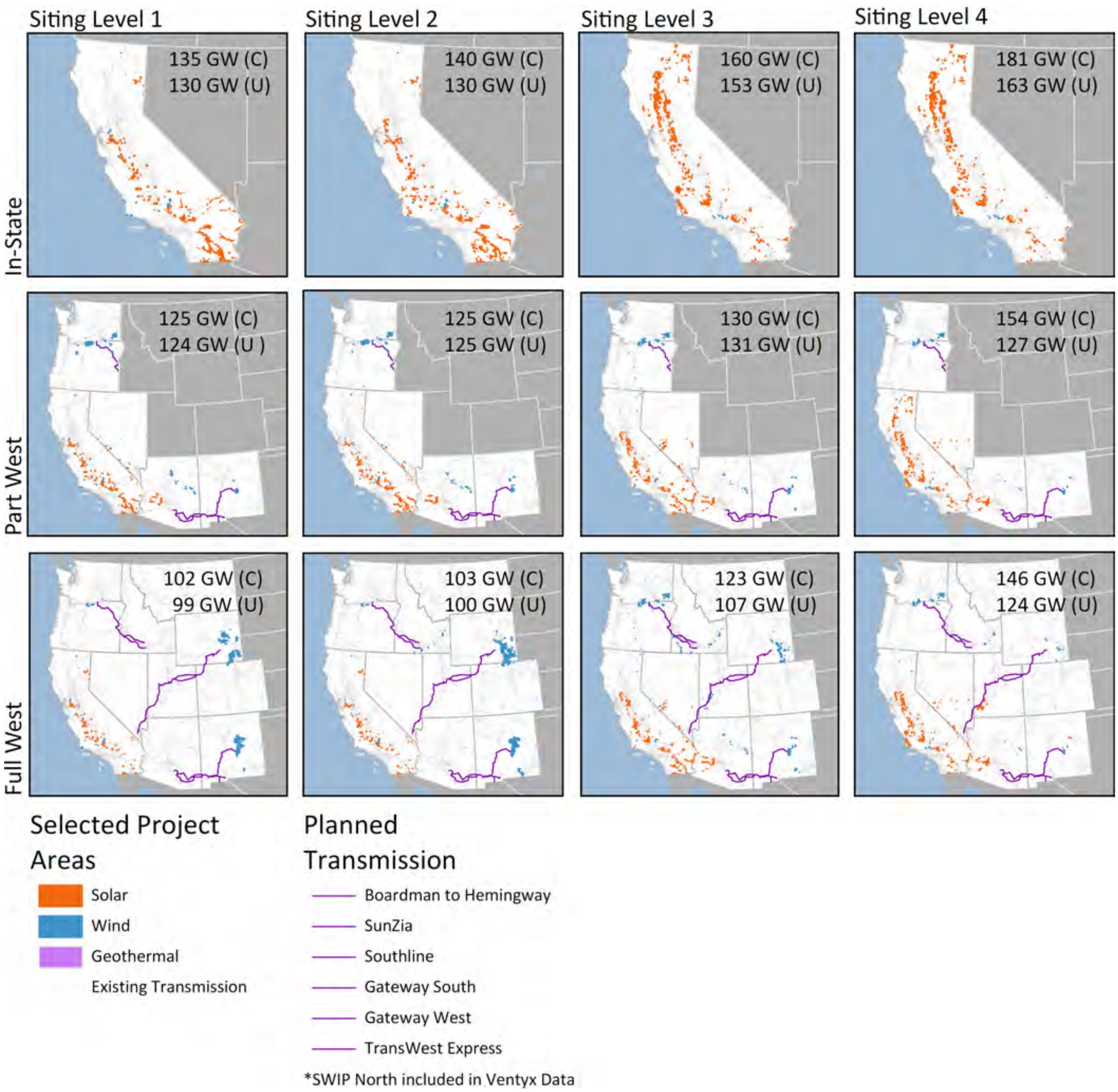


Figure 11: Selected Project Areas (SPAs) in the *Constrained* scenarios. Siting Levels are shown in columns and Geographic cases are shown in rows. Text in each panel shows total installed capacity for *Constrained* scenarios (C) and *Unconstrained* scenarios (U).

3.3 Strategic environmental assessment

3.3.1 Ecological impacts of generation infrastructure

Construction of new solar and wind projects could have significant ecological impacts depending on the level of land protection achieved. There is a high degree of overlap (>50%) between selected project areas and Environmental Exclusion Categories 3 and 4 (Fig. 12A). This suggests that the application of Environmental Exclusions in practice has the potential to significantly affect the build-out of wind and solar power plants, and that the lack of ecological protections above the RESOLVE Base leaves open the potential for the build-out to impact natural lands. In the *Part West* cases, general ecological impacts of solar selected project areas can be equal to or greater than for wind in Base case and Siting Levels 1–3—since prime farmland occupies a significant fraction of the impacts in Base through SL 2. However, in the *Full West* cases, the impacts of wind development are far greater than for solar in Base through Siting Level 2, and are the highest across all scenarios examined. Category 3 and 4 land areas are significantly impacted by *In-State* solar under Siting Level 2 and 3 assumptions.

However, the generation-associated impacts to specific ecological metrics—Critical Habitat, Important Bird Areas, Eagle Habitat, Sage Grouse habitat, Big Game habitat, Wetlands, and Wildlife linkages—are less significant compared to to aggregated Environmental Exclusion Categories (Cat 1-4). This suggests that ecological siting considerations are likely to be dominated by other factors not captured in the specific metrics highlighted here. Example "other factors" include sensitive grassland birds and TNC portfolio areas. In the *In-State* case, impacts to these individual ecological impact metrics are the lowest; impacts are greater under *Part West* and *Full West* geographic assumptions (Fig. 12A).

Wind The most significant ecological impacts from wind development are in Wyoming and the Pacific Northwest (Fis. 26B, 27). Big Game habitat and corridors are impacted for the RESOLVE Base and Siting Level 1 scenarios, with about a quarter and one-third of all wind development overlapping with Big Game areas in the *Part West* (in the Pacific Northwest) and *Full West* (in Wyoming) Geographies, respectively (Fig. 26B, 27). Wildlife Linkage impacts follow a similar trend as Big Game areas but are considerably more significant—comprising up to 50% of all wind development areas—in Siting Levels 2 and 3 in the *Full West* (Wyoming) Geography (SI Fig. 27).

In *Unconstrained* cases, the additional wind development in Arizona (*Part West*) and Wyoming has significant overlap with Wildlife Linkage areas. Sage Grouse habitat is impacted by wind development in Wyoming only for Siting Level 1, while little or no Big Game impacts occur in any state for Siting Levels 2-4 (SI Fig. 31).

Solar Solar development can largely avoid key ecological impacts examined here, except on Important Bird Areas in California for RESOLVE Base and Siting Levels 1 and 2 within the *In-State* and *Part West* Geographies and on Wildlife Linkages in Nevada in Siting Level 3 in the *Part West* Geography (SI Fig. 26). In *Unconstrained* case, there are higher impacts on Important Bird Areas due to solar development in Base and Siting Level 1 scenarios in California across all Geographies (SI Figs. 30, 31).

3.3.2 Agricultural and other land impacts of generation infrastructure

Both wind and solar impacts on agricultural lands are significant. One-third to half of all solar capacity could be sited on agricultural land in California across all Siting Levels and Geographies

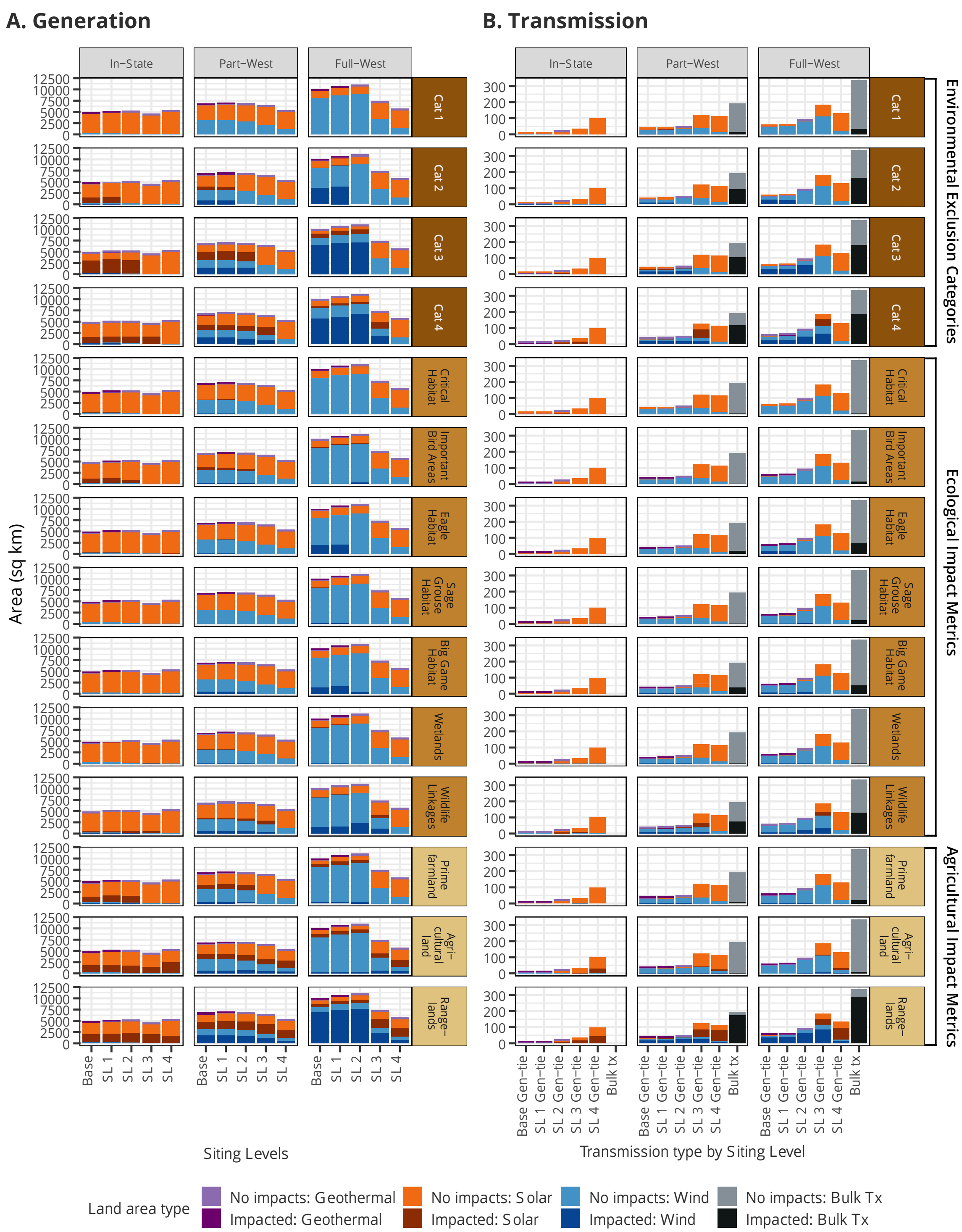


Figure 12: Environmental impacts for generation (A) and modeled gen-tie and planned bulk transmission corridors (B) summed across all regions for the *Constrained* assumptions case. Bulk transmission is shown in a separate column. Cat 1–4 refer to datasets in the Environmental Exclusion Categories created for the site suitability analysis (Section 2.2). No impacts are expected for Siting Levels equal or greater than the Category (e.g., no Category 3 and 4 environmental exclusion impacts should exist for Siting Level 3).

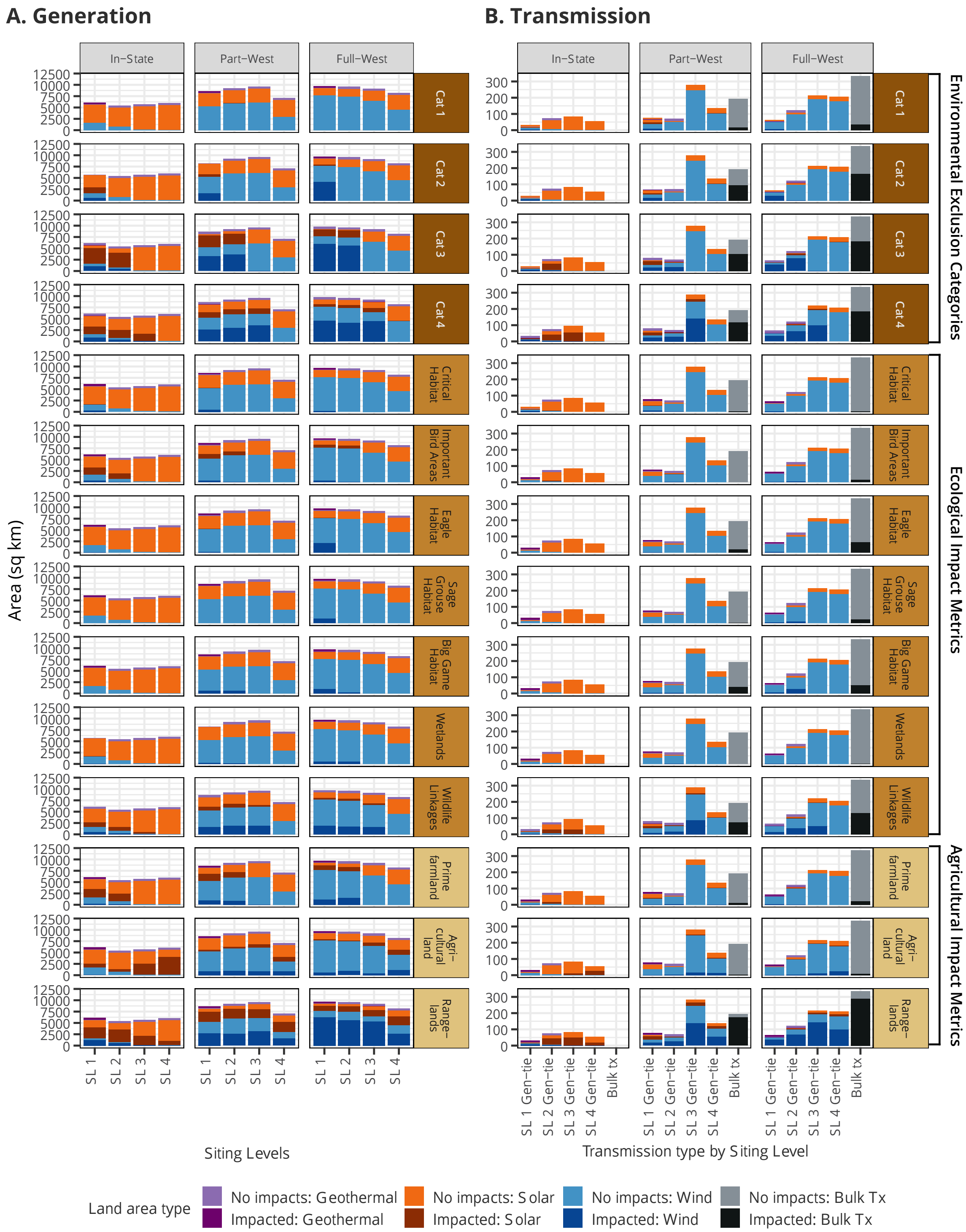


Figure 13: Environmental impacts for generation (A) and modeled gen-tie and planned bulk transmission corridors (B) summed across all regions for the *Unconstrained* assumptions case. Cat 1–4 refer to datasets in the Environmental Exclusion Categories created for the site suitability analysis (Section 2.2). No impacts are expected for Siting Levels equal or greater than the Category (e.g., no Category 3 and 4 environmental exclusion impacts should exist for Siting Level 3).

in the *Constrained* case (SI Fig. 26). Percentage of solar capacity on non-prime agricultural lands increases under higher Siting Levels 3 and 4. Of those agricultural lands impacted, nearly all of it is considered prime farmland in RESOLVE Base and Siting Levels 1–2 (due to environmental exclusions, no impacts are allowed on prime farmland in Siting Levels 3 and 4; Fig. 12A). Lower fractions of wind development overlap with prime or other agricultural lands, with up to half of sites in Pacific Northwest under SL 4 and one-third of sites in New Mexico under SL 1 and 2. Impacts to rangelands, which are native or non-native grass or shrub-like vegetation suitable for grazing or browsing by livestock, are similarly important for solar development across all scenarios, with approximately half of all solar in California and nearly all solar in Arizona and Nevada sited on rangelands (SI Fig. 26). Large fractions of wind generation are also sited on rangelands—a little under 50% of sites in the Pacific Northwest and nearly all sites in New Mexico and Wyoming across all Siting Levels and Geographies (SI Fig. 26). Rangeland habitats tend to have high biodiversity value, provide significant habitat connectivity, and form the foundation for a number of ecosystem services [42]. However, total agricultural and rangelands in both California and the West are abundant relative to impact—less than 1% of agricultural and rangelands are impacted.

Compared to the *Constrained* case, impacts on agricultural lands across all states in the *Unconstrained Part* and *Full West* Geographies are proportionally lower (Figs. 12A, 13A). As with the *Constrained* case, both solar and wind selected in the *Unconstrained* cases are largely sited on rangelands in Arizona, New Mexico, and Wyoming, and to a lesser extent in California with more siting protections in place (SI Figs. 30, 31).

Average housing density of Selected Project Areas generally increases with higher levels of environmental siting protections (Fig. 34). This trend is most clearly observed for solar in the *Part* and *Full West* Geographies (Fig. 34B). On the whole, solar Selected Project Areas have higher housing density compared to wind across all Siting Levels and Geographies (Fig. 34C).

Transmission impacts Compared to the environmental impacts of generation infrastructure, gen-tie transmission impacts in the *In-State* and *Part West* Geographies are proportionally lower (Fig. 13). The three most notable ecological metrics impacted by transmission gen-ties are Wildlife Linkages in California and Wyoming under Siting Level 3, Big Game habitat in Wyoming under SL 3, and Eagle Habitat in Wyoming under SL 1 and 2 (SI Figs. 28, 29). Bulk transmission impacts are proportionally greater than gen-tie impacts in Siting Levels 2-4 (Fig. 13). Almost all bulk transmission corridors planned in the Pacific Northwest could overlap with Big Game habitat (SI Figs. 28, 29). Little agricultural land is impacted by either bulk or gen-tie transmission corridors, except in California in the *In-State* and Siting Level 4 scenarios (SI Fig. 28). Similarly to generation, large percentages of gen-tie and almost all bulk transmission corridors are located on rangelands in nearly all regions except the Pacific Northwest for gen-tie corridors.

4 Discussion

We find that technology choices, resource costs, and the landscape of infrastructure build-out to achieve California's climate targets are highly sensitive to the level of environmental siting protection and whether California has access to renewable resources from other Western states. Importantly, these technology choices and spatial build-outs have different impacts on natural and working lands in the West.

With planning, California can develop the renewable energy required to achieve deep decarbonization in 2050 and limit land impacts. However, the options for achieving multiple policy goals including conservation and renewable energy development have their own sets of benefits and trade-offs, which we discuss below.

In absence of a plan to limit land impacts and scale up renewable energy deployment, impacts to natural and agricultural lands can be high. In the Siting Levels that only exclude current legally and administratively protected areas, overall ecological impacts due to wind and solar generation infrastructure and additional transmission requirements are significant. These impacts include loss of Important Bird Areas, Eagle Habitat, Big Game Habitat, and Wildlife Linkages. However, we find that these ecological impacts can be largely avoided with portfolios created under Siting Level 3 and 4 assumptions, while still meeting clean energy targets, by protecting lands with high conservation value and high landscape intactness (Categories 3 and 4).

Solar and wind development are likely to impact agricultural lands regardless of Geography or Siting Level. Between 35% to 50% of all solar capacity in all *In-State* Geographic scenarios is sited on existing agricultural lands (either cropland or pastureland), with prime farmland comprising the majority of the impacted farmland in Siting Levels Base, 1, and 2. More than half of all wind and solar across all Siting Levels is sited on rangelands in the two out-of-state Geographies. Thus, to reduce or avoid siting conflicts, agrivoltaics [43] and wind-friendly farming and ranching practices, including siting on degraded agricultural lands ([44]), as well as wildlife-friendly design and operational practices will be important for the future of renewable energy development in the Western U.S. In California, it will be important to align solar energy planning with groundwater management activities that will require retirement of agricultural lands driven by the Sustainable Groundwater Management Act. Working lands with wind turbines can have multiple additional uses, due to typical wide spacing of turbines. Strategies to facilitate wind development will be important in areas where wind energy occurs on working lands (e.g., land leasing programs, farmer engagement).

A regional energy market is more cost-effective because it enables access to western wind resources. Interconnection to a wider, regional energy market is more cost-effective than limiting new renewable resource development to California due to the availability of high-value western wind resources. While the *In-State* scenarios require the least new interconnection and bulk transmission investment in comparison to regional scenarios, the *In-State* transmission cost savings are offset by the lower overall cost of decarbonization in the *Full West* scenarios.

Achieving the best conservation outcomes is more cost-effective at a regional scale. While lower impact siting can increase system costs, increasing geographic availability of renewable resources can offset these cost increases. Of the four Siting Levels considered, Siting Level 4 achieves the lowest ecological impacts, but leads to significant cost increases for all Geographies (increases are less significant when current constraints in planning assumptions—discount factor, RESOLVE Zone boundaries—are removed). However, costs do not change linearly between Siting Levels. We find that achieving Siting Level 3 may be much more cost-effective, especially when out-of-state resources are available. When California has access to *Part West* resources, we find that a significantly greater level of protection under Siting Level 3 can be achieved at the same cost as the much lower level of *In-State* protection under the RESOLVE Base case. In the regional scenario (*Full West*), the portfolio protecting high-conservation-value lands (SL 3) is approximately 10% less expensive than the same level of protection in the California (*In State*) scenario.

Environmental impacts are greater outside of California under the business-as-usual scenarios in which only legally and administrative protections are enforced. The finding that environmental impacts are greater in the *Part* and *Full West* Geographies in the less protective scenarios demonstrates the need for ensuring the necessary standards for permitting non-California projects if California compliance regulations do allow out-of-state wind development. Similar standards for low-impact permitting should be in place for out-of-state projects to ensure that greater land protections in California do not lead to leakage of biodiversity impacts. Otherwise, under legal protections alone, there may be impacts to Eagle Habitat, Big Game Habitat, and Wildlife Linkages, among others. Impacts to Wildlife Linkages under Siting Level 3 do remain, which points to the importance of design and operational practices that can minimize impacts to wildlife and habitat. The large overlap of selected capacity in the low protection scenarios (SL 1 and 2) with land areas in Environmental Exclusion Categories 2, 3, and 4 suggests that renewable energy project developers may face siting challenges for a sizable majority of projects (e.g., SL 1 can have Selected Project Areas in Categories 2-4 land areas, as these Categories were not excluded from SL 1, and SL 2 can have Selected Project Areas located in Categories 3 and 4 land areas). This overlap also indicates that a large percentage of desirable development sites also have environmental and social value that state agencies and land managers should anticipate and manage to avoid conflicts. These findings underscore the importance of effective screening tools early in the project development cycle in conjunction with effective planning and procurement practices for renewable energy, alongside incentivizing development in low-impact locations, aggressive energy efficiency, and land-sparing renewable energy technologies.

Out-of-state Geographies significantly increase both gen-tie and planned bulk transmission requirements, presenting an important trade-off. The need for additional transmission—in some cases, an order of magnitude greater—is an important trade-off for an otherwise clear finding that increasing regional resource availability makes sense from both cost and environmental impact points of view. Although transmission land use requirements are a small fraction of the total land use build-out (<5% including planned bulk transmission lines), transmission projects are known to have disproportionate siting impacts due to landscape fragmentation and have long lead times for permitting and construction. They are known to suffer from permitting uncertainty, as well as cost allocation uncertainty, when crossing state boundaries.

Compared to those for solar, siting options for wind are more geographically and environmentally constrained, and drive the prevailing trends in cost and generation mix. The low costs and relative abundance of solar PV enable large shares of solar capacity to be selected across all scenarios (50% or greater). Due to their relatively low costs and because their generation profiles complement that of solar, wind resources tend to be higher value in a high-variable-renewables system. However, compared to solar, wind is more limited in the lower-impact scenarios because there are relatively fewer low-conflict high-quality wind resource areas. Wind resources are generally more heterogeneous (i.e., patchy) across larger spatial scales, while also having lower land use efficiencies when considering turbine spacing, making it more sensitive to land use restrictions. Thus, in wind-limited scenarios (e.g., *In-State* Geographies and Siting Levels 3 and 4 in *Full West*), solar is the vast majority of the capacity selected. A solar-dominated grid requires significant battery storage, driving up total costs.

Removing or relaxing the current *Constrained* resource availability assumptions increases wind capacity two- or three-fold in the more protective Siting Levels, which achieves high levels of land protection at even lower costs. *Unconstrained* resource assumptions allow access to high-quality wind resources in several western states under more protective siting levels, enabling a larger share of wind capacity in the generation mix, reducing the total generation capacity and storage required, and reducing system costs of achieving lower impact development. Moreover, in Siting Level 3, although twice as much wind is selected to meet California's demand when constraints are lifted (about 40 GW compared to 20 GW), 53 GW of wind potential will still be available to meet the needs of other states. Also, by applying limits to solar potential on all zones uniformly, capacity expansion models can underestimate the amount of low-impact potential in high resource quality zones. Although these resources may be captured and identified through resource assessment studies, they should also be reflected in electricity capacity expansion models to ensure that downstream transmission planning studies are able to consider low-impact, high-quality zones.

Distributed energy resources (DER) can play an important role in reducing the land use impacts of renewable energy development, but large quantities of utility-scale solar and wind are still needed to meet clean energy targets. High rooftop solar scenarios (an additional 9 GW compared to baseline 2050 forecast, or a 35% increase) provide multiple benefits: locational value (reduce loads and thus allow deferral of distribution system upgrades), avoided line losses, and land conservation benefits. Results show that about 11–14% of California's 2050 electricity demand can be met with behind-the-meter (BTM) residential solar PV. Compared to the Base case, the high rooftop solar sensitivity scenarios reduced utility-scale capacity build-out by 3–6%, or 200–445 km^2. California will still require 95 GW (*Full West* Base Siting Level) to 132 GW (*In-State* Siting Level 4) of utility-scale generation capacity, or between 3,800 km^2 and 10,700 km^2 of land area. However, there may be opportunities to increase the DER contribution. The scenarios in this study are limited in assuming development of 25% of technical rooftop PV potential (both residential and commercial) in California, which includes rooftop PV on 90% of homes built after 2020. If 50% of technical potential for BTM PV in California can be realized by 2050 (effectively doubling the high BTM PV assumptions in this study), this would likely reduce electricity demand by another 12-14% percentage points, leaving about 70-75% of total demand that will still need to be met by utility-scale generation. However, these DER adoption assumptions do not include exogenous assumptions about non-rooftop BTM commercial PV (e.g., community solar) or other forms of innovative land-sparing distributed PV systems such as floatovoltaics.

4.1 Uncertainties

Policy changes and technology evolution could alter the balance of trade-offs and co-benefits. This study examines only California's electricity demand and whether it can be met by currently available west-wide wind and solar resources. As other states pursue equally ambitious climate goals by increasing renewable energy development, increased competition for the best wind and solar sites may change resource availability in the West, leading to inefficiencies and higher land use impacts if not adequately planned and managed. At high levels of cumulative wind and solar penetration, the marginal value of solar-balancing (storage) or solar-complementary resources (e.g., geographically diverse wind resources) may increase. Development of off-shore wind resources, which are not included in this study, can also alter the balance of options by enabling access to much needed wind generation in an *In-State* case. It will be important to explore the interaction of multiple states' electricity demand and policies and the potential contributions of offshore wind in future work.

Enabling conditions for access to best regional resources and more optimal inter-state resource sharing are uncertain, but some programs and institutions are in place. Changes in any of the following conditions can drive the future toward any one of the scenarios in this study: transmission access (planning, approval, financing and construction of new lines, and agreements on acceptable uses for these new lines), market structure (e.g., Energy Imbalance Market), regulatory framework (existing definitions of three types of Renewable Portfolio Standard eligibility may not easily allow out-of-state resources to qualify towards meeting RPS mandates), and the governance framework for inter-state resource sharing. For example, current RPS definitions tend to drive development toward the *In-State* Geography. Further development of the Energy Imbalance Market can drive states toward the *Full West* Geography. Emerging time-of-day GHG emissions accounting standards (see IRP Clean Net Short calculator) can drive the future toward the *Unconstrained* case, in particular the *Unconstrained* wind resource characterization, because wind hourly profiles tend to complement solar hourly profiles. Hence the value of wind is rising especially for generation during off-solar-peak hours, which encourages more wind development, some of which may be outside of RESOLVE Zones.

5 Conclusions

By accounting for siting impacts in planning processes for renewable energy deployment, it is possible for California to achieve its renewable and carbon-free electricity goals with minimal impacts to the west-wide network of natural and working lands.

Avoided impacts In the business-as-usual scenarios, impacts to natural and working lands in California and across the West are high. When environmental values are explicitly considered in siting of generation and transmission, impacts are avoided or reduced significantly.

Regional resources Our findings show that increasing the level of land use protection can increase portfolio cost, but expanding the geography reduces portfolio cost. When combining protections with a larger geography, these effects can offset each other, resulting in a portfolio that satisfies multiple policy goals (increased protections and lower cost). However, while increasing land protections can increase total resource costs, these costs do not reflect the additional costs that projects in sensitive areas may face due to land-related siting conflicts (e.g., mitigation, permitting, project delays, project resizing), which may be severe and significant in the less protective Siting Levels (SL 1 and 2).

Resource assumptions The cost increase associated with siting protections can be significantly reduced or offset by expanding resource potential estimates beyond current modeling assumption constraints. By enabling development outside of RESOLVE Zones, greater quantities of low-impact wind capacity can be selected, which lowers costs while protecting natural and working lands.

Differences in regional and *In-State* portfolios In the *In-State* scenarios, the vast majority of generation is supplied by solar PV due to the scarcity of wind potential. Thus, these portfolios rely heavily on battery storage to make solar generation available at night. In the regional scenarios, economically competitive wind resources with generation profiles that complement that of solar PV can avoid heavy reliance on battery storage. While regional wind resources are an economically attractive solution, they often occur on lands with high natural resource value.

Solar and wind impacts The working land impacts of both solar and wind are significant in all scenarios; one-third to one-half of all solar could be sited on agricultural land, and more than half of all solar and wind could be sited on rangelands.

6 Definitions

Candidate Project Area A GIS-modeled parcel of land with estimated renewable energy attributes (e.g., square km, MW, capacity factor, estimated annual generation, estimated capital cost, spatial boundary). Candidate Project Areas are the output of the site suitability analysis that apply spatially-explicit techno-economic and environmental exclusions for development that were then subdivided into typical large-scale renewable energy project-sized areas (typically 50-100 MW project size). 6

capacity factor A figure of merit used for evaluating the performance of electricity generation power plants. Expressed as a percentage, indicating the typical generation in a typical year, as a percent of the maximum theoretical generation that could be produced if the plant were operating at maximum capacity at all times. As an example, if a wind power plant has a 30% capacity factor, this means that in a typical meteorological year, this plant generates 30% of the amount of electricity that would theoretically be generated if wind speed remained continuously at maximum rated velocity for this turbine model, for all 8760 hours of the year.. 7

case A group of model runs, made up of a collection of inputs and outputs, that examine a single model modification in combination with changes to other variables (e.g., *In-State* Geographic case, *Unconstrained* case). 7

Constrained A case describing a version of the resource potential estimate that limits the resource potential to areas within the RESOLVE Zones and applies a maximum value on the solar resource potential per zone (20% of that zone's gross resource potential for the California Energy Commission's version of RESOLVE). 7

Environmental Exclusion Category A group of environmental siting criteria that share a common theme (e.g., all data sources in Category 1 fit that Category's definition, "Areas with legal restrictions against energy development"). These Environmental Exclusion Categories are used in the site suitability analysis to "exclude" land from renewable energy development.. 8

Geography Geographic areas within which renewable energy resources are assumed to be available for development. Three Geographies are defined for this study: *In-State* (California), *Part West*, and *Full West*. 16

portfolio A list of renewable energy resources (MW per RESOLVE Zone) selected by the capacity expansion model, representing the total or selected amount of new capacity that must be built to satisfy the model's constraints (e.g., meet electricity demand, achieve greenhouse gas emissions cap, minimize cost). 7

resource potential An estimated value describing the amount of renewable energy which could be developed within a specified area. For example, the estimated amount of wind resource potential within the New Mexico RESOLVE Zone is 36.1 gigawatts (GW). 9

scenario A model run (inputs and outputs) with a unique full combination of input assumptions (e.g., Siting Level 1, *In-State* Geography, *Constrained* resource assumption, base electricity demand forecast, Base battery cost). 16

Selected Project Area A Candidate Project Area (see definition) that was selected through the spatial disaggregation process using capacity requirements in a capacity expansion portfolio (see definition). The capacity expansion model specifies the total amount of energy or generation capacity selected, per RESOLVE Zone, after which the spatial disaggregation process uses the Candidate Project Areas to identify specific project footprints—Selected Project Area—at a finer geographic scale. 8

sensitivity A set of scenarios for which all input assumptions were held constant, except for a single input variable. The single variable was changed in order to determine the magnitude of the impact of that variable on the results. For this study two sensitivity analyses were defined, "High DER" and "Low Battery Cost". 8

Siting Level A case or set of scenarios in which a limited number of Environmental Exclusion Categories were applied. For example, in Siting Level 3, all of the following Environmental Exclusions were applied: Category 1, Category 2, and Category 3. 7

supply curve A list of supply-side power generation resources that are available to the capacity expansion model, including resource characteristics such as resource potential per zone (e.g., in megawatts of capacity) and capacity factor, and typically ranked in order of general economic value (or capacity factor). The model can select its optimal power mix from the supply curve. The supply curves in this study are based on the total amount of generation capacity within all Candidate Project Areas within a RESOLVE Zone. 6

technology Renewable energy generation technology type (e.g., wind, solar, and geothermal are the primary technologies under consideration in this study). 6

Unconstrained A case describing a version of the resource potential estimate that includes resource potential within and outside of RESOLVE Zones (i.e., state-wide) and does not limit the solar resource potential per zone (see definition for *Constrained*). 7

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Appendices

A Additional methods

Table 6: Techno-economic datasets for site suitability modeling

Broad category	Dataset name	Source	Website	Description	Data type/ resolution	Threshold or buffer
Renewable resource	WIND Toolkit dataset	NREL	https://data.nrel.gov/submissions/54 https://www.nrel.gov/grid/wind-toolkit.html	Point locations of simulated wind speeds and estimated annual average capacity factors of quality wind resource areas in the U.S.	CSV with geographic coordinates/ 2 km	Include all areas
Renewable resource	Solar PV capacity factors	NREL	https://sam.nrel.gov/	Point locations of estimated annual average capacity factors for fixed tilt solar PV calculated using SAM [1]	CSV with geographic coordinates/ 10 km	Include all areas
Renewable resource	Geothermal candidate locations	Black&Veatch	https://energyarchive.ca.gov/reti/documents/index.html	Point locations of candidate geothermal locations with estimated MW capacity for WesternU.S.as part of the Western Renewable Energy Zones study [21], and was also included in the Renewable Energy Transmission Initiative (RETI) 1.0 study [20]. The data download link is called,"GIS Data for Phase 2B".	Geodatabase point feature classes	Include all areas, buffered points using a radius calculated using a land use efficiency of 25.5 MW km^{-2}
Technical constraint	Slope	CGIAR	http://www.cgiar-csi.org/data/srtm-90m-digital-elevation-database-v4-1	Calculated slope in percentage from STRM digital elevation model - Resampled 250 m SRTM 90m Digital Elevation Database v4.1	Raster/ 250m	Solar: exclude >5%, Wind: exclude >25%
Physical constraint	Water bodies and rivers	West-wide wind mapping project (WWWMP)	http://wwmp.anl.gov/maps-data/	Permanent water bodies in the U.S. (lakes and rivers)	Shapefile	Wind and solar: include areas >250m outside of water bodies
Socio-economic constraint	Census urban zones	2017 TIGER/ Line®	https://www.census.gov/geo/maps-data/data/tiger-line.html	Urban areas as defined by the U.S. Census	Shapefile	Solar: include areas >500m, Wind: include areas >1000m
Socio-economic constraint	Population density	ORNL Landscan	https://landscan.ornl.gov/	Persons per km^2	Raster/ 1km	Wind and solar: include areas <100 persons/km^2
Socio-economic constraint	Military areas	West-wide wind mapping project (WWWMP)	http://wwmp.anl.gov/maps-data/	Includes the following areas: DOD High Risk of Adverse Impact Zones, DOD Restricted Airspace and Military Training Routes, Utah Test and Training Range	Shapefile	Solar: include areas >1000m, Wind: include areas >5000m

[1] Solar PV capacity factor calculation assumptions for SAM: Ground Mount Fixed-tilt Racking Configuration, DC/AC Ratio = 1.35, Average Annual Soiling Losses = 3%, Module Mismatch Losses = 2%, Diode and Connection Losses = 0.5%, DC Wiring Losses = 2%, AC Wiring Losses = 1%, Availability Losses = 1%, Degradation = 0.35% in first year and 0.7%/year thereafter

Socio-economic constraint	Military areas	Protected Areas Database–U.S.	https://gapanalysis.usgs.gov/padus/	Filtered PAD-US feature class using: Des_Tp = 'MIL'	Geo-database feature class	Solar: include areas >1000m, Wind: include areas >5000m
Hazardous constraint	Active mines	USGS Active mines and mineral plans in the U.S.	https://mrdata.usgs.gov/mineplant/	Mine plants and operations for commodities monitored by the National Minerals Information Center of the USGS. Operations included are those considered active in 2003 and surveyed by the USGS.	CSV of geographic coordinates	Wind and solar: include areas >1000m
Hazardous constraint	Airports and runways	National Transportation Atlas Database (NTAD) from the U.S. Department of Transportation (USDOT) and Bureau of Transportation Statistics	http://osav-usdot.opendata.arcgis.com/datasets?keyword=Aviation	The airports dataset including other aviation facilities is as of July 6, 2017, and is part of the U.S. Department of Transportation (USDOT)/Bureau of Transportation Statistics' (BTS') National Transportation Atlas Database (NTAD).	Shapefile	Solar: include areas >1000m, Wind: include areas >5000m
Hazardous constraint	Railways	National Transportation Atlas Database (NTAD) from the U.S.DOT and Bureau of Transporation Statistics	http://osav-usdot.opendata.arcgis.com/	The Rail Network is a comprehensive database of North America's railway system at 1:24,000 to 1:100,000 scale as of October 10, 2017.	Shapefile	Wind and Solar: include areas >250m
Hazardous constraint	Flood zones	National Flood Hazard (FEMA) in WECC Environmental Data Viewer Geodatabase	https://ecosystems.azurewebsites.net/WECC/Environmental/	SQL filtered feature class using: "ALLTYPES1" LIKE "Flood Zone" OR "ALLTYPES2" LIKE "Flood Zone" OR "ALLTYPES3" LIKE "Flood Zone" OR "ALLTYPES4" LIKE"Flood Zone"	Geo-database feature class	Wind and Solar: include areas >0m

Table 7: Existing and planned energy infrastructure datasets

Broad category	Dataset name	Source	Website	Description	Data type/ resolution	Usage in study
Existing power plant locations	United States Wind Turbine Database (USWTDB)	USGS, Berkeley Lab, AWEA	https://eerscmap.usgs.gov/uswtdb/data/	Point locations of on-shore and off-shore turbines in the U.S. It is updated quarterly. Accessed on 9/13/18	Shapefile or Geojson	Exclude from potential project areas
Existing power plant locations	Ventyx/ABB EV Energy Map - Existing wind farm boundaries	Ventyx/ABB	https://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite	The Wind Farm Boundaries EV Energy Map layer depicts the land area for turbines for a particular wind plant site. This layer was developed from various sources such as maps filed with permit applications, FAA obstacle data or aerial imagery and includes both operational and proposed wind plants.	Shapefile	Exclude from potential project areas
Existing power plant locations	Surface area of solar arrays in the conterminous United States as of 2015	USGS [33]	https://www.sciencebase.gov/catalog/item/57a25271e4b006cb45553efa	Footprint area of solar arrays in the conterminous U.S. based on EIA utility-scale facilities data from 2015	Shapefile	Exclude from potential project areas

Existing power plant locations	Surface area of utility-scale solar arrays in California as of 2018	The Nature Conservancy [32]	Unpublished	Footprint area of solar arrays in California created using satellite imagery	Shapefile	Exclude from potential project areas
Existing power plant locations	California's commercial wind and solar project locations	DataBasin, Black & Veatch, Public Utilities Commission	https://databasin.org/maps/365216c4ead144718ed6b29d035a2646	Existing and commercial wind and solar project locations (those with power purchase agreements from RPS Calculator and the California Public Utilities Commission)	Shapefile (point locations)	Used in conjunction with footprint areas to exclude from potential project areas
Existing power plant locations	Renewable Portfolio Standard Executed Projects (California)	Public Utilities Commission	http://cpuc.ca.gov/RPS_Reports_Data/	Public information of investor owned utility renewable contracts under the RPS program include: contract summaries, contract counterparties, resource type, location, delivery point, expected deliveries, capacity, length of contract, and online date.	Spreadsheet with geographic coordinates of project locations	Used in conjunction with footprint areas to exclude from potential project areas
Transmission infrastructure	California electric transmission line	California Energy Commission	http://caenergy.maps.arcgis.com/home/item.html?id=260b4513acdb4a3a8e4d64e69fc84fee	Transmission line locations as polylines with attribute data on voltages. This data are usually updated quarterly. Accessed on 1/18/2018	Geodatabase feature class	Selecting potential project areas and modeling transmission corridor needs. Used lines > 69 kV
Transmission infrastructure	EV Energy Map - Transmission lines	Ventyx/ABB	https://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite	Electric transmission lines EV energy map layer consists of market significant transmission lines generally greater than 115 kV.	Geodatabase feature class	Selecting potential project areas and modeling transmission corridor needs. Used lines > 69 kV
Transmission infrastructure	BLM recently approved Transmission lines	Environmental Planning Group LLC, Bureau of Land Management, Argonne National Labs	View lines: https://bogi.evs.anl.gov/section368/portal/	We included the following planned transmission corridors in "advanced development" and "recently approved": Gateway South, Gateway West, Southline, SunZia, TransWest Express, SWIP North, and Boardman to Hemingway. Spatial data can be requested from Argonne National Labs. These lines are listed as being in Phase 2 or 3 of the WECC Path Rating Process in the California Energy Commission's RETI 2.0 report "RETI 2.0 Western States Outreach Project Report" (https://www.energy.ca.gov/reti/reti2/documents/)	Geodatabase feature class	Selecting potential project areas and modeling transmission corridor needs. Buffered lines using project reports' planned corridor width

Table 8: Planned interstate bulk transmission data and corridor width assumptions

Transmission line name	Average corridor width source	Spatial data format	Average corridor width
TransWest Express	https://eplanning.blm.gov/epl-front-office/projects/nepa/65198/92789/111798/AppB_TWE_POD.pdf	Polyline	250 ft
Boardman to Hemingway	https://boardmantohemingway.com/documents/11-26-18/USFS_ROD_Nov_2018.pdf	Polyline	250 ft

SunZia	https://openei.org/w/images/b/b7/SunZia_Southwest_Transmission_Project_FEIS_and_Proposed_RMP_Amendments.pdf	Polyline	400 ft
Southline	NA	Polygon	NA
Gateway South	https://eplanning.blm.gov/epl-front-office/projects/nepa/53044/92847/111847/EGS-RecordofDecision.pdf	Polyline	250 ft
Gateway West	https://eplanning.blm.gov/epl-front-office/projects/nepa/39829/95570/115576/GWW_Segments_8_and_9_FINAL_ROD_without_appendices.pdf	Polyline	250 ft

Table 9: Datasets for environmental impact metrics

Metric	Dataset name	Source	Environmental Exclusion Category	Unique ID	Data type/ resolution
Critical habitat	Critical habitat		2	0051	Shapefile
Critical habitat	Desert tortoise critical habitat	WWWMP (high level)	2	0075	Shapefile
Critical habitat	Coastal critical habitat		2	0101	Shapefile
Critical habitat	Critical habitat	WWWMP (high level)	2	0262	Shapefile
Sage Grouse habitat	Priority habitat management area - exclusion	WWWMP - BLM	2	0257	Shapefile
Sage Grouse habitat	Priority habitat management area, high level siting considerations	WWWMP - BLM	2	0258	Shapefile
Sage Grouse habitat	General habitat management area, high level siting considerations	WWWMP - BLM	3	0259	Shapefile
Sage Grouse habitat	General habitat management area, moderate level siting considerations	WWWMP - BLM	3	0260	Shapefile
Sage Grouse habitat	Greater sage grouse priority areas for conservation	FWS	2	0266	Shapefile
Important Bird Areas	Important Bird Areas - state and globally important (Apr 2018)	Audubon Society	3	0110	Shapefile
Wetlands	National Wetlands Inventory	USFWS	2	0052	Shapefile
Wetlands	Priority Wetlands Inventory - Nevada	Nevada Natural Heritage Program	2	0054	Shapefile
Wetlands	Globally important wetlands	Site Wind Right (TNC)	2	0249	Shapefile
Wetlands	Playa wetland clusters	Site Wind Right (TNC)	3	0137	Shapefile
Wetlands	Vernal pools	USFWS	2	0077	Shapefile
Wetlands	Vernal pools - Great Valley, CA (Witham et al. 2014 update)	USFWS	2	0078	Shapefile
Wetlands	Vernal pools - San Diego	USGS	2	0079	Shapefile
Wetlands	Vernal pools - South Coast Range	California Department of Fish and Wildlife	2	0080	Shapefile
Wetlands	Vernal pools - Modoc National Forest	U.S.Forest Service	2	0081	Shapefile
Wetlands	California state wetlands	California Department of Fish and Game	2	0046	Shapefile
Big game corridors	Wyoming Big Game Crucial Habitat (Elk, Mule Deer, Bighorn Sheep, Pronghorn, White-tailed Deer)	Wyoming Game and Fish	2	0100	Shapefile
Big game corridors	WECC Big Game (ALLTYPES3 LIKE '%Big Game Winter Range%')	WECC	3	0105	Shapefile
Big game corridors	Washington Deer areas	Washington Department of Fish and Wildlife	3	0123	Shapefile
Big game corridors	Washington Elk areas	Washington Department of Fish and Wildlife	3	0124	Shapefile
Big game corridors	Oregon Elk and Deer Winter Range	Oregon Department of Fish and Wildlife	3	0149	Shapefile
Big game corridors	Columbian White-tailed deer range	USFWS	3	0155	Shapefile
Wildlife linkages	Wildlife linkages with corridor values > 34.3428	The Wilderness Society [40]	4	0172	Shapefile

Eagle habitat	Bald Eagle habitat	WWWMP - BLM	2 (wind only)	0076	Shapefile
Eagle habitat	West-wide eagle risk data using the 2 of quantile bins (top 30% of eagle habitat)	USFWS (Bedrosian et al. 2018)	2 (wind only)	0102	Shapefile
Eagle habitat	Golden Eagle habitat	WWWMP	2 (wind only)	0228	Shapefile
Prime farmland	Prime farmland based on high quality soils	Natural Resources Conservation Service	3	0267	Shapefile
Agricultural land	Crop and pasturelands (used class #556-Cultivated Cropland and #557-Pasture/Hay)	National GAP Landcover https://gapanalysis.usgs.gov/gaplandcover/data/download/	NA	NA	raster/ 30m
Rangelands	U.S.rangelands extent using NRI-LANDFIRE model	[41]	NA	NA	raster/ 30m
Housing density	Housing density (2010)	USFS http://silvis.forest.wisc.edu/data/housing-block-change/	NA	NA	geo-database

Table 10: Datasets for Environmental Exclusion Category 1 (site suitability). Definitions: Exclude development (EX), Avoid development (AV), WECC Environmental Risk Class (RC 1, 2, 3, 4), BLM High Level Siting Considerations (HLSC), BLM Moderate Level Siting Considerations (MLSC), Information not available (NA)

Unique Data ID	Environmental Category	Technology	Data Publisher Organization	Dataset Name	ORB 2015	BLM WSEP	BLM WWW-MP	BLM DRECP	WECC	WREZ	RETI CPUC
1	1	All	National Park Service	NPS boundaries - National Historic Trails	EX	EX	EX	EX	RC 2	EX	EX
2	1	All	BLM - WWWMP	National Scenic Trails	NA	EX	EX	EX	NA	EX	NA
3	1	All	BLM - WWWMP	National Historic Landmarks	NA	NA	EX	NA	NA	NA	NA
4	1	All	BLM - WWWMP	National Natural Landmarks	NA	NA	EX	NA	NA	NA	NA
5	1	All	United States Geological Survey	Wild and Scenic Rivers	NA	EX	EX	NA	RC 3	EX	EX
6	1	All	Natural Resources Conservation Service	Easements	EX	NA	NA	NA	RC 3	EX	EX
8	1	All	National Conservation Easement Database	Conservation Easements	NA	NA	NA	NA	NA	NA	NA
9	1	All	Bureau of Land Management	BLM Solar Energy Program SEZ non-dev	NA	EX	NA	NA	NA	NA	NA
10	1	All	BLM - WWWMP	Visual Resource Management	NA	EX	EX	NA	NA	AV	NA
11	1	All	Bureau of Land Management	BLM Solar Energy Program exclusions	NA	NA	NA	NA	NA	NA	NA
12	1	All	USGS PAD-US	National Primitive Area	EX	NA	NA	NA	RC 4	EX	NA
13	1	All	USGS PAD-US	National Wildlife Refuge	EX	NA	NA	NA	RC 4	EX	EX
14	1	All	USGS PAD-US	Units of the National Parks System (excluding National Recreation Areas and National Trails)	EX	EX	NA	NA	RC 4	EX	EX
15	1	All	USGS PAD-US	Wilderness Area	EX	EX	EX	NA	RC 4	EX	EX
16	1	All	USGS PAD-US	Wilderness Area (Recommended)	NA	NA	NA	NA	RC 4	EX	NA
17	1	All	USGS PAD-US	Wilderness Study Area	EX	EX	EX	NA	RC 4	EX	EX
20	1	All	BLM - WWWMP	National Conservation Area	EX	EX	EX	NA	RC 3	EX	EX
21	1	All	USGS PAD-US	National Monument	EX	EX	EX	NA	RC 3	EX	EX
22	1	All	USGS PAD-US	National Recreation Area	EX	NA	NA	NA	RC 3	EX	EX
23	1	All	USGS PAD-US	Research Natural Area – Proposed	EX	NA	NA	NA	RC 3	NA	NA
24	1	All	BLM - WWWMP	Desert Renewable Energy Conservation Plan Special Recreation Management Area	EX	EX	EX in CA; MLSC elsewhere.	EX	NA	AV	EX in DRECP area
25	1	All	USGS PAD-US	State Park	EX	NA	NA	NA	RC 3	EX	EX
26	1	All	USGS PAD-US	State Wildlife Management Areas	EX	NA	NA	NA	RC 3	AV	NA
28	1	All	BLM - WWWMP	National Register Historic Places		NA	EX	NA	NA	NA	NA
29	1	All	USGS PAD-US	State Wilderness Areas	EX	NA	NA	NA	NA	EX	EX

30	1	All	USGS PAD-US	DFW Wildlife Areas and Ecological Reserves	EX	NA	NA	NA	NA	NA	NA
31	1	All	USGS PAD-US	Existing Conservation and Mitigation Bank	EX	NA	NA	NA	NA	EX	EX
32	1	All	USGS PAD-US	Watershed Protection Area	EX	NA	NA	NA	NA	EX	NA
33	1	All	USGS PAD-US	Marine Protected Area	EX	NA	NA	NA	NA	EX	NA
34	1	All	USGS PAD-US	Historic or Cultural Area	EX	EX	NA	NA	NA	AV	EX
35	1	All	California State Agencies	Habitat Conservation Plan	AV	NA	NA	NA	Non-preferred dataset	AV	EX
36	1	All	California State Agencies	Natural Community Conservation Plan	AV	NA	NA	NA	Non-preferred dataset	AV	EX
38	1	All	BLM - WWWMP	DRECP NCL	NA	NA	NA	EX	NA	NA	NA
39	1	All	BLM - WWWMP	Park boundaries	NA	NA	NA	NA	NA	NA	NA
43	1	All	BLM - WWWMP	vrmII	NA	NA	NA	NA	NA	NA	NA
190	1,2	Cat1(s); Cat2 (w,g)	USGS PAD-US	Right of Way exclusion	NA	NA	NA	NA	RC 3	NA	NA
240	1,2	All	Colorado Natural Heritage Program	Colorado protected lands	NA	NA	NA	NA	NA	NA	NA
252	1	All	BLM - WWWMP	conservation	NA	NA	EX	NA	NA	NA	NA
256	1	All	BLM - WWWMP	Right of Way exclusion	NA	NA	EX	NA	NA	NA	NA

Table 11: Datasets for Environmental Exclusion Category 2 (site suitability). Definitions: Exclude development (EX), Avoid development (AV), WECC Environmental Risk Class (RC 1, 2, 3, 4), BLM High Level Siting Considerations (HLSC), BLM Moderate Level Siting Considerations (MLSC), Information not available (NA)

Unique Data ID	Environmental Category	Technology	Data Publisher Organization	Data Set Name (subset of area type)	ORB 2015	BLM WSEP	BLM WWW-MP	BLM DRECP	WECC	WREZ	RETI CPUC
18	2	All	BLM - WWWMP	Areas of Critical Environmental Concern	EX	EX	EX	EX	RC 3	EX	EX
27	2	All	New Mexico County governments	New Mexico County wind ordinances	NA	NA	NA	NA	NA	NA	NA
42	2	All	U.S.Census Bureau	Tribal Lands	NA	NA	NA	NA	RC 2	NA	NA
43	2	All	BLM - WWWMP	Visual Resource Management II	NA	NA	HLSC	NA	NA	NA	NA
44	2	All	USGS PAD-US	State Forest	EX	NA	NA	NA	RC 3	EX	EX
45	2	All	BLM - WWWMP	National Park Service Areas of High Potential Resource Conflict	NA	NA	MLSC	NA	NA	NA	AV
46	2	All	California Department of Fish and Game	Central Valley Wetland and Riparian Areas	EX	NA	NA	NA	RC 3	EX	EX
47	2	All	BLM - WWWMP	No Surface Occupancy	EX	EX	HLSC	NA	NA	NA	NA

51	2	All	United States Fish and Wildlife Service	Critical Habitat for Threatened and Endangered Species Composite Layer	AV	EX	HLSC	NA	RC 3	NA	AV
52	2	All	United States Fish and Wildlife Service	Wetlands - prc	EX	NA	NA	NA	RC 2	EX	NA
53	2	All	United States Forest Service	National Inventoried Roadless Areas	EX	NA	NA	NA	RC 3	EX	EX
54	2	All	Nevada Natural Heritage Program	Priority Wetlands Inventory	NA	NA	NA	NA	RC 2	NA	NA
55	2	All	Wyoming Game and Fish	crucial winter areas	NA	NA	NA	NA	RC 3	NA	NA
56	2	All	Wyoming Game and Fish	crucial winter areas	NA	NA	NA	NA	RC 3	NA	NA
57	2	All	USGS PAD-US	Special Interest Area	AV	NA	NA	NA	RC 3	AV	NA
58	2	All	BLM - WWWMP	Desert Renewable Energy Conservation Plan Extensive Recreation Management Area	NA	NA	HLSC	AV	NA	NA	NA
59	2	All	BLM - WWWMP	Desert Renewable Energy Conservation Plan Wildlife Allocation	NA	NA	EX	AV	NA	NA	EX in DRECP
60	2	All	BLM - WWWMP	Desert Renewable Energy Conservation Plan Off Highway Vehicles	NA	NA	EX	EX	NA	AV	NA
61	2	All	BLM - WWWMP	Off Highway Vehicle	NA	NA	MLSC	NA	NA	AV	NA
62	2	Wind	BLM - WWWMP	Development Focus Area - solar and geothermal only (excluding wind)	NA	NA	EX	Prioritize (varies by technology)	NA	NA	NA, except in SJV/DRECP screen
63	2	All	USGS PAD-US	U.S. Army Corps of Engineers Land	NA	NA	NA	NA	RC 2	NA	NA
64	2	All	USGS PAD-US	Native Allotments	NA	NA	NA	NA	RC 2	NA	NA
65	2	All	USGS PAD-US	Other private non-profit land	EX	NA	NA	NA	RC 2	NA	NA
66	2	All	TNC WAFO	TNC__Lands__Features	EX	NA	NA	NA	NA	NA	EX
67	2	All	WA DNR	Spotted Owl Management Units	NA	NA	NA	NA	NA	EX	EX
68	2	All	WA DNR	Habitat Conservation Plan Lands	NA	NA	NA	NA	NA	EX	EX
71	2	All	USGS PAD-US	State Reserves	AV	NA	NA	NA	NA	NA	NA
72	2	All	USGS PAD-US	Other wildlife areas and ecological reserves	AV	NA	NA	NA	NA	NA	NA
73	2	All	Los Angeles County	Significant ecological areas	AV	NA	NA	NA	NA	NA	AV
75	2	All	BLM - WWWMP	Desert Tortoise Critical Habitat	AV	NA	HLSC	NA	NA	NA	NA
76	2	Wind	BLM - WWWMP	Bald Eagle	NA	NA	MLSC	NA	NA	NA	NA
77	2	All	USFWS	Vernal pools	NA	NA	NA	NA	NA	NA	AV
78	2	All	USFWS	2012RemapVernalPoolsFINAL.zip	NA	NA	NA	NA	NA	NA	AV
79	2	All	CDFW	SANGIS__ECO__VERNAL__POOLS.shp	NA	NA	NA	NA	NA	NA	AV
80	2	All	CDFW	ds948.shp	NA	NA	NA	NA	NA	NA	AV
81	2	All	USDA Forest Service, Modoc National Forest.	Vernal pools, Modoc. ds949.zip	NA	NA	NA	NA	NA	NA	AV

82	2	All	BLM	BLM Lands with Wilderness Characteristics (DRECP)	NA	EX	EX	See CMAs	NA	AV	NA
83	2	All	BLM - WWWMP	BLM Lands with Wilderness Characteristics (WWWMP)	NA	EX	EX	See CMAs	NA	AV	NA
85	2	All	Bureau of Land Management DRECP	National Landscape Conservation Survey Preferred Subareas	NA	EX	EX	EX	NA	EX	NA
91	2	Wind	TNC ”Site Wind Right” study	Cooperative Whooping Crane Tracking Project database Pearse et al. (2015) National Wetlands Inventory	NA	NA	NA	NA	NA	NA	NA
92	2	Wind	University of Kansas, Kansas Biological Survey	SGPCHAT	NA	NA	NA	NA	NA	NA	NA
96	2	All	Colorado Parks and Wildlife	Preble S Jumping Mouse	NA	NA	NA	NA	NA	NA	NA
97	2	All	Colorado Parks and Wildlife	Mule deer	NA	NA	NA	NA	NA	NA	NA
100	2	Wind	Wyoming Game and Fish	Big Game Crucial Habitat	NA	NA	NA	NA	RC 3	NA	NA
101	2	All	NOAA/USFWS	Critical Habitat Designations (map service layer)	AV	NA	NA	NA	NA	NA	NA
102	2	Wind	FWS	West-Wide Eagle Risk Data	NA	NA	NA	NA	NA	NA	NA
185	2	All	USGS PAD-US	Research Natural Area	EX/AV	NA	NA	NA	RC 3	AV	EX
194	2	All	USGS PAD-US	Native American Lands	NA	NA	NA	NA	RC 2	NA	NA
225	2	All	WSDOT	WSDOT - Tribal Reservation and Trust Lands	NA	NA	NA	NA	RC 2	NA	NA
228	2	Wind	BLM - WWWMP	Golden Eagle suitable habitat	NA	NA	MLSC	NA	NA	NA	NA
234	2	Wind	Colorado Parks and Wildlife	Bald Eagle nest sites, roosting sites, concentration areas	NA	NA	NA	NA	NA	NA	NA
239	2	Wind	Colorado Parks and Wildlife	Colorado Least Tern nesting and foraging sites	NA	NA	NA	NA	NA	NA	NA
240	1,2	All	Colorado Natural Heritage Program	Colorado protected lands	NA	NA	NA	NA	NA	NA	NA
248	2	All	Contact TNC MT chapter for more information.	Montana Wetland Areas	NA	NA	NA	NA	NA	NA	NA
249	2	All	WHSRN	Globally important wetlands	NA	NA	NA	NA	NA	NA	NA
257	2	Wind	BLM - WWWMP	Sage Grouse Priority Habitat Management Area exclusion	NA	NA	EX	NA	NA	NA	NA
258	2	Wind	BLM - WWWMP	Sage Grouse Priority Habitat Management Area, High Level Siting Requirements	NA	NA	HLSC	NA	NA	NA	NA
262	2	All	BLM - WWWMP	critical habitat	NA	NA	HLSC	NA	NA	NA	NA
263	2	All	BLM - WWWMP	Special Recreation Management Area	NA	NA	HLSC	EX	NA	NA	NA
266	2	Wind	TNC	GreaterSageGrousePACs.gdb	NA	NA	NA	NA	NA	NA	NA
271	2	Wind and solar only, geothermal is an exception	County government	Imperial County: areas outside Renewable Energy Overlay	NA	NA	NA	NA	NA	NA	NA

272	2	All	County government	Inyo County: areas outside Solar Energy Development Areas (SEDAs)	NA	NA	NA	NA	NA	NA	NA

Table 12: Datasets for Environmental Exclusion Category 3 (site suitability). Definitions: Exclude development (EX), Avoid development (AV), WECC Environmental Risk Class (RC 1, 2, 3, 4), BLM High Level Siting Considerations (HLSC), BLM Moderate Level Siting Considerations (MLSC), Information not available (NA)

Unique Data ID	Environmental Category	Technology	Data Publisher Organization	Dataset Name	ORB 2015	BLM WSEP	BLM WWW-MP	BLM DRECP	WECC	WREZ	RETI CPUC
49	3	All	Montana Dept of Fish Wildlife and Parks: Crucial Areas Planning System (CAPS)	Bighorn Sheep & Mountain Goat Habitat	AV	NA	NA	NA	RC 3	NA	NA
103	3	All	BLM - WWWMP	Visual Resource Management lands level III	NA	NA	MLSC	NA	NA	NA	NA
104	3	All	Colorado Division of Wildlife	Species Activitiy Data: Severe Winter Range, Winter Concentration, Winter Range, Migration Patters, and Migration Corridor	NA	NA	NA	NA	RC 3	NA	NA
105	3	All	Montana Dept of Fish Wildlife and Parks: Crucial Areas Planning System (CAPS)	Big Game Winter Range Habitat	NA	NA	NA	NA	RC 3	NA	NA
111	3	All	Federal Highway Administration	America's Byways	NA	NA	NA	NA	RC 2	NA	NA
112	3	All	Caltrans	California Scenic Highways	NA	NA	NA	NA	RC 2	NA	NA
113	3	All	Idaho Department o Transportation	Scenic Byways of Idaho	NA	NA	NA	NA	RC 2	NA	NA
114	3	All	Colorado Department of Transportation	Colorado Scenic and Historic Byways	NA	NA	NA	NA	RC 2	NA	NA
115	3	All	Washington State Department of Transportation	Washington Scenic Highways	NA	NA	NA	NA	RC 2	NA	NA
118	3	All	Wyoming Game and Fish	Shapefile: WYPrairieDogComplexes_WGFDWAFWA.	NA	NA	NA	NA	NA	NA	NA
121	3	Wind	Wyoming Natural Heritage Program	WYGrasslandBirds	NA	NA	NA	NA	NA	NA	NA
123	3	All	WDFW	Deer Areas (Polygons)	NA	NA	NA	NA	NA	NA	NA
124	3	All	WDFW	Elk Areas (Polygons)	NA	NA	NA	NA	NA	NA	NA
125	3	All	U.S. Fish and Wildlife Service	USFWS Upland Species Recovery Units	AV	NA	NA	NA	NA	NA	NA
126	3	All	California Department of Conservation	Williamson act –Farmland Mapping and Monitoring Program (FMMP) in CA	Cat3	NA	NA	NA	EX	EX	EX
127	3	All	The Nature Conservancy	Mojave Ecorgeional Assessment	Cat3	NA	NA	NA	NA	NA	NA
129	3	All	Herpetological Conservation and Biology	Mojave Desert Tortoise Linkages	Cat3	NA	MLSC	NA	NA	NA	NA
133	3	All	BLM - WWWMP	Desert Tortoise Connectivity	NA	NA	MLSC	NA	NA	NA	NA

136	3	All	TNC	High integrity grasslands	NA	NA	NA	NA	NA	NA	NA
137	3	Wind	Playa Lakes Joint Venture	Playa clusters	NA	NA	NA	NA	NA	NA	NA
138	3	Wind	Colorado Parks and Wildlife	Greater prairie-chicken optimal habitat	NA	NA	NA	NA	NA	NA	NA
139	3	All	Colorado Natural Heritage Program	Potential Conservation Areas	NA	NA	NA	NA	NA	NA	NA
140	3	Wind	Colorado Parks and Wildlife	Columbian sharptail grouse production areas and winter range	NA	NA	NA	NA	NA	NA	NA
141	3	Wind	Colorado Parks and Wildlife	Plains sharptail grouse concentration areas, winter concentration areas, migratino corridors, severe winter range	NA	NA	NA	NA	NA	NA	NA
142	3	All	Colorado Parks and Wildlife	Pronghorn	NA	NA	NA	NA	NA	NA	NA
143	3	Wind	Colorado Parks and Wildlife	Least tern production areas and foraging areas	NA	NA	NA	NA	NA	NA	NA
144	3	Wind	Colorado Parks and Wildlife	Piipng plover production areas and foraging areas	NA	NA	NA	NA	NA	NA	NA
145	3	Wind	Colorado Parks and Wildlife	CPW Nest area and potential nesting area	NA	NA	NA	NA	NA	NA	NA
146	3	Wind	Wyoming Natural Heritage Program	Tree roosting bats (Silver-haired bat, Hoary, Eastern Red)	NA	NA	NA	NA	NA	NA	NA
148	3	All	New Mexico Department of Game and Fish	Big Game Priority Habitat	NA	NA	NA	NA	RC 3	NA	NA
149	3	All	Oregon Department of Fish and Wildlife	Elk and Deer Winter Range	NA	NA	NA	NA	RC 3	NA	NA
150	3	All	New Mexico Department of Transportation	New Mexico State and National Scenic Byways	NA	NA	NA	NA	RC 2	NA	NA
151	3	All	Oregon Department of Transportation	Oregon Scenic Byways	NA	NA	NA	NA	RC 2	NA	NA
152	3	All	Wyoming Department of Transportation	Wyoming Scenic Highways and Byways	NA	NA	NA	NA	RC 2	NA	NA
155	3	All	USFWS	Columbian white-tailed deer	NA	NA	NA	NA	NA	NA	NA
156	3	All	BLM	BLM Nominated ACECs	NA	NA	NA	NA	NA	NA	NA
157	3	All	TNC	TNC Nominated ACECs. Areas with high conservation value as determined through TNC ecoregional analysis (if/when they become ACEC they would move up to Cat 2).	NA	NA	NA	NA	NA	NA	NA
158	3	All	TNC	Ecologically core areas. Contact TNC NV chapter for more information,	NA	NA	NA	NA	NA	NA	NA
159	3	All	TNC OR	The Nature Conservancy Portfolio Areas	Cat3	NA	NA	NA	NA	NA	NA
160	3	All	ODFW	Oregon Conservation Strategy	NA	NA	NA	NA	NA	NA	NA
161	3	All	TNC	TNC Nevada priority landscapes layer	NA	NA	NA	NA	NA	NA	NA
162	3	All	NDOW	Critical habitat rank 1 or 2	NA	NA	NA	NA	NA	NA	NA

164	3	All	Arizona Department of Roads	Arizona Scenic Roads	NA	NA	NA	NA	RC 2	NA	NA
170	3	All	CEC and USGS, Las Vegas Field Station	Mohave Ground Squirrel (candidate species) Maxent site suitability model at 0.438 cutoff	Cat4	NA	NA	NA	NA	NA	NA
187	3, 4	All	TNC	The Nature Conservancy Portfolio Areas	NA	NA	NA	NA	NA	NA	NA
241	3	All	Colorado natural Heritage Program	Potential Conservation Areas (CO)	NA	NA	NA	NA	NA	NA	NA
259	3	All	BLM - WWWMP	Sage Grouse General Habitat Management Area, High Level Siting Requirements	NA	NA	HLSC	NA	NA	NA	NA
260	3	All	BLM - WWWMP	Sage Grouse General Habitat Management Area, Moderate Level Siting Requirements	NA	NA	MLSC	NA	NA	NA	NA
261	3	All	BLM - WWWMP	Sagebrush Focal Area	NA	NA	EX	NA	NA	NA	NA
267	3	All	NRCS	Westwide Prime farmland classification	NA	NA	NA	NA	NA	NA	EX
268	3	All	TNC	Priority Conservation Areas	NA	NA	NA	NA	NA	NA	NA
269	3	All	NatureServe	Mojave Desert Tortoise Species Distribution Model - Threshold	NA	NA	NA	NA	NA	NA	NA

Table 13: Datasets for Environmental Exclusion Category 4 (site suitability). Definitions: Exclude development (EX), Avoid development (AV), WECC Environmental Risk Class (RC 1, 2, 3, 4), BLM High Level Siting Considerations (HLSC), BLM Moderate Level Siting Considerations (MLSC), Information not available (NA)

Unique Data ID	Environmental Category	Technology	Data Publisher Organization	Dataset Name	ORB 2015	BLM WSEP	BLM WWW-MP	BLM DRECP	WECC	WREZ	RETI CPUC
165	4	All	Conservation Science Partners Inc.	Landscape intactness	NA	NA	NA	NA	NA	NA	NA
166	4	All	TNC	The Nature Conservancy Ecologically Intact for CA deserts	Cat4	NA	NA	NA	NA	NA	NA
169	4	All	CDOT, CDFG, and FHA	Essential Connectivity areas of California	Cat4	NA	NA	NA	RC 3	NA	NA
172	4	All	The Wilderness Society	Least cost linkages	NA	NA	NA	NA	NA	NA	NA
173	4	All	AGFD	AZ multi-species corridors	NA	NA	NA	NA	NA	NA	NA

Table 14: Scenario List

Number	Name
1	In-State Base
2	In-State Base High DER
3	In-State Base Low Battery Cost
4	In-State Siting Level 1 Constrained Base
5	In-State Siting Level 1 Constrained High DER
6	In-State Siting Level 1 Constrained Low Battery Cost
7	In-State Siting Level 1 Unconstrained Base
8	In-State Siting Level 2 Constrained Base
9	In-State Siting Level 2 Constrained High DER
10	In-State Siting Level 2 Constrained Low Battery Cost
11	In-State Siting Level 2 Unconstrained Base
12	In-State Siting Level 3 Constrained Base
13	In-State Siting Level 3 Constrained High DER
14	In-State Siting Level 3 Constrained Low Battery Cost
15	In-State Siting Level 3 Unconstrained Base
16	In-State Siting Level 3 Unconstrained High DER
17	In-State Siting Level 3 Unconstrained Low Battery Cost
18	In-State Siting Level 4 Constrained Base
19	In-State Siting Level 4 Constrained High DER
20	In-State Siting Level 4 Constrained Low Battery Cost
21	In-State Siting Level 4 Unconstrained Base
22	Part West Base
23	Part West Base High DER
24	Part West Base Low Battery Cost
25	Part West Siting Level 1 Constrained Base
26	Part West Siting Level 1 Constrained High DER
27	Part West Siting Level 1 Constrained Low Battery Cost
28	Part West Siting Level 1 Unconstrained Base
29	Part West Siting Level 2 Constrained Base
30	Part West Siting Level 2 Constrained High DER
31	Part West Siting Level 2 Constrained Low Battery Cost
32	Part West Siting Level 2 Unconstrained Base
33	Part West Siting Level 3 Constrained Base
34	Part West Siting Level 3 Constrained High DER
35	Part West Siting Level 3 Constrained Low Battery Cost
36	Part West Siting Level 3 Unconstrained Base
37	Part West Siting Level 4 Constrained Base
38	Part West Siting Level 4 Constrained High DER
39	Part West Siting Level 4 Constrained Low Battery Cost
40	Part West Siting Level 4 Unconstrained Base
41	Full West Base
42	Full West Base High DER
43	Full West Base Low Battery Cost
44	Full West Siting Level 1 Constrained Base
45	Full West Siting Level 1 Constrained High DER
46	Full West Siting Level 1 Constrained Low Battery Cost
47	Full West Siting Level 1 Unconstrained Base
48	Full West Siting Level 2 Constrained Base
49	Full West Siting Level 2 Constrained High DER
50	Full West Siting Level 2 Constrained Low Battery Cost
51	Full West Siting Level 2 Unconstrained Base
52	Full West Siting Level 3 Constrained Base
53	Full West Siting Level 3 Constrained High DER
54	Full West Siting Level 3 Constrained Low Battery Cost
55	Full West Siting Level 3 Unconstrained Base

56	Full West Siting Level 3 Unconstrained High DER
57	Full West Siting Level 3 Unconstrained Low Battery Cost
58	Full West Siting Level 4 Constrained Base
59	Full West Siting Level 4 Constrained High DER
60	Full West Siting Level 4 Constrained Low Battery Cost
61	Full West Siting Level 4 Unconstrained Base

B Additional results

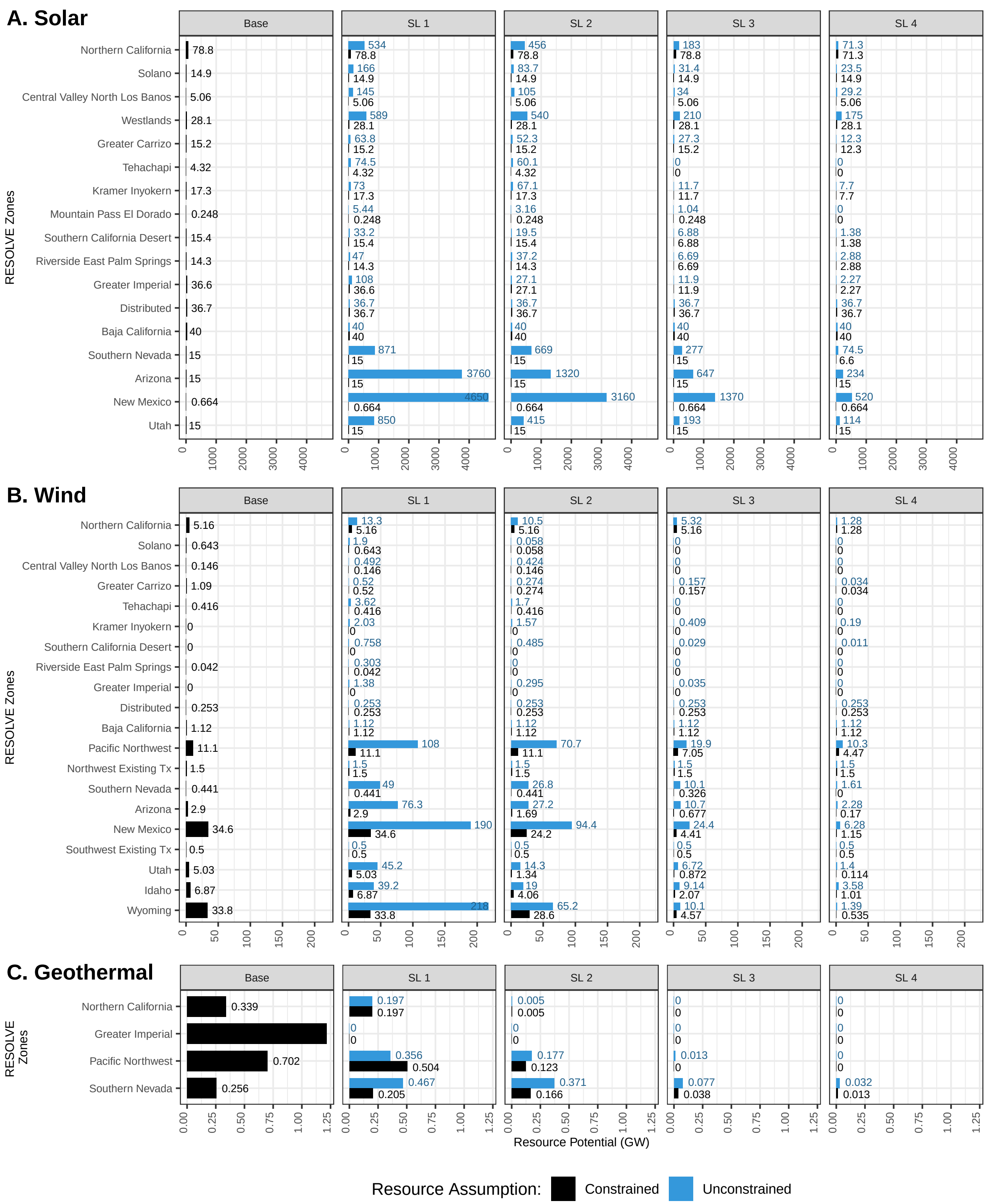

Figure 14: Supply curves (resource potential estimates from sites suitability analysis) for each Siting Level used as inputs to RESOLVE for solar (A), wind (B), and geothermal (C) technologies for the *Constrained* (bars and data values in black) and *Unconstrained* (bars and data values in blue) resource assumption case. No *Unconstrained* bars are in the Base panel plots because the RESOLVE Base case assumes *Constrained* resources.

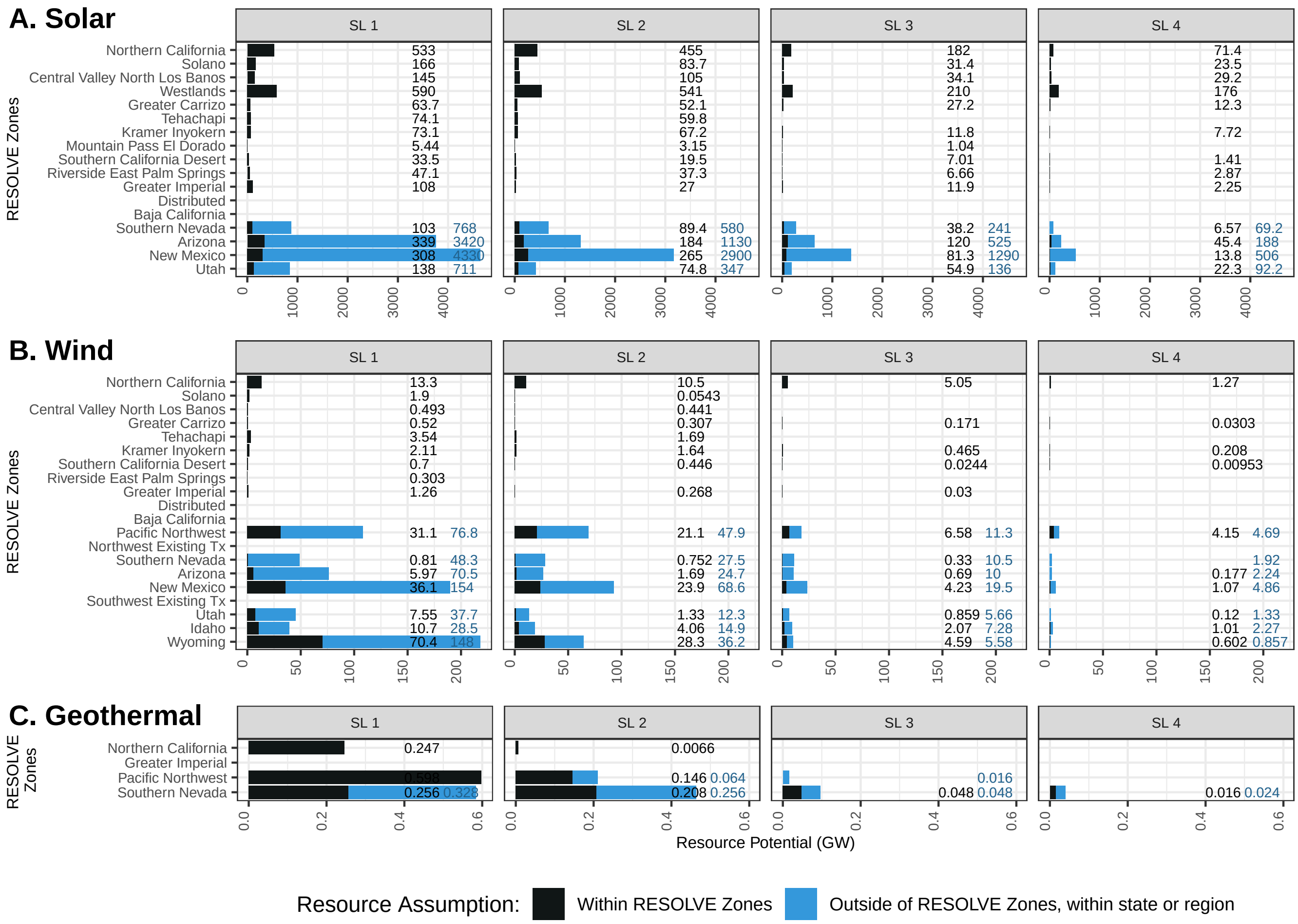

Figure 15: Unadjusted supply curves under each Siting Level for solar (A), wind (B), and geothermal (C) technologies with stacked bars showing the amount of potential within RESOLVE Zones (black bars) and outside of RESOLVE Zones within the region or state for non-California regions (grey bars). The "within RESOLVE zones" data label is the left-most label and the "Outside of RESOLVE Zone" data labels is the far right label within each panel. The "Outside of RESOLVE Zone" data labels indicate the amount of potential within the grey bars, not of the absolute length of the bars. The absolute length of the bars is the sum of the two data labels, and it indicates the amount of resource potential in the *Unconstrained* case.

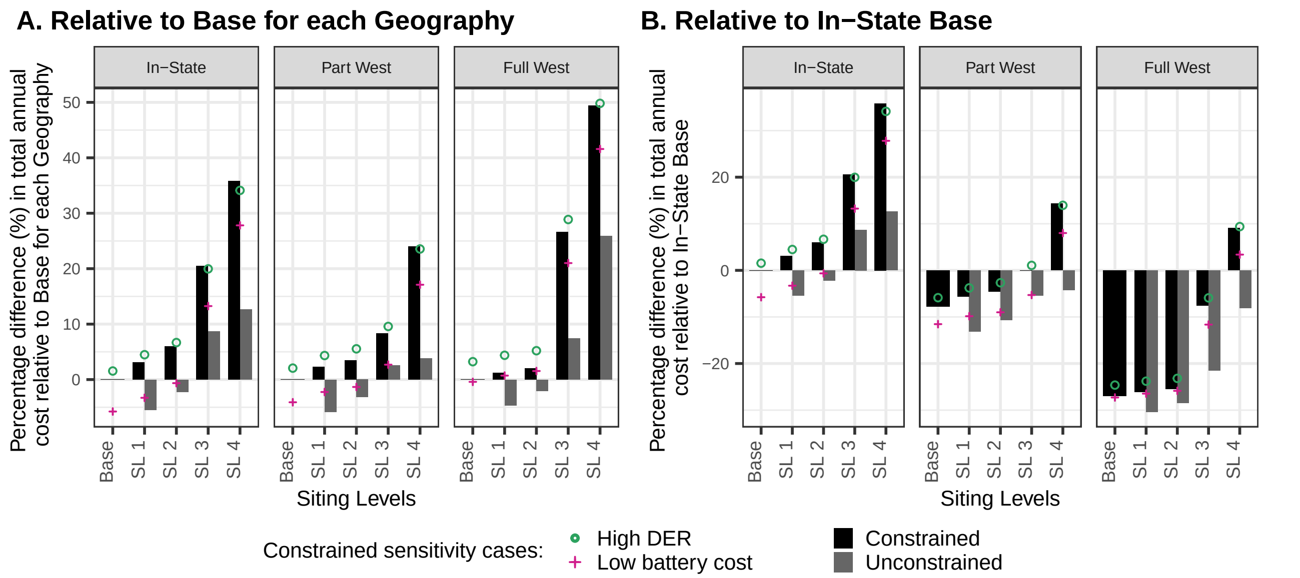

Figure 16: Percentage cost differences of only modeled resource costs relative to the RESOLVE Base for each Geographic case (A) and relative to *In-State* RESOLVE Base (B) for all Siting Levels and *Constrained* and *Unconstrained* assumptions case. See Fig. 7 for percentage cost differences using total (modeled and non-modeled) costs.

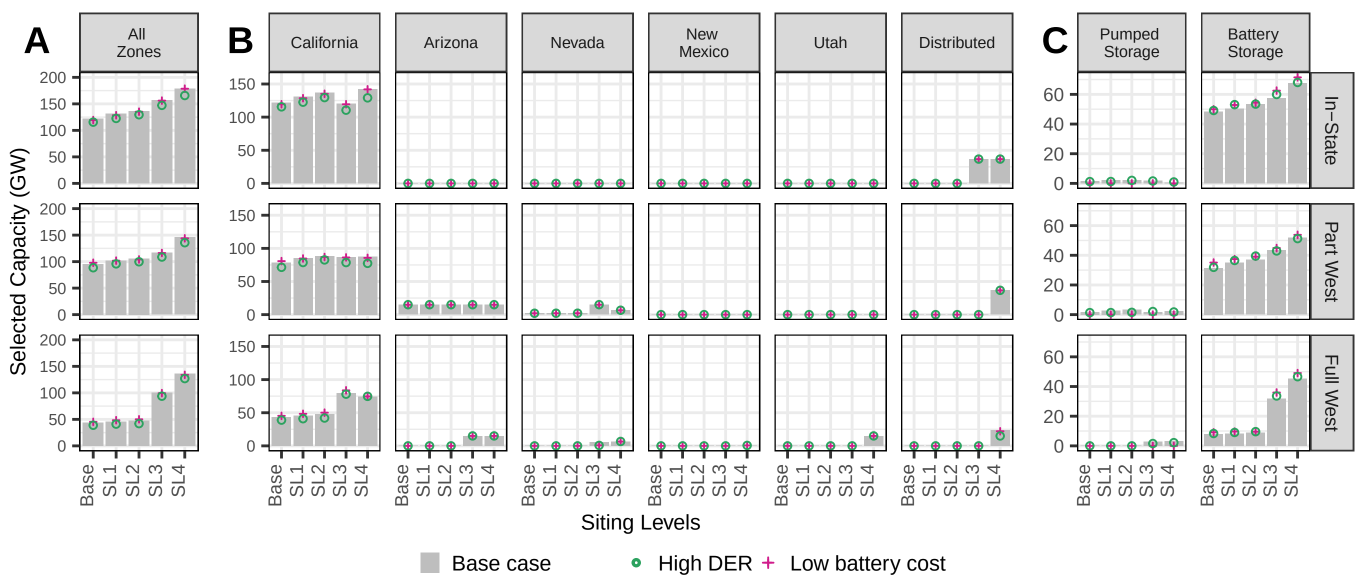

Figure 17: Selected solar capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases for the *Constrained* assumptions case.

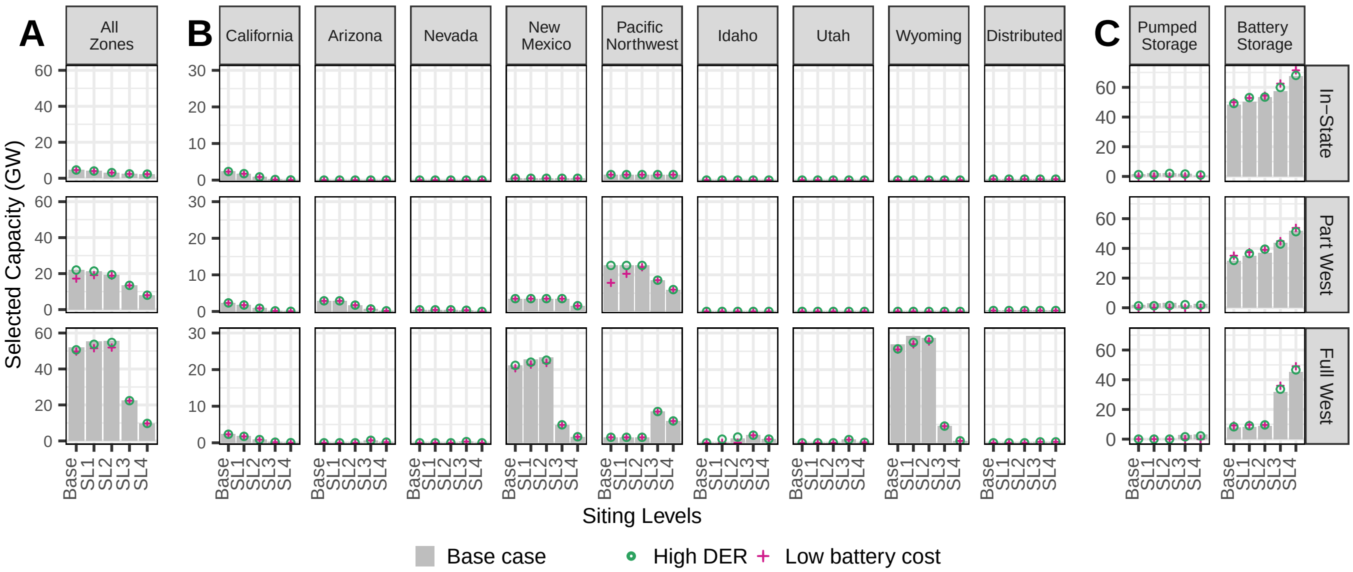

Figure 18: Selected wind capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases for the *Constrained* assumptions case.

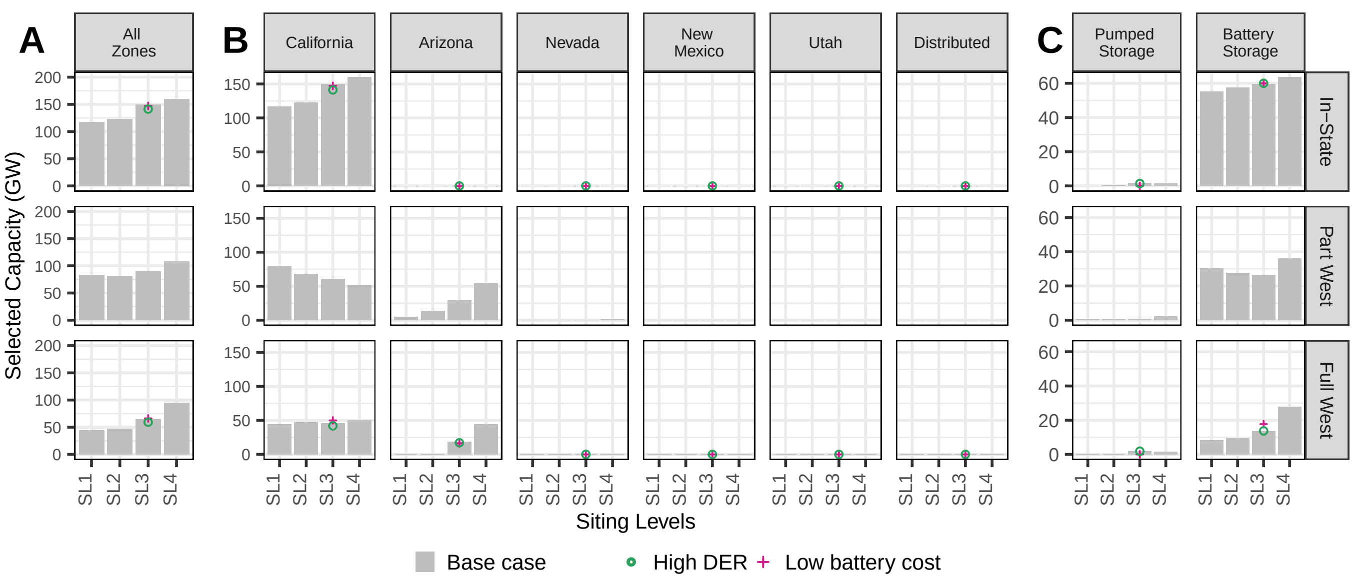

Figure 19: Selected solar capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases in the *Unconstrained* assumptions case. Note, since we did not expect sensitivities to affect results significantly, we only performed DER and Battery cost sensitivity analyses on Siting Level 3 for the *In-State* and *Full West* cases.

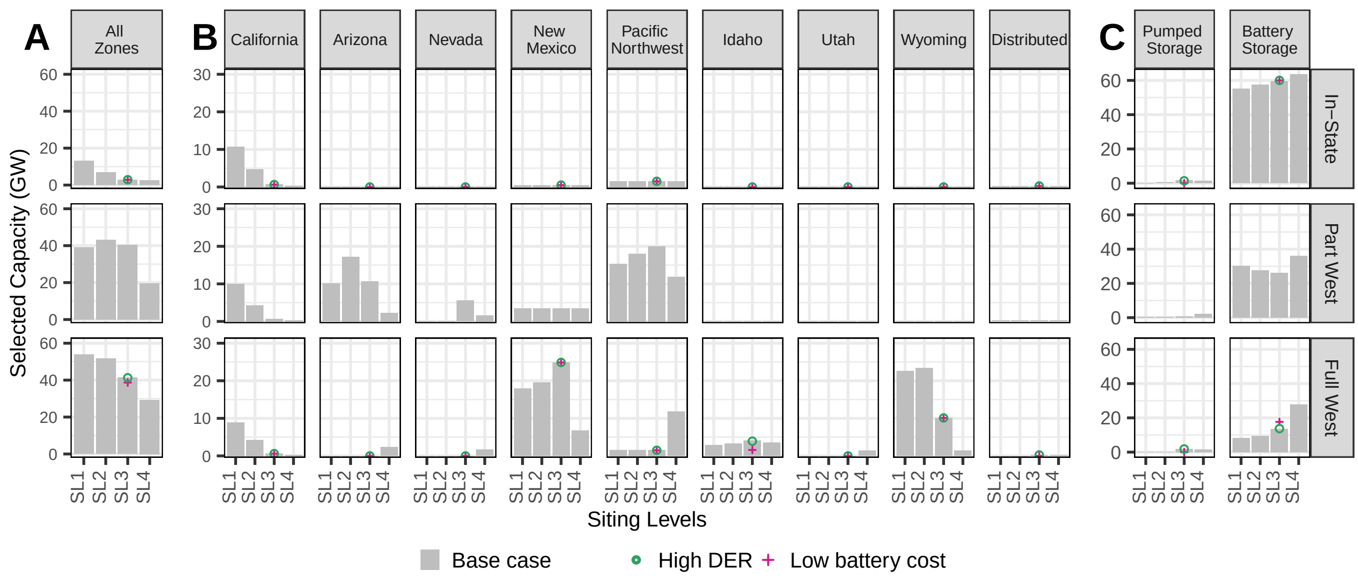

Figure 20: Selected wind capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases in the *Unconstrained* assumptions case.

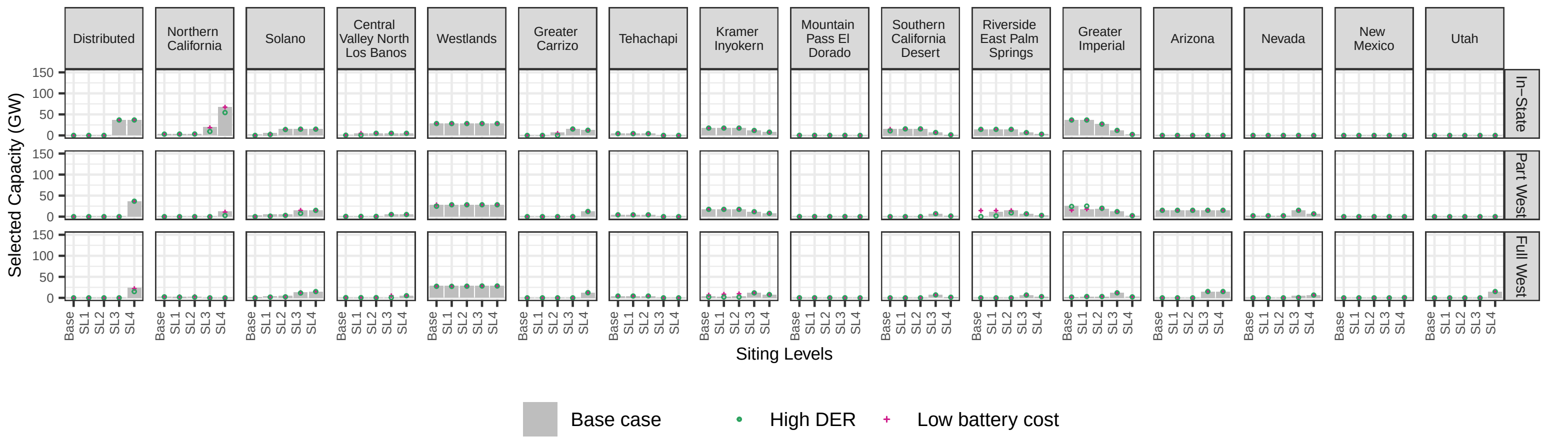

Figure 21: Comparison between California solar RESOLVE Zones for the *Constrained* assumptions case— Selected solar capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases. RESOLVE Zones within California have been included here (compared to Fig. 17) in order to show the effect on solar distribution within California.

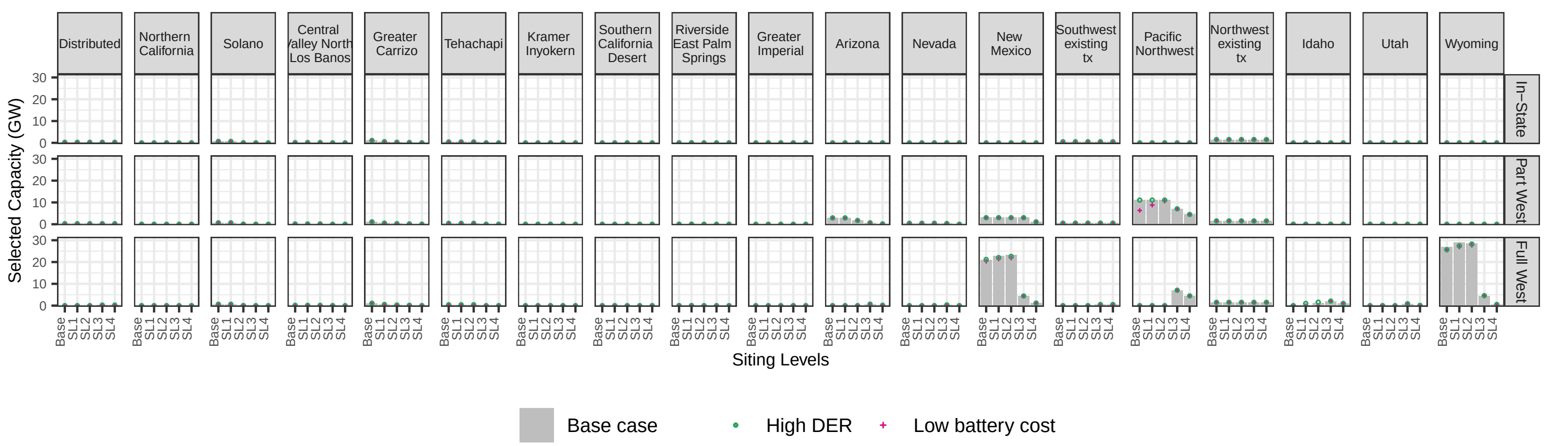

Figure 22: Comparison between California wind RESOLVE Zones for the *Constrained* assumptions case— Selected wind capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases. RESOLVE Zones within California have been included here (compared to Fig. 18) in order to show the effect on wind distribution within California.

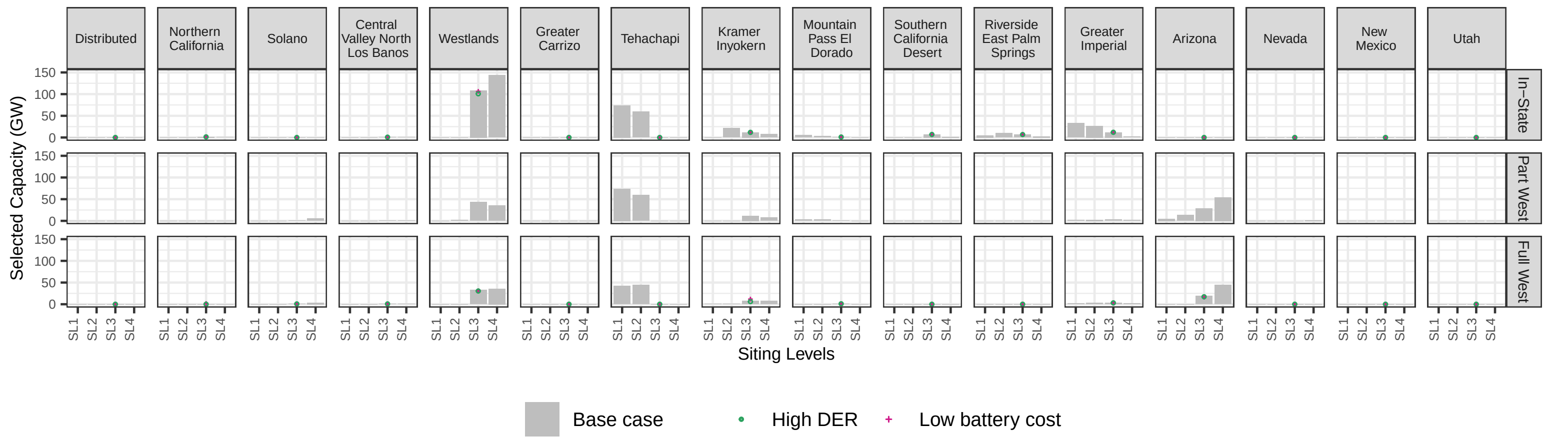

Figure 23: Comparison between California solar RESOLVE Zones for the *Unconstrained* assumptions case—Selected solar capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases. RESOLVE Zones within California have been included here (compared to Fig. 17) in order to show the effect on solar distribution within California.

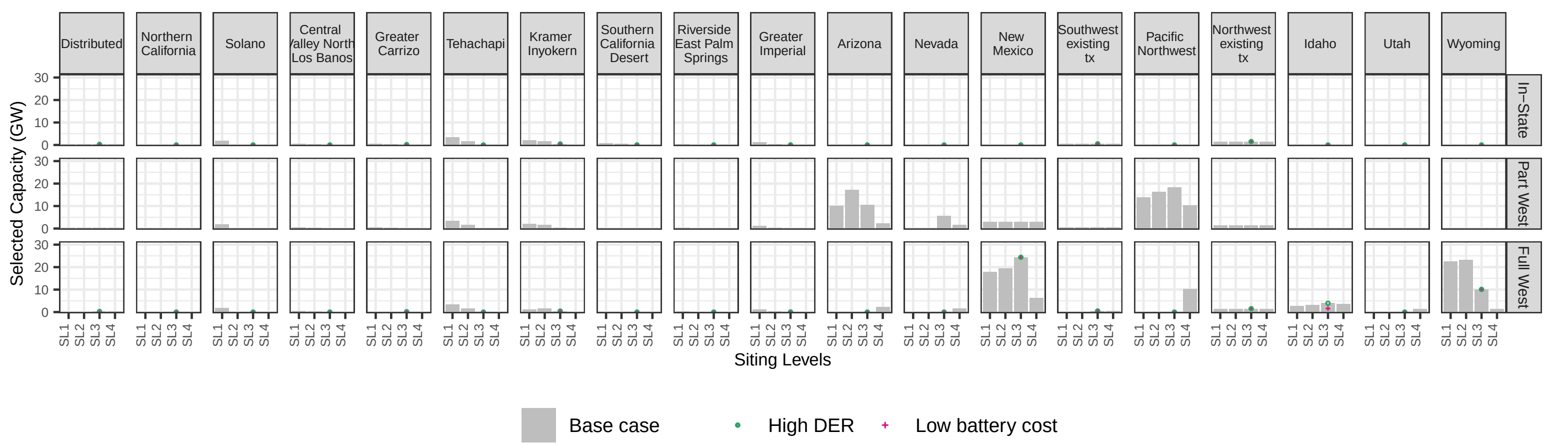

Figure 24: Comparison between California wind RESOLVE Zones for the *Unconstrained* assumptions case—Selected wind capacity comparing the Base case with Low Battery Cost and High DER sensitivity cases. RESOLVE Zones within California have been included here (compared to Fig. 18) in order to show the effect on wind distribution within California.

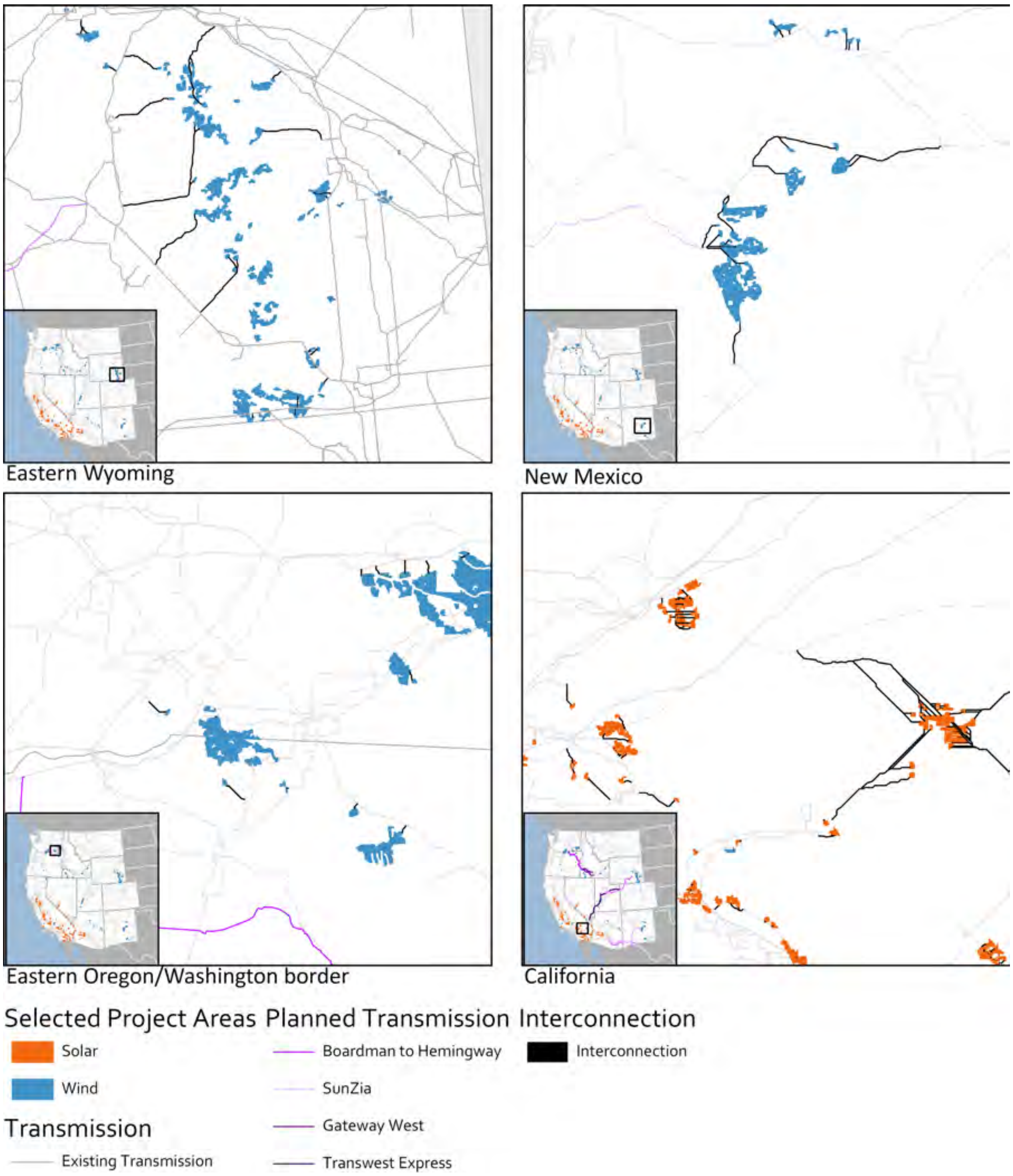

Figure 25: Representative Selected Project Areas and least cost path gen-tie transmission corridors to serve selected generation project areas in the *Full West*, Siting Level 3, *Constrained* scenario.

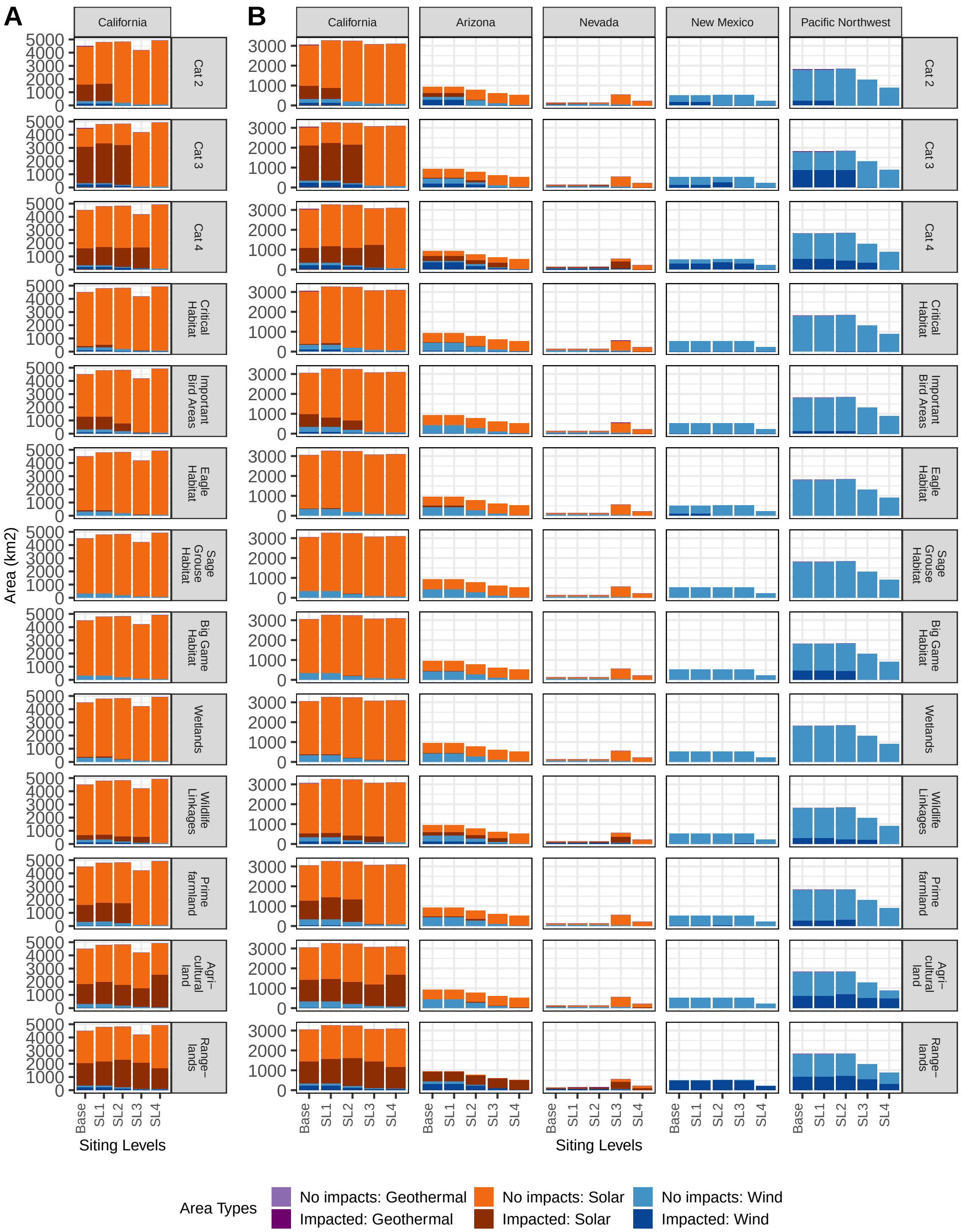

Figure 26: Environmental impacts of selected generation projects within each state for the *In-State* (A) and *Part West* (B) Geographic cases in the *Constrained* assumptions case.

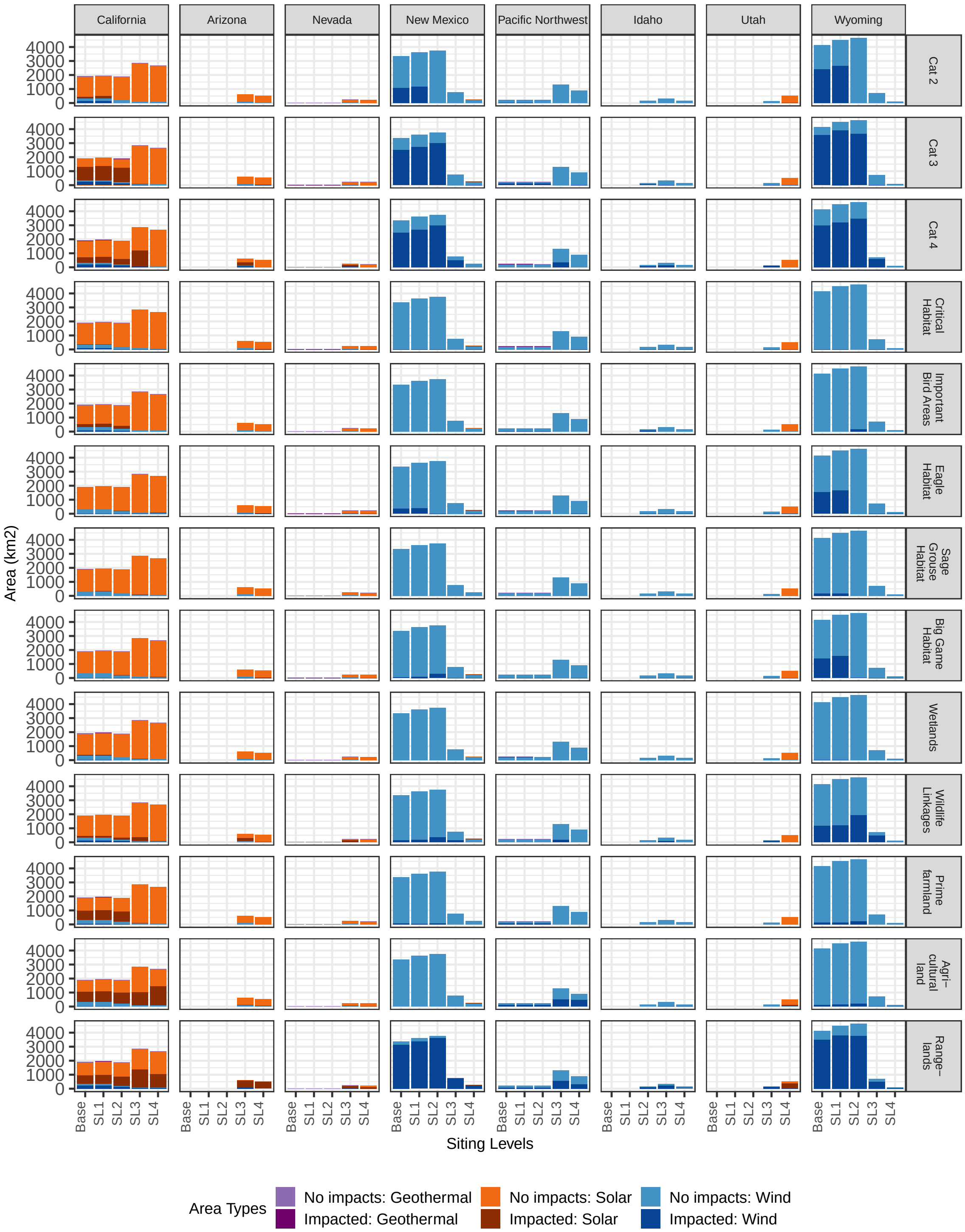

Figure 27: Environmental impacts of selected generation projects within each state for the *Full West* Geographic cases and in the *Constrained* assumptions case.

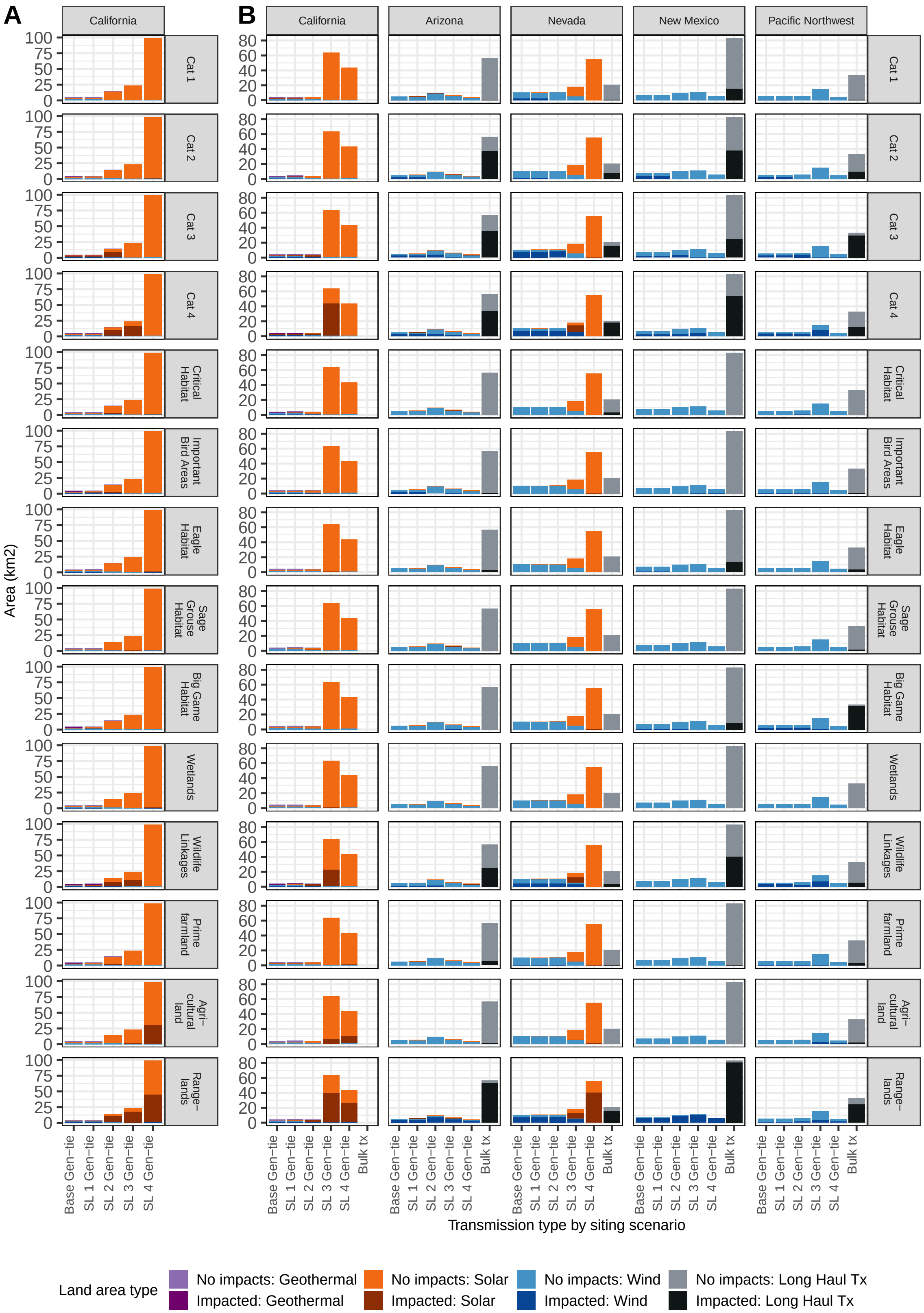

Figure 28: Environmental impacts of gen-tie and bulk transmission corridors within each state for the *In-State* (A) and *Part West* (B) Geographic cases in the *Constrained* assumptions case.

Figure 29: Environmental impacts of gen-tie and bulk transmission corridors within each state for the *Full West* Geographic cases in the *Constrained* assumptions case.

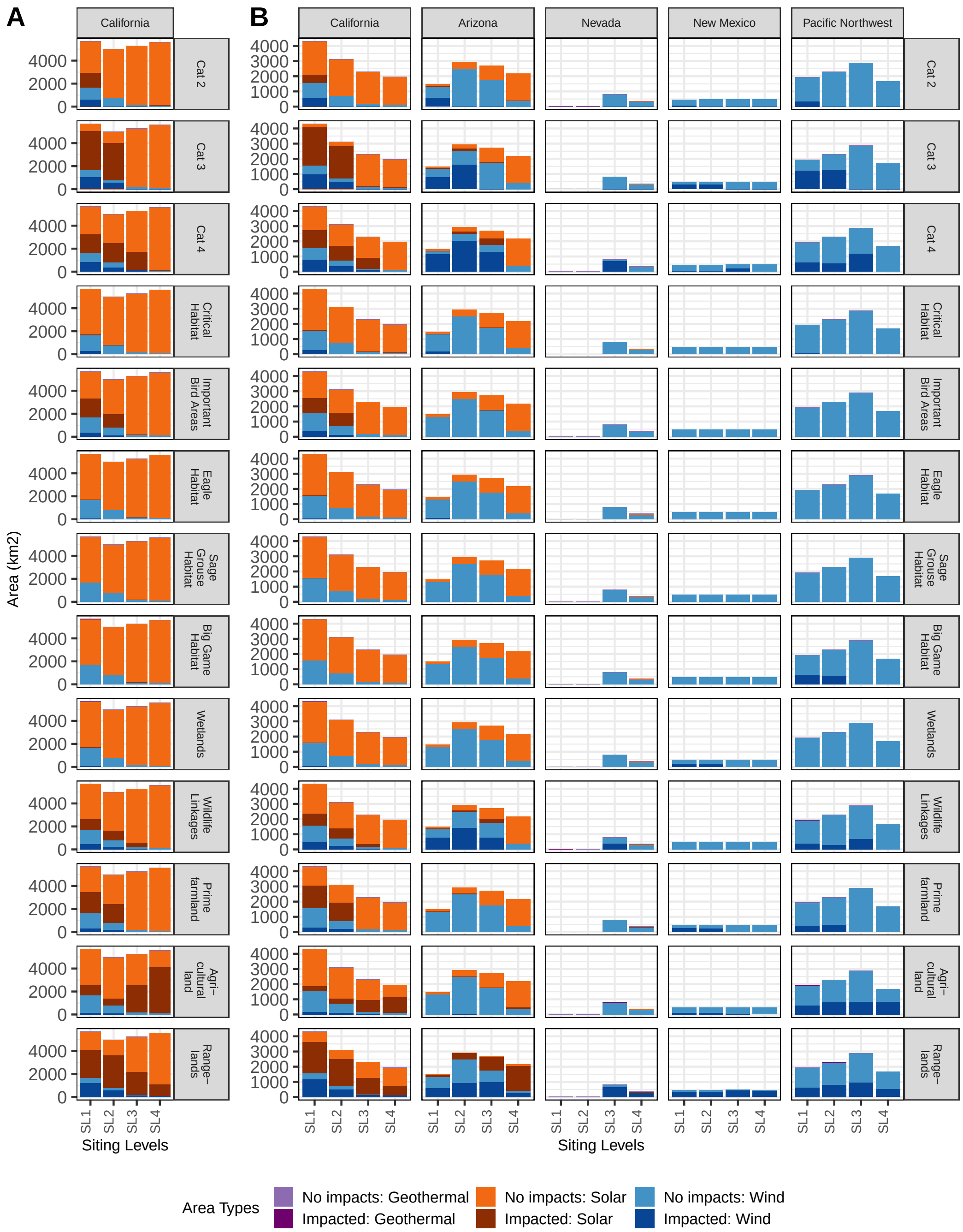

Figure 30: Environmental impacts for selected generation project areas within each state for the *In-State* (A) and *Part West* (B) Geographic cases for the *Unconstrained* assumptions case.

Figure 31: Environmental impacts for selected generation project areas in the *Full West* Geographic cases for the *Unconstrained* assumptions case.

Figure 32: Environmental impacts for modeled gen-tie and planned bulk transmission corridors within each state for the *In-State* (A) and *Part West* (B) Geographic cases for the *Unconstrained* assumptions case.

Figure 33: Environmental impacts for modeled gen-tie and planned bulk transmission corridors within each state in the *Full West* Geographic cases for the *Unconstrained* assumptions case.

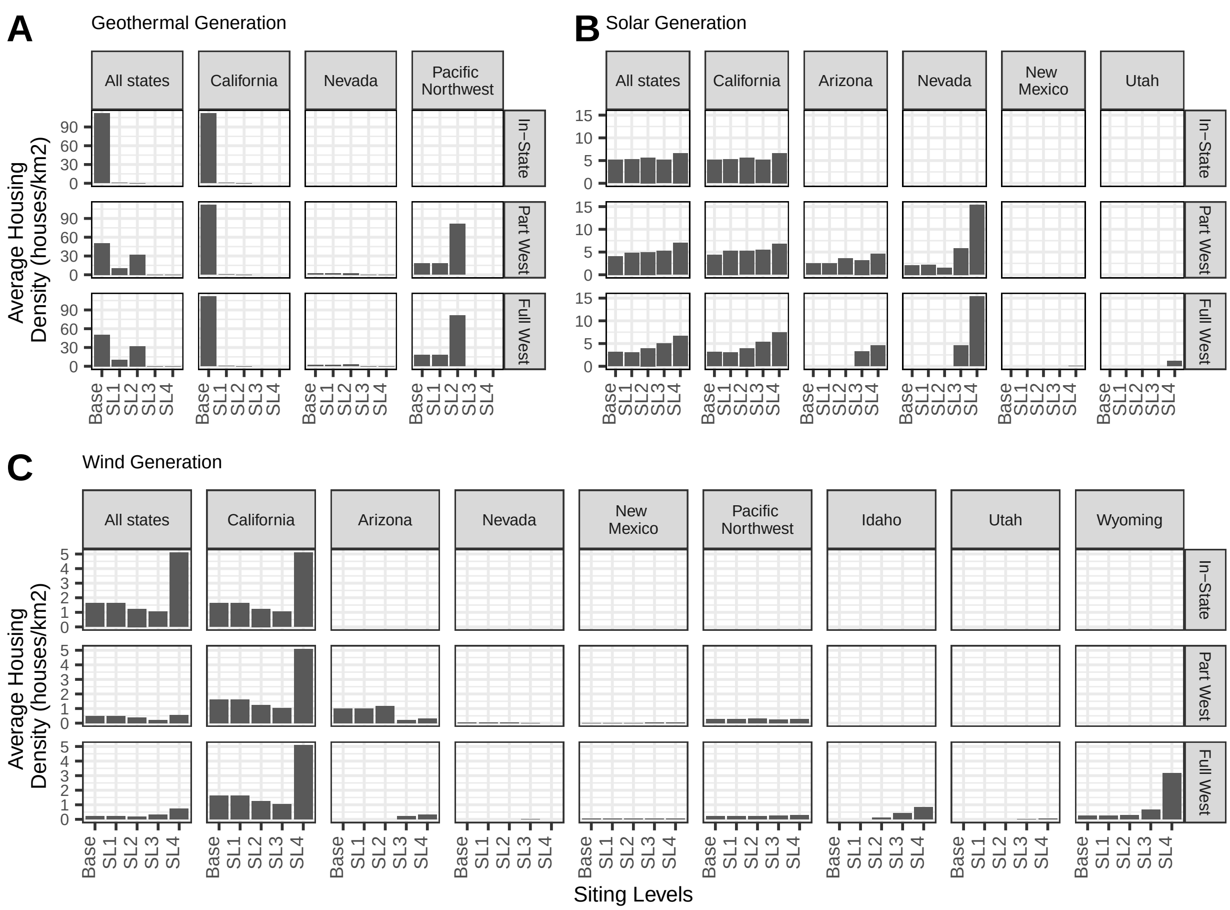

Figure 34: Average housing density for selected generation project areas in the *Constrained* assumptions case.

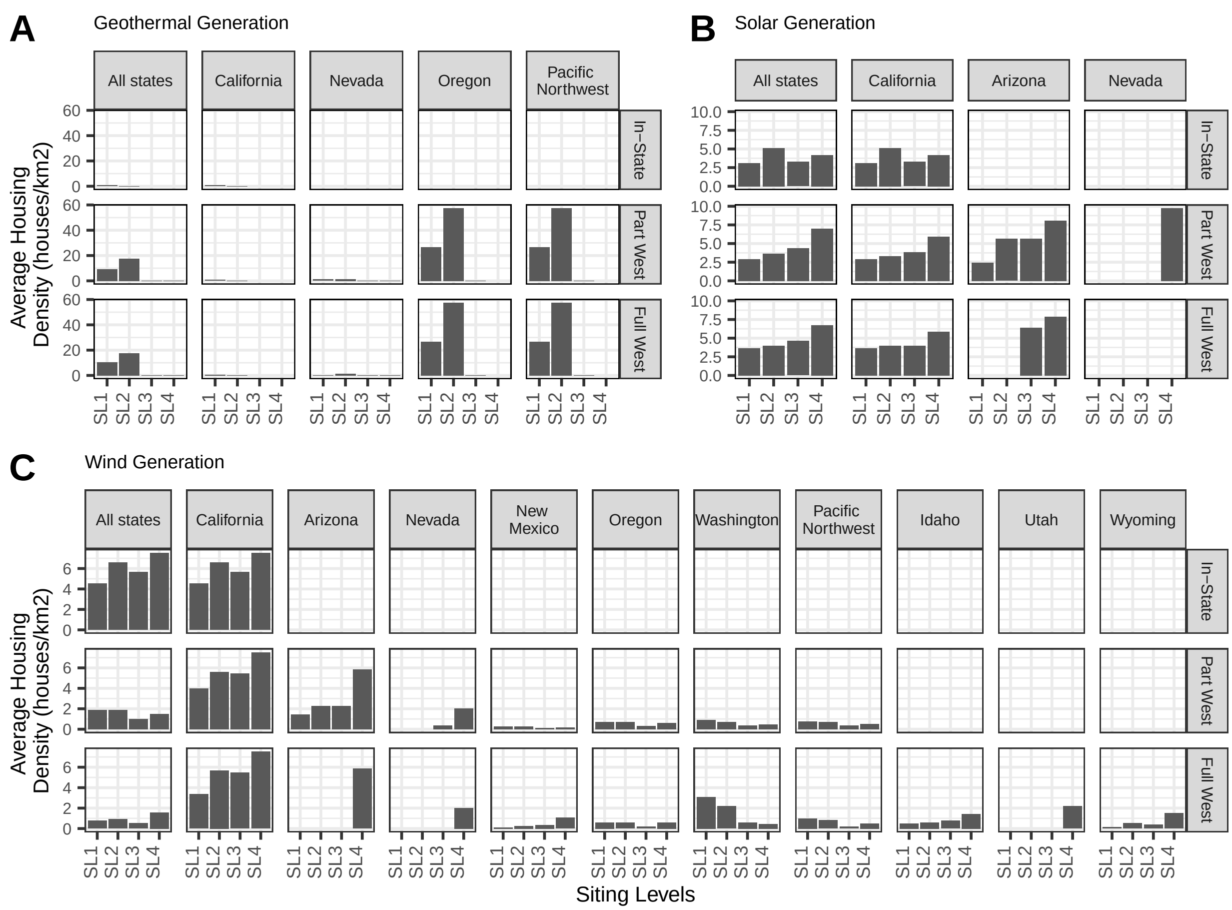

Figure 35: Average housing density for selected generation project areas in *Unconstrained* assumptions case.

Table 15: Generation land area (km^2) for each technology for each scenario

	Technology	Geographic scenario	RESOLVE sensitivity	Base	Cat1	Cat2	Cat3	Cat4
1	Geothermal	Full West	Constrained Basecase	54	43	14	2	1
2	Geothermal	Full West	Constrained High DER	54	43	14	2	1
3	Geothermal	Full West	Constrained Low Battery Cost	54	43	14	2	1
4	Geothermal	Full West	Unconstrained Basecase		41	27	4	2
5	Geothermal	Full West	Unconstrained High DER				4	
6	Geothermal	Full West	Unconstrained Low Battery Cost				4	
7	Geothermal	Part West	Constrained Basecase	54	43	14	2	1
8	Geothermal	Part West	Constrained High DER	54	43	14	2	1
9	Geothermal	Part West	Constrained Low Battery Cost	54	43	14	2	1
10	Geothermal	Part West	Unconstrained Basecase		49	27	4	2
11	Geothermal	InState	Constrained Basecase	20	10	0	0	0
12	Geothermal	InState	Constrained High DER	20	10	0	0	0
13	Geothermal	InState	Constrained Low Battery Cost	20	10	0	0	0
14	Geothermal	InState	Unconstrained Basecase		10	0	0	0
15	Geothermal	InState	Unconstrained High DER				0	
16	Geothermal	InState	Unconstrained Low Battery Cost				0	
17	Solar	Full West	Constrained Basecase	1545	1611	1676	3434	3821
18	Solar	Full West	Constrained High DER	1392	1461	1497	3215	3821
19	Solar	Full West	Constrained Low Battery Cost	1605	1708	1763	3407	3821
20	Solar	Full West	Unconstrained Basecase		1591	1690	2255	3236
21	Solar	Full West	Unconstrained High DER				2067	
22	Solar	Full West	Unconstrained Low Battery Cost				2292	
23	Solar	Part West	Constrained Basecase	3264	3483	3610	3978	3724
24	Solar	Part West	Constrained High DER	3042	3276	3415	3708	3388
25	Solar	Part West	Constrained Low Battery Cost	3343	3476	3560	3967	3661
26	Solar	Part West	Unconstrained Basecase		2882	2818	3070	3660
27	Solar	InState	Constrained Basecase	4152	4455	4626	4107	4844
28	Solar	InState	Constrained High DER	3937	4172	4394	3767	4398
29	Solar	InState	Constrained Low Battery Cost	4070	4367	4575	4061	4827
30	Solar	InState	Unconstrained Basecase		4003	4184	5080	5468
31	Solar	InState	Unconstrained High DER				4801	
32	Solar	InState	Unconstrained Low Battery Cost				5001	
33	Wind	Full West	Constrained Basecase	8056	8682	8979	3512	1517
34	Wind	Full West	Constrained High DER	7861	8421	8822	3512	1517
35	Wind	Full West	Constrained Low Battery Cost	7698	8094	8362	3512	1517
36	Wind	Full West	Unconstrained Basecase		7681	7457	6500	4545
37	Wind	Full West	Unconstrained High DER				6478	
38	Wind	Full West	Unconstrained Low Battery Cost				6144	
39	Wind	Part West	Constrained Basecase	3170	3170	2910	2092	1235
40	Wind	Part West	Constrained High DER	3170	3170	2910	2092	1235
41	Wind	Part West	Constrained Low Battery Cost	2456	2822	2834	2092	1235
42	Wind	Part West	Unconstrained Basecase		5285	5972	6098	2996
43	Wind	InState	Constrained Basecase	341	341	207	95	82
44	Wind	InState	Constrained High DER	341	341	207	95	82
45	Wind	InState	Constrained Low Battery Cost	341	341	207	95	82
46	Wind	InState	Unconstrained Basecase		1678	798	183	119
47	Wind	InState	Unconstrained High DER				183	
48	Wind	InState	Unconstrained Low Battery Cost				183	

Table 16: Gen-tie transmission land area (km2) for each technology for each scenario

	Technology	Geographic scenario	RESOLVE sensitivity	Base	Cat1	Cat2	Cat3	Cat4
1	Geothermal	Full West	Constrained Basecase	1	1.1	0.0	0.0	0.0
2	Geothermal	Full West	Constrained High DER	1	1.1	0.0	0.0	0.0
3	Geothermal	Full West	Constrained Low Battery Cost	1	1.1	0.0	0.0	0.0
4	Geothermal	Full West	Unconstrained Basecase		2.9	1.8	0.0	0.0
5	Geothermal	Full West	Unconstrained High DER				0.0	
6	Geothermal	Full West	Unconstrained Low Battery Cost				0.0	
7	Geothermal	Part West	Constrained Basecase	1	1.1	0.0	0.0	0.0
8	Geothermal	Part West	Constrained High DER	1	1.1	0.0	0.0	0.0
9	Geothermal	Part West	Constrained Low Battery Cost	1	1.1	0.0	0.0	0.0
10	Geothermal	Part West	Unconstrained Basecase		2.9	1.8	0.0	0.0
11	Geothermal	InState	Constrained Basecase	1	1.1	0.0	0.0	0.0
12	Geothermal	InState	Constrained High DER	1	1.1	0.0	0.0	0.0
13	Geothermal	InState	Constrained Low Battery Cost	1	1.1	0.0	0.0	0.0
14	Geothermal	InState	Unconstrained Basecase		1.1	0.0	0.0	0.0
15	Geothermal	InState	Unconstrained High DER				0.0	
16	Geothermal	InState	Unconstrained Low Battery Cost				0.0	
17	Solar	Full West	Constrained Basecase	1	0.7	2.6	64.1	107.5
18	Solar	Full West	Constrained High DER	1	0.9	2.9	62.9	107.5
19	Solar	Full West	Constrained Low Battery Cost	1	0.8	2.6	64.0	107.5
20	Solar	Full West	Unconstrained Basecase		0.2	10.0	15.2	23.1
21	Solar	Full West	Unconstrained High DER				15.7	
22	Solar	Full West	Unconstrained Low Battery Cost				25.2	
23	Solar	Part West	Constrained Basecase	1	2.1	2.7	76.1	98.8
24	Solar	Part West	Constrained High DER	1	2.1	0.1	74.3	98.5
25	Solar	Part West	Constrained Low Battery Cost	2	2.0	2.6	62.7	98.8
26	Solar	Part West	Unconstrained Basecase		26.7	5.2	30.9	26.5
27	Solar	InState	Constrained Basecase	1	1.6	12.9	22.5	97.5
28	Solar	InState	Constrained High DER	1	1.3	12.8	18.0	61.7
29	Solar	InState	Constrained Low Battery Cost	1	1.6	12.8	83.2	94.7
30	Solar	InState	Unconstrained Basecase		4.8	55.3	82.0	53.5
31	Solar	InState	Unconstrained High DER				79.4	
32	Solar	InState	Unconstrained Low Battery Cost				81.4	
33	Wind	Full West	Constrained Basecase	49	52.7	82.2	112.3	22.8
34	Wind	Full West	Constrained High DER	49	49.7	81.7	112.3	22.8
35	Wind	Full West	Constrained Low Battery Cost	47	48.9	81.3	112.3	22.8
36	Wind	Full West	Unconstrained Basecase		52.3	99.7	194.2	179.2
37	Wind	Full West	Unconstrained High DER				190.3	
38	Wind	Full West	Unconstrained Low Battery Cost				181.1	
39	Wind	Part West	Constrained Basecase	30	30.1	37.5	38.8	15.1
40	Wind	Part West	Constrained High DER	30	30.1	37.5	38.8	15.1
41	Wind	Part West	Constrained Low Battery Cost	28	29.2	36.9	38.8	15.1
42	Wind	Part West	Unconstrained Basecase		38.8	51.6	246.3	104.5
43	Wind	InState	Constrained Basecase	2	2.2	1.5	0.9	1.3
44	Wind	InState	Constrained High DER	2	2.2	1.5	0.9	1.3
45	Wind	InState	Constrained Low Battery Cost	2	2.2	1.5	0.9	1.3
46	Wind	InState	Unconstrained Basecase		14.7	6.9	1.4	1.8
47	Wind	InState	Unconstrained High DER				1.4	
48	Wind	InState	Unconstrained Low Battery Cost				1.4	

Table 17: Gen-tie transmission land area percentage (%) out of total area (gen-tie transmission and generation) for each technology for each scenario

	Technology	Geographic scenario	RESOLVE sensitivity	Base	Cat1	Cat2	Cat3	Cat4
1	Geothermal	Full West	Constrained Basecase	2	2.6	0.0	0.0	0.0
2	Geothermal	Full West	Constrained High DER	2	2.6	0.0	0.0	0.0
3	Geothermal	Full West	Constrained Low Battery Cost	2	2.6	0.0	0.0	0.0
4	Geothermal	Full West	Unconstrained Basecase		6.6	6.2	0.0	0.0
5	Geothermal	Full West	Unconstrained High DER				0.0	
6	Geothermal	Full West	Unconstrained Low Battery Cost				0.0	
7	Geothermal	Part West	Constrained Basecase	2	2.6	0.0	0.0	0.0
8	Geothermal	Part West	Constrained High DER	2	2.6	0.0	0.0	0.0
9	Geothermal	Part West	Constrained Low Battery Cost	2	2.6	0.0	0.0	0.0
10	Geothermal	Part West	Unconstrained Basecase		5.6	6.2	0.0	0.0
11	Geothermal	InState	Constrained Basecase	5	10.5	0.0		
12	Geothermal	InState	Constrained High DER	5	10.5	0.0		
13	Geothermal	InState	Constrained Low Battery Cost	5	10.5	0.0		
14	Geothermal	InState	Unconstrained Basecase		10.5	0.0		
15	Geothermal	InState	Unconstrained High DER					
16	Geothermal	InState	Unconstrained Low Battery Cost					
17	Solar	Full West	Constrained Basecase	0	0.0	0.2	1.8	2.7
18	Solar	Full West	Constrained High DER	0	0.1	0.2	1.9	2.7
19	Solar	Full West	Constrained Low Battery Cost	0	0.0	0.1	1.8	2.7
20	Solar	Full West	Unconstrained Basecase		0.0	0.6	0.7	0.7
21	Solar	Full West	Unconstrained High DER				0.8	
22	Solar	Full West	Unconstrained Low Battery Cost				1.1	
23	Solar	Part West	Constrained Basecase	0	0.1	0.1	1.9	2.6
24	Solar	Part West	Constrained High DER	0	0.1	0.0	2.0	2.8
25	Solar	Part West	Constrained Low Battery Cost	0	0.1	0.1	1.6	2.6
26	Solar	Part West	Unconstrained Basecase		0.9	0.2	1.0	0.7
27	Solar	InState	Constrained Basecase	0	0.0	0.3	0.5	2.0
28	Solar	InState	Constrained High DER	0	0.0	0.3	0.5	1.4
29	Solar	InState	Constrained Low Battery Cost	0	0.0	0.3	2.0	1.9
30	Solar	InState	Unconstrained Basecase		0.1	1.3	1.6	1.0
31	Solar	InState	Unconstrained High DER				1.6	
32	Solar	InState	Unconstrained Low Battery Cost				1.6	
33	Wind	Full West	Constrained Basecase	1	0.6	0.9	3.1	1.5
34	Wind	Full West	Constrained High DER	1	0.6	0.9	3.1	1.5
35	Wind	Full West	Constrained Low Battery Cost	1	0.6	1.0	3.1	1.5
36	Wind	Full West	Unconstrained Basecase		0.7	1.3	2.9	3.8
37	Wind	Full West	Unconstrained High DER				2.9	
38	Wind	Full West	Unconstrained Low Battery Cost				2.9	
39	Wind	Part West	Constrained Basecase	1	0.9	1.3	1.8	1.2
40	Wind	Part West	Constrained High DER	1	0.9	1.3	1.8	1.2
41	Wind	Part West	Constrained Low Battery Cost	1	1.0	1.3	1.8	1.2
42	Wind	Part West	Unconstrained Basecase		0.7	0.9	3.9	3.4
43	Wind	InState	Constrained Basecase	1	0.6	0.7	0.9	1.6
44	Wind	InState	Constrained High DER	1	0.6	0.7	0.9	1.6
45	Wind	InState	Constrained Low Battery Cost	1	0.6	0.7	0.9	1.6
46	Wind	InState	Unconstrained Basecase		0.9	0.9	0.8	1.5
47	Wind	InState	Unconstrained High DER				0.8	
48	Wind	InState	Unconstrained Low Battery Cost				0.8	

Table 18: Gen-tie transmission land area percentage (%) out of total area (gen-tie transmission and generation) summed across technologies for each scenario

	Geographic scenario	RESOLVE sensitivity	Base	Cat1	Cat2	Cat3	Cat4
1	Full West	Constrained Basecase	1	0.5	0.8	2.5	2.4
2	Full West	Constrained High DER	1	0.5	0.8	2.5	2.4
3	Full West	Constrained Low Battery Cost	1	0.5	0.8	2.5	2.4
4	Full West	Unconstrained Basecase		0.6	1.2	2.3	2.5
5	Full West	Unconstrained High DER				2.4	
6	Full West	Unconstrained Low Battery Cost				2.4	
7	Part West	Constrained Basecase	0	0.5	0.6	1.9	2.2
8	Part West	Constrained High DER	1	0.5	0.6	1.9	2.4
9	Part West	Constrained Low Battery Cost	1	0.5	0.6	1.6	2.3
10	Part West	Unconstrained Basecase		0.8	0.7	2.9	1.9
11	InState	Constrained Basecase	0	0.1	0.3	0.6	2.0
12	InState	Constrained High DER	0	0.1	0.3	0.5	1.4
13	InState	Constrained Low Battery Cost	0	0.1	0.3	2.0	1.9
14	InState	Unconstrained Basecase		0.4	1.2	1.6	1.0
15	InState	Unconstrained High DER				1.6	
16	InState	Unconstrained Low Battery Cost				1.6	

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Browse terms related to these fuel groups:

alternative fuels

coal

electricity

natural gas

nuclear

petroleum

renewable

B

Backup fuel: In a central heat pump system, the fuel used in the furnace that takes over the space heating when the outdoor temperature drops below that which is feasible to operate a heat pump.

Backup generator: A generator that is used only for test purposes, or in the event of an emergency, such as a shortage of power needed to meet customer load requirements.

Backup power: Electric energy supplied by a utility to replace power and energy lost during an unscheduled equipment outage.

Balancing authority (electric): The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. NERC definition

Balancing item: Represents differences between the sum of the components of natural gas supply and the sum of the components of natural gas disposition. These differences may be due to quantities lost or to the effects of data reporting problems. Reporting problems include differences due to the net result of conversions off low data metered at varying temperature and pressure bases and converted to a standard temperature and pressure base; the effect of variations in company accounting and billing practices; differences between billing cycle and calendar period time frames; and imbalances resulting from the merger of data reporting systems that vary in scope, format, definitions, and type of respondents.

Barrel: A unit of volume equal to 42 U.S. gallons.

Barrels per calendar day: The amount of input that a distillation facility can process under usual operating conditions. The amount is expressed in terms of capacity during a 24-hour period and reduces the maximum processing capability of all units at the facility under continuous operation (see Barrels per Stream Day) to account for the following limitations that may delay, interrupt, or slow down production. 1. the capability of downstream processing units to absorb the output of crude oil processing facilities of a given refinery. No reduction is necessary for intermediate streams that are distributed to other than downstream facilities as part of a refinery's normal operation; 2. the types and grades of inputs to be processed; 3. the types and grades of products expected to be manufactured; 4. the environmental constraints associated with refinery operations; 5. the reduction of capacity for scheduled downtime due to such conditions as routine inspection, maintenance, repairs, and turnaround; and 6. the reduction of capacity for unscheduled downtime due to such conditions as mechanical problems, repairs, and slowdowns.

Barrels per stream day: The maximum number of barrels of input that a distillation facility can process within a 24-hour period when running at full capacity under optimal crude and product slate conditions with no allowance for downtime.

Base bill: A charge calculated by taking the rate from the appropriate electric rate schedule and applying it to the level of consumption.

Base gas: The quantity of natural gas needed to maintain adequate reservoir pressures and deliverability rates throughout the withdrawal season. Base gas usually is not withdrawn and remains in the reservoir. All natural gas native to a depleted reservoir is included in the base gas volume.

Base load: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Base load capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Base load plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Base period: The period of time for which data used as the base of an index number, or other ratio, have been collected. This period is frequently one of a year but it may be as short as one day or as long as the average of a group of years. The length of the base period is governed by the nature of the material under review, the purpose for which the index number (or ratio) is being compiled, and the desire to use a period as free as possible from abnormal influences in order to avoid bias.

Base rate: A fixed kilowatthour charge for electricity consumed that is independent of other charges and/or adjustments.

Baseboard heater: As a type of heating equipment, a system in which either electric resistance coils or finned tubes carrying steam or hot water are mounted behind shallow panels along baseboards. Baseboards rely on passive convection to distribute heated air in the space. Electric baseboards are an example of an "Individual Space Heater."

bbl: The abbreviation for barrel(s).

bbl/d: The abbreviation for barrel(s) per day.

bbl/sd: The abbreviation for barrel(s) per stream day.

bcf: The abbreviation for billion cubic feet.

Benzene (C_6H_6): An aromatic hydrocarbon present in small proportion in some crude oils and made commercially from petroleum by the catalytic reforming of naphthenes in petroleum naphtha. Also made from coal in the manufacture of coke. Used as a solvent in the manufacture of detergents, synthetic fibers, petrochemicals, and as a component of high-octane gasoline.

Bi-fuel vehicle: A motor vehicle that operates on two different fuels, but not on a mixture of the fuels. Each fuel is stored in a separate tank.

Bilateral agreement: A written statement signed by two parties that specifies the terms for exchanging energy.

Bilateral energy transaction: A transaction between two willing parties who enter into a physical or financial agreement to trade energy commodities. Bilateral transactions entail reciprocal obligations and can involve direct negotiations or deals made through brokers.

Billing period: The time between meter readings. It does not refer to the time when the bill was sent or when the payment was to have been received. In some cases, the billing period is the same as the billing cycle that corresponds closely (within several days) to meter-reading dates. For fuel oil and LPG, the billing period is the number of days between fuel deliveries.

Biodiesel: A fuel typically made from soybean, canola, or other vegetable oils; animal fats; and recycled grease. It can serve as a substitute for petroleum-derived diesel or distillate fuel. For EIA reporting, it is a fuel composed of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats, designated B100, and meeting the requirements of ASTM (American Society for Testing materials) D 6751.

Biofuels: Liquid fuels and blending components produced from biomass feedstocks, used primarily for transportation.

Biogenic: Produced by biological processes of living organisms. Note: EIA uses the term "biogenic" to refer only to organic nonfossil material of biological origin.

Biogenic emissions: Emissions that are naturally occurring and are not significantly affected by human actions or activity.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

Biomass gas: A medium Btu gas containing methane and carbon dioxide, resulting from the action of microorganisms on organic materials such as a landfill.

Biomass waste: Organic non-fossil material of biological origin that is a byproduct or a discarded product. Biomass waste includes municipal solid waste from biogenic sources, landfill gas, sludge waste, agricultural crop byproducts, straw, and other biomass solids, liquids, and gases; but excludes wood and wood-derived fuels (including black liquor), biofuels feedstock, biodiesel, and fuel ethanol. **Note:** EIA biomass waste data also include energy crops grown specifically for energy production, which would not normally constitute waste.

Biomass-based diesel fuel: Biodiesel and other renewable diesel fuel or diesel fuel blending components derived from biomass, but excluding renewable diesel fuel coprocessed with petroleum feedstocks.

Bitumen: A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its natural occurring viscous state, is not recoverable at a commercial rate through a well.

Bituminous coal: A dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke. Bituminous coal is the most abundant coal in active U.S. mining regions. Its moisture content usually is less than 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu per ton on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Black liquor: A by product of the paper production process, alkaline spent liquor, that can be used as a source of energy. Alkaline spent liquor is removed from the digesters in the process of chemically pulping wood. After evaporation, the residual "black" liquor is burned as a fuel in a recovery furnace that permits the recovery of certain basic chemicals.

Black lung benefits: In the content of the coal operation statement of income, this term refers to all payments, including taxes, made by the company attributable to Black Lung.

Blast furnace: A furnace in which solid fuel (coke) is burned with an air blast to smelt ore.

Blast-furnace gas: The waste combustible gas generated in a blast furnace when iron ore is being reduced with coke to metallic iron. It is commonly used as a fuel within steel works.

Blending components: See Motor gasoline blending components.

Blending plant: A facility that has no refining capability but is either capable of producing finished motor gasoline through mechanical blending or blends oxygenates with motor gasoline.

Block-rate structure: An electric rates schedule with a provision for charging a different unit cost for various increasing blocks of demand for energy. A reduced rate may be charged on succeeding blocks.

BLS: Bureau of Labor Statistics within the U.S. Department of Labor

BOE: Barrels of Oil Equivalent (used internationally)

Boiler: A device for generating steam for power, processing, or heating purposes; or hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes found in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Boiler fuel: An energy source to produce heat that is transferred to the boiler vessel in order to generate steam orhot water. Fossil fuel is the primary energy source used to produce heat for boilers.

Boiling-water reactor (BWR): A light-water reactor in which water, used as both coolant and moderator, is allowed to boil in the core. The resulting steam can be used directly to drive a turbine.

Bonded petroleum imports: Petroleum imported and entered into Customs bonded storage. These imports are not included in the import statistics until they are (1) withdrawn from storage free of duty for use as fuel for vessels and aircraft engaged in international trade; or (2) withdrawn from storage with duty paid for domestic use.

Bone coal: Coal with a high ash content; it is dull in appearance, hard, and compact.

Book value: The portion of the carrying value (other than the portion associated with tangible assets) prorated in each accounting period, for financial reporting purposes, to the extracted portion of an economic interest in a wasting natural resource.

Booked costs: Costs allocated or assigned to inter-departmental or intra company transactions, such as on-system or synthetic natural gas (SNG) production and company-owned gas used in gas operations and recorded in company books or records for accounting and/or regulatory purposes.

Borderline customer: A customer located in the service area of one utility, but supplied by a neighboring utility through an arrangement between the utilities.

Bottled gas: See Liquefied petroleum gases.

Bottled gas, LPG, or propane: Any fuel gas supplied to a building in liquid form, such as liquefied petroleum gas, propane, or butane. It is usually delivered by tank truck and stored near the building in a tank or cylinder until used.

Bottom ash: Residue mainly from the coal burning process that falls to the bottom of the boiler for removal and disposal.

Bottom-hole contribution: A payment (either in cash or in acreage) that is required by agreement when a test well is drilled to a specified depth regardless of the outcome of the well and that is made in exchange for well and evaluation data.

Bottoming cycle: A waste-heat recovery boiler recaptures the unused energy and uses it to produce steam to drive a steam turbine generator to produce electricity.

bp: The abbreviation for boiling point.

Branded product: A refined petroleum product sold by a refiner with the understanding that the purchaser has the right to resell the product under a trademark, trade name, service mark, or other identifying symbol or names owned by such refiner.

Break-even cutoff grade: The lowest grade of material that can be mined and processed considering all applicable costs, without incurring a loss or gaining a profit.

Breccia: A coarse-grained clastic rock, composed of angular broken rock fragments held together by a mineral cement or in a fine-grained matrix.

Breeder reactor: A reactor that both produces and consumes fissionable fuel, especially one that creates more fuel than it consumes. The new fissionable material is created by a process known as breeding, in which neutrons from fission are captured in fertile materials.

Breeze: The fine screenings from crushed coke. Usually breeze will pass through a 1/2-inch or 3/4-inch screen opening. It is most often used as a fuel source in the process of agglomerating iron ore.

British thermal unit: The quantity of heat required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit at the temperature at which water has its greatest density (approximately 39 degrees Fahrenheit).

Btu: The abbreviation for British Thermal Unit(s).

Btu conversion factor: A factor for converting energy data between one unit of measurement and British thermal units (Btu). Btu conversion factors are generally used to convert energy data from physical units of measure (such as barrels, cubic feet, or short tons) into the energy-equivalent measure of Btu. (See http://www.eia.gov/totalenergy/data/monthly/pdf/sec13.pdf for further information on Btu conversion factors.)

Btu per cubic foot: The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas that would occupy a volume of 1 cubic foot at a temperature of 60 degrees F if saturated with water vapor and under a pressure equivalent to that of 30 inches of mercury at 32 degrees F and under standard gravitational force (980.665 cm. per sec. squared) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state.(Sometimes called gross heating value or total heating value.)

BTX: The acronym for the commercial petroleum aromatics-- benzene, toluene, and xylene.

Budget plan: An agreement between the household and the utility company or fuel supplier that allows the household to pay the same amount for fuel for each month for a number of months.

Building shell (envelope) DSM program: A DSM program that promotes reduction of energy consumption through improvements to the building envelope. Includes installations of insulation, weather stripping, caulking, window film, and window replacement. (Also see DSM, Demand-Side Management Programs.)

Building shell conservation feature: A building feature designed to reduce energy loss or gain through the shell or envelope of the building. Data collected by EIA on the following specific building shell energy conservation features: roof, ceiling, or wall insulation; storm windows or double- or triple-paned glass (multiple glazing); tinted or reflective glass or shading films; exterior or interior shadings or awnings; and weather stripping or caulking. (See Roof or Ceiling Insulation, Wall Insulation, Reflective or Shading Glass or Film, Storm Window or Triple-Paned Glass, Building Shell (Envelope), and Weather Stripping or Caulking.)

Built-in electric units: An individual-resistance electric-heating unit that is permanently installed in the floors, walls, ceilings, or baseboards and is part of the electrical installation of the building. Electric-heating devices that are plugged into an electric socket or outlet are not considered built in. (Also see Heating Equipment.)

Bulk power transactions: The wholesale sale, purchase, and interchange of electricity among electric utilities. Bulk power transactions are used by electric utilities for many different aspects of electric utility operations, from maintaining load to reducing costs.

Bulk sales: Wholesale sales of gasoline in individual transactions which exceed the size of a truckload.

Bulk station: A facility used primarily for the storage and/or marketing of petroleum products, which has a total bulk storage capacity of less than 50,000 barrels and receives its petroleum products by tank car or truck.

Bulk terminal: A facility used primarily for the storage and/or marketing of petroleum products, which has a total bulk storage capacity of 50,000 barrels or more and/or receives petroleum products by tanker, barge, or pipeline.

Bundled utility service (electric): A means of operation whereby energy, transmission, and distribution services, as well as ancillary and retail services, are provided by one entity.

Bunker fuels: Fuel supplied to ships and aircraft, both domestic and foreign, consisting primarily of residual and distillate fuel oil for ships and kerosene-based jet fuel for aircraft. The term "international bunker fuels" is used to denote the consumption of fuel for international transport activities. Note: For the purposes of greenhouse gas emissions inventories, data on emissions from combustion of international bunker fuels are subtracted from national emissions totals. Historically, bunker fuels have meant only ship fuel.

Burn days: The number of days the station could continue to operate by burning coal already on hand assuming no additional deliveries of coal and an average consumption rate.

Burnup: Amount of thermal energy generated per unit mass of fuel, expressed as Gigawatt-Days Thermal per Metric Ton of Initial Heavy Metal (GWDT/MTIHM), rounded to the nearest gigawatt day.

Bus: An electrical conductor that serves as a common connection for two or more electrical circuits.

Butane (C_4H_{10}): A straight-chain or branch-chain hydrocarbon extracted from natural gas or refinery gas streams, which is gaseous at standard temperature and pressure. It includes isobutane and normal butane and is designated in ASTM Specification D1835 and Gas Processors Association specifications for commercial butane.

Butylene (C_4H_8): An olefinic hydrocarbon recovered from refinery or petrochemical processes, which is gaseous at standard temperature and pressure. Butylene is used in the production of gasoline and various petrochemical products.

Buy-back oil: Crude oil acquired from a host government whereby a portion of the government's ownership interest in the crude oil produced in that country may or should be purchased by the producing firm.

BWR: Boiling-Water Reactor

Bypassed footage: Bypassed footage is the footage in that section of hole that is abandoned as the result of remedial sidetrack drilling operations.

Byproduct: A secondary or additional product resulting from the feedstock use of energy or the processing of nonenergy materials. For example, the more common byproducts of coke ovens are coal gas, tar, and a mixture of benzene, toluene, and xylenes (BTX).

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Browse terms related to these fuel groups:

alternative fuels

coal

electricity

natural gas

nuclear

petroleum

renewable

P

Packaged air conditioning units: Usually mounted on the roof or on a slab beside the building. (These are known as self-contained units, or Direct Expansion (DX). They contain air conditioning equipment as well as fans, and may or may not include heating equipment.) These are self-contained units that contain the equipment that generates cool air and the equipment that distributes the cooled air. These units commonly consume natural gas or electricity. The units are mounted on the roof top, exposed to the elements. They typically blow cool air into the building through duct work, but other types of distribution systems may exist. The units usually serve more than one room. There are often several units on the roof of a single building. Also known as Packaged Terminal Air Conditioners (PTAC). These packaged units are often constructed as a single unit for heating and for cooling.

Packaged units: Units built and assembled at a factory and installed as a self-contained unit to heat or cool all or portions of a building. Packaged units are in contrast to engineer-specified units built up from individual components for use in a given building. Packaged Units can apply to heating equipment, cooling equipment, or combined heating and cooling equipment. Some types of electric packaged units are also called "Direct Expansion" or DX units.

PAD Districts or PADD: See Petroleum Administration for Defense Districts.

Parabolic dish: A high-temperature (above 180 degrees Fahrenheit) solar thermal concentrator, generally bowl-shaped, with two-axis tracking.

Parabolic trough: A high-temperature (above 180 degrees Fahrenheit) solar thermal concentrator with the capacity for tracking the sun using one axis of rotation.

Paraffin (oil): A light-colored, wax-free oil obtained by pressing paraffin distillate.

Paraffin (wax): The wax removed from paraffin distillates by chilling and pressing. When separating from solutions, it is a colorless, more or less translucent, crystalline mass, without odor and taste, slightly greasy to touch, and consisting of a mixture of solid hydrocarbons in which the paraffin series predominates.

Paraffinic hydrocarbons: Saturated hydrocarbon compounds with the general formula C_nH_{2n+2} containing only single bonds. Sometimes referred to as alkanes or natural gas liquids.

Parent: A firm that directly or indirectly controls another entity.

Parent and its Consolidated Entities: A parent and those firms (if any) that are affiliated with the parent entity for purposes of financial statements prepared in accordance with Generally Accepted Accounting Principles (GAAP). An individual shall be deemed to control a firm that is directly or indirectly controlled by him/her or by his/her father, mother, spouse, children, or grandchildren. See firm.

Parent company: An affiliated company that exercises ultimate control over a business entity, either directly or indirectly, through one or more intermediaries.

Partial requirements consumer: A wholesale consumer with generating resources insufficient to carry all its load and whose energy seller is a long-term firm power source supplemental to the consumer's own generation or energy received from others. The terms and conditions of sale are similar to those for a full requirements consumer.

Particulate: A small, discrete mass of solid or liquid matter that remains individually dispersed in gas or liquid emissions. Particulates take the form of aerosol, dust, fume, mist, smoke, or spray. Each of these forms has different properties.

Parting: A layer of rock within a coalbed that lies roughly parallel to the coalbed and has the effect of splitting the bed into two divisions.

Passenger-miles traveled: The total distance traveled by all passengers. It is calculated as the product of the occupancy rate in vehicles and the vehicle miles traveled.

Passive solar heating: A solar heating system that uses no external mechanical power, such as pumps or blowers, to move the collected solar heat.

Payables to municipality: The amounts payable by the utility department to the municipality or its other departments that are subject to current settlement.

Payment method for utilities: The method by which fuel suppliers or utility companies are paid for all electricity, natural gas, fuel oil, kerosene, or liquefied petroleum gas used by a household. Households that pay the utility company directly are classified as "all paid by household." Households that pay directly for at least one but not all of their fuels used and that has at least one fuel charge included in the rent were classified as "some paid, some included in rent." Households for which all fuels used are included in rent were classified as "all included in rent." If the household did not fall into one of these categories, it was classified as "other." Examples of households falling into the "other" category are (1)households for which fuel bills were paid by a social service agency or a relative, and (2) households that paid for some of their fuels used but paid for other fuels through another arrangement.

PBR: Performance-Based Rates

PBR: pebble-bed reactor

PCB: PolyChlorinated Biphenyl

Peak day withdrawal: The maximum daily withdrawal rate (Mcf/d) experienced during the reporting period.

Peak demand: The maximum load during a specified period of time.

Peak kilowatt: One thousand peak watts.

Peak load: The maximum load during a specified period of time.

Peak load month: The month of greatest plant electrical generation during the winter heating season (Oct-Mar) and summer cooling season (Apr-Sept), respectively.

Peak load plant: A plant usually housing old, low-efficiency steam units, gas turbines, diesels, or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peak megawatt: One million peak watts.

Peak watt: A manufacturer's unit indicating the amount of power a photovoltaic cell or module will produce at standard test conditions (normally 1,000 watts per square meter and 25 degrees Celsius).

Peaking capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Peat: Peat consists of partially decomposed plant debris. It is considered an early stage in the development of coal. Peat is distinguished from lignite by the presence of free cellulose and a high moisture content (exceeding 70 percent). The heat content of air-dried peat (about 50 percent moisture) is about 9 million Btu per ton. Most U.S. peat is used as a soil conditioner. The first U.S. electric power plant fueled by peat began operation in Maine in 1990.

Pentanes plus: A mixture of liquid hydrocarbons, mostly pentanes and heavier, extracted from natural gas in a gas processing plant. Pentanes plus is equivalent to natural gasoline.

Percent difference: The relative change in a quantity over a specified time period. It is calculated as follows: the current value has the previous value subtracted from it; this new number is divided by the absolute value of the previous value; then this new number is multiplied by 100.

Percent utilization: The ratio of total production to productive capacity, times 100.

Perfluorocarbons (PFCs): A group of man-made chemicals composed of one or two carbon atoms and four to six fluorine atoms, containing no chlorine. PFCs have no commercial uses and are emitted as a byproduct of aluminum smelting and semiconductor manufacturing. PFCs have very high 100-year Global Warming Potentials and are very long-lived in the atmosphere.

Perfluoromethane: A compound (CF4) emitted as a byproduct of aluminum smelting.

Permanently discharged fuel: Spent nuclear fuel for which there are no plans for reinsertion in the reactor core.

Permeability: The ability of a rock formation to transmit fluids. A measure of how much resistance a rock formation has to the movement of fluids through it. Formations where fluids readily move through them are permeable and typically have many large, well-connected pores. Low-permeability formations typically are made up of finer grains or mixed grains with smaller, fewer, or less-interconnected pores. Permeability is measured in darcys.

Persian Gulf: The countries that surround the Persian Gulf are: Bahrain, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates.

Person: An individual, a corporation, a partnership, an association, a joint-stock company, a business trust, or an unincorporated organization.

Person-year: One whole year, or fraction thereof, worked by an employee, including contracted man power. Expressed as a quotient (to two decimal places) of the time units worked during a year (hours, weeks, or months) divided by the like total time units in a year. For example: 80 hours worked is 0.04 (rounded) of a person-year; 8 weeks worked is 0.15 (rounded) of a person-year; 12 months worked is 1 person-year. Contracted manpower includes survey crews, drilling crews, consultants, and other persons who worked under contract to support a firm's ongoing operations.

Personal computer: A microcomputer for producing written, programmed, or coded material; playing games; or doing calculations. Laptop and notebook computers are excluded for the purposes of EIA surveys.

Petrochemical feedstocks: Chemical feedstocks derived from refined or partially refined petroleum fraction, principally for use in the manufacturing of chemicals, synthetic rubber, and a variety of plastics.

Petrochemicals: Organic and in organic compounds and mixtures that include but are not limited to organic chemicals, cyclic intermediates, plastics and resins, synthetic fibers, elastomers, organic dyes, organic pigments, detergents, surface active agents, carbon black, and ammonia.

Petroleum: A broadly defined class of liquid hydrocarbon mixtures. Included are crude oil, lease condensate, unfinished oils, refined products obtained from the processing of crude oil, and natural gas plant liquids. Note: Volumes of finished petroleum products include non hydrocarbon compounds, such as additives and detergents, after they have been blended into the products.

Petroleum Administration for Defense District (PADD): The 50 U.S. states and the District of Columbia are divided into five districts, with PADD 1 further split into three subdistricts. PADDs 6 and 7 encompass U.S. territories. The PADDs include the states and territories listed below:

- PADD 1 (East Coast):
  - PADD 1A (New England): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
  - PADD 1B (Central Atlantic): Delaware, District of Columbia, Maryland, New Jersey, New York, and Pennsylvania.
  - PADD 1C (Lower Atlantic): Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.
- PADD 2 (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, and Wisconsin.
- PADD 3 (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.
- PADD 4 (Rocky Mountain): Colorado, Idaho, Montana, Utah, and Wyoming.
- PADD 5 (West Coast): Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.
- PADD 6: U.S. Virgin Islands and Puerto Rico.
- PADD 7: Guam, American Samoa and the Northern Mariana Islands Territory.

Map of the PADD districts (PADDs 6 and 7 are not shown on the map and are not included in U.S. totals for EIA data.)

Petroleum and other liquids: All petroleum including crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal to liquids and gas to liquids). Not included are liquefied natural gas (LNG) and liquid hydrogen. See liquid fuels.

Petroleum coke: See Coke (petroleum).

Petroleum coke, catalyst: The carbonaceous residue that is deposited on the catalyst used in many catalytic operations (e.g., catalytic cracking). Carbon is deposited on the catalyst, thus deactivating the catalyst. The catalyst is reactivated by burning off the carbon producing heat and CO2. The carbonaceous residue is not recoverable as a product.

Petroleum coke, marketable: Those grades of coke produced in delayed or fluid cokers that may be recovered as relatively pure carbon. Marketable petroleum coke may be sold as is or further purified by calcining.

Petroleum consumption: See Products supplied

Petroleum imports: Imports of petroleum into the 50 states and the District of Columbia from foreign countries and from Puerto Rico, the Virgin Islands, and other U.S. territories and possessions. Included are imports for the Strategic Petroleum Reserve and withdrawals from bonded warehouses for onshore consumption, offshore bunker use, and military use. Excluded are receipts of foreign petroleum into bonded warehouses and into U.S. territories and U.S. Foreign Trade Zones.

Petroleum jelly: A semi-solid oily product produced from de-waxing lubricating oil basestocks.

Petroleum products: Petroleum products are obtained from the processing of crude oil (including lease condensate), natural gas, and other hydrocarbon compounds. Petroleum products include unfinished oils, liquefied petroleum gases, pentanes plus, aviation gasoline, motor gasoline, naphtha-type jet fuel, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products.

Petroleum refinery: An installation that manufactures finished petroleum products from crude oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Petroleum stocks, primary: For individual products, quantities that are held at refineries, in pipelines and at bulk terminals that have a capacity of 50,000 barrels or more, or that are in transit thereto. Stocks held by product retailers and resellers, as well as tertiary stocks held at the point of consumption, are excluded. Stocks of individual products held at gas processing plants are excluded from individual product estimates but are included in other oils estimates and total.

PFCs: See Perfluorocarbons

PGA: Purchased Gas Adjustment

pH: A measure of acidity or alkalinity. A pH of 7 represents neutrality. Acid substances have lower pH. Basic substances have higher pH.

Photosynthesis: The manufacture by plants of carbohydrates and oxygen from carbon dioxide and water in the presence of chlorophyll, with sunlight as the energy source. Carbon is sequestered and oxygen and water vapor are released in the process.

Photovoltaic and solar thermal energy (as usedat electric utilities): Energy radiated by the sun as electromagnetic waves (electromagnetic radiation) that is converted at electric utilities into electricity by means of solar (photovoltaic) cells or concentrating (focusing) collectors.

Photovoltaic cell (PVC): An electronic device consisting of layers of semiconductor materials fabricated to form a junction (adjacent layers of materials with different electronic characteristics) and electrical contacts and being capable of converting incident light directly into electricity (direct current).

Photovoltaic cell net shipments: Represents the difference between photovoltaic cell shipments and photovoltaic cell purchases.

Photovoltaic module: An integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environmental degradation, and suited for incorporation in photovoltaic power systems.

Pig iron: Crude, high-carbon iron produced by reduction of iron ore in a blast furnace.

Pipeline (natural gas): A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of utilization. Also refers to a company operating such facilities.

Pipeline (petroleum): Crude oil and product pipelines used to transport crude oil and petroleum products, respectively (including interstate, intrastate, and intracompany pipelines), within the 50 states and the District of Columbia.

Pipeline freight: Refers to freight carried through pipelines, including natural gas, crude oil, and petroleum products (excluding water). Energy is consumed by various electrical components of the pipeline, including, valves, other, appurtenances attaches to the pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.

Pipeline fuel: Gas consumed in the operation of pipelines, primarily in compressors.

Pipeline purchases: Gas supply contracted from and volumes purchased from other natural gas companies as defined by the Natural Gas Act, as amended (52 Stat. 821), excluding independent producers, as defined in Paragraph 154.91(a), Chapter I, Title 18 of the Code of Federal Regulations.

Pipeline quality natural gas: A mixture of hydrocarbon compounds existing in the gaseous phase with sufficient energy content, generally above 900 British thermal units, and a small enough share of impurities for transport through commercial gas pipelines and sale to end-users.

Pipeline, distribution: A pipeline that conveys gas from a transmission pipeline to its ultimate consumer.

Pipeline, gathering: A pipeline that conveys gas from a production well/field to a gas processing plant or transmission pipeline for eventual delivery to end-use consumers.

Pipeline, transmission: A pipeline that conveys gas from a region where it is produced to a region where it is to be distributed.

Pipelines, rate regulated: FRS (Financial Reporting System Survey) establishes three pipeline segments: crude/liquid (raw materials); natural gas; and refined products. The pipelines included in these segments are all federally or State rate-regulated pipeline operations, which are included in the reporting company's consolidated financial statements. However, at the reporting company's option, intrastate pipeline operations may be included in the U.S. Refining/Marketing Segment if they would comprise less than 5 percent of U.S. Refining/Marketing Segment net PPE, revenues, and earnings in the aggregate; and if the inclusion of such pipelines in the consolidated financial statements adds less than $100 million to the net PPE reported for the U.S. Refining/Marketing Segment.

Pitcheblende: Uranium oxide (U_3O_8). It is the main component of high-grade African or domestic uranium ore and also contains other oxides and sulfides, including radium, thorium, and lead components.

Place in service: A vehicle is placed in service if that vehicle is new to the fleet and has not previously been in service for the fleet. These vehicles can be acquired as additional vehicles (increases the size of the company fleet), or as replacement vehicles to replace vehicles that are being retired from service (does not increase the size of the company fleet).

Planetary albedo: The fraction of incident solar radiation that is reflected by the Earth-atmosphere system and returned to space, mostly by back scatter from clouds in the atmosphere.

Planned generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained either (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Planning authority (electric): The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. NERC definition

Plant: A term commonly used either as a synonym for an industrial establishment or a generating facility or to refer to a particular process within an establishment.

Plant condensate: Liquid hydrocarbons recovered at inlet separators or scrubbers in natural gas processing plants at atmospheric pressure and ambient temperatures. Mostly pentanes and heavier hydrocarbons.

Plant hours connected to load: The number of hours the plant is synchronized to load over a time interval usually of 1 year.

Plant liquids: Those volumes of natural gas liquids recovered in natural gas processing plants.

Plant or gas processing plant: A facility designated to achieve the recovery of natural gas liquids from the stream of natural gas, which may or may not have been processed through lease separators and field facilities, and to control the quality of the natural gas to be marketed.

Plant products: Natural gas liquids recovered from natural gas processing plants (and in some cases from field facilities), including ethane, propane, butane, butane-propane mixtures, natural gasoline, plant condensate, and lease condensate.

Plant use: The electric energy used in the operation of a plant. Included is the energy required for pumping at pump-storage plants.

Plant-use electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant.

Play : A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play differs from an assessment unit; an assessment unit can include one or more plays. A play is often used to refer to a natural gas accumulation, i.e., a natural gas shale play. http://energy.cr.usgs.gov/WEcont/chaps/GL.pdf

Plugged-back footage: Under certain conditions, drilling operations may be continued to a greater depth than that at which a potentially productive formation is found. If production is not established at the greater depth, the well may be completed in the shallower formation. Except in special situations, the length of the well bore from the deepest depth at which the well is completed to the maximum depth drilled is defined as "plugged-back footage." Plugged-back footage is included in total footage drilled but is not reported separately.

Plutonium (Pu): A heavy, fissionable, radioactive, metallic element (atomic number 94) that occurs naturally in trace amounts. It can also result as a byproduct of the fission reaction in a uranium-fuel nuclear reactor and can be recovered for future use.

Pneumatic device: A device moved or worked by air pressure.

Pole-mile: A unit of measuring the simple length of an electric transmission/distribution line/feeder carrying electric conductors, without regard to the number of conductors carried.

Pole/Tower type: The type of transmission line supporting structure.

Polystyrene: A polymer of styrene that is a rigid, transparent thermoplastic with good physical and electrical insulating properties, used in molded products, foams, and sheet materials.

Polyvinyl chloride (PVC): A polymer of vinylchloride. Tasteless, odorless, insoluble in most organic solvents. A member of the family vinyl resin, used in soft flexible films for food packaging and in molded rigid products, such as pipes, fibers, upholstery, and bristles.

Pondage: The amount of water stored behind a hydroelectric dam of relatively small storage capacity; the dam is usually used for daily or weekly control of the flow of the river.

Pool: In general, a reservoir. In certain situations, a pool may consist of more than one reservoir.

Pool site: One or more spent fuel storage pools that has a single cask loading area. Each dry cask storage area is considered a separate site.

Population-weighted Degree Days: Heating or cooling degree days weighted by the population of the area in which the degree days are recorded. To compute national population-weighted degree days, the Nation is divided into nine Census regions comprised of from three to eight states that are assigned weights based on the ratio of the population of the region to the total population of the Nation. Degree day readings for each region are multiplied by the corresponding population weight for each region, and these products are then summed to arrive at the national population weighted degree day figure.

Pore: An intergranular space or discrete void within a rock that can contain natural gas, water, hydrocarbons, or other fluids. Porosity is the percentage of pore space, or pore volume, in a body of rock. If the pores are interconnected, the rock will have permeability.

Pore space: The open spaces or voids of a rock taken collectively. It is a measure of the amount of liquid or gas that may be absorbed or yielded by a particular formation.

Porosity: The percentage of pore space, or pore volume (in other words, the volume within sedimentary rock that can contain fluids). Primary porosity, such as spaces between grains that were not compacted or cemented together completely, develops during sedimentary rock deposition. Secondary porosity is developed when rock is altered, such as when some mineral grains dissolve from the rock. Fracture porosity can be generated by the development of fractures. Effective porosity is the interconnected pore volume in a rock that supports fluid flow in a reservoir. Total porosity is the total void space in the rock including isolated pores. Typically, effective porosity is less than total porosity.

Portable electric heater: A heater that uses electricity and that can be picked up and moved.

Portable fan: Box fans, oscillating fans, table or floor fans, or other fans that can be moved.

Portable kerosene heater: A heater that uses kerosene and that can be picked up and moved.

Post-mining emissions: Emissions of methane from coal occurring after the coal has been mined, during transport or pulverization.

Potential consumption: The total amount of consumption that would have occurred had the intensity of consumption remained the same over a period of time.

Potential peak reduction: The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. (Please note that Energy Efficiency and Load Building are not included in Potential Peak Reduction.) It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

Pounds (district heat): A weight quantity of steam, also used to denote a quantity of energy in the form of steam. The amount of usable energy obtained from a pound of steam depends on its temperature and pressure at the point of consumption and on the drop in pressure after consumption.

Power: The rate of producing, transferring, or using energy, most commonly associated with electricity. Power is measured in watts and often expressed in kilowatts (kW) or megawatts (mW). Also known as "real" or "active" power. See Active Power, Apparent Power, Reactive Power, Real Power

Power (electrical): An electric measurement unit of power called a voltampere is equal to the product of 1 volt and 1 ampere. This is equivalent to 1 watt for a direct current system, and a unit of apparent power is separated into real and reactive power. Real power is the work-producing part of apparent power that measures the rate of supply of energy and is denoted as kilowatts (kW). Reactive power is the portion of apparent power that does no work and is referred to as kilovars; this type of power must be supplied to most types of magnetic equipment, such as motors, and is supplied by generator or by electrostatic equipment. Voltamperes are usually divided by 1,000 and called kilovoltamperes (kVA). Energy is denoted by the product of real power and the length of time utilized; this product is expressed as kilowatthours.

Power ascension: The period of time between a plant's initial fuel loading date and its date of first commercial operation (including the low-power testing period). Plants in the first operating cycle (the time from initial fuel loading to the first refueling), which lasts approximately 2 years, operate at an average capacity factor of about 40 percent.

Power exchange: An entity providing a competitive spot market for electric power through day- and/or hour-ahead auction of generation and demand bids.

Power exchange generation: Generation scheduled by the power exchange. See definition for power exchange.

Power exchange load: Load that has been scheduled by the power exchange and is received through the use of transmission or distribution facilities owned by participating transmission owners.

Power factor: The ratio of real power (kilowatt) to apparent power kilovolt-ampere for any given load and time.

Power loss: The difference between electricity input and output as a result of an energy transfer between two points.

Power marketers: Business entities engaged in buying and selling electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission (FERC) for status as a power marketer.

Power pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Power production plant: All the land and land rights, structures and improvements, boiler or reactor vessel equipment, engines and engine-driven generator, turbo generator units, accessory electric equipment, and miscellaneous power plant equipment are grouped together for each individual facility.

Power transfer limit: The maximum power that can be transferred from one electric utility system to another without overloading any facility in either system.

Powerhouse: A structure at a hydroelectric plant site that contains the turbine and generator.

PPE, additions to: The current year's expenditures on property, plant, and equipment (PPE). The amount is predicated upon each reporting company's accounting practice. That is, accounting practices with regard to capitalization of certain items may differ across companies, and therefore this figure in FRS (Financial Reporting System) will be a function of each reporting company's policy.

PPI: Producer Price Index

Prediscovery costs: All costs incurred in an extractive industry operation prior to the actual discovery of minerals in commercially recoverable quantities; normally includes prospecting, acquisition, and exploration costs and may include some development costs.

Pregnant solution: A solution containing dissolved extractable mineral that was leached from the ore; uranium leach solution pumped up from the underground ore zone though a production hole.

Preliminary permit (hydroelectric power): A single site permit granted by the FERC (Federal Energy Regulatory Commission), which gives the recipient priority over anyone else to apply for a hydroelectric license. The preliminary permit enables the recipient to prepare a license application and conduct various studies for economic feasibility and environmental impacts. The period for a preliminary permit may extend to 3 years.

Premium gasoline: Gasoline having an antiknock index, i.e., octane rating, greater than 90. Includes both leaded premium gasoline as well as unleaded premium gasoline. Note: Octane requirements may vary by altitude. See Octane Rating.

Preparation plant: A mining facility at which coal is crushed, screened, and mechanically cleaned.

Preproduction costs: Costs of prospecting for, acquiring, exploring, and developing mineral reserves incurred prior to the point when production of commercially recoverable quantities of minerals commences.

Pressurized-water reactor (PWR): A nuclear reactor in which heat is transferred from the core to a heat exchanger via water kept under high pressure, so that high temperatures can be maintained in the primary system without boiling the water. Steam is generated in a secondary circuit.

Preventive maintenance program for heating and/or cooling equipment: A HVAC conservation feature consisting of a program of routine inspection and service for the heating and/or cooling equipment. The inspection is performed on a regular basis, even if there are no apparent problems.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Primary coal: All coal milled and, when necessary, washed and sorted.

Primary energy: Energy in the form that it is first accounted for in a statistical energy balance, before any transformation to secondary or tertiary forms of energy. For example, coal can be converted to synthetic gas, which can be converted to electricity; in this example, coal is primary energy, synthetic gas is secondary energy, and electricity is tertiary energy. See Primary energy production and Primary energy consumption.

Primary energy consumption: Consumption of primary energy. The U.S. Energy Information Administration includes the following in U.S. primary energy consumption:

- Coal consumption
- Coal coke net imports
- Petroleum consumption (petroleum products supplied)
- Dry natural gas—excluding supplemental gaseous fuels—consumption
- Nuclear electricity net generation (converted to Btu using the average annual heat rate of nuclear plants)
- Conventional hydroelectricity net generation (converted to Btu using the average annual heat rate of fossil-fuel fired plants)
- Geothermal electricity net generation (converted to Btu using the average annual heat rate of fossil-fuel fired plants), geothermal heat pump energy and geothermal direct-use energy
- Solar thermal and photovoltaic electricity net generation (converted to Btu using the average annual heat rate of fossil-fuel fired plants)
- Solar thermal direct-use energy
- Wind electricity net generation (converted to Btu using the average annual heat rate of fossil-fuel fired plants)
- Wood and wood-derived fuels consumption
- Biomass waste consumption
- Fuel ethanol and biodiesel consumption
- Losses and co-products from the production of fuel ethanol and biodiesel
- Electricity net imports (converted to Btu using the electricity heat content of 3,412 Btu per kilowatthour)

Primary energy consumption also includes all non-combustion uses of fossil fuels. Energy sources produced from other energy sources—e.g., coal coke from coal—are included in primary energy consumption only if their energy content has not already been included as part of the original energy source. As a result, U.S. primary energy consumption does include net imports of coal coke, but it does not include the coal coke produced from domestic coal.

Primary energy consumption expenditures: Expenditures for energy consumed in each of the four major end-use sectors, excluding energy in the form of electricity, plus expenditures by the electric utilities sector for energy used to generate electricity. There are no fuel-associated expenditures for associated expenditures for hydroelectric power, geothermal energy, photovoltaic and solar energy, or wind energy. Also excluded are the quantifiable consumption expenditures that are an integral part of process fuel consumption.

Primary energy production: Production of primary energy. The U.S. Energy Information Administration includes the following in U.S. primary energy production: coal production, waste coal supplied, and coal refuse recovery; crude oil and lease condensate production; natural gas plant liquids production; dry natural gas excluding supplemental gaseous fuels production; nuclear electricity net generation (converted to Btu using the nuclear plant heat rates); conventional hydroelectricity net generation (converted to Btu using the fossil-fuels plant heat rates); geothermal electricity net generation (converted to Btu using the fossil-fuels plant heat rates), and geothermal heat pump energy and geothermal direct use energy; solar thermal and photovoltaic electricity net generation (converted to Btu using the fossil-fuels plant heat rates), and solar thermal direct use energy; wind electricity net generation (converted to Btu using the fossil-fuels plant heat rates); wood and wood-derived fuels consumption; biomass waste consumption; and biofuels feedstock.

Primary fuels: Fuels that can be used continuously. They can sustain the boiler sufficiently for the production of electricity.

Primary metropolitan statistical area (PMSA): A component area of a Consolidated metropolitan statistical area consisting of a large urbanized county or cluster of counties (cities and towns in New England) that demonstrate strong internal economic and social links in addition to close ties with the central core of the larger area. To qualify, an area must meet specified statistical criteria that demonstrate these links and have the support of local opinion.

Primary recovery: The crude oil or natural gas recovered by any method that may be employed to produce them where the fluid enters the well bore by the action of natural reservoir pressure(energy or gravity).

Primary transportation: Conveyance of large shipments of petroleum raw materials and refined products usually by pipeline, barge, or ocean-going vessel. All crude oil transportation is primary, including the small amounts moved by truck. All refined product transportation by pipeline, barge, or ocean-going vessel is primary transportation.

Prime mover: The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cells).

Prime supplier: A firm that produces, imports, or transports selected petroleum products across State boundaries and local marketing areas, and sells the product to local distributors, local retailers, or end users.

Private fueling facility: A fueling facility which normally services only fleets and is not open to the general public.

Privately owned electric utility: A class of ownership found in the electric power industry where the utility is regulated and authorized to achieve an allowed rate of return.

Probable (indicated) reserves, coal: Reserves or resources for which tonnage and grade are computed partly from specific measurements, samples, or production data and partly from projection for a reasonable distance on the basis of geological evidence. The sites available are too widely or otherwise in appropriately spaced to permit the mineral bodies to be outlined completely or the grade established throughout.

Probable energy reserves: Estimated quantities of energy sources that, on the basis of geologic evidence that supports projections from **proved reserves**, can reasonably be expected to exist and be recoverable under existing economic and operating conditions. Site information is insufficient to establish with confidence the location, quality, and grades of the energy source. Note: This term is equivalent to "Indicated Reserves" as defined in the resource/reserve classification contained in the U.S. Geological Survey Circular 831, 1980. Measured and indicated reserves, when combined, constitute **demonstrated reserves**.

Process cooling and refrigeration: The direct process end use in which energy is used to lower the temperature of substances involved in the manufacturing process. Examples include freezing processed meats for later sale in the food industry and lowering the temperature of chemical feedstocks below ambient temperature for use in reactions in the chemical industries. Not included are uses such as air-conditioning for personal comfort and cafeteria refrigeration.

Process fuel: All energy consumed in the acquisition, processing, and transportation of energy. Quantifiable process fuel includes three categories natural gas lease and plant operations, natural gas pipeline operations, and oil refinery operations.

Process heating or cooling demand-side management (DSM) program: A DSM program designed to promote increased electric energy efficiency applications in industrial process heating or cooling.

Process heating or cooling waste heatrecovery: An energy conservation system whereby some space heating or water heating is done by actively capturing byproduct heat that would otherwise be ejected into the environment. In nonresidential buildings, sources of waste heat include refrigeration/air-conditioner compressors, manufacturing or other processes, data processing centers, lighting fixtures, ventilation exhaust air, and the occupants themselves. Not to be considered is the passive use of radiant heat from lighting, workers, motors, ovens, etc., when there are no special systems for collecting and redistributing heat.

Processed gas: Natural gas that has gone through a processing plant.

Processing: Uranium-recovery operations whether at a mill, an in situ leach, byproduct plant, or other type of recovery operation.

Processing gain: The volumetric amount by which total output is greater than input for a given period of time. This difference is due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.

Processing loss: The volumetric amount by which total refinery output is less than input for a given period of time. This difference is due to the processing of crude oil into products which, in total, have a higher specific gravity than the crude oil processed.

Processing of uranium: The recovery of uranium produced by nonconventional mining methods, i.e., in situ leach mining, as a byproduct of copper or phosphate mining, or heap leaching.

Processing plant: A surface installation designed to separate and recover natural gas liquids from a stream of produced natural gas through the processes of condensation, absorption, adsorption, refrigeration, or other methods and to control the quality of natural gas marketed and/or returned to oil or gas reservoirs for pressure maintenance, repressuring, or cycling.

Producer: A company engaged in the production and sale of natural gas from gas or oil wells with delivery generally at a point at or near the wellhead, the field, or the tailgate of a gas processing plant. For the purpose of company classification, a company primarily engaged in the exploration for, development of, and/or production of oil and/or natural gas.

Producer and distributor coal stocks: Producer and distributor coal stocks consist of coal held in stock by producers/distributors at the end of a reporting period.

Producer contracted reserves: The volume of recoverable salable gas reserves committed to or controlled by the reporting pipeline company as the buyer in gas purchase contracts with the independent producer as seller, including warranty contracts, and which are used for acts and services for which the company has received certificate authorization from the Federal Energy Regulatory Commission.

Producing property: A term often used in reference to a property, well, or mine that produces wasting natural resources. The term means a property that produces in paying quantities (that is, one for which proceeds from production exceed operating expenses).

Product supplied: Approximately represents consumption of petroleum products because it measures the disappearance of these products from primary sources, i.e., refineries, natural gas-processing plants, blending plants, pipelines, and bulk terminals. In general, product supplied of each product in any given period is computed as follows field production, plus refinery production, plus imports, plus unaccounted-for crude oil (plus net receipts when calculated on a PAD District basis) minus stock change, minus crude oil losses, minus refinery inputs, and minus exports.

Production: See production terms associated with specific energy types.

Production capacity: The amount of product that can be produced from processing facilities.

Production costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. The following are examples of production costs (sometimes called lifting costs): costs of labor to operate the wells and related equipment and facilities; repair and maintenance costs; the costs of materials, supplies, and fuels consumed and services utilized in operating the wells and related equipment and facilities; the costs of property taxes and insurance applicable to proved properties and wells and related equipment and facilities; the costs of severance taxes. Depreciation, depletion, and amortization (DDA) of capitalized acquisition, exploration, and development costs are not production costs, but also become part of the cost of oil and gas produced along with production (lifting) costs identified above. Production costs include the following subcategories of costs: well workers and maintenance; operating fluid injections and improved recovery programs; operating gas processing plants; ad valorem taxes; production or severance taxes; other, including overhead.

Production expenses: Costs incurred in the production of electric power that conform to the accounting requirements of the Operation and Maintenance Expense Accounts of the FERC Uniform System of Accounts.

Production payments: A contractual arrangement providing a mineral interest that gives the owner a right to receive a fraction of production, or of proceeds from the sale of production, until a specified quantity of minerals (or a definite sum of money, including interest) has been received.

Production plant liquids: The volume of liquids removed from natural gas in natural gas processing plants or cycling plants during the year.

Production, crude oil: The volumes of crude oil that are extracted from oil reservoirs. These volumes are determined through measurement of the volumes delivered from lease storage tanks or at the point of custody transfer, with adjustment for (1) net differences between opening and closing lease inventories and (2) basic sediment and water. Crude oil used on the lease is considered production.

Production, lease condensate: The volume of lease condensate produced. Lease condensate volumes include only those volumes recovered from lease or field separation facilities.

Production, natural gas: The volume of natural gas withdrawn from reservoirs less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs, and conservation operations; less (2) shrinkage resulting from the removal of lease condensate; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. Flared and vented gas is also considered production. (This differs from "Marketed Production" which excludes flared and vented gas.)

Production, natural gas liquids: Production of natural gas liquids is classified as follows:

- **Contract Production**. Natural gas liquids accruing to a company because of its ownership of liquids extraction facilities that it uses to extract liquids from gas belonging to others, thereby earning a portion of the resultant liquids.
- **Leasehold Production**. Natural gas liquids produced, extracted, and credited to a company's interest.
- **Contract Reserves**. Natural gas liquid reserves corresponding to the contract production defined above.
- **Leasehold Reserves**. Natural gas liquid reserves corresponding to leasehold production defined above.

Production, natural gas, dry: The volume of natural gas withdrawn from reservoirs during the report year less:

1. the volume returned to such reservoirs in cycling, repressuring of oil reservoirs, and conservation operations; less
2. shrinkage resulting from the removal of lease condensate and plant liquids; and less
3. nonhydrocarbon gases where they occur insufficient quantity to render the gas unmarketable.

Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, because the latter also excludes vented and flared gas, but contains plant liquids.

Production, natural gas, wet after lease separation: The volume of natural gas withdrawn from reservoirs less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs, and conservation operations; less (2) shrinkage resulting from the removal of lease condensate; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Note: Volumes of gas withdrawn from gas storage reservoirs and native gas that has been transferred to the storage category are not considered part of production. This production concept is not the same as marketed production, which excludes vented and flared gas.

Production, oil and gas: The lifting of oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. The production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank. If unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

Production, wet after lease separation: See production, natural gas, wet after lease separation.

Productive capacity: The maximum amount of coal that a mining operation can produce or process during a period with the existing mining equipment and/or preparation plant in place, assuming that the labor and materials sufficient to utilize the plant and equipment are available, and that the market exists for the maximum production.

Profit: The income remaining after all business expenses are paid.

Program cost: Utility costs that reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM (demand-side management) programs. They are reported in the year they are incurred, regardless of when the actual effects occur.

Propane (C_3H_8): A straight-chain saturated (paraffinic) hydrocarbon extracted from natural gas or refinery gas streams, which is gaseous at standard temperature and pressure. It is a colorless gas that boils at a temperature of -44 degrees Fahrenheit. It includes all products designated in ASTM Specification D1835 and Gas Processors Association specifications for commercial (HD-5) propane.

Propane air: A mixture of propane and air resulting in a gaseous fuel suitable for pipeline distribution.

Propane, consumer grade: A normally gaseous paraffinic compound (C_3H_8), which includes all products covered by Natural Gas Policy Act Specifications for commercial and HD-5 propane and ASTM Specification D 1835. Excludes: feedstock propanes, which are propanes not classified as consumer grade propanes, including the propane portion of any natural gas liquid mixes, i.e., butane-propane mix.

Proportional interest in investee reserves: The proportional interest at the end of the year in the reserves of investees that are accounted for by the equity method.

Proposed rates: New electric rate schedule proposed by an applicant to become effective at a future date.

Propylene (C_3H_6): An olefinic hydrocarbon recovered from refinery or petrochemical processes, which is gaseous at standard temperature and pressure. Propylene is an important petrochemical feedstock.

Prospecting: The search for an area of probable mineralization; the search normally includes topographical, geological, and geophysical studies of relatively large areas undertaken in an attempt to locate specific areas warranting detailed exploration. Prospecting usually occurs prior to the acquisition of mineral rights.

Prospecting costs: Direct and indirect costs incurred to identify areas of interest that may warrant detailed exploration. Such costs include those incurred for topographical, geological, and geophysical studies; rights of access to properties in order to conduct such studies, salaries, equipment, instruments, and supplies for geologists, including geophysical crews, and others conducting such studies; and overhead that can be identified with those activities.

Proved (measured) reserves, coal: Reserves or resources for which tonnage is computed from dimensions revealed in outcrops, trenches, workings, and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, and mineral content are well established. The computed tonnage and grade are judged to be accurate within limits that are stated, and no such limit is judged to be different from the computed tonnage or grade by more than 20 percent.

Proved energy reserves: Estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions. The location, quantity, and grade of the energy source are usually considered to be well established in such reserves. Note: This term is equivalent to "Measured Reserves" as defined in the resource/reserve classification contained in the U.S. Geological Survey Circular 831, 1980. Measured and indicated reserves, when combined, constitute demonstrated reserves.

Public authorities: Electricity supplied to municipalities, divisions, or agencies of state and Federal governments, usually under special contracts or agreements that are applicable only to public authorities.

Public authority service to public authorities: Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State or Federal governments under special contracts, agreements, or service classifications applicable only to public authorities.

Public street and highway lighting: Electricity supplied and services rendered for the purpose of lighting streets, highways, parks, and other public places; or for traffic or other signal system service, for municipalities or other divisions or agencies of State or Federal governments.

Public utility: Enterprise providing essential public services, such as electric, gas, telephone, water, and sewer under legally established monopoly conditions.

Public utility district: Municipal corporations organized to provide electric service to both incorporated cities and towns and unincorporated rural areas.

Public Utility Holding Company Act of 1935 (PUHCA): This act prohibits acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric business. The legislation also restricts ownership of an electric business by non-utility corporations.

Public Utility Regulatory Policies Act of 1978: The Public Utility Regulatory Policies Act of1978, passed by the U.S. Congress. This statute requires States to implement utility conservation programs and create special markets for co-generators and small producers who meet certain standards, including the requirement that States set the prices and quantities of power the utilities must buy from such facilities.

Public Utility Regulatory PoliciesAct (PURPA) of 1978: One part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. Principal among these were suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources. The Commission has primary authority for implementing several key PURPA programs.

Publicly owned electric utility: A class of ownership found in the electric power industry. This group includes those utilities operated by municipalities and State and Federal power agencies.

PUD: See Public Utility District

PUHCA: See Public Utility Holding Company Act of 1935

Pulp chips: Timber or residues processed into small pieces of wood of more or less uniform dimensions with minimal amounts of bark.

Pulp wood: Roundwood, whole-tree chips, or wood residues.

Pulping liquor (black liquor): The alkaline spent liquor removed from the digesters in the process of chemically pulping wood. After evaporation, the liquor is burned as a fuel in a recovery furnace that permits the recovery of certain basic chemicals.

Pumped-storage hydroelectric plant: A plant that usually generates electric energy during peak load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Purchase-contract imports of uranium: The amount of foreign-origin uranium material that enters the United States during a survey year as reported on the "Uranium Industry Annual Survey (UIAS), Form EIA-858, as purchases of uranium ore, U_3O_8, natural UF_6, or enriched UF_6. The amount of foreign-origin uranium materials that enter the country during a survey year under other types of contracts, i.e., loans and exchanges, is excluded.

Purchased: Receipts into transportation, storage, and/or distribution facilities within a state under gas purchase contracts or agreements whether or not billing or payment occurred during the report year.

Purchased power: Power purchased or available for purchase from a source outside the system.

Purchased power adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and its cost varies from a specified unit base amount.

Pure pumped-storage hydroelectric plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

PURPA: See Public Utility Regulatory Policies Act of 1978

PV: Photovoltaic

PVC: See Photovoltaic Cell; polyvinyl chloride

PVCs that convert sunlight directly into energy: A method for producing energy by converting sunlight using photovoltaic cells (PVCs) that are solid-state single converter devices. Although currently not in wide usage, commercial customers have a growing interest in usage and, therefore, DOE has a growing interest in the impact of PVCs on energy consumption. Economically, PVCs are competitive with other sources of electricity.

PWR: See Pressurized-Water Reactor

Pyrolysis: The thermal decomposition of biomass at high temperatures (greater than 400° F, or 200° C) in the absence of air. The end product of pyrolysis is a mixture of solids (char), liquids (oxygenated oils), and gases (methane, carbon monoxide, and carbondioxide) with proportions determined by operating temperature, pressure, oxygen content, and other conditions.

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LETTER

Implications of the timing of residential natural gas use for appliance electrification efforts

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Abstract

Current strategies for deep decarbonization of the residential building sector invoke the following three pillars of action: (1) radically improve the efficiency of end-use electricity consumption, (2) shift to 100% renewable generation of electrical grid power, and (3) move aggressively to electrify all remaining fossil fuel end-uses. Due to the previous unavailability of high temporal resolution natural gas consumption data, the pursuit of this policy agenda has largely occurred in the absence of a thorough understanding of hourly variations in the intensity of household natural gas use. These variations can have important downstream impacts on the electricity system once electrification has been achieved. This study presents a series of analyses which are based upon a novel dataset of hourly interval natural consumption data obtained for (N = 17,072) households located within a low-income portion of Southern California Gas Company's service territory. Results indicate that diurnal patterns of hourly natural gas use largely coincide with the timing of daily peak electricity loads. These findings suggest that the aggressive electrification of residential end-use appliances has the potential to exacerbate daily peak electricity demand, increase total household expenditures on energy, and, in the absence of a fully decarbonized electrical grid, likely result in only limited greenhouse gas emissions abatement benefits.

1. Introduction

1.1. Deep decarbonization pathways

Among global OECD countries, energy consumed within residential buildings can account for between 16–22% of total domestic primary energy use [1]. The greenhouse gas (GHG) emissions associated with this consumption is a major contributor to anthropogenic global climate change. Within the U.S., integrated assessments conducted at both the state and national levels have found electrification to be the cheapest and most efficacious approach to the deep decarbonization of the residential building sector [2–5]. A pair of 2017 studies published by National Renewable Energy Laboratory (NREL) investigating the potential impacts of widespread electrification found that existing barriers within the residential building sector could be overcome with public intervention [6, 7]. These studies also concluded that while the electrification of space and water heating end-uses would increase electricity loads, the rate and extent of this growth could be effectively managed through concomitant energy efficiency measures.

Investigations of California's residential energy sector funded by the California Energy Commission (CEC), the California Public Utility Commission (CPUC), and others have arrived at similar conclusions. A 2015 review of statewide energy models with GHG mitigation scenarios found that electrification of residential buildings was a less costly and uncertain option for meeting the state's GHG abatement goals than the other alternatives considered, including those involving the large scale production of renewable gas [8]. A 2019 CPUC funded study of low-rise residential building electrification also came to a similar conclusion: assuming that government intervention sufficiently decreases the cost of fuel-switching and increases residential energy efficiency, electrification was deemed the most feasible and least costly approach [9].

1.2. California's policy context

California is the world's fifth largest economy and, due to its historically progressive legislature, has become a testbed for energy policy innovation. The state's efforts to decarbonize residential buildings are subsumed under its major climate change mitigation law, Assembly Bill 32 [10]. Passed in 2006, AB 32 gave the California Air Resources Board (CARB) the authority to plan and coordinate efforts to meet initial GHG abatement targets set earlier that year by Executive Order S-3-05 [10]. AB 32 directed CARB to create a Climate Change Scoping Plan, in which:

> *...the maximum technologically feasible and cost-effective reductions in GHG emissions from sources or categories of sources of GHGs were to be identified and pursued* [11].

Public agencies are then responsible for devising and implementing measures to realize these reductions, and ensuring that the entities they regulate comply.

Accordingly, California is moving to expand programs to encourage residential electrification. In 2019 the CPUC decided to allow investor-owned utilities (IOUs) to offer incentives for electric space and water heaters as part of their energy efficiency programs, on which over a billion dollars are spent annually [12]. As of 2020, the CPUC has begun considering whether to introduce additional fuel-switching incentives directed at residential consumers [13]. Decarbonization efforts are also supported by the CEC's funding of related research studies, policy evaluations, and demonstrations of new efficiency and electric heating technologies.

California's push to decarbonize its residential building sector comes during an awkward economic moment however. The explosion in domestic natural gas extraction enabled by hydraulic fracturing has led to precipitous declines in the price of natural gas [14]. Meanwhile the costs of generating and transmitting electricity are expected to rise in the short and medium-term, driven by aging grid infrastructure and the integration of more renewable generating capacity in accordance with the state's Renewable Portfolio Standard (RPS) [15, 16]. These price trends may weaken incentives for consumers to electrify end-uses of natural gas and other fossil fuels, slowing the proliferation of electric heating technologies in existing buildings, and increasing energy costs for those consumers already living in fully electrified structures.

The decision by the CPUC to require IOUs to transition all of their customers to Time-of-Use (TOU) rate structures also potentially complicates decarbonization of the residential building sector. Initiated by CPUC Decision D.15.07-001, IOUs were to begin transitioning residential customers to TOU rates in 2019, but the rollout of these new rate structures has been delayed in some instances to 2020 or 2021 out of concern for their impacts on low-income customers and other implementation issues [17]. TOU rate structures are intended to better match the supply of renewable energy with demand by disincentivizing consumption during peak periods. This, it is hoped, will reduce the need for additional investment in generation and transmission infrastructure. However, the effects of TOU rates on the total expenditures on energy among different customer groups are still uncertain [18, 19].

There have been a number of recently published studies focused on the systemic impacts likely to result from the more widespread electrification of California's residential building sector [20–22]. In all of these however, diurnal patterns of gas use were either estimated or inferred using a combination of national lab reference data, ground-up physics based simulation model results, and household survey responses. This study's analyses are based upon a large and novel sample of hourly interval, metered natural gas consumption data. These real-world usage data are combined with available information about average hourly residential electricity loads, domestic electricity and natural gas rate tariff schedules, and hourly grid electricity GHG emissions intensities to deliver important insights about the potential for electrification efforts to contribute to electricity load growth, increase total household expenditures on energy, and achieve GHG emissions abatement.

2. Methods

2.1. Account level hourly gas use data

Account level hourly natural gas usage data were requested from Southern California Gas (SCG) for all residential accounts located within two target zipcodes: 91746 & 91732. These zipcodes comprise environmentally disadvantaged communities within the areas South El Monte, Bassett, and Avocado Heights, as determined from census tract level CalEnviroScreen 3.0 aggregate scores ($\geq$ 75*th percentile*) [23]. This sample was specifically selected to be representative of communities with high proportions of renters and low-income families - household types which are known to be the most challenging, but also among the most important, to reach through decarbonization efforts [24]. This data request was submitted through SCG's public Energy Data Access Program (EDRP) website on 6/18/2019 [25]. Following a

Table 1. Included attributes for SCG customers in the provided sample of customer hourly natural gas usage data.

Attribute	Description
BILL_ACT_KEY	Bill account key associated with each service address
MTR_BDG_NBR	Meter badge ID number
MTR_DESC	Meter type description (Individually Metered, Master Metered, etc)
DA_NBR	Service address house number
SVC_ADDR1	Service address street name and type
SVC_ADRR2	Additional service address information such as apartment numbers
SVC_CITY	Service address city
SVC_STATE	Service address state
SVC_ZIP	Service address 5-digit ZIP Code
RATE	Billing rate code

review period under the EDRP protocol and the signing of a non-disclosure agreement between SCG and UCLA, the request was successfully processed and the requested data released via a secure Electronic Data Transfer (EDT) portal on 9/25/2019. The usage data provided comprised one year's worth of usage for a total of (N = 17,072) individual households. The attributes included within the data provided by SCG are detailed in table 1. For all normalized energy comparison involving natural gas an energy unit conversion factor of (99,976.12 $Btu/_{US}Therm$) was used.

2.2. Static hourly electricity load profile data

Static hourly electricity load profile data computed from the sample of all Southern California Edison (SCE) residential customers was obtained from the SCE website for the 2018 & 2019 calendar years. Data files for these two years were concatenated and filtered to reflect the data collection period (8/8/2018 - 8/15/2019) for the sample of SCG usage data. For all normalized energy unit comparison calculations involving electricity an energy conversion factor of (3,412.14 Btu/kWh) was used. A discussion of the comparability of statistics derived from these two data samples has been provided in the supplementary material submitted in conjunction with this manuscript.

2.3. Electrical appliance energy efficiency gains

When evaluating the potential for electrification efforts to contribute to a daily peak electricity loads it is necessary to consider whether the electric versions of appliances might be more or less energy efficient. Previous work by Ebrahimi *et al* has characterized the range of end-use energy efficiency gains for available electrical alternatives to common residential natural-gas appliances [20]. Due to the uncertainties involving the technology implementation choices of future electrification efforts, we used this range efficiency values to calculate the best/worst case scenarios in terms of the average household wide efficiency gain expected from full house electrification. We then applied this range of efficiency factors to generate lower and upper bounds on the expected contribution of fuel switching to daily peak electricity load growth.

2.4. CAISO hourly GHG emissions intensity data

15 minute interval grid generation supply mix data were obtained from CAISO through the OASIS application programmatic interface (API). A nearly continuous time series was assembled for a nine year historical period spanning 1/1/2010 through 12/31/2019. There were a small number of days ($N < 15$) during this period for which information was not available through the OASIS API. GHG emissions intensity factors (kg CO_2/MWh) for each generator category were obtained from The Climate Registry for the relevant data periods [26]. Hourly average GHG emissions intensities were computed by applying generator specific factors to hourly generator output data and aggregating according to hour of day.

2.5. Electricity and Gas utility rate tariff data

bDomestic electricity rate tariffs for SCE were obtained from NREL's OpenEI utility rate tariff database [27]. The tariff schedules under consideration were restricted to SCE's currently available domestic TOU rates: *TOU-D-4-9PM*, *TOU-D-5-8PM*, *TOU-D-PRIME*. Domestic natural gas rate tariffs for SCG were obtained from regulatory filings: *SCHEDULE-GR* [28]. For natural gas, seasonal variations in fuel procurement costs were addressed by assessing the range of reported monthly procurement costs over the previous year. In order to enhance the comparability of rates between fuel types, only baseline tier consumption levels were considered. This was done to avoid the need to address differences in demand charges at successive consumption tiers between the two fuel types.

3. Results

3.1. Temporal patterns in residential gas use

Figure 1 contains a set of fan-plots which depict the average hourly natural gas use rates per household aggregated across the months in the year (a), the days in the week (b), and the hours in the day (c) observed within our sample of hourly interval natural gas usage data. This type of plot is useful for illustrating changes in the distribution of values across discrete periods in time. The quantiles of the distribution of natural gas use rates are broken into 5-percentile intervals, each of which is plotted as a continuous horizontal band of color. According to this convention, the top and bottom-most bands, which are shown with the greatest transparency, correspond to the 95^{th} and the 5^{th} percentiles, respectively. Similarly, the 50^{th} percentiles, which correspond to the median values, are plotted as solid black lines.

The first subplot (figure 1(a)) shows, as expected, that average hourly rates of natural gas use are higher in winter months (December–February) than in summer months (June–August). What is interesting about this trend however, is the absolute magnitude of the variation in peak use rates between the different months. For example, in this particular year, the overall maximum use rates occurred during the month of February and reached levels which 2.5*x* higher than the highest rates of use observed at any time throughout the summer period. This degree of seasonal variation in peak consumption levels is larger that that which is commonly observed relative to residential electricity load profiles, even among households with heavy summer air conditioning use.

The second subplot (figure 1(b)) shows that on average, median rates of natural gas use tend to be somewhat higher during the weekend than during the work week. However, in the case of this trend, the magnitude of the differences are far less significant than the seasonal trends. Moreover, the minimum and maximum percentiles of average hourly use rates are fairly consistent across all of the days in the week. This indicates that the cadence of the common work schedule is not a hugely significant determinant of average rates of natural gas use within the sampled homes.

Finally, in the third subplot (figure 1(c)) there is significant diurnal variation in hourly natural gas use rates. This average hourly natural gas use rate profile is characterized by two two distinct peaks: one in the morning, beginning at 5 AM and tapering off around Noon, and then another in the evening, beginning around 4PM and then tapering off again around 9PM. Crucially, this pattern of variation almost exactly mimics the well-known pattern of diurnal variations in electricity demand.

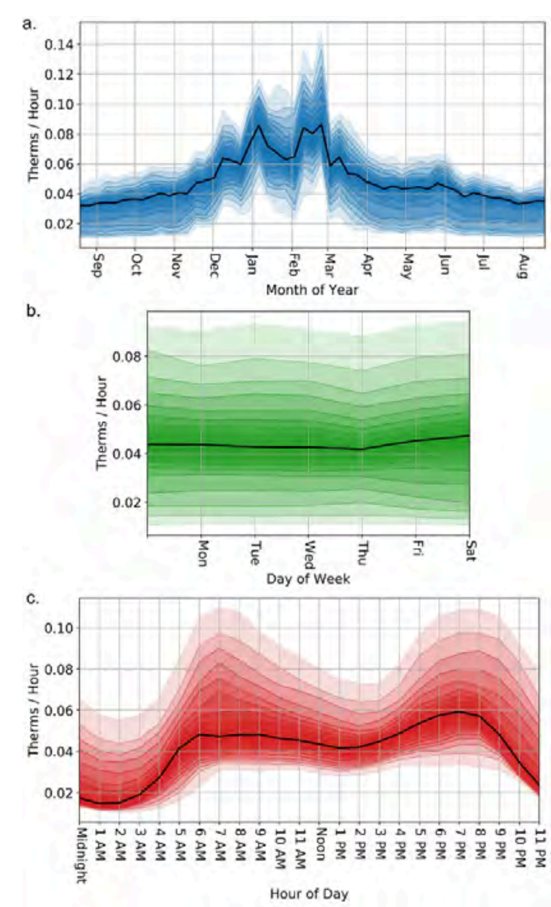

Figure 1. Fan-plots illustrating variations in monthly (a), daily (b), and hourly (c) patterns of average hourly natural gas usage rates computed for a sample of (N = 17,072) SoCal Gas residential accounts between 8/15/2018 - 8/15/2019.

3.2. Implications for peak electricity load growth

The first issue stemming from these observed patterns in hourly natural gas use relates to the potential for household appliance electrification to exacerbate peak electricity loads. Figure 2 contains a set of subplots which illustrate how the full electrification of the average residential household could potentially impact daily peak electricity loads. The first of these subplots (figure 2(a)) provides a direct comparison of daily peak energy demands for natural gas versus electricity for the typical residential household. This comparison is provided in standardized energy units of ($MMBtu/hr$). In the case of natural gas, the typical household represents an aggregation of use data collected from the 17,072 households sampled as part of this study. Conversely, in the case of electricity, the average household represents an aggregation of usage data collected from all of the residential service accounts throughout SCE's entire service territory. These data are made publicly available by SCE as part of CPUC regulatory reporting requirements.

As expected, daily peak natural gas loads were found to be largest during the winter months while daily peak electricity loads were found to be largest during summer months. More important that these seasonal variations however, were the relative magnitudes of the peak loads observed for each energy source. The average daily peak load for natural gas was (0.007135 $MMBtu/hr$). This is more than twice the average daily peak load levels calculated for electricity, at (0.003613$MMBtu/hr$).

The second subplot (figure 2(b)) provides an area plot depicting a range of percentage increases in peak daily electricity loads which have been calculated assuming: the full electrification of all existing natural gas end-uses and the application of a set of upper (75%—green) and lower bounds (17%—red) on the efficiency gain of electrified appliances. As this data shows, even with aggressive assumptions about the

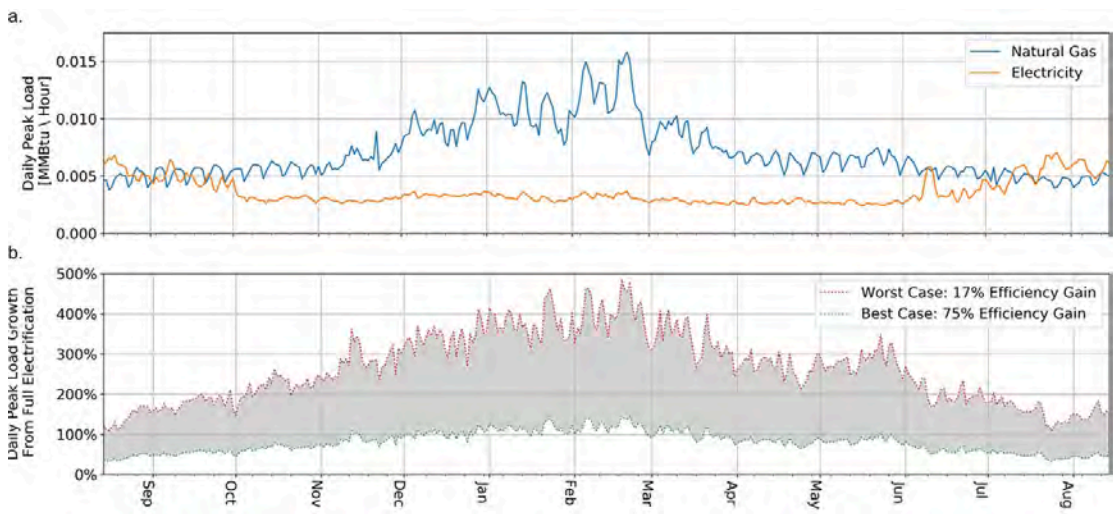

Figure 2. Line plot providing a unit standardized comparison of daily peak natural gas use for the average household within the SCG sample dataset relative to daily peak electricity loads for the average residential household within SCE service territory (*MMBtu/hr*) (a). Shaded area plot depicting the estimated range in the growth of daily peak electricity loads due to full household electrification calculated using best case upper (75%) and worst case lower (17%) bounds on the assumed overall efficiency of gain of a fully electrified household (b).

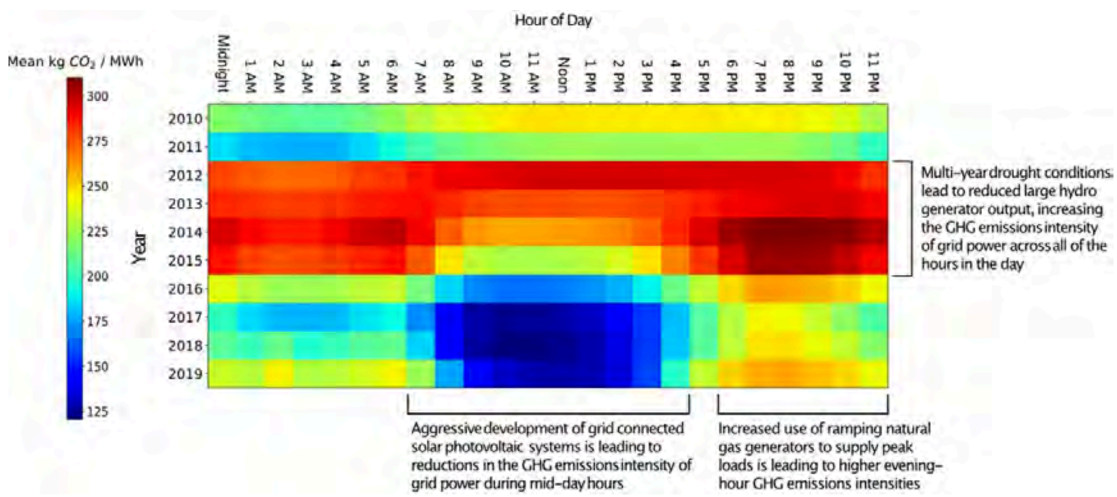

Figure 3. Heat-map illustrating variations in the average hourly GHG emissions intensity of grid sourced electricity within the CAISO balancing region for each hour in the day for the years 2010–2019. A multi-year period of anomalously high GHG emissions intensities, caused by drought related reductions in large-hydro generator outputs, are highlighted at right. Joint impacts of expanded solar PV output, stemming from the success of the state's RPS, as well as the increased reliance on natural gas thermal generators to supply ramping peak loads, are highlighted at bottom.

potential for energy efficiency improvements stemming from fuel switching, the potential impacts on daily peak electricity loads are likely to be dramatic. Under best case efficiency assumptions, full electrification is expected to increase daily peak loads, on average throughout the year, by 80%. Conversely, under worst case assumptions, daily peak loads are estimated to increase by an average of 265%.

3.3. Implications for GHG Emissions Abatement

A second issue involving the timing of residential natural gas use relates to the potential GHG emissions abatement benefits from undertaking widespread electrification. Figure 3 contains a heat-map which depicts year over year changes in the average hourly GHG emissions intensities ($kg\ CO_2/MWh$) of generators supplying CAISO's balancing territory between 2010–2019. The changing patterns of color in this figure reflect structural changes in the output of the regional grid's portfolio of generator assets - given the different characteristic emissions intensities of different generator types (thermal, hydro, solar, wind, etc). The first, most noticeable feature of this plot is the prominent discontinuity in the annual pattern of GHG intensity levels, visible as a prominent horizontal band of red colored cells spanning the period from 2012–2015. These years correspond to a multi-year drought which negatively impacted

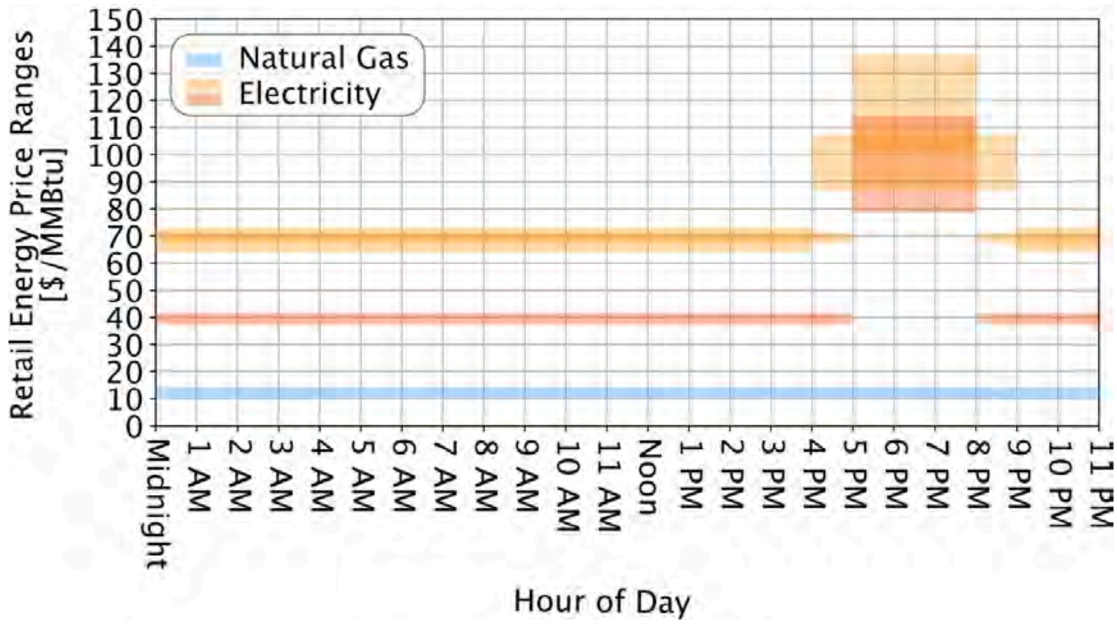

Figure 4. Comparison of local retail price ranges for electricity (red & orange) and natural gas (blue) using standardized energy units ($/*MMBtu*), by hour of day throughout the course of a year. These figures assume current residential rate tariff schedules and within-baseline-tier consumption levels. Note: the two different electricity rate tariffs depicted (red & orange) have different daily basic charges, minimum daily charges, and baseline credits. Thus, the range of values plotted only reflect the marginal cost of energy procurement.

the ability of the state's large hydro generating stations to supply power at nominal levels. This temporary loss of zero-emissions generator output was offset by the increased output of natural gas fired thermal generators possessing much higher GHG emissions intensities.

In addition to the impacts of the statewide drought, beginning in 2013, a significant shift in GHG emissions intensities during mid-day hours (10AM–4PM) becomes apparent in the circular collection of blue colored cells located in the lower portion of the figure. These changes reflect the rapid increase in the penetration of grid connected solar generation assets procured under the state's RPS during this period. Interestingly, and largely in proportion to these mid-day declines in GHG emissions intensities, corresponding increases in the GHG emissions intensities of grid power consumed during peak hours (6AM–9AM & 5PM–10PM) are also visible. These proportional increases reflect the increased use of rapid ramping peaker natural gas turbines to offset the predicable diurnal pattern of solar generator output.

This trend calls into question the extent of the GHG abatement benefits which are likely to accrue from electrification efforts in the absence of a fully decarbonized electric grid. As it stands, the GHG emissions intensities of electrical power consumed during peak hours are increasing year over year. These increases are due to the rapid decline in solar generator output each day being offset by rapid ramping in the output of natural gas fired peaker power plants. These plants' higher GHG emissions intensities are due not only to their fuel source but also due to design features required to facilitate their rapid ramp-rates and intermittent operation [29].

3.4. Implications for household expenditures on energy

The third potential implication from the timing of natural gas use relates to changes in the total annual expenditures on energy of households due to fuel switching. Current diurnal patterns in the average hourly GHG emissions intensities of grid power consumption are largely a product of parallel growth in renewable generation output and early-evening peak electricity loads. Among the efforts which have been undertaken to combat this phenomenon, commonly referred to as the *duck curve*, has been the introduction of a requirement for IOUs to implement new, mandatory default TOU rates for all of their customers [30]. This requirement, currently in the early phases of roll-out, means that residential customers who do not opt-out from the new default TOU rates, the price of electricity will fluctuate throughout the hours of the day, the days of the week, and the months of the year [17].

The complexity of these TOU rate structures have been intentionally designed to mirror the complexity of the dynamics between renewable generation output and consumer electricity demand, as previously discussed. An unfortunate result of this complexity however, is that it can be difficult to quantitatively assess what constitutes the *typical* or *average* annual expenditures incurred by a member of a given customer class. Figure 4, provides a rough comparison of the normalized cost of energy between electricity and natural gas for standard residential rate tiers. The horizontal yellow bands of color plot the range of electricity prices possible at each hour of the day - depending upon the day of the week and month of the year - under currently available residential TOU rate structures within SCE service territory. By comparison, the horizontal blue band within the figure, shows the price of natural within SCG territory, which does not vary by time-of-use. In both cases, the energy prices reflect levels of consumption occurring within the baseline tier.

As figure 4 illustrates, the prevailing cost of a unit of energy delivered in the form of electricity is at least 4–6x higher than for natural gas within this region. Moreover, under existing TOU electricity rate structures, the price premium for electrical energy can grow to a factor of 12*x* during peak hours (4PM–9PM). In the absence of significant future increases in the relative cost of natural gas, either due to changing market dynamics or external government intervention, it is likely the that the widespread electrification will result in an increase in total annual household expenditures on energy. This is due to the relative inflexibility of most work and educational schedules.

4. Discussion

On paper, California's three pronged approach to the decarbonization of its residential building sector makes logical sense. However, if the transition is to be successful in practice, policy makers will be required to navigate numerous potential pitfalls. Careful, integrated planning and sequencing of future electrification policies and programs will be necessary to avoid unintended consequences. The results of this study show, under current conditions, whole house electrification programs are likely to exacerbate daily peak electricity loads and increase total household expenditures on energy. Moreover, the state's continued reliance on natural gas peaker-plants means that these efforts will likely only produce modest GHG emissions abatement benefits.

There are a number of concrete strategies which can be adopted to address these concerns. First, regarding peak electricity load growth, electrification initiatives should initially target natural gas end-use appliances which have the highest expected efficiency gains and whose anticipated time-of-use least coincides with periods of peak-electricity demand. New, highly efficient, hybrid heat-pump based electric water heating technologies represent a significant opportunity in this regard. These systems are both more energy efficient than their natural gas based counterparts and also provide interesting opportunities for the use of thermal energy storage to decouple the timing of energy usage from the timing of energy service delivery.

Secondly, regarding the potential GHG emissions abatement benefits of electrification, it is critical that California expand requirements for the development of new energy storage capacity to absorb the growing surplus of renewable energy supply generated during certain periods [31]. Increasing the state's ability to store and redistribute renewably generated energy is essential to counteract the growing GHG emissions intensities of peak period grid power. IOU energy storage capacity procurement requirements must be expanded and elaborated. For example, new small scale distributed energy generation projects, such as rooftop solar PV systems, could be required to incorporate a minimum amount of diurnal energy storage capacity, equivalent to say four hours worth of the system's nominal rated power output. Alternatively, for larger facilities, such a grid scale wind farm, the coupled storage requirement could instead focus on seasonal capacity. Rule 21, which currently allows utilities to dictate the characteristics of generation assets seeking interconnection to the grid, provides a natural mechanism for the articulation of these types of detailed storage requirements [32].

Finally, regarding the potential for widespread electrification of natural gas appliances to increase total household expenditures on energy—it appears that some level of energy cost increases are likely to be inevitable as part of any transition to a fully decarbonized residential building sector. The crucial question is how to minimize these costs and ensure that they be equitably distributed among rate-payers. Low income households in under-resourced and environmentally disadvantaged communities are likely to have very little flexibility in terms of the timing of their end-use energy consumption. This is due to the fact that members of these communities typically have to engage in longer distance commutes to their places of employment and have less flexibility in their work schedules [24]. A well designed electrification program should provide incentives not only to help under-resourced community members to overcome the initial, up-front costs of purchasing new electric appliances but also with rebates or other mechanisms for reducing the ongoing marginal cost of consuming a more expensive source of energy.

5. Conclusions

Decarbonization pathways involving extensive electrification efforts will require unprecedented integration of natural gas and electricity systems planning and policy implementation in order to be successful. On the electricity side, California's establishment of a progressive RPS was pioneering and has stimulated dramatic expansion of renewable generation capacity. Yet, despite this success, there remains insufficient grid scale energy storage capacity. This growing storage deficit is diminishing the marginal value of future renewable generation investments required by the RPS.

Related to this issue, has been the dramatically expanded use of natural gas thermal generators to supply the state's large and growing peak electricity demands. The further entrenchment of these gas facilities is a pernicious problem and has been largely responsible for the imminent rollout of new default TOU rates for all IOU customers. Raising the price of electricity during peak hours will unevenly impact different customer classes due to differences in the ability to either reduce the volume of their energy consumption or shift its occurrence in time. Without policy measures which cause natural gas to become far more expensive, reflecting its true environmental and social cost in air pollution health effects and global climate change impacts, the price differential between TOU electricity and the use of natural gas for heating and cooking may be insurmountable. Moreover, it is likely that low-income residents of disadvantaged communities, who have the least flexible work schedules, the least access to high-efficiency appliances and energy management systems, and inhabit the most poorly insulated housing stock, will be most adversely effected by these changes.

Previous modeling assumptions about the extent to which the efficiency improvements gains of electrified appliances will be able to compensate for peak-load growth seem overly optimistic. An improved understanding of real world efficiency improvements, based upon the ex-post analysis of metered consumption data, will likely be necessary in order to accurately assess the long term energy cost implications associated with electrifying different natural gas appliances.

Finally, the extent to which renewable generation, demand response, and distributed storage technologies will able to resolve these issues remains uncertain. Recent efforts to simulate the performance of California's residential energy system under high penetration levels of these new technologies found that only 48% of the additional electricity load was able to be met by otherwise excess renewable generation due to misalignment between the timing of energy demand and that of renewable supply [33]. If these imbalances persist it will result in the need for addition grid capacity and the sustained production of GHG emissions.

All of these issues point to the need for the development of more integrated policy approaches to decarbonization, and perhaps, for measures to ensure that natural gas pricing reflects the fuel's true costs to society. Deep decarbonization of the energy system will require much greater investment in energy storage assets, delivered at multiple scales. Additionally, funds must be provided to directly support the participation of under-resourced communities in this transition. Failure to do so will dramatically limit the GHG reduction potential of electrification and exacerbate existing socio-economic disparities in access to high quality, low carbon energy services.

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infrastructure and institutions. The barrier to technological change that carbon prices address, the higher cost of renewable energy, is ceasing to be relevant. Where such costs are still relevant, technology support instruments are more effective. We do have a window of opportunity to stop climate change within a range of safety, and therefore need to use that time to develop and implement policies that actually make a difference.

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AUTHOR CONTRIBUTIONS

A.P. and J.L. conceived of and wrote the article together.

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COMMENTARY

Getting to Zero Carbon Emissions in the Electric Power Sector

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The electric power sector is widely expected to be the linchpin of efforts to reduce greenhouse gas (GHG) emissions. Virtually all credible pathways to climate stabilization entail twin challenges for the electricity sector: cutting emissions nearly to zero (or even net negative emissions) by mid-century, while expanding to electrify and consequently decarbonize a much greater share of global energy use.[1,2] In light of this fact, a flurry of recent studies has outlined and explored pathways to "deep decarbonization" of the power sector, defined here as an 80%–100% reduction in carbon dioxide (CO_2) emissions from current levels. Here we review and distill insights from 40 such studies published since the most recent Intergovernmental Panel on Climate Change review in 2014 (summarized in Table 1).

Despite differing methods, scopes, and research questions, several consistent insights emerge from this literature. The studies collectively outline and evaluate two overall paths to decarbonize electricity: one that relies primarily (or even entirely) on variable renewable energy

Table 1. Review of Electricity Deep Decarbonization Studies

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
1	Akashi et al.	2014	Halving global GHG emissions by 2050 without depending on nuclear and CCS	*Climatic Change*	Global	W	I	50% below 2010 economy-wide (>80% in electricity sector)	bio, bio CCS, coal, coal CCS, gas, gas CCS, nuc, oil, oil CCS	N	N	N
2	Amorim et al.	2014	Electricity decarbonization pathways for 2050 in Portugal: a TIMES (The Integrated MARKAL-EFOM System) based approach in closed versus open systems modeling	*Energy*	Portugal	E	O	zero CO_2	coal, gas, res. hydro (existing), oil, bio	N	L	N
3	Becker et al.	2014	Features of a fully renewable US electricity system: optimized mixes of wind and solar PV and transmission grid extensions	*Energy*	Continental USA	E	O, S	zero CO_2	none	Y	Y	Y
4	Bibas and Méjean	2014	Potential and limitations of bioenergy for low carbon transitions	*Climatic Change*	Global	W	I	98% below business as usual in 2050, 99.3% in 2100	bio CCS, coal, coal CCS, gas, gas CCS, nuc, oil	N	N	N
5	Boston and Thomas	2015	Managing flexibility whilst decarbonizing the GB electricity system	The Energy Research Partnership	UK	E	O, S	~80% below 1990 (50g CO_2/kWh)	bio (existing), coal CCS, gas (existing), gas CCS, nuc	S	S	S
6	Brick and Thernstrom	2016	Renewables and decarbonization: Studies of California, Wisconsin and Germany	*The Electricity Journal*	California, Wisconsin, and Germany	E	S	80% renewable portfolio standard	gas CCS, nuc	N	N	N

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Table 1. Continued

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
7	Brown et al.	2018	Synergies of sector coupling and transmission reinforcement in a cost-optimized, highly renewable European energy system	*Energy*	Europe	E, T, H	O	95% below 1990	gas, res. hydro (existing)	Y	Y	Y
8	Connolly and Mathiesen	2014	A technical and economic analysis of one potential pathway to a 100% renewable energy system	*I.J. Sustainable Energy Planning and Management*	Ireland	E, T, H	S	net zero CO_2 (renewables only, including biofuels)	bio, CHP	Y	N	Y
9	Connolly et al.	2016	Smart Energy Europe: The technical and economic impact of one potential 100% renewable energy scenario for the European Union	*Renewable and Sustainable Energy Reviews*	EU-28	E, T, H	S	net zero CO_2 (renewables only, including biofuels)	bio, CHP	Y	N	Y
10	de Sisternes et al.	2016	The value of energy storage in decarbonizing the electricity sector	*Applied Energy*	Texas ERCOT-like system	E	O	90% below 2016	gas, nuc	N	N	N
11	Després et al.	2016	Storage as a flexibility option in power systems with high shares of VRE sources: a POLES-based analysis	*Energy Economics*	EU-28, Norway and Switzerland	E	O	~80% below 1990 (EU 2°C policy)	bio, coal, coal CCS, gas, gas CCS, res. hydro (existing), nuc, oil	N	N	Y

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Table 1. Continued

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
12	Elliston et al.	2014	Comparing least cost scenarios for 100% renewable electricity with low emission fossil fuel scenarios in the Australian National Electricity Market	*Renewable Energy*	Australia National Energy Market (NEM)	E	S	net zero CO_2 (renewables only, including biofuels)	bio, coal, coal CCS, gas, gas CCS, res. hydro (existing)	N	L	N
13	Fernandes and Ferreira	2014	Renewable energy scenarios in the Portuguese electricity system	*Energy*	Portugal	E	S	net zero CO_2 (renewables only, including biofuels)	bio, res. hydro (existing), CHP	Y	Y	N
14	Frew et al.	2016	Flexibility mechanisms and pathways to a highly renewable US electricity future	*Energy*	Continental USA	E	O	zero CO_2 (100% renewable portfolio standard)	geo, res. hydro (existing)	Y	Y	Y
15	Heal	2016	What would it take to reduce US greenhouse gas emissions 80% by 2050?	National Bureau of Economic Research	USA	E	A	80% below 2005	bio, coal, gas, geo, hydro, nuc, oil	N	Y	N
16	Heuberger et al.	2017	A systems approach to quantifying the value of power generation and energy storage technologies in future electricity networks	*Computers & Chemical Engineering*	UK	E	O	zero CO_2	coal CCS, gas, gas CCS, nuc	N	L	N
17	Heuberger et al.	2017	Power capacity expansion planning considering endogenous technology cost learning	*Applied Energy*	UK	E	O	80% below 1990	bio CCS, coal CCS, gas, gas CCS, nuc	N	L	N

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Table 1. Continued

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
18	Jacobson et al.	2014	A roadmap for repowering California for all purposes with wind, water, and sunlight	*Energy*	California	W	S	zero CO_2	geo, res. hydro (existing)	Y	Y	Y
19	Jacobson et al.	2015	100% clean and renewable wind, water, and sunlight (WWS) all-sector energy roadmaps for the 50 United States	*Energy & Environmental Science*	USA	W	S	zero CO_2	geo, res. hydro (existing)	Y	Y	Y
20	Jacobson et al.	2015	Low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes	*PNAS*	Continental USA	W	S	zero CO_2	geo, res. hydro (existing)	Y	Y	Y
21	Kim et al.	2014	Nuclear energy response in the EMF27 study	*Climatic Change*	Global	W	R	~80%–100% below 2000 (450 ppm CO_2e)	multiple models with different firm resource options and choices regarding storage, transmission, and flexible demand. In all 18 models, **nuc** was selected in most stringent decarbonization scenarios			
22	Knorr et al.	2014	Kombikraftwerk 2	German Federal Ministry for the Environment	Germany	E	S	Net zero CO_2 (renewables only, including biofuels)	**bio, geo, res. hydro (existing)**	Y	Y	Y
23	Koelbl et al.	2014	Uncertainty in carbon capture and storage (CCS) deployment projections: a cross-model comparison exercise	*Climatic Change*	Global	W	R	~80%–100% below 2000 (450 ppm CO_2e)	multiple models with different firm resource options and choices regarding storage, transmission, and flexible demand. In all 18 models, a combination of coal CCS and gas CCS was selected in most stringent decarbonization scenarios			

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Table 1. Continued

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
24	Krey et al.[1]	2014	Getting from here to there – energy technology transformation pathways in the EMF27 scenarios	*Climatic Change*	Global	W	R	~80%–100% below 2000 (450 ppm CO_2e)	multiple models with different firm resource options and choices regarding storage, transmission, and flexible demand. Bio, coal CCS, and gas CCS are selected in most abundance in lowest cost decarbonization scenarios			
25	Kriegler et al.[2]	2014	The role of technology for achieving climate policy objectives: overview of the EMF 27 study on global technology and climate policy strategies	*Climatic Change*	Global	W	R	~80%–100% below 2000 (450 ppm CO_2e)	multiple models with different firm resource options and choices regarding storage, transmission, and flexible demand. Bio, coal CCS, gas CCS, and nuc are selected in most stringent decarbonization scenarios			
26	Lenzen et al.	2016	Simulating low-carbon electricity supply for Australia	*Applied Energy*	Australia	E	O	net zero CO_2 (renewables only, including biofuels)	bio, res. hydro (existing)	N	Y	N
27	MacDonald et al.[10]	2016	Future cost-competitive electricity systems and their impact on US CO_2 emissions	*Nature Climate Change*	Continental USA	E	O	80% below 1990	gas, res. hydro (existing), nuc. (existing)	N	Y	N
28	Mai et al.	2014	Envisioning a renewable electricity future for the United States	*Energy*	Continental USA	E	O	80% renewable portfolio standard	bio, coal, gas, geo, res. hydro (existing), nuc (existing)	N	Y	Y
29	Mai et al.[7]	2014	Renewable electricity futures for the United States	*IEEE Trans. Sustainable Energy*	Continental USA	E	O	80% renewable portfolio standard	bio, coal, gas, geo, res. hydro (existing), nuc (existing)	N	Y	Y
30	Mathiesen et al.	2015	IDA's Energy Vision 2050: a smart energy system strategy for 100%	Aalborg University	Denmark	W	S	net zero CO_2 (renewables only, including biofuels)	bio, geo	Y	N	Y

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Table 1. Continued

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
			renewable Denmark									
31	Mileva et al.	2016	Power system balancing for deep decarbonization of the electricity sector	*Applied Energy*	US Western Electricity Coordinating Council (WECC)	E	O	85% below 1990	bio, coal, gas, res. hydro (existing), **geo**, **nuc**	Y	Y	S
32	Pleßmann and Blechinger[8]	2017	How to meet EU GHG emission reduction targets? A model based decarbonization pathway for Europe's electricity supply system until 2050	*Energy Strategy Reviews*	EU-28	E	O	>95% below 2015 (24 Mt CO_2e/yr)	coal, gas, res. hydro (existing), nuc	Y	Y	Y
33	Riesz et al.	2015	Assessing "gas transition" pathways to low-carbon electricity—an Australian case study	*Applied Energy*	Australia National Energy Market (NEM)	E	O	>80% below 2010	coal, gas, res. hydro (existing)	N	N	N
34	Safaei and Keith	2015	How much bulk energy storage is needed to decarbonize electricity?	*Energy & Environmental Science*	Texas ERCOT-like system	E	O	zero CO_2	dispatchable-zero-carbon source (a proxy for any combination of bio, coal CCS, geo, gas CCS, or nuc), gas	N	N	N
35	Schlachtberger et al.	2017	The benefits of cooperation in a highly renewable European electricity network	*Energy*	Europe	E	O	95% below 1990	gas, res. hydro (existing)	Y	Y	N
36	Schlachtberger et al.[9]	2018	Cost optimal scenarios of a future highly renewable	*Energy*	Europe	E	O	zero CO_2	res. hydro (existing)	Y	Y	N

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Table 1. Continued

	Authors	Year	Title	Publication	Geographic Scope	Sectors	Methodology	Strictest CO_2 Limit	Firm Resources Considered (Selected in Lowest CO_2 Cases)	Long-Duration Storage	Transmission	Flexible Demand
			European electricity system									
37	Sepulveda, et al.[3]	2018	The role of firm low-carbon resources in deep decarbonization of electricity generation	*Joule*	New England, Texas	E	O	zero CO_2	bio, gas CCS, nuc	S	S	S
38	Sithole et al.	2016	Developing an optimal electricity generation mix for the UK 2050 future	*Energy*	UK	E	O	~zero CO_2 (1.9 g/kWh)	bio, bio CCS, coal, coal CCS, gas, gas CCS, res. hydro (existing), nuc	N	N	N
39	White House	2016	United States mid-century strategy for deep decarbonization	United States White House	USA	W	R	≥80% below 2005	bio, bio CCS, coal, coal CCS, gas, gas CCS, geo, nuc	N	Y	Y
40	Williams et al.	2014	Pathways to deep decarbonization in the United States	Sustainable Development Solutions Network	USA	W	S	80% below 1990 (<1,080 $MtCO_2e/yr$)	bio, coal, coal CCS, gas, gas CCS, geo, nuc	N	N	N

Sectors: E, electricity; T, transport; I, industry; H, heat; W, economy-wide; Methodologies: O, techno-economic cost optimization; I, integrated climate-economic-energy cost optimization; S, scenario-based simulation; A, accounting-based; R, review or inter-model comparison; Long-duration storage, transmission, flexible demand: N, not in any cases; Y, yes in all cases; S, in some sensitivity cases; L, limited interconnection with neighboring region only.To be included in our review, studies had to be published in English and feature one or more scenarios in which the electricity sector reduced CO_2 emissions by more than 80% below contemporary levels. While this review focuses on the electricity sector, we also included a subset of 15 multi-sector or economy-wide studies in order to survey insights regarding the role of the electricity sector within broader mitigation efforts. This is not an exhaustive catalog of all research on this topic, but spans a wide range of studies and is intended to be broad enough to capture the critical insights from recent research.

sources (chiefly wind and solar power) supported by energy storage, greater flexibility from electricity demand, and continent-scale expansion of transmission grids; and a second path that relies on a wider range of low-carbon resources including wind and solar as well as "firm" resources such as nuclear, geothermal, biomass, and fossil fuels with carbon capture and storage (CCS) (see Sepulveda et al. in the November 2018 issue of this journal[3]).

Whichever path is taken, we find strong agreement in the literature that reaching near-zero emissions is much more challenging—and requires a different set of low-carbon resources—than comparatively modest emissions reductions (e.g., CO_2 reductions of 50%–70%). This is chiefly because more modest goals can readily employ natural gas-fired power plants as firm resources. Pushing to near-zero emissions requires replacing the vast majority of fossil fueled power plants or equipping them with CCS.

Given the long-lived nature of power sector capital equipment and long gestation period for R&D efforts, it is critical to examine the distinct challenges inherent to deep decarbonization today; a policy of "muddling through" is unlikely to produce optimal outcomes. The literature outlines potentially feasible decarbonization solutions, but also clarifies several challenges that must be overcome along each path to a zero-carbon electricity system. In light of these challenges, and the considerable technological uncertainty facing us today, we conclude that a strategy that seeks to improve and expand the portfolio of available low-carbon resources, rather than restrict it, offers a greater likelihood of affordably achieving deep decarbonization.

Failing to Affordably Decarbonize Electricity Could Imperil Global Climate Efforts

Studies considering economy-wide GHG reduction goals consistently envision the power sector cutting emissions further and faster than other sectors of the economy, achieving close to zero (or net negative) emissions in 2050.[2] Because electricity is technically easier and less costly to decarbonize than other sectors,[4] economy-wide studies rely upon expanded generation of carbon-free electricity to meet greater shares of energy demand for heating, industry, and transportation. Across global decarbonization scenarios produced by 18 modeling groups, for example, electricity demand increases 20%–120% by 2050 (median estimate of 52%) and 120%–440% by 2100; electricity supplies 25%–45% of total energy demand by mid-century and as much as 70% by 2100.[1] In the United States, electricity use could increase 60%–110% by 2050 as electricity (and fuels produced from electricity, e.g., hydrogen) expand from around 20% of final energy demand at present to more than 50% by 2050.[5]

In short, scholars agree that the electricity sector must not only decarbonize but also steadily increase its end-use market share through mid-century and beyond. It follows that a failure to deeply decarbonize the power sector would imperil climate mitigation efforts across the broader economy. At the same time, costly routes to decarbonization that substantially increase the price of electricity would make low-carbon electricity a less attractive substitute for oil, natural gas, and coal in transportation, heating, and industry. Finding feasible and affordable routes to decarbonize the power sector thus takes on outsized importance in global climate mitigation efforts.

Renewables May Drive Decarbonization, but Challenges Increase Sharply as Variable Renewable Energy Penetration Approaches 100%

Multiple studies indicate that achieving deep decarbonization primarily or even exclusively with variable renewable energy (VRE) sources may be technically possible. Despite a diversity of contexts and analytical methods, these studies also exhibit a high degree of agreement on several key features of VRE-centric power systems that must fall into place for this decarbonization pathway to be feasible and affordable. Most of these features arise from the need to manage the variable nature of wind and solar power, which are the predominant renewable energy sources in most studies because they offer the most abundant resource potential. Importantly, challenges associated with the variability of wind and solar increase nonlinearly as the share of energy from these sources rises. As a result, issues that may be manageable at more modest penetration levels can quickly become significant barriers as VRE shares approach 100% of generation.[6]

Continent-Scale Transmission Expansion

First, in order to smooth renewable energy variation across wider regions, high-VRE scenarios routinely entail a continent-scale expansion of long-distance transmission capacity. To reach 80% renewable electricity in the United States (with only 50% from wind and solar), for example, a National Renewable Energy Laboratory study proposes a 56%–105% increase in long-distance transmission capacity.[7] Other studies envision tens of thousands of miles of new high-voltage direct-current transmission linking all regions in the United States, while two renewables-focused studies for the European Union see interconnection capacity between EU nations expanding 4- to 9-fold by 2050.[8,9] The necessary long-distance transmission capacity reported in these studies typically does not include the additional transmission lines needed *within* each region to access renewable energy sites. As transmission makes up a relatively small share of the cost of delivered electricity in most regions,

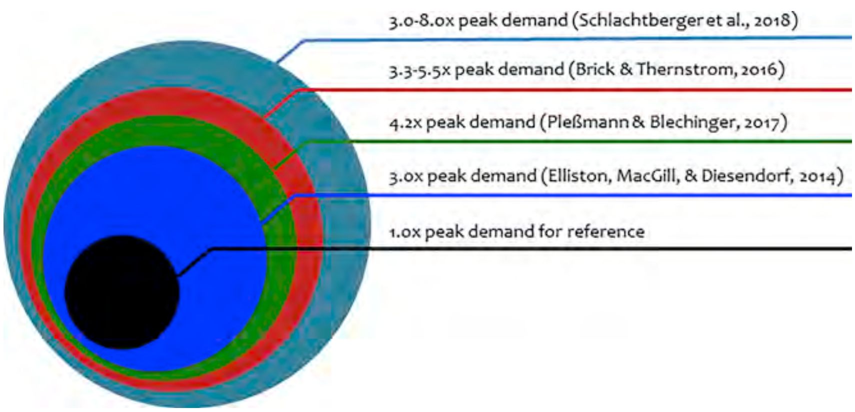

Figure 1. Total Installed Generation and Storage Capacity in Selected High-Renewables Scenarios

even a large-scale transmission build-out may have modest impacts on total system costs.[10] However, grid expansion of this magnitude would need to overcome persistent challenges related to siting and cost allocation that frequently prevent (or severely delay) planned transmission infrastructure.

Flexible Demand

In most of the populated regions of the world, the availability of wind and solar energy varies substantially not just on a daily cycle but over weekly, monthly, and seasonal periods. As a result most scenarios highly reliant on wind and solar assume that sources of electricity consumption will become much more flexible and responsive to power system needs in the future. To varying degrees, these scenarios envision reshaping demand to match variable supply, rather than shaping supply to match variable demand, as is commonplace in all power systems today. Electrification of transportation, heating, and industry will increase demand for electricity, as discussed above, but some of these new sources of demand could also become flexible resources that help manage power systems. For example, electric vehicles must be ready when drivers need them, but they are parked most of the time. Smart controls could modulate charging rates (or return power to the grid) to help balance supply and demand while lowering costs for vehicle owners. Thermal inertia in buildings and water tanks can also shift the timing of heating and cooling to some extent without affecting occupancy comfort.[11] The demand flexibility considered in these studies typically helps address daily fluctuations in wind and solar output, rather than multi-week and seasonal resource deficits; the ability and willingness of businesses or households to curtail demand for multi-day periods, weeks, or months are as yet untested.

Inefficient Utilization Requires Very-Low-Cost Wind and Solar to Make Overcapacity Economical

Due to their intrinsic variability, relying on very high shares of wind or solar to achieve deep decarbonization involves overbuilding total installed capacity (relative to peak demand) to produce sufficient energy during periods when available wind or solar output is well below average (Figure 1). As a corollary, during periods of the year when wind or solar is abundant, available electricity production exceeds total demand in these scenarios. This excess generation must either be curtailed (wasted) or stored for later use. While overgeneration and curtailment are manageable at lower penetration levels, the challenge increases significantly as VRE supply reaches high levels. For example, one study finds that curtailment is negligible if the share of renewables is held to 60% or below, but rises nonlinearly at higher penetrations (Figure 2). At 100% renewables, curtailment wastes enough energy (in this study) to meet at least 40% of current annual United States electricity demand, even after assuming continent-scale transmission expansion, flexible demand (in the form of controllable electric vehicle [EV] charging), and widespread deployment of battery energy storage.

Overbuilding capacity and wasting a large fraction of available energy to curtailment results in low utilization rates for wind and solar capacity, especially the marginal capacity installed to reach greater than 80% energy shares. As such, total system costs also rise nonlinearly as renewable energy shares increase toward 100% (Figure 2). To counteract this escalation in total costs and keep VRE-dominant routes to electricity decarbonization affordable, capital costs for wind and solar must therefore fall much further than in scenarios where they share the market with a mix of other low-carbon resources.

Either "Firm" Generation or "Seasonal" Storage Is Needed to Ensure Reliability in Wind- and Solar-Dominated Scenarios

While overgeneration arises during periods of abundant supply, periods of scarce wind or solar production are the flip side of the variability challenge. Prolonged periods of calm wind speeds lasting days or weeks during winter months with low solar insolation are particularly challenging for VRE-dominated systems. These sustained lulls in available wind and solar output are too long to bridge with shorter-duration batteries or flexible demand.

Power systems with high VRE shares consequently require sufficient capacity from reliable electricity sources that can sustain output in any season and

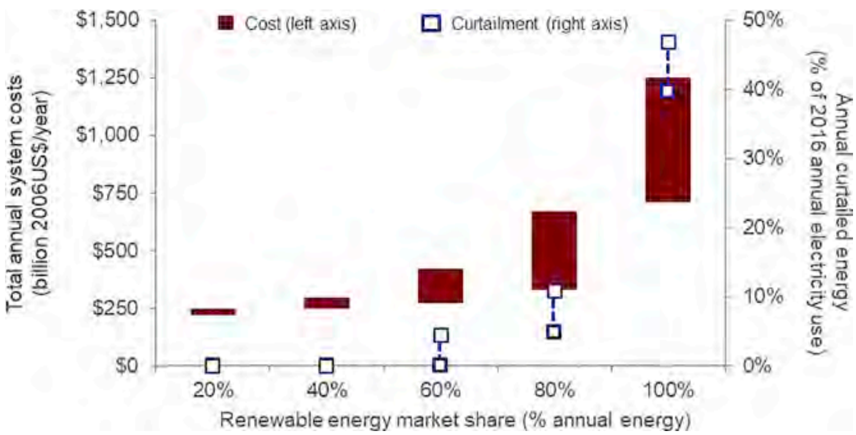

Figure 2. Nonlinear Increases in Total Annual Electricity System Cost and Curtailed Wind and Solar Energy as Renewable Energy Share Increases

Graphic is authors' with data from Frew et al. (2016), see Table 1 for full citation. Low cost and curtailment correspond to "Agg. PEV" scenario (with continent-wide transmission, flexible EV charging) and high cost and curtailment correspond to "Indep. PEV" scenario (limited transmission, flexible EV charging). Curtailment is converted to percentage of 2016 annual electricity use based on *U.S. EIA, Electric Power Annual*, Table 2.2: "Sales and Direct Use of Electricity to Ultimate Customers."

for long periods (weeks or longer). This "firm" capacity[3] is often provided by augmenting wind and solar with dispatchable generation—e.g., natural gas plants, geothermal, hydropower with large reservoirs, nuclear power, or bioenergy. In high-VRE scenarios, however, these firm resources suffer from a lower utilization rate than they do in more balanced scenarios. This means that resources with low capital costs and high variable costs (e.g., bioenergy, hydrogen, or natural gas fueled power plants) are economically better suited to pair with high wind and solar shares.

Other studies partially or fully replace firm generation with one or more energy storage media capable of sustained output over weeks or longer and suited to low annual utilization rates. No such energy storage options exist at large scale today. Even at $100 per kWh of installed energy capacity (less than a third of today's costs), enough Li-ion batteries to store one week of United States electricity use would cost more than $7 trillion, or nearly 19 years of total United States electricity expenditures. Scenarios that eschew firm generation therefore must rely upon one or more long-term energy storage technologies with an order-of-magnitude lower cost per kWh, including thermal energy storage, production of hydrogen from electrolysis and storage in underground salt caverns or pressurized tanks, or conversion of electrolytic hydrogen to methane. Considerable uncertainty remains about the real-world cost, timing, and scalability of these storage options.

Firm Low-Carbon Resources Can Lower Decarbonization Costs

Most of the challenges associated with very high shares of wind or solar energy can be avoided by adopting a more balanced portfolio of resources. Across decarbonization scenarios that harness variable renewables alongside firm low-carbon generation resources—including nuclear power, coal or natural gas plants with CCS, and greater shares of firm renewable resources such as bioenergy or geothermal power plants—total installed capacity is more closely sized to peak demand, all resources enjoy higher asset utilization, and substantial curtailment of renewable energy output is avoided. None of these scenarios require the long-duration "seasonal" storage technologies discussed above. Moreover, while all scenarios benefit from cost-effective demand flexibility and transmission expansion, these features have less impact on the cost of decarbonization in more technology-diversified scenarios.

Twenty of the studies surveyed employ techno-economic optimization or integrated assessment modeling techniques to find the most affordable path to deep decarbonization and considered one or more scalable, firm low-carbon resources (beyond geothermal energy and existing reservoir hydropower, which are severely constrained in most models due to available sites suitable for expansion). Notably, all of these studies include a substantial share of firm low-carbon generation in their lowest cost resource portfolio (see Table 1). In other words, firm low-carbon resources are a consistent feature of the most affordable pathways to deep decarbonization of electricity.

However, all currently available firm low-carbon energy sources face challenges that may impede adoption at the scale or pace desired for climate stabilization.[12] Worldwide, deployment of new nuclear power is barely keeping pace with retirement of aging reactors, while high-profile cost overruns and bankruptcies have plagued nuclear construction in the United States and Europe. Carbon-capture technologies continue to make progress at the demonstration scale, but commercial deployment remains nearly nonexistent. Furthermore, while solid biomass use is rapidly increasing, driven particularly by renewable energy policies in Europe, researchers have raised serious questions about the net life-cycle greenhouse gas benefits of biomass from both managed forests and dedicated energy crops. Reservoir hydropower systems are mature, but new construction is geographically limited and entails substantial environmental impact, including the release of methane.[13] Conventional geothermal energy technologies are constrained to locations with ideal geological conditions, while enhanced or engineered geothermal systems, which could unlock widespread resource potential, are pre-commercial.

Expanding and Improving the Low-Carbon Electricity Portfolio Increases Chances of Affordable Decarbonization

Given the challenges now facing available firm low-carbon resources, it is tempting for policymakers, socially conscious businesses, and research efforts to bet exclusively on today's apparent winners: solar photovoltaics (PV), wind, and battery energy storage. That would be a mistake.

As this review indicates, several obstacles must be overcome to cost-effectively decarbonize electricity regardless of whether wind and solar are expected to deliver the vast majority of electricity or we pursue a more diverse portfolio of resources. We cannot assume that public opposition and siting challenges for new, continent-spanning transmission networks can be overcome; that flexible demand will be unlocked at sufficient scale; that wind and solar PV will continue deep and sustained cost declines; or that order-of-magnitude cheaper "seasonal" storage technologies will become widely scalable. Any one of these things may well happen, but it is far less likely all will be simultaneously achieved.

Assume hypothetically that each of these four key outcomes (grid expansion, flexible demand, very-low-cost wind and solar, and seasonal storage) has the same odds as rolling a dice and not coming up with a 1. Despite this five-out-of-six chance for each individual outcome, the joint probability of all four occurring (0.833^4) would be just 48%—effectively a coin flip.

Given the high stakes, it would be prudent to expand and improve a wide set of clean energy resources, each of which may fill the critical niche for firm, low-carbon power should other technologies falter. For example, nuclear power, CCS, bioenergy, and enhanced geothermal energy each have the ability to fill the firm role in a low-cost, low-carbon portfolio. Assume that each resource has only a 50% probability of becoming affordable and scalable within the next two decades. If all four options are pursued, however, the odds that *at least one* succeeds ($1–0.5^4$) would be 94%. A strategy that supported the development of all low-carbon options, both firm and variable, would raise the chance of success of at least one affordable pathway to decarbonize electricity to 97% (using the hypothetical odds given above).

These examples are purely illustrative, but the logic is critical. Eschewing the development of firm low-carbon technologies because they face challenges today would amount to betting the planet on the assumption that *all* of the conditions needed for an affordable wind and solar-centered path to decarbonize electricity will fall into place. Supporting an expanded and diversified portfolio of clean energy options that can substitute for one another hedges the risk of technology failure and substantially improves the chances of achieving a zero-carbon energy system.

Obstacles remain along any path to zero-carbon electricity, and the true probabilities of success are unknowable. It is therefore vitally important that decision makers identify and pursue prudent strategies to improve the odds of feasible and cost-effective decarbonization.

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Charting Pathways to Deep Decarbonization: Challenges for Analysts, Policymakers, Advocates and the Public

Presentation to the UCSD Deep Decarbonization Initiative

Steve Brick, Senior Advisor

Clean Air Task Force

31 January 2018

Clean Air Task Force

- Established in 1997 to work on conventional air pollution issues
- Began to focus on climate change in 2000
- Current focus on innovation needed to bring forward scalable, cost-competitive low-carbon technologies for electricity, industry and transport
    - Advanced nuclear
    - Fossil CCS for utilities and industry
    - Ammonia and hydrogen as potential zero carbon liquid fuel substitutes
- Working assumption: deep decarbonization only happens if low-carbon substitutes are at cost parity with current options

A few words on modeling and models

- What is modeling for?
  - Defining the terrain in which possible solutions might lie
  - Framing important questions
- Hard data—soft data—analysis—interpretation
  - Where does one end and another begin?
- Which tools?
  - Fedex and Delta Airlines
  - Pathways to 2050

Deep decarbonization

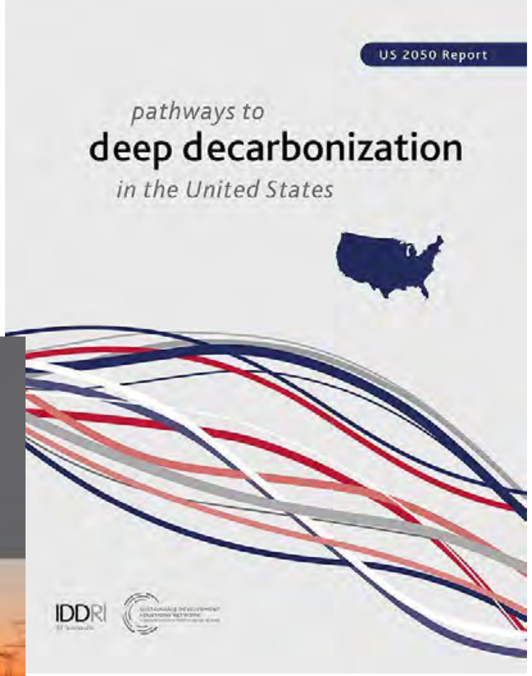
- How can we eliminate carbon from global electricity systems by 2050-2070 in light of the following constraints?
    - We will drive new end uses to electricity
    - We will provide electricity to 1.8 billion global citizens who have none
    - We will increase electricity supply to 2-3 billion global citizens who have *inadequate* access to electricity
    - We will minimize costs
    - We will maintain or improve current levels of system reliability
    - We will protect other environmental values

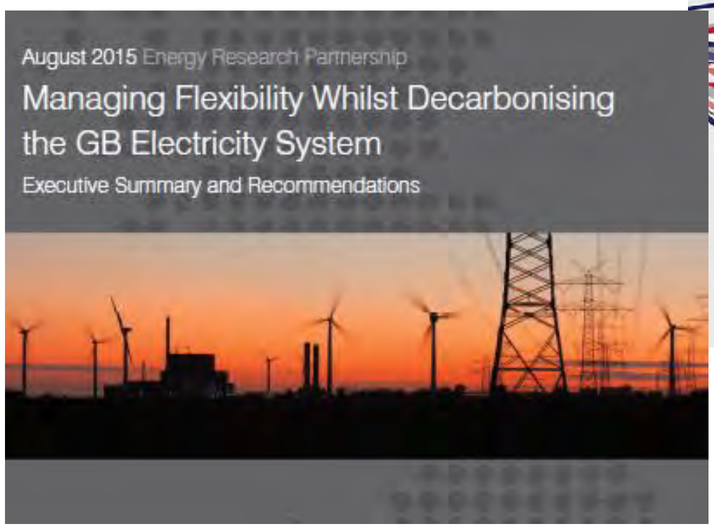
Top level conclusions

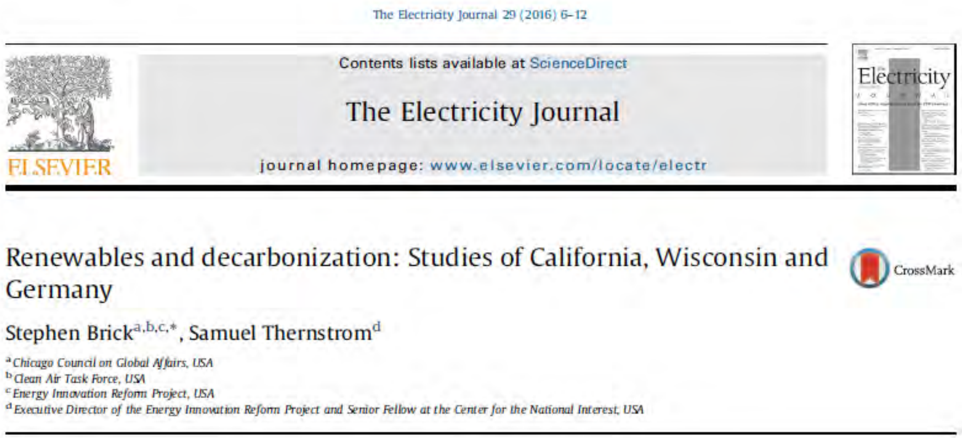
- If you aim to develop a 70 percent decarbonized grid, a combination of variable renewables and natural gas will do the job
- If you aim to develop a 90-100 percent decarbonized grid, a diverse portfolio (including zero carbon baseload of some sort) is needed
  - We don’t need (nor can we) select a final 2050 portfolio today (although this is what most of the fuss has been about….)
  - We do need to create as diverse an arsenal as possible for reducing emissions

Recent studies find …

- Systems with high proportions of wind and solar are
  - Larger
  - Costlier
  - Less effective at reducing carbon than diversified approaches
- Diversified portfolios that include zero carbon baseload yields systems that are
  - Smaller
  - Cheaper
  - Lower carbon



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Renewables and decarbonization: Studies of California, Wisconsin and Germany

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[c] Energy Innovation Reform Project, USA
[d] Executive Director of the Energy Innovation Reform Project and Senior Fellow at the Center for the National Interest, USA

Two new meta-analyses find the same

EIRP
ENERGY INNOVATION REFORM PROJECT

DEEP DECARBONIZATION OF THE ELECTRIC POWER SECTOR
INSIGHTS FROM RECENT LITERATURE

JESSE D. JENKINS AND SAMUEL THERNSTROM

MARCH 2017

Renewable and Sustainable Energy Reviews 76 (2017) 1122–1133

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

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ELSEVIER

Burden of proof: A comprehensive review of the feasibility of 100% renewable-electricity systems

CrossMark

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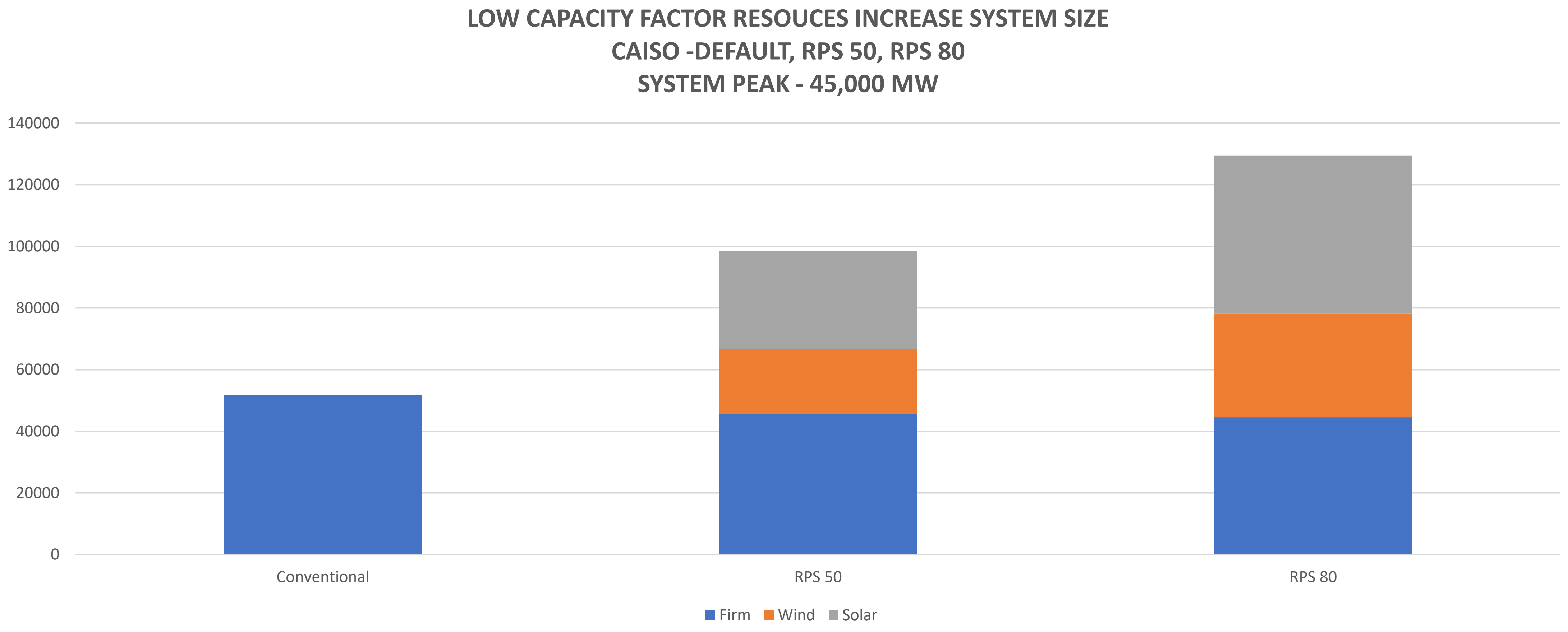
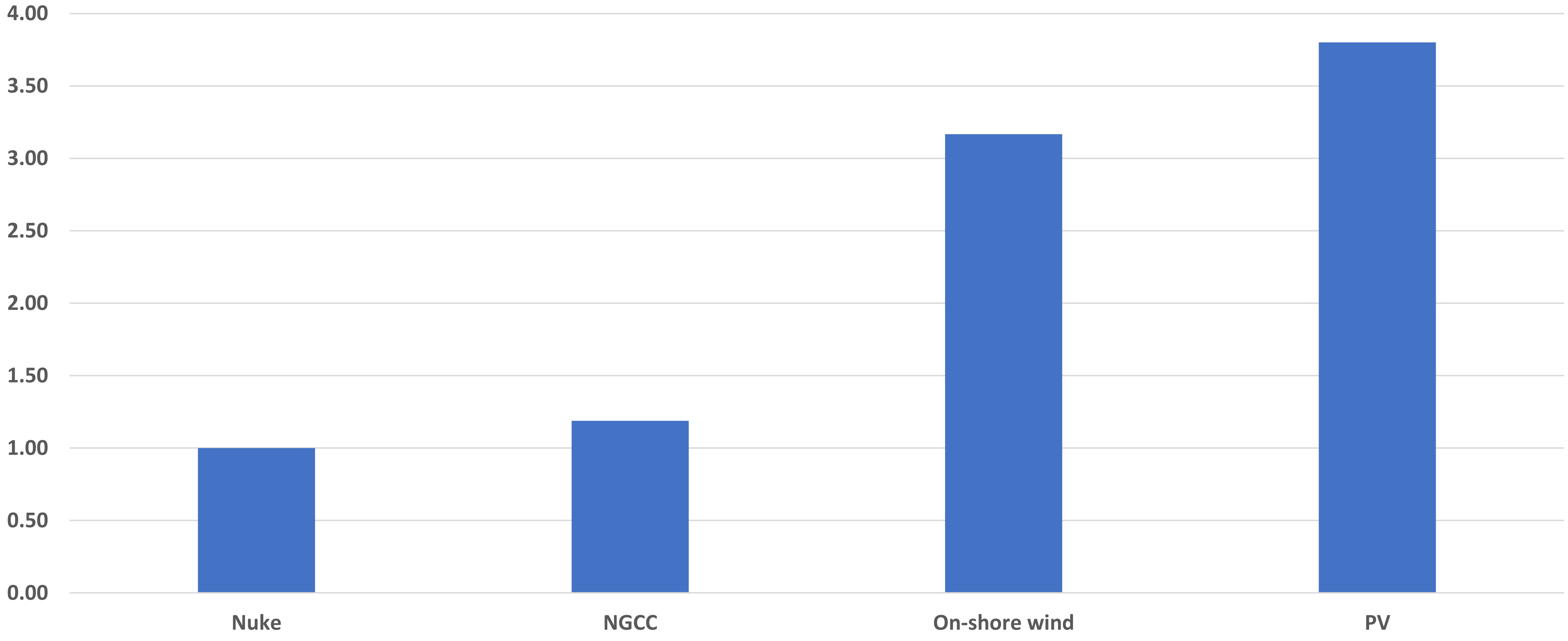
ARTICLE INFO

ABSTRACT

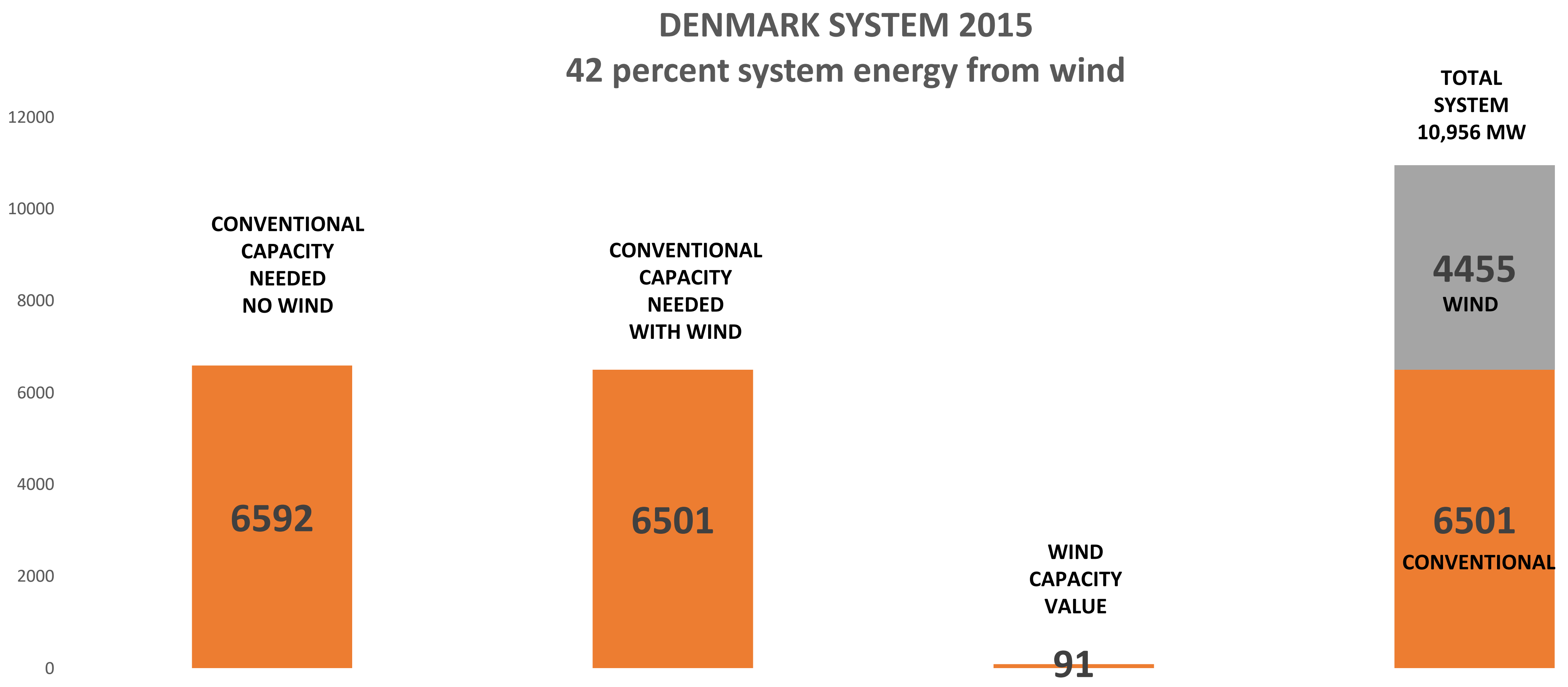
How much larger?



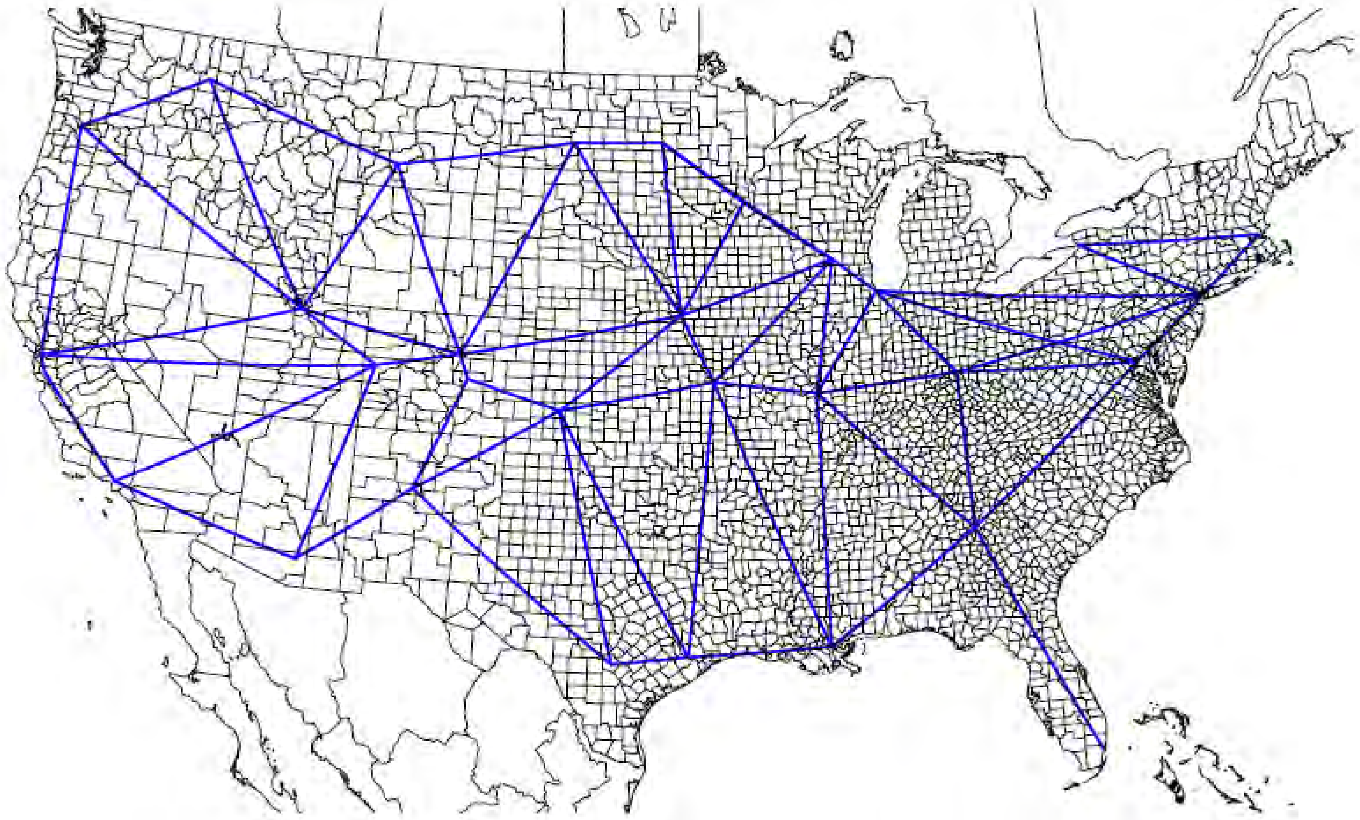
Larger, because more variable capacity is required to produce the same output …



Larger, because variable resources have limited capacity value …

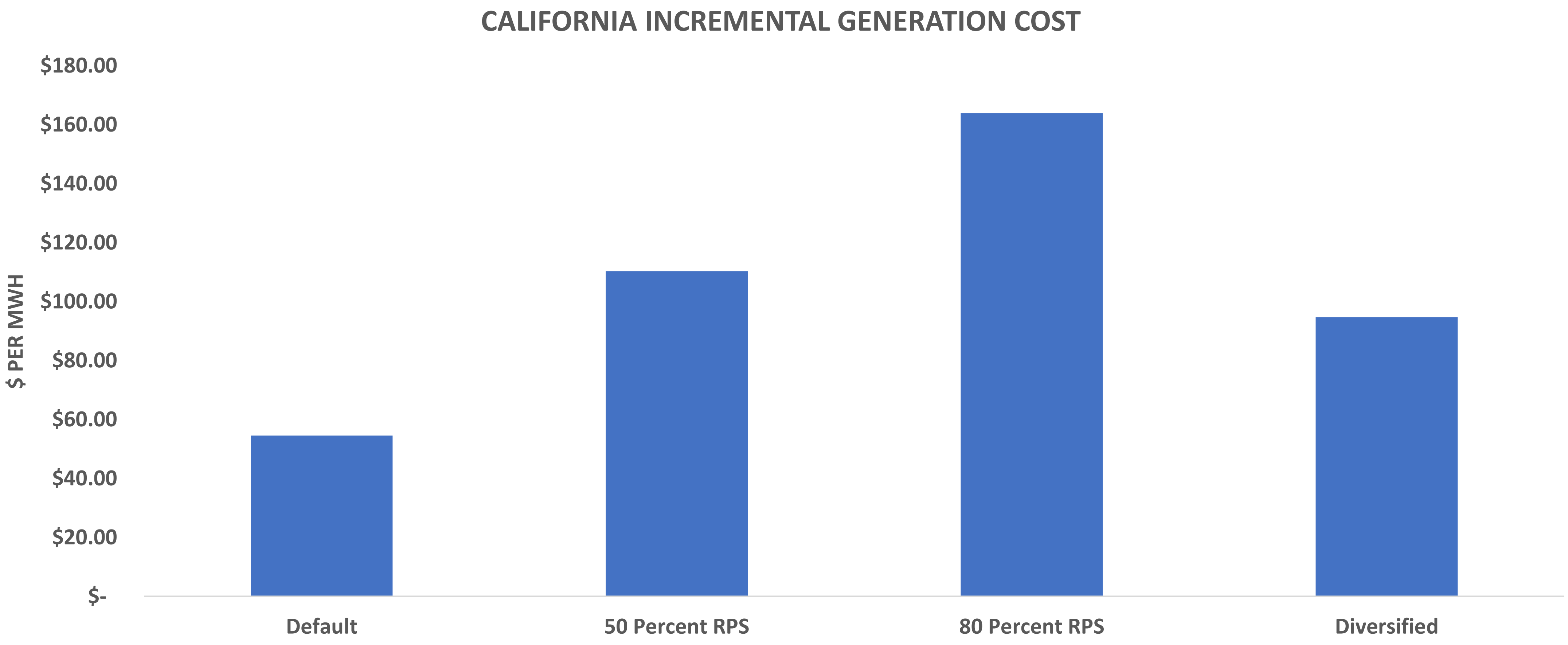


Larger, because systems with high penetrations of variable resources require more transmission …

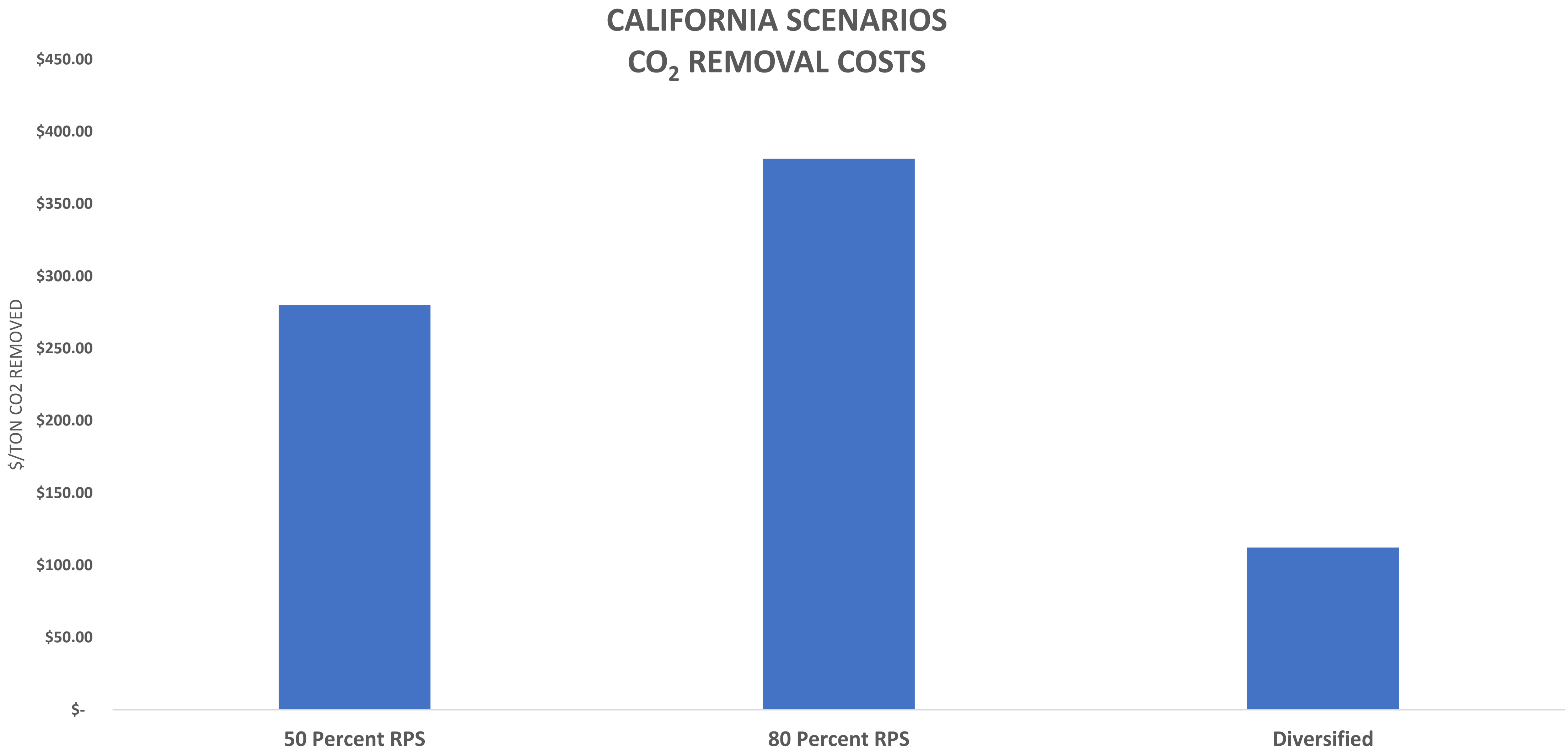


Source: MacDonald, et. al., Nature Climate Change, DOI:10.1038/NCLIMATE2921

Costlier, because they are larger …



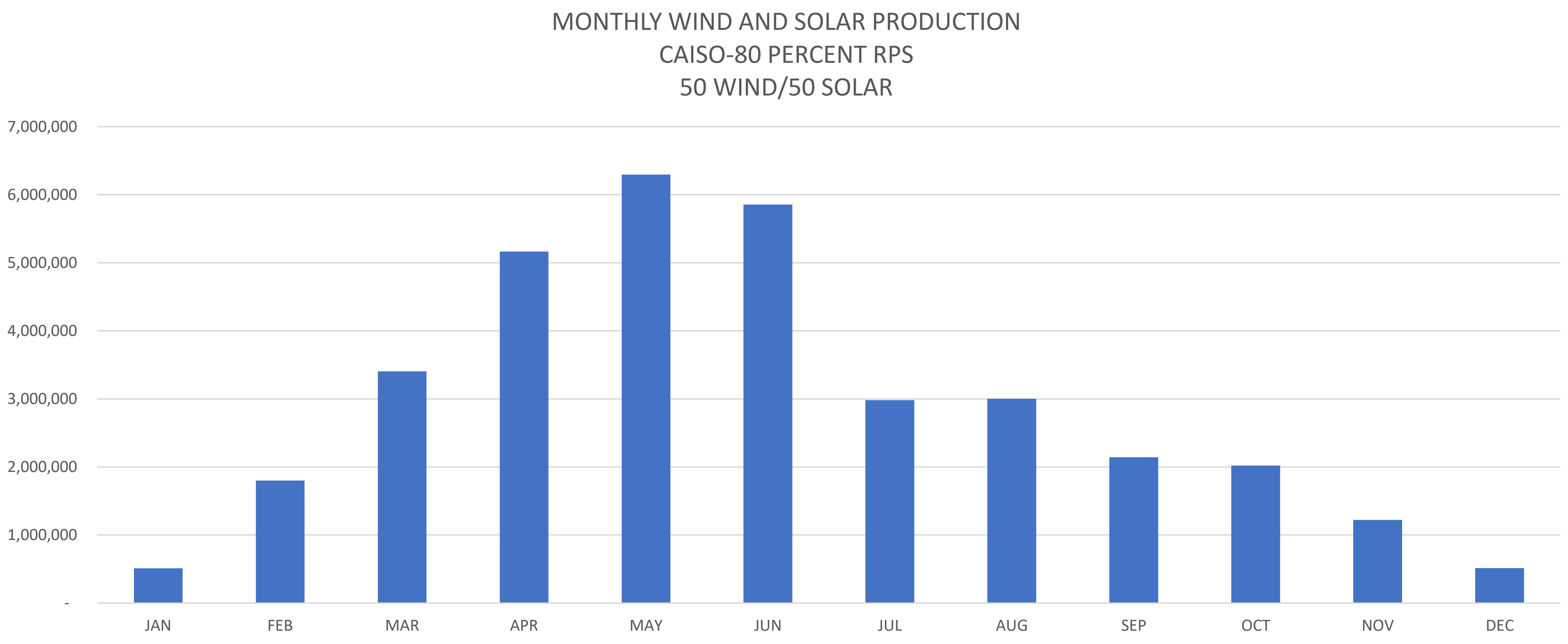
Less effective in terms of \$/ton of CO_2 removed …



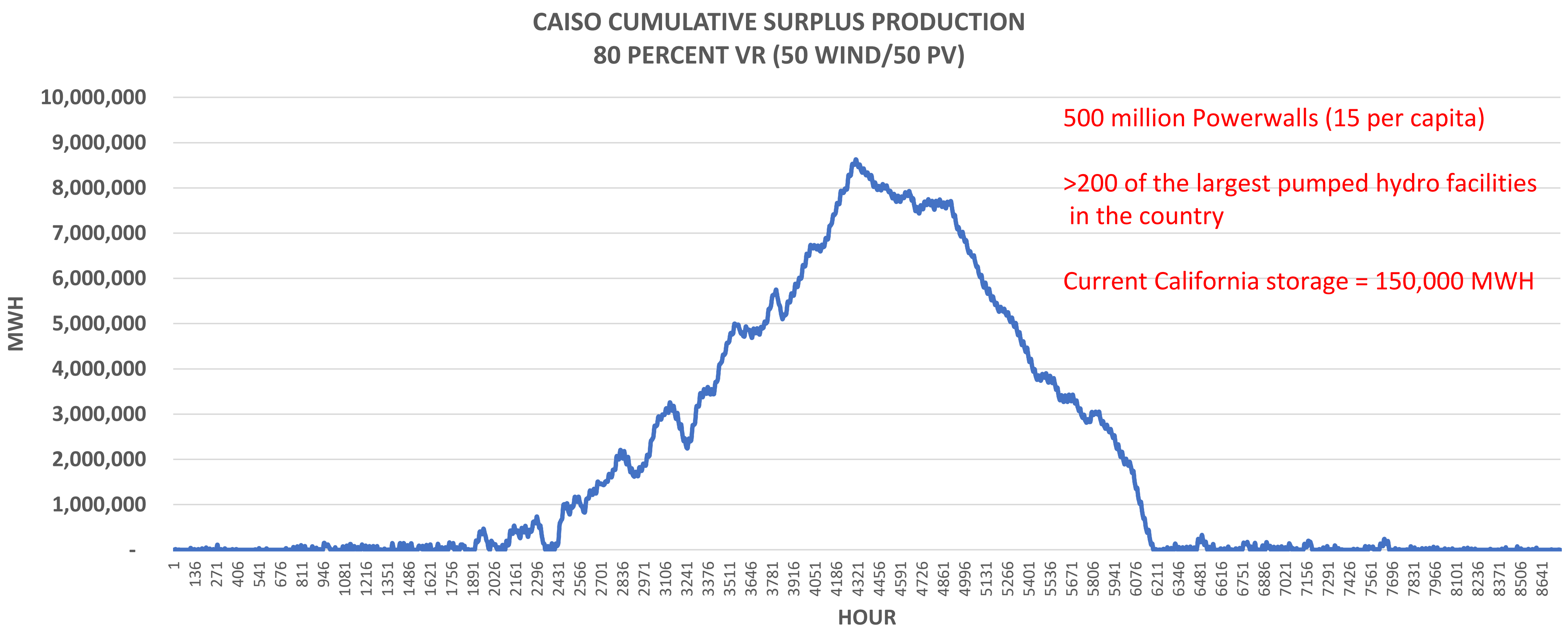
Finding Number 1: <u>Storage doesn't materially change the conclusions</u>

- *<u>Seasonal imbalances</u>* created by wind and solar cannot be managed by known or anticipated storage technologies
  - Batteries may be useful on a diurnal basis in behind-the-meter or distribution level applications, but not for long-term storage of seasonal surplus from variable renewables
  - Pumped hydro is costly, environmentally destructive and geographically limited

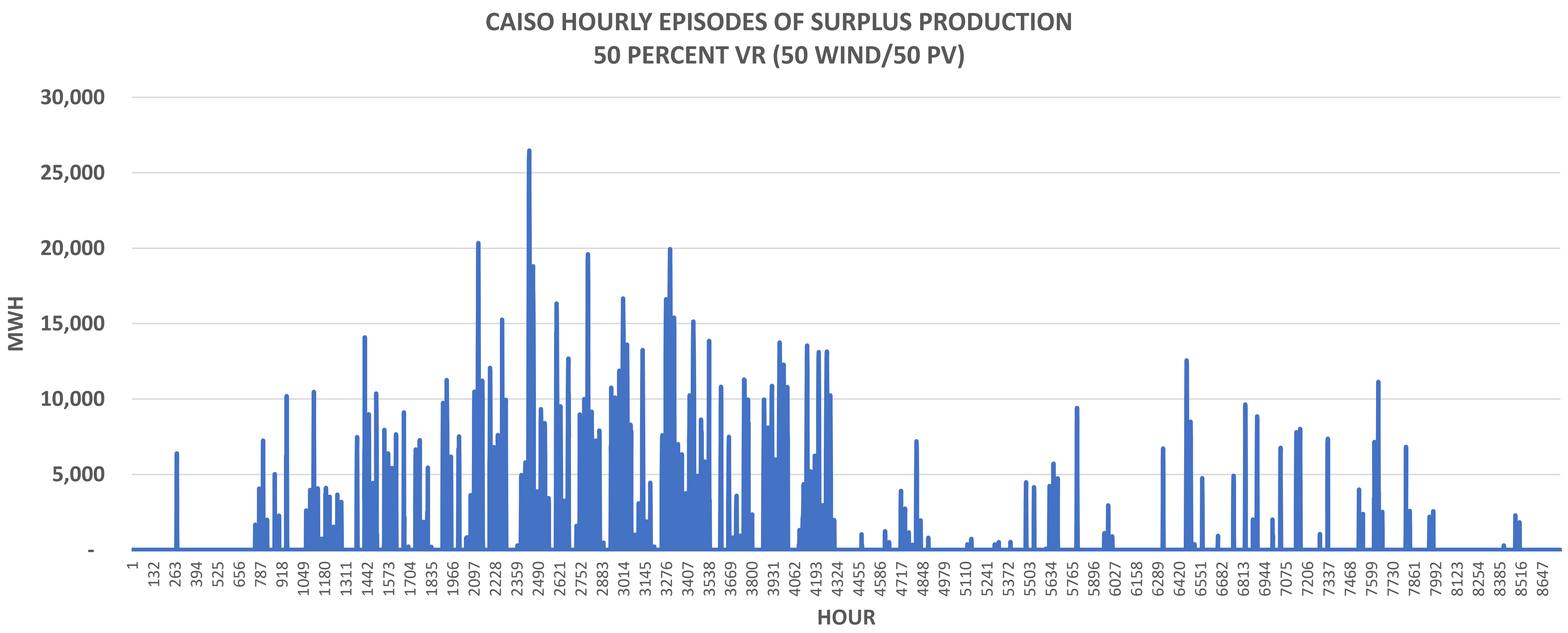
Seasonality of wind and solar is the major challenge



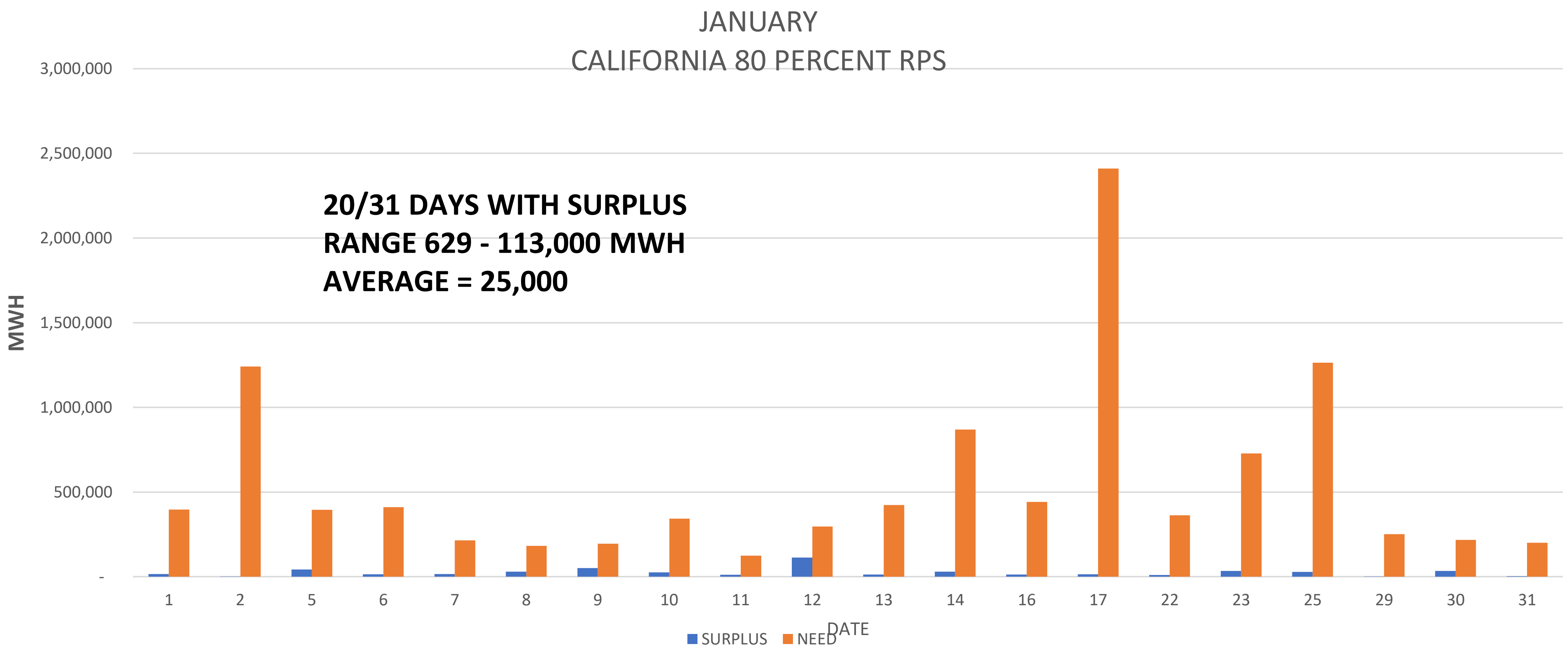
Cumulative surplus is very difficult to manage



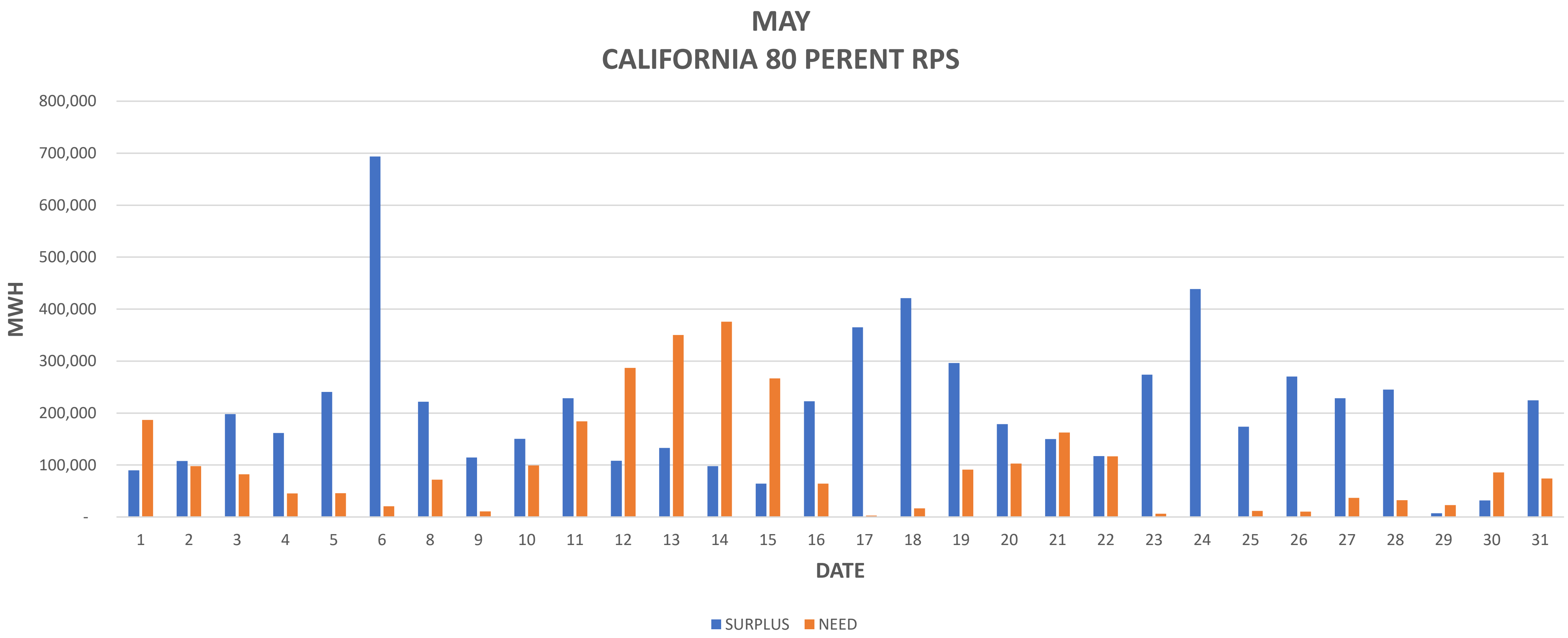
Commercial challenge—
how do you size a storage system to use this product?



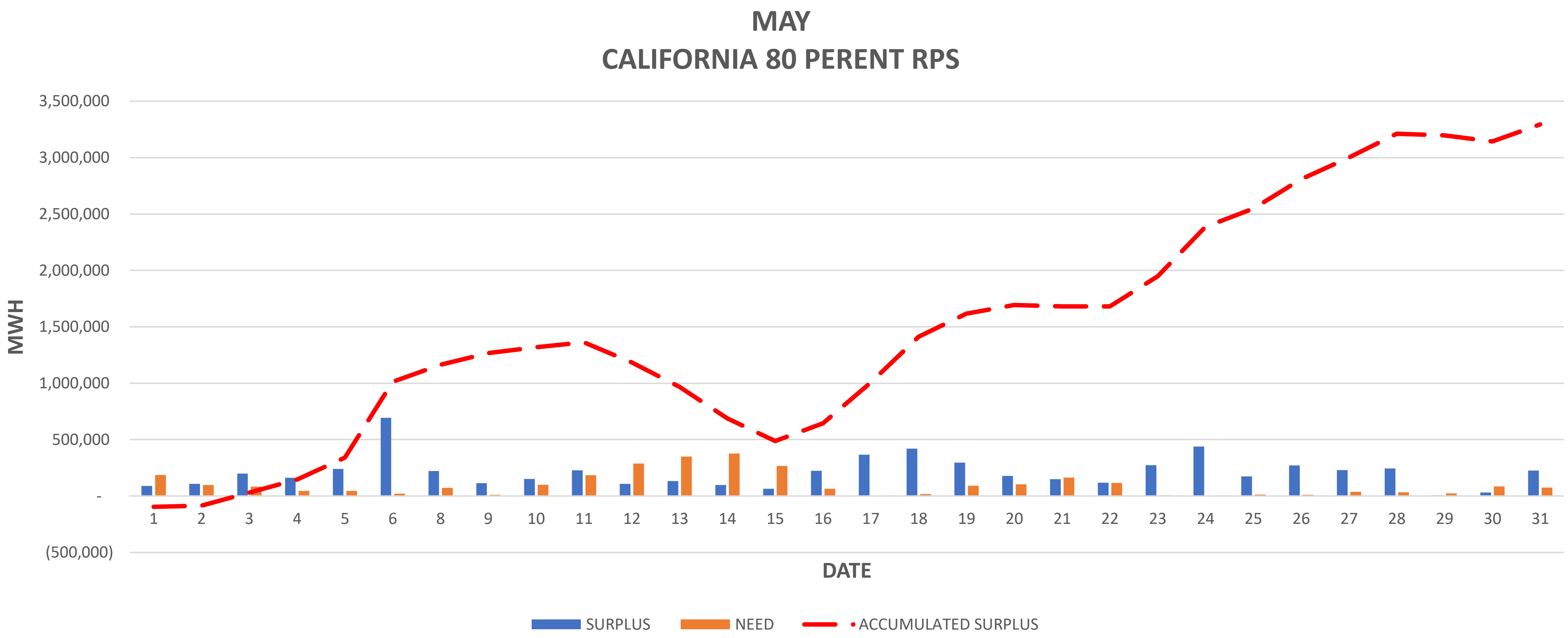
A truly wicked problem



Wicked, continued

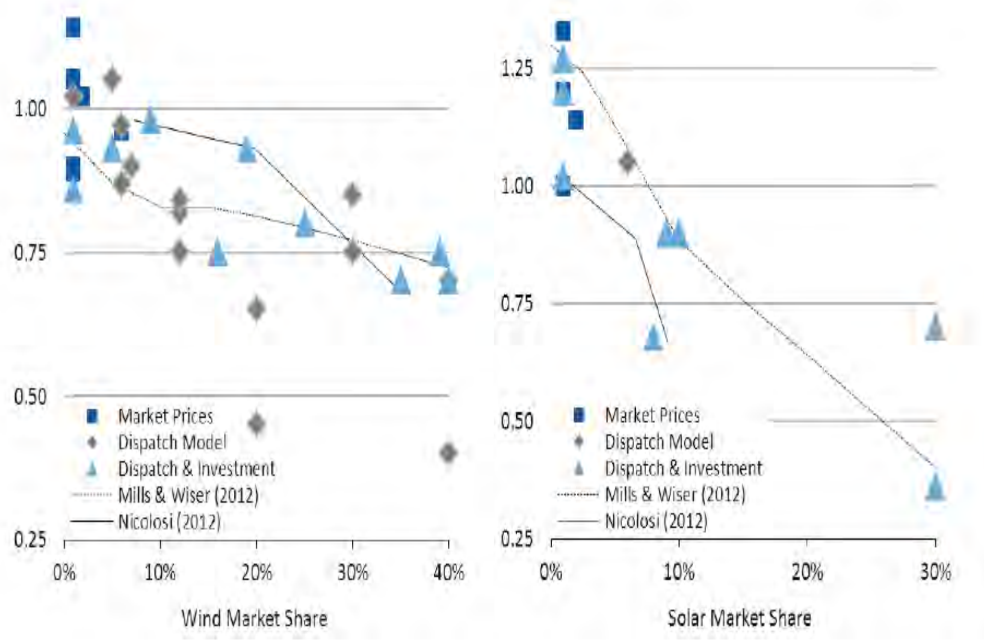


Wicked, continued

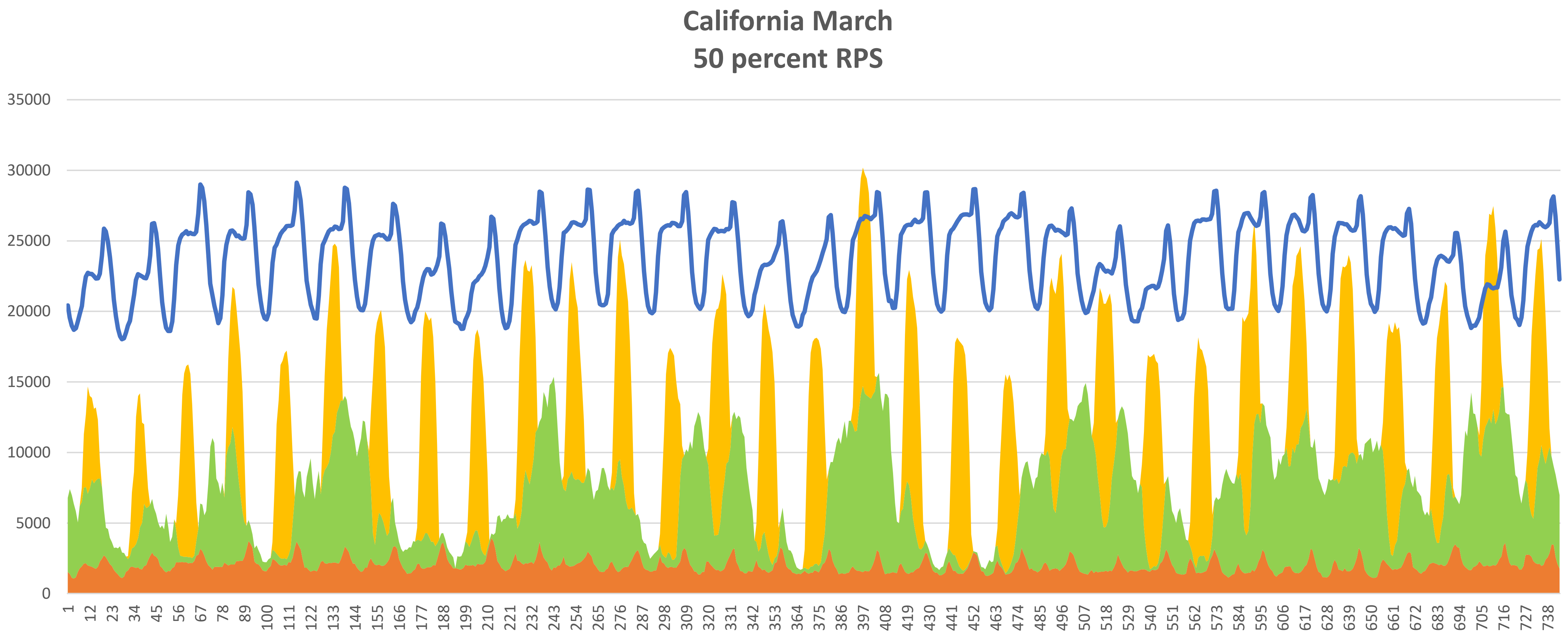


Finding Number 2: At penetrations above 30-40 percent, wind and solar eat their own lunch …

- Surplus electricity production drives costs to zero
  - Surplus in inherent in penetrations above 40-50 percent
- This HURTS developers of wind and solar, as the addition of incremental capacity leads to diminishing returns for all



Finding Number 3: Even modest penetrations of wind and solar could preclude zero carbon baseload from competing



Finding Number 4: Systems with high penetrations of wind and solar top out at 70-80 percent CO_2 reduction ….

- If 70-80 percent reduction is all that is wanted, this may be okay
- Costs and system size remain genuine concerns
- **This path may be a dead-end with respect to deep-decarbonization**

Troubling confusion of ends and means

- Much of the green community and its political allies have conflated renewable/efficiency with climate mitigation
  - Given the size of the lift, limiting the options seems unwise
- Evident in Paris and in the shape of the CPP
  - Why did they not choose to spell out 2° or 1.5° C?
- Why was there not more outcry from the green community over the toothless nature of the Paris agreements?

Balanced portfolios

- Have room for all types of resources
  - Variable renewables: 30-40 percent
  - Zero carbon base resources: 30-40 percent
  - As much efficiency as possible
- Achieve deeper carbon reductions at lower cost than constrained portfolios

DOCKETED	
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TN #:	233380
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Filer:	Courtney Wagner
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Submitter Role:	Commission Staff
Submission Date:	6/9/2020 1:14:49 PM
Docketed Date:	6/9/2020

CALIFORNIA
ENERGY COMMISSION

California Energy Commission

STAFF PAPER

Thermal Efficiency of Natural Gas-Fired Generation in California: 2019 Update

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Data Integration and Policy Office
Energy Assessments Division

Gavin Newsom, Governor
June 2020 | CEC-200-2020-03

ABSTRACT

The Thermal Efficiency of Natural Gas-Fired Generation: 2019 Update staff paper provides a brief overview of the general trends in power generation in California from 2001 through 2018. The paper details the changes in the type of power plants used over the past 18 years to meet load and documents the total annual natural gas usage for thermal power generation. By providing an accurate assessment of historical natural gas-usage, the paper supports the state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. Topics covered in the paper include data collection, power plant categories, annual generation trends, and a comparison of hourly peak loads on the hottest days in each of the past two years.

Keywords: Combined-cycle, heat rate, gas-fired generation, thermal efficiency

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EXECUTIVE SUMMARY

Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) directed the California Energy Commission adopt an Integrated Energy Policy Report (IEPR) every two years. Senate Bill 100 (de León, Chapter 312, Statutes of 2018) mandates that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. California's systemwide average thermal efficiency has improved by 30 percent since 2001 because of the use of combined-cycle plants, the phase-out of once-through-cooling plants, and the retirement of aging steam turbines. Total natural gas fuel use for power generation was the second lowest in the past 18 years. The new thermal plants are providing a sustained 23-percent improvement in fuel efficiency. The lower fuel use is also a result of significant growth in renewable energy, especially solar photovoltaic systems.

The rapid growth of utility-scale solar generation and residential rooftop solar systems, along with new state policy mandates, are limiting the long-term outlook for natural gas-fired generation. California has added more than 10,000 MW of utility-scale solar capacity since 2009, now producing about 25,000 gigawatt-hours (GWh) annually. In 2018, solar generation increased 12 percent, contributing to a dampening of supply from the state's most efficient combined-cycle plants during daylight hours. California's remaining aging gas plants were dispatched more in summer months to meet a steeper daily load requirement compared to other months of the year. Similarly, peaker plants operated earlier in the day and further into the evening hours during summer months to support changing system conditions. In 2018, California's natural gas fleet provided 47 percent of in-state generation while zero-carbon electric generation accounted for 53 percent.

CHAPTER 1: Introduction

Background

The general trends in the thermal efficiency of California's natural gas-fired generation fleet from 2001 through 2018 are presented in this staff paper. Documenting changes in the performance of power plants and the related impact on California's generation mix helps inform policy makers charged with guiding energy procurement decisions and overseeing resource planning for load-serving entities. Senate Bill 100 (de León, Chapter 312, Statutes of 2018) has established a new state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. This policy will effectively curb the use of natural gas power generation serving retail electricity customers in the future. The original impetus for this paper stems from the requirements of Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002), which directs the California Energy Commission (CEC) adopt an Integrated Energy Policy Report (IEPR) every two years.

To provide context for the trends observed, this staff paper begins with a brief overview of the data collection process. Chapter 2 describes the total statewide generation mix and the method used for grouping various classes of natural gas-fired power plants. Chapter 3 discusses the metrics used to measure power plant performance. Chapter 4 highlights the trends in natural gas-fired generation since 2001. Chapter 5 analyzes hourly generation and profiles the highest coincident load day of the year. Finally, Chapter 6 summarizes observed trends.

Data Collection

The paper incorporates power generation and fuel use data collected by the CEC under the authority of the California Code of Regulations, Title 20, Division 2,Chapter 3, Section 1304(a)(1)-(2). Under the regulations, all owners of power plants with a nameplate capacity of 1 megawatt (MW) or more directly serving California end users must report their respective generation, fuel, and water usage for each calendar year. “Nameplate capacity" is defined as the maximum rated output of a generator under specific conditions as designated by the manufacturer. The Energy Commission compiles and posts the power plant data on its website. Data have been compiled based on attributes of the natural gas-fired generating units within each power plant, and units have been assigned to one of five categories. All data categories are mutually exclusive, and no unit is double-counted.

The reporting regulations also apply to a small number of out-of-state power plants that are electrically within a California balancing authority's control area and directly serving California end users. A “balancing authority” is responsible for controlling the generation and transmission of electricity within its control area and between neighboring balancing authorities through imports and exports. These out-of-state power plants include the Desert Star Energy Center in Nevada and the La Rosita Power Project and Termoeléctrica De Mexicali in Mexico. There are also numerous wind and solar energy projects located in adjacent jurisdictions that are within a California balancing authority's control.

CHAPTER 2: Natural Gas Generation Categories

California's Quarterly Fuels and Energy Reporting (QFER) regulations require power plant owners to report generation and fuel use data to the CEC for all generators with a nameplate capacity of 1 MW and larger. These data form the basis for determining the statewide generation mix each year. The data collection regulations do not apply to distributed generation systems under 1 MW such as residential rooftop solar photovoltaic (PV) systems.

Power Plants in California

As of December 31, 2018, California has about 81,000 MW of utility-scale generation capacity shared among more than 1,500 power plants. Natural gas-fired power plants account for more than half of the state's total generation capacity with slightly more than 42,000 MW. Renewable generation accounts for about 24,000 MW with 11,900 MW from solar and 6,000 MW from wind. Large hydroelectric power plants provide an additional 12,200 MW of capacity, while California's only operational nuclear power plant, Pacific Gas and Electric's Diablo Canyon Power Plant, provides 2,400 MW.

The natural gas-fired power plants examined in this paper are grouped into five categories based on a combination of duty cycles, vintage of the generating unit, and technology type. The five categories are aging, cogeneration, combined-cycle, peaking, and miscellaneous. The combined-cycle category includes three power plants that are not located in California but are electrically within the balancing area of the California ISO — they are dynamically scheduled by the California ISO for power delivery to California utilities. The three plants are the 536 MW Desert Star Energy Center in Boulder City, Nevada; the 1,100 MW La Rosita Power Plant, of which 547 MW is dedicated to California; and the 600 MW Termoelectrica de Mexicali. Both La Rosita and Termoelectrica are near Mexicali, Mexico, a few miles south of the international border. A detailed listing of the data set is published on the CEC website.[1]

Aging and Once-Through-Cooling Plants

The Aging category includes natural gas-fired power plants built and operational before 1980. Almost all are steam turbines that use once-through-cooling (OTC) technology. In OTC, power plants draw water from the ocean or other large body of water to condense steam after it has passed through a turbine to create power. However, the process results in the yearly loss of billions of aquatic organisms and the degradation of aquatic ecosystems.[2]

1 California Energy Commission website. *QFER CEC-1304 Power Plant Owner Reporting Database*. Accessed October 8, 2019. See https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/index_cms.php.

2 California Energy Commission Official Blog. Phase Out Looms for Power Plants That Use Water for Cooling. May 17, 2017. Accessed October 2, 2018. See http://calenergycommission.blogspot.com/2017/05/phase-out-looms-for-power-plants-that.html.

As a result of these environmental concerns, in 2010 the State Water Resources Control Board (State Water Board) adopted a statewide policy requiring all owners of OTC plants to implement a best available control technology to achieve water quality goals, specifically, a closed-cycle evaporative cooling system. Two compliance tracks established to meet the new OTC policy involved reducing intake flows to levels equivalent to those for closed-cycle evaporative cooling. Alternatively, a plant could comply by shutting down.[3] Most plants have a compliance date of December 31, 2020, while a few have compliance dates of December 31, 2024 and 2029.

On August 13, 2019, the joint-agency Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) issued a draft report recommending the State Water Board extend OTC policy compliance dates from 2020 to 2022. SACCWIS recommended the extension based on the sooner-than-expected retirement of the Etiwanda Generating Station (640 MW) in June 2018, the recently announced early retirement of the Inland Empire Energy Center (680 MW) at the end of 2019 and reduced net qualifying capacity values for wind and solar resources to meet modeled peak system needs. With 5,298 MW of OTC capacity scheduled to retire by December 31, 2020, SACCWIS recommended up to 1,163 MW of capacity from some combination of Alamitos Units 3, 4, and 5 and some portion of the remaining 2,579 MW of OTC capacity be delayed until December 31, 2022.[4] This remaining capacity (2,579 MW) is produced by Huntington Beach Generating Station Unit 2 (215 MW), Ormond Beach Generating Station Units 1 and 2 (1,516 MW), and Redondo Beach Generating Station Units 5, 6, and 8 (848 MW).

In 2001, before implementation of the State Water Board's OTC policy, there were 27 aging natural gas-fired power plants with a nameplate capacity of almost 20,000 MW. Seventeen of the 27 aging plants were classified as OTC, reflecting 15,134 MW in total nameplate capacity. On February 6, 2018, Mandalay Generating Station retired, shutting down two aging OTC steam turbines and a smaller peaking unit. On June 1, 2018, the 1,049 MW Etiwanda Generating Station retired after more than 55 years of operation. Most recently, the Encina Power Station retired December 11, 2018, removing another 965 MW of OTC capacity from the state's portfolio. By the close of 2018, nine aging power plants remained, accounting for 6,584 MW or about 8 percent of total statewide capacity. Six of these aging plants are also classified as OTC with a total capacity of 6,155 MW.

Cogeneration Plants

The Cogeneration category consists of a mix of combined-cycle units, combustion turbine generators, and steam turbine generators that produce electricity and thermal energy for useful purposes. These plants are also commonly referred to as "combined heat and power, or

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3 California Energy Commission. *Tracking Progress. Once-Through Cooling Phase Out*. See http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

4 California State Water Resources Control Board, *Report of the Statewide Advisory Committee on Cooling Water Intake Structures - Local and System-Wide 2021 Grid Reliability Studies - Final August 23, 2019*, Accessed November 8, 2019. See https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/sccwf.pdf.

"CHP," plants. Cogeneration plants have an onsite (or nearby) thermal host, such as a petroleum refinery or college campus, as well as a contract with the local utility that ensures all associated electricity generated is purchased. These plants are often classified as "qualifying facilities," or QFs, as defined under the Code of Federal Regulations Public Utility Regulatory Policies Act of 1978 (PURPA).[5] PURPA fostered innovation in renewable generation and levelized competition with traditional fossil fuel generators for small power producers.

QFs fall into two categories: qualifying cogeneration facilities and qualifying small power production facilities of 80 MW or less whose primary energy source is renewable, biomass, waste, or geothermal resources. For QFs that are cogeneration facilities, there is no size limit. The primary benefit of being classified as a QF is the ability to sell power to utilities at avoided-cost rates. "Avoided-cost rates" are defined as the rate that would approximate the cost for a utility to generate or purchase the same amount of electricity from another source.

Traditionally, utilities were able to purchase nonutility electricity at rates below their own generation costs, and this ability put small power producers and cogenerators at a disadvantage. Since cogenerators serve dedicated thermal hosts, they do not have the same flexibility as traditional power plants to curtail their electric generation without also affecting their thermal operations. By attaining QF status under PURPA, CHP plants are guaranteed to be able to sell their power to a local utility. Over the years since the PURPA regulations took effect, utilities have tried to limit the definition of cogeneration as it applies to CHP plants due in part to the high fixed costs associated with interconnecting to cogeneration facilities. However, federal courts have consistently maintained a broad interpretation of the definition of cogeneration and what constitutes a QF facility. The PURPA regulations have resulted in qualifying cogeneration facilities operating at consistently high capacity factors, as observed over the past 18 years of QFER data.

The number of cogeneration plants in California continues to decline, from 151 plants in 2001 to 120 plants at the end of 2018. Total capacity is down 942 MW from 2001 levels to 5,438 MW in 2018, about 7 percent of statewide capacity. Two-thirds of California's cogeneration plants are rated at 50 MW or less with a median capacity of 27 MW.

Combined-Cycle Plants

The Combined-Cycle category of power plants is defined as having a generation block consisting of at least one combustion turbine, a heat recovery steam generator (HRSG), and a steam turbine. The higher fuel efficiency results from the ability of the HRSG to capture exhaust gas from the combustion turbine to produce steam for the steam turbine, often augmented with duct burning of natural gas within the HRSG. For this report, the Combined-Cycle category consists of those plants constructed since 2000 with a total capacity of 100 MW or more.

California's newer combined-cycle plants produce electricity with better heat rates than either stand-alone combustion turbines or steam turbines. Historically, these plants have been used as baseload generation. "Baseload generation" refers to those plants designed to operate at an

5 Qualifying facilities as defined in 16 U.S.C. §796(18)(A) and 18 CFR 292.203.

annualized capacity factor of at least 60 percent. However, with the increasing integration of renewable generation, along with the inherent regulatory must-take generation from QFs, combined-cycle plants are being tasked for flexible, load-balancing requirements that involve more frequent fast starts, cycling, and load-following ancillary services.[6]

Load-following ancillary services are reserved electric generating capacity that can be increased or decreased through automatic generation control systems to allow continuous balance between generating resources and electricity demand. Load following is the difference in generation requirements between the hour-ahead energy forecast and the five-minute-ahead forecast within a balancing authority.[7]

In 2001, the 550 MW Sutter Energy Center in Yuba City (Sutter County) and the 594 MW Los Medanos Energy Center in Pittsburg (Contra Costa County) were the only combined-cycle power plants in this category. By the close of 2018, California had 35 large combined-cycle plants totaling almost 20,000 MW in nameplate capacity, or about 25 percent of statewide electric generation capacity. However, as described below, the planned closure of the Inland Empire Energy Center will reduce total capacity in the state by 810 MW.

On June 19, 2019, the Inland Empire Energy Center, LLC, a subsidiary of General Electric Company (GE), announced the closure of the 10-year old Inland Empire Energy Center combined-cycle power plant because of economics and increasing incompatibility with the high levels of renewables in California's electricity market. The plant was designed for baseload operation, obtaining fuel efficiency at the expense of fast-start flexibility, with the use of a pair of newly designed GE 7H single-shaft combined cycle generators. Inland Empire achieved industry-leading thermal efficiencies greater than 60 percent. For perspective, in 1990, typical combined-cycle efficiency was 50 percent. By 2010, the best plants reached 59 percent efficiency.[8]

This model of combustion turbine has had limited use worldwide. The result was an orphaned technology that required roughly 2.5 times higher operational and maintenance costs than other comparable combined-cycle installations. In addition, retrofitting the Inland Empire plant to improve start-up times, ramp rates, turndown ratios, or maintenance costs was not economically feasible. The Inland Empire plant will be retired and replaced with a utility-scale

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6 "Must-take generating resources" are identified by the California ISO or a local regulatory authority as generating units that are subject to an existing QF contract or a power purchase agreement with mandatory obligations under federal law. Must-take generation also includes generation from nuclear units and generation delivered from cogeneration plants with mandatory requirements to serve a thermal host.

7 Makarov, Yuri V., Clyde Loutan, Jian Ma, and Phillip de Mello. 2009. *Operational Impacts of Wind Generation on California Power Systems.* *IEEE Transactions on Power Systems,* Vol. 24, No. 2. See http://www.caiso.com/Documents/OperationalImpacts-WindGenerationonCaliforniaPowerSystems.pdf.

8 Breeze, Paul. 2011. "Efficiency Versus Flexibility: Advances in Gas Turbine Technology." *Power Engineering International.* Issue 3, Volume 19. Accessed on September 20, 2019. See https://www.powerengineeringint.com/2011/04/01/efficiency-versus-flexibility-advances-in-gas-turbine-technology/.

battery energy storage system (BESS) to integrate renewable generation.[9] A BESS is an array of batteries designed to provide instantaneous energy to the grid, thereby avoiding fuel use from a natural gas turbine operating at minimum loads. Unlike a BESS, natural gas turbines have minimum operating loads, much like an automobile idling at rest.

Peaking Plants

The Peaking category consists of simple-cycle generating units. These units have a peaking duty cycle role — specifically, they are called upon to meet peak demand loads for a few hours or less on short notice, often in the 15-minute or 5-minute-ahead real-time market. This category also includes peaking plants with integrated BESS technology. BESS technology enables instantaneous energy to the grid, thereby avoiding fuel use and related emissions from gas turbine operation at minimum loads.

Traditionally, peaking plants have provided nonspinning reserves, a term denoting nonoperating plants capable of ramping up to full capacity and synchronizing to the grid within 10 minutes of dispatch. However, with the BESS hybrid configurations, these plants can now provide spinning reserves without operating the gas turbine. “Spinning reserves” is a term referencing operating (in other words, spinning) resources that are synchronized and ready to meet electric demand within 10 minutes through ramping to maintain system stability. The BESS provides instantaneous ramping to accommodate renewable integration and results in fewer starts for the gas turbine, reduced water usage, and reduced emissions. GHG and criteria pollutant emissions are reduced as the BESS allows the turbine to operate at more efficient, full-load output levels more often and reduces the times when the turbine operates at partial load.

In 2001, there were 29 peaking plants in California; by the close of 2018, there were 74 facilities with 9,526 MW of nameplate capacity, about 12 percent of total statewide capacity. The newest peaker, the 525 MW Carlsbad Energy Center, came on-line incrementally over three months in 2018. It was built on the existing Encina Power Station site and planned as a direct replacement for Encina’s aging OTC units. A unique feature of the new Carlsbad plant is the five, fast-starting simple-cycle combustion turbines that provide rapid response to peak demand requirements. Each turbine is nominally rated at 105 MW. The flexibility of the simple-cycle units will also help accommodate the integration of renewable generation at a net efficiency of 44 percent.

Miscellaneous Plants

All remaining natural gas-fired power plants are included in the Miscellaneous category. These include technologies such as fuel cell and reciprocating engine applications, turbine testing facilities, as well as older generating units built before the 2000s that are not considered aging, peaking, or cogeneration. This category also includes generating units that have been

9 California Energy Commission, 01-AFC-17C, June 20, 2019. *Inland Empire Energy Center Decommissioning and Demolition Plan*. Accessed on September 20, 2019. See https://efiling.energy.ca.gov/GetDocument.aspx?tn=228806&DocumentContentId=60139.

repowered from stand-alone to combined-cycle operation. At the close of 2018, this category totaled 838 MW, about 1 percent of total capacity in the state.

CHAPTER 3: Performance Metrics

This chapter presents three measurements of performance for each category of natural gas-fired generation. Annual capacity factors, heat rates, and thermal efficiencies are defined and used to describe the typical operation of the average power plant within each category. Where appropriate, cogeneration plants are excluded due to the intrinsic capability to produce electricity and useful heat for nongeneration purposes. **Table 1** summarizes the performance metrics for 2018.

Table 1: Natural Gas-Fired Power Plant Summary Statistics, 2018

Category	Capacity (MW)	Energy (GWh)	Capacity Factor	Fuel Use (MMBtu)	Heat Rate (Btu/kWh)	Thermal Efficiency
State Total/Average	42,282	97,756	25.7%	848,059,844	7,728	44.2%
Combined-Cycle	19,896	67,017	38.3%	491,284,846	7,331	46.6%
Cogeneration	5,438	22,663	46.4%	267,737,303	N/A	N/A
Aging	6,584	2,332	3.4%	30,804,852	13,212	25.8%
Peaking	9,526	4,140	5.1%	43,264,444	10,450	32.7%
Miscellaneous	838	1,604	21.8%	14,968,399	9,333	36.6%

Source: QFER CEC-1304 Power Plant Data Reporting

Capacity Factor

The statewide capacity factor for natural gas-fired generation in 2018 is about 26 percent, down from 45 percent in 2001. The “capacity factor” is the ratio, expressed as a percentage, of the actual output of a power plant over a given period to the related maximum potential output over the same period. The capacity factors shown in **Table 2** provide a breakdown of the statewide average into the five categories of natural gas-fired power plants in California since 2001.

The primary driver of the capacity factor for natural gas generation is the seasonal availability of hydroelectric energy. Combined-cycle generation is displaced in wet hydrological years by hydroelectric energy as it is the only category large enough, at almost 20,000 MW, that can absorb the displacement of 14,000 MW of hydroelectric generating capacity.

Table 2: Capacity Factors, 2001 – 2018

Year	Combined-Cycle	Aging	Peaking	Cogeneration	Miscellaneous	State Average
2001	53.9%	42.1%	11.8%	68.0%	9.9%	44.9%
2002	65.7%	21.1%	5.3%	73.4%	9.8%	32.7%
2003	53.5%	15.5%	4.1%	71.3%	14.3%	30.3%
2004	58.6%	16.2%	4.4%	71.9%	15.4%	33.3%
2005	53.3%	10.1%	4.0%	66.3%	17.7%	30.1%
2006	53.6%	9.6%	3.7%	62.9%	16.6%	31.0%
2007	62.3%	9.1%	4.2%	64.4%	18.9%	34.2%
2008	62.2%	10.4%	4.4%	63.1%	19.9%	34.6%
2009	58.3%	7.6%	4.0%	61.2%	15.8%	32.1%
2010	52.2%	4.4%	3.0%	60.1%	18.1%	29.1%
2011	37.5%	4.1%	3.5%	59.1%	23.4%	24.2%
2012	55.3%	7.6%	5.1%	57.2%	22.4%	32.2%
2013	53.0%	5.9%	5.2%	56.5%	24.6%	30.8%
2014	51.5%	5.4%	5.8%	55.0%	24.3%	30.6%
2015	50.7%	6.0%	5.9%	52.3%	25.1%	30.6%
2016	40.7%	3.9%	5.1%	49.0%	23.2%	25.7%
2017	35.9%	4.2%	5.2%	46.4%	23.3%	24.5%
2018	38.3%	3.4%	5.1%	46.4%	21.8%	25.7%

Source: QFER CEC-1304 Power Plant Data Reporting

Table 3 lists the annual total generation for natural gas-fired generation and hydroelectric generation in California. As measured over the past 18 years, statewide natural gas and hydroelectric electric generation are negatively correlated.[10] About half of the variance between natural gas-fired generation and hydroelectric generation is explained by correlation. While there are other factors that influence natural gas-fired generation, the availability of hydroelectric generation is a primary driver.

A secondary factor impacting combined-cycle capacity factors is the growth of solar PV generation. Like hydroelectric generation, solar PV generation is displacing natural gas-fired generation during daylight hours. California has added more than 10,000 MW of utility-scale solar PV capacity since 2009, now producing about 25,000 gigawatt-hours (GWh) annually. “Utility-scale” is defined as systems rated at 1 MW or larger in nameplate capacity. Similarly, behind-the-meter residential solar PV systems have added an additional 8,000 MW of capacity since 2009, producing about 14,000 GWh annually.

10 With a correlation coefficient r= -0.681, the coefficient of determination, r^2, is 0.46.

Table 3: Natural Gas-Fired Electric Generation, 2018 (GWh)

Year	Combined-Cycle	Aging	Cogeneration	Peaking	Misc.	Total In-State Natural Gas Generation	Total In-State Hydroelectric Generation	Total In-State Generation
2001	2,730	73,000	37,898	1,752	1,024	116,404	24,988	202,733
2002	12,954	36,526	40,923	1,317	1,013	92,733	31,359	187,057
2003	26,335	25,877	39,329	1,145	1,809	94,496	36,321	194,572
2004	37,605	24,937	39,358	1,304	2,064	105,268	34,490	199,023
2005	42,576	14,639	36,559	1,206	2,145	97,125	40,263	202,310
2006	57,481	14,132	34,552	1,214	1,840	109,219	48,559	218,869
2007	71,357	13,339	35,500	1,471	2,099	123,766	27,106	212,928
2008	75,936	15,303	34,824	1,840	1,919	129,823	24,460	209,646
2009	75,382	11,193	33,559	1,796	1,513	123,443	28,540	207,546
2010	72,472	6,216	32,660	1,436	1,714	114,498	34,190	205,893
2011	54,748	5,679	31,372	1,757	2,517	96,072	42,737	201,618
2012	85,090	10,421	30,231	2,615	2,348	130,705	27,461	199,860
2013	87,179	7,586	29,699	3,554	1,800	129,818	24,101	199,809
2014	88,187	6,221	28,675	4,388	1,779	129,249	16,482	199,732
2015	86,990	6,448	27,022	4,444	1,846	126,749	13,996	197,073
2016	71,158	3,892	25,198	3,934	1,708	105,890	28,986	198,632
2017	62,750	3,183	23,270	4,202	1,721	95,126	43,303	206,488
2018	67,017	2,332	22,663	4,140	1,604	97,755	26,291	195,405

Source: QFER CEC-1304 Power Plant Data Reporting

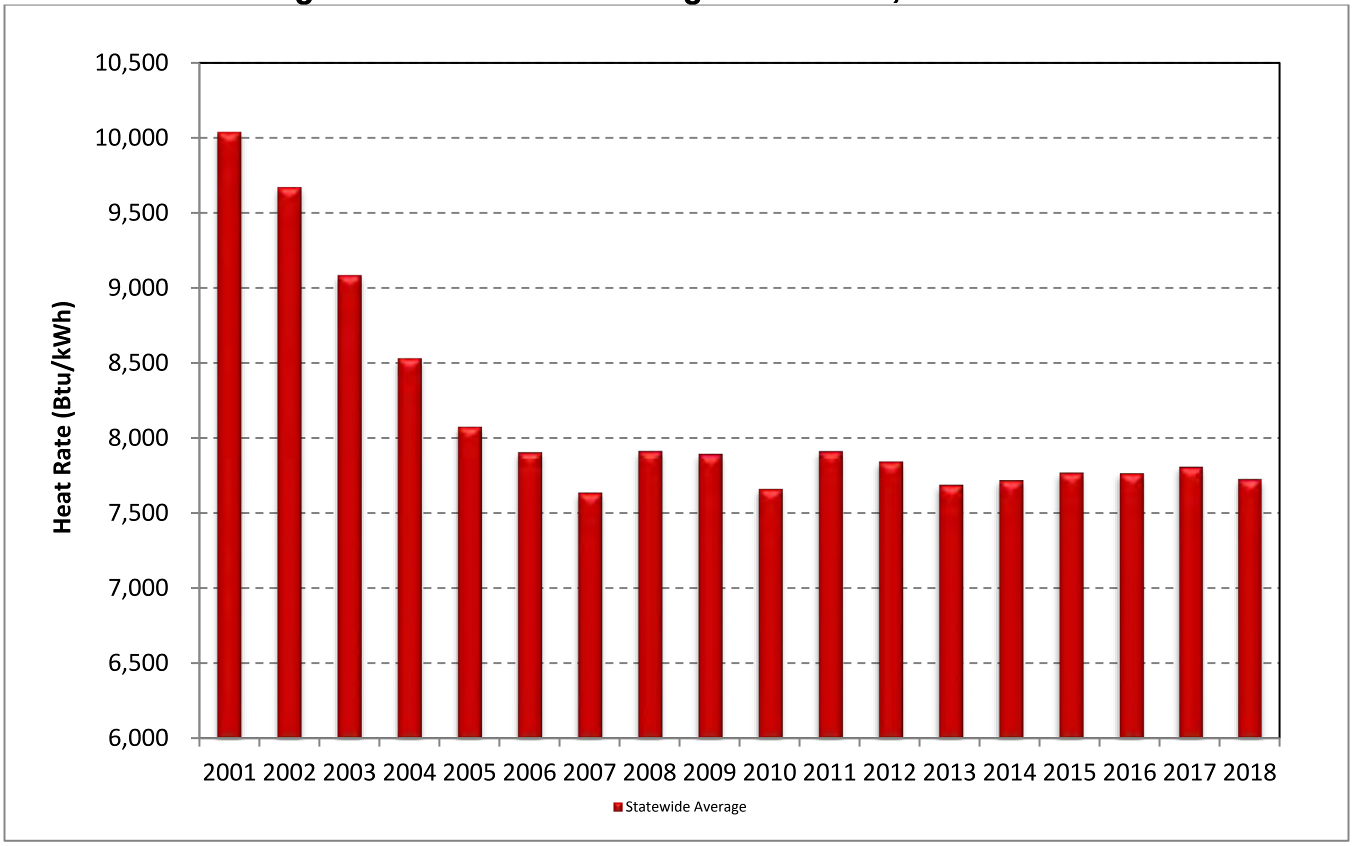
Heat Rate

All fuels, including natural gas, are converted into useful energy according to the associated heat content, which is measured in British thermal units (Btu). The heat content quantifies the amount of heat released during an exothermic reaction such as combustion. A "Btu" is the amount of energy required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

In a natural gas-fired generation plant, the relative efficiency is measured by the related heat rate. The heat rate expresses how much fuel is required to generate 1 kilowatt-hour (kWh) of electric energy.[11] A higher heat rate indicates a less efficient useful energy conversion process. **Figure 1** displays the annual statewide average heat rate from 2001 through 2018. The improvement in the statewide average heat rate since 2001 reflects the transition away from the use of inefficient steam turbines to more fuel-efficient combined-cycle turbines. More recently, the availability of hydroelectric generation during wet hydrological years has restricted potential improvements in the statewide average heat rate.

11 Heat rates are calculated in higher heating value terms. Higher heating value includes the latent heat of vaporization of water in the combustion of natural gas.

Figure 1: Statewide Average Heat Rate, 2001-2018



Source: QFER CEC-1304 Power Plant Data Reporting

Ultimately, there are practical limits to the state's ability to reduce its systemwide heat rate. The primary factor is how often natural gas-fired power plants operate over the available hours. The increasing growth of wind and solar generation has resulted in increased flexibility requirements of the existing natural gas fleet. Wind and solar generation are inherently variable and partially unpredictable. Flexibility requires natural gas power plants to cycle power output by starting up, shutting down, or ramping up and down within a prescribed set of operational limits. Ramping and cycling result in increased fuel consumption, a result of the large temperature and pressure changes that take place in plant equipment. For those power plants designed to operate most efficiently at constant output levels, cycling leads to greater wear and tear and reduced lifespan of the equipment, along with reduced thermal efficiency. Studies have found that cycling results in a 1 percent permanent degradation in the heat rate of a generating unit over four to five years.[12]

12 Kumar, N., P. Besuner, S. Lefton, D. Agan, and D. Hilleman. National Renewable Energy Laboratory. July 2012. *Power Plant Cycling Costs*. Accessed on October 9, 2019. See https://www.nrel.gov/docs/fy12osti/55433.pdf.

Table 4 provides the heat rate for each category that contributes to the statewide average shown in **Figure 1**.[13] Combined-cycle generation had the lowest heat rate of the past three years, pushing the statewide average down by 1 percent to 7,728 Btu/kWh, the fourth-lowest average since 2001. The statewide average heat rate has remained below 8,000 Btu/kWh since 2007 as aging generation has fallen to just 3 percent of the 2001 levels. From 2007 through 2018, the natural gas-fired generation fleet has provided a consistent 23 percent improvement in fuel efficiency compared to 2001.

Table 4: Heat Rates, 2001 – 2018 (Btu/kWh)

Year	Combined-Cycle	Aging	Peaking	Miscellaneous	State Average
2001	6,974	10,122	11,336	10,153	10,040
2002	7,147	10,529	10,866	9,530	9,672
2003	7,209	10,835	10,820	10,296	9,086
2004	7,178	10,917	10,804	9,957	8,751
2005	7,230	11,279	10,798	9,947	8,376
2006	7,229	11,282	10,762	9,975	8,121
2007	7,190	10,971	10,862	9,988	7,889
2008	7,147	11,131	10,582	10,074	7,915
2009	7,227	11,590	10,832	10,409	7,896
2010	7,199	11,677	11,012	9,923	7,663
2011	7,287	12,297	10,740	9,671	7,913
2012	7,231	11,702	10,858	9,585	7,844
2013	7,220	11,406	10,333	9,545	7,690
2014	7,273	11,775	10,309	9,351	7,720
2015	7,320	11,676	10,227	9,478	7,771
2016	7,339	12,311	10,268	9,432	7,766
2017	7,346	12,262	10,533	9,844	7,810
2018	7,331	13,212	10,450	9,333	7,728

Source: QFER CEC-1304 Power Plant Data Reporting

Displacement by hydroelectric generation during wet hydrological years is a limiting factor in attaining higher fuel efficiency as measured by the heat rate. Other factors that limit or constrain California's ability to reach higher thermal efficiency levels include topography and climate. Power plant efficiency is impacted by the location, elevation, and ambient weather conditions at each plant site. Locational factors may include emissions limits by air quality management districts, localized noise limits, and limits on hours of operation.[14] Power plants in higher elevations experience reduced air density; lower air density decreases power generated

13 Cogeneration plants are excluded from the statewide average heat rate since these plants produce thermal energy simultaneously with electrical energy. There is no industrywide standard for determining the heat rate for these systems.

14 South Coast Air Quality Management District, Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions. See http://www.aqmd.gov/docs/default-source/rule-book/reg-xx/rule-2012.pdf.

by the gas turbine. Ambient weather also has a significant impact on thermal efficiency. Like high altitude factors, power plants located in areas with high average temperatures also experience reduced air density with a consequential loss in power generation efficiency.

Thermal Efficiency

Thermal efficiency is a unitless measure of the efficiency of converting a fuel to energy and useful work. Under ideal conditions of energy conversion with no losses, 3,412 Btu equals 1 kWh. The thermal efficiency is determined by comparing the ideal conversion of fuel to energy with the measured heat rate of each category of natural gas-fired generation. Based on the heat rates from **Table 4**, the thermal efficiency for each category is shown in **Table 5**. The cogeneration category is not included in the table as there is not enough information to determine the additional fuel the cogeneration system consumes above what would have been used by a boiler to produce the thermal output of the cogeneration system.[15]

As observed with the heat rates, the statewide thermal efficiency has improved from 34 percent in 2001 to 44.2 percent in 2018, a 30 percent improvement, because of the proliferation of combined-cycle generation replacing steam turbine generation. The thermal efficiency of the aging category declined over the past 18 years as steam turbines were decommissioned once they reached the end of the useful service life or because of OTC compliance requirements. However, in recent years the average thermal efficiency of the combined-cycle category has dropped by about 1 percent as these units have been displaced by the significant growth of solar generation. The displacement by solar generation is being listed as a primary reason the owners of 810 MW Inland Empire Energy Center announced its retirement after 10 years of operation.

15 United States Environmental Protection Agency. Methods for Calculating CHP Efficiency. Accessed on October 10, 2019. See https://www.epa.gov/chp/methods-calculating-chp-efficiency.

Table 5: Thermal Efficiency, 2001 – 2018

Year	Combined- Cycle	Aging	Peaking	Miscellaneous	State Average
2001	48.9%	33.7%	30.1%	33.6%	34.0%
2002	47.8%	32.4%	31.4%	35.8%	35.3%
2003	47.3%	31.5%	31.5%	33.1%	37.6%
2004	47.5%	31.3%	31.6%	34.3%	39.0%
2005	47.2%	30.3%	31.6%	34.3%	40.7%
2006	47.2%	30.2%	31.7%	34.2%	42.0%
2007	47.5%	31.1%	31.4%	34.2%	43.3%
2008	47.8%	30.7%	32.3%	33.9%	43.1%
2009	47.2%	29.4%	31.5%	32.8%	43.2%
2010	47.4%	29.2%	31.0%	34.4%	44.5%
2011	46.8%	27.8%	31.8%	35.3%	43.1%
2012	47.2%	29.2%	31.4%	35.6%	43.5%
2013	47.3%	29.9%	33.0%	35.8%	44.4%
2014	46.9%	29.0%	33.1%	36.5%	44.2%
2015	46.6%	29.2%	33.4%	36.0%	43.9%
2016	46.5%	27.7%	33.2%	36.2%	43.9%
2017	46.4%	27.8%	32.4%	34.7%	43.7%
2018	46.6%	25.8%	32.7%	36.6%	44.2%

Source: QFER CEC-1304 Power Plant Data Reporting.

CHAPTER 4: Generation Trends

Total System Electric Generation

The combination of California's own generation and imported energy from other balancing authorities in the Western Interconnection is referred to as "total system electric generation" or "total system power"; both terms are used interchangeably. In a typical calendar year, California generates about 70 percent of its electrical energy and imports the remaining 30 percent. California's natural gas plants accounted for 47 percent (90,691 GWh) of total in-state electric generation. The total system electric generation summary for 2018 is shown in **Table 6**.

Table 6: California's Total System Electric Generation, 2018

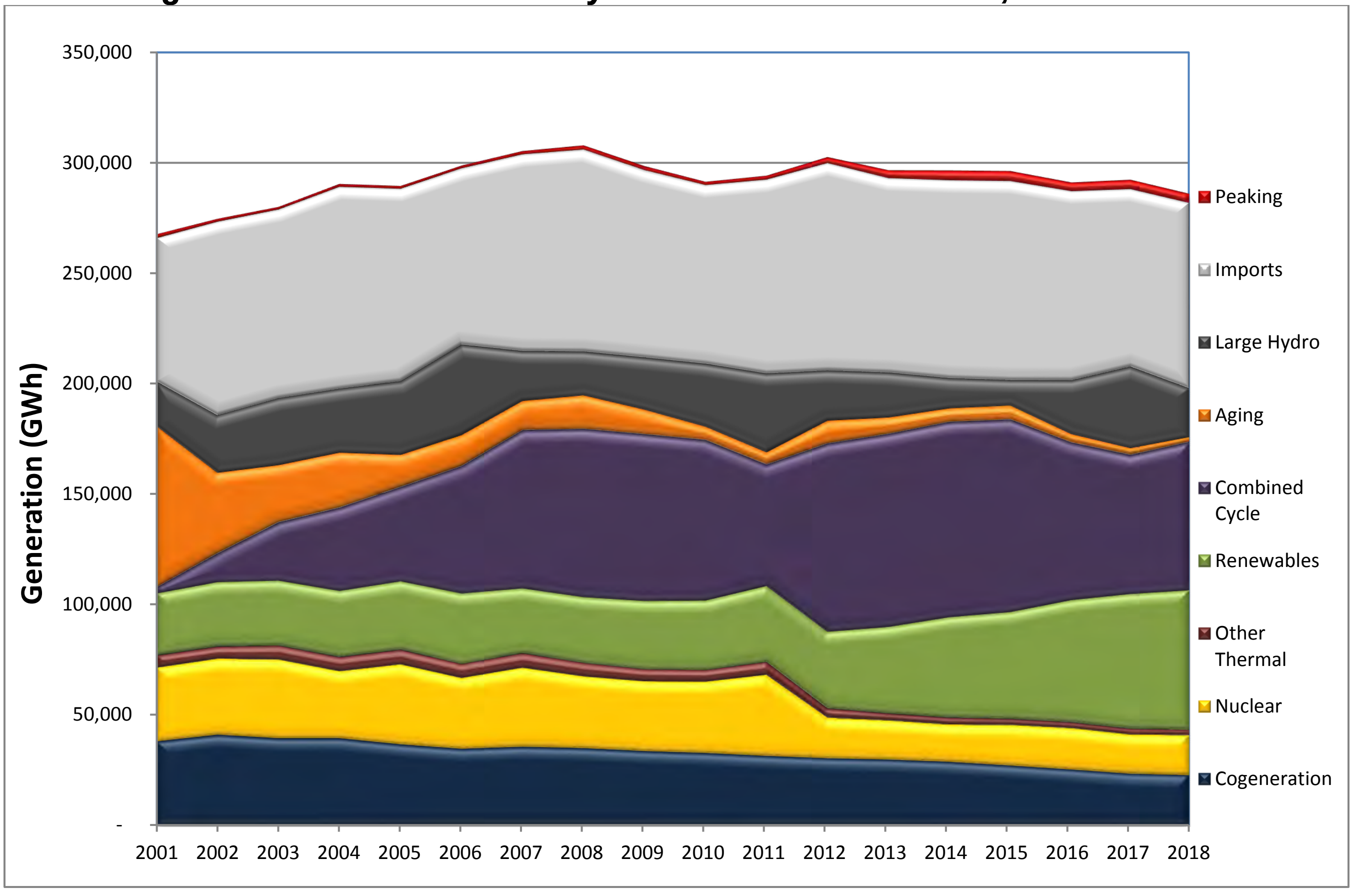
Fuel Type	California Generation (GWh)	Imports (GWh)	Total Generation (GWh)	Percentage Share
Coal	294	9,139	9,433	3.3%
Large Hydroelectric	22,096	8,403	30,499	10.7%
Natural Gas	90,691	8,953	99,644	34.9%
Nuclear	18,268	7,573	25,841	9.1%
Oil	35	0	35	0.0%
Other (Petroleum Coke/Waste Heat)	430	9	439	0.2%
Renewables	63,028	26,474	89,502	31.4%
Biomass	5,909	798	6,707	2.3%
Geothermal	11,528	1,440	12,968	4.5%
Small Hydro	4,248	335	4,583	1.6%
Solar	27,265	5,268	32,533	11.4%
Wind	14,078	18,633	32,711	11.5%
Unspecified Sources of Power	N/A	30,095	30,095	10.5%
Total	194,842	90,646	285,488	100.0%

Source: QFER CEC-1304 Power Plant Data Reporting

Total generation for California in 2018 was 285,488 gigawatt-hours (GWh), with in-state generation providing 68 percent of the total annual energy requirement. Noncarbon dioxide-(CO_2) emitting electric generation categories (nuclear, large hydroelectric, and renewables) accounted for 51 percent of statewide supply, while natural gas served about 35 percent of total demand. Though not included in the annual summary, behind-the-meter solar PV generation is estimated at 14,000 GWh for 2018. When added to total system power, California's total electric generation requirement is about 300,000 GWh.

Figure 2 summarizes California's annual energy mix. The chart illustrates the relative contribution of each category of natural gas-fired generation to the state's total generation, including imports. The slow and steady decline of cogeneration output over the past 18 years becomes apparent in the chart. The closure of the San Onofre Nuclear Generating Station is observable by the steep drop in nuclear generation output in 2012. Hydroelectric generation was strong in 2011 and 2017, displacing combined-cycle generation in those years. In 2018, California experienced its thirty-fourth driest year since 1895 as drought conditions returned to the state and hydroelectric generation fell by 40 percent to 26,344 GWh from 2017 levels. Solar generation increased 12 percent in 2018, helping boost California's renewable generation to 32 percent of total in-state supply.

Figure 2: California's Total System Electric Generation, 2001 – 2018



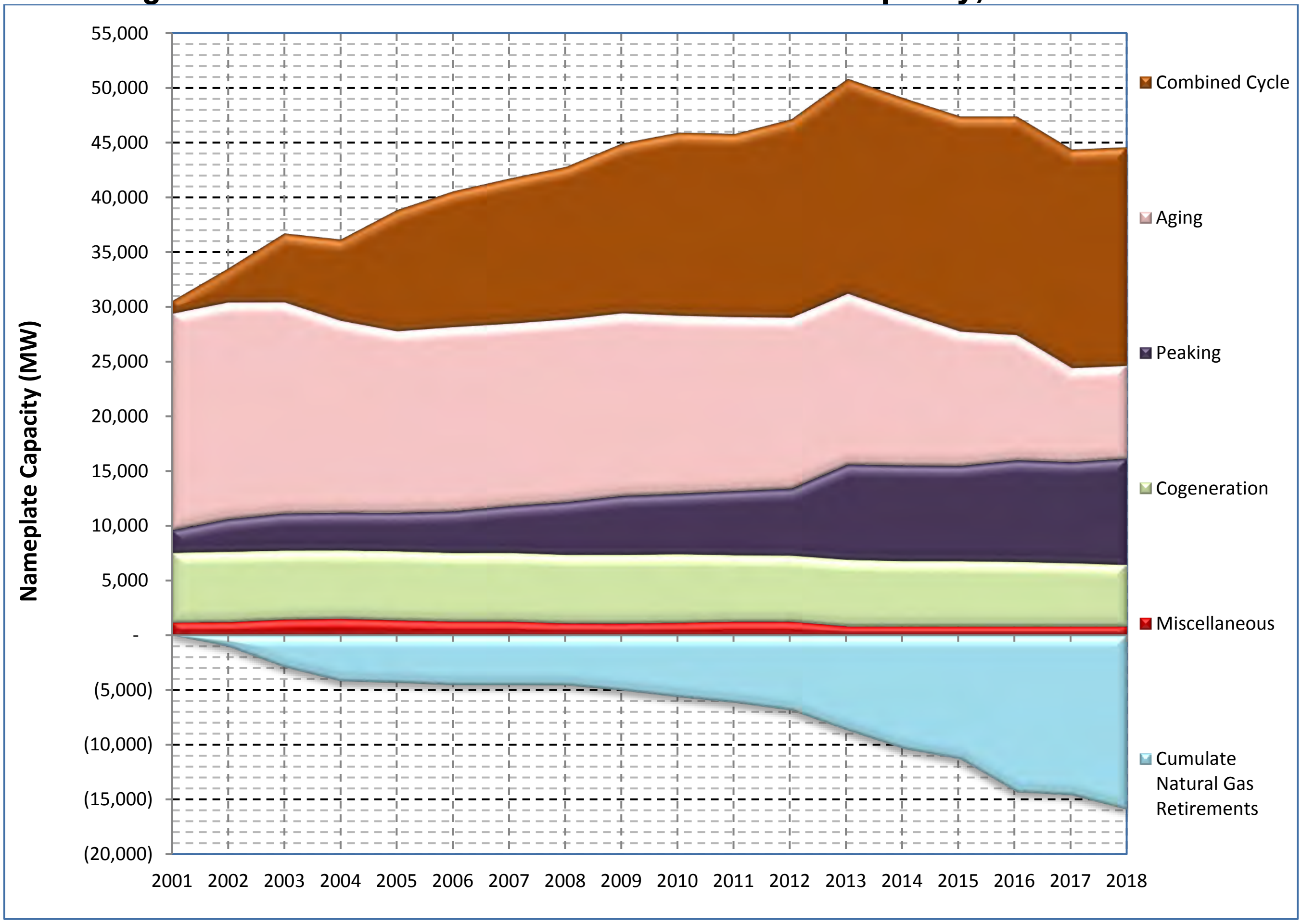
Source: QFER CEC-1304 Power Plant Data Reporting

Natural Gas Generation

Overall, in-state natural gas-fired electric generation was like that of 2017, accounting for almost 47 percent of in-state generation or 90,691 GWh, up 1.3 percent from 89,564 GWh. Imported natural gas-fired generation contributed an additional 8,953 GWh. As a result, natural gas totaled 99,644 GWh or about 35 percent of the California power mix.

Figure 3 displays the changes in natural gas-fired generation capacity for each category over the past 18 years. The peaking category continues to expand in capacity as larger, load-following combustion turbines are dispatched to integrate solar and wind generation. Combined-cycle capacity has remained relatively stable over the past three years, while aging and cogeneration plants have been slowly but steadily retired over the years. Cumulative retirements are depicted by the blue area under the stacked-area graph. More than 16,900 MW of natural gas-fired capacity has been retired since 2001.

Figure 3: Annual Natural Gas-Fired Generation Capacity, 2001 – 2018



Source: QFER CEC-1304 Power Plant Data Reporting

California's aging power plants accounted for about 3 percent (2,332 GWh) of natural gas-fired electric generation in 2018 but still hold 16 percent of California's gas-fired generation capacity. With an average heat rate of 13,212 Btu/kWh, California's aging plants continue to carry the distinction of having the most inefficient heat rates. The low capacity factors suggest the primary value of this group of power plants is in providing capacity support for local reliability that may include voltage control, frequency control, and other ancillary services.[16] Control of voltage and frequency within a power system is essential to maintaining the balance between generation and load.

As hydroelectric generation is a large determinant of natural gas-fired generation, **Figure 4** displays the monthly hydroelectric generation for 2018 within a band that represents the minimum and maximum monthly generation reported over the previous five years. Based on snowpack conditions and precipitation levels, 2018 was considered a dry hydrological year by the State Water Board. While there is no statewide definition of what constitutes a wet or dry

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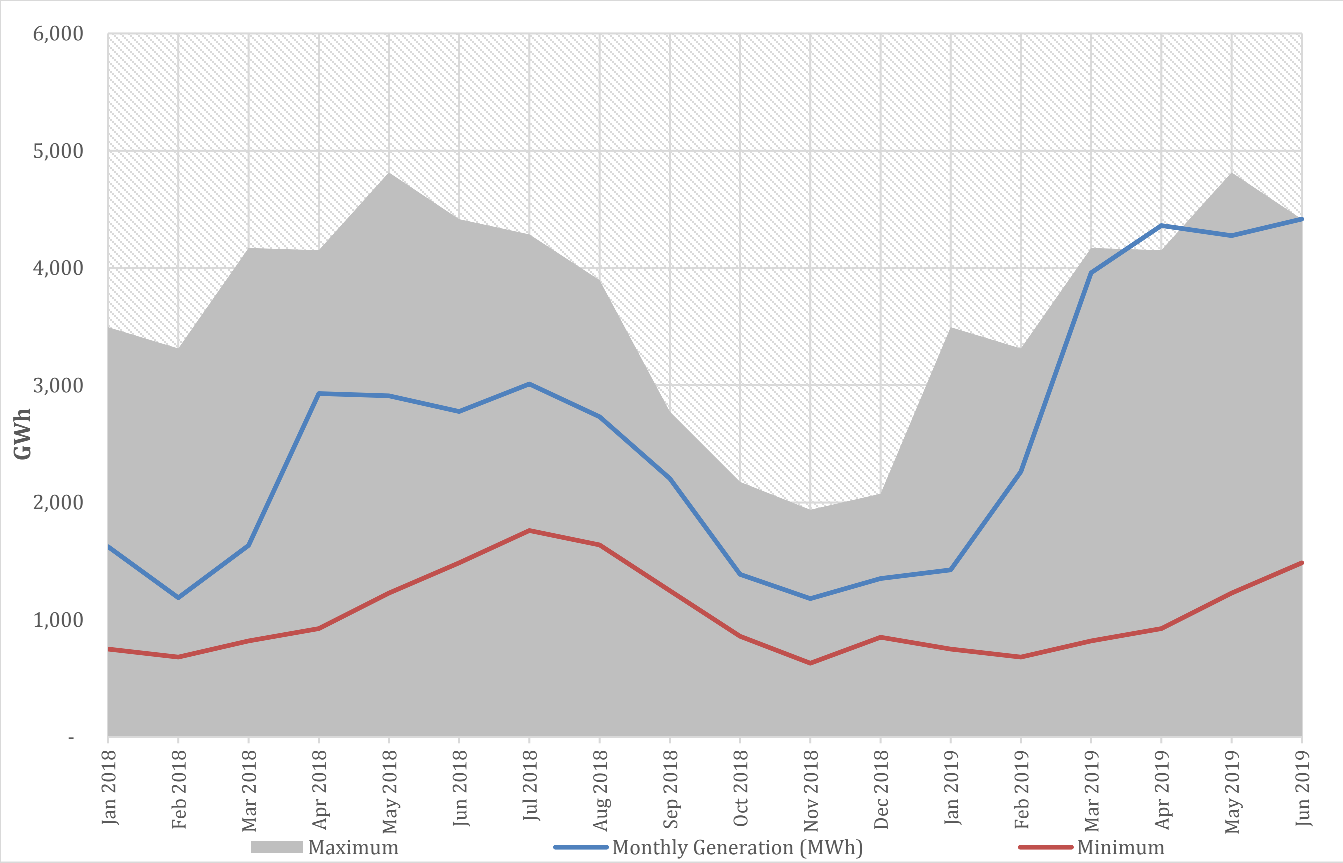
16 California Energy Commission. *The Role of Aging and Once-Through-Cooling Power Plants in California — An Update*. CEC-200-2009-018. See http://www.energy.ca.gov/2009publications/CEC-200-2009-018/CEC-200-2009-018.PDF.

hydrological year, 75 percent of California's annual precipitation occurs from November through March, with 50 percent occurring from December through February. A water year begins on October 1 and runs through September 30. The state's precipitation totals depend upon a relatively small number of storms and, as such, a few storms determine if the year will be wet or dry. California's dry years of 2012 through 2016 were followed by an above-average wet year in 2017. However, in 2018 dry conditions returned and combined-cycle generation grew by 7 percent over 2017 levels.

Figure 4: Hydroelectric Generation, 2018 – 2019



Source: QFER CEC-1304 Power Plant Data Reporting

Looking ahead, hydroelectric generation appears to be on track for further displacement of natural gas-fired generation for the 2019 calendar year. Snowpack levels on April 1, 2019, were 175 percent of average, and statewide reservoir levels on September 30, 2019, were 128 percent of average, making 2019 a wet hydrological year. QFER reporting by power plant owners for the first six months of 2019 indicate hydroelectric generation is up 60 percent over the same period in 2018. March through June show above-average generation compared to historical periods.

CHAPTER 5: California ISO Hourly Generation

Statistics comparing the hourly generation of aging, combined-cycle, and peaking power plants in the California ISO balancing area are presented in **Table 7**. For each year, the fleet totals and plant averages were calculated using hourly output values greater than 1 MWh. Values less than or equal to 1 MWh were eliminated to avoid inclusion of partial hours of operation that tend to exaggerate the statistical differences in the calculation of standard deviation and the average. Previous staff reports have used a 10 MW threshold, but this threshold removed too many smaller values from the peaking category, as most of plants in that category are less than 50 MW in capacity.

Table 7: Hourly Generation Summary, 2017 – 2018

Category	Aging 2017	Aging 2018	Combined-Cycle 2017	Combined-Cycle 2018	Peaking 2017	Peaking 2018
Fleet: Total Generation (GWh)	2,778	2,068	49,157	54,223	3,114	3,159
Plant: Avg. Hourly Output (MWh)	87	73	307	340	39	42
Plant: Std. Deviation (MWh)	103	87	174	187	33	35
Fleet: Operational Hours	32,096	28,306	160,002	153,257	79,333	75,746
Fleet: Total Available Hours	227,760	192,720	306,600	289,080	884,760	928,460
Number of Generating Units	26	22	35	33	101	106

Source: California ISO

In 2018, combined-cycle power plants within the California ISO had an average hourly output of 340 MWh, up 10 percent from 307 MWh in 2017. While the total number of operational hours declined 4 percent from 2017 levels, the total generation from combined-cycle plants within the California ISO increased by 10 percent to 54,223 GWh. The variability of hourly generation, as defined by the standard deviation, increased from 174 MWh to 187 MWh. Overall, the hourly output of combined-cycle power plants ranged from 153 MWh and 527 MWh 68 percent of the time. The higher average output, combined with increased variability and fewer operational hours in 2018, support the observation that combined-cycle plants were ramped more frequently to higher levels of output to balance intermittent solar and wind generation.

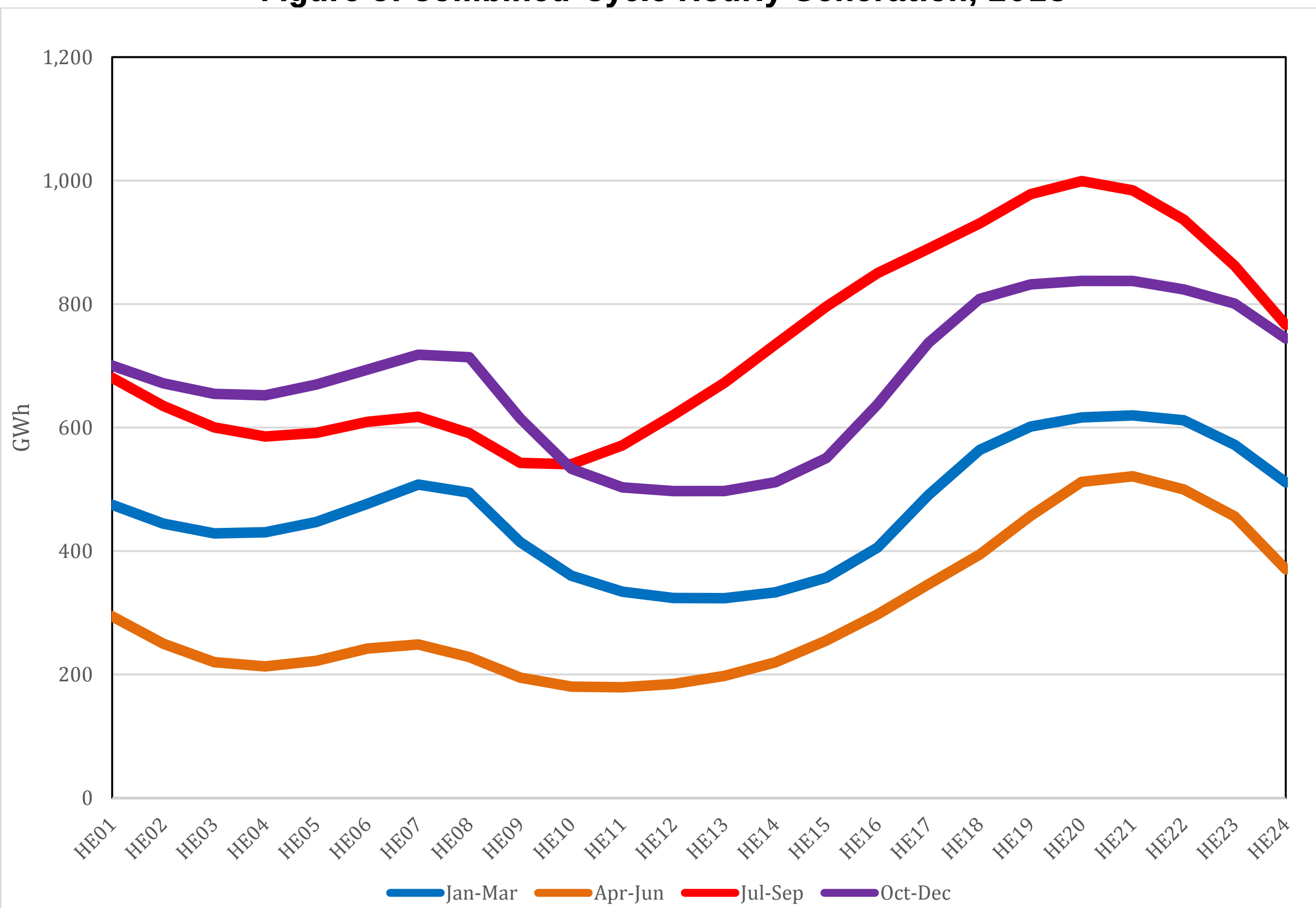
Aging units generated less energy in 2018, down 26 percent to 2,068 GWh. The average hourly output declined by 16 percent to 73 MWh in 2018. Retirements in 2017 included Moss Landing and Broadway. In 2018, Mandalay, Etiwanda, and Encina closed in February, June, and December, respectively. Retirements resulted in 12 percent fewer operational hours with 22 aging units operating in 2018.

Peaking plants in the California ISO generated 3,159 GWh in 2018, marginally higher than 2017 (3,114 GWh). The average hourly output was up slightly from 39 MWh to 42 MWh in 2018. The average hourly output is growing due to the construction of larger, load-following plants such as the 525 MW Carlsbad Energy Center and the 400 MW Panoche Energy Center. These plants use multiple simple-cycle combustion turbines, nominally rated at 100 MW – 105 MW each. Previously, peaking plants consisted almost exclusively of 50 MW combustion turbines. Variability about the mean was about the same as 2017 at 35 MWh. Peaking plants operated during 8 percent of all available hours, down slightly from 2017.

Hourly Profiles

Figure 5 displays the annual generation provided by combined-cycle plants for each hour in 2018. Generation in July through September shows a significantly flatter, almost linear, slope of increasing electric generation from 10:00 a.m. (HE10) through to 8:00 p.m. (HE20). The combined-cycle fleet steadily increases output across these hours to replace declining solar generation from noon through sunset. The steepest ramping occurs in the winter (January through March) and fall (October through December) as there are fewer available daylight hours for solar generation.

Figure 5: Combined-Cycle Hourly Generation, 2018

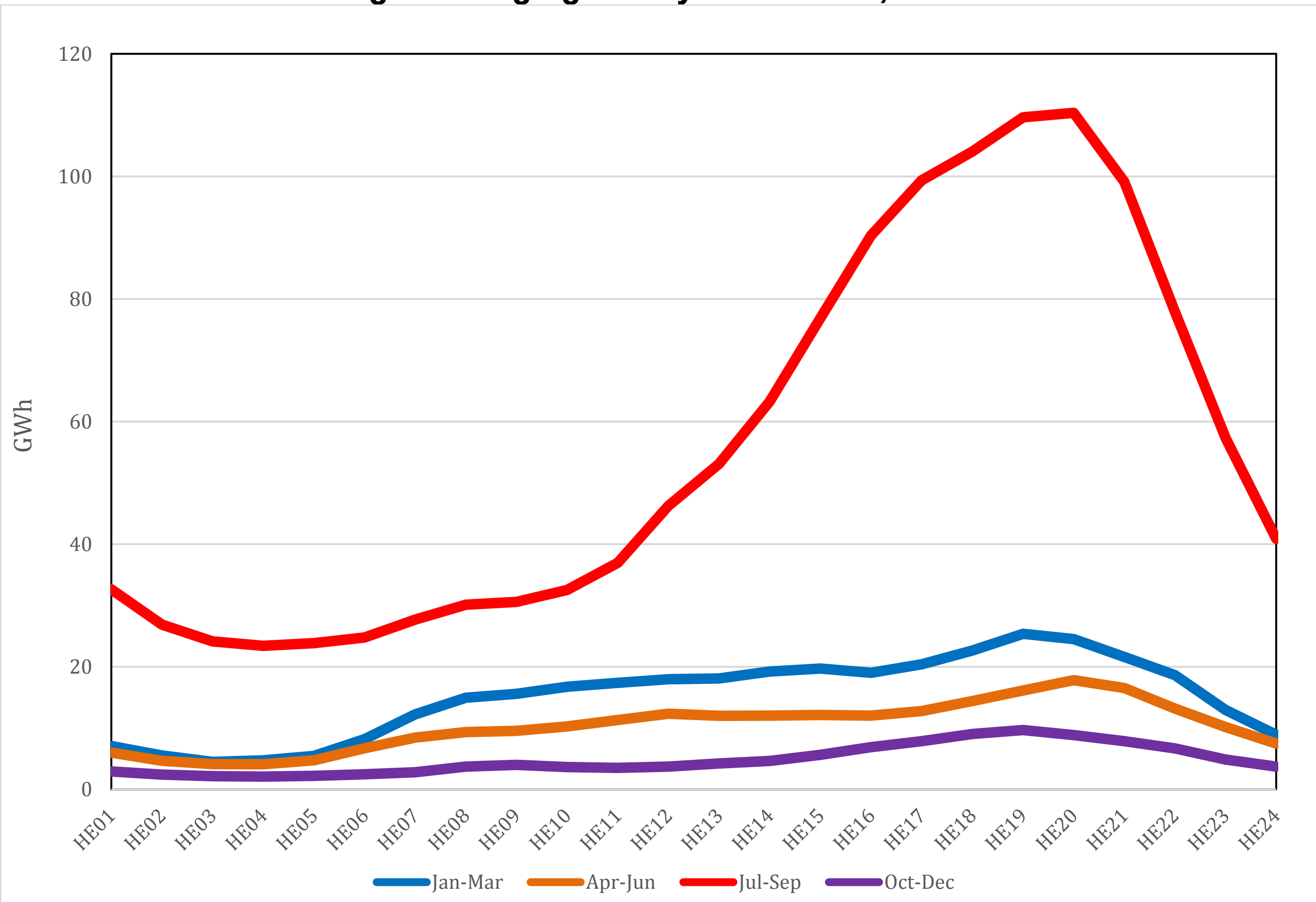


Source: California ISO

In the previous chapter, **Figure 4** indicated hydroelectric generation was below average in the first three months of 2018. **Figure 5** suggests combined-cycle generation made up for that reduced hydroelectric availability, depicted by the blue line in the chart. However, by spring, improved snowpack and precipitation conditions provided for more abundant, and cheaper, hydroelectric generation. Spring is also time of longer daylight hours and milder temperatures, reducing demand for space heating and air conditioning. These factors help push combined-cycle generation to their lowest levels of the year, depicted by the green line at the bottom of the chart.

With the same grouping as shown in **Figure 5**, generation from aging plants in the California ISO balancing area is shown in **Figure 6**. In 2018, aging plants were used most often in the summer months, from July through September, as depicted by the red line in the chart. However, they provided but a fraction of the output level of combined-cycle plants. In all other seasons, aging plants were marginally used, generation bumping up very slightly in the hours from HE17 through HE20.

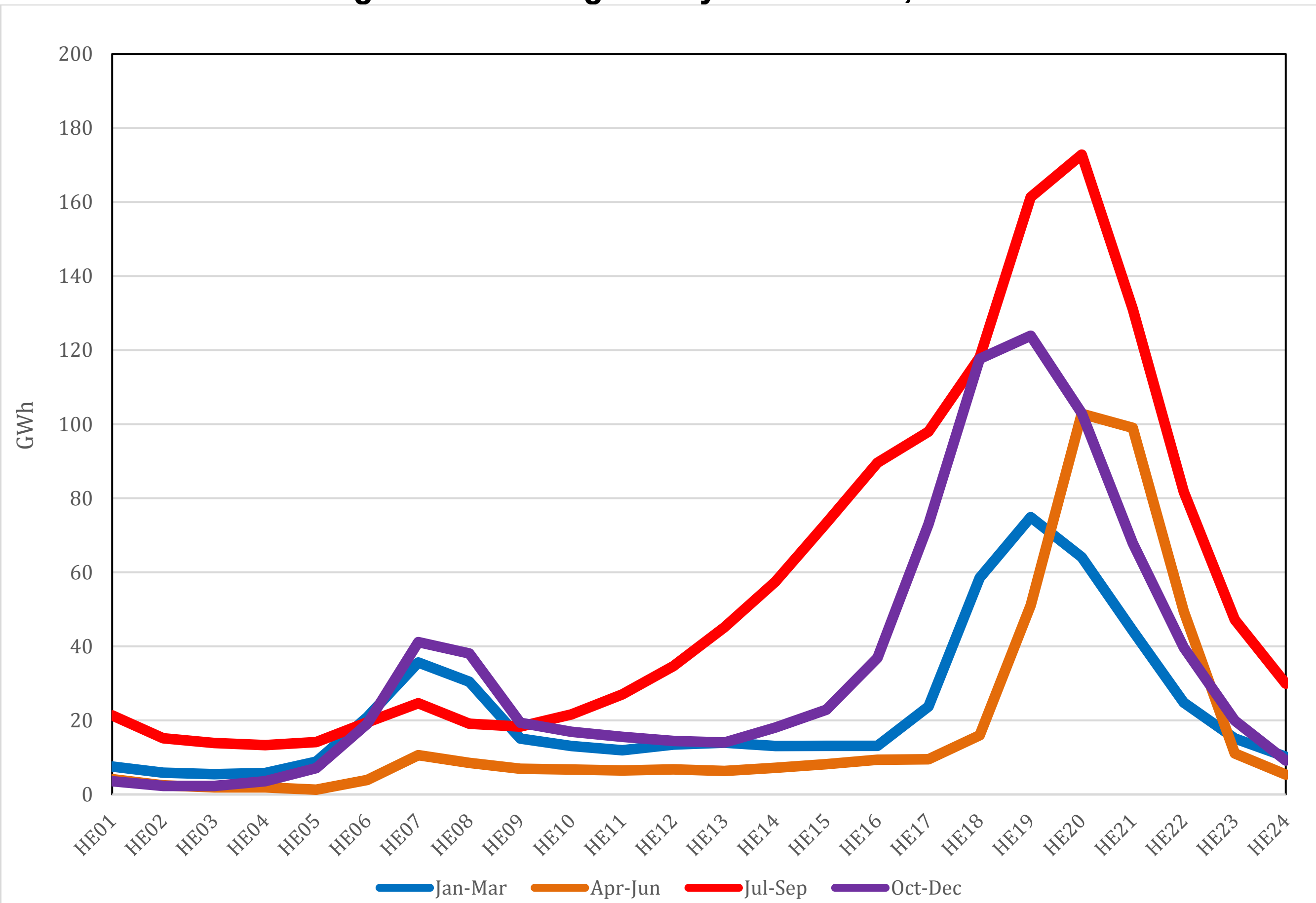
Figure 6: Aging Hourly Generation, 2018



Source: California ISO

Figure 7 summarizes peaking generation energy for the same groups of months across each hour of the day. Peaking plants deliver the most energy between HE17 and HE22. However, during the summer months they contribute much more power across all periods after HE10.

Figure 7: Peaking Hourly Generation, 2018

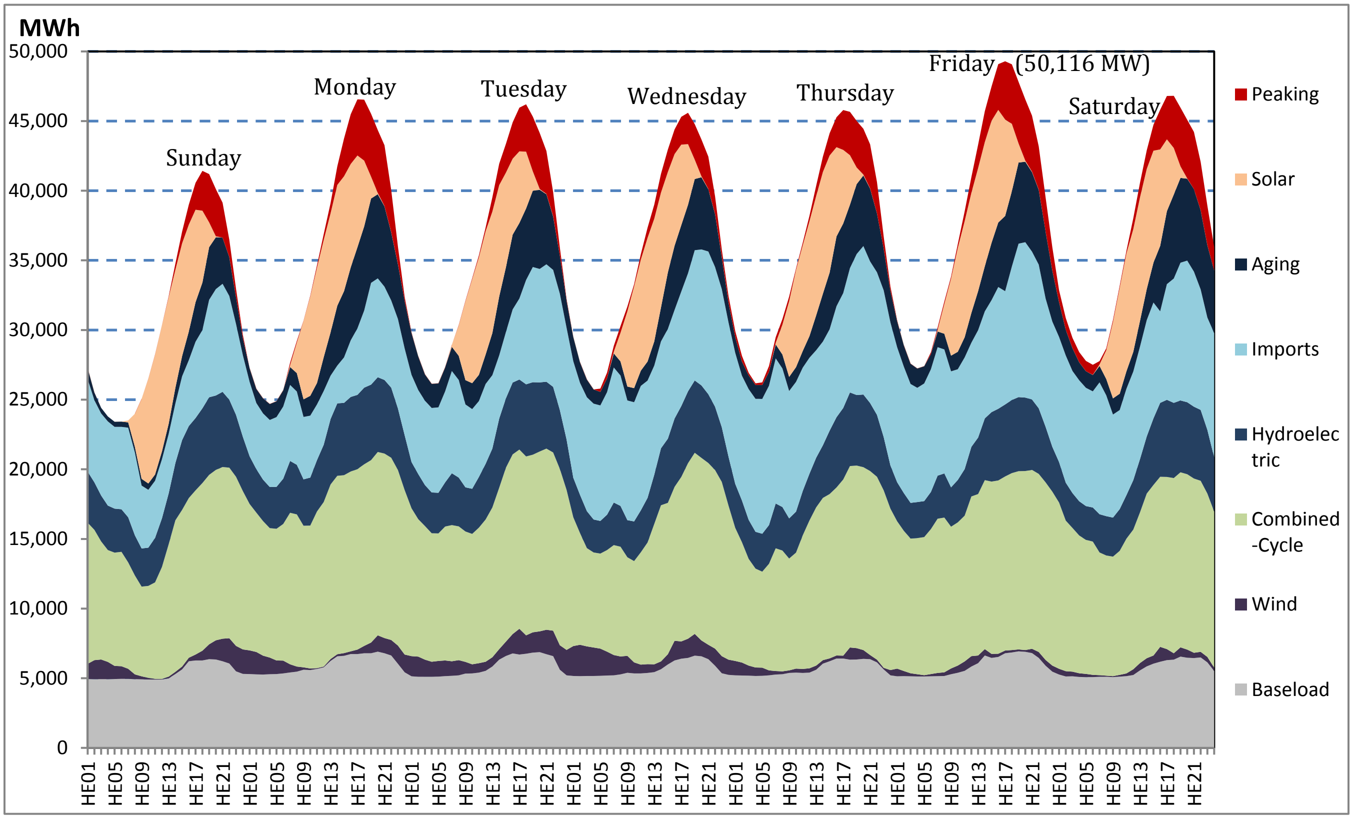


Source: California ISO

Annual Peak Load

Figure 8 and **Figure 9** show the hourly peak load in the California ISO for a one-week period in which the coincident peak load occurred in 2017 and 2018, respectively. The charts display the contribution of aging, combined-cycle, and peaking generation to the total hourly loads across the week on which the annual peak-load occurred. Solar, wind, and hydroelectric generation are displayed separately along with a baseload generation category that groups energy from biomass, cogeneration, geothermal, nuclear, refinery waste-heat, petroleum coke, and other technologies. Imports are classified separately as they represent bulk energy transfers from neighboring balancing authorities and no fuel type information is available. An observation on both charts is the usage of aging generation to meet load peak requirements during the hottest hours of the day.

Figure 8: Hourly Generation Mix, August 27 – September 2, 2017

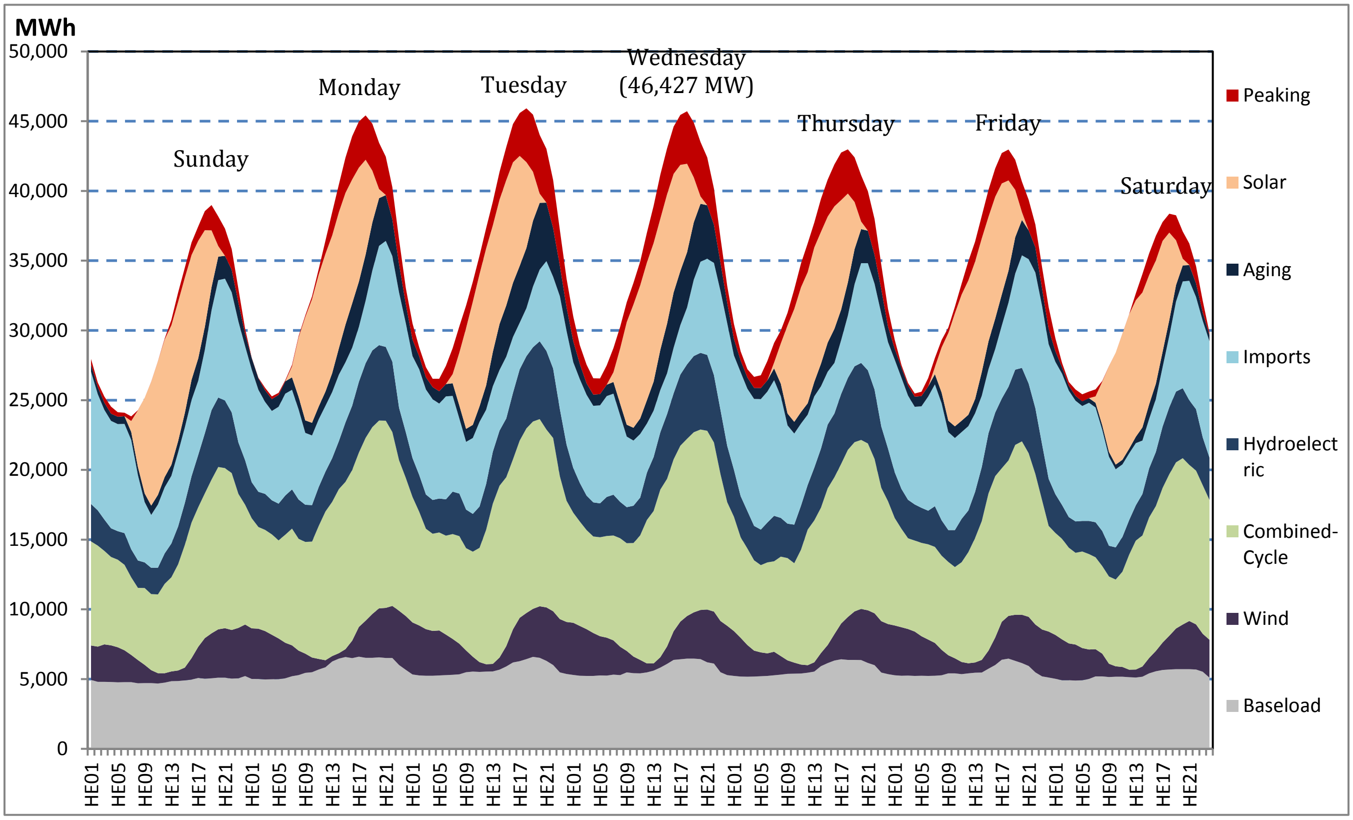


Source: California ISO aggregated data

To recap, the instantaneous peak load within the California ISO was 50,016 MW, occurring at 3:58 p.m. on Friday, September 1, 2017. The peak was a result of record-breaking temperatures as a high-pressure ridge stalled over California during the week of August 27 to September 2, 2017. By Friday, September 1, San Francisco reached 106° Fahrenheit (F), and Salinas, in Monterey County, recorded 109°F; both cities typically average 70°F on this day.[17]

17 Weather.com, All-Time Record-High Temperature Set in San Francisco; Record Heat Shifts to the Northwest This Week, Linda Lam, September 4, 2017. See https://weather.com/forecast/regional/news/west-heat-wave-all-time-record-heat-early-september-2017.

Figure 9: Hourly Generation Mix, July 22 – July 28, 2018



Source: California ISO aggregated data

In 2018, the California ISO issued two consecutive statewide "flex alerts" calling for customers to reduce their energy use from 5:00 to 9:00 p.m. on Tuesday, July 24 and Wednesday, July 25, "due to high temperatures across the western United States, reduced electricity imports, tight natural gas supplies in the Southern California area, and high wildfire risk."[18] As hot temperatures impacted multiple states in the West, there was concern about accessing electricity imports across the region. The California ISO forecasted a peak of 49,481 MW for July 25, 2018, but only had 45,633 MW of available capacity. The flex alerts requested customers reduce nonessential loads, raise thermostat settings for air conditioners, and postpone the use of large appliances until later in the evening. The California ISO stated Californians collectively reduced demand by 450 MW on July 24 and 540 MW on July 25, 2018.[19] Slightly lower realized temperatures combined with reduced demand resulted in a peak load of 46,427 MW on July 25, the highest load the year.

18 California ISO. Flex Alert Issued for Tuesday and Wednesday, July 24 & 25, 2018. Accessed on October 23, 2019. See https://www.flexalert.org/news.

19 Green Tech Media. July 31, 2018. "Californians Slash Energy Use to Protect the Electric Grid." Accessed on October 23, 2019. See https://www.greentechmedia.com/articles/read/californians-slash-energy-use-to-protect-the-electric-grid.

CHAPTER 6: Conclusion

California continues to benefit from a significant improvement in the systemwide thermal efficiency of its natural gas-fired power plant fleet. With a thermal efficiency of 44.2 percent in 2018, the systemwide thermal efficiency has improved by 30 percent since 2001. This improvement is attributed primarily to the continued reliance upon combined-cycle power plants and the phaseout of less efficient aging and OTC power plants.

The annual average heat rate for natural gas-fired generation improved to 7,728 Btu/kWh in 2018 partly because of a 27 percent reduction in the use of aging power plants. The annual heat rate corresponds to a 23 percent improvement in the average fuel efficiency of the fleet compared to 2001. This heat rate improvement has remained above 20 percent (as compared to 2001) every year since 2007. Combined-cycle plants increased output by 7 percent in 2018, raising the capacity factor to 38 percent for the year and pushing total natural gas-fired generation up by 3 percent over 2017. The increase helped improve the average capacity factor for combined-cycle plants to almost 26 percent, similar to 2016 levels. Continued strong growth in solar generation in 2018, some 12 percent higher than 2017, was a contributing factor to limiting the growth in generation from natural gas-fired power plants.

Finally, total natural gas fuel usage for electric generation in California increased by just over 1 percent in 2018 to 848 million MMBtu, the second-lowest level of the past 18 years and 30 percent lower than 2001. In all, in-state natural gas power plants supplied almost 47 percent of California total in-state electricity supply. The slight decline in hydroelectric generation combined with the large growth in utility-scale solar generation resulted in 53 percent of California's in-state generation coming from zero-carbon resources in 2018.

ACRONYMS

Acronym	Definition
BESS	Battery Energy Storage System
Btu	British thermal unit
California ISO	California Independent System Operator
CEC	California Energy Commission
CHP	Combined heat and power
CPUC	California Public Utilities Commission
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GHG	Greenhouse gas
GWh	Gigawatt-hour
HRSG	Heat recovery steam generator
IEPR	*Integrated Energy Policy Report*
ISO	Independent System Operator
kWh	Kilowatt-hour
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
OTC	Once-through-cooling
QF	Qualifying facility
QFER	Quarterly Fuels and Energy Reports
PURPA	Public Utility Regulatory Policies Act of 1978
RTO	Regional Transmission Organization
SACCWIS	Statewide Advisory Committee on Cooling Water Intake Structures
State Water Board	State Water Resources Control Board
WECC	Western Electricity Coordinating Council

GLOSSARY

Term	Definition
Aging plant	Natural gas-fired steam turbines that were built and operational before 1980.
Ancillary services	Within the California ISO, the four types of ancillary services are regulation up, regulation down, spinning reserve, and nonspinning reserve. These services support the stable operation of the grid.
Baseload generation	Power plants that are designed to operate at an annualized capacity factor of at least 60 percent.
Capacity factor	A measure of the actual output of a power plant over a specific period compared to the total potential output a power plant could have provided by operating at its nameplate capacity over the same period.
Cogeneration plant	A power plant that produces electricity and useful thermal energy (heat or steam) simultaneously.
Combined-cycle plant	A power plant has a generation block consisting of at least one combustion turbine, a heat recovery steam generator, and a steam turbine.
Dispatch	The action that signals a power plant to turn on or turn off.
Frequency control	The ability to dispatch generation due to decreases in supply or increases in load within a power system.
Generating unit	A combination of connected generators, reactors, boilers, combustion turbines and other prime movers operated together to produce electric power. In the context of this staff paper, a generating unit can only be assigned to a single natural gas-fired generation category.
Heat rate	Expresses how much fuel is necessary (measured in British thermal units [Btu]) to produce one unit of electric energy (measured in kilowatt-hours [kWh]).
Higher heating value	In the determination of a heat rate, higher heating value includes the latent heat of vaporization of the water in the combustion of natural gas.
Load-following	The ability to dispatch a power plant to meet changing system load requirements.
Lower heating value	In the determination of a heat rate, this measurement would not include the latent heat from the vaporization of the water.
Nonspinning reserves	An ancillary service that requires non-operating plants to be capable of ramping up to full capacity and synchronizing to the grid within 10 minutes of dispatch.

Term	Definition
Once-through-cooling	The usage of water from the ocean or other body of water to cool steam after it has passed through a turbine.
Peaking plant	Fast-starting power plants intended to operate for short durations to meet peak-load system requirements.
Power plant	A power plant is defined as a station composed of one or more electric generating units.
Ramping/cycling	Like load-following, power plants altering output levels, including shutdowns and restarts, in response to changes in system load and the availability of renewable generation on the electrical grid. Includes the ancillary services of regulation up and regulation down.
Spinning reserves	An ancillary service that recognizes operating power plants (that is, spinning) that are already synchronized and ready to meet electric demand within 10 minutes.
Thermal efficiency	A unitless measure of the efficiency of converting a fuel to energy and useful work.
Unspecified power	Power that can no longer be traced to the original fuel source.

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Nomenclature

AC	Air conditioner
ASHP	Air source heat pump
BA	Building America
COP	Coefficient of performance
COP_{sys}	System coefficient of performance
c_p	Specific heat
d	Discount rate
DF	Discount factor
DHWESG	Domestic hot water event schedule generator
e	Fuel escalation rate
E_{cons}	Consumed site energy
E_{cool}	Space cooling energy
E_{del}	Delivered site energy
E_{elem}	Heat added by electrical element
E_{heat}	Space heating energy
$E_{hp,tank}$	Heat added by a heat pump
E_{nrmlz}	Normalization energy
E_{WH}	Water heater energy consumption
EF	Energy factor
FEF	Fuel escalation factor
ER	Electric resistance
HPF	Heat pump fraction
HPWH	Heat pump water heater
HVAC	Heating, ventilation, and air conditioning
IC_{base}	Base case water heater net installed cost
IC_{HPWH}	Heat pump water heater net installed cost
m	Mass
MC	Heat pump water heater maintenance cost
n	Study length
NPB	Net present benefit
NPC	Net present cost

NPV	Net present value
PTC	Personal tax credit
SRP	State rebate program
URP	Utility rebate program
WH	Water heater
$\$_{saved}$	Annual utility bill savings
T_{out}	Water heater outlet temperature
T_{req}	Required outlet temperature
η	Efficiency

Executive Summary

Heat pump water heaters (HPWHs) have recently reappeared in the U.S. residential market and have the potential to provide homeowners with significant energy savings over traditional electric resistance (ER) water heaters (WHs). HPWHs typically have a rated efficiency at least twice as high as typical electric WHs. However, questions remain about their actual performance and energy savings potential, especially in unconditioned space, and their impact on space heating and cooling loads when they are located in conditioned space. To help answer these questions, a 50-gal HPWH was simulated in both conditioned and unconditioned space at more than 900 locations across the continental United States and in Hawaii. Base cases of typical residential gas and electric WHs were also simulated so the energy savings of an HPWH relative to both technologies could be calculated.

Simulations included a Building America benchmark home and several combinations of space heating and cooling equipment to quantify the HPWH's impact on a home's annual energy consumption. A mixed draw profile, consistent with the hot water use level of a three-bedroom home in the Building America House Simulation Protocol, was used. The tempered draws allowed for variations in the hot water usage level, with a low draw volume of about 45 gal in locations with warm mains water and 60 gal for locations with cold mains water. All energy savings calculations were done on a source energy basis to account for the net savings in any mixed fuel cases. The breakeven cost (the required net installed cost of an HPWH to make it cost neutral with a traditional WH) was calculated for all cases to show their cost savings potential.

The HPWH can save some source energy savings relative to a typical electric WH in all cases considered here, although the source energy savings are often lower than expected based on the rated efficiency of the HPWH. The largest source energy savings are seen in the southern regions of the United States, especially in the hot-humid climate. For all-electric homes with high efficiency space heating equipment (an air source heat pump [ASHP]), higher source energy savings are seen when the HPWH is installed in conditioned space in heating-dominated climates; for cases with low efficiency space heating (ER heat) installations in unconditioned space have higher source energy savings. The source energy savings for a case with an ASHP when the HPWH is installed in unconditioned space is shown in Figure ES–1. When comparing to gas WHs, positive source energy savings are only realized in the Southeast, parts of southern California and Arizona, and Hawaii. This is true for installations in conditioned and unconditioned space, although higher source energy savings are seen in conditioned space.

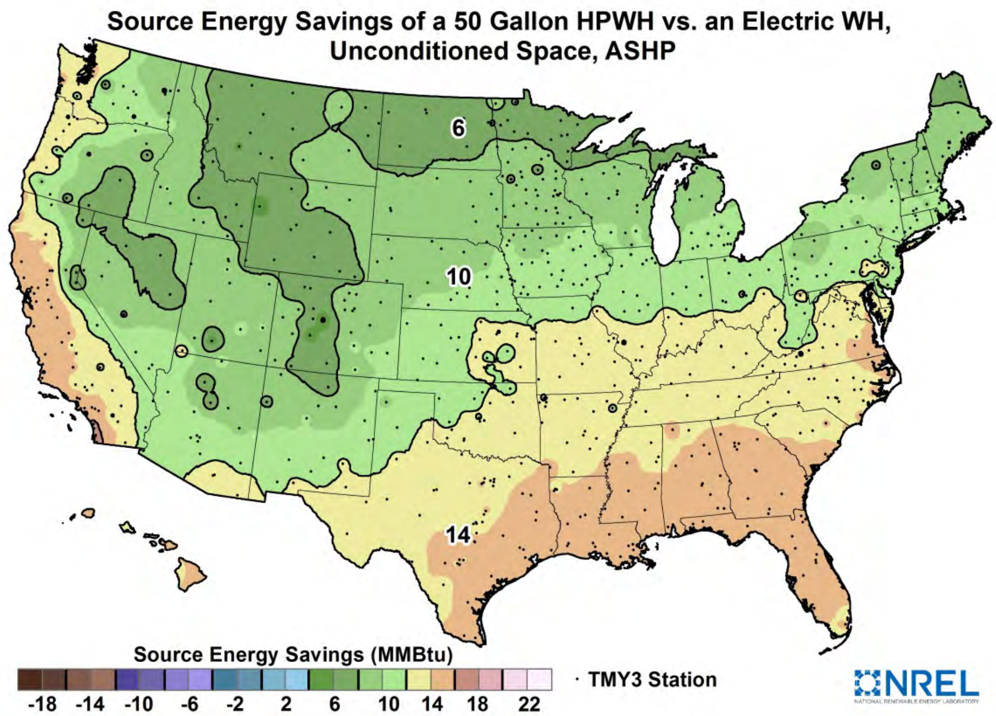

Figure ES–1. Source energy savings of an HPWH versus an electric WH in unconditioned space for a home with an ASHP

The 50-gal HPWH has a favorably high breakeven cost compared to an electric WH in most of the country, except the Pacific Northwest and parts of the northern Mountain region when located in conditioned space for homes with highly efficient space conditioning equipment. The highest breakeven costs occur in California, the South, and the Northeast. For homes with less efficient space heating equipment, the breakeven costs are significantly reduced across the country and high breakeven costs are most common in locations with the smallest heating loads. When installing in unconditioned space (see Figure ES–2), the HPWH may break even in most locations except the Pacific Northwest, most of the Mountain census region, and the northern Midwest, depending on its actual net installed cost. When comparing to gas WHs, breakeven is only likely in parts of the Southeast, central Washington, and Hawaii. However, when federal and local incentives are factored in, HPWHs become cost effective in several more locations.

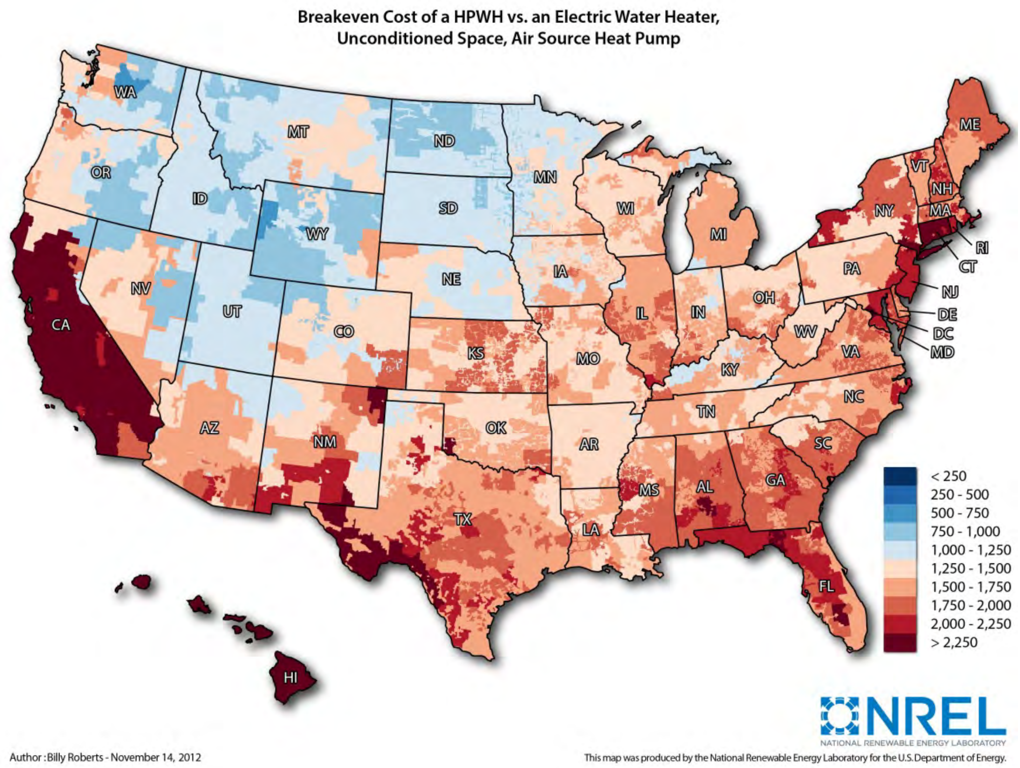

Figure ES–2. Breakeven cost of an HPWH versus an electric WH in unconditioned space for a home with an ASHP

To account for differences in potential energy savings and breakeven costs for different sized HPWHs, an 80-gal HPWH was also modeled and presented in Appendix B. In the 80-gal case, higher source energy savings and breakeven costs are possible, particularly in colder regions. Although this study does examine regional variations in HPWH performance and savings, it looks at only one hot water usage level and one home. The parameters chosen for this study were assumed to be roughly representative, but actual savings will vary significantly with hot water use, the overall efficiency of a home, and the actual HPWH installed.

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1 Introduction

1.1 Heat Pump Water Heaters Versus Traditional Water Heaters

Water heating is a significant energy use in U.S. homes (EIA, 2009). It accounts for 17.7% of the total energy consumed, or 1.8 quads annually. The U.S. residential water heater (WH) market is dominated by storage type WHs. Gas and electric resistance storage WHs comprised about 94% of residential WH shipments in 2009 (U.S. Department of Energy, 2010). Although conventional gas and electric storage WHs are the cheapest and most common options, many higher efficiency water heating options are available. One such option that has recently reappeared on the U.S. market is the integrated heat pump water heater (HPWH) (see Figure 1), which takes heat from the ambient air and adds it to a hot water storage tank via a vapor compression refrigeration cycle. These units are much more efficient than conventional electric WHs, with a rated efficiency (energy factor [EF], defined as the average efficiency over a standard 24-h test) of 2–2.5; typical electric WHs have an EF of ~0.9.

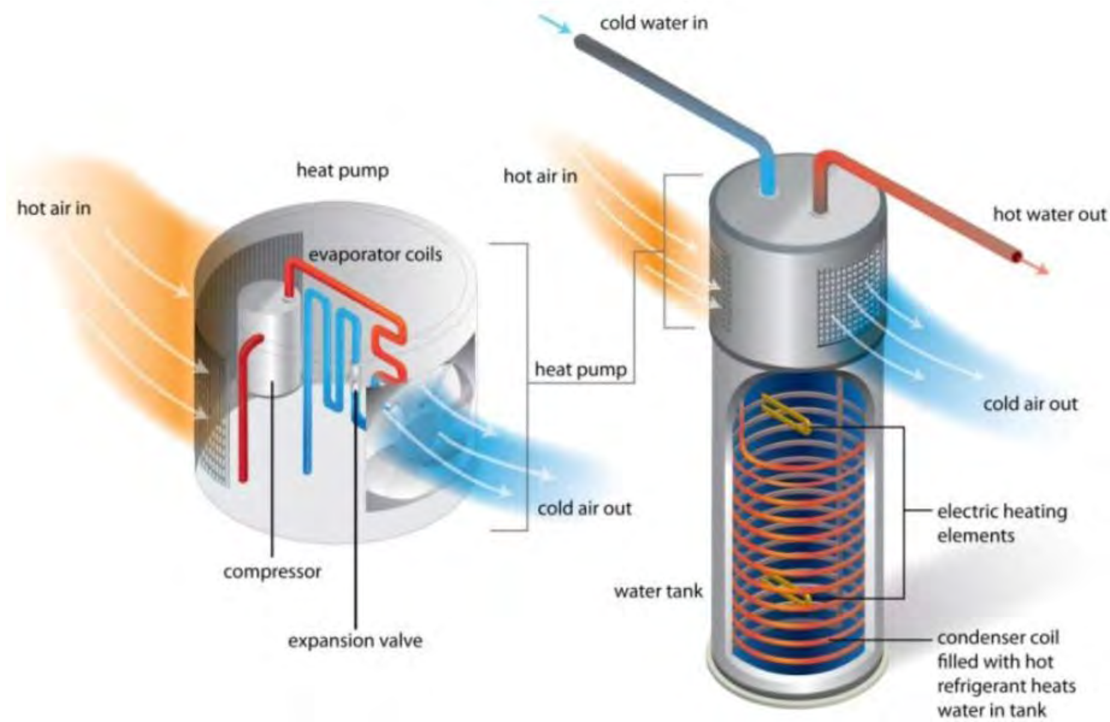


Figure 1. Schematic of an HPWH

(Illustration by Marjorie Schott/NREL)

HPWHs in the United States typically feature both a heat pump and at least one electric resistance element for heating. The electric resistance element(s) are activated if the heat pump cannot keep up with the load, or if the ambient air conditions prevent the heat pump from running. Each manufacturer has its own control logic (designed to work with its particular HPWH) for determining when to switch to the backup electric resistance element(s). How often these element(s) have to be used is heavily dependent on climate and hot water use and has a large impact on overall efficiency.

1.2 Heat Pump Water Heater Efficiency, Reliability, and Cost

The heat pump efficiency (coefficient of performance [COP], defined as the amount of energy delivered divided by the amount of energy consumed) depends heavily on the temperature of water adjacent to the condenser, ambient air temperature and humidity, set point temperature, hot water draw profile, and operating mode. All these factors can cause efficiency to vary widely, particularly if the unit is in unconditioned space where the ambient air temperature can vary significantly over the course of a year. This unit will cool and dehumidify the space it is in while the heat pump is running, which may be either a net benefit or a detriment, depending on the climate and the efficiency of the space conditioning equipment. An HPWH could be ducted to the outdoors or to an unconditioned space to offset the heating penalty associated with running the heat pump; however, many HPWHs are not configured for ducting. Ducting was not simulated in this study, but may provide some benefits to HPWH performance in some locations.

HPWHs have historically seen poor market penetration, although they have been sporadically available for many years. The main reason for this is the high first cost, which can be several times as high as a comparable electric storage WH. This presents a significant barrier to market entry. HPWHs are also perceived by some to have reliability issues (Dubay, Ayee, & Gereffi, 2009), based on experience with earlier generations of HPWHs. Although the current generation has not yet shown any of the problems previous generations had, people who were aware of previous HPWH pilot programs may still be skeptical. Several large manufacturers have recently entered the market and currently have ENERGY STAR®-qualified HPWHs available, which may bode well for improved reliability. Also, new residential WH efficiency standards, which go into effect in 2015, will effectively require all new electric WHs larger than 55 gal to be HPWHs (U.S. Department of Energy, 2010), which should increase market penetration.

Fifty-two percent of U.S. homes use natural gas as the primary water heating fuel and 41% use electricity (EIA, 2009). The rest use other fuel sources such as fuel oil, propane, wood, and solar. Figure 2 shows the distribution of WH fuels by census region. A more detailed breakdown, including a state-by-state breakdown of water heating fuel for the 16 most populous states, is provided in Appendix A.

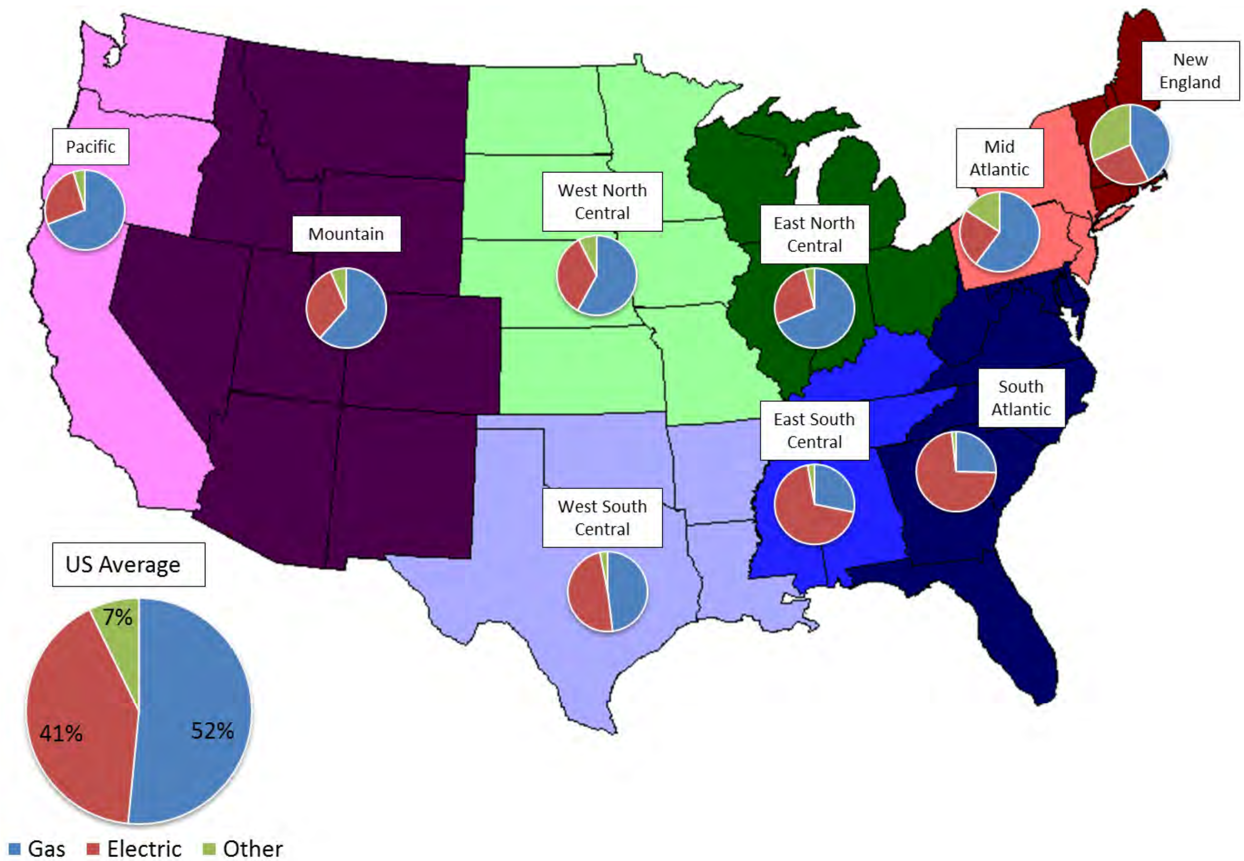


Figure 2. Distribution of fuel types for installed residential WHs by census region (EIA, 2009)

To determine the in-use efficiency of an HPWH in the United States, annual simulations were performed of an HPWH at Typical Meteorological Year 3 sites (Wlicox & and Marion, 2008) across the continental United States and in Hawaii. A sub-hourly hot water draw profile, described in further detail in Section 2.2, was used for this study. This draw profile is intended to represent typical hot water use and has an average daily draw volume of 45–60 gal/day, depending on mains water temperature. For every simulation, a home was also modeled to quantify the interaction between the HPWH and the space heating and cooling equipment. Simulations were performed with the WH located in both conditioned and unconditioned space for two sets of space conditioning equipment (a furnace/air conditioner [AC] combination and an air source heat pump [ASHP]); postprocessing calculations were done to create a case with electric resistance (ER) space heating and an AC. Simulations of standard gas and electric storage WHs were also performed to determine savings.

1.2.1 Source Energy Efficiency

An HPWH could be installed as a replacement for either electric or gas storage WHs. However, several factors come into play when considering a switch from natural gas to electricity for water heating. One key factor is the difference between site and source energy. Source energy takes into account all the primary energy that must be consumed to provide energy to a home; site energy takes into account only the energy consumed at the home. To calculate how much source energy is consumed by a WH in this study, national average source to site ratios of 3.365 for electricity and 1.092 for gas are used throughout (Hendron & Engelbrecht, Building America House Simulation Protocol, 2010). Although the EF of an HPWH is much higher than that of a gas storage WH (EF ≈ 0.6 for typical natural draft units), EF is defined in terms of site energy. Source efficiency, calculated as EF divided by the source to site ratio, provides a more general metric for determining how efficient switching fuel would be. Table 1 shows the EF and source efficiency of each WH considered here.

Table 1. EF and Source Efficiency of Each WH Considered Here

Water Heating Technology	EF	Source Efficiency
Natural draft gas storage	0.60	0.55
Electric storage	0.91	0.27
HPWH	2–2.5	0.59–0.74

1.2.2 Cost

It is also important to consider the relative cost of natural gas and electricity when looking at fuel switching scenarios. In 2010, national average residential electricity rates were $33.81/MMBtu ($0.1153/kWh); average residential gas rates were $11.13/MMBtu ($1.11/therm) (EIA, 2012). Gas costs about one third of what electricity costs per unit of site energy, so an HPWH needs to provide significant energy savings to be cost effective. In retrofit scenarios, it is generally easier to not switch fuels, as additional costs may be incurred.

The HPWH's breakeven was also calculated to determine its economic viability as a replacement for a typical gas or electric WH. Breakeven cost is the net system cost that achieves cost neutrality with the current water heating technology. Breakeven cost is used as the primary metric for economic analysis in this study because HPWHs are relatively new to the U.S. market and their installation costs and economic value are not fully understood. Capital costs may change quickly if their adoption was to rapidly increase and site-specific considerations may cause installation costs to vary significantly from household to household. Identifying the HPWH breakeven costs provides a benchmark that may be used as a point of comparison for fluctuating HPWH system prices. The breakeven costs here were calculated using the same methodology that has previously been applied to residential photovoltaic systems (Denholm, Margolis, Ong, & Roberts, 2009) and residential solar WHs (Cassard, Denholm, & and Ong, 2011).

2 Technical Approach

All modeling was done using TRNSYS (Klein, 2010), a modular energy simulation environment that provides a large library of models and allows new models to be easily created. The HPWH model used here is based on one 50-gal unit with an EF = 2.35 that recently appeared on the U.S. market. An 80-gal HPWH with an EF = 2.3 was also modeled to determine if greater savings could be achieved by installing a larger HPWH. Results are presented in Appendix B. The HPWH models used here are based on extensive laboratory testing of several HPWHs (Sparn, Hudon, & Christensen, 2011); each model is based on one specific HPWH. Both units were modeled as operating in the factory default mode, which attempts to balance efficiency with providing adequate hot water at the default set point temperature of 120°F. Performance curves for power and capacity were taken directly from laboratory testing results. The 50-gal HPWH was chosen and presented here because of its performance during laboratory testing and its size, which is comparable to a typical electric WH and would allow this unit to be easily installed in retrofit scenarios. Because the available HPWHs show considerable variations, a “typical” HPWH is difficult to define. However, this unit had roughly average performance during the laboratory testing compared to the other tested HPWHs.

Base cases of electric and gas storage WH were also simulated to determine the potential source energy savings from replacing one of these units with an HPWH. Both were 50-gal units with typical rated efficiencies for the technology (EF = 0.60 for gas, EF = 0.91 for electric). The model parameters for each were derived from its rated efficiency (Burch & Erikson, 2004). These units had the same set point temperature (120°F) as the HPWH. For an electric WH, all tank losses were assumed to go to the ambient air. For a gas WH, one third of the losses were assumed to go out the flue and two thirds to the ambient air. This split was determined based on the estimated impact of a flue damper on the overall tank loss coefficient of a gas WH (U.S. Department of Energy, 2001).

The TRNSYS house model used here is based on the Building America (BA) program Benchmark home (Hendron & Engebrecht, 2010), which is consistent with current building practices. The model is generally consistent with the BA specifications; however, some simplifications were made for this study. In general, these simplifications lead to the space heating and cooling loads (and corresponding energy consumption) being approximately 5%–30% larger than what is seen in a Benchmark home simulated in BEopt. A detailed description of the building model along with a list of differences between a Benchmark home and the building used here is provided in (Maguire, 2012). The home is a 2500-ft^2, two-story, single-family residence with three bedrooms, two bathrooms, and a 420-ft^2 attached garage. The envelope and all walls, floors, and ceilings separating conditioned and unconditioned spaces have insulation consistent with 2009 International Energy Conservation Code requirements (ICC, 2009)and the amount of insulation changes depending on which climate zone the home is modeled in. The foundation type (slab on grade, basement, or crawlspace) for each house was assumed to be consistent with regional building practices and was modeled as whatever is most common in each state (Labs, et al., 1988) (see Figure 3). When the WH is located in unconditioned space, that space is defined as a basement if a home has one or the garage if it has a slab or crawlspace. Basements were assumed to have insulation on the ceilings, and a small amount of infiltration was modeled to avoid scenarios where the heat pump could reduce the humidity to zero (because the basement model had no other moisture source). If the basement insulation had been applied only to the walls and there was no infiltration, the basement temperature would have approached the conditioned space temperature (which would benefit the HPWH in colder climates, where most basements are located.) However, an HPWH located in such a basement would have a greater impact on the home's space heating and cooling loads (which would be a net detriment in colder climates).

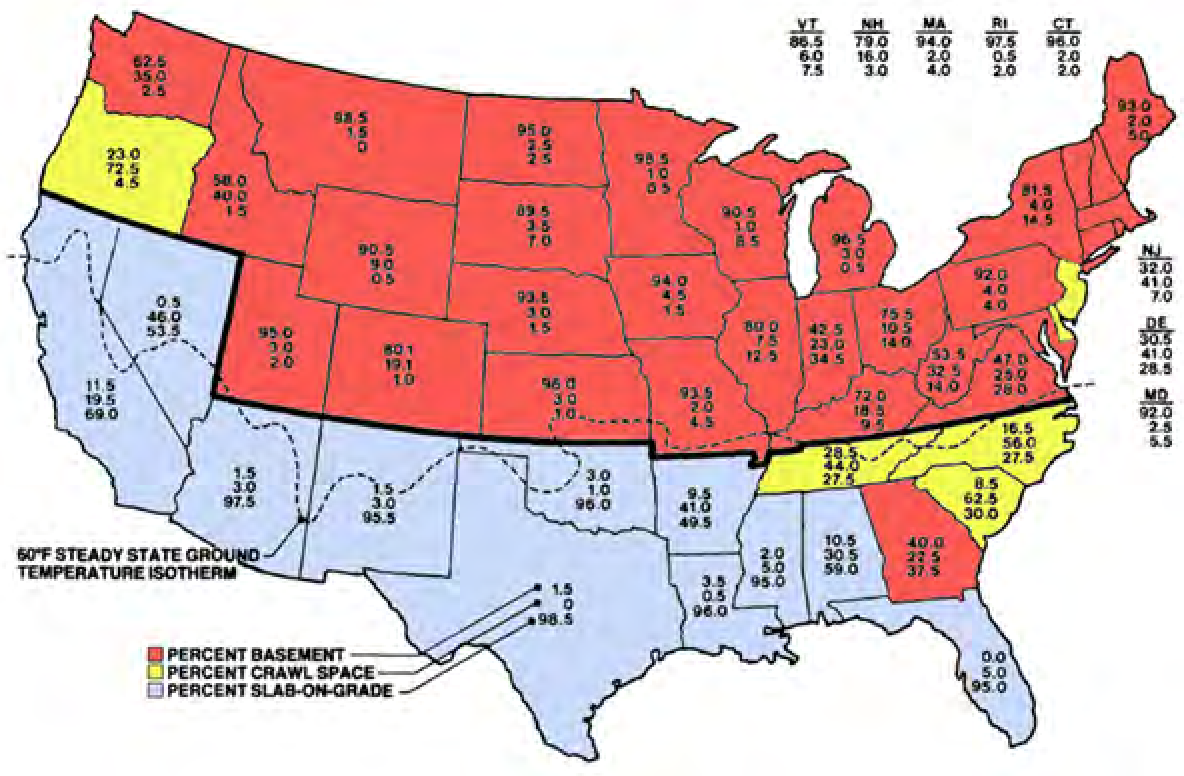


Figure 3. Share of residential foundations by state (Labs, et al., 1988)[1]

From *Building Foundation Design Handbook*,
ORNL/Sub-86-72143/1, Oak Ridge National Laboratory/US Dept. of Energy.

2.1 Space Conditioning Equipment

Two sets of space conditioning equipment were explicitly simulated here: a gas furnace and AC and a reversible ASHP. This home was modeled without ducts for simplicity. The furnace has an annual fuel utilization efficiency of 0.78 and the AC has a seasonal energy efficiency ratio of 13. The ASHP has a heating season performance factor of 7.7 and a seasonal energy efficiency ratio of 13. In addition to these two sets of equipment, a case of ER (baseboard) space heating with an efficiency of 1.00 and an AC was analyzed based on postprocessing of the results from the furnace/AC case. TRNSYS has no autosizing method for space heating and cooling equipment,

[1] For this study, whichever foundation had the largest share in a state was assumed for all homes in that state. Homes in Hawaii were assumed to have a slab-on-grade foundation.

so all equipment was oversized to ensure the space conditioning equipment would be able to meet the load in any climate. The furnace had a capacity of 100 kBtu/h and both the AC and the ASHP had a capacity of 5 tons. The capacity of the ER space heating was the same as the furnace.

2.2 Domestic Hot Water

An event-based domestic hot water draw profile was used for this study. The HPWH model needs a subhourly draw profile to accurately capture how the control logic for this WH responds to large draws. A 1-min time step was used for the draw profile to ensure this was captured. The BA Domestic Hot Water Event Schedule Generator (DHWESG) was used to provide the necessary discrete draw profile (Hendron & Burch, 2007). The DHWESG is a statistical tool that generates discrete events based on a probability distribution of draw events corresponding to the average distribution of hourly hot water use included in the Building America House Simulation Protocols (Hendron & Engebrecht, 2010). The DHWESG is based on studies of residential hot water use and uses separate probability distributions for each end use (showers, baths, clothes washing, dishwashing, and sinks) (Mayer, 1999). For each day, a number of discrete events for each end use are assigned based on distribution functions for each fixture. The DHWESG assigns these events to different times of day to account for the study results, including clustering for events of the same end use, differences in weekday and weekend hot water use, and several vacation periods per year. Vacations occur for three days in May, one week during August, and four days in December. A sample day of draws with all end uses aggregated is compared to the House Simulation Protocols draw event probability in Figure 4.

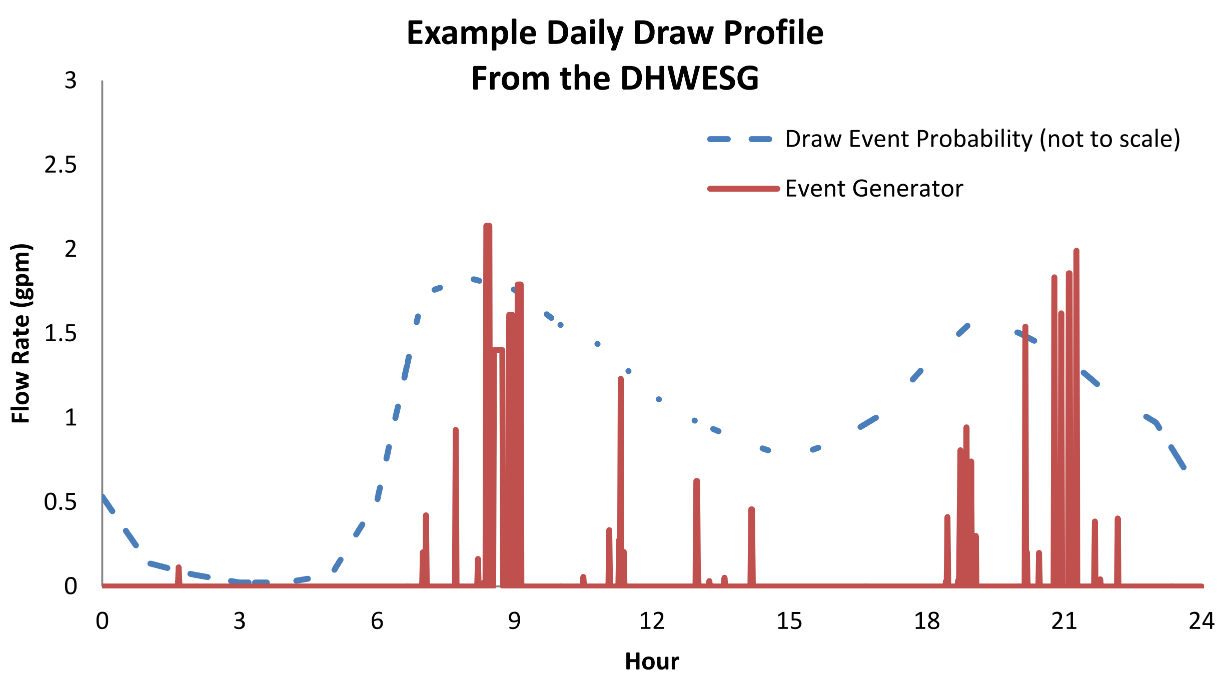


Figure 4. Sample daily draw profile

For sink, shower, and bath draws, events have a specified mixed flow rate, which is what an occupant would actually use. Appliances that use hot water (clothes washers and dishwashers) have a specified hot flow rate because these devices generally do not temper the incoming hot water to any specific temperature. For mixed events, a homeowner will temper the hot water with cold mains water to a useful mixed draw temperature. The mains water temperature used here is calculated based on an algorithm developed at the National Renewable Energy Laboratory (Burch & Christensen, 2007). The mixed draw temperature is defined as 105°F. Tempered draws comprise about 80% of the volume of hot water drawn annually (Hendron & Burch, 2007). Specifying a mixed flow rate as opposed to a hot flow rate allows the amount of hot water drawn to vary with mains water temperature, which leads to different volumes of water being drawn at different locations. The annual mains water temperature also influences the load that the WH needs to meet, as more energy is required to bring colder water up to the set point temperature. Figure 5 shows the simulated water heating load at various locations.

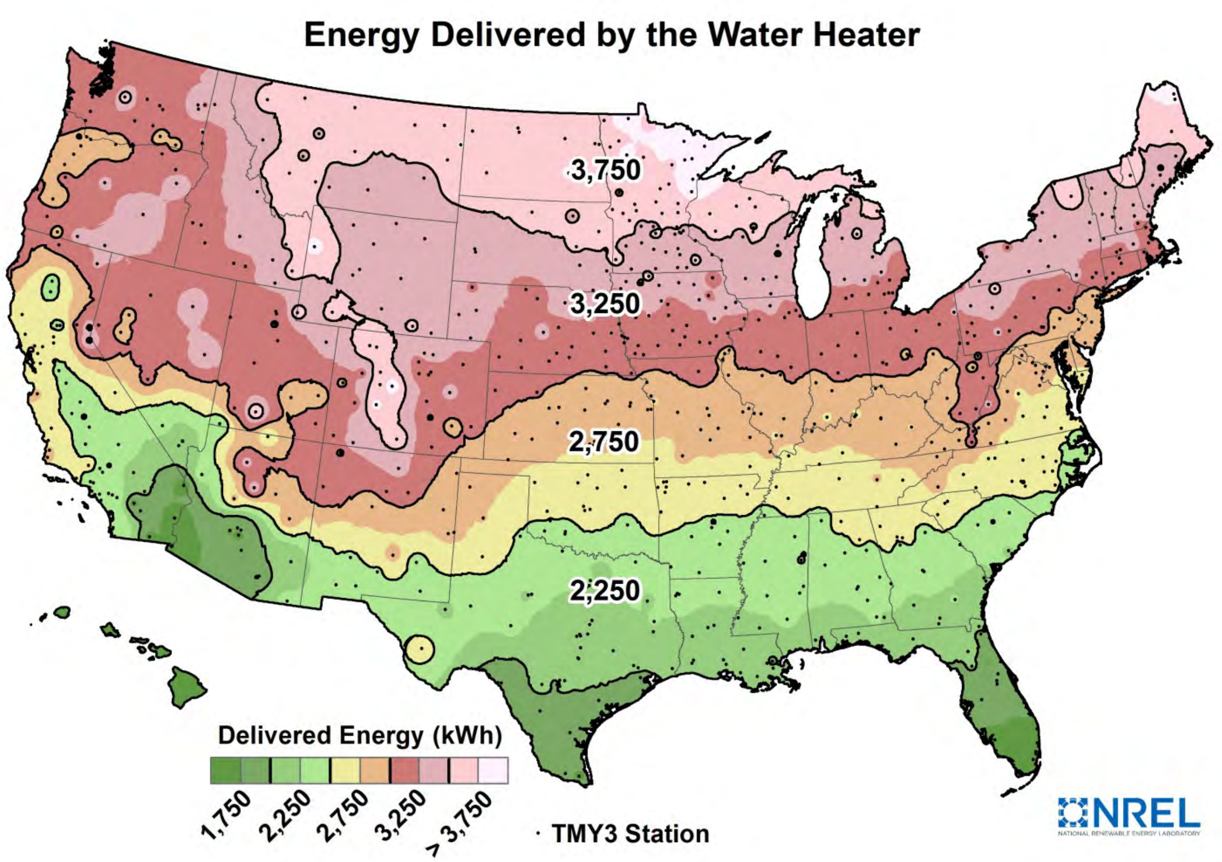


Figure 5. Simulated annual water heating load for the assumed draw profile and mains water temperatures

3 Heat Pump Water Heater Performance

Two metrics were used to evaluate the performance of an HPWH: heat pump fraction (HPF) and system COP (COP_{sys}). HPF is defined as the amount of heat added to the tank by the heat pump divided by the total amount of heat added by the heat pump and the backup electric elements. It is expressed as:

$$HPF = \frac{E_{hp,tank}}{E_{hp,tank}+E_{elem}} \tag{1}$$

where,

$E_{hp,tank}$	=	the heat added to the storage tank by the heat pump and
E_{elem}	=	the heat added to the storage tank by the electric elements

This gives a metric for how often the heat pump can be used to meet the water heating load. The COP_{sys} metric is defined as the amount of energy delivered by the HPWH divided by the net energy consumed (from the heat pump, electric elements, fan, and standby controls) by the HPWH and is expressed as:

$$COP_{sys} = \frac{E_{del}}{E_{cons}} \tag{2}$$

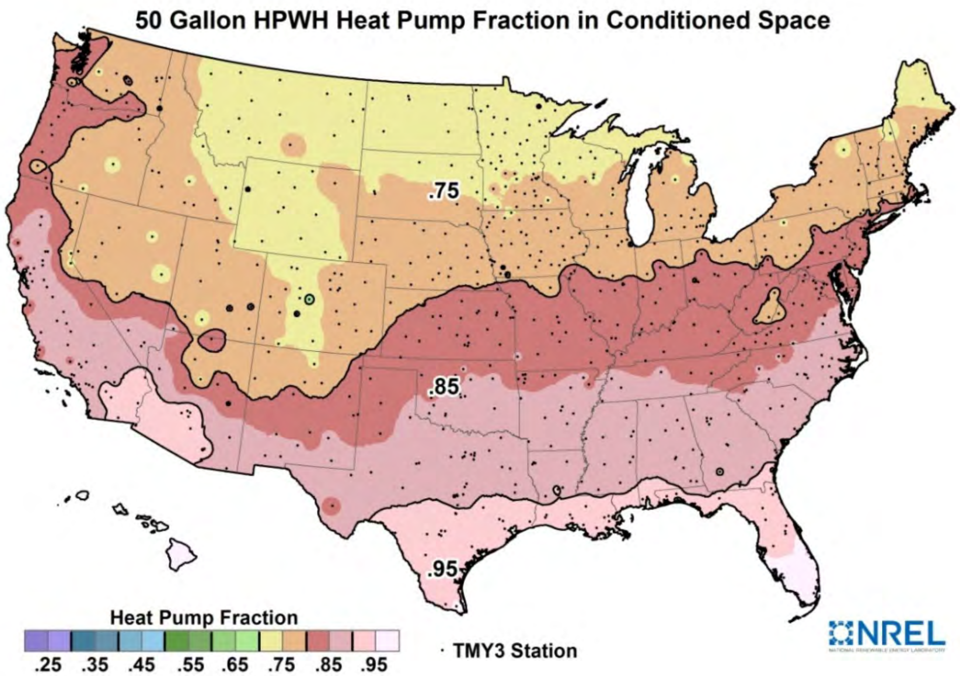
where,

E_{del}	=	the delivered site energy and
E_{cons}	=	the consumed site energy

The COP_{sys} metric is calculated similarly to the efficiency (including the rated efficiency, EF) of traditional gas and electric WHs. Although COP_{sys} and HPF are related, the HPF metric provides information about how often the heat pump can run and COP_{sys} gives the overall efficiency of the HPWH. Neither accounts for any impacts on a home's heating, ventilation, and air conditioning (HVAC) energy use.

The performance of this HPWH is not necessarily representative of all available HPWHs, which vary in storage tank volume, heat pump design, control logics, and other factors. Thus, the HPF and COP_{sys} can vary significantly between units. However, the unit modeled here performed reasonably well during laboratory testing (Sparn, Hudon, & Christensen, 2011) and provides approximately typical performance for a 50-gal HPWH. The 50-gal unit is first analyzed here as units of this size are easier to install in retrofit scenarios (where they would often replace a 50-gal WH) and have been more widely available. Appendix B provides simulation results for an 80-gal HPWH.

Figure 6 shows the HPFs for this HPWH in both conditioned and unconditioned space. The HPF is generally much higher in conditioned space than in unconditioned space. If the ambient air temperature in unconditioned space is outside the range where the heat pump can run (45°–120°F for this particular HPWH), the HPWH uses the electric resistance elements to meet the water heating load. This happens in unconditioned space for part of the year in very cold locations, leading to low HPFs in these regions. The heat pump capacity (which is a function of wet bulb temperature and mains temperature) and tank control logic determines whether the heat pump can heat the tank quickly enough after a draw event or whether the electric elements need to turn on to provide faster recovery. In colder locations, the colder mains water temperature creates a larger load and the lower ambient air temperatures cause the heat pump's capacity to decrease. These factors lead to higher electric element use and a reduced HPF.



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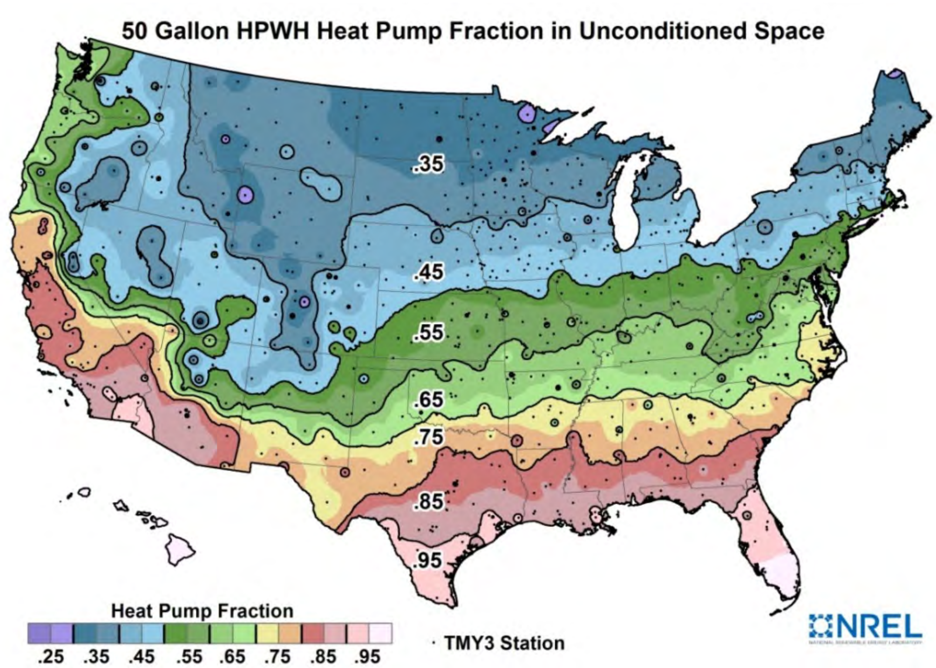

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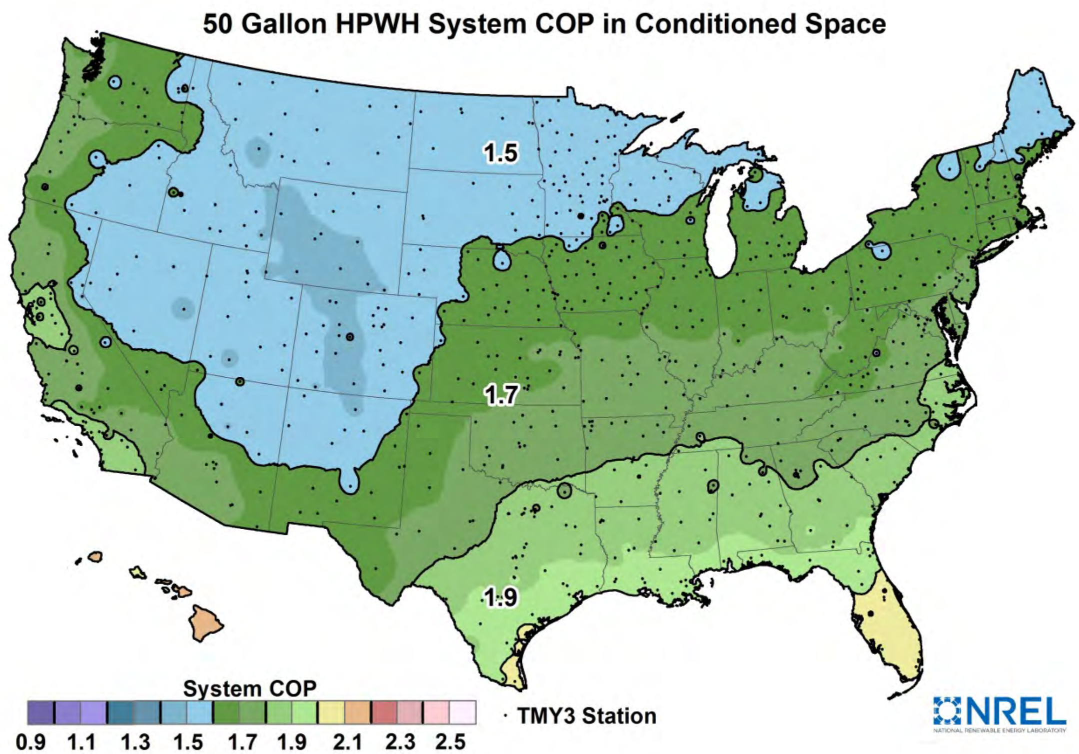
Figure 6. HPF of the 50-gal HPWH in (a) conditioned and (b) unconditioned space

Figure 7 shows the COP_{sys} in conditioned and unconditioned space. HPF and COP_{sys} are closely related metrics, so the same trends of higher performance in conditioned space and more variability in unconditioned space case are seen. COP_{sys} is an efficiency metric that can be compared with the rated efficiency, because it is similarly calculated. This particular HPWH has a rated EF of 2.35, which is higher than even the highest COP_{sys} seen in this study. The discrepancy between rated and simulated performance has also been seen in field studies (Amarnath & Bush, 2012) and is due to differences in the operating conditions used in the EF test procedure (which has an unrealistic draw profile) and what was simulated. There are also large variations in the COP_{sys}, especially when the WH is installed in unconditioned space, which indicates the difficulty in trying to use a single number (EF) to represent an HPWH's efficiency in all U.S. locations.

These metrics help to evaluate the performance of the HPWH; however, neither accounts for the change in a building's space conditioning energy consumption that comes from installing an HPWH. These factors are taken into account in Section 4.



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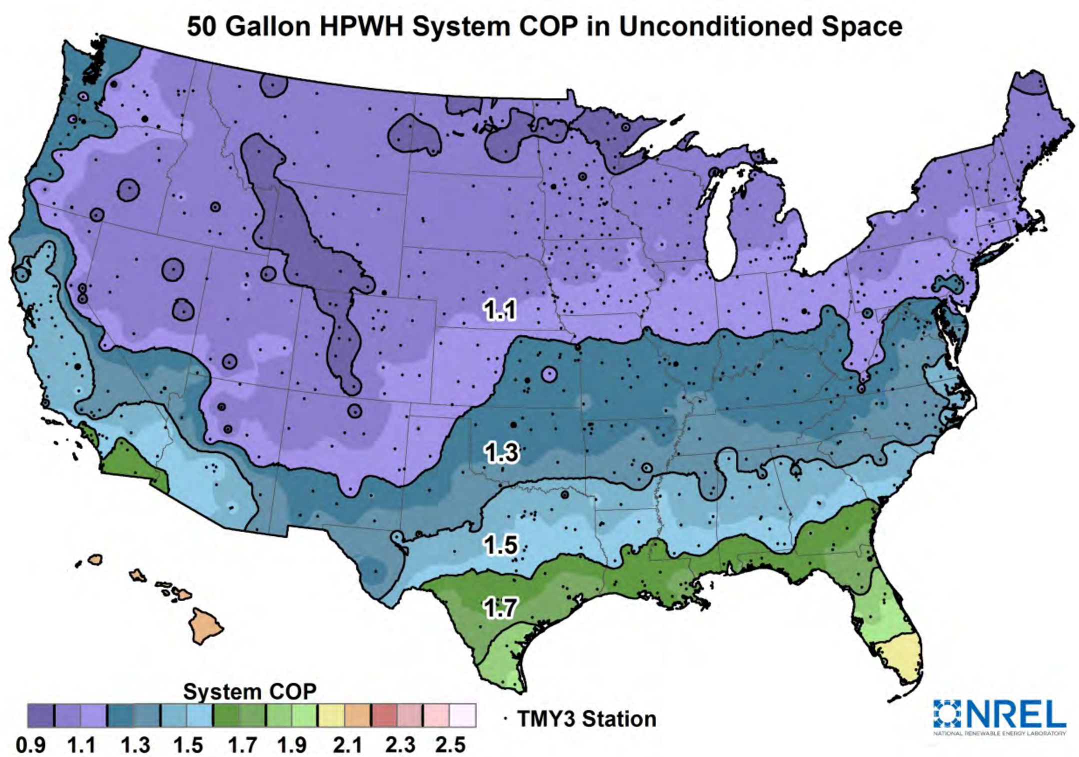

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Figure 7. COP_{sys} of the HPWH in (a) conditioned and (b) unconditioned space

4 Energy Savings Potential

When comparing WHs in the same location, several factors besides the WH energy consumption need to be considered. To keep the comparison as even as possible, all WHs should meet the same load. Because the heat pump has a lower heating capacity relative to a typical gas burner or electric resistance element, the HPWH outlet temperature sags more in high demand situations. To ensure all WHs met the same load, their energy use was normalized to account for unmet load. In actual use there would be no normalization energy, although homeowners may change their hot water use, the set point temperature of their WHs, or the operating mode if they frequently experience unacceptable sag in the outlet temperature. However, including normalization energy ensures WHs that frequently have sag in the outlet temperature do not receive an efficiency benefit from this sag without assuming exactly how occupants will deal with sag. The normalization energy is defined as the additional thermal energy required to meet the load divided by the efficiency of the WH during the time step (see Equation 3):

$$E_{nrmlz} = \frac{mc_p(T_{out} - T_{req})}{\eta} \tag{3}$$

where,

E_{nrmlz}	=	the normalization energy consumption,
m	=	the mass of water drawn during the time step,
c_p	=	the specific heat of water,
T_{out}	=	the water heater outlet temperature,
T_{req}	=	the required outlet temperature to meet the load, and
η	=	water heater efficiency

The efficiency is defined (Equation 4) as:

$$\eta = \frac{E_{del}}{E_{cons}} \tag{4}$$

where,

E_{del}	=	the delivered site energy and
E_{cons}	=	the consumed site energy

The normalization energy was calculated for any time step when the outlet temperature was lower than that required to meet the load (105°F for mixed draws and 120°F for hot draws). All the WHs required some normalization energy for very high demand situations, but the HPWH required significantly more than either of the conventional WHs considered here. Although the normalization energy is quantified here to ensure a fair comparison, the outlet temperature sag is a thermal comfort issue for homeowners. It may be dealt with in several ways, some of which will have impacts on the HPWH's annual energy consumption. For example, a homeowner could raise the HWPH set point to compensate for the sag, but this would increase standby losses and reduce the heat pump's efficiency, leading to higher energy consumption than what is predicted here.

The energy savings of an HPWH over either a gas or electric conventional WH is calculated as:

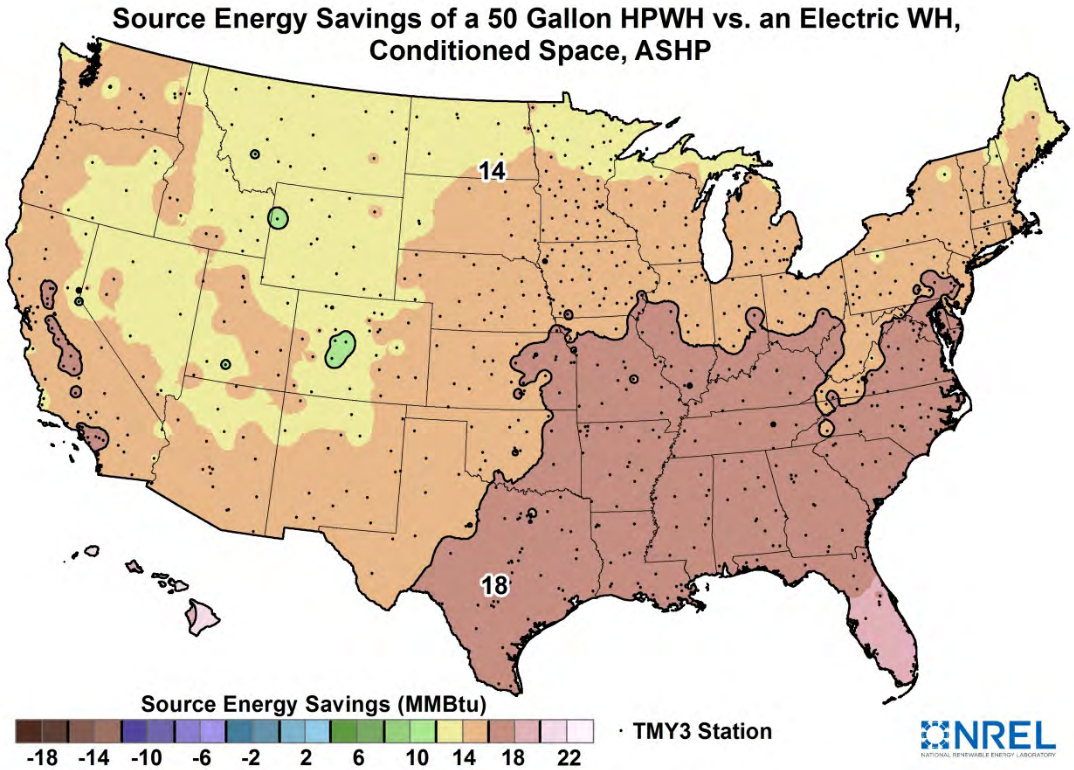
$$E_{saved,HPWH} = \Delta E_{WH} + \Delta E_{nrmlz} + \Delta E_{heat} + \Delta E_{cool} \tag{5}$$

where,

ΔE_{WH}	=	the change in water heater energy consumption,
ΔE_{nrmlz}	=	the change in normalization energy consumption,
ΔE_{heat}	=	the change in space heating energy consumption, and
ΔE_{cool}	=	the change in space cooling energy consumption.

In all cases, the change in energy consumptions was calculated as the energy consumed by a conventional WH minus the energy consumed by the HPWH. To ensure a fair comparison in cases where both gas and electricity were used all energy savings were calculated on a source energy basis. To demonstrate the impact of each factor considered in Equation 5 on the net source energy savings, the value of each term is given by climate zone for all cases in Appendix C.

Figure 8 shows the source energy savings of an HPWH relative to an electric WH for an all-electric home with an ASHP. In this case, there are source energy savings at all U.S. locations, even the worst-case scenario (installed in unconditioned space in a very cold climate). The HPWH saves significantly more energy in conditioned space than unconditioned space, especially in colder regions. This is due to the much higher HPF in conditioned space and the relatively high efficiency of the ASHP for heating. Installing in conditioned space allows the HPWH to operate using the heat pump for the entire year (except during high demand situations, when the electric elements will come on to provide faster recovery) and the high COP of the ASHP significantly reduces the HPWH's impact on increasing the space heating energy consumption. The lessened impact on the space heating equipment also leads to less variation in source energy savings across the United States. In cooling-dominated climates, the HPWH provides a net cooling benefit. Its impact is greater than the boost in performance the HPWH receives from being located in unconditioned space in hot locations, leading to higher energy savings in hot climates when the WH is located in conditioned space.



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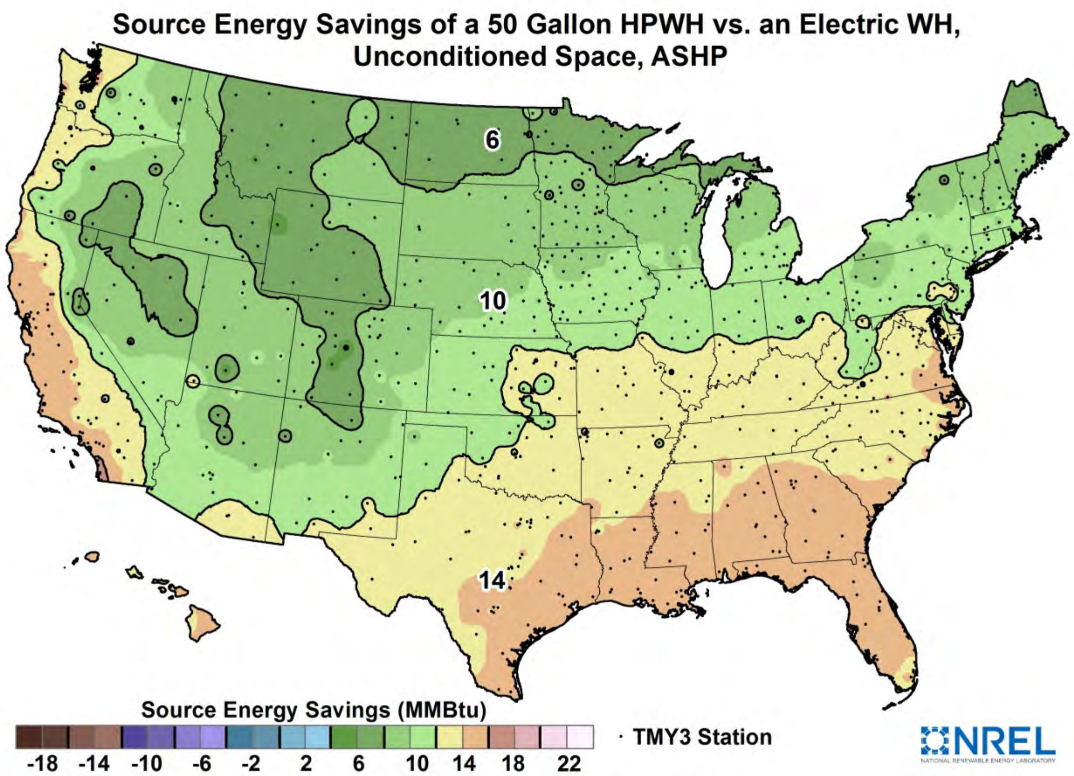
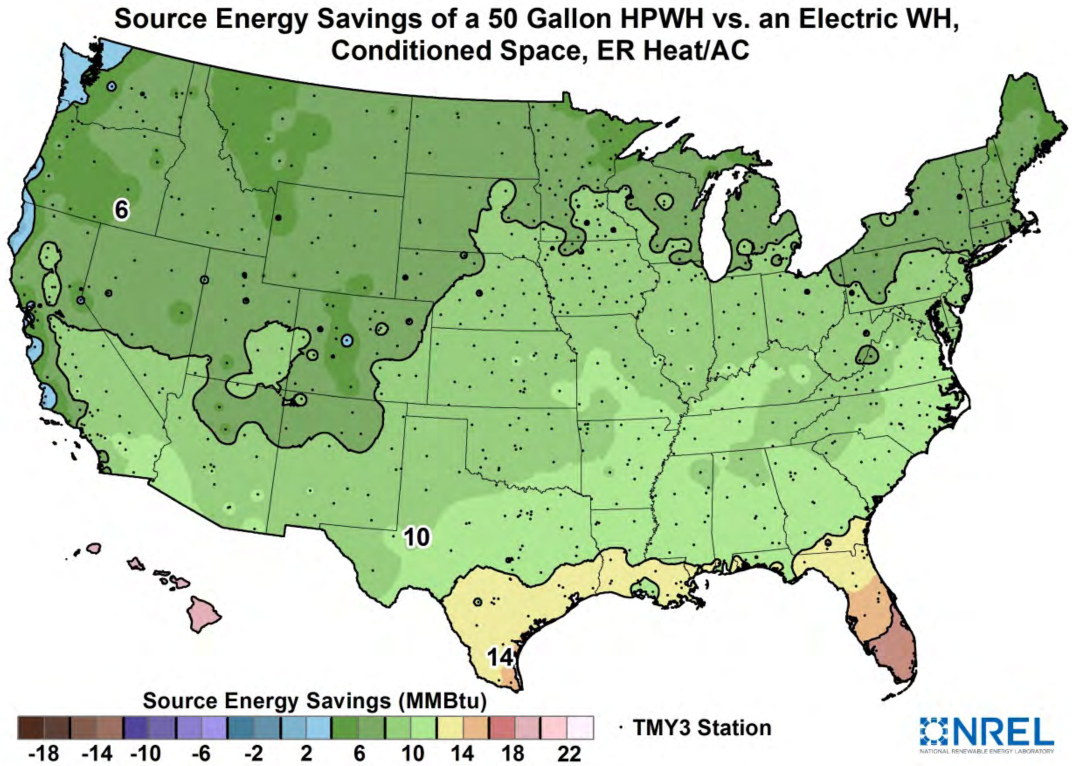


(b)

Figure 8. Source energy savings of an HPWH relative to an electric WH for a home with an ASHP when the WH is in (a) conditioned and (b) unconditioned space

If the ASHP is replaced by ER heating and an AC, HPWHs compare less favorably to electric WHs (see Figure 9). Although the source energy savings potential is lower in this case, especially when the WH is installed in conditioned space in heating-dominated climates, there are always some positive source energy savings. If the WH is located in unconditioned space, the change in HVAC energy consumption is slight. Interactions between unconditioned and conditioned space are relatively small for these homes because the walls and floors separating conditioned and unconditioned space are relatively well insulated. However, if these boundaries were not insulated, the interactions could be larger, although the space temperatures would also have fewer variations. The interactions are especially small when the WH is located in a garage, which is the predominant unconditioned space location in warmer climates. In colder climates where basements are more common, the impact of changing HVAC equipment is greater because of the higher levels of interaction between the basement and conditioned space.

For WHs located in conditioned space, cases with ER heat and an AC have significantly lower source energy savings than those with an ASHP. This is due to the lower efficiency of the ER heat (η=1) compared to an ASHP. The ASHP heating efficiency varies from 1 to 3 (the average efficiency across all climates is about 2) depending on climate. The lower efficiency of the ER heating means that it can take up to three times as much energy for ER heating equipment to meet the space heating load imposed by the HPWH on the conditioned space. Although the source savings decrease across the country (except for Hawaii and southern Florida, which has a negligible space heating load), the greatest change is along the west coast, particularly in the Pacific Northwest. This region has a marine climate, which is relatively mild but has a small heating load for much of the year. This means that the HPWH will have a greater detrimental effect as it imposes a net heating load all year long when it is located in conditioned space.



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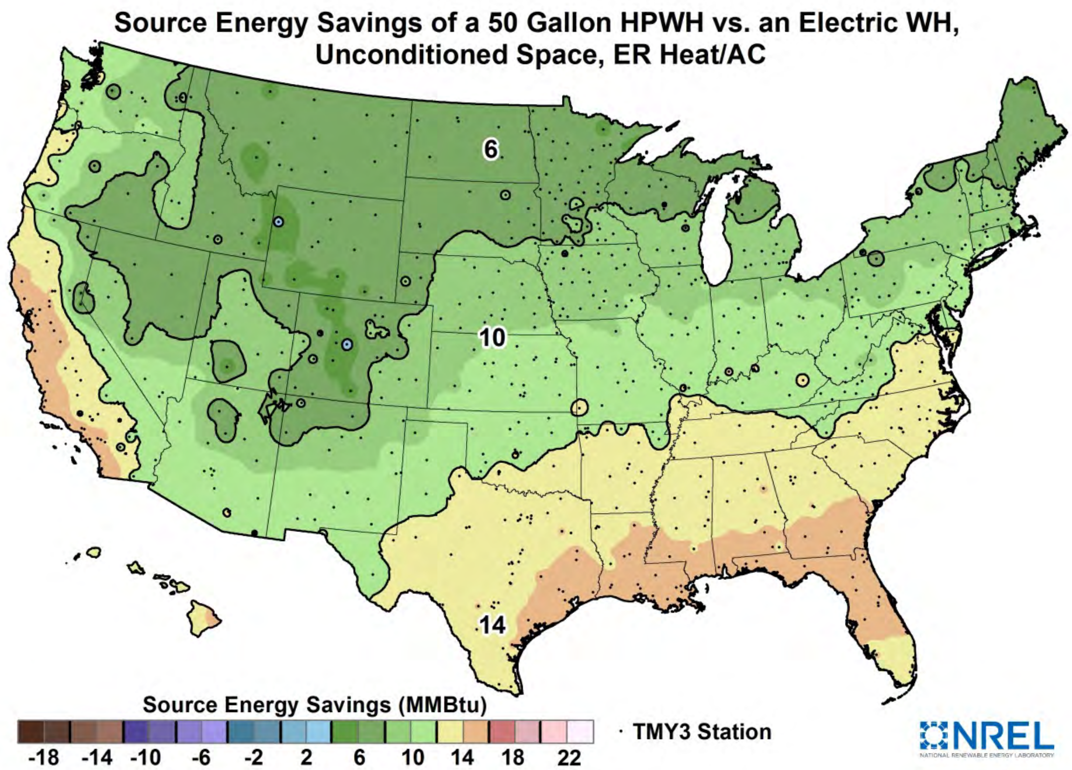

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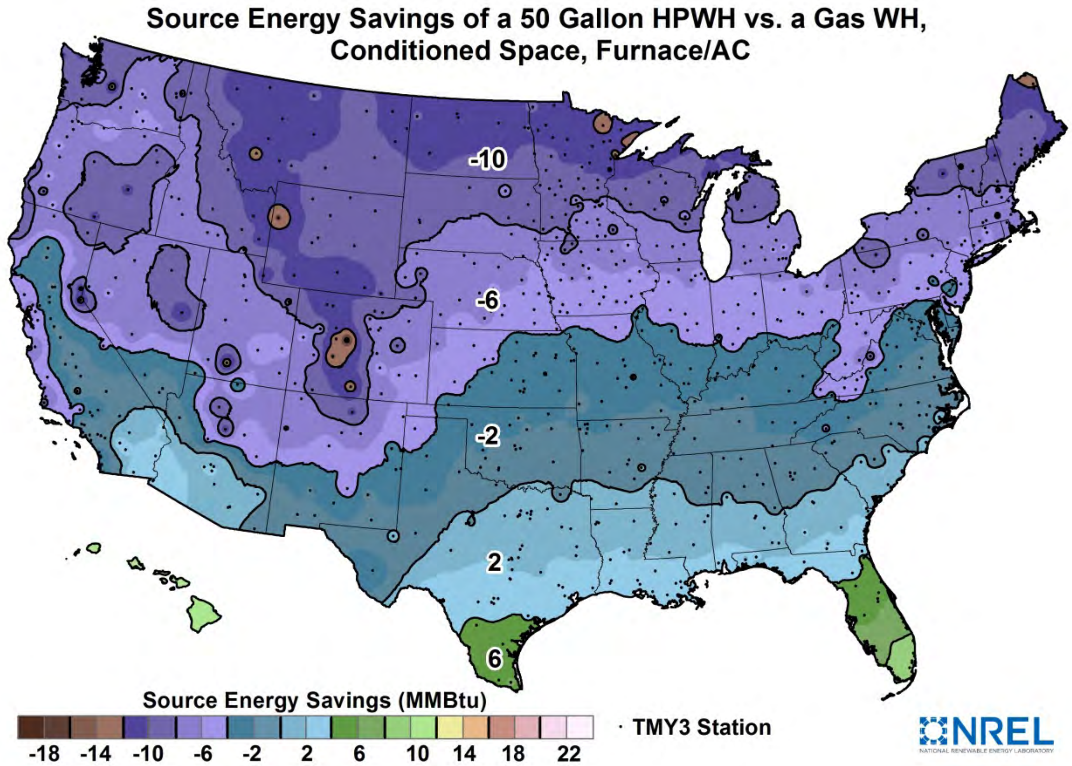
Figure 9. Source energy savings of an HPWH relative to an electric WH for a home with ER heat/AC when the WH is in (a) conditioned and (b) unconditioned space

When comparing an HPWH to a gas WH, the HPWH provides positive source energy savings only in the southernmost parts of the United States (see Figure 10). The source to site ratio for natural gas (1.092) is much smaller than that of electricity (3.365), so the site energy savings from the HPWH must be significant to reduce source energy consumption. There are thus net source energy savings only in Hawaii, the southeastern United States, and parts of Arizona and southern California, where the HPWH is most efficient and has the largest space conditioning benefit.

Although the HPWH does save a modest amount of source energy compared to a gas WH in some southern regions, these regions predominantly use electricity for water heating. Gas water heating is much more common in California and the northern and Mountain regions. The overall national source energy savings potential of replacing gas WHs with HPWHs is thus even lower than suggested in Figure 10.



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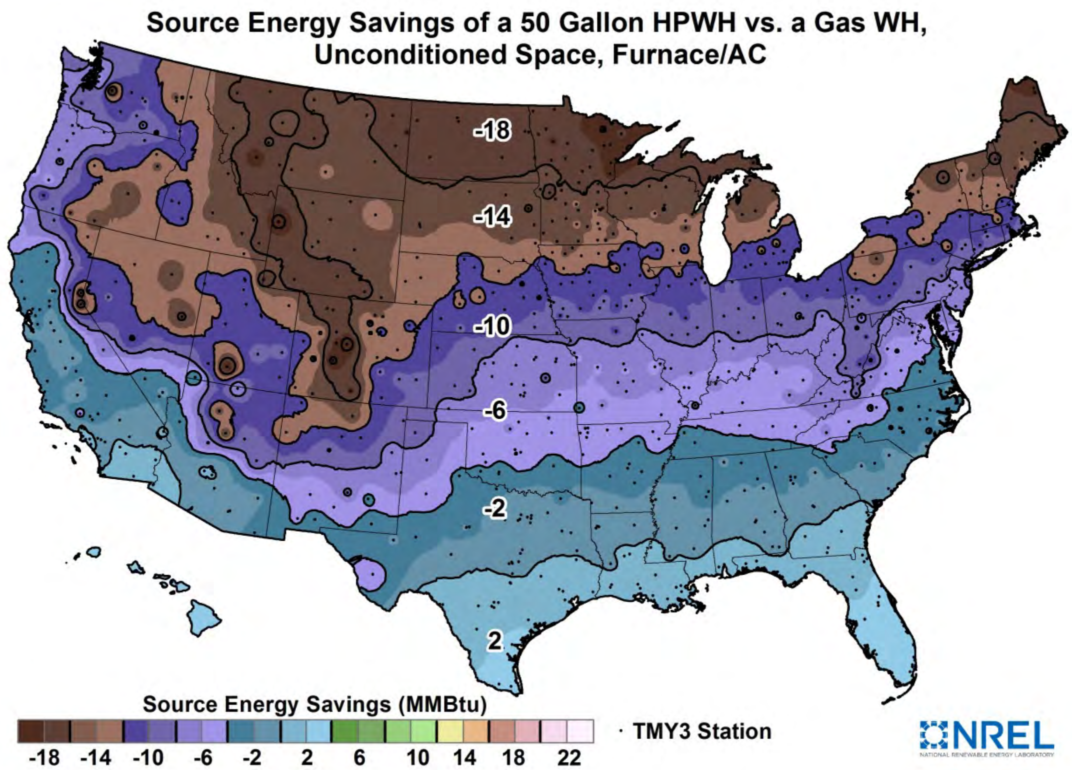

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Figure 10. Source energy savings of an HPWH relative to a gas WH for a home with a furnace/AC when the WH is in (a) conditioned and (b) unconditioned space

5 Heat Pump Water Heater Breakeven Cost

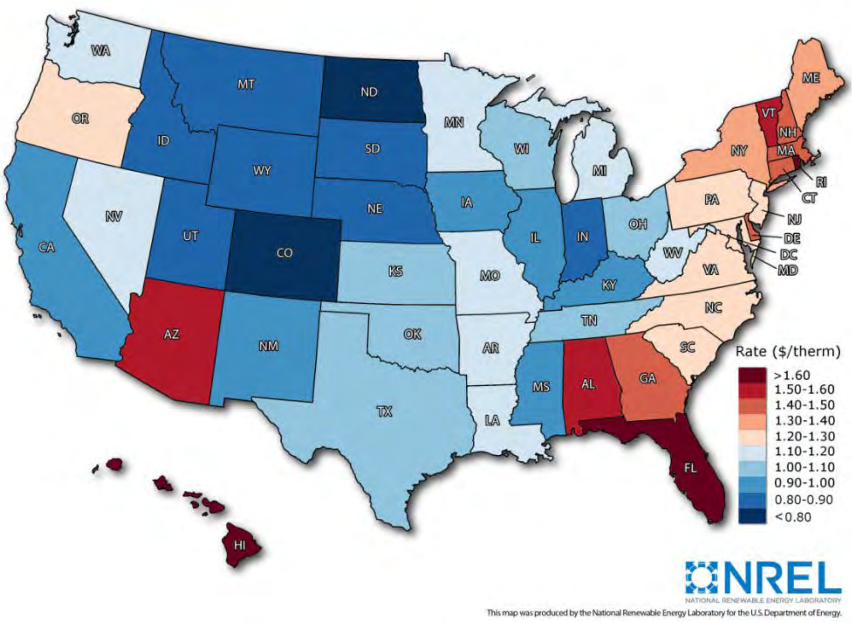
The HPWH breakeven cost is the net installed cost that achieves cost neutrality with a current water heating technology. It depends on climate, incentives, local utility rates, and other factors. In the United States, where these factors vary substantially across regions, breakeven costs vary significantly. Breakeven cost was used as the primary metric for economic analysis in this study, because these units are relatively new to the market. Their installation costs are thus not well known and the capital costs could change relatively quickly if their adoption were to rapidly increase. Installation costs may also vary significantly from household to household as some installations may incur additional costs associated with condensate drains, louvered doors, venting, or other site-specific considerations. Additional costs associated with fuel switching (for example, capping a gas line or adding a new circuit for the HPWH) may also be incurred if a gas WH is replaced by an HPWH. Recent estimates for the net installed cost (the cost of the WH plus all installation costs) of HPWHs with this efficiency range from $1300 to $2200; the estimated average net installed cost is about $1500 (U.S. Department of Energy, 2010).

The HPWH breakeven cost is defined as the point at which the net present cost (NPC) of the HPWH equals the net present benefit (NPB) realized to its owner—the difference between the NPB and NPC yields the net present value (NPV) of the system. By definition, an HPWH system is at (or better than) breakeven when its net installed cost falls below the breakeven value. For example, in an area with a breakeven cost of $2000, all HPWH systems that have an installed cost of less than $2000 are at—or better than—breakeven. Equations for the NPC, NPB, and breakeven cost are presented in Appendix D.

The NPC includes all capital costs, installation costs, maintenance costs, and incentives; the NPB is the cumulative discounted benefit of reduced electricity or gas bills. The NPC assumes a system purchased with cash (no financing) and a discount rate of 5% per year. Future fuel price escalation was also considered in the cash flow calculation. Both electricity and gas had a real price escalation of 0.5% per year. The HPWH was assumed to have a maintenance cost of $100 every 5 years for the heat pump; the typical gas and electric WHs were assumed to have no maintenance. Because the HPWH was assumed to be installed in either new construction or replacing a recently failed WH, the cost of a typical gas or electric WH factored into the breakeven cost. Typical gas and electric storage WHs were assumed to have net installed costs of $1,080 and $590, respectively (U.S. Department of Energy, 2010). These costs are the average of new construction and retrofit scenarios weighted by the annual number of new construction and retrofit installations. Breakeven costs for a case where the HPWH is replacing a functioning WH with remaining useful life are provided in Appendix E.

The evaluation period for this analysis was 15 years, which was assumed to correspond to the full lifetime of an HPWH or a typical gas or electric WH. Although this lifetime is slightly longer than the typical life of a gas or electric WH (13 years (U.S. Department of Energy, 2010)), a 15-year life makes any future comparisons to solar WHs (which have a lifetime of 30 years) (Cassard, Denholm, & and Ong, 2011) easier. The HPWH is assumed to have the same life as a typical gas or electric WH; however, the current generation of HPWHs has been on the market for only a few years and their actual lifetime is still unknown.

The breakeven costs were calculated using state average annual gas rates for 2010 (EIA, 2012) and utility-specific annual average electricity rates from the same year (EIA, 2012). These rates will fluctuate, so the breakeven costs here are only a snapshot of the recent market. Significant changes to utility rates (for example, the sharp decline in natural gas rates over the past few years) will change the breakeven results presented here. Figure 11 shows the gas and electricity rates used in this study.



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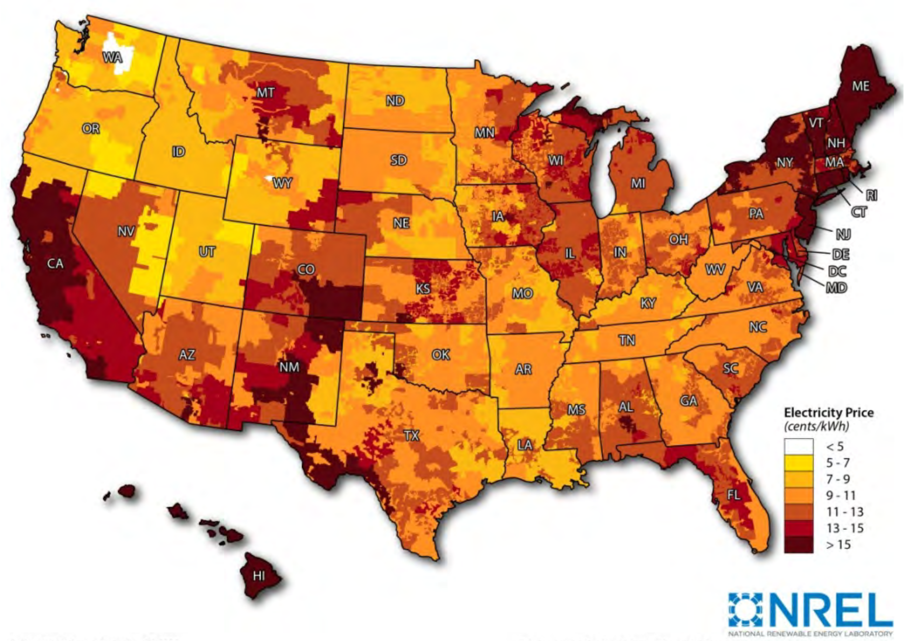

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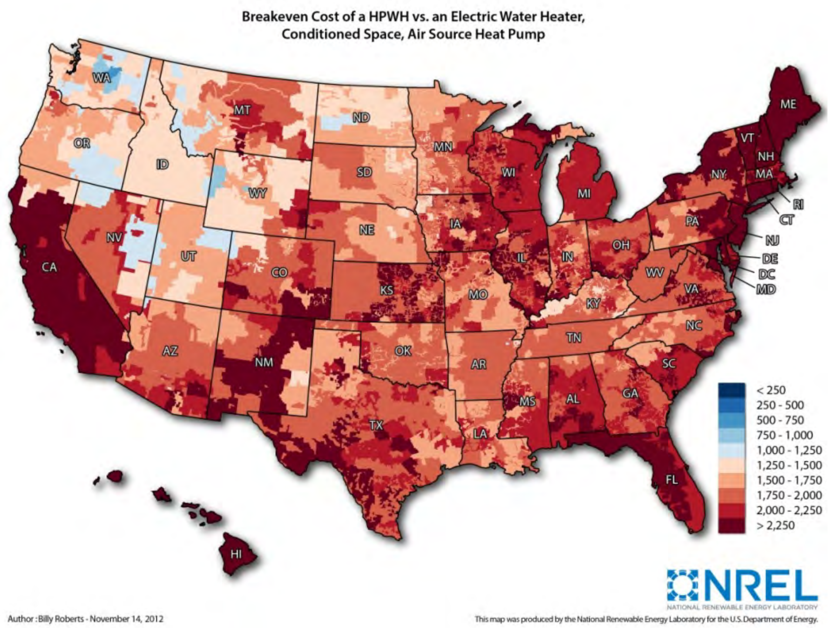
Figure 11. (a) Natural gas and (b) electricity rates used in this study

Figure 12 shows the breakeven cost for an HPWH relative to an electric WH for a home with an ASHP and no incentives. The breakeven cost depends on the net energy savings and local utility rates and varies significantly across the country. However, it is higher in conditioned space than in unconditioned space, because the energy savings for this case are always greater in conditioned space. In the conditioned space case, the highest breakeven cost is seen in Hawaii, California, Florida (because of high energy savings and high electricity rates for Hawaii and California) and New England (because of high electricity rates). When the WH is installed in unconditioned space the breakeven cost drops throughout most of the country.



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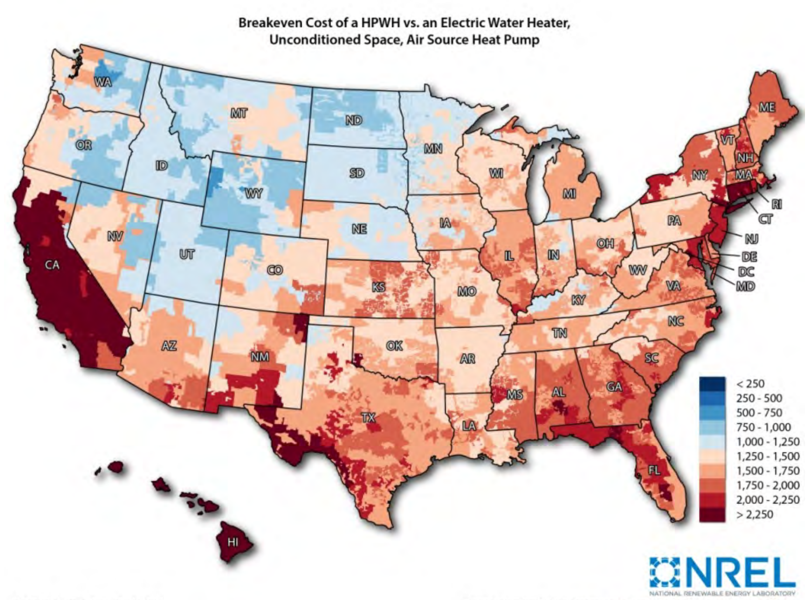

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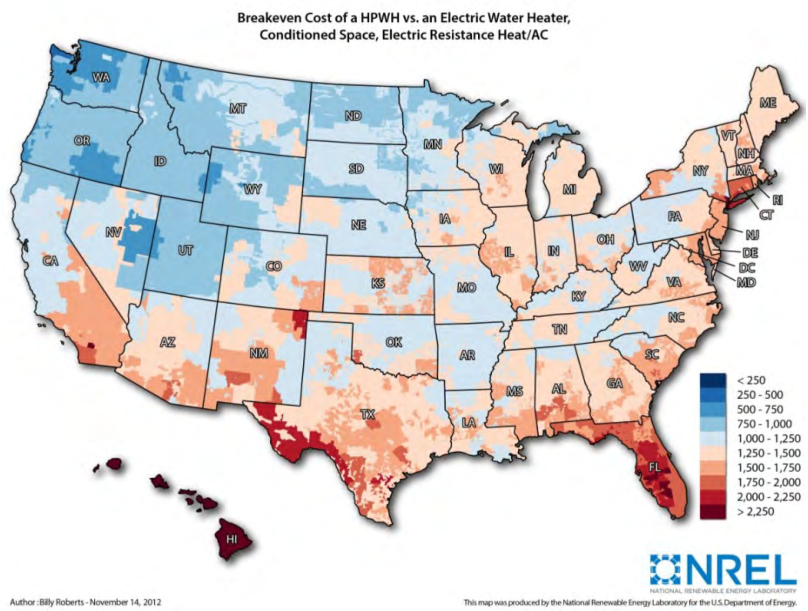
Figure 12. Breakeven cost of a 50-gal HPWH relative to an electric WH for a home with an ASHP when the WH is in (a) conditioned and (b) unconditioned space

Figure 13 shows the breakeven costs for the case where an HPWH is replacing an electric WH in a home with ER heating and an AC. Because the space heating equipment is less efficient, the space heating penalty is significantly larger and the breakeven costs in the conditioned space case drop across the country. In many cases the space conditioning penalty was large enough to make installing in unconditioned space more cost effective. The breakeven costs in unconditioned space are largely unchanged from the case with an ASHP, because the space heating and cooling interactions are relatively small.



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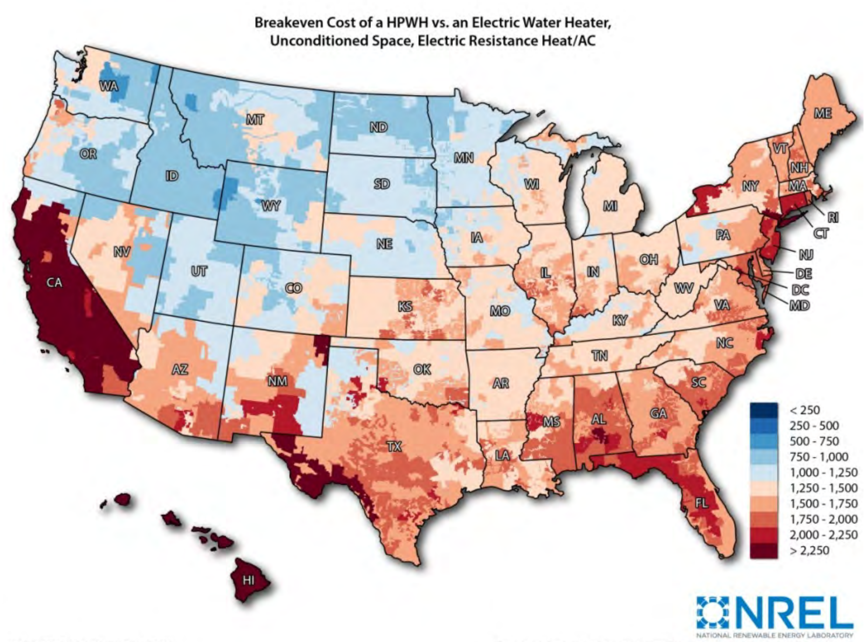

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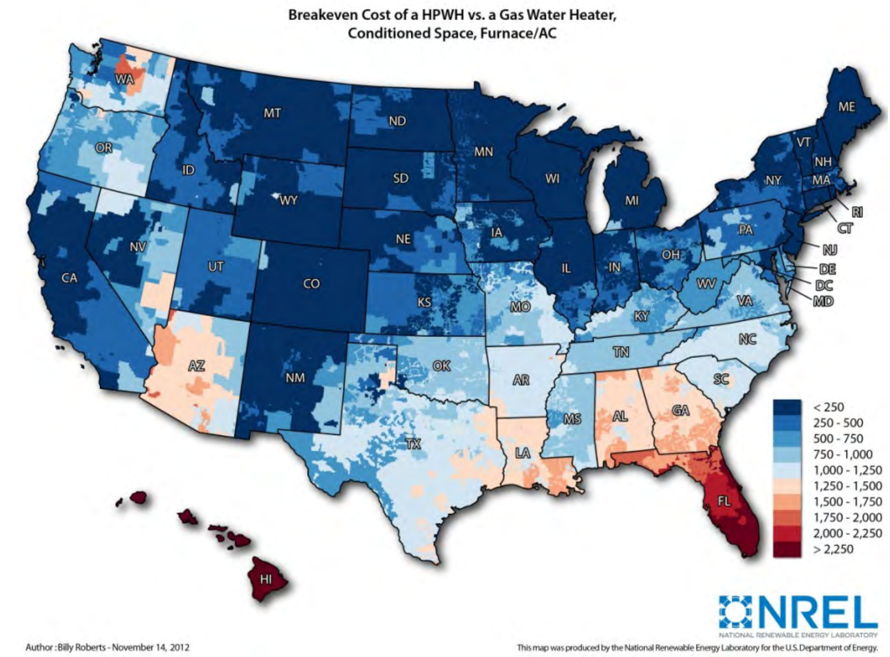
Figure 13. Breakeven cost of a 50-gal HPWH relative to an electric WH for a home with ER heat and an AC when the WH is in (a) conditioned and (b) unconditioned space

When looking at the breakeven costs of an HPWH relative to a gas WH, very few regions are likely to break even (Figure 14). For both the conditioned and unconditioned cases, the HPWH is likely to be economically viable only in parts of the Pacific Northwest, the Southeast, Arizona, and Hawaii. Both the Pacific Northwest and the Southeast are dominated by electric water heating, so the market for replacing gas WHs with HPWHs in these regions is relatively small.



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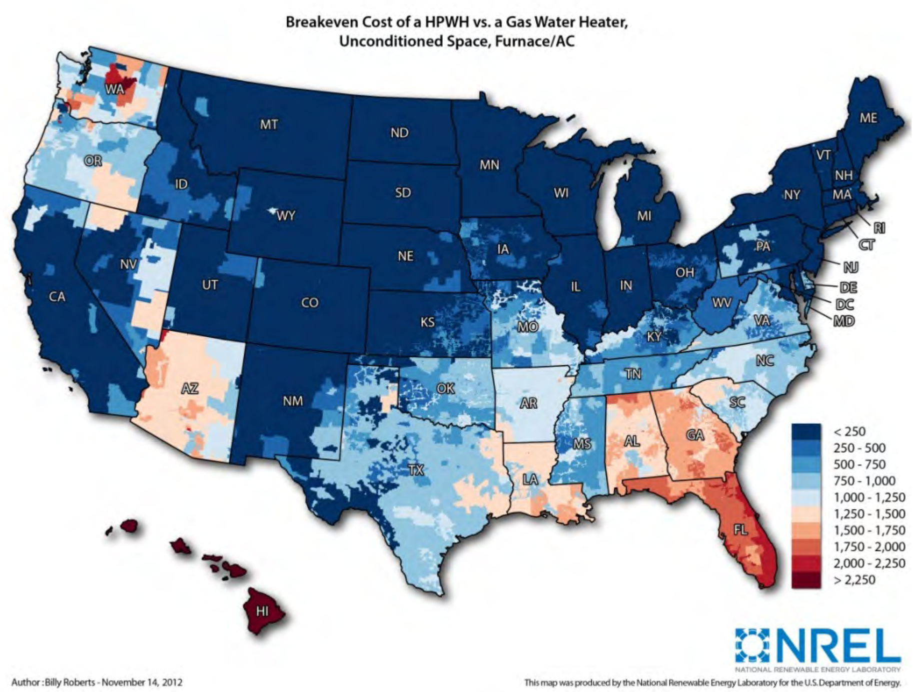

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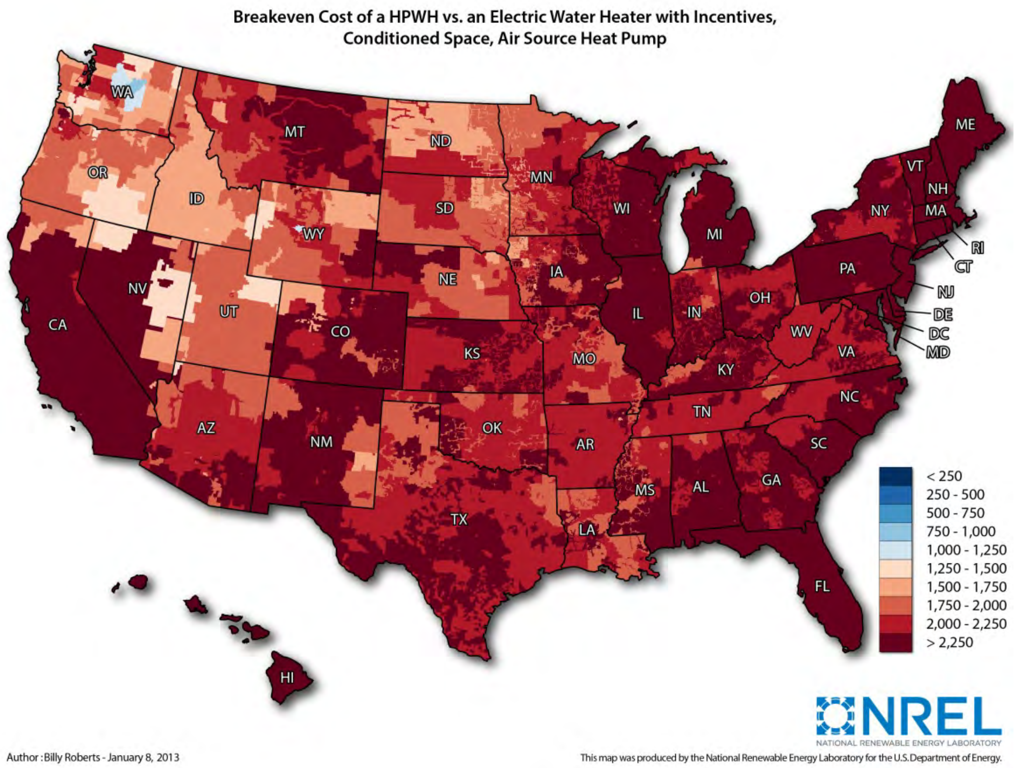
Figure 14. Breakeven cost of a 50-gal HPWH relative to a gas WH for a home with a furnace and an AC when the WH is in (a) conditioned and (b) unconditioned space

Cases with incentives were also considered to show the impact of current incentives on the breakeven cost of an HPWH. There are currently a $300 federal tax incentive and numerous local incentives for all HPWHs with an EF $\geq$ 2.0. All local incentives were taken from the Database of State Incentives for Renewable Energy (Interstate Renewable Energy Council, 2012) and a complete list of incentives is provided in Appendix F. Some are case specific and may apply only to situations where either a gas or electric WH is replaced or if the HPWH is installed in unconditioned space. Because the residential water heating market is dominated by retrofit situations, incentives that applied only to new construction scenarios were not considered here. Most incentives that applied to HPWHs were rebates, although a few states offered personal tax credits. To account for the delay in receiving a rebate or tax credit, all incentives were assumed to apply one year after the HPWH was installed and were discounted appropriately.

Figure 15 through Figure 17 show cases with incentives. Local incentives are distributed across the country; utilities in 35 states offer some incentives for HPWHs. Four states also offer some incentive for purchasing an HPWH. Although the federal incentive causes breakeven costs to rise everywhere, noticeable increases from large local incentives combined with the federal incentives are seen in several locations, including most of Massachusetts, Montana, Arkansas, Pennsylvania, and Kentucky.



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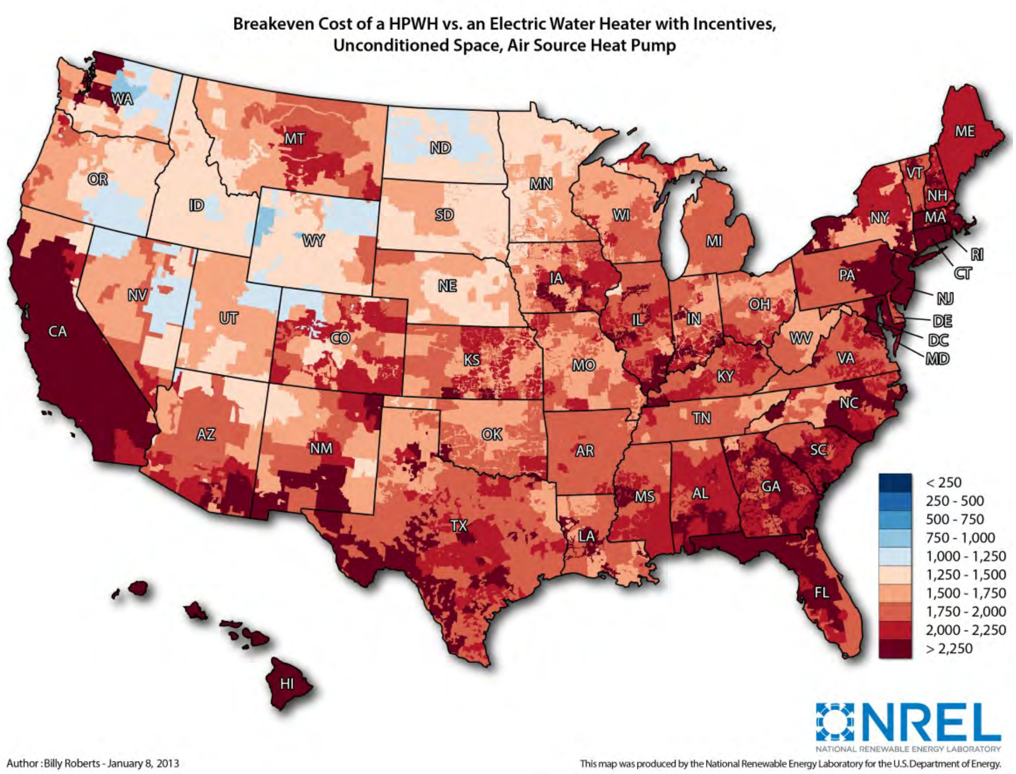

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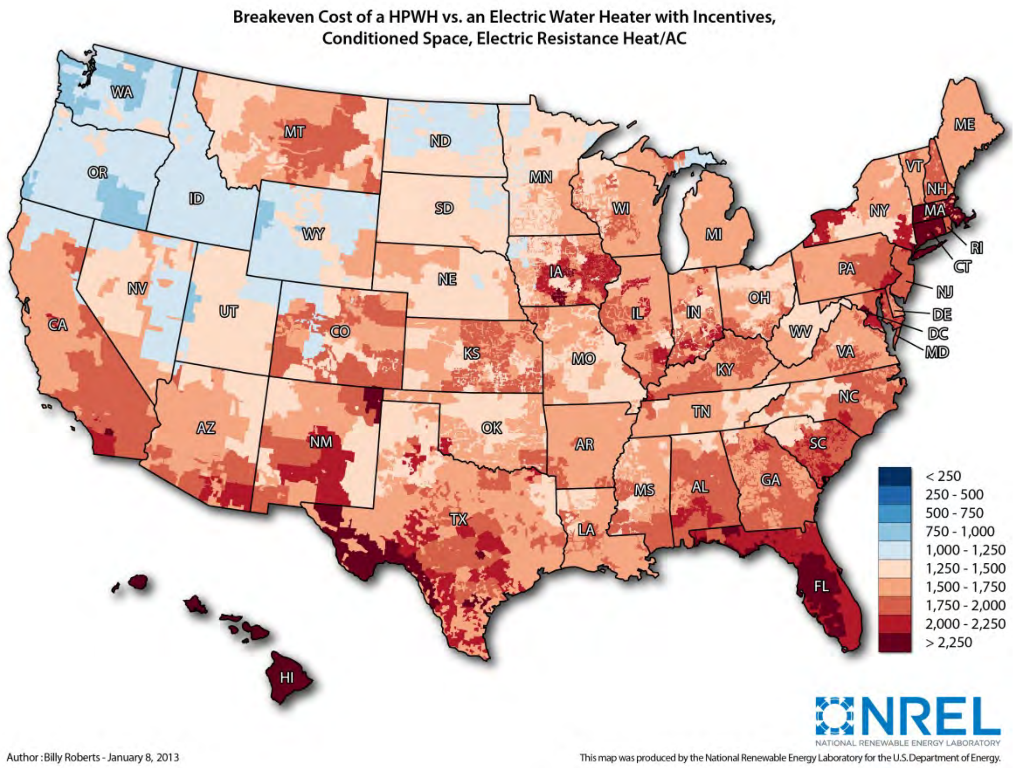
Figure 15. Breakeven cost with incentives of a 50-gal HPWH relative to an electric WH for a home with an ASHP when the WH is in (a) conditioned and (b) unconditioned space



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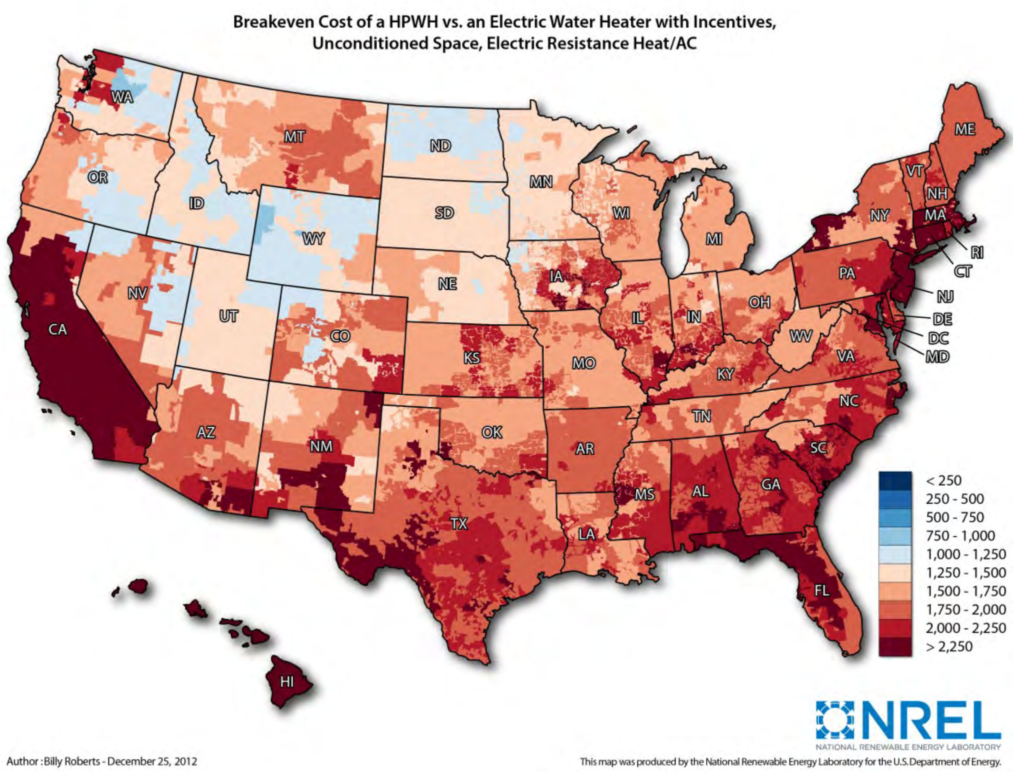

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Figure 16. Breakeven cost with incentives of a 50-gal HPWH relative to an electric WH for a home with ER heat/AC when the WH is in (a) conditioned and (b) unconditioned space