Final Assessment Report – Potential Impacts of California's High Electrification Scenario

24 November 2021

CONTENTS

List of Figures

List of Tables

Acronyms and Abbreviations

ACS	U.S. Census Bureau American Community Survey
AFUE	Annual Fuel Utilization Efficiency
BEV	Battery Electric Vehicle
BGEPA	Bald and Golden Eagle Protection Act
BLM	U.S. Bureau of Land Management
BTM	Behind-the-meter
Cal-ISO	California Independent System Operator
CARE	California Alternate Rates for Energy
CDFW	California Department of Fish and Wildlife
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CPUC	California Public Utilities Commission
CRIT	Colorado River Indian Tribes
CRT	California Rangeland Trust
CSP	Concentrating solar power
DCFC	Direct Current Fast Charging
DRECP	Desert Renewable Energy Conservation Plan
E3	Energy + Environmental Economics, Inc.
EA	Environmental Assessment
EIA	U.S. Energy Information Administration
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EO	Executive Order
ERM	ERM-West, Inc.
ESA	Endangered Species Act
EV	Electric Vehicle
EVSE	Electric vehicle supply equipment
FCEV	Fuel Cell Electric Vehicle
FERA	Family Electric Rate Assistance Program
GHG	Greenhouse gas
GW	Gigawatt
HES	High Electrification Scenario
IEPR	Integrated Energy Policy Report
Km2	Square kilometer
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LOLE	Loss-of-load events
LUPA	BLM Land Use Plan Amendment
MW	Megawatt
NBES	No Building Electrification Scenario
NGBS	Natural Gas Ban Scenario
NOx	Oxides of nitrogen
NREL	National Renewable Energy Laboratory
PHEV	Plug-In Hybrid Electric Vehicle
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
RECAP	Renewable Energy Capacity Planning Model

RESOLVE	Renewable Energy Solutions Model
RETI	Renewable Energy Transmission Initiative
SB 100	Senate Bill 100 California Renewables Portfolio Standard Program
SL	Siting Level
TAC	Toxic Air Contaminant
TWh	Terawatt hour
TNC	The Nature Conservancy
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
VMT	Vehicle miles traveled
VOC	Volatile organic compound
VRE	Variable Renewable Energy
WDFW	Washington Department of Fish and Wildlife
ZEV	Zero-emissions vehicle

EXECUTIVE SUMMARY

This report focuses on potential impacts to California from the High Electrification Scenario or HES, a scenario developed in various reports commissioned by the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and others on pathways to meeting California's greenhouse gas (GHG) emission reduction goals. The premise is that California's GHG emissions must be reduced to 86 million metric tons per year to obtain an 80 percent reduction in GHG emissions from 1990 levels by 2050. Focusing on this goal, the CEC, CPUC and others developed the HES, which was first elaborated in a 2018 report (Mahone et al. 2018) and then analyzed further in later reports.

The premise of the HES is that California will achieve its 2050 GHG goals through a combination of electricity derived from renewable energy generation and behavior change that leads to both a reduction in gas usage and an increase in electricity usage. In effect, the state envisions the near-complete electrification of space heating and cooling loads in buildings, the near-complete electrification of transportation, and extensive investments in renewable electricity generation and energy storage in order to supply the electricity necessary to support these loads. Behavior changes such as fewer vehicle miles traveled (VMT), greater purchase of electric vehicles (EVs), and less energy use per capita drive further emission reductions. Further details on the assumptions of the HES are provided in the Introduction.

This analysis focuses on the HES as elaborated in various 2018-2019 reports. ERM reviewed HES-related studies and prepared this assessment of the potential implications, from economic, equity, and environmental standpoints, of HES implementation as a framework for further discussion and research. The report also describes various assumptions of the HES and whether they accurately reflect likely behavior and reality in 2050, the year of assumed full HES implementation.

Potential implications of the HES include the following:

- By 2050 installed capacity will need to increase by approximately 480 to 650 percent for solar and 30 to 250 percent for wind to provide necessary supply.[1] This is a net increase of between 101.5 to 107.3 gigawatts (GW) of solar and 4.7 to 15.42 GW of wind.
- The HES assumes that, relative to 2015, per-capita VMT will decline by 12 percent by 2030 and 24 percent by 2050. However, in recent years excluding 2020, VMT has been on average only 3.6 percent below 2015 levels. If VMT does not drop as assumed, the necessary service load for the HES will be approximately 31.3 terawatt hours (TWh) or 6.1 percent higher in 2050 than currently indicated.

1. Various sources report different 2020 installed industrial solar and wind capacity in California. Ming et al. 2019 ("E3-CP" or "E3-Calpine") *Long Run Resource Adequacy Under Deep Decarbonization Pathways for California* estimated that total installed capacity for 2020 was 21.2 gigawatts (GW) of industrial solar and 16.7 GW of wind. However, the CEC reports that California's 2020 production capacity was only 15.63 GW of solar and 5.98 GW of wind.

Economic

- Documentation to date does not include all costs to implement the HES. The 2019 figure of \$116.1 billion annually[2] is more likely to be \$221.6 to \$256.7 billion when project permitting and mitigation, land acquisition, decommissioning, equipment and infrastructure, transmission and distribution upgrades, environmental siting protections, wildlife adaptation, and optimism bias adjustment costs are included. This is a near doubling of previously reported values.
- Average annual residential electric bills are estimated to rise from \$1,226 in 2019 to \$4,941 in 2050, a change of 303 percent. Average annual commercial electric bills are estimated to rise from \$11,104 in 2019 to \$44,764 in 2050.
- Residential gas rates are estimated to increase 80 percent by 2030 and 480 percent by 2050 as fixed costs are spread over a smaller customer base. For customers who remain on the gas system, total energy bills (electric plus gas) are estimated to increase 327% compared to 2019.
- Though residential customers who switch to electric face lower or no gas bills, their combined energy bills are estimated to rise up to 150% compared to 2019.
- The assumed 86 percent decline in petroleum demand in 2050 may lead to up to 179,000 job losses, including over 7,000 jobs in the San Joaquin Valley specifically.
- Labor income for the oil and gas industry could decline by \$13.4 billion (57 percent), with a \$34.1 billion decline in GDP (63 percent). Total output may decrease by \$100 billion (69 percent), decreasing state and local tax revenue by \$14.2 billion.
- If the current state renewable energy property tax incentive continues, development of solar and wind facilities will cost California counties more than \$300 million in annual property tax revenue by 2050. San Joaquin Valley counties would forego about \$150 million, almost half of the total impact to the state, and the largest impact would be in Kern County, which could lose \$59 million in property taxes. If the renewable energy tax incentive is discontinued, then the annual revenue requirements for electricity generation may increase by \$300 million, further increasing future electricity rates.

Equity[3]

- Total annual residential energy costs would increase statewide by approximately \$79 billion or \$3,800 per household.
- In 2050, the 1.7 million households in California below the poverty level would see their energy costs increase from 16 to 46 percent of their annual income, an additional \$3,100 per year.

2. Ming et al. 2019. ("E3-CP" or "E3-Calpine") *Long Run Resource Adequacy Under Deep Decarbonization Pathways for California* (Figure 22). Adjusted from 2016 to 2019 dollars using the Consumer Price Index.

3. The equity analysis is based on residential energy bill data from the American Community Survey, which differs from the residential bill data used in the HES; however, the magnitude of the impacts are comparable. The equity analysis uses the mid-point of the range of the 2x optimism bias and the 3x optimism bias adjustments or 50.4 cents per kwh.

- In 2050, the approximately 10.8 million households in California below the living wage would see their energy costs increase from 4 to 11 percent of income, an additional $3,400 per year.
- These energy costs would nearly triple the number of households living in energy poverty, from 1.7 to 6.3 million, and would cause an additional 300,000 households to fall below the living wage.
- If assistance to low-income households remains at the same rates in 2050, then 4.6 million households will receive a total of $7.3 billion offsetting 38 percent of the $19.1 billion increase in their energy bills. However, all other rate payers, including middle-class families, will see an additional $2.6 billion increase in energy costs.
- Disadvantaged communities may face particular hardships as counties where at least 25 percent of the population lives in disadvantaged communities are anticipated to see an increase of $4,000 per year in energy costs, and these counties are in warmer parts of the state, where households face larger heating and cooling costs in general.
- Households in the Central Valley (with a much higher population of disadvantaged communities) may see an annual change in energy costs of $4,844, as compared to households in the Central Coast (with a very low population of disadvantaged communities), where household costs are anticipated to increase by $2,773.

Environmental

- Assuming California has access to renewable energy from other western states, approximately 3,000 to 5,000 square kilometers (km^2) (740,000 to 1.24 million acres) will be converted from agricultural, rangeland, and open space to industrial land in order to supply the electricity needed in the HES.
- This is between 14 and 24 percent of the approximately 21,000 km^2 (5.19 million acres) of already urbanized land in California. Thus, the HES would add up to another one quarter of the current total of urbanized land in California.
- This increase in development is also approximately 6 to 10 times the amount of land currently developed for solar in California. For perspective, installed solar PV capacity in Fresno and Kings counties in the San Joaquin Valley is equivalent to roughly 53.2 km^2, or only 1.3 percent of the 4,000 km^2 of land area that could be needed for the HES.
- A 2019 assessment of the HES (E3-TNC) assumes most solar projects would provide 120 MW of capacity on a land area of 4 km^2 (988 acres); however, existing solar projects in California are generally much smaller, with average production capacity of 17 MW over 0.6 km^2 (139 acres).
- HES implementation would require annual build rates for solar and wind averaging as high as the highest historic annual build rate for the next 25 years. This is equivalent to the estimated average land development of 33 km^2 for solar, and 23 km^2 for wind.
- E3-TNC's 2019 assessment of the Full West Siting Level 4 constrained case[4] assumes roughly 70 percent of overall land development will occur in the combined San Joaquin

[4] The Full West scenario allows for robust wind imports from eight other western states with the balance of renewable development in California, the Siting Level 4 excludes legally protected lands, prime

Valley and Mohave/Sonoran desert regions. However, after discounting for permitting and other constraints, the combined available land within these two regions would meet only 30 percent of the total HES needs.

- Even in the Full West Siting Level 4 constrained case, with high levels of environmental protection, impacts to environmentally and agriculturally significant lands will likely be unavoidable. While E3-TNC's mapped data are too coarse for detailed analysis, applying a coarseness factor to the land areas identified for development in this scenario shows that solar development in California could impact up to 11,000 acres of wetland, 43,000 acres of critical habitat, 40,000 acres of important bird areas, 2,000 acres of wildlife linkages, 119,000 acres of prime farmland, 100,000 acres of agricultural land, and 30,000 acres of rangeland, if sensitive resources cannot be avoided.

The present study is based on a limited data set from the 2018-2019 timeframe, and is not intended to be a comprehensive survey of all issues or all available data pertaining to the HES. However, though preliminary, these findings suggest that further research is needed to verify the underlying assumptions of the HES, analyze potential impacts from economic, environmental, and equity perspectives, and continue to evaluate the HES as a viable pathway to meeting California's GHG emission reduction goals.

agriculture, important avian habitat, high biological resource lands, and other lands that have high connectivity from development, and the constrained case restricts renewable resource development to within RESOLVE zones and applies the RESOLVE Base as the maximum limit for development in each zone.

1. INTRODUCTION

California has established numerous climate change-driven policy objectives, including a mandated 40 percent reduction in greenhouse gas (GHG) emissions by 2030, and an 80 percent reduction in GHG emissions from electricity, buildings, transportation, and industry by 2050, relative to 1990 levels. These policy objectives are consistent with a long-term trend in California's policy making. For instance:

- Executive Order S-3-05 (2005) sets a GHG emission reduction target of 80 percent below 1990 levels by 2050.
- Executive Order S-21-09 (2009) directed the California Air Resources Board to adopt regulations that would require 33 percent renewable energy generation by 2020.
- In 2015, California passed Senate Bill (SB) 350, the Clean Energy and Pollution Reduction Act, which increased the Renewables Portfolio Standard to 50 percent and resulted in a series of other changes to increase energy efficiency and decrease fossil fuel use.
- Senate Bill (SB) 100 (2018), referred to as the California Renewables Portfolio Standard Program, calls for renewable and zero-carbon resources to supply 100 percent of retail sales and electricity procured for all state agencies by 2045.
- Executive Order B-55-18 (2018) calls for the state to achieve carbon neutrality by no later than 2045.

Related to the 2017-18 Integrated Resource Planning process, the California Energy Commission (CEC) and others commissioned a series of reports on pathways to meet the state's GHG emissions reduction goals. This led to the development of a scenario labeled the High Electrification Scenario (HES), which was first introduced in a 2018 report (Mahone et al. 2018) and then analyzed further in a series of other reports. These reports, and the primary sources for this assessment, include:

- Aas, Dan et al. 2020. ("E3-GasFut") The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. California Energy Commission. Publication Number: CEC-500-2019-055-F.
- Mahone et al. 2018. ("E3-Decarb") *Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model.* This 2018 CEC-sponsored report by Energy + Environmental Economics (E3) focuses on HES as the low-risk, low-cost approach for reducing total California GHG emissions by 80 percent from 1990 levels and has emerged as the state's primary energy policy blueprint for 2050 planning.
- Ming et al. 2019. ("E3-CP" or "E3-Calpine") *Long Run Resource Adequacy Under Deep Decarbonization Pathways for California.* This 2019 report was prepared by E3 for Calpine (CP) Corporation and details the need to retain gas generation in-state and import capacity to control the costs of the 2050 HES developed in E3-Decarb.
- Wu et al. 2019. ("E3-TNC") *Power of Place: Land Conservation and Clean Energy Pathways for California.* This report was prepared by E3 for The Nature Conservancy (TNC) and provides additional detail concerning potential environmental constraints and the potential size, location and cost of new solar, wind, bulk transmission generation and geothermal facilities in California and other states required to implement the HES by 2050.

Notably, the CEC has continued to develop the HES concept post-2019. For instance, the SB100 Joint Agency Report (CEC 2021a), published in March 2021, elaborated a somewhat different version of the HES than is analyzed in the reports from 2018-2019. The difference arises from, among other things, different assumptions about electricity generation technology costs, reflecting updated cost forecasts; and different assumptions about load growth and other information from subsequent CEC documents. However, the SB100 version of the HES has been less extensively studied than the 2018-2019 iteration, including by the CEC itself. For this reason, the present analysis focuses on the HES as elaborated in the 2018-2019 reports noted above.

The HES premise is that California GHG emissions must be reduced to 86 million metric tons per year to meet the goal of an 80 percent reduction in GHG emissions by 2050, relative to 1990 levels, even as population is projected to increase 0.81 percent per year (Kavalec et al. 2018). Under the HES, three primary strategies are proposed in order to achieve these emissions reductions: (a) the near-complete electrification of space heating and cooling loads in buildings, (b) the near-complete electrification of transportation, and (c) massive investments in renewable electricity generation and energy storage. Electrification would reduce emissions from the building and transportation sectors by replacing almost all fossil fuel use from those sectors with electrical power generated mainly from wind and solar assets to be developed in California and outside the state.

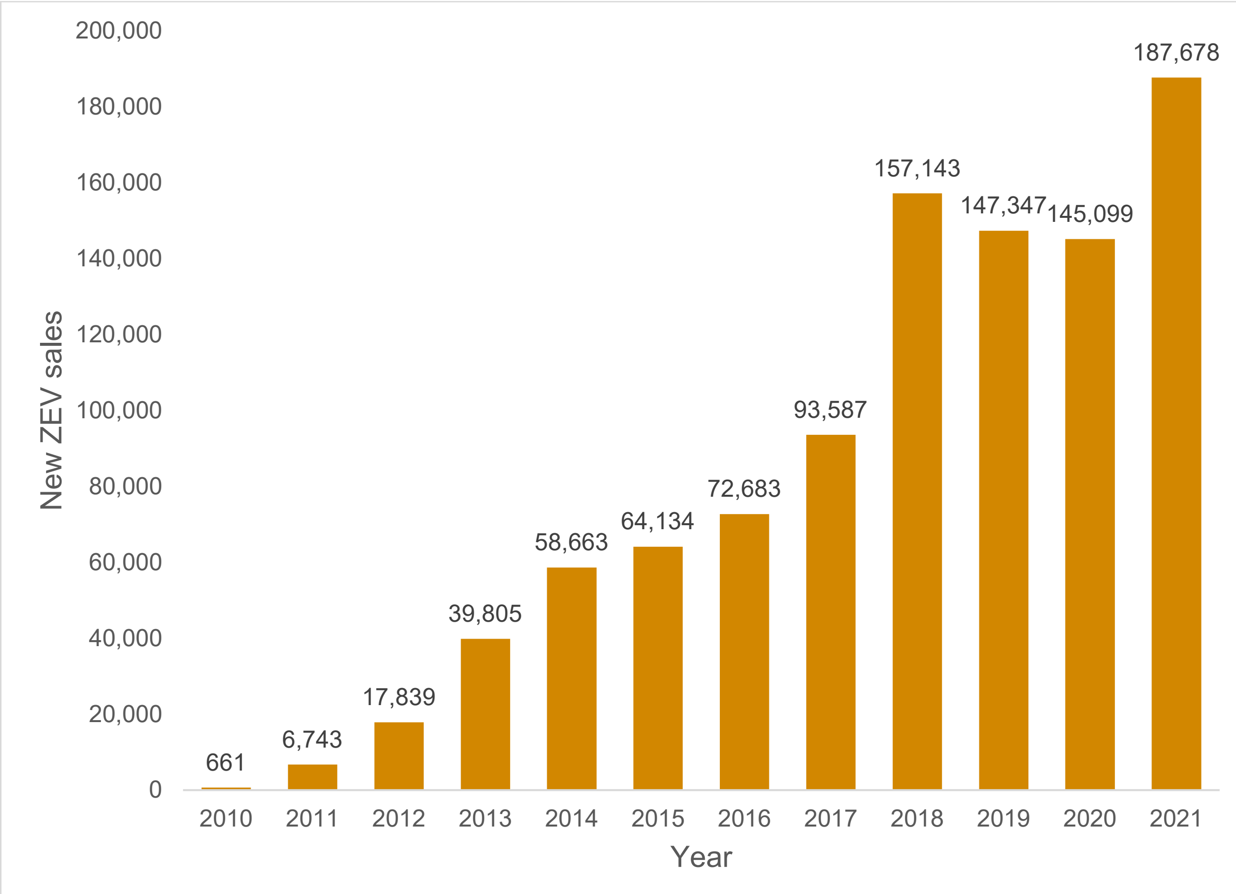
Building electrification. The near-complete electrification of space heating and cooling in buildings assumed in the HES would require a rapid transition to electric heat pumps. At present about 67 percent of all state households use natural gas for heating (EIA 2021a, EIA 2021b). Existing gas powered devices in almost all homes and buildings will need to be replaced in most cases with electrical heating, cooling, cooking, and other equipment.[5] The HES assumes that at least 50 percent of new sales of water heaters and HVAC equipment will be electric by 2030, and 100 percent of new sales will be electric by 2050. The HES reports from 2018-2019 note that these targets are quite aggressive, given the state of the market at that time, and identify several challenges to achieving them – including high capital costs, contractors' lack of experience sizing and installing heat pump systems, and customers' lack of experience. These reports identify "market transformation" as a key policy objective to avoid early retirement of functioning equipment, and provide an analysis of additional costs in the event that early retirements are needed. The HES also assumes rapid adoption of other energy-saving measures in buildings, such as LED lighting and more efficient refrigeration, and electrification of cooking and clothes drying.

Transportation. Electrification of transportation would require the complete phase out of internal combustion engines for both light duty vehicles and trucks and commercial vehicles. As of September 2021, the state had about 425,000 registered EVs compared with a total of 26 million cars and 6 million non-commercially registered (non-CRVA) trucks, meaning that EVs comprise about 1.4 percent of all vehicles (AFDC 2021, DMV 2019). The HES assumes that so-called zero emission vehicles (ZEVs), which include battery EVs (BEVs), plug-in hybrid EVs (PHEVs), and hydrogen fuel cell EVs (FCEVs), would comprise 6 million light-duty vehicles by 2030. By 2050, the HES assumes that 96 percent of light duty vehicles are EVs (35 million EVs total), including 19 BEVs, 11 million PHEVs, and 5 million FCEVs. Figure 1-1 shows trends in new ZEV sales in California since 2010, demonstrating that the number of new ZEVs has

[5] According to EIA (2021a) there are 11.1 million residential natural gas customers as of 2019, which is over 80 percent of all households in the state.

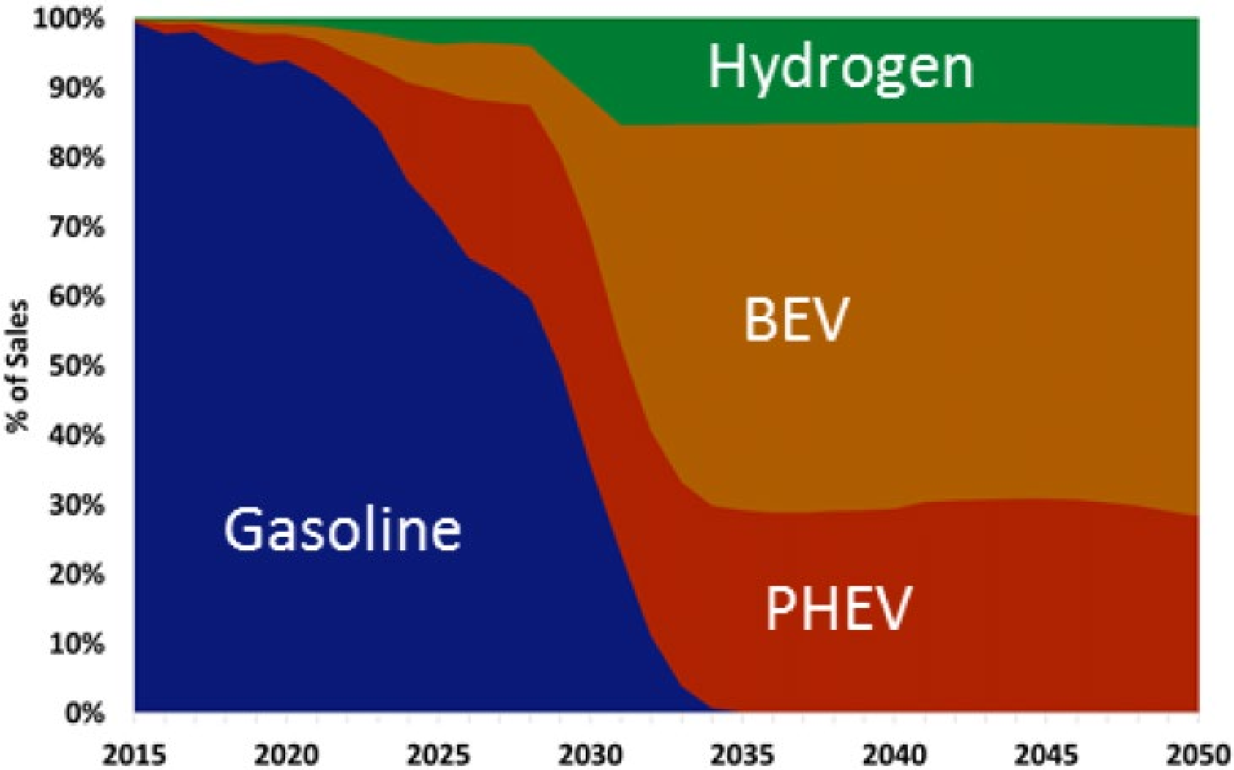
increased dramatically in recent years. However, Figure 1-2 shows that substantial additional progress is needed to reach the HES goal, given that ZEV sales must transition from over 90 percent in 2020 to zero percent by 2035, including a drop of approximately 30 percent of sales in the five years between 2030 and 2035.

Figure 1-1: New ZEV Sales in California, by Year



Source: CEC 2021c. Data for 2021 is through October 29, 2021. ZEV sales are updated on a quarterly basis by examining the DMV Vehicle Registration database for vehicles which show no evidence of transfer of ownership, and were purchased within the specified timeframe. To account for vehicles which may have been brought in from outside California, only those vehicles with a low odometer reading are treated as new sales.

Figure 1-2: Percent of New Sales of Light Duty Vehicles by Technology Type Under HES



Source: E3-Decarb (Figure 10).

The HES also assumes 47 percent of trucks are BEVs or FCEVs, and has aggressive goals for electrification of buses (88 percent), rail lines, ports, and harbor craft (Table 1-1). In addition, the HES assumes that by 2030, per-capita vehicle miles traveled (VMT) in light-duty vehicles declines by 12 percent relative to 2015, and by 2050, VMT declines by 24 percent relative to 2015.

Table 1-1: HES Measures Assumed in 2030 and 2050

Measure or Assumption	HES (2030)	HES (2050)
Building efficiency (% reduction in total building energy demand relative to 2015)	10%	34%
Transportation VMT (% reduction in per capita light duty VMT relative to 2015)	12%	24%
Industrial Efficiency (% reduction in total industrial energy demand relative to 2015 in non-petroleum industries)	22%	22%
Building electrification (% of new sales of water heaters and HVAC that are electric heat pumps)	50%	100%
LDV electrification (Millions of ZEVs)	6	35

LDV electrification (ZEV % of total stock)	20%	96%
LDV electrification (ZEV % of new sales)	64%	100%
Trucking electrification (% of trucks that are BEVs or FCEVs)	4%	47%
Trucking - alternative fuels (% of trucks that are hybrid & CNG)	6%	31%
Bus electrification (% of total)	32%	88%
Rail electrification (% of total)	20%	75%
Port electrification (% of total)	27%	80%
Industry electrification (% of non-petroleum industry end use fossil replaced with electricity)	0%	0%
Petroleum industry demand reduction	14%	86%
Advanced biofuels (% of fossil end-uses replaced with advanced biofuels)[1]	10%	46%
Advanced biofuels (Total exajoules)	0.34	0.56
Power-to-gas (% of non-electric-generation pipeline gas supplied by hydrogen and renewable synthetic methane)	0%	0%
Hydrogen fuel for vehicles (Total exajoules)	0.02	0.11
Reductions in methane (% reduction relative to 2015)	34%	42%
Reductions in F-gases (% reduction relative to 2015)	43%	83%
% zero-carbon electricity, including large hydro and nuclear[2]	74%	95%
Approximate % RPS	70%	103%
Total electricity demand (TWh)	295	456
Electric sector combustion emissions (MMT CO2e)	32	9

Source: E3-Decarb, Appendix A.
(1) Excludes hydrogen and synthetic methane used for fuel-cell vehicles and in the pipeline.
(2) In-state nuclear is assumed to retire by 2025. Imports of nuclear from Palo Verde continue until retirement in 2047.

The HES also assumes reduced GHG emissions from certain other contributing sectors. The following paragraphs document key assumptions of the HES with respect to other contributing sectors to GHG emissions in California.

Oil and gas extraction. The HES does not explicitly assume reduced activity for petroleum exploration, production, or extraction, or export of crude oil or natural gas,[6] but it does assume a substantial reduction in methane emissions from oil and gas extraction, processing, and transport in-state: a 45 percent reduction from the Reference scenario by 2030, and an 80

6. However, in July 2021, Governor Newsom directed the California Air Resources Board to evaluate how to achieve carbon neutrality by 2035, including an "analysis of how to reduce or eliminate demand for fossil fuel in California and end oil extraction in our state."

percent reduction from the Reference scenario by 2050. The costs for the HES include $4 billion per year (as of 2030) to control methane emissions from these oil and gas extraction, processing, and transport activities (E3-Decarb, p. 51).

Based on current technologies, the International Energy Agency (IEA 2021) estimates that it is only technically possible to avoid around three-quarters of today's methane emissions from oil and gas operations, on average, globally. Thus, the assumed 80 percent reduction by 2050 would require development of additional technology for methane capture. If this proves unachievable, a requirement to reduce methane by 80 percent would essentially force the cessation of oil and gas production in the state.

Oil and gas refining. The HES assumes a 14 percent decline in in-state refinery production by 2030, and 86 percent by 2050.[7] The documentation for the HES notes that "it is not known how California's refining sector will respond to a long-term, structural shift towards lower demand for gasoline and diesel in California from vehicle electrification. The sector could shift towards becoming a net-exporter of petroleum products, or it could reduce in-state production, as modeled. However, if GHG emissions from the refining sector do not decline significantly, it will make meeting the state's long-term climate goal very challenging" (E3-Decarb, p. 38).

Industrial electrification. The HES does not assume any industrial electrification. This is due to its relatively high cost, which arises from the inefficiency of substituting electricity for combustion to make heat. E3-Decarb notes that heat pumps offer efficiency advantages for room-temperature heating applications in buildings, due to their dual function in providing cooling and heating services. However, heat pumps do not offer the same advantage for high-temperature industrial heating processes (E3-Decarb, p. 37). Rather, industrial electrification is contemplated as a "reach technology" that could serve as a backstop mitigation option in the event that less expensive mitigation options are not available (E3-Decarb, p. 37).

Behavioral changes. Documentation of the HES notes that business and household decisions will play a pivotal role in the ability of the state to achieve its low-carbon objectives. These include higher purchases of EVs and electric equipment for cooking, water heating, and HVAC, but also some behavioral changes regarding the use of this equipment. Two areas are particularly notable: an assumed reduction in VMT, and flexible timing for EV charging and other loads. With regard to VMT reductions, the HES assumes the aggressive deployment of smart growth strategies – including more multi-family homes and more mixed-use community design, resulting in increased use of public transit, walking, and bicycling. Quantitatively, this leads to the assumption in the HES that by 2030, per-capita VMT in light-duty vehicles will decline by 12 percent relative to 2015, and by 2050, VMT will decline by 24 percent relative to 2015.

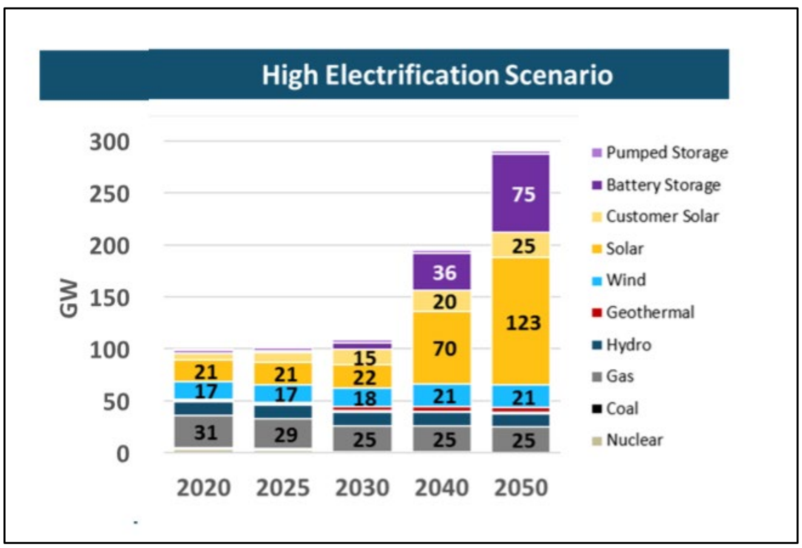
The HES also assumes a substantial portion of loads for both EV charging and building end uses are "flexible," meaning that they could occur at a point in the 24-hour cycle when generation is relatively high or other demand is relatively low. Specifically, the HES assumes that by 2030, 20 percent of building end uses and 50 percent of light duty vehicle (LDV) EV charging is flexible and by 2050, 80 percent of building end uses and 90 percent of LDV EV charging is flexible (E3-Decarb, Tables 4 and 5). Given that much of the future electrical

7. E3-Decarb, Table A-1 and A-2, states that the HES assumes a 14% petroleum industry demand reduction by 2030 and 86% by 2050. E3-Decarb, p. 38, states that the HES assumes a 14% decline in in-state refinery production by 2030, but does not provide a comparable figure for 2050, nor is this figure stated anywhere in this report or any other source we identified. ERM assumed that the assumed decline in petroleum industry demand in the HES maps one-for-one onto an assumed decline in in-state refinery production in 2050, as it evidently does in 2030.

generation assets will be solar, this implies that most of this 'flexible' load will amount to daytime loads; importantly, this means that the HES assumes a large proportion of EV owners (at least among those who do not work from home) have access to workplace charging. The HES documentation notes that flexible loads provide significant value to the grid in terms of being able to avoid short-duration storage that would otherwise need to be procured to integrate solar production with electricity demand. However, the documentation also notes that while many flexible loads can move electricity demand within the day, they cannot move it across days or weeks. Accordingly, it appears that the HES does not assume that flexible loads can be moved across days or weeks (E3-Calpine, p. 55-56).

If EV charging and building end uses cannot be moved flexibly as assumed in the HES, this would result in higher costs due to the need for more short-duration energy storage. However, it seems reasonable to expect that these loads could be positioned flexibly over the course of the day. For instance, loads from commercial building end uses are typically greatest during daytime working hours. The assumptions regarding VMT reductions and cost of EV chargers (both residential and in the workplace) are analyzed in further detail in Section 2.

Physical Scale and Pace of HES Development. E3-CP's 2019 study estimated total installed capacity in 2020 of 21.2 gigawatts (GW) of industrial solar and 16.7 GW of wind and estimated total future installed capacity by 2050 as 123 GW and 21.4 GW (E3-CP Figure 10 and Table 31). An excerpt from Figure 10 of the E3-CP report is provided below.

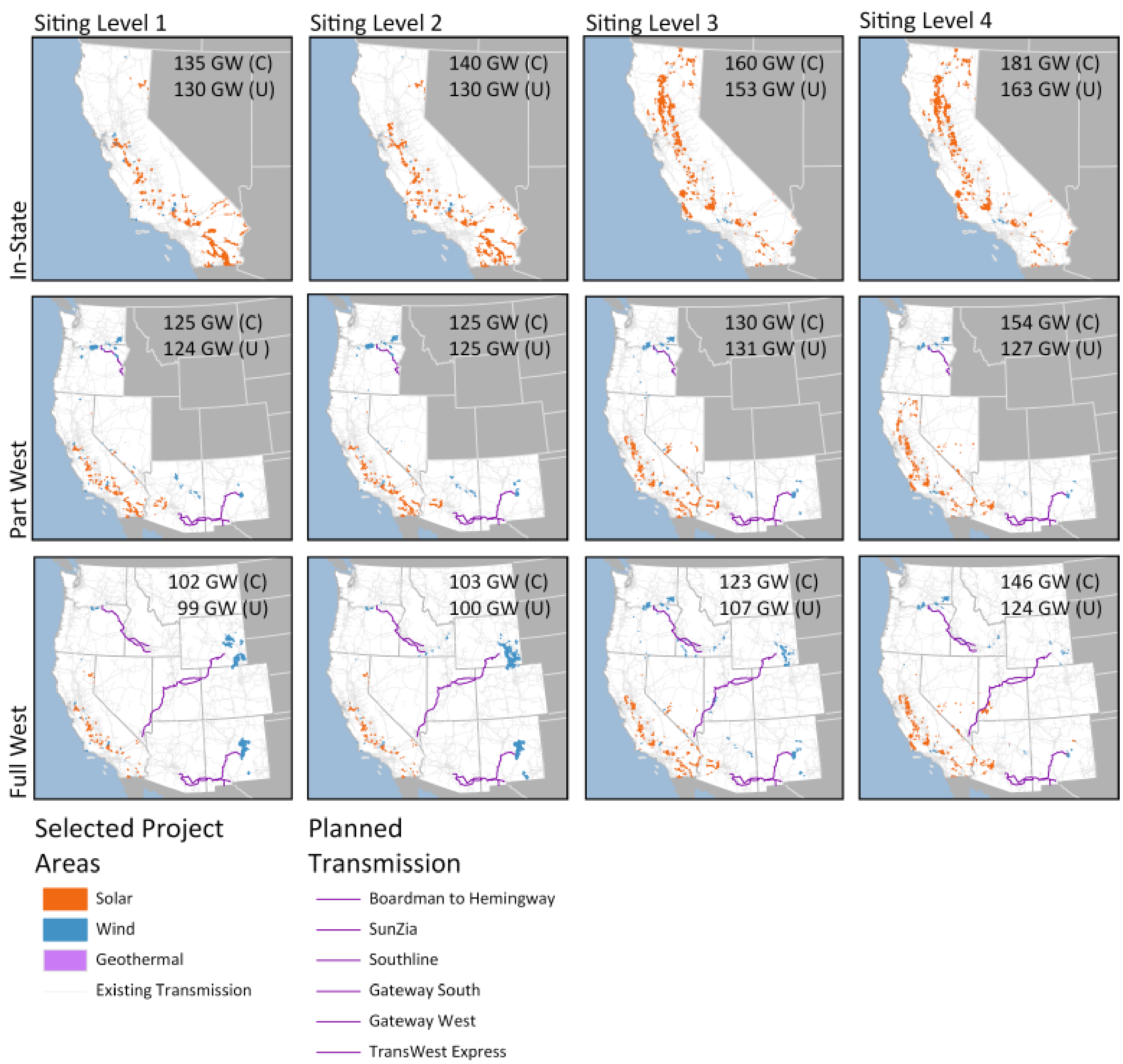


Source: E3-CP, excerpt from Figure 10 Total Resource Portfolio Results.

By comparison, CEC lists California's 2020 existing operational solar photovoltaic (PV) and solar thermal electricity production capacity, including imports, as 15.63 GW, and wind energy production capacity as 5.98 GW, excluding imports (CEC 2021b). Using E3-CP's capacity estimates, the projected net increase in capacity for industrial solar and wind is 101.5 GW and 4.7 GW, respectively, or a 480 percent increase in industrial solar capacity (nearly a 5-fold increase over current capacity), and a 30 percent increase in wind capacity. This multiple increases to 650 percent when using the CEC's 2020 baseline of installed solar capacity.

E3-TNC provides estimates of the potential scale and location of solar, wind, and geothermal generation as well as generation-tie lines (gen-tie) and long-haul bulk transmission in California and other states required to implement the HES by 2050. E3-TNC creates three different geographic scenarios, In-State, Part West, and Full West. The In-State scenario assumes all resources required to achieve the HES are generated within California, the Part West scenario allows for limited out-of-state generation imports from five states, while the Full West scenario allows for robust wind imports from eight other western states. E3-TNC also considers two different resource assumption scenarios, constrained and unconstrained. The **constrained** cases restrict renewable resource development potential to within RESOLVE zones and apply the RESOLVE Base as the maximum limit in each zone. The **unconstrained** cases expand renewable resource development potential to the rest of the state and do not impose maximum limits, except for New Mexico Wind in the Part West scenario.

E3-TNC then uses screening factors to reach an estimate of developable land in each scenario, using a series of four successively more stringent environmental exclusions, or "**siting level**" (SL) cases. SL1 generally excludes legally protected lands, such as national parks. SL2 excludes all of the SL1 land, plus Native American, federal or state and other lands that require permits for development. SL3 excludes SL1-SL2 lands, plus prime agriculture, "important avian habitat" and similarly high biological resource lands. SL4 excludes all of the SL1-SL3 land, plus lands that TNC believes have high connectivity or natural "intactness." E3-TNC Figure 11, presented below, demonstrates the varying solar, wind, and geothermal development that would occur in various scenarios, given specific siting levels and geographic constraints.



Source: E3-TNC 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).

E3-TNC's Full West SL4 Constrained scenario, which is discussed in detail in this report, would result in land area of 3,821 km^2 (943,787 acres) for solar and 1,517 km^2 (374,700 acres) for wind. Of this amount, approximately 2,723 km^2 (672,581 acres) of solar and 80 km^2 (19,760 acres) would be constructed in California, and the remaining land areas would be dispersed in other western states.

Other scenarios result in potentially higher or lower land areas. For example, in the Full West and In-State cases, and depending on the siting level, land areas for solar range from 1,545 to 4,844 km^2 (381,615 to 1,196,468 acres), respectively, and 82 to 8,170 km^2 (20,254 to 2,017,990 acres) for wind in In-State and Part West scenarios, respectively (E3-TNC Table 15).

Applying E3-TNC's land use benchmarks of 120 MW of solar generation per 4 km^2 , and 55 MW for wind generation per 9 km^2, E3-CP's 2050 net deployment estimates of 101.5 GW solar and

4.7 GW of wind would require 3,383 km^2 (835,683 acres) and 769 km^2 (189,965 acres) for solar and wind development, respectively. However, these assumptions regarding HES development may underestimate or exclude certain components such as additional major new bulk lines, local electrical grid upgrades, local EV chargers, and new waste disposal facilities.

For perspective, a land area of 2,723 km^2 (672,581 acres), which represents the area of new solar development in California under the Full West SL4 constrained scenario, is roughly equivalent to much of the metropolitan Los Angeles region, from the City of Burbank to Los Angeles Harbor (see Figure 4-1 for a pictoral depiction of this area). For additional perspective, there are approximately 21,000 km^2 (8,200 square miles, 5,187,000 acres) of urbanized land in California as listed in the 2010 U.S. Census (Census Bureau 2010), or roughly three times the City of Los Angeles. Thus, under the HES, a very substantial amount of land would have to be developed with solar resources, at levels far higher than achieved in the state to date.

The high variability in land required to implement the HES reflects the uncertainties around the ultimate mix (solar, wind, distributed generation, etc.) and source location of new renewable energy generation; the contribution from battery storage and distributed energy; the contribution from "stretch" technologies that are not yet commercially available at scale (e.g., west coast offshore wind); and numerous demand factors. The combined magnitude and range of land cover estimates highlights the variability of the underlying model inputs, and thus the uncertainty regarding the practical ability to achieve the level of physical buildout required under any HES scenario.

Cost Implications of Different Buildout Scenarios. E3-TNC's multiple HES buildout scenarios have different implications for development costs. For example:

- System costs may be reduced with wider geographic deployment because wind and solar availability is diversified.
- RESOLVE constrained deployments generally cost more than deployments over a larger area in and out of state.
- In all cases modeled by E3-TNC, the model relies heavily on utility-scale solar photovoltaic (PV) resources to achieve the HES objectives, reflecting the substantial declines in the price of solar panels in the last decade.

Siting Levels are 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 $116 billion in the RESOLVE Base case to $133 billion under Siting Level 4, an increase of $17 billion or 14.7 percent (Table 1-2 below, adapted from E3-TNC p.29). Siting Levels 1 and 2 have modest incremental annual costs impacts ($1.3 billion and $2.5 billion, or 1.3 percent and 2.5 percent, respectively), while the incremental impacts of the SL 3 and 4 are more significant ($9.8 billion and $17 billion, or 8.4 percent and 14.7 percent, respectively). This pattern holds across Part West and Full West cases, with the exception of the Part West SL3, where the marginal impact of achieving SL 3 is about 3 percent (E3-TNC Figs. 5B and 7A).

Table 1-2: Cost of HES Siting Level Protections for the TNC Constrained In-State Case

	RESOLVE Base Case	Siting Level 1	Siting Level 2	Siting Level 3	Siting Level 4
Cost of Siting Level Protection (2019 billion $)	$116.1	$117.6	$119.0	$125.9	$133.1
Percent Increase from Base Case		1.3%	2.5%	8.4%	14.7%
Source: E3-TNC p.29, adjusted from year 2016 to year 2019 dollars using the CPI.					

The amount of available and selected wind capacity decreases with higher levels of environmental protection (higher SLs), which also results in a greater need for battery storage. Applying higher protections also results in higher costs and higher revenue requirements. Specifically, the highest siting level projections, SL4, would add an additional $17 billion (in 2019 dollars) to the annual revenue requirement in 2050 (E3-TNC, pp. 28-29).

HES Assessment Report Organization. The remainder of this report analyzes the impacts of the HES scenario on environmental, economic, and equity levels and discusses whether important information and assumptions are missing from the HES as previously analyzed. This report is intended to provide a framework for further discussion and research on questions such as:

- Are the estimated energy costs complete?
- What are the potential economic and equity consequences of the displacement of natural gas customers, particularly to low-income and minority households, middle-income production employees, and similar vulnerable groups?
- What are the practical hurdles to achieve the amount of land development required for new renewable generation and transmission?
- What are the potential adverse cumulative effects on land use, community integrity, and natural and cultural resources resulting from the physical buildout required to achieve the HES objectives?

The remainder of this assessment report is organized as follows:

- Chapter 2 provides an energy cost analysis associated with implementing the HES.
- Chapter 3 provides an equity analysis of the potential disruptive consequences of the HES on the California economy as well as the unequal impacts to disadvantaged communities.
- Chapter 4 provides an overview of land use development constraints and the estimated potential environmental consequences related to utility-scale renewable energy development associated with physical buildout of the HES.
- Chapter 5 addresses waste characteristics and waste volumes associated with future end-of-life disposal of renewable energy infrastructure.
- Chapter 6 provides references.

2. ENERGY COST ANALYSIS

CEC uses the RESOLVE model to evaluate least-cost capacity expansion options to meet California electricity and generation dispatch demand. CEC acknowledges that RESOLVE is a planning level model that omits certain cost elements, such as a thorough analysis of reliability and resource adequacy, potential costs from early retirement of functional end-use heating equipment, and market and non-market costs associated with land use conversion and land acquisition. However, there are several other omitted categories, or ways in which the projected resource build costs are likely to be underestimated, which are not mentioned by CEC. This section characterizes these additional elements and, where possible, provides quantitative estimates of their magnitude. In many cases these elements are little studied, so quantification is difficult, but this report attempts to provide representative cost ranges for each element based on related studies.

The analysis that follows relies primarily on four types of sources. First, ERM used published reports from CEC, E3 and CPUC, including E3-Decarb, E3-Calpine, E3-TNC, and E3-GasFut. Second, ERM used a 2019 version of E3's RESOLVE model, which provides the ability to dig more deeply into the estimates provided in published reports that include high-level outputs of RESOLVE.[8]

Third, ERM used administrative data from the US Census Bureau, US Energy Information Administration, and similar sources, which provide additional analytical elements that help to contextualize and support analysis of the E3/CEC outputs. Finally, a variety of academic studies and grey literature from recognized organizations provide additional context and analysis to help demonstrate the viability of certain assumptions in the CEC analyses, as well as insight on realistic costs for certain elements that are excluded or under-emphasized in the CEC reports.

Another CEC model that provides inputs into RESOLVE – called the PATHWAYS model – evaluates scenarios of GHG reduction measures to meet the long-term energy demand of the state of California through 2045. Assumptions about electric technology adoption curves and energy efficiency drive both the level and timing of projected system-wide electric demand. Assumptions about capacity expansion options and least-cost dispatch drive projected system-wide revenue requirements and costs. CEC uses emissions constraints from PATHWAYS and load projections from the Integrated Energy Policy Report (IEPR) and other sources (CEC, 2021b) as inputs into RESOLVE.

8. ERM was not able to obtain a version of the RESOLVE model that precisely matches the model used to produce the analysis of the HES in either E3-2019 or E3-TNC. These reports are dated June 2019 and E3-2019 states that the version of RESOLVE used for the report was the version released in September 2017, but further modified. E3-TNC states it used the version of RESOLVE utilized for the 2017-2018 IRP, also further modified. ERM searched available documentation including the CPUC website of proceedings and the historical IRP records, and was able to obtain a version of RESOLVE dated October 1, 2019 but not any earlier version. There are a few differences evident between the HES output of this model version and the output documented in E3-2019. Where these differences affect the analysis, they are noted in the text, along with documentation of how ERM approached the analysis to accommodate the differences.

2.1 Resource Requirements in the HES

According to E3-Decarb (Table 31), the CEC proposes to service the load envisioned under the HES by building massive new utility-scale solar and customer (behind-the-meter) solar, as well as battery storage resources. The HES would also involve building some new onshore wind resources, and would involve the retirement of some gas peaker plants. The HES does not assume any new construction of customer-side battery (storage) installation.

Table 2-1 shows the total installed capacity by technology under the HES, according to E3-Decarb (Table 31). This includes some currently available resources that RESOLVE assumes would remain online in future years, as well as some new buildout, and also incorporates some planned or assumed retirements of existing capacity.

Table 2-1: Total Resources under HES (MW of capacity)

Technology Type	2027	2030	2035	2040	2045
Nuclear	3,379	2,229	1,079	1,079	0
Combined heat and power (CHP)	72	27	27	0	0
Coal	1,800	1,800	0	0	0
Gas, combined-cycle (CCGT)	20,742	20,742	20,195	20,195	20,195
Gas peaker	10,084	8,192	4,830	4,830	4,830
Large hydro	12,610	12,610	12,610	12,610	12,610
Small hydro	595	595	595	595	595
Biomass	787	787	787	787	787
Geothermal	1,586	1,586	4,196	4,516	4,516
Wind	16,748	16,748	17,724	21,438	21,438
Wind offshore	0	0	0	0	0
Solar	21,152	21,741	22,376	70,051	122,657
Customer solar	5,821	9,596	15,335	20,002	24,742
Battery storage	478	1,530	5,916	36,131	74,889
Pumped storage	3,049	3,049	3,049	3,049	3,049
Demand response	1,752	1,752	1,752	1,752	1,752
Flexible load	0	0	618	3,427	3,427
Hydrogen electrolysis	79	102	138	264	349
Total	100,734	103,086	111,227	200,726	295,836
Variable Renewable Energy (VRE)	43,721	48,085	55,435	111,491	168,837
VRE % of total resources (excluding flexible load and demand response)	44%	47%	51%	57%	58%

Source: E3-Calpine Table 31, and authors' calculations. Variable renewable energy (VRE) is calculated as the sum of wind and solar.

According to E3-Calpine, the HES would entail about 12.2 percent curtailment of utility-scale wind and solar resources. This rate of curtailment may impact project economics, depending on how individual solar and wind generators are compensated for power produced but curtailed.

Several studies suggest that falling technology costs imply it is cheaper to overbuild solar and wind, and curtail excess output rather than investing in relatively costly battery storage (e.g. Denholm et al. 2021, Perez and Rabago 2019). However, to the extent that assumptions regarding straightforward environmental permitting (see Section 4) or other elements that affect costs (Section 2.3) are overly optimistic, the costs to overbuild and then curtail wind and solar resources will be understated. For instance, if solar and wind resources prove more challenging to build for economic or logistical reasons, planners may find they need to install more-costly storage technologies, beyond those that are currently anticipated under the HES.

2.2 Reliability and Resource Adequacy

Throughout all documentation of the HES, the CEC acknowledges the need for natural gas generation to help ensure resource adequacy and reliability during periods of low renewables generation. For instance, both E3-Decarb and E3-Calpine state repeatedly that achieving 100% zero-carbon generation appears to be cost prohibitive without major advances in low-cost energy storage, including long-duration energy storage.

Accordingly, in the HES, 25 GW of natural gas generation capacity is retained for reliability throughout the planning horizon (Table 2-1). According to E3-Calpine, this is the quantity of gas capacity that minimizes the total cost of electric service while reducing carbon emissions to 10 million metric tons. E3-Calpine (p. 41) states that forcing additional gas generation to retire and replacing the capacity it provides with renewables and storage would be extremely costly, given that gas generation capacity can be dispatched when most needed by the grid.[9]

As documented in E3-Calpine, E3 considered scenarios involving 10 GW or 0 GW of gas generation capacity and concluded that these scenarios would require significantly longer-duration storage technologies and substantially higher revenue requirements: an additional $28 billion and $65 billion, respectively (year 2016 dollars). E3 also concluded that the 0 GW gas case would require a 230 percent increase in solar capacity and 50 percent annual curtailment of renewable energy production. E3 does note that, while potential future breakthroughs in long-duration energy storage technology could result in optimal portfolios that entail less renewable overbuild, current technology for long-duration storage is impractically expensive.

The HES also assumes that 10 GW of imported power is available, at all times of the year, for resource adequacy purposes. E3-Calpine (Section 4.1) states that "this assumption is generally consistent with assumptions used in the CPUC's Integrated Resource Planning proceeding, as well as other assessments of the state's ability to import power during peak periods." These "other assessments" appear to allude to the notion that power demand peaks in winter in the northwestern US but in the summer in California, which means that the northwestern US would be able to provide capacity to California in summer. However, there is some uncertainty about the availability of imports in the future, especially as loads grow, coal generation retires, and regional loads may become more temporally coincident (E3-Calpine, p. 33).

9. As E3-Calpine states (p. 41), "Replacing natural gas generation capacity with additional intermittent renewables and storage requires one or both of the following approaches: (1) oversizing the renewable generation so that it can serve load even when solar and wind production are low; (2) significantly increasing the duration of energy storage so that it can ride through periods of low renewable generation without completely discharging. Oversizing renewables generally entails significant renewable curtailment under normal conditions. Significantly increasing storage duration is prohibitively expensive given current technology."

Accordingly, E3-Calpine conducted a sensitivity analysis under a scenario in which no out-of-state imports would be available for resource adequacy purposes, thus requiring all resource adequacy needs to be met with resources within the state. This analysis found that to the extent that import availability is lower than the assumed 10 GW, the optimal quantity of natural gas generation capacity would increase approximately 1-for-1: that is, to a total of 35,264 MW of gas generation capacity, rather than the 25,025 indicated in Table 2-1. The cost for operation and maintenance of this gas generation capacity would amount to a $1 billion increase in annual revenue requirement (year 2016 dollars; E3-Calpine, Table 10).

2.2.1 Probabilistic Simulation Model for Resource Adequacy

It is worth noting that RESOLVE, as a long-run capacity expansion model, uses somewhat simplified assumptions to assess reliability of a selected resource portfolio. However, the HES as developed and documented in E3-Calpine applies a loss-of-load probability model developed by E3 – the Renewable Energy Capacity Planning (RECAP) model – to test for resource adequacy. RECAP calculates the probability of loss-of-load events (LOLE) by simulating the electricity system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and randomly assigned forced outages of electric generation resources and imports. RECAP simulates the system thousands of times under different conditions, with probabilistic assignment of these underlying conditions or 'states of nature,' to develop a distribution of system performance parameters, including LOLE.

The HES documented in E3-Calpine (which is also the basis for the HES that is documented in E3-TNC) is adjusted for resource adequacy by running RECAP to assess the reliability of resource portfolios produced by RESOLVE, and improve them by adding resources when the reliability is insufficient (i.e., where LOLE exceeds 2.4 hours per year).[10] E3-Calpine (Table 8) reports that according to RECAP, the loss-of-load expectation in 2050 under the HES would be 1.05 hours per year, which is less than the incidence of LOLE in 2018 (1.15 hours per year).

Notably, a subsequent version of HES – one that is documented in the March 2021 Joint Agency Report (CEC 2021a) – was not adjusted for resource adequacy using RECAP or any other form of probabilistic modeling. Indeed, the documentation for the March 2021 iteration of the HES notes repeatedly that more extensive analysis is needed to fully assess resource adequacy and reliability.[11]

2.2.2 Additional Benchmark Data

To provide an additional perspective on resource adequacy and reliability in the HES, it is worth considering the large number of academic studies have raised concerns about the reliability of electrical grids with a large share of VRE. In a recent review article, Jenkins et al. (2018) reviewed 40 studies published from 2014 to 2018 of "deep decarbonization" pathways in the power sector, defined as a reduction of 80 to 100 percent in CO2 emissions from current levels. As they note, "despite differing methods, scopes, and research questions, several consistent

---

10. E3-Calpine notes that there is no single uniform standard for sufficiency with respect to resource adequacy, either promulgated by the North American Electric Reliability Coordinating Council (NERC) or the state of California. A commonly referenced standard is "1 day in 10 years," but even this can be interpreted in different ways (e.g., 24 hours over 10 years, 2.4 hours per year, or 1 event in 10 years).

11. Instead, the HES that is documented in CEC (2021a) assumes a 15 percent planning reserve margin over peak loads, which is a common proxy for LOLE-based reliability standards, and is also consistent with the resource adequacy program that the CPUC requires for load-serving entities.

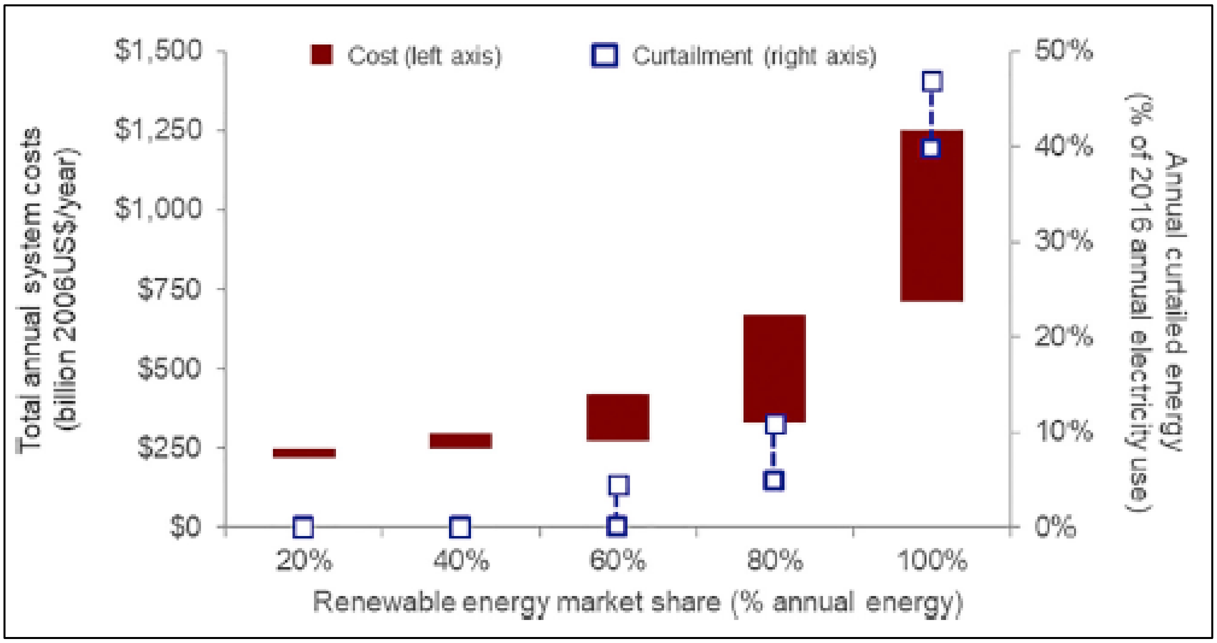
insights emerge from this literature." One of the key insights is that there is "strong agreement in the literature that reaching near-zero emissions is much more challenging – and requires a different set of low-carbon resources – than comparatively modest emissions reductions" (on the order of 50 to 70 percent), because lower reductions "can readily employ natural gas-fired power plants as firm resources". This finding is consistent with the retention of natural gas in the HES.

Of particular note for California's efforts, the fact that wind and solar generation varies substantially not just on a daily cycle but also over weekly, monthly, and seasonal periods implies that scenarios that are highly reliant on VRE must also take care to temporally balance loads with variable supply. Jenkins et al. (2018) suggest part of this temporal balancing would require technological improvements such as "smart" controls that allow EV owners to modulate charging rates (or potentially return power to the grid). Although Jenkins et al. (2018) do not specifically address utility planning or modeling frameworks that could be used to plan for resource adequacy, ERM's conclusion is that the "2019 HES" as elaborated in E3-Calpine and E3-TNC, including with the extensive simulations of LOLE modeled in RECAP and resulting adjustments made to the resource portfolio selected for the HES, is sufficient to address concerns about resource adequacy.

Jenkins et al. (2018) also take note of the fact that "inefficient utilization requires very-low-cost wind and solar to make overcapacity economical". That is, overbuilding VRE capacity to meet peak demand and then curtailing the VRE supply during periods of lower-than-peak demand, while maybe less expensive than battery or pumped hydro storage, relies on inexpensive land, inexpensive generation resources, and readily available transmission corridors. If wind and solar do not remain at extremely low costs, the overbuilding of VRE capacity necessary to make a high VRE system reliable may no longer be cost-effective.

Like other researchers, Jenkins et al. (2018) demonstrate that the variability of solar and wind generation over hours, weeks, months, and seasons implies exponential increases in the total cost of grid systems as the share of renewable energy increases. This point is also described in two other recent studies, one by Brown et al. (2018) and one by Denholm et al. (2021), both of which provide a detailed discussion of the challenges of achieving a 100 percent renewable energy system. All three of these studies agree, however, that levels of renewable energy penetration up to about 70 to 80 percent do not require the extraordinarily costly measures that would be necessary to guarantee reliability and resource adequacy in a system approaching 100 percent renewable energy. For instance, Jenkins et al. (2018) report that a (hypothetical) continental US electric grid with 80 percent of annual energy coming from renewable sources would experience on the order of 10 percent curtailment of renewable energy, which is broadly consistent with the output of RESOLVE. Jenkins et al. (2018) find that only at levels of VRE over 80 percent and approaching 100 percent does wind and solar curtailment jump to the much more substantial level of 40 to 50 percent (Figure 2-1).

Figure 2-1: Nonlinear Increases in Cost and Curtailed Wind and Solar as Renewable Energy Share Increases



Source: Jenkins et al. (2018), Figure 2.

It is instructive – though also potentially misleading – to compare these study results to the assumptions of the HES. As indicated in Table 2-1, under the HES in 2050, VRE would represent 58 percent of total generation capacity, and RE (including pumped hydro and battery energy storage) would represents 95 percent of capacity. The former is well within the "reasonable curtailment and cost" range of Jenkins et al. (2018), but the latter is not. However, the comparison is potentially misleading, for two reasons. First, there is no one threshold that either Jenkins et al. (2018) or other papers agree is "too much" VRE or RE on a system (i.e., without incurring extraordinary costs). This arises in part because of complexities within individual systems, such as the extent of daily, monthly, and seasonal variation in VRE generation patterns and in demand patterns, and to what extent these supply and demand variations align. Given these complexities and system-level variations, different systems have different abilities to accommodate different levels of penetration of RE or VRE without incurring extraordinary costs, so there is no "one-size-fits-all" prescription.

This gives rise to the second reason that the comparison is misleading. The gold standard of predicting whether a given resource portfolio provides sufficient resource adequacy to ensure reliability is probabilistic simulation modeling that incorporates system-specific data, such as the temporal patterns of generation associated with specific (existing or future) generation assets, and the temporal patterns of demand. The nature of the analysis in Jenkins et al. (2018), and similar studies with higher-level indicative conclusions about a range of systems, precludes this kind of probabilistic simulation modeling.

In this sense, comparing the HES assumptions to the papers discussed here provides something of a benchmark, but the probabilistic simulation modeling of loss-of-load events performed by the RECAP model – which informs the resource portfolio selected in the HES – provides a more precise and accurate analysis. This analysis also has the advantage of being based in data specific to California, both in terms of demand and supply. That is, the analysis of the HES using the RECAP probabilistic simulation model – showing, as it does, that the level of reliability in 2050 under the HES is within the acceptable range for NERC – and the projected incidence of LOLE is *lower* than that in 2018 – is more convincing than the models reviewed by Jenkins et al. (2018). Of course, as noted above, the HES assumes the retention of 25 GW of natural gas generation capacity to increase system reliability throughout the planning horizon.

2.3 Costs Excluded from HES Documentation

As noted in the introduction, CEC acknowledges certain cost elements that RESOLVE omits; however, there are several other omitted categories that are not mentioned by CEC. This section characterizes these additional elements and their potential implications for revenue requirement and electric rates. To provide an overview, Table 2-2 summarizes the categories reviewed in this section. The focus throughout is on the annual revenue requirement as of 2050, and implications for electric rates (i.e., cost per kWh) in 2050.

Table 2-2: Adjustments to Revenue Requirements and Implications for Rates

Item	2050 Revenue Requirement (billions of 2019 $, annual)	Implied Cost per kWh, cents (2019 $)[1]
2019 HES from E3-Calpine (Figure 22)[2]	$116.1	22.7
Resource costs in addition to revenue requirement	$20.3	4.0
Optimism bias adjustment, 2x	$35.2	6.9
Optimism bias adjustment, 3x	$70.3	13.7
Project permitting and mitigations	$1.1	0.2
Land acquisition	$0.32	0.1
Decommissioning expenses	$0.7	0.1
EV chargers and supply equipment	$2.0	0.4
Transmission and distribution system upgrades	$8.5	1.7
Frequency regulation	$0.006	0.001
SL4 environmental siting protections	$17.0	3.3
Wildfire adaptation	$20.4	4.0
Total resource cost (with 2x OBA)	$221.6	43.3
Total resource cost (with 3x OBA)	$256.7	50.1

(1) Based on total consumption of 512,120 GWh/year in 2050 (E3-Calpine, Table 32).
(2) Updated from 2016 to 2019 dollars using CPI (i.e., multiplying by 1.065).

The first row in Table 2-2 is simply the stated revenue requirement from E3-Calpine, converted from 2016 to 2019 dollars using the CPI. The subsections that follow provide additional information and demonstrate the analysis used to produce the quantitative estimate for each subsequent row in the table.

2.3.1 Resource Costs in Addition to Revenue Requirement

The revenue requirement does not capture all of the cost to provide power. E3-Calpine estimates a revenue requirement of $109 billion in 2050 (2016 dollars). This source also states that the load in 2050 amounts to 512,120 GWh annually (E3-Calpine, Table 32), and the retail rate would be 25 cents per kWh (2016 dollars; E3-Calpine, Figure 23). This implies an additional annual cost of $19 billion (2016 dollars), as of 2050. (This is equivalent to $20.3 billion in year 2019 dollars.) The genesis of this additional cost is not explained in E3-Calpine. However, the RESOLVE model provides a clue, by including a line item for "Scenario-Specific Customer Cost" that is added to the revenue requirement to produce a total resource cost (which is then used to calculate the retail rate, in cents per kWh).

This "Scenario-Specific Customer Cost" is not defined or mentioned in written documentation ERM has been able to locate, either in E3/CEC/CPUC reports or otherwise. For the purposes of these calculations, ERM assumed that the HES includes a $20.3 billion additional annual cost (as of 2050; 2019 dollars) that must also be paid by retail ratepayers. It is possible that this cost encompasses some of the components that are itemized separately here (e.g., incremental capital costs for equipment to be purchased by end users), but without further documentation from E3/CEC it is not possible to know.

2.3.2 Optimism Bias

Optimism bias is a well-documented cognitive bias that leads people to believe that they are less likely to experience a negative event and more likely to experience a positive event. This is also a well-documented phenomenon in public works in California and other locations. To cite just one example from extensive academic literature, Oxford University management expert Bent Flyvbjerg (2011) documents numerous examples of such cost overruns in major projects, and notes that "In recent surveys of major projects, nine out of 10 had cost overruns, cost overruns of 50 to 100 percent were common, and overruns above 100 percent were not uncommon."

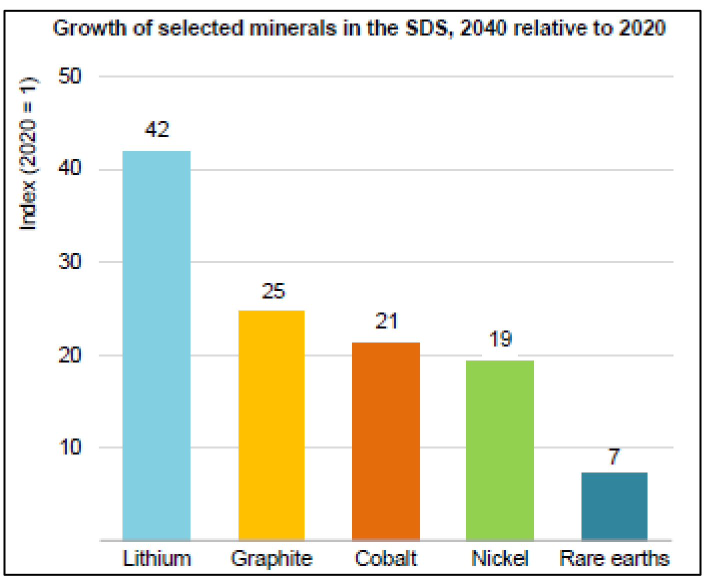
California has its share of projects in which planners provide overly optimistic timelines and projected expenditures for public projects. The Bay Bridge is a notable example. In 1996, the California Department of Transportation announced the state would spend just over $1 billion over seven years to replace the Bay Bridge, but the bridge ultimately opened in 2013 (10 years later than expected) at a total cost of $6.4 billion. Retrospective analysis indicates the cost increase and delay was driven by a complex set of factors: local mayors who pressed for a more aesthetically pleasing structure, planners who were concerned about conflicts with other plans in place and the need to coordinate efforts, local opposition in some areas, increased insurance costs driven partly by unforeseen events (including the September 11, 2001, terrorist attacks), national increases in construction and materials costs, and overly optimistic assumptions about design and construction aspects (Angell 2013). Other high-profile ambitious projects that have suffered schedule extensions and cost overruns include the California Water Fix and Eco Restore project (formerly known as the Bay Delta Conservation Plan) and the California High-Speed Rail project.

Although there are some critical differences between the Bay Bridge example and the HES – most notably, the HES involves numerous relatively small projects with initial capital provided by a multiplicity of private and public actors, whereas the Bay Bridge was one large project with a smaller number of mainly public funders – there are critical similarities as well, including the overall complexity of the project, a long planning horizon, and a multiplicity of actors involved.

Characteristics of the HES fit very well into the definition of "major projects" that are likely to suffer from optimism bias according to Flyvbjerg (2011)'s systematic study. Among other things, the HES is inherently risky due to a long planning horizon and complex interfaces; decision-making, planning and management are multi-actor processes with conflicting interests; there may be overcommitment to a certain project concept at an early stage; and complexity and unplanned events are largely unaccounted for.

Another element that makes the HES inherently risky is that many other jurisdictions in the US and overseas are likely to be attempting deep decarbonization efforts in the same timeframe as California. Global simultaneous investments in similar technologies could also result in higher costs for materials and labor, as numerous parties around the world attempt to develop very similar projects on a scale previously unseen. This is especially true to the extent that essential components such as lithium-ion batteries and inverters for solar panels and wind turbines are critically dependent upon a steady and growing supply of rare-earth minerals, the production of which is concentrated in China and other countries with a high degree of geopolitical power and whose relations with the US may not be stable or predictable over the long run (IEA 2021; Mills 2021; Lipton et al. 2021). To illustrate, Figure 2-2 shows the projected increase in demand for minerals that are used in clean energy technologies, according to IEA (2021). The figure demonstrates that under the "Sustainable Development Scenario" – that is, the deployment of clean energy technologies that would be necessary to meet GHG emissions commitments under the Paris Agreement – the demand for lithium would increase by 42 times between 2020 and 2040, the demand for cobalt would increase by 21 times, and the demand for rare earth metals would increase by 7 times.

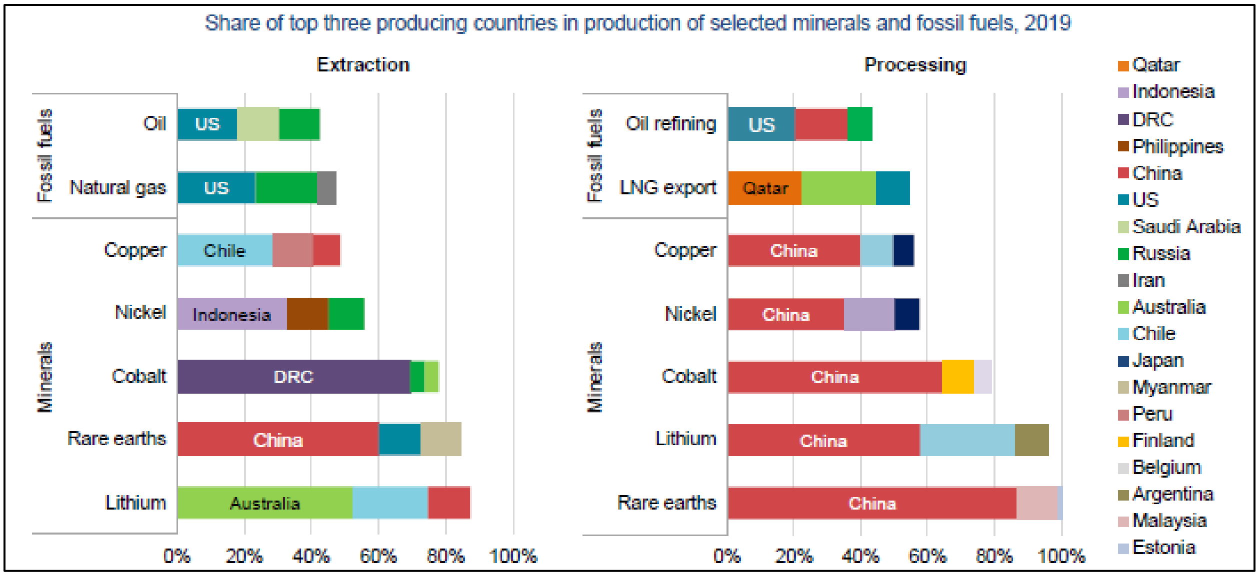
Figure 2-2: Mineral Demand for Clean Energy Technologies



Source: IEA (2021). SDS = Sustainable Development Scenario.

Figure 2-3 demonstrates further the geographic concentration of current production of these critical minerals. Unlike the extraction and processing of oil and natural gas – which are relatively broadly diversified, with the top three producing countries representing less than half of global production – the extraction and processing of critical minerals that underlie non-fossil energy resources is more concentrated in a smaller number of countries. Several of these countries (or international companies that operate mining concessions) have relations with the US that may not be stable or predictable over the long run (Lipton et al. 2021, IEA 2021).

Figure 2-3: Geographic Concentration of Mineral Production for Clean Energy



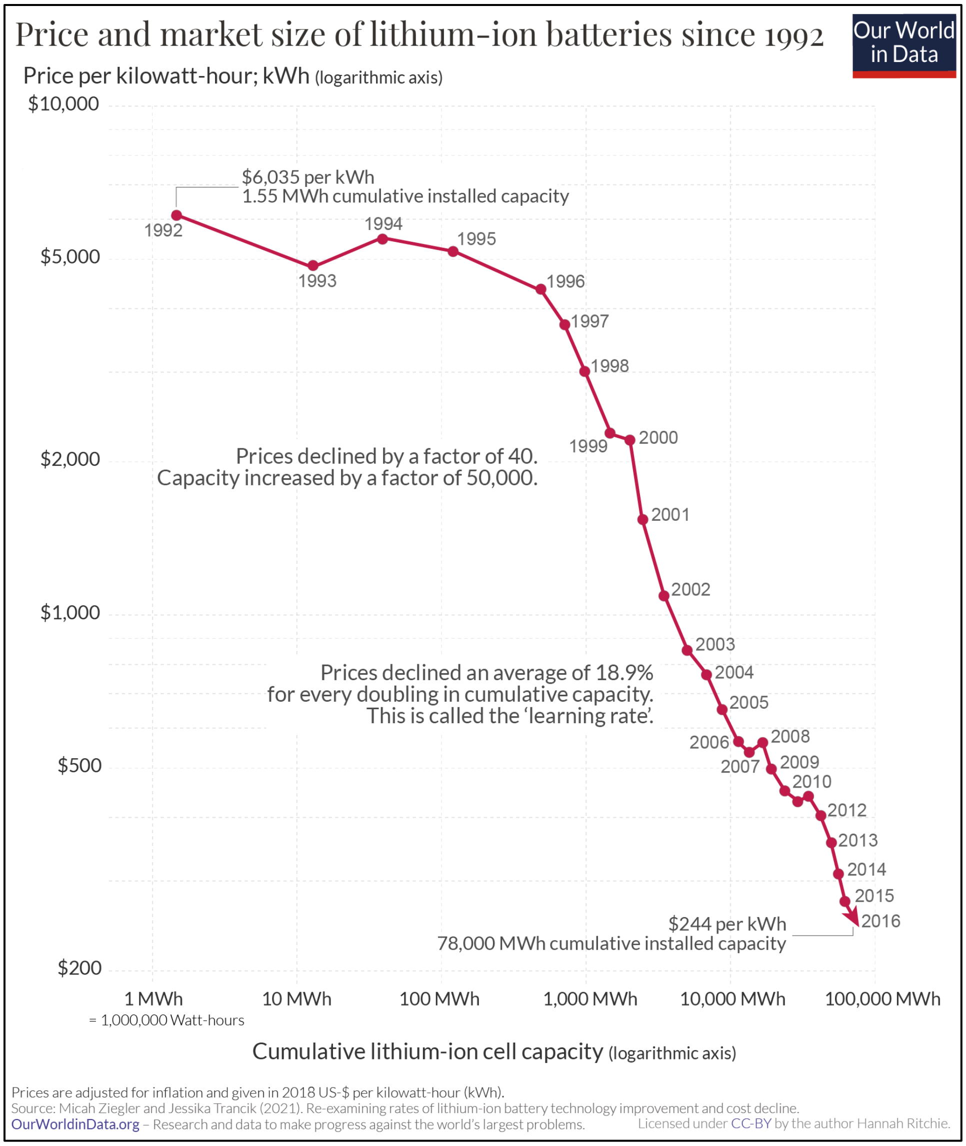
Source: IEA (2021).

Beyond issues of geographic concentration of production, shortages may arise as well, barring more efficient use of critical minerals (particularly in battery storage) or the use of alternative materials. For instance, the US Department of Energy (2021) notes that EV batteries can contain up to 20 kg of cobalt per 100 kWh battery pack. If this is the cobalt content for the battery in each of the 35 million EVs envisioned under the full HES buildout, the total amount of cobalt in these batteries alone would be 700,000 metric tons, which is five times the 2020 global production and amounts to nearly 10 percent of the estimated global reserves of 7.1 million tons (USGS 2021). Extraordinarily high prices for cobalt are driving battery manufacturers to consider other metals in its place, but cobalt oxide provides performance characteristics that prove difficult to substitute for (US Department of Energy 2020). Similarly, the estimated lithium content for a 100 kWh EV battery is about 16 kg (Martin 2017); this would imply the EVs alone projected under the HES would use 560,000 metric tons of lithium, which is about 7 times global production in 2020 and about 2.7 percent of estimated global reserves (USGS 2021).

Thus, shortages of or competition for raw materials, especially for batteries, could contribute to optimism bias. There could also be increased competition for renewable energy itself and increased costs for waste disposal.

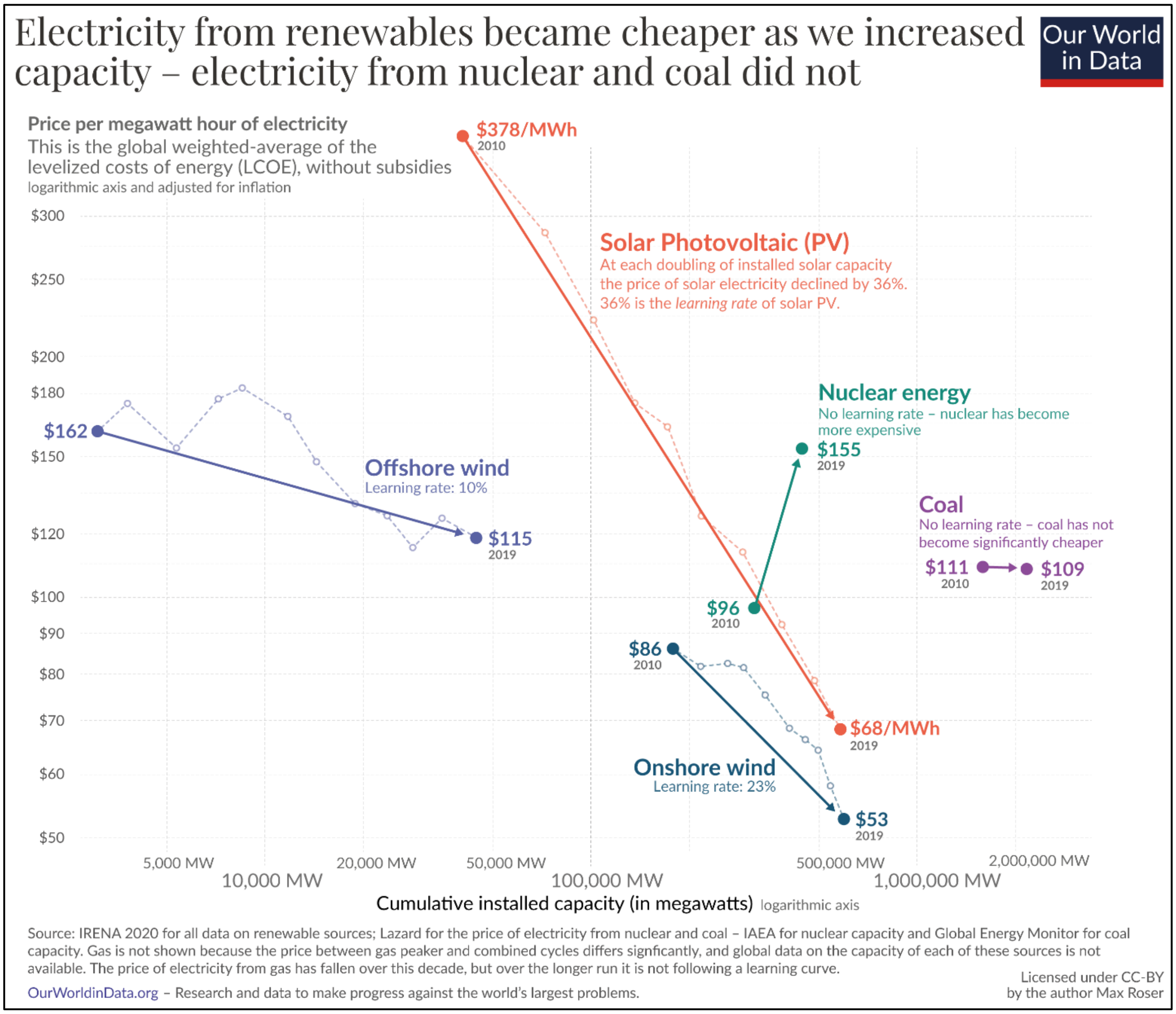
However, if the costs of materials can be managed or controlled, the fact that many other jurisdictions are likely to be attempting deep decarbonization efforts in the same timeframe could also have beneficial implications for costs. For instance, a large scientific literature has repeatedly demonstrated the existence of technological learning effects, by which costs for new technologies decline rapidly with increased production and adoption (e.g., Roser 2020; Thomassen et al. 2020). In this sense, widespread and multi-country demand for energy-efficient equipment, electric end-user devices, solar and wind generation assets, and energy storage devices would likely lead to continued advances in technological learning and thus reduced costs. To provide two relevant examples, Figure 2-4 provides an overview of the price of lithium-ion batteries compared to cumulative installed capacity, and Figure 2-5 provides a similar overview for various electricity generation technologies. Figure 2-4 demonstrates that for every doubling in cumulative capacity, prices for lithium-ion batteries declined an average of 18.9 percent - the "learning rate." Figure 2-5 demonstrates learning rates of 22 percent in onshore wind and 36 percent in solar PV.

Figure 2-4: Price and Market Size of Lithium-Ion Batteries Since 1992



Source: Ziegler and Trancik 2021, as reported in Roser 2020.

Figure 2-5: Electricity Generation Cost per MWh and Cumulative Capacity



Source: Roser (2020).

Regardless of how technological progress and learning curves develop, the more conventional and common issues raised in Flyvbjerg (2011) remain. Given that optimism bias is a well-documented phenomenon relevant for project planning across a wide variety of projects in many jurisdictions, ERM considers it reasonable to incorporate a correction for optimism bias into the calculation of costs that correspond to outputs of the CEC's RESOLVE planning model.

To adjust the predicted costs and revenue requirements for optimism bias, ERM adjusted the 2019 RESOLVE model to incorporate two different levels of adjustment for capital costs associated with new buildout of solar, wind, and other new generating assets, as well as energy storage. Under the assumption that capital costs are 2 times greater than predicted in the HES, the total annual revenue requirement in 2050 would increase by about $35.2 billion (in 2019 dollars). ERM also analyzed a scenario in which capital costs are three times greater than predicted in the HES, which is above the average of the projects analyzed in the Flyvbjerg (2011) study, but well within the range reported therein. In this scenario, the total annual revenue requirement in 2050 would increase by about $70.3 billion over the level documented in E3-Calpine.

2.3.3 Permitting and Land Acquisition

Permitting costs – including CEQA and/or NEPA analysis, other state, federal, and local permits, and potential litigation – could be substantial, especially given the wide-scale nature of the development of new resources envisioned in the HES. A typical rule of thumb in the construction industry – that ERM has found to hold up in its own projects – is that permitting costs add up to 1 to 2 percent of capital costs. We used the higher (more conservative) value due to anticipated higher concerns as the HES-guided buildout of projects continues, which may also make for a more difficult process regarding such elements as the cumulative analysis (i.e., analyzing environmental impacts of a particular project along with other past, present, and reasonably foreseeable future projects in the same geographic area). ERM also added an additional 1 percent of capital costs to account for mitigation measures that project sponsors may have to put in place to minimize adverse impacts following CEQA or other review. Adjusting RESOLVE to increase capital costs for all new generation assets by a total of 3 percent (i.e., 2 percent for permitting and 1 percent for mitigation measures) results in an increase in annual revenue requirements of about $1.1 billion each year through 2050.

ERM also estimated land acquisition costs. As documented in Section 4.3.1, ERM estimates that land acquisition costs would be about $4.9 billion in total. Annualizing this cost over 30 years at a 5 percent cost of capital suggests an annual revenue requirement of about $319 million.

2.3.4 Decommissioning Expenses

Decommissioning costs include disassembly, removal, management of waste streams, and site remediation associated with the retirement of a power-generating asset. Given that the expected useful life of all generation assets is finite, it is best practice to include decommissioning expense when projecting costs and revenue requirements for a program such as the HES. However, it appears from the published reports from E3, CPUC, and CEC that the RESOLVE-based analyses do not include these costs in their assessments.

Relatively few solar or wind generation assets have reached the end of their useful lives, so industry experience with decommissioning these facilities is limited. However, a paper from Resources for the Future (Raimi, 2017) provides a review of available information and a summary of decommissioning expenses for solar and wind. These are provided on a per-MW basis and include the costs for equipment disassembly, disposal, and transportation to appropriate materials recovery facilities and/or landfills, as well as site decommissioning and remediation.

As noted in Raimi (2017), a key element in the net decommissioning expenses for wind farms is the estimated value of scrap materials generated in the process of dismantling towers and turbines. In many cases, plant owners estimate that the total cost of decommissioning will be offset by 50 percent or more from the sale of these scrap materials. However, as the author points out, prices for steel and other metals can be highly volatile. The average per-MW decommissioning cost estimate identified in Raimi (2017), from a sample of about 25 decommissioning plans for onshore wind, is about $40,000 (Raimi 2017, Figure 14). The documentation for these plans is not always sufficient to verify the sources for estimated commodity prices used to impute materials salvage values. As a result, a more conservative estimate – one that discounts the purported salvage values, and keeps in mind that there is very little actual experience to date with decommissioning wind power plants – would be in the range of $80,000 per MW.

Decommissioning costs for solar PV units tend to be somewhat higher than for wind turbines on a per-MW basis as PV facilities are composed of hundreds or thousands of individual modules, and thus dismantling them is time- and labor-intensive. Raimi (2017) notes that one estimate of solar PV decommissioning costs prepared by the state of New York estimates that nearly 90 percent of the costs arise from dismantling and removing equipment – removing each module, dismantling the support structure, removing electrical wiring, and breaking up concrete – and only 10 percent come from activities such as site grading and restoration. Raimi (2017) also notes that like wind turbines, expected decommissioning costs for solar PV units depend substantially on assumptions regarding the salvage value of materials. Removing the decommissioning plans that contain the most optimistic estimates for salvage value of panels (and noting that most plans estimate $0 for salvage value) leaves an average estimate decommissioning cost of $69,000 per MW (Raimi 2017, Table 9).

Both of these figures are in year 2016 dollars and escalating to year 2019 dollars yields an estimate of $85,000 per MW for wind, and $73,000 per MW for solar. Based on estimated build-out of 126,000 MW of new solar (including 110,657 MW of utility scale solar and 15,282 MW of BTM solar), and 15,903 MW of new wind, decommissioning expenses would total $10.6 billion. Annualizing this cost over 30 years at a 5 percent cost of capital leads to an annual revenue requirement of about $686 million.

2.3.5 Costs for Electric Vehicle Charging Infrastructure

As noted in Section 1, the HES assumes near-complete electrification of the light-duty vehicle fleet by 2050, with an expected 19 million BEVs, 11 million PHEVs, and 5 million FCEVs comprising the LDV fleet by that year. The massive expansion of EVs will also require a corresponding investment in both residential and non-residential charging infrastructure. These costs appear to be excluded from the revenue requirements and total resource costs documented in E3/CEC published reports.[12]

As a result of increased usage of EVs, both residences and commercial buildings alike will require installation of EV charging infrastructure (also called electric vehicle supply equipment, or EVSE). Costs associated with charging stations vary based on level, region, and the number of vehicles the station supports. The EV industry classifies charging stations by level, with higher levels offering higher capacity flow and thus faster charging. However, charge time also varies with parameters of the specific vehicle, and there are also differences within levels (e.g., direct current fast charging or DCFC chargers are currently available in capacities of 50, 150, and 350 kW). Average capital costs by station are shown in Table 2-3.

12. E3-Decarb includes a cryptic note in a table labeled "Transportation Data Sources" (p. B-7) about "EV incremental costs" that refers to a PG&E report on identifying locations for EV charging stations. The table entry indicates that some information from this PG&E report (but precisely what is not specified) was "Used for LDV auto and truck, PHEV and BEV costs and PHEV utility factors." The table also notes an assumption that workplace EV chargers would cost $4100 per vehicle (2012 dollars) to install, as of 2030, but does not provide a source for this figure, or any comment on how that figure was used.

Table 2-3: Unit Costs for EV Charging Stations

Charging Station Type	Component Cost (2019 $)	Outlet Type (Volts)	Full Charge Time
Level 1	$0	120	12-36 hours
Level 2 (residential)	$380-$689	240	6-35 hours
Level 2 (commercial)	$2500-$4900	240	6-13 hours
DCFC (150 kW)	$75,600-$100,000	480	40 minutes
DCFC (350 kW)	$128,000-$150,000	480	17 minutes

Note: Level 1 charging uses a regular wall 120 V socket, so ERM assumed zero additional cost for this form of charging. Costs for Level 2 residential and commercial chargers, and DCFC, are from a 2019 charging infrastructure survey reported in Rocky Mountain Institute (2020). Full charge times are based on a 100 kWh battery back, but in practice would depend on vehicle model and battery pack size as well as charging station type. Capital costs include charging station equipment only, and not (for commercial chargers) costs such as credit card readers or data contracts.

A 2017 NREL report on how charging infrastructure needs in the US to support both PHEVs and BEVs suggests that installation of 3.4 DCFC stations for every 1,000 BEVs, and 40 commercial Level 2 stations for every 1,000 plug-in EVs (including both BEVs and PHEVs), would provide sufficient coverage. The primary scenario studied in NREL (2017) assumes these DCFC chargers would be rated for 150 kW. These benchmarks are based on a detailed geospatial model of charging infrastructure relative to current road networks and the locations of cities and towns, as well as driving range for currently available models of PHEVs and BEVs. The NREL report also uses multiple simulations of millions of miles of real-world daily driving schedules sourced from large public and commercial travel data sets, and assumes that BEVs are concentrated in cities whereas residents outside cities primarily own PHEVs.

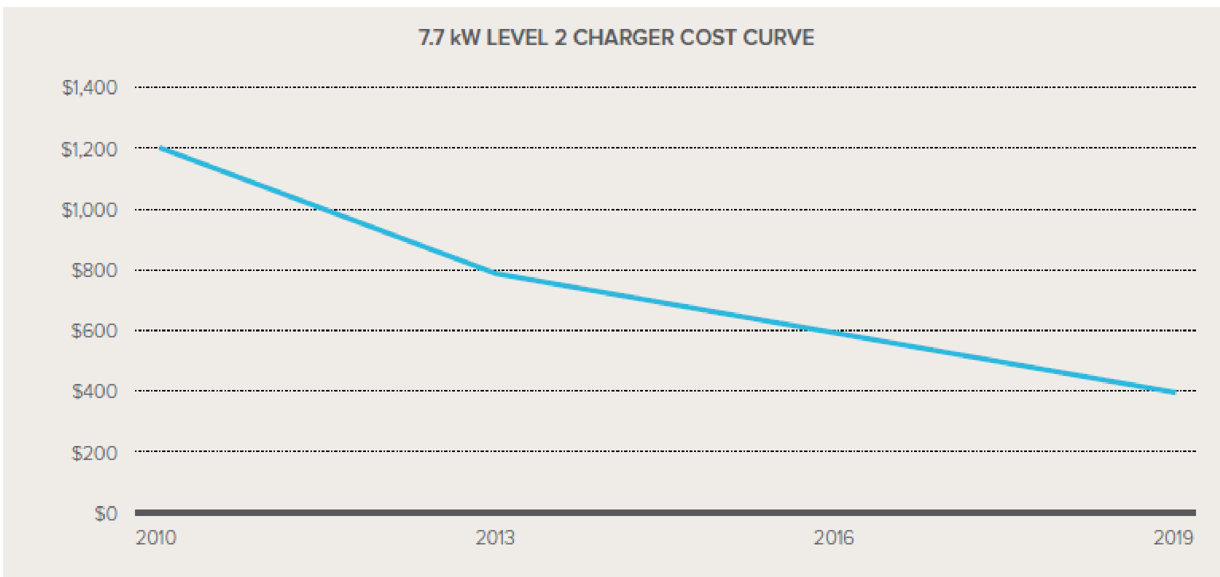
As noted above, the HES also assumes significant deployment of FCEVs: 5 million by 2050. The HES documentation does acknowledge that FCEVs are a "reach technology." FCEVs are advantageous in many cases because they permit refueling in a matter of minutes, similar to gasoline-powered engines. However, there are very few hydrogen fueling stations in the US: in November 2021, a total of 48 retail stations available nationwide (albeit with more under construction), mostly in California (AFDC 2021). Accordingly, very little data is available to project the cost of constructing new fueling stations. From 2009 to 2020, $125 million has been invested through the CEC's Clean Transportation Program to install or upgrade 62 publicly available hydrogen stations capable of LDV fueling (CEC 2020). Presumably the implied average cost of about $2 million per station will decline as more stations are built out, due to technological learning and economies of scale, but how much and how fast is exceedingly difficult to predict.

To provide a representative cost estimate for FCEV refueling infrastructure, ERM assumed that FCEV refueling costs would be comparable to the high end of currently available DCFC charging infrastructure. The industry survey conducted by RMI (2020) found that the capital cost for a 350 kW DCFC charger (which could provide a full charge for a 100 kWh battery pack in about 17 minutes) ranged up to $150,000 (2019 dollars). Using this estimate as a proxy for FCEV refueling infrastructure essentially implies that if the FCEV technology is not widely available and supported by 2050, drivers would instead use the fastest (currently) available charging technology instead, and that the costs for EVSE would be comparable to current costs.

In practice, (i) higher-speed electric chargers may be available by 2050, (ii) they would likely be more expensive than 350 kW chargers (comparing both technologies circa 2050), and (iii) costs for all levels of EV chargers will likely decline between now and 2050 due to economies of scale, experience and technological learning-by-doing, and market competition.

To provide for a conservative analysis, ERM did not assume further cost declines for charging stations, although sources such as RMI (2020) note that it is likely that the cost of charging station hardware will continue to decline even without any special intervention or regulatory guidance. This is because the EV charging industry is still in its relative infancy, and manufacturers are learning how to refine production processes. Indeed, RMI (2020) shows that the average hardware cost for a 7.7 kW level 2 charger has fallen steadily, from about $1,200 in 2010 to about $400 in 2019, in 2019 dollars; see Figure 2-6

Figure 2-6: Experience Curve for Level 2 EV Charger



Source: RMI (2020), Exhibit 3.

Table 2-4 provides a summary of EV charging station capital costs, based on the number of chargers needed to support the EV projections assumed in E3-Decarb. The table accounts for residential and non-residential chargers. To estimate costs for residential chargers, ERM assumed three-quarters of the projected 18 million households in California would install residential Level 2 charging capability and the remainder would not install special charging devices (either because they do not own an EV or because Level 1 charging is sufficient for their needs). The number of commercial Level 2 chargers and DCFC chargers is based on the factors from NREL (2017) documented above.

Table 2-4: EV Charging Station Capital Costs

Charging Station Type	Number of Stations	Unit Capital Cost (2019 $)	Total Capital Cost (2019 $ millions)
Level 1	4,500,000	0	0
Level 2 (residential)	13,500,000	$802	$10,824

Level 2 (commercial)	1,400,000	$5,550	$7,770
DCFC (150 kW)	64,600	$131,700	$8,508
DCFC (350 kW)	17,000	$225,000	$3,825
Total			$30,926

Notes: Unit capital costs are the midpoints of the corresponding component costs in Table 2-3, other than for the 350 kW DCFC charger, which uses the high end of the range as explained in the text. Component costs are then multiplied by a factor of 1.5 to account for balance-of-system and installation costs (based on RMI, 2020).

The $30.9 billion total capital cost equates to an annual cost of $2.0 billion assuming a 5 percent cost of capital and a 30 year repayment period. The costs shown do not include any required upgrades to utility system distribution infrastructure. These are documented in the following section.

2.3.6 Costs for Grid Upgrades

A long-run historical analysis of transmission and distribution (T&D) system costs in the US, based on publicly available data since 1960, suggests that increased use of electricity, by itself, need not lead to higher T&D system costs on a per-kWh basis (Fares and King 2017). This analysis found that average annual transmission, distribution, and administration (TD&A) costs were roughly $700 to $800 per customer per year from 1960-2014, with temporary exceptions during periods of major build-out of new T&D infrastructure in the late 1960s and early 1970s, and again in the 2010s (the latter driven mostly by transmission investments). The TD&A cost per kWh declined rapidly between 1960 and 1980 – evidently due to increasing energy consumption, rather than decreasing service costs – but was approximately constant, staying within a range of 2.5 to 3.5 cents per kWh, from 1980 to 2014 (Fares and King 2017). This is true even though average electricity consumption in the US rose about 35 percent during the same period (OECD/IEA 2014).

The widespread adoption of EVs, in particular, will require a significant increase in the capacity of the transmission and distribution (T&D) system to manage high charging demand in certain locations and time periods. The same DCFC stations that enable rapid charging for BEVs also, of course, draw substantial amounts of power from the grid very rapidly. For instance, 1,000 BEVs charging simultaneously overnight with a Level 2 charger rated at 12 kW (sufficient to fully charge a 100 kWh battery in about 8 hours) would demand 12 MW of grid capacity. However, if just 20 percent of those BEVs were charged simultaneously with 150 kW DCFC chargers (sufficient to replenish a 100 kWh battery in 40 minutes), this would demand 30 MW of grid capacity. That is the same amount of capacity demanded by roughly 5,000 homes at their peak capacity needs.

Utilities must invest in new and upgraded T&D assets – especially on the distribution side – to ensure the grid can handle this demand. To quantify the costs of these investments, BCG (2019) modeled six representative utilities with a given initial system capacity, electricity system sales, and wholesale prices, and found that on average, a utility would need to invest between $1,700 and $5,800 per EV (2019 dollars). The actual cost depends on a number of factors specific to an individual utility – including the physical layout of the grid, the density of areas that would require enhanced capacity for fast charging, and the age and status of current equipment. The cost also depends on customers' charging patterns, which in turn are driven partially by policy (e.g., the application of time-of-use pricing or other incentives to temporally align demand and supply).

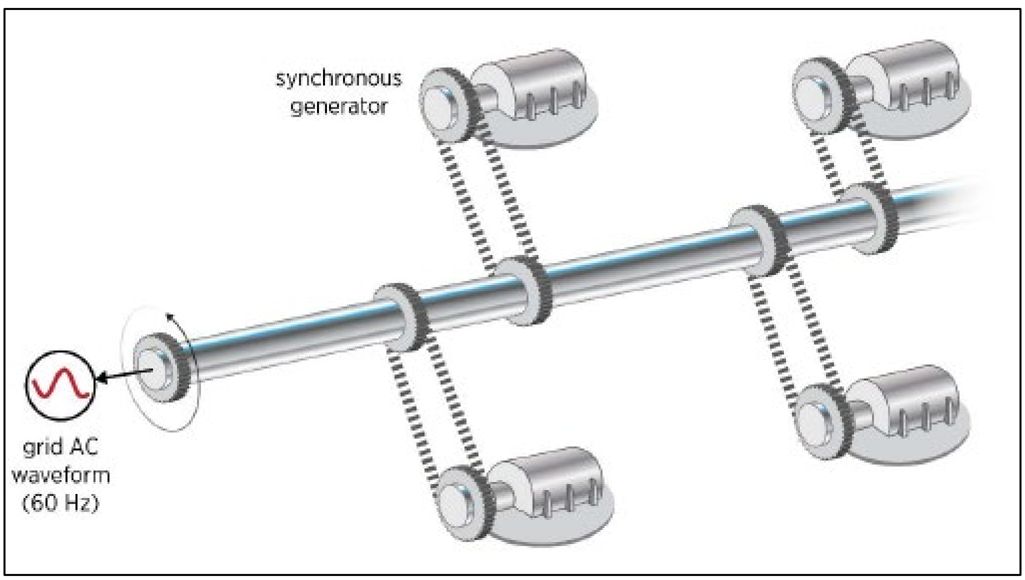
Using the midpoint of the BCG estimate (i.e., $3,750 per EV) and applying this factor to 35 million EVs by 2050 leads to a total capital cost requirement of $131 billion for T&D system upgrades. This annualizes to $8.5 billion per year assuming a 5 percent cost of capital and a 30-year repayment period.

It is worth noting that the BCG report focused on a low penetration rate of EVs in comparison to the HES (BCG's primary scenarios place EV penetration at 10 to 20 percent of total LDV stock while the HES assumes EV comprise 96 percent of the LDV stock in 2050). However, BCG provides some quantitative prediction of rate impacts for higher levels of EV penetration, ranging up to 50 percent. The per-kWh cost that corresponds to our $13.9 billion per year estimate, based on 2050 electricity consumption (2.7 cents, see Table 2-2), is within the range that BCG identified for a higher level of EV penetration. For instance, BCG found that at 50 percent EV penetration, the impact on rates is between 0.25 and 4.75 cents per kWh, depending on how much utilities can optimize charging to temporally align demand and supply.

2.3.7 Frequency Regulation

Power grids designed around conventional thermal and hydropower rotating generators possess abundant inertia, which gives these generators the tendency to remain rotating (Figure 2-7). This stored energy can be especially valuable when a large power plant fails or a large transmission node goes offline, as the inertia can temporarily make up for the power lost from the failed generator or transmission node. This temporary response, which typically lasts for a few seconds, is often sufficient to allow for the operation of mechanical switches that then trigger demand response – from customer loads that are specifically contracted and compensated for the demand response services they provide – so as to rebalance demand and supply on the grid.

Figure 2-7: Synchronous Generators Working Together in an Electrical Grid



Source: NREL (2020), Figure 1.

Increasing penetration of inverter-based resources, including solar PV, battery storage, and wind, reduces the inertia available on the grid.[13] It is well understood that this decrease in inertia can result in the need to compensate in other ways: in the absence of demand response, the loss of a significant generation source or transmission node would result in a significant drop off in the frequency of the alternating current waveform, below 60 Hz, which in turn could result in disruptions to grid reliability, serious damage to end-use equipment and infrastructure, and damage to other generators (NREL 2020).

The RESOLVE model does not incorporate the costs that may arise from this decreased inertia in the power grid as energy sources move from those with demand response to inverter-based resources under the HES, nor is this issue addressed in the CEC or E3 reports. Technologies exist that allow wind and solar resources to provide "fast frequency response" or inverter-based frequency regulation, but costs for these novel technologies have not been simulated or analyzed thoroughly (Denholm et al. 2021, NREL 2020).

As an alternative, we document the costs of providing synchronous condensers (also called synchronous compensators), which represent the upper-bound cost for frequency regulation. These are essentially synchronous generators that lack a prime mover to provide active power, meaning that they can provide all the ancillary services of conventional generators except those requiring active power. Synchronous condensers have been installed recently to provide these services in California, Germany, Denmark, Norway, Brazil, and New Zealand (Brown et al. 2018). In detailed system simulations (i.e., much more temporally detailed than RESOLVE), they have also been shown to substantially improve stability during severe fault events in a study of high renewable penetration in the US Western Interconnection (Miller et al. 2015).

Brown et al. (2018) report a range of cost estimates for synchronous condensers in the literature. Using the highest of these, and assuming installation of a synchronous condenser of similar capacity as was used in Miller et al. (2015) to provide frequency stability in the event of a major fault on the Western Interconnection, results in a total annual cost (including annualized capital and O&M) of about $6 million.[14]

2.3.8 SL4 Siting Protections

As noted in E3-TNC, and also summarized in Section 4 of this report, the amount of available and selected wind capacity decreases with higher levels of environmental protection, which are operationalized in E3-TNC in the concept of "Siting Levels" (SLs). Higher SLs, which imply the exclusion of certain land types from consideration for siting new generation assets, result in greater needs for battery storage as well as higher costs and higher revenue requirements. Specifically, SL4 protections – the highest level of protection – would add an additional $16

---

13. Wind turbines are also rotating generators, but utility-scale wind generation typically uses inverters and produces direct current because this enhances generation efficiency. Thus, wind is considered an inverter-based resource that does not provide inertia.

14. Brown et al. (2018) reports the high end of capital costs in the literature is 100 euros per thousand volt-amperes of reactive power (kVAr), with fixed O&M costs of 3.5 euro per kVAr per year. Converting to 2019 US dollars and annualizing the capital costs over a 30-year useful life (Brown et al., 2018) at a 5% cost of capital yields an annual cost of $12 per kVAr (2019 dollars). Miller et al. (2015) models the installation of a 500 MVAr-capacity synchronous condenser in the Western Interconnection. This implies an annual cost, including capital and fixed O&M, of $6 million to build and maintain this magnitude of condenser.

billion (2016 dollars) to the annual revenue requirement in 2050 (E3-TNC, pp. 28-29). This corresponds to a cost of $17 billion in year 2019 dollars.

2.3.9 Wildfire Adaptation Costs

California's electric utilities must spend billions of dollars to fund grid upgrades to reduce the risk of wildfires evidently caused in part by the proximity of trees and other vegetation to transmission and distribution lines (and in part by more intense wildfire seasons that are exacerbated by climate change). CEC required the state's largest electric utilities to file wildfire mitigation plans and associated rate increases for regulatory approval. The RESOLVE model does not include wildfire adaptation costs in the revenue requirement estimates. CEC projects an additional $20.0 billion per year in revenue requirements for electric utilities to fund wildfire prevention initiatives (E3-GasFut). This cost appears to be in 2018 dollars; adjusting to 2019 dollars yields an estimate of $20.4 billion. It is worth noting that these costs are not attributable to the HES, and would occur regardless of HES implementation.

2.3.10 Behavioral Assumptions: Reduced Vehicle Miles Traveled

As noted in Section 1, the HES assumes that by 2030, per-capita VMT in light-duty vehicles will decline by 12 percent relative to 2015, and by 2050, VMT will decline by 24 percent relative to 2015. To provide some insight into whether the anticipated declines in VMT are realistic, Table 2-5 provides a trend analysis in statewide per capita VMT since 2010. The per capita VMT data are from the Federal Highway Administration Traffic Volume Trends, a monthly report based on hourly traffic count data reported by California and other states (FHWA, 2021). The analysis demonstrates that VMT per capita reached a relative peak in 2015 (it was about the same in 2016 and slightly lower in 2017-2019, before dropping dramatically in 2020 and 2021 due to COVID-19). However, the decline anticipated for 2030 and especially for 2050 would require a significant change in behavior. E3-Decarb notes that ambitious smart growth strategies are necessary, particularly for meeting the 2030 GHG goals when fossil-fueled transportation still represents the largest share of statewide GHG emissions (E3-Decarb, p. 66). At the same time, the limited time available between now and 2030 leaves little time for smart growth strategies to be implemented and thus have a substantial effect on VMT.

Table 2-5: Historical and Projected VMT

Year	Estimated VMT (millions)	Population	VMT per Capita	Percent Change Relative to 2015
2010	346,014	37,253,956	9,288	-5.9%
2011	345,846	37,561,624	9,207	-6.7%
2012	337,536	37,924,661	8,900	-9.8%
2013	347,982	38,269,864	9,093	-7.9%
2014	353,478	38,556,731	9,168	-7.1%
2015	383,568	38,865,532	9,869	0.0%
2016	386,838	39,103,587	9,893	0.2%
2017	381,228	39,352,398	9,688	-1.8%
2018	379,404	39,519,535	9,600	-2.7%

2019	378,690	39,605,361	9,562	-3.1%
2020	324,954	39,648,938	8,196	-17.0%
2021	362,844	39,466,855	9,194	-6.8%
2030 (HES)			8,685	-12.0%
2050 (HES)			7,501	-24.0%

Sources: FHWA (2021), California Department of Finance (2020), E3-Decarb, and calculations by the authors. VMT is taken as the average of June and December, multiplied by twelve to estimate an annual value.

If the VMT reductions assumed in the HES are not realized, and per-capita VMT in 2050 is comparable to that in 2015 (i.e., about 9,869 miles per capita rather than 7,501), the service load would be approximately 31.3 TWh higher in 2050 than is indicated in the HES (i.e., about 6.1 percent higher than the 2050 service load of 512 TWh in 2050). This is based on the forecasted population of 44 million people in 2050 (California Department of Finance, 2020) and an assumed efficiency of 30 kWh per 100 miles traveled (current light-duty EVs range from about 24 to 44 kWh per 100 miles, depending on vehicle weight and model).

The higher demand would not likely lead to a measurable increase in electricity rates, since the higher cost and revenue requirement would be accompanied by an increase in demand, and thus spread out over the greater load. However, the increase in load of about 6.1 percent would require a corresponding increase in land required to build solar and wind generation assets, since presumably the higher load would be supplied by renewable sources.

So-called “smart growth” policies can also increase housing costs, because housing in these areas is typically in urban in-fill locations that are also close to employment, commercial centers, and public transit. Both land and building costs in these areas are higher in such in-fill areas, compared to outlying areas. This would imply that to meet or maintain affordable housing goals, smart growth policies that are implemented as part of the HES would need to be accompanied by subsidies that would allow lower-income households to rent or purchase homes in in-fill areas. Such subsidies would effectively increase the cost of implementing the HES.

At the same time, research suggests that programs oriented around affordable housing should also consider the combined cost of housing and transportation. Hamidi et al. (2016) note that while the vast majority of guidelines, policies, and analysis of affordable housing focuses on the costs of housing alone, a more accurate metric would consider housing and transportation together – considering that while housing is typically a household's largest single expense, transportation is typically the second-largest. Empirical analysis demonstrates a clear tradeoff between the housing and transportation expenses of families with one or more working members: Families that spend more than half of their total household expenditures on housing put 7.5 percent of their budget toward transportation. By contrast, families that spend 30 percent or less of their total budget on housing spend nearly one quarter of their budget on transportation – three times as much as those in less affordable housing (Hamidi et al. 2016, Lipman 2006).

A nationwide analysis of over 4,000 transit station areas across 39 regions in the United States found that housing costs were indeed higher in areas that met minimum thresholds for walkability and housing density (“transit-oriented development”), compared to areas that did not.

However, for families with at least one working member, the analysis found that combined average transportation and housing costs were *lower* in the transit-oriented development areas (Renne et al. 2016). This suggests that the smart-growth policies assumed in the HES would indeed increase housing costs, but may lead to lower combined housing and transportation costs, all else equal. The implication for the estimated cost of the HES is unclear. If affordable housing policies continue to focus on housing costs alone, then implementing the HES with its assumed smart-growth policies would likely require additional housing subsidies to ensure there is sufficient affordable housing within in-fill development areas. If affordable housing policies take into account the combined costs of transportation and housing, then the HES implementation may not incur additional incremental costs to accommodate its smart growth objectives.

2.4 Utility Rate and Bill Impacts

The foregoing analysis clarifies some of the known and lesser-known cost-contributing factors in the HES, which in turn result in potential underestimation of retail electricity costs in RESOLVE. This section addresses how these additional cost drivers would affect customer rates and bills.

In 2019, California had the seventh highest residential electric rates in the United States at 19.2 cents per kilowatt-hour. This is 48 percent higher than the national average of 13.01 cents per kilowatt-hour (EIA 2019a). California's large, diverse geography drives higher than average maintenance, generation, transmission, and distribution costs. Rate design also contributes to high retail rates, as approximately 70 percent of volumetric rates recover fixed costs of operations that remain the same regardless of customer use. Fixed costs also include the high cost of subsidies to fund programs for energy efficiency, rooftop solar adoption, and low-income rate relief programs. Pacific Gas and Electric rates are currently 80 percent higher than the national average, Southern California Edison rates are 45 percent higher, and San Diego Gas and Electric rates are double the national average (Borenstein 2021).

Nevertheless, retail rates – including both residential and commercial rates – would increase further under the HES. Based on the total resource cost including our analysis of missing components (Table 2-2), and the total retail load of 512,120 GWh in 2050, the retail rate in 2050 would be 43.3 cents per kWh for a 2x OBA, and 50.1 cents per kWh for a 3x OBA. Since cross-class subsidies in California (like many other places) favor commercial users, residential retail rates would be even higher.

2.4.1 Commercial and Residential Rates

Neither RESOLVE nor the E3 published reports distinguish rates by customer class (i.e., residential versus commercial) in the way that would be needed to estimate distinct residential and commercial rates. However, the sales and rate data can be decomposed using additional data from the U.S. Energy Information Administration (EIA). EIA (2019) provides electricity sales and rates for California (and other states) by customer class. Table 2-6 presents imputed rates for commercial and residential customers using the ratios of residential and commercial user base and cross-class rate subsidies from the 2019 EIA data for California.

Table 2-6: Class Components of Retail Sales and Electric Rates

Item	Residential	Commercial
Number of customers (2019)	13,707,126	1,718,601
Average consumption (kWh), 2019	6,384	66,492
Total consumption by customer class (GWh), 2019	87,506	114,273
Percent of consumption (residential and commercial classes only)	43.4%	56.6%
Percent of consumption (all users)[1]	35.1%	45.8%
Average rate in 2019, cents per kWh	19.2	16.7
Imputed rate under total resource cost reported in HES[2]	28.8	25.0
Imputed rate under 2x OBA, cents per kWh	46.7	40.6
Imputed rate under 3x OBA, cents per kWh	54.1	47.1

Sources: EIA (2019) and calculations by the authors. All costs are in year 2019 dollars.
(1) EIA (2019) reports the total consumption in 2019 in California was 249,588 GWh; retail sales (i.e., residential and commercial) was 201,780 GWh.
(2) The "Imputed rate under total resource cost reported in HES" refers to the HES total resource costs identified in the top two rows of Table 2-2.

It is worth noting, again, that the increase in costs is not entirely attributable to the HES; for instance, utilities would incur wildfire adaptation costs regardless of the HES implementation. Also, some of the changes represented by the HES are already codified in existing policy and/or envisioned in existing initiatives. **However, as the table shows, with full implementation of the HES, the residential rate stands to increase by up to 143 percent compared to 2019 under a 2x optimism bias adjustment, and up to 182 percent under a 3x optimism bias adjustment.**

2.4.2 Residential and Commercial Electric Bills

The increase in sales from 249,588 GWh in 2019 (EIA 2019a) to 512,120 GWh in 2050 (E3-Calpine, Table 32) is largely driven by increases in average use as current electric customers use more electricity to power new electric appliances. Increased retail sales are also driven by new customers, which can be attributed to growth in the number of households. CEC's energy demand forecast for 2018-2030 forecasts customer growth using a projected 0.94 percent annual growth in the number of households (Kavalec 2018).[15] Customer numbers are extrapolated from 2019 EIA customer number data to determine the expected number of customers in 2020 and 2050. Average annual use is then estimated by dividing forecasted HES residential and commercial sales by the projected number of customers. This estimated average

15. This growth rate assumption is slightly higher than projections from the California Department of Finance (2021). Based on the data in that source, the number of households in California is projected to grow by 0.80% per year from 2020 to 2030. If the number of households were to grow at this lower rate it would imply that fixed costs would be spread over a smaller number of households in future years, which would translate into higher rates, all else equal – but the projected service load would also be lower, as would the costs for elements like replacement of end-user equipment.

annual kWh use is multiplied by the forecasted rate to estimate average annual bills. Table 2-7 presents the results of this analysis.

Table 2-7: Bill Impacts of HES by Customer Class, 2050

Item	Residential (2019)	Residential (2050)	Commercial (2019)	Commercial (2050)
Total sales (by class), GWh[1]	87,506	179,550	114,273	234,472
Number of customers[2]	13,707,126	18,319,293	1,718,601	2,296,875
Average annual consumption, kWh	6,384	9,801	66,492	102,083
Rate per kWh, cents (year 2019 $)[3]	19.2	50.4	16.7	43.9
Annual bill	$1,226	$4,941	$11,104	$44,764

(1) Assumes that residential and commercial use each constitute the same proportion of total use in 2050 as in 2019.
(2) Number of both residential and commercial customers in 2050 is projected based on the annual figure provided in Kavalec (2018).
(3) Uses the midpoint of the 2x and 3x optimism bias adjustment cases from Table 2-6.

As the table demonstrates, although the estimated increase in rates per kWh is 163 percent, the resulting change in bills is about 303 percent. This arises from 54 percent higher average annual use from 2019 to 2050. This, in turn, is caused by higher adoption rates of electric heat pumps, electric water heaters, electric cooking, and electric vehicles.

Aggregate residential bills are projected to be $90.5 billion in 2050, compared to $16.8 billion in 2019; aggregate commercial bills would be $102.8 billion in 2050, compared to $19.1 billion in 2019. It is worth noting that a portion of the higher expenditures on electricity bills would be offset by lower expenditures on other forms of energy, such as gas for heating and cooking, and motor vehicle fuel.

2.4.3 Residential Gas Customers

Approximately 80 percent of California homes, representing 11.2 million residential customers, connect to the natural gas system (E3-GasFut, EIA 2021). If implemented, the HES will result in lower demand for natural gas due to the installation of electric heat pumps and water heaters in new construction, as well as declining (and eventually eliminated) sales of gas appliances to replace gas-powered appliances that reach the end of their useful life. Declining natural gas demand will place upward pressures on gas rates and bills, since the capital cost of gas transmission and distribution infrastructure will be spread over a smaller quantity of customers. Higher gas rates will, in turn, cause more customers to choose electricity over gas – independent of the above-mentioned policy changes – which will cause a spiraling effect that leaves even fewer customers to pay for fixed system costs (E3-GasFut).

Pacific Gas and Electric and Southern California Gas together service approximately 94 percent of gas demand in California. The gas utility revenue requirement for these two utilities was $7 billion in 2019 to operate, maintain, and invest in over 165,000 miles of transmission, distribution, and underground storage assets (E3-GasFut). The gas system infrastructure serves building heat loads, electric generation, some industrial facilities, and residential and commercial retail customers. By design, the system infrastructure is sized for more demand than it serves because utilities strategically build infrastructure in advance of forecasted growth. For example, infrastructure is in place to serve the demands of 13 million residential gas customers but there are only 11.2 million current residential customers using the gas system. However, residential rates are designed to recover the costs incurred to serve current and future customers, which in this case is 13 million.

Under the HES, the system will not need to be expanded but the state still needs the infrastructure for use during the transition period to continue to provide service for remaining gas customers along with thermal power plants that use natural gas as a fuel. The cost of maintaining the existing gas system during and after this transition period will be borne by remaining customers. The CEC estimates gas utility revenue requirements will increase to $12.2 billion in 2050 assuming historical safety, operation, and maintenance investment levels continue (E3-GasFut). At the same time, CEC estimates that the number of residential gas customers will fall from 11.2 million to two million by 2050 under the HES, which assumes that no new gas appliances are sold after 2040.

The erosion of residential customers means that the fixed costs of gas infrastructure will be spread over a smaller customer base. Though this customer base will still include industrial customers (either combusting gas for heat, or using gas as a feedstock for other products) and some thermal power plants that remain online and combust gas to generate electricity, residential customers have historically borne the highest rates, essentially cross-subsidizing industrial and commercial users. Assuming that this pattern continues, the residential customers who remain will have to pay a larger portion of the fixed costs of the gas system (which will eventually become a set of stranded assets). **As a result, CEC estimates residential gas rates will increase 80 percent by 2030 and 480 percent by 2050 (E3-GasFut). Average annual residential gas bills were $750 in 2020 (Statista 2021). The projections from CEC (E3-GasFut) suggest this would increase to $4,351 in 2050, under the HES.**

Table 2-8 provides a summary of the implications for residential customers who switch to electric appliances and those who remain on gas. According to the analysis, both types of customers would see a substantial increase in combined gas and electric bills, amounting to a 150 percent increase for all-electric customers and a 327 percent increase for those who remain on gas.

Table 2-8: Gas and Electric Bill Impacts of HES, for Residential Customers

Item		All-Electric Customers in 2050		Customers Remaining on Gas in 2050	
	Bill in 2019	Bill in 2050	Percent change vs 2019	Bill in 2050	Percent change vs 2019
Average annual gas bill	$750	$0	-100%	$4,351	480%
Average annual electric bill	$1,226	$4,941	303%	$4,080	233%
Combined gas and electric bill	$1,976	$4,941	150%	$8,431	327%

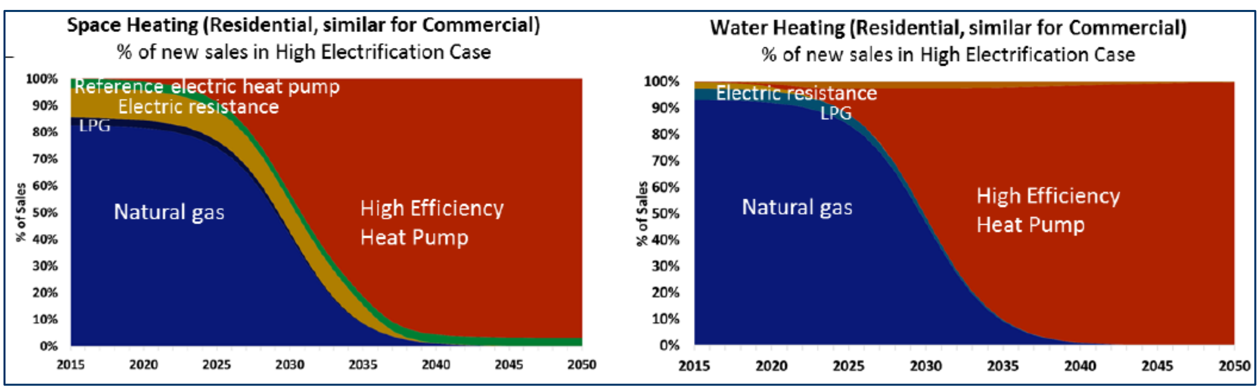
Sources: Statista (2021), EIA (2019), E3-GasFut, and calculations by the authors. Residential electricity rates are based on the midpoint of the 2x and 3x optimism bias adjustment cases (as in Table 2-6). Assumes that for customers who remain on gas, the increment of annual electricity consumption in 2050 versus 2019 is half that for those who switch to all-electric.

It is worth noting, however, that motor vehicle fuel purchases would be reduced substantially for households that purchase BEVs or FCEVs (although not PHEVs). For instance, based on per-capita VMT in 2019 (9,562 miles according to FHWA, 2021) and the number of people per household (2.97 in 2015 according to California Department of Finance (2020), and assumed fuel economy of 25 mpg, per-household gasoline consumption was about 1,136 gallons in 2019.[16] If gasoline costs $4.50 per gallon, this represents an annual expenditure of $5,112. Households that switch to BEVs or FCEVs would replace this expenditure with spending on electricity instead (as reflected in the annual average electricity consumption, and bill, in 2050). In this scenario, the combined cost for residential gas and electric bills plus gasoline is $7,087 in 2019 ($5,112 + $1,976). Those who switch to all-electric residential appliances would see a 30 percent decrease for combined gas, electric, and gasoline expenditures (from $7,087 to $4,941). Those who remain on gas would see a 19 percent increase (from $7,087 to $8,431). These comparisons are only representative since, in practice, many households would continue to purchase gasoline to fuel the 11 million PHEVs that the HES assumes are still in the LDV fleet as of 2050. However, they provide a potentially useful point of comparison.

2.5 Costs and Adoption Rates of New End-User Equipment

The HES projects adoption rates of new residential electric water heaters and furnaces along with electric vehicles. The pace at which consumers purchase new electric equipment or swap out gas equipment that has reached the end of its useful life drives the HES retail sales projections. While the HES assumes no early retirements of functional equipment, E3-Decarb notes that this will hold only if policies support aggressive market development, especially for electric heat pumps. For instance, E3-Decarb notes that in the HES, "new heat pump sales must represent no less than approximately 50 percent of new sales of HVAC and water heating equipment by 2030" (see Figure 2-8).

Figure 2-8: Percent of New Sales in HES for Residential Space Heating and Water Heating, by Technology Type



Source: E3-Decarb, Figure 8.

In addition to these assumptions about electric water heaters and electric heat pumps for space heating, the HES's assumptions also imply that gas stoves would no longer be available for residential or commercial cooking. The following sections provide an analysis of the capital

16 .This implies a total statewide household gasoline consumption of about 15 billion gallons in 2019, which is consistent with data from the Energy Information Administration (EIA, 2019c).

costs required to replace equipment used for space heating, water heating, and cooking, as well as the incremental capital costs for electric vehicles.

The analysis is conservative in the sense that it focuses on incremental capital costs for comparable electric appliances (compared to gas appliances). That is, it assumes there are no early retirements of functional equipment, so the incremental capital cost for a given unit is simply the difference between the upfront cost for an electric unit and that for a comparable gas unit. Even under this conservative assumption, as the sections below demonstrate, the incremental costs to residential and commercial consumers would be substantial.

2.5.1 Space Heating

Electric heat pumps cost more upfront than comparable gas heating units, resulting in incremental equipment costs to consumers. E3-Decarb provides a range of costs for gas furnaces and radiators (in year 2012 dollars) between $2,500/unit (reference gas furnace) and $4,000/unit (high-efficiency gas radiator) and notes that a high-efficiency electric heat pump costs $4,500/unit. Taking a simple average of the gas furnace and radiator costs, across both high-efficiency and reference types, and converted to year 2019 dollars, produces a cost of $3,828. This is $1,183 less than the cost for an electric heat pump (when converted to 2019 dollars).

The analysis above does not account for equipment replacement costs at the end of useful life. E3-Decarb (Appendix B) notes that the expected useful life of electric heat pumps and gas furnaces is the same (18 years), but of gas radiators is larger (25 years). All else equal, this would lead to slightly higher costs for electric heat pumps (than shown in this comparison) if the alternative is a gas radiator. On the other hand, it also does not account for the fact that electric heat pumps can substitute for air conditioning units (since they can also be run in cooling mode, unlike furnaces and radiators). In households with air conditioning units, this would lead to lower relative costs for all-electric space conditioning than what is shown here, all else equal, since households that previously had gas space heating and air conditioners, upon converting to electric heat pumps, would no longer need to replace the air conditioner at the end of its useful life.

The number of homes and businesses that must install electric heat pumps to replace retired gas space heating equipment, by 2050, is a function of the number of customers heating with electricity and gas in 2019, and the number anticipated to stay on gas in 2050. As Table 2-9 shows, currently 25 percent of households in California heat with electricity, and 67 percent with gas (comparable statistics are not available for commercial entities, but ERM assumed a similar percentage). The HES assumes 2 million households would remain gas customers (E3-GasFut). Factoring in projected annual growth in the number of households (see Section 2.4.2), there would be 18.3 million households in California in 2050, resulting in just over 16 million expected electric heat customers in 2050 under the HES.

Since 25 percent of California households heat with electricity—approximately 3.5 million customers (EIA 2019b, EIA 2021)—the incremental electric heating users expected in 2050 is about 12.9 million customers (Table 2-9). Assuming that upfront costs for electric and gas heating units are the same in the future as they are today, the total cost to replace all gas heating with electric amounts to about $15.2 billion. Similar calculations for commercial space heating suggest an estimated additional $2.2 billion in replacement costs.

Table 2-9: Incremental Capital Cost for Electric Space Heating

Item	Residential	Commercial
Number of electricity customers, 2019	13,707,126	1,718,601
Number of electricity customers, 2050	18,319,293	2,296,875
Percent of customers heating with electricity	25%	25%
Percent of customers heating with gas	67%	67%
Number of customers heating with electricity, 2019	3,426,782	429,650
Number of customers heating with gas, 2019	9,183,774	1,151,463
Number of customers heating with electricity, 2050	16,319,293	2,296,875
Number of customers heating with gas, 2050	2,000,000	0
Number of new electric heating units needed (2019-2050)	12,892,512	1,867,225
Average capital cost for gas heating unit	$3,828	$3,828
Average capital cost for electric heat pump	$5,011	$5,011
Incremental capital cost for electric heating	$1,183	$1,183
Total cost ($ million)	$15,253	$2,209

Sources: EIA (2018), EIA (2019b), EIA (2021), Kavalec (2018), E3-Decarb, and calculations by the authors. All costs are in year 2019 dollars. Proportion of commercial customers heating with electricity and gas is assumed to be same as in EIA (2018); ERM also assumed no commercial customers would heat with gas in 2050, and assumed a comparable differential in capital cost for electric heating for commercial users as for residential users.

2.5.2 Water Heating

Like space heating equipment, electric water heaters also cost more upfront than comparable gas water heaters. E3-Decarb estimates that gas water heaters cost $920/unit (year 2012 dollars) and electric $2,630 with a cost differential in 2019 dollars of $1,904.

As for space heating, the analysis here does not account for equipment replacement costs at the end of useful life. E3-Decarb (Appendix B) states that the expected useful life of electric water heaters is 16 years for residential settings and 14 years for commercial water heaters, compared to 9 years for gas water heaters (residential settings) and 12 years for commercial gas water heaters. All else equal, this would imply slightly lower costs for electric water heaters than shown in this comparison.

The number of homes and businesses that must install electric heat pumps to replace retired gas space heating equipment, by 2050, is a function of the number of customers heating with electricity and gas in 2019, and the number anticipated to stay on gas in 2050. Table 2-10 provides a set of calculations to estimate the number of residential and commercial water heater units that would need to be replaced between 2019 and 2050. According to the EIA's Residential Energy Consumption Survey (EIA 2018), currently 32 percent of households in the Pacific West region (which is the closest geographic unit to California) heat water with electric water heaters, and 64 percent with gas (comparable statistics are not available for commercial entities, but ERM assumed the percentage is about the same).

Factoring in projected annual growth in the number of households (see Section 2.4.2), there would be 18.3 million households in California in 2050. ERM assumed that the 2 million households who would remain gas customers in 2050 (E3-GasFut) would use gas water heaters. This implies about 11.9 million new electric water heaters would need to be installed by 2050 under the HES.

Assuming that upfront costs for electric and gas heating units are the same in the future as they are today, the total cost to replace all gas water heating with electric amounts to about $22.8 billion. Similar calculations for commercial water heating suggest an estimated additional $3.3 billion in replacement costs.

Table 2-10: Incremental Capital Cost for Electric Water Heating

Item	Residential	Commercial
Number of electricity customers, 2019	13,707,126	1,718,601
Number of electricity customers, 2050	18,319,293	2,296,875
Percent of customers heating water with electricity	32%	32%
Percent of customers heating water with gas	64%	64%
Number of customers heating water with electricity, 2019	4,364,839	547,264
Number of customers heating water with gas, 2019	8,729,678	1,094,528
Number of customers heating water with electricity, 2050	16,319,293	2,296,875
Number of customers heating water with gas, 2050	2,000,000	0
Number of new electric water heaters needed (2019-2050)	11,954,454	1,749,611
Average capital cost for gas water heater	$1,024	$1,024
Average capital cost for electric water heater	$2,929	$2,929
Incremental capital cost for electric water heating	$1,904	$1,904
Total cost ($ million)	$22,763	$3,331

Sources: EIA (2018), EIA (2019d), EIA (2021), Kavalec (2018), E3-Decarb, and calculations by the authors. All costs are in year 2019 dollars. Proportion of commercial customers heating water with electricity and gas is assumed to be same as in EIA (2018); ERM also assumed no commercial customers would use gas water heaters in 2050, and assumed a comparable differential in capital cost for electric water heating for commercial users as for residential users.

2.5.3 Cooking

Electric stoves and ovens, particularly high-efficiency induction cooktops, cost more upfront than comparable gas units. E3-Decarb does not provide cost estimates for cooking equipment, but Mahone et al. (2019) do, for residential cookstoves. This source estimates that gas cookstoves cost $1,400-$2,200 (year 2012 dollars); electric resistance stoves cost $1,700-$2,100; and electric induction cost $1,900-$2,300. Taking the midpoint of each range, and averaging electric resistance and electric induction stoves, the cost differential in 2019 dollars is $223.

As with space and water heating, the number of homes and businesses that must install electric cooking to replace gas equipment by 2050 depends on the number of customers using each technology type in 2019. Table 2-11 shows the calculations to estimate the number of residential and commercial water heater units that would need to be replaced between 2019 and 2050. According to the Residential Energy Consumption Survey (EIA 2018), currently 48 percent of households in the Pacific West region (which is the closest geographic unit to California) use electricity as the primary technology for cookstoves, and 47 percent use gas. (Comparable statistics are not available for commercial entities, but ERM assumed that all commercial entities that customers operate stoves, use gas. ERM also assumed that 20 percent of commercial customers use stoves.)

Applying these factors to the number of residential customers in 2019, and accounting for growth in the number of residential and commercial customers by 2050, yields an estimate of 11.7 million new electric stoves to install between 2019 and 2050. This assumes that the households who would remain gas customers for space and water heating in 2050 (E3-GasFut) would nonetheless transition to electric stoves. Assuming that the cost differential in upfront costs for electric and gas cookstoves are the same in the future as they are in 2019, the total cost to install all necessary new electric cooking equipment amounts to about $2.6 billion for residential customers, and $51 million for commercial customers.

Table 2-11: Incremental Capital Cost for Electric Cooking

Item	Residential	Commercial
Number of electricity customers, 2019	13,707,126	1,718,601
Number of electricity customers, 2050	18,319,293	2,296,875
Percent of customers cooking with electricity	48%	0%
Percent of customers cooking with gas	47%	100%
Number of customers cooking with electricity, 2019	6,638,042	0
Number of customers cooking with gas, 2019	6,379,417	343,720
Number of customers cooking with electricity, 2050	18,319,293	459,375
Number of customers cooking with gas, 2050	0	0
Number of new electric stoves needed (2019-2050)	11,681,251	459,375
Average capital cost for gas stove	$2,004	$2,450
Average capital cost for electric stove	$2,227	$2,561
Incremental capital cost for electric cooking	$223	$111
Total cost ($ million)	$2,601	$51

Sources: EIA (2018), EIA (2019d), EIA (2021), Kavalec (2018), Mahone et al. (2019), and calculations by the authors. All costs are in year 2019 dollars. ERM assumed 20 percent of commercial customers operate stoves, and that 100 percent of commercial customers who operate stoves use gas. ERM also assumed no commercial customers would use gas stoves in 2050. For the differential in capital cost for electric and gas stoves, ERM used the high end of the range in Mahone et al. (2019) for gas and electric induction.

2.5.4 Electric Vehicles

The HES projects a significant increase in sales of EVs throughout the study period. Currently about 0.5 million of California's light-duty vehicles are EVs (CEC 2021c); the HES projects a total of 6 million EVs in the LDV fleet in 2030 (E3-Decarb, Table A-1) and a total of 35 million by 2050 (E3-Decarb, Table A-2).

As with electric heat and water heating equipment, EVs presently cost more than their gasoline counterparts. E3-Decarb reports a current average cost for BEV automobiles of $43,050 (year 2016 dollars), compared to an average of $35,490 for comparable internal combustion engine vehicles. The difference, converted to 2019 dollars, is $8,053. E3-Decarb assumes that by 2030 the cost differential would be zero, based on recent observed declines for electric vehicles due to technological improvements, but also in part on favorable policy. In particular, the assumption of zero cost differential by 2030 rests on the notion that the incentives presently in place to bridge the cost gap with conventional vehicles will remain in place until at least 2030 (Mahone et al. 2018).

However, if the disparity in vehicle costs remains at the current level, the incremental cost for 5.5 million BEVs, compared to internal combustion engine vehicles, would be $44.3 billion by 2030 (i.e., $8,053 times 5.5 million). The incremental cost by 2050—representing 34.5 million EVs in addition to the 0.5 million currently on the road—could be up to $278 billion, if the current cost differential persists.

3. ECONOMIC AND EQUITY IMPACTS

3.1 Economic Impacts

This section reviews two significant impacts of the HES scenario on the California economy. The oil and gas industry, which is an important contributor to the California economy, will undergo a transformation, which will affect employment and tax revenues throughout the state and particularly in the San Joaquin Valley. In addition, current California state property tax policy limits the ability of counties to modify their tax base in response to changes in response to HES implementation. As with many aspects of the HES, the magnitude of these economic impacts is highly uncertain. The distributional effect, i.e., the groups that will ultimately bear the brunt of the impact, is also uncertain.

The California oil and gas industry contributes to over 365,000 jobs and $21.6 billion in state and local taxes. (LAEDC 2019) (Table 3-1). Almost 80 percent of active oil wells are located in Kern County; however, half of the industry employment is in Southern California[17], with an additional 20 percent in the San Francisco Bay area, 17 percent in the San Joaquin Valley, and 14 percent in the rest of the state (LAEDC 2019). Average annual wages within the industry vary widely, ranging from $25,000 for gas stations to $334,000 for petrochemical manufacturing, indicating that the industry provides livelihoods for a wide-range of income groups (2017$, LAEDC 2019).

The HES study assumes there will be an 86 percent decline in petroleum demand by 2050. The documentation for RESOLVE is ambiguous as to the baseline against which this change is being measured. Moreover, it is unclear how much change the industry would undergo because of electrification and the growth of renewable energy, independent of the HES. For this section, we assume the 86 percent decline is associated with the HES scenario. The impact of the decline will vary by industry sector, with the refinery sector sustaining the largest impacts. However, Mahone et al. (2018) also acknowledges that there is significant uncertainty surrounding how the industry will react to a long-term, structural shift.

This section shows that the HES may result in the loss of about 179,000 jobs by 2050, which is more than a 50 percent decline from current levels. The impact on other economic metrics may be even larger: labor income could decline by $13.4 billion (57 percent), with a $34.1 billion decline in GDP (63 percent).[18] Total state output may decrease by $100 billion (69 percent), decreasing state and local tax revenue by $14.2 billion.

Table 3-1: Impact of the Oil and Gas Industry on the California Economy 2017 vs. 2050

Annual Economic Impact	(2017)	2050
Employment (jobs)	365,970	179,000
Labor income ($B)	$26.1	$13.4
GDP (value added) ($B)	$59.3	$34.1
Output ($B)	$152.3	$100.1

17. Includes Imperial, Los Angeles, Orange, Riverside, San Bernardino, and San Diego counties.

18. GDP includes labor income; these statistics are not additive.

State and Local Taxes ($B)	$21.6	$14.2[19]
Source: LAEDC 2019.		

Geographically, the largest employment impacts (51 percent) are likely to occur in Southern California, where the midstream, downstream, and market industries are focused. The San Joaquin Valley has the highest dependence on the oil and gas industry for employment (2 percent), and by 2050, the HES may reduce employment in that area by more than 7,000 jobs.

The HES will also affect county finances. Currently, there is a state renewable energy tax incentive that allows land used for large-scale solar projects to be taxed at the same assessed value that applied before the project was built (Morgen 2021). If this incentive continues, it will cost California counties more than $300 million in annual property tax revenue by 2050. The largest impact would be $59 million in Kern County, which the HES estimates will have more than 400 km^2 of solar development. San Joaquin Valley counties would forego about $150 million in property tax revenue due to the HES which is almost half of the total impact to the state. The tax incentive is scheduled to sunset at the end of 2024. If it does, then the annual revenue requirements for electricity generation will increase by $300 million, further increasing future electricity rates throughout California.

3.1.1 Oil and Gas Industry Impacts

LAEDC Summary

The Los Angeles County Economic Development Corporation (LAEDC) Institute for Applied Economics published a study in 2019, "Oil & Gas in California: The Industry, Its Economic Contribution and User Industries at Risk." The study analyzes the economic contributions of the industry to the California Economy as of 2017, the most recent year for which data was available.[20] The LAEDC study uses the economic input-output model IMPLAN to conduct the economic impact assessment. IMPLAN is an input-output model that uses data from the U.S. Bureau of Economic Analysis, Bureau of Labor Statistics, U.S. Census Bureau, and other sources. Private companies, governmental agencies and academic institutions regularly use IMPLAN to evaluate the macro-economic effects of policies, programs, and specific infrastructure investments.

IMPLAN assigns each industrial or service activity (e.g., agriculture, mining, manufacturing, trade, services) to an economic sector. Using detailed U.S. Department of Commerce information, IMPLAN relates the purchases of goods and services each industry makes from other industries to the value of output in each industry. As such, IMPLAN describes the supply chain of each industry in terms of output, GDP labor income, employment levels, and state and local tax revenue.

For example, when an oil & gas company expands a pipeline, it hires local labor and contractors and purchases components and materials from other in-state and out-of-state suppliers. Those suppliers have their own expenses and wages that spread the money throughout the economy.

19. Calculated based on the ratio of state and local taxes to output for the oil and gas industry as a whole. The LAEDC report does not report tax impacts for specific sectors of the industry.

20. IMPLAN can measure the impact of a shock on the economy or the contribution of an industry to the economy. However, IMPLAN does not estimate the long-run response of the economy and cannot show the net impact after prices and industries adjust.

IMPLAN models these transactions throughout the economy to calculate the total economic impact of the industry.

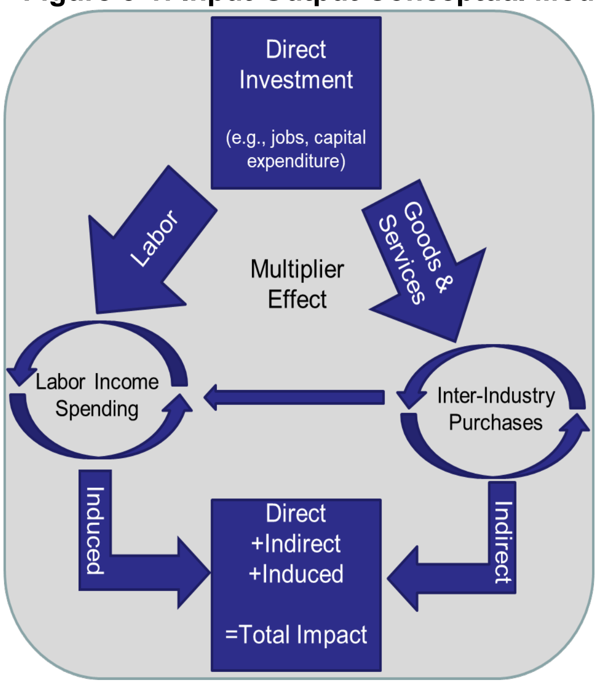
As depicted below, IMPLAN estimates three types of impacts, which are combined to estimate the total impact of each modeled scenario:

1. ***Direct impact*** – the initial change in the value of the output, employment, and labor earnings from the segments of the oil & gas industry,

2. ***Indirect impact*** – the resulting increase in the output, employment and labor earnings in the oil & gas industry supply chain (e.g., industrial lubricants for the oil wells); and

3. ***Induced impact (household spending)*** – the increase in spending by workers in the oil & gas industry and their supply chain (e.g., restaurants, dry cleaners, and local businesses).

Figure 3-1: Input-Output Conceptual Model



IMPLAN economic impact analysis typically reports impacts associated with five categories, described below:

- ***Employment*** – A job in IMPLAN is equal to the annual average of monthly jobs in an industry. One job lasting 12 months equals two jobs lasting six months; each equals three jobs lasting four months. A job can be full time or part time.
- ***Labor Income*** – Labor income includes all forms of employment income, such as employee compensation (wages and benefits) and proprietor income (payments received by self-employed individuals and unincorporated business owners).
- ***Output*** – The total annual value of industry production, which includes total revenue plus the value of inventory.
- ***Gross Domestic Product (GDP)*** – Also known as value added this is the value of output less the value of intermediate consumption; it is a measure of the contribution to GDP.

- ***Taxes*** – The fiscal impact a project or industry has at the state and local level.

It is important to note that IMPLAN can measure the change in the contribution of an industry to the economy; however, IMPLAN does not estimate the long-run response of the economy and cannot show the net impact after prices and industries adjust to the changes.

LAEDC uses IMPLAN to estimate contribution that the oil and gas industry makes to the California economy, focusing on four main sectors of the oil and gas industry, defined below:

- Upstream: oil and gas extraction, drilling oil and gas wells, support activities for oil and gas operations, oil and gas field machinery and equipment manufacturing.
- Midstream: Oil and gas pipeline and related structures construction, petroleum and petroleum products merchant wholesalers, and pipeline transportation.
- Downstream: Petroleum refineries, petroleum lubricating oil and grease manufacturing, and petrochemical manufacturing.
- Market: Natural gas distribution, gasoline stations, fuel dealers.

Table 3-2 shows the direct, indirect/induced, and total employment for each sector of the oil and gas industry. The downstream (refinery) industry has the smallest direct employment at 12,100 jobs (8% of total direct) although, the total job impact is 89,000 jobs, or 24% of total employment because downstream industries have a 7.4 employment multiplier, which means that each direct job supports an additional 6.4 jobs. According to LAEDC, downstream also accounts for over 43 percent of the industry's contribution to GDP, $25.6 billion annually.

Table 3-2: Distribution of Employment Impacts by Industry Segment, California 2017

Sector	Direct Jobs	Indirect/Induced Jobs	Total Jobs	Multiplier
Upstream	20,730	17,770	38,500	1.9
Midstream	20,720	21,620	42,340	2.0
Downstream	12,100	76,900	89,000	7.4
Market	98,550	97,530	196,080	2.0
Total	152,100	213,820	365,920	2.4
Source: LAEDC 2019.				

Potential Impact of HES

The HES assumes that by 2050, petroleum industry demand will be reduced by 86 percent (Mahone et al. 2018, p. A-4). The most pronounced impact of the HES will be on downstream industries, namely refinery activity,[21] because the refineries primarily support California's high demand, rather than supplying other states or countries (LAEDC 2019). However, this impact is uncertain: "It is not known how California's refining sector will respond to a long-term, structural shift towards lower demand for gasoline and diesel in California from vehicle electrification. The sector could shift towards becoming a net-exporter of petroleum products, or it could reduce in-state production, as modeled" (Mahone et al. 2018).

21. The HES focuses on the refinery sector for emissions reductions, estimating a 90 percent reduction in greenhouse gas emissions by 2050 (Mahone et al. 2018, p. 38).

The upstream sector is unlikely to be significantly affected by the HES. California oil production has been fairly steadily decreasing over time. Production has decreased by about 2 percent per year from 1985 to 2017 (LAEDC 2019); at that rate, even without the HES, production will likely be minimal by 2050. However, even if decline were to stop without the HES, then the HES impact would be modest, because upstream industries would likely continue to produce crude for sale to other states or countries. Similarly, the midstream industries that transport crude oil currently will be affected by the HES, but could remain active to the extent that transportation to refineries could be adjusted to provide transportation to ports. Midstream industries could also continue to transport refined petroleum products to other markets (i.e., Reno, Las Vegas, and Phoenix) (CEC 2020).

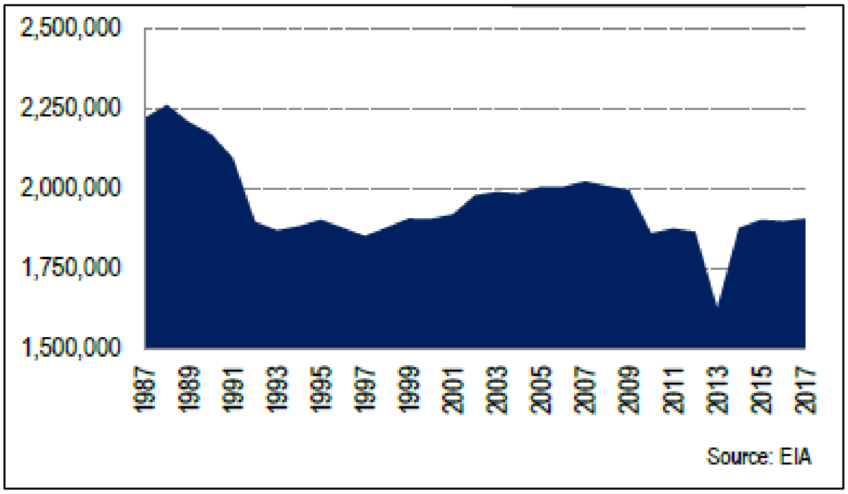
The impact of the HES on the Market sector is highly uncertain. There are over 8,000 retail gas stations in California, with the vast majority also having convenience stations. Although gasoline sales account for about 2/3 of their revenue, with 1/3 coming from in-store purchases, the profit margin on gasoline sales is much lower than for in-store purchases. The extent to which the reduction in gasoline sales will also result in reduced in-store purchases is unclear. Moreover, there are other economic factors, including the pandemic, that are changing the landscape for gas stations, independent of the HES. Market industries would see some level of decreased sales due to the reduction in gasoline demand, but since gas stations also serve as convenience stores, they are unlikely to completely disappear as a result of the HES. Nationwide, a recent study by the Boston Consulting Group estimated that 25 to 80 percent of gas stations could be unprofitable by 2035[22](Boston Consulting Group, 2019), if they do not adequately adapt to changing market conditions, depending on the degree to which EVs are adopted.

Refinery Impacts

The data indicate that in the absence of the HES, the economic contribution of downstream refineries to the California economy would not change materially through 2050. First, although refinery capacity has fallen since 1987 by 14.1 percent, this is significantly less than the decrease in oil field production (56 percent since 1987) (LAEDC 2019). Second, in spite of some volatility, refinery capacity has not changed materially since the early 1990s (Figure 3-2).

22. Is There a Future for Service Stations? (bcg.com)

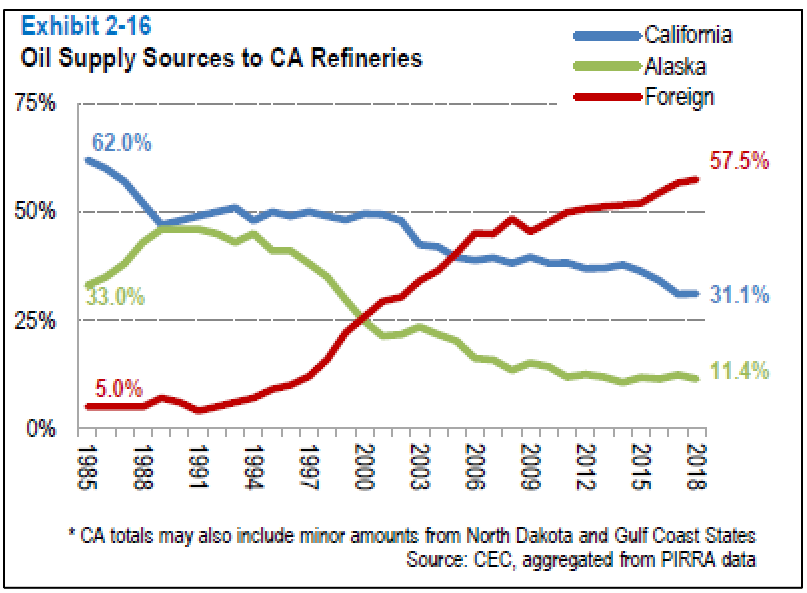
Figure 3-2: Annual Operating Capacity in California (barrels per calendar day)



Source: LAEDC 2019.

Second, as California oil production has decreased, the proportion of oil supplied to refineries from foreign sources has increased (Figure 3-3). "In 2017, California imported 72 percent of its crude oil consumption and 91 percent of its natural gas consumption" (LAEDC 2019, p.6). The California oil supply to California refineries has decreased about 31 percent from 1985 to 2017, about 1 percent per year. This indicates that despite the decline in California-sourced oil supply, the refinery sector has not been affected as foreign supply has made up the difference.

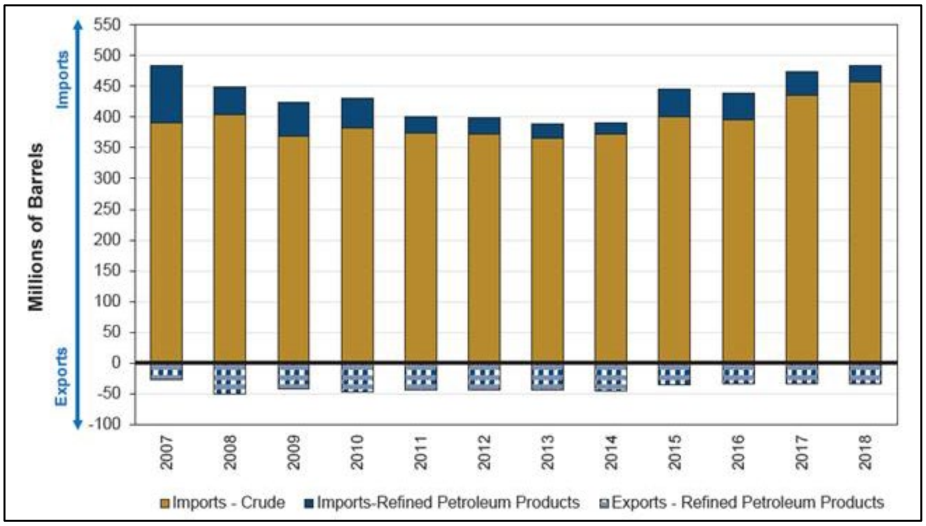
Figure 3-3: Oil Supply Sources to California Refineries



Source: LAEDC 2019.

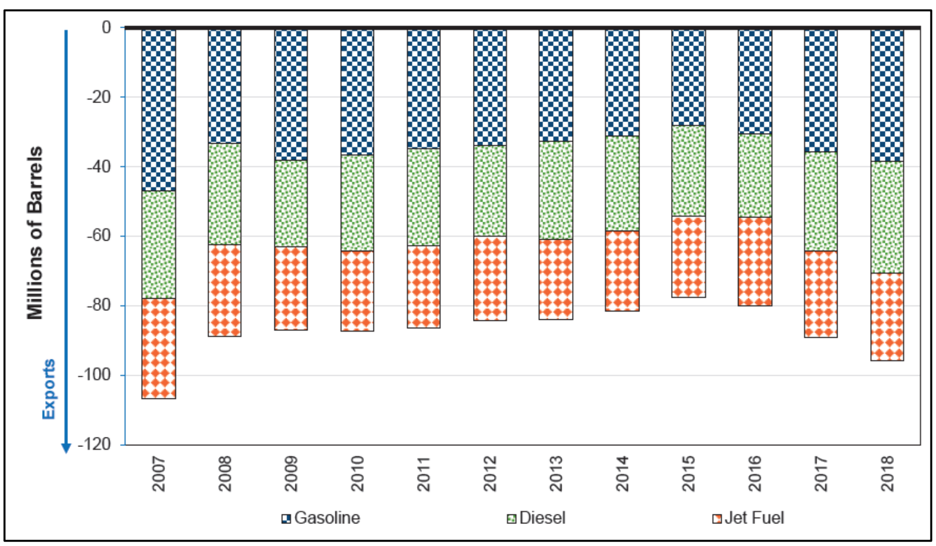
Third, the refinery industry exports some refined petroleum products to other markets. As of 2018, California exported about 35 million barrels of refined petroleum products per year by ship (Figure 3-4), and sent over 90 million barrels of refined petroleum products to other states via pipeline (Figure 3-5) (CEC 2020). Although the EIA does not report total refinery production for California, refinery and blender production for PADD 5 (which includes California)[23] averaged about 1.1 billion barrels of petroleum products from 2015-2021 (EIA 2021b). California exports are about 11 percent of that total.

Figure 3-4: Imports and Exports of All Petroleum Products by Marine Transportation



Source: CEC 2020.

Figure 3-5: Exports of Refined Petroleum Products by Pipeline



Source: CEC 2020.

23. Petroleum Administration for Defense District (PADD) 5 includes Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington. (EIA 2021a)

Economic Impact of HES

This section estimates the impact of the HES's decreased demand for gasoline and diesel on the oil and gas industry, based on the HES assumption of an 86 percent reduction in petroleum demand and the LAEDC estimated contributions of the oil and gas industry to the California economy. Table 3-3 applies the HES 86 percent reduction to the current economic impacts of the downstream petroleum industry, which includes petroleum refineries, petroleum lubricating oil and grease manufacturing, and petrochemical manufacturing. As shown in the table, meeting the HES would result in a loss of about 10,400 direct jobs in the downstream industries, and 76,500 total jobs across the California economy.

Table 3-3: Potential Economic Impact of HES in 2050

	2017	2050 Under HES	Loss
Direct Impacts on Downstream Petroleum Industry			
Jobs	12,100	1,700	10,400
Total Impacts from Downstream Petroleum Industry Effects (direct, indirect, induced)			
Jobs	89,000	12,500	76,500
Labor income ($B)	$7	$1	$6
Value added ($B)	$26	$4	$22
Output ($B)	$88	$12	$76
State and Local Taxes ($B)	$13	$2	$11

The HES will also affect other sectors of the oil and gas industry. The impact on midstream and market sectors is not specified by the HES, but must be somewhere between unaffected (0 percent) and the full impact of the 86 percent demand decrease. A complete loss to those sectors is unlikely as pipelines transporting refined products to other states would continue and could potentially expand, and some gas stations will adapt and will continue to serve customers other products, potentially including electric vehicle charging stations. Table 3-4 thus uses the midpoint, a 43 percent decline, to represent the impact in the midstream and market sectors. The continuing decline in oil and gas extraction is likely to continue regardless of HES implementation; therefore, the impact to upstream activities is unlikely to be material and is not included in Table 3-4.

Table 3-4: Estimated Direct Job Impact of the HES in 2050

Industry Segment	2017 Direct Jobs	Estimated Reduction from HES (percent)	Estimated Reduction from HES (jobs)
Midstream	20,700	43%	8,900
Downstream	12,100	86%	10,400
Market	98,600	43%	42,400
Total	**131,400**	**47%**	**61,700**

Table 3-5 shows the impact of the HES on the California economy, beyond just direct employment. Because of data limitations, Table 3-5 applies the same percent reductions from the direct job impacts to the total economic impacts of each sector and for all of the economic metrics.[24] **Across the three sectors, Table 3-5 estimates a total loss of 179,100 jobs and $34.1 billion in GDP.**

Table 3-5: Estimated Total Economic Impacts of HES in 2050 with Additional Sector Impacts

	Employment (Jobs)	Labor Income ($B)	Value Added ($B)	Output ($B)	State/ Local Taxes ($B)[25]
2017 Economic Impacts					
Midstream	42,300	3.1	5.3	8.4	1.2
Downstream	89,000	7.7	25.6	88.3	12.5
Market	196,100	12.6	22.8	47.8	6.8
Total	**327,400**	**23.4**	**53.7**	**144.5**	**20.5**
HES Loss from 2050					
Midstream	18,200	1.3	2.3	3.6	0.5
Downstream	76,500	6.6	22.0	75.9	10.8
Market	84,300	5.4	9.8	20.6	2.9
Total	**179,100**	**13.4**	**34.1**	**100.1**	**14.2**

Geographic Consequences

Table 3-6 shows the distribution of oil and gas industry jobs throughout the state (LAEDC 2019). The San Joaquin Valley has the highest employment in the upstream sector as Kern County ranks fifth in the US for oil producing counties (LAEDC 2019). The majority of midstream and downstream activity occurs in Southern California and the San Francisco Bay area. Market industries tend to have the highest employment in areas with high populations, such as Southern California. Although the Southern California and San Francisco Bay area sub-regions have the highest percentages of oil and gas industry-supported employment (42 and 20 percent, respectively), the San Joaquin Valley relies more heavily than the other regions on the industry for employment. Two percent of employment in the San Joaquin Valley is supported by the oil and gas industry.

24 IMPLAN is a linear model; however, the economy generally does not respond in a linear fashion to supply and demand shocks.

25. Calculated based on the ratio of state and local taxes to output for the oil and gas industry as a whole. The LAEDC report does not report tax impacts for specific sectors of the industry.

Table 3-6: Geographic Distribution of Oil and Gas Industry Jobs by Sector

Sector	Southern California[26]	San Joaquin Valley[27]	Central Coast[28]	San Francisco Bay Area[29]	Rest of State[30]
Upstream	4,555	7,642	2,150	875	466
Midstream	19,799	4,458	649	9,059	1,410
Downstream	5,553	872	83	5,092	189
Market	35,937	10,554	3,527	11,660	10,181
Total Direct Employment	**65,844**	**23,520**	**6,410**	**26,686**	**12,246**
Percent of CA Industry Employment	43.3%	15.5%	4.2%	17.5%	8.1%
Percent of Total CA Contribution	42.0%	10.6%	3.1%	20.3%	5.0%
Percent of Sub-region Total	1.2%	2.0%	1.0%	1.4%	0.8%

Table 3-7 applies the 2050 HES impacts from Table 3-4 to the regions described in Table 3-6. The largest direct job loss occurs in Southern California, which has the highest oil and gas industry employment overall. The San Joaquin Valley will likely have higher impacts than those shown in Table 3-7, due to the decline in the upstream industries that have the highest employment in that sub-region. If upstream production continues to fall at the current rate, there could be a loss of more than 7,000 additional upstream jobs in that sub-region. The San Joaquin Valley is also where 45 percent of the solar and wind generation development is expected to occur, exacerbating the effects on the economy in that area (see Section 4.3).

Table 3-7: Geographic Distribution of 2050 HES Direct Employment Impacts

Sector	HES Impact	Southern California	San Joaquin Valley	Central Coast	San Francisco Bay Area	Rest of State
Midstream	43%	8,514	1,917	279	3,895	606
Downstream	86%	4,776	750	71	4,379	163
Market	43%	15,453	4,538	1,517	5,014	4,378

26. Southern California includes Imperial, Los Angeles, Orange, Riverside, San Bernardino, and San Diego counties.
27. San Joaquin Valley includes Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare counties.
28. Central Coast includes Monterey, San Luis Obispo, Santa Barbara, and Ventura counties.
29. San Francisco Bay area includes Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, and Sonoma counties.
30. Includes the remaining 31 counties not already included in the previous sub-regions.

Total		**28,742**	**7,205**	**1,867**	**13,288**	**5,147**

Property Tax Impacts of HES

The HES involves installation of 2,723 km^2 of solar generation capacity (see Section 4.3). Currently, California exempts large-scale solar projects from reassessment of the assessed value of the land for property tax purposes. This tax exclusion keeps the value of the land the same as it was for the prior use, which is typically agricultural. Kern County estimates that the exemption is costing the county $19.9 million per year in property tax revenue over the 36,000 acres of renewable energy currently existing in the county, or about $550 per acre (Morgen 2021). Data for other counties is not available. Therefore, to estimate the statewide impact, we use the Kern County per-acre cost estimate as a starting point and adjust for differing average property tax rates in each county using the Tax-rates.org 2021 calculator (Tax-rates.org 2021) and compute the per acre tax loss for other counties.[31] This value is applied to the HES anticipated land area of solar development in California (land areas are described further in Section 4).[32] Table 3-8 shows the potential county-level property tax impacts. Across California, the solar tax exclusion could reduce annual property tax revenues by $314 million, with $155 million of this occurring in the San Joaquin Valley (49 percent). Kern County has the largest amount of new HES solar generation planned and could suffer an addition annual impact of $59 million.

Table 3-8: County-Level Property Tax Impacts from Solar Tax Exclusion

County	Solar Generation Area (km^2)	Annual Tax Loss ($M)
Alameda	1	$0.1
Contra Costa	0	$0.0
Fresno	298	$33.1
Imperial	54	$6.5
Inyo	25	$2.1
Kern	433	$59.1
Kings	50	$5.2
Lassen	13	$1.3
Los Angeles	37	$3.7
Madera	21	$2.1
Merced	56	$6.2
Mono	7	$0.6
Monterey	19	$1.6
Placer	4	$0.6

31. If a county has a tax rate that is 75% of the Kern County rate, than the lost property tax revenue is $316=.75*$555

32. Estimated area of solar development land is described in Section 4.4.2.

County	Solar Generation Area (km^2)	Annual Tax Loss ($M)
Riverside	238	$32.5
Sacramento	90	$10.5
San Bernardino	308	$33.2
San Diego	110	$11.4
San Joaquin	225	$28.0
San Luis Obispo	229	$22.7
Santa Barbara	152	$13.2
Solano	91	$10.7
Stanislaus	149	$16.8
Sutter	6	$0.7
Tulare	42	$4.6
Yolo	64	$7.5
Total	**2,723**	**$314.1**
San Joaquin Valley	1,275	$155.2

The solar energy exclusion is set to expire in 2024. If it does not, it means that areas with large solar installations, such as Kern County, bear a higher social cost for renewable energy because the foregone property tax is not providing revenue for services such as schools, fire protection, and infrastructure. Conversely, if the solar tax exclusion expires as planned in 2024, then the cost of increased property taxes will be included in the revenue requirements for the HES in the form of higher electric rates. In this instance, the rates could be slightly higher for all consumers while the areas with large solar installations would reap the benefits from the additional tax revenue.[33]

3.2 Equity Impacts

The HES may have significant negative economic impacts on disadvantaged families and communities, which will grow over time. The results of previous studies demonstrate the already significant impact of energy costs on low-income families and communities (Lesser 2015, St. Marie et al. 2018). Lesser (2015) reports that in 2012, "nearly 1 million California households faced 'energy poverty' – defined as energy expenditures exceeding 10 percent of household income. In certain California counties, the rate of energy poverty was as high as 15 percent of all households." In 2016, the CPUC reported that 27 percent of residential gas and electric customers qualified for and received California Alternate Rates for Energy (CARE) rates, including almost 50 percent of the Central Valley Region customers (St. Marie et al. 2018). The assessment in this section shows that the HES implementation is likely to worsen this situation going forward, unless there are significant increases in support for households living in energy poverty.

33. RESOLVE documentation does not supply sufficient information to evaluate how this exclusion is treated in the model.

The assessment uses two metrics in assessing the impact of higher energy costs – the poverty level of income and the living wage, both of which vary by household size. The federal poverty level is three times the cost of the minimum food diet and is used to determine eligibility for federal aid programs. The living wage is a more robust environmental justice benchmark, which takes into account not just basic food costs, but also the cost of childcare, health insurance, housing, transportation, and other basic household necessities (Nadeau 2020). The current average living wage in California is $100,686 based on data from the U.S. Census Bureau (2020), roughly six times the federal poverty level. While about 10 percent of California families are below the poverty level, 60 percent are below the living wage.

The following assessment is based on the impact of the 2.5x optimism electric rate (i.e., the midpoint of the 2x and 3x optimism rates) associated with the 2050 HES (discussed in Section 2).

If the HES 2.5x optimism bias adjustment rates occur in 2050 they would cause the following impacts:

- The estimated 1.7 million households at or below the poverty level would see their energy costs increase from 16 to 46 percent of their income.
- An additional 300,000 households would fall below the living wage.
- The number of households in energy poverty will increase from 1.7 to 6.3 million.
- Total energy costs for all California households would increase by $79 billion. An additional increase in the rate burden for all households that are not eligible for rate assistance programs. Low-income households may receive increased CARE or Family Electric Rate Assistance Program (FERA) rate assistance to offset $7.3 billion of their energy bill increase, based on current policy. However, if current policy remains in place, other households will pay higher energy costs to cover the rate assistance programs in addition to the direct HES related increases.

To focus on key distributional issues, this assessment uses a simplified version of the 2050 HES scenario. It assumes that the distribution of income does not change between now and 2050 and that there are no changes in real income. Furthermore, the assessment uses population growth values from Table 2-7. Also, there is considerable uncertainty about when solar and wind power could actually be brought online under the HES, and when (and how many) people will actually convert to electric from gas. As discussed in Section 2, as gas assets become stranded, there could be severe increases in gas rates. However, an alternative response is that all gas users simply convert to electric because the increase in cost is less. This alternative response provides a lower bound estimate of the impact on residential gas users. Therefore, our 2050 residential energy costs assume that all residents are using only electricity. Attempting to model these changes would require additional assumptions and complexity without adding insights into the results. This assessment contrasts the 2019 rates with the estimated 2050 2.5x optimism bias adjustment residential rate of 50.4 cents/kwh (from Section 2), and increasing energy use by 10 percent for climate change (Franco and Sanstad 2006). Section 2 provides a discussion of the total impact on residential bills; this section focuses only on the impacts for current levels of energy use (i.e., heating/cooling, lighting, electronics, cooking, etc.) and excludes increases for EV charging.

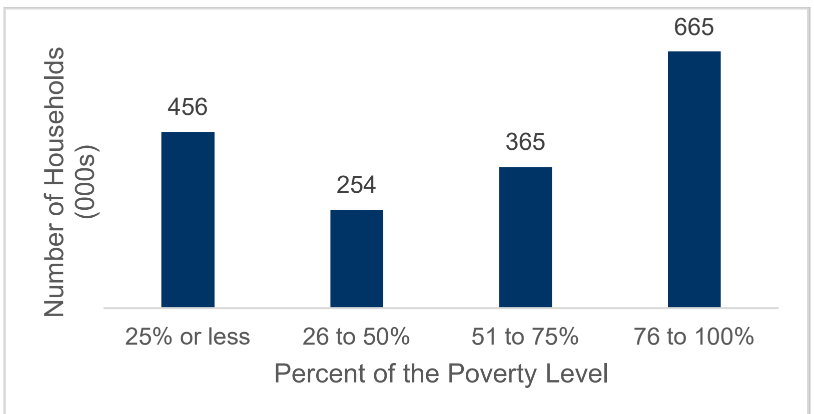
The primary data source is the 2019 U.S. Census Bureau American Community Survey (ACS) Microdata (Ruggles et al. 2021). This dataset includes individual-level information on household energy costs for 130,000 survey respondents, which provides the opportunity to focus on the families that will be most affected by energy cost changes. According to the ACS data, the average annual energy cost for Californians is $2,250 per household, with an annual gas cost of $700 and electric cost of $1,550. The average annual income is $114,000, meaning that statewide, energy costs average 2 percent of household income.[34] These energy costs reflect the cost to the respondent, after discounts provided by the CARE and FERA programs. Thus, for eligible low-income families, the reported energy costs are lower than they would have been in the absence of these programs. Applying the survey weights from the ACS to the 130,000 survey respondents yields an estimated 12 million households. These survey weights are increased to yield the 13.7 million households reported in Table 2-7. For the 2050 impacts of the HES, the weights are scaled up to yield the 2050 population from Table 2-7 (i.e., 18.3 million households).

3.2.1 Low-Income Households

Impact Based on Poverty Level

The estimated number of households that will be below the poverty level in 2050 is about 1.7 million, compared to 1.2 million in 2019. Figure 3-6 shows the breakdown of these households by the percent of the poverty level. Approximately 455,000 of these households would be in the bottom quartile, with income that is 25 percent or less of the poverty level. Similarly, 254,000 households below the poverty level would have income that is 26 to 50 percent of the poverty level. An estimated 665,000 households below the poverty level would have incomes between 76 and 100 percent of the poverty level.

Figure 3-6: Percent of Households below Poverty Level by Poverty Level Quartile, 2050

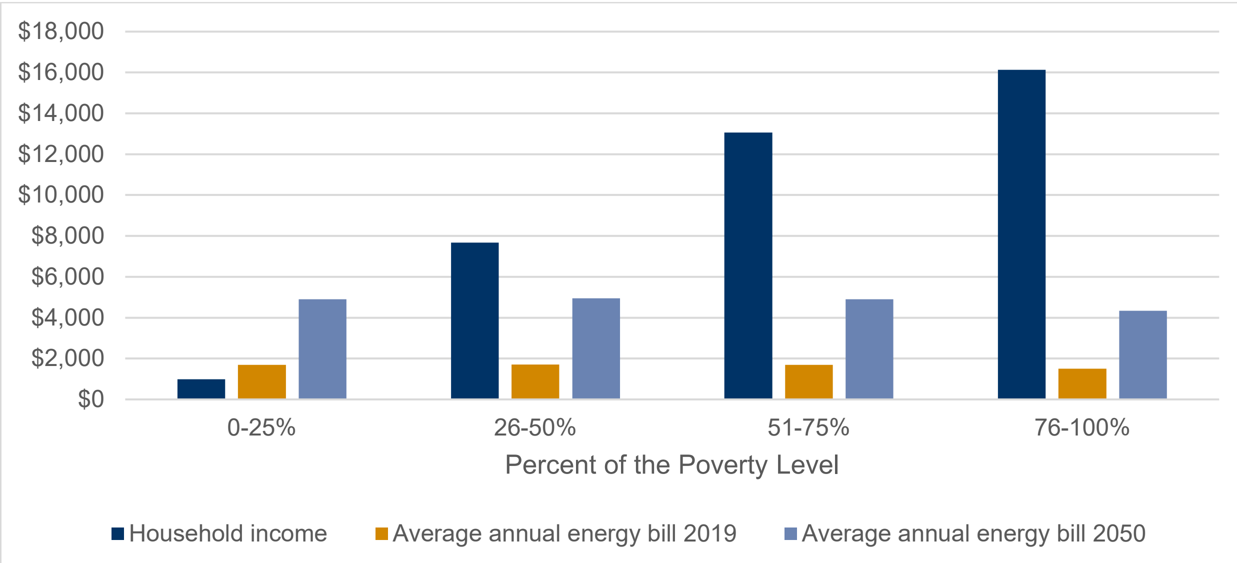


The impact of the HES on households below the poverty level is shown on Figure 3-7. The graph shows households grouped by their income as a percent of the poverty level. The 2019 average annual energy bill (including both gas and electric costs) is between $1,500 and $1,700 per household, and increases to $4,300 to $4,900 (depending on quartile) for the 2050 HES. To a large extent, the bill does not vary across income category; however, income does. The poorest households average an annual income of only about $1,000, which is not enough to cover energy bills currently, much less under the 2050 HES. Even at the top end of income for

34. These data exclude respondents who did not provide energy cost estimates because their energy costs are included in their rent.

households below the poverty level, energy bills will be more than a quarter of their $16,000 income with HES implementation.

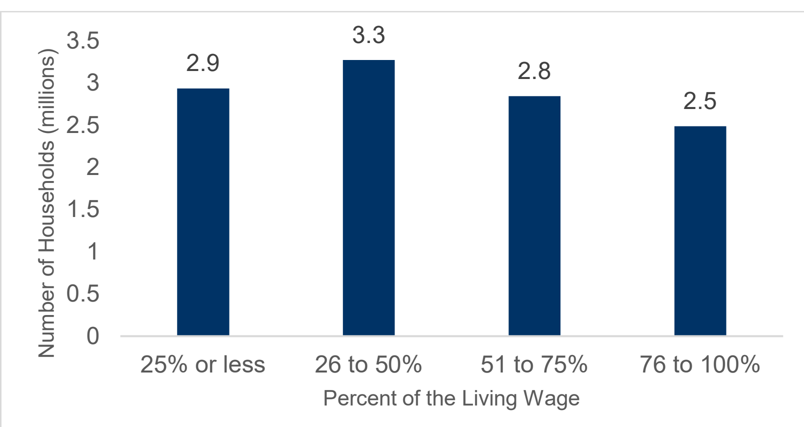
Figure 3-7: Household Income and Annual Energy Costs per Household, by Percent of the Poverty Level, 2019 vs. 2050



Impact Based on the Living Wage

The living wage is another equity benchmark for assessing policy impacts. The living wage measures the minimum income a family needs to meet their basic needs. The living wage varies by family composition, based on the number of working adults and the number of dependent children (Nadeau 2020). The current average living wage in California is $100,686 (U.S. Census Bureau 2020). Figure 3-8 shows that in 2050, there will be 10.9 million households below the living wage, with most of them below 50 percent of the living wage.

Figure 3-8: Number of Households below Living Wage by Living Wage Quartile (Millions)



The HES 2.5x optimism bias adjustment has two impacts with respect to the living wage. Currently, 60.5 percent of California households are below the living wage. This number will increase by 0.3 million households, to 61.9 percent, in 2050 under the HES. This is because the average per household annual energy bills will increase by $3,800, which means the living wage must increase by the same amount, which pushes more households below it.

Table 3-9: Average Annual Energy Costs for Households below the Living Wage

Group	Number of Households in 2050 (M)	Average Annual Energy Cost Per Household[35]		Energy Cost as Percent of Income	
		2019	2050	2019	2050
Households below the living wage	10.9	$ 1,800	$ 5,100	4%	11%
Households falling below the living wage due to the HES	0.3	$ 2,200	$ 6,300	2%	6%
Households remaining above the living wage	7.1	$ 2,400	$ 6,900	1%	3%
All California Households	18.3	$ 2,000	$ 5,800	2%	5%

For households at or below the living wage, HES would increase energy costs from an average of 4 percent of income to 11 percent at the 2050 2.5x optimism bias adjustment.

Summary of the HES Equity Impacts

The total annual increase in energy costs for all households statewide is estimated to be $79.4 billion (Table 3-10). For the 1.7 million households below the poverty level in 2050, the estimated total annual increase in energy costs is $5.7 billion. The increase for the 10.8 million households below the living wage in 2050 is $41.5 billion. Statewide, energy costs will increase by 286 percent, including both the rate increase and the population increase.

Table 3-10: Statewide Impacts on Households below the Poverty Level and Living Wage in 2050

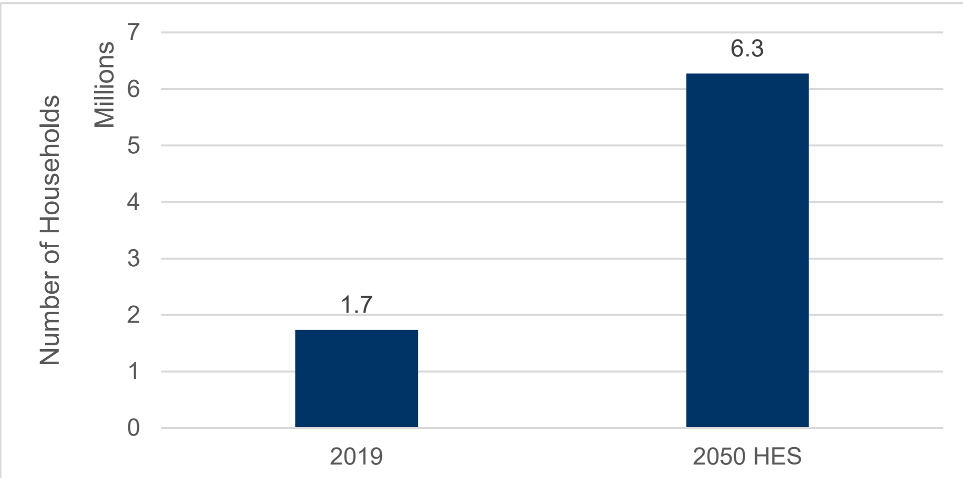
Group	Number of Households (millions)		Energy costs as Percent of HH Income (1)		Total Energy Costs (billions)		Increase		
	Current	2050	Current	HES 2050	Current	HES 2050	$Billions	Per Household ($)	Percent
Statewide	13.7	18.3	2%	5%	$27.7	$107.1	$79.4	$3,800	286%
Below the Poverty Level	1.2	1.7	16%	46%	$2.0	$7.7	$5.7	$3,100	287%
Below the Living Wage	8.1	10.8	4%	11%	$14.5	$56.0	$41.5	$3,400	285%
	(1) Percent of income statistics do not include people who report their income as zero.								

35. Includes both gas and electric costs for 2019, and all electric costs for 2050.

Figure 3-9 shows the number of households living in energy poverty, defined as energy costs that are more than 10 percent of household income, in 2019 versus under the 2050 HES. **The predicted increase in energy costs and population will more than triple the number of households in energy poverty.**

Figure 3-9: Households Living in Energy Poverty

(Households with energy expenses above 10 percent of income)



Impact of Energy Assistance Programs

It is uncertain how much of the cost increase from the HES will actually be paid by each income group described above. While there are numerous ways that these equity issues could be handled (Borenstein et al. 2021), which may address other inequities as well, there does not appear to be a consensus on the appropriate approach. The analysis below thus assumes that the CARE and FERA programs continue in their current form. The CARE program provides low-income[36] customers a 20 to 35 percent discount on electric bills[37] and a 20 percent discount on gas bills. Customers of Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric whose income slightly exceeds CARE income limits are eligible for an 18 percent discount on their electric bills through the FERA Program. A rate surcharge applied to all other utility customers funds these low-income rate assistance programs (CPUC 2021). Assuming these programs continue, average energy bills for low-income customers would increase less than the overall average due to CARE and FERA discounts, while other customers would likely see a higher increase than the overall average as their rates increased to pay for the rate assistance programs.

36. Households with an income at or below 200 percent of the Federal Poverty Level guidelines, adjusted for household size (CPUC 2021).

37. Utilities with 100,000 or more customer accounts offer a 30-35 percent discount and utilities with less than 100,000 accounts offer a 20 percent discount.

Based on the ACS income data, there will be 4.6 million households eligible for CARE assistance in 2050 (26 percent), and potentially as many as 0.6 million more could be eligible for FERA (3 percent).[38] Under the HES, CARE assistance costs would increase by an average of $1,500 per eligible household annually, or a total of $6.6 billion.[39] FERA assistance costs could increase by $1,100 per eligible household, or a total of $0.7 billion (assuming all households with eligible income are served by a participating utility). Combined, the 5.2 million households eligible for assistance could receive $7.3 billion, or $1,400 per household.

These additional costs would be partially borne by the roughly 13.1 million households in 2050 that would not be eligible for these programs.

The CARE/FERA costs would increase the revenue requirement by about 3 percent, similarly increasing the resulting electric rate by 3 percent from 50.4 cents to 51.9 cents. For households that are not eligible for CARE/FERA, the higher rate would mean that the average household energy cost would increase by about $4,000 rather than the $3,800 in Table 3-10.

Table 3-11: Impact of CARE/FERA Rate Assistance Programs under the HES 2050

	HES 2050
CARE/FERA eligible households	
Total Increase in Energy Cost Burden from the HES	$19.1B
Total Reduction of Burden from CARE/FERA	$7.3B
Average Reduction per CARE/FERA eligible family	$1,400
Non CARE/FERA eligible households	
Total Increase in Energy Cost Burden from HES	$60.3B
Additional total increase from CARE/FERA costs	$2.6B[1]
Percent increase	3%
Additional increase per kWh	$0.015
Additional increase per Household	$195
Average increase per household for HES 2050, with additional cost of CARE/FERA	$4,000

(1) A portion of the CARE/FERA cost will be borne by commercial customers.

3.2.2 Disadvantaged Communities

This section reports the impact of implementing the HES on disadvantaged communities. Disadvantaged communities are defined by the California Office of Environmental Health Hazard Assessment for the purpose of SB 535 (OEHHA 2021), and are based on a variety of

38. Households must enroll in these programs to receive assistance, so not all eligible households necessarily receive the benefit. The income eligibility levels for CARE and FERA change annually for inflation; this analysis uses the 2019 eligibility because the income data is for 2019. Also, FERA is only available to customers of specific utilities, and the ACS data does not identify the utility serving each household. This estimate reflects the maximum number of potential FERA recipients, if all eligible households were served by one of the FERA utilities.

39. Assumes that CARE-eligible households receive 30 percent rate assistance.

economic, environmental and social metrics at the census tract level. However, for this analysis we focus on the county level, looking at those counties with the highest level of disadvantaged communities. Table 3-12 shows impacts for counties where at least 25 percent of the population lives in disadvantaged communities, which account for over 80 percent of the statewide disadvantaged population. The counties are: San Joaquin Valley (Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus, Tulare); as well as Imperial, Los Angeles, Mariposa, and San Bernardino counties. Table 3-13 compares the average characteristics of these 12 counties to the other counties in the state. As shown in Table 3-13, the disadvantaged communities suffer lower education levels, higher unemployment, lower wages, and are disproportionately minority and of poorer health.

Table 3-12: Statewide Impacts on Disadvantaged Community Households below Poverty Level and Living Wage

Group	Number of Households (millions)		Energy costs as Percent of Household Income		Total Energy Costs ($billions)		Increase		
	Current	2050	Current	HES 2050	Current	HES 2050	$billions	Per Household	Percent
Counties where more than 25% of the population lives in disadvantaged communities.	5.7	7.7	2%	6%	$12.2	$47.1	$35.0	$4,000	287%
Below the Poverty Level	0.7	0.9	16%	45%	$1.1	$4.4	$3.2	$3,300	287%
Below the Living Wage	3.8	5.1	4%	11%	$7.3	$28.0	$20.7	$3,500	285%

Table 3-13: Disadvantaged Community Profile

Characteristic	12 Counties with 25%+ Disadvantaged Population	All Other Counties
No high school diploma (over 25 years old)	22%	14%
Minority (all except white, non-Hispanic)	72%	56%
Occupied housing units with more people than rooms	10%	7%
Households with no vehicle	12%	8%
Unemployment rate	8%	6%
Net migration index(1)	97	104
Average annual growth in wages/salaries index(2)	84	106
Per capita personal income	$54,000	$71,000
% of population at or below the living wage	73%	66%
% of population below poverty level	18%	12%
% of population in fair or poor health	18%	14%
Average number of physically unhealthy days	3.8	3.4
Average number of mentally unhealthy days	3.8	3.6

(1) Average net domestic migration rate from 2009 to the latest year available. This index measures the extent to which people are migrating to a region, and excludes other population dynamics such as births. An index over 100 indicates more people entering the region than leaving.
(2) Average annual rate of change in wage and salary earnings per work from 2002 to the latest year available, based on the place of work, not the area of residence. This index measures employee compensation based on where the activities occurred, and higher values indicate stronger growth in earnings.

These 12 counties include nearly 6 million households, of which 700,000 are below the poverty level and 3.8 million are below the living wage. The annual increase in energy bills for these residents will be $4,000 per year, which will increase energy costs from 2% to 6% of annual income.

3.2.3 People of Color

People of color throughout the state will also be affected by the HES implementation.[40] People of color include all non-white, non-Hispanic households. As a group they will experience a $3,500 per household increase in energy costs.

40. These values are comparable to the total statewide values.

Table 3-14: Statewide Impacts on People of Color Households below Poverty Level and Living Wage

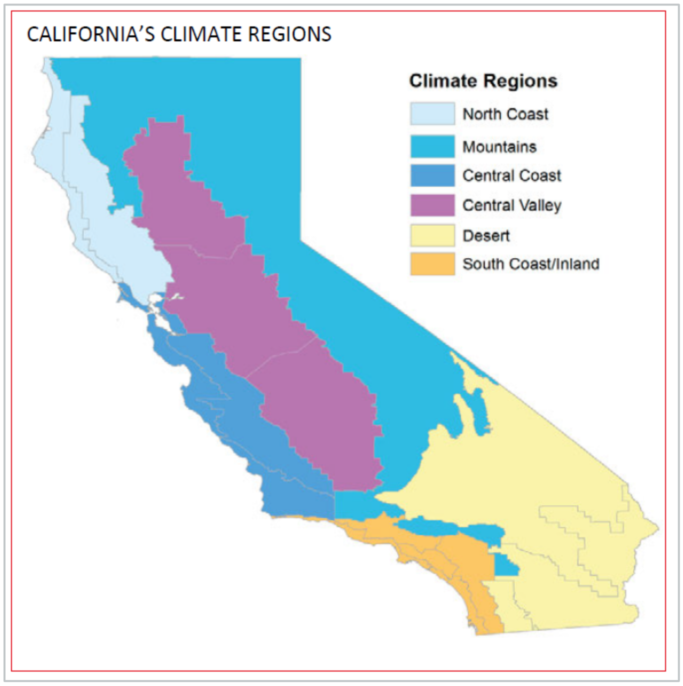
Group	Number of Households (millions)		Energy costs as Percent of Household Income		Total Energy Costs ($billions)		Increases		
	Current	HES 2050	Current	HES 2050	Current	HES 2050	$billions	Per House-hold ($)	Percent
People of Color	5.0	6.6	2%	5%	$9.1	$35.2	$26.1	$3,500	286%
Below the Poverty Level	0.6	0.8	15%	42%	$0.9	$3.3	$2.5	$2,900	287%
Below the Living Wage	3.0	4.1	4%	10%	$5.1	$19.7	$14.6	$3,200	287%

3.2.4 Climate Regions

Implementing the HES will also have distributional impacts based on geography and climate. The California Public Utilities Commission Policy and Planning Division identifies six climate regions in California (Figure 3-10). These are areas where the climate is similar, and thus energy use is also similar (Rockzsfforde and Zafar 2015). In 2015, CPUC conducted a study of annual electricity use by zip code and climate region. We used that data to calculate the increase in energy bills. For the purposes of this analysis, we calibrate the data such that statewide average annual increase in the energy bill in 2050 is $3,800, the same value reported in Section 3.1. The dataset also includes information on the proportion of customers enrolled in the CARE program.

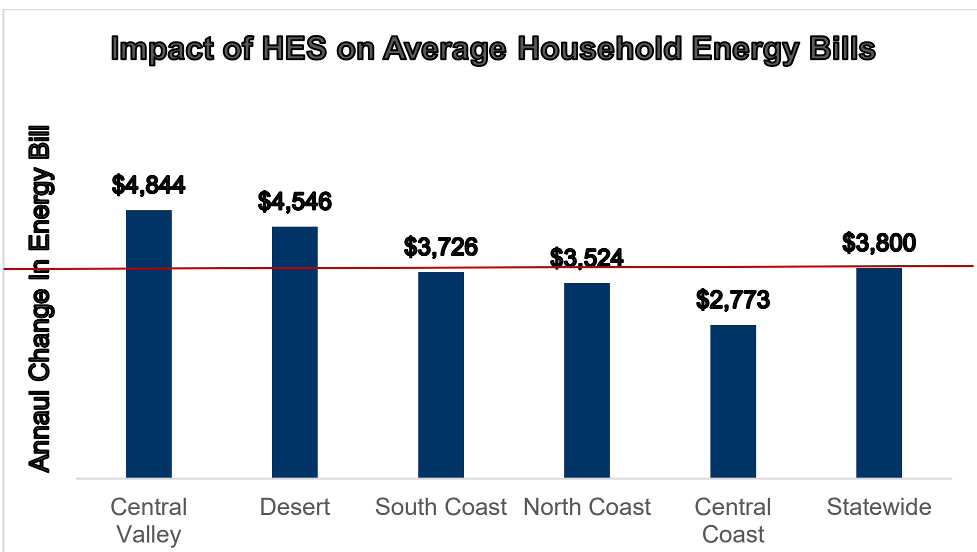
Figure 3-10 shows the impact of the HES across the climate regions. The Central Valley region would experience the highest increase in energy bills, $4,844 per year, while the Central Coast would experience the lowest, $2,773 per year. At the time of the study, the climate region with the highest enrollment of customers in CARE was the Central Valley, at 32 percent. The lowest enrollment in CARE was the Central Coast, at 19 percent. Finally, the median income for ZIP codes in the Central Valley was 25 percent lower than the Central Coast. This is additional confirmation that the burden of the HES will disproportionately fall on lower income households.

Figure 3-10: California Climate Regions



Source: Rockzsfforde and Zafar 2015.

Figure 3-11: Impact of the HES on Household Energy Bills Based on Climate Zone[41]



41. Current graph only includes electricity. Additional adjustments will be necessary to include gas use.

4. LAND USE AND ENVIRONMENTAL ANALYSIS

Development of renewable energy resources will primarily impact California's rural landscape, with potential broad-scale direct and indirect land use, community, and environmental and cultural resource impacts. This chapter describes the estimated scale and location of development required to achieve HES objectives; highlights challenges and uncertainties of achieving this level of land development; and discusses the potential impacts that are likely to occur in California should this level of development be achieved.

- Section 4.1 reviews the estimated solar and wind capacity required by 2050 to achieve HES electrification objectives; the associated land area required for new solar and wind during this timeline; and the variability of these land area estimates.
- Section 4.2 provides additional details of the E3-TNC study methodology and results; and reviews other regional land use studies to provide further perspective on the amount and likely location of land that will be impacted by the HES buildout.
- Section 4.3 reviews practical hurdles to renewable energy development at the project level to provide perspective on the challenges and uncertainties of land development at the HES scale.
- Section 4.4 provides quantitative estimates of the potential statewide and regional impacts to environmental resource categories based on interpretation of data provided by E3-TNC for a representative HES buildout scenario.
- Section 4.5 provides further qualitative discussion of reasonably foreseeable impacts associated with broad-scale renewable energy development and presents illustrative examples in the environmental issue areas often cited in renewable energy project assessments.

4.1 Physical Scale and Pace of HES Solar and Wind Development

As explained above, E3-CP's 2019 study estimated total installed capacity for 2020 and total future installed capacity by 2050, with a projected net increase in capacity for industrial solar and wind of 101.5 GW and 4.7 GW, respectively.

California's in-state onshore wind resources, in contrast to solar development potential, are largely already developed, and the remaining preferred onshore wind resource sites are largely not available to development. Therefore, E3-TNC's projected wind resources are largely sourced from out of state. The potential contribution from offshore wind is not considered in the E3-TNC analysis; however, it is worth noting that this source could contribute to future generation capacity.[42]

E3-TNC provides benchmarks for the typical land area and capacity for individual industrial solar and wind projects that would be developed under the HES:

42. According to E3-TNC 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, and, secondarily, because 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. CSP is considered in the supply curve for existing versions of RESOLVE, but E3-TNC considered the estimated capital costs to be too prohibitive for new capacity to be selected under any scenario.

- Most solar projects would provide about 120 megawatts (MW) of capacity on a land area of 4 km^2, or 988 acres, 1.54 square miles.
- Most wind facilities would provide about 55 MW of capacity and install turbines on about 9 km^2 of land, or 2,223 acres, 3.47 square miles.

Applying these benchmarks to the E3-CP incremental capacity estimates (101.5 GW solar and 4.7 GW wind) indicates a cumulative land development footprint of 3,383 km^2 (836,000 acres; 1,300 square miles) for new industrial solar, and 352 km^2 (87,000 acres, 136 square miles) for wind. This land area is within the range of estimates developed by E3-TNC, and it is close to the estimated 3,821 km^2 (943,787 acres) that E3-TNC anticipates will be needed for solar development under their Full-West siting level 4 constrained scenario, which is discussed further below, and serves as a benchmark for additional analysis of potential impacts.

It is worth noting that existing solar PV generation sites in California are generally much smaller than 4 km^2. According to CEC's list of Solar PV and Solar Thermal Electricity Production, there are 759 operational solar PV projects in California (CEC 2021b). Of this total, 55 facilities have a production capacity of 50 MW or more and the average production capacity is 17 MW (14% of E3-TNC's benchmark). Applying E3-TNC's benchmark from above suggests an average land area per facility of 0.6 km^2 (139 acres). These land area estimates do not account for clustering of multiple facilities at contiguous sites; however, these data suggest that E3-TNC's benchmark for future land development may underestimate the number of individual future development sites, and overestimates the average land area for future solar development sites.

E3-CP's analysis also anticipates that California would need 74 GW of new 6-hour duration battery capacity (up from less than 1 GW of lower-duration 2020 battery capacity). Battery energy storage systems are not land intensive as compared to solar arrays; however, this level of battery development and associated substation equipment could require an estimated additional 10 km^2 (about 2,470 acres), assuming an average yield of 30 MW of battery storage per acre. Many of these facilities will be co-located with solar PV or with new and existing electrical substations, and others will be stand-alone facilities that are strategically sited on private lands located at optimal grid interconnection points in various rural and urban settings.

E3-CP's analysis also anticipates 19 GW of new behind-the-meter solar (up from about 6 GW in 2020, a 3-times increase). Retained gas generation facilities would be used for longer duration solar and wind power outages.

The actual land area that may be required to achieve HES buildout is highly uncertain given the multiple potential scenarios that depend on the amount of generation imported to California (mostly wind resources), constraints on the scale of new generation facilities, and extent of distributed energy resources such as rooftop solar.

In addition, the actual land area may be greater than indicated in E3-TNC's scenarios due to factors such as:

- Greater reliance on overbuilding of solar and wind with curtailment due to relatively higher cost of battery storage. As noted in Section 2, studies suggest that falling technology costs imply it is less expensive to overbuild solar and wind, and curtail excess output rather than investing in relatively costly battery storage (e.g. Denholm et al. 2021, Perez and Rabago 2019).
- Lower adoption rates of behind-the-meter solar and other distributed energy resources, with correspondingly greater reliance on utility-scale solar and wind facilities.

These and other factors may lead to more land being needed to develop the same amount of resources.

In E3-TNC's In-State scenario, the estimated incremental solar generation land area ranges from 3,937 to 5,001 km^2, with negligible wind development primarily due to the scarcity of developable in-state wind resources. In the Part West scenario, the estimated incremental solar generation land area ranges from 3,042 to 3,660 km^2, and the land area for new wind resources ranges from 1,235 to 6,098 km^2. And under a Full West scenario, the estimated land area for solar is 1,461 to 3,821 km^2 due to a substantial increase in wind resources from out of state, and associated long-distance transmission. Land areas for new generation-tie line (gen-tie) and transmission corridors are relatively low (less than 10 km^2) in most scenarios, but range up to 100 km^2 in the high-import Full West scenario. (E3-TNC [Wu et al. 2019]; Tables 15 - 16)

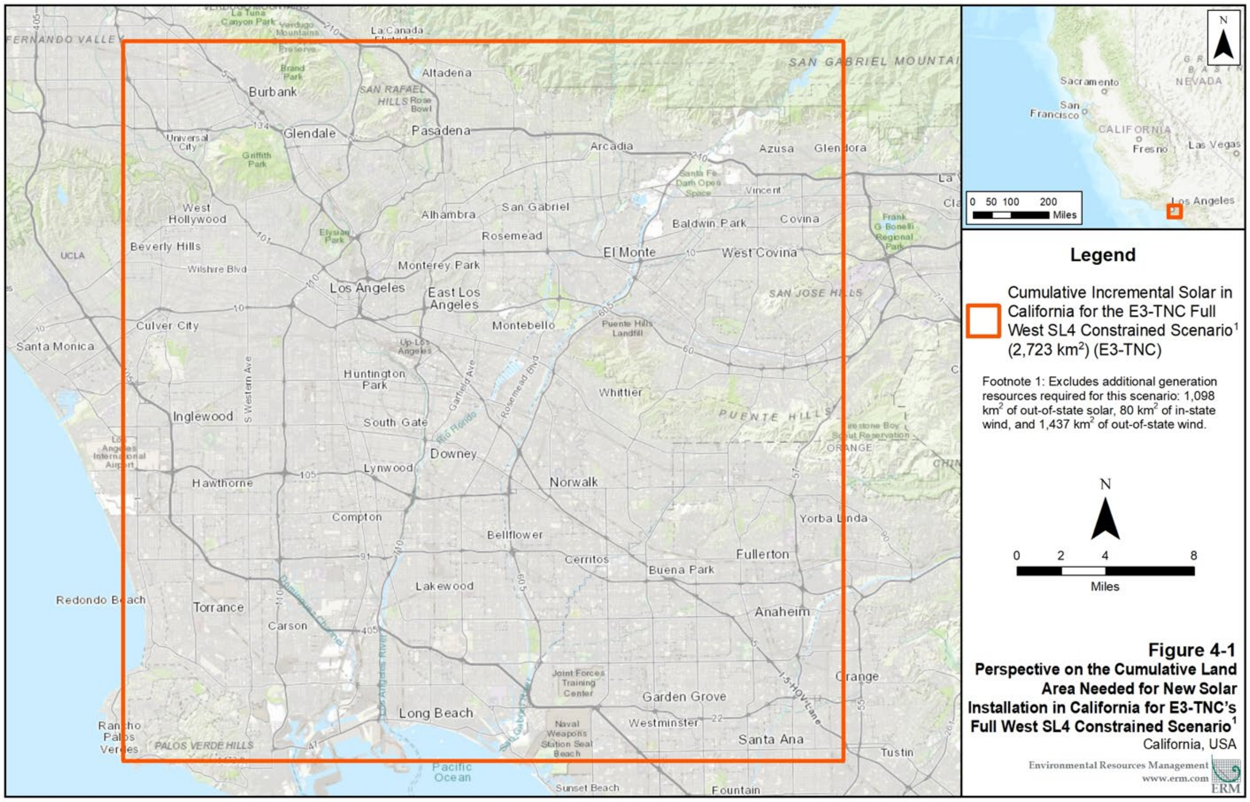
A plausible mid-range land development scenario within E3-TNC's analysis range is 3,000 to 5,000 km^2 with a mid-point of 4,000 km^2 reflecting a case that is generally between E3-TNC's Part West and Full West scenarios, because it is reasonable to assume that some of the expanded generation will come from out of state. For the purpose of quantified impact analyses presented later in this section, we assume a land area of 3,821 km^2 of solar development, of which 2,723 km^2 (672,581 acres) would be developed in California; this is based on E3-TNC's Full-West scenario in the constrained case, and with the highest level of environmental resource protections.

Using CEC's 2020 solar capacity figure stating that 15.63 GW, including imports, of solar thermal electricity production capacity is available in California, and E3-TNC's benchmark of 120 MW of solar availability per 4 km^2 area, the current land already developed for solar generation in California is approximately 521 km^2. Thus, **under the Full West SL4 Constrained scenario, which requires less land in California for solar development than in other scenarios, approximately 5 times the estimated land area currently developed for solar will need to be operational in California to meet the HES needs. Under the Part West and In-State scenarios, which require more land in California for solar development, approximately 6 to 10 times the amount of land area currently developed for solar will need to be operational to meet the HES buildout**.

To put the necessary land area in California for solar development under the HES in further perspective, a land area of 2,723 km^2 (672,581 acres), which represents the area of new solar development in California under the Full West SL4 constrained scenario, is roughly equivalent to the metropolitan Los Angeles region from Burbank to Long Beach, as illustrated in Figure 4-1.

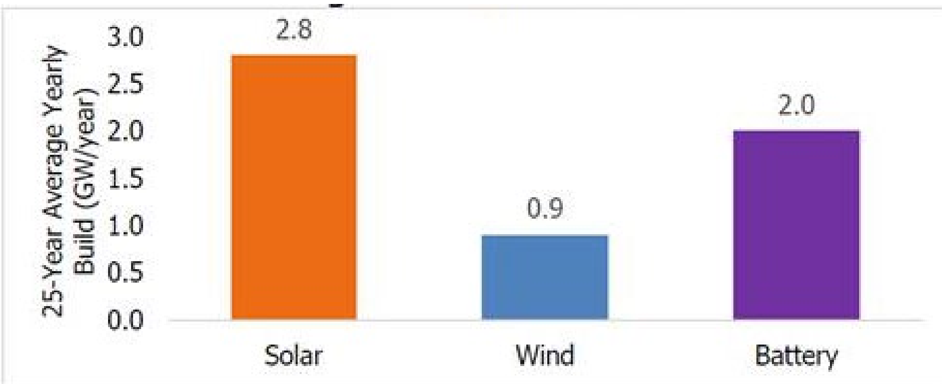
For further perspective, the 2020 installed solar PV capacities in Fresno and Kings counties in southern San Joaquin Valley – two counties with large relative shares of the state's installed solar projects – are 1,008 MW and 590 MW, respectively (1.6 GW total, or approximately 10% of the state-wide total) (CEC 2021b). Using the same benchmark as above for land area per MW of production, this is equivalent to roughly 53.2 km^2 of land area dedicated to solar PV, excluding gen-tie and transmission corridors. **This is only 2 percent of the estimated 2,723 km^2 of land area needed to meet the solar buildout in California under the HES Full West SL4 Constrained scenario, and only 1.4 percent of the total estimated solar development when including out-of-state development**.

Figure 4-1: Cumulative Estimated Land Area of 2,723 km^2 Required for New Solar Installation in California for E3-TNC's Full West SL4 Constrained Scenario



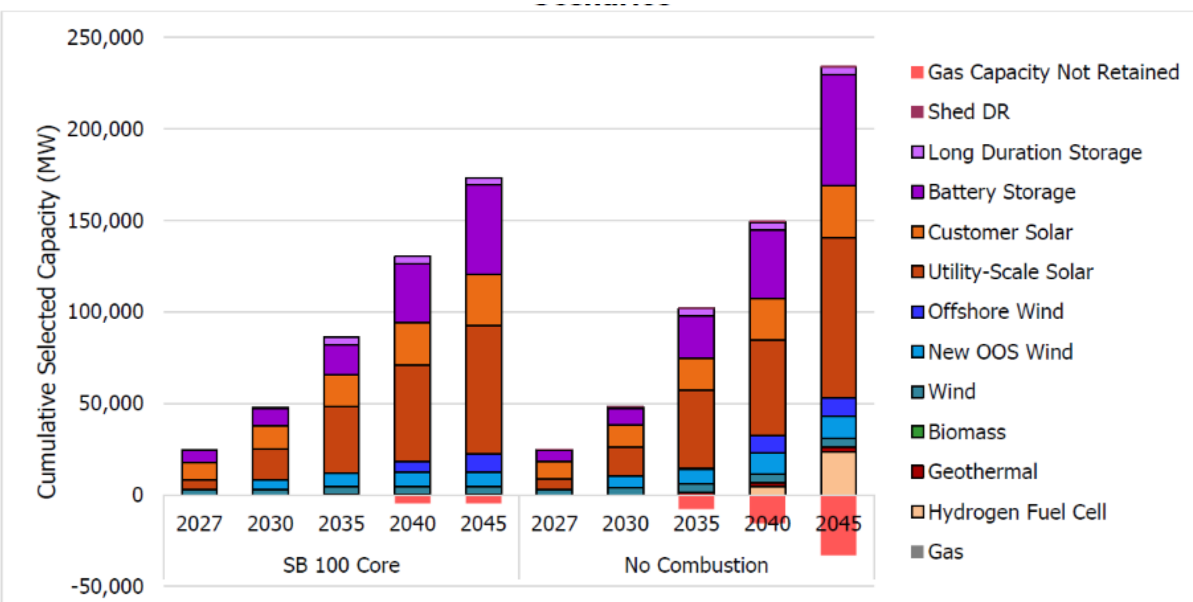
For additional perspective, 4,000 km^2 is roughly 20 percent of the approximately 21,000 km^2 (8,200 square miles) of urbanized land in California as listed in the 2010 U.S. Census (Census Bureau 2010), or roughly three times the City of Los Angeles. Thus, under the HES, California land development for solar resources would need to occur at levels far higher than achieved in the state to date.

In addition, achieving the HES would require the development of solar, wind, and battery storage projects over the course of 25 years at a rate never seen in California. The CEC's SB 100 Joint Agency Report shows the 25-year average yearly build rate necessary for solar, wind and battery to achieve the HES buildout. Over the last decade, California has built on average 1 GW of utility-scale solar and 300 MW of wind per year, with a maximum annual build of 2.7 GW of utility-scale solar and 1 GW of wind capacity. The highest annual build rate that has ever occurred is 2.7 GW for solar and 1.0 GW wind (CEC 2021a). As shown in Figure 5 of the SB 100 Report (shown below), **the HES would require annual build rates averaging as high as the highest historical annual build rate for 25 years.** This is equivalent to an estimated average and maximum annual build rate of 33 km^2 and 90 km^2, respectively, for solar, and 23 km^2 and 75 km^2, respectively, for wind.



Source: CEC 2021a. SB 100 Joint Agency Report Figure 5. Average Resource Build Rates for Solar, Wind and Batteries in the SB 100 Core Electrification Scenario.

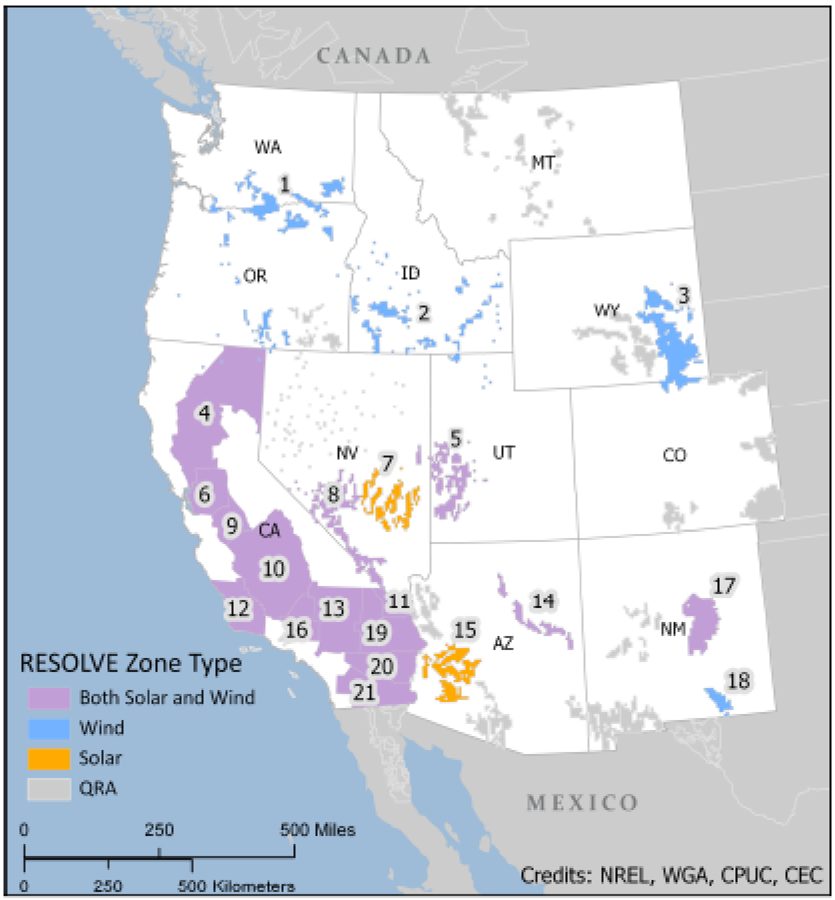
The SB 100 Study projects a relatively straight-line progression of development between 2027 and 2045 (SB 100 Report Figure 8, left portion, shown below). However, according to the E3-CP study (E3-CP Figure 10, shown above), much of the anticipated development is concentrated in the 10-year period after 2040; adding 50 GW of solar to the grid during this period.



Source: CEC 2021a. SB 100 Joint Agency Report Figure 8. Cumulative Capacity Additions for the SB 100 Core and No Combustion Scenarios.

4.2 E3-TNC Study Methodology and Results

E3-TNC assumes that California will implement the HES approach to achieve California's goal of reducing greenhouse gas emissions by 80 percent by 2050. It uses E3's California-wide RESOLVE model, developed for the CEC, with modifications, to consider how a number of different conservation and siting assumptions would affect the protection of important resources while minimizing costs. RESOLVE is an electricity sector capacity expansion energy planning model developed by E3 for the CEC to guide energy planning and regulations in support of climate commitments. RESOLVE zones are the spatial units with which the capacity expansion model, RESOLVE, aggregates generation supply characteristics, including cost, generation potential, generation temporal profiles, and transmission availability. RESOLVE zones include areas designated in the state model for future renewable development based on various siting and grid reliability factors. A map of RESOLVE zones is shown below, as presented in E3-TNC.[43]



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

Source: E3-TNC Figure 2 RESOLVE Zone names and locations for solar-only, wind-only, and both technologies.

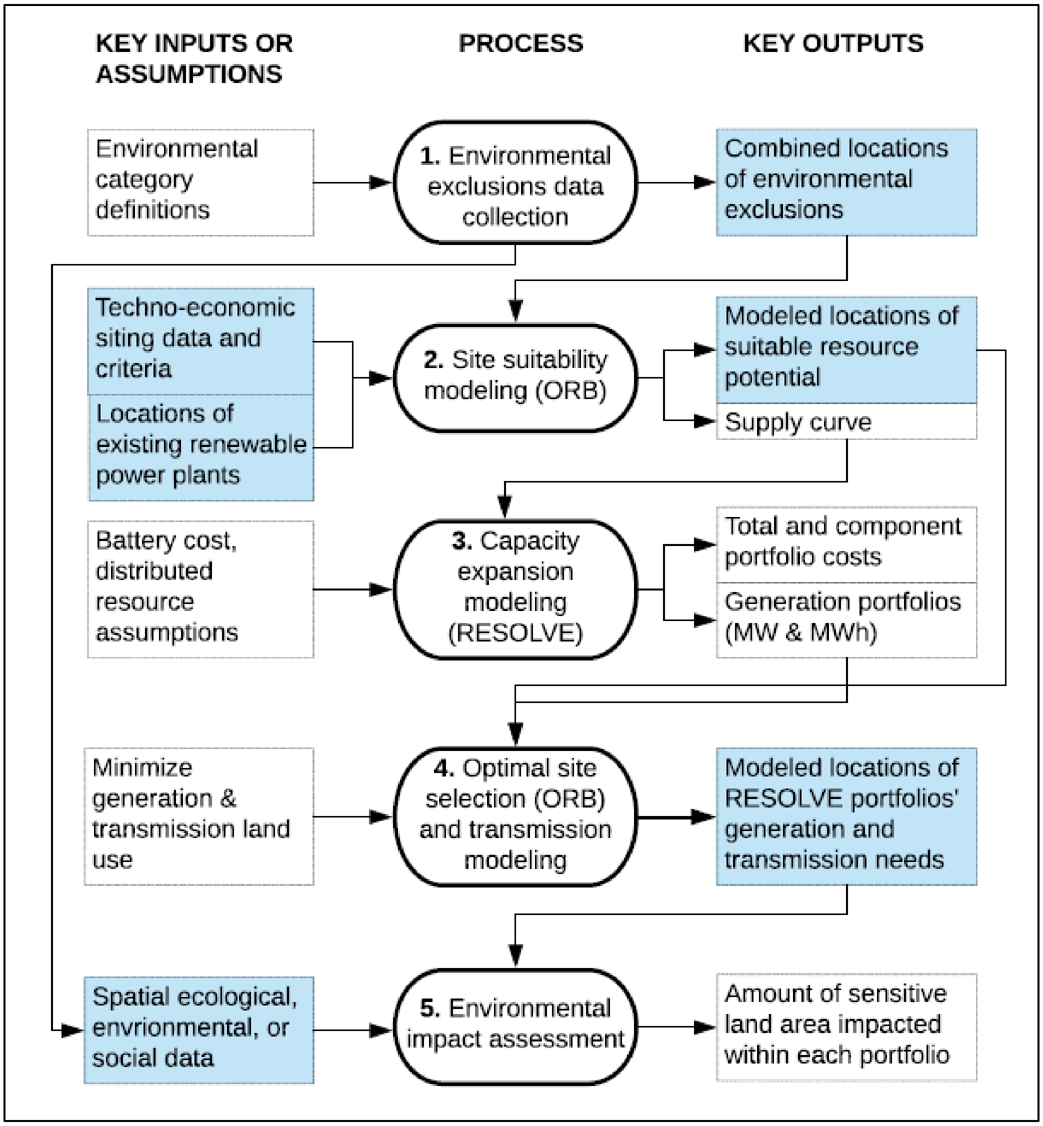
The RESOLVE model first identifies portions of the state and other western U.S. locations where new wind or solar energy production facilities could be located (RESOLVE zones). The model then "selects" or optimizes the mix of available energy resources to minimize cost while meeting a specific level of demand and reliability. To reflect potential permitting or other development constraints, the CPUC has historically reduced or discounted the potential size of

43. See also: E3-CP Figure 30; and https://databasin.org/maps/7a82b5656b11454e901b194090de0835/

the RESOLVE zones by a significant factor, such as by 95 percent in the 2017-2018 planning cycle extending to 2030. Most of the E3 studies expand the potential size of the RESOLVE zones beyond this level, and all extend the model from 2030 to 2050. For example, the CEC RESOLVE model discounts by 80%. E3-TNC also uses an 80% discount (i.e., allows development on 20 percent of the RESOLVE zone land area versus just 5 percent) as well as including in-state and out of state solar and wind siting located outside of the RESOLVE zones, in order to minimize potential impacts to biologically sensitive, preserved public and private lands and other factors identified by TNC. Given that the CPUC discounts the land available in RESOLVE zones by up to 95%, it is uncertain whether and to what extent E3-TNC's expansion of the buildable land within the RESOLVE zones beyond the CPUC's 95% discounted level is reasonable.

E3-TNC then estimates the total area of solar, wind and geothermal generation, and bulk transmission, that would be required to achieve HES buildout in several potential geographic scenarios (In State, Part West, and Full West) in 2050, in both the constrained and unconstrained cases and under various siting levels (1 through 4).

E3-TNC then conducts a screening level assessment of potential environmental impacts from each of the scenarios by overlaying the HES buildout land necessary in each scenario with an estimate of the resource values of the affected locations. Figure 1 from the E3-TNC study depicts this assessment process.



Source: E3-TNC Figure 1. Flow diagram of key methodological inputs, processes, and outputs. Blue boxes indicate spatially explicit inputs or outputs.

E3-TNC Figure 11 demonstrates the varying solar, wind, and geothermal development that would occur in various scenarios, given specific siting levels and geographic constraints.

- For the In-State scenario, increasing the Siting Level causes site selection to shift away from Southern California toward Northern California. Much of this increased development would occur in the Northern Central Valley ecoregion and foothills fronting the Cascades, Eastern Cascades Slopes and Foothills, and Northern and Central Basin and Range ecoregions.
- As the geography expands from In-State to Part West, wind development shifts from California toward rangeland habitats of New Mexico and the Oregon-Washington border. 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 with a 3,000 MW transmission limit included in this scenario. As Siting Levels

become more protective, solar distribution shifts northward and wind experiences a smaller shift away from New Mexico and toward the Pacific Northwest.

- Expanding the geography from Part West to Full West lifts the 3,000 MW transmission limit for New Mexico wind and thus up to 24,000 MW of wind development occurs in New Mexico. New Selected Project Areas also occur in Wyoming to the maximum extent possible within the constraints of the model, removing most wind development from California. This scenario includes additional new long-distance high voltage transmission lines, referred to as 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. With increasing Siting Levels, Wyoming and New Mexico wind resources become smaller and more dispersed and then are replaced by smaller wind resources in the Pacific Northwest and Idaho at the highest Siting Levels.

E3-TNC's environmental impact results of the various scenarios are presented in bar charts in units of km^2. For each environmental resource topic (e.g., wetlands and waters, avian corridors, critical habitat), the bar charts indicate the total land area necessary to develop solar, wind, and geothermal generation for the base case and various siting levels, and the portion of that land area that could have resources impacted by the development. Numerical impact data for the environmental resource categories and development site data are not provided; therefore, the coarse-level presentation of the study results precludes a detailed review of the specific resources such as wetlands and waters that could be present at the site level but not apparent in the E3-TNC screening analysis.

For example, California has approximately 1.8 million acres of mapped freshwater wetlands, pond, and other water features, excluding marine estuaries, lakes, and rivers (USFWS 2021). Such resources are typically avoided during project siting. However, as is common with site development, very often micro-siting factors exist, such as previously unmapped wetlands and waters, or substantial wildlife habitats that are not captured in the E3-TNC desktop analysis. Although it is difficult to quantify the cumulative effects of site-specific impacts to waters or other resources, it is reasonable to expect that actual site conditions will present development constraints that either cause solar and wind projects to be reduced in scale, potentially be relocated to less energy-suitable areas (necessitating larger development footprints), or result in direct loss of previously unmapped resources in order to achieve the desired scale and density of development required by the HES.

According to E3-TNC large amounts of agricultural land and rangelands in and out of state would be unavoidably impacted in all scenarios. As California expands the HES buildout to adjacent states, and as conservation protections of open lands become more stringent, solar, wind and related facilities may tend to become clustered in closer proximity to areas that have higher average residential density. Consequently, in addition to potential conflicts with other states for access to high quality wind and solar sites, HES buildout may directly or indirectly impact the land adjacent to existing communities and result in permitting conflicts or development opposition.

As noted in the E3-TNC study:

> *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. 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.* (p.5)

> *[C]apacity 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 … 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.* (p.5)

To the extent that such permitting conflicts or development opposition preclude projects from being developed in certain locations, further pressure is put on other locations in California to meet the land area necessary for the HES and there is the potential for a greater amount of more distributed land area to be developed if projects are opposed due to size.

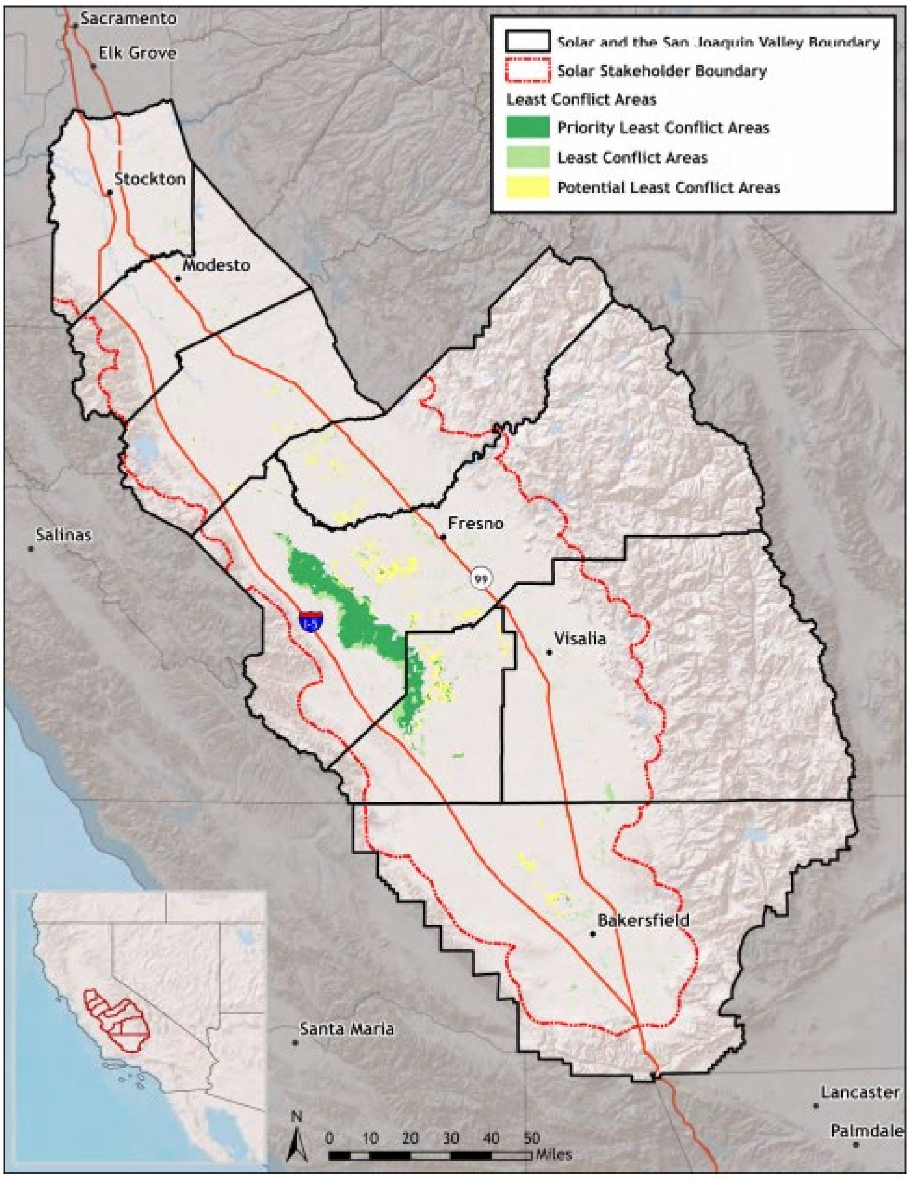
From an environmental resource perspective, the predominant impacts associated with land development for incremental renewable energy generation and distribution are related to the conversion of agricultural crop land, rangeland, scrubland, and other open lands needed for solar PV and associated transmission and distribution upgrades.

E3-TNC does not provide quantitative results by geographic location. Based on a review of E3-TNC's limited geographical siting information, new solar and wind generation will be relatively concentrated in the San Joaquin Valley and desert region of California, and to a lesser extent in the Sacramento Valley. For example, under the Full West SL4 constrained scenario, approximately 47 percent of new solar development will be sited in an eight-county portion of the San Joaquin Valley region; 24 percent will be concentrated in the Mojave and Colorado/Sonoran desert regions region of Los Angeles, Imperial, Riverside, San Bernardino, and Inyo Counties; and 9 percent will be sited in the three-county region of Solano, Sacramento and Yolo counties.

In addition, nearly all of E3-TNC's in-state wind would be sited in northern Los Angeles County and southeastern Kern County, along the northern and southern fringes of the Antelope Valley near Palmdale and Lancaster; and along the Interstate 5 corridor north of Santa Clarita. Smaller clusters of potential wind development are identified in Yucca Valley in southern San Bernardino County; southwestern Santa Barbara County along State Route 1 between Gaviota and Lompoc; and in northeastern Shasta County. Previous studies and additional information related to renewable energy siting potential in these California sub-regions are described below.

4.2.1 San Joaquin Valley Path Forward Study

As noted above, E3-TNC's Full West SL4 constrained scenario identifies approximately 47 percent of new solar development in an eight-county portion of the San Joaquin Valley region. The San Joaquin Valley Path Forward Study addresses land characteristics and suitability for renewable energy development within the San Joaquin Valley that generally aligns with E3-TNC's siting results. The study area encompasses 9.5 million acres within eight counties and describes the Valley's important role in supplying suitable land for renewable energy development due to its temperate climate and high solar insolation. The study provides an example of the conflicts between development of renewable resources and the environmental impacts on the developed land. As of 2016, existing facilities in the study are averaged approximately 500 acres with a cumulative capacity of 67 MW. Despite its potential for development of renewable resources, the Valley is also home to some of the richest, most productive farmland in the world and is home to rare plants, special status wildlife, and natural habitats. The study team thus undertook a stakeholder-led process to identify least-conflict lands for solar development. The project identified 470,000 acres of least-conflict land, amounting to roughly 5 percent of the 9.5 million acres in the stakeholder study area (Berkeley Law 2016). The stakeholder work utilized the Data Basin San Joaquin Valley Gateway (www.sjvp.databasin.org), a web-based resource that provides mapping data to support land use analyses. Figure 9 from the Path Forward study, presented below, illustrates the composite mapping results of identified least-conflict areas. As shown below, the identified priority least-conflict, least-conflict, and potential least-conflict areas are generally clustered within western Fresno and Kings Counties.



Source: Berkeley Law. 2016. Path Forward Study, Figure 9 Least conflict composite output.

E3-TNC's benchmark of a typical utility-scale PV project (4 km^2 [988 acres] for a 120 MW project) is roughly equivalent to the actual per-project capacity based on land size reported in the San Joaquin Valley 2016 study area (500 acres, 67 MW per project). Using E3-TNC's land development benchmark and E3-CP's HES incremental capacity requirement, 100 percent buildout of the 470,000 acres of identified San Joaquin Valley least-conflict lands would yield 54.6 GW, or approximately half of E3-CP's HES PV solar buildout target of 102 GW.

However, achieving 100 percent buildout of these priority lands within San Joaquin Valley is not realistic due to land development constraints that are typically addressed at the project level. As noted in E3-TNC:

> *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.* (Section 2.4.2, p. 14)

Applying an 80 percent discount factor to the priority lands in San Joaquin Valley reduces the potential capacity in this region to only 10.9 GW, which is only 10 percent of E3-CP's HES PV solar buildout target of 102 GW. Alternatively, solar development will need to be expanded onto lower priority lands, which in turn increases the level of uncertainty of successful development and could require more land overall to be developed.

As noted in E3-TNC and the San Joaquin Valley Path Forward study, practical issues will need to be overcome to achieve even this level of development in the Valley as well as the development needed in other sub-regions to meet the HES goals. These challenges include:

- Lack of transmission capacity serving the San Joaquin Valley requires prioritization of least-conflict areas and right-sizing of new facilities for future expansion.
- Solar PV permitting entails uncertainty and complexity, along with large soft costs associated with siting, deployment, operations and mitigation. Cooperation among federal, state and local agencies and solar and transmission developers and other stakeholders is essential but not assured. Given their land use authority and role in environmental pre-clearance and advance mitigation, counties need funds for advance planning and upfront environmental review.
- Lack of agreement concerning solar PV compatibility with agricultural and habitat values. Solar PV development may be compatible with agricultural uses and species habitat on a case-by-case basis, provided the development is completed according to best practices on installation and configuration. As noted in the Path Forward study:

  > *However, there is uncertainty regarding the overall market potential, rural economic development capability, and specific solar configurations that may be compatible with agricultural and habitat values. Due to the recent growth of the industry, little long-term data exist regarding the environmental impacts of solar PV. Solar PV projects may be compatible with habitats for some species and with some forms of agriculture, particularly livestock grazing. However, the scarcity of sufficient long-term surveys and appropriately vetted information stands in the way of broad acceptance of solar compatibility with some agricultural and habitat values* (p.66).

The San Joaquin Valley Path Forward Study concludes:

> *The San Joaquin Valley process resulted in a credible snapshot of significant least-conflict lands for solar PV development. But it also underscores the remaining complex issues that*

warrant additional conversation, if the Valley is to realize its full potential as part of California's renewable energy future. These issues include how best to balance renewable energy interests with agricultural interests and conservation of wildlife and natural communities in a rapidly changing environment. This effort is therefore just a start. The opportunity remains to continue the conversation and act on consensus recommendations that can simultaneously protect sensitive wildlife, conserve farmland, and help meet California's renewable energy goals while promoting economic development in the San Joaquin Valley (p.68).

4.2.2 Desert Renewable Energy Conservation Plan

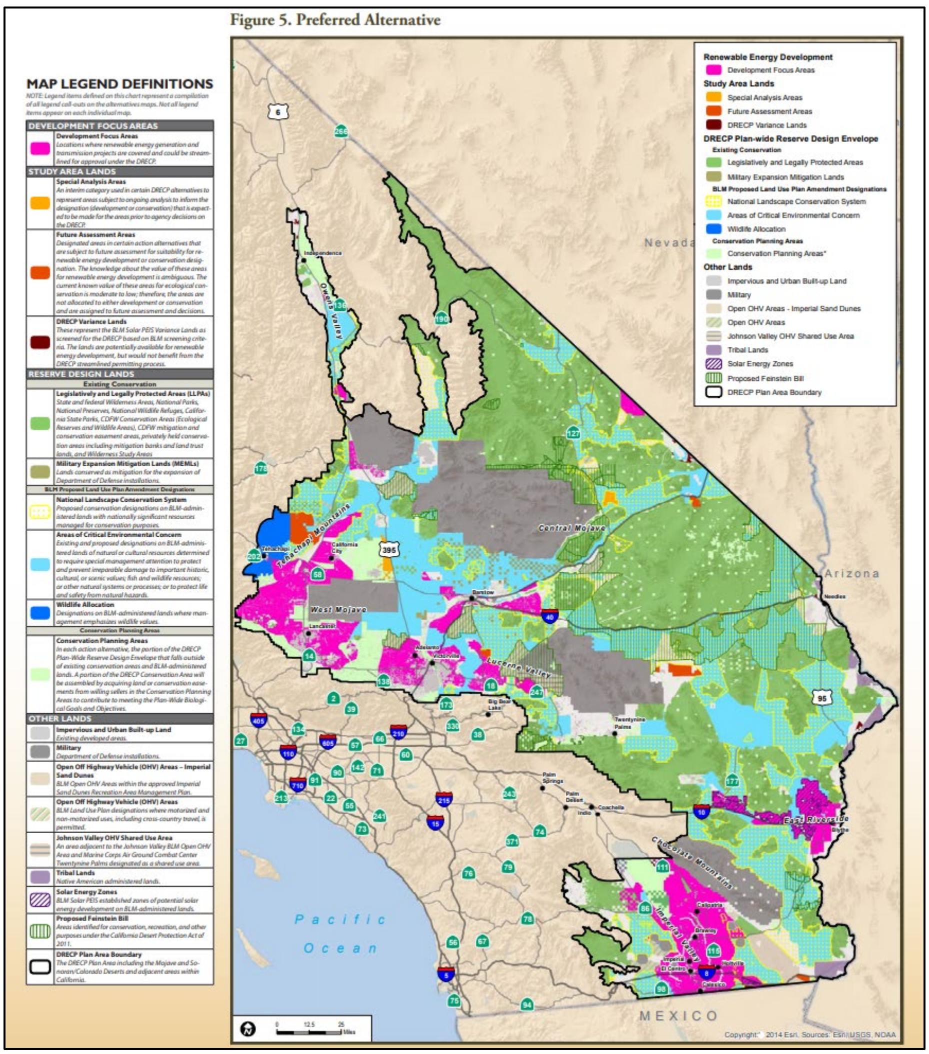
E3-TNC's Full West SL4 constrained scenario places approximately 24 percent of solar future solar development in the Mojave and Colorado/Sonoran desert regions region of Los Angeles, Imperial, Riverside, San Bernardino, and Inyo Counties. Sub-regions of development include Antelope Valley, Victorville, and Lucerne Valley; central Imperial Valley; and eastern Riverside County's Blythe area. These areas generally align with the study area of the U.S. Bureau of Land Management's (BLM) Desert Renewable Energy Conservation Plan (DRECP) area. The DECRP is a landscape-scale planning effort to facilitate renewable energy development while also conserving sensitive desert resources, which also underscores the challenges and conflicts in permitting and developing renewable resources. The BLM, under its Land Use Plan Amendment (LUPA) to the California Desert Conservation Area Plan, and Bishop and Bakersfield Resource Management Plans, manages 10.8 million acres of land in the DRECP and nearby areas. In total, the DRECP planning area covers 22.5 million acres of land in California focused in the Mojave and Colorado/Sonoran desert regions, where some of the best solar, wind, and geothermal resources in the nation are located (BLM, 2016). As part of the planning process, the BLM and cooperating DRECP agencies, identified areas appropriate for renewable energy development, as well as areas important for biological, environmental, cultural, recreation, social, and scenic conservation. A total of 6.5 million acres were designated to conserve biological, cultural, and other values. Approximately 3.6 million acres were recognized for recreational values and protected from development. Within these two areas, totaling approximately 10.1 million acres (or almost half of the DRECP planning area), renewable energy development is generally prohibited. Renewable energy may be permitted in approximately 800,000 acres. Within that area, specific development areas with streamlined permitting processes totaled only 388,000 acres, or 3.6 percent of the LUPA area (CEC and BLM 2019).

Figure 5 from the DRECP, presented below, illustrates the composite mapping results of the study's identified development focus areas (purple areas). These "preferred alternative" lands are generally clustered within Antelope Valley, Victorville, Lucerne Valley and other West Mohave sub-regions; central Imperial Valley; and eastern Riverside County's Blythe area.

Using E3-TNC's land development benchmark and E3-CP's HES incremental capacity requirement, the hypothetical buildout of 100 percent of the maximum 800,000 acres available for potential project siting would yield 97 GW, or nearly all the land needed to achieve E3-CP's HES PV solar buildout target of 102 GW. However, as with San Joaquin Valley and other regions, numerous development challenges apply in the Mohave and Sonoran Desert regions, on both federal and private lands, suggesting that achieving 100 percent buildout on BLM's California desert lands is not realistic. Applying an 80 percent discount factor to account for site-specific land development constraints (consistent with E3-TNC methodology) reduces this potential capacity to 19.4 GW, or about 20 percent of the HES buildout target. Full development of the priority lands (388,000 acres) available for streamlined permitting processes would yield 46 GW, or nearly half of E3-CP's HES PV solar buildout target of 102 GW. However, applying an 80 percent discount factor (consistent with E3-TNC methodology) reduces this potential capacity to only 9.2 GW, which is less than 10 percent of the state's buildout target.

Though BLM and other federal agencies have established robust datasets to facilitate project siting (e.g., Corridor Mapper, Solar Mapper), federal development review processes are extensive and costly multi-year efforts, including exhaustive National Environmental Policy Act (NEPA) review, Tribal and interagency consultations, and public debate in parallel with affected county California Environmental Quality Act (CEQA) reviews and public policy debates. These processes can stall or stop development, greatly increase costs, and thus reduce the likelihood that lands sufficient to meet the HES goals are developed.

As with the San Joaquin Valley, alternative sites will need to be identified in less optimal locations in order to meet HES targets, thus again increasing the level of uncertainty of successful development at the levels necessary to meet the HES and potentially increasing the amount of land overall the will need to be developed.



Source: CEC and BLM 2019. Desert Renewable Energy Conservation Plan, Figure 5 Preferred Alternative.

4.2.3 Northern Central Valley

E3-TNC identifies California's northern Central Valley as another area of potentially intensive solar development. In E3-TNC's Full West SL4 constrained scenario approximately 9 percent of new solar development is sited in the three-county region of Solano, Sacramento and Yolo counties. This region has experienced relatively few large-scale solar developments to date. According to the CEC, the 10-county region that makes up the Northern California RESOLVE zone provides a cumulative 2020 solar PV capacity of 55.7 MW (CEC 2021b). Of this amount, about 30 MW are generated in two counties (17.4 MW in Tehama County, and 12.1 MW in Yolo County). Using E3-TNC's land development benchmark, this represents approximately 2 km^2, or about 460 acres of cumulative solar PV development.

There are few comprehensive studies of suitable land development in this region. The CEC's California Statewide Energy Gateway, a portal for statewide, regional, and county studies (https://caenergy.databasin.org/), lists a limited set of baseline resource studies, but provides no relevant siting studies for the Northern Sacramento Valley and Modoc Plateau planning regions. Thus, there is even less certainty over potential success of development in the Sacramento Valley and foothill rangelands than in the better-studied San Joaquin Valley and Mohave regions.

This area has not historically seen extensive solar development and has a high existing agricultural job base, as well as biological and non-biological resources that could be impacted due to the likelihood of development on farmland and rangeland. The Butte County Habitat Conservation Plan (HCP) (Butte County 2015) provides a snapshot of typical resources in this region. The HCP describes landscape characteristics of 564,219 acres in western Butte County. This area consists of the western lowlands and foothills of the northern Central Valley. The resources described in this HCP are typical of the northern Central Valley that are within the mapped area for solar development for the in-state, part-west, and full-west SL3 and SL4 scenarios. The HCP lists biological resources including threatened and endangered species (including the willow flycatcher, greater sandhill crane, Sierra Nevada red fox, and green sturgeon), and non-biological resources (including agricultural resources, water resources, noise, recreation, and visual resources) that would could be impacted by future development. The magnitude of development in this region under these scenarios is comparable, or potentially greater than the land areas mapped for development in the San Joaquin Valley under the full-west scenario described above.

In summary, while the E3-TNC study assumes that roughly 70 percent of the overall land development necessary for the HES will occur in the combined San Joaquin Valley and Mohave/Sonoran desert regions, as shown in Table 4-1 below, after discounting for permitting and other constraints, the combined available land within these two regions would meet only 30 percent of the total HES needs. The remaining 70 percent of HES lands would presumably be developed in regions of the state that have not been studied for renewable energy development at a programmatic level, such as northern Central Valley, coastal ranges, or private lands.

Table 4-1: Summary of Buildout Potential in Previously Studied California Regions

Solar Development Region	Priority Buildable Land Identified in Prior Studies (km^2 and Acres)	GW Potential at Full Buildout	80 Percent Discounted GW Potential	Percent of HES Solar Requirement (102 GW) at Discounted Buildable Potential
San Joaquin Valley	1,903 (470,000)(1)	57	11.4	11.2
DECRP Mohave and Sonoran Deserts	3,239 (800,000)(2)	97	19.4	19.1
Total	**5,142 (1,270,000)**	**154**	**30.8**	**30.3**
Balance of California			69.2	69.7

(1) San Joaquin Valley Path Forward Study (Berkeley Law 2016)
(2) Desert Renewable Energy Conservation Plan (BLM 2016)

4.3 Project-Level Development Constraints

Land development at the scale contemplated by the HES buildout scenarios is unprecedented and, given past experiences with permitting renewable energy projects in California, will be very challenging, and potentially infeasible, from a practical standpoint. The SB 100 Joint Agency Report acknowledges that one of the key factors in achieving the HES is the current regulatory structure for project approvals:

> *SB 100 is a state energy policy, but project implementation is a local process and must address local resource values. Today, most of California's local jurisdictions are not equipped with plans achieve the state's energy goals* (CEC 2021a. SB 100 Joint Agency Report, p.37).

E3-TNC notes the uncertainties in land development and consequences for eventual buildout of the various HES scenarios studied in their analysis:

> *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. (p.43)*

Development at any single site is subject to a wide range of considerations for the developer, and large areas of suitable land can be dismissed for a wide range of reasons. Potential hurdles at the project level include:

- Land acquisition, lease costs, and price escalation (discussed below)

- Cost and availability of electrical distribution tie-in and related planning issues - transmission capacity, required network upgrades, Power Purchase Agreement (PPA) negotiations, delayed or modified interconnection studies
- Distance to distribution tie-in, and required property easements
- Impaired site conditions such as subsurface impacted soils, grading, or other site modification requirements that substantially increase site preparation costs
- Lack of seller interest, or potential for seller or lessor resistance
- Insufficient parcel size or complex ownership structure
- Financing
- Local, state and federal permitting hurdles including CEQA review and associated mitigation commitments including land conservation easements
- Community resistance
- Local and county-level policies and ordinances
- Site-specific resource constraints

Land and right-of-way acquisition is a key factor in capital projects. Some observers of California's high speed rail project have suggested that this is one of the leading causes for cancellation of major sections of California's high speed rail project, and that one of the biggest problems with the project involves challenges with land acquisition, which has contributed to construction delays, cost increases, litigation and the launch of a federal audit (Vartabedian 2019).

4.3.1 Cost of Land for the HES

Land costs for solar and wind development for the HES scenario are highly uncertain, but could be material, especially the foregone environmental value. **This section estimates that statewide costs range from $8.4 to $84.0 billion. A significant portion of the costs will occur in San Joaquin Valley, where the range is from $3.8 to $39.0 billion.** These estimates include both the direct financial costs of land acquisition, which are not included in the Resolve LCOE, and the indirect loss of environmental value, which are often borne by the population living near the acquired land.

Table 4-2 summarizes the direct land acquisition costs. It shows the estimated county-level and total land acquisition costs using reasonable, alternative assumptions about the key cost drivers. The amount of land acquired in each county are based on GIS data described in Section 4.4.2 of this report. County-level farmland acquisition costs are from the USDA 2017 Census of Agriculture (USDA 2017). The USDA Census of Agriculture is conducted every 5 years, and includes all farms "from which $1,000 or more of agricultural products were produced and sold, or normally would have been sold, during the census year" (USDA 2017). As part of the census, respondents are asked to estimate the market value of their farming land and buildings that they own. The market value of land and buildings is used because solar development would affect not just the land itself, but also any buildings on the land that are replaced by solar.

The direct acquisition costs range from $0.1M per km2 in Inyo County to $6.1M per km2 in San Diego County, with an average of $2.8M (in 2020 dollars) (USDA 2017). Average estimated pastureland market values are $0.6M per km2. There is insufficient information to determine the proportion of land for solar and wind development that will come from farmland vs. pastureland; thus, we provide costs for two alternative scenarios:

- Alternative 1: 100 percent of the land used for solar and wind projects will come from pasture land.
- Alternative 2: 62 percent of the land will come from pasture and 38 percent will come from cropland (see Section 4 of this report).

The table shows that the direct costs of land acquisition to meet the HES range from $2.2 to $4.9 billion, a value that is not included in RESOLVE. The end of Table 4-2 shows that approximately 45 percent of the land is in the San Joaquin Valley,[44] with a cost range from $0.9 to $2.0 billion, about 40 percent of the total costs.

Table 4-2: Summary of Land Acquisition Direct Costs

County	Estimated Area	All Pasture	62% Pasture, 38% Crop
Solar	**(km^2)**	**Cost ($millions)**	**Cost ($millions)**
Alameda	0.7	0.3	0.7
Contra Costa	0.3	0.1	0.3
Fresno	298.2	205.5	463.2
Imperial	54.4	36.8	82.8
Inyo	25.1	0.9	2.1
Kern	432.9	193.9	437.0
Kings	50.3	33.0	74.4
Lassen	13.1	1.7	3.8
Los Angeles	36.9	41.6	93.8
Madera	20.8	13.9	31.2
Merced	56.1	44.6	100.5
Mono	7.2	0.8	1.9
Monterey	18.6	8.3	18.8
Placer	4.4	1.8	4.1
Riverside	237.8	261.8	590.0
Sacramento	90.2	55.0	123.9
San Bernardino	308.4	372.3	839.2
San Diego	109.9	154.8	348.9
San Joaquin	225.0	205.0	462.2
San Luis Obispo	229.2	104.9	236.5
Santa Barbara	151.7	95.6	215.4
Solano	91.2	50.6	114.1

44. Includes Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare counties.

County	Estimated Area	All Pasture	62% Pasture, 38% Crop
Stanislaus	148.7	140.9	317.6
Sutter	5.9	3.4	7.7
Tulare	42.4	30.2	68.1
Yolo	63.5	37.4	84.3
Total	**2,723.1**	**2,095.2**	**4,722.6**
Wind	**(km^2)**	**Cost ($millions)**	**Cost ($millions)**
Los Angeles	68	76.7	172.8
Other	12	7.7	17.4
Total	**80**	**84.4**	**190.2**
Solar + Wind Total	**2,803.1**	**2,179.6**	**4,912.8**
San Joaquin Valley	1,274.5	867.0	1,954.1
Other	1,528.6	1,312.6	2,958.6

The indirect land costs are the lost environmental value of ecosystem services because of the land use conversion. Ecosystem services, also called natural capital or nature's benefits, are the benefits that natural systems provide to society. Benefits include carbon sequestration, habitat, biodiversity, water storage and quality, aesthetics, recreation, and soil quality. For example, rangeland can often improve water quality. When this ecosystem service is lost, its' value can be measured by estimating the water treatment costs that would be required to provide the same level of improvement in water quality.

Ecosystem services are often categorized into provisioning, regulating, habitat, and cultural services (see figure). Some beneficial services, such as provisioning services, tend to accrue to the owner of the land and may have market values, while others, such as habitat and regulating services, benefit the public at large and are rarely traded in markets for a price. Because these services are not traded in markets, there is no easily collectable data about their value or prices. Typically, the value must be inferred from detailed site-specific calculations or from the results of other site-specific studies for similar natural resources (i.e., value transfer studies).

Source: CRT 2021.

A recent study by the California Rangeland Trust (CRT 2021) provides useful, order of magnitude estimates of the value of lost ecosystem services that may occur because of land conversion to renewable development necessary for the HES. The Trust funded a study to estimate the value of ecosystem services on the over 300,000 acres that they maintain as rangelands through conservation easements. These values reflect the total value of the ecosystem services; they are not adjusted to reflect the percent of total services that would be lost as a result of a particular type of land use conversion. Using benefit values from other studies, the CRT study estimates the lands with conservation easements provide ecosystem service values of between $1,100 and $4,500 per acre per year (CRT 2021).

The range is due to the difference in the source and type of studies included in the value transfer. The high-end values use a traditional benefits transfer approach, relying on consumer surveys that ask people how much they would be willing-to-pay to protect lands that provide different types of ecosystem services. The low-end values are developed using an ecosystem value database study that estimated global average per acre values for three biomes: grassland, woodland, and temperate forest (CRT 2021). These estimates can be a combination of consumer surveys and engineering estimates of avoided costs.

The average annual values described above can be translated into a present value, which is conceptually similar to a market value, of between $20,900 and $82,600 per acre. It is worth noting that the CRT uses a discount rate of 5 percent. The discount rate is used to convert values that are provided in the future into present day dollars. The higher the discount rate, the lower the future value. The USEPA and most government agencies use a discount rate of 3 percent. Using a rate of 3 percent increases the present value to between $29,400 and $116,500 per acre. Finally, the extent to which these services will be lost because of solar development is unclear. It is unlikely that all of the services will be lost (e.g., micro-siting can often avoid wetlands or other site-specific resources) and mitigation options could be implemented to reduce the losses.

Table 4-3 provides directional estimates of the potential loss of ecosystem services that might result from the HES scenario. It underscores both the potential magnitude and uncertainty of the losses. The table shows the range of potential losses to the area of 2,803 km^2 (from Table 4-1) under several scenarios, varying the following components and assumptions:

- Present value: Using the high and low per acre present values from the CRT, calculated over the same period as the CRT analysis, 50 years (CRT 2021).
- Discount rate: Using the CRT discount rate of 5 percent, and the U.S. Environmental Protection Agency (USEPA) discount rate of 3 percent.
- Percent of services lost: Incorporating a range of estimates for the percent of services lost because of the conversion. Because no data are available about the losses, the impacts are shown with a 50 percent loss and a 100 percent loss.

The results show that ecosystem service losses could range from $7 to $81 billion, depending on the underlying assumptions. In the San Joaquin Valley, this impact ranges from $3 to $37 billion.

Table 4-3: Summary of Potential Ecosystem Service Losses

Discount Rate Scenario	Discount Rate	Present Value per acre	50 Percent Service Loss $billions	100 Percent Service Loss $billions
Statewide				
Low-end CRT values	5%	$20,900	7	14
High-end CRT values	5%	$82,600	29	57
Low-end CRT values	3%	$29,400	10	20
High-end CRT values	3%	$116,500	40	81
San Joaquin Valley				
Low-end CRT values	5%	$20,900	3	7
High-end CRT values	5%	$82,600	13	26
Low-end CRT values	3%	$29,400	5	9
High-end CRT values	3%	$116,500	18	37

4.3.2 Regional and Local Approval Issues

Recent and ongoing development efforts illustrate the complexities of land development for industrial scale renewables. As noted above, there is a tension between the wide range of stakeholders, who are very supportive overall of climate change reduction policies but not necessarily supportive of the land development that is required to achieve these objectives, resulting in a "green vs. green" debate at both the policy and project level. For example, San Bernardino County, which has a long history with utility-scale renewable energy development, captures this point in their General Plan Renewable Energy and Conservation Element:

> *Although renewable energy provides a path to a clean energy future, [renewable energy] facilities have the potential to cause unintended negative effects on sensitive biological species and habitat, visual resources, cultural resources, and nearby communities. To achieve a clean energy future that minimizes negative effects consistent with local values, the County has considered how to reduce energy use through energy efficiency and conservation measures, and identified renewable energy facility standards that concentrate on community-oriented RE facilities that produce electricity for local consumption.* (County of San Bernardino 2017, page 1)

This statement suggests that the County is focused less on utility-scale renewable development that would be necessary to meet the HES, and more on local-serving renewables that may not be at the level required to achieve HES goals.

Within the agricultural sector specifically, there is tension between agricultural preservation and renewable energy activists, as stated in Fresno County's solar guidelines:

> *The need to accommodate new renewable energy technology must be balanced with the need to protect important farmlands and minimize impacts to existing agricultural operations.* (County of Fresno 2017)

At a regional and county level where project entitlement decisions are made, land use policies generally support climate goals and renewable energy development but there is a growing body of policies and land use protective ordinances, driven by local resistance at both the project and regional level, that will further constrain development and – in combination with land acquisition and technical or financial factors – will increase uncertainty about the timing and cost of achieving the development necessary to meet HES targets.

Stakeholders cite a range a reasons to oppose utility-scale renewable energy projects, including concerns over industrialization of rural areas; perceived blight and adverse aesthetic changes; physical environment changes (e.g., solar and wind may increase local surface temperatures; wind turbines may causes light flicker); loss of property tax revenue (e.g., in locations where wind and solar may be exempt from property taxes and thus reduce regional tax revenues); perceived adverse effects on property values from adjacent industrial development; and potential conflict with agricultural and other land uses (e.g., aircraft fertilization and pesticide application can be constrained by wind and solar development).

In response to these concerns, some counties have enacted policies and ordinances that limit renewable energy development expansion. Conservation organizations are highly active stakeholders in this arena and it is likely that local agency reviews and stakeholder involvement will continue to limit the pace and scale of renewable development, potentially in a way that precludes the pace and size of development needed to meet the HES.

A February 2021 report prepared by Columbia Law School's Sabin Center for Climate Change Law provides state-by-state information on local laws to block, delay or restrict renewable energy and demonstrates that opposition to renewable energy is widespread. The cited cases include moratoria on wind or solar energy development; outright bans on wind or solar energy development; regulations that are so restrictive that they act as de facto bans on wind or solar energy development; and zoning amendments that are designed to block a specific proposed project (Columbia Law 2021).

California local ordinances cited in the report include:

- San Bernardino County: In 2019, the San Bernardino County Board of Supervisors banned "utility oriented renewable energy" in rural areas. The law does allow individual household solar panels and community solar projects.
- San Diego County: San Diego County limits small wind turbine height to 80 feet regardless of parcel size (contrary to state law requiring that small wind turbine regulations allow turbines to be at least 100 feet).

Contested projects cited in the report include:

- Aramis and SunWalker Solar Projects: The Aramis (410 acres) and SunWalker (70 acres) solar projects, near Livermore, have been met with opposition by local politicians and interest groups. The Aramis project is discussed further below.
- Panoche Valley Solar Project: In 2009, San Benito County approved a 399-MW solar facility near the town of Hollister. Shortly thereafter, the Sierra Club, the Santa Clara Valley Audubon Society and Defenders of Wildlife sued the county, alleging that the project endangered key populations of native species. The parties reached a settlement in 2019, reducing the size of the project to one-third of the original plan. This project is discussed further below.
- Terragen Wind Project: In late 2019, Terragen Wind applied to the Humboldt County Board of Supervisors to construct 47 wind turbines on the Monument and Bear River ridges near Scotia. This proposal was met with opposition by members of the local community, who argued that the ridges were sacred prayer sites of the Tsakiyuwit tribe. The Board of Supervisors ultimately denied the project application.

Table 4-4 lists these and additional examples of existing county policies and ordinances that limit renewable development, and examples of agency and public opposition to renewable energy projects.

Table 4-4: Examples of California County Renewable Energy Policies and Impacted Projects.

County	2020 Installed Solar (MW)[1]	Renewable Energy Local Policies, Ordinances, and Project Cases	Project Development Implications
Southern California			
Los Angeles County	1242	Los Angeles County Renewable Energy Ordinance	Prohibits utility-scale solar facilities in Significant Ecological Areas (SEAs) and Economic Opportunity Areas (EOAs), and prohibits all utility-scale wind facilities (2)
		Southern Owens Valley Solar Project (200 MW)	Project proposal for the 1,200 acre project was withdrawn due to community opposition (3)
Riverside County	2043	Riverside County Board of Supervisors Solar Ordinance	Ordinance requires solar project owners to pay an annual fee of $150 per acre of land involved in power generation with an annual increase of 2% (4)
San Bernardino County	1725	County of San Bernardino Resolution No. 2019-17, Amendment to the General Plan Renewable Energy and Conservation Element	Policies restrict where utility-oriented renewable energy projects can be sited (5)
		Soda Mountain Solar Project 2,059-acre, 287 MW)	County Board of Supervisors voted against the project due to conservation groups' opposition (6)
Imperial County	1639	Tessera Solar/ Imperial Valley Solar Project (709 MW)	Project halted due to tribal opposition and nearby historical sites (7)
San Diego County	147.6	JVR Energy Park Project (70 MW)	Local planning board voted to request a reduction for the 650-acre utility solar project due to community opposition (8)
Central California			
Fresno County	1008	Cal. Farm Bureau Federation v. County of Fresno	Stakeholder sued the County for the cancellation of Williamson Act Contracts to build a 20,000 acre utility solar project.(9)
		County of Fresno Solar Facility Siting Guidelines	Policy for restricting solar development on farmland (10)
Alameda County	17.8	Aramis Renewable Energy Project (400 acres, 100 MW)	Community opposition and litigation to protect rangeland (11)

County	2020 Installed Solar (MW)[1]	Renewable Energy Local Policies, Ordinances, and Project Cases	Project Development Implications
Northern California			
Inyo County	N.A.	Inyo County Renewable Energy General Plan Amendment	Policy sets acreage restrictions and allowable megawatt development for areas in four designated solar energy development areas. (12)
		Hidden Hills Solar Project (500 MW)	Project withdrawn by owner due to County Commission and environmental group opposition (13)
San Benito County	146	Panoche Valley Solar Project (399 MW)	Project was scaled back by 117MW due to a settlement agreement with three environmental groups (14)
		SunWalker Solar Project (70 acres, 155 MW)	Project scaled back due to community opposition.
Humboldt County	8.5	Terragen Wind Project (47 turbines)	County Board of Supervisors voted to deny the project due to community opposition and multiple cultural and ecological impacts (15)
Napa County	2.	Napa County Renewable Energy Ordinance	Policy created to prohibit commercial solar projects from some agricultural land use zones (16)
Tehama County	17.4	Napa County Renewable Energy Ordinance	County Board of Supervisors denied two projects due to the incompatibility with the proposed land's Williamson Act contracts (17)
Out of State			
Clark County, NV	812	Clark County Solar Ordinance	County ordinance allowing development on farmlands received opposition from hundreds of local community members (18)
		Gemini Solar Project (7,100 acres, 690 MW)	Project delayed due to historic significance of the nearby region and controversy due to its multiple environmental impacts (19)
Benton County, WA	N.A.	Horse Heaven Ridge Wind and Solar	WDFW requests removal of wind facilities due to ridgeline wildlife impacts (20)

(1) CEC 2021b. California 2020 Installed In-State Electric Generation Capacity by Fuel Type (MW).
(2) County of Los Angeles Board of Supervisors. 2017. Renewable Energy Ordinance Amending Title 22.
(3) https://sierrawave.net/press-release-from-manzanar-committee-owens-valley-committee-on-solar-projects/
(4) Riverside County Board of Supervisors. 2013. Solar Power Plants Policy B-29
(5) http://www.sbcounty.gov/uploads/LUS/Renewable/2019_WEBSITE/RES-LUS-2-28-19-RECE_SIGNED.pdf

(6) https://pv-magazine-usa.com/2016/08/25/san-bernardino-county-rejects-287-mw-soda-mountain-solar-project/

(7) https://www.sandiegouniontribune.com/sdut-judge-blocks-imperial-valley-solar-project-2010dec17-htmlstory.html

(8) https://www.sandiegouniontribune.com/business/story/2021-07-09/sd-county-planning-commission-recommends-approval-of-jacumba-solar-project

(9) https://www.cleanenergylawreport.com/energy-regulatory/farmers-advocacy-group-enters-foray-against-solar-energy-siting/

(10) https://www.co.fresno.ca.us/departments/public-works-planning/divisions-of-public-works-and-planning/development-services-division/planning-and-land-use/photovoltaic-facilities-p-1621

(11) https://www.pleasantonweekly.com/news/2021/04/21/livermore-community-groups-sue-alameda-county-for-approving-aramis-solar-project

(12) https://www.inyocounty.us/sites/default/files/2020-04/FinalREGPA33015.pdf

(13) https://www.kcet.org/redefine/company-to-withdraw-proposed-solar-tower-project-in-inyo-county

(14) https://pv-magazine-usa.com/2017/07/25/the-panoche-valley-solar-farm-gets-downsized/

(15) https://www.northcoastjournal.com/NewsBlog/archives/2019/12/17/why-the-supes-denied-terra-gens-wind-project-despite-a-series-of-11th-hour-concessions-from-the-company

(16) https://www.countyofnapa.org/DocumentCenter/View/14809/Renewable-Energy-Ordinance-Draft-10-25-2019

(17) https://www.chicoer.com/2013/05/01/tehama-county-rejects-solar-projects-on-farm-land/

(18) https://www.centralwinews.com/a-main/2021/05/25/clark-county-to-develop-wind-and-solar-ordinance/?destination=tribune-phonograph

(19) https://www.reviewjournal.com/opinion/editorials/editorial-environmentalists-oppose-building-largest-solar-plant-in-us-1693225/

(20) https://www.efsec.wa.gov/energy-facilities/horse-heaven-wind-project

In addition to the challenges from local renewable energy policies and project objection, project approvals are highly dependent on local agency reviews and the estimated effectiveness of mitigation for project impacts. Each proposed solar and wind project, as well as major grid upgrades and storage projects, will require analysis under CEQA and, where applicable NEPA and associated federal agency consultations for biological and resources effects, and in certain cases require "take" permits for listed species and/or federal and state waters permits, among other things.

Many of the mitigations required for significant impacts, such as offsetting land conservation easements and other short-term and long-term commitments, add substantial new costs to the project and, in many cases, need to be implemented prior to project approval and construction.

Agha et al (2020) performed a literature review of wind and solar project biological resource mitigation strategies, and evaluated their general effectiveness. The study provides evidence of successful mitigation within complex biological environments, and recommends continued research to address data gaps. The study provides a positive outlook on the continued improvements for effective mitigation on large scale renewable projects, but also acknowledges the limitations of existing data. The study concludes, in part that:

> *[T]he ecological effects of utility-scale renewable energy development on wildlife are still fraught with substantial uncertainties, largely due to the lack of [before-and-after-control-impact] BACI studies and mitigation strategies being mostly species-specific.*(Agha et al 2020).

There are also additional and reasonably foreseeable costs and delays associated with CEQA or NEPA litigation. Solar and wind projects have been required to implement technically novel and costly mitigation for impacts to avian species (e.g., radar detection coupled with rotor shutdowns and large-scale species relocation and preservation requirements) and several have been subject to CEQA or NEPA lawsuits, which significantly increases project cost and delays development.

As new projects are proposed in areas where there is existing solar and wind development, the cumulative effects may be magnified, and stakeholder involvement may intensify. In areas that are only beginning to experience utility-scale development, the local response may be less understood, leading to prolonged studies and project revisions, and even higher uncertainties, even if there is apparent support by the local agency decision-makers. The CEQA and NEPA review processes are designed to be adaptable to addressing these issues, but these processes do not provide assurances of project success to prospective developers and thus many may choose not to participate in development of these projects or project costs may increase by significant amounts in order to meet environmental review, litigation, mitigation, and public process costs.

The specific projects discussed below provide further insights into the project-level challenges and costs of permitting renewable development that may hamper California's ability to develop renewable resources at the rate necessary to meet HES goals.

Aramis Solar Project, Alameda County

The Aramis Solar Energy Generation and Storage Project in the North Livermore community of Alameda County proposes to construct 100 MW of solar PV on 350 acres within a 747-acre site that is currently used for grazing and dry land farming (Ruggiero 2021).[45] If constructed, this will be one of the largest solar projects in the San Francisco Bay Area. Alameda County's CEQA analysis determined that the project would have a less-than-significant impact on Agriculture and Forestry Resources. Two residents running in the election for the Alameda County Board of Supervisors, in partnership with citizen group Save North Livermore Valley, urged the board to place a moratorium on solar development on agricultural land. Opponents of the project argue that the project's locations "conflict with agriculture, natural habitat, open space, and visual and scenic resources." The East County Board of Zoning Adjustments approved the Aramis and Sunwalker (70-MW) projects. As of December 2020, four separate appeals had been filed (Columbia Law 2021). Soon after Alameda County issued a Conditional Use Permit in March 2021, several newly created non-governmental organizations, formed by community ranchers, farmers, and environmentalists solely to oppose Aramis, filed suit. Litigation is ongoing at the time of this report preparation.

A media quote from a local stakeholder representative sums up the Aramis project developer's challenge and a larger pattern of utility-scale renewable project development challenges in rural lands:

> *North Livermore is particularly important in terms of its heritage of grazing cattle, scenic areas, and habitat for threatened and endangered species. While we support the need for renewable energy to combat climate change, we cannot justify allowing solar projects to destroy the environment in the name of protecting it," said Tamarus Reus, president of the Friends of Open Space and Vineyards board in a statement.* (Ruggiero 2021)

Panoche Valley Solar Project, San Benito County, California

After years of opposition from environmental groups and substantial agency and stakeholder input, a project in San Benito County, promoted at the time as one of the world's largest solar power projects, was scaled back from 399 MW to 130 MW in a settlement with environmental groups and the State of California. After a Conditional Use Permit was issued to the original project by San Benito County in 2015, which would have generated the county $5.4 million in sales tax, environmental groups sued to challenge the Final Supplemental Environmental Impact Report asserting that the County had not adequately protected the endangered giant kangaroo rat, blunt-nosed leopard lizard, and San Joaquin kit fox, along with bird species such as the tri-colored blackbird that live in the ranchlands (Hanson, 2017). While these lawsuits failed, according to the developer Con Edison, the "company signed the agreement because even though the environmental groups had lost multiple lawsuits over the project, they still had cases they could appeal that could have slowed or killed it" (Rogers, 2017). As part of the settlement agreement between the environmental groups and the California Department of Fish and Wildlife (CDFW), which reduced the size of the project, San Benito County would no longer receive any sales tax revenue.

45. Also see: https://ioi8o1p8x9p46guq1v415xb7-wpengine.netdna-ssl.com/wp-content/uploads/2020/04/Aramis-fact-sheet.pdf, and https://baynature.org/2021/05/06/controversial-solar-development-east-bay/.

Horse Heavens Hills Wind, Solar, and Battery Storage Project, Benton County, Washington

A 1,150 MW combined wind, solar, and storage project is proposed at the eastern end of the lower Columbia River Gorge in Benton County, Washington. The project would include up to 244 wind turbines and 6,500 acres of solar sites at an estimated construction cost of $1.7 billion. Energy generated by the project is expected to be sold either in California or across the Pacific Northwest. In its June 2021 scoping comment letter, the Washington Department of Fish and Wildlife (WDFW) summarized the anticipated impacts to habitats and listed species; and noted the difficulty of mitigating these impacts in habitat that "represents some of the last remaining functional and uninterrupted shrub-steppe and natural grasslands in Benton County" (Ritter 2021). A number of wildlife species would be impacted including migrating songbirds and sandhill cranes as well as burrowing owls and various hawk and falcon species, which commonly use the area as nesting or forage habitat. WDFW's recommendations include removal of the wind turbines and associated gen-ties to preserve the ridgeline wildlife corridor and avoid impacts to the Ferruginous hawk, a state-listed threatened species; and other measures to protect pronghorn antelope and other terrestrial species and preserve wildlife connectivity.

These project examples and the other projects described below are intended to illustrate a sub-set of the development hurdles that increase cost, protract the development schedule (which can lead to financing and other logistical challenges), and/or limit the scale of individual large scale renewable developments (thus limiting investor interest), all together raising the level of uncertainty around the cost and feasibility of the HES target buildout.

4.4 California Resource Impact Estimates

4.4.1 State-Wide Impacts

E3-TNC's environmental impact results are presented as bar charts that indicate the amount of land (km^2) required in California and other western states for solar, wind, and geothermal generation, and for grid interconnection buildout. An example of these results is provided in Figure 4-2. This figure provides excerpts from E3-TNC's estimates of the total California land area required to achieve buildout (a range of approximately 2,000 to 5,000 km^2 depending on the scenario), and, in this example, the estimated impacts to wetlands.

For each scenario (In-State, Part-West, and Full West, constrained and unconstrained), and impact resource parameter, E3-TNC presents their results for the RESOLVE base case and Siting Levels (SL) 1 through SL4. For each SL, the estimated land areas needed for solar, wind and geothermal are further divided into "impacted" (darker shades) and "no impacts" (lighter shades). E3-TNC does not explicitly describe the threshold used to determine an "impacted" resource; rather, they describe two types of impacts – specific and generalized:

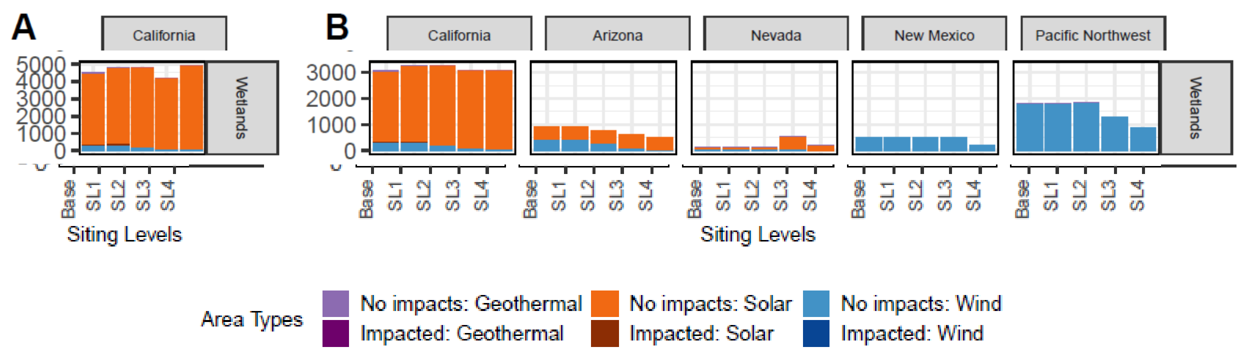
> *The specific metrics (e.g., sage grouse habitat and wildlife linkages) were intended to explore areas of focus in current public discourse in energy planning forums. Thus, several specific metrics were chosen to explore trends and implications to key species. In contrast, the generalized metrics (e.g., impacts to Environmental Exclusion Category 3 lands) are meant to explore overall impacts to natural and working lands for a given resource portfolio.* (E3-TNC p.25)

For the purpose of this assessment, it is assumed that the physical land area indicated by E3-TNC as "impacted" refers to development in areas that results in either specific or generalized (i.e., direct or indirect) impact to the subject resource, as opposed to areas listed as "no impacts" which are assumed to completely avoid impacts to the resource.

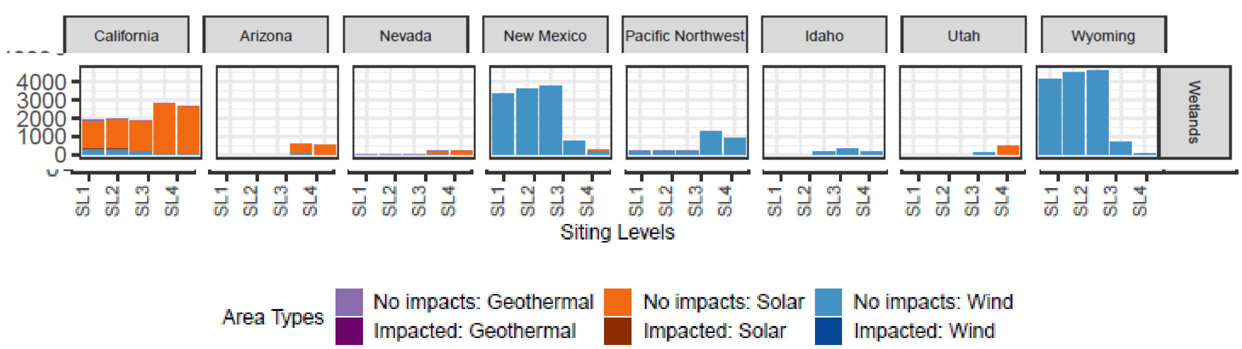
California has approximately 1.8 million acres of mapped freshwater wetlands, pond, and other water features, excluding marine estuaries, lakes, and rivers (NWI 2021). For the In-State constrained case[46], E3-TNC concludes that solar and wind generation buildout (excluding transmission) **would impact roughly 50 to 200 km^2 (12,350 to 49,400 acres) of wetlands throughout California under the RESOLVE base case (i.e., RESOLVE zone with no siting constraints) or SL1 scenario, and less than 50 km^2 impacts to wetlands would occur in siting levels 2, 3, and 4**, as these scenarios would attempt to avoid such impacts**.** Similar acreage results are indicated for the Part West[47] and Full West[48] constrained cases and for the unconstrained cases[49] (E3-TNC, Figures 26, 27, 30, and 31). **Grid interconnection and transmission corridors could impact between 1 and 10 km^2** (247 to 2,470 acres) of wetlands (E3-TNC, Figures 28, 29, 32, and 33).

Figure 4-2: E3-TNC Wetland Impact Estimates

Excerpt 1 from E3-TNC Results (from Figure 26): wetlands impacts (km^2) for In-State (A) and Part West (B) scenarios, constrained case.

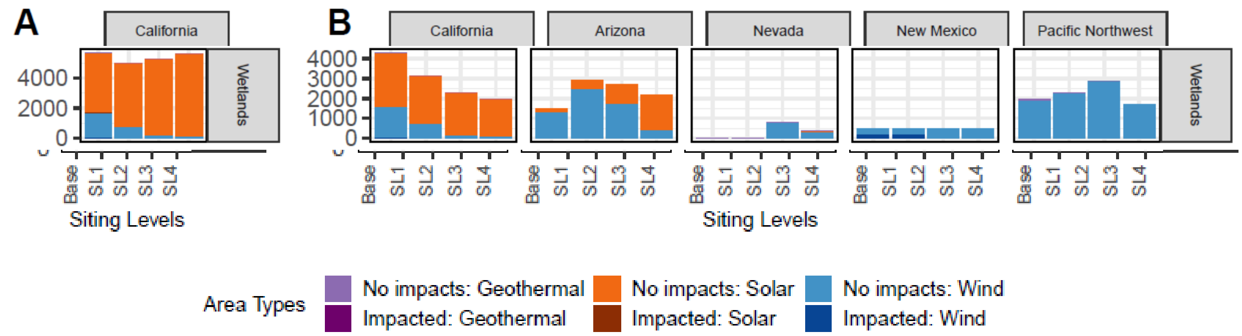


Excerpt 2 from E3-TNC Results (from Figure 27): wetlands impacts (km^2) for Full West scenario, constrained case.

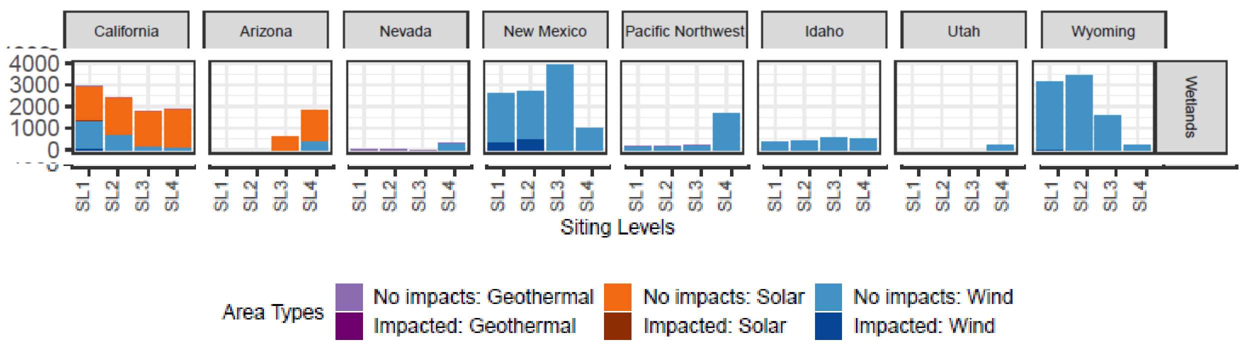


46. Figure 4-2, excerpt 1, column A
47. Figure 4-2, excerpt 1, column B
48. Figure 4-2, excerpt 2
49. Figure 4-2, excerpts 3 and 4

Excerpt 3 from E3-TNC Results (from Figure 30): wetlands impacts (km²) for In-State (A) and Part West (B) scenarios, unconstrained case.



Excerpt 4 from E3-TNC Results (from Figure 31): wetlands impacts (km²) for the Full West Scenario, unconstrained case.



Source: E3-TNC Figures 26, 27, 30, and 31.

Summary of State-Wide Environmental Resource Impacts

Table 4-5 provides a summary of E3-TNC's estimated impacts (km² and acres) to California state-wide resources based on the forecasted generation and gen-tie and transmission buildout across the full range of scenarios (out-of-state resource impacts are not tabulated but are shown in E3-TNC's bar charts, such as in Figure 4-2 above, for wetlands). Results are summarized here for California wetlands, critical habitat, important bird areas, wildlife linkages, prime farmland, agricultural land, and rangeland. Results are listed as ranges of km² and acres of impacted land based on interpretation of the bar charts in E3-TNC's Figures 26 through 33. For each resource category, the state-wide area within California is provided as a baseline, where suitable data are available. The range of results indicates the variability of environmental resource impacts that would occur between the constrained and unconstrained cases and the In-State, Part West, and Full West scenarios at different siting levels.

Table 4-5: E3-TNC Estimates of California State-Wide Environmental Resource Impacts across Multiple Scenarios.

Environmental Resource	California State-Wide Resource Area, km^2 (acres)	E3-TNC Estimated Impacts – Base Case and SL1, km^2 (acres)	E3-TNC Estimated Impacts – SL2 through SL4, km^2 (acres)
Wetlands(1)	7,284 km^2 (1.8 million ac) (1)	<50 to 200 (<12,350 to 49,400)	<50 to 100 (<12,350 to 24,700)
Critical habitat(2)	67,731 km2 (16,736,801 ac) (2)	50 to 400 (12,350 to 98,800)	5 to 50 (1,235 to 12,350)
Important bird areas(3)	23,299 km^2 (5,757,316 ac) (3)	200 to 2,500 (49,400 to 617,500)	<50 to 1,000 (<12,350 to 247,000)
Wildlife linkages(4)	18,330 km2 (4,529,688 ac) (4)	100 to 1,600 (24,700 to 395,200)	<50 to 1,000 (<12,350 to 247,000)
Prime farmland(5)	36,421 km^2 (9,000,000 ac) (5)	800 to 2,500 (197,600 to 617,500)	<50 to 2,000 (<12,350 to 494,000)
Agricultural land(5)	174,014 km^2 (43,000,000 ac) (5)	300 to 2,000 (74,100 to 494,000)	400 to 4,000 (98,800 to 988,000)
Rangeland(6)	29,137 km^2 (7,200,000 ac) (6)	700 to 3,800 (172,900 to 938,600)	800 to 3,800 (197,600 to 938,600)

Source: E3-TNC Tables 26-33.

(1) National Wetlands Inventory, excluding marine, estuaries, lakes, bays, and rivers. Online at: https://www.fws.gov/wetlands/

(2) USDA Environmental Conservation Online System. Online at: https://ecos.fws.gov/ecp/report/table/critical-habitat.html

(3) Audubon. Online at: https://www.audubon.org/important-bird-areas/state/california

(4) California State Geoportal, NSNF Wildlife Linkages. Online at: https://gis.data.ca.gov/datasets/CDFW::nsnf-wildlife-linkages-cdfw-ds1005/explore?location=38.907405%2C-121.059465%2C7.89

(5) California Department of Food and Agriculture. "Agricultural Land Loss & Conservation." No date. Online at: https://www.cdfa.ca.gov/agvision/docs/Agricultural_Loss_and_Conservation.pdf

(6) USEPA. "California Rangeland." No date. Online at: https://www.epa.gov/sites/production/files/2015-09/ca_rangeland_hay.doc

These results indicate that every scenario will likely have some impacts across each environmental resource area. The actual impact on environmental resources will depend on the generation scenario and the degree of resource avoidance during project-level siting (SL1 through SL4). In general as resource protection (siting level) increases, projects are increasingly located on agricultural lands and rangelands (which has its own impacts), rather than on other environmentally significant land. The range of results indicates the uncertainty of the impacts that will occur from future development.

Table 4-6 provides a further detailed breakdown of state-wide estimates of impacted resources in California for solar and wind generation for each scenario, In-State, Part West, or Full West under either the base case and SL1 siting protections or under SL2 through SL4 siting protections and under constrained or unconstrained cases. Table 4-6 demonstrates that, in comparing In-State vs. Full West (larger geography) scenarios, in-state impacts are generally higher in all categories, including agricultural land and rangeland, especially in the constrained case. This is because development is spread across eight western states in the Full West scenario. For the unconstrained case, the pattern is similar, but the differences are less pronounced due to the greater flexibility in project siting. In comparing constrained (restricted to RESOLVE zones) vs. unconstrained scenarios, impacts of the constrained case are generally higher than unconstrained. This is generally due to the reduced flexibility available in project siting, leading to a reduced ability to avoid sensitive resources in the constrained scenarios.

Table 4-6: E3-TNC Estimates of State-Wide Impacted Resources in California by Solar Generation and Gen-Tie for Selected Siting Scenarios (km^2)$^{(1)}$

		California Resource	Wetland		Critical Habitat		Important Bird Areas		Wildlife Linkages		Prime Farmland		Agricultural Land		Rangeland		Reference
		Siting Level (2)	Base case, SL1	SL2-SL4	Base case, SL1	SL2-SL4	Base case, SL1	SL2-SL4	Base case, SL1	SL2-SL4	Base case, SL1	SL2-SL4	Base case, SL1	SL2-SL4	Base case, SL1	SL2-SL4	
Scenario																	
Generation	In-State	Constrained	<50-100	<50	150-300	<50	1000-1200	<50-600	300-500	<50-500	1200-1800	<50-1800	1500-2000	1500-2500	1800-2200	1500-2500	E3-TNC Figure 26
Generation	Part West	Constrained	<50-100	<50	50-100	<50	600-800	<50-500	200-300	<50-300	800-1200	<50-1400	1000-1200	1200-1800	1200-1500	1200-1600	E3-TNC Figure 26
Generation	Full West	Constrained	<50-100	<50-100	50-100	<50	200-400	<50-300	100-300	<50-400	800-1000	<100-800	1000-1200	1000-1500	700-1000	1000-1500	E3-TNC Figure 27
Generation	In-State	Unconstrained	50-100	<50	200-300	<50	2000-2500	1200-1500	1200-1500	<50-1000	2000-2500	<50-2000	800-1000	500-4000	3500-3800	1200-3800	E3-TNC Figure 30
Generation	Part West	Unconstrained	<50	<50	300-400	<50	1300-1500	<50-1000	1200-1600	<50-1000	1800-2000	<50-1500	400-600	600-1200	3000-3500	800-3000	E3-TNC Figure 30
Generation	Full West	Unconstrained	150-200	<50	200-300	<50	1200-1500	<50-1000	1000-1200	<50-1000	1000-1200	<50-1200	300-500	400-1200	2200-2400	800-1500	E3-TNC Figure 31
Gen-Tie	In-State	Constrained	<5	<5	<5	<5-5	<5	<5-5	<5-5	<5-15	<5	<5	<5	<5-45	<5	10-45	E3-TNC Figure 28
Gen-Tie	Part West	Constrained	<5	<5	<5	<5	<5	<5	<5-5	<5-20	<5	<5	<5	<5-10	<5	<5-40	E3-TNC Figure 28
Gen-Tie	Full West	Constrained	<5	<5	<5	<5	<5	<5	<5	<5-25	<5	<5	<5	<5-10	<5	<5-40	E3-TNC Figure 29
Gen-Tie	In-State	Unconstrained	<5	<5	8-12	6-8	<5	5-10	8-12	<5-30	<5	15-20	<5	<5-30	15-20	20-50	E3-TNC Figure 32
Gen-Tie	Part West	Unconstrained	<5	<5	5-10	<5	<5	<5	30-40	<5-12	5-10	<5	<5	<5-10	30-40	10-20	E3-TNC Figure 32
Gen-Tie	Full West	Unconstrained	<5	<5	5-10	<5	<5	<5	5-10	<5-10	<5	<5-10	<5	<5-10	10-12	10-20	E3-TNC Figure 33
Range of Results(3)																	
Lower Bound			<50	<50	50	5	200	<50	100	<50	800	<50	300	400	700	800	
Middle Bound			100	50	200	15	1200	500	1000	500	1800	1200	1000	1500	2000	1500	
Upper Bound			200	100	400	50	2500	1000	1600	1000	2500	2000	2000	4000	3800	3800	
Uncertainty Factor																	
Lower-to-Middle Bound Factor			20X	10X	4X	3X	6X	10X	10X	10X	2X	20X	3X	4X	3X	2X	
Lower-to-Upper Bound Factor			40X	20X	8X	10X	12.5X	20X	16X	20X	3X	40X	7X	10X	5.5X	5X	
Middle-to-Upper Bound Factor			2X	2X	2X	3.5X	2X	2X	1.5X	2X	1.5X	1.5X	2X	2.5X	2X	2.5X	

Source: Interpretation of land area bar charts presented in E3-TNC Tables 26-33.
(1) For each resource category and siting level, E3-TNC data indicate the total amount of land that would be needed to achieve HES buildout and the subset of that land that would impact a specific resource (indicated as dark shades). An entry of "<50" indicates low or no discernable results are shown in E3-TNC bar chart results.
(2) Base case applies only to Constrained scenarios.

Table 4-7 provides a focused comparison of resource impacts for both the SL1 and SL4 siting levels for the Full West Constrained Scenario. This table illustrates the reduction in impacts if the SL4 siting protections are incorporated into generation siting decisions. In comparing the results across siting levels, the potential impacts to sensitive resources (e.g., wetlands, critical habitat) from the base case and SL1 (excludes federal lands) are higher than other siting levels due to the progressively greater restrictions on land use. Potential impacts to ecological resources are lowest in SL4 due to the higher land use protections; however, impacts to agricultural land and rangeland are progressively higher due to more of this land being used for development as other environmentally sensitive land is protected.

Table 4-7: E3-TNC Estimates of Impacted Resources in California – Comparison of Siting Levels 1 and 4 for the Full West Constrained Scenario (km^2)

	California Resource	Wetland		Critical Habitat		Important Bird Areas		Wildlife Linkages		Prime Farmland		Agricultural Land		Rangeland		Reference
	Siting Level(1)	SL1	SL4	SL1	SL4	SL1	SL4	SL1	SL4	SL1	SL4	SL1	SL4	SL1	SL4	
Generation Scenario																
Full West Constrained(2)		50	<50	100	<50	400	<50	300	<50	800	<50	1000	1500	1000	1500	E3-TNC Figure 27

(1) E3-TNC bar chart data from the referenced source table indicate the amount of land that would be needed to achieve HES buildout and the subset of that land that would impact a specific resource (indicated as dark shades) within each siting level. An entry of "<50" here indicates low or no discernable results are shown in E3-TNC bar chart results.
(2) Includes solar and wind generation. Excludes gen-tie and transmission resource impacts. These impacts are generally under 20 km^2, or less than 5% of estimated generation impacts.

As shown in Table 4-7, depending on the level of siting protections, and assuming the less impactful Full West scenario, development impacts to environmentally and agriculturally significant California lands will not be fully avoidable and could be substantial given the scale of development needed to meet the state's renewable energy goals: potentially up to 50 km^2 (12,350 acres) of wetlands, critical habitat, important bird areas, wildlife linkages, and prime farmland (this assumes an upper bound of 50 km^2 in cases where E3-TNC's bar charts show no discernible "impacted" lands but where micro siting may result in project-level impacts that were not considered), and up to 3,000 km^2 (741,000) acres of agricultural land and rangelands are developed.

These values may underestimate micro-siting factors that could increase impacts or lead to more land being developed than anticipated in the E3-TNC study due to avoidance of impacts, especially at lower siting level protections. Typically, attempts are made to avoid sensitive resources during project siting. However, as described in Section 4.2 above, very often micro-siting factors exist in land development, such as previously unmapped wetlands and waters, or wildlife habitats that are not captured in the E3-TNC analysis and could increase the impacts described above. Although it is difficult to quantify the cumulative effects of site-specific impacts to sensitive resources, it is reasonable to expect that actual site conditions will present development constraints that either cause solar and wind projects to be reduced in scale, to be relocated to less energy-suitable areas (and thus require more projects), or result in direct loss of previously unmapped resources in order to achieve the desired scale and density of development.

Where impacts are not fully avoided, agency-required mitigation measures add costs to the project that need to be implemented prior to project approval and/or during construction and operations. Mitigation costs can be in the form of offsite land conservation easements (land banking), onsite restoration and habitat enhancements, and other short-term and long-term commitments. These costs can vary widely depending on factors such as local jurisdiction policies and the type and magnitude of the impacted resource (USFWS 2019a). For example, the cost to restore or offset wetland resources can be ten times the cost of comparable acreage or upland habitat restoration. In cases where a USFWS Section 10 HCP is required for obtaining an incidental take permit, the process requires intensive studies by qualified biologists, purchase of land, land restoration, and perpetual maintenance. HCPs have many components (e.g., species information, habitat needs, project-related effects to the species, biological goals and objectives, management strategy, etc.) and implementation costs can vary between several hundred thousand to multiple millions of dollars, depending on the cost of land and other factors. As noted in Section 2, a general assumption of 1 percent of capital costs is used to account for mitigation measures that project sponsors may need to put in place to address adverse impacts.

4.4.2 Regional Impacts

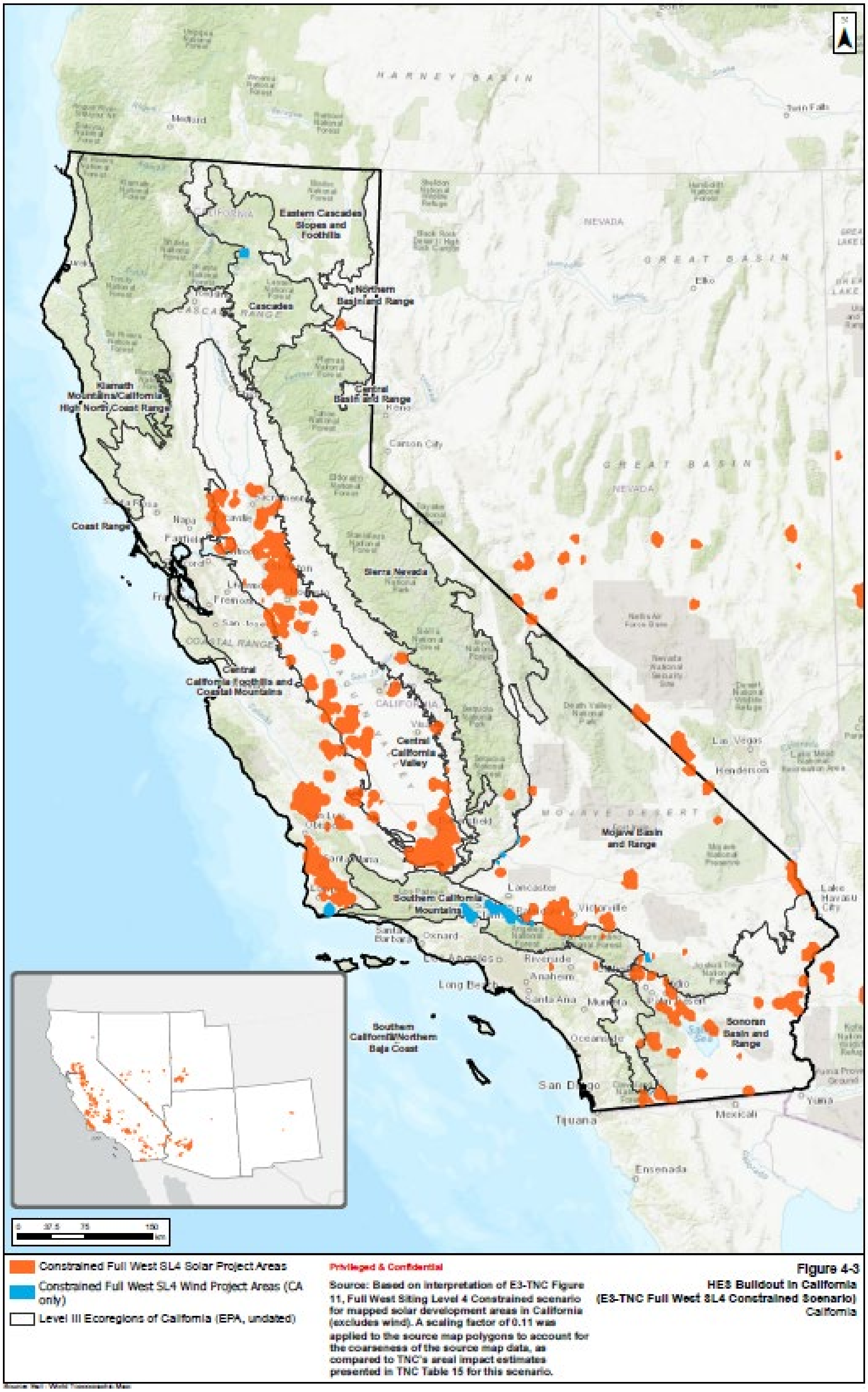
Regional impacts were estimated for the environmental resource categories listed above using E3-TNC's Full West SL4 Constrained scenario as a representative buildout scenario. E3-TNC development area results are presented in a series of coarse-level maps, as background data for the E3-TNC study were not available for this analysis. GIS tools were used to replicate the geographical areas presented by E3-TNC for the Full West SL4 Constrained scenario as presented in E3-TNC Figure 11. The solar and wind development area polygons were then overlaid onto USEPA-defined ecoregions[50] to illustrate the various ecological sub-regions (USEPA 2016) that could be impacted by this scenario. Publicly available data sets were then applied to the mapped polygons to quantify the areal extent of environmental resources that would be impacted within solar development areas for each ecoregion. Figure 4-3 shows the potential solar and wind development locations and corresponding ecoregions within California for this analysis.

As noted on Figure 4-3 a scaling factor of 0.11 was applied to the source map polygons to account for the coarseness of the E3-TNC source map data (i.e., it appears that the E3-TNC mapped polygons represent an area approximately nine times larger than the estimated future development footprint for the corresponding scenario to improve map readability). This factor was derived by comparing the total area of the mapped polygons for solar development in California (approximately 34,800 km^2) to the E3-TNC's study's areal impact estimates for the corresponding scenario (3,821 km2) as presented in E3-TNC Table 15, Lines 17 through 19.

The land area shown on Figure 4-3 and listed below in Table 4-8 represents approximately 71% (2,723 km^2) of the 3,821 km^2 of land that would be developed for solar generation in the Full West SL4 Constrained scenario. The remaining approximately 29% of potential solar development (1,098 km^2) would be sourced primarily from Arizona, southwestern Utah, and southern Nevada.

50. Ecoregions denote areas of general similarity in ecosystems and in the type, quality, and quantity of environmental resources and provide a spatial framework for the assessment, management, and monitoring of ecosystems. Regions are identified based on spatial patterns and the composition of biotic and abiotic phenomena that affect or reflect differences in ecosystem quality and integrity, taking into consideration geology, physiography, vegetation, climate, soils, land use, wildlife, and hydrology (Wiken 1986; Omernik 1987, 1995, cited in USEPA 2016). Levels I through IV provide progressively more detailed breakdown of each region. There are 13 level III ecoregions and 177 level IV ecoregions in California and most continue into ecologically similar parts of adjacent States of the United States or Mexico. Explanations of the methods used to define these ecoregions are given in Omernik (1995), Omernik and others (2000), and Omernik and Griffith (2014), as cited in USEPA 2016.

Figure 4-3: HES Buildout in California under E3-TNC's Full West Constrained Scenario



Specific resource impacts due to solar development were then derived by applying the 0.11 scaling factor within the mapped polygons, and comparing the totals for each resource category within the mapped polygons to E3-TNC's state-wide estimates (as described above) and shown in bar charts in E3-TNC Figure 27 for the Full West SL4 constrained scenario. Table 4-8 summarizes the results of the analysis, including the estimated total land area that would be developed with solar resources within each ecoregion, and the total estimated land area within each ecoregion that would see impacts to specific environmental resource lands from solar development. Data sources are listed in notes to Table 4-8.

Table 4-8: Environmental Resource Impacts from Utility Solar PV for the E3-TNC SL4 Full West Constrained Scenario, by Ecoregion in California (km^2 and acres).

ECOREGION[1]	Sierra Nevada	Central California Foothills and Coastal Mountains	Central California Valley	Southern California Mountains	Central Basin and Range	Mojave Basin and Range	Northern Basin and Range	Sonoran Basin and Range	Southern California/ Northern Baja Coast	Total
Mapped Area Developed with Solar Resources by Ecoregion (California Portion of the Full West SL4 Constrained Scenario)	15.64 (3,865)	638.45 (157,761)	1,244.71 (307,568)	19.86 (4,907)	16.27 (4,020)	362.20 (89,500)	6.76 (1,607)	368.39 (91,029)	50.87 (12,570)	**2,723.15 (672,890)**
Environmental Resource Impacts of Solar Development by Ecoregion (km^2 and acres, except as noted otherwise)										
Wetlands and Waters[2]	0.27 (66.7)	7.00 (1,729.7)	33.12 (8,184.0)	0.10 (24.7)	0.87 (215.0)	2.38 (588.1)	0.04 (9.9)	3.82 (943.9)	0.97 (239.7)	**48.56 (11,994.3)**
Critical habitat[3]	0.47 (116.09)	50.42 (12,453.7)	63.91 (15,785.8)	0.48 (118.56)	0.00 (0.00)	8.57 (2,116.79)	0.00 (0.00)	49.58 (12,246.3)	3.69 (911.43)	**177.12 (43,748.6)**
Important bird areas[4]	1.80 (444.6)	41.03 (10,134.4)	73.41 (18,132.3)	0.00 (0.00)	3.49 (862.03)	5.57 (1,375.79)	1.64 (405.08)	34.87 (8,612.89)	0.49 (121.03)	**162.30 (40,088.1)**
Wildlife linkages[5,6]	0.00 (0.0)	2.97 (733.59)	4.99 (1,232.53)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	**7.95 (1,963.65)**
Prime farmland[7,8]	0.03 (7.41)	35.95 (8,879.65)	(412.97 (102,004)	0.00 (0.00)	0.00 (0.00)	1.72 (424.84)	0.00 (0.00	30.14 (7,444.58)	1.14 (281.58)	**481.95 (119,042)**
Agricultural land (FMMP excluding prime farmland) [7,8]	0.01 (2.47)	45.12 (11,144.6)	335.41 (82,846.3)	0.00 (0.00)	0.00 (0.00)	3.18 (785.46)	0.00 (0.00	17.82 (4,401.54)	0.15 (37.05)	**401.68 (99,213)**
Rangeland[9]	9.73 (2,403.31)	488.63 (120,692)	213.39 (52,707.3)	15.05 (3,717.35)	11.32 (2,796.04)	271.33 (67,018.5)	6.58 (1,625.26)	192.74 (47,606.8)	47.46 (11,722.6)	**1,256.23 (31,0289)**
Scenic Highways (km)[10]	0.00 (0.00)	27.24 (6,728.28)	8.09 (1,998.23)	0.66 (163.02)	1.42 (350.74)	23.45 (5,792.15)	0.00 (0.00)	11.28 (2,786.16)	4.95 (1,222.65)	**77.09 (19,041.2)**

Source: Based on interpretation of E3-TNC Figure 11, Full West SL4 Constrained scenario for mapped solar and wind development areas in California (table excludes wind land areas). For the mapped areas and each environmental resource, a scaling factor of 0.11 was applied to the source map polygons to account for the coarseness of the source map data, as compared to TNC's areal impact estimates presented in TNC Table 15 for this scenario. The total area for the scenario is 3,821 km^2 as presented in Table 15; and 71% of this area (2,723 km^2) is in California.

(1) USEPA. "Level III Ecoregions of California." No date. Online at: https://www.epa.gov/eco-research/ecoregion-download-files-state-region-9
(2) USFWS. "National Wetlands Inventory" excluding marine, estuaries, lakes, bays, and rivers. 5/1/2021. Online at: https://www.fws.gov/wetlands/data/State-Downloads.html
(3) USFWS. "Threatened and Endangered Species Active Critical Habitat." 10/6/2021. Online at: https://ecos.fws.gov/ecp/report/table/critical-habitat.html
(4) National Audubon Society. "Important Bird Areas." Online at: https://www.audubon.org/important-bird-areas/state/california
(5) California State Geoportal, NSNF Wildlife Linkages. Online at: https://gis.data.ca.gov/datasets/CDFW::nsnf-wildlife-linkages-cdfw-ds1005/explore?location=38.907405%2C-121.059465%2C7.89
(6) CDFG. "Wildlife Linkages." 1/31/2020. Online at: https://gis.data.ca.gov/datasets/CDFW::nsnf-wildlife-linkages-cdfw-ds1005/explore?location=38.937887%2C-121.059465%2C7.96
(7) California Department of Food and Agriculture. "Agricultural Land Loss & Conservation." No date. Online at: https://www.cdfa.ca.gov/agvision/docs/Agricultural_Loss_and_Conservation.pdf
(8) CA Department of Conservation. "Farmland Mapping and Monitoring Program." 2018. Online at: https://data.cnra.ca.gov/dataset/california-important-farmland-2018
(9) USFS. "Rangelands." 10/1/2019. Online at: https://data.fs.usda.gov/geodata/rastergateway/rangelands/index.php
(10) Caltrans. "California State Scenic Highways." 4/27/2021. Online at: https://services1.arcgis.com/8CpMUd3fdw6aXef7/arcgis/rest/services/Scenic_New1_4_WFL1/FeatureServer/0

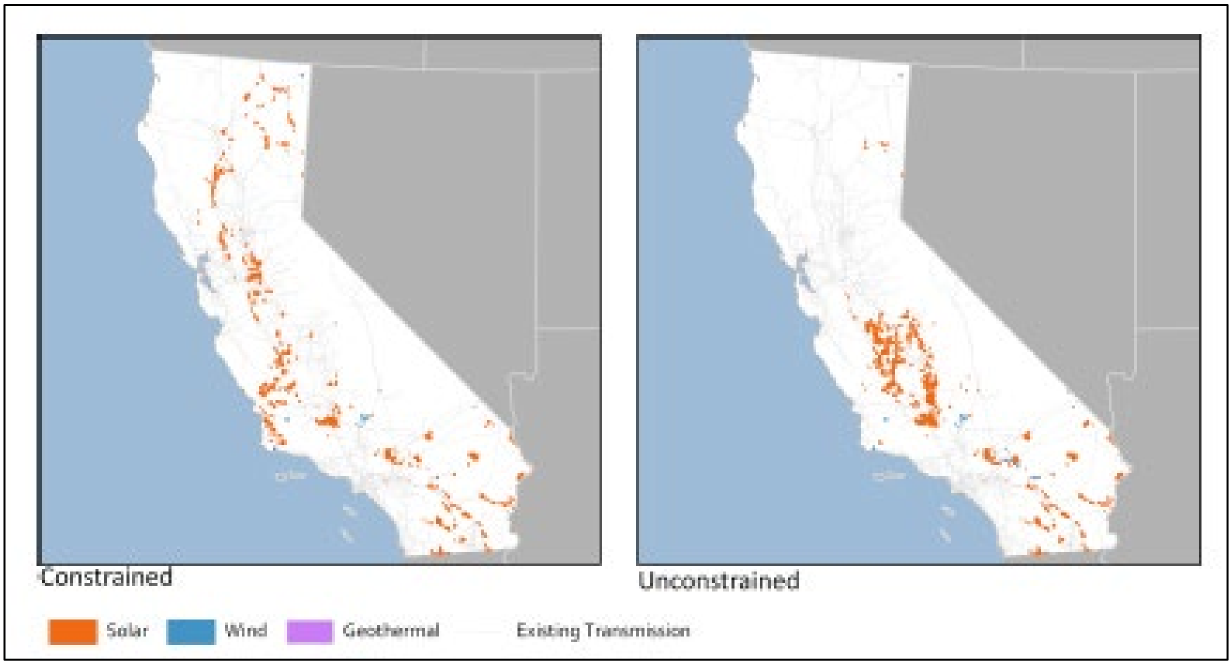
Wind Development Areas

Wind development areas for this scenario are shown on E3-TNC Figure 11 and are replicated in Figure 4-3. E3-TNC's estimated land area for wind generation in California under the SL4 Full West Constrained scenario covers an additional approximately 80 km^2 based on comparison of E3-TNC's Full West and In-State scenario maps and E3-TNC's tabulated results for this scenario. This land area is about 3% of the estimated land area required for solar development in California.

About 85% (about 68 km^2) of this amount is clustered in the Southern California Mountains ecoregion, in two general areas within northern Los Angeles County: one cluster is sited along the southern fringe of the Antelope Valley near Palmdale and Lancaster, and another cluster is sited near the Interstate 5 corridor near Castaic Junction, north of Santa Clarita. The remaining wind sites are depicted in several smaller clusters: the Antelope Valley in southeastern Kern County (Tehachapi Range, edge of the Sierra Nevada and Mohave Basin and Range ecoregions); Yucca Valley in southern San Bernardino County (Mohave Basin and Range ecoregion); southwestern Santa Barbara County near Gaviota (California Foothills and Coastal Mountains ecoregion); and in northeastern Shasta County, in the Cascade Range (edge of the Northern and Central Basin and Range ecoregions).

Potential resource impacts from these wind developments are not quantified here due to the limitations of the data presented in E3-TNC's report. However, given the nature of wind development siting and the general characteristics of the Southern California Mountains ecoregion and other affected ecoregions, resource impacts could include loss of wildlands due to new road construction in remote areas; erosion and sedimentation due to construction in steep terrain; introduction of fire hazards in high fire hazard zones; introduction of invasive species; impacts to cultural resources; and visual resource impacts due to ridgeline developments visible from public viewing areas and scenic roadways. Section 4.5 provides additional qualitative discussion of potential impacts of wind development.

The balance of the total estimated land area of 1,517 km^2 of wind generation for the scenario (approximately 1,437 km^2) is sourced from out of state wind resource areas, primarily clustered in the Columbia River region of southern Washington and northern Oregon; and smaller clusters in southern Idaho, eastern Wyoming, and central New Mexico.



Transmission Corridor Development

As noted above, 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[51], and the Full West scenario includes additional new long-distance high voltage transmission lines, TransWest Express, Gateway South, Gateway West, Boardman to Hemingway, and Southwest Intertie Project (SWIP) North with a total distance of 5,356 km to deliver wind power from Wyoming and Idaho to California.[52]

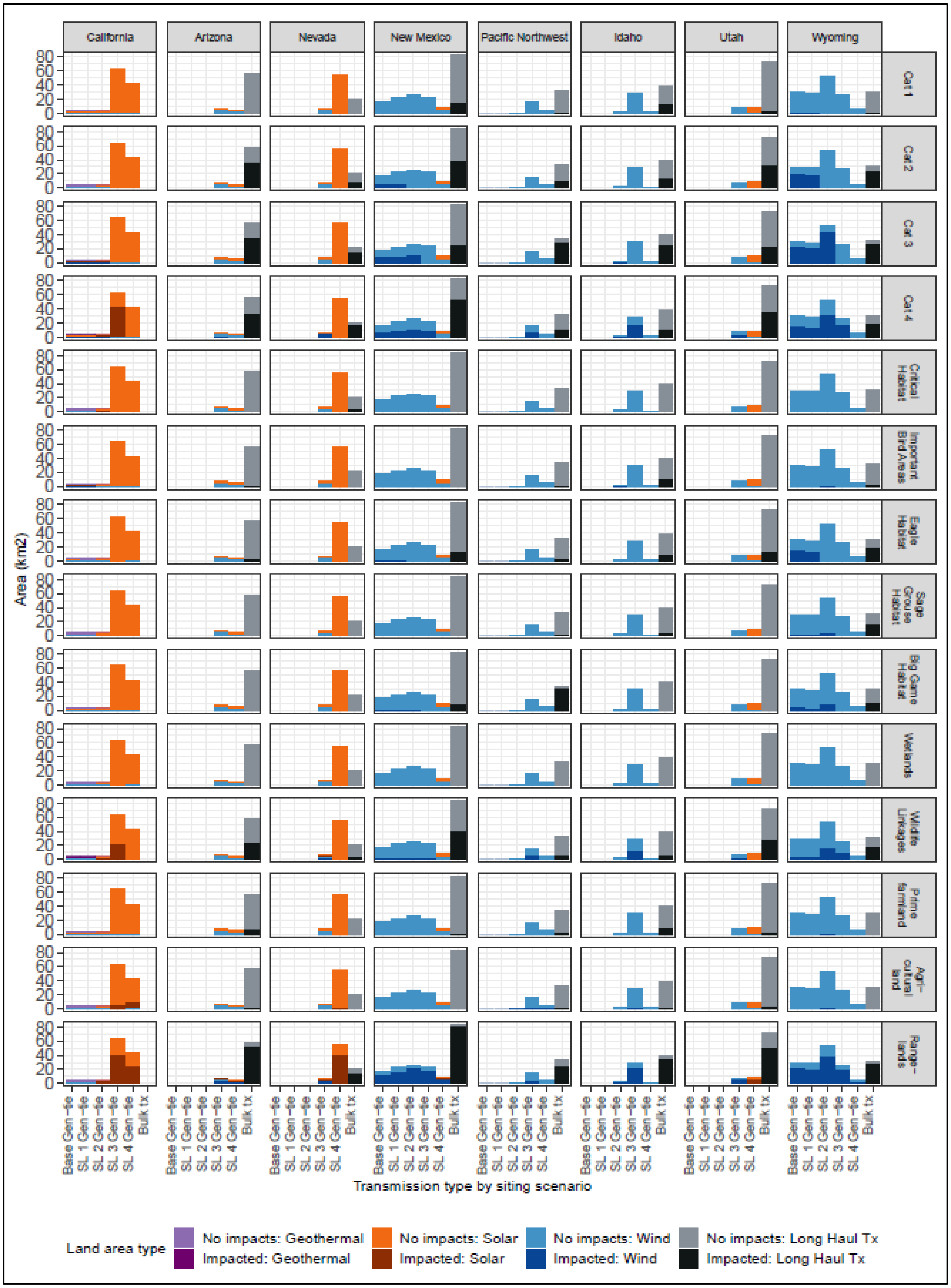
E3-TNC Figure 11 illustrates these long-haul transmission routes for the Part-West and Full-West scenarios. These lines would be utilized for imported generation under each of the four siting levels. The Full West SL4 constrained scenario portion of Figure 11 is provided below as an example. E3-TNC Figure 29 presents their analysis of resource impacts related to gen-tie and long haul transmission and E3-TNC Tables 15 and 16 present the estimated land areas for new gen-tie and transmission corridors. Land areas are relatively low (less than 10 km^2) in most scenarios, but range up to 100 km^2 in the high-import Full West scenario (E3-TNC Tables 15 - 16). The bar chart results, shown below, indicate varying degrees of potential impacts (indicated as dark shaded colors and presented as km^2) to eagle habitat, sage grouse habitat, big game habitat, and wildlife linkages, as well as rangelands, in various western states including Arizona, Nevada, New Mexico, Oregon, Idaho, Utah, and Wyoming.

51. https://sunzia.net/blm/; http://www.southlinetransmissionproject.com/

52. http://www.transwestexpress.net/; https://www.pacificorp.com/transmission/transmission-projects/energy-gateway/gateway-south.html; http://www.gatewaywestproject.com/maps_segment.aspx; https://www.boardmantohemingway.com/; https://www.nwcouncil.org/reports/columbia-river-history/intertie

These long-haul transmission projects are in various stages of permitting, alternative routing analysis, and environmental review.[53] Comment received during the environmental review processes have expressed various concerns about the impacts of construction, operations, and maintenance of the transmission lines on visual and cultural resources, as well as wildlife resources such as greater sage-grouse, migratory bird habitat, and other sensitive and protected species. For example, in the case of the Gateway South Transmission Project USFWS requested expanded analysis of migratory birds and greater sage-grouse, and that the project be sited to avoid vegetation clearing in areas of potential yellow-billed cuckoo habitat or that such areas be spanned without vegetation removal and that access roads should avoid intact riparian habitats. USFWS also suggested that compensation for lost habitat services should include compensation for long-term (post-construction) habitat loss, alteration, and fragmentation.

53. See for example these NEPA-related documents for the SunZia, Southline, Gateway South, Gateway West, TransWest Express, Boardway to Hemingway, and Southwest Intertie Transmission Projects: https://www.energy.gov/nepa/downloads/eis-0474-final-environmental-impact-statement; https://eplanning.blm.gov/eplanning-ui/project/2011785/570; https://eplanning.blm.gov/public_projects/nepa/53044/74052/81404/AppP_CommentsandResponses.pdf http://www.gatewaywestproject.com/environmental_review.aspx; https://eplanning.blm.gov/eplanning-ui/project/65198/570; https://www.bpa.gov/efw/Analysis/NEPADocuments/Pages/Boardman-to-Hemingway.aspx; https://www.wapa.gov/regions/DSW/Environment/Pages/southwest-intertie-nepa.aspx



Source: E3-TNC 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.

In summary, the aggregated state-wide results (derived from E3-TNC's tabulated and bar chart data tables) and the aggregated regional results (derived from E3-TNC's mapped data) are in general alignment and provide insight into the various potential outcomes of solar and wind buildout. However, data derived from E3-TNC printed maps are too coarse to allow for precise comparison of future development sites and underlying resources, and thus potential resource impacts within individual sub-areas are approximations, particularly for scenarios that apply the SL4 siting criteria. Nonetheless, the data on potential impacts to lands of varying environmental resources illustrate that impacts to various sensitive lands in California are likely unavoidable during implementation of the HES.

4.5 Environmental Resource Constraints

This section summarizes the range of reasonably foreseeable impacts associated with broad-scale renewable energy development to highlight the types and severity of potential environmental impacts, and the implications for land development in currently open lands.

4.5.1 Rangeland and Agricultural Land Conversion

As noted above an estimated 1,256 km^2 of rangeland would be developed state-wide in the Full West SL4 Constrained scenario. Over half (56%) of these rangelands (702 km^2) are located within the combined Central California Valley and Central California Foothills and Coastal Mountains ecoregions, and another 37% (464 km^2) are located within the combined Mohave Basin and Range and Sonoran Basin and Range ecoregions. In addition, almost all bulk transmission corridors within California and other western states are anticipated to be located on rangelands. As shown in E3-TNC Figure 29 (excerpted above), bulk transmission lines will impact roughly 20 to 80 km^2 of rangeland.

Another one-third to half of all solar capacity would be sited on agricultural lands. Agricultural lands, particularly prime farmlands, provide an economic base for food production. Agricultural lands and associated irrigation canals also provide non-agricultural benefits such as open vistas from scenic roadways; ecological function as forage and nesting habitat and wildlife corridors for numerous wildlife species; and regional water conveyance systems. In particular, the agricultural lands of the California Central Valley ecoregion include flat valley basins of deep sediments adjacent to the Sacramento and San Joaquin Rivers, as well as fans and terraces around the edge of the valley. The region contains remnants of once-extensive prairies, oak savannas, desert grasslands in the south, riparian woodlands, freshwater marshes, and vernal pools. More than half of the region is now in cropland, about three-fourths of which is irrigated. General environmental concerns in the region include salinity due to evaporation of irrigation water, groundwater contamination from heavy use of agricultural chemicals, loss of wildlife and flora habitats, and urban sprawl (USEPA 2016).

Under typical CEQA analysis methodology, impacts to agricultural lands are considered significant when development converts prime farmland, unique farmland, or farmland of statewide importance; conflicts with applicable land use plans, policies, or regulations; or disrupts agriculture uses on surrounding lands such that it impairs the use of these lands for agricultural uses. Biological values associated with agricultural lands are also considered.

Prime farmland can be particularly attractive for solar development because it is likely to be flat, dry, and open as opposed to more marginal agricultural lands; and it is likely to be proximate to existing infrastructure. Solar development on agricultural land results in conversion to an industrial, nonagricultural use. Construction activities can affect surrounding cultivated agricultural land uses by depositing particulate matter on row crops and altering drainage and flow patterns during site construction. Mitigations such as fugitive dust plans, stormwater plans, erosions and sediment control plans, and traffic control plans, can be effective at minimizing these impacts on surrounding agricultural land uses provided that the measures are properly designed and implemented.

The Panoche Valley Solar Project described above included a mitigation measure that required the applicant to pay for the creation of either a 4,563-acre conservation easement on grazing land or a 285-acre conservation easement on high quality cropland in the San Juan Valley of San Benito County. This measure compensates for the individual and cumulative adverse impacts on agriculture from converting project site lands out of agricultural use.

Rangelands provide particular value as they make up a substantial aspect of the California Floristic Province, a biodiversity hot spot known for high levels of species richness and endemism. In biologically rich areas like this, land cover change has the potential to greatly impact ecological value and function. E3-TNC describes the natural resource values of these areas:

> *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 [projected future] solar in California and nearly all solar in Arizona and Nevada sited on rangelands… Rangeland habitats tend to have high biodiversity value, provide significant habitat connectivity, and form the foundation for a number of ecosystem services.* (Wu et al. 2019, p.39, citing Cameron et al. 2014*)*

Regulatory and policy decisions at the local level in California can and often do discourage the "energy sprawl" that results from industrial scale development within the built environment and near population centers in favor of development within shrublands and scrublands (Copeland et al. 2011; McDonald et al. 2009). A 2015 analysis of 161 planned, under construction, or operating industrial solar projects in California found that regulatory and policy decisions concentrated development in either biologically rich rangeland cover types, or areas of productive cultivated cropland, generally concentrated in the Central Valley and interior of southern California (Hernandez et al. 2015). The projects were broadly concentrated in Central Valley and the interior of southern California and included:

- 6,995 MW sited in 375 km² of shrubland and scrubland
- 4,103 MW sited in 118 km² of converted cultivated cropland
- 1,555 MW sited in 72 km² of grass/herbaceous lands
- 1,434 MW sited in 37 of km² of pasture/hay lands

Of the projects greater than 20 MW capacity, 51 percent (9.9 GW) of the generating capacity and 62 percent (484 km²) of the land area used for industrial solar projects was previously rangeland cover types including shrubland, scrubland, grass, or pasture. Another 21 percent (4.1 GW) of the analyzed generating capacity displaced 71 km² of cultivated crops.

Using E3-TNC's land development benchmark and E3-CP's HES incremental capacity target of 102 GW, and assuming a 65%-35% split between rangeland and agricultural land, HES buildout could impact an estimated 2,200 km^2 (543,200 acres) of rangeland and 1,180 km^2 (292,500 acres) of agricultural land. For context, the average farm in California's Central Valley was 1.8 km² in 2002 (UC AIC 2009) and thus several hundred farms or potentially thousands of farms could be converted to meet the HES goals.

The Panoche Valley Solar Project described above is located in the Panoche Valley in San Benito County. During the Panoche Solar Project NEPA review process, stakeholders such as the Center of Biological Diversity described the diverse valleys of this region (USACE 2015). This sub-region is representative of rangeland values, and is particularly notable for its extensive grassland habitat, a rare and declining ecosystem throughout California and the U.S. It remains one of the few intact places in the Central Valley that still contains a suite of upland San Joaquin Valley species, three of which are federally endangered (San Joaquin kit fox, blunt-nosed leopard lizard, and giant kangaroo rat). Panoche Valley contains habitat for these species because it is relatively isolated, remains largely undeveloped, and contains expansive grasslands that have not been converted to row crops. The Recovery Plan for the Upland Species of the San Joaquin Valley cites Panoche Valley as important to the recovery of species that formerly occupied large areas of the San Joaquin Valley floor (USFWS 1998). Therefore, because agricultural lands are known to be suitable habitat for the species, and the potential HES buildout will occupy agricultural lands, impacts to these species would be nearly unavoidable. Species that are particularly vulnerable to renewable energy development are discussed further below.

4.5.2 Avian and Other Wildlife

Direct and indirect wildlife impacts associated with solar and wind development vary by region and site and are typically well documented at the project level. Illustrative examples are summarized here: avian mortality, giant kangaroo rat, San Joaquin kit fox, blunt-nose leopard lizard, and desert tortoise.

Avian Fatalities

Utility-scale solar developments are known as a source of fatality for birds (Kagan et al. 2014). There are questions about the cause of solar energy related fatalities and whether these fatalities could ultimately impact bird populations and, if not addressed, impede the development of solar energy (Walston 2018). Collisions with solar infrastructure, including solar panels and other facility structures, has been observed at all types of utility-scale solar facilities as various project features, including artificial habitat from cooling ponds and high concentration of prey, attract birds to the site. The "lake effect," whereby migrating birds confuse the PV panes with bodies of water and collide as they attempt to land, is also a factor (Walston 2015).

An Argonne National Laboratory 2016 study estimated that collisions with photovoltaic panels at U.S. utility-scale solar facilities kill between 37,800 and 138,600 birds per year. The annual estimate for southern California ranged between 16,200 and 59,400 birds (Walston 2016). A 2020 study at 10 utility-scale solar energy projects in southern California found an average annual fatality rate of 2.49 birds per megawatt of installed capacity (Kosciuch et al. 2020). Using this ratio, installation of approximately 102 GW (4,000 km^2) of photovoltaic panels would result in a statewide average annual avian fatality rate of 253,980 birds. This is 4 to 16 times the 2016 estimated avian mortality in southern California.

While these numbers are relatively low compared with building and vehicle avian strikes (building strikes in the U.S. have been estimated to be on the order of 500 million birds annually), the magnitude of this impact will almost certainly increase with the HES buildout, even with the incorporation of best management practices designed to avoid attracting birds to the project sites. Additional research is needed to further understand how and when avian mortality occurs and how to prevent it. Various studies are underway, including the use of artificial intelligence (AI) to more efficiently track avian activity at solar sites (Nunez 2020). If not properly addressed, these interactions could present an impediment to solar energy development through delays in environmental reviews and decision making, or increased costs associated with avian monitoring and mitigation activities. There is also the threat of potential litigation; in 2014 the Center for Biological Diversity issued a "notice of intent" to sue the U.S. Fish and Wildlife Service (USFWS) and BLM for failing to protect endangered birds after Yuma Clapper Rails were found dead at two utility-scale solar projects in Riverside and Imperial Counties (CBD 2014; Roth 2014).

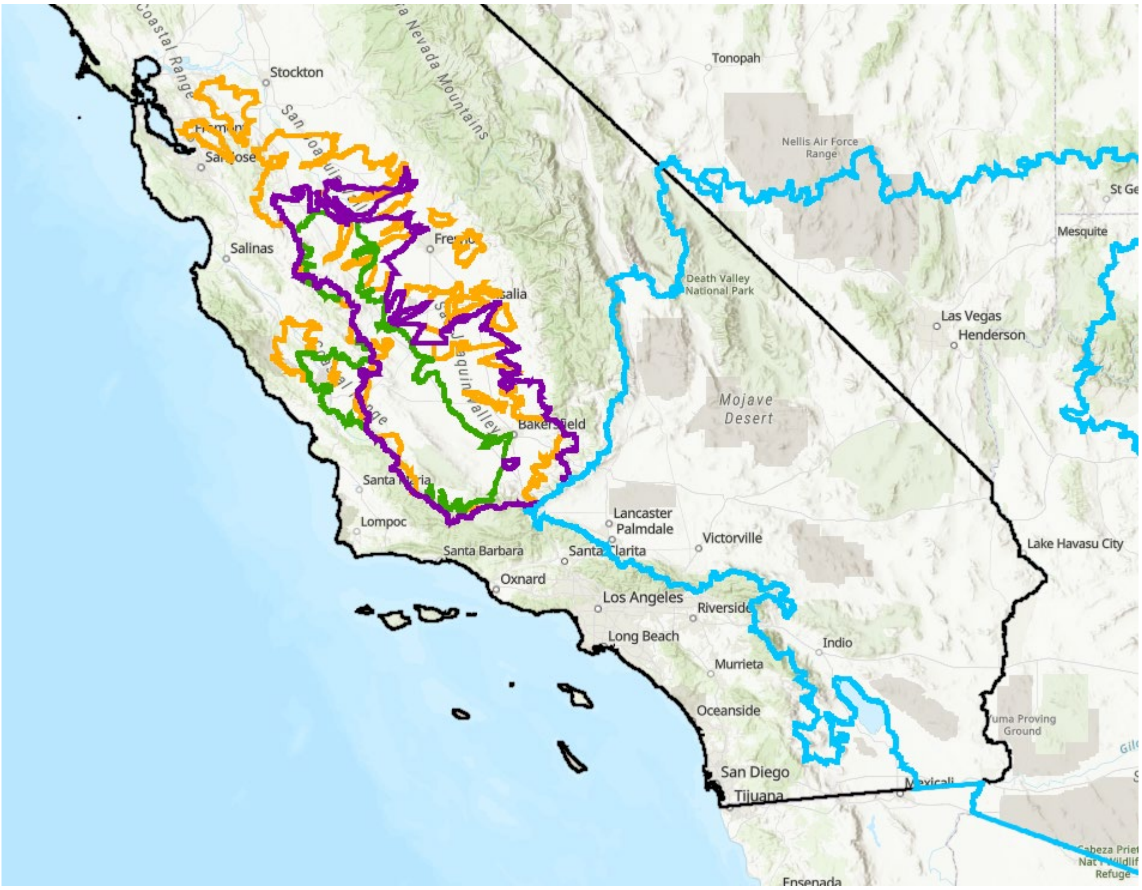
Avian impacts can also be construed in terms of breeding productivity and loss of habitat. In 2019 the USFWS issued an Environmental Assessment (EA) for an eagle take permit pursuant to the Bald and Golden Eagle Protection Act (BGEPA) for the California Flats Solar Project, a 283 MW solar facility on approximately 3,000 acres in unincorporated Monterey County. The applicant sought a 30-year incidental eagle take permit for the reoccurring loss of breeding productivity in the vicinity of the project due to disturbance from operation and maintenance activities at the facility and loss of habitat from land development. The USFWS estimated that two active golden eagle nesting territories were susceptible to continual loss of productivity and potential territory abandonment due to the proximity of the project. Measures imposed to reduce potential impacts included operational steps, such as limiting non-routine operation and maintenance activities during eagle breeding season, vehicle restrictions and speed limits, garbage abatement, limiting rodenticide use, livestock carcass management, and employee awareness training; and compensatory mitigation per the BGEPA regulations. Compensation consisted of payment for retrofit of electric power poles that are an electrocution risk to eagles, at an estimated cost of $1,470,000. The applicant also incurred mitigation costs for potential cumulative impacts of eagle take through funding of a permanent conservation easement of golden eagle habitat within a 6,204-acre area (USFWS 2019b).

In summary, mitigating for impacts to avian species can add substantial costs to a project, particularly as the cost of obtaining conservation easement lands to mitigate project impacts can increase over time as fewer suitable mitigation lands are available.

4.5.3 Protected Species of the Central Valley and Desert Regions

The Central Valley and adjoining foothills provide habitat for the federally protected San Joaquin kit fox, blunt-nosed leopard lizard, and giant kangaroo rat. The southern California desert region provides habitat for the federally protected desert tortoise. If not properly addressed, impacts to these and other state- and federally-protected species can both impede conservation efforts and affect the feasibility of solar and wind energy development through delays in environmental reviews and decision making, or increased costs associated with monitoring and mitigation activities, and potential litigation. These species are briefly described below and Figure 4-4 indicates the overall range of these species.

Figure 4-4: Ranges of Certain Protected Species of the San Joaquin Valley and Desert Regions(1)



Source: USFWS 2021.

(1) Blue = Desert tortoise range; purple = blunt-nosed leopard lizard range; green = giant kangaroo rat range; orange = kit fox San Joaquin Valley population range

Giant Kangaroo Rat

The giant kangaroo rat is a federally and state listed endangered species that generally occurs in grasslands and shrub communities on gentle slopes. It persists in isolated populations along the arid southwestern edge of Central California's San Joaquin Valley and the adjacent Inner Coastal Ranges. Development within kangaroo rat habitat can result in habitat loss and displacement as well as direct injury or mortality due to construction activities; disruption of movement caused by open trenches, which can lead to predation and starvation; or loss of habitat due on-site roads and infrastructure. Other potential effects include reduced habitat functionality on undisturbed lands that may become completely or partially surrounded by solar arrays or wind turbines and associated infrastructure and other development, and reduced availability of mammal burrows for refuge.

San Joaquin Kit Fox

No critical habitat has been designated for the San Joaquin kit fox. However, it is known to exist in San Luis Obispo County, western Kern County, and the Ciervo-Panoche area in western Fresno and eastern San Benito Counties. Optimal habitat for San Joaquin kit fox includes arid habitats with relatively low grassland vegetation. Preferred habitat is often dependent on the density of kangaroo rats and rabbits, the two favored prey items for the kit fox.

Development within potential San Joaquin kit fox habitat can result in direct and indirect impacts similar to those described above such as injury and mortality due to relocation efforts, and increased predation. Similar to the giant kangaroo rat, the San Joaquin kit fox is susceptible to habitat loss and displacement due to human activity and noise associated with intensified land development.

Blunt-Nose Leopard Lizard

Blunt-nosed leopard lizard is federally endangered and a California fully protected species, meaning no take may be authorized except for scientific research. Blunt-nosed leopard lizard is endemic to the San Joaquin Valley (Montanucci 1970; Tollestrup 1979 in USFWS 1998) and its current range is thought to include scattered populations throughout the undeveloped San Joaquin Valley and in the foothills of the Coast Range below 2,600 feet (Montanucci 1970; Alborn 1988 in USFWS 1998). As with other upland species in these regions, land development can result in short- and long-term direct effects and long-term indirect effects on the quality and quantity of habitat available for the species from construction and operations of new infrastructure, and reduced habitat functionality on the remaining undisturbed lands that may become surrounded by development.

Desert Tortoise

Desert tortoise range extends throughout the entire Southern California desert region as well as most of southern and central Nevada and Arizona (USGS 2021), and it generally coincides with the extent of the Mohave Basin and Range and Sonoran Desert and Range ecoregions. In the Full West SL4 Constrained scenario, approximately 644 km^2, or 24% of the state-wide solar development, would occur within the desert tortoise range.

This range, within southwestern United States, including California, is particularly well suited for development of industrial solar due to the region's high solar energy potential (USDOI and USDOE 2011). However, these arid ecosystems are particularly sensitive as they also possess exceptional biodiversity and high concentrations of threatened and endangered species (Flather 1998). They are also frequently at risk of environmental degradation on a local and regional scale due to land development (Abbasi 2000). Impacts to wildlife and wildlife habitat from construction and operation of industrial solar include direct impacts (e.g., mortality) and indirect impacts in the form of habitat loss, degradation, fragmentation, and modification (Kuvlevsky et al. 2007).

The desert tortoise is protected as threatened under the Endangered Species Act (ESA). It is considered a flagship species of the Mojave Desert and is frequently cited as potentially impacted by industrial solar development in California, Nevada, and other southwest deserts. Its geographic overlap with other species extends protection to other plants and animals within its range, making the importance of the desert tortoise greatly disproportionate to its intrinsic value as a species (Lovich et al 2011). Organizations that advocate for conservation of California and Nevada desert landscapes, such as Basin and Range Watch and Desert Tortoise Council, frequently point to potential mortality as a key issue of concern and a basis for objecting to solar projects where translocated desert tortoises may face increased predation and overheating (Basin and Range Watch, undated; basinandrangewatch.org 2021).

The 690-megawatt, 7,100-acre Gemini Solar Project is located on BLM administered land northeast of Las Vegas, Nevada. According to the project's 2019 Biological Assessment prepared by the BLM for the USFWS, the project will affect an estimated 219 adult tortoises and 1,139 juvenile desert tortoises, which would need to be relocated during construction. This represents about 0.7 percent of the USFWS' estimated 200,000 tortoises that remain in the wild. The Biological Assessment identifies translocation as an accepted conservation strategy and also indicates that it carries some risk of mortality or decreased fitness (BLM 2019).

The Gemini Solar Project also provides an example of project costs associated with mitigation of impacts to desert tortoise. The project was approved with mitigation requirements that include temporary and permanent desert tortoise fencing, monitoring during and after construction, and compensatory mitigation of $902 per acre to support desert tortoise recovery. Compensation fees totaled $4,359,366 after accounting for a reduction in the fee due to mowing of vegetation and preservation of soils in a portion of the project site (BLM 2019). The project's long term potential impacts on desert tortoise were documented during the permitting process.

Certain stakeholders, such as the Desert Tortoise Council, expressed concerns regarding the viability of the tortoise migration corridor linking protected populations; potential cumulative effects on migration from multiple projects in the area; and uncertainties as to whether the tortoise can fully adapt to habitat beneath solar panels and their shade (Magill 2020). Long-term monitoring of the desert tortoise populations in and around the Gemini solar site is necessary to address these questions and provide scientific data to support analyses of future solar projects.

4.5.4 USFWS Designated Critical Habitat

Critical habitat is a term defined in the federal Endangered Species Act to mean specific geographic areas that contain features essential to the conservation of an endangered or threatened species and that may require special management and protection. Critical habitat may also include areas that are not currently occupied by the species but will be needed for its recovery (USFWS 2021)[54]. Due to the nature of anticipated land development, HES deployment has the potential to impact designated critical habitat for federally listed species; however, E3-TNC's SL1 through SL4 siting criteria include avoidance of critical habitat. Therefore, by definition, these resource areas are presumed to be avoided in the siting of potential solar and wind candidate development zones. In addition, site developers often attempt to screen out critical habitat early in the siting process in order to avoid resource impacts and the associated effort and costs of permitting, consultations, and mitigation.

Siting data from E3-TNC's analysis were not available for this study, and E3-TNC's published maps of solar and wind development locations (e.g., E3-TNC Figure 11, presented above, and as replicated here in Figure 4-3) are depicted at a scale that is approximately 9 times the actual site size (presumably for map readability). Therefore, for the purpose of this assessment, only a cursory review of potential impacts to critical habitat is possible.

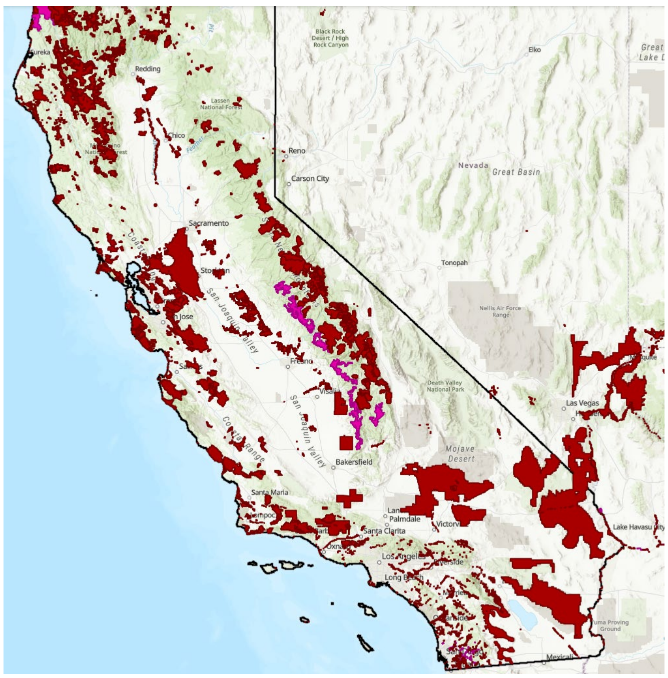
Figure 4-5 provides side-by-side comparison views of USFWS designated 'final' critical habitat (in red) and 'proposed' critical habitat (in purple) for various species state-wide; and the general locations determined to be suitable for solar (in orange) and wind (in blue) development under E3-TNC's Full West SL4 Constrained scenario (right side, excepted from Figure 4-3 above).

A qualitative comparison of these maps suggests that the sites selected for development in this scenario, as well as in other scenarios for SL1 through SL4, will generally avoid direct impacts to critical habitat, but that development could be in close proximity to, or potentially encroaching into current or future critical habit. For example, a designated solar development area in

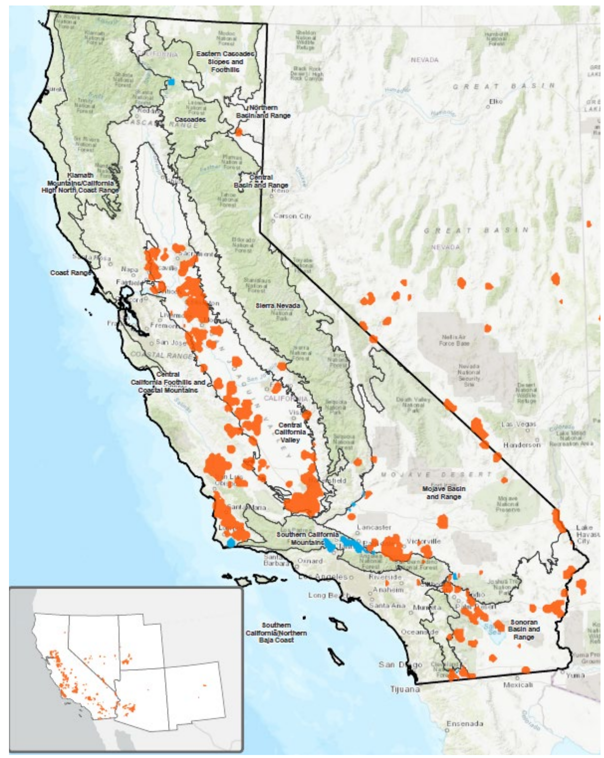
54. https://www.fws.gov/endangered/what-we-do/critical-habitats-faq.html

Mohave Valley east of Barstow is immediately adjacent to Desert Tortoise Critical Habitat to the north and south. In other locations, such as in northern San Luis Obispo County, a designated solar development area is immediately adjacent to, and potentially overlapping, a designated vernal pool fairy shrimp critical habitat located east and north of US 101 near Paso Robles. While it not possible to quantify potential direct impacts to these resources in this assessment, it is clear that critical habitat avoidance will be a key determinant in HES buildout.

Figure 4-5: USFWS Critical Habitat (left) and Likely Solar Development Locations under the E3-TNC Full West SL4 Constrained Scenario (right)



Source: USFWS 2021.



4.5.5 Habitat Conservation Plans and Natural Community Conservation Plans

Habitat Conservation Plans (HCPs) are planning documents required as part of an application for a federal incidental take permit. They describe the anticipated effects of the proposed taking; how those impacts will be minimized, or mitigated; and how the HCP is to be funded. HCPs can apply to both listed and non-listed species, including those that are candidates or have been proposed for listing. HCPs are an important tool in conserving species before they are in danger of extinction to provide early benefits and prevent the need for listing. (USFWS 2021)

HCPs are the federal counterpart to California's Natural Community Conservation Plan (NCCP) program. NCCPs provide a means of complying with the Natural Community Conservation Plan Act (NCCP Act) and securing take authorization at the State level. The primary objective of the NCCP program is to conserve natural communities at the ecosystem scale while accommodating compatible land uses. To be approved by the California Department of Fish and Wildlife, an NCCP must provide for the conservation of species and protection and management of natural communities in perpetuity within the area covered by permits. NCCPs are different from HCPs because the NCCP Act requires that conservation actions improve the overall condition of a species, whereas HCPs typically only require avoidance of a net adverse impact on a species.

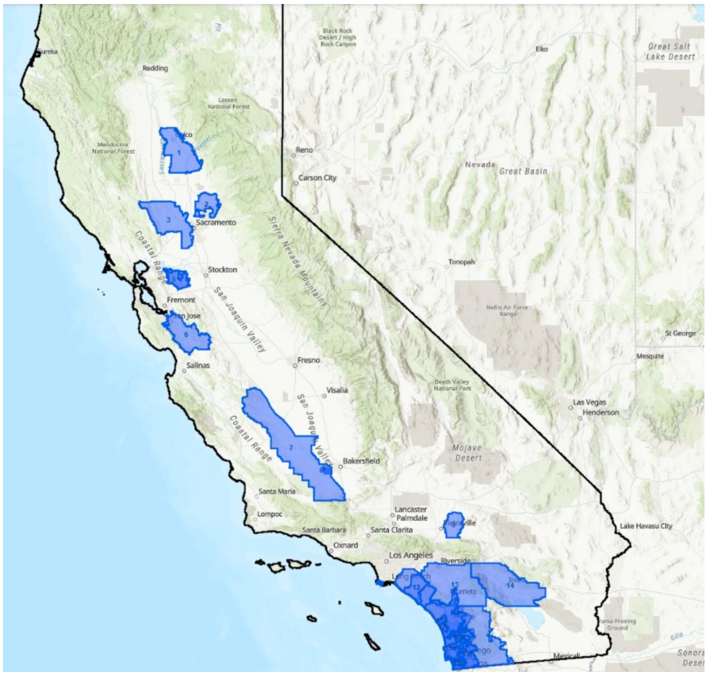
HES deployment has the potential to impact habitats that are earmarked for conservation within the planning areas of various HCPs and NCCPs. As with critical habitat, E3-TNC's published maps allow only a cursory review of solar and wind development areas in relation to HCP boundaries.

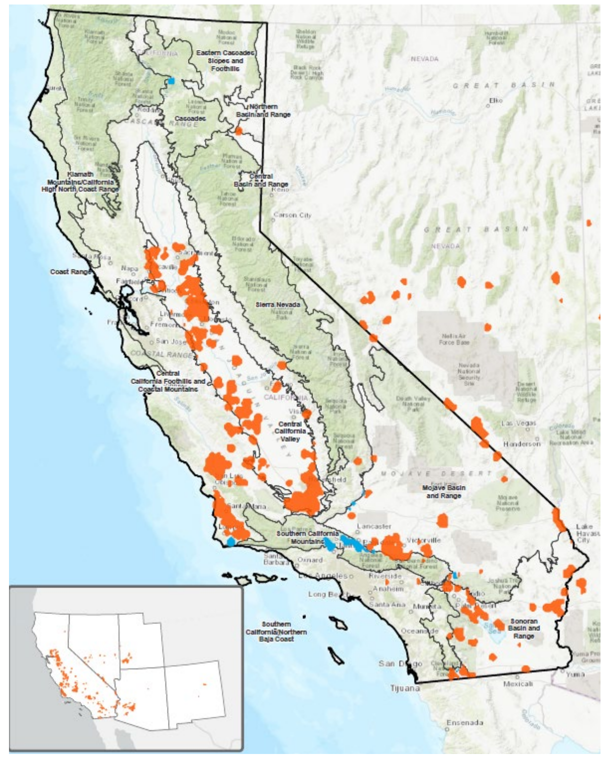
Figure 4-6 provides side-by-side comparison views of adopted HCPs and NCCPs in California (left side) and the general locations determined to be suitable for solar and wind development under E3-TNC's Full West SL4 Constrained scenario (right side, excepted from Figure 4-3 above). A qualitative comparison of these maps suggests that the sites selected for development in this scenario, as well as in other scenarios for SL1 through SL4, will avoid development within most HCP land area, with some exceptions. For example, much of the solar development sited in southwest San Joaquin Valley would be partially or wholly within the Aera SW San Joaquin Valley HCP, an area located generally west of Interstate 5 between Bakersfield and Lemoore. Solar development within the Coachella Valley in central San Bernardino County largely overlaps with the Coachella Multiple Species NCCP/HCP planning area[55]; and solar development within Yolo County, west of Woodland, would be partially sited within the Yolo County NCCP/HCP[56]. While it not possible to quantify direct impacts to sensitive habitats within these and other planning areas, it appears that at least some of the planned solar development will be sited within plan areas, and thus there is a potential to impair the effectiveness of the NCCP/HCP conservation efforts.

55. https://cvmshcp.org/

56 .https://www.yolohabitatconservancy.org/about

Figure 4-6: California HCPs and NCCPs (left) and Likely Solar Development Locations (right) under the E3-TNC Full West SL4 Constrained Scenario





Source: USFWS 2021.

4.5.6 Cultural Resources

Construction of utility-scale solar energy projects has the potential to damage or destroy irreplaceable cultural resources that can represent thousands of years of human history. These impacts can occur directly through construction activity such as clearing, grading, and excavation, or indirectly as a result of erosion of soils, or site contamination that degrades or destroys nearby cultural resources (Wescott 2013). Additionally, construction sites and access corridors placed in previously inaccessible areas often increase access by recreationalists, thus exposing cultural sites to a higher risk of disturbance, and potential looting and vandalism. While no example of this impact could be found in the literature, every solar development that was examined for this assessment identified this potential indirect impact from increased accessibility.

Aside from these direct and indirect impacts, the mere presence of utility-scale solar energy development can affect a cultural resource for which visual integrity is a component of the site's significance, such as sacred sites and landscapes, historic structures, trails, and historic landscapes. The Colorado River Indian Tribes (CRIT) sued the federal government on the basis that construction of the Modified Blythe Solar Power Project in Riverside County is within the ancestral homelands of the CRIT and would cause irreparable harm stating:

> *The Project site is located within the ancestral homelands of the members of the Colorado River Indian Tribes…whose reservation begins just a few miles northeast of the site. The religion and culture of CRIT's members are strongly connected to the physical environment of the area, including the ancient*

> *trails, petroglyphs, grindstones, hammerstones, and other cultural resources known to exist there. The removal or destruction of these artifacts and the development of the Project as planned will cause CRIT, its government, and its members irreparable harm.* [Colorado River Indian Tribes v. Dept. of Interior, Case 5:4-cv-02504, C.D. Cal. 4 December 2014)]

Another example of Tribal concerns expressed over solar development in ancestral lands is the 90 MW JVR Energy Park outside of Jacumba, in eastern San Diego County. Environmental studies in preparation by the County indicate that the project could disturb cultural resources that tell the story of over 10,000 years of human occupation (von Kaenel 2021):

> *The Kumeyaay people…are the indigenous people of the Jacumba Region. Some of the oldest and most continuous archaeological sites have been found in the region. Jacumba is a key location in the creator stories; as told through the Shuluk Songs which document the travels of the creator through our region…[which] was a major crossroads from the pacific coast to the desert and Colorado River region.* (Campo Band of Mission Indians 2018)

Tribal concerns were also expressed in the Environmental Impact Statement (EIS) for the 350 megawatt Crimson Solar Project in Moreno Valley, California:

> *… the Mule Mountains are important to [the Chemehuevi and Yaqui] religious beliefs and practices, and the proposed Project, if constructed, would interfere with these beliefs and practices. During a BLM consultation meeting with the tribe to discuss their comments, the tribe told the BLM that while they are not against renewable energy, they are opposed to the location of the proposed Project (and other solar projects on BLM-administered lands in the Chuckwalla Valley/Palo Verde Mesa area) because they believe that the entirety of undeveloped desert lands within their ancestral territory, including the cultural and natural resources found here, are of great importance to tribal culture and identity.* (US Department of the Interior 2021)

The Tribes raised concerns throughout the permitting process, eventually submitting protests that the BLM failed to adequately respond to the Tribe's comments on the Draft Resource Management Plan Amendment/Draft Environmental Impact Statement regarding failure to analyze the Project's modifications and comply with requirements under the Western Solar Plan. The BLM denied the protests and approved the project in May 2021, stating:

> *The BLM California is proud to support responsible development of renewable energy projects as part of our mission to sustainably manage public lands. The Crimson Solar project showcases the agency's commitment to meeting California's energy and economic needs with 21st Century technology.* (Karen Mouritsen, California Director of the BLM, 3 May 2021)

Other regions of likely HES buildout, such as the San Joaquin Valley and Sacramento, are also culturally rich and have strong links to Tribal interests. When Tribes in the San Joaquin Valley were consulted for the "Solar and the San Joaquin Valley Identification of Least-Conflict Lands Project," they proposed several management recommendations for planning renewable energy in their homeland. These recommendations included:

- Conducting thorough research and cultural resources survey with both professional archaeologists and Tribal members early in the design process
- Integrating buffers to avoid impacts to cultural sites

- Developing inadvertent discovery burial agreements with Tribes prior to construction
- Including Tribal members in construction monitoring, particularly when avoidance is not feasible
- Avoiding damaging known cultural resources during decommissioning
- Considering conservation easements in culturally sensitive areas.

Many of these measures are reflective of Tribal requests on other projects that were denied.

In addition to cultural concerns affecting the planning and potential approval of a project, impacts arising during construction can impact the cost and schedule of the project. At the Genesis Solar Energy Project in Chuckwalla Valley, in eastern Riverside County California, human remains and cultural artifacts were uncovered during site development in 2011. While this slowed construction, the project was eventually completed over the objection of the Colorado River Indian Tribes. The resulting destruction of prehistoric trails, funerary, and other important artifacts is believed to represent thousands of years of Tribal history. As mitigation for the loss of cultural resources, Genesis was required to contribute $3 million to an ethnographic study as well as scholarships for Native students (Krol 2021). While this mitigation may offset the impact, the non-renewable resources that were destroyed can never be replaced.

4.5.7 Air Quality and Dust Control

Development of renewables will likely decrease air pollution from most pollutants on a statewide level, due to the reduced operational emissions from fuel combustion, which in turn decreases oxides of nitrogen (NOx), volatile organic compounds (VOCs), toxic air contaminants (TACs), and ozone (smog) formation. However, implementation of the HES could increase statewide wind-blown dust generated during grading and construction activities on the large land area that will be disturbed by construction of the renewable developments needed to meet the HES goals, especially solar developments. In addition, HES implementation may increase dust on a net basis when the currently existing vegetation no longer protects the soil being entrained by the wind.[57]

Regionally, development of large-scale renewable projects can also decrease air quality impacts due to construction exhaust emissions and dust, though local air quality may also improve due to the reduction in combustion of natural gas in homes, at commercial and industrial sources, and in the operation of gasoline and diesel vehicles. For example, in California's Antelope Valley, dust issues during construction of the 230-MW Antelope Valley Solar Ranch 1 (AVSR1) project led to violations of the Federal Ambient Air Standard, resulting in a halt to construction by the Antelope Valley Air Quality Management District and Los Angeles County. According to media reports, residents of the area also blamed dust for causing respiratory distress and potential exposure to soil-borne Valley Fever (Trabish 2013).

57. Utility-scale solar energy projects transform the landscape, not only within the footprint of the generating facility, but also through associated roads and transmission lines. Typically, this requires significant site preparation, including vegetation removal and grading. These activities create significant dust emissions, particularly in arid environments. Munson SM, Belnap J, Okin GS. 2011. Responses of wind erosion to climate-induced vegetation changes on the Colorado Plateau. Proceedings of the National Academy of Sciences 108: 3854–3859.

Construction of utility-scale solar projects have also been claimed to lead to outbreaks of Valley Fever in San Luis Obispo County (Cart 2013).

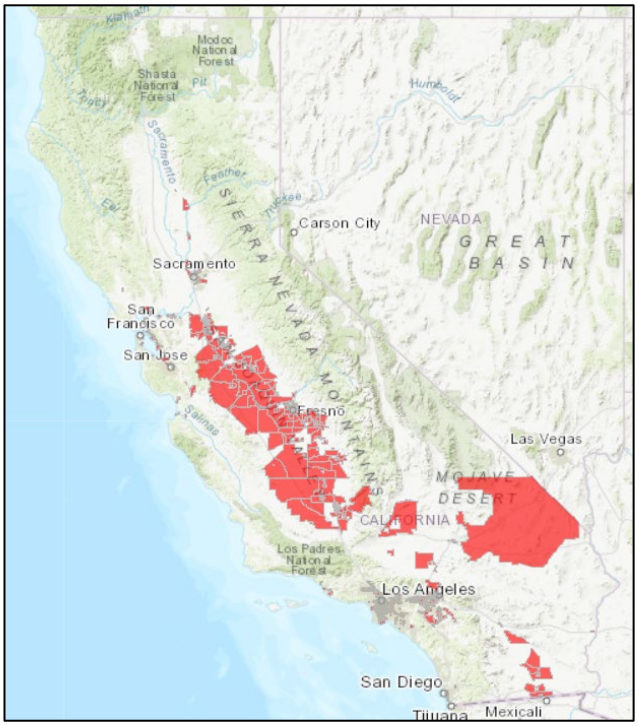
Overall, under the HES buildout, some communities will have better air quality (due to regional and local variations) while others will have worse air quality (due to local variations). While there will likely be a net benefit to statewide air quality by moving toward renewable sources, certain portions of the state may face an increase in localized emissions due to the sheer number of projects required to be developed to meet HES goals.[58]

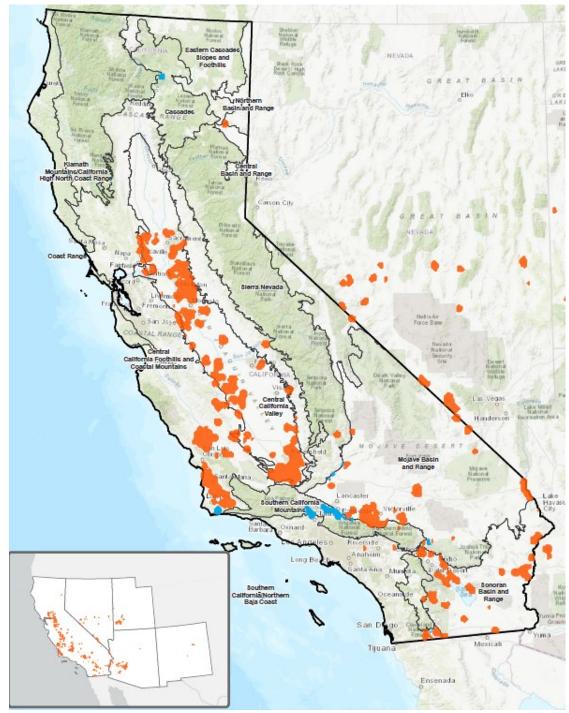
These localized impacts may be disproportionately located near disadvantaged communities. Air quality impacts from the developments necessary to meet the HES goals would occur at or near the facilities as well as at or near any infrastructure improvements associated with the facilities. For example, construction and O&M air emissions would occur at the facilities themselves, while transportation emissions associated with construction, O&M, and end of life activities would be emitted at roadways going to and from the sites and would therefore also be largely proximate to the sites themselves. Associated infrastructure (T&D and substations for example) will often have to tie in directly to the sites and have similar construction, operational, and transportation related air quality sources near to site development.

Disadvantaged communities are defined as the top 25% scoring areas from CalEnviroScreen along with other areas with high amounts of pollution and low populations. Figure 4-7 provides a map of SB535 Disadvantaged communities from the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA). These areas represent the 25% highest scoring census tracts in CalEnviroScreen 3.0, along with other areas with high amounts of pollution and low populations. Figure 4-3, presented above and a section of which is presented again below in Figure 4-7 for ease of reference, presents the most likely development locations under the HES scenario. As discussed above and indicated by comparison of these two maps, disadvantaged communities and areas of likely development tend to be co-located and thus it is likely that disadvantaged communities will experience some impacts on air quality due to HES development.

58. A detailed socioeconomic assessment of these potential localized air quality impacts on various disadvantaged communities is not performed here. Additional study, likely case by case, will be needed to ensure that disadvantaged communities are not disproportionately impacted by local emissions associated with these construction projects.

Figure 4-7: California Disadvantaged Communities (L) and Likely Solar Development Locations (R)





Source: OEHHA 2021.

4.5.8 Aesthetics and Other Community Issues of Concern

Utility-scale solar projects are increasingly facing local opposition due to adverse visual impacts on local communities. In the open desert landscapes of the southwestern U.S., utility-scale solar projects can be a source of negative aesthetic impact due to their large size, strong regular geometry, and highly reflective surfaces (Sullivan et al. 2012a). Strong public reactions against proposed projects are frequently focused on changes to the visual character and quality of an area (Smarden and Pasqualetti 2017). When mitigation is required for visual impacts, it often involves relocating project elements late in the process, creating project delays and additional engineering and environmental investigations, raising costs (Donaldson 2018).

San Bernardino County Supervisor Robert Lovingood has commented that the rapid development of utility-scale solar projects in the County has led to longtime residents finding their views of the desert transformed by fields of panels (Baker and Dent 2019). Residents have also expressed fears that several newly proposed utility-scale solar projects would make it difficult to have nearby California Highway 247 designated as a state scenic highway, due to the permanent changes in the desert landscape. As described above, the County amended its General Plan Land Use Element in response to these concerns to prohibit utility solar projects in certain areas of the County, if more than 50 percent of a project's output is sold "to the energy grid." This has the effect of restricting solar development on more than 1 million acres (about 1,600 square miles) of private lands (County of San Bernardino 2019; Roth 2019; Roselund 2019.). As noted in trade journal PV Magazine, land use restrictions raise further uncertainty about the amount of land that can be developed moving forward on either public or private lands:

This is not the first time that large-scale solar projects have run into conflicts in the California desert, despite this area being the home of the first large-scale solar projects in the United States, the Solar Energy Generating Systems (SEGS).

Many large concentrating solar power (CSP) and solar PV plants which were planned for public lands in the California desert have been effectively blocked by conservationists and Native American tribes, often using the strictness of the California Environmental Quality Act to their favor.

And as the use of public land provided more avenues to challenge these projects, many solar developers often shifted to private land, including former agricultural lands. However, the irony of San Bernardino County's ban is that is applies to private land, and County staff have even proposed that development be shifted back to public land, "apart from existing unincorporated communities" (Roselund 2019).

5. WASTE MATERIALS AND VOLUMES

Renewable energy development will expand the volume of waste materials during the life cycles of various material components utilized for solar and wind development. The issue will grow in importance as the use of renewables increases and older equipment reaches the end of its useful life. Waste material disposal could impact landfills and communities close to landfills, due to additional volumes and associated transportation impacts, including GHG impacts. This section provides a semi-quantitative overview of the anticipated waste materials, waste volumes, and associated waste management issues related to disposal of renewable energy infrastructure.

5.1 Waste Materials Assessment

An assessment of the potential waste implications of various renewable energy development at end of life was conducted by a review of available literature from academic publications as well as manufacturers to determine the end-of-life impact of waste streams resulting from decommissioned wind turbines, solar PV panels, and both commercial and industrial sized energy storage batteries. Due to the similar operational conditions and requirements of the three types of units, there is considerable overlap between their components and associated waste streams. Twenty-one (21) different components were identified, resulting in fifteen (15) unique waste streams. Storage batteries and their resulting waste streams are included in the overall analysis for wind and solar technologies, as batteries are commonly used as external power storage devices to capture excess energy generated by wind and solar systems.

In addition to understanding the specific waste streams that will be generated by increased renewable development, it is important to understand the regulatory implications for each of these waste streams, as each must be categorized and managed according to federal and state requirements.

5.1.1 Waste Categorization

The options available for disposal of a waste stream depend on the characteristics of that waste such as toxicity, or feasibility of recycling. The state of California, through its Department of Toxic Substances Control (DTSC), classifies wastes under different categories to regulate the management and disposal of each waste stream. The following definitions apply to the majority of the waste categories identified:

- Nonhazardous Solid Waste – These are wastes commonly found in households and businesses and can be disposed of through a municipal garbage service. Nonhazardous solid wastes are most likely to end up in a landfill.
- Hazardous waste – Certain wastes are categorized as hazardous because they are either explicitly listed as hazardous by state or federal regulations, or the waste exhibits characteristics described as hazardous in the regulations (based on toxicity, corrosivity, reactivity and ignitability criteria). There are additional subcategories of hazardous waste in California. The two most relevant to renewable energy technology components are Universal waste and used oil:
  - Universal wastes include waste streams that are generated across most businesses and industry sectors, and come primarily from consumer products that contain hazardous substances. The Universal waste requirements can be applied to these waste streams

provided that the wastes are managed in a specific way, and are recycled at end of life. Examples include rechargeable batteries, solar PV modules, electronic waste, and light bulbs. If these waste streams are disposed of by landfill or incineration rather than by recycling, the waste stream must be managed as a hazardous waste.

- Used oil is handled as a hazardous waste in California. Used oil must be collected by an approved used oil collection center (UOCC) which operates under the DTSC's regulations for recycling and disposal.

Table 5-1 identifies the potential waste streams likely to be generated at end of life from wind turbines, solar panels, and their associated battery storage. The table also includes the likely categorization of each waste stream.

Table 5-1: Renewable Energy Waste Stream Analysis

Renewable Energy Source	Waste Streams	Components	Potential Categorization	Options for Management	Applicable Requirements	References
Wind	Cabling/electrical wiring	Cables	Universal waste	Recycle through a certified e-waste recyclers	N/A	https://www2.calrecycle.ca.gov/WasteCharacterization/MaterialType
	e-Waste	Control electronics Wind sensors Internal and External Lights Transformer	Universal waste	Recycle through a certified e-waste recyclers	Electronic Waste Recycling Act of 2003	https://www.calrecycle.ca.gov/electronics/act2003 https://dtsc.ca.gov/electronic-hazardous-waste/ https://www.calrecycle.ca.gov/Electronics/RegInfo/
	Fiberglass	Blades Nacelle	Nonhazardous Solid Waste	Disposed through local municipal waste agency. Generally is not recycled.	14 CCR § 17017	https://aceinsulation.biz/2019/09/if-i-remove-my-old-insulation-myself-how-do-i-get-rid-of-it/
	Fire extinguishers	Fire extinguishers	Hazardous waste (if not empty) Nonhazardous Solid Waste (if empty)	Disposed of or recycled through local municipal waste agency.	California Code of Regulations on Fire Extinguishers	https://www.smcfire.org/how-to-dispose-of-fire-extinguisher
	Light bulbs	Internal and External Lights	Nonhazardous Solid Waste	Disposed through local municipal waste agency.	N/A	https://lessismore.org/materials/278-led-lights/
	Metal scrap	Gear box Cap Brakes Generator Cooling fan Tower Transformer	Nonhazardous Solid Waste	Metals recycler	22 CCR § 66260.10	https://dtsc.ca.gov/hazardous-waste-management-for-scrap-metal-recyclers/
	Transformer oil	Transformer	Used oil	Dispose of through a qualified handler	22 CCR § 66261.3	https://www.calrecycle.ca.gov/HomeHazWaste/reporting/form303/materialtype
	Used oil	Generator	Used oil	Recycle through a qualified recycler	14 CCR § 18600	https://www.calrecycle.ca.gov/usedoil
Solar	Aluminum/alloy	Mounting System	Nonhazardous Solid Waste	Metals recycler	22 CCR § 66260.10	https://dtsc.ca.gov/hazardous-waste-management-for-scrap-metal-recyclers/
	Cabling/electrical wiring	Cabling Inverter Transformer	Universal waste	Recycle through a certified e-waste recyclers	N/A	https://www2.calrecycle.ca.gov/WasteCharacterization/MaterialType
	e-Waste	Transformer Inverter	Universal waste	Recycle through a certified e-waste recyclers	Electronic Waste Recycling Act of 2003	https://www.calrecycle.ca.gov/electronics/act2003 https://dtsc.ca.gov/electronic-hazardous-waste/ https://www.calrecycle.ca.gov/Electronics/RegInfo/
	Metal scrap	Inverter Transformer	Nonhazardous Solid Waste	Metals recycler	22 CCR § 66260.10	https://dtsc.ca.gov/hazardous-waste-management-for-scrap-metal-recyclers/
	PV module (silicon wafers)	Photovoltaic Module	Universal waste	Recycle through a qualified recycler	22 CCR § 66260	https://dtsc.ca.gov/photovoltaic-modules-pv-modules-universal-waste-management-regulations/
	Solar glass	Photovoltaic Module	Universal waste	Disposed of or recycled through local municipal waste agency.	14 CCR § 17017	https://www.calrecycle.ca.gov/glass
	Transformer oil	Transformer	Hazardous waste	Dispose of through a qualified handler	22 CCR § 66261.3	https://www.calrecycle.ca.gov/HomeHazWaste/reporting/form303/materialtype
Batteries (same for solar/wind farms	Cabling/electrical wiring	Cables	Universal waste	Recycle through a certified e-waste recyclers	N/A	https://www2.calrecycle.ca.gov/WasteCharacterization/MaterialType

Renewable Energy Source	Waste Streams	Components	Potential Categorization	Options for Management	Applicable Requirements	References
or individual units, only difference is scale)	e-Waste	Control Unit	Universal waste	Recycle through a certified e-waste recyclers	Electronic Waste Recycling Act of 2003	https://www.calrecycle.ca.gov/electronics/act2003 https://dtsc.ca.gov/electronic-hazardous-waste/ https://www.calrecycle.ca.gov/Electronics/RegInfo/
	Lithium ion cells	Lithium Ion modules	Universal waste	Recycle through a certified and state-authorized battery recycler.	AB 1125, Sher, Chapter 572 Statutes of 2005	https://dtsc.ca.gov/universalwaste/how-is-california-doing-with-recycling-rechargeable-batteries/
	Metal scrap	Enclosure Control Unit	Nonhazardous Solid Waste	Metals recycler	22 CCR § 66260.10	https://dtsc.ca.gov/hazardous-waste-management-for-scrap-metal-recyclers/
	Plastic	Lithium Ion modules Control Unit Enclosure	Nonhazardous Solid Waste	Disposed of or recycled through local municipal waste agency.	14 CCR § 17017	https://www.nature.com/articles/494169a

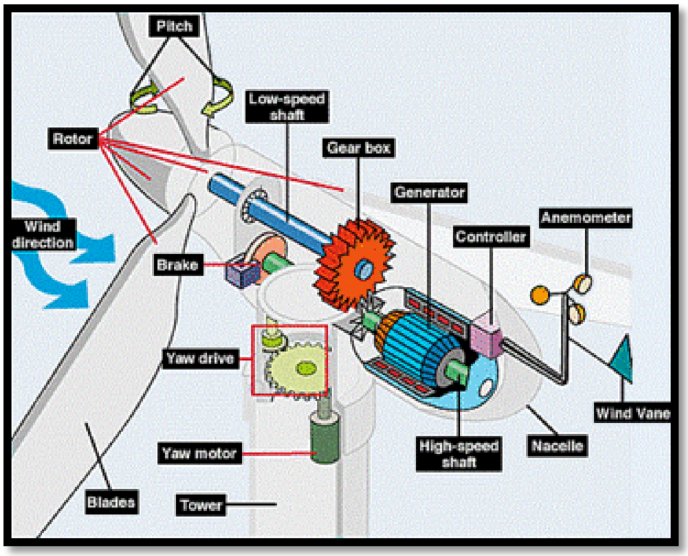
Wind Turbines

Of the three selected energy sources, turbines have the most components and waste streams, the most unique being the fiberglass blades. The majority of the turbine waste streams are nonhazardous or universal, with the exception of transformer oil and generator oil, which are treated as used oil.

Wind turbine blades are composites of fiberglass, carbon fiber, and epoxy resin, cured to stay in place. This combination of materials provides the lightweight rigidity of the blades, but also makes it very difficult to separate the materials back out. Although there are various emerging technologies for recycling in development,[59] currently, turbine blades most often end up in landfills. Manufacturers have also announced plans to shift towards building materials designed to allow for recycling at end of life.

59. See, for example: https://www.reuters.com/business/sustainable-business/end-wind-power-waste-vestas-unveils-blade-recycling-technology-2021-05-17/; Wind energy giant Siemens Gamesa claims world-first in blade recycling (cnbc.com)

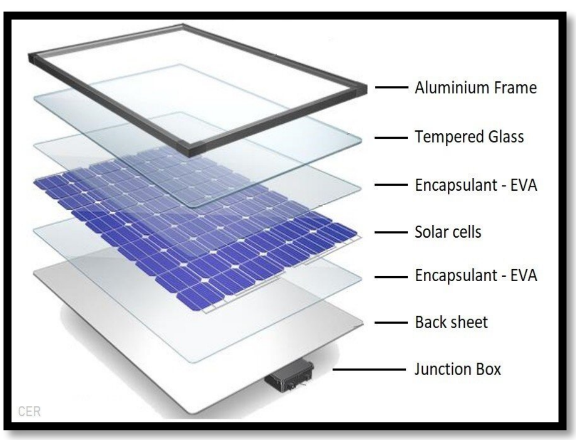
Figure 5-1: Component Breakdown of a Wind Turbine



Solar Panels

Most solar panel waste streams are nonhazardous or universal wastes, with the exception of transformer oil. PV modules are composed primarily of silicon-based panels, glass, and aluminum. These components can be disassembled or shredded and separated by material. Much of the glass and metal parts can be reused for new modules or other applications. The process to recycle the silicon panels, however, is extremely energy intensive. Panels must be heated at very high temperatures in order to ease the binding between the modular cells. This heating process also releases evaporated plastic which can be harmful if breathed. Recyclers are developing methods to reuse the evaporated plastic in order to generate the heat required in the recycling process, thus reducing plastic vapor emissions as well as energy demands, but this process is not yet fully achieved.

Figure 5-2: Component Breakdown of a Solar Panel

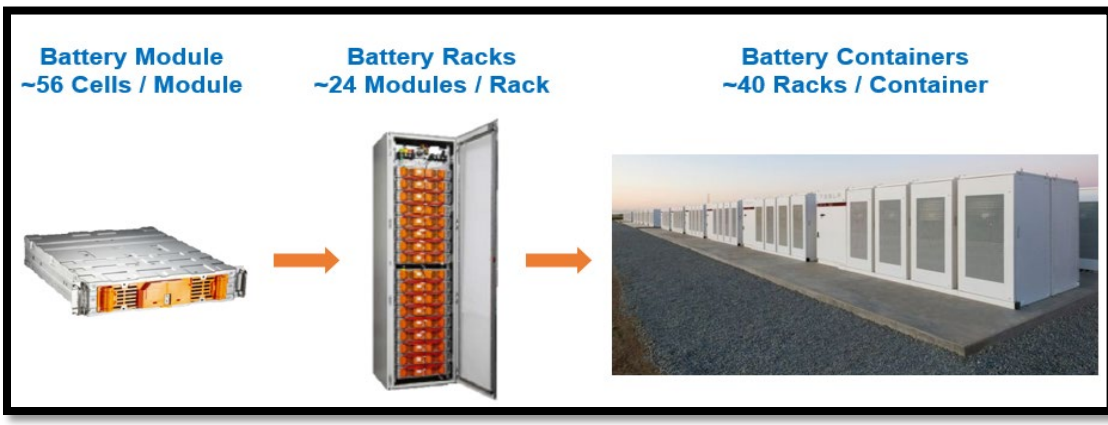


Batteries

Energy storage batteries are made from lithium-ion cells, placed inside modules, which are then housed in larger enclosures that contain various monitoring and control electronics. These components are the same for commercial units used to power homes or buildings and industrial units, typically utilized to store excess power generated on wind farms or solar fields. The materials used in each application are similar to the waste streams generated upon disposal, with the major difference between the two being size and scale.

The state of battery recycling is constantly changing with new processes still in development. Currently battery modules vary widely in construction and are difficult to disassemble due to the materials used to build them.[60] The chemistries used in most rechargeable batteries are corrosive, and when not stored safely, they have the potential to swell, smoke, and start fires, creating significant safety hazards. The operational and safety challenges associated with the handling of batteries makes it difficult to create efficient recycling systems for the technology. Currently, it is less expensive for battery makers to buy freshly mined metals than to use recycled materials, but the economics around this are changing rapidly as new investments are made. Governments around the world are making progress to implement battery recycling requirements, and businesses are investing heavily in emerging battery remanufacturing and recycling technologies.[61] Due to the complexity of the technological and economic factors around battery manufacturing, remanufacturing and recycling, options will need to be reevaluated at end of life to determine the best available options for management.

Figure 5-3: Component Breakdown of Energy Storage Batteries



5.2 Waste Volumes

Literature sources were reviewed to estimate the material inputs and the volume and rate of solid and hazardous waste that would be generated as a result of HES deployment and periodic replacement and disposal of solar, wind, transmission, and battery infrastructure. Waste volumes were calculated using estimates of material inputs to renewable energy technologies per unit of power output, and then applying these unit rates to the estimated installed generation capacity in 2050.

---

60. See for example: https://www.science.org/content/article/millions-electric-cars-are-coming-what-happens-all-dead-batteries
61. See for example: https://www.nature.com/articles/s41586-019-1682-5

Material inputs to solar and wind facilities are provided in USDOE's 2015 Quadrennial Technology Review (USDOE 2015). Table 10.4 of this report, provided below, lists the material requirements for solar PV, wind, and other generation technologies, in units of tons per TWhr for aluminum, cement, concrete, copper, glass, iron, plastic, silicon, and steel. These data were generated from the Argonne National Labs Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) model. (This model does not address electrical transmission infrastructure.)

Table 10.4 Range of materials requirements (fuel excluded) for various electricity generation technologies[52]

Materials (ton/TWh)	Generator only				Upstream energy collection plus generator			
	Coal	NGCC	Nuclear PWR	Biomass	Hydro	Wind	Solar PV (silicon)	Geothermal HT binary
Aluminum	3	1	0	6	0	35	680	100
Cement	0	0	0	0	0	0	3,700	750
Concrete	870	400	760	760	14,000	8,000	350	1,100
Copper	1	0	3	0	1	23	850	2
Glass	0	0	0	0	0	92	2,700	0
Iron	1	1	5	4	0	120	0	9
Lead	0	0	2	0	0	0	0	0
Plastic	0	0	0	0	0	190	210	0
Silicon	0	0	0	0	0	0	57	0
Steel	310	170	160	310	67	1,800	7,900	3,300

Key: NGCC = natural gas combined cycle; PWR = pressurized water reactor; PV = photovoltaic; HT = high temperature

Source: DOE 2015. Table 10.4 Range of materials requirements (fuel excluded) for various electricity generation technologies.

E3-CP lists annual generation by technology, in units of GWh, in 5 and 10-year increments between 2020 and 2050. Table 32 from E3-CP is presented below.

Annual Generation	Unit		2020	2025	2030	2040	2050
Nuclear	GWh		29,597	19,523	9,450	9,450	-
CHP	GWh		626	237	237	-	-
Coal	GWh		12,532	12,271	-	-	-
Gas CCGT	GWh		56,075	57,230	64,855	45,309	25,023
Gas Peaker	GWh		1,122	799	268	-	11
Hydro	GWh		28,720	28,704	28,783	28,430	27,765
Hydro (Small)	GWh		5,211	5,211	5,211	5,211	5,211
Biomass	GWh		6,892	6,892	6,892	6,892	6,892
Geothermal	GWh		13,894	13,894	33,430	35,673	35,673
Wind	GWh		52,390	52,287	55,404	66,810	66,936
Wind_Offshore	GWh		-	-	-	-	-
Solar	GWh		57,396	57,590	59,515	184,546	316,346
Customer Solar	GWh		11,578	19,084	30,498	39,781	49,206
Battery Storage	GWh		3	(322)	(1,398)	(11,197)	(24,490)
Pumped Storage	GWh		(191)	(551)	(690)	(1,264)	(1,490)
Energy Efficiency	GWh		-	-	-	-	-
DR	GWh		-	9	5	-	-
Imports	GWh		**41,940**	**39,653**	**27,298**	**19,441**	**9,616**
Exports	GWh		**(1,460)**	**(1,529)**	**(1,265)**	**(2,217)**	**(4,578)**
Load			**316,325**	**310,979**	**318,490**	**426,864**	**512,120**

Source: E3-CP Table 32 Annual Generation by Technology (High Electrification Scenario).

The material input requirements per unit of power output from DOE 2015 were applied to E3-CP's forecasted 2050 wind and solar generation capacity. The results are shown in Table 6-2. Battery materials are not quantified in the DOE Quadrennial report.

Table 5-2: Material Volumes of Installed Solar and Wind Infrastructure in 2050

Materials (ton)	Solar PV (Silicon) (1)	Wind (1)
Aluminum	215,115	2,343
Cement	1,170,480	0
Concrete	110,721	535,488
Copper	268,894	1,540
Glass	854,134	6,158
Iron	0	8,032
Plastic	66,433	12,718
Silicon	18,032	0
Steel	2,499,133	120,485

(1) Based on E3-CP Table 32, 2050 estimated annual generation by technology (316,346 GWh solar and 66,936 GWh wind) and DOE 2015 Table 10.4 (tons/TWh)

Waste streams will be generated as these material inputs reach their end of life. The timing and annual rate of waste generation will depend on factors such as the useful life of individual components. Current and projected longevity and rate of turnarounds/replacement of installed equipment for wind, solar, and battery storage are summarized below.

- A 30-year panel lifetime is a common assumption in PV lifetime environmental impact analysis (e.g. in life cycle assessments) and is recommended by the International Renewable Energy Agency (IRENA) and the International Energy Agency Photovoltaic Power Systems (IEA-PVPS) Programme (Frischknecht et al. 2016, cited in IRENA 2016; USDOE 2015).
- Wind turbines typically last 20 to 25 years (TWI 2021).
- Lithium-ion Batteries have a typical life of 13 years based on a study that found 2.3% performance decrease each year, on average. According to Wheeler (2021), batteries are typically retired when they have 70-80% capacity remaining. After 13 years, at 2.3% degradation each year, a battery has 74% of capacity remaining (Wheeler 2021).

These lifecyles suggest that the installed solar and wind material volumes from Table 6-2, such as 850,000 tons of glass that make up the PV panels and 12,700 tons of plastics in wind turbines will be replaced at least once during the next 30 years, and that installed Lithium-ion batteries will be replaced at least twice during this timeframe.

Other energy generation and battery energy storage system components such as the electronic controls, metal racking, steel enclosures, cabling, and concrete will have varying life cycles. Certain materials, such as cement and concrete may become permanent, or this material may be crushed and reused onsite or at other locations for a future land use. (Some of the materials listed by DOE, such as plastics were not identified in the waste material assessment above.)

DOE's material input estimates exclude transmission and distribution infrastructure such as new poles, towers, conductors, and substations, as well as the estimated 13 GW of new behind-the-meter solar equipment. Gen-ties and long-haul transmission systems typically consist of wood, steel, concrete, and conductor cabling. E3-TNC provides estimated land area for gen-tie and long-haul transmission under different scenarios, but they do not distinguish gen-ties (typically steel poles and conductors carrying distribution voltages from the solar or wind generation facility to the existing grid) from long-haul transmission (typically lattice steel towers, spaced farther apart and carrying high voltages over long-distances). E3-TNC's land area estimates assume an average gen-tie or transmission corridor width of 76 meters. Using this metric and applying it to their estimated corridor land area of 107 km^2 in the Full-West constrained scenario suggests a total length of about 1,400 km of new transmission corridor infrastructure for this scenario. Assuming a typical spacing of 250 meters per transmission pole or lattice tower, and double circuit construction, this scenario would require construction and maintenance of an estimated 11,300 steel poles/towers with associated concrete, cabling and other components. The lifespan of these facilities will vary, and can be reasonably expected to require repair and maintenance, and sometimes replacement, over a 30-year period.

Similarly, a rough order calculation of substation materials can be derived by using E3-TNC's estimate of 120 MW for a typical utility scale solar installation. Assuming each new solar facility requires a stand-alone substation averaging 5 acres each, and further assuming a net new 101 GW of incremental solar (per E3-CP), suggests that on the order of 840 new substations, or 4,200 acres of substation infrastructure – primarily steel, aluminum, copper and other cabling, and concrete – will need to constructed and maintained, with associated material inputs and periodic replacement.

5.3 Landfill Capacity

Literature sources were reviewed to determine whether California's landfills and recycling facilities may be constrained by future inflows from end-of-life renewable energy infrastructure. As noted above, solar panel recycling is expensive and many components are being landfilled. Current costs to recycle a panel can be $20 to $30 versus $1 to $2 to send it to a landfill (NREL representative cited in Wesoff and Beetz 2021). An estimated 26,000 tons of PV panels were predicted to end up as waste in 2020 (Wesoff and Beetz 2021).

A recent assessment by CalRecycle indicated that 21 of California's 58 counties, having 41 percent of the population, will exhaust their disposal capacity within 15 years. Of these, 17 counties have 8 years or less capacity (CalRecycle 2021a, pp. 4, 31). Policies are in place to ensure a continuous 15-year planning horizon for landfill capacity. However, this process is time consuming (typically a 7 to 10 year planning process) and land intensive. Future inflows from end-of-life renewable energy materials will likely add to the demand for additional landfill capacity.

California's recycling rate was 37% in 2019, meaning that it did not meet the 75 percent statewide recycling goal in 2020 as set out in AB 341 (CalRecycle 2021b). Continued low recycling rates can add to landfill capacity limitations.

In 2019, California exported 19% (by weight) of recyclable materials (CalRecycle 2021b. p.3). China has been the largest importer of California's recyclable materials since 2000. In 2019, China imported 32 percent of all seaborne recyclable materials by weight and 23 percent by vessel value (CalRecycle 2021b. p.16). Therefore, in 2019, 6% of exported recyclables went to China (32% of 19%). Based on 77.5 million tons of material generated in 2019, almost 5 million tons were exported to China. Multiple countries, including China, have implemented policies related to international trade of recyclable materials (CalRecycle 2021b. p.22). China has banned imports of trash, including recyclables, with a rule that started in January 2021 (Rapoza 2020). Consequently offshore exports of recyclable materials are decreasing. For example, Total Seaborne Recyclable Materials exports from California decreased by 7% (by weight) and 14% (by vessel value) from 2018 to 2019 (CalRecycle 2021b. pp. 14-15). This reduction in exports, including recyclables and non-recyclables from end-of-life renewables, may increase the demand on California's recycling and landfilling capacities.

6. REFERENCES

Chapter 1 Introduction

Aas, Dan, et al. 2020. ("E3-GasFut") The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. California Energy Commission. Publication Number: CEC-500-2019-055-F.

Alternative Fuels Data Center (AFDC). 2021. Electric Vehicle Registrations by State. Online at https://afdc.energy.gov/data/10962, accessed November 2021.

California Department of Motor Vehicles (DMV). 2019. Estimated Vehicles Registered by County for the Period of January 1, 2019 through December 31, 2019. Online at https://www.dmv.ca.gov/portal/uploads/2020/06/2019-Estimated-Vehicles-Registered-by-County-1.pdf, accessed November 2021.

CEC. 2021a. SB 100 Joint Agency Report - Achieving 100 Percent Clean Electricity in California: An Initial Assessment. https://www.energy.ca.gov/sb100#anchor_report. Accessed May 2021.

CEC. 2021b. California 2020 Installed In-State Electric Generation Capacity by Fuel Type (MW). https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy; https://ww2.energy.ca.gov/almanac/renewables_data/solar/index_cms.php. Accessed May 2021.

CEC. 2021c. California Energy Commission Zero Emission Vehicle and Infrastructure Statistics. Data last updated October 29, 2021. Retrieved November 22, 2021, from http://www.energy.ca.gov/zevstats.

Energy and Environmental Economics, Inc. (E3). 2020. Achieving Carbon Neutrality in California, PATHWAYS Scenarios Developed for the California Air Resources Board. October. Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board. Accessed May 2021.

Energy Information Administration (EIA). 2021a. California State Energy Profile. Retrieved November 2021 from https://www.eia.gov/state/print.php?sid=CA.

Energy Information Administration (EIA). 2021b. Natural Gas: Number of Natural Gas Consumers – California. Retrieved June 17, 2021, from https://www.eia.gov/dnav/ng/NG_CONS_NUM_DCU_SCA_A.htm.

International Energy Agency (IEA). 2021. Methane Emissions from Oil and Gas. Online: https://www.iea.org/reports/methane-emissions-from-oil-and-gas. Accessed November 2021.

Kavalec, Chris, Asish Gautam, Mike Jaske, Lynn Marshall, Nahid Movassagh, and Ravinderpal Vaid. 2018. California Energy Demand 2018 — 2030 Revised Forecast. California Energy Commission, Electricity Assessments Division. Publication Number: CEC-200-2018-002-CMF.

Mahone, Amber, J Kahn-Lang, V Li, N. Ryan, Z Subin, D Allen, G De Moor, and S Price. 2018. ("E3-Decarb") Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model.

Ming, Z, A Olson, G De Moor, H Jiang, and N Schlag. 2019. ("E3-CP"). Long-Run Resource Adequacy under Deep Decarbonization Pathways for California, Calpine Corporation, June. Prepared by E3 for Calpine Corporation. https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf. Accessed May 2021.

U.S. Census Bureau 2010. Table GCT-PH1 - Population, Housing Units, Area, and Density: 2010 – State- Urban/Rural and Inside/Outside Metropolitan and Micropolitan Area, 2010 Census Summary File 1.

Wu, GC, E Leslie, D Allen, O Sawyerr, DR Cameron, E Brand, B Cohen, M Ochoa, and A Olson. 2019. ("E3-TNC"). Power of Place: Land Conservation and Clean Energy Pathways for California. June. Technical Report prepared by E3 for The Nature Conservancy. https://www.scienceforconservation.org/assets/downloads/Technical_Report_Power_of_Place.pdf. Accessed May 2021.

Chapter 2 Energy Cost Analysis

Aas, Dan, et al. 2020. ("E3-GasFut") The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. California Energy Commission. Publication Number: CEC-500-2019-055-F.

Angell, Isabel. 2013. Why the New Bay Bridge Cost $6.4 Billion. WNYC. https://www.wnyc.org/story/316201-brief-history-64-billion-bay-bridge/.

Alternative Fuels Data Center. 2021. Alternative Fueling Station Locator. Accessed November 4, 2021. https://afdc.energy.gov/stations/#/find/nearest?fuel=HY&lpg_secondary=true&country=US.

Beach, Emily. 2018. Comparing Cost: Gas Furnace vs. Electric Heater. SFGate. https://homeguides.sfgate.com/comparing-cost-gas-furnace-vs-electric-heater-61395.html.

Borenstein, Severin, et al. 2021. Designing Electricity Rates for An Equitable Energy Transition. Energy Institute WP 314. Energy Institute at Haas. February 2021.

Boston Consulting Group (BCG). 2019. The Costs of Revving Up the Grid for Electric Vehicles. December 20.

Brown, TW, T Bischof-Niemz, K Blok, C Breyer, H Lund, and BV Matthiessen. 2018. Response to burden of proof: a comprehensive review of the feasibility of 100% renewable-electricity systems. Renewable and Sustainable Energy Reviews 92, 834–847.

California Air Resources Board (CARB). 2019. EV Charging Infrastructure: Nonresidential Building Standards.

California Department of Finance, 2020. Table P-4: Projected Households, Household Population, Group Quarters and Persons per Household for the Counties and State of California. June.

CEC. 2021a. SB 100 Joint Agency Report - Achieving 100 Percent Clean Electricity in California: An Initial Assessment. https://www.energy.ca.gov/sb100#anchor_report. Accessed May 2021.

CEC. 2021b. SB100 Joint Agency Report: Inputs and Assumptions. Accessed May 2021.

CEC. 2020. 2020 Total System Electric Generation. Online: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation.

CEC, 2020. Energy Commission Approves Plan to Invest Up to $115 Million for Hydrogen Fueling Infrastructure. Online: https://www.energy.ca.gov/news/2020-12/energy-commission-approves-plan-invest-115-million-hydrogen-fueling.

Clean Vehicle Rebate Project (CVRP). 2021. Electric Vehicle Charging Overview. Retrieved October 26, 2021, from https://cleanvehiclerebate.org/eng/ev/technology/fueling/electric.

CPUC. 2018. Delivery, Consumption & Prices for Utility Service within California. Retrieved June 15, 2021, from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/California%20Regions%20Final.pdf.

CPUC. 2021. CARE/FERA Programs. Retrieved June 15, 2021, from https://www.cpuc.ca.gov/lowincomerates/.

Energy Information Administration (EIA). 2018. Residential Electricity Consumption Survey. Online at https://www.eia.gov/consumption/residential/index.php, accessed October 2021.

EIA. 2019a. Table T4: 2019 Total Electric Industry – Average Retail Price (cents/kWh). Retrieved June 15, 2021, from https://www.eia.gov/electricity/sales_revenue_price/.

EIA. 2019b. State Electricity Profiles. Retrieved October 26, 2021, from https://www.eia.gov/electricity/state/.

EIA. 2019c. State Energy Data System (SEDS), Table F3: Motor Gasoline Consumption, Price, and Expenditure Estimates, 2019. https://www.eia.gov/state/seds

EIA. 2021. Natural Gas: Number of Natural Gas Consumers – California. Retrieved June 17, 2021, from https://www.eia.gov/dnav/ng/NG_CONS_NUM_DCU_SCA_A.htm.

Fares, R.L., and C.W. King. 2017. Trends in transmission, distribution, and administration costs for U.S. investor-owned electric utilities. Energy Policy 105:354-362.

Federal Highway Administration (FHWA). 2021. Traffic Volume Trends. Online at https://www.fhwa.dot.gov/policyinformation/travel_monitoring/tvt.cfm, accessed November 2021.

Flyvbjerg, Bent. 2011. "Over Budget, Over Time, Over and Over Again: Managing Major Projects". In Morris, Peter WG; Pinto, Jeffrey; Söderlund, Jonas (eds.). The Oxford Handbook of Project Management. Oxford: Oxford University Press. pp. 321–344.

Hamidi, Shima, Reid Ewing, and John Renne. 2016. How Affordable Is HUD Affordable Housing? Housing Policy Debate 26:3, 437-455. DOI: 10.1080/10511482.2015.1123753.

International Energy Agency (IEA). 2021. The Role of Critical Minerals in Clean Energy Transitions. Online: https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions.

Jenkins, JD, M Luke, and S Thernstrom. 2018. Getting to zero carbon emissions in the electric power sector. Joule 2, 2498–2510.

Kavalec, Chris, et al. 2018. California Energy Demand 2018 — 2030 Revised Forecast. California Energy Commission, Electricity Assessments Division. Publication Number: CEC-200-2018-002-CMF.

Lipman, BJ. 2006. A heavy load: The combined housing and transportation burdens of working families. Technical report prepared for Center for Housing Policy. Washington, D.C.

Lipton, E, D Searcey, and M Forsythe. 2021. Race to the Future: What to Know About the Frantic Quest for Cobalt. The New York Times, November 20. Online: https://www.nytimes.com/2021/11/20/world/china-congo-cobalt-explained.html, accessed November 2021.

Mahone, Amber, et al. 2018. ("E3-Decarb") Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model. California Energy Commission. Publication Number: CEC-500-2018-012.

Martin, P. 2017. How Much Lithium is in a Li-Ion Vehicle Battery? Online: https://www.linkedin.com/pulse/how-much-lithium-li-ion-vehicle-battery-paul-martin/.

Miller, Nicholas W, Bruno Leonardi, Robert D'Aquila, and Kara Clark. 2015. Western Wind and Solar Integration Study Phase 3A: Low Levels of Synchronous Generation. National Renewable Energy Laboratory (NREL) Technical Report TP-5D00-64822. November.

Mills, Mark P. 2021. Biden's Not-So-Clean Energy Transition. The Wall Street Journal, May 11.

NREL. 2017. National Plug-In Electric Vehicle Infrastructure Analysis. September.

Organization for Economic Cooperation and Development (OECD) and International Energy Agency (IEA). 2014. Electric power consumption (kWh per capita) - United States. Online at https://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC?locations=US, accessed October 2021.

Padeiro, Miguel, Ana Louro, and Nuno Marques da Costa. 2019. Transit-oriented development and gentrification: a systematic review. Transport Reviews 39:6, 733-754, DOI: 10.1080/01441647.2019.1649316.

Perez, Richard, and Karl R. Rabago. 2019. A radical idea to get a high-renewable electric grid: Build way more solar and wind than needed. Greenbiz, May 30. Online: https://www.greenbiz.com/article/radical-idea-get-high-renewable-electric-grid-build-way-more-solar-and-wind-needed.

Renne, John L, T Tolford, S Hamidi, and R Ewing. 2016. The Cost and Affordability Paradox of Transit-Oriented Development: A Comparison of Housing and Transportation Costs Across Transit-Oriented Development, Hybrid and Transit-Adjacent Development Station Typologies. Housing Policy Debate 26:4-5, 819-834, DOI: 10.1080/10511482.2016.1193038.

Rocky Mountain Institute (RMI). 2020. Reducing EV Charging Infrastructure Costs. Chris Nelder and Emily Rogers.

Roser, M. 2020. Why did renewables become so cheap so fast? Online: https://ourworldindata.org/cheap-renewables-growth, accessed October 2021.

Statista 2021. Average Monthly Residential Utility Costs in the United States in 2020, by State. Retrieved June 17, 2021, from https://www.statista.com/statistics/1108684/monthly-utility-costs-usa-state/#main-content.

Thomassen, G., S.V. Passel, and J. Dewulf. 2020. A review on learning effects in prospective technology assessment. Renewable and Sustainable Energy Reviews 130: 109937.

US Department of Energy. 2021. Reducing Reliance on Cobalt for Lithium-ion Batteries. Office of Energy Efficiency and Renewable Energy, Vehicle Technologies Office. Online: https://www.energy.gov/eere/vehicles/articles/reducing-reliance-cobalt-lithium-ion-batteries#:~:text=Cobalt%20is%20considered%20the%20highest,in%20lithium%20ion%20EV%20batteries.

U.S. Geological Survey (USGS). 2021. Mineral Commodity Summaries: Cobalt. January. Online: https://pubs.usgs.gov/periodicals/mcs2021/mcs2021.pdf.

Chapter 3 Equity Analysis

Beach, Emily. 2018. Comparing Cost: Gas Furnace vs. Electric Heater. SFGate. https://homeguides.sfgate.com/comparing-cost-gas-furnace-vs-electric-heater-61395.html.

Borenstein, Severin, Meredith Fowlie, and James Sallee. 2021. "Designing Electricity Rates for an Equitable Energy Transition." Energy Institute at University of California Berkeley Haas School of Business. https://haas.berkeley.edu/wp-content/uploads/WP314.pdf

California Energy Commission (CEC). March 2020. Petroleum Watch. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf

CensusReporter.org. California. ACS 2019 1-year data. https://censusreporter.org/profiles/04000US06-california/. Accessed 13 July 2021.

Energy Information Administration (EIA). 2021a. Glossary. Accessed October 29, 2021. https://www.eia.gov/tools/glossary/index.php?id=petroleum%20administration%20for%20defense%20district

EIA. 2021b. PADD 5 Refinery and Blender Net Production. Accessed October 29, 2021. https://www.eia.gov/dnav/pet/pet_pnp_refp_dc_r50_mbbl_a.htm

Franco, Guido, and Alan Sanstad. 2006. "Climate Change and Electricity Demand in California." http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.169.2878&rep=rep1&type=pdf

Lesser, Jonathan A. 2015. Less Carbon, Higher Prices: How California's Climate Policies Affect Lower-Income Residents. Center for Energy Policy and the Environment at the Manhattan Institute.

Mahone, Amber, et al. 2018. Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model. California Energy Commission. Publication Number: CEC-500-2018-012.

Morgen, Sam. 2021. "Kern supervisors fire shot at state tax incentive that discounts taxes for renewable energy properties." Bakersfield Californian. March 29, 2021. https://www.wind-watch.org/news/2021/03/30/kern-supervisors-fire-shot-at-state-tax-incentive-that-discounts-taxes-for-renewable-energy-properties/

Nadeau, Carey Anne. 2020. Living Wage Calculator User's Guide/Technical Notes: 2020-2021 Update. Department of Urban Studies and Planning, Massachusetts Institute of Technology. https://livingwage.mit.edu/resources/Living-Wage-Users-Guide-Technical-Documentation-2021-05-21.pdf.

Office of Environmental Health Hazard Assessment (OEHHA). Accessed November 8, 2021. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535

Rockzsfforde, Reagan R, and Marzia Zafar. 2015. Comparative Analysis of Utility Services & Rates in California. California Public Utilities Commission Policy and Planning Division.

Ruggles, Steven, Sarah Flood, Sophia Foster, Ronald Goeken, Jose Pacas, Megan Schouweiler, and Matthew Sobek. 2021. IPUMS USA: Version 11.0 [dataset]. Minneapolis, MN: IPUMS, 2021. https://doi.org/10.18128/D010.V11.0.

St. Marie, Stephen, Richard White, and Marzia Zafar. 2018. Delivery, Consumption & Prices for Utility Service within California. California Public Utilities Commission Policy & Planning Division.

Tax-rates.org. 2021. Property Tax Estimator. Accessed Nov 4, 2021. http://www.tax-rates.org/california/kern_county_property_tax

U.S. Census Bureau. 2020. "Community Resilience Estimates." Small Area Estimates Program: Social, Economic, and Housing Statistics Division.

Chapter 4 Land Use and Environmental Analysis

4.1. Physical Scale and Pace of HES Solar and Wind Development

Berkeley Law. 2016a. A Path Forward - Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley MAY 2016. https://www.law.berkeley.edu/wp-content/uploads/2016/05/A-PATH-FORWARD-May-2016.pdf. Accessed June 2021.

Berkeley Law. 2016b. https://sjvp.databasin.org/pages/least-conflict/. Accessed June 2021.

CEC. 2021a. SB 100 Joint Agency Report - Achieving 100 Percent Clean Electricity in California: An Initial Assessment. SB 100 Joint Agency Report | California Energy Commission. Accessed April 2021.

CEC. 2021b. California 2020 Installed In-State Electric Generation Capacity by Fuel Type (MW). https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy; https://ww2.energy.ca.gov/almanac/renewables_data/solar/index_cms.php. Accessed May 2021.

CEC and U.S. Bureau of Land Management (BLM). 2019. Desert Renewable Energy Conservation Plan. December 2019. "Desert Renewable Energy Conservation Plan Overview." https://www.energy.ca.gov/sites/default/files/2019-12/DRECP_Overview_Fact_Sheet_ada.pdf. Accessed 15 July 2021.

County of Fresno. 2017. County of Fresno Solar Facility Guidelines. https://www.co.fresno.ca.us/departments/public-works-planning/divisions-of-public-works-and-planning/development-services-division/planning-and-land-use/photovoltaic-facilities-p-1621.

County of San Bernardino. 2017. General Plan Renewable Energy and Conservation Element. http://www.sbcounty.gov/uploads/LUS/Renewable/2019_WEBSITE/REC%20Element.pdf.

Ming, Z, A Olson, G De Moor, H Jiang, and N Schlag. 2019. ("E3-CP"). Long-Run Resource Adequacy under Deep Decarbonization Pathways for California, June. Prepared by E3 for Calpine Corporation. https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf. Accessed May 2021.

U.S. Census Bureau 2010. Table GCT-PH1 - Population, Housing Units, Area, and Density: 2010 – State- Urban/Rural and Inside/Outside Metropolitan and Micropolitan Area, 2010 Census Summary File 1.

USEPA. 2016. Level III and Level IV Ecoregions of California https://www.epa.gov/eco-research/ecoregion-download-files-state-region-9#pane-04. Accessed October 2021.

4.2 E3-TNC Study Methodology and Results

Berkeley Law. 2016a. A Path Forward - Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley, May 2016. https://www.law.berkeley.edu/wp-content/uploads/2016/05/A-PATH-FORWARD-May-2016.pdf. Accessed June 2021.

Butte County. 2015. Butte Regional Conservation Plan, Public Draft Environmental Impact Statement / Environmental Impact Report. Retrieved from: http://www.buttehcp.com/BRCP-Documents/Formal-Public-Draft-EISEIR/index.html

CEC and U.S. Bureau of Land Management (BLM). 2019. Desert Renewable Energy Conservation Plan. December 2019. "Desert Renewable Energy Conservation Plan Overview." https://www.energy.ca.gov/sites/default/files/2019-12/DRECP_Overview_Fact_Sheet_ada.pdf. Accessed July 15, 2021.

Databasin.org. 2021. https://databasin.org/maps/7a82b5656b11454e901b194090de0835/. Accessed July 2021.

Hoffacker et al. 2017. Land-Sparing Opportunities for Solar Energy Development in Agricultural Landscapes: A Case Study of the Great Central Valley, CA, United States. Madison K. Hoffacker, Michael F. Allen, and Rebecca R. Hernandez. Published in *Environmental Science & Technology* **2017** *51* (24), 14472-14482. DOI: 10.1021/acs.est.7b05110. https://pubs.acs.org/doi/10.1021/acs.est.7b05110. Accessed May 2021.

USFWS. 2021. National Wetland Inventory Wetlands Mapper. https://www.fws.gov/wetlands/data/mapper.html. Accessed June 2021.

Wu, GC, E Leslie, D Allen, O Sawyerr, DR Cameron, E Brand, B Cohen, M Ochoa, and A Olson. 2019. ("E3-TNC"). Power of Place: Land Conservation and Clean Energy Pathways for California. June. Technical Report prepared by E3 for The Nature Conservancy.

https://www.scienceforconservation.org/assets/downloads/Technical_Report_Power_of_Place.pdf. Accessed May 2021.

4.3 Project-Level Development Constraints

Agha, Mickey, et al 2020. Environ. Res. Lett. 15 075004. Wind, sun, and wildlife: do wind and solar energy development 'short-circuit' conservation in the western United States? https://iopscience.iop.org/article/10.1088/1748-9326/ab8846/pdf. Accessed July 2021.

Bureau of Labor Statistics (BLS). 2021. Historical Consumer Price Index for All Urban Consumers (CPI-U): U.S. City Average, All Items, By Month. https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202109.pdf

California Rangeland Trust (CRT). 2021. Evaluating Ecosystem Services: Value and Return on Investment of Conservation Easements held by the California Rangeland Trust. https://rangelandtrust.org/wp-content/uploads/2020/10/Full-Report_Corrected.pdf

Columbia Law School. 2021. Opposition to Renewable Energy Projects in the United States. February. Accessed October 2021. https://climate.law.columbia.edu/sites/default/files/content/Opposition%20to%20Renewable%20Energy%20Facilities%20in%20the%20US%202%2023%2021.pdf.

County of Fresno. 2017. County of Fresno Solar Facility Guidelines. https://www.co.fresno.ca.us/departments/public-works-planning/divisions-of-public-works-and-planning/development-services-division/planning-and-land-use/photovoltaic-facilities-p-1621.

County of San Bernardino. 2017. General Plan Renewable Energy and Conservation Element. http://www.sbcounty.gov/uploads/LUS/Renewable/2019_WEBSITE/REC%20Element.pdf.

Hansen, Glen. 2017. "A Cautionary Tale About Development Agreements: The Panoche Valley Utility-Scale Solar Project." Land Use Law Blog. 13 September. https://blog.aklandlaw.com/2017/09/articles/ceqa/cautionary-tale-development-agreements-panoche-valley-utility-scale-solar-project/. Accessed 15 July 2021.

Ritter, Michael. 2021. Washington Department of Fish and Wildlife Scoping comment letter to the Washington Energy Facility Site Evaluation Council regarding the Horse Heaven Wind, Solar, and Battery Storage Project, Benton County, Washington. https://www.efsec.wa.gov/energy-facilities/horse-heaven-wind-project

Rogers, Paul. 2017. Giant California solar project cut back after environmentalists oppose it. Bay Area News Group. 21 July. https://www.eastbaytimes.com/2017/07/21/giant-solar-project-reduced-due-to-environmentalists-opposition/. Accessed 15 July 2021.

Ruggiero, A. 2021. Livermore ranchers, farmers sue county to halt solar project, Bay Area News Group. 22 April. https://www.mercurynews.com/2021/04/22/livermore-ranchers-farmers-sue-county-to-halt-solar-project/. Accessed June 2021.

United States Department of Agriculture (USDA), National Agricultural Statistics Service. 2020. Land Values 2020 Summary. August. https://www.nass.usda.gov/Publications/Todays_Reports/reports/land0820.pdf

United States Department of Agriculture (USDA). 2017. 2017 Census of Agriculture – County Data. California 323. Table 8. Farms, Land in Farms, Value of Land and Buildings, and

Land Use: 2017 and 2012. https://www.nass.usda.gov/Publications/AgCensus/2017/Full_Report/Volume_1,_Chapter_2_County_Level/California/ https://www.nass.usda.gov/Publications/AgCensus/2017/Full_Report/Volume_1,_Chapter_2_County_Level/California/st06_2_0008_0008.pdf

Vartabedian, Ralph. 2019. California bullet train's mishandling of land deals adds to mounting costs and delays. Los Angeles Times. https://www.latimes.com/california/story/2019-09-15/california-bullet-train-land-acquisition. Accessed June 2021.

Wu, GC, E Leslie, D Allen, O Sawyerr, DR Cameron, E Brand, B Cohen, M Ochoa, and A Olson. 2019. ("E3-TNC"). Power of Place: Land Conservation and Clean Energy Pathways for California. June. Technical Report prepared by E3 for The Nature Conservancy. https://www.scienceforconservation.org/assets/downloads/Technical_Report_Power_of_Place.pdf. Accessed May 2021.

4.4 Quantified Impact and 4.5 Environmental Resource Constraints

Refer to Tables 4-3 and 4-6 for additional citations.

4.5.1 Rangeland and Agricultural Land Conversion

Berton, Hal. 2021. A proposed $1.7 billion wind and solar project generates hopes and fears in South Central Washington state. Seattle Times. 5 May. https://www.spokesman.com/stories/2021/may/05/a-proposed-17-billion-wind-and-solar-project-gener/. Accessed 7 July 2021.

Cameron, DR, J Marty, and RF Holland. 2014. Whither the Rangeland?: Protection and Conversion in California's Rangeland Ecosystems. PLOS ONE 9(8): e103468. https://doi.org/10.1371/journal.pone.0103468. Accessed 7 July 2021.

Copeland HE, A Pocewicz, and JM Ki. 2011. Geography of energy development in western North America: Potential impacts on terrestrial ecosystems. Energy Development and Wildlife Conservation in Western North America, ed. Naugle, DE (Island Press, Washington, DC), pp 7–22.

gofundme.com. 2021. Save North Livermore Valley. https://gofund.me/56689fb1. Accessed July 2021.

Hernandez et al. 2015. Proceedings of the National Academy of Sciences (PNAS) Volume 112, Number 44, pp 13579-13584. Solar energy development impacts on land cover change and protected areas. 3 November. https://www.pnas.org/content/112/44/13579. Accessed July 2021.

McDonald, RI, J Fargione, J Kiesecker, WM Miller, and J Powell. 2009. Energy Sprawl or Energy Efficiency: Climate Policy Impacts on Natural Habitat for the United States of America. PLOS ONE 4(8): e6802. https://doi.org/10.1371/journal.pone.0006802. Accessed June 2021.

Ruggiero, A. 2021. Livermore ranchers, farmers sue county to halt solar project. Bay Area News Group. 22 April. https://www.mercurynews.com/2021/04/22/livermore-ranchers-farmers-sue-county-to-halt-solar-project/. Accessed June 2021.

University of California Agricultural Issues Center (UC AIC). 2009. The Measure of California Agriculture. University of California Agricultural Issues Center. August. https://aic.ucdavis.edu/wp-content/uploads/2019/01/moca09.pdf. Accessed June 2021.

U.S. Army Corps of Engineers (USACE). 2015. Draft Environmental Impact Statement Panoche Valley Solar Facility, San Benito County, California. September. Draft Environmental Impact Statement, Panoche Valley Solar Facility, San Benito County, CA (army.mil). Accessed June 2021.

U.S. Fish and Wildlife Service (USFWS). 1998. Recovery Plan for Upland Species of the San Joaquin Valley, California. https://www.fws.gov/sacramento/es_species/Accounts/Mammals/giant_kangaroo_rat/documents/980930a.pdf). Accessed June 2021.

Wu, GC, E Leslie, D Allen, O Sawyerr, DR Cameron, E Brand, B Cohen, M Ochoa, and A Olson. 2019. ("E3-TNC"). Power of Place: Land Conservation and Clean Energy Pathways for California. June. Technical Report prepared by E3 for The Nature Conservancy. https://www.scienceforconservation.org/assets/downloads/Technical_Report_Power_of_Place.pdf. Accessed May 2021.

4.5.2, 4.5.3, 4.5.4, and 4.5.5 Avian and Other Wildlife, Protected Species, Critical Habitat, and HCPs/NCCPs

Abbasi et al. 2000. The likely adverse environmental impacts of renewable energy sources. Applied Energy 65: 121–144.

Basin and Range Watch. Undated. Example letter in opposition to the Gemini Solar Project. https://myemail.constantcontact.com/Oppose-the-Gemini-Solar-Project.html?soid=1130207326880&aid=b4e7p4F3xlA.

basinandrangewatch.org. 2021. Solar Project Causes Tortoise Die-Off. https://www.basinandrangewatch.org/.

California Energy Commission. 2021. Mitigating Impacts of Solar Energy Development on Desert Tortoises, Indoor Rearing and Release of Head-Started Desert Tortoises. Online at: https://www.energy.ca.gov/sites/default/files/2021-07/CEC-500-2021-039.pdf

Center for Biological Diversity (CBD). 2014. Lawsuit Launched to Protect Endangered California Birds From Large-scale Desert Solar Projects. https://www.biologicaldiversity.org/news/press_releases/2014/yuma-clapper-rail-08-21-2014.html. Accessed July 2021

Flather, CH, et al. 1998. Threatened and endangered species geography. BioScience 48: 365–376.

Kagan et al. 2014. Avian Mortality at Solar Energy Facilities in Southern California: A Preliminary Analysis, National Fish and Wildlife Forensics Laboratory, April. https://www.ourenergypolicy.org/wp-content/uploads/2014/04/avian-mortality.pdf. Accessed July 2021.

Kosciuch et al. 2020. A summary of bird mortality at photovoltaic utility scale solar facilities in the Southwestern U.S. PLOS ONE 15(4): e0232034. https://doi.org/10.1371/journal.pone.0232034. Accessed July 2021.

Kuvlesky et al. 2007. Wind energy development and wildlife conservation: Challenges and opportunities. Journal Wildlife Management 71: 2487–2498.

Lovich, Jeffrey E, et al. 2011. Wildlife Conservation and Solar Energy Development in the Desert Southwest, United States. Published in BioScience, Vol. 61, No. 12, pp. 982–992, doi:10.1525/bio.2011.61.12.8.

Magill, Bobby. 2020. Article entitled Massive Desert Solar Project 'Experiment' in Tortoise Survival. Published in Bloomberg Law. 9 January. https://news.bloomberglaw.com/environment-and-energy/massive-desert-solar-project-experiment-in-tortoise-survival. Accessed June 2021.

Nunez, Christina. 2020. Deep learning system will monitor birds at solar facilities. 3 June. https://www.anl.gov/article/deep-learning-system-will-monitor-birds-at-solar-facilities. Accessed June 2021.

Roth, Sammy. 2014. Lawsuit over desert solar plants' bird deaths. Desert Sun article. 21 August. https://www.desertsun.com/story/news/environment/2014/08/22/solar-plant-agencies-lawsuit/14426871/. Accessed June 2021.

Roth, Sammy. 2019. Article entitled California's San Bernardino County slams the brakes on big solar projects. Los Angeles Times. 28 February. https://www.latimes.com/business/la-fi-san-bernardino-solar-renewable-energy-20190228-story.html. Accessed June 2021.

U.S. Bureau of Land Management (BLM). 2019. Solar Partners XI, LLC, Biological Assessment, Gemini Solar Project. https://eplanning.blm.gov/public_projects/nepa/100498/20008149/250009604/508_Gemini_Solar_Project_Draft_BA_06142019.pdf.

U.S. Department of the Interior (USDOI) and U.S. Department of Energy (USDOE). 2011. Draft Programmatic Environmental Impact Statement for Solar Energy Development in Six Southwestern States. U.S. Department of Energy. Report no. DOE/EIS-0403. 19 September. http://solareis.anl.gov/documents/dpeis/index.cfm.

U.S. Fish and Wildlife Service (USFWS). 2019a. Final Environmental Assessment for the Issuance of an Eagle Take Permit for California Flats Solar Project, California. https://www.fws.gov/cno/conservation/MigratoryBirds/California_Flats_Solar_Project/PDF_docs/CaliforniaFlatsSolar_EaglePermit_FONSI_Attachment1-EA.pdf. Accessed July 2021.

USFWS. 2019b. Endangered Species Permits. HCPs – Frequently Asked Questions. Online at: https://www.fws.gov/midwest/endangered/permits/hcp/hcp_faqs.html

USFWS 2021. https://www.fws.gov/endangered/what-we-do/hcp-overview.html

Walston, LJ, KE Rollins, KP Smith, and KE LaGory. 2015. A Review of Avian Monitoring and Mitigation Information at Existing Utility-Scale Solar Facilities (No. ANL/EVS-15/2). Argonne National Laboratory, April. https://blmsolar.anl.gov/program/avian-solar/docs/Avian_Monitoring_Mitigation_Solar.pdf. Accessed June 2021

Walston, LJ, KE Rollins, KE LaGory, KP Smith, and SA Meyers. 2016. A preliminary assessment of avian mortality at utility-scale solar energy facilities in the United States, Argonne National Laboratory, July.

https://www.sciencedirect.com/science/article/pii/S0960148116301422. Accessed June 2021.

Walston, LJ, HM Hartmann, MA Grippo, KE Szoldatits, and KP Smith. 2018. Existing Data Sources and Ongoing Monitoring Effects to Inform Understanding of Avian-Solar Interactions, Argonne National Laboratory, August. https://blmsolar.anl.gov/program/avian-solar/docs/Avian-Solar_Data_and_Monitoring_Report.pdf. Accessed June 2021.

4.5.6 Cultural Resources

Campo Band of Mission Indians. 2018. Letter to Susan Harris, Planning and Development Services, San Diego County. RE: JVR Energy Park PDS2018-MUP-18-022, Log No. PDS2018-ER-18-22-001. Comment Letter T-2 to the Draft EIR for the JVR Energy Park.

Krol, Debra Utacia. 2021. Tribes want Biden to balance technology and cultural issues in renewable energy projects. https://www.azcentral.com/in-depth/news/local/arizona-environment/2021/01/18/tribes-want-biden-balance-renewable-energy-and-cultural-issues/4102836001/. Accessed 20 July 2021.

Rosenthal, JS, GG White, and MQ Sutton. 2010. Chapter 10. The Central Valley: A View from the Catbird's Seat. 2007, pp. 147-163. In: Terry L. Jones and Kathryn A. Klar (eds.), "California Prehistory: Colonization, Culture and Complexity," AltaMira Press.

US Department of the Interior. 2021.

von Kaenel, Camille. 2021. Jacumba residents fight back against proposed 650-acre solar project. https://inewsource.org/2021/03/22/jacumba-residents-fight-back-against-proposed-650-acre-solar-project/. Accessed 15 July 2021.

Wescott, Konnie. 2013. Impacts of Utility-Scale Solar Development on Cultural Resources. Environmental Sciences Division, Argonne National Laboratory. https://www.bia.gov/sites/bia.gov/files/assets/as-ia/ieed/ieed/pdf/idc1-021612.pdf. Accessed 15 July 2021.

4.5.7 Air Quality and Dust Control

Cart, Julie. 2013. Officials study valley fever outbreak at solar power projects. https://www.latimes.com/local/la-xpm-2013-apr-30-la-me-solar-fever-20130501-story.html. Accessed June 2021.

Munson, SM, J. Belnap, and GS Okin. 2011. Responses of wind erosion to climate-induced vegetation changes on the Colorado Plateau. Proceedings of the National Academy of Sciences 108: 3854–3859.

Trabish, HK. 2013. Construction Halted at First Solar's 230 MW Antelope Valley Site. Green Tech Media. https://www.greentechmedia.com/articles/read/Construction-Halted-At-First-Solars-230-MW-Antelope-Valley-Site. Accessed June 2021.

4.5.8 Aesthetics and Other Community Issues of Concern

Baker, DR, and M Dent. 2019. NIMBYs Shoot Down Green Projects Next Door While Planet Burns. , 17 September 2019, Bloomberg. https://www.bloomberg.com/news/features/2019-09-17/nimbys-shoot-down-green-projects-next-door-while-planet-burns. Accessed June 2021.

County of San Bernardino. 2019. County Resolution No. 2019-17. Amendment of the Renewable Energy and Conservation Element of the County General Plan. http://www.sbcounty.gov/uploads/LUS/Renewable/2019_WEBSITE/RES-LUS-2-28-19-RECE_SIGNED.pdf. Accessed June 2021.

Donaldson, JJ. 2018. Mitigating Visual Impacts of Utility-Scale Energy Projects. Visual Resource Stewardship Conference Proceedings, GTR-NRS-P-183. https://www.fs.fed.us/nrs/pubs/gtr/gtr-nrs-p-183papers/23-donaldson-VRS-gtr-p-183.pdf. Accessed 21 June 2021.

Roselund, Christian. 2019. San Bernardino County bans large-scale solar, wind in some areas. 1 March 2019 article in PV Magazine. https://pv-magazine-usa.com/2019/03/01/san-bernardino-county-bans-large-scale-solar-wind-in-some-areas/. Accessed July 2021.

Roth, Sammy. 2019. California's San Bernardino County slams the brakes on big solar projects. Los Angeles Times, 28 February. https://www.latimes.com/business/la-fi-san-bernardino-solar-renewable-energy-20190228-story.html. Accessed June 2021.

Smarden, R, and MJ Pasqualetti. 2017. Social acceptance of renewable energy landscapes. In: Apostol, D, J Palmer, MJ Pasqualetti, R Smardon, and R Sullivan, eds. 2017. The renewable energy landscape: preserving scenic values in our sustainable future. New York, NY: Routledge: 108-142.

Sullivan, R, et al. 2012. Visual Impacts of Utility-scale Solar Energy Facilities on Southwestern Desert Landscapes. In Proceedings of the National Association of Environmental Professionals 37th Annual Conference, Portland, OR, 21-24 May. https://blmwyomingvisual.anl.gov/docs/Solar_Visual_Impacts.pdf. Accessed 21 June 2021.

Chapter 5 Waste Materials and Volumes

CalRecycle. 2021a. Beyond 2000: California's Continuing Need for Landfills. https://www.calrecycle.ca.gov/swfacilities/landfills/needfor. Accessed November 2021.

CalRecycle. 2021b. State of Disposal and Recycling for Calendar Year 2019. Feb. 12, 2021. file:///C:/Users/Tim.Murphy/Downloads/State%20of%20Disposal%20and%20Recycling%20Report%20for%20Calendar%20Year%202019.pdf. Accessed November 2021.

International Renewable Energy Agency (IRENA). 2016 End-of-Life Management – Solar Photovoltaic Panels. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2016/IRENA_IEAPVPS_End-of-Life_Solar_PV_Panels_2016.pdf. Accessed October 2021.

Rapoza, Kenneth. 2020. China Doesn't Want The World's Trash Anymore. Including 'Recyclable' Goods. Published in Forbes. November 29, 2020.

https://www.forbes.com/sites/kenrapoza/2020/11/29/china-doesnt-want-the-worlds-trash-anymore-including-recyclable-goods/?sh=138d9aef7290. Accessed November 2021.

TWI. 2021. How Long Do Wind Turbines Last? https://www.twi-global.com/technical-knowledge/faqs/how-long-do-wind-turbines-last. Accessed October 2021.

USDOE. 2015 Quadrennial Technology Review - An Assessment of Energy Technologies and Research Opportunities. https://www.energy.gov/sites/prod/files/2017/03/f34/quadrennial-technology-review-2015_1.pdf. Accessed October 2021.

Wesoff, Eric and B. Beetz. 2020. Solar panel recycling in the US - a looming issue that could harm industry growth and reputation. Published in PV Magazine. December 3, 2020. https://pv-magazine-usa.com/2020/12/03/solar-panel-recycling-in-the-us-a-looming-issue-that-could-harm-growth-and-reputation/. Accessed November 2021.

Wheeler. 2021. The Need to Examine the Life Cycles of All Energy Sources: A Closer Look at Renewable-Energy Disposal. https://www.heritage.org/renewable-energy/report/the-need-examine-the-life-cycles-all-energy-sources-closer-look-renewable. Accessed October 2021.

Refer to Table 5-1 for additional citations.

ERM has over 160 offices across the following countries and territories worldwide

Argentina	The Netherlands
Australia	New Zealand
Belgium	Norway
Brazil	Panama
Canada	Peru
Chile	Poland
China	Portugal
Colombia	Puerto Rico
France	Romania
Germany	Russia
Ghana	Senegal
Guyana	Singapore
Hong Kong	South Africa
India	South Korea
Indonesia	Spain
Ireland	Sweden
Italy	Switzerland
Japan	Taiwan
Kazakhstan	Tanzania
Kenya	Thailand
Malaysia	UAE
Mexico	UK
Mozambique	US
Myanmar	Vietnam

ERM's Walnut Creek Office

1277 Treat Boulevard
Suite 500
Walnut Creek, CA 94597

T: +1 925 946 0455
F: +1 925 946 9968

www.erm.com

The business of sustainability

ERM