Energy Research and Development Division

FINAL PROJECT REPORT

Building a Healthier and More Robust Future: 2050 Low-Carbon Energy Scenarios for California

California Energy Commission

Gavin Newsom, Governor

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PREFACE

The California Energy Commission's Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the California Public Utilities Commission established the Electric Program Investment Charge (EPIC) to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The California Energy Commission and the state's three largest investor-owned utilities – Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company – were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The Energy Commission is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Building a Healthier and More Robust Future: 2050 Low Carbon Energy Scenarios for California is the report for the Building a Healthier and More Robust Future: 2050 Low-Carbon Energy Scenarios for California project (EPC-14-072) conducted by Lawrence Berkeley National Laboratory. The information from this project contributes to the Energy Research and Development Division's EPIC program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

The research team developed several long-term energy scenarios for California that detail how the state can meet its aggressive climate targets for 2030 and 2050 (40 percent and 80 percent greenhouse gas reduction from 1990 levels, respectively). The team harmonized assumptions with two concurrent California Energy Commission projects (led by Energy and Environmental Economics and the University of California, Irvine) using different models. The research team modeled the electricity system across the entire Western Electricity Coordinating Council to investigate the path dependence of electricity system buildout (or building for interim carbon targets in 2030 compared to grid planning and building for long-term stringent carbon reduction goals) and the impact of climate change on future electricity system buildout costs.

The results indicate that achieving a 40 percent reduction in greenhouse gas emissions by 2030 will be extremely difficult if a high percentage of vehicles are gasoline-powered and natural gas appliances are still in operation. However, this target can be met if California begins electrifying energy services and decarbonizing power generation at a substantially faster rate. For example, electrification of buildings must start by 2020 to meet the 2030 target. Critical to this task are programs supporting the greater adoption of clean technologies such as zero-emission vehicles and heat-pump water heaters. Non-energy interventions, such as a 25 percent reduction in hot water demand, will contribute substantially toward meeting the 2030 target. Electrification of the industrial sector will be more challenging, mostly due to higher costs, although the technical potential is high. The study also found that clean electricity generation technology adoption does not necessarily improve local air quality and public health. In the Central Valley, decarbonizing residential fuel combustion (such as wood-burning stoves and fireplaces) and diesel-powered transportation is more urgent than installing rooftop solar for improved air quality.

Keywords: Decarbonization, energy system scenarios, electricity grid modeling, low-carbon electricity, clean technology adoption, greenhouse gas reduction policies, ZEV, industry decarbonization, health damages from criteria emissions, environmental justice, climate change, electricity demand projections, electrification, renewable energy resource land mapping, heat-pump water heaters, fuel cell electric vehicles

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EXECUTIVE SUMMARY

Introduction

California has set aggressive targets to reduce greenhouse gas (GHG) emissions – a 40 percent reduction from 1990 levels by 2030 and an 80 percent reduction by 2050. For the state to meet these GHG targets, ramping up electrification of energy services (for example, adopting zero-emission vehicles [ZEVs] and electric end-use appliances such as heat pumps) is critical. To meet the 2030 target, electrifying buildings must start by 2020 with special focus on water and space heating. More aggressive decarbonization in the electricity sector is necessary to compensate for the lack of market-ready decarbonization options in other sectors, such as heavy-duty trucks and industry.

More customers must adopt electrified end-use technologies to capitalize on economies of scale and technological learning. Regional collaboration on mandates and targets for the adoption of clean technologies and consumer and industry stakeholder education (such as contractor outreach and training) are critical in promoting the rapid expansion of these markets.

Project Purpose

The long-term energy scenarios project was a coordinated portfolio of studies funded by the California Energy Commission and conducted by Energy and Environmental Economics (E3); Lawrence Berkeley National Laboratory with the University of California (UC), Berkeley; and UC Irvine. The project team produced scenarios for the state's electricity sector to reduce GHG emissions to 80 percent below 1990 levels by 2050 while considering the potential effects of climate change to the energy system. The Lawrence Berkeley National Lab research team developed several long-term energy scenarios for California that map out how the state can meet both aggressive climate targets while coordinating assumptions with the other two studies, even though the three studies used different modeling tools. E3 provided most of the assumptions to be as compatible as practical with the California Air Resources Board Scoping Plan, while UC Irvine estimated climate impacts on renewable generation and evaluated the effectiveness of adaptation strategies to offset those impacts. The main goal was to investigate if differences in modeling approaches could result in significantly different outcomes. Overall, the three groups reached similar conclusions with compatible insights.

Project Process

The Lawrence Berkeley National Lab research team used two modeling tools for the energy sector: the Solar and Wind Energy Integrated with Transmission and Conventional Sources (SWITCH) model for the electricity supply system and the Long-range Energy Alternatives Planning (LEAP) model for the state's non-electricity fuel demands. Two economic side cases for heat pump-based water heating and fuel cell electric vehicles were performed outside the main modeling framework, but with similar underlying assumptions as those used for the rest of the energy sector. The non-energy sector (such as agriculture) is not treated in detail in this study; however, the work from the team's previous study was incorporated in this project.

The research team used the same climate change scenarios (projections on how climate will change) in 2050 for California and the rest of the Western Electricity Coordinating Council (WECC) in modeling an 80 percent carbon reduction across the WECC The WECC is a nonprofit corporation to assure energy reliability across 14 western states, two Canadian provinces, and the northern portion of Baja California, Mexico. This study incorporated climate change inputs in heating and cooling degree days to 2050 from the U.S. Environmental Protection Agency and the National Renewable Energy Laboratory and building load shapes from UC Irvine.

Project Results

This study found that in the WECC region, it is more effective and cost-efficient to optimize the power system for the long-term GHG goal (an 80 percent reduction by 2050) rather than taking the interim step of optimizing grid supply resources for a medium-term target (2030). Planning for the long term reduces stranded assets and minimizes overall costs. Alternatively, the optimal solution can be achieved by having stronger carbon cap policies by 2030 (such as a 26 percent emissions reduction from 1990 levels across the WECC by 2030).

The research team estimated a total increase in installed electric-generation capacity of 2 percent to 7 percent in 2050 compared to the non-climate-change scenario. For generation in the WECC by 2050, on average, wind generates 57 percent and solar 18 percent. Electricity generation in California in 2050 will be dominated by solar, geothermal, and hydropower (67 percent on average). Wind generation in California in 2050 is lower than these three sources due to ecological and environmental land constraints.

Typical electricity-grid capacity expansion models make investment decisions with fixed inputs (for example, fixed electricity demands and hydropower availability). The resulting electricity supply system may not be able to support future climate change-driven uncertainties in energy demand and supply. This report presents the first stochastic (probabilistic rather than deterministic or fixed) long-term (2050) capacity expansion electricity grid model for the Western North America electricity region (Stochastic Solar and Wind Energy Integrated with Transmission and Conventional Sources [SWITCH]-WECC model) using high resolution in time and spatial dimensions. The Stochastic SWITCH-WECC model generates an optimal or least-cost portfolio of power plant capacity that can adjust to varying future climate conditions. This study found that the most robust electricity supply portfolio in the WECC for 2050 has about a 4 percent higher overall installed capacity than the average mix of the three scenarios modeled and about 5.6 percent higher installed gas capacity. The team concluded this is because of the greater demand for operating the system with more flexibility under the wider range of possible conditions.

The team also evaluated the land demand for potential solar energy development in California across four nonconventional land-cover types: the built environment, salt-affected land, contaminated land, and water reservoirs (floatovoltaics) in the Central Valley. Accounting for technology efficiencies, the study found a vast solar potential on these land-cover types that exceeds California's 2025 projected electricity demands by up to 13 times in gigawatt-hours for solar photovoltaic (PV) and two times for concentrating solar power.

California's response to climate change can be viewed as an opportunity to reduce the adverse public health effects of fossil fuel-derived pollution. Of particular concern are disadvantaged communities, who bear a disproportionate burden of pollution effects from transportation, power plants, and factories.

This report provides the first detailed assessment of statewide and regional health damages based on the 2016 California Air Resources Board pollutant emissions inventory. The team estimated statewide health damages from all-source emissions in 2016 to be about $25 billion. About 20 percent of damages are from on-road motor vehicles, 18 percent from other mobile sources (such as off-road equipment, aircraft, and farm equipment), 17 percent are dust-related, and 13 percent are from residential fuel combustion. Electricity and cogeneration make up only 1.3 percent of the state's total health damages. The team also noted the distribution of health damages by emissions source varies widely across the state. For example, dust-related sources and farming operations make up 40 percent of health damages in Fresno County, yet only 6 percent in Los Angeles County.

Transforming California's vehicle inventory to electrified light-duty and heavy-duty vehicles will achieve GHG reductions and improved air quality from reduced vehicle tailpipe and oil refinery emissions. It is essential to have a more complete understanding of the larger economic ramifications of a sharp transition away from the oil industry and what is required for an associated scaling up of the biofuel industry. In particular, future research on potential replacements for oil industry-derived feedstocks is required.

Electrifying the industrial sector will be difficult due to costs and other market barriers, though the technical potential for electrification is high, and innovative methods and approaches to electrifying industrial processes are an opportunity for further research and development. The study found that electric boilers could be a potential technology option for augmenting the operation of natural gas-fired boilers in a hybrid boiler configuration and potentially provide grid support for increasing amounts of intermittent renewable electricity as a flexible load.

Energy-related policies and incentives should consider the necessity of balancing policy objectives and impacts, including GHG reductions, health damage reductions, and environmental justice equity issues. For example, if the policy objective is air pollution reduction in Fresno County, then diesel truck pollution, commercial cooking, and wood burning stoves are more urgent areas to address than providing incentives for rooftop solar panels or natural gas-based residential space- and water-heating efficiency measures.

The range of climate change impacts - direct and indirect effects – must be factored into energy system planning. For example, recent warming has led to lower heating-related GHG emissions but greater demand for air conditioning. This aspect has important policy implications, such as tighter efficiency standards for room air conditioners.

Recent reports highlight that current emission inventories underestimate methane emissions and may underestimate nitrous oxide emissions as well. This conclusion is a key risk area that could increase 2016 baseline emissions by up to almost 13 percent and highlights the increased risk to meeting the 2030 GHG target.

Benefits to California

This research offers numerous benefits to California. By rigorously analyzing potential future scenarios for California's energy sector, the study offers a sound planning tool that can be used to craft realistic policy helping California meet the ambitious goals laid out in Senate Bill 350 (De León, Chapter 547, Statutes of 2015) and Senate Bill 32 (Pavley, Chapter 249, Statutes of 2006). Detailed energy scenarios that consider multiple options and variables allow policy makers to inform their choices for the most appropriate pathways to a low-carbon future, even as California's energy supply and demand become more difficult to forecast because of climate change-related variabilities.

Additional research produced by this study also offers benefits to California by demonstrating different possibilities for reducing GHG emissions. For example, this study highlights California's enormous potential for solar energy (Chapter 6), which can lower GHG emissions within the state and reduce California's dependence on out-of-state energy sources. In addition, the findings of this study on possible decarbonization strategies for the buildings sector (Chapter 4), for the industrial and transportation sectors (Chapter 5), and for household appliances such as water heaters (Chapter 7) demonstrate the many ways California can attain a low-carbon future.

Last, this report also benefits California by consistently considering the impacts on marginalized or disadvantaged communities. By exploring how the effects of climate change and adaptation measures undertaken affect the state's most vulnerable populations, this study ensures that future efforts toward a low-carbon future will benefit all Californians.

Knowledge Transfer and Dissemination

The results and scenarios of this study are being shared with stakeholders in multiple venues to help ensure efforts for a low-carbon future. These venues include the following:

- Conferences and technical meetings include the 2017 American Council for an Energy Efficient-Economy Hot Water Forum in Portland, Oregon, and the 2017 American Geophysical Union Fall Meeting in New Orleans.
- Three journal papers were written from this research and have been cited seven times in international technical literature. The research team has also shared these papers with key decision makers at the U.S. Department of Energy.
- The research team has had discussions with nongovernmental organizations, California legislative staff, and key policy makers to share the findings of this research project at past events and ongoing discussion forums and plans to share project findings at upcoming state climate policy-related events For example, in March 2018, the research team met with Jim Metropulos of California Assemblymember Laura Friedman's (D-Glendale) office to discuss Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018), a bill to assess how to reduce greenhouse gas emissions from the state's building stock by 40 percent below 1990 levels by 2030. The research team shared the results of this work on building efficiency and water heating decarbonization. The bill was signed into law by Governor Edmund G. Brown Jr. on September 13, 2018.

CHAPTER 1: Introduction

California is a worldwide test bed for low-cost and low-greenhouse gas (GHG) energy policies and strategies to build a low-carbon economy. During the past several years, California has set ambitious goals to curb GHG emissions. These goals include a target to reduce overall GHG to 1990 levels by 2020 (Assembly Bill 32 [Nunez, Chapter 488, Statutes of 2006]) and an 80 percent reduction goal in 2050 from 1990 levels (Executive Order S-3-05). Recent legislation has set more aggressive targets for 2030 and includes:

- Doubling of the rate of energy efficiency and achieving a 50 percent Renewables Portfolio Standard (RPS) by 2030 (Senate Bill 350 [De León, Chapter 547, Statutes of 2015]).
- A 40 percent reduction target in GHG emissions from the 1990 level by 2030 (Senate Bill 32 [Pavley, Chapter 249, Statutes of 2006]).

Aggressive reduction targets for short-lived climate pollutants including methane, black carbon, and hydrofluorocarbon gases by 2030 (Senate Bill 1383 [Lara, Chapter 395, Statutes of 2016]).

Also, the state's existing Cap-and-Trade Program was strengthened and extended to 2030 by Assembly Bill 398 (Eduardo García, Chapter 135, Statutes of 2017).

California has a vital role to play for national and global climate policy in setting benchmarks, sending strong and sustained signals of market support to clean energy technology providers, and leading and participating in regional agreements for clean technology adoption, such as the *Multi-State Zero Emissions Vehicle (ZEV) Action Plan,*[1] which includes California and eight other states.

1.1 Electricity System Modeling

As in previous studies, the team developed several long-term energy scenarios for the state incorporating the recent climate legislation described above and including future energy demand estimates from the largest three energy-consuming sectors (transportation, buildings, and industry). For the electricity sector, as in previous scenario modeling work for the California Energy Commission, the team used the Solar and Wind Energy Integrated with Transmission and Conventional Sources (SWITCH) capacity-expansion model for the western United States including California, under different scenarios of climate change, policies, and technology availability from the present day to 2050. The team modeled the entire Western Electricity Coordinating Council (WECC) to investigate whether a change of geographical coverage can affect the long-term energy scenarios using a model of the electricity system that

1 For example, https://www.zevstates.us/.

is more granular in space and time, such as using several load centers in the WECC instead of representing California as a single area.

1.1.1 Incorporating Climate Change

Previous studies on long-term decarbonization scenarios (Williams et al. 2012, Wei et. al 2013, Greenblatt 2015) do not model the impacts of climate change. The research team observed the impact of climate change on the state's GHG emissions, for example, heating demand decreased. In 2014-2015, there was a 19 percent drop in residential heating sector emissions compared to the previous 10 years, with this reduction attributed to 2014-2015 being record-setting hot years[2] (Figure 1). Climate change can impact the hydrological cycle (Tarroja et al. 2016) and increase cooling demands, such as air conditioning. Greater weather extremes are expected, and this change requires a more robust energy system and planning. A key objective for this research is to include climate change-induced energy supply-and-demand impacts in the long-term scenario modeling. Here, building electricity load shapes and fuel demands for three climate models (HadGEM2-ES [warm/dry], CanESM2 ["average climate"], and Miroc5) were modeled by UC Irvine, with technical support from Lawrence Berkeley National Laboratory (LBNL), and used as an input into the SWITCH electricity system model. Climate change can also have indirect effects on the energy system by affecting crop yields for biofuels and impacting wildfire frequency, intensity, and duration that can lead to greater emissions from the forestry sector.[3]

1.1.2 Health Damages From Pollution Sources and Environmental Justice

Disadvantaged communities are of particular concern regarding health damages because they experience a disproportionate burden of pollution effects from transportation, power plants, and industrial factories. Disadvantaged communities are areas in California that suffer from a combination of economic, health, and environmental burdens. These communities are often the most vulnerable to climate change effects and experience the most damages in concurrent health impacts from fossil fuel pollution. In addition, these communities can least afford clean energy technologies such as plug-in electric vehicles, energy efficiency upgrades, and rooftop solar PV panels.

A well-designed, large-scale transformation of the current energy system to one that relies on cleaner energy sources and energy-efficient end uses presents an immense opportunity for health impact savings and societal benefits, but it also poses notable implementation challenges. Environmental justice[4] is inextricably linked to this energy transition and is an issue

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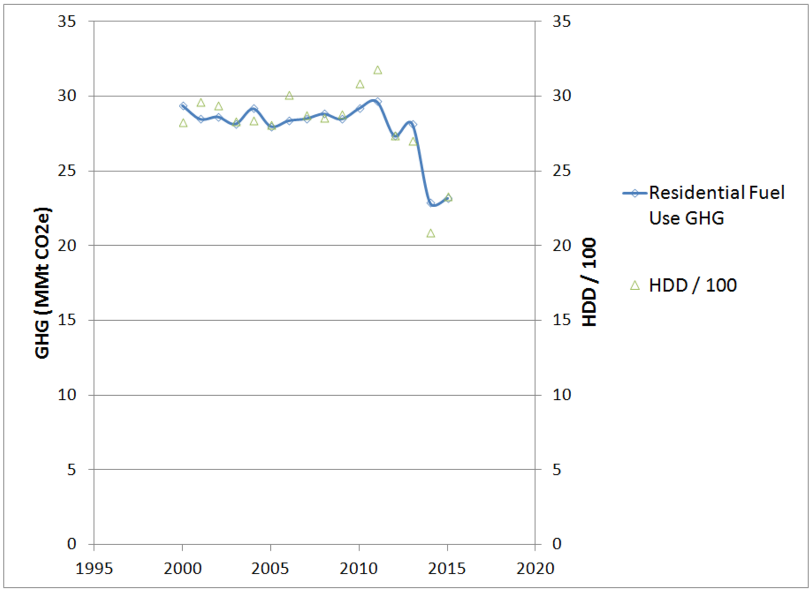
2 California Air Resources Board. June 6, 2017. *California Greenhouse Gas Emissions for 2000 to 2015 – Trends of Emissions and Other Indicators*, Available at https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2015/ghg_inventory_trends_00-15.pdf.

3 GHG emissions from wildfires are not currently counted in the California Air Resources Board (CARB) inventory but are an active area of discussion at CARB.

4 "Environmental justice" encompasses the following issues in disadvantaged communities: (1) pollutant exposures (air, water, soil, etc.) and resultant human health impacts (for example, respiratory illness, premature deaths); (2) access and distributional equity of clean technologies (such as rooftop solar photovoltaics (PV), zero-emission vehicle (ZEV), energy-efficient appliances); and (3) inclusion of disadvantaged communities into the policymaking process. The research team focused on pollutant sources and health damages here. A statewide map to help identify California

recognized by California, the U.S. Environmental Protection Agency (EPA), and governments and agencies in other regions of the world. The challenge will be achieving deep reductions in GHG emissions while reducing health-damaging copollutants to improve health outcomes in those communities most burdened by the current energy system. Moreover, this transition should ensure that health, economic, technological, and other benefits are equitably distributed and that front-line communities are included in policymaking.

Figure 1: Residential Fuel Use Greenhouse Gases, 1995-2020



Residential fuel use GHG dropped by 19 percent in 2014 and 2015 compared to the previous 10 years, primarily due to less space-heating demand due to record-breaking heat. Over the two same periods, heating degree days dropped by 24 percent (HDD = heating degree days).

Source: California Air Resources Board 2016 and National Oceanic and Atmospheric Administration 2016[5]

While aligning many policy objectives for air quality, public health, and environmental equity is politically, technically, and economically critical to reach climate policy goals, in practice this arrangement is often not achieved. For example, incentives for clean energy technologies such as solar PV and plug-in electric vehicles benefit primarily more affluent populations. In California, several recent bills have passed to achieve greater environmental justice and more equitable distribution of revenues from the Cap-and-Trade Program[6] (for example Senate Bill 535 [De León, Chapter 830, Statutes 2006], Assembly Bill 1550 [Gomez, Chapter 369, Statutes of

communities that are disproportionately burdened by multiple sources of pollution is available online at CalEnviroScreen 3.0 (https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30).

5 https://www.arb.ca.gov/cc/inventory/data/data.htm, accessed September 14, 2018; https://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp# . Accessed November 29, 2016.

6 *Cap-and-trade* is a market-based regulation that is designed to reduce greenhouse gases (GHGs) from multiple sources. Cap-and-trade sets a firm limit or cap on GHGs and minimize the compliance costs of achieving AB 32 goals. The cap will decline about 3 percent each year beginning in 2013. (https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm, accessed September 14, 2018).

2016], Assembly Bill 617 [Cristina Garcia, Chapter 136, Statutes of 2017], and Assembly Bill 793 [Quirk, Chapter 589, Statutes of 2015]).

This report assesses current health damages based on the 2016 California Air Resources Board (CARB) emissions inventory and a closed-form health impacts model that has been used by the EPA in the past (Heo et al. 2016). This study focused on oxides of nitrogen (NO_x), sulfur oxides (SO_x), and particulate matter ($PM_{2.5}$),[7] since, generally speaking, these three criteria pollutants have the highest human health and environmental externality impacts. This near-term focus on health damages provides a useful lens through which to view the relative impacts of various sectors (such as on-road mobile vs. residential fuel combustion), sectoral sources by pollutant type, health damages by region of the state, and some background and context for further policy development. The health damages modeling here includes a discussion of Fresno and Los Angeles Counties, but a detailed discussion of distributional issues and policy-stakeholder inclusivity issues or impacts across the entire state was beyond the scope of this study.

The future thus brings significant challenges, from aggressive 2030 climate targets to greater climate warming and variability. These challenges necessitate climate policy and planning that are resilient to future uncertainties while bringing cleaner technologies in a fair and equitable manner and producing public health benefits, especially in disadvantaged communities.

1.1.3 Importance of Technology Deployment Programs

Electrifying end uses, in conjunction with a low-carbon electricity supply, has been highlighted as a key decarbonization pathway in previous long-term energy modeling (Williams et al 2012, Wei et al 2013). The state has set aggressive targets in the electricity supply sector. A key challenge hindering the medium- and long-term decarbonization strategies necessary to meet GHG targets is the rate of adoption of clean technologies such as zero-emission vehicles (ZEV) and heat pumps for residential and commercial building water heating. In many cases, the upfront cost of these technologies is a large barrier.

With greater technology adoption, cost reductions can be achieved through economies of scale, greater technology learning and innovation, and greater market competition. A higher rate of adoption is critical in driving down the cost of clean technologies. One common way for viewing this objective is through the lens of technology "experience curves." Briefly defined, these are curves of historical product or technology cost versus cumulative production volume (for example the cost of rooftop solar PV modules per kilowatt [kW] vs. cumulative installations in gigawatt [GW]).[8] Plotted on logarithmic scales, these curves typically have piecewise linear behavior where the slope of each linear segment is characterized by the "learning rate" for that technology. A higher learning rate has a larger cost reduction for a given increase in cumulative production.

7 Criteria pollutants include carbon monoxide (CO), lead, nitrogen oxides (NOx), ozone, particulate matter (PM), and sulfur oxides (SOx). PM2.5 refers to atmospheric particulate matter that have a diameter of less than 2.5 micrometers, and PM10 refers to particulate matter that are less than 10 micrometers in diameter.

8 The experience curve framework is described in Appendix A.

Highlighted are recent findings in the literature that underscore the importance of programs supporting technology adoption and potential increases in the rate of learning. Experience curves are empirically observed to decrease sharply, or bend down, in many cases for energy supply technologies and end-use energy technologies specifically moving from one learning rate to a faster learning rate, with this downward bend in the experience curve strongly correlated to the programs (Wei et al. 2017, Smith et al. 2016, Van Buskirk et al. 2014). These programs can be incentives and rebates, market targets, standards-setting and testing protocols, informational campaigns, public outreach, and contests. Market targets (for example, the Governor's ZEV goal of 1.5 million ZEVs on the road by 2025[9]) and regional partnerships such as the multistate *ZEV Action Plan* for 3.3 million ZEVs by 2025 are examples of programs that signal strong and sustained policy support to technology providers (ZEV automakers in this case) and can spur greater competition and a faster rate of innovation. This work describes the importance of strong deployment programs for two technology examples: heat-pump water heating and fuel cell electric vehicles (Chapter 8).

This report includes modeling analysis, discussion, and policy implications of the following items:

- Chapter 2 describes the modeling approach and description of scenarios.
- Chapter 3 details electricity system modeling, including climate change and hydrological sector impacts on electricity supply using the SWITCH model.
- Chapter 4 quantifies the resource potential for solar photovoltaic (PV) in the Central Valley related to potential from energy production and respecting environmental concerns.
- Chapter 5 discusses the decarbonization of the building sector and includes climate change impacts on cooling demands and load shapes in that sector.
- Chapter 6 presents modeling of transportation and industry demands and decarbonization pathways for 2030 and 2050 climate targets in these sectors.
- Chapter 7 provides an overview of 2016 emission sources and health damages across the state, as well as case study data for Fresno and Los Angeles Counties.
- Chapter 8 provides two economic case studies related to electrification: residential water heating decarbonization and fuel cell electric-vehicle light-duty vehicle cost reduction.
- Chapter 9 has a summary of scenario results and some key risks and wild cards for GHG emissions, including GHG emissions from more intense wildfires and methane leakage.
- Chapter 10 provides conclusions and future research directions.

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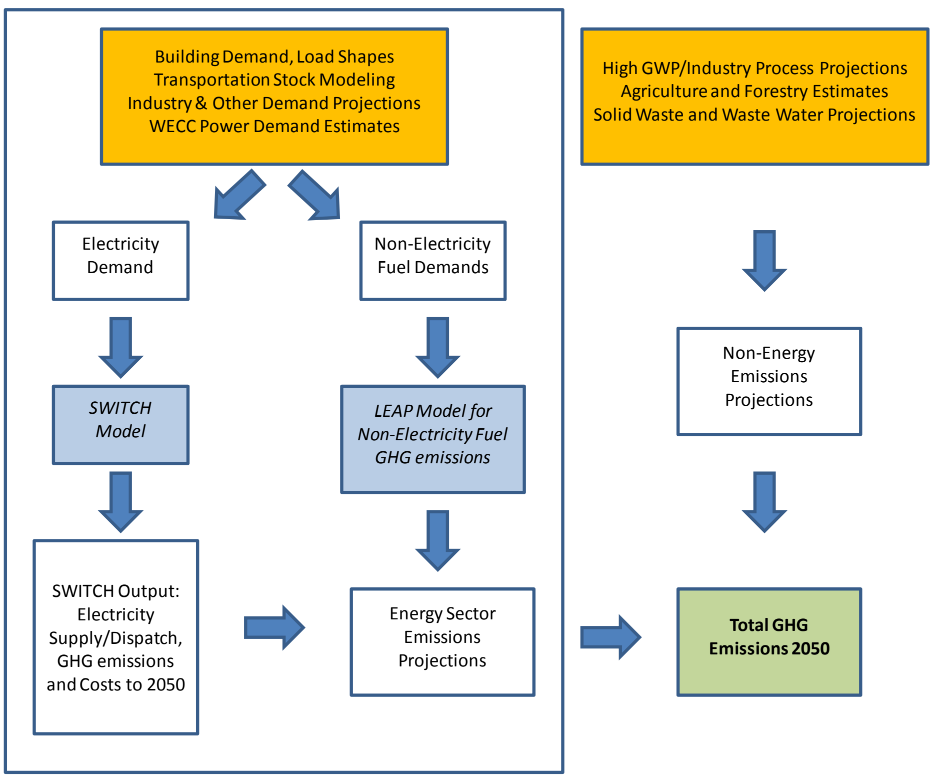
9 See, for example, *2016 ZEV Action Plan: An Updated Roadmap Toward 1.5 Million Zero-Emission Vehicles on California Roadways by 2025*, Governor's Interagency Working Group on Zero-Emission Vehicles, Governor Edmund G. Brown Jr. October 2016, available at https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf.

CHAPTER 2: Modeling Approach and Scenarios

The energy system model structure is similar to Wei et al. (2012, 2014) and Nelson et al. (2014) (also referred to as CCC1/2) but updated with the most recent demand estimates and regulatory changes (such as SB 350 and SB 32) (Figure 2). As in CCC1/2, two modeling tools are used for the energy sector: the Solar and Wind Energy Integrated with Transmission and Conventional Sources (SWITCH) model for the electricity supply system and Long-range Energy Alternatives Planning (LEAP) model for the state's non-electricity fuel demands. The two economic side cases in Chapter 8 for heat pump-based water heating and fuel cell electric vehicles are done outside the main modeling framework using Python-based and Excel-based modeling but with similar underlying assumptions as those in the modeling. The non-energy sector is not treated in detail but was detailed in the team's previous report for the California Energy Commission (Wei et al. 2014). The results are adapted from that study to this work.

Figure 2: Structure of the Model



Source: Max Wei, Shuba V. Raghavan1, Patricia Hidalgo-González, LBNL

Electricity demand is synthesized from existing and recently updated sources and new vehicle demand scenarios and then input into the SWITCH supply model. Non-electricity sector fuel demands are tracked in the LEAP model, which is essentially a graphical bookkeeping tool linking bottom-up demands with overall fuel requirements and greenhouse gas emissions. A more detailed description of the energy model structure can be found in Wei et al. (2012, 2014). A brief description of model components and key updates to the modeling output are provided.

A scenario approach is adopted in the energy sector to estimate total GHG emissions in 2050. The research team first developed a frozen efficiency scenario by estimating energy demands that would follow from a trajectory with no additional energy efficiency measures. Then successive elements are added to the frozen efficiency case and the respective impacts calculated for electricity demand, fuel demands, and resultant emissions with the objective to achieve 80 percent emissions reductions in the energy sector relative to the 1990 level in this sector.

As in Greenblatt et al. (2011) and Wei et al. (2012), a compliant scenario is defined as being composed of aggressive building energy efficiency, clean (lower carbon intensity than present day) electricity, partial electrification of building and industrial heating, partial electrification of the transportation sector, and low-carbon biofuels.

For the most part, this technology envelope includes "within-paradigm" items that exist in the marketplace today or are beyond the demonstration and prototyping stage. For example, known technologies such as solar PV and wind are modeled and included in the electricity supply, but enhanced (deep) geothermal is not demonstrated nor proven at reasonable cost or scale and is not included. Heat pump technologies are assumed to be available in buildings but promising "out-of-paradigm" heating ventilation, and air-conditioning (HVAC) technologies such as novel thermodynamic cycle cooling systems are excluded.

2.1 Scenario Descriptions

Table 1 describes the scenario assumptions for this work:

- **The Frozen Demand:** This case essentially assumes baseline *California Energy Commission-Integrated Energy Policy Report (IEPR)* demand projections without SB350 savings, and a low rate of electrification to 2030 and 2050.
- **SB350:** This case achieves the SB 350 target of doubling the rate of energy efficiency by 2030. A low rate of electrification for buildings is assumed.
- **SB350 + Electrification:** This scenario is the same as the SB350 scenario but adds aggressive building electrification starting in 2020.
- **Aggressive EE Without Electrification:** This scenario assumes a higher rate of energy efficiency retrofits starting in 2020 than the SB 350 case but with a low rate of building electrification.
- **Aggressive EE With Electrification ("Compliant"):** This case is similar to the preceding case but with aggressive building electrification starting in 2020 and more aggressive adoption of ZEVs in transportation (BEV and FCEV) and electrified and fuel cell-powered trucks.

Table 1: Scenarios for This Work

Scenario Name	Buildings	Transportation	Industry
Frozen Demand	CEC-IEPR extended	Low electrification rate in line with IEPR-2016 (11,000 GWh by 2030 & 19450 by 2050)	CEC-IEPR extended
SB 350 [Without Building Electrification]	SB 350 savings till 2030 and holding percentage of savings fixed till 2050	Same as Frozen Demand above	Moderate Energy Efficiency reduced demand
SB 350 + Electrification	SB 350 savings through energy efficiency with intermediate rates of retrofit and electrification	Same as Frozen Demand above	Moderate EE measures + electrification
Aggressive EE [Without Building Electrification]	Aggressive retrofit rate with high energy efficiency	Aggressive Electrification with total electricity demand in 2050 ~125,000 GWh	Same as SB 350 Scenarios
Aggressive EE With Electrification ("Compliant")	Aggressive retrofit rate with high energy efficiency and building electrification	Aggressive Electrification with total electricity demand in 2050 ~125,000 GWh	Same as SB 350 + Industry Electrification

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

For all scenarios, electricity sector emissions in California are capped at levels that are more aggressive than the 2030 target and 2050 goal, at 56 percent GHG reductions from 1990 in 2030 and 86 percent reduction in 2050. These numbers were intentionally set to be more aggressive than a 40 percent GHG reduction and 50 percent RPS in 2030 per SB 32 and SB 350, respectively, and higher than the 80 percent GHG reduction goal in 2050. This team's earlier work (Wei et al. [2012, 2014]) and other studies (such as Greenblatt et al. 2011) find it extremely challenging to achieve 80 percent reductions in other sectors such as heavy-duty transportation fuels and industry. More aggressive targets in the electricity sector help compensate for the relatively higher level of emissions in these other sectors. The optimal mix of electricity supply options are then determined by SWITCH at these more aggressive GHG caps.

Biomass supply is assumed to follow the modified biomass supply presented in the *2016 Mid Century Repor*t (White House 2016) but exclude energy crops in the supply. California is assumed to have access to its population-weighted "fair share" of this supply, which is estimated to be about 91 million bone dry tons of biomass in 2030, and 120 million bone dry tons in 2050.

CHAPTER 3: SWITCH: Electricity Sector Modeling

3.1 Introduction

It is expected that future electricity systems will have high levels of renewable energy sources such as solar and wind. The variability and volatility of these sources may pose several challenges in power systems, in particular when high penetration levels of these sources are present. Earlier studies indicate greater storage and transmission expansion are necessary to promote the efficient integration of variable renewables while maintaining a reliable and secure system. To decide these optimal investments, complex temporal and spatial resolution must be considered in expansion planning models.

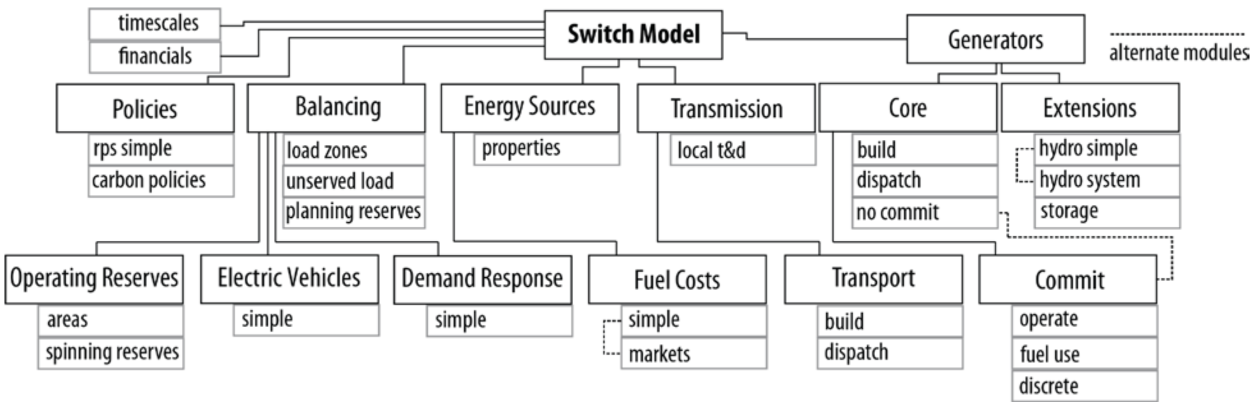
Traditionally, expansion planning models in electricity systems consider a simplified version of the grid to decide *what types of technology*, *where*, and *when* to install infrastructure in the system, such as generators or transmission lines. These models usually do not capture the chronological sequence of time and the spatial location of the resources, so the complex temporal and spatial distribution of variable renewable resources is not considered. Investment portfolios are then evaluated in detailed models to simulate the operational performance of the system in particular years.

This study used the SWITCH model (initial version and Version 2.0) to decide the optimal investment decisions and explore the cost of generation, transmission, and storage options for a future electricity system (Fripp 2012; Nelson et al. 2012).

SWITCH 2.0[10] is a Python package that can be used to create and solve power system expansion planning models. Taking advantage of the Python framework, SWITCH uses a modular architecture that allows users to include specific components through a list of modules, depending on the complexity of study; these components are depicted in Figure 3. It uses the open-source Python Optimization Modeling Objects (Pyomo) package as a framework to define optimization models, load data, and solve the optimization models using commercial or open-source solvers.

10 The SWITCH electric power system planning model was created at the University of California, Berkeley, by Dr. Matthias Fripp, then developed by Dr. James Nelson, Dr. Ana Mileva, Dr. Josiah Johnston, and Patricia Hidalgo-González. SWITCH WECC Python was adapted and further developed by Hidalgo-González, Johnston, and Rodrigo Henríquez. The model is maintained and developed in Professor Daniel Kammen's Renewable and Appropriate Energy Laboratory (RAEL) at the University of California, Berkeley.

Figure 3: List of Modules in SWITCH 2.0



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

SWITCH operates across many spatial and temporal scales to minimize the cost of transitioning from the current state to a future decarbonized power system. The model uses a set of chronological time series with hourly demand and renewable generation profiles in a planning expansion model. Using this framework allows consideration of the hourly behavior of variable renewable sources, such as wind and solar, and storage in representative time series over several periods. The model also considers an electric network with several load zones connected through a transmission system with limitations to realistic capacity levels modeled by using a derating technique over the lines. Also, policies such as renewable portfolio standards and carbon cap constraints are simultaneously considered with the investment decisions to evaluate the changes on the power system infrastructure buildouts. SWITCH concurrently optimizes the investment decisions and operational dispatch of the power system infrastructure. This optimization allows the research team to evaluate the variable renewable capacity of the sources under a wide range of future system configurations in different spatial zones and across time.

In this study, SWITCH is used to examine the future of the electric power of system of California and across the WECC interconnection region under different scenarios of climate change and policies through the present day to 2050. These scenarios, with the associated particular characteristics, are detailed in Sections 3.3 and 3.4.

3.2 2030/2050 Power System Planning Path Dependency

3.2.1 Introduction

For more than 20 years, policy makers have been negotiating agreements to reduce greenhouse gas emissions to stabilize the concentration of these emissions at a level that would prevent dangerous anthropogenic (human activity) interference with the climate system.[11] The most recent international meeting was the 21st Session of the Conference of the Parties to the United Nations Framework Convention on Climate Change (COP 21), held in Paris, France, in December 2015. The main outcome was the reaffirmation to limit the increase in global temperature to

11 http://www.c2es.org/international/history-international-negotiations.

below 2 degrees Celsius compared to preindustrial levels while urging efforts to limit the increase to 1.5 degrees.[12] In 2007, the Intergovernmental Panel on Climate Change (IPCC) had stated that the 2-degree goal could be achieved if different economic sectors in industrialized countries would reduce their emissions to specific targets. The electricity sector in particular would have to reduce emissions to 80 percent below 1990 levels by 2050 (IPCC 2007). In an attempt to achieve this long-term goal, the United States proposed in 2015 the Clean Power Plan (CPP) targets[13] with a target for power systems to reduce its emissions to 32 percent below 2005 levels by 2030 (equivalent to 11 percent below 1990 levels) (EPA 2015). Moreover, California set its statewide carbon cap target to reduce emission 40 percent below 1990 levels by 2030.[14]

These different emissions reductions goals with different time frames present a challenge for power system regulators and investors. What is the most economically efficient way to plan and operate the power system? Should investments for new power plants be planned for 2030 emissions targets (such as CPP) and from there optimize until 2050 to achieve the long-term emission targets (such as IPCC)? Or should power system capacity expansion be optimized from today until 2050?

These questions have been studied across the entire economy using different global integrated assessment models. It has been shown (Luderer et al. 2013, Riahi et al. 2013, Kriegler et al. 2014, Bertram et al. 2013) that less aggressive climate near-term targets delay the transition toward a cleaner economy and will require aggressive subsequent action to achieve climate stabilization goals. These studies also show that, because of the lack of foresight, unproductive near-term investments take place, which result in fossil fuels lock-ins and higher long-term mitigation costs. Therefore, it is relevant to study the impacts of short- or medium-term policy for the electric power system. To the best knowledge of the team, this type of analysis has not been applied to the electric power sector, and this study fills that gap. Furthermore, the electric power sector is particularly important because it is tied with the transportation sector as the highest GHG-emitting sector in the United States in 2016.[15]

3.2.2 Method

To study the consequences of short-sighted electricity policy, the research team used the SWITCH model. As an optimization problem, it is classified as a deterministic linear or mixed-integer program. The objective function minimizes the total power system cost, which includes investment and operation costs of generation and transmission. In addition to operational (reserves, ramping, etc.), technological, and resource potential constraints, different policy constraints can be modeled (for examples, carbon cap, carbon tax, Renewables Portfolio Standard [RPS], etc.). To the best of the team's knowledge, SWITCH's high temporal and geographical resolution is unique among power system capacity expansion models. This

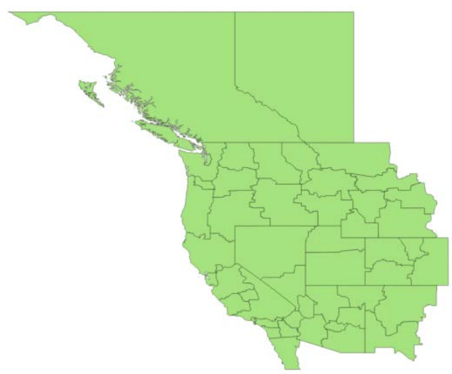
12 United Nations. Paris Agreement, United Nations Conference on Climate Change, 2015.
13 The CPP, under the current Trump administration, has been proposed to be repealed.
14 https://www.gov.ca.gov/news.php?id=18938.
15 https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks, accessed September 13, 2018.

resolution allows for a more realistic study of the expansion and operation of the electrical grid, with variable renewable energy resources such as wind and solar power included.

To date, the SWITCH model has been developed for four regions in the world: the Western Electricity Coordinating Council (WECC) in North America (Wei et al. 2013, Mileva et al. 2013, Nelson et al 2012), China (He et al. 2016), Chile (Carvallo et al. 2014), and Nicaragua (Ponce de Leon Barido et al. 2015). This study uses SWITCH-WECC as it is most relevant for policymaking in California and the WECC.

To study the effect of insufficient planning horizons on weak near-term policies, two optimization methods are used: “long optimization” and “medium optimization.” The control case or long optimization is the traditional deterministic optimization from 2016 to 2055. The optimization horizon was divided in four investment periods of 10 years each: 2016-2025 (which call “2020”), 2026-2025 (“2030”), 2036-2045 (“2040”), and 2046-2055 (“2050”). Each period simulated 72 hours of dispatch. For one year per period, the team sampled every two months, two days per month (median and peak load days) and four hours per day (six months times two days/month times six hour/day = 72 hours). A full month is represented by one peak day and n-1 median days, where n is the number of days of that month. Geographically, the SWITCH WECC model divides the WECC in 50 zones or load areas (Figure 4).

Figure 4: Western Electricity Coordinating Council Divided Into 50 SWITCH Load Zones



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

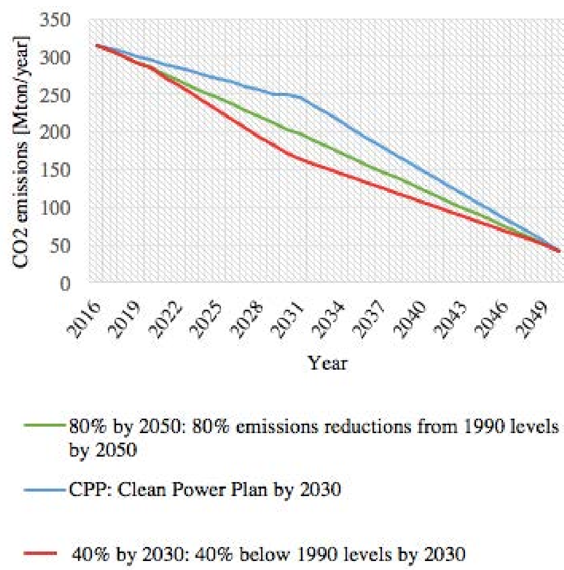
The research team developed the medium optimization for this study to analyze the impacts of short-term policy goals on the power system operations and capacity expansion. The basic idea behind the medium optimization is to break investment planning into two stages: present day until 2030 and 2030-2050. The first step minimized the cost of the power system operation and investment from 2016 to 2030 considering all policy constraints until 2030 (for example, annual carbon cap). The second step consisted of optimizing investments and operations from 2031-2055 with stronger emission policies for 2050 (80 percent reductions). This medium optimization re-creates the challenge of optimizing the expansion and operation of the power system in phases. Investment decisions made until 2030 become the initial state for the second step of the optimization. The second step optimizes decisions from 2031 to 2055 to comply with more stringent polices by 2050. Therefore, the hypothesis was that the first step would expand and operate the system in a shortsighted way, with consequent carbon lock-ins, and the second step would have to change the energy mix more aggressively to transition toward a cleaner electric grid by 2050 compared to the long optimization (which optimizes in only one step).

The long optimization was modeled over the complete time horizon 2016-2055 and thus used the constraints (policies) for all years. The long and medium optimizations used the same periods and hours sampled for consistency reasons and to isolate the impact and carbon locks-in produced by weak medium-term electricity policies.

3.2.3 Scenarios

The carbon cap policy scenarios that were used in this study are shown in Figure 5.

Figure 5: Western Electricity Coordinating Council Carbon Cap Scenarios



In green are the 80 percent emissions reductions from 1990 levels by 2050 scenario (80 percent by 2050), in blue the Clean Power Plan scenario (CPP), and in red 40 percent emissions reductions by 2030 (40 percent by 2030).

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

The scenario with the green line ("80 percent by 2050") corresponds to a linear decrease in emissions from 2016 until 2020, where emissions are restricted to 1990 levels (California Assembly Bill 32 applied to the entire WECC),[16] followed by a linear decrease from 2021 until 2050, where 80 percent reductions from 1990 levels are enforced (IPCC 2007). The blue line ("CPP") corresponds to a linear decrease in emissions from 2016 until 2020, where emissions are restricted to 1990 levels, and then a linear decrease in emissions until 2030, where the Clean Power Plan (CPP) target is enforced (32 percent reductions from 2005 levels, or equivalently, 11 percent reductions from 1990 levels). From 2031 until 2050, the cap has a linear decrease until 80 percent reductions from 1990 levels are achieved by 2050. Finally, the red line ("40 percent by 2030") corresponds to the same linear decrease in emissions from 2016 until 2020 where emissions are restricted to 1990 levels followed by a linear decrease until

16 http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

2030, when 40 percent of reductions are enforced according to SB 32,[17] simulating the case of this policy being expanded to the entire WECC. Then there is a linear decrease from 2030 to 2050, meeting the 80 percent reduction goal by 2050. The three scenarios will be referred to as "80 percent by 2050," "CPP," and "40 percent by 2030," respectively.

In addition to the constraints in Figure 5, the long and medium-term optimizations used operational constraints and current RPS in the WECC states. However, according to previous SWITCH-WECC results, these RPS constraints are not binding by 2030 because the carbon caps necessitate more than enough renewable deployment to satisfy RPS goals. Thus, RPS constraints are irrelevant but are kept in the study to be consistent with current policy.

The intuition behind the first step of the medium optimization is that it provides decisions that would be made until 2030 without knowledge of the more stringent policy that will be enforced in the long term. Therefore, they reflect the signals that are given to the investors of the power system and to the operators of the grid. On the other hand, the second step of the medium optimization faces the challenge of achieving the more stringent carbon caps from 2031 until 2050 having a grid already built by 2030 (from the first step) that did not consider in the expansion of future carbon caps. Therefore, the medium optimization seeks to mimic the way the power system would expand in WECC if near-term policies are imposed as policy makers have done so far. This study assumes that there will be stringent carbon cap policies in place by 2050, and whether they should be considered and planned for (long optimization) or not (medium optimization). Consequently, the research question studied was, how to plan and implement policy in the power system efficiently? From today until 2030 and then until 2050? Or plan from today until 2050?

3.2.4 Results and Analysis

3.2.4.1 Optimal Energy Mix for the Three Scenarios in the Long Optimization Case

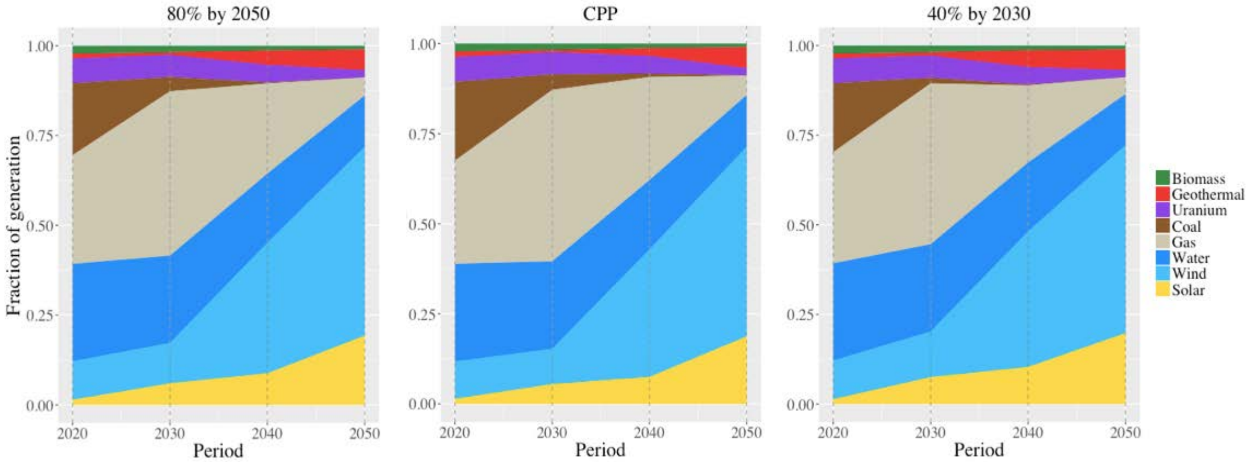
To understand the effects of medium-term planning, it is essential to first examine results from the long-run optimizations for each scenario (Figure 6). One can observe how, in all the scenarios, coal power plants are decommissioned progressively over the four periods. Each scenario presents a different transition rate for decommissioning and generating electricity from coal power plants. By 2030, the scenario that reduces coal power generation the most is "40 percent by 2030," with a 1.6 percent of participation of coal. The scenario "80 percent by 2050" follows with 4 percent and finally the "CPP" scenario with 4.4 percent of energy generated by coal.

From 2020 to 2030, all scenarios present an increase in energy generated by gas power plants. This increase in gas generation ranges from 45 percent by 2030 ("40 percent by 2030") to 48 percent ("CPP"). Another trend is the consistent increase in wind and solar power generation from 2020 until 2050. Nonetheless, solar and wind generation reach a more significant share only by 2050. By 2050, solar power energy ranges between 19 percent ("CPP") and 20 percent

17 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.

("40 percent by 2030"), and wind power ranges between 52 percent ("40 percent by 2030") and 53 percent ("CPP").

Figure 6: Energy Generation Share per Fuel and Period for Long-Term Optimization of Each Scenario



On the left side is the "80 percent by 2050" scenario, in the middle the "CPP," and on the right side the "40 percent by 2030."

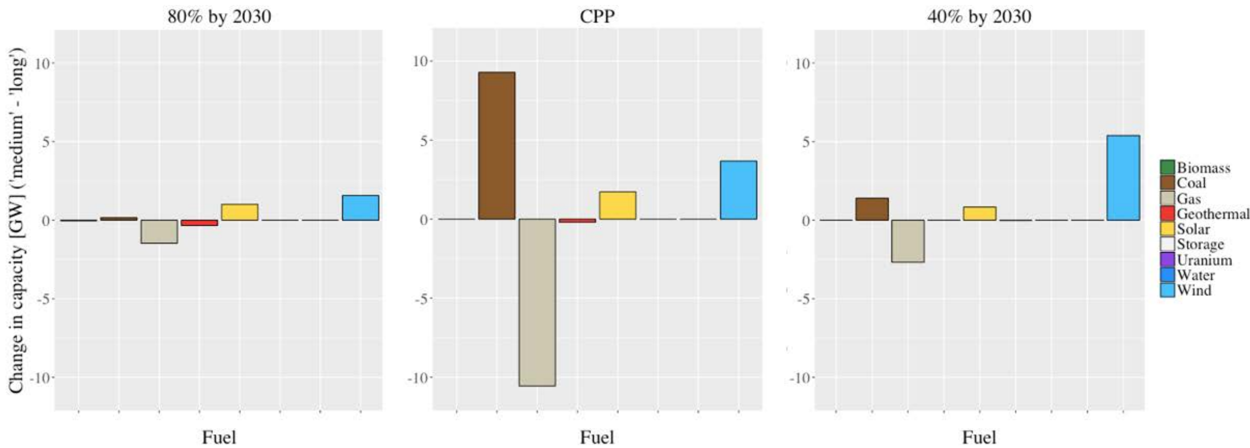
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.2.4.2 Comparing Optimal Capacity Installed in 2030 Between Medium and Long Optimization Scenarios

As depicted in Figure 7, all scenarios in the medium optimization use more carbon emission-intensive (ton CO_2/MWh) technologies at the expense of less use of cleaner technologies compared to the long optimization. In the medium optimization, "80 percent by 2050," "CPP," and "40 percent by 2030" scenarios show more coal and fewer gas power plants installed by 2030 compared to the capacity installed by 2030 in the long optimization case.

In the medium optimization cases because of the lack of early foresight regarding the more stringent carbon cap by 2050, coal power plants are decommissioned at a slower rate than in the long optimization. This results in a higher installed capacity of coal power plants in the medium optimization compared to the long optimization—a carbon lock-in. In addition, fewer gas power plants are deployed by 2030. Therefore, across all scenarios, the medium optimization does not optimally invest in cleaner technologies by 2030 as it would when facing a more stringent policy by 2050. Instead, it results in a carbon lock-in that the electric grid will have to overcome in a shorter time frame (20 years instead of 40 years).

Figure 7: Change in Capacity Installed in Gigawatts by 2030 per Fuel for Scenarios



The difference corresponds to capacity per fuel installed by 2030 in the medium optimization minus the capacity installed in 2030 in the long optimization for each case. On the left is the "80 percent by 2050" scenario, in the middle the "CPP" scenario (more coal and less gas are installed in the medium optimization), and on the right side the "40 percent by 2030" scenario.

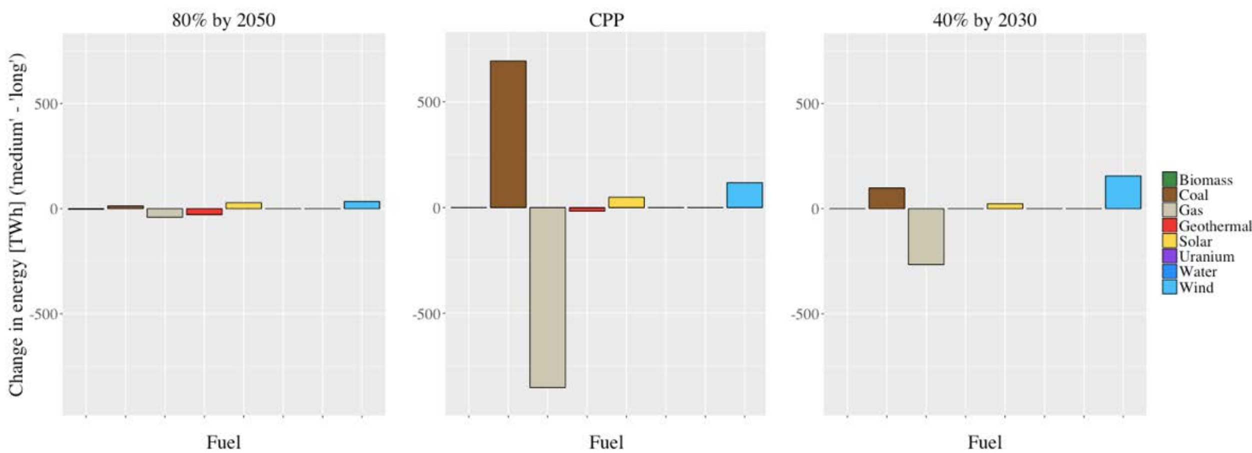
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

The scenario that shows the greatest difference in gigawatts installed of coal and gas power plants between the medium and long optimization is "CPP." In the medium optimization, the installed capacity of coal exceeds the capacity installed in the long optimization by 9.3 gigawatts (GW). In the case of the installed capacity of gas power plants, the medium optimization installs 11 GW less than the long optimization. In the other two scenarios, the difference in capacity installed by the medium optimization compared to the long optimization is 5 GW or less for all fuels. Another interesting trend across all scenarios is that wind and solar power are used more in the medium optimization.

3.2.4.3 Comparing Optimal Energy Generation by 2030 Between the Medium and Long Optimization Scenarios

As expected, the difference between the energy generated in the medium and long optimizations follows the same pattern as the capacity installed. Figure 8 shows the difference between the medium and long optimizations in terawatt-hours.

Figure 8: Change in Energy Generated in Terawatt-Hour per Fuel During 2030 for the Scenarios



The difference corresponds to the generation per fuel by 2030 in the medium optimization minus the generation in 2030 in the long optimization. On the left is the "80 percent by 2050" scenario, in the middle the "CPP" scenario (more coal and less gas are used in the medium optimization), and on the right side the "40 percent by 2030" scenario.

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

In all scenarios in 2030, the medium optimization generates more electricity from coal plants than in the long optimization. The additional energy produced by coal plants in the medium optimization compared to the long optimization varies from 13 terrawatt hours (TWh) ("80 percent by 2050") to 690 TWh ("CPP"). The general trend of substituting power plants fueled by gas with coal power plants holds true in the case of energy generation. For the "CPP" and "80 percent by 2050" scenarios, this trend can be observed as a straightforward substitution of gas generation for coal generation.

The "CPP" scenario shows the greatest difference in generation across all scenarios. In the medium optimization, it produces 690 TWh more of energy from coal plants compared to the long optimization, while it is short by 850 TWh of energy produced from gas power plants. To put this in perspective, 690 TWh corresponds to roughly 7.4 percent of the total load in the 2030 period.

Substituting gas in favor of coal for the "CPP" scenario can be explained that "CPP" does not have a stringent carbon cap by 2030; therefore, the medium optimization does not transition from more carbon-intensive technologies to cleaner ones by 2030. However, the long optimization considers the stringent carbon cap by 2050; and by 2030, it already decommissioned coal to efficiently reach the 2050 target.

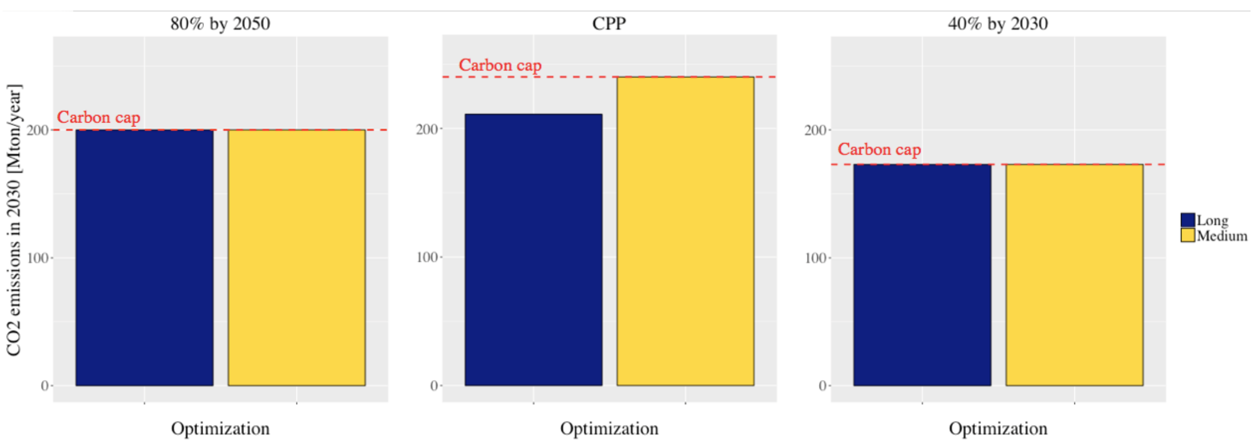
3.2.4.4 Comparing Optimal Emissions by 2030 between Medium and Long Optimization

The explanation behind the carbon lock-in in the medium optimizations for "CPP" lies in the optimal CO_2 emissions by 2030. Emissions in 2030 for all the scenarios for the medium (in yellow) and long (in blue) optimizations are shown in Figure 9. The red dashed lines correspond to the carbon cap for each scenario in 2030. The medium optimization does not have early foresight (as opposed to the case of the long one) of the more stringent carbon caps it will have to face after 2030. Therefore, it is best to emit as much carbon as the 2030 cap allows when yellow bars are at the same height as the carbon cap. This is because carbon-intensive technologies are, generally speaking, cheaper to use.

For the "CPP" case, the long optimization emitted less carbon (blue bar) in 2030 than the carbon cap since the long optimization has perfect foresight in the 2030 period about the more stringent carbon caps targets in 2050 (80 percent reductions from 1990). Therefore, in the long optimization, it is cost-effective to start using cleaner energy as early as 2030 to optimally reach the stricter goal by 2050. This is why emissions are below the carbon cap in 2030 (inactive constraint) and shows the importance of optimizing the power system in the long term when medium-term policies are weak. (CPP is weak compared to an 80 percent reduction of emissions.)

For the medium optimization for "CPP," due to its lack of foresight of the more stringent carbon cap in 2050, it emits CO_2 at the maximum allowed in 2030. This weaker policy by 2030 in the first step of the medium optimization results in decommission of carbon-intensive technologies at a slower rate.

Figure 9: Carbon Dioxide Emissions in 2030 for Medium (yellow) and Long Optimization (blue)



The red dashed line represents the carbon cap for 2030 for each scenario. On the left side is the "80 percent by 2050" scenario, in the middle the "CPP" scenario, and on the right side the "40 percent by 2030" scenario.

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

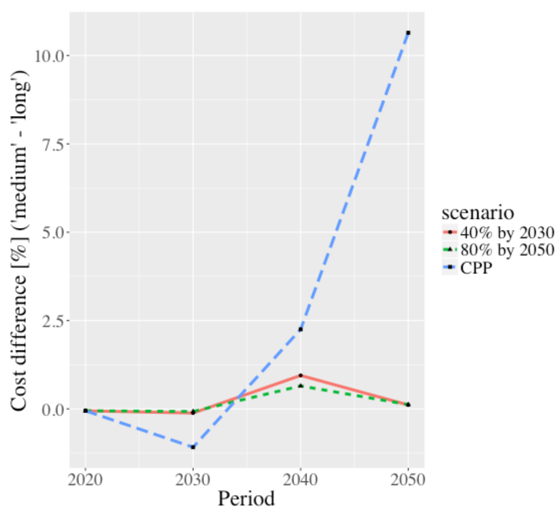
For the scenarios "80 percent by 2050" and "40 percent by 2030," optimal carbon emissions in 2030 for the long optimizations are equal to the respective carbon caps and result in the carbon cap constraints being active for all periods. This suggests that the carbon caps in 2030 for "80 percent by 2050" and "40 percent by 2030" are well-aligned with the ultimate carbon cap in 2050. Therefore, these two scenarios show that stronger medium-term policies yield to an expansion of the power grid closer to the optimal expansion resulting from optimizing in the long term.

In practice, one way to cope with the lack of foresight of optimizing in the medium term would be to enforce more stringent electricity policies for 2030. For example, in the case of the "CPP" scenario, regulators would need to force 26 percent carbon emissions reductions from 1990 levels by 2030 (which corresponds to the optimal reductions achieved in the long optimization), as opposed to the current 11 percent reductions from 1990 proposed by the Clean Power Plan. This more stringent carbon cap by 2030 would entail a smoother and cheaper transition to meet the 80 percent reduction by 2050.

3.2.4.6 Cost Analysis

Figure 10 shows the increase in cost per period from using the medium optimization instead of the long optimization. There are minor to no savings in 2020 and 2030 from using the medium optimization. Thus, there is no economic benefit of having weaker policies by 2030. However, expanding and operating the power system from the medium optimization in 2040 and 2050 are more expensive than the cost incurred by the long optimization in those periods. The most extreme case is for the “CPP” scenario, where the total cost of expanding and operating the grid in 2050 is 11 percent more expensive than for the long optimization. This suboptimality is due to the more abrupt transition to clean energy that has to take place in the last two periods. In the other two scenarios, the increase in cost was small. Nonetheless, this minor increase in cost in 2040 and 2050 reflects the fact that more coal was deployed in 2030 instead of gas compared to the long optimization. Therefore, these two scenarios also had to adjust their grid in the last two periods but in a lesser extent compared to “CPP.” Thus, the medium-term carbon policies of these scenarios were strong enough to allow a closer-to-optimal transition to meet the strongest carbon cap policy by 2050.

Figure 10: Increase in Cost per Period from Using the Medium Optimization



The red solid line represents cost increases from “40 percent by 2030” scenario, the short dashed green line corresponds to “80 percent by 2050,” and the long dashed blue line represents “CPP” scenario.

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.3 Long-Term Power System Planning in Western North America: Deterministic Scenarios

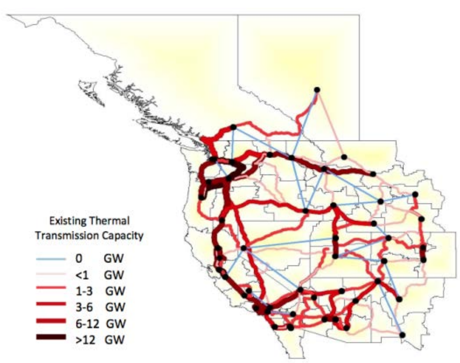
3.3.1 Model Description

As before, the optimization horizon was divided into four investment periods of 10 years: 2016-2025 ("2020"), 2026-2025 ("2030"), 2036-2045 ("2040"), and 2046-2055 ("2050"). Each period simulates 144 hours of dispatch in this case. For one year per period, the team sampled every month, two days per month (median and peak load days) and every four hours per day (12 months times two days/month times 6 hour/day = 144 hours). A full month is represented by one peak day and n-1 median days, where n is the number of days of that month.

The transmission system was obtained from Ventyx geolocated transmission line data (2012) and used thermal limit data from the Federal Energy Regulatory Commission (FERC). In total, there are 105 existing transmission lines connecting load zones in SWITCH (Figure 11). SWITCH can decide to build more transmission lines if it is optimal. Derating of lines and transmission losses was also considered.

Electricity demand profiles come from historical hourly loads from 2006 (FERC, Platts and ITRON). These profiles were updated to current projections described in Section 3.3.2. Hourly existing wind farm power output is derived from the 3TIER Western Wind and Solar Integration Study (WWSIS) wind speed dataset (3TIER 2010; GE Energy 2010) using idealized turbine power output curves on interpolated wind speed values. A proportion of possible Category 3 wind sites were removed from California based on Wu et al. 2015. Category 3 encompasses areas that are legally excluded for energy deployment, protected ecological areas and areas of social value, and conservation areas. For solar energy, hourly capacity factors of each project throughout 2006 were simulated using the System Advisor Model from the National Renewable Energy Laboratory (National Renewable Energy Laboratory 2013a).

Figure 11: Simplified Existing Transmission Lines Between Load Zones



In light blue are nonexisting lines, but they can be installed in the optimization. Each black dot represents the largest substation in the load zone.[18]

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

18 http://rael.berkeley.edu/old_drupal/sites/default/files/SWITCH-WECC_Documentation_October_2013.pdf.

All current (2017) Renewables Portfolio Standards were modeled for each load zone in the WECC as unbundled renewable energy certificates (RECs). A WECC-wide carbon cap was modeled to achieve the 80 percent emissions reductions from 1990 levels by 2050. Moreover, a California carbon cap was modeled to attain 40 percent emissions reductions by 2030 and a linear decrease to achieve 80 percent reductions by 2050.

Fuel prices projections were obtained from the United States Environmental Information Agency (U.S. EIA) (2017). Biomass supply data were obtained from multiple sources (De La Torre Ugarte 2000, University of Tennessee 2007, Parker 2011, Milbrandt 2005, Kumarappan 2009). Capital costs and operation and maintenance costs were obtained from Black and Veatch (2012) and Energy and Environmental Economics (E3, 2016). The current pool of existing power plants in the WECC was also obtained from EIA (EIA-860, EIA-923, 2016 data). Hydropower historical generation was also obtained from EIA-923 data.

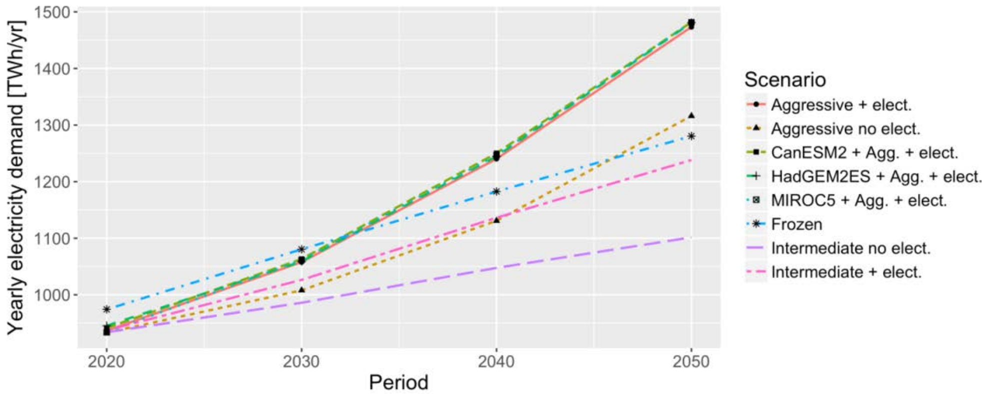
3.3.2 Description of Scenarios

3.3.2.1 Electricity Demand Scenarios and Climate Change Scenarios

Eight demand scenarios were modeled for this study. The frozen, intermediate energy efficiency with and without electrification (SB350), and aggressive energy efficiency with and without electricity cases are described in Chapter 2. Figures 12 and 13 show total annual demands for the WECC and California in the periods simulated with the Python SWITCH-WECC model. In addition to these five load scenarios, the team also modeled three load projections from climate change models. The climate models used were CanESM2, HadGEM2ES, and MIROC5. Industrial Economics and the U.S. Environmental Protection Agency (EPA) provided heating degree days (HDD) and cooling degree days (CDD) projections with a spatial resolution of 5,163 ½-degree grids for the United States for all years until 2100 (Pierce et al. 2014). Using these data, HDD/CDD projections for the SWITCH load zones until 2100 were calculated. The National Renewable Energy Laboratory provided 135 linear regression models to predict hourly changes in load using as input HDD/CDD, hour of the day, and season of the year (Sullivan et al. 2015). The linear regression models predicted hourly load changes for the NREL Regional Energy Deployment System (ReEDS) balancing areas. The research team translated its prediction models into equivalent models for the SWITCH-WECC load zones. Finally, the hourly load predictions were postprocessed so they would be aligned with the predictions for California from the University of California, Irvine.

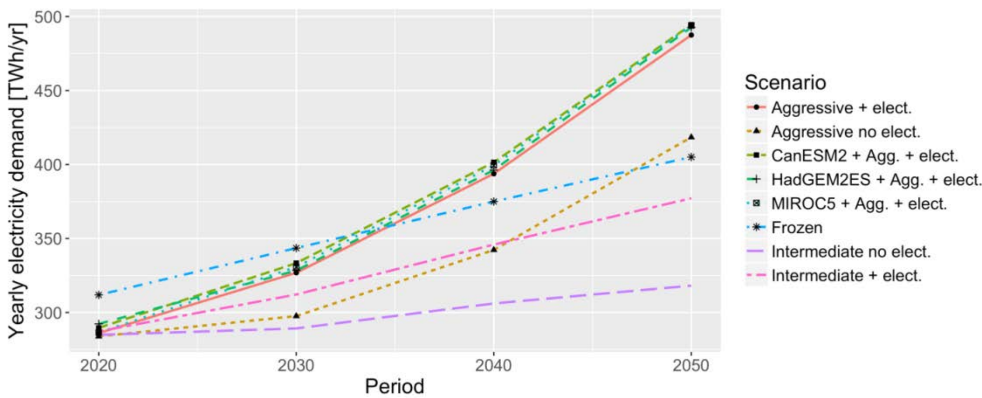
For the climate change scenarios, in addition to new hourly load projections, the team also included monthly hydropower availability projections until 2050 from Industrial Economics. The spatial resolution of these hydropower projections matched the 135 ReEDS balancing areas. The research team mapped these projections to each hydropower plant in the WECC.

Figure 12: Electricity Demand Scenarios for Western Electricity Coordinating Council



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 13: Electricity Demand Scenarios for California



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.3.2.2 Electrical Vehicles and Demand Response: Aggressive Efficiency with Electrification

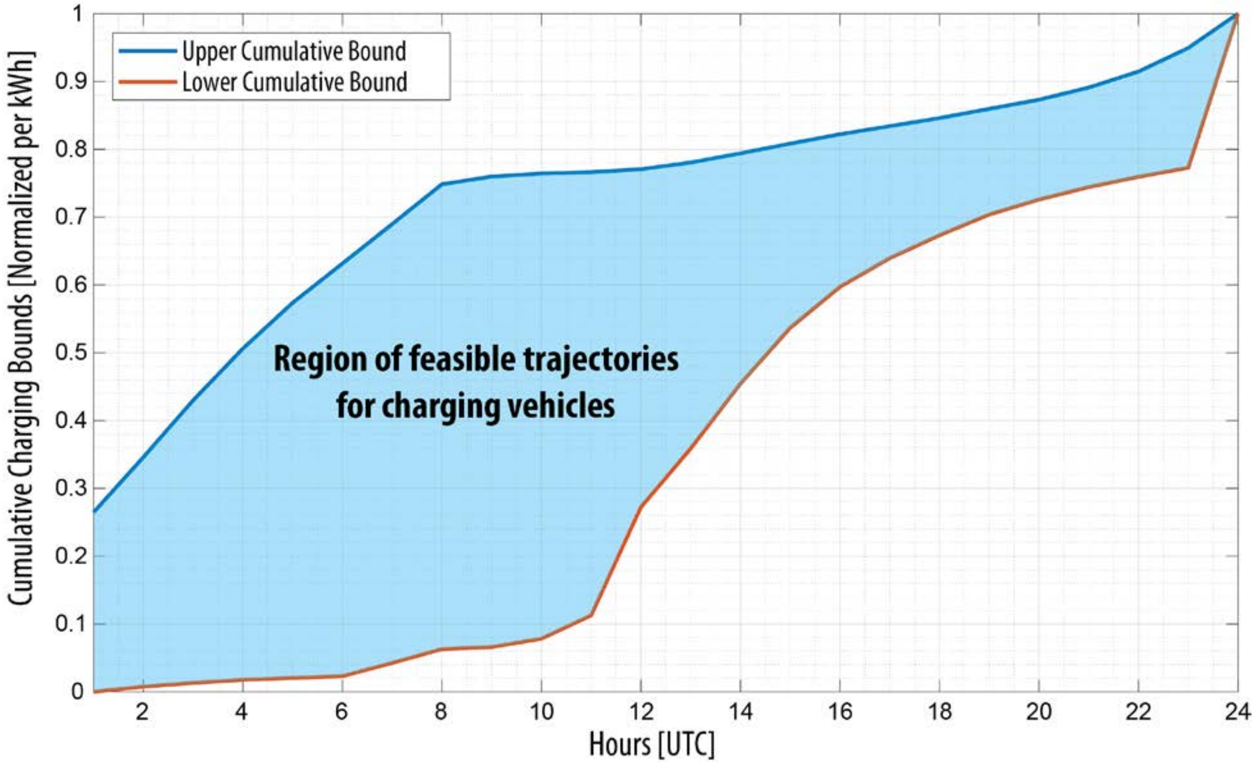
In this study, the impacts of smart charging of light-duty electric vehicles (LDVs) are analyzed in SWITCH. In particular, the differences in investment portfolios and dispatch decisions are highlighted here when the flexible charging of LDVs is available to system operators or system resource aggregators at no cost.

For this purpose, the trajectory of charging is found to be constrained between two bounds, determined by the BEAM model, detailed in Sheppard et al, 2017, that will depend on vehicle adoption, vehicle performance parameters, users' characteristics, and charging profiles. The BEAM Model simulates the mobility and charging behavior for a representative day in a week for three types of charging stations: public, residential and work. Each of these vehicles will have particular charging constraints that depends on users' availability to charge.

Based on those charging sessions, aggregated profiles (calculated as the addition of the vehicles) are created for defining energy bounds for the cumulative charge of vehicles. Figure 14 presents the aggregated profiles, normalized per kWh, that generates the region of feasible trajectories for the charging of PEVs used on the SWITCH model across a 24-hour day.

Figure 14: Average Bounds on Cumulative Charging Trajectories

Source: Lawrence Berkeley National Laboratory



In Appendix B, Table B-1 provides the estimation of energy use for EVs, based on growth projection on expected sales of EVs and average expected use, in particular miles traveled per year and efficiency of the batteries in kWh per mile. These energy requirements will be enforced in SWITCH through scaling the normalized charging profile, depending on each zone and year.

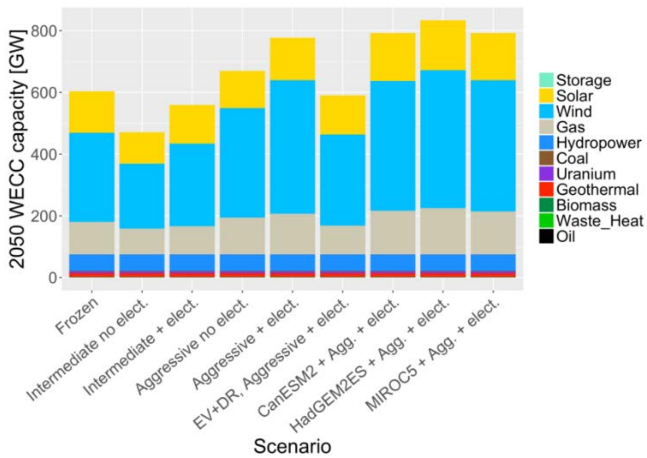
In addition, the load-shifting service of demand response (DR) at no cost is available with this scenario. In this case study, the research team is interested in assessing the value of DR for homes and businesses. When DR is being considered, the amount of load that can be shifted per hour is limited to a specified amount of energy. This amount of energy will depend on the specific flexibility at each load zone and period. The percentages of available load shifting are shown in Appendix B, Table B-2. Throughout the day, the total load shifted between hours must sum to zero to ensure that the total demand is maintained even if the DR is available or not.

3.3.3 Results and Analysis

3.3.3.1 Installed Capacity by 2050 in the Western Electricity Coordinating Council and California

Figures 15 and 16 show installed capacity by fuel in the WECC and California, respectively. As expected, the capacity required in the WECC by 2050 increased as the electricity demand increased for each scenario. Specific numbers for installed capacity are in Tables B-3 and B-4 in Appendix B. In all scenarios, wind power is the dominant technology. The greatest wind share was 56 percent in the Aggressive Efficiency with Electrification case, and the smallest was 45 percent in the Intermediate Efficiency (SB 350) scenario. The second most used technology in the WECC by 2050 was solar power, with the technology share ranging between 22 percent (frozen and intermediate efficiency scenarios) and 18 percent (aggressive efficiency without climate change scenarios). Gas power comes in third with capacity installed by 2050, with the associated use ranging between 16 percent and 18 percent. The capacity of hydropower ranges from 6 to 11 percent. There is less than 3 percent of installed capacity for geothermal, nuclear energy, and biomass.

Figure 15: Installed Capacity in the Western Electricity Coordinating Council by 2050 for All Scenarios



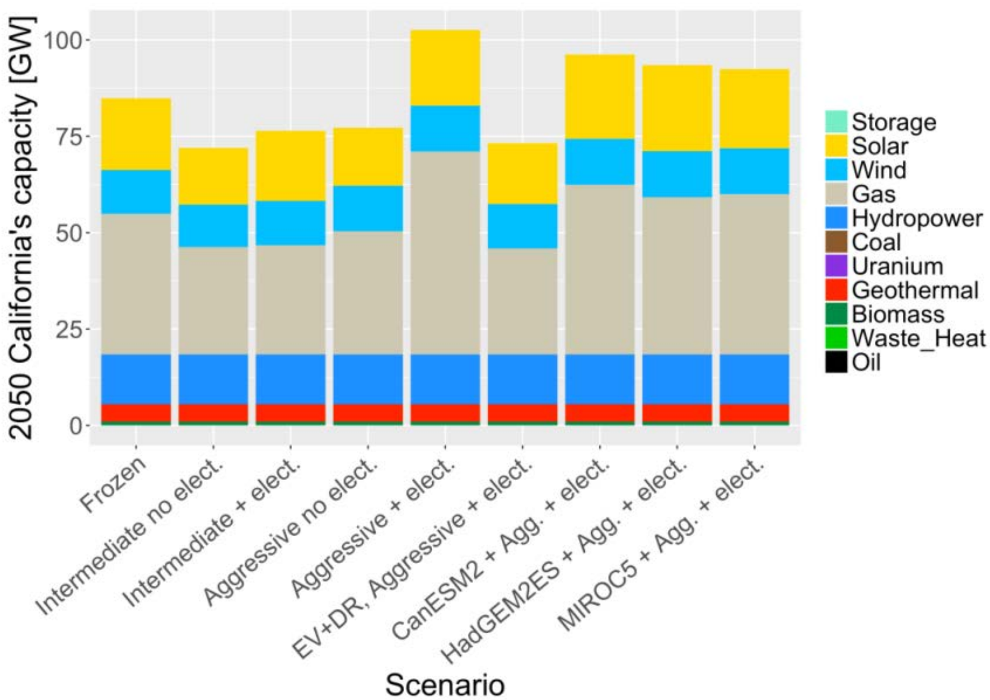
Source: Max Wei, Shuba V. Raghavan, Patricia Hidalgo-González, LBNL

In the climate change scenarios, the total capacity installed in the WECC is 2 percent to 7 percent higher than in the non-climate-change counterpart (aggressive efficiency and electrification). Load and hydropower availability projections from HadGEM2ES presented the highest stress for the power grid (7 percent higher total capacity).

California observed a similar trend as in the WECC for total installed capacity by 2050. As expected, the total capacity increased along with total load in the different scenarios. For specific numbers, refer to Tables B-5 and B-6 in Appendix B. Gas power is the predominant technology for California in 2050, with the associated share of capacity ranging from 51 percent to 38 percent in the aggressive efficiency and electrification scenario and in the EV and DR scenario, respectively. The next technology that follows gas power is solar energy. Solar power ranged between 24 percent and 19 percent. The climate change scenario from HadGEM2ES and the intermediate efficiency and electrification showed a 24 percent share of solar power. The next technology used the most in California is hydropower. The installed capacity of hydropower ranges between 13 percent and 18 percent, depending on the scenario, then wind power, with 1 percent or 2 percent lower fraction compared to hydropower. The smaller participation of wind power in California compared to the WECC can be explained by the land exclusion applied to the deployment of wind farms (refer to Wu et al. 2015).

An interesting result in California is from the climate change scenarios. The total capacity installed by 2050 for the three scenarios using climate change was lower than the non-climate-change counterpart (aggressive efficiency and electrification). The total capacity in the climate change scenarios is 6 percent to 10 percent lower than the capacity installed in the aggressive efficiency and electrification scenario. This result is counterintuitive because of the higher annual load that California faces under climate change. Transmission line expansion between California and the rest of the WECC explains this result. Thus, the modeling finds investing more in transmission between California and the rest of the WECC minimizes costs when considering climate change impacts.

Figure 16: Installed Capacity in California by 2050 for All Scenarios



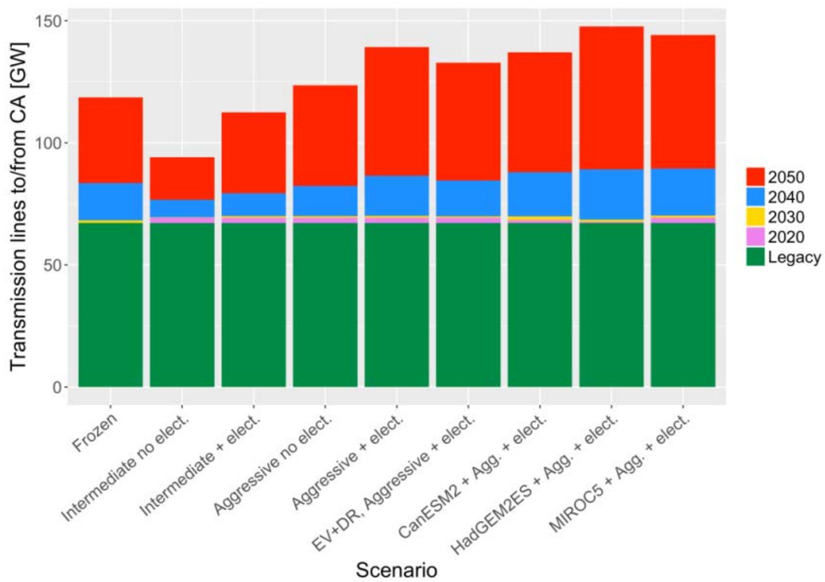
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.3.3.2 Installed Transmission by Periods in the Western Electricity Coordinating Council and California

In Figure 17, the team observed that two of the climate change scenarios expanded the transmission system between California and the rest of the WECC more than in the non-climate-change scenario (aggressive efficiency and electrification). For HadGEM2ES, there was 6 percent more transmission capacity used in 2050 between California and the WECC compared to the non-climate-change scenario. In the MIROC5, scenario there was 4 percent more transmission capacity installed. For further reference, Table B-7 in the appendix shows total transmission capacity for each scenario. This increase in transmission capacity between California and the rest of the WECC is optimal compared to increasing California's generation capacity.

Another interesting finding is that to meet the strict carbon cap goals and higher load by 2050, transmission lines must be expanded more aggressively in 2050 compared to the other periods simulated. Between 18 percent and 40 percent of the total transmission lines capacity is built in the 2050 time frame, depending on the scenario.

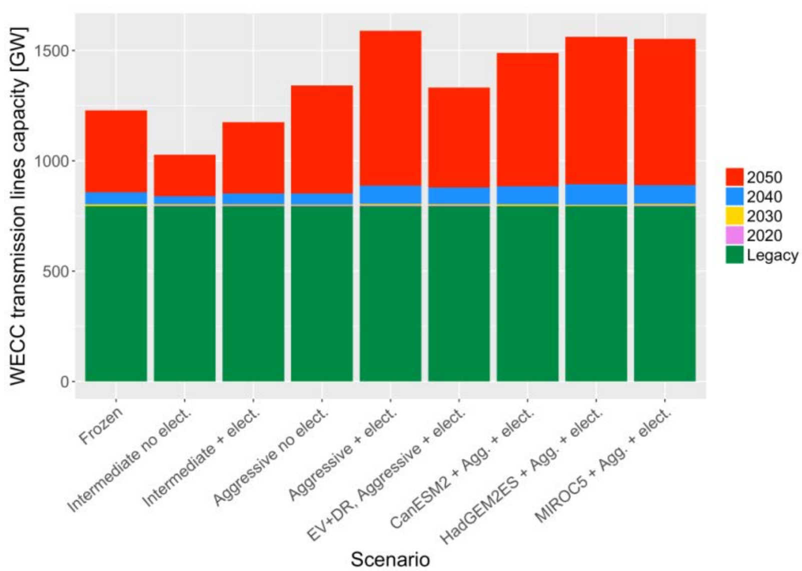
Figure 17: Existing and New Transmission Lines Capacity for All Periods and All Scenarios Between California and the Rest of the Western Electricity Coordinating Council



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 18 shows the expansion in transmission capacity in the WECC by period for each scenario. There is a proportional relationship between the scenarios with more annual load and more transmission capacity being expanded. Between 18 percent and 44 percent of the total transmission capacity installed by the end of the simulation is expanded in the last period (2050), depending on the scenario. See Appendix B for more details.

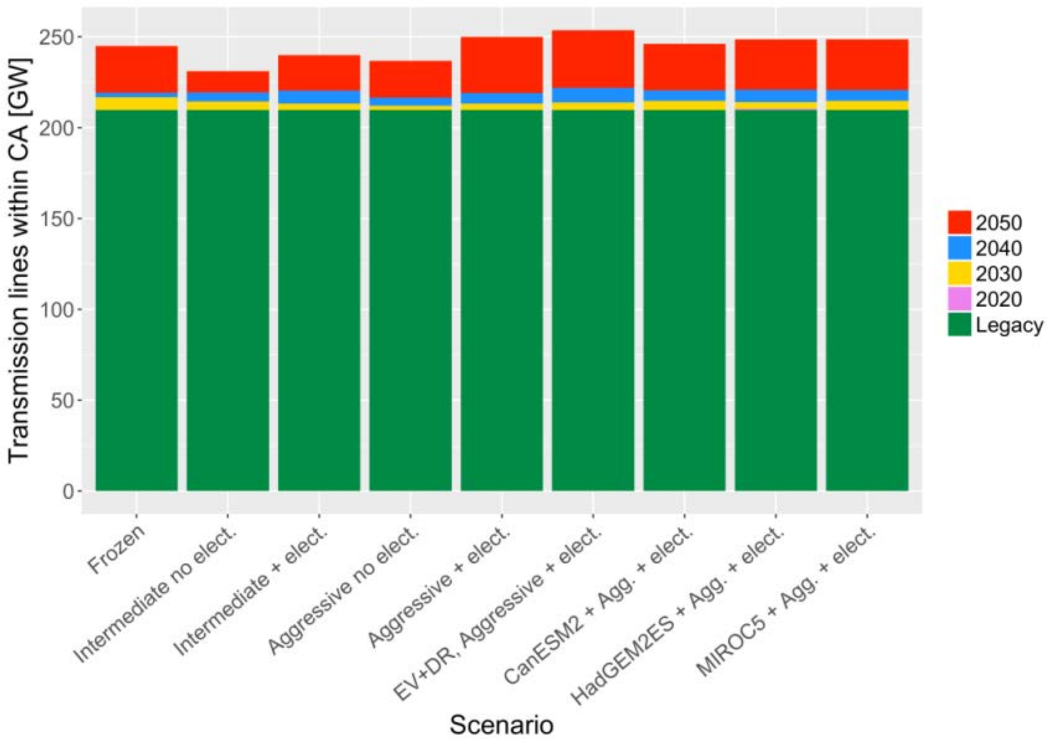
Figure 18: Existing and New Transmission Lines Capacity for All Periods in the Western Electricity Coordinating Council for All Scenarios



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 19 shows transmission capacity expansion within California by period for all scenarios. Most of the transmission capacity is already in place in the system. In 2050, California's transmission system gets expanded by between 5 percent and 12 percent of the cumulative installed capacity at the end of the simulation.

Figure 19: Existing and New Transmission Lines Capacity for All Periods and All Scenarios Between Load Zones in California

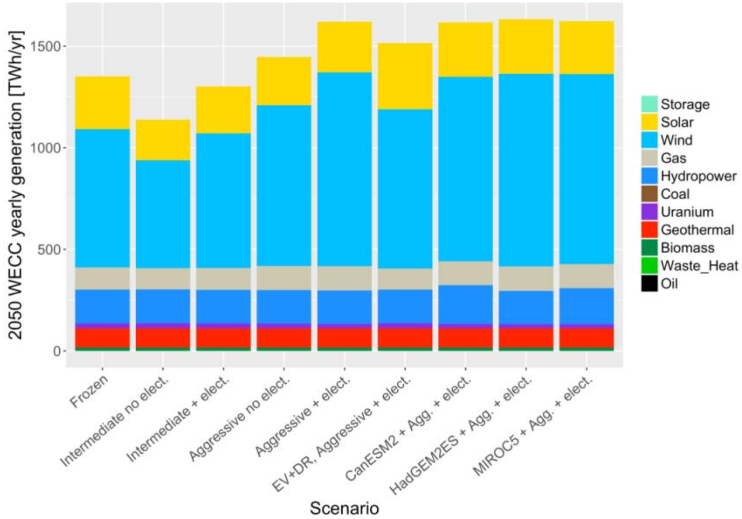


Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.3.3.4 Yearly Generation by 2050 in the Western Electricity Coordinating Council and California

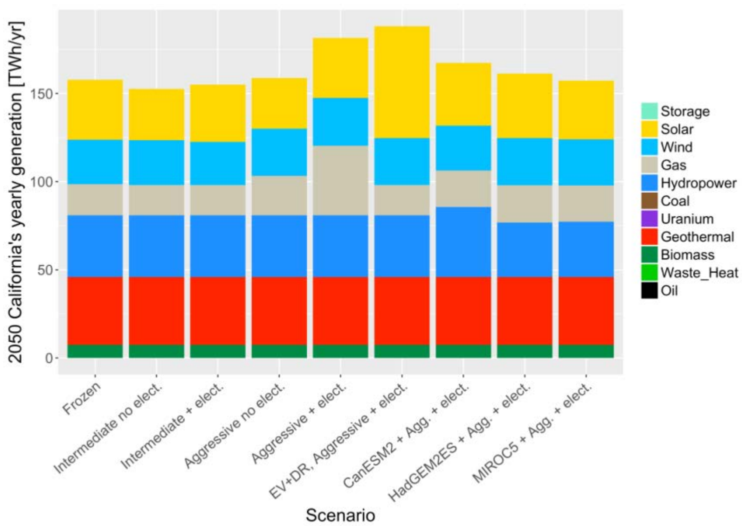
Figures 20 and 21 show yearly electricity generation in 2050 for the WECC and California, respectively. Most of the energy generated in 2050 in the WECC comes from wind power. Wind generation constitutes between 47 percent and 59 percent of the energy mix by 2050, depending on the scenario. The scenarios that show the highest participation of wind generation are the aggressive efficiency and electrification scenario (59 percent) and the climate change scenarios (56 percent-58 percent). Solar generation is the next most prevalent supply source, generating between 15 percent and 21 percent. Because the EV demand can better use the solar PV peak output, the electrical vehicles and demand response scenario deploys solar energy the most (21 percent) compared to the other scenarios. Generation from hydropower ranges between 10 percent and 15 percent. Gas power generation varies between 7 percent and 9 percent. The scenarios that show the lowest gas share (7 percent) are the aggressive efficiency and electrification, electrical vehicles and demand response, and the climate change scenarios.

Figure 20: Yearly Generation in the Western Electricity Coordinating Council by 2050 For All Scenarios



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 21: Yearly Generation in California by 2050 for All Scenarios



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

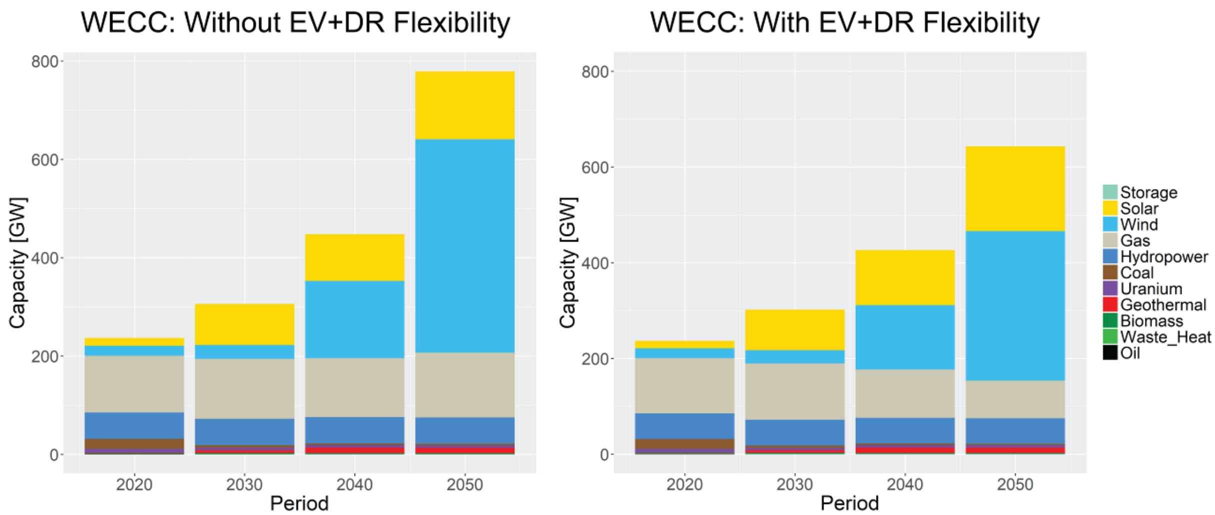
In the case of California, geothermal, hydropower, and solar power generate the most energy for all scenarios in 2050 (between 59 percent and 73 percent). Wind power comes next, with a generation share ranging between 14 percent and 17 percent. Generation from gas power plants is restricted to between 9 percent and 14 percent, except for the aggressive efficiency and electrification, where the share is 22 percent. As expected, the electrical vehicles and demand response scenario show the least generation from gas (9 percent) and greatest from solar generation (34 percent) because the flexibility provided by EV and DR can replace the flexibility that gas peaker plants provide.

In the climate change scenarios, less total energy is generated in-state compared to the analogous scenario without climate change. This result corroborates the importance of the transmission system between California and the rest of the WECC to minimize total costs to operate the grid under climate change.

3.3.3.5 Electrical Vehicles and Demand Response: Aggressive Efficiency With Electrification

Runs using SWITCH shows significant differences in installed capacity when the flexibility of EV and DR is considered in the model. Figure 22 depicts the installed capacity in WECC by technology through periods 2020 to 2050.

Figure 22: Installed Capacity in the Western Electricity Coordinating Council System Without and With Flexibility of Electric Vehicles and Demand Response

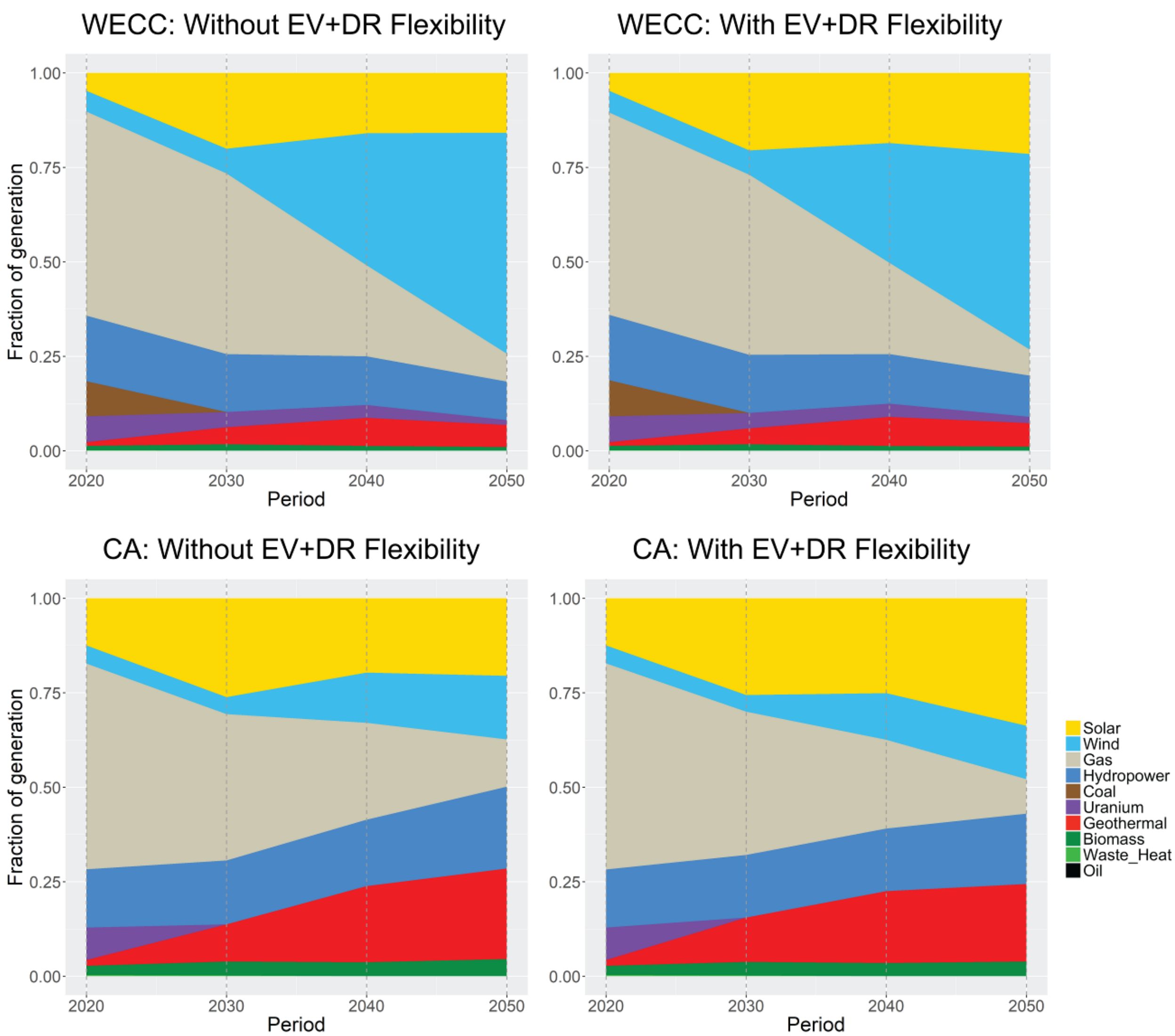


Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

The total installed capacity in 2050 is reduced by more than 100 GW while increasing the proportion of solar energy in the system. This reduction occurs because the flexibility of EVs and DR is used to reduce the peak of the system and, hence, reduces the necessity of capacity in peak hours, while shifting load and charging vehicles to sunny hours, and so uses the solar resource more efficiently. This effect is also noticed in the dispatched energy in the region as observed in Figure 23.

With this flexibility, solar energy can be used more efficiently, particularly in California, where the flexibility of EV and DR is higher than in other states, allowing the percentage of solar energy use to increase by 12 percent. Results show that this flexibility yields savings around 5.2 percent of the total investment and operational costs through 2020 to 2050. However, these results implicitly assume that smart charging and DR are costless to dispatch and procure, and demand shifting is achieved by the system planner, operator, or third-party service provider.

Figure 23: Fraction of Generation in Western Electricity Coordinating Council and California Systems Without/With Flexibility of Electric Vehicles and Demand Response



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.4 Stochastic Optimization Under Climate Change Uncertainty

3.4.1 Introduction

Expanding the capacity of a power system and operating it cost-effectively are complex. On one hand, power plants have lifetimes ranging from 20 years to more than 50 years. On the other hand, transmission lines can be used for more than 100 years. Deciding the mix of power plant technologies and transmission lines to build, the associated capacity, location, and year to start building can be convoluted. In addition, this complexity relies on the long lifetimes of the components of the system and the related high capital costs. This challenge becomes a high financial burden if decisions are not made optimally. Moreover, if adding the operational layer to the capacity expansion problem, the complexity grows because the size of the optimization increases from making yearly decisions (expansion of capacity) to hourly decisions (operation of the power system).

Besides this complexity, there is the uncertainty in the parameters used as inputs during the entire time horizon modeled that makes it even more challenging to find an ideal solution. For example, how capital costs will vary over the years for each technology, how fuel costs will fluctuate, what will be the hourly electricity demand, the variability of hourly capacity factors for wind and solar power plants, hydropower seasonal and annual variability are all uncertain parameters. In most power system capacity expansion studies, the method used to address these uncertainties is to analyze different possible scenarios. To generate data for different types of analyses, there is research that focuses on demand and supply inputs, such as forecasting demand, and future solar and wind capacity factors.

Lastly, climate change adds another dimension of complexity in the forecast of climate-driven parameters. Electricity demand and hydrology are the main parameters in power system modeling that could be affected by climate change. There has been an ongoing effort in trying to predict demand and hydrology under different climate models and RCPs. Several climate change models exist. However, the scientific community has not been able to determine which climate model will predict more accurately changes in temperature, precipitation and snowfall. The impacts on these variables vary widely depending on the climate model.

Consequently, to study the best expansion of a power system considering the uncertainty on impacts from climate change, a scenario-based approach will shed light only on independent possible routes of capacity expansion. Each set of inputs projected from a climate change model would produce an independent possible capacity expansion. Although this type of approach can provide useful information in discovering how the system should expand and operate for each of the different load and hydrological projections, it falls short in providing a definitive answer for policy makers, regulators, and investors. A firm approach would provide an ideal and unique capacity expansion despite the uncertainty around future climate change and hydrology by using as input different load and hydrological projections from different climate models. These possible scenarios (each with an associated probability) would optimize the buildout of the power system for all the scenarios, so operating the system would be feasible, and the expected value of the total cost (investment and operation) would be minimized. This would be an ideal buildout of power plants and transmission lines for all the years of the simulation, and the capacity expansion would be resilient since it was calculated by considering different possible scenarios. This approach, thus, uses a set of possible climate change predictions.

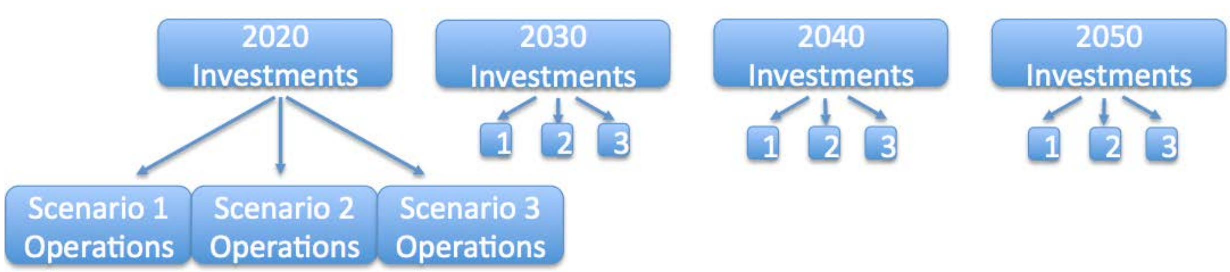
A stochastic optimization approach that efficiently models the durable approach to power system capacity expansion under uncertainty is the multistage optimization (Conejo et al. 2016), described in Section 3.4.2. Recently, there have been two power systems models of the WECC that, to some extent, incorporate uncertainty in the framework of stochastic programming. The Pacific Northwest National Laboratory developed a model (Makarov et al. 2016) in 2015 that simulates operation (not investment) in a probabilistic manner for 38 load zones in the WECC. This model considers load, wind, and solar forecast errors (not from climate change), and generation outages. The Johns Hopkins University developed the JHSMINE model for the WECC in 2016 (Ho et al. 2016). The JHSMINE makes investment decisions for transmission and generation in addition to operational constraints (similar to SWITCH). However, the planning horizon is until 2024 (opposed to 2050 for SWITCH). JHSMINE considers different scenarios for fuel prices, load growth, technology and policies but does not consider uncertainty from climate change.

The novelty and contribution of this work are the first stochastic long-term (2050) capacity expansion and operations model of the WECC with a high temporal (hourly) and spatial resolution (50 load zones and ~8,000 possible power plants to decide to install) and that consider uncertainty in hourly loads and hydropower availability due to climate change. The stochastic SWITCH-WECC model can consider uncertainty in any of the inputs (loads, capacity factors, fuel costs, capital costs, hydropower availability, transmission costs, and policies). For this study, the focus was on modeling the uncertainty from climate change, thus including uncertainty from hourly loads and hydropower availability for each month and year of the simulation period.

3.4.2 Model Description: Stochastic SWITCH-WECC

The mathematical formula used was a two-stage optimization. The team modeled three climate change scenarios: CanESM2ES, HadGEM2ES and MIROC5. Each scenario was assumed to have the same probability (1/3). The SWITCH model has two types of decision variables: investment and operation. In the two-stage formula, the investment decisions are the first-stage variables, and the operation decisions are the second-stage variables. In other words, investment decisions for all periods will be the same for the three scenarios (i.e., resilient investment decisions), and operation decisions will be specific to each climate change scenario. The objective function is the expected value of the total net present value of the three scenarios. In other words, there is only one objective function for the simulation with three climate change scenarios. Figure 24 depicts a schematic of decision variables and how they relate to each scenario.

Figure 24: Decision Variables for Stochastic SWITCH-WECC



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

For this study, the research team developed Stochastic SWITCH-WECC and made this software open source. The value for policy makers of this modeling approach is that a unique optimal capacity expansion portfolio is obtained as an output with an input of three possible climate change scenarios. Thus, a climate change-resilient capacity expansion is found with this two-stage stochastic optimization approach.

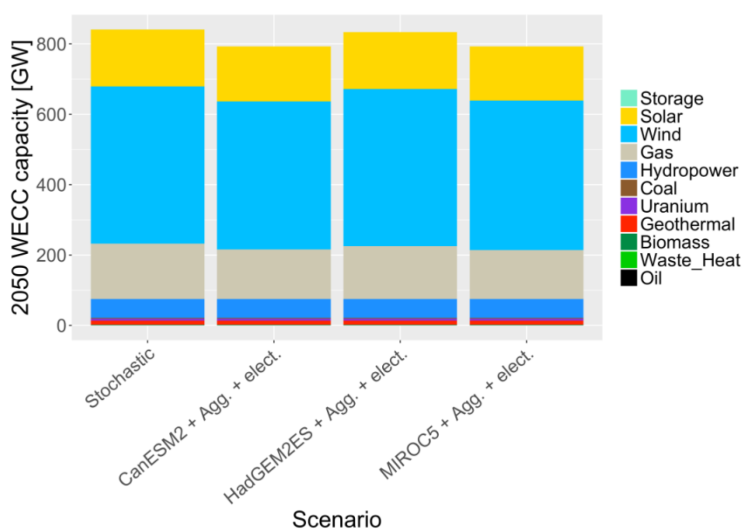
3.4.3 Results and Analysis

3.4.3.1 Installed Capacity by 2050 in the Western Electricity Coordinating Council and California

Figures 25 and 26 show the ideal capacity expansion for 2050 in the WECC and California, respectively. The first notable finding is the optimal capacity installed in the WECC by 2050 in the "Stochastic" or climate change-resilient simulation is higher than in the rest of the deterministic climate scenarios. By 2050, 840 GW were installed in the "Stochastic" simulation, and in the climate change scenarios, the total capacity ranged between 790 GW and 830 GW. This result is expected because the "Stochastic" simulation has to invest in enough capacity by 2050 to provide feasible and most favorable dispatch decisions for each of the climate change scenarios.

Another interesting finding is that the relative share in capacity of gas power plants by about 6 percent (from to 18 percent of capacity in the deterministic cases to 19 percent in the "Stochastic" formulation). This result can be explained due to the model looking at three dispatch scenarios instead of one (deterministic case). With three times the number of constraints (dispatch equal or greater than load for all hours), the modeled system will have a greater demand for flexibility, which can be provided by natural gas power plants. Total installed capacity by 2050 of wind and solar power decreases by 1 percent in the "Stochastic" formulation.

Figure 25: Installed Capacity in the Western Electricity Coordinating Council by 2050 for Deterministic and Stochastic Climate Change Scenarios

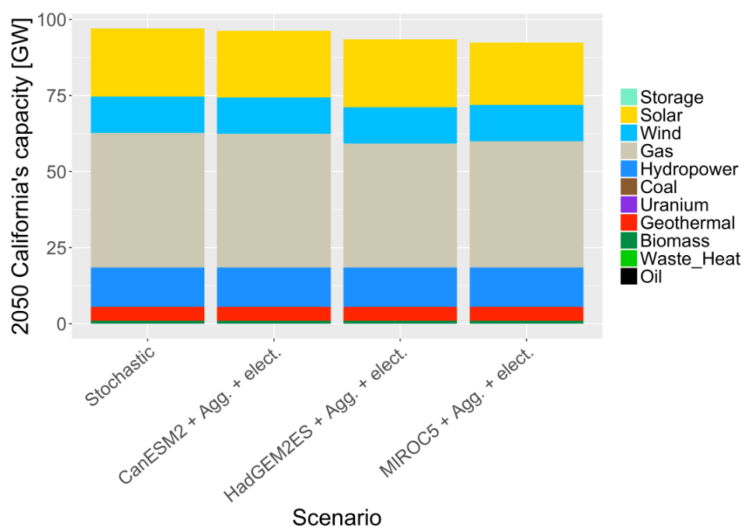


Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Similar findings can be observed in the total capacity installed by 2050 in California for the "Stochastic" climate change formula compared to the deterministic climate change scenarios.

By 2050, 97 GW were installed in the “Stochastic” case, whereas the total capacity installed in the deterministic scenarios varied between 92 and 96 GW. The gas capacity installed in the resilient climate change simulation (“Stochastic”) corresponded to 46 percent of the total capacity. Gas capacity in the deterministic climate change scenarios varied between 46 percent and 44 percent.

Figure 26: Installed Capacity in California by 2050 for Deterministic and Stochastic Climate Change Scenarios



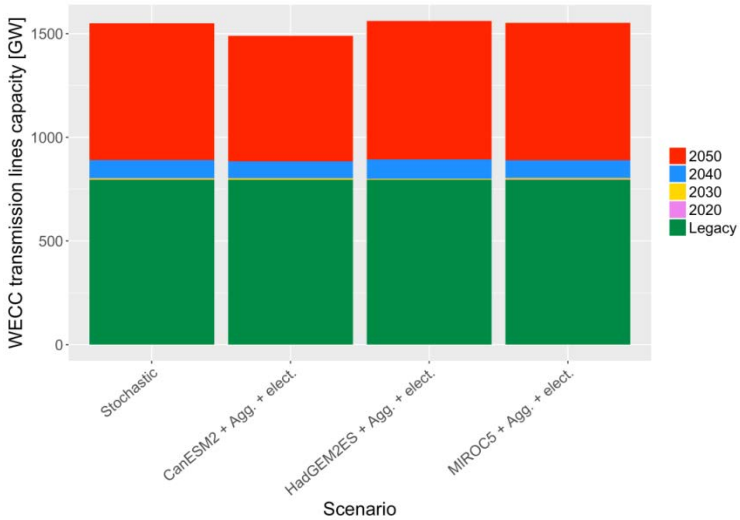
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

3.5.3.2 Installed Transmission by Periods in the Western Electricity Coordinating Council and California

The total transmission line capacity by 2050 in the WECC was slightly lower for the “Stochastic” climate change simulation compared to the deterministic scenarios (Figure 27). The “Stochastic” simulation optimally installed 1,550 GW of transmission, while the deterministic cases installed between 1,560 and 1,450 GW. This difference can be explained by the greater total generation capacity the “Stochastic” simulation shows. Less transmission is necessary because more capacity is available for generation in the WECC.

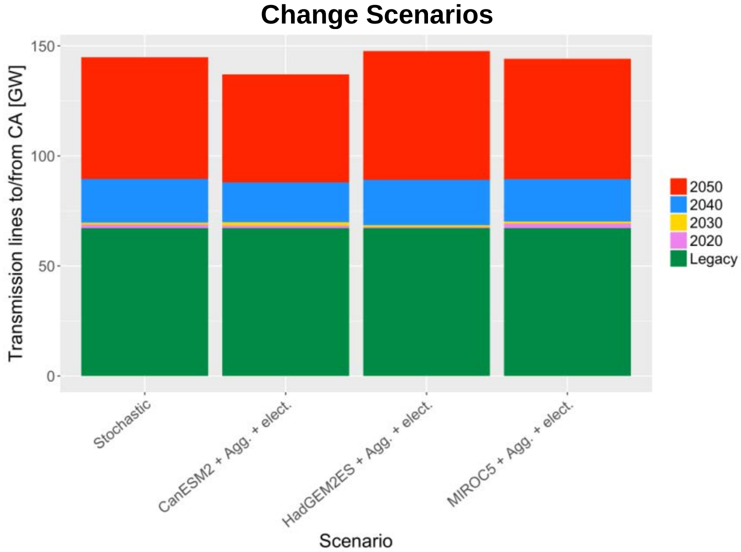
Despite the overall slight reduction in total transmission installed by 2050 in the WECC for the “Stochastic” simulation, the transmission between California and the WECC was within the range of transmission installed in the deterministic climate change scenarios (Figure 28). Transmission installed in the “Stochastic” or resilient case was 145 GW, while the deterministic cases ranged between 137 and 148 GW.

Figure 27: Existing and New Transmission Lines Capacity for All Periods in the Western Electricity Coordinating Council for Deterministic and Stochastic Climate Change Scenarios



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 28: Existing and New Transmission Lines Capacity Between California and the Western Electricity Coordinating Council for All Periods, for the Deterministic and Stochastic Climate Change Scenarios



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

CHAPTER 4: Mapping of Solar Resources in the Central Valley Across Four Synergistic Land-Cover Types

This section is drawn from a recent published journal paper by the research team as part of this project (Hoffacker et al. 2017). Key results are presented in this chapter and full details of the analysis and analysis assumptions can be found in the journal paper.

Land-cover change from energy development, including solar energy, presents trade-offs for land used to produce food and conserve ecosystems. Solar energy plays a critical role in contributing to the alternative energy mix to address climate change and meet policy milestones; however, the extent that solar energy development on nonconventional surfaces can address land scarcity is understudied.

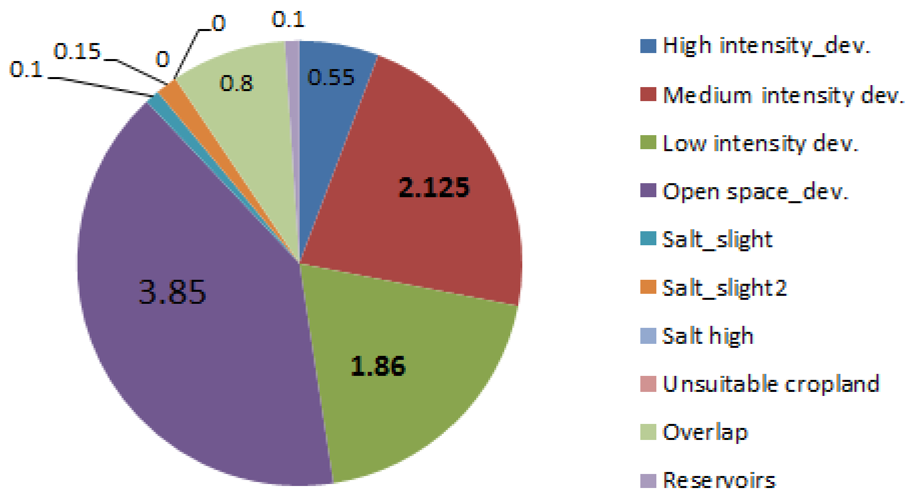
The team quantifies the potential of solar energy development within the Central Valley in California, a model system for understanding land-food-energy-water nexus issues, across four synergistic land-cover types: the built environment, salt-affected land, contaminated land, and water reservoirs ("floatovoltaics"). In total, the Central Valley encompasses 15 percent of California, and within this area, 13 percent or 8,415 km^2 were identified for the synergistic siting of solar energy. Accounting for technology efficiencies, this synergistic siting of solar energy could provide up to 12 and 2 times more electricity for PV and concentrating solar projects (CSP), respectively, than is required for California's 2025 electricity demand projection (Figure 29).

Solar energy synergies can provide environmental co-benefits beyond the utility as a low-carbon fuel source, including reductions in future land-cover change and water consumption for agriculture. This study shows the Central Valley has tremendous solar resources and, although it is a vulnerable yet indispensable region for food production globally, can adequately adapt with the evolving energy landscape without compromising critical farmland or protected habitats.

The Central Valley could, in principle, build up its solar assets and become a long-term energy exporter but only if the systematic time-dependent output of solar output can be either stored or used for value-added activity. The study underscores the potential of strategic renewable energy siting to reduce environmental trade-offs typically coupled with energy sprawl in agricultural landscapes.

The analysis of health damages in Chapter 7 can also be applied to general policy considerations. For example, fugitive dust was shown to be an important source of $PM_{2.5}$ pollution in the Central Valley, and any solar PV development should take care not to permanently disturb vegetation and increase dust generation.

Figure 29: Distributed and Utility-Scale Photovoltaic Generation Potential



In number of times over 2025 California electricity demand in GWh; 10X nominal total. (Not shown: CSP generation potential number of times over 2025 CA electricity demand ~2.4X in GWh)

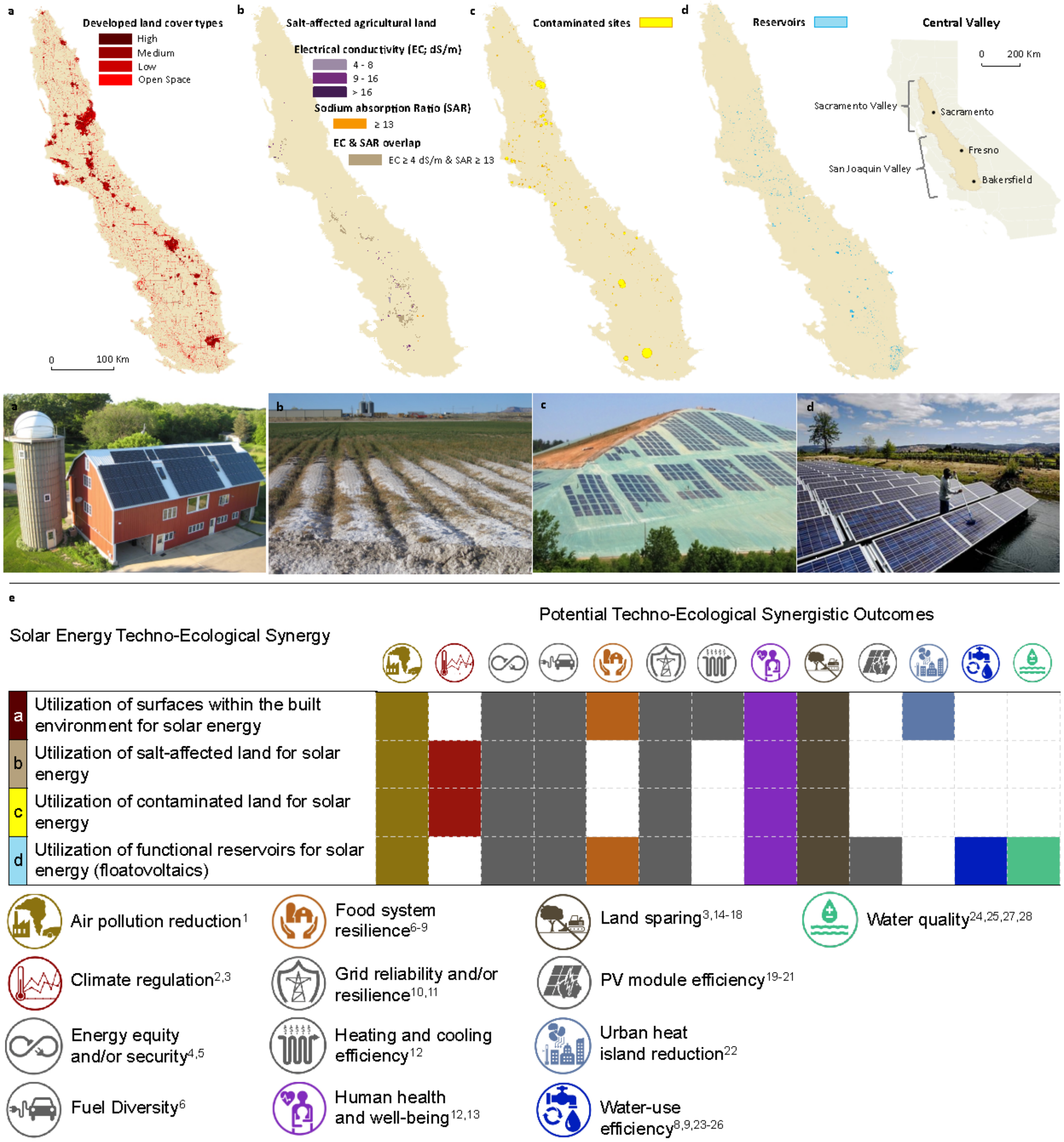
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

4.1 Introduction

While most research has focused on the negative environmental impacts of ground-mounted utility-scale solar energy (USSE, ≥1 megawatt [MW]) installations (Macknick et al., 2013; Feldman et al., 2014), there is increasing attention on the design and enterprise of solar energy that produce technological outcomes favorable for humans (for example energy security, fuel diversity) and benefits supporting ecosystem goods and services, including sparing land (Hernandez et al., 2014).

In this chapter, the research team defines *land sparing* as siting decisions for solar energy infrastructure that obviate the requirement for land use and land cover change (LULCC) that may have otherwise occurred within prime agricultural land and natural environments, respectively, including intermediates between these land-cover types. The research team posits that this framework, known *techno-ecological synergy* (TES), proposed by Bakshi et al. (2015) (Hernandez et al., 2014) and other studies suggest that several potential techno-ecological outcomes may be concomitantly achieved when nonconventional surfaces are used for siting solar energy (Figure 30). Specifically, using 1) the built environment specifically developed areas characterized by impermeable surfaces and human occupation, 2) land with salt-affected soils, 3) contaminated land, and 40 reservoirs as recipient environments for solar energy infrastructure may provide techno-ecological outcomes necessary for meeting sustainability goals in landscapes characterized by complex, coupled human and natural systems, such as those within intensive agricultural areas.

Figure 30: Land-Sparing Solar Energy Siting Opportunities Within California's Central Valley



Includes within/over a, the built environment, b, salt-affected soils, c, contaminated land, and d, reservoirs. Contaminated sites are shown accurately according to actual area but not shape. The research team posits that these land-sparing siting opportunities for solar energy development may also function individually (e) as a techno-ecological synergy (TES), a framework for engineering mutually beneficial relationships between technological and ecological systems that engender both technocentric outcomes (grey icons), as well as support for sustainable flows of ecosystem goods and services (colored icons). Numbers refer to citations that provide justification for all outcomes (Appendix C).

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

The Central Valley is an ideal region to study land-sparing benefits of solar energy TESs and to inform on broader issues related to the intersection between energy and land (Hudson, 1987). Located in one of the world's five Mediterranean climate regions, California is valued as the largest agricultural producer within the United States, responsible for more than half of the country's fruits and nuts, and is productive year-round (Hudson, 1987; Butler et al., 2001).

There are few studies assessing the potential of solar energy within agricultural landscapes in ways that may promote synergistic outcomes on technological and ecological systems beyond avoided emissions (Lopez et al., 2012; Hernandez et al., 2014). In this study, the-research team evaluated the land-sparing potential of solar energy development across four nonconventional land-cover types: the built environment, salt-affected land, contaminated land, and water reservoirs, as floatovoltaics, within the Central Valley. The team also quantified the theoretical and technical (specifically generation-based) potential of PV and CSP technologies within the Central Valley and across these potential solar energy TESs to determine where technical potential for development is greatest geographically. Finally, the team tested how the current and projected (2025) electricity needs for California can be met across all four potential land-sparing opportunities.

4.2 Methods

The theoretical, or capacity-based, solar energy potential is the radiation incident or has an effect on earth surfaces that can be used for energy production, including solar energy (McKay, 2013). The researcher team used satellite-based radiation models developed by the National Renewable Energy Laboratory (NREL, Perez et al. 1997, and Bahaidarah et al.,2013) to estimate the theoretical solar energy potential of PV and CSP technologies operating at full, nominal capacity over 0.1-degree surface cells (~10 km in size).

To evaluate the technical, or generation-based, solar energy potential in identified areas for land-sparing PV development, the theoretical potential was multiplied by a capacity factor. Next, the research team calculated solar energy potential for small and large-scale solar energy projects, where a minimum parcel size of 28,490 square meters (m^2) and 29,500 m^2 were required for PV and CSP facilities, respectively, producing 1 MW or more.

The researcher team delineated the Central Valley (58,815 km^2) based on the Central Valley Region (Brillinger et al., 2013), composed of the geographic subdivisions of the Sacramento Valley, San Joaquin Valley, and all Outer South Coast Ranges encompassed within the San Joaquin Valley (Figure 4.2). The PV and CSP radiation models overlaid the four land-sparing land-cover types within the CV and calculated total area (km^2) and solar energy potentials (TWh y^{-1}). Across all four potential solar energy TESs, lands protected at the federal and state levels and threatened and endangered species habitats from areas identified as salt-affected were eliminated. Further, all water bodies (such as wetlands and rivers), occurring in salt-affected areas, with the exception of reservoirs, were removed as they may function as essential habitats for birds and other wildlife. Salt-affected soils within farmlands identified as primary, unique, or of statewide or local importance (Myers et al., 2000) were also not included in the final estimates for solar energy potential.

To ensure energy potentials were not double-counted (such as salt-affected lands within the built environment), the research team calculated the spatial overlap across three solar energy TESs. Specifically, the research team observed overlap of land-sparing potential among the built environment, salt-affected regions, and reservoirs.

4.3 Results and Discussion

The research team found that 8,415 km^2 (equivalent to more than 1.5 million American football fields) and 979 km^2 (about 183,000 American football fields) of nonconventional surfaces could serve as land-sparing recipient environments for PV and CSP solar energy development, respectively, within the Central Valley and in places that do not conflict with important farmlands and protected areas for conservation (Figure 29, Table 2). These surfaces could supply a generation-based solar energy potential of up to 4,287 TWh y^{-1} for PV and 762 TWh y^{-1} for CSP, which represents 2.8 (CSP) – 14.4 percent (PV) of the Central Valley area.

Among the potential solar energy TESs studied, the built environment offers the largest land-sparing potential in area with the highest solar energy potential for PV systems (Figure 4.2), representing between 57 percent (USSE only) to 76 percent (small to USSE) of the total energy potential for PV.

California's projected annual electricity consumption demands for 2025, based on moderate assumptions, is 321 TWh. The land-sparing solar energy TESs explored in this study could meet California's projected 2025 needs for electricity consumption between 10 and 13 times over with PV technologies and more than two times over with CSP technologies (Table 2).

This study found contaminated sites are clustered within or near highly populated cities, many with populations that are projected to rapidly expand owing to urban growth. Thus, contaminated sites may serve as increasingly desirable recipient environments for solar energy infrastructure within the Central Valley.

California's Central Valley is a vulnerable yet indispensable region for food production globally. This study reveals that California's Central Valley could accommodate solar energy development on nonconventional surfaces in ways that may preclude loss of farmland and nearby natural habitats that also support agricultural activities by enhancing pollinator services (such as wild bees) and crop yields (California Energy Commission, 2015; California Energy Commission, 2014). California expects to derive half of its electricity generation (160 TWh) from renewable energy sources by 2030, and the research shows that the Central Valley can supply 100 percent of electricity needs from solar energy without compromising critical farmlands and protected habitats. This analysis reveals a model sustainability pathway for solar energy development on nonconventional surfaces that may be useful to other agricultural landscapes threatened by trade-offs associated with energy development and sprawl.

Table 2: Number of Times Photovoltaic and Concentrating Solar Power Solar Energy Technologies Can Meet California's Projected Electricity Consumption Needs for 2025 (321 TWh)

		PV				CSP	
		Distributed and USSE		USSE only		USSE	
Land-cover type[a]		Capacity-based (times over)	Generation-based (times over)	Capacity-based (times over)	Generation-based (times over)	Capacity-based (times over)	Generation-based (times over)
Central Valley		378.6	68.1 - 83.4	378.6	68.1	398.2	129.7
DNI ≥ 6 kWh m^{-2} da^{-1}		--	--	--	--	135.4	46.9
Developed	High intensity	2.8	0.5 - 0.60	1.5	0.3		
	Medium intensity	10.8	1.9 - 2.35	7.5	1.3 - 1.6		
	Low intensity	9.3	1.7 - 2.02	1.6	0.3 - 0.4	0.2	0.1
	Open space	19.2	3.5 - 4.2	6.2	1.1 - 1.4	1.9	0.7
Salt affected soil	EC ≥ 4 and ≤ 8	0.6	0.1	0.6	0.1	0.2	0.1
	EC > 8 and ≤ 16	0.8	0.1 - 0.2	0.8	0.1 - 0.2	0.3	0.1
	EC > 16	0.1	0.0	0.1	0.0	0.0	0.0
	SAR ≥ 13	0.2	0.0	0.2	0.0	0.0	0.0
	Overlap (EC ≥ 4 AND SAR ≥ 13)	3.9	0.7 - 0.9	3.9	0.7 - 0.9	1.4	0.4
Reservoirs		0.7	0.1 - 0.2	0.6	0.1	--	--
Contaminated		7.1	1.3 - 1.6	7.0	1.3 - 1.6	3.0	1.0
TOTAL		55.4	9.9 - 12.1	30.1	5.4 - 6.6	7.0	2.4
Overlapping areas		1.3	0.2 - 0.3	0.6	0.1	0.1	0.0
TOTAL (accounting for overlapping areas)		54.1	9.7 - 11.8	29.5	5.3 -6.5	6.9	2.4

[a]Total energy potentials account for overlaps in land-cover types to avoid double counting.

Based on land-sparing opportunities within the Central Valley, California: 1) developed, 2) salt-affected soil, 2) reservoirs, and 4) contaminated sites. Capacity-based potential represents the full energy potential offered from the sun, whereas the generation-based potential estimates the energy potential given current technology capabilities

Source: Lawrence Berkeley National Laboratory

CHAPTER 5:
Decarbonizing the Building Sector

Residential and commercial building energy consumption generated 9 percent of California's total GHG emissions in 2015 (23 million and 14 million tons, respectively). These emissions are primarily due to the combustion of natural gas and other fuels for space heating, water heating, steam generation, and cooking. Annual emissions from fuel combustion for this sector depend upon total energy consumption, appliance and building efficiency standards, and the weather. From 2011 to 2014, a steady decline in the use of heating was observed due to warmer winters during those years. However, 2015 had a relatively cooler winter and in that year, there was a 10 percent increase from 2014 in GHG emissions (CARB, 2016A).

In this chapter, several scenarios are considered for this sector to meet the state's climate measures of annual energy savings (SB 350) and achieve emissions reduction of 40 percent by 2030 (SB 32) and 80 percent by 2050 (Executive Order S-3-05) relative to 1990 levels. To realize these goals, the analysis indicates that the state must begin phasing in aggressive strategies to decarbonize heating consumption in buildings no later than 2020. The scenarios are based on electrifying heating accompanied by adopting high-efficiency electric heat pumps for heating and cooling.

Wide-scale electrification of building loads will increase user demand for electricity. Furthermore, electrification will have varying effects on the electricity load shape, depending on the climate zone and season. To illustrate, plots of sample hourly load profiles for different climate zones are given. Electricity-based appliances, especially water heaters, can perform active demand response, providing flexibility to the grid and thereby contributing to optimal grid management.

In addition to decarbonizing end uses in the building sector, the state can meet its emissions targets cost-effectively by reducing demand through energy conservation or by reducing the demand for energy services.[19] Finally, sustained policies over time will provide consistent policy signals to the equipment manufacturing industry to anticipate and plan for potential new demands. Such consistency in policies would also provide lead time for grid planners and utilities to plan for any additional electrical load.

5.1 Current Status

In January 2016, California's population was composed of 39.3 million individuals and 13.4 million households (CA DOF, 2016). The residential sector's electricity and natural gas consumption for that year was estimated at roughly 92,000 GWh and 4,300 million therms, respectively (California Energy Commission Database, 2017). Based on this, the unit energy consumption (UEC) of a household was, on average, 6,800 kWh of electricity and 320 therms of

19 For example, "energy efficiency" in a given end use such as water heating refers to a more energy-efficient water heater, but "energy conservation" here refers to a reduction in customer hot-water demand.

natural gas. Total commercial floor space in 2016 was estimated at 7,382 million square feet. The estimated electricity consumption by commercial buildings for 2016 was 107,185 GWh, and the natural gas consumption for the year 2014 was 1,917 million therms (California Energy Commission *2016 IEPR Update*).

Senate Bill 350 calls for a doubling of savings in electricity and natural gas demands, resulting in an annual savings by 2030 of around 68,000 GWh and 1,200 million therms, respectively. These savings are compared to the "business-as-usual" or frozen scenario and are expected to be roughly equivalent to a 20 percent reduction (California Energy Commission, 2016). While the statute does not prescribe the exact mechanism by which this can be achieved, it expects much of this untapped energy potential to be gained from efficiency improvements in existing buildings. An estimated 50 percent of existing buildings in California were built before 1978, when the state's first building standards went into effect. Mandating the retrofitting of existing buildings to improve efficiency is difficult and expensive. For the new buildings, California's *Zero Net Energy (ZNE) Action Plan* (2015) suggests incentives for high-efficiency building designs and end-use appliances for all new homes and commercial buildings to be ZNE by 2020 and 2030, respectively.

5.2 Building Stock Projection

For 2016 to 2026, the California Energy Commission's *2016 Integrated Energy Policy Report Update* mid-demand projections for the population, number of households, and total commercial square footage in the state are assumed. For 2050, the California Department of Finance projects the state's population to be at 49.8 million. Commercial space in 2050 is projected to be around 10,400 million square feet.

The existing and future stock of buildings is divided into four categories (Greenblatt, 2015). They are:

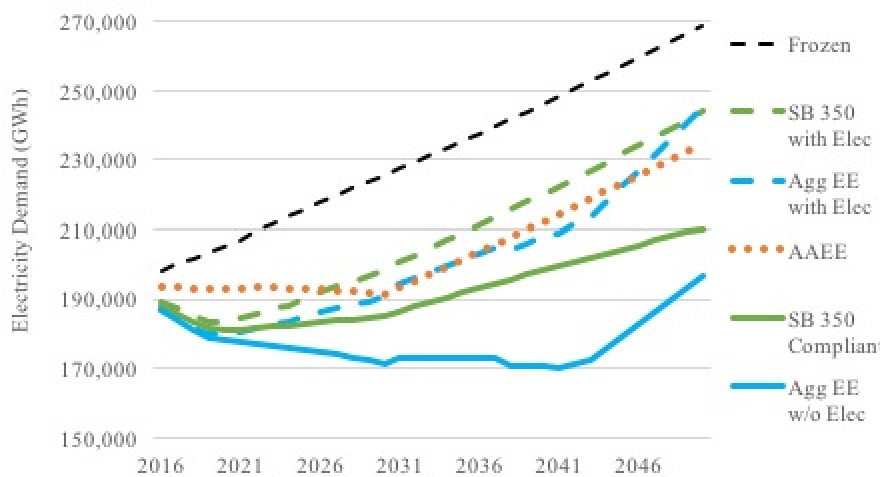
1. New buildings (ZNE). It is assumed that these buildings will be built to maximize cost-effectiveness and energy efficiency and to satisfy policy targets for ZNE buildings; a gradual decline in UECs is assumed as a proxy for this. Assumptions on efficiency gains and the percentage of ZNEs that choose to electrify heating differ by scenario.
2. Rebuilds (after demolition). It is assumed that 0.5 percent of residential buildings and 1 percent of commercial space are demolished and rebuilt annually.[20] Rebuilt spaces are assumed to adhere to the same efficiency standards as new buildings in the above ZNE category and will be grouped with ZNE for this analysis.
3. Retrofits. Annually some percentage of building stock will lower the associated electric and NG UECs either by improving thermal efficiency of the building shell and windows or through upgrading appliances. The percentage of buildings retrofitted annually, efficiency gains, and electrification rates all vary by scenario.
4. Remaining existing stock. Untouched and assumed to have the original UECs.

20 While new construction numbers fall out of growth projections, the research team was not able to find existing estimates of the number of houses or commercial spaces that are annually demolished or retrofitted.

5.3 Scenarios for Energy Demand Projection

The research team developed five scenarios of future electricity and natural gas demands: (1) Frozen, (2) SB 350, (3) SB 350 + Electrification, (4) Aggressive Energy Efficiency without Electrification, and (5) Aggressive Energy Efficiency + Electrification. Figure 31 illustrates the electricity demand in building sector for these scenarios. Figure 32 shows the breakdown of natural gas demand in the building sector in 2050 from existing, retrofitted and new buildings in each of the scenarios. The GHG emissions reduction in each of the scenarios for 2030 and 2050 can be seen in Figure 33. Emissions trajectories from natural gas demand are illustrated in Figure D.2 in Appendix D.

Figure 31: Electricity Demand of Buildings (Residential and Commercial) With Scenarios



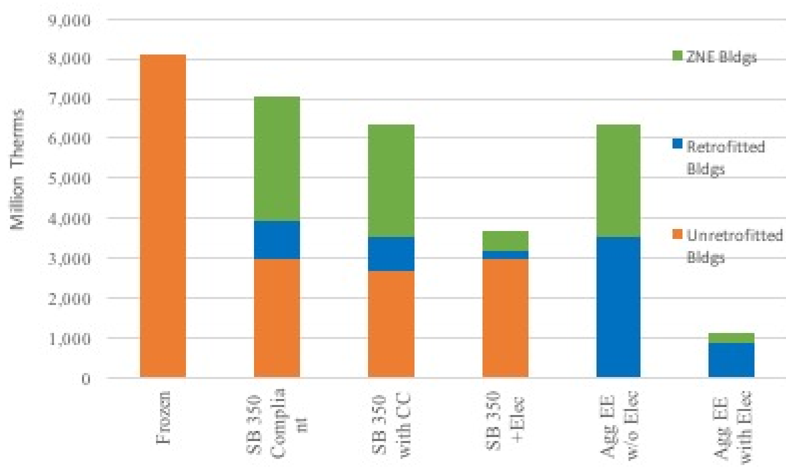
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

- ***Frozen Scenario:*** In this scenario, the UECs remain fixed for the period 2016 to 2050 with no further efficiency gains. Demand for residential and commercial electricity from 2016 to 2026 is assumed to be the same as in the Energy Commission IEPR 2016 mid-demand scenario. From 2026 to 2050, residential and commercial building electricity demand is assumed to grow at 0.9 percent, the implied annual growth rate for 2000 to 2026. Average UEC for electricity per household remains fixed from 2016 to 2050 at 6,800 kWh per household and 13.9 kWh per square foot for commercial space. The research team assumed the natural gas UEC per household and UEC per square footage of commercial space remains fixed at 320 therms and 0.268 therms, respectively, from 2016 until 2050.
- ***SB 350:*** As SB 350 does not specify definite pathways or efficiency assumptions to achieve the specified savings, the research team has developed a scenario with assumptions on efficiency and retrofit rates that moves the state closer to the electricity and natural gas savings mandated by SB 350. For existing buildings, the team has

assumed an annual modest retrofit rate of 0.5 percent,[21,] resulting in efficiency improvements given in Appendix D, Tables D.1 and D.2. The assumed efficiency gains in electricity are from improvements in lighting, appliances such as refrigerators, and plug loads. Efficiency gains in natural gas are assumed to result from improved thermal efficiency in buildings and efficiency gains in appliances. For ZNEs, the UEC of electricity and NG decrease are shown in Tables D.3 and D.4 in Appendix D. Figure D.1 illustrates the housing stock turnover in this scenario.

By 2030, annual savings in electricity of 19 percent are achieved and gradually increases to about 22 percent by 2050 (Figure 31). The NG demand in 2030 drops by about 1,000 Mtherms from the frozen scenario (Figure 32), close to what is called for in SB 350 (Energy Commission, 2017). This decrease results in only a 5 percent reduction in 2030 emissions from 1990 levels. From 2030 to 2050 with no further efficiency gains assumed and with no fuel substitution or electrification of heating loads, there is an uptick in natural gas usage demand with population growth. Even with a doubling of the retrofit rate and the efficiency gains due to appliances and better thermal insulation in buildings, one can see that this scenario will not meet the SB 32 GHG reduction targets.

Figure 32: Natural Gas Demand of All Buildings in 2050



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

- ***SB 350 + Electrification:*** The same annual retrofit rate of 0.5 percent as in the previous scenario (SB 350) is assumed here. Beyond increased efficiency, it is further assumed that a certain percentage of retrofitted buildings and ZNEs electrify the respective heating loads per the schedule given in Tables D.5 and D.6. Efficiency gains with electrification, given in Table D.6, are due to the assumed adoption of efficient electric heat pumps, whose energy factors are between 3.0 and 4.0 today. A large percentage of retrofitted buildings are assumed to be electrified. However, the low assumed rate of

21 Current residential retrofit programs have very low market penetration rates. See, for example, http://www.energy.ca.gov/2017publications/CEC-500-2017-009/CEC-500-2017-009.pdf.

retrofits implies that ultimately only 10 percent of the building stock in 2050 is electrified. In this scenario, emissions reduction is 20 percent in 2030 and 40 percent by 2050 and does not meet SB 32 or Executive Order S-3-05.

- ***Aggressive EE without Additional Electrification:*** Three percent of existing buildings are assumed to be annually retrofitted to improve energy efficiency. Nearly 380,000 homes and 212 million square feet of commercial space are retrofitted annually until all existing stock is upgraded by 2041. An uptick in electricity demand after 2041 can be seen because with no further decrease in demand for energy from existing homes, new growth will increase demand from 2041 to 2050. This scenario assumes no fuel substitution or forced electrification. The energy reduction in ZNE buildings is the same as in the SB 350 case. By 2050, the existing stock of buildings in 2016 would have seen an efficiency upgrade, and new buildings will be built with low UECs. However, with the insignificant reduction in NG demand, the emissions remain fairly high even in 2050, slightly lower than the SB 350 case, but substantially higher than the SB350+Elec scenario (Figure D.2 in Appendix D).
- ***Aggressive EE with Electrification:*** In this case, the research team assumes that a high percentage of retrofitted buildings are electrified (Table D.6 in Appendix D). This leads to GHG emissions reductions of more than 40 percent in 2030 and 80 percent in 2050 relative to 1990 levels (Figure D.3 in Appendix D). The additional electricity demand is reduced mainly by adopting high-efficiency heat pumps. This scenario results in substantial savings of electricity relative to the frozen scenario but falls short of the savings recommended in SB 350, although it will result in an annual natural gas savings of more than 80 percent. The research team cautions that the high electrification rates assumed are extremely difficult to achieve and chosen as a means of illustration.

5.4 Discussion

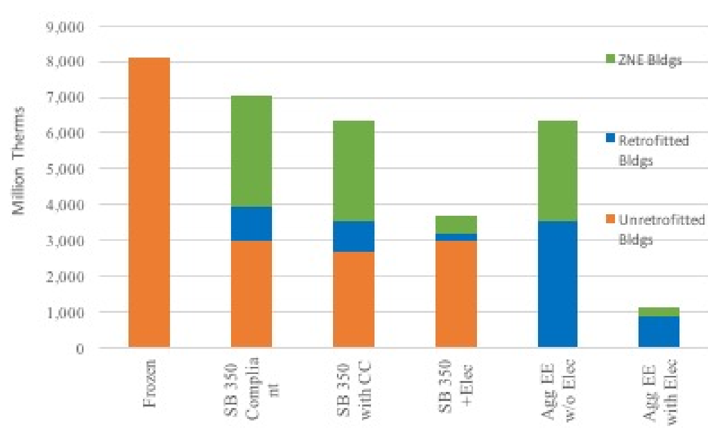
The analyses demonstrate that low retrofitting rates along with low rates of heating electrification, as in the SB 350 + Electricity scenario, are inadequate to meet the emissions targets for SB 32. The Aggressive Efficiency Without Electrification scenario, which had high retrofit rates where every existing building had efficiency upgrades by 2041, and where new buildings were built with considerably low UECs by today's standards, is also insufficient to meet emissions reduction targets. However, this sector can meet the climate goals of 2030 and 2050, if the Aggressive EE + Electrification scenario begins in 2020, with a high percentage of buildings being retrofitted and with high percentage of heating demand electrified. The energy improvements are all front-loaded. Therefore, the state must begin retrofitting at high rates in the near term with eventual tapering off after 2040.

As a sensitivity case, a more moderate alternate scenario can be considered ("Moderate Electricity"), which gradually increases electrification rates – 10 percent by 2020, 50 percent by 2030, and 100 percent by 2050. In this scenario, all other assumptions remain fixed: the retrofit rate of 3 percent and efficiency gains are the same as in the Aggressive EE with Electrification scenario. This scenario can be viewed as more achievable than the Aggressive EE with Electrification scenario; but this falls slightly short of the state's emissions goals. Because of lower electrification rates assumed in 2020, the reduction in 2030 falls short of the 40 percent reduction goal, and this scenario does not get the state to the 80 percent emissions reduction in 2050 either, as a substantial stock of buildings remain with natural gas heating in 2050.

However, if an additional assumption is made that future homes and commercial spaces are, for instance, 20 percent smaller or that low-UEC multifamily units will make up a larger share of new homes, and if existing and retrofitted homes can lower overall natural gas demand by another 20 percent through conservation and behavior change (such as lower hot water use and better thermostat controls), overall emissions from this sector can be reduced by up to 20 percent. With energy conservation, this “Moderate Electricity with Conservation” scenario can result in a 45 percent reduction in emissions in 2030 and 75 percent reduction in 2050. This can be a potential complementary strategy to meet the SB 32 goal for 2030.

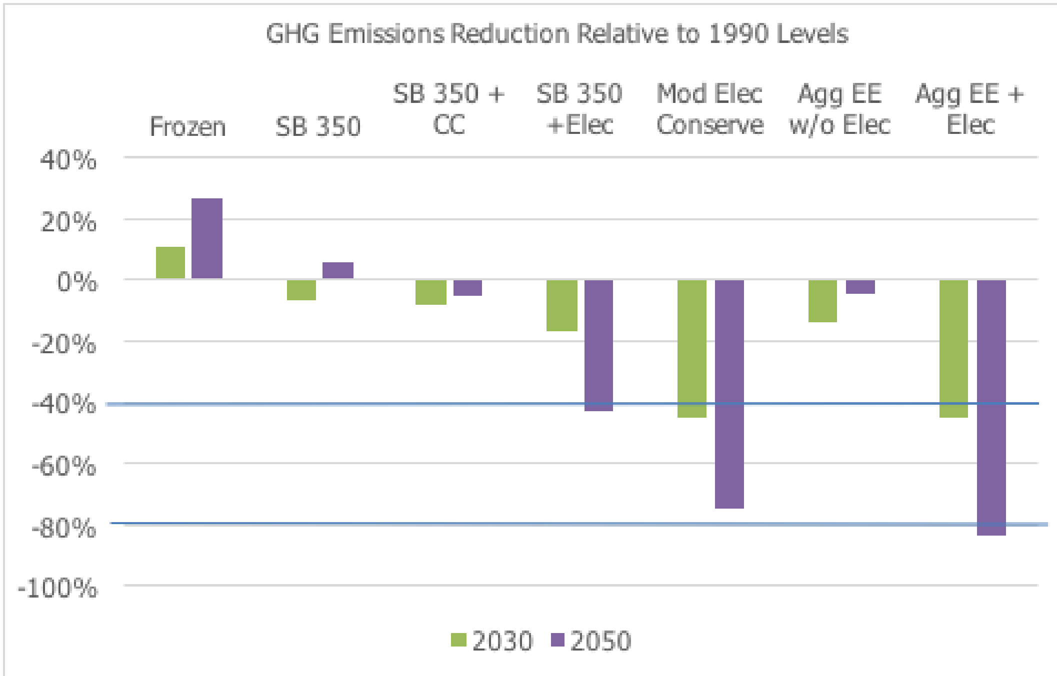
Figure 31 provides the electricity demands for the scenarios, and Figure 32 provides the 2050 natural gas demand for the scenarios. With climate change a 10 percent reduction in heating demand is assumed in the scenario “SB 350 + Elec” with CC. (For consistency, the rest of the scenarios to the right of this scenario all have a 10 percent reduction in emissions levels in 2050). Emissions reductions achievable in 2030 and 2050 can be seen in Figure 33. Aggressive energy efficiency updates coupled with aggressive electrification of retrofitting existing buildings at an annual rate of 3 percent (“AggEE + Elec”) is necessary for the sector to meet 40 percent and 80 percent emissions reductions by 2030 and 2050, respectively. However, with energy conservation, a more realistic gradual phase in of electrification of existing buildings (“Mod Elec + Conserve”) can still get the sector close to emissions goals. (Figure 33). Finally, the additional demand from electrification of buildings can be capped by the adoption of high-efficiency heat pumps. Furthermore, the high costs of adopting heat pumps can be lowered with energy conservation and the capability of the electric appliances to participate in demand response.

Figure 32: Natural Gas Demand of All Buildings in 2050



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 33: Greenhouse Gas Emissions Reduction in 2030 and 2050 Relative to 1990 Level*



***In SB 350 with Climate Change (SB 350 with CC), the research team assumed a 10 percent reduction in NG demand in 2050 and, hence, a 10 percent drop in emissions. All the scenarios to the right of SB350 with CC assume a similar 10 percent drop in emissions.**

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

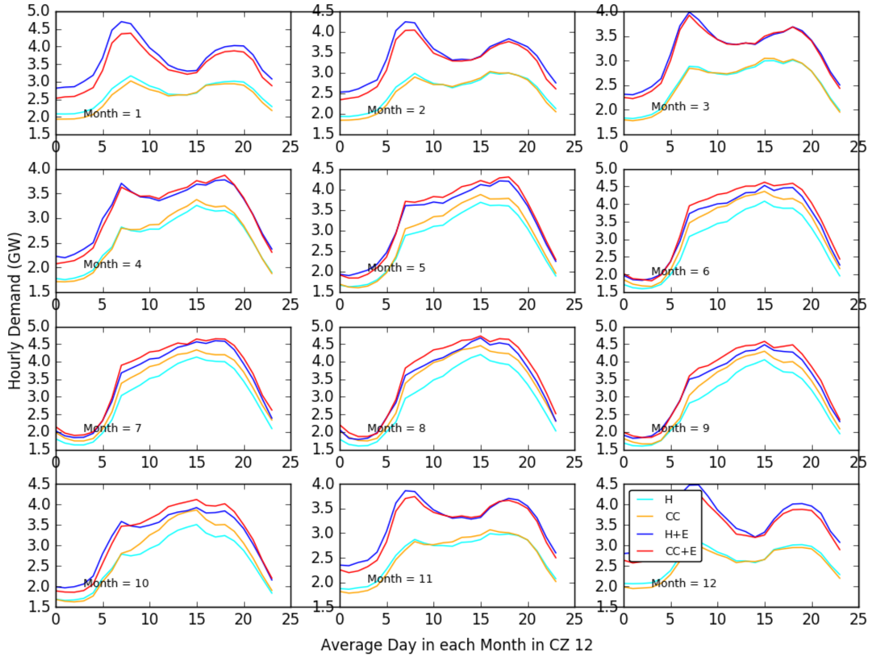
5.5 Impact of Climate Change and Additional Electrification

Wide-scale electrification of building loads will increase electricity demand and affect the electricity load shifts and the grid in different ways, depending on climate zones and seasons. Similarly, the effect of climate change on the grid will vary with climate zone and season. The climate models forecast warmer winters and hotter summers, reducing heating demand and increasing air-conditioning demand.

Figure 34 illustrates the average daily load profiles of the buildings in Climate Zone 12 (Sacramento area) in each of the 12 months.22 (Load profiles for CZ3 and CZ9 are included in Appendix D). The underlying data are based on simulations of building energy demands by the UC Irvine and LBNL teams[23, 24] using EnergyPlus, a whole-building energy simulation program.

22 CZ3, part of the San Francisco Bay Area in Northern California (Oakland and San Francisco), has mild climate; CZ9 is in Southern California (Los Angeles) with hot summers and mild winters; CZ 12 is part of Northern California's Central Valley with cooler winters and hotter summers. CZ3, CZ9 and CZ12 represent 10%, 16% and 12.5%, respectively, of the state's population.
23 The UC Irvine team provided hourly demands for cooling and heating for a mix of buildings and for all 16 climate zones of California
24 The LBNL team provided modeling profiles for a subset of commercial buildings.

Figure 34: Average Hourly Electricity Load Profiles of Buildings Climate Zone 12



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Observing the hourly load profiles with historical climate conditions ("H" in turquoise) and with climate change ("CC" in orange),[25] the team noticed that in the early hours of most months, energy demand is lower with climate change. Similar observations can be made for the electrified hourly load profiles with historical climate conditions ("H+E" in blue) and the hourly electrified load profiles with climate change ("CC+E" in red). This is because the climate models predict lower heating demand days (HDD) or warmer winter temperatures in 2050, thus decreasing the demand for heating. However, with hotter summers by midcentury, increased cooling degree days (CDD) will increase air-conditioning demand. This outcome can be observed by higher demand with climate change relative to historical load profiles, during middle of the day during the summer.

5.6 Conclusion

In the absence of aggressive strategies to decarbonize the heating sector, it is difficult for this sector to meet the 40 percent emissions reduction target of SB 32 in 2030 or the 80 percent reduction goal of AB 32 for 2050 relative to 1990. To achieve these emissions goals, efficiency gains along with aggressive electrification of natural gas-based heating loads accompanied by adoption of high-efficiency electric heat pumps are necessary. However, the upfront cost of adopting high-efficiency electric appliances for water heating and space heating and cooling can be high. Several utilities in the state, including Sacramento Municipal Utility District (SMUD) and City of Palo Alto, offer rebates for heat pump-based water heaters. In addition, several utilities

25 The research team used "HadGEM2-ES" under RCP 8.5 for the climate change scenario.

are launching programs to support electrification of heating. Some barriers observed so far in increased adoption of heat pump-based electric appliances have been the high upfront costs and lack of trained, knowledgeable plumbers and contractors.

Another barrier in achieving the emission reduction goals is the required large-scale retrofitting of existing homes. Current residential retrofit programs have very low market penetration rates. To increase retrofit updates of homes, several barriers must be overcome, including first-cost and financing challenges, the cost of home energy assessments, lack of experienced whole-house performance sales personnel, and other logistical challenges. However, sustained policies can help market dynamics, and bulk procurement can help bring the costs down through economics of scale. (Energy Commission, 2017B; Berman, 2013)

In this chapter, the research team looked at substituting natural gas by electricity. Another possibility is substituting natural gas with net-zero-carbon biomethane; however, this option is subject to limitations in supply and cost. Furthermore, the limited supply of biomass-based energy is possibly better served for use in heavy-duty trucking and some industrial applications that are otherwise difficult to decarbonize.

Identifying and evaluating the potential hidden costs and benefits from wide-scale electrification are areas of study to be pursued. Similarly, the impact to natural gas infrastructure and maintenance and possible avoided costs of building fewer natural gas transmission and distribution (T&D) infrastructure from wide-scale electrification of buildings should be evaluated. In either case, resiliency studies could look at future risks to infrastructure buildouts under more extreme weather and climate conditions.

CHAPTER 6: Industry and Transportation Sectors

6.1 Industry Summary

The industrial sector is difficult to decarbonize because of the diverse nature and cost-sensitivity of industrial processes and the lack of current policies beyond cap-and-trade. One key uncertainty for future industry emissions is sectoral change, specifically how will various industrial sectors grow or contract in California. In this work, no sectoral shifts in industry are assumed aside from the wholesale downsizing of the oil and gas industry. Any direct or indirect impacts of climate change on industry (such as water, supply chain, or feedstocks) are also not considered. Cap-and-trade is a key policy lever for the industrial sector but was not in the scope of this work to model the marginal cost of GHG abatement in industry nor the complex dynamics of banking credits and offsets. To the extent that more industrial activity is offshored in places like China and Southeast Asia and brought back into the state as either finished products or material inputs such as steel, real changes in the state's effective industry emissions can be masked. A detailed accounting of these flows and how they are changing over time was not considered in this work.

Electrification in industry faces many barriers such as higher energy costs, lack of engineering resources, and risk aversion, as well as some practical considerations, for example, the difficulty in moving away from highly efficient combined heat and power (CHP) processes to full electrification. Other industry decarbonization approaches not discussed here include carbon capture and storage (CCS) for heavy industry such as the cement industry and using renewable energy for process heating such as solar water heating or geothermal energy.

Boilers and hybrid electric/natural gas boilers are highlighted as opportunities for GHG reduction and as potential technologies to provide demand response and grid support for greater supplies of intermittent renewable electricity. However, Brolin et al. (2017) highlight the general lack of market mechanisms currently in place to support greater industrial participation in demand response markets, as well as the need for market mechanisms and industry outreach to achieve greater adoption of electrified processes.

The future of the California petroleum industry raises a key question. For example, will petroleum exports increase in the near term to midterm, or will there be a conversion of petroleum refining to other processes? Moving wholesale to clean electricity-powered transport would decarbonize the transportation sector with the state's increasingly low-carbon power sector, and reducing oil refining would also reduce a large source of industrial pollution and health damages. However, these strategies may have large ramifications for the state's economy and industrial sector.

6.1.1 Industry Electrification Outlook

Electrification of industry coupled with low-carbon electricity sources has been highlighted as a key decarbonization pathway in the past. The technical potential of industry electrification is enormous, but so, too, is the challenge. Even with higher efficiency end-use equipment, electrified heating is typically more expensive than fossil fuel-based heating because the current costs of natural gas are so low. Electrification, however, can offer many production benefits, such as improved process control, better product quality, or lower on-site emissions.

One important complication for fuel switching in industry is the intensive degree of integrated process design, including extensive use of CHP in several sectors and, in particular, in the oil and gas refining and chemicals/petrochemical sectors. Further, the oil refining industry has extensive "own-use" fuel consumption, where by-products of oil refining (for example, refinery or still gases obtained during crude oil distillation) are used as fuel in upstream or downstream processes. Attempting to electrify these processes would complicate the design and increase the energy cost above a sector that does not have this type of extensive process integration and own-use energy consumption.

Table E.2 in Appendix E provides an outlook for industry electrification by industry sector. Beyond technical potential and the potential production benefits described above, other practical barriers to end-use electrification must be addressed: (1) the potentially higher cost of energy, (2) a high degree of process design and integration, and (3) the degree to which CHP systems are used. Each of these factors would pose a practical challenge for a vendor or manufacturer to convert to electrified processes — e.g., having to pay higher energy costs, reengineer manufacturing processes, and either redesign or move away from existing tightly integrated CHP processes. Based on these three factors, ideal candidates for industrial electrification include factories with low to medium process temperatures, less integrated existing process designs, and a lower fraction of CHP processes.

6.1.1.1 Electric Boilers

Hybrid natural gas/electric boilers have been used in the Southeast when inexpensive off-peak electricity is available. The energy costs of electric boilers are unable to compete with currently low natural gas prices, even though electric boilers are virtually 100 percent efficient. However, there may be increasing times during the year in California when low-cost electricity is available from large quantities of renewable electricity coming on-line (such as solar PV ramp-up in the spring outstripping demand). For example, the marginal value of each kW of installed PV drops as the overall installed capacity increases (Mills and Wiser 2012). There are already hours in the California Independent System Operator (California ISO) region when excess renewable electricity can be exported to neighboring states (Penn 2017) even when California ISO is compensating off-taking customers up to $25/MWh for this power. As RPS standards increase and without large storage or demand shifting, curtailed power is expected to increase with greater adoption of solar and wind.

Industrial electrification options such as electric boilers have the potential to use low-cost electricity, and coordinating electrified end uses with the grid could help promote more renewable electricity generation. Electric boilers in particular are a relatively simple technology to implement (compared to electrifying higher-temperature process heating, for example) and could be installed in a dual-boiler mode with natural gas boilers to ensure adequate supply of process steam or heat.

6.1.1.2 Market and Operational Barriers and Opportunities

For these types of implementations to occur, however, several operational barriers must be met. Industry must accommodate flexible operation (for example, specified shifts for electrically powered production), and the communications and control systems must be in place to effectively exploit low-cost electricity. More generally, the potential for electrified industrial end uses to participate in load-following or ancillary services DR markets could provide additional value to the industrial customer of electricity. But the growth of these opportunities from electrified industrial end uses would need expansion in market development, industrial awareness, and demonstrated value propositions, and requisite capabilities in communication and controls of end-use equipment (Brolin et al.2017).

6.1.1.3 Impacts to Oil and Gas Industry

More globally, recent policy directives phasing out the sales of internal combustion engine vehicles by 2040 in France and Great Britain (Castle 2017) and movements in that direction in Germany (Schmitt 2016) may impact future overall petroleum product demands, while more widespread global policy changes may make major investments in overhauling oil refinery processing toward electrification or greater energy efficiency an even larger hurdle.

If the oil and gas industry is downsized or, as the team assumed, was completely superseded by cleaner transportation technologies, this would represent a profound change in the industrial sector since oil and gas refining represents such a large subsector and provides output to many other sectors (as fuel and industrial feedstocks). The research team has not explored potential economic, employment, infrastructure, and environmental ramifications of this transition, but this would be an important topic to study more fully. Furthermore, considerable non-energy outputs – petrochemicals, asphalts, road oil, kerosene, plastics, fabrics, waxes, lubricants, and so forth – are derived from the oil and gas industry and alternative production pathways would need to be developed and scaled up.

6.1.2 2030/2050 Energy Scenarios

The research team considered three scenarios: Frozen, Aggressive Energy Efficiency (Agg EE), and Aggressive EE + Electrification. The AggEE scenario assumes 14 percent energy efficiency in the fuel consumption sector in 2030 based on Masanet 2011 and 25 percent in 2050. The AggEE for electricity assumes 12 percent savings from Frozen case in 2030 and 30 percent in 2050.

The Aggressive EE Electrification scenario assumes 20 percent of fuel demand is switched to electrification in 2030 and 30 percent of frozen fuel demand is fuel switched to electricity by 2050. This targets end uses applications are replaced with heat pumps and electric boilers, and this fuel switching adds an additional 16,000 GWh by 2050. This fuel switching to electricity increases the industrial electricity demand back to close to the Frozen scenario demand as in

Figure E.1 in Appendix E. A key assumption in the last scenario is that there is aggressive energy efficiency across industrial subsectors, there is electrification of industrial processes, and the oil and gas industry is superseded in 2050 with clean transportation options such as electrification, renewable hydrogen, and low-carbon biofuels.

6.2 Transportation Sector

6.2.1 Transportation Sector Summary

Zero-emission-vehicle (ZEV) technology adoption is critical in the light-duty transportation sector. To meet the state's 2030 SB 32 target and 2050 GHG goal, annual growth in sales must continue above 20 percent per year to 2025 and close to that from 2025 to 2030 in the compliant Aggressive EE Electrification Scenario.

This Aggressive EE Electrification Scenario assumes aggressive adoption of plug-in electric vehicles (PEVs) and fuel cell electric vehicles (FCEVs), with FCEVs reaching a 15 percent market share of new vehicles by 2050. The market acceptance of FCEVs is still unknown; however, a primary advantage of FCEV – driving ranges commensurate with internal combustion engine (ICE) vehicles – is becoming less pronounced as longer-range battery electric vehicles (BEVs) are increasingly available in the marketplace. A second advantage of FCEV is fueling times comparable to ICE vehicles are still applicable though, somewhat lessened, with the greater availability of fast charging stations. A discussion of future potential cost reductions in FCEV passenger vehicles is presented in Section 8.2.

Adopting more PEVs opens the possibility of providing grid support from the controlled charging of fleets of PEVs, either grid-to-vehicle or, in the future, vehicle-to-grid. These concepts are not detailed in this study but are an area of research and could potentially provide another stream of value to PEV owners. Hydrogen production for FCEVs also has the possibility for grid support if the hydrogen is produced by water electrolysis. For example, hydrogen could be produced by electrolysis generation stations during periods of low-cost electricity, such as during times of excess renewable generation. The hydrogen could then be stored for future use for FCEV fueling or as an industry feedstock. Small quantities of hydrogen can also be injected into the natural gas pipeline.

For heavy-duty vehicles (HDVs), technologies for sharply reduced GHG emissions are not as mature as for light-duty vehicles (LDVs) but are rapidly developing. For example, Tesla recently announced a long-range, fully electric heavy-duty truck with a quoted range of 500 miles on a charge.[26]

Partnerships, target-setting, and demonstration projects for ZEV or near ZEV trucks with other states or regions can help stimulate market development, technology learning, and cost reductions as businesses realize that the policy supports their technology development.

Trucks and diesel trucks in particular are a large source of air pollutants, and $PM_{2.5}$ from trucks are high in disadvantaged dense urban communities such as Fresno and Los Angeles. CARB has

26 https://www.cnbc.com/2017/11/16/tesla-semi-truck-has-a-500-mile-range-ceo-elon-musk-reveals.html, accessed January 10, 2018.

set aggressive targets to reduce NO_x and $PM_{2.5}$ emissions. A transition to ZEV or near-ZEV trucks coupled with low-carbon electricity in the state could reduce these emissions to nearly zero. Therefore, a strategy of electrifying trucks or shifting to renewable hydrogen-powered trucks in dense urban areas would achieve the dual policy goals of sharply reduced GHG and much improved air quality and public health.

6.2.2 Transportation Sector Emissions and Policies

Transportation is the main sector to decarbonize in the state, making up about 36 percent of the state's GHG from 2013-2015, down from about 38 percent from 2000-2012. In the last few years, governments globally have worked to establish new policies to reduce and address the impacts of climate change by lowering the greenhouse gases emissions. In this framework, the electrification of transportation coupled with low-carbon electricity sources has become one of the main themes for decarbonizing the transportation sector.

For example, in March 2012, to accelerate the automotive market transition to new technologies, California Governor Edmund G. Brown Jr. issued Executive Order B-16-2012, which established several milestones toward reaching 1.5 million ZEVs in California by 2025. ZEVs include BEVs, PHEVs, and hydrogen FCEVs. The executive order specified intermediate goals and benchmarks for 2015 and 2020 and identified a target of 80 percent reduction in transportation-sector GHG emissions by 2050, relative to 1990 levels. In concert with this, California passed SB 350 in 2015, mandating a Renewables Portfolio Standard (RPS) of 50 percent by 2030. Moreover, many countries and companies have indicated plans to move away sharply from ICE-powered vehicles. Germany's Bundesrat[27] passed a bipartisan resolution calling for a ban on sales of new vehicles powered by internal combustion engines, which includes gasoline and diesel, with new combustion-engine cars sold after 2030. In mid-2017, Volvo also announced that it would move to all-hybrid or all-electric vehicle new car sales by 2019.

California has supported advanced transportation measures with the 2025 ZEV mandate and other policies supportive of cleaner transportation such as state incentives for ZEV vehicle purchases and leasing, the Low Carbon Fuel Standard (LCFS), and Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013). AB 8 dedicates up to $20 million per year until 2024 to support the construction of at least 100 hydrogen fueling stations.

6.2.3 Heavy-Duty Trucks

In California, heavy-duty transportation makes up about 22 percent of on-road vehicle emissions and about 75 percent of all freight emissions. Deep GHG reduction strategies include low-carbon biofuels, battery-electric trucks, and hydrogen fuel cell-powered trucks. Natural gas trucks can also lower emissions and reduce criteria pollutants, but conventional natural gas trucks alone are not sufficient to reach 2050 GHG goals, and overall GHG emissions will depend on actual natural gas system-related fugitive emissions. Low-carbon biofuels include liquid fuels and biomethane, which could be derived from existing biogas sources (landfills, waste

27 The Bundesrat is one body of the German bicameral legislature along with the Bundestag.

treatment plants, dairies) or from biomass gasification and subsequent processing into synthetic natural gas. Challenges to alternative fuels include costs for unit vehicles, fueling infrastructure, and effective GHG reduction considering upstream, fugitive, and tailpipe emissions.

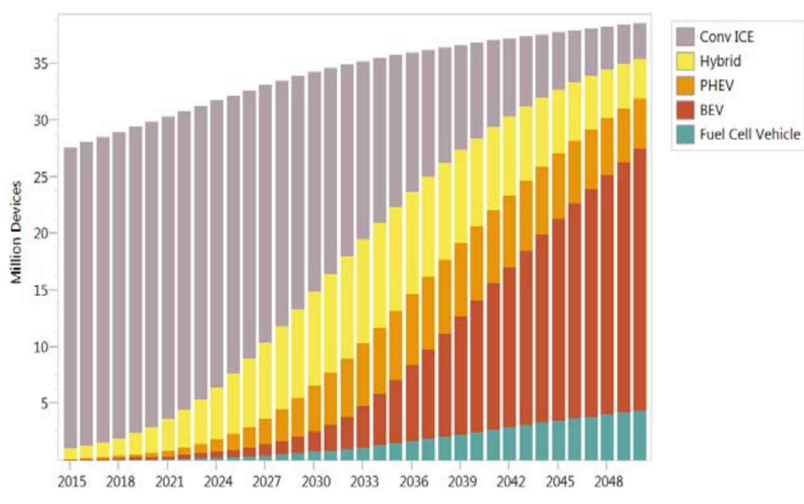
Related to hydrogen-based trucks, Section 8.2 describes the future potential cost reductions in fuel cell electric passenger vehicles. To the extent that BEVs and FCEVs in the passenger sector are adopted in California and globally, any battery or fuel cell stack unit cost reductions from BEV and FCEV market growth are expected to apply to cost reductions in battery-powered and FC-powered trucks, respectively.

6.2.4 LDV Scenarios

The Aggressive EE Electrification Scenario for LDVs is discussed in this section; other scenarios and the heavy-duty sector are discussed in Appendix E. The Aggressive EE Electrification Scenario assumes that ZEV sales ramp up sharply over the next decade (Figure E.5 in Appendix E), reaching about 20 percent of the vehicle stock in 2030 and more than 80 percent of vehicle stock in 2050 (Figure 35). This implies a ramp in ZEV sales from 4.6 percent of sales or 73,000 in 2016[28] to almost half a million new car sales in 2025, and 1.06 million new car sales in 2030. These translate to an annual growth rate of 23 percent from 2017-2025 and 17 percent from 2025 to 2030.

Vehicle fuel efficiency assumptions are shown in Table 3. Demand from PEVs is seen to grow to about 65,000 GWh in 2050 (Figure E.6) and hydrogen demand to about 15,000 GWh (or about 0.43 M tons of H_2). Fossil fuel-based GHG in Figure 36 is estimated to be 71.1 MMt CO_2e in 2030 and 10.7 MMt CO_2e in 2050.

Figure 35: LDV Stocks by Technology Type



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

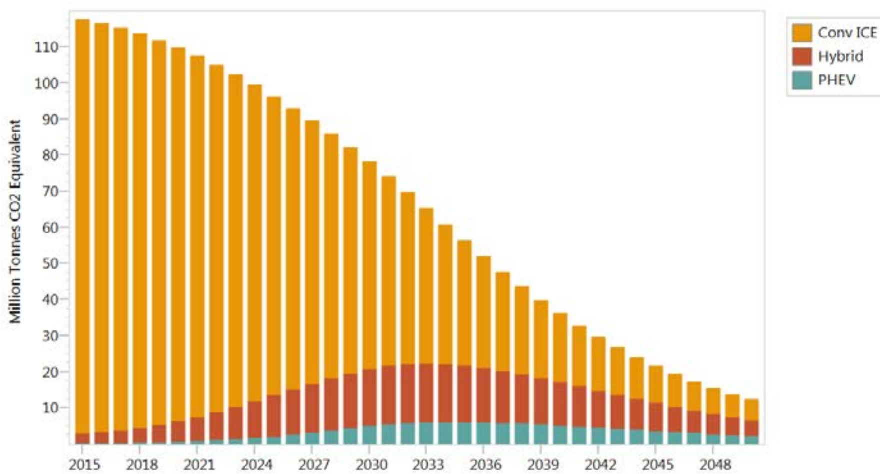
28 http://drivingzev.com/zev-state/california, accessed December 6, 2017.

Table 3: Efficiencies of Aggressive Energy Efficiency Electrification Scenario Vehicles

Parameter	Unit	Year							
		2015	2020	2025	2030	2035	2040	2045	2050
FCEV efficiency	mpg	76	80	86	86	89	92	95	98
BEV efficiency	mpg	110	119	127	135	139	142	144	145
ICEV efficiency	mpg	27	31	34	38	41	45	48	52
Hybrid efficiency	mpg	55	57	60	62	64	66	68	70

Source: Yang et al. 2015

Figure 36: Greenhouse Gases from Internal Combustion Engine, Hybrid, and Plug-in Hybrid Electric Vehicles in the Aggressive Energy Efficiency Electrification Scenario



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

CHAPTER 7: Analysis of Health Damages Based on the California Emissions Inventory

In the last 25 years, California has made enormous strides in improving air quality and reducing harmful ground-level ozone levels. Moreover, California has several measures to reduce short-lived climate pollutants (SLCP) in the next decade that, in addition to supporting the state's goal of GHG emissions reduction targets, will also improve local air quality with concomitant public health benefits.

This chapter provides an overview of recent air pollution-related policies, describes sources of pollution, and provides an estimate of health damages from the three leading criteria air pollutants: oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and $PM_{2.5}$. This study looks broadly at emission sources that have the greatest health impact from a statewide perspective. The goal is to attain insights into how various regions within the state are affected differently by air quality policies. To achieve this, 2016 California emissions inventory data are paired with a reduced-order air quality and health impact model, the Estimating Air pollution Social Impact Using Regression (EASIUR) model (Heo and Adams, 2016), which uses emissions, location, and season of emissions to estimate social and public health costs. Further, to illustrate regional differences in pollution sources and damages, Fresno and Los Angeles counties are compared. For the city of Fresno, a more detailed look is provided for four regions of 16 km^2 each.

Using the EASIUR model, the estimated total health damages from criteria pollutants in California in 2016 is about \$25 billion.[29] About 20 percent of the health damages are from on-road motor vehicles, 18 percent from off-road mobile sources, 17 percent are dust-related, 13 percent are from residential fuel combustion, and 8 percent from cooking. Electricity and cogeneration make up only 1.3 percent of the state's total health damages.

7.1 Recent Related State Policies and Strategies

Recently, the state has set aggressive targets for SLCP, which include black carbon (soot), methane, and fluorinated gases (F-gases). Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) sets targets for statewide reductions in SLCP emissions of 40 percent below 2013 levels by 2030 for methane and hydrofluorocarbons (HFCs) and 50 percent below 2013 levels by 2030 for anthropogenic black carbon, as well as providing specific direction for reductions from dairy and livestock operations and from landfills by diverting organic materials (CARB, 2017A). Senate Bill 605 (Lara, Chapter 523, Statutes of 2014) also requires the CARB to develop a plan to reduce emissions of SLCPs. In July 2017, Governor Brown signed Assembly Bill 398 (Garcia, Chapter 135, Statutes of 2017), strengthening and extending California's existing Cap-and-

29 An upper range estimate is about \$50 billion.

Trade Program until 2030. A key feature in the extension is prioritizing cap-and-trade spending to ensure funds go where they are needed most, including reducing diesel emissions in the most impacted communities. In addition, California Assembly Bill 617 (Garcia, Chapter 136, Statutes of 2017) and Assembly Bill 1647 (Muratsuchi, Chapter 589, Statutes of 2017) have tasked CARB with monitoring and measuring pollution from some stationary and petroleum refinery-related community. CARB's *Mobile Source Strategy* (CARB, 2016B), a comprehensive mobile source plan of action complementary to the state's aggressive climate targets, calls for minimizing health risks from exposure to toxic air contaminants by achieving multiple goals by 2030-2031.

Reducing SLCP emissions in California will help several disadvantaged parts of the state, where pollution levels and related health impacts are high. Furthermore, the collective implementation of SLCP reduction measures can bring thousands of jobs and billions of dollars of investment in clean technologies and strategies. Potential revenues and efficiency savings could reduce some of the initial costs. (CARB, 2017A).

Four areas in California are designated as nonattainment regions for the 12 micrograms/m^3 annual U.S. EPA $PM_{2.5}$ standard: the South Coast Air Basin, San Joaquin Valley, Imperial County, and the city of Portola in Plumas County. For the South Coast, a 50 percent reduction in NO_x levels is projected due to existing CARB and district control programs. However, current modeling indicates NO_x emissions will need to decline by 70 percent and 80 percent in 2023 and 2031, respectively, to provide for attainment in the South Coast Air Basin (CARB 2016). For attainment requirements in the San Joaquin Valley, current control programs will continue to provide NO_x reductions with a 50 percent reduction by 2031. Meeting $PM_{2.5}$ standards present the greater air quality challenge. Reduction from sources of directly emitted $PM_{2.5}$ under local district control will be critical, given the contribution of these pollutants to ambient $PM_{2.5}$ levels in the valley. Section 7.3.2 compares leading sources of pollution and health impacts in Los Angeles and Fresno counties which are large population bases in Southern California and the San Joaquin Valley, respectively.

7.2 Sources of Emissions

Sources of emissions are categorized in CARB's inventory documentation as (i) stationary sources that include power plants, refineries, and factories; (ii) mobile sources (on-road automobiles, off-road engines and equipment, as well as farming equipment, locomotives, and marine vessels); and (iii) "areawide" sources, where the emission sources are spread over a wide area such as home combustion for heating, fireplaces, commercial cooking, road dust, and farming operations (CARB, 2017B).

Table 4 provides the total SO_x, NO_x and $PM_{2.5}$ emissions from the three emissions sources. While mobile sources contribute the majority of NO_x, areawide emissions account for the majority of $PM_{2.5}$. While one can break down these this data by subcategories, as well as by counties or by census block, overall, it is a challenge to interpret these data without further analysis. One of the goals of this analysis is to look broadly at which emissions sources have the most detrimental health impact from a statewide perspective. The research team compared the statewide emissions and the leading sources of health impact to sources from a representative disadvantaged county in the San Joaquin Valley (Fresno County). $PM_{2.5}$ refers to directly emitted $PM_{2.5}$, not secondary $PM_{2.5}$ formed from SO_x or NO_x.

Table 4: California Statewide Emissions

	SOx (Tons/day)	NOx (Tons/day)	PM2.5 (Tons/day)
Stationary	56.6	262.6	72.8
Mobile	16.6	1,402	62.8
Area wide	4.0	62.7	236.7

Source: CARB, 2017B

7.3 Modeling Health Damages

Here the research team examines how various populations within the state may be impacted differently by potential energy-related policies. For this, California emissions inventory data are paired with a reduced-order air quality and health impact model, the Estimating Air Pollution Social Impact Using Regression (EASIUR) model (Heo and Adams, 2016), which uses emissions, location, and season of emissions to estimate social and public health costs. The analysis is a simplified, first-cut analysis that provides useful insight, especially in ranking the importance of emissions sources.

7.3.1 The EASIUR Model

The EASIUR model estimates the intake fraction[30] (in ppm) and marginal social cost (in \$/ton of emitted pollutant) for air pollutants emitted anywhere in the United States and emissions from offshore (margin vessels), as well as from neighboring areas in Canada and Mexico. The social costs of EASIUR are derived from the effect of ambient $PM_{2.5}$ on mortality, which usually accounts for more than 90 percent of social costs. The model estimates damages based on one primary $PM_{2.5}$ species, elemental carbon (EC), and three secondary $PM_{2.5}$ precursor species (sulfur dioxide and nitrogen oxides [NO_x], and ammonia [NH_3]). The model estimates marginal damages across the United States using a grid where each cell covers an area of 36 km x 36 km. EASIUR costs differentiate emissions at three levels for each location, depending on the emission source: ground level, stack height of 150 meters, and stack height of 300 meters. Three pieces of information are taken as inputs: (i) the amount of emissions, (ii) the location of emissions (longitude and latitude of emissions), and (iii) the season of the emissions. While large changes in SO_x, NO_x, and NH_3 may change the chemical environment in the atmosphere that affects $PM_{2.5}$ formation, the marginal damages of primary species (or elemental carbon) will not change.

The marginal damages are derived based on meteorology and emissions from 2005. For the derivation of social costs in this chapter, 2016 emissions data from CARB (CARB, 2017B) are

30 *Intake fraction* is the ratio of the mass of pollutant inhaled or ingested to the mass of the pollutant emitted.

used. The social costs per ton of pollutant are computed at the county level, considering population and income level, apart from emissions data. To arrive at the social cost or health damages due to the pollutants, the U.S. EPA's value of statistical life (VSL) of $4.8 million in 1990 U.S. dollars and 1990 income level is used. It is then adjusted using U.S. EPA's official adjustment factors for inflation and income level factors. All health damages given in this chapter are in 2015 dollars. Finally, EASIUR reports damages by emission location rather than health damage location. Hence, all "health damage" results presented in the next few sections follow the EASIUR reporting limitations (Heo and Adams, 2016), and "damages" reported at the county or subcounty level are those from pollution emanating from that county or subcounty area, and that actual health damages incurred may occur outside the county or subcounty area.

7.3.2 Health and Environmental Damage Model Results

For 2016, the total social costs from criteria pollutants in California are estimated at $24.9 billion. Table 5 provides a breakdown of the overall damages by pollutant type and by category. As can be seen, the damages from SO_x are only a fraction of those of NO_x and $PM_{2.5}$. Table F.1 in the Appendix F provides the underlying average cost at the state level for each of the pollutants per metric ton by emission category; these costs fall within the estimates for ranges of emission-weighted seasonal averages given in Heo and Adams (2016). The share of damages due to each category is given below. Further detailed breakup of damages by subcategories can be found in Table F.2.

Table 5: Annual Statewide Cost of Damages from Local Pollutants

	SOx Damages ($ Millions)	NOx Damages ($ Millions)	PM 2.5 Damages ($ Millions)
Stationary	456.1	836.3	2,121
Mobile	137.2	5,170	4,284
Areawide	27.8	277	11,569
Total	621.1	6,283	17,974

Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

7.3.2.1 Mobile Sources

Mobile sources and the fuels that power them contribute more than 80 percent of NO_x, 90 percent of the diesel particulate matter (DPM), a subset of PM2.5, and about 37 percent of the statewide GHG emissions. Of the current statewide NO_x emissions, most are from heavy-duty trucks (CARB, 2017B). This analysis estimates that damages from NO_x and $PM_{2.5}$ emissions from mobile sources are responsible for more than $9 billion, or around 36 percent of the state's burden. In the on-road category, the NO_x damages are dominated by diesel-based vehicles, especially heavy-duty trucks (HHDV). However, $PM_{2.5}$ damages are predominantly from light-duty automobiles (LDA) and light-duty trucks (LDV), which mostly run on gasoline. It is found that the off-road sources category displays a similar pattern, with diesel use in commercial harbor crafts and oceangoing vessels responsible for more than $1.5 billion in damages, while off-road equipment accounts for another $1 billion of damages. Diesel-powered farm equipment is responsible for a billion dollars in damages.

7.3.2.2 Areawide Sources

Areawide sources are dominated by damages from $PM_{2.5}$. Of the $11.6 billion in damages from $PM_{2.5}$, $3 billion is from residential combustion and another $2 billion from cooking. More than 90 percent of the $PM_{2.5}$ emissions in residential combustion are due to wood combustion in woodstoves and fireplaces. In fact, the research team found that just 10 counties (~9 percent of the state's population) with the highest per-capita emissions due to residential combustion are burdened with 30 percent of damages due to this sector. $PM_{2.5}$ emissions from the cooking subcategory is predominantly (~80 percent) from commercial charbroiling. $PM_{2.5}$ from dust-based sources contributes another $3.3 billion; fugitive windblown dust, and dust from paved and unpaved roads are responsible for $1.2 billion, $1.4 billion, and $0.7 billion, respectively. Construction and demolition, farming operations, and managed burning and disposal are responsible for $1 billion each.

7.3.2.3 Stationary Sources

For stationary sources, fuel combustion is responsible for around $1.5 billion in damages (roughly 50 percent from NO_x and $PM_{2.5}$), and industrial processes are responsible for another $1.3 billion.

7.3.2.4 Comparing Damages in Fresno and Los Angeles Counties

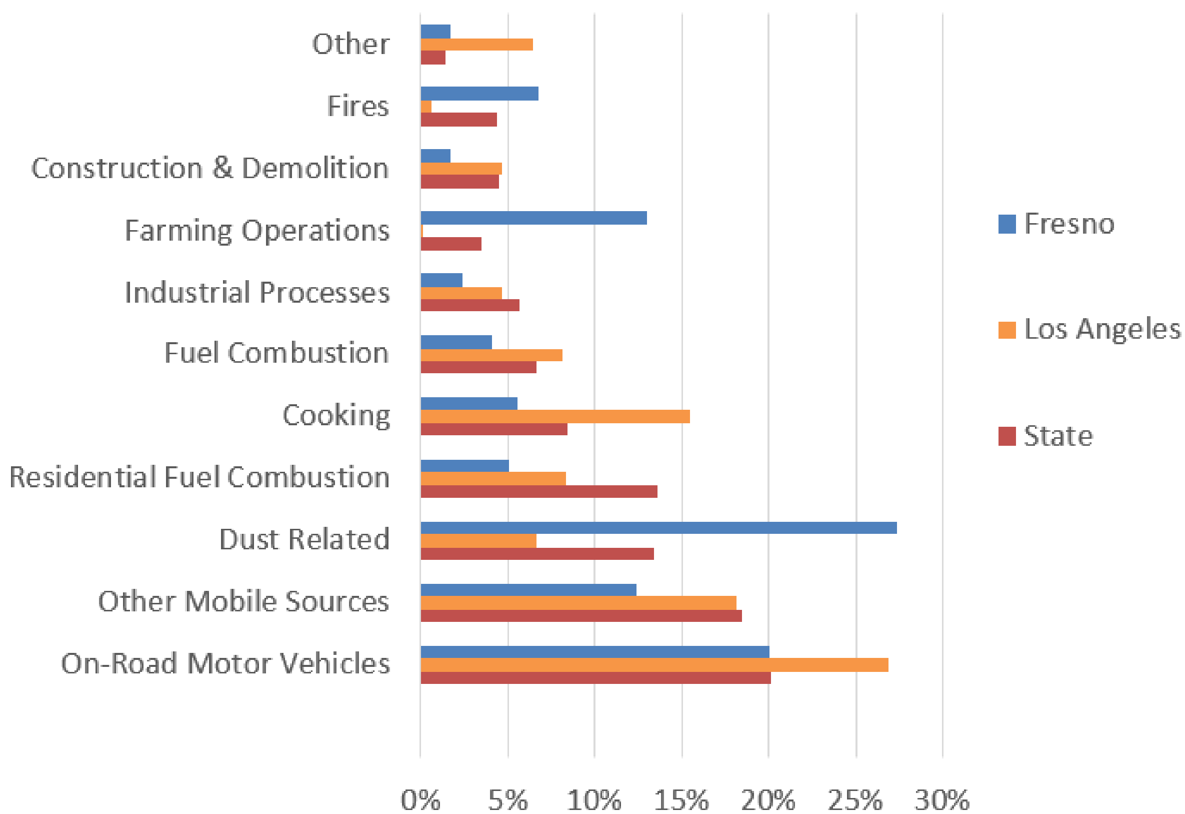
The EASIUR estimate of overall cost of health damages for Fresno County is $0.5 billion, whereas the total damages for Los Angeles County is more than $5 billion. The share of damages attributed to each source vary widely between Fresno and Los Angeles counties (Figure 37). Nonresidential and non-energy sources – $PM_{2.5}$ emissions from farming operations and dust (fugitive windblown and paved and unpaved road dust) – are responsible for more than 40 percent of the overall damages in Fresno. By contrast, in Los Angeles, on-road motor vehicles and off-road sources account for more than 45 percent of the county's emissions. Figure 38 gives the breakdown of on-road pollution sources and shows that while mostly heavy-duty trucks contribute the majority of damages from on-road vehicles in Fresno, the shares of light-duty vehicles and trucks are closer in Los Angeles. Figure 39 shows the breakdown for off-road sources. Farming equipment in Fresno and off-road equipment in Los Angeles are the biggest regional sources, contributing 60 percent and 40 percent, respectively, of the counties' transportation-sector damages.

7.3.2.5 Damages in Fresno County

Total health damages in Fresno County are estimated to be $519 million. As seen from Figure 37, the fraction of total damages from stationary sources – residential fuel combustion, cooking, and other fuel combustion – is relatively small. Damages by subcategories is provided in Table F.3. It can be seen that eliminating all nonwood home fuel combustion to zero would reduce overall county health damages only by 1.4 percent, and that eliminating home electricity use (such as, through rooftop solar PV and storage) would reduce overall county health damages only by half a percentage point (Table F.4). This result suggests that a larger residential energy opportunity for improving health and air quality is to reduce wood burning or replace wood-burning stove and fireplaces with cleaner-burning fuels. Wood stoves and fireplaces contribute 3.7 percent of overall damages, but no breakdown of the two subcategories was available.

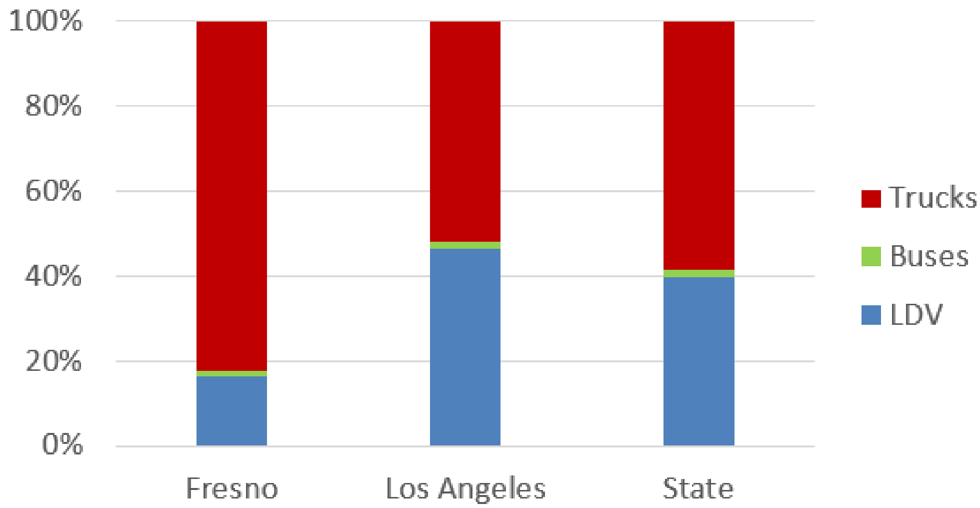
These data show that technology measures can achieve different policy objectives and that achieving higher energy efficiency, implementing more rooftop PV, or electrifying natural gas appliances may save energy (and reduce customer bill costs in the first two cases) but do not significantly shift the balance for air quality and health outcomes in the Central Valley. These data are for damages in 2016. As transport pollution (for example, NO_x) is cleaned up, residential combustion will have a larger relative share of damages, but $PM_{2.5}$ will still be a small fraction of non-energy sources.

Figure 37: Share of Damages for Fresno and Los Angeles Relative to California



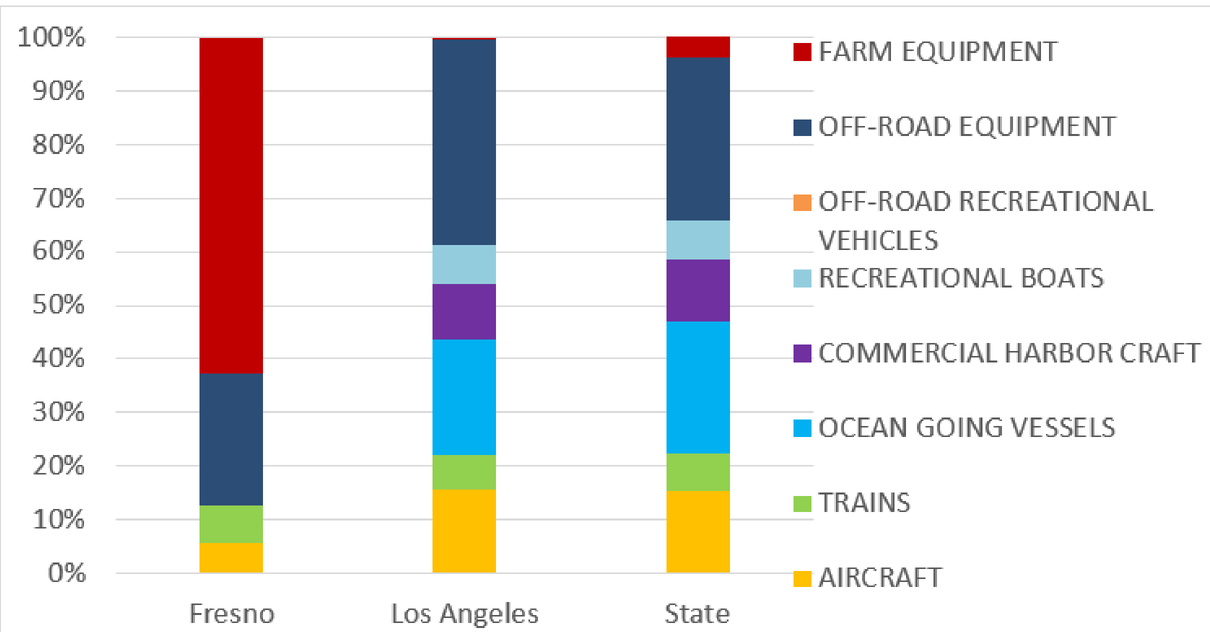
Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 38: Comparing Shares of Damages From On-Road Vehicles



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

Figure 39: Comparing Shares of Damages From Off-Road Mobile Sources



Source: Max Wei, Shuba V. Raghavan, and Patricia Hidalgo-González, LBNL

7.4 Conclusions

Using emissions inventories from the California Air Resources Board coupled with an air quality and health impact model, the research team estimates damages from the NO_x, SO_x, and $PM_{2.5}$ all-source emissions to be about $25 billion. About 20 percent of emissions are from on-road motor vehicles, 18 percent are from other mobile sources, 17 percent are dust-related and 13 percent are from residential fuel combustion (dominated by wood-burning stoves and fireplaces).

Based on 2015 estimated damages in Fresno County, residential wood burning has a bigger impact as a mitigation measure for air quality and health impacts than residential rooftop PV, home retrofits for energy efficiency, or electrification of natural gas-based end uses.

These emissions and damages are not static and will change with population, growth, economic activity, technological changes, and policy regulations. For example, with aggressive state policies for NO_x emissions controls, the ratio of direct $PM_{2.5}$ emissions to NO_x emissions (in tons per day) in the Central Valley will increase from about a 1:5 ratio in 2013 to 1:3 ratio by2025.[31] To expedite the reduction in NO_x and $PM_{2.5}$ from diesel trucks, focusing on the most affected regions such as dense urban areas with a confluence of freeways and targeting older vehicles with the highest emissions per vehicle ("cash for clunkers" or cash-for-repair programs) would be beneficial.

31 CARB presentation, public workshop, Fresno, California, December 1, 2016.

CHAPTER 8: Cost Analysis Case Studies

8.1 Scenarios to Decarbonize Residential Water Heating

This section is taken from a recent published journal paper by the research team as part of this project (Raghavan et al 2017). Key results are presented in this section and full details of the analysis and analysis assumptions can be found in the journal paper.

This study presents a detailed long-term stock turnover model to investigate scenarios to decarbonize California's residential water heating, which is dominated by natural gas. Here the focus is on decarbonizing residential water heating by the adoption of high-efficiency electric heat pumps (HP), leveraging the lowering carbon intensity of the grid. While for new homes electrified water and space heating might be cost-effective under several scenarios, mandating existing homes to retrofit or replace appliances with nonconventional heating equipment can be expensive and difficult. To avoid locking in expensive assets that might be less than ideal in the long run, a careful analysis of multiple aspects of available and emerging technologies should be undertaken.

In this backdrop, technically feasible scenarios to reduce the 2050 annual GHG emissions from residential water heating by 80 percent below 1990 levels are developed. This reduction will result in annual savings of roughly 10 million metric tons of emissions. However, unless hot water demand can be reduced by 25 percent from the current level, these scenarios fall short of the state's 2030 emissions target of 40 percent reduction below 1990 levels (SB 32). The net present value of the incremental cost of these pathways is estimated to be 5 percent to 15 percent higher than the business-as-usual, frozen scenario (Appendix G, Table G-2), not including any additional grid supply costs. This analysis demonstrates that fuel switching to electricity must begin phasing in before 2020 for California to achieve its 2050 emissions goals.

8.1.1 Model Overview

Six broad categories of available water-heating technologies are modeled: natural gas storage water heater (NGWH), instantaneous or tankless natural gas WH (INGWH), electric-resistant WH (ERWH), propane WH (PWH), air source heat pump WH (HPWH), advanced heat pumps (AdvHP) with CO_2 (global warming potential = 1) as refrigerant, and solar thermal water heaters (SThWH). Efficiencies, costs, and adoption timeline of these water heating technologies can be found in Appendix G.

The stock turnover model takes into account five factors that influence emissions from using water heaters: (i) carbon intensity of the fuel source; (ii) heating equipment energy efficiency given by the energy factor (EF) and existing federal and state energy efficiency appliance standard; (iii) timing of fuel switching, such as starting in 2020 compared to 2030; (iv) global warming potential (GWP) of refrigerants and emissions from refrigerant leaks; and (v) hot water consumption. A comparison of energy consumption, emissions, and life-cycle costs under different adoption years of the WH technologies can be found in in Figures G-1, G-2, and G-3 in Appendix G.

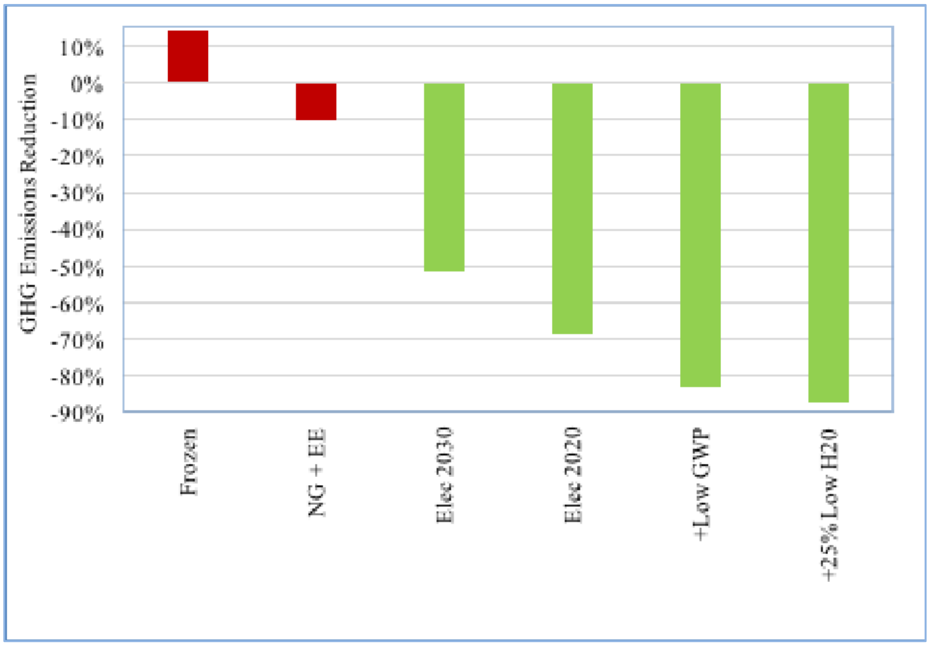
The scenarios developed here start with the current natural gas-dominated, business-as-usual or frozen scenario with current appliance efficiency standards held fixed into the future and where electricity generation meets the 50 percent Renewables Portfolio Standard by 2030. Water heaters are replaced only on natural retirement, and the transition to alternative technologies is phased in gradually over time. Each subsequent scenario incrementally adds possible future policy assumptions above the previous one, progressively reducing GHG emissions. The technology fuel type and efficiency of replacement water heaters vary depending on the particular scenario. A combination of the six WH technologies described above constitutes the market share of the residential market share of water heaters in any specific year depending on the scenario. A description of the six scenarios considered is given in Table G-4. Some of the policies considered here are gradually reducing grid carbon intensity to meet the 2050 goal of 80 percent GHG emissions reduction, increasing WH efficiencies every decade, and switching to heat pumps with lower GWP refrigerants. The high GWP (more than 1,400) efficiencies (HFCs) based refrigerants in appliances such as heat pumps have to be phased down to lower GWP alternatives to comply with SB 1383 and the recent amendment to Montreal Protocol (U.S. EPA-GWP, 2016).

8.1.2 Conclusion and Policy Implications

The researchers found that for the sector's 2050 emissions to decrease by 80 percent relative to 1990, the following factors have to occur: (i) a gradual electrification phase-in by 2020, (ii) an increase in water heating appliance efficiencies, (iii) a decrease in GWP of refrigerants, and (iv) a decrease in grid carbon intensity. Contribution of each of these four factors in emissions reduction is shown in Figure 40. The first two bars are natural gas-based scenarios. Figure 41 shows the total energy demand in 2050 from each of the scenarios. Table G-5 gives a range of overall costs associated with the various scenarios.

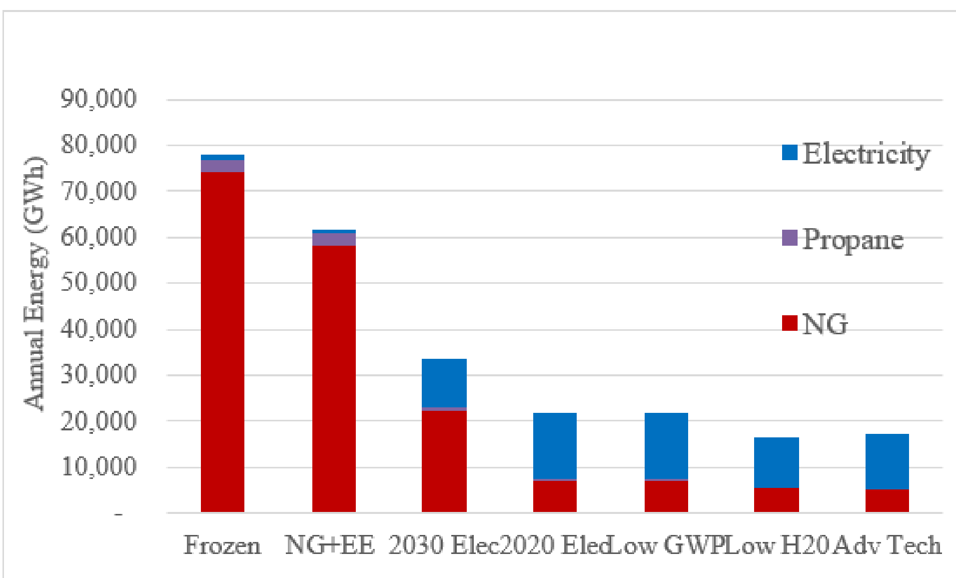
The cost range of the scenarios depends on energy and equipment costs, as well as hot water consumption. Adhering to a strict pathway of decarbonizing the electricity supply, phasing in electrification of water heating, achieving steady gains in heat pump water heater energy efficiency, and transitioning to lower global warming potential refrigerants can result in the desired emissions reduction. However, only by combining these measures with a 25 percent reduction in hot water can the sector meet the 2030 target; this will also help bring down the energy and life-cycle costs of adopting heat pump technologies. The team found that waiting until 2030 for the natural gas stock to switch to electricity (assuming gradual rates of adoption, i.e. the research team does not assume a "forced" transition), can at best reduce the 2050 emissions by 50 percent and that electrification phase-in would need to occur in 2020 to meet the 2050 decarbonization target. A forced replacement could in principle move out the latest year for electrification but would result in greater stranded equipment costs, would not provide the equipment manufacturing industry time to ramp up production, and would constitute greater discontinuity to electricity load for grid planners and utilities. An aggregated population of electric storage water heaters could provide grid support or greater flexibility for a grid with more intermittent renewables, and more studies or testing in this area would be informative for utilities and grid planners. Further, the demand-response capability can help lower the costs of electric storage-based water heaters, especially those of high-efficiency heat pumps.

Figure 40: Stepwise Emissions Reduction in 2050 From 2016 Under "2020 Elec + Low GWP"



Source: Lawrence Berkeley National Laboratory

Figure 41: Total Energy Demand in 2050 Under Different Scenarios



Source: Lawrence Berkeley National Laboratory

8.2 Future Cost Reduction of Hydrogen Fuel Cell Vehicles

This section is taken from a recently published journal paper by the research team as part of this project (Ruffini and Wei 2018). Key results are presented in this section, and full details of the analysis and analysis assumptions can be found in the journal paper.

Many countries and regions of the world are pursuing aggressive decarbonization policies in the transportation sector to sharply reduce the sales of conventional gasoline and diesel-powered internal combustion engine vehicles (ICEV). Zero-emission vehicles such as battery-electric vehicles (BEV) and fuel cell electric vehicles (FCEV) have zero tailpipe emissions but can still be considerably more expensive than ICEVs, a key factor hampering wider-scale adoption. Beyond “first-cost” barriers, there are other market adoption barriers such as information awareness and range anxiety for BEVs and lack of a hydrogen fueling infrastructure for FCEVs.

To compare FCEV costs with BEVs and ICEVs, researchers developed a top-down model starting from the latest assumptions for vehicle adoption scenarios from the International Energy Agency (IEA 2016), shown in Figure G-5 in Appendix G. The economic effects given by technology learning and economies of scale are applied to vehicle and infrastructure costs, and the station network needed to support the vehicle fleet is assessed. Researchers then performed a life-cycle cost (LCC) analysis to evaluate the total cost of ownership, including vehicle purchasing and operational costs, as well as the externality cost of carbon emissions to power the LDV.

8.2.1 Results

The 10-year LCC evolution over time of the three vehicle technologies considered is presented in Figure G-7 in Appendix G. The cost trends obtained from the sum of four contributions:

- Vehicle purchase price
- Nonfuel operational costs (insurance, maintenance, etc.)
- Fuel operational costs
- CO_2 emissions costs

The LCC is the NPV cost of these four factors. Based on the inputs used in the model, the FCEV LCC decreases strongly until 2030, mostly from rapid cost reduction of the vehicle and hydrogen, while afterward it remains almost constant at a value of just under $50,000. The break-even point between FCEVs and ICEVs occurs around 2021 in the Optimistic case, whereas in the Base case, it occurs in or around 2024.

8.2.1.1 Sensitivity Analysis

To establish the parameters that most affect the results, a sensitivity analysis was performed. Figure 42 shows the sensitivity analysis results. Reducing the FC system learning rate leads to the most significant modification in the results compared to the nominal case. With an 8 percent learning rate for the fuel cell system, the break-even point of the FCEVs with ICEVs would happen around 2050, and the economic competitiveness of FCEVs with other technologies would not depend on the vehicle deployment scenario, given that the life-cycle cost for both cases analyzed is almost the same after 2030.

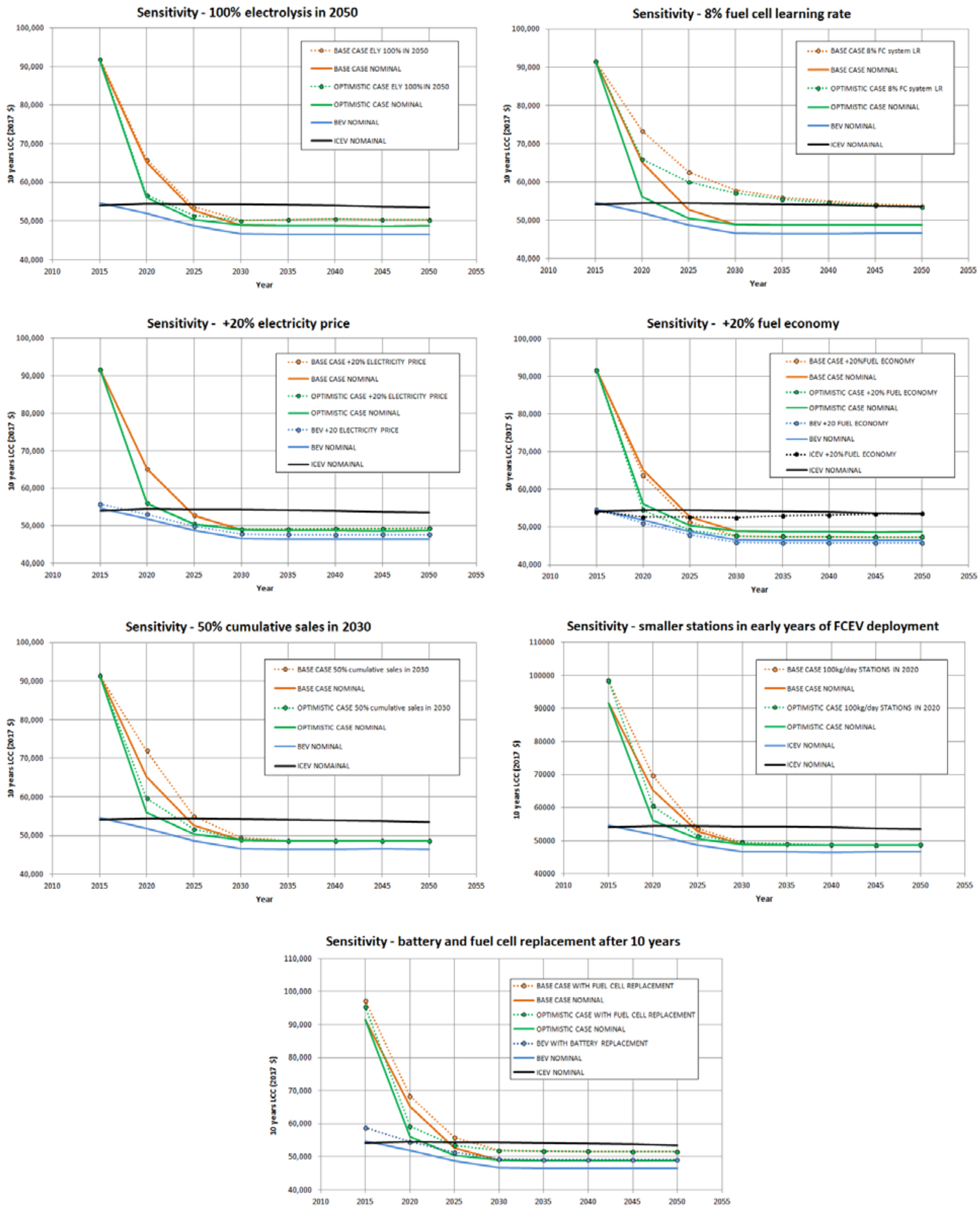
8.2.2 Conclusions

The primary aim of this work was to explore the possible cost-competitiveness of FCEVs compared to BEV and ICEV technologies in California by assessing the main potentials and sensitive factors that lead to the TCO reduction over time. In particular, a learning rate-based approach was used to quantify the effects of future vehicle adoption scenarios on the forecasted hydrogen and vehicle costs, which were evaluated together with the economic value of carbon emissions and operating costs. The results can be summarized as follows:

- The FCEVs adoption scenario affects the LCC only in the first phase of vehicles deployment. Independent of the learning rates used, cost curves tend to converge to the same value by 2030. However, the base case and sensitivity case assume 8 million and 4 million FCEV in 2030, respectively, and current international targets are much lower than this at around 1 million vehicles in 2030. Appendix G discusses the importance of establishing FCEV adoption targets globally.
- The biggest potential for cost reduction is associated with the fuel cell system, which in 2015 accounts for almost 35 percent of the total cost of ownership calculated on a 10-year lifetime. In this regard, the FC learning rate plays an outsize role in determining the cost-competitiveness of FCEVs with other vehicle technologies.
- A slower adoption rate is another factor that can reduce the competitiveness of FCEVs relative to the ICE reference case by several years. If there is a slower adoption rate, for example, 50 percent lower adoption and single-digit learning rate, FCEVs will have difficulty competing with ICEVs and BEVs until/before 2050.
- The cost of hydrogen, produced either through central SMR or by on-site electrolysis, shows a significant reduction until 2025 and remains constant afterward. Price increases in electricity and fuel inputs compensate for the reductions in investment costs from equipment learning rates and station utilization improvements.

Future areas of work include a deeper-level analysis on the learning rate potential of fuel cell systems in FCEVs, in particular for the fuel cell stack, balance of plant components, integration of balance of plant components, and continued study of historical cost reductions in fuel cell systems and other electrochemical technologies. Finally, the role of deployment programs such as incentives, rebates, and national targets on the learning rates and cost reductions of other low-emission vehicle technologies are a topic for further study to apply best lessons and practices to FCEVs deployment programs.

Figure 42: Sensitivity Analysis Results



Source: Ruffini and Wei 2018

CHAPTER 9:
Scenario Results and Key Risk Areas

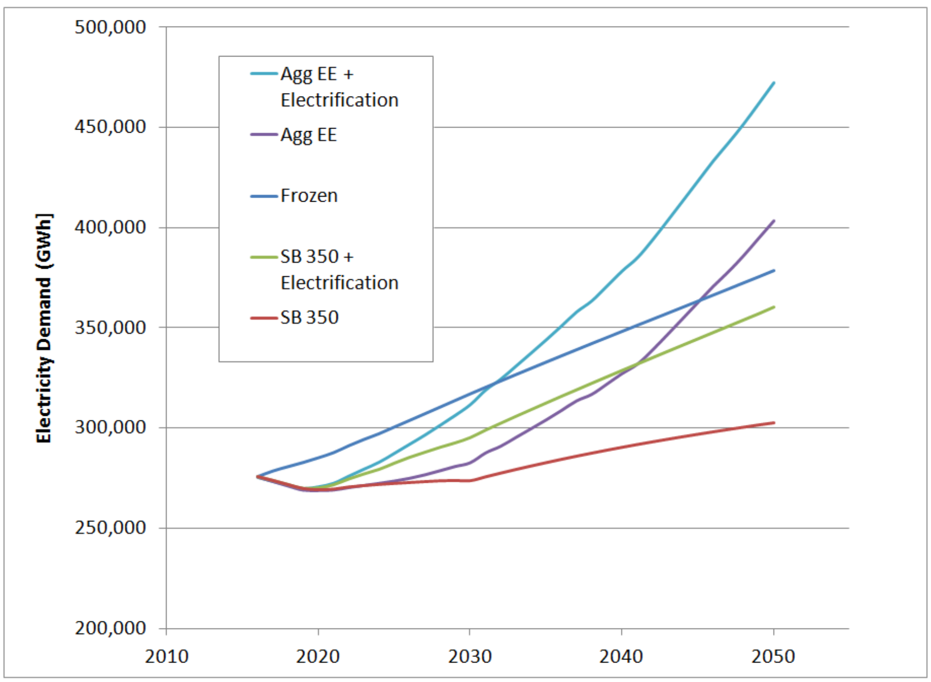
9.1 Electricity Demands

Total California electricity demands by scenario are summarized and shown in Figure 43.

- Frozen scenario demand increases to 317,000 GWh in 2030 and 379,000 GWh in 2050.
- SB 350 load is estimated to be 274,000 GWh in 2030, increasing to 303,000 GWh in 2050.
- SB 350+Electrification load is at 295,000 GWh in 2030, increasing to 360,000 GWh in 2050.
- Aggressive EE reduces the load to 263,000 GWh in 2030, increasing to 297,000 in 2050.
- Aggressive EE + Electrification increases load to 312,000 in 2030 and 473,000 GWh in 2050.

The key points are that the SB 350 scenario electricity demand grows by only 10 percent from 2016 to 2050 with a 0.3 percent annual growth rate, but electricity demand for the compliant Aggressive EE + Electrification scenario grows by 75 percent from 2016 to 2050, with five times the growth rate (1.6 percent annual growth rate). The compliant case also has an 18 percent higher load in 2030 than the SB 350 case, driven by higher electric vehicle adoption and the onset of building electrification starting in 2020, as described in Chapter 5.

Figure 43: Total Electricity Demand From 2016 to 2050 for the Five Key Scenarios



Source: Lawrence Berkeley National Laboratory

9.1.1 Biomass Supply

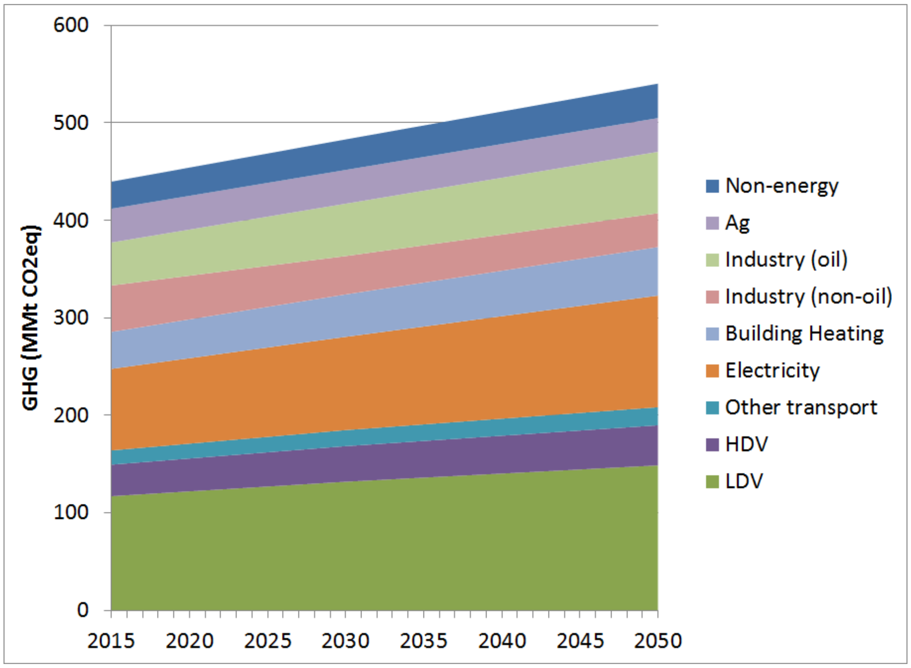
As described in Chapter 2, the biomass supply is assumed to follow the modified biomass supply presented in the 2016 Mid-Century Report (White House 2016) but excludes energy crops on cropland in the supply. California is assumed to have access to a population-weighted "fair share" of this supply which is estimated to be about 91 million bone dry tons of biomass in 2030, and 120 million bone dry tons in 2050.

9.1.2 GHG Emissions by Scenario

Overall GHG emissions are show in Figures 44 through 46. Frozen demand emissions are estimated to grow to 540 MMt CO_2e in 2050 from 440 MMt in 2015. The SB 350 scenario is estimated to grow to 355 MMt CO_2e in 2030 and decrease to 317 MMt CO_2e in 2050. This is 37 percent over the SB 32 target of 258.6 MMt CO_2e in 2030 and more than three and a half times greater than the 2050 goal of 86 MMt CO_2e.

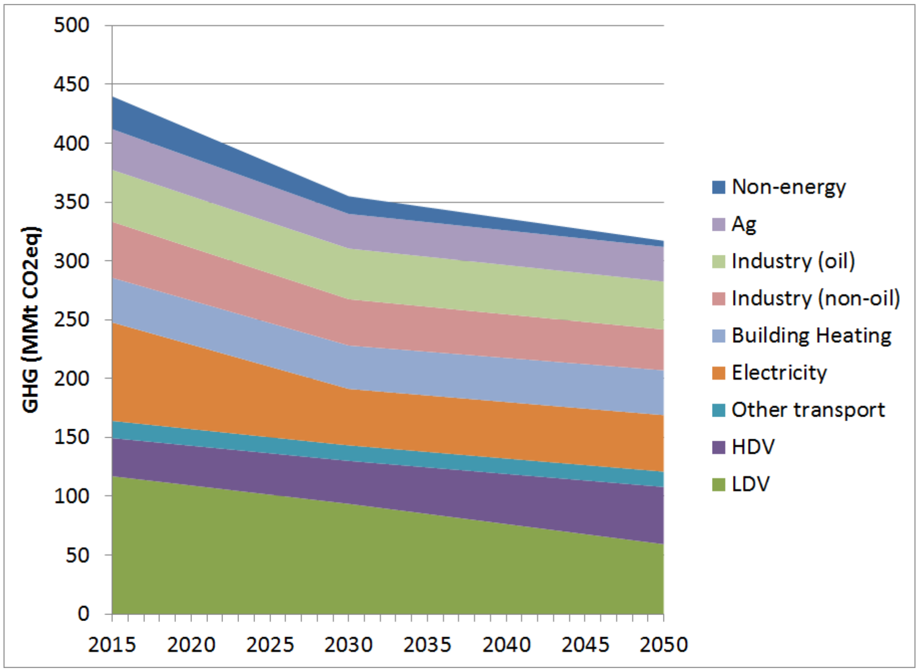
The compliant Aggressive EE + Electrification scenario shown in Figure 9.4 meets the 2030 target and 2050 goal with 5.0 billion gallons of gasoline equivalent (Bgge) of biofuels in 2030 and 4.5 Bgge of biofuels in 2050. This outcome represents California using 105 percent of its population-weighted fair share in 2030 and 72 percent of its fair share in 2050. While California is slightly above its population-weighted fair share of biomass in 2030, this may not be an issue if the rest of the United States is not biomass-constrained due to national or regional climate policies.

Figure 44: Frozen Scenario Greenhouse Gases



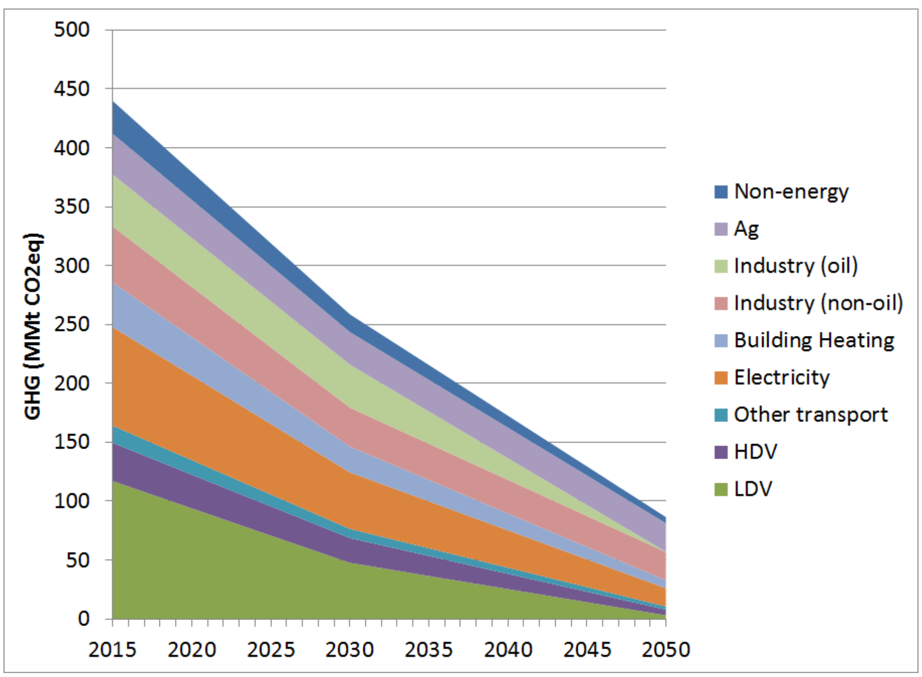
Source: Lawrence Berkeley National Laboratory

Figure 45: Senate Bill 350 Scenario Greenhouse Gases



Source: Lawrence Berkeley National Laboratory

Figure 46: GHG Emissions for the Aggressive EE + Electrification Scenario

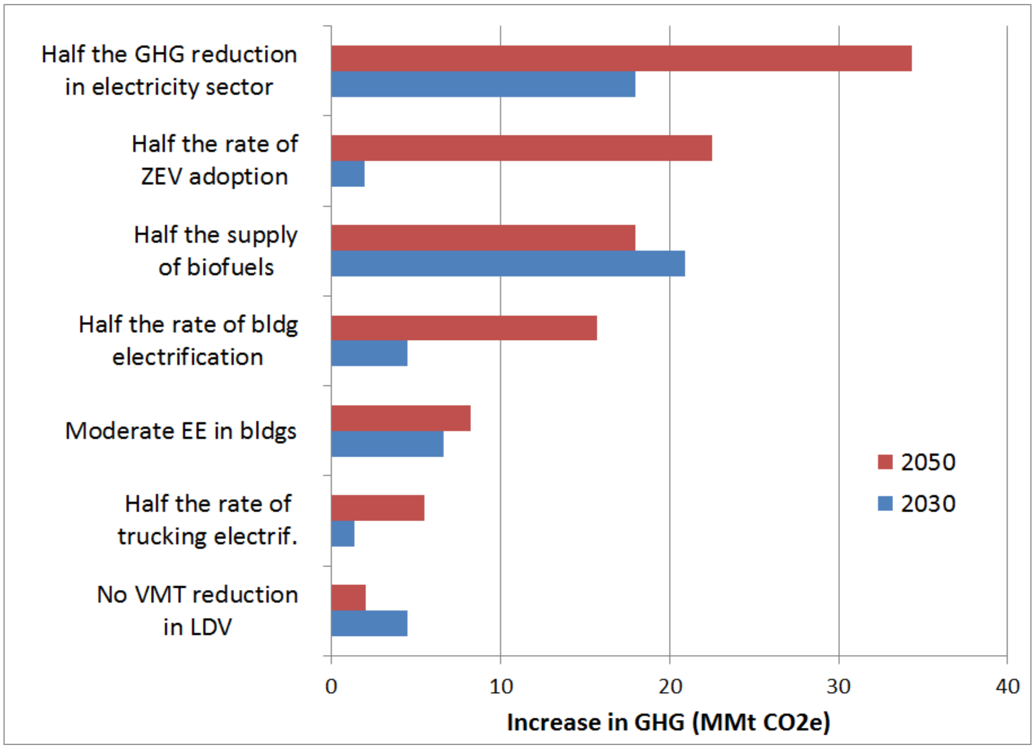


This scenario complies with the SB 32 target of 40 percent reduction from 1990 (258.6 MMt CO2e) and the 2050 goal of 80 percent reduction from 1990 (86MMt CO2e).

Source: Lawrence Berkeley National Laboratory

Sensitivity to some of the key assumptions for the compliant Aggressive EE + Electrification scenario is shown in Figure 47. For 2050, the electricity sector, ZEV adoption, biofuel supply, and the rate of building electrification are seen to have the highest sensitivities, while for 2030, biofuels, the electricity sector, and energy efficiency in buildings have the largest sensitivities.

Figure 47: Sensitivity of Greenhouse Gas Emissions in 2030 and 2050



Source: Lawrence Berkeley National Laboratory

9.2 Additional Risks for 2030 and 2050

9.2.1 Methane and Nitrous Oxide

Two areas of higher potential emissions are methane and nitrous oxide emissions. Methane emissions are widely thought to be significantly higher than the reported values. Recent research from LBNL indicates methane emissions are 1.2–1.8 times higher than the CARB inventory, and N_2O emissions are 1.5–2.5 times higher (Jeong 2016, Jeong 2018). High-emitting N_2O sectors include agricultural soils, industrial processes and product use, and manure management.

Table 6 shows adjusted GHG emissions considering a nominal 1.5X increase in methane emissions from the 2016 CARB inventory and a nominal 2X increase in N_2O emissions. These increases contribute a total of almost 33 MMt additional CO_2 and increase the gap from 2016 emissions to the 2030 target of 259 MMt by 19 percent. A worse-case increase of 1.8 times for methane and 2.5 times for N_2O would increase 2016 emissions by 51.2 MMt CO_2e. (For reference, the entire heavy-duty vehicle sector's GHG emissions in 2016 was 35.6 MMt CO_2e).

Table 6: Adjusted Overall Greenhouse Gas Emissions for 2016 Compared to 2030 Target and 2050 Goal

	Current GHG (2016) and Adjusted Emissions MMt CO2	Individual factor's increase in emissions	Cumulative Increase in emissions	**Cumulative Gap to 2030 Target of 259 MMt CO2e**	Pct. Increase in Gap to 2030	Gap to 2050 goal of 86 MMt CO2e	Pct. Increase in Gap to 2050
Current GHG Emissions, 2016	429.4	-		**171.4**	-	343.2	-
2016 emissions, with 1.5X increase in CH4 leakage(+19.5MMt)	448.9	4.5%	4.5%	**190.3**	**11%**	362.7	5.7%
2016 emissions, adding 2X increase in N2O (+13.4 MMt)	462.3	3.1%	7.7%	**203.7**	**19%**	376.1	9.6%

Source: Lawrence Berkeley National Laboratory

9.2.2 Wildfires

California has experienced an upsurge in large wildfires in the past few years (Rim Fire 2013, Northern California Wine Country 2017, Thomas Fire 2017). The severity of these wildfires is attributed in part to hotter, drier weather from climate change. However, CARB does not include wildfires or forestry emissions in the state's official scoping plan GHG inventory. CARB is working on a carbon stock and emissions projection analysis and is scheduled to complete this work by the end of 2018.

Updated data for 2001-2010 and documentation for the carbon inventory for forests and natural lands are posted at https://www.arb.ca.gov/cc/inventory/sectors/forest/forest.htm.

One study (Gonzalez et al. 2015) estimated that from 2001 through 2010, the amount of carbon stored in California's natural and working lands decreased by 150 million metric tons, with 80 percent of those losses coming from wildfires (Baker 2017).

Estimated GHG emissions from wildfires for 2013, 2014, and 2015 were an average of 23 MMt CO_2e emissions per year as estimated from California wildfires on federal lands during this time frame, with about half of the emissions from large fires (Tarnay et al. 2016). If this sector is included in the state's GHG inventory, these recent data suggest that this sector could be an additional source of emissions, although in the long term, forestry contributions to net GHG emissions may be lower than the full amount incurred in a given calendar year due to regrowth and future carbon sequestration. Forests and working lands, therefore, are an important area for the state to continue to work on for policy mitigation and planning.

This analysis highlights the need for continued focus on natural and working lands, reducing fugitive methane emissions, and better management of N_2O emissions, as well as strengthening climate policies in other sectors to compensate for these potential future increases in GHG emissions.

CHAPTER 10: Conclusions and Future Directions

A key theme of this project is that large-scale changes are required in the energy supply and the end-use demand side to meet California's 2030 GHG target and 2050 GHG goal. On the supply side, the state has aggressive targets for renewable electricity, and clean electricity from renewable energy sources should continue to be the cornerstone of the state's climate plans. The team assumed more aggressive targets than 40 percent GHG reduction (SB 32) and the SB 350 50 percent RPS target in the electricity sector in 2030 to compensate for other sectors that are more difficult to decarbonize. Low-carbon biofuels such as advanced liquid biofuels are important decarbonization routes for heavy-duty transportation and industrial processes. SWITCH

For electricity supply modeling using the SWITCH 2.0 deterministic model, the team finds that modeling three climate change scenarios (HadGEM2-ES, CanESM2, and Miroc5) does not markedly change the electricity generation portfolio in the WECC, with a 2-7 percent increase in capacity compared to the non-climate change scenario.

Modeling climate change uncertainty with a new stochastic modeling approach (Stochastic SWITCH-WECC), the team finds that the ideal robust electricity supply portfolio in the WECC for 2050 has about a 4 percent higher overall installed capacity than the average mix of the three scenarios modeled separately, and about 5.6 percent higher installed gas capacity, due to the greater need for operational flexibility under the wider range of possible conditions.

The land mapping study of the Central Valley reveals that this region of California could accommodate solar energy development on nonconventional surfaces in ways that may preclude loss of farmland and nearby natural habitats that also support agricultural activities by enhancing pollinator services (such as wild bees) and crop yields. Given the diffuse nature of solar energy, advances in battery storage would likely only enhance the economic and environmental appeal of the four solar energy techno-ecological synergies evaluated. The realization of this potential may also confer other techno-ecological synergistic outcomes, and additional research could be conducted to improve the certainty and accuracy of these potential benefits. For example, the degree to which achieving solar energy potential in agricultural landscapes on nonconventional surfaces contributes to food system resilience by alleviating competition of valuable land among farmers, raising property values, generating clean energy for local communities, enhancing air quality, and providing new job opportunities remains largely unexplored.

For the decarbonization of buildings, the research team's analysis shows that it is difficult to meet the 2050 target without beginning an intensive electrification phase by 2020 and assuming no "forced replacement" of existing equipment. A forced replacement could in principle move out the latest year for ramping up the electrification of building heating but would result in greater stranded equipment costs, would not provide the equipment manufacturing industry as much time to ramp up production, and could represent a bigger discontinuity in electricity load for grid planners and utilities.

Sustained policies over time that support building electrification will provide consistent policy signals to the equipment manufacturing industry. Sustained policies allow manufacturers and builders to anticipate and plan for potential new demands, especially heat pump-based equipment. They also provide lead time for grid planners and utilities to plan for the additional electricity load. For a large-scale shift to high-efficiency electrical heat pumps, one of the main impediments is the high upfront cost. Policies to encourage the adoption of heat pump technologies, such as equipment rebates and incentives, could result in larger market adoption, increased learning by doing, and economies of scale in manufacturing.

For the economic case study of residential water heating decarbonization, the research team concludes that an 80 percent or above reduction in 2050 emissions relative to 1990 is technically feasible and formulates multiple representative pathways to achieve this. The cost range of the scenarios depends on energy and equipment costs, as well as hot water consumption. Hot water conservation is a potentially large policy lever in reducing decarbonization costs in the residential hot water heating sector, but the costs of reducing hot water consumption still need to be better quantified.

Since greater customer adoption is critical to achieve the state's decarbonization goals, two high-level deployment goals for vehicles and heat-pump-based heating equipment may provide high leverage: (1) a large-scale outreach and education to consumers, building contractors, plumbers, and heating, ventilation, and air-conditioning (HVAC) technicians and (2) developing regional or even international partnerships that set market adoption targets (such as the eight state multistate ZEV Action Plan[32]), standard-setting, or performance goals in areas such as heat pumps and low-carbon trucking technologies.

On the end-use demand side, a large ramp-up of zero-emission light-duty passenger vehicles (ZEV) and electrified end uses in the building sector is essential. Continued cost reductions in ZEVs (battery-electric vehicles and fuel cell electric vehicles) will hinge on global adoption trends. Recent encouraging global policies include the phasing out of internal combustion engines (ICEs) in several countries by 2040. To ensure the transformation of the light-duty fleet, continued strong deployment policies and state and regional market adoption targets are critical.

Trucks, and diesel trucks in particular, are a large source of air pollutants, and $PM_{2.5}$ emissions from trucks are high in disadvantaged, dense urban communities such as Fresno and Los Angeles. CARB has set aggressive targets to reduce NO_x and $PM_{2.5}$ emissions, as described in Chapter 3. A transition to zero-emission or near-zero-emission trucks, coupled with the state's low-carbon electricity supply mix, could reduce NO_x and $PM_{2.5}$ emissions to nearly zero in these urban regions. A strategy of electrifying trucking or shifting to renewably produced hydrogen-

32 https://www.arb.ca.gov/newsrel/newsrelease.php?id=620, accessed December 3, 2017.

powered trucks in dense urban areas would achieve the policy goals of reduced GHG and improved air quality.

Energy-related policies and incentives should consider balancing multiple policy objectives and impacts, including greenhouse gas (GHG) reduction, health damage reductions, and environmental justice equity issues. If, for example, the policy objective is air pollution reduction for public health improvement in Fresno County, then diesel truck pollution, commercial cooking, and wood-burning stoves are more urgent areas to address than offering incentives for rooftop solar panels or natural gas-based residential space- and water-heating efficiency measures. The prioritization and design of policy measures to synergize these multiple policy objectives and impacts are an important area for further development.

Future work in power sector modeling should build upon these initial stochastic runs in the Western Electricity Coordinating Council (WECC) to analyze resilient capacity investments under different scenarios. Some recommended scenarios to test under this robust optimization framework include megadroughts, wildfires and the related impact on transmission lines, and runs that include a wider data set of historical hourly profiles of wind and solar capacity factors. The research team also recommends extending the planning horizon of future grid simulations to beyond 2050 (for example, 2080 or 2100), since climate change models project a much higher climate impact after 2050.

In the framework of minimizing total costs, the team finds that by 2050, gas plants remain in the system but generate electricity only for a few hours during the year. This result invites researchers to work on redesigning electricity markets so this method of gas plant operations can be profitable for gas power plant investors (such as capacity market designs).

Electrification barriers in industry were described and some practical considerations highlighted (such as the difficulty in moving away from highly efficient combined heat and power processes to full electrification). Other industry decarbonization approaches not discussed in this study include carbon capture and storage for heavy industry such as the cement industry; and using renewable energy such as solar water heating or geothermal energy for process heating.

Electric boilers and hybrid electric/natural gas boilers are highlighted as opportunities for GHG reduction and as potential technologies to provide demand response and grid support for greater supplies of intermittent renewable electricity. The research team recommends more work in this area in technoeconomic analysis and demonstration projects.

One key risk area for the state's 2030 climate target is that the current inventory may significantly underestimate non-CO_2 emissions from methane leakage and N_2O sources. Accounting for these emission could increase the 2016 baseline emissions by up to 51.2 MMt CO_2e or 12.9 percent. This observation highlights the need to improve reduction of these gases and/or to increase mitigation efforts in other sectors to compensate for this increase.

LIST OF ACRONYMS AND ABBREVIATIONS

CARB	California Air Resources Board
BEV	Battery-electric vehicle
CAISO	California Independent System Operator
CARB	California Air Resources Board
CC	Climate change
CCC1	California Carbon Challenge 1
CCC2	California Carbon Challenge 2
CDD	Cooling-degree day
CHP	Combined heat and power
CSP	Concentrating solar power (CSP)
CV	Central Valley
DNI	Direct normal irradiance
DR	Demand response
EE	Energy efficiency
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EVSE	Electric vehicle supply equipment
FCEV	Fuel cell-electric vehicle
FCS	Fuel cell system
GHG	Greenhouse gases
GW	Gigawatt
GWh	Gigawatt-hour
GWP	Global warming potential
HDD	Heating-degree day
HDV	Heavy-duty vehicle
HH	Households
HPWH	Heat pump water heater

kW	Kilowatt
kWh	Kilowatt-hour
LCC	Life-cycle cost
LDV	Light-duty vehicle
LR	Learning rate
LULCC	Land-use and land-cover change
NG	Natural gas
NO_x	Oxides of nitrogen
PG&E	Pacific Gas and Electric Company
PHEV	Plug-in hybrid vehicle
PM	Particulate matter
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act
SLCP	Short-lived climate pollutants
SMR	Steam methane reforming
SMUD	Sacramento Municipal Utility District
SO_x	Oxides of sulfur
SWITCH	Electricity supply capacity-expansion model developed at UC-Berkeley
TES	Technoeconomic synergy
TW	Terawatt
TWh	Terawatt-hour
UEC	Unit energy consumption
USSE	Utility-scale solar energy
WECC	Western Electricity Coordinating Council
WH	Water heater
ZEV	Zero-emissions vehicle
ZNE	Zero net energy

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APPENDIX A: Experience Curves

Technology learning is widely accepted as a mechanism through which technology costs reductions can occur, a concept originating from observations that manufacturing processes improve as production increases (Wright, 1936). This has important implications for understanding past technology developments and program benefits, as well as forecasting technology market growth for policy planning and scenario modeling.

Experience curves are the most common framework for assessing technology learning and cost reduction with increasing production volume. These curves are thought to follow a power law, with the rate of cost reduction a power law function of cumulative production volume:

$$C(t_2)/C(t_1) = (V(t_2)/V(t_1))^{-b}$$

where

$C(t_2)$ = cost at time t_2 and $V(t_2)$ = cumulative production volume at time t_2

$C(t_1)$ = cost at time t_1 and $V(t_1)$ = cumulative production volume at time t_1

and b is an empirically observed parameter. For every doubling in cumulative production volume,

$$C(t_2)/C(t_1) = 2^{-b}$$

The percentage by which cost decreases for every doubling of production is referred to as the learning rate ($LR= 1-2^{-b}$), while the fraction of initial cost after every doubling of production is defined as the progress ratio (PR=1-LR) (Wright, 1936).

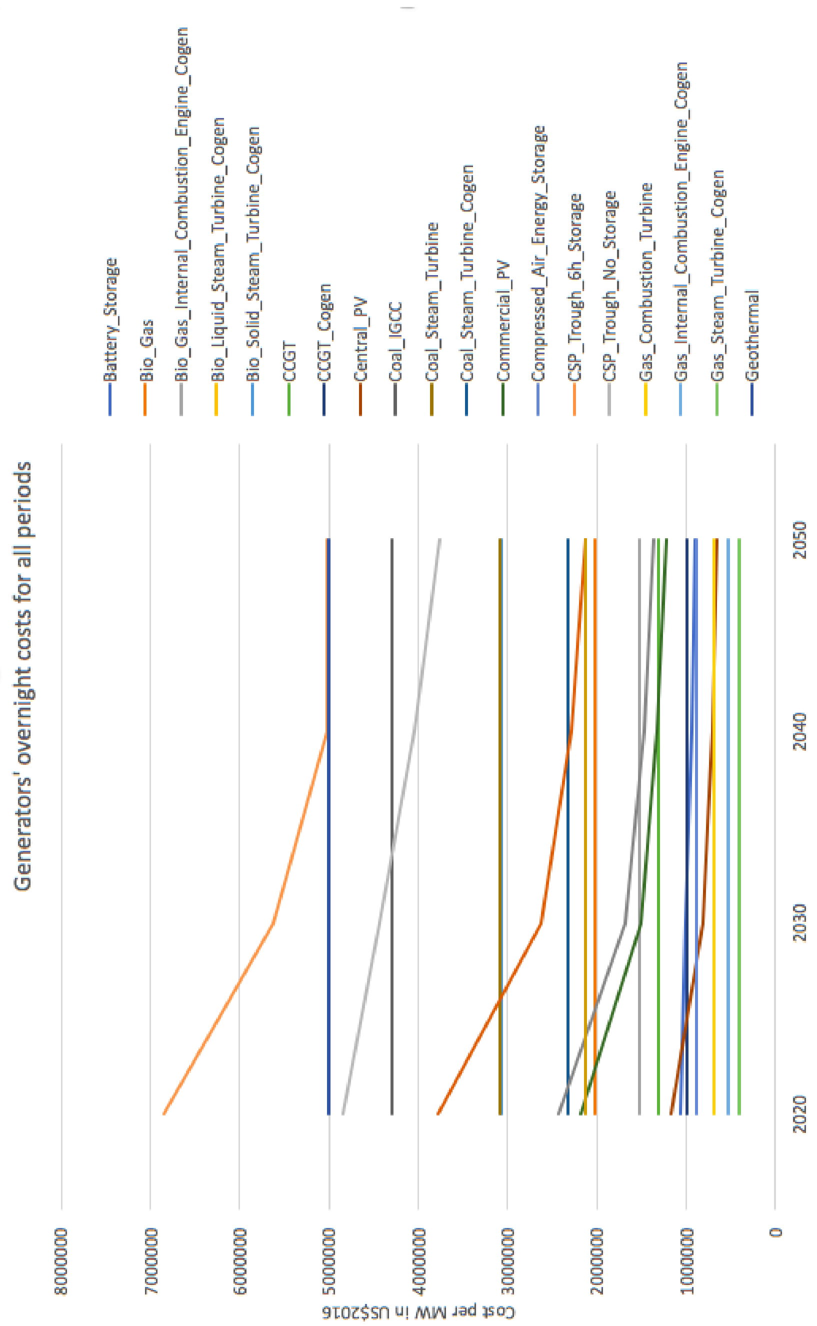
Learning curves, which directly relate cumulative production to labor costs, are a subset of experience curves, which relate cumulative production to overall cost or price (although the terms “learning curve” and “experience curve” are often used interchangeably). Therefore, learning curves reflect short-run learning by doing, while experience curves incorporate a broader set of cost components (Hall, 1985). Shifts in production cost may be reflected in the experience curve by a change in the learning rate, or slope of the curve.

Experience curves are commonly fit as a single-power law, with the learning rate derived from the exponent of the resulting equation (Weiss et al., 2009). In the research team’s broad study of historical energy technology development, the team found that many experience curves can be better fit with piecewise power laws, indicating a change in the learning rate at some point in time. The team discusses development of these experience curves and implications of changing learning rates for program analysis and technology projections.

Market prices are often used as a proxy for a product’s manufactured costs since market prices are more directly observable than manufacturing costs. However, prices can mask the cost structure of a product and introduce uncertainties in the technology learning of the product due to pricing and market effects. Despite these caveats, market prices are often used for experience curve analyses.

APPENDIX B:
SWITCH Data

Figure B-1: SWITCH Overnight Costs



Source: Black and Veatch (2012) and Energy and Environmental Economics (E3, 2016)

Table B-1: Expected Device Stocks and Energy Required for Charging per Zone and Year

	LDVs (PHEV + BEV) stock [million units]				Energy required [GWh]			
Year / Zone	2020	2030	2040	2050	2020	2030	2040	2050
CA	0.85	6.59	19.98	31.67	2636.62	16362.59	46856.60	91493.80
RM-AZNM	0.007	0.41	3.09	9.77	200.00	1600.00	8292.308	24107.69
WECC-CAN	0.044	0.72	3.28	7.21	600.00	4223.08	12738.46	26123.08
NWPP	0.09	1.40	6.25	13.48	1200.0	8192.31	24215.38	48807.69

Table B-2: Fraction of Shifted Demand by Period and Zone

Average Moveable Percentage of Hourly Total Demand	Period			
	2020	2030	2040	2050
Total % CA [w.r.t. total load]	**0.30%**	**2.00%**	**7.00%**	**10.00%**
Total % non-CA [w.r.t. total load]	**0.00%**	**0.30%**	**2.00%**	**7.00%**

w.r.t. = with respect to

SWITCH outputs

Table B-3: Total WECC Capacity Installed in 2050 for Each Scenario

Scenario	GW in 2050
Frozen	603
SB 350	470
SB 350_Electrif.	559
Aggressive EE	669
Aggressive EE_Electrif.	777
EV+DR, Aggressive EE_Electrif.	643
CanESM2 + Agg. EE_Electrif.	792
HadGEM2ES + Agg. EE_Electrif.	833
MIROC5 + Agg. EE_Electrif.	792

Table B-4: Total WECC Capacity by Fuel Installed in 2050 for Each Scenario

Fuel	Period	Scenario	Capacity_GW	Percent
Storage	2050	Frozen	10.8	2%
Solar	2050	Frozen	134.4	22%
Wind	2050	Frozen	288.7	48%
Gas	2050	Frozen	94.5	16%
Hydropower	2050	Frozen	53.6	9%
Coal	2050	Frozen	2.6	0%
Uranium	2050	Frozen	5.4	1%
Geothermal	2050	Frozen	11.1	2%
Biomass	2050	Frozen	2.3	0%
Waste_Heat	2050	Frozen	0.0	0%
Oil	2050	Frozen	0.0	0%
Storage	2050	SB 350	1.7	0%
Solar	2050	SB 350	101.9	22%
Wind	2050	SB 350	210.0	45%
Gas	2050	SB 350	82.2	17%
Hydropower	2050	SB 350	53.6	11%
Coal	2050	SB 350	2.6	1%
Uranium	2050	SB 350	5.4	1%
Geothermal	2050	SB 350	11.1	2%
Biomass	2050	SB 350	2.3	0%
Waste_Heat	2050	SB 350	0.0	0%
Oil	2050	SB 350	0.0	0%
Storage	2050	SB 350_Electrif.	7.8	1%
Solar	2050	SB 350_Electrif.	125.1	22%
Wind	2050	SB 350_Electrif.	267.6	48%
Gas	2050	SB 350_Electrif.	83.6	15%
Hydropower	2050	SB 350_Electrif.	53.6	10%
Coal	2050	SB 350_Electrif.	2.6	0%
Uranium	2050	SB 350_Electrif.	5.4	1%
Geothermal	2050	SB 350_Electrif.	11.1	2%
Biomass	2050	SB 350_Electrif.	2.3	0%
Waste_Heat	2050	SB 350_Electrif.	0.0	0%
Oil	2050	SB 350_Electrif.	0.0	0%
Storage	2050	Aggressive EE	31.2	5%
Solar	2050	Aggressive EE	120.6	18%
Wind	2050	Aggressive EE	354.9	53%
Gas	2050	Aggressive EE	87.7	13%
Hydropower	2050	Aggressive EE	53.6	8%
Coal	2050	Aggressive EE	2.6	0%

Fuel	Period	Scenario	Capacity_GW	Percent
Uranium	2050	Aggressive EE	5.4	1%
Geothermal	2050	Aggressive EE	11.1	2%
Biomass	2050	Aggressive EE	2.3	0%
Waste_Heat	2050	Aggressive EE	0.0	0%
Oil	2050	Aggressive EE	0.0	0%
Storage	2050	Aggressive EE_Electrif.	36.7	5%
Solar	2050	Aggressive EE_Electrif.	137.8	18%
Wind	2050	Aggressive EE_Electrif.	432.7	56%
Gas	2050	Aggressive EE_Electrif.	94.8	12%
Hydropower	2050	Aggressive EE_Electrif.	53.6	7%
Coal	2050	Aggressive EE_Electrif.	2.6	0%
Uranium	2050	Aggressive EE_Electrif.	5.4	1%
Geothermal	2050	Aggressive EE_Electrif.	11.1	1%
Biomass	2050	Aggressive EE_Electrif.	2.3	0%
Waste_Heat	2050	Aggressive EE_Electrif.	0.0	0%
Oil	2050	Aggressive EE_Electrif.	0.0	0%
Storage	2050	EV+DR, Aggressive EE_Electrif.	6.8	1%
Solar	2050	EV+DR, Aggressive EE_Electrif.	137.8	20%
Wind	2050	EV+DR, Aggressive EE_Electrif.	376.9	53%
Gas	2050	EV+DR, Aggressive EE_Electrif.	108.5	15%
Hydropower	2050	EV+DR, Aggressive EE_Electrif.	53.6	8%
Coal	2050	EV+DR, Aggressive EE_Electrif.	2.6	0%
Uranium	2050	EV+DR, Aggressive EE_Electrif.	5.4	1%
Geothermal	2050	EV+DR, Aggressive EE_Electrif.	11.1	2%
Biomass	2050	EV+DR, Aggressive EE_Electrif.	2.3	0%
Waste_Heat	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Oil	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Storage	2050	CanESM2 + Agg. EE_Electrif.	34.8	4%
Solar	2050	CanESM2 + Agg. EE_Electrif.	155.8	20%
Wind	2050	CanESM2 + Agg. EE_Electrif.	420.5	53%
Gas	2050	CanESM2 + Agg. EE_Electrif.	106.4	13%
Hydropower	2050	CanESM2 + Agg. EE_Electrif.	53.6	7%
Coal	2050	CanESM2 + Agg. EE_Electrif.	2.6	0%
Uranium	2050	CanESM2 + Agg. EE_Electrif.	5.4	1%
Geothermal	2050	CanESM2 + Agg. EE_Electrif.	11.1	1%
Biomass	2050	CanESM2 + Agg. EE_Electrif.	2.3	0%
Waste_Heat	2050	CanESM2 + Agg. EE_Electrif.	0.0	0%
Oil	2050	CanESM2 + Agg. EE_Electrif.	0.0	0%
Storage	2050	HadGEM2ES + Agg. EE_Electrif.	43.3	5%
Solar	2050	HadGEM2ES + Agg. EE_Electrif.	161.7	19%

Fuel	Period	Scenario	Capacity_GW	Percent
Wind	2050	HadGEM2ES + Agg. EE_Electrif.	446.6	54%
Gas	2050	HadGEM2ES + Agg. EE_Electrif.	106.8	13%
Hydropower	2050	HadGEM2ES + Agg. EE_Electrif.	53.6	6%
Coal	2050	HadGEM2ES + Agg. EE_Electrif.	2.6	0%
Uranium	2050	HadGEM2ES + Agg. EE_Electrif.	5.4	1%
Geothermal	2050	HadGEM2ES + Agg. EE_Electrif.	11.1	1%
Biomass	2050	HadGEM2ES + Agg. EE_Electrif.	2.3	0%
Waste_Heat	2050	HadGEM2ES + Agg. EE_Electrif.	0.0	0%
Oil	2050	HadGEM2ES + Agg. EE_Electrif.	0.0	0%
Storage	2050	MIROC5 + Agg. EE_Electrif.	34.5	4%
Solar	2050	MIROC5 + Agg. EE_Electrif.	153.3	19%
Wind	2050	MIROC5 + Agg. EE_Electrif.	425.2	54%
Gas	2050	MIROC5 + Agg. EE_Electrif.	104.4	13%
Hydropower	2050	MIROC5 + Agg. EE_Electrif.	53.6	7%
Coal	2050	MIROC5 + Agg. EE_Electrif.	2.6	0%
Uranium	2050	MIROC5 + Agg. EE_Electrif.	5.4	1%
Geothermal	2050	MIROC5 + Agg. EE_Electrif.	11.1	1%
Biomass	2050	MIROC5 + Agg. EE_Electrif.	2.3	0%
Waste_Heat	2050	MIROC5 + Agg. EE_Electrif.	0.0	0%
Oil	2050	MIROC5 + Agg. EE_Electrif.	0.0	0%

Table B-5: Total Capacity Installed in California in 2050 for Each Scenario

Scenario	GW in 2050
Frozen	84
SB 350	71
SB 350_Electrif.	76
Aggressive EE	77
Aggressive EE_Electrif.	102
EV+DR, Aggressive EE_Electrif.	90
CanESM2 + Agg. EE_Electrif.	96
HadGEM2ES + Agg. EE_Electrif.	93
MIROC5 + Agg. EE_Electrif.	92

Table B-6: Total Capacity Installed in California by Fuel in 2050 for Each Scenario

Fuel	Period	Scenario	Capacity_GW	Percent
Storage	2050	Frozen	1.1	1%
Solar	2050	Frozen	18.7	22%
Wind	2050	Frozen	11.3	13%
Gas	2050	Frozen	35.4	42%
Hydropower	2050	Frozen	12.9	15%
Coal	2050	Frozen	0.0	0%
Uranium	2050	Frozen	0.0	0%
Geothermal	2050	Frozen	4.5	5%
Biomass	2050	Frozen	1.0	1%
Waste_Heat	2050	Frozen	0.0	0%
Oil	2050	Frozen	0.0	0%
Storage	2050	SB 350	0.2	0%
Solar	2050	SB 350	14.7	20%
Wind	2050	SB 350	10.9	15%
Gas	2050	SB 350	27.7	38%
Hydropower	2050	SB 350	12.9	18%
Coal	2050	SB 350	0.0	0%
Uranium	2050	SB 350	0.0	0%
Geothermal	2050	SB 350	4.5	6%
Biomass	2050	SB 350	1.0	1%
Waste_Heat	2050	SB 350	0.0	0%
Oil	2050	SB 350	0.0	0%
Storage	2050	SB 350_Electrif.	0.1	0%
Solar	2050	SB 350_Electrif.	18.2	24%
Wind	2050	SB 350_Electrif.	11.5	15%
Gas	2050	SB 350_Electrif.	28.2	37%
Hydropower	2050	SB 350_Electrif.	12.9	17%
Coal	2050	SB 350_Electrif.	0.0	0%
Uranium	2050	SB 350_Electrif.	0.0	0%
Geothermal	2050	SB 350_Electrif.	4.5	6%
Biomass	2050	SB 350_Electrif.	1.0	1%
Waste_Heat	2050	SB 350_Electrif.	0.0	0%
Oil	2050	SB 350_Electrif.	0.0	0%
Storage	2050	Aggressive EE	12.2	16%
Solar	2050	Aggressive EE	15.1	20%
Wind	2050	Aggressive EE	11.8	15%
Gas	2050	Aggressive EE	19.7	26%
Hydropower	2050	Aggressive EE	12.9	17%
Coal	2050	Aggressive EE	0.0	0%

Fuel	Period	Scenario	Capacity_GW	Percent
Uranium	2050	Aggressive EE	0.0	0%
Geothermal	2050	Aggressive EE	4.5	6%
Biomass	2050	Aggressive EE	1.0	1%
Waste_Heat	2050	Aggressive EE	0.0	0%
Oil	2050	Aggressive EE	0.0	0%
Storage	2050	Aggressive EE_Electrif.	14.9	15%
Solar	2050	Aggressive EE_Electrif.	19.7	19%
Wind	2050	Aggressive EE_Electrif.	11.9	12%
Gas	2050	Aggressive EE_Electrif.	37.7	37%
Hydropower	2050	Aggressive EE_Electrif.	12.9	13%
Coal	2050	Aggressive EE_Electrif.	0.0	0%
Uranium	2050	Aggressive EE_Electrif.	0.0	0%
Geothermal	2050	Aggressive EE_Electrif.	4.5	4%
Biomass	2050	Aggressive EE_Electrif.	1.0	1%
Waste_Heat	2050	Aggressive EE_Electrif.	0.0	0%
Oil	2050	Aggressive EE_Electrif.	0.0	0%
Storage	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Solar	2050	EV+DR, Aggressive EE_Electrif.	22.2	25%
Wind	2050	EV+DR, Aggressive EE_Electrif.	11.9	13%
Gas	2050	EV+DR, Aggressive EE_Electrif.	37.0	41%
Hydropower	2050	EV+DR, Aggressive EE_Electrif.	12.9	14%
Coal	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Uranium	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Geothermal	2050	EV+DR, Aggressive EE_Electrif.	4.5	5%
Biomass	2050	EV+DR, Aggressive EE_Electrif.	1.0	1%
Waste_Heat	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Oil	2050	EV+DR, Aggressive EE_Electrif.	0.0	0%
Storage	2050	CanESM2 + Agg. EE_Electrif.	12.3	13%
Solar	2050	CanESM2 + Agg. EE_Electrif.	21.9	23%
Wind	2050	CanESM2 + Agg. EE_Electrif.	11.9	12%
Gas	2050	CanESM2 + Agg. EE_Electrif.	31.7	33%
Hydropower	2050	CanESM2 + Agg. EE_Electrif.	12.9	13%
Coal	2050	CanESM2 + Agg. EE_Electrif.	0.0	0%
Uranium	2050	CanESM2 + Agg. EE_Electrif.	0.0	0%
Geothermal	2050	CanESM2 + Agg. EE_Electrif.	4.5	5%

Fuel	Period	Scenario	Capacity_GW	Percent
Biomass	2050	CanESM2 + Agg. EE_Electrif.	1.0	1%
Waste_Heat	2050	CanESM2 + Agg. EE_Electrif.	0.0	0%
Oil	2050	CanESM2 + Agg. EE_Electrif.	0.0	0%
Storage	2050	HadGEM2ES + Agg. EE_Electrif.	13.7	15%
Solar	2050	HadGEM2ES + Agg. EE_Electrif.	22.3	24%
Wind	2050	HadGEM2ES + Agg. EE_Electrif.	11.9	13%
Gas	2050	HadGEM2ES + Agg. EE_Electrif.	27.1	29%
Hydropower	2050	HadGEM2ES + Agg. EE_Electrif.	12.9	14%
Coal	2050	HadGEM2ES + Agg. EE_Electrif.	0.0	0%
Uranium	2050	HadGEM2ES + Agg. EE_Electrif.	0.0	0%
Geothermal	2050	HadGEM2ES + Agg. EE_Electrif.	4.5	5%
Biomass	2050	HadGEM2ES + Agg. EE_Electrif.	1.0	1%
Waste_Heat	2050	HadGEM2ES + Agg. EE_Electrif.	0.0	0%
Oil	2050	HadGEM2ES + Agg. EE_Electrif.	0.0	0%
Storage	2050	MIROC5 + Agg. EE_Electrif.	10.9	12%
Solar	2050	MIROC5 + Agg. EE_Electrif.	20.5	22%
Wind	2050	MIROC5 + Agg. EE_Electrif.	11.9	13%
Gas	2050	MIROC5 + Agg. EE_Electrif.	30.6	33%
Hydropower	2050	MIROC5 + Agg. EE_Electrif.	12.9	14%
Coal	2050	MIROC5 + Agg. EE_Electrif.	0.0	0%
Uranium	2050	MIROC5 + Agg. EE_Electrif.	0.0	0%
Geothermal	2050	MIROC5 + Agg. EE_Electrif.	4.5	5%
Biomass	2050	MIROC5 + Agg. EE_Electrif.	1.0	1%
Waste_Heat	2050	MIROC5 + Agg. EE_Electrif.	0.0	0%
Oil	2050	MIROC5 + Agg. EE_Electrif.	0.0	0%

Table B-7: Total Transmission Capacity Installed Between California and the Rest of the WECC in 2050 for Each Scenario

Scenario	GW in 2050
Frozen	119
SB 350	94
SB 350_Electrif.	112
Aggressive EE	124
Aggressive EE_Electrif.	139
EV+DR, Aggressive EE_Electrif.	134
CanESM2 + Agg. EE_Electrif.	137
HadGEM2ES + Agg. EE_Electrif.	148
MIROC5 + Agg. EE_Electrif.	144

Table B-8: Total Transmission Capacity Installed in the WECC in 2050 for Each Scenario

Scenario	GW in 2050
Frozen	1229
SB 350	1027
SB 350_Electrif.	1175
Aggressive EE	1342
Aggressive EE_Electrif.	1590
EV+DR, Aggressive EE_Electrif.	1459
CanESM2 + Agg. EE_Electrif.	1489
HadGEM2ES + Agg. EE_Electrif.	1562
MIROC5 + Agg. EE_Electrif.	1552

Table B-9: Transmission Capacity Installed by Period in the WECC for Each Scenario

Period	Scenario	Capacity_GW	Percent
2050	Frozen	372	30%
2040	Frozen	54	4%
2030	Frozen	9	1%
2020	Frozen	0	0%
Legacy	Frozen	794	65%
2050	SB 350	188	18%
2040	SB 350	36	4%
2030	SB 350	5	0%
2020	SB 350	4	0%
Legacy	SB 350	794	77%
2050	SB 350_Electrif.	323	28%
2040	SB 350_Electrif.	50	4%
2030	SB 350_Electrif.	4	0%
2020	SB 350_Electrif.	4	0%
Legacy	SB 350_Electrif.	794	68%
2050	Aggressive EE	490	37%
2040	Aggressive EE	50	4%
2030	Aggressive EE	3	0%
2020	Aggressive EE	4	0%
Legacy	Aggressive EE	794	59%
2050	Aggressive EE_Electrif.	702	44%
2040	Aggressive EE_Electrif.	82	5%
2030	Aggressive EE_Electrif.	6	0%
2020	Aggressive EE_Electrif.	4	0%
Legacy	Aggressive EE_Electrif.	794	50%
2050	EV+DR, Aggressive EE_Electrif.	452	39%

Period	Scenario	Capacity_GW	Percent
2040	EV+DR, Aggressive EE_Electrif.	76	5%
2030	EV+DR, Aggressive EE_Electrif.	5	0%
2020	EV+DR, Aggressive EE_Electrif.	4	0%
Legacy	EV+DR, Aggressive EE_Electrif.	794	54%
2050	CanESM2 + Agg. EE_Electrif.	605	41%
2040	CanESM2 + Agg. EE_Electrif.	82	5%
2030	CanESM2 + Agg. EE_Electrif.	7	0%
2020	CanESM2 + Agg. EE_Electrif.	1	0%
Legacy	CanESM2 + Agg. EE_Electrif.	794	53%
2050	HadGEM2ES + Agg. EE_Electrif.	668	43%
2040	HadGEM2ES + Agg. EE_Electrif.	93	6%
2030	HadGEM2ES + Agg. EE_Electrif.	5	0%
2020	HadGEM2ES + Agg. EE_Electrif.	1	0%
Legacy	HadGEM2ES + Agg. EE_Electrif.	794	51%
2050	MIROC5 + Agg. EE_Electrif.	663	43%
2040	MIROC5 + Agg. EE_Electrif.	85	5%
2030	MIROC5 + Agg. EE_Electrif.	6	0%
2020	MIROC5 + Agg. EE_Electrif.	4	0%
Legacy	MIROC5 + Agg. EE_Electrif.	794	51%

Table B-10: Transmission Capacity Installed by Period Between California and the WECC for Each Scenario

Period	Scenario	Capacity_GW	Percent
2050	Frozen	35	30%
2040	Frozen	15	13%
2030	Frozen	1	1%
2020	Frozen	0	0%
Legacy	Frozen	67	57%
2050	SB 350	17	18%
2040	SB 350	7	8%
2030	SB 350	0	0%
2020	SB 350	2	2%
Legacy	SB 350	67	71%
2050	SB 350_Electrif.	33	30%
2040	SB 350_Electrif.	9	8%
2030	SB 350_Electrif.	1	1%
2020	SB 350_Electrif.	2	2%
Legacy	SB 350_Electrif.	67	60%

Period	Scenario	Capacity_GW	Percent
2050	Aggressive EE	41	33%
2040	Aggressive EE	12	10%
2030	Aggressive EE	1	1%
2020	Aggressive EE	2	2%
Legacy	Aggressive EE	67	54%
2050	Aggressive EE_Electrif.	53	38%
2040	Aggressive EE_Electrif.	16	12%
2030	Aggressive EE_Electrif.	1	1%
2020	Aggressive EE_Electrif.	2	2%
Legacy	Aggressive EE_Electrif.	67	48%
2050	EV+DR, Aggressive EE_Electrif.	48	35%
2040	EV+DR, Aggressive EE_Electrif.	15	13%
2030	EV+DR, Aggressive EE_Electrif.	1	1%
2020	EV+DR, Aggressive EE_Electrif.	2	2%
Legacy	EV+DR, Aggressive EE_Electrif.	67	50%
2050	CanESM2 + Agg. EE_Electrif.	49	36%
2040	CanESM2 + Agg. EE_Electrif.	18	13%
2030	CanESM2 + Agg. EE_Electrif.	2	1%
2020	CanESM2 + Agg. EE_Electrif.	1	1%
Legacy	CanESM2 + Agg. EE_Electrif.	67	49%
2050	HadGEM2ES + Agg. EE_Electrif.	59	40%
2040	HadGEM2ES + Agg. EE_Electrif.	21	14%
2030	HadGEM2ES + Agg. EE_Electrif.	1	1%
2020	HadGEM2ES + Agg. EE_Electrif.	0	0%
Legacy	HadGEM2ES + Agg. EE_Electrif.	67	45%
2050	MIROC5 + Agg. EE_Electrif.	55	38%
2040	MIROC5 + Agg. EE_Electrif.	19	13%
2030	MIROC5 + Agg. EE_Electrif.	1	1%
2020	MIROC5 + Agg. EE_Electrif.	2	1%
Legacy	MIROC5 + Agg. EE_Electrif.	67	47%

Table B-11: Generation in 2050 in the WECC for Each Scenario

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Storage	2050	Frozen	20562	2%
Solar	2050	Frozen	259072	19%
Wind	2050	Frozen	680661	50%
Gas	2050	Frozen	89338	7%
Hydropower	2050	Frozen	165273	12%
Coal	2050	Frozen	0	0%

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Uranium	2050	Frozen	24764	2%
Geothermal	2050	Frozen	94351	7%
Biomass	2050	Frozen	16556	1%
Waste_Heat	2050	Frozen	16	0%
Oil	2050	Frozen	0	0%
Storage	2050	SB 350	3099	0%
Solar	2050	SB 350	199794	18%
Wind	2050	SB 350	530105	47%
Gas	2050	SB 350	102235	9%
Hydropower	2050	SB 350	165244	15%
Coal	2050	SB 350	18	0%
Uranium	2050	SB 350	26137	2%
Geothermal	2050	SB 350	94346	8%
Biomass	2050	SB 350	16555	1%
Waste_Heat	2050	SB 350	21	0%
Oil	2050	SB 350	1	0%
Storage	2050	SB 350_Electrif.	14688	1%
Solar	2050	SB 350_Electrif.	231369	18%
Wind	2050	SB 350_Electrif.	661118	51%
Gas	2050	SB 350_Electrif.	93773	7%
Hydropower	2050	SB 350_Electrif.	165226	13%
Coal	2050	SB 350_Electrif.	2	0%
Uranium	2050	SB 350_Electrif.	24203	2%
Geothermal	2050	SB 350_Electrif.	94350	7%
Biomass	2050	SB 350_Electrif.	16556	1%
Waste_Heat	2050	SB 350_Electrif.	17	0%
Oil	2050	SB 350_Electrif.	0	0%
Storage	2050	Aggressive EE	52274	4%
Solar	2050	Aggressive EE	237782	16%
Wind	2050	Aggressive EE	790839	55%
Gas	2050	Aggressive EE	66422	5%
Hydropower	2050	Aggressive EE	165273	11%
Coal	2050	Aggressive EE	0	0%
Uranium	2050	Aggressive EE	23153	2%
Geothermal	2050	Aggressive EE	94351	7%
Biomass	2050	Aggressive EE	16556	1%
Waste_Heat	2050	Aggressive EE	15	0%
Oil	2050	Aggressive EE	0	0%
Storage	2050	Aggressive EE_Electrif.	54727	3%
Solar	2050	Aggressive EE_Electrif.	249300	15%

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Wind	2050	Aggressive EE_Electrif.	953709	59%
Gas	2050	Aggressive EE_Electrif.	64775	4%
Hydropower	2050	Aggressive EE_Electrif.	165269	10%
Coal	2050	Aggressive EE_Electrif.	0	0%
Uranium	2050	Aggressive EE_Electrif.	20933	1%
Geothermal	2050	Aggressive EE_Electrif.	94351	6%
Biomass	2050	Aggressive EE_Electrif.	16556	1%
Waste_Heat	2050	Aggressive EE_Electrif.	15	0%
Oil	2050	Aggressive EE_Electrif.	0	0%
Storage	2050	EV+DR, Aggressive EE_Electrif.	11291	1%
Solar	2050	EV+DR, Aggressive EE_Electrif.	262242	17%
Wind	2050	EV+DR, Aggressive EE_Electrif.	890533	57%
Gas	2050	EV+DR, Aggressive EE_Electrif.	96364	6%
Hydropower	2050	EV+DR, Aggressive EE_Electrif.	165274	11%
Coal	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Uranium	2050	EV+DR, Aggressive EE_Electrif.	23095	1%
Geothermal	2050	EV+DR, Aggressive EE_Electrif.	94351	6%
Biomass	2050	EV+DR, Aggressive EE_Electrif.	16556	1%
Waste_Heat	2050	EV+DR, Aggressive EE_Electrif.	16	0%
Oil	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Storage	2050	CanESM2 + Agg. EE_Electrif.	46886	3%
Solar	2050	CanESM2 + Agg. EE_Electrif.	268632	17%
Wind	2050	CanESM2 + Agg. EE_Electrif.	907149	56%
Gas	2050	CanESM2 + Agg. EE_Electrif.	70606	4%
Hydropower	2050	CanESM2 + Agg. EE_Electrif.	191893	12%
Coal	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Uranium	2050	CanESM2 + Agg. EE_Electrif.	20935	1%
Geothermal	2050	CanESM2 + Agg. EE_Electrif.	94351	6%
Biomass	2050	CanESM2 + Agg. EE_Electrif.	16556	1%
Waste_Heat	2050	CanESM2 + Agg. EE_Electrif.	15	0%
Oil	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Storage	2050	HadGEM2ES + Agg. EE_Electrif.	57138	4%
Solar	2050	HadGEM2ES + Agg. EE_Electrif.	269069	16%
Wind	2050	HadGEM2ES + Agg. EE_Electrif.	947050	58%
Gas	2050	HadGEM2ES + Agg. EE_Electrif.	63273	4%
Hydropower	2050	HadGEM2ES + Agg. EE_Electrif.	164459	10%
Coal	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Uranium	2050	HadGEM2ES + Agg. EE_Electrif.	20033	1%
Geothermal	2050	HadGEM2ES + Agg. EE_Electrif.	94351	6%
Biomass	2050	HadGEM2ES + Agg. EE_Electrif.	16556	1%

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Waste_Heat	2050	HadGEM2ES + Agg. EE_Electrif.	15	0%
Oil	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Storage	2050	MIROC5 + Agg. EE_Electrif.	49594	3%
Solar	2050	MIROC5 + Agg. EE_Electrif.	260098	16%
Wind	2050	MIROC5 + Agg. EE_Electrif.	935081	58%
Gas	2050	MIROC5 + Agg. EE_Electrif.	68507	4%
Hydropower	2050	MIROC5 + Agg. EE_Electrif.	177697	11%
Coal	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Uranium	2050	MIROC5 + Agg. EE_Electrif.	20551	1%
Geothermal	2050	MIROC5 + Agg. EE_Electrif.	94351	6%
Biomass	2050	MIROC5 + Agg. EE_Electrif.	16556	1%
Waste_Heat	2050	MIROC5 + Agg. EE_Electrif.	14	0%
Oil	2050	MIROC5 + Agg. EE_Electrif.	0	0%

Table B-12: Generation in 2050 in California for Each Scenario

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Storage	2050	Frozen	2134	1%
Solar	2050	Frozen	34037	22%
Wind	2050	Frozen	25190	16%
Gas	2050	Frozen	15467	10%
Hydropower	2050	Frozen	34998	22%
Coal	2050	Frozen	0	0%
Uranium	2050	Frozen	0	0%
Geothermal	2050	Frozen	38589	24%
Biomass	2050	Frozen	7369	5%
Waste_Heat	2050	Frozen	0	0%
Oil	2050	Frozen	0	0%
Storage	2050	SB 350	368	0%
Solar	2050	SB 350	29050	19%
Wind	2050	SB 350	25443	17%
Gas	2050	SB 350	16808	11%
Hydropower	2050	SB 350	34970	23%
Coal	2050	SB 350	0	0%
Uranium	2050	SB 350	0	0%
Geothermal	2050	SB 350	38588	25%
Biomass	2050	SB 350	7369	5%
Waste_Heat	2050	SB 350	0	0%
Oil	2050	SB 350	0	0%
Storage	2050	SB 350_Electrif.	138	0%

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Solar	2050	SB 350_Electrif.	32419	21%
Wind	2050	SB 350_Electrif.	24467	16%
Gas	2050	SB 350_Electrif.	17094	11%
Hydropower	2050	SB 350_Electrif.	34952	23%
Coal	2050	SB 350_Electrif.	0	0%
Uranium	2050	SB 350_Electrif.	0	0%
Geothermal	2050	SB 350_Electrif.	38589	25%
Biomass	2050	SB 350_Electrif.	7369	5%
Waste_Heat	2050	SB 350_Electrif.	0	0%
Oil	2050	SB 350_Electrif.	0	0%
Storage	2050	Aggressive EE	18611	12%
Solar	2050	Aggressive EE	28735	18%
Wind	2050	Aggressive EE	26730	17%
Gas	2050	Aggressive EE	3733	2%
Hydropower	2050	Aggressive EE	34999	22%
Coal	2050	Aggressive EE	0	0%
Uranium	2050	Aggressive EE	0	0%
Geothermal	2050	Aggressive EE	38589	24%
Biomass	2050	Aggressive EE	7369	5%
Waste_Heat	2050	Aggressive EE	0	0%
Oil	2050	Aggressive EE	0	0%
Storage	2050	Aggressive EE_Electrif.	19970	11%
Solar	2050	Aggressive EE_Electrif.	34004	19%
Wind	2050	Aggressive EE_Electrif.	27213	15%
Gas	2050	Aggressive EE_Electrif.	19422	11%
Hydropower	2050	Aggressive EE_Electrif.	34995	19%
Coal	2050	Aggressive EE_Electrif.	0	0%
Uranium	2050	Aggressive EE_Electrif.	0	0%
Geothermal	2050	Aggressive EE_Electrif.	38589	21%
Biomass	2050	Aggressive EE_Electrif.	7369	4%
Waste_Heat	2050	Aggressive EE_Electrif.	0	0%
Oil	2050	Aggressive EE_Electrif.	0	0%
Storage	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Solar	2050	EV+DR, Aggressive EE_Electrif.	39817	24%
Wind	2050	EV+DR, Aggressive EE_Electrif.	25926	16%
Gas	2050	EV+DR, Aggressive EE_Electrif.	17201	10%
Hydropower	2050	EV+DR, Aggressive EE_Electrif.	35000	21%
Coal	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Uranium	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Geothermal	2050	EV+DR, Aggressive EE_Electrif.	38589	24%

Fuel	Period	Scenario	Gen_GWh_yr	Percent
Biomass	2050	EV+DR, Aggressive EE_Electrif.	7369	4%
Waste_Heat	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Oil	2050	EV+DR, Aggressive EE_Electrif.	0	0%
Storage	2050	CanESM2 + Agg. EE_Electrif.	12409	7%
Solar	2050	CanESM2 + Agg. EE_Electrif.	35553	21%
Wind	2050	CanESM2 + Agg. EE_Electrif.	25501	15%
Gas	2050	CanESM2 + Agg. EE_Electrif.	8218	5%
Hydropower	2050	CanESM2 + Agg. EE_Electrif.	39726	24%
Coal	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Uranium	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Geothermal	2050	CanESM2 + Agg. EE_Electrif.	38589	23%
Biomass	2050	CanESM2 + Agg. EE_Electrif.	7369	4%
Waste_Heat	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Oil	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Storage	2050	HadGEM2ES + Agg. EE_Electrif.	14117	9%
Solar	2050	HadGEM2ES + Agg. EE_Electrif.	36565	23%
Wind	2050	HadGEM2ES + Agg. EE_Electrif.	26750	17%
Gas	2050	HadGEM2ES + Agg. EE_Electrif.	7152	4%
Hydropower	2050	HadGEM2ES + Agg. EE_Electrif.	30794	19%
Coal	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Uranium	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Geothermal	2050	HadGEM2ES + Agg. EE_Electrif.	38589	24%
Biomass	2050	HadGEM2ES + Agg. EE_Electrif.	7369	5%
Waste_Heat	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Oil	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Storage	2050	MIROC5 + Agg. EE_Electrif.	12271	8%
Solar	2050	MIROC5 + Agg. EE_Electrif.	33237	21%
Wind	2050	MIROC5 + Agg. EE_Electrif.	26214	17%
Gas	2050	MIROC5 + Agg. EE_Electrif.	8257	5%
Hydropower	2050	MIROC5 + Agg. EE_Electrif.	31346	20%
Coal	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Uranium	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Geothermal	2050	MIROC5 + Agg. EE_Electrif.	38589	25%
Biomass	2050	MIROC5 + Agg. EE_Electrif.	7369	5%
Waste_Heat	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Oil	2050	MIROC5 + Agg. EE_Electrif.	0	0%

Table B-13: Capacity by 2050 in the WECC for the Climate Change Stochastic Simulation and the Deterministic Climate Change Scenarios

Fuel	Period	Scenario	Capacity_GW	Percent
Storage	2050	Stochastic	43	5%
Solar	2050	Stochastic	161	19%
Wind	2050	Stochastic	447	53%
Gas	2050	Stochastic	114	14%
Hydropower	2050	Stochastic	54	6%
Coal	2050	Stochastic	3	0%
Uranium	2050	Stochastic	5	1%
Geothermal	2050	Stochastic	11	1%
Biomass	2050	Stochastic	2	0%
Waste_Heat	2050	Stochastic	0	0%
Oil	2050	Stochastic	0	0%
Storage	2050	CanESM2 + Agg. EE_Electrif.	35	4%
Solar	2050	CanESM2 + Agg. EE_Electrif.	156	20%
Wind	2050	CanESM2 + Agg. EE_Electrif.	420	53%
Gas	2050	CanESM2 + Agg. EE_Electrif.	106	13%
Hydropower	2050	CanESM2 + Agg. EE_Electrif.	54	7%
Coal	2050	CanESM2 + Agg. EE_Electrif.	3	0%
Uranium	2050	CanESM2 + Agg. EE_Electrif.	5	1%
Geothermal	2050	CanESM2 + Agg. EE_Electrif.	11	1%
Biomass	2050	CanESM2 + Agg. EE_Electrif.	2	0%
Waste_Heat	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Oil	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Storage	2050	HadGEM2ES + Agg. EE_Electrif.	43	5%
Solar	2050	HadGEM2ES + Agg. EE_Electrif.	162	19%
Wind	2050	HadGEM2ES + Agg. EE_Electrif.	447	54%
Gas	2050	HadGEM2ES + Agg. EE_Electrif.	107	13%
Hydropower	2050	HadGEM2ES + Agg. EE_Electrif.	54	6%
Coal	2050	HadGEM2ES + Agg. EE_Electrif.	3	0%
Uranium	2050	HadGEM2ES + Agg. EE_Electrif.	5	1%
Geothermal	2050	HadGEM2ES + Agg. EE_Electrif.	11	1%
Biomass	2050	HadGEM2ES + Agg. EE_Electrif.	2	0%
Waste_Heat	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Oil	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Storage	2050	MIROC5 + Agg. EE_Electrif.	35	4%
Solar	2050	MIROC5 + Agg. EE_Electrif.	153	19%
Wind	2050	MIROC5 + Agg. EE_Electrif.	425	54%
Gas	2050	MIROC5 + Agg. EE_Electrif.	104	13%
Hydropower	2050	MIROC5 + Agg. EE_Electrif.	54	7%

Fuel	Period	Scenario	Capacity_GW	Percent
Coal	2050	MIROC5 + Agg. EE_Electrif.	3	0%
Uranium	2050	MIROC5 + Agg. EE_Electrif.	5	1%
Geothermal	2050	MIROC5 + Agg. EE_Electrif.	11	1%
Biomass	2050	MIROC5 + Agg. EE_Electrif.	2	0%
Waste_Heat	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Oil	2050	MIROC5 + Agg. EE_Electrif.	0	0%

Table B-14: Capacity by 2050 in California for the Climate Change Stochastic Simulation and the Deterministic Climate Change Scenarios

Fuel	Period	Scenario	Capacity_GW	Percent
Storage	2050	Stochastic	9	9%
Solar	2050	Stochastic	22	23%
Wind	2050	Stochastic	12	12%
Gas	2050	Stochastic	36	37%
Hydropower	2050	Stochastic	13	13%
Coal	2050	Stochastic	0	0%
Uranium	2050	Stochastic	0	0%
Geothermal	2050	Stochastic	5	5%
Biomass	2050	Stochastic	1	1%
Waste_Heat	2050	Stochastic	0	0%
Oil	2050	Stochastic	0	0%
Storage	2050	CanESM2 + Agg. EE_Electrif.	12	13%
Solar	2050	CanESM2 + Agg. EE_Electrif.	22	23%
Wind	2050	CanESM2 + Agg. EE_Electrif.	12	12%
Gas	2050	CanESM2 + Agg. EE_Electrif.	32	33%
Hydropower	2050	CanESM2 + Agg. EE_Electrif.	13	13%
Coal	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Uranium	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Geothermal	2050	CanESM2 + Agg. EE_Electrif.	5	5%
Biomass	2050	CanESM2 + Agg. EE_Electrif.	1	1%
Waste_Heat	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Oil	2050	CanESM2 + Agg. EE_Electrif.	0	0%
Storage	2050	HadGEM2ES + Agg. EE_Electrif.	14	15%
Solar	2050	HadGEM2ES + Agg. EE_Electrif.	22	24%
Wind	2050	HadGEM2ES + Agg. EE_Electrif.	12	13%
Gas	2050	HadGEM2ES + Agg. EE_Electrif.	27	29%
Hydropower	2050	HadGEM2ES + Agg. EE_Electrif.	13	14%
Coal	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Uranium	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Geothermal	2050	HadGEM2ES + Agg. EE_Electrif.	5	5%

Fuel	Period	Scenario	Capacity_GW	Percent
Biomass	2050	HadGEM2ES + Agg. EE_Electrif.	1	1%
Waste_Heat	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Oil	2050	HadGEM2ES + Agg. EE_Electrif.	0	0%
Storage	2050	MIROC5 + Agg. EE_Electrif.	11	12%
Solar	2050	MIROC5 + Agg. EE_Electrif.	21	22%
Wind	2050	MIROC5 + Agg. EE_Electrif.	12	13%
Gas	2050	MIROC5 + Agg. EE_Electrif.	31	33%
Hydropower	2050	MIROC5 + Agg. EE_Electrif.	13	14%
Coal	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Uranium	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Geothermal	2050	MIROC5 + Agg. EE_Electrif.	5	5%
Biomass	2050	MIROC5 + Agg. EE_Electrif.	1	1%
Waste_Heat	2050	MIROC5 + Agg. EE_Electrif.	0	0%
Oil	2050	MIROC5 + Agg. EE_Electrif.	0	0%

Table B-15: Transmission Capacity Installed by Period in the WECC for the Climate Change Stochastic Simulation and the Deterministic Climate Change Scenarios

Period	Scenario	Capacity_GW	Percent
2050	Stochastic	660	43%
2040	Stochastic	88	6%
2030	Stochastic	6	0%
2020	Stochastic	3	0%
Legacy	Stochastic	794	51%
2050	CanESM2 + Agg. EE_Electrif.	605	41%
2040	CanESM2 + Agg. EE_Electrif.	82	5%
2030	CanESM2 + Agg. EE_Electrif.	7	0%
2020	CanESM2 + Agg. EE_Electrif.	1	0%
Legacy	CanESM2 + Agg. EE_Electrif.	794	53%
2050	HadGEM2ES + Agg. EE_Electrif.	668	43%
2040	HadGEM2ES + Agg. EE_Electrif.	93	6%
2030	HadGEM2ES + Agg. EE_Electrif.	5	0%
2020	HadGEM2ES + Agg. EE_Electrif.	1	0%
Legacy	HadGEM2ES + Agg. EE_Electrif.	794	51%
2050	MIROC5 + Agg. EE_Electrif.	663	43%
2040	MIROC5 + Agg. EE_Electrif.	85	5%
2030	MIROC5 + Agg. EE_Electrif.	6	0%
2020	MIROC5 + Agg. EE_Electrif.	4	0%
Legacy	MIROC5 + Agg. EE_Electrif.	794	51%

Table B-16: Transmission Capacity Installed by Period Between California and the WECC for the Climate Change Stochastic Simulation and the Deterministic Climate Change Scenarios

Period	Scenario	Capacity_GW	Percent
2050	Stochastic	55	38%
2040	Stochastic	20	14%
2030	Stochastic	1	1%
2020	Stochastic	2	1%
Legacy	Stochastic	67	46%
2050	CanESM2 + Agg. EE_Electrif.	49	36%
2040	CanESM2 + Agg. EE_Electrif.	18	13%
2030	CanESM2 + Agg. EE_Electrif.	2	1%
2020	CanESM2 + Agg. EE_Electrif.	1	1%
Legacy	CanESM2 + Agg. EE_Electrif.	67	49%
2050	HadGEM2ES + Agg. EE_Electrif.	59	40%
2040	HadGEM2ES + Agg. EE_Electrif.	21	14%
2030	HadGEM2ES + Agg. EE_Electrif.	1	1%
2020	HadGEM2ES + Agg. EE_Electrif.	0	0%
Legacy	HadGEM2ES + Agg. EE_Electrif.	67	45%
2050	MIROC5 + Agg. EE_Electrif.	55	38%
2040	MIROC5 + Agg. EE_Electrif.	19	13%
2030	MIROC5 + Agg. EE_Electrif.	1	1%
2020	MIROC5 + Agg. EE_Electrif.	2	1%
Legacy	MIROC5 + Agg. EE_Electrif.	67	47%

APPENDIX C:
Mapping Solar Resources

The official classification description used by the NLCD. (National Land Cover Database) related to percentage of impervious surfaces of total land area.

- **Developed, High Intensity** – highly developed areas where people reside or work in high numbers. Examples include apartment complexes, row houses, and commercial/industrial. Impervious surfaces account for 80% to 100% of the total cover.
- **Developed, Medium Intensity** – areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 50% to 79% of the total cover. These areas most commonly include single-family homes.
- **Developed, Low Intensity** – areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 20% to 49% percent of total cover. These areas most commonly include single-family homes.
- **Developed, Open Space –** areas with a mixture of some constructed materials but mostly vegetation in the form of lawn grasses. Impervious surfaces account for less than 20% of total cover. These areas most commonly include large-lot single-family homes, parks, golf courses, and vegetation planted in developed settings for recreation, erosion control, or aesthetics.

Note: There is not a distinction between roads and parking lots vs. rooftops for the data and analysis.

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APPENDIX D: Buildings

Figure D-1: Stock Turnover Under "SB 350" **Under "Agg EE"**

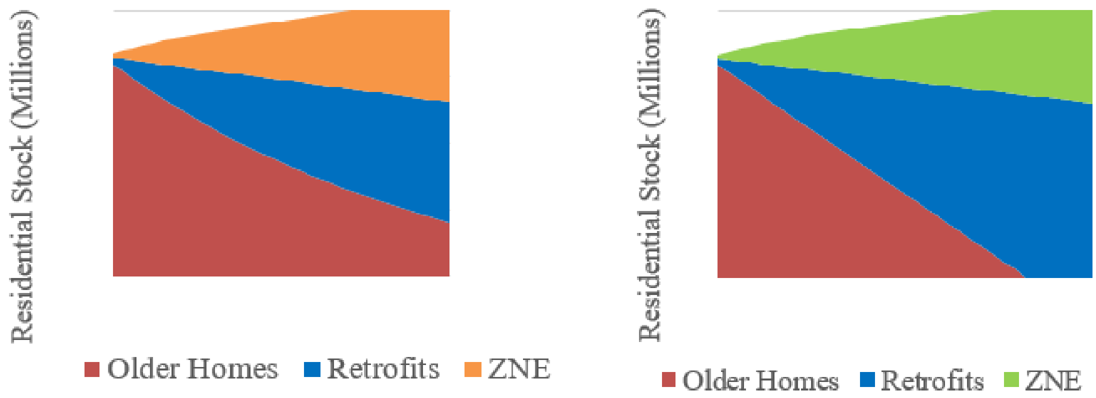


Figure D-2: GHG Emissions Due to Natural Gas Demand in Buildings

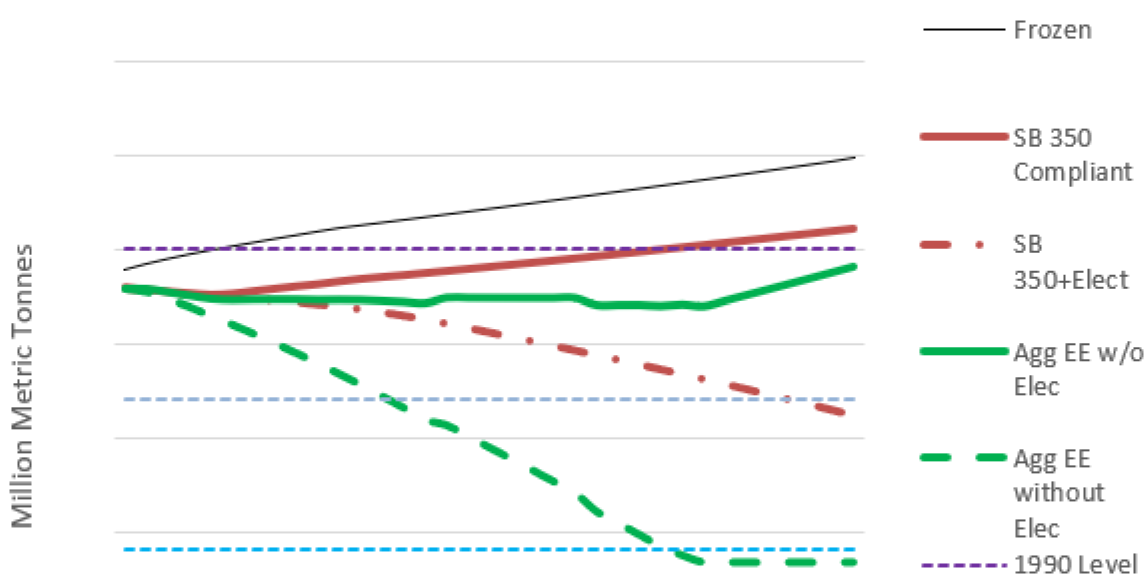


Table D-1: Residential Retrofit Assumptions

	Retrofit UEC without elec (kWh/HH)	Retrofit UEC with elec (kWh/HH)	Retrofit UEC w/o elec (therms/HH	Retrofit UEC With elec (therms/HH)	Retrofit Elec UEC (% Reduction 2016 frozen level)	Retrofit NG % reduction from frozen
2016	5,466	5,599	261.6	262	20%	20%
2020	4,782	5,367	303.1	182	20%	20%
2030	4,782	6,490	284.2	28	30%	25%
2050	4,782	6,699	284.2	0	30%	25%

Table D-2: Commercial Retrofit Rates

	Retrofit UEC without elect (kWh/sf)	Retrofit UEC with elec (kWh/sf)	Retrofit UEC w/o elec (therms/sf)	Retrofit UEC With elec (therms/sf)	Retrofit Elec UEC (% Reduction 2016 frozen level)	Retrofit NG % reduction from frozen
2016	11.8	11.93	0.228	0.228	15%	15%
2020	11.8	12.32	0.228	0.159	15%	15%
2030	9.7	11.25	0.201	0.020	30%	25%
2050	9.7	11.40	0.201	0.000	30%	25%

Table D-3: Residential New Construction Assumptions

	ZNE UEC w/o electrification (kWh/hh)	ZNE UEC with electrification (kWh/hh)	ZNE UEC w/o electrification (therms/hh)	ZNE UEC with electrification (therms/hh)	ZNE Elec UEC (% Reduction 2016 frozen level)	ZNE NG % reduction from frozen
2016	5,466	5,465.6	303.1	303.1	20%	20%
2020	4,782	6,031.3	265.2	132.6	30%	30%
2030	4,099	6,152.9	227.3	22.7	40%	40%
2050	4,099	6,319.4	227.3	-	40%	40%

Table D-4: Commercial New Construction Assumptions

	ZNE UEC w/o electrification (kWh/hh)	ZNE UEC with electrification (kWh)	ZNE UEC without electrification (therms/sf)	ZNE UEC with electrification (therms)	ZNE Elec UEC (% Reduction from 2016 frozen level)	ZNE NG % reduction from 2016 frozen level
2016	11.8	11.815	0.2278	0.228	15%	15%
2020	11.1	12.003	0.2144	0.107	20%	20%
2030	8.3	9.891	0.1608	0.016	40%	40%
2050	8.3	10.009	0.1608	0.000	40%	40%

Table D-5: SB 350 Compliant + Electrification Scenario

	Elec. Rate of New Residential & Commercial Buildings	Elec. Rate of Residential Retrofits	Elec. Rate of Commercial Retrofits	Efficiency Gains With Electrification
2016	0%	0%	0%	3.5
2020	50%	40%	30%	4.0
2030	90%	90%	90%	4.0
2050	100%	100%	100%	4.0

Table D-6: Aggressive EE + Electrification Scenario

	Elec. Rate of New Buildings	Elec. Rate of Residential Retrofits	Elec. Rate of Commercial Retrofits	Efficiency Gains With Electrification
2016	0%	0%	0%	3.5
2020	80%	70%	50%	4.0
2030	100%	90%	90%	4.0
2050	100%	100%	100%	4.0

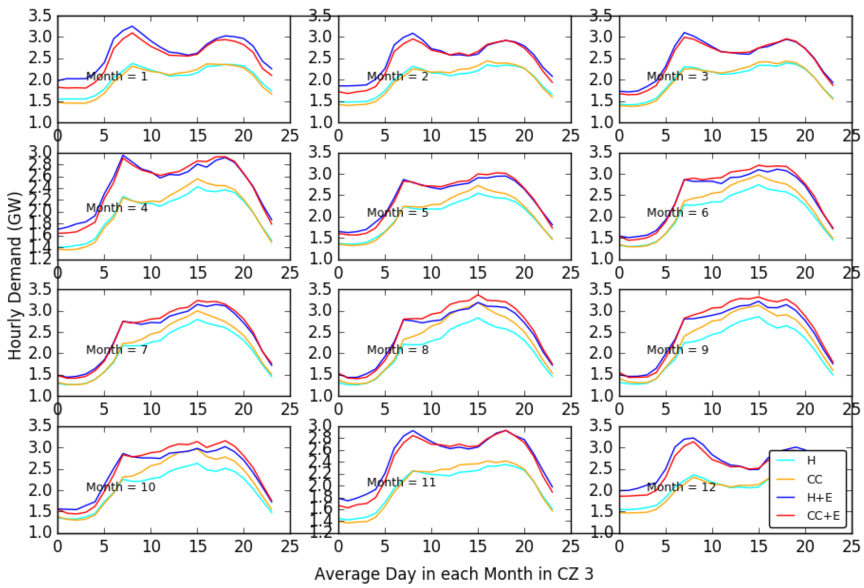
Table D-7: Rooftop PV Potential in New ZNE Homes

	New Units (Million HH or Million sf)	Solar PV Ready Space on Rooftops (million sf)	PV Technical Potential Capacity(GW)	PV Energy – Technical Potential (GWh)	ZNE Electricity Demand (GWh)
Residential 2030	2.7	441	7.12	12,467	11,230
Commercial 2030	2,100	504	8.31	14,600	19,300
Residential 2050	7.8	1,300	20.5	36,000	32,300
Commercial 2050	7,600	1,800	30	52,560	67,200

Impact of Climate Change and Additional Electrification

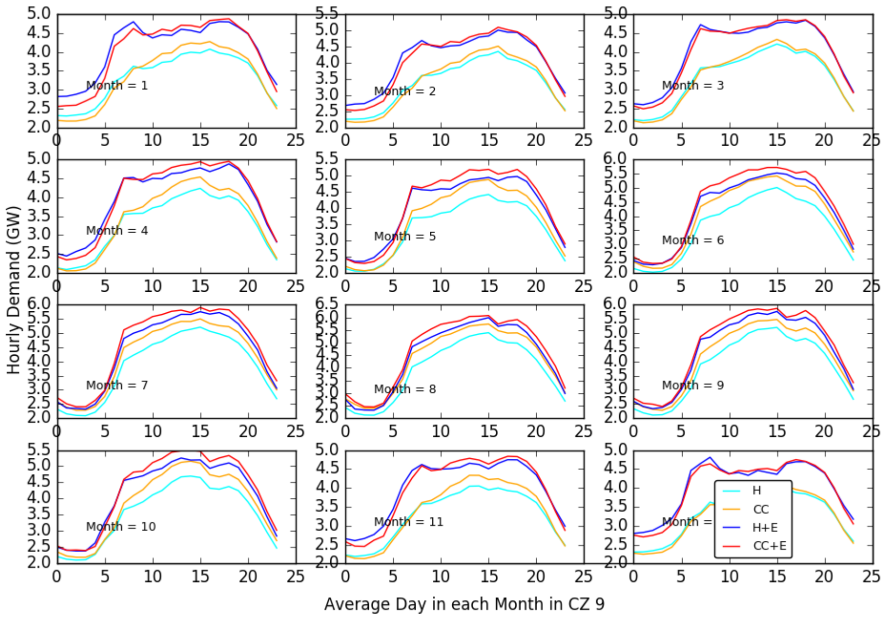
Figures 5.4, 5.5, and 5.6 illustrate the average daily load profiles of the buildings in Climate Zones 3 and 9 in each of the 12 months[33] (in blue) and the hourly load profiles under climate change-electrified ("CC+E" in red). This is because the climate models predict lower heating demand days (HDD) or warmer temperatures for 2050, thus decreasing the demand for heating. However, with hotter summers by mid-century, increased cooling degree days (CDD) will increase air-conditioning demand. This can be observed by higher demand with climate change relative to historical load profiles, during middle of the day during the summer.

Figure D-3: Average Hourly Electricity Load Profiles of Residential and Commercial Buildings in Climate Zone 3



33 CZ3 is part of the San Francisco Bay Area in Northern California (Oakland & San Francisco) has mild climate; CZ9 is in Southern California (Los Angeles) with hot summers and mild winters; CZ12 is part of the Northern California Central Valley with cooler winters and hotter summers. CZ3, CZ9 and CZ12 represent 10%, 16%, and 12.5%, respectively, of the state's population.

Figure D-4: Average Hourly Electricity Load Profiles of All Buildings in Climate Zone 9



APPENDIX E: Industry and Transportation

2015 Industry Snapshot

The 2015 CARB inventory snapshot of non-electricity sector industry emissions was 92 MMt CO_2e, of which about 70 MMt are from fuel combustion emissions, 14 MMt from process and product emissions, and 8MMt from fugitive emissions. Oil and gas refining and extraction are the largest industry sector by far (about 60% of GHG emissions). The research team further broke down fuel combustion, process/product, and fugitive emissions.

Fuel combustion emissions. Natural gas makes up about 80% of fuel combustion energy, 14% of fuel combustion emissions are from petroleum-derived fuels, and about 3% of energy each comes from coal and biomass.

Process emissions. Cement and H_2 production make up about 75% of the process emissions or about 5 MMt CO_2e each. (High GWP gases are broken out in a separate category. These are gases that are used as refrigerant gases for refrigeration and air-conditioning equipment and foam, fire extinguishers, and a few other niche applications. High-GWP gases alone contributed 19 MMt CO_2e to the 2015 GHG inventory and are the fastest growing sector).[34]

Fugitive emissions. For fugitive emissions, more than half are from natural gas transmission and distribution. Recent reports have indicated that fugitive methane emissions are higher than those reported by the EPA, and improved quantification of fugitive emissions remains an active area of research.[35]

Industry Health Damages

Industry was seen to contribute a relatively small fraction of overall health damages in California at about 7% of overall damages, which amounts to about $1.7 billion per year.

The 20 most damaging sites for industry in 2015 are shown in Table 8. The five sites with the highest levels of health damages are all oil refineries or petroleum product facilities, four in the San Francisco Bay Area and one in Los Angeles County. $PM_{2.5}$ contributes the most damages. Twelve of the top 20 sites with the most health damages are either oil and gas refineries (FSIC code 2911) or petroleum products (FSIC code 2999). Reducing the carbon footprint of the transportation sector would result in a dramatically reduce oil and gas refining and extraction, with benefits in health from sharply reduced damages from tailpipe emissions from vehicles and a reduction of pollutant emissions from the oil and gas supply industry.

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34 In part, the high growth of high GWP gases or hydrofluorocarbon (HFC) gases are from the earlier generation of ozone-destroying refrigerant gases such as chlorofluorocarbons (CFCs) that are being phased out in favor of HFCs and are not counted in the ARB GHG inventory.

35 For example, a recent study by Mehrotra et al. 2017 suggests that while a sample of measurements for gas storage facilities were within a factor of 2 of emissions reported to the U.S. EPA or CARB, average emissions from 15 measurements of the three refineries were roughly an order of magnitude more than reported.

The 10 industrial sites that generate the most health damages contribute 31% of overall industry damages, the top 50 sites contribute 54%, and the top 300 sites contribute about 80% of damages. This finding suggests that pollution reduction could be focused in the near term on a relatively small number of sites.

About two-thirds of overall damages is from direct $PM_{2.5}$, and this is the most localized pollutant compared to NO_x and SO_x. For $PM_{2.5}$, 36% is from the oil and gas industry (mostly from refining); 12% from electric power generation, and 9% from nonmetallic minerals (for example, cement and glass).

Table E-1: Twenty Industrial Sites With the Highest Levels of Annual Health Damages in California (2016)

FNAME	FCITY	FSIC	COID	DISN	NOX damages	SOX damages	PM2.5 damages	Sum Damages
SHELL MARTINEZ REFINERY	MARTINEZ	2911	CC	BAY AREA AQMD	$ 13,658,077	$ 25,299,158	$ 81,225,696	$ 120,182,931
CHEVRON PRODUCTS COMPANY	RICHMOND	2911	CC	BAY AREA AQMD	$ 9,785,609	$ 8,819,126	$ 80,612,916	$ 99,217,651
TESORO REFINING & MARKETING COMP	MARTINEZ	2911	CC	BAY AREA AQMD	$ 14,315,692	$ 22,255,812	$ 37,797,875	$ 74,369,379
TESORO REFINING & MARKETING CO, LL	CARSON	2911	LA	SOUTH COAST AQN	$ 6,983,940	$ 8,389,046	$ 29,342,981	$ 44,715,967
PHILLIPS 66 CARBON PLANT	RODEO	2999	CC	BAY AREA AQMD	$ 5,620,175	$ 35,153,612	$ 3,346,912	$ 44,120,700
LEHIGH SOUTHWEST CEMENT COMPANY	CUPERTINO	3241	SCL	BAY AREA AQMD	$ 15,971,556	$ 22,694,367	$ 2,895,587	$ 41,561,509
TESORO REFINING AND MARKETING CO	WILMINGTON	2911	LA	SOUTH COAST AQN	$ 7,393,156	$ 2,729,094	$ 23,881,624	$ 34,003,874
CHEVRON PRODUCTS CO.	EL SEGUNDO	2911	LA	SOUTH COAST AQN	$ 7,933,367	$ 5,008,801	$ 20,264,009	$ 33,206,177
VALERO REFINING COMPANY - CALIFOR	BENICIA	2911	SOL	BAY AREA AQMD	$ 14,352,217	$ 2,333,673	$ 13,514,577	$ 30,200,468
EXXONMOBIL OIL CORPORATION	TORRANCE	2911	LA	SOUTH COAST AQN	$ 5,342,303	$ 5,565,589	$ 18,158,608	$ 29,066,501
OWENS-BROCKWAY GLASS CONTAINER	OAKLAND	3221	ALA	BAY AREA AQMD	$ 5,963,464	$ 4,786,249	$ 16,065,988	$ 26,815,702
PHILLIPS 66 COMPANY - SAN FRANCISC	RODEO	2911	CC	BAY AREA AQMD	$ 3,303,486	$ 8,436,898	$ 10,092,139	$ 21,832,523
PHILLIPS 66 CO/LA REFINERY WILMINGT	WILMINGTON	2911	LA	SOUTH COAST AQN	$ 5,162,984	$ 2,209,823	$ 13,430,807	$ 20,803,614
SIERRAPINE LTD AMPINE DIVISION	MARTELL	2493	AMA	AMADOR COUNTY	$ 414,686	$ 2,182	$ 19,746,988	$ 20,163,857
PHILLIPS 66 COMPANY/LOS ANGELES RE	CARSON	2911	LA	SOUTH COAST AQN	$ 4,194,489	$ 5,671,961	$ 6,271,864	$ 16,138,314
U.S. BORAX	BORON	1474	KER	KERN COUNTY APC	$ 2,197,564	$ 55,311	$ 13,501,608	$ 15,754,483
MAGTFTC MCAGCC TWENTYNINE PALMS	TWENTYNINE P	9711	SBD	MOJAVE DESERT A	$ 878,669	$ 329,040	$ 14,080,908	$ 15,288,616
CALPORTLAND - ORO GRANDE	ORO GRANDE	3241	SBD	MOJAVE DESERT A	$ 3,760,939	$ 304,283	$ 10,610,871	$ 14,676,092
US ARMY NATIONAL TRAINING CTR.	FORT IRWIN	9711	SBD	MOJAVE DESERT A	$ 3,365,425	$ 288,684	$ 9,669,744	$ 13,323,853
CALIFORNIA PORTLAND CEMENT CO.	MOJAVE	3241	KER	KERN COUNTY APC	$ 5,779,423	$ 5,331,405	$ 1,972,931	$ 13,083,758

Source: CARB 2017B

Industry Decarbonization Options

For decarbonization approaches in the future, the team makes a distinction between combustion energy sources and process emissions. Fugitive emissions characterization and reduction are not treated in further detail in the study.

Combustion Emissions. At a high level, natural gas-fired fuel consumption could be decarbonized through electrified processes. Another pathway could replace pipeline natural gas with biogas or renewable synthetic natural gas. Excluding the oil refining industry, petroleum-derived fuel use and coal could also be decarbonized either by electrification or fuel switching to biogas or renewable synthetic natural gas (SNG). Within the oil refining industry, however, it would be difficult to achieve wholesale electrification. There are two immediate difficulties for electrification in oil refineries. First, there is a high degree of integrated processes in oil refining that would require major process redesign and reengineering. Second, the "own-use" energy of refineries is high. In other words, the energy required to make refined oil products uses by-product fuels from refining. Not using these products would constitute a major issue for oil refinery electrification for energy costs, energy use, and capture (Schwartz et al 2018).

Process Emissions

- Hydrogen production is most commonly done by steam methane reforming of natural gas, which produces CO_2. Hydrogen production can be fully decarbonized with water electrolysis powered by renewable electricity.
- Cement is harder to decarbonize. One possibility is to employ carbon capture and storage, which could be expensive but is certainly feasible. Several carbon-capture technologies have been proposed for use in the cement industry.[36]
- In this work in the main scenarios, H_2 production is assumed to be 100% produced by renewable electricity by water electrolysis by 2050, but cement process emissions are assumed to be unavoidable.

Table E-2: Outlook for Industry Electrification in California

Industrial Sector	Boiler System	CHP	Process Heating	High-Temperature Process Steps [Brown, 1996]	Temp L/M/H	Disposition for Electrification
	Percentage On-site Nat. Gas Fuel Consumption					
Petroleum and Coal Products Manufacturing	18%	14%	61%	e.g.: Catalytic cracking 900□F (482□C), Catalyst reforming 1000□F (538□C), Boiler 422□F (217□C)	HIGH	Hard b/c high degree of process design and own-use fuel consumption
Food and Beverages	44%	11%	27%	250-350□F boiler (121-149□C); 450□F (232□C) baking oven; 930□F charcoal regen (cane sugar) (499□C); 600□F lime kiln (beet sugar) (316□C)	MED/ HIGH	Good candidate except high degree of CHP systems
Chemical Manufacturing	29%	13%	44%	H2, Ammonia – 1550□F furnace (840□C), Ammonia 600□F boiler (315□C); Pharma 250□F (121□C) boiler, drying; Ethanol cooker/dryer 212□F (100□C) Boiler 250□F (121□C)	HIGH	Some lower temperature process steps (e.g. boilers and dryers)
Plastics and Rubber Products	56%	3%	19%	Polystyrene Heater 500F (260C); Synthetic Rubber Dryer 180F (82C)	LOW/ MED	Good candidate for electrification
Nonmetallic Mineral Proc	1%	2%	90%	Flat glass (2900□F, 1593□C furnace, 1600□F (870□C)final heat treatment; Cement 2700□F (1482□C) dry kiln; Brick 2100□F (1149□C) kiln	HIGH	Very high temperatures make this challenging but technically possible
Fabricated Metal Products	7%	5%	58%	Al sheet, foil furnace melting 1250F (680C); preheating 1000F (540C); annealing 800F (430C)	HIGH	Induction heating/melting candidate

36 See, for example, https://hub.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-cement/62-costs-applying-co2, accessed 11/19/17.

Industrial Sector	Boiler System	CHP	Process Heating	High-Temperature Process Steps [Brown, 1996]	Temp L/M/H	Disposition for Electrification
	Percentage On-site Nat. Gas Fuel Consumption					
Transportation Equipment	22%	2%	30%	Motor vehicle car body Drier 300F (150C); Vehicle parts Furnace 2900F (1600C)	MED/ HIGH	Driers ok for electrification but Furnace challenging
Primary Metals	6%	6%	74%	Primary Al Furnace 2200F (1200C); Copper furnace 1200C; Zinc Furnace (1260C)	HIGH	Induction melting candidate
Machinery	16%	1%	36%	Farm and construction equipment Heat Treatment 1350F (732C)	HIGH	Induction heating candidate
Paper Mills	27%	36%	26%	Pulp/Paperboard mll lime kiln 1200F (650C);	HIGH	High degree of integrated process design

Source: Masanet (2013), Brown (1996) and authors' calculations. Table entries are ordered by approximate natural gas usage, from largest to smallest natural gas consumption.

For future industry electrification, some key considerations for feasible or economic potential include the following:

- Several sectors have relative high boiler use. These are candidates for electrification with electric boilers (described further below). This finding assumes that gas-fired boilers are relatively stand-alone equipment that can be replaced with electric boilers.
- Several sectors have a high fraction of CHP or cogeneration. This CHP fraction is a proxy for a high degree of process integration. These industries may find it challenging from a design and cost perspective to redesign their process lines and potentially incur lower overall energy efficiency.
- Several industry sectors have been highlighted as promising candidates for induction heating: primary metals, fabricated metal products, and machinery. Induction heating can offer better product quality, higher yield, greater operational flexibility, and other manufacturing advantages.
- A few sectors feature low process temperature and relatively low CHP adoption (for example, plastics and rubber products), but overall energy consumption is small for these sectors. Some sectors have only a few high temperature steps such as lime kiln firing in the paper mills sector and sugar product-charcoal regeneration and lime kiln firing in the food processing sector. These may be more difficult to electrify than most other process heating steps in these sectors.
- Heating, ventilating and air conditioning (HVAC) using onsite fuel sources is a small fraction of overall industry fuel use (less than 5% nationally), but this end use could be electrified. For example, HVAC comprises a relatively large fraction of fuel consumption in transportation equipment, machinery, fabricated metal products, plastics, and rubber

products. High-efficiency heat pumps have been highlighted as a near-term option for these end uses.

- Considerations in Table 5 are a starting framework for the feasible or economic potential of industry electrification, but the triggering factors for industry electrification in specific sectors and end-use applications may be driven as much by potential product benefits in productivity, or process control. A detailed accounting or quantification of these product benefits would require more product-specific process modeling and is beyond the scope of this report.
- "Low-hanging" fruit in this regard based on technological availability and degree of process intrusion are heat pumps and electric boilers.

Non-Energy Petroleum Industry-Derived Product Replacement

For California in 2015, the EIA estimates that the energy in feedstock for these products is 289 TBtu (or 47 million barrels-equivalent energy of petroleum product or 6.5 MMtons of product). How would the state replace these products if the petroleum industry is significantly downsized in the long term? There are two potentially complementary pathways: biobased feedstocks and H_2-derived feedstocks (Lechtenbohmer).[37] The first pathway is a point of reference for the potential biomass resource needed to provide current levels of petroleum-based feedstocks.

For 1 million tons of refined product per year, dry biomass required would be of the order of 3 million tons (Roddy 2013).[38] This finding implies that biomass demand would be 20 MdT in 2015 to meet 2015 demand at this ratio. For a historical growth rate in refined products of about 0.5 MBBl/yr, this implies a biomass quantity of 18-27 MdT in 2050, assuming a biomass dry tonnage to tons of refined product in the ratio of 2:1 to 3:1. A median value of about 24MdT biomass in 2050 or a rough equivalent to 1.4 Bgge advanced fuel, which is on the order of 15% to 30% of the biomass supply required for biofuels in 2050. This preliminary biomass range does not consider full range of technical options and recent or potential advances in biotechnology. (https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2859252/).

These biobased production sites could in the future supersede existing petrochemical feedstock production sites. Depending on the locations of industry sites and the emissions associated with a biobased feedstock industry, these sites could also reduce pollutant emissions from this subsector. Biobased feedstocks could have climate change-dependent supply issues, cost issues, and potential land area issues.

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37 Whether the petroleum refining industry can continue to provide feedstocks to other industrial sectors within the constraints of aggressive carbon policy and reduction in petroleum-derived liquid fuels is an out-of-scope question here, but from a revenue standpoint, it is not favorable as 76% of the current revenue from a barrel of crude oil is from fuels and 17% from chemical and 7% from other uses (https://www.energy.gov/sites/prod/files/2016/12/f34/beto_strategic_plan_december_2016_0.pdf).

38 Roddy, D. J. 2013. "Biomass in a Petrochemical World." *Interface Focus*, *3*(1), 20120038, http://doi.org/10.1098/rsfs.2012.0038.

It is worth highlighting the scale of this industry and to reiterate the lengthy duration of time it takes from demonstration to market adoption and scale-up of new technologies. By raw weight, 6.5 million tons of petroleum product per year are equivalent in weight to manufacturing almost 5 million 1.5-ton cars per year.

Figure E-1: Industry Sector Electricity Use by Scenario

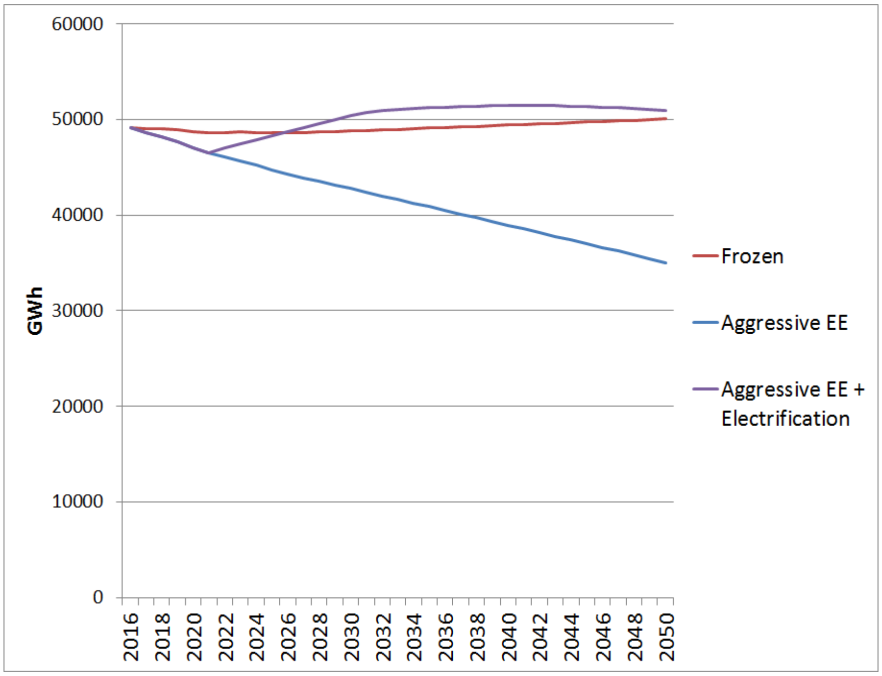
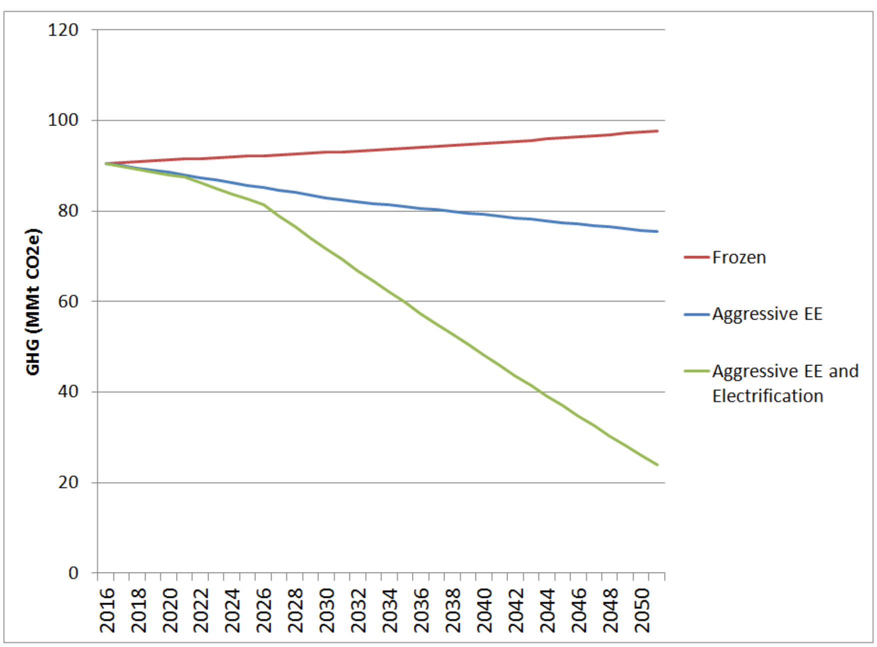


Figure E-2: Industry Sector Emissions by Scenario



Transportation Sector

SB 350 Scenario

The SB 350 (Intermediate EE) scenario assumes that the ZEV mandate is met in 2025 and that there is slow growth in hybrid, PHEV, BEV and FCEV after 2030. The resulting LDV stock and GHG are shown in Figures E-3 and E-4.

Figure E-3: SB 350 Scenario Light-Duty Vehicle Stocks

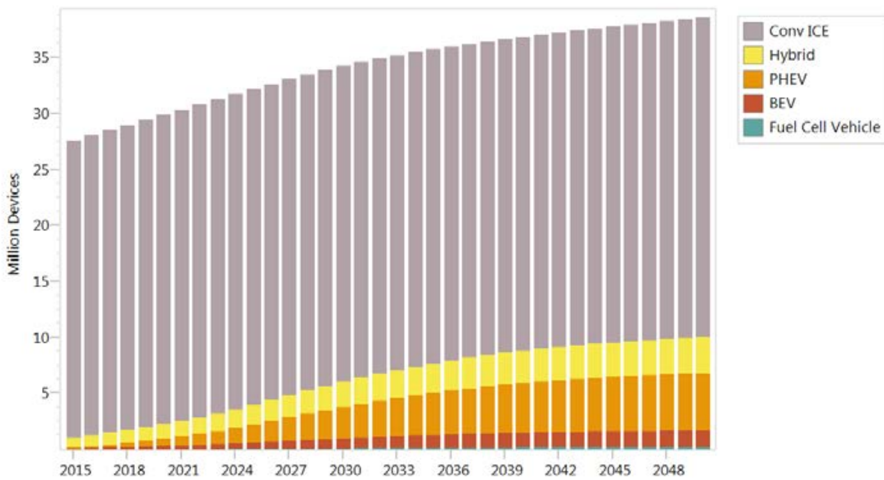


Figure E-4: SB 350 Scenario GHG Drop From About 117 Mt CO_2 in 2015 to 91 Mt in 2030 and 58 Mt in 2050

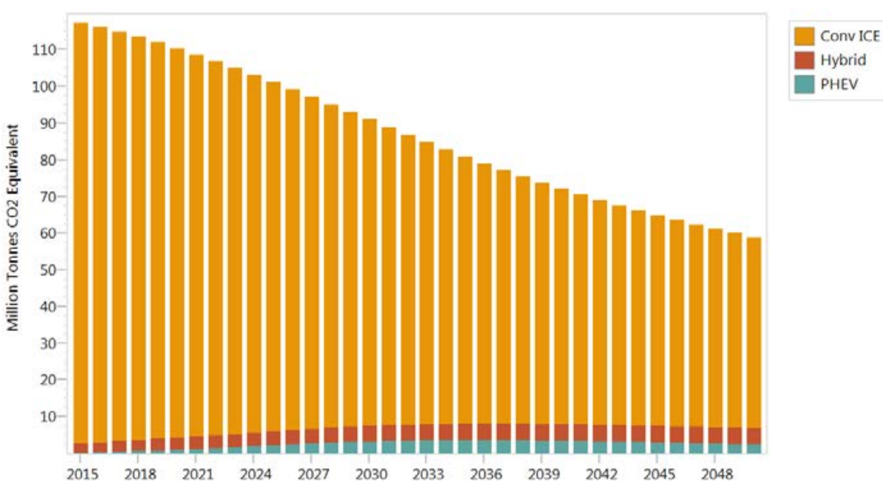


Figure E-5: Sales Share by Drive Train Technology in Aggressive EE Electrification Scenario

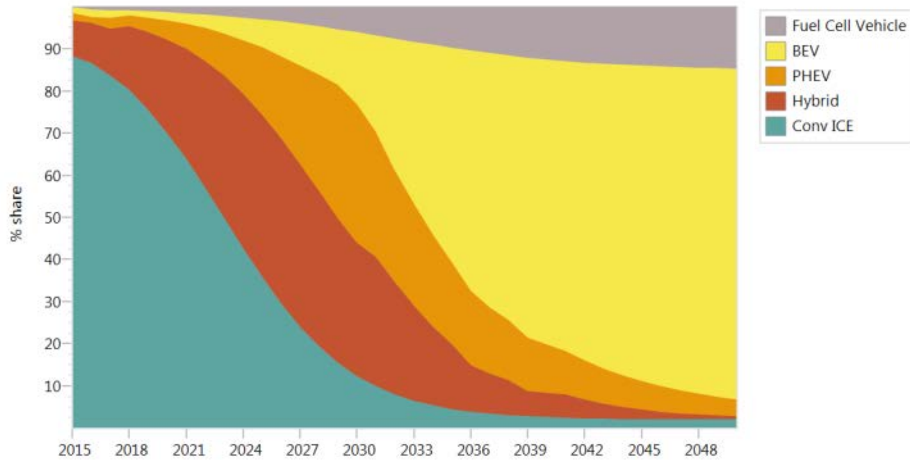
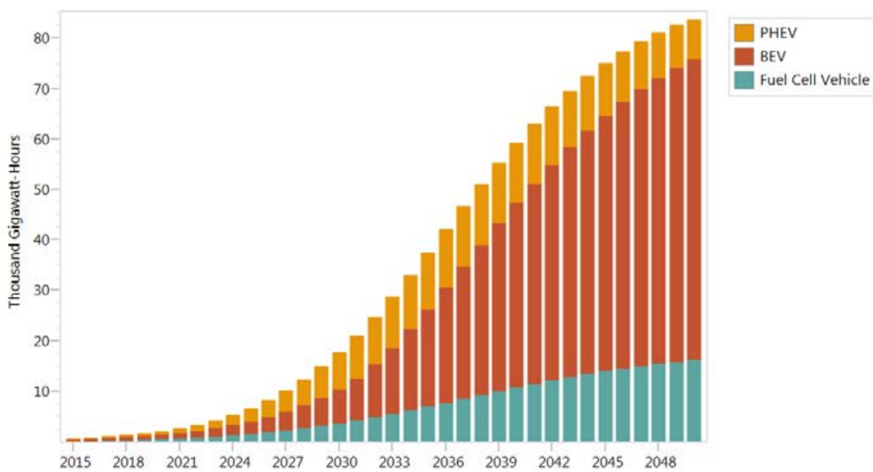


Figure E-6: PHEV, BEV Electricity Demands and Fuel Cell Hydrogen Demand in GWh - Aggressive EE Electrification Scenario



Medium- and Heavy-Duty Trucks

Alternative fuel truck technologies include:

- **Natural gas (NG) trucks.** NG trucks can use liquified NG or compressed natural gas (CNG) for storage, with CNG being the most common. Only 1% of the total truck stock were natural gas trucks in 2015. CNG costs one-half the cost of liquified natural gas (LNG), but LNG has 12 times more energy density than CNG. CNG trucks can give reductions in NO_x, $PM_{2.5}$, and volatile organic compounds, although incomplete combustion can be an important issue. NG trucks also have less noise than current diesel trucks.
- **Biofuels.** These fuels can be produced from wastes or crops. Biodiesel, hydrotreated vegetable oil, and biomethane are the most widely used. Deployment depends on the volume of fuel production, suitability of freight vehicles, and fueling infrastructure. GHG

emissions from biofuels depend highly on production pathway, and air quality impacts can depend on fuel composition and engine design.

- **Electric battery-powered trucks.** The key performance indicators for battery-powered trucks are gravimetric and volumetric battery energy density, specific power, durability, and temperature management. Truck motive efficiency is much higher than diesel and can take advantage of regenerative braking. The costs are still much higher for electric trucks than diesel trucks. For example, a heavy-duty drayage truck (CALSTART 2013) is expected to cost three times as much in 2013, dropping to twice as much in 2020 and be 56% more expensive in 2030, driven by anticipated drop in battery prices from $600/kWh in 2013, $317 in 2020, and $211 in 2030.
- **Electric road systems (ERS).** ERS use conductive catenary lines or inductive power transfer for powering trucks with electric motors. Catenary lines have a high capital cost and could be most easily deployed in fixed trucking routes. Both battery-powered trucks and electric road systems would have no tailpipe pollution, and upstream pollution depends on the generation technology uses for electricity.
- **Hydrogen-powered trucks (H_2).** H_2-powered trucks are essentially battery-electric vehicles powered by electricity produced by onboard fuel cells. Hydrogen has a very high energy density but low volumetric density, so hydrogen storage is of cardinal importance. FC trucks have on-board batteries that are charged by the fuel cell for transient high-power operation and regenerative braking. FC-powered trucks also have zero tailpipe emissions, and upstream pollution depends on H_2 production, transportation, and distribution. Hydrogen can be produced renewably through the electrolysis of water using renewable electricity sources. FC trucks have higher costs than all-electric trucks, but again these may drop if FCEV passenger vehicles are more widely adopted.

HDV – Aggressive EE Electrification Scenario

For heavy-duty vehicles, the research team divides truck classes into medium-duty trucks and heavy-duty trucks or those between 10,000 and 33,000 pounds and those above 33,000 pounds, referred to as Class 3 and Class 4, respectively. Class 3 and Class 4 truck miles were calibrated to the CARB Emissions Factors (EMFAC) 2014 model in 2015 and 2050 calendar years for vehicle miles traveled (VMT) and to calendar year 2015 for liquid fuel quantities and GHG.

For the Aggressive EE Electrification Scenario, Class 3 trucks are assumed to become 50% electrified by 2050, with 20% of vehicle miles powered by natural gas (Figure E.7). Class 4 trucks as assumed to be more difficult to electrify and are assumed to start a partial transition to hydrogen fuel cell-powered trucks in 2020, reaching 25% of vehicle miles by 2050 (Figure E.8).

GHG emissions from the HDV sector are shown in Figure E.9. GHG are estimated at 30.4 MMt CO_2 in 2030 and 22.2 MMt CO_2 in 2050. The 2050 value is higher than the LDV sector's 10.7 MMt because HDVs are harder to transition to ZEV technologies than passenger vehicles.

Figure E-7: Aggressive EE Electrification Scenario Class 3 Truck Fuel Switching

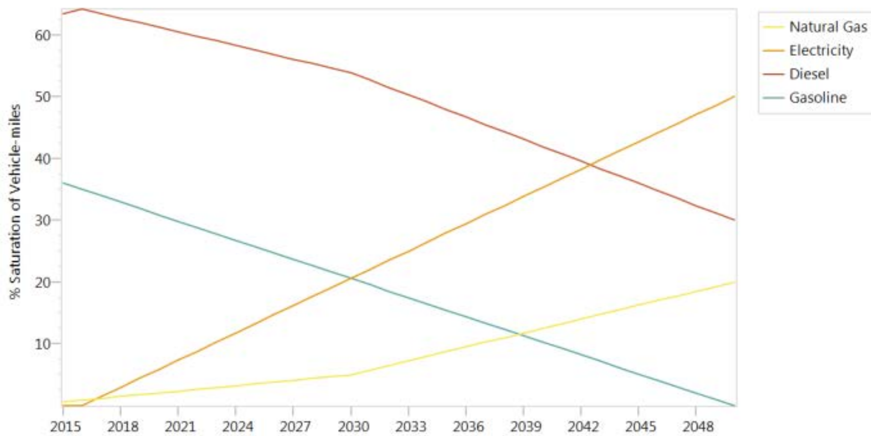
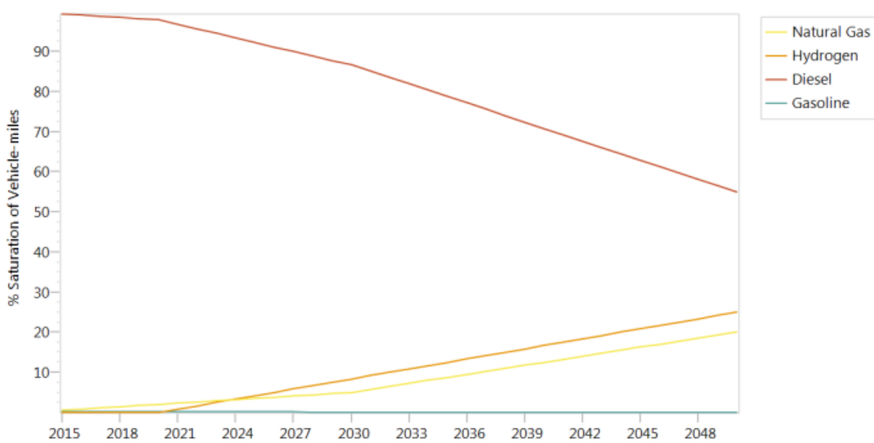


Figure E-8: Aggressive EE Electrification Scenario Class 4 Truck Fuel Switching



APPENDIX F:
Health Damages

Table F-1: Statewide Average Annual Cost of Health Damages per Ton of Pollutants

	SOx Dam ($/ton)	NOx Dam ($/ton)	PM 2.5 Dam ($/ton)
Stationary	22,080	8,725	79,820
Mobile	22,650	10,100	186,900
Area Wide	19,000	12,100	133,910

Table F-2: Statewide Health Damages for 2016

CATEG	DESC	SOX dam [$M]	Nox Dam [$M]	PM2.5 dam [$M]	% SOXDam	% NoxDam	% PM2.5Dam	SoxDam cumul.	NoxDam cumul.	PM2.5Dam cumul.
MISC	RESIDENTIAL FUEL COMBUSTION	$ 18.8	$ 254.0	$ 3,112	3.0%	4.0%	17.3%	3.0%	4.0%	17.3%
ON-ROAD MOTOR VEHICLES	ON-ROAD MOTOR VEHICLES	$ 33.9	$ 2,668.4	$ 2,299	5.5%	42.5%	12.8%	8.5%	46.5%	30.1%
MISC	COOKING	$ -	$ -	$ 2,094	0.0%	0.0%	11.6%	8.5%	46.5%	41.8%
Other mobile sources	Other mobile sources	$ 103.4	$ 2,501.7	$ 1,985	16.6%	39.8%	11.0%	25.1%	86.3%	52.8%
MISC	PAVED ROAD DUST	$ -	$ -	$ 1,447	0.0%	0.0%	8.0%	25.1%	86.3%	60.8%
MISC	FUGITIVE WINDBLOWN DUST	$ -	$ -	$ 1,193	0.0%	0.0%	6.6%	25.1%	86.3%	67.5%
MISC	CONSTRUCTION AND DEMOLITION	$ -	$ -	$ 1,100	0.0%	0.0%	6.1%	25.1%	86.3%	73.6%
INDUSTRIAL PROCESSES	INDUSTRIAL PROCESSES	$ 186.5	$ 130.1	$ 1,099	30.0%	2.1%	6.1%	55.1%	88.4%	79.7%
MISC	MANAGED BURNING AND DISPOSAL	$ 9.0	$ 21.5	$ 954	1.5%	0.3%	5.3%	56.6%	88.7%	85.0%
MISC	FARMING OPERATIONS	$ -	$ -	$ 865	0.0%	0.0%	4.8%	56.6%	88.7%	89.8%
Fuel combustion	Fuel combustion	$ 213.7	$ 663.9	$ 781	34.4%	10.6%	4.3%	91.0%	99.3%	94.2%
MISC	UNPAVED ROAD DUST	$ -	$ -	$ 680	0.0%	0.0%	3.8%	91.0%	99.3%	98.0%
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM PRODUCTION AND MARKETING	$ 43.4	$ 20.6	$ 90	7.0%	0.3%	0.5%	98.0%	99.6%	98.5%
MISC	FIRES	$ -	$ 1.1	$ 89	0.0%	0.0%	0.5%	98.0%	99.7%	99.0%
CLEANING AND SURFACE COATINGS	CLEANING AND SURFACE COATINGS	$ -	$ 0.3	$ 89	0.0%	0.0%	0.5%	98.0%	99.7%	99.5%
Waste Disposal	Waste Disposal	$ 12.6	$ 21.4	$ 59	2.0%	0.3%	0.3%	100.0%	100.0%	99.8%
MISC	OTHER (MISCELLANEOUS PROCESSES)	$ -	$ 0.1	$ 35	0.0%	0.0%	0.2%	100.0%	100.0%	100.0%
Solvent Evaporation	Solvent Evaporation	$ -	$ -	$ 4	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%

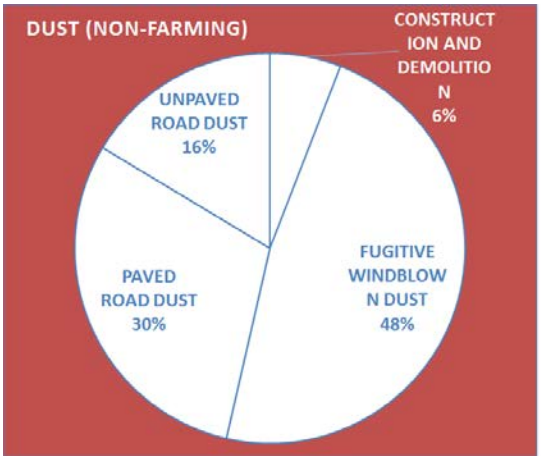
Table F-3: Fresno County Health Damages for 2016

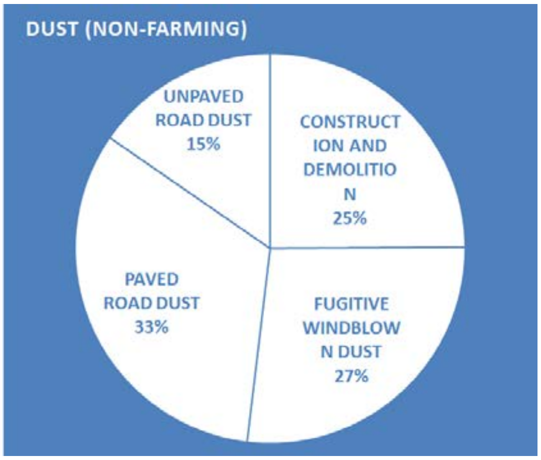
CATEG	SUBCATEG	SOX dam [$M]	Nox Dam [$M]	PM2.5 dam [$M]	Tot Dam	% OF Tot Dam	TotDam cumul. %
MISC	FUGITIVE WINDBLOWN DUST	$ -	$ -	$ 72.1	$ 72.1	13.9%	13.9%
MISC	FARMING OPERATIONS	$ -	$ -	$ 67.4	$ 67.4	13.0%	26.9%
MISC	PAVED ROAD DUST	$ -	$ -	$ 45.4	$ 45.4	8.7%	35.6%
MISC	MANAGED BURNING AND DISPOSAL	$ 0.2	$ 1.3	$ 31.7	$ 33.2	6.4%	42.0%
MISC	COOKING	$ -	$ -	$ 28.9	$ 28.9	5.6%	47.6%
ON-ROAD MOTOR VEHICLES	ON-ROAD MOTOR VEHICLES	$ 0.8	$ 75.4	$ 28.1	$ 104.3	20.1%	67.6%
Other mobile sources	Other mobile sources	$ 0.3	$ 36.9	$ 27.0	$ 64.2	12.4%	80.0%
MISC	UNPAVED ROAD DUST	$ -	$ -	$ 24.8	$ 24.8	4.8%	84.8%
MISC	RESIDENTIAL FUEL COMBUSTION	$ 0.3	$ 3.5	$ 22.3	$ 26.1	5.0%	89.8%
Fuel combustion	Fuel combustion	$ 1.2	$ 8.1	$ 11.7	$ 21.1	4.1%	93.8%
INDUSTRIAL PROCESSES	INDUSTRIAL PROCESSES	$ 5.6	$ 2.9	$ 11.4	$ 19.9	3.8%	97.7%
MISC	CONSTRUCTION AND DEMOLITION	$ -	$ -	$ 8.9	$ 8.9	1.7%	99.4%
MISC	FIRES	$ -	$ 0.0	$ 1.9	$ 2.0	0.4%	99.8%
CLEANING AND SURFACE COATINGS	CLEANING AND SURFACE COATINGS	$ -	$ -	$ 0.6	$ 0.6	0.1%	99.9%
Waste Disposal	Waste Disposal	$ 0.1	$ 0.1	$ 0.3	$ 0.5	0.1%	100.0%
MISC	OTHER (MISCELLANEOUS PROCESSES)	$ -	$ -	$ -	$ -	0.0%	100.0%
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM PRODUCTION AND MARKETING	$ 0.1	$ 0.1	$ -	$ 0.1	0.0%	100.0%
Solvent Evaporation	Solvent Evaporation	$ -	$ -	$ -	$ -	0.0%	100.0%
SUM		$ 8.6	$ 128.2	$ 382.5	$ 519.3	100%	

Table F-4: Fresno Health Damages – Residential and On-Road Transportation

Category and subcategory	Within Category Share	% of ALL DAMAGES
RESIDENTIAL FUEL COMBUSTION		
NATURAL GAS SPACE AND WATER HEATING	21%	**1.1%**
WOOD STOVES AND FIREPLACES	74%	**3.7%**
OTHER	5%	0.3%
COOKING		
RESIDENTIAL SHARE	Not reported	**-**
COMMERCIAL SHARE	80%	4.5%
FUEL COMBUSTION		
RESID. ELECTRICITY SHARE	12%	**0.5%**
NON-RES ELECTRICITY SHARE	25%	1.0%
NON-ELECTRICITY SHARE	63%	2.6%
ON-ROAD TRANSPORTATION		
HDV	84%	16.8%
LDV	16%	**3.2%**

Figure F-1: Health Damages From Nonfarming Dust in Fresno County (left) and State (right)





A Closer Look at the City of Fresno

The research team also looked more closely at the city of Fresno emissions using as a proxy 4 kilometers (km) times 4 km grid cells from the CARB CALNEX public inventory of HDV and LDV emissions from 2010.[39] The team addressed how these emissions are distributed across the county, specifically how disproportionate are health damage impacts by location within Fresno County, and illustrated this analysis method.

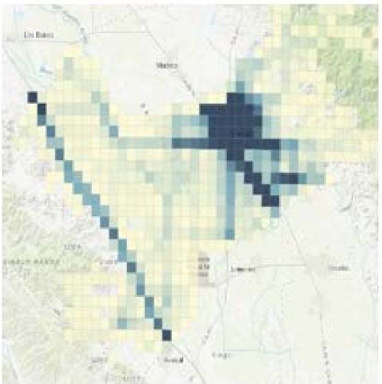
An example of HDV $PM_{2.5}$ emissions by grid cell in Fresno County in 2010 is shown in Figure F.2. This figure tracks emissions from Interstate 5 (I-5) on the left side of figure (diagonal line) and California State Highway 99 (CA-99) as expected. (CA-99 goes through Fresno and is parallel to I-5 in a northwest to southeast direction). The research team takes this as a proxy for activity in 2016. Similar mapping has been done for LD vehicles (and for all industrial sites) but is not shown here.

For this analysis, the research team choose four cells in Fresno that have similar population levels (average population about 45,000 and average population density is 7,300 per square mile). Grid Cells A, B, C, and D can be roughly considered as Northwest Fresno, Central Fresno, East Fresno, and Southeast Fresno, respectively. County-level emissions and damages in 2016 from HDVs and LDVs were apportioned by associated percentages of $PM_{2.5}$ emissions by grid cell from the 2010 CALNEX inventory. These "damages" refer to the total health damages from pollutants emitted in a particular grid cell; however, the damages may not all occur in the source grid cell. $PM_{2.5}$ is more localized than NO_x and SO_x emissions, so this analysis focuses on $PM_{2.5}$. In other words, there is a more direct link between direct $PM_{2.5}$ emissions and local health impacts than NO_x and SO_x emissions, which have more regional impacts.

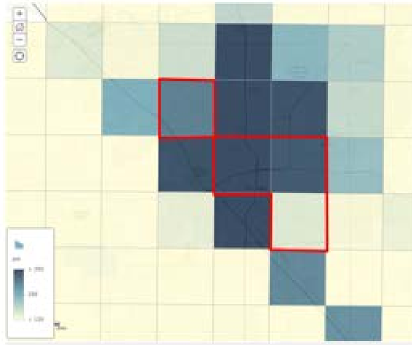
The results of this analysis are in Table F.5. From the data, Cell B or Central Fresno appears to represent a local "hot spot" in $PM_{2.5}$ emissions and related damages with 3.7% of county damages from HD $PM_{2.5}$ and 4.4% of LD $PM_{2.5}$ damages.

39 https://www.arb.ca.gov/research/calnex2010/calnex2010.htm, accessed June 10, 2017.

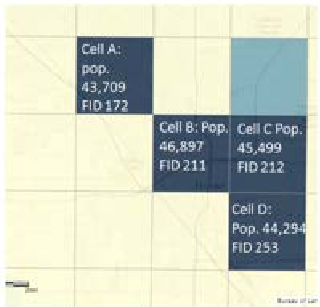
Figure F-2: Grid PM2.5 Emission Intensity in Fresno County and the City of Fresno



(a)



(b)



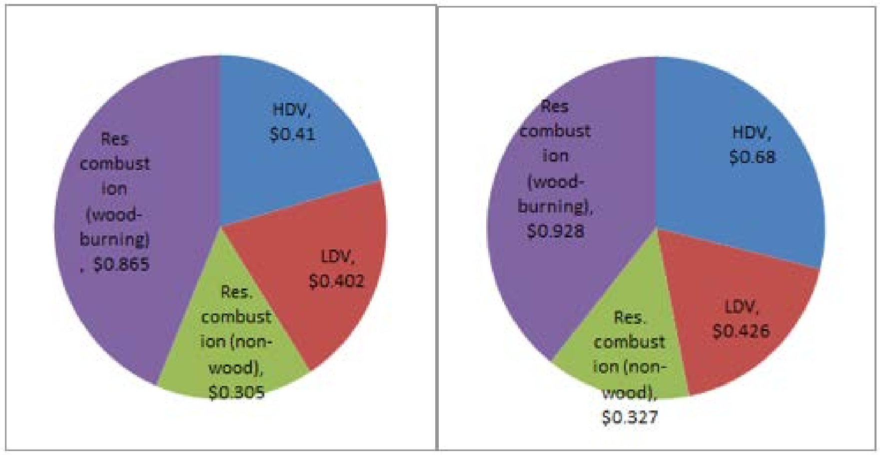
(c)

(a) 2010 HDV PM2.5 emissions by 4 km x 4 km grid cell in Fresno County (PMEDS HDV 2.5 from Calnex database); (b) Zoom in Fresno municipal area for 2010 HD PM2.5 emissions (PMEDS HDV PM2.5 from Calnex database); (c) Zoom in of four highlighted grid cells in Fresno.

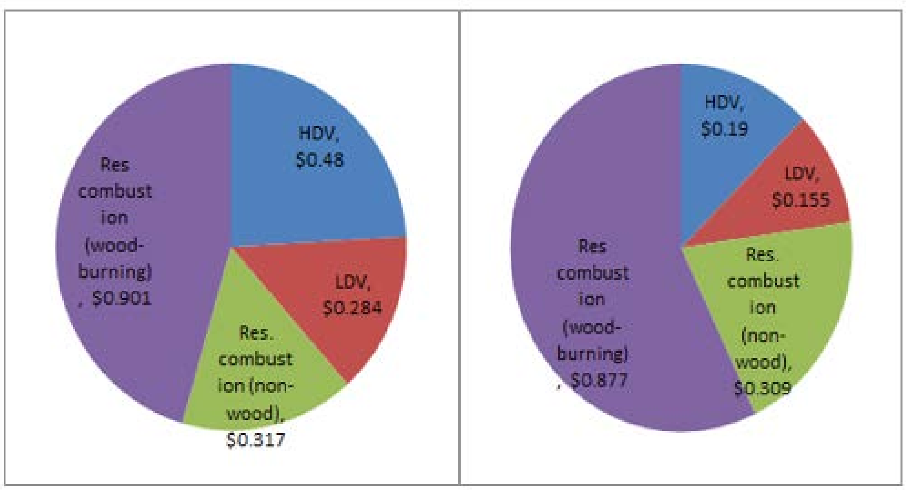
Table F-5: On-Road HD, LD Transportation, and Stationary Fuel Combustion Damages From Direct PM2.5 Emissions in 2015

Cell	pop	HH	HH frac of county	PM2.5 HD Dam% of county HD tot	HD dam ($M)	PM2.5 LD Dam% of county LD tot	LD dam ($M)	HD, LD PM2.5 dam ($M)
A	43,709	14,100	4.5%	2.2%	0.41	4.1%	0.402	0.81
B	46,897	15,128	4.8%	3.7%	0.68	4.4%	0.426	1.11
C	45,499	14,677	4.7%	2.6%	0.48	2.9%	0.284	0.76
D	44,294	14,288	4.5%	1.1%	0.19	1.6%	0.155	0.35
SUM	180,399	58,193	19%	9.6%	1.76	13.0%	1.27	3.0

Figure F-3: Fresno's On-Road and Stationary Fuel Combustion Damages ($M) From Direct $PM_{2.5}$



Northwest Fresno (Grid Cell A) *Central Fresno(Grid Cell B)*



APPENDIX G:
Cost Analysis Case Studies

Water Heating

Figure G-1: Comparison of Energy Consumption of Different Technologies

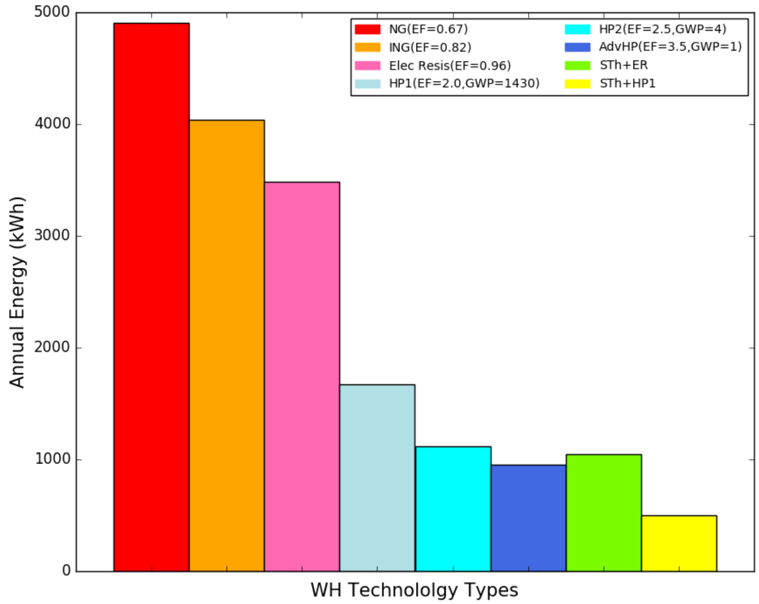


Figure G-2: Average Annual Emissions From Fuel (Solid Color) and Refrigerant Leakage

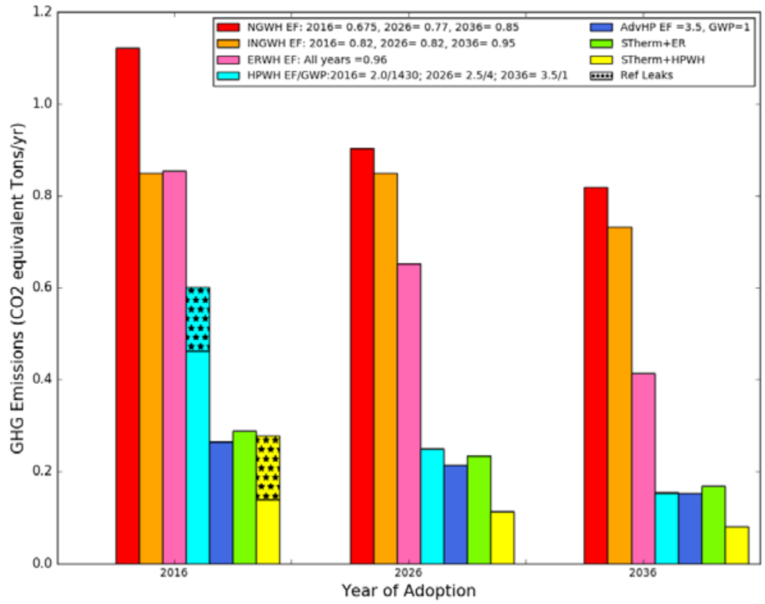


Figure G-3: Life-Cycle Cost Comparisons for Different Adoption Years

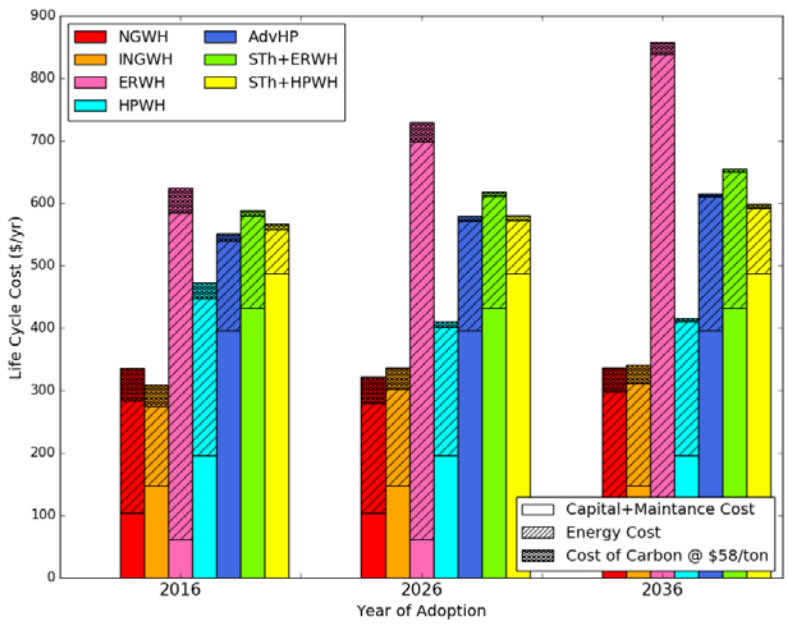


Table G-1: Model Assumptions

Occupied Households in California 2016(Millions)	12.87 (assuming 7.4% vacancy)[a]
Annual Population Growth	0.82%
Cost of NG in 2016 ($/therm)[b]	1.138
Cost of Electricity in 2016 ($/kWh)[b]	0.175
Cost Propane in 2026 ($/gallon)	2.05
Carbon Intensity Factor for electricity (kg/kWh)[c]	0.277 (2016), 0.203 (2030), 0.063 (2050)
Carbon intensity of NG (kg/therm)[d]	6.1
Carbon intensity of Propane (kg/gallon)	5.67
Annual increase in fuel price	2%
Discount Rate (social)	4%

Table G-2: Costs and Efficiency Assumptions

	NG	ING	ER	HP	Advanced HP	SThWH +ER or (+HP)
2016 EF	0.675	0.82	0.95	2.0 (Refrigerant with GWP = 1430)	3.5 (Refrigerant with GWP =1)	2.4 (or 5.0) solar fraction = 70%
Capex ($)	850 (a)	900 (a, c)	300 (a,c)	1400 (a,c)	4500 (g)	6500+Capex of backup (c,f)
Install/retrofit/fuel switch ($)	500 (a)	500 + 900 (retrofit)	500 (b)	500 +500 (fuel switch)	500	1500 (c)
Annual O &M ($)	0	85 (a)	0	16 (a)	16	25 (a)
Avg. Lifetime (years)	13 (e)	20 (e)	13 (b)	13 (b)	13	

Table G-3: Adoption *Timeline* of *Technologies*

WH Technology	Time Horizon	Energy Factor Assumption *
Natural Gas	2016	0.62 (weighted avg. EF of existing stock)
	2016-2020 (a)	0.675
	2020 -2030	0.77
	2030-2050	0.85
Instantaneous Natural Gas	2016-2030	0.82
	2030 -2050	0.95
Electric Resistance	<2020	0.96
	>2020	0.96
Heat Pumps	<2020	2.0 with Refrigerant GWP =1430
	2020-2030	2.5 with Refrigerant GWP = 4
	2030-2050	3.5 with Refrigerant GWP = 4
Advanced HP	2016	3.5 with Refrigerant GWP = 1

Table G-4: Description of Scenarios

Scenarios	Assumptions on Stock	Other Assumptions
Frozen	Retiring NG- and propane-based stock will be replaced by same fuel based technology, but with 2016 efficiency standards. ERWH will be replaced by HPWH of EF of 2.0. All new homes will adopt INGWH of EF 0.82 (CA-BEES, 2016).	2030 Grid emissions are 40% lower than 1990 levels (CA-SB 32) Grid emissions from 2030 to 2050 will be held fixed. No efficiency gains from 2016 to 2050. No reduction in GWP of refrigerants used in HPWH.
NG+ Efficiency Efficiency (NG+EE)	No fuel substituting. Of the retiring NG stock: 25% will be replaced by INGWH and 75% by NGWH. All new homes get INGWH.	GHG Emissions from the grid continue to drop after 2030. The 2050 emissions drop to 80% below 1990 levels. Efficiency improves every decade as per table 2. No GWP improvement as in the frozen case.
2030 Electrification	Electrification gradually phased in 2030. Starting 2030, retiring non-electric WHs in the existing homes and new homes will switch to electric HPWH, ramping to 60% the retiring stock in 2040; 100% by 2050.	Same as NG + EE Scenario

Scenarios	Assumptions on Stock	Other Assumptions
2020 Electrification	Electrification gradually phased in 2020.Starting in 2020, retiring old heaters and new homes start adopting electric HPWH. 60% , 90% and 100% of the retiring stock will adopt electric HPWH by 2030, 2040 and 2050, respectively.	Same as NG + EE Scenario
2020 Elec + Low GWP	Same as 2020 Electrification Scenario	In addition to last scenario, 2020 on the GWP of refrigerant drops to 4 from 1430.
Advanced Technology	Percentage of retiring existing stock choosing to electrify same as above. 3 electric WHs available for replacement for retiring stock: HPWH, STh+HP and AdvHP: 80% choose cheapest, 15% 2nd cheapest and 5% the most expensive. From 2020, new Homes will adopt either STh+HP or AdvHP.	Solar Thermal water heater has a HPWH as a backup. With learning by doing, installed costs of these Solar Thermal WH and AdvHP technologies will drop over time.

Table G-5: Net Present Value of Costs in 2016 for *Adoption Scenarios* for 2016-2050

	NPV of Energy Cost ($billions)	NPV of Replacement Cost ($billions)	NPV Carbon Cost (@$58/ton) ($billions)	Total NPV Cost ($billions)	Cumulative GHG emissions (MMT CO_2e)
Frozen	*75.7*	*24.7*	*15.8*	***116.2***	524
NG+EE	*68.1*	*26.0*	*14.4*	***108.5***	463
2030 Elec	*68.6*	*28.8*	*13.8*	***111.2***	419
2020 Elec	*70.9*	*33.1*	*12.7*	***116.8***	360
‘2020 Elec with Low GWP’	*70.9*	*33.1*	*11.8*	***115.8***	321
‘2020 Elec with Low GWP’ With 25% low H20	*54.0*	*33.1*	*9.1*	***96.0***	242
‘2020 Elec + Low GWP’ With Elec price increases at 5%	*96.0*	*33.1*	*11.8*	***141.0***	321
‘2020 Elec+ Low GWP’ with high HPWH price*	*70.9*	*41.0*	*11.8*	***124.0***	321
Adv Tech	*65.0*	*42.8*	*11.0*	***119.0***	300

	NPV of Energy Cost ($billions)	NPV of Replacement Cost ($billions)	NPV Carbon Cost (@$58/ton) ($billions)	Total NPV Cost ($billions)	Cumulative GHG emissions (MMT CO_2e)
'Adv Tech' with High Elect price increases at 5%	*83.0*	*42.8*	*11.0*	***137.0***	300

Fuel Cell Vehicles

Figure G-4 illustrates the model scheme used to evaluate FCEV costs. This type of analysis can yield several insights: (1) are the top-down vehicle adoption scenarios consistent with learning rate-derived cost reductions and cost-competitiveness for fuel cell vehicles; (2) what are the differences in LCC cost by technology as a function of these market adoption scenarios, and what do they imply for the level of incentives or other technology development that is necessary to make FCEVs more competitive; and (3) what are the sensitivities of FCEV LCC cost as a function of learning rate assumptions and other input costs?

The current capital and operating and maintenance costs of producing, distributing, and dispensing hydrogen are here evaluated using the H2A calculation model, available from the U.S. Department of Energy (DOE).

Vehicle costs are based on global adoption scenarios and assumptions for component learning rates. To assess infrastructure and fueling costs, a regional case study for California was analyzed, since many infrastructure development and deployment cost studies have been done in this study. First, in-state vehicle adoption scenarios were developed based on in-state projections, then fuel infrastructure requirements were derived to meet resulting H_2 demand. Fueling station sizes and hydrogen generation technologies are specific to California; however, fueling station components are assumed to have learning rates derived from a global market. These fueling assumptions provide an assessment for fueling costs in the future for this California case study, but the results are generalized by considering several sensitivity cases.

Vehicle Deployment Scenarios

This analysis assumes that the vehicles and hydrogen supply resources, such as electrolyzers and hydrogen storage tanks, are part of a global market. In this section, two FCEV adoption scenarios (a Base case and an Optimistic case) and one projection for BEV future adoption are depicted in Figure G-5. Forecasts of ICEV sales are not analyzed in this study, since ICEVs are a highly mature market and are therefore assumed to have less potential for cost reduction related to technology learning.

The FCEV sales scenario is drawn from the 2DS High H_2 model by IEA (IEA 2016). This scenario presents an energy system deployment pathway and an emissions trajectory consistent with at least a 50% chance of limiting the average global temperature increase to 2°C. This ambitious FCEV sales scenario estimates 400,000 FCEVs annual sales in European Union countries (Germany, UK, France, and Italy), Japan, and the United States in 2025, cumulative sales of 8 million FCEVs in 2030, and that hydrogen vehicles reach about 25% share of vehicle stock by 2050. However, considering IEA global EV sales targets as a proxy, the contribution of the emerging countries market (such as China and India) may not be negligible and the 2DS H_2 scenario sales are assumed to grow from no additional sales in 2015 to 30% additional sales in 2050.

Figure G-4: FCEV Cost Model Flow Diagram

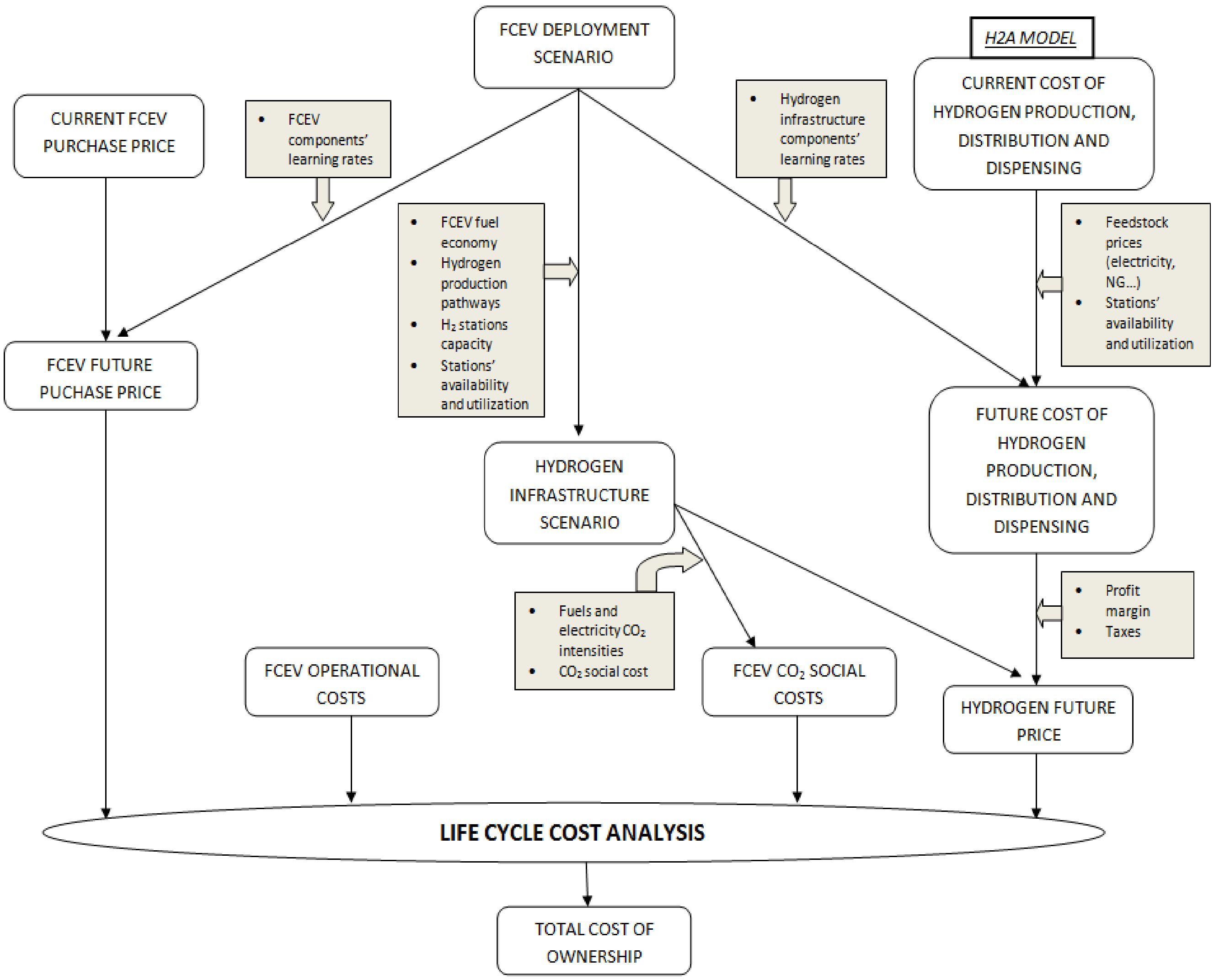
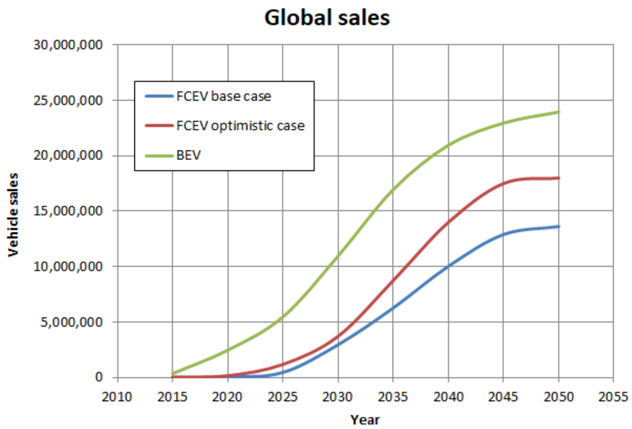


Figure G-5: Global Vehicles Adoption Scenarios



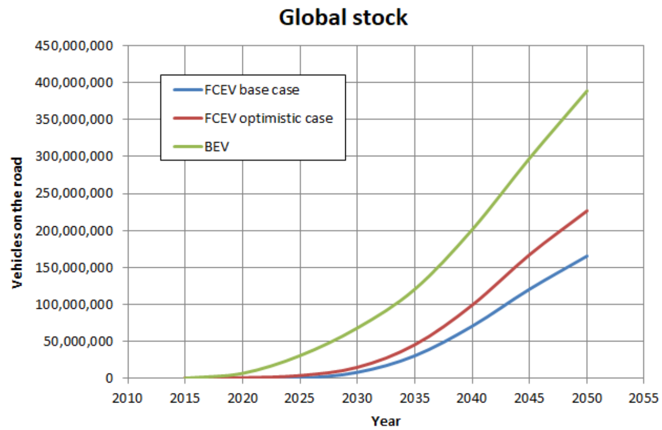
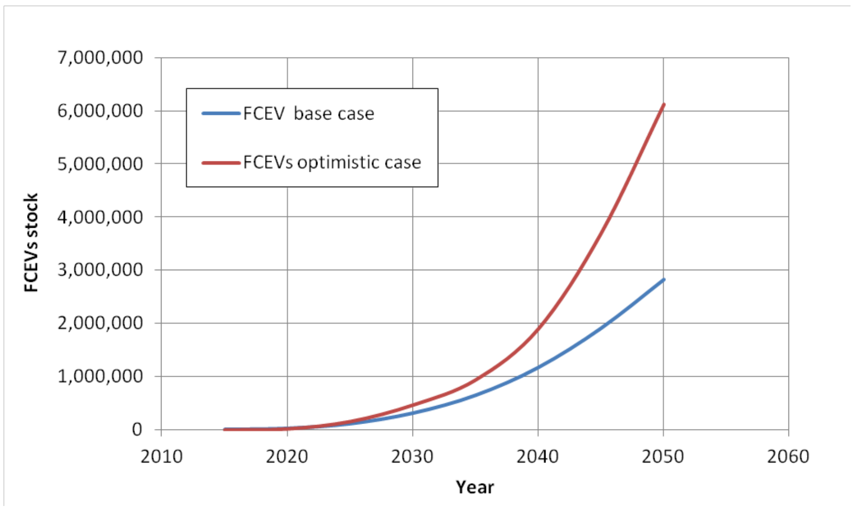


Figure G-6: Light Duty FCEVs Stock Projections in California



Hydrogen and Electricity Infrastructure Scenario in California

Two main production pathways are considered in this study: centralized steam methane reforming and on-site electrolysis. Considering the FCEV roll-out scenario in California, the fuel demand that must be satisfied by each production pathway and the related number of stations were assessed assuming the vehicle performance, annual use, and equipment availability (Table G-7). Station capacities are based on literature review and the assumption that station utilization steadily increases over time.

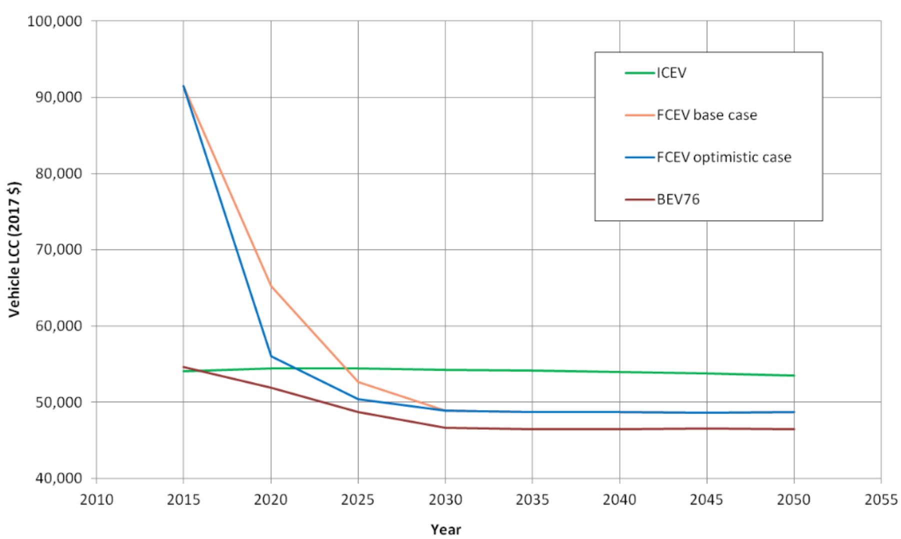
Table G-6: Vehicle Efficiencies and Annual Driving Range

Parameter	Unit	Year							
		2015	2020	2025	2030	2035	2040	2045	2050
FCEV efficiency	mpg	76	80	86	86	89	92	95	98
BEV efficiency	mpg	110	119	127	135	139	142	144	145
ICEV efficiency	mpg	27	31	34	38	41	45	48	52
Annual driving range	miles/yr	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000

Table G-7: Percentage Share of Hydrogen Production, Use, and Availability

Parameter	Unit	Year							
		2015	2020	2025	2030	2035	2040	2045	2050
Electrolysis production	%	20	22	24	26	28	30	32	34
SMR production	%	78	74	70	66	62	58	54	50
Other production pathways (such as production from biomethane)	%	2	4	6	8	10	12	14	16
Utilization	%	30	65	80	84	86	87	88	89
Availability	%	85	86	87	88	89	90	91	92

Figure G-7: Life-Cycle Cost Compared Among Different Vehicle Technologies



NPV for 10 years ownership.

Importance of Global Use Targets for FCEV

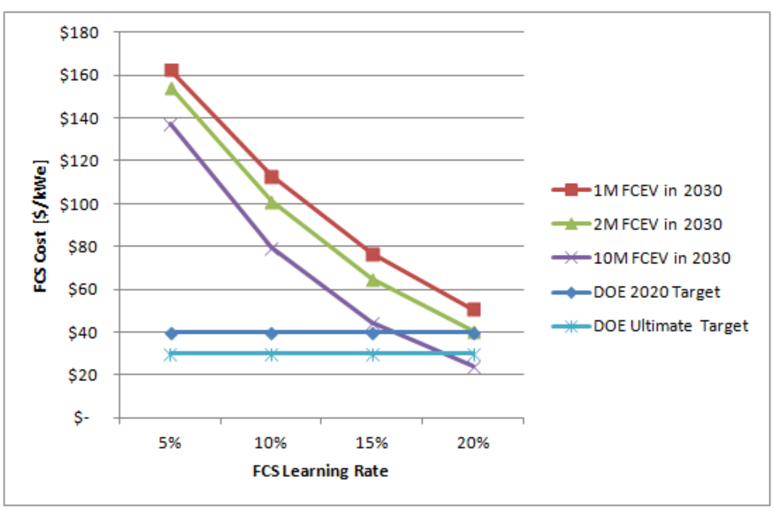
This section illustrates the importance of establishing global use targets for FCEV in achieving cost reduction targets in an alternative way focused on the fuel cell system cost only. The market for FCEVs is assumed to be a global market, and emerging technologies such as FCEVs are assumed to require continued government support to overcome market adoption barriers and to provide public investment supporting infrastructure for at least the next 10 to 15 years.

Future FCEV FC system cost depends on cumulative volume and learning rate (described in Chapter 1 and Appendix A). Key cost components for FCEV fuel cell systems are the fuel cell stack and balance of plant components. Current FCEV policies in the EU, North America, Japan, and China target about 2 million units by 2030 (IPHE 2017). Using this global target for FCEV and the current cost of fuel cell systems, the projected cost for fuel cell systems can be evaluated and compared to the U.S. Department of Energy fuel cell system ultimate target cost as a function of installed units and assumed learning rate.

The risks for fuel cell system cost-competitiveness (therefore, FCEV cost-competitiveness) are highlighted in Figure 6-5, assuming a current cost of $230/kW (Wilson et al 2016) and current vehicle stock of about 9,200 fuel cell electric vehicles. At the cumulative volume corresponding to current national targets (about 2 million units in 2030), the fuel cell system cost is seen to just achieve the 2020 DOE target only by 2030, and the ultimate $30/kW target is not met, even with a learning rate above 20%. This would be a very high learning rate for an electrochemical technology. For reference, the Li-ion battery learning rate is between 6% and 9% (Nykvist and Nilsson 2015). The fuel cell vehicle adoption scenario in Chapter 9 assumes 8 million FCEV units in 2030, and the sensitivity analysis in Figure G-8 assumes 4 million units in 2030.

Thus, to give the best chance for ZEV-FCEV cost competitiveness, more aggressive deployment targets would be needed by regions such as California and national governments

Figure G-8: Fuel Cell System Projected Cost in 2030 vs DOE $30/kW Ultimate Cost Target



The 2030 cost is a function of the fuel cell system learning rate and the global stock of FCEV in 2030.