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Deep carbon reductions in California require electrification and integration across economic sectors

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Abstract
Meeting a greenhouse gas (GHG) reduction target of 80% below 1990 levels in the year 2050 requires detailed long-term planning due to complexity, inertia, and path dependency in the energy system. A detailed investigation of supply and demand alternatives is conducted to assess requirements for future California energy systems that can meet the 2050 GHG target. Two components are developed here that build novel analytic capacity and extend previous studies: (1) detailed bottom-up projections of energy demand across the building, industry and transportation sectors; and (2) a high-resolution variable renewable resource capacity planning model (SWITCH) that minimizes the cost of electricity while meeting GHG policy goals in the 2050 timeframe. Multiple pathways exist to a low-GHG future, all involving increased efficiency, electrification, and a dramatic shift from fossil fuels to low-GHG energy. The electricity system is found to have a diverse, cost-effective set of options that meet aggressive GHG reduction targets. This conclusion holds even with increased demand from transportation and heating, but the optimal levels of wind and solar deployment depend on the temporal characteristics of the resulting load profile. Long-term policy support is found to be a key missing element for the successful attainment of the 2050 GHG target in California.

Keywords: energy system modeling, renewable energy, long term energy scenarios, electricity system optimization, deep carbon reduction

S Online supplementary data available from stacks.iop.org/ERL/8/014038/mmedia

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1. Achieving the 2050 GHG target

California has become an internationally important test-bed for low-cost, low-GHG energy planning. California's landmark AB32 law mandates a return of State GHG emissions to the 1990 level by 2020, and Executive Order S-3-05 sets a goal for the State to reduce emissions to 80% below this level by 2050 [1, 2][6].

In this work, we take an integrated approach and evaluate GHG emissions across the electricity, building, transportation, and industrial sectors—90% of the current total—and do not treat agriculture or non-energy based emissions [3]. Taking the 1990 baseline of energy and industry emissions as 405 million metric tons CO_2-equivalent ($MtCO_2$-eq), an 80% reduction gives a 81 $MtCO_2$-eq target for California in 2050 [4]. We take a conservative approach by predominantly using technologies that exist in the marketplace or are beyond the demonstration stage.

Integrated long-term planning and a portfolio of public policies are being developed to meet GHG targets in California. Previous work [5–10] has highlighted the electricity sector as key to deep GHG reduction in California. This study complements and expands on previous work by providing a detailed, bottom-up assessment of electricity demand and supply. Load profiles for increased efficiency, vehicle electrification, and heating electrification are developed as inputs to a state-of-the-art variable renewable resource capacity planning model of the electric power sector. The SWITCH model [11–13] is used to explore generation, transmission, and storage deployment through 2050 in the synchronous western North American electricity grid, of which California represents roughly one-third of total demand.

We find that meeting the 2050 GHG target is achievable, but requires dramatic changes in the way California produces, delivers, and uses energy. Figure 1 shows the cumulative impact of measures that can reach the 2050 target ('Compliant Case'). Figure 2 shows the radical shift in overall primary energy resulting from these measures. Increased efficiency, low-GHG electricity, electrification of heating and vehicles, and deployment of sustainable biofuels reduce emissions to just under 100 $MtCO_2$-eq in 2050 (figure 1). Thus additional elements are required to meet the 81 $MtCO_2$-eq target, such as higher imports of low-GHG biofuels, higher penetration of electrification in industry and transportation, or savings from energy conservation (see online supplementary material available at stacks.iop.org/ERL/8/014038/mmedia). Conservation is highlighted in sections 2 and 3 as an additional element to attain the 80% target. The electricity sector modeling in sections 4 and 5 does not include demand reduction from conservation since there are other pathways to meet the 80% target (e.g., the 100 $MtCO_2$-eq case above coupled with higher biofuel imports). Table 1 provides a summary of energy demands and emission intensities for buildings, industry, and transportation sectors for 2011 and four 2050 cases.

2. Transportation electrification and biofuels are critical

Managing transportation sector emissions is vital to achieving the long-term GHG target as it makes up approximately 40% of California emissions [9]. As dictated by the current status of technology, two primary pathways are proposed to achieve low-GHG transportation and displace petroleum-based fuels: low-GHG biofuels and electrification[7]. This work does not consider hydrogen vehicles due to the multiple challenges posed by hydrogen distribution, storage, fuel cell technology, and cost, though under certain circumstances this pathway could become another viable, low-GHG option for the transportation sector.

In our analysis, all biomass is directed towards biofuel production and none is made available for electricity, owing to the difficulty in electrifying some transportation modes and the relative abundance of low-GHG sources of electricity. In keeping with the technical potential framework used in the building and industry sectors, we adopt 94 million dry tons of biomass for an overall supply of 7.5 billion gallons gasoline-equivalent in 2050 [6]. This biomass scenario results from high growth in herbaceous and forest residues, improved technical yield recovery, substantial investment in additional energy crops, and utilization of abandoned agricultural and non-productive forest lands. Consistent with State Executive Order S-06-06,[8] we limit imported biofuels to 25% of total supply. Still, total biofuels fall short of projected liquid fuel demand by 32%, necessitating a shift to electric transportation.

A stock turnover model is used to project light-duty electric vehicle deployment, with 45% of passenger vehicle miles from electricity in 2050. Passenger vehicle electrification assumes that plug-in hybrid and battery electric vehicles quickly enter the market, and by 2050 become the majority of the fleet. Vehicle sales adoption curves by drive train technology are shown in figure S6 (supplementary material available at stacks.iop.org/ERL/8/014038/mmedia), and recent State policy targets call for similarly aggressive market penetration through 2025 [14]. Fixed, nighttime load profiles for electric vehicles are developed as inputs for the electric sector model below. 81 000 GWh of demand are added to the electric power system in 2050 from vehicle electrification (figure 1(b)). Aviation, marine transport, and most heavy-duty transport are not electrified due to range and weight requirements, but other modes, including some short-distance trucks, intra-city buses, and rail transport are completely electrified.

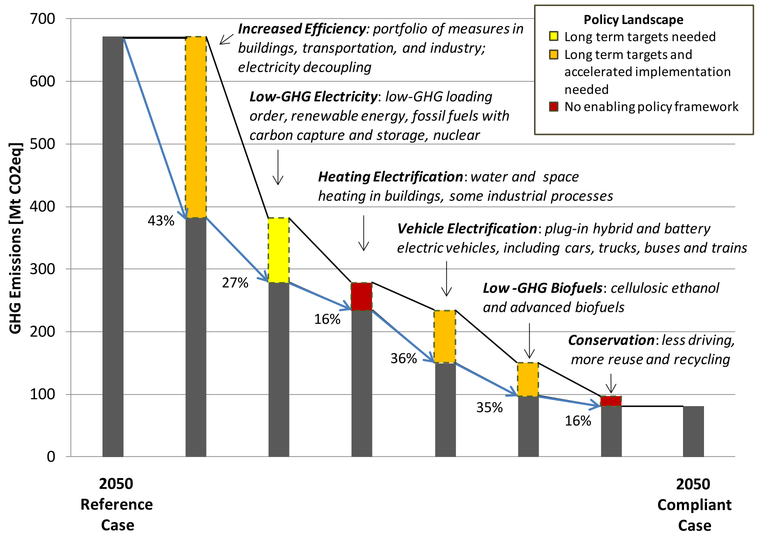
3. Bottom-up building efficiency and electrification modeling

Natural gas currently provides most energy for building and industry heat, so a major shift in State energy policies and end-use technologies would be required to enable a transition away from fossil fuel in these sectors [15–18]. For industry, low and medium temperature processes—39% of industry fuel demand—are electrified by 2050, totaling

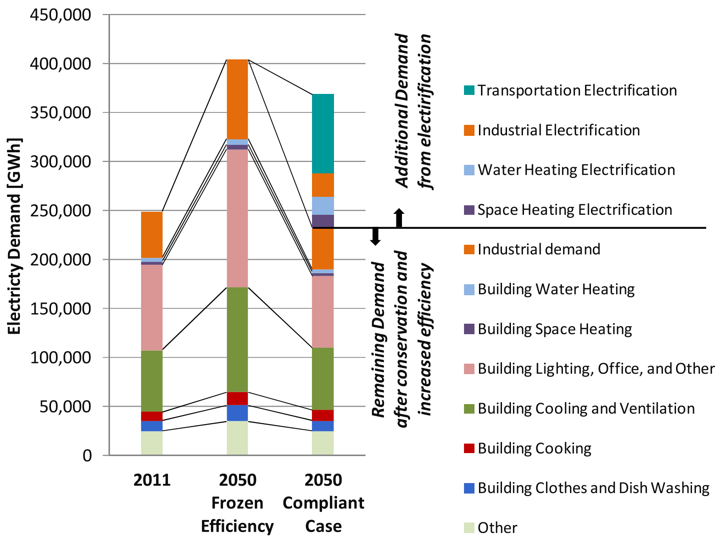
[6] Detailed information describing California climate programs can be found at www.arb.ca.gov/cc/cc.htm (Climate Change Programs, California Environmental Protection Agency, Air Resources Board).

[7] See for example http://gov.ca.gov/news.php?id=17472 (Office of Governor Edmund G Brown, State of California, Executive Order B-16-2012).

[8] Climate Change Programs, California Environmental Protection Agency, California Air Resources Board, www.arb.ca.gov/fuels/altfuels/incentives/eos0606.pdf. Accessed 1 June 2012.



(a)



(b)

Figure 1. (a) The California 2050 GHG target of 81 $MtCO_2$-eq can be met with a combination of GHG reduction pathways, each of which is insufficient on its own. Shown here is a compliant case combining increased efficiency across sectors [28], clean electricity, electrification of heating and vehicles, biofuel deployment and savings from energy conservation. The GHG savings percentages associated with each pathway relative to the previous level of emissions are shown and are representative of the savings potential for each measure. Note that the magnitude of GHG savings for each pathway depends on the presentation order. An assessment of the policy landscape is shown for each pathway. All pathways lack long-term policy targets, and no enabling policy for heat electrification or conservation currently exists.
(b) Electricity system demand. Increased efficiency in the building and industry sector can reduce California's 2050 demand from the frozen efficiency case by 35%, and conservation can provide a further 16% electricity demand reduction. Increases in electricity demand stem from electrification of building heat, industry process heating, and vehicles.

24 000 GWh of additional demand based on analysis of end-use applications by industry sector and the availability of multiple electric-based process heating technologies. Residential and commercial space and water heating are fully electrified by 2050 (figure 1(b)) through a transition to high-efficiency heat pump technology.

Hourly load profiles for electricity demand from space and water heating in buildings are developed based on historical heating load profiles, disaggregated by California climate zone, and scaled up to displace all remaining GHG-intensive heating demands within buildings (figure 3). Electricity demand from water and space heating is greatly increased (figure 1(b)), adding 32 000 GWh to the electricity load in 2050.

In addition to minimizing fossil fuel demand from the State's non-electricity energy supply, increased efficiency of electrical devices in all buildings is also assumed [19, 20]. Without increased efficiency, much higher electricity demand and greater capacity of generation supply would be required. For reference, we consider a 'frozen efficiency' case where efficiency levels are held at present day levels.

A bottom-up stock model is used to simulate efficiency improvements in residential and commercial buildings [21, 22], achieving 38% electricity savings in 2050 relative to

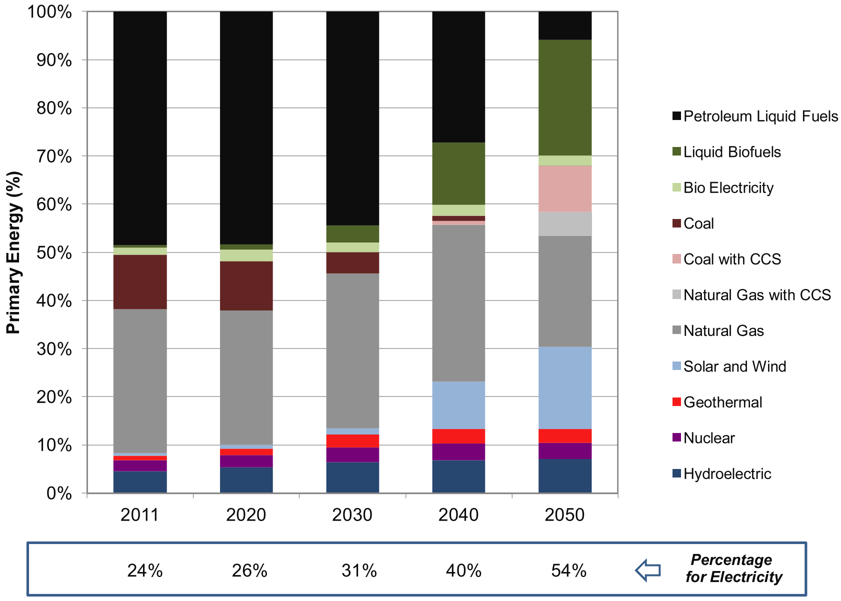


Figure 2. Primary energy evolution in California from 2011 and 2050 for the compliant case depicted in figure 1. Note the dramatic shift in energy sources over time, with the percentage of primary energy for electricity doubling present levels by 2050. Petroleum-based liquid fuel is sharply reduced and the fossil fuel fraction of primary energy drops from 90% in 2011 to 44% in 2050. Primary energy for combustible fuels (petroleum, natural gas, coal, biomass, biogas) is defined as the higher heating value of the fuel prior to combustion, whereas primary energy for non-combustible fuels (hydroelectric, nuclear, geothermal, solar, wind) is defined as the heat content of net electricity generated. Net energy from imports and exports of electricity to and from California are calculated hourly using the SWITCH model as the fraction imported multiplied by the out-of-State electricity generation minus the fraction exported multiplied by the in-State electricity generation.

the frozen efficiency case. For existing buildings, 100% of technically feasible opportunities to improve efficiency on a retrofit or 'replace on burnout' basis are applied to eligible buildings by 2050 (supplementary material available at stacks.iop.org/ERL/8/014038/mmedia). Energy savings from new construction is similar to California Public Utilities Commission initiatives for Zero Net Energy New Construction buildings [23]: 100% of new residential (commercial) buildings achieve at least 35% (30%) electricity savings by 2025 (2030) compared to 2005 efficiency standards.

Load profiles are synthesized from the mix of end-use demands and technologies using a load profile database for both efficiency and building electrification [24]. Efficiency load profiles for 8760 h yr^{-1} in 14 California climate zones and 20 end-uses are synthesized and provided as inputs to the electric sector model.

Efficiency savings in 2050 are dominated by a small number of end-uses. For residential buildings, 63% of cumulative efficiency savings come from lighting, refrigeration, and central air-conditioning. For commercial buildings, just three uses contribute 81% of the savings: interior lighting, cooling, and refrigeration.

4. High-resolution electricity sector modeling

GHG reduction from electrification is predicated on a shift to low-GHG electricity. Despite aggressive efficiency measures, overall electricity demand in the compliant case is only 10% lower than the frozen case due to increases from transportation and heating. As a result, drastic but technically feasible shifts in the electric power system appear necessary to decarbonize California's energy system.

New plants will replace a large fraction of electricity generation in today's power system by 2050, representing an opportunity to transform the State's current mix of power plants and increase the reliance on low-GHG power sources. Large-scale integrated planning using suitable policies and investments is needed to minimize the cost of this transition.

In order to leverage the spatial and temporal synergies among two of the most promising low-GHG generation technologies (solar and wind), careful combinations of investments are needed to ensure low-GHG, low-cost, and reliable electric power. High-quality renewable resources are unevenly distributed both spatially and temporally throughout western North America [25]. It is therefore essential to include the entire western North American synchronous interconnect—the geographic area of the Western Electricity Coordinating Council (WECC)—in an analysis of future California low-GHG electricity supply.

The SWITCH electric power system planning model is used to explore future electricity scenarios with a WECC-wide cap on power sector GHG emissions, reaching 80% below the 1990 level in 2050. Power sector GHG allowances are implicitly assumed to be tradable across WECC. The version of SWITCH used in this study minimizes the cost of producing and delivering electricity from present day until 2050 using a combination of existing grid assets and new generation, transmission, and storage capacity.

Shifting vehicle and heating demand toward electricity would drastically change seasonal and diurnal load profiles (figure 3). By 2050, the load profile exhibits a strong morning peak in winter due to added demand from water heating, as well as a new evening peak throughout the year due to electric vehicle charging. In addition, air conditioning

Table 1. Summary table of energy demands and emission intensities for buildings, industry, and transportation sectors for 2011 and four 2050 cases. State population is assumed to increase 60% to 59.5 million residents in 2050 from 37.7 million residents currently.

		Energy					Relative emissions intensity relative to current (2011 = 1)			
Energy supply	Units	2011	2050 frozen efficiency	2050 increased efficiency	2050 increased efficiency, low-GHG electricity, electrification, biofuels	2050 compliant (increased efficiency, low-GHG electricity, electrification, biofuels, conservation)	2050 frozen efficiency	2050 increased efficiency	2050 increased efficiency, low-GHG electricity, electrification, biofuels	2050 compliant (increased efficiency, low-GHG electricity, electrification, biofuels, conservation)
Buildings										
Liquid, solid fuels	Tbtu	52	77	54	17	15	1	1	1	1
Gaseous fuel	Tbtu	710	1 052	735	227	209	1	1	1	1
Sum	Tbtu	762	1 129	789	244	224				
Change			48%	−30%	−69%	−8%				
Electricity	GWh	176 500	288 200	178 800	213 400	196 500	1	1	0.12	0.12
Change			63%	−38%	19%	−8%				
Industry										
Liquid, solid fuels	Tbtu	496	611	276	130	94	1	1	0.86	0.86
Gaseous fuel	Tbtu	1 039	1 255	604	322	232	1	1	0.94	0.94
Sum	Tbtu	1 535	1 866	880	452	325				
Change			22%	−53%	−49%	−28%				
Electricity	GWh	47 200	81 100	58 400	91 900	66 200	1	1	0.12	0.12
Change			72%	−28%	57%	−28%				
Transportation										
Liquid, solid fuels	Bgge	21.4	38.5	20.2	10.6	8.8	1	1	0.50	0.50
Change			80%	−48%	−48%	−17%				
Electricity	GWh	0	0	0	97 000	80 900	1	1	0.12	0.12
Change						−17%				

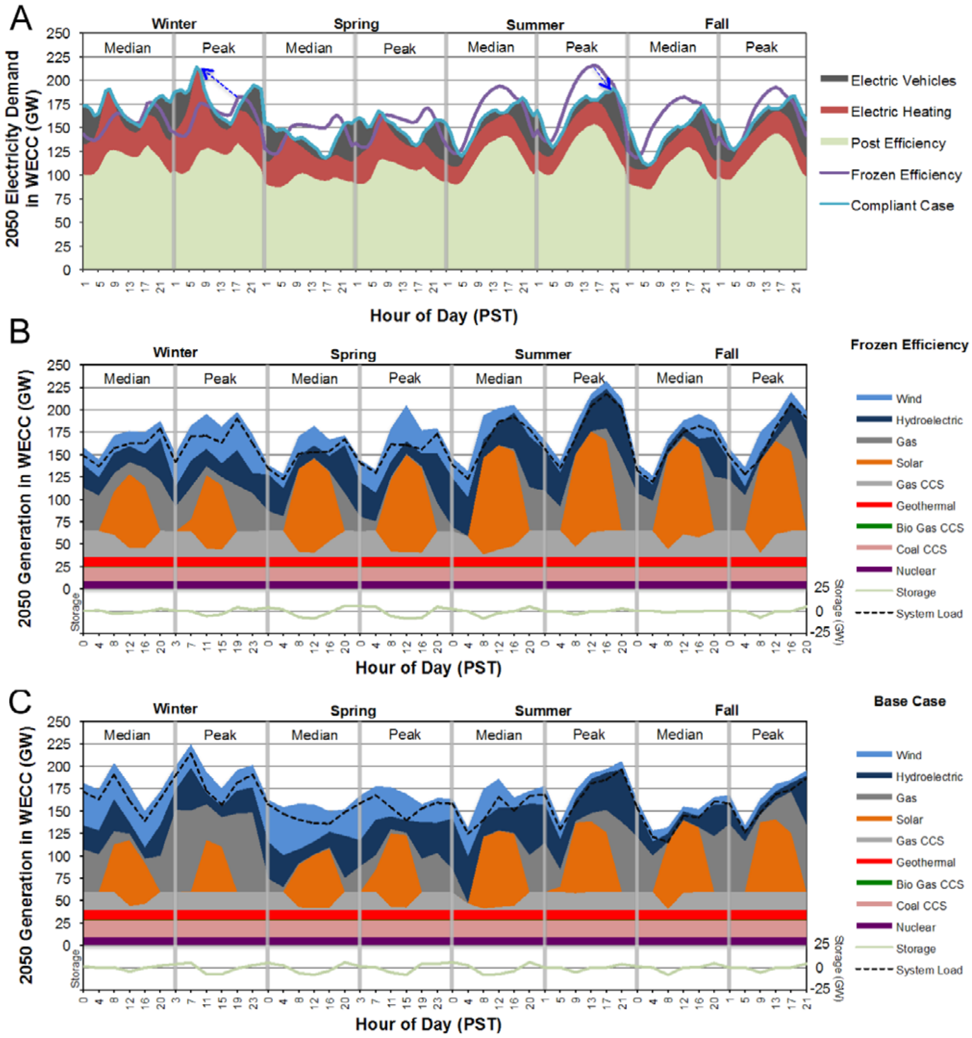


Figure 3. (a) Drastic shifts in load profile are seen from the implementation of efficiency ('post efficiency' scenario) and subsequent addition of loads from electric vehicles and heating. The compliant case ('Base Case') represents the load profile used as an input to the SWITCH model. One peak and one median demand day per season are shown in the figure for clarity, though the SWITCH model uses six days per season for each decadal time step. (b) WECC-wide electricity generation in 2050 as dispatched by SWITCH for the frozen efficiency load profile (c) WECC-wide electricity generation in 2050 as dispatched by SWITCH for the compliant case from figures 1(b) and 3(a). Note the shift from solar to wind power as the amount of efficiency and vehicle and heating electrification is increased from the frozen efficiency load profile.

loads in summer afternoons remain prominent even after new efficiency measures are introduced, producing an electricity system with high demand periods in both summer and winter. We model this load profile separately for each of 50 areas within WECC for six hours of each of 24 representative days in the decades 2020–2050. Both peak and median load days from each month are represented to ensure that SWITCH plans for average and peak conditions across an entire year. In each modeled hour, demand must be met by the optimization, as well as capacity and operational reserve margin constraints to ensure system reliability. Results from investment optimizations are validated using a full year of hourly load and variable renewable resource data.

5. Many cost-effective electricity generation options

Using the SWITCH model, we find that the WECC electricity system in 2050 has a diverse set of generation options that can cost-effectively meet aggressive GHG reduction targets, even with drastic changes in load profile shape due to efficiency and large vehicle and heating loads (supplementary material available at stacks.iop.org/ERL/8/014038/mmedia). The scenarios explored in this study show that variable renewable resources (wind and solar) could economically contribute as little as one-third or as much as three-fifths of generated power within WECC by 2050. Despite their variability, both wind and solar technologies appear poised to supply large amounts of inexpensive, low-GHG electricity to the WECC power system of the future.

The optimal fractions of wind and solar deployment are a function of the temporal characteristics of the load profile, with increasing vehicle and heating electrification favoring wind over solar power (figure 3). As nighttime heating and electric vehicle loads increase, the energy and capacity value of wind power increases relative to that of solar. Increasing

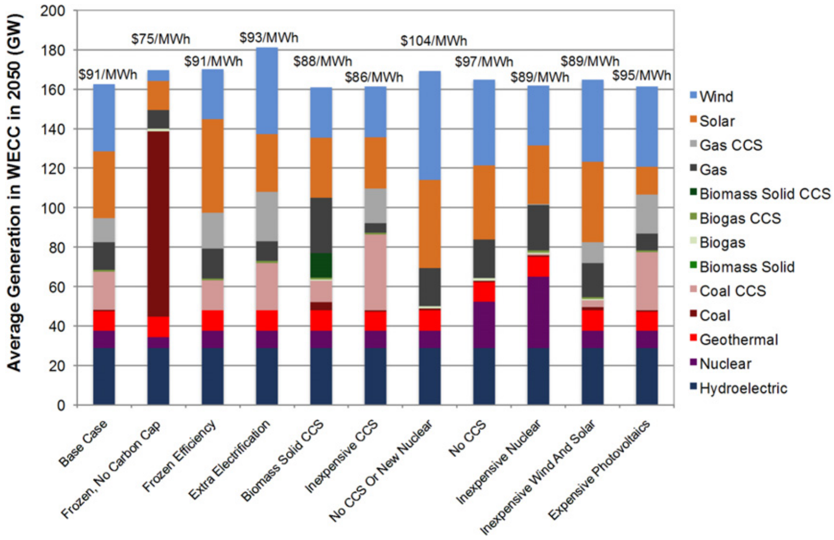


Figure 4. Average 2050 electricity generation by fuel category, and average 2050 power cost (in $2007 per MWh) for ten electricity scenarios in which WECC-wide power sector emissions are capped at 80% below 1990 levels. The biomass solid CCS scenario includes further GHG reductions. The frozen, no carbon cap scenario does not include a cap on GHG emissions. The compliant case ('Base Case') is the starting point on which other sensitivity scenarios are based. Information on specific scenarios can be found in the supplementary material (available at stacks.iop.org/ERL/8/014038/mmedia). The average power cost varies by less than $20 per MWh across GHG-capped scenarios, indicating that many low-cost, low-GHG options exist for the power sector.

demand flexibility could incentivize either wind or solar power, depending on their relative delivered costs.

Using operating reserve requirements and large balancing areas similar to those evaluated in the Western Wind and Solar Integration Study [26], we find that the majority of spinning reserves in WECC can be provided by hydroelectric power and storage technologies, with the balance provided by gas-fired technologies. Sub-hourly load balancing does not appear to be a major limitation for achieving deep emissions reduction in a future electricity grid with up to 60% of energy from variable renewable generation.

Nuclear power and fossil fuel generation with CO_2 capture and sequestration (fossil/CCS) may be attractive low-GHG baseload technologies, but neither is essential to meeting GHG targets (figure 4). With the costs assumed in this study, generating electricity from fossil/CCS can lower the cost of power while meeting emissions targets. Installation of new nuclear power is found to be a backstop against rising power costs, but is not cost-effective given our base cost assumptions.

Greater fractions of energy from variable renewable resources are found to increase the magnitude of transmission and storage deployment (figures S69 and S71 available at stacks.iop.org/ERL/8/014038/mmedia). Power systems in this study that generate less than half of their electricity from variable renewable resources are not found to need drastic expansion of the transmission system nor large-scale deployment of electric energy storage. However, as the fraction of electricity from variable renewable resources exceeds fifty per cent, increasing amounts of transmission and storage are installed in order to spatially and temporally move electricity from the point of generation to the point of consumption.

The average cost per MWh of electricity stays relatively constant between present day and 2050 across a range of cost and generator availability scenarios. While this result is in part dependent on technological improvement driving declining capital costs, sensitivity analyses show that three future supply options with the most uncertain costs—solar photovoltaics, nuclear, and fossil/CCS—are not individually essential to keep the cost of electricity low. In all scenarios, total power system cost increases roughly in proportion to load, so while increasing demand adds to total expenditures, the average cost per MWh is stable through 2050. Relative to a scenario in which no cap on GHG emissions is enforced, achieving 80% GHG reductions in the power sector raises the cost of power by 18%–42%. The tight range of power system costs found amongst a variety of scenarios (figure 4) indicates that GHG reduction via electrification is a robust strategy, as the risk of power cost overruns is reduced by the availability of a portfolio of technologies.

6. Discussion—the need for integrated planning and policy

Long-range planning can ensure that current policies and pathways are consistent with long-term goals. Policies that focus on improving natural gas heating or conventional internal combustion engine efficiency without transitioning away from fossil fuel may be appropriate for the short term, but are not sufficient for meeting long-term GHG targets. Similarly, the electrification of heating will only be an effective measure for meeting an 80% reduction goal if the electricity supply has a near zero-GHG intensity. The interaction among different sectors and various GHG-reduction pathways should continue to be an active area of research and optimization.

Technology does not appear to be the limiting factor for the State to meet its economy-wide 2050 GHG emissions target, though this conclusion is predicated upon ample low-GHG biomass supplies (with little or no associated indirect land use impacts), steady technological development and cost reduction of existing technologies, and more modest economic growth than assumed in other studies [5, 6]. Much of the technology already exists for increased electrification and building efficiency, but may need policy support to achieve cost-effective production at scale and more importantly, to induce widespread adoption (tables S1 and S2 available at stacks.iop.org/ERL/8/014038/mmedia). Plug-in electric vehicles are being rapidly developed by the automotive sector, but there is less activity in other transportation sectors. Availability of biomass and low-GHG process development are pivotal for reducing fuel-use GHG emissions.

In addition to technological solutions, substantial reductions are also possible from conservation measures [27]. Preliminary modeling of these GHG-saving measures was conducted based on historical trends in non-energy behaviors including public health, safety, and diet. By 2050, as much as 16% of GHG emissions could be conserved by measures such as reductions in vehicle-miles traveled, eco-driving, increased energy conservation, improved diets, waste reduction, and increased recycling (section 9, supplementary material available at stacks.iop.org/ERL/8/014038/mmedia). Human and social factors should be a topic for further research, as they are directly coupled with public policy, technology deployment, and market development.

Expansion of California's policy framework is needed to enable energy system changes suggested herein. Aggressive codes and standards will be required to meet building, vehicle, and industry efficiency targets. While efficiency is already a focus for the State, implementation and adoption of additional efficiency measures is critical, especially for building retrofits. Policies are currently in place for both vehicle electrification and low-GHG biofuels, but will need extension and expansion to meet the 2050 climate goal. Multiple barriers exist for building electrification, and policy development is urgently needed to ensure the transition to electrified heating. An 80% reduction in electricity sector emissions can be ensured with a continuation and expansion of aggressive renewable energy and/or GHG targets in the future.

Meeting the State's 2050 GHG target is found to be feasible but requires a portfolio of measures and a commitment to integrating and coordinating policies in the electricity, buildings, transportation, and industrial sectors. The GHG reduction measures put forward here include an increase in the efficiency of energy use for all sectors, a drastic decrease in the GHG intensity of electricity and liquid fuels, and a substitution of end-use fuel consumption for electricity. Behavioral factors may also be able to play an important role in GHG emission reduction. Long-term policy support is found to be a key missing element for the successful attainment of the 2050 GHG target in California.

7. Materials and methods

Future electricity and fuel demands were projected for three economic sectors (buildings, transportation, and industry) with piecewise additive scenarios for energy demand and energy supply. First, energy efficiency is applied across sectors, then clean electricity is added, followed by electrification, low carbon biofuels, and then energy conservation. Electricity and fuel supply mixes were developed to meet overall demand subject to biofuel availability and GHG constraints for electricity. GHG emissions were calculated for each scenario based on overall energy demands and carbon intensity of energy supplies. Assumptions for the boundaries and scope of GHG emission treatment are discussed in the supplementary material (available at stacks.iop.org/ERL/8/014038/mmedia).

Energy demand for a frozen efficiency case was first estimated as a reference case with growth rates informed by historical trends and other studies. An energy efficiency case was then developed assuming that technical potential levels of efficiency are achieved across all three sectors. A low-GHG electricity supply was added to this scenario (energy supply modeling is described below). Fuel-switching was introduced by assuming wide spread electrification from gasoline-based internal combustion engines to electrified or partially electrified passenger vehicles and from largely natural gas based heating processes to electrified heating in buildings and industry. Further carbon reduction was achieved by assuming technical potential availability of liquid biofuels and finally by assuming conservation measures are aggressively adopted.

Energy demand was disaggregated into building, transportation, and industry sectors for California. Estimates utilized a median population and economic growth forecast based on State and California Energy Commission (CEC) estimates, respectively. Building demands for electricity and fuel (e.g., natural gas for heating) were developed for residential and commercial buildings as described in the supplementary material (available at stacks.iop.org/ERL/8/014038/mmedia) and further disaggregated into single/multi-family units and new/existing buildings. Stock turnover analysis was done for a comprehensive set of end-use demands. Commercial buildings demand estimates utilized historical trends of energy demand per square foot of space by building type. Electricity demand for the rest of the Western Electricity Coordination Council geographic region was estimated from a synthesis of US Energy Information Administration data and regional utility forecasts.

Transportation demand estimates utilized vehicle stock modeling for passenger vehicles and aviation with projections for other transportation modes consistent with State or federal models. Stock modeling assumptions of vehicles per capita, vehicle-miles travelled (VMT) per vehicle, and market penetrations by vehicle drivetrain (internal combustion engines, hybrid electric vehicles, plug-in hybrid vehicles, and battery electric vehicles) are described in the supplementary material (available at stacks.iop.org/ERL/8/014038/mmedia). Industry demand estimates employed sector-based (oil and gas, food and beverage, etc) economic growth projections from the CEC.

The energy efficiency scenario utilized technical potential estimates for each sector. The building sector employed a list of over 200 unique efficiency measures while the transportation sector adopted fuel efficiency potential from existing national and State studies. Industry technical potential estimates were based on CEC reports disaggregated by industry sector and end-use (process heating, boiler-based systems, motor systems, heating, ventilation, air-conditioning, etc).

Electrification projections are based on stock modeling for building water and space heating and for passenger vehicles assuming aggressive transition to electricity-based heating systems in buildings starting in 2015 and to alternative passenger vehicles in transportation, respectively, with market penetration assumptions described in the supplementary material (available at stacks.iop.org/ERL/8/014038/mmedia).

The carbon savings potential for energy conservation was estimated using a simple adoption rate model of energy saving actions. From a database of historical non-energy actions, long-term adoption rates were estimated for a set of conservation actions in home energy usage and passenger vehicle mile reduction, as well as a number of other measures in diet, recycling, and consumption. Carbon savings as a function of time were estimated by calculating carbon intensities for electricity (CO_2/kWh) and transportation (CO_2/VMT).

Low-GHG electricity modeling utilized a high-resolution variable renewable resource capacity planning model (SWITCH) of the interconnected Western North American grid. SWITCH used spatially resolved, time-synchronized hourly solar, wind, and demand data to explore future low carbon electricity scenarios. Optimizations minimized the cost of power between present day and 2050 while subject to reliability and policy constraints. Carbon emissions were constrained to reach 80% below 1990 levels in the year 2050.

Biofuel supply estimates were made with all biomass directed to liquid biofuels and resultant biofuel assumed to replace oil-based liquid fuel. Biomass and biofuel availability projections utilized technical potential assumptions for in-State biomass supply, biomass supply mix, biofuel yield, and life-cycle carbon emission associated with biofuel production. Biofuel production was assumed to replace gasoline in the transportation sector. Sources for biomass materials availability include earlier reports from Oak Ridge National Laboratory, the University of California, Berkeley, and the University of California, Davis.

All methods and key assumptions are described more fully in the supplementary material available online at (stacks.iop.org/ERL/8/014038/mmedia) .

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None of the authors have a conflict of interest for this work.

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Supplementary Material for

Deep Carbon Reductions in California Require Electrification and Integration Across Economic Sectors

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Supplementary Material Text

Figs. S1 to S86

Tables S1 to S20

1. OVERVIEW OF SUPPLEMENTARY MATERIAL

The framework for this study is similar to other 2050 studies (7-10). First and most critically, aggressive energy efficiency measures are pursued and implemented across all sectors. We utilize existing studies for the most part for "technical potential" energy efficiency in the buildings, industry and transportation sectors. Technical potential energy savings assumes technically achievable energy savings with existing technology with less focus on costs.

Second, the electricity supply system is constrained to be largely de-carbonized and able to either meet or exceed its sectoral target of 80% reduction from 1990 since there are a variety of technologies to support this (renewable energy sources such as solar PV, solar thermal, wind and biomass; nuclear power; and fossil fuel power plants combined with carbon capture and sequestration). In keeping with the long-term, technical-potential spirit of this work, we include nuclear power as an option although nuclear construction is currently banned in California. The legal status of nuclear power could be changed and it is also possible that nuclear plants could be built outside the state and power imported to the state. Technologies used in the electricity sector are selected by minimizing the investment and operating costs of the power system within the de-carbonization constraint.

Together with the de-carbonization of the power sector and the need to meet overall emission targets in all sectors, we also assume that much of the heating sector in buildings and to a lesser extent in industry are electrified through high efficiency heat pumps and/or electrified process heating. This is required in the overall building and industrial heating sector where it would otherwise be technically unable to meet 80% reduction targets.

Finally in the transportation sector, we assume that in addition to efficiency improvements, a significant de-carbonization of transport is pursued through a combination of vehicle electrification and the production of low emission bio-fuels.

Our 2050 "Base Case" energy system has four critical pathways:

- aggressive energy efficiency across all sectors (at technical potential levels for buildings and industry);
- low-GHG electricity;
- electrification of vehicles as well as buildings and to a lesser extent, industry heat; and
- low-GHG biofuels.

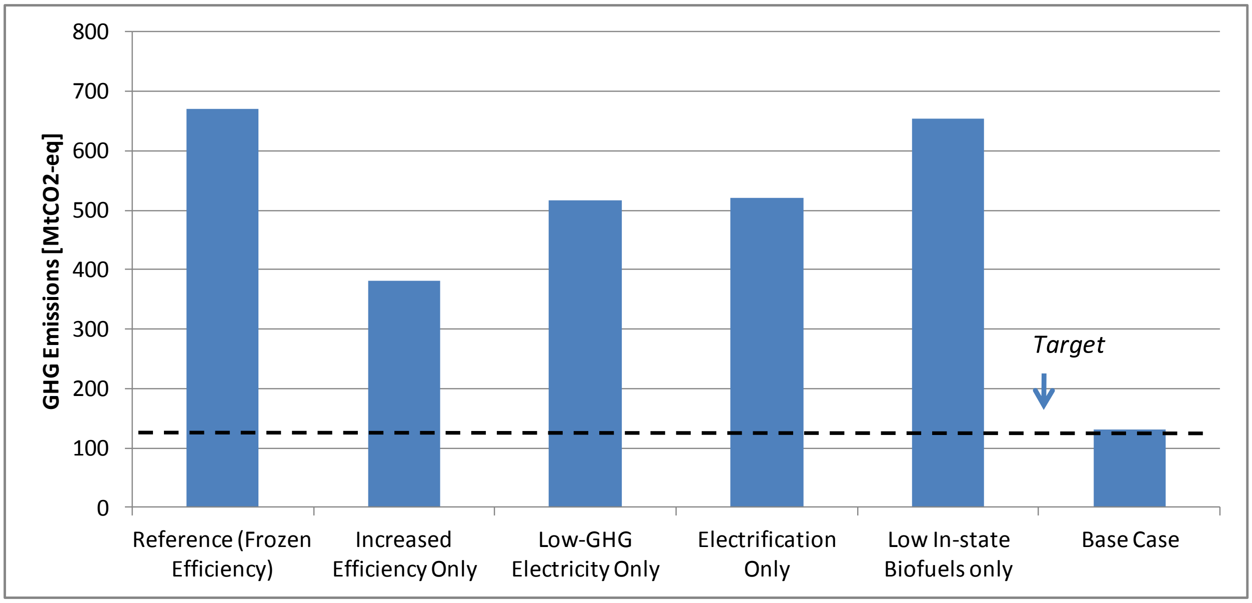


Figure S1. *2050 emissions for the Base Case approach the 2050 target. Any one pathway alone is insufficient and far from meeting target. The base case includes all four preceding pathways (technical potential energy efficiency, low-GHG electricity, electrification, and low in-state biofuels).*

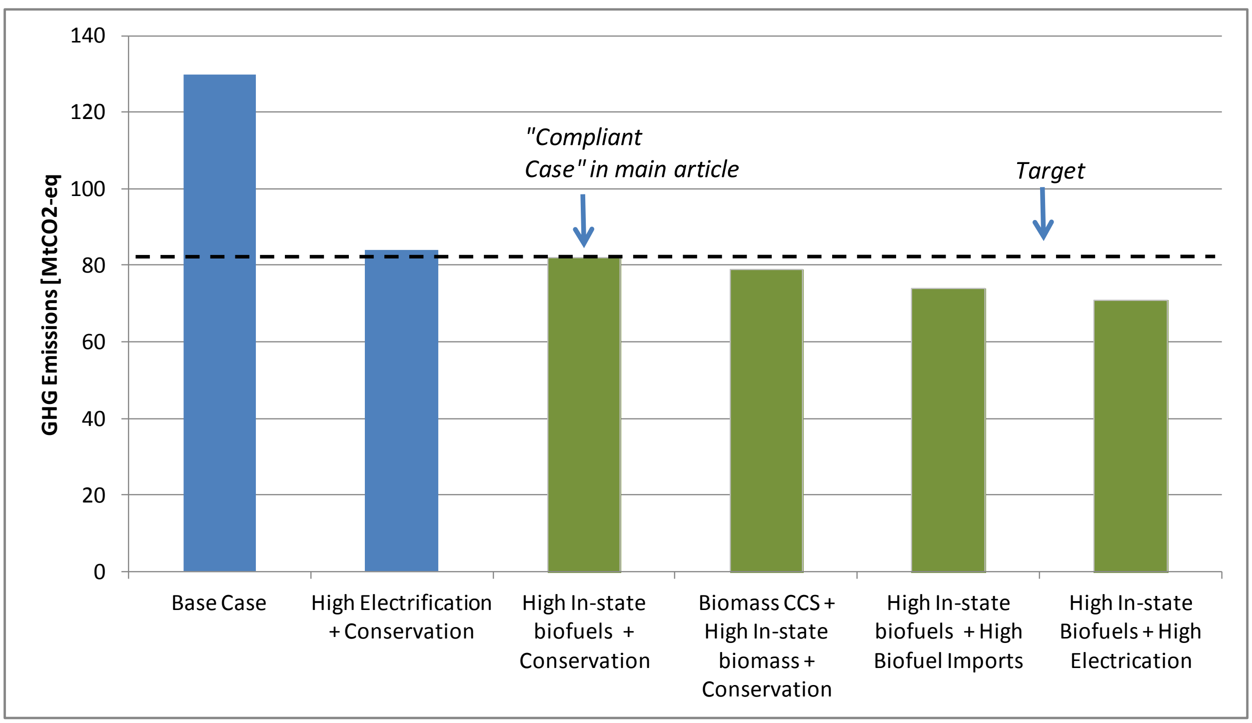


Figure S2. *Several scenarios can meet the 2050 GHG emissions target. The "High in-state biofuels + Conservation" case is taken as a "Compliant Case" in the main article text, but several scenarios can meet the 80% reduction target.*

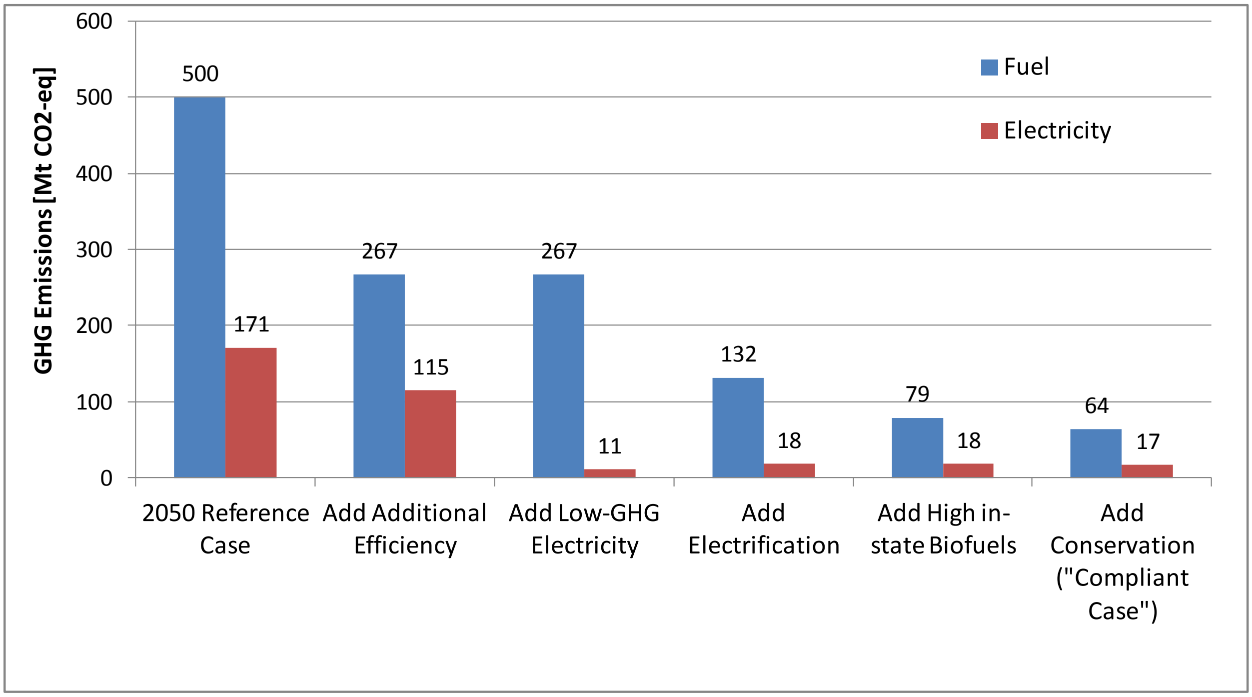


Figure S3. *Evolution of GHG emissions for 2050 Compliant Case.*

Fig. S1 shows overall emissions for the base case approaching the 2050 target compared to the reference ("frozen efficiency") case, relying upon large-scale adoption of existing or near-commercial supply and demand technologies. Also shown is the impact of pursuing each pathway individually. Any one pathway on its own is seen to be insufficient and far from meeting the target. All four elements are needed to be close to achieving the target. For example, a cleaner electricity system is required to enable large-scale electrification as a path to reduce emissions. The base case is estimated to have 130 Mt-CO2eq in 2050 or about a 68% reduction from the 1990 baseline of 405 Mt-CO2eq.

Fig. S2 shows several scenarios beyond the base case that can meet or come very close to the 2050 target of 81Mt CO2eq, considering additional advances in technology or behavior, such as:

- high electrification and energy conservation (84 Mt);
- high in-state biofuels and energy conservation (81Mt, "Compliant Case").
- biomass power with carbon capture and sequestration with high in-state biomass supply and high adoption behavior savings (79 Mt);
- high in-state biofuels and high biofuel imports (74Mt); and
- high in-state biofuels and high electrification (71Mt).

Fig. S3 shows the evolution of GHG emissions for the 2050 Compliant case.

The 2050 target can be met with some combination of at least two of the following additional pathways: higher degree of electrification penetration in passenger vehicles, energy conservation, high in-state biofuels, and biomass power with carbon capture and sequestration. Including only one of these additional pathways is not sufficient to meet the target. The "high in-state biofuels + conservation" case is taken as the "Compliant Case" in the main article text for illustration .

An integrated assessment of base case requirements in terms of technological availability and policy framework is summarized in Table S1. From a policy standpoint, California can build upon its policy portfolio to support the long term GHG target (e.g. building codes and standards, EV support, RPS, utility energy efficiency programs). However, electrification of heating appears to be a policy gap, not sufficiently addressed in the state's long term energy policies.

Key Requirement	Technology Availability	Policy Framework	Comment
Energy Efficiency	Many measures commercially available today while other measures need further development	Need aggressive long term targets	Exisiting policies a basis to build continued aggressive targets (utility programs, appliance standards, building codes)
Clean or Low Carbon Electricity	Many technologies commercially available today while some need further development	Need aggressive long term targets	33% RPS in 2020 in place; Need continued aggressive targets beyond 2020 and additional policies to enable consideration of other low carbon sources including CCS and nuclear
Electrification of vehicles	Hybrids commercially available today, Plug-in hybrids and all-electric vehicles in small volume	Need aggressive long term targets	Exisiting policies a basis to build continued aggressive targets
Electrification of heat	Some equipment commercially available today; other equipment and systems need development	No existing policy framework	Paradigm shift with concomitant policy framework needed (e.g. rebate programs for electric appliances, carbon tax on heating fuels, codes and standards, technology development for industry electrification, etc.)
Low Carbon Biofuels	Technologies for high in-state production of low carbon biofuels need development	Need aggressive long term targets	Federal research funding and California LCFS and other policies in place for cleaner fuels; need aggressive targets beyond 2020
Meet 2020 GHGTarget	Mostly commercially available	AB32, Cap and Trade, Others in place	AB32, RPS, LCFS, Cap and Trade, Vehicle emission standards among other policies should enable the state to meet its 2020 target with reasonable confidence
Meet 2050 GHG Target	Technology and manufacturing development needed across first five sectors above	More aggressive policies and targets needed; policy framework needed for electrification	AB32, Cap and Trade, RPS and other policies helpful but not sufficient for 2050.

Table S1. *Assessment of technology availability and policy framework for 2050 greenhouse gas targets.*

A policy and regulatory framework and technology development program consistent with meeting the 2050 targets would include the following for maximal chance of meeting the 2050 target:

- Energy efficiency programs that build upon and strengthen existing utility programs, standards, and building codes. Many energy efficiency measures have market penetration and adoption rates which are lower than what is needed (see Section 4 for more discussion). Moreover, current building codes and standards are inadequate to meet 2050 goals and need continuous tightening to meet the 2050 target.

- Continuing to increase automobile fuel efficiency standards and maintaining support for transitioning to cleaner vehicles.
- In industry, a strategy to exploit "low hanging" energy efficiency opportunities.
- Commitment to the 33% RPS target in 2020 and sustained ratcheting the targets upward after 2020 for clean or low carbon electricity, as well as regulatory and technology support for transmission infrastructure and optimal load balancing. To reduce long-term risk and the cost of electricity, the state should include a diversity of low, zero, or negative carbon electricity generation sources in the planning process such as renewable energy, nuclear power, and carbon capture and sequestration. Appropriate regulatory policies to support these options would also be required.
- Electrification policy and technology development infrastructure to support aggressive building electrification, and technology assistance and development to support electrified heating systems in industry.
- For biofuels, maximal utilization of biomass sources and aggressive development of higher in-state biomass supplies as well as continued support for the development of advanced low carbon biofuels such as cellulosic ethanol. The availability and supply of low carbon biofuels is a key hinge point for future emissions and the amount of the state's and nation's biomass supply as well as the total carbon impact of biofuel production including indirect CO2 impacts will be critical issues moving forward.
- AB32 and carbon trading policy are helpful but insufficient in their current form to meet 2050 targets. AB32 for example is focused on meeting the 2020 climate targets. Nonetheless, existing policies are an excellent basis to build upon, but more aggressive targets and policies in efficiency, electrification and biofuels are needed to achieve the 2050 goal.

1.1 Technology Assumptions

In terms of technology we consider a research and development (R&D) chain as in Table S2. For the most part our technology envelope includes "within paradigm" items which exist on 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" HVAC technologies such as thermal absorption cooling and novel thermodynamic cycle cooling systems[1] are excluded.

Clearly, there are gray areas; for example basic technology may be known and stage 1 and 2 research and early development been done (Table S2), but no products are available. High temperature industry heating is one such example where it is assessed that technologies exist but product development would be needed and this technology application is not included.

[1] See for example http://www.coolerado.com/

Stage	Technology Development Stage	Building Examples	Electric Power Examples	Industry Examples	Bio-energy Examples
1	Research / Invention / Technology Exploration	Micro recovery of waste heat	Deep Geothermal	Carbon Capture from atmosphere	Artificial photosynthesis for fuel production
2	Early Development/Prototyping		Tidal Power	Process intensification	Algae oils for biofuel
3	Development for Manufacturing	LED lighting for incandescent/CFL replacement	Carbon Capture and sequestration		Advanced biofuels (cellulosic ethanol and alternatives)
4	Deployment and Piloting			Ultra boilers	
5	Low Volume Manufacturing	Heat Pumps for residential space and water heating	Concentrating PV Systems	Membrane separation	
6	High Volume Manufacturing	Condensing furnaces and water heaters	PV, Wind	Variable speed motors	Corn ethanol, Sugar cane ethanol

Table S2. *Technology Stages. In general, this report includes stages 3-6 (in development for manufacturing or already in manufacturing) and does not include technologies in the research/invention/technology exploration stage or in early development (stages 1-2).*

We do not consider "breakthrough" technologies that are in the stages of 1 or 2 in research or early development. For example, this might include start-up technologies in cement, new batteries, or novel photovoltaic technology. It may be the case also that technologies are more mature in some sectors than others (e.g. perhaps buildings compared to transportation) and that further energy savings potentials differ beyond the technical potential described.

1.2 GHG Accounting

Our accounting does not include so-called "upstream" GHG emissions from fossil fuels, in accordance with California Air Resources Board (CARB) rules. While perhaps technically correct as most of those emissions do not originate in California, they do occur elsewhere and ultimately need to be addressed in order to achieve global GHG reductions. In other studies (8) such upstream emissions were formally included in California's emissions, and together with other differences such as higher economic growth, led to the conclusion that technology development must play a decisive role in achieving the State's 2050 GHG target. Accounting for upstream emissions for all fossil fuels in the compliant case would add about 27% additional emissions to the compliant case.

The only exception to this treatment is for biofuels, where biofuel emissions are assumed to evolve to 20% of gasoline life cycle emissions by 2050 (31). Most biofuel production is assumed to be in-state by 2050 and life-cycle emissions from industrial activity and indirect land use are assumed to be captured in this LCA factor, and secondly the mix of biofuels is assumed be be dominated by low carbon biofuels.

1.3 Modeling Approach

The model structure is shown in Figure S4. We utilize two separate modeling tools – one for the power sector and one for non-electricity or fuel sectors. Electricity demand is synthesized from existing sources which is then input into the SWITCH supply model. Non-power sector demands are rolled up into the LEAP model, which is essentially a graphical bookkeeping tool linking bottom-up demands with overall fuel requirements and greenhouse gas emissions.

1.4 LEAP modeling tool

The LEAP modeling tool is used for non-electricity demands and emissions. It provides many features such as the ability to do activity based energy modeling and stock modeling/turnover for equipment and vehicles. It also provides a flexible platform for building new scenarios copied from existing ones or inheriting specified attributes from other scenarios. LEAP also has the capability to model energy balancing of supply sources of fossil fuel and electricity generators although we only use LEAP here to model energy demands and GHG emissions. In the California Carbon Challenge (CCC) model, there is a supply constraint to the amount of available biomass and imported biofuels and the carbon emissions from the electricity system are capped but there are no supply constraint for fossil fuels such as oil and natural gas.

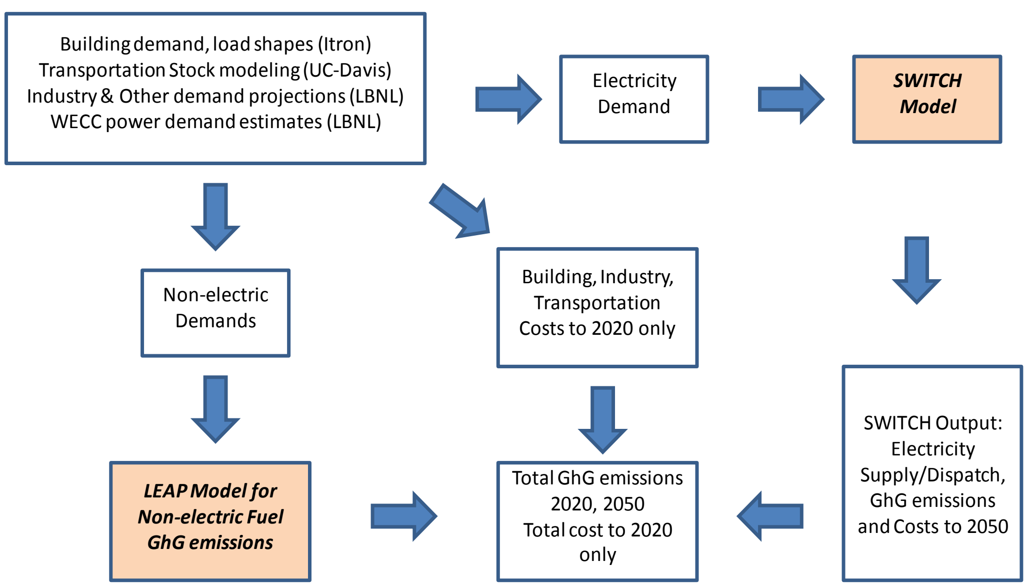


Figure S4. *Structure of the CCC Model.*

For buildings and industry fuel demands, we use activity based energy modeling in LEAP based on existing energy efficiency technical potential studies. For transportation, we utilize the stock modeling capability for light duty vehicles, but activity based modeling for the other transportation sectors (trucks, buses, aviation, marine, and rail).

The energy activity decomposition for buildings end uses (energy services) is as follows:

End use energy of energy service i ~ UEC_i [Annual energy/HH](t) * HH(t) * Saturation Factor

where

UEC_i ~ Energy service * Energy/Service * Usage factor,

HH = number of households, and

Saturation = fraction of households with the service

For example,

UEC (lighting) per household ~ [lumens] * [Watts/lumen] * Time of use [hours]

Note that in this decomposition, factors such as fuel switching and behavior can be readily modeled through the saturation factor and usage factor, respectively.

For a given end use or sector, the percentage of fuel type can be assigned in LEAP. For example, electric space heating in single family homes could have an initial saturation of 12% of households with the remaining 88% of households having fuel based space heating, of which 85% is natural gas and 3% other fuels. Over time saturation of electricity and fuels can be modeled to increase or decrease.

For this study we utilize the output of existing energy efficiency studies for buildings, transportation, and industry for UEC values and projected energy efficiency. For example, we utilize the UEC and energy efficiency data generated by Itron's bottom up stock turnover model for buildings (23) and light duty stock modeling data from University of California-Davis (16).

Population estimates are based on CEC Department of Finance estimates from 2007 (33) employed in earlier Itron, LBNL, and UC-Davis studies (21, 34). California population is projected to increase 60% to 59.5 million people by 2050 or 1.18% annually.

An integrated picture of overall fuel usage and emissions can thus be synthesized over time based on this set of population, households, energy usage data, energy efficiency data, and fuel mixes.

The following sectors are not treated with the same detailed methodology: landfills, wastewater disposal, high GWP gases and agriculture. Emissions from these sectors are included in LEAP and technical potential savings based on CEC reports are applied to 2020 and extrapolated to 2050.

The LEAP model is static in the sense that it is not currently set up to respond to changes in GDP growth assumptions. Rather, historical data is used to project UEC consumption and growth rates, commercial square footage per capita, miles driven per capita, etc. In this sense the model is a "median case" population growth, "medium growth" GDP case. The model does not include elasticity of response to fuel prices and for the most part, there are no feedbacks between energy supply or demand with industrial output, i.e. a scenario with high PV electricity supply does not impact industrial output. The one exception to this is in the area of transportation fuels. We attempt to capture the electricity demand incurred by increasing production of in-state biofuels. Similarly, as the in-state demand for oil and natural gas is reduced from greater efficiency, higher biofuels and increasing vehicle and heating electrification, we reduce the size of the oil and gas industry in the state proportionate to the reduction in demand.

1.5 Modeling Electricity Demand

California electricity demand modeling primarily utilizes existing studies. Itron building demands, technical potential efficiency for residential and commercial buildings, and new demand from fuel switching are used for buildings. Industry manufacturing demands utilize a PIER 2011 study (21) and the CALEB energy database (35) is used for other industry demands. Industry fuel switching to electricity is estimated primarily from low temperature process heating. Transportation stock modeling and activity is based on modeling from UC-Davis.

For WECC demand we utilize utility reports (36-38) and apply California incremental vehicle and heating electrification demands to the rest of the WECC (ROW). Demands are projected to 2050 based on AEO 2010 projections. We assume the same technical potential savings levels as California for the ROW. Similar vehicle electrification and electrification of heating as California is applied to the ROW but delayed to 10 years after California.

By aggregating sector level demands, WECC region annual electricity demands are generated to 2050. These annualized demands are combined with hourly load shapes and are given to the SWITCH electricity supply model, which will be described below. Combining LEAP model output for non-electric fuel GHG emissions and non-energy emissions and SWITCH output for electricity emissions yield total GHG emissions for California. Carbon emissions from SWITCH are calculated for the entire WECC and as California values are not easily disaggregated, proportional carbon reduction constraints for WECC are assumed to hold true for California. In other words, we assume that an 80% carbon constraint for the WECC in 2050 translates into an 80% carbon constraint for California. This assumption will be more thoroughly validated in future work.

1.6 SWITCH Modeling Tool for Power Sector

We utilize a state-of-the-art electricity supply optimization model, SWITCH, to simultaneously optimize the evolution of new generation, storage and transmission capacity as well as grid operations in the electric power sector. SWITCH is a mixed integer linear program that is implemented in this study for the WECC region of North America. The SWITCH model addresses many of the problems associated with intermittent generation by utilizing time-synchronized hourly load and intermittent renewable generation profiles in a capacity expansion model. SWITCH determines the contribution of baseload, dispatchable and intermittent generation options alongside storage and transmission capacity on a least-cost basis in order to meet projected electricity load while subject to policy constraints. Here, we model the evolution of the electricity grid between the present day and 2050 under a cap on carbon emissions. For most cases in this work, we require an 80% reduction from 1990 emission levels for the electricity sector.

Economic optimization is only done for the electricity system and not for the entire energy system. For most cases in this work, we require an 80% reduction from 1990 levels for the electricity sector emissions. This is consistent with a proportionate contribution to the 80% reduction target for all sectors. An optimization of the entire economic system might lead to different apportionments of emission reductions between sectors. As the electric power sector has many large and potentially inexpensive emission reduction options, future studies will investigate a stronger cap on electricity emissions.

Note that fuller documentation of the overall work can also be found in LBNL Report 5448E (102).

2. SCENARIOS TOWARD MEETING LONG TERM CLIMATE TARGETS

2.1 Reference Case

Our reference case is a "frozen efficiency" case with all future efficiency savings turned off and frozen sales adoption curves of vehicle types. No further fuel switching is assumed and biofuel supply is unchanged from current levels. This case does not have a carbon cap for the electricity system in 2050. We do not call this case "business-as-usual" (BAU) since it does not include existing and planned policies. However, we still adopt this as our reference case since all energy efficiency improvements are calculated relative to a frozen efficiency baseline. We also consider a frozen efficiency case that does have a carbon cap ("frozen efficiency and electricity cap") for the electricity system in 2050 to see the impact of having a cleaner electricity system but with everything else at frozen levels. All scenarios are described in Table S3 below.

2.2 Base Case

The base case includes aggressive energy efficiency, vehicle and heat electrification and 3.7 billion gallons gasoline equivalent (Bgge) per year of overall biofuels in California in 2050 (biomass/biofuels to be discussed further below). The base case uses current default values for technology costs in SWITCH.

For all non-reference cases, efficiency savings are taken at technical potential levels for buildings, industry and transportation. These savings levels will be described in the demand chapters of this report

2.3 Electricity supply

All scenarios except the two biomass CCS cases assume an 80% reduction from 1990 GHG emission levels for the WECC region. The biomass CCS cases assume electricity carbon neutrality in 2050 in the WECC, i.e. overall net emissions in the electric power sector are brought to zero with biomass CCS, a net negative carbon technology. Several variants in the electricity supply are modeled, including a high renewable case, high nuclear case, a high CCS case, a no CCS case, and an expensive solar photovoltaics case. These are modeled by separately adjusting the cost trajectories of each of these technologies either downward or upward over time from their baseline trajectories, or by entirely excluding certain generation options.

Scenario	Efficiency	Electrification of Heating and Vehicles	Electricity Supply (SWITCH)	2050 Carbon Cap for Electricity [% reduction from 1990 Emission Levels]	In-State Biomass	SWITCH biomass supply curve [Mdt]	Biomass for fuel [Mdt]	Instate Biofuel [Bgge]	Imported biofuel [Bgge]
Frozen Efficiency	Frozen Efficiency	BAU	Without carbon cap	N/A	BAU	0	35	2.8	0.93
Frozen Efficiency + Electricity Cap	Frozen Efficiency	BAU	With carbon cap	80%	BAU				
Base case	Tech. Potential	Median (Base case level)	Base case		Low, for liquid fuel				
High Nuclear			Inexpensive nuclear		Low, for liquid fuel				
High CCS			Inexpensive CCS		Low, for liquid fuel				
No CCS or New Nuclear			No CCS or New Nuclear		Low, for liquid fuel				
No CCS			All CCS excluded		Low, for liquid fuel				
High Solar and Wind			Inexpensive solar and Wind		Low, for liquid fuel				
Expensive Photo-voltaics			Expensive Photo-voltaics		Low, for liquid fuel				
Biomass CCS			Biomass CCS	100%	Low, for electricity	23	12	1.0	0.3
Biomass CCS + Hi in-state biomass			Biomass CCS	100%	High, for electricity and liquid fuel	23	71	5.7	1.9
High in-state biofuels			Base case	80%	High, for liquid fuel	0	94	7.5	2.5
Hi in-state & High imported biofuels					High in-state + High imports, for liquid fuel				7.5
High Electrification		High			Low, for liquid fuel		35	2.8	0.9
High Electrification & High in-state biofuels		High			High, for liquid fuel		94	7.5	2.5

Table S3. *CCC scenarios and assumptions for each scenario. Each of these scenarios are treated with and without energy conservation savings. The compliant case from the main article is the "High in-state biofuel case" with energy conservation.*

2.4 Electrification

All but the last two scenarios assume "base case" electrification of vehicles and building and industry heat described in the transportation, building and industry chapters. The last two scenarios assume a higher degree of vehicle and industry electrification but keep the same level of building electrification.

2.5 Biomass CCS and Biofuels

Biomass supply and bio-energy technologies constitute a key hinge factor in future energy systems. Biomass can be used in stand-alone biomass power plants, power plants that co-fire biomass and fossil fuel, or biogas power plants. Biomass can also be used for making transportation fuels such as ethanol, cellulosic ethanol or other advanced biofuels. Bio-refineries for biofuels can produce electricity as one output. Biomass can also offer the technical possibility of negative carbon emissions in the case of biomass based power generation coupled with carbon sequestration and capture of combusted biomass CO_2. Further uncertainly is added when considering future technology progress. Technologies such as algae based fuels or hypothetical artificial photosynthesis can offer further supply or technology pathways toward producing transportation fuels.

With the exception of two of our scenarios, all biomass is directed to the production of biofuels and is not made available to the power sector modeling in SWITCH. We consider two cases, biomass CCS and biomass CCS with high in-state biomass supply, where biomass is made available to SWITCH in conjunction with a deep carbon reduction in the power sector from carbon capture of combusted biomass. As SWITCH optimizes for the cost of electricity, biomass cost projections are needed to correctly include biomass in the model. For the two biomass CCS cases, the 23 Mdt of biomass supply available to the power sector draws on data from existing supply curve projections (39,40). Any residual biomass not included in the SWITCH supply curve is made available for biofuel production: 12Mdt in the biomass CCS case and 71Mdt in the biomass CCS high in-state biomass supply case. For all other cases, where biomass is dedicated to liquid biofuel production, we either take the in-state biomass supply as the cost curve based supply plus of 23 Mdt plus additional municipal solid waste (MSW) sources (yard wastes, food, and construction debris) and energy crops (overall 35 million dry ton biomass supply); or we adopt a "high in-state" biomass supply (overall 94 million dry ton biomass supply) by taking the technical potential biomass supply for the state based on an earlier study (8).

Finally, behavior savings with sensitivities for a nominal adoption case and a high adoption case are estimated for each scenario.

3. BIOMASS SUPPLY

In this section we describe the study's in-state biomass availability and biofuel supply assumptions. We do not discuss biomass to biofuel conversion technology or biomass production and land issues since that has been treated in great detail in other references.

The research team made the following simplifications in the disposition of biomass supply. First, our intention was to direct all biomass supply to either biofuels or bio-power (electric power). This simple approach is considered to be within the scope of the overall study and illustrative of two extremes of biomass utilization.

In all cases but the two biomass CCS cases, all in-state biomass is directed to biofuel production with none made available for electricity. In the biomass CCS cases only, we utilize a supply curve based biomass supply for SWITCH. Existing supply curve data out to 2020-2030 is employed, as the team was not comfortable with extrapolating existing supply curves to 2050. Not all available biomass supply is utilized by SWITCH, and the residual supply was made available to produce biofuels.

Biomass supply curves for California are taken primarily from the following sources: POLYSIS/University of Tennessee based supply curves to 2030 for agriculture residues and energy crops (39), and 2020 municipal solid waste (MSW) estimates from UC-Davis (40). Biomass supply curves were generally inclusive of costs up to <$100/dry ton. Technical potential biomass supply estimates were taken from an earlier study (8) for California. Extending these results to generate longer term supply curves and projecting supply curves technical potential biomass supply is an area for follow up work.

Our base case takes 35 Million dry tons available for biofuel in 2050 as a synthesis of POLYSIS 2007 and UC-Davis estimates. For the Biomass CCS scenarios, we take a biomass supply of 23M dry tons i.e. the biomass supply for which there are supply curves available to 2030 for agricultural residues and 2020 for MSW (35 million dry ton overall supply less 7 million dry tons of yard waste, food waste and construction demolition and less 5 million dry tons of energy crops). The remaining 12 million dry tons are made available to biofuels in this scenario. In the biomass CCS high biomass supply case, we take a higher estimate for overall instate biomass supply (94 Mdt) and again make 23Mdt available for electricity and the rest for biofuels. In all other case, biomass supply is directed exclusively to biofuel production.

High estimates for biomass supply range from 40-110M dry tons for California (8). The CCST study takes 94 million dry tones for an overall supply of 7.5 billion gallons gasoline equivalent. We adopt this as the high biomass supply case in our scenarios, consistent with the technical potential framework that is used in the building and industry sectors.

The high biomass scenario results from higher growth in herbaceous and forests residues, improved technical yield recovery[2] (from 40% to 64%), substantial investment in additional energy crops (woody and herbaceous), and utilization of abandoned agricultural and non-productive forest lands. Possible scenarios based on earlier California Energy Commission reports and the higher biomass case are shown in Figure S5.

[2] Technical yield is defined as the product of technical yield percentage and gross biomass in dry tons.

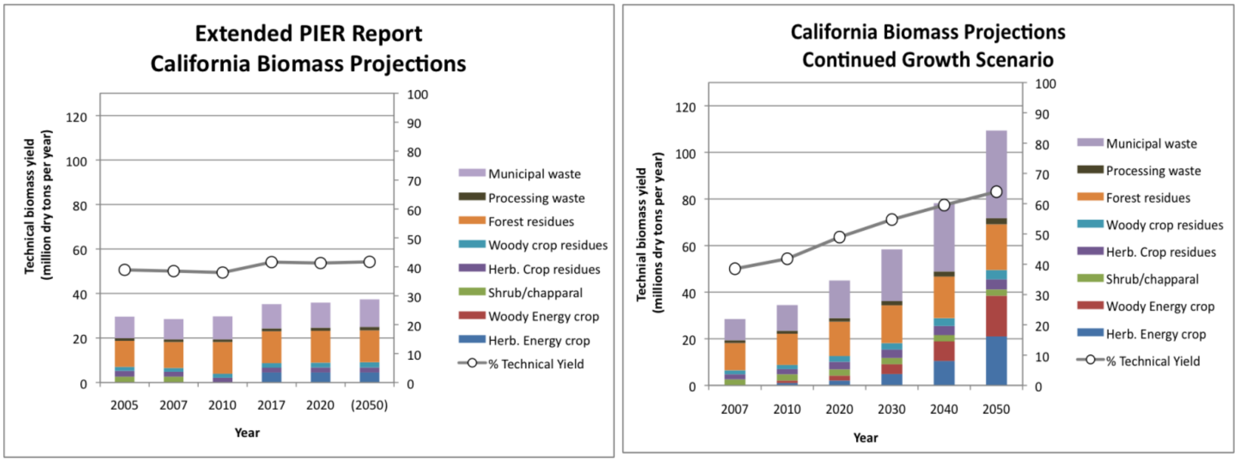


Figure S5. *Biomass supply projections for California (from Heather Youngs). Residues, wastes and energy crops make up 29%, 36%, and 35% of supply in 2050.*

We assume cellulosic ethanol has a production yield of 70 gallons per dry ton today and increases to 112 gallons per dry ton in 2050 (80 gallons gasoline equivalent per dry ton) which is the current technical limit. We also assume that the overall biofuel CO2-eq impact on a life-cycle basis is 70% of gasoline LCA emissions currently based on the present mix of biofuels in the state, evolving to 20% of gasoline LCA impact in 2050 (31) as the in-state and out of state mix of biofuels become dominated by low carbon biofuels. Biomass supply assumptions and lifecycle emissions associated with liquid biofuels are a key hinge factor for future state emissions (e.g. indirect CO2 impacts of energy crops). Sensitivity to biofuel production and life-cycle assumptions will be quantified in future work.

4. TRANSPORTATION EFFICIENCY

4.1 Transportation Demands And Energy Usage

Transportation in California is the largest contributor to energy use and greenhouse gas emissions and as such faces an important challenge to make significant and deep reductions in GHGs if California is to meet its long-term emissions reduction goals.

A number of studies have assessed the potential for reducing GHG emissions in transportation and this analysis draws on this literature to develop a scenario for the transport sector in California. Much of the previous analysis of efficiency and emissions reduction potential focuses on light-duty vehicles (LDVs) as it is the largest fuel-using and emissions-producing subsector within transportation.

Transportation emissions can be decomposed into the product of four terms based upon a Kaya-type formulation (41,42).

$$CO_{2,Transport} \equiv (Population)\left(\frac{Transport}{Person}\right)\left(\frac{Energy}{Transport}\right)\left(\frac{Carbon}{Energy}\right) \quad (1)$$

$$CO_{2,Transport} \equiv \quad P \quad \times \quad T \quad \times \quad E \quad \times \quad C \quad (2)$$

Transport intensity (T) is defined as individual passenger, vehicle or freight miles per capita (e.g., miles/person), depending on the particular subsector. The latter two parameters in the identity are energy intensity (E), which describes the energy use per-mile (e.g., MJ/mile) of transport, and carbon intensity (C), which describes the carbon emissions per unit of fuel energy (e.g., gCO_2e/MJ).

4.2 In-State versus Overall Emissions

State-level emissions for transportation can fall into one of two categories; emissions from trips that fall entirely within state boundaries (i.e. *In-state*) and from trips that cross state boundaries (i.e. *Out of state*). In general, only *In-state* transportation emissions are regulated by the state. However, it is important to keep an inventory and understand the contribution to emissions from *Out of state* sources as well. In some subsectors, the *Out of state* category can be further broken down into *Interstate* and *International* trips and emissions.

4.3 Light-duty vehicles

Light-duty vehicles are the passenger cars and light trucks that make up the vast majority of vehicles found on highways. There are over 25 million light-duty cars and trucks in California. Nearly all of them, in California as elsewhere in the U.S., are powered by gasoline internal combustion (spark-ignited) engines. Light-duty vehicles make up roughly 67% of total *in-state* transportation emissions (and about half of total transportation emissions). There are a number of alternative technologies for LDVs commercially available currently or will be over the next few years, but none of these alternatives has achieved a significant penetration into the market. There are many classes of cars and trucks ranging from sub-compact cars all the way to large trucks, vans and SUVs.

4.3.1 Approach

This analysis uses a light-duty stock turnover model to represent the adoption and fleet persistence of vehicles in the system. This model is based upon previous light-duty analysis for California (43). This analysis combines all vehicle classes into one average class and tracks the adoption and stock of four key vehicle types based upon drivetrain (conventional ICE vehicle, hybrid electric vehicle (HEV), plug-in hybrid electric vehicle (PHEV) and full battery electric vehicle (BEV)). Vehicle efficiency, mileage, stock and vintage of each vehicle type were tracked each year to calculate total fuel demanded by type (gasoline or similar liquid fuel and electricity). Hydrogen fuel cell vehicles were not considered in this analysis.

4.3.2 Vehicle efficiency

The fleet of light-duty vehicles currently operating in California is relatively inefficient. There is significant potential for improvements in fuel economy even without changes to the drivetrain. However, the use of an electric drivetrain, including hybridization, plug-in hybrids and full battery vehicles can further increase the efficiency of vehicles. Electricity is a higher quality fuel than gasoline and can be converted to mechanical work with much greater efficiency on a vehicle than a liquid fuel in an engine.

Conventional gasoline powered vehicles can improve efficiency quite a bit over the next few decades by adopting a number of near-term technologies, including variable valve timing, direct injection, cylinder deactivation, better transmissions (continuously variable transmission), vehicle weight reduction, improved aerodynamics. These factors, if all applied to improving fuel economy, would lead to a doubling of fuel economy of conventional vehicles by 2050 (44,45) to around 42 mpg[3].

Hybridization increases efficiency by integrating an electric motor and storage batteries with the conventional engine, allowing for smaller and more efficient engine operation, as well as energy capture through regenerative braking. It is assumed that hybrids may achieve up to 64 mpg by 2050. A plug-in hybrid electric vehicle (PHEV) is similar to a hybrid except that the battery is larger than in a hybrid and can be charged via plugging into the electricity grid. The efficient operation of an electric drivetrain enables significantly higher energy efficiency when operating on electricity (charge depleting mode), though when the battery is depleted (i.e. operating in charge sustaining mode), a PHEV will operate with similar fuel economy to a hybrid. The size of the battery will determine the relative fraction of driving that is powered by gasoline vs electricity. Over time, it is assumed that the battery capacity of the PHEV fleet increases and thus the fraction of miles driven on electricity increases from 25% in 2010 to 60% in 2050 (which corresponds to about a 12 mile all-electric battery range in 2010 increasing to a 40 mile range in 2050). This corresponds to a combined fuel economy (on gasoline and electricity) of approximately 91 mpgge[4]. BEVs always use electricity to operate and are quite efficient, achieving 126 mpgge (0.26 kWh/mile) for new vehicles in 2050. The fuel economy values quoted are for new vehicles, but the fleet average fuel economy is lower due to persistence of older vehicles in the fleet (approximately 6% of the fleet in any given year are new vehicles).

Not considered here is aggressive material substitution such as lightweight carbon fibers for vehicle light weighting, nor "out of paradigm" vehicle design concepts. These would provide further technical potential efficiency savings but would face adoption and insertion issues in the auto industry and marketplace, although there appears to be more interest in these area from automakers.[5]

4.3.3 Travel demand and vehicle adoption – Base Case and High Electrification Cases

Base Case

In 2010, conventional gasoline vehicles make up the vast majority of the vehicle fleet (~99%). Vehicle sales adoption curves assume for the base case is shown in Figure S6. This figure shows the projected annual sales mix by vehicle drivetrain to 2050. Hybrids grow quickly and, by 2050, become the largest component of the vehicle fleet (36%), with PHEVs and BEVs at 33% and 23% respectively (Figure S7).

[3] Fuel economy numbers quoted in the text are on-road numbers, which will be lower than tested fuel economy numbers, such as from the EPA.

[4] Miles per gallon of gasoline equivalent – the number of miles that a vehicle can travel using the amount of energy in a gallon of gasoline (120 MJ = 33.3 kWh)

[5] See for example http://www.autospies.com/news/BMW-Fights-Volkswagen-for-Carbon-Fiber-Supremacy-64055/; also http://www.oilendgame.com/ accessed on August 3, 2011; also see Lovins 2004.

Given the mix of vehicle types, including a range of older and newer vehicles of each type in the fleet, the fleet average fuel economy is about 72 mpgge.

High Electrification Case

In this case, a much more aggressive transition to PHEVs and hybrids are assumed with conventional gasoline vehicles phasing out by 2024, and battery electric vehicles ramping to 50% by 2050. In 2050 the passenger fleet is dominated by PHEV and BEV at 57% and 37% respectively. Fleet average fuel economy in 2050 is about 91 mpgge (Figures S9 to S11). A transition to electric powered vehicles at this rate would be difficult to implement in practice. Beyond electric vehicle cost and availability issues, lack of widespread electric charging infrastructure could limit market penetration. However this case is a useful limiting case for modeling fuel reduction and electricity system requirements in world where conventional vehicles are essentially eliminated by 2050. The degree of electrification in other vehicle sectors (truck, rail, bus) is the same for both the base and high electrification scenarios.

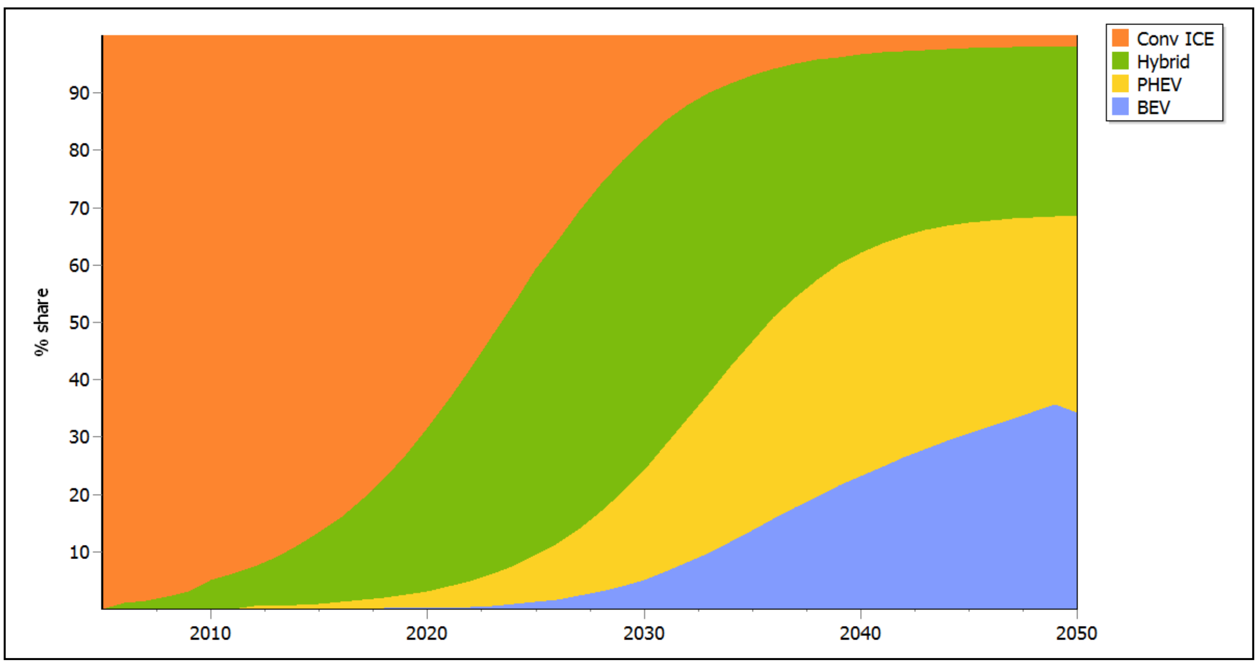


Figure S6. *Vehicle sales adoption curves assumed for vehicle electrification base case.*

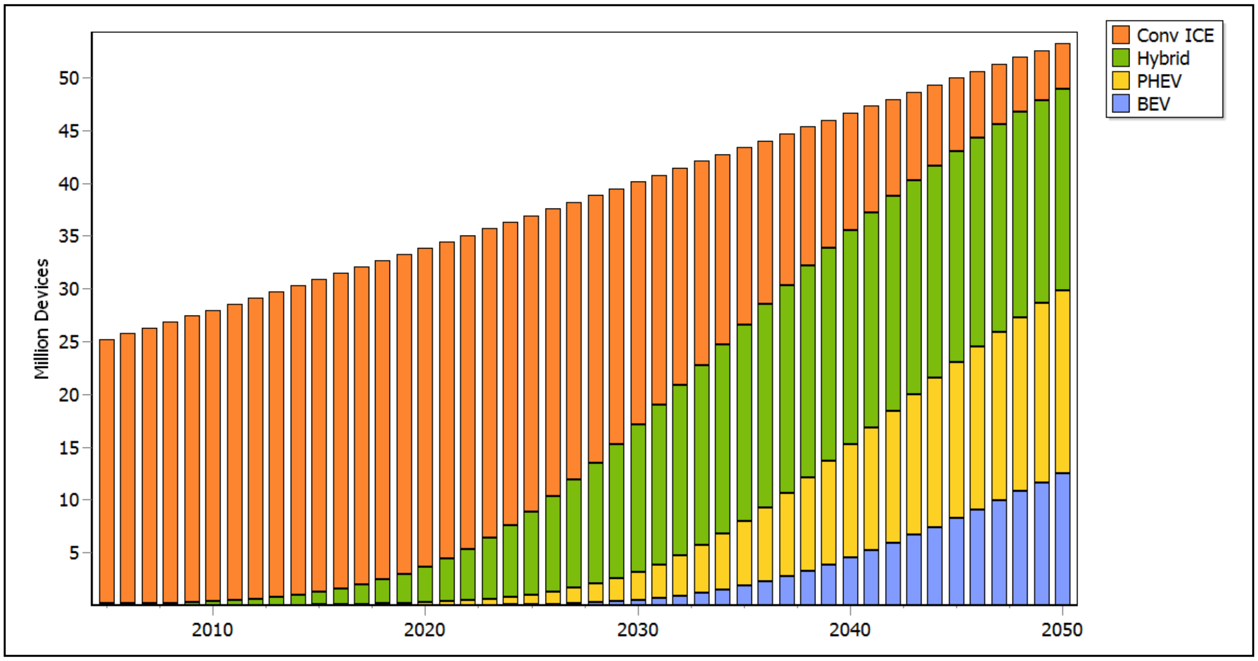


Figure S7. *Total number of light-duty vehicles by type in base case.*

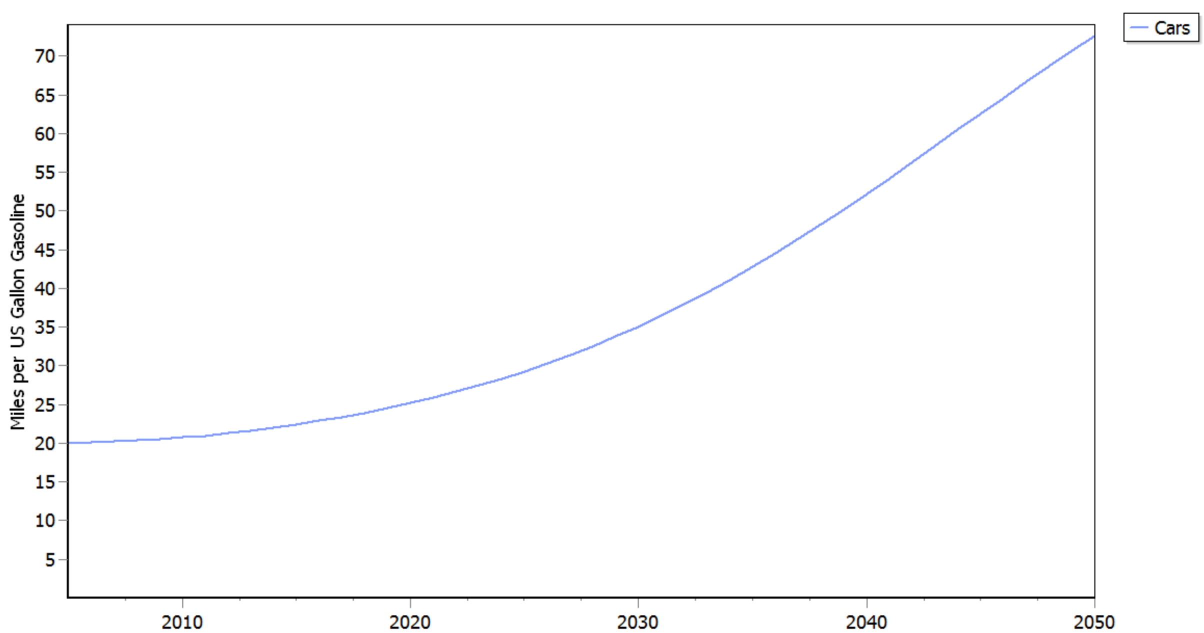


Figure S8. *Fleet average fuel economy for base case.*

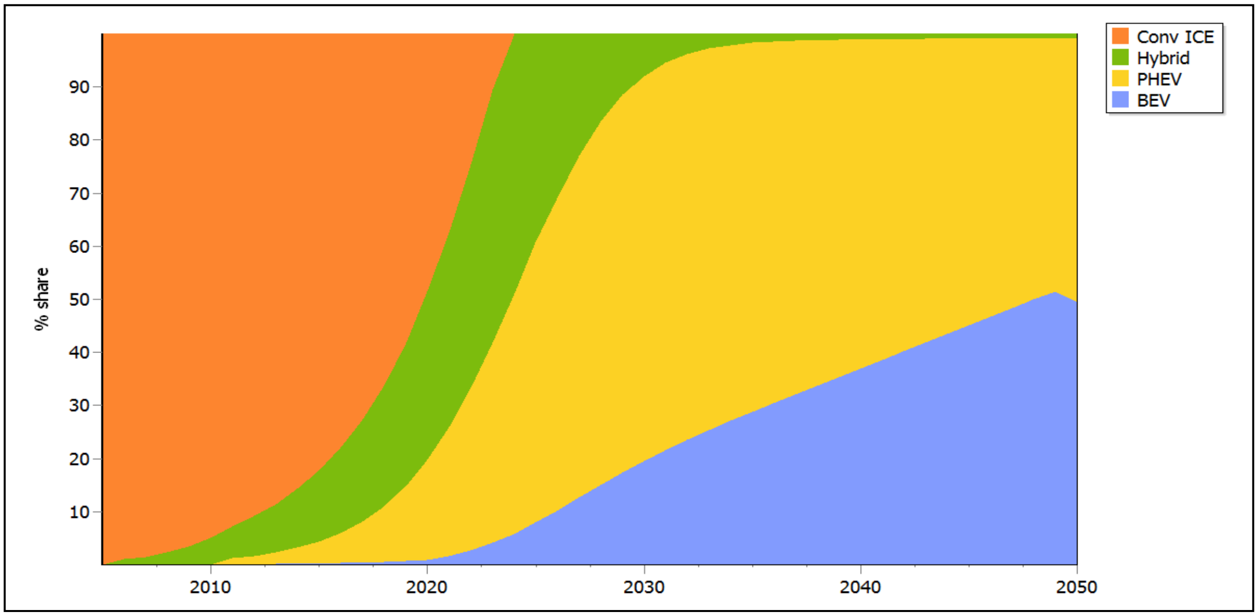


Figure S9. *Vehicle sales adoption curves assumed for high electrification case.*

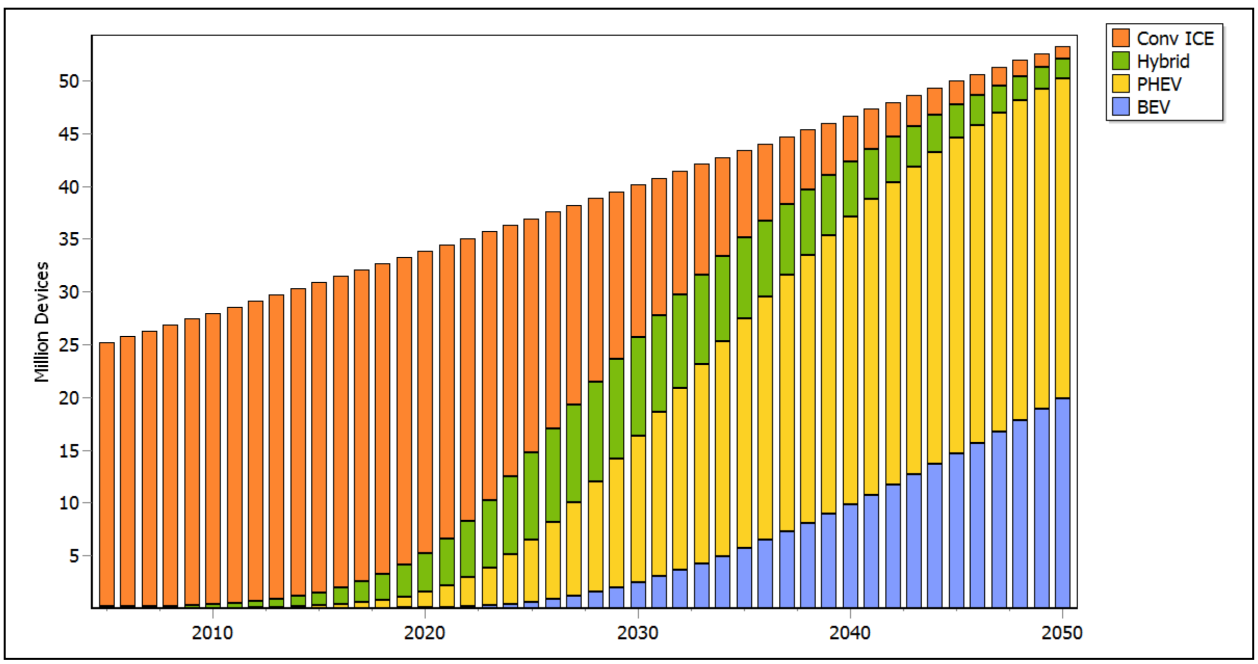


Figure S10. *Total number of light-duty vehicles by type in high electrification case.*

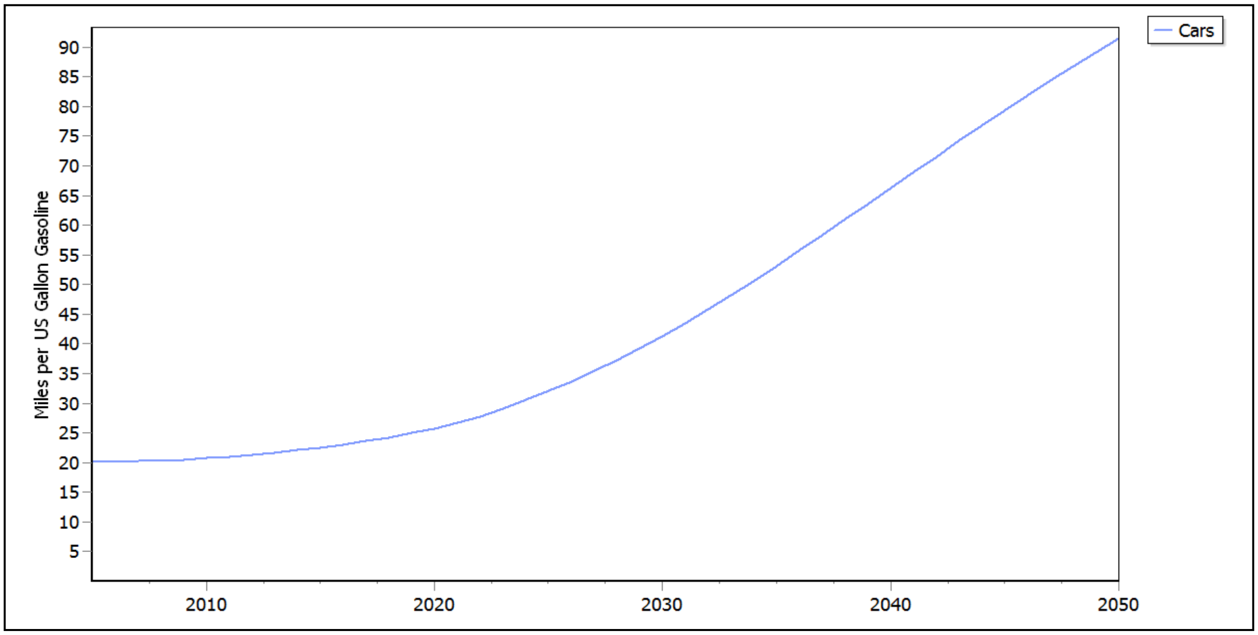


Figure S11. *Fleet average fuel economy for high electrification case.*

4.3.4 Fuel Use

Base Case

Annual VMT for new vehicles is assumed in this analysis to remain relatively constant from 2010 until 2050, but due to population growth, the total VMT for the state increases. In the base case scenario we further assume that vehicle ownership per capita increases from current 0.7 to 0.9 vehicles per capita, consistent with U.S. trends. In this scenario, total VMT increases to 615 billion miles in 2050

Total fuel usage declines significantly (47% from 2010 to 2050) as shown in Figure S12. This is due primarily to the large increase in light-duty fleet fuel economy (240% increase). From an energy security perspective the amount of liquid fuels used (potentially coming from petroleum) declines even more substantially (65% reduction). Electricity demand increases to 85,000 GWh in 2050, split about evenly between PHEVs and BEVs. Overall electricity powers about 45% of vehicle miles in 2050 (Figure S15).

High Electrification Case

In this scenario, total VMT increases to 615 billion miles in 2050 as in the base case and total fuel usage declines significantly (56% from 2010 to 2050) as shown in Figure S16. From an energy security perspective the amount of liquid fuels used (potentially coming from petroleum) declines even more substantially (83% reduction). Electricity demand increases to 138,000 GWh in 2050, again split about evenly between PHEVs and BEVs. Overall electricity powers about 72% of vehicle miles in 2050 (Figure S19).

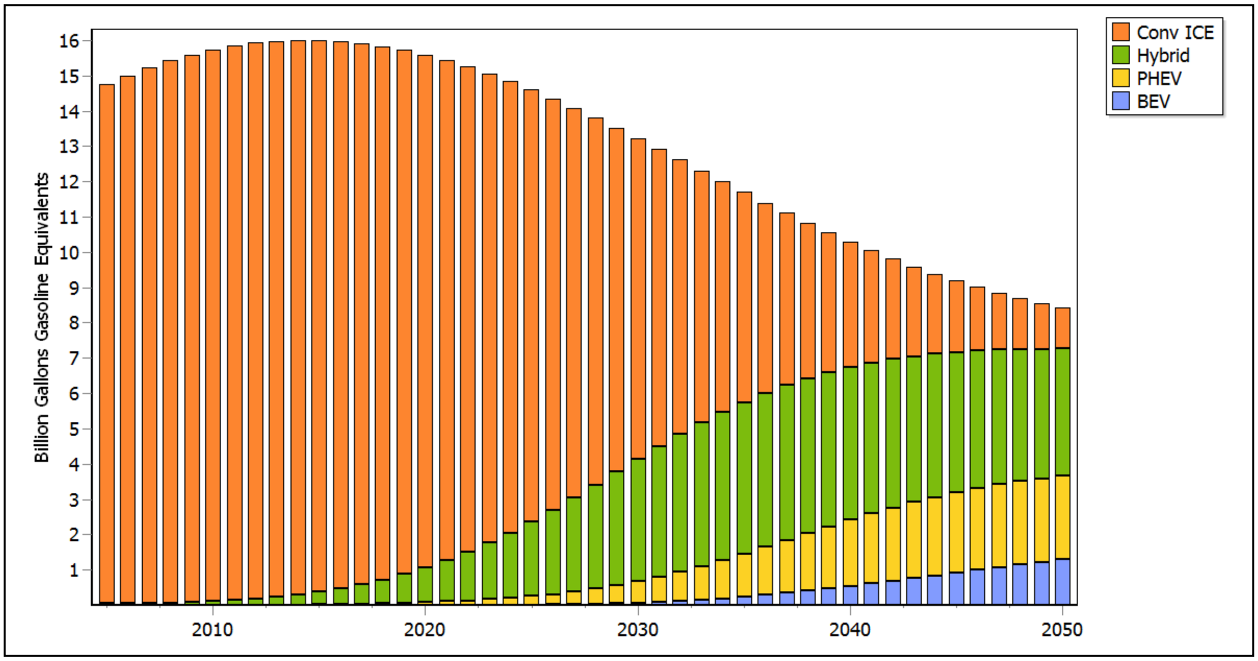


Figure S12. *Fuel use by type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles for base case. Here end use electricity demand is included but in units of Bgge.*

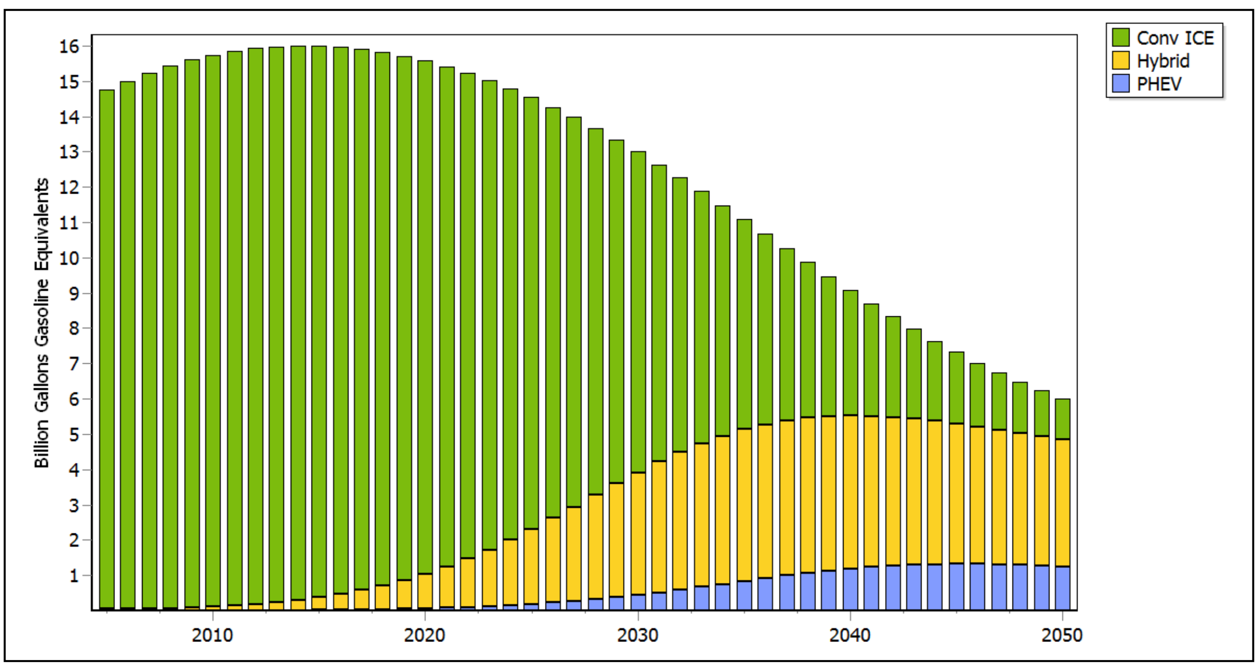


Figure S13. *Base case liquid fuel use by vehicle type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*

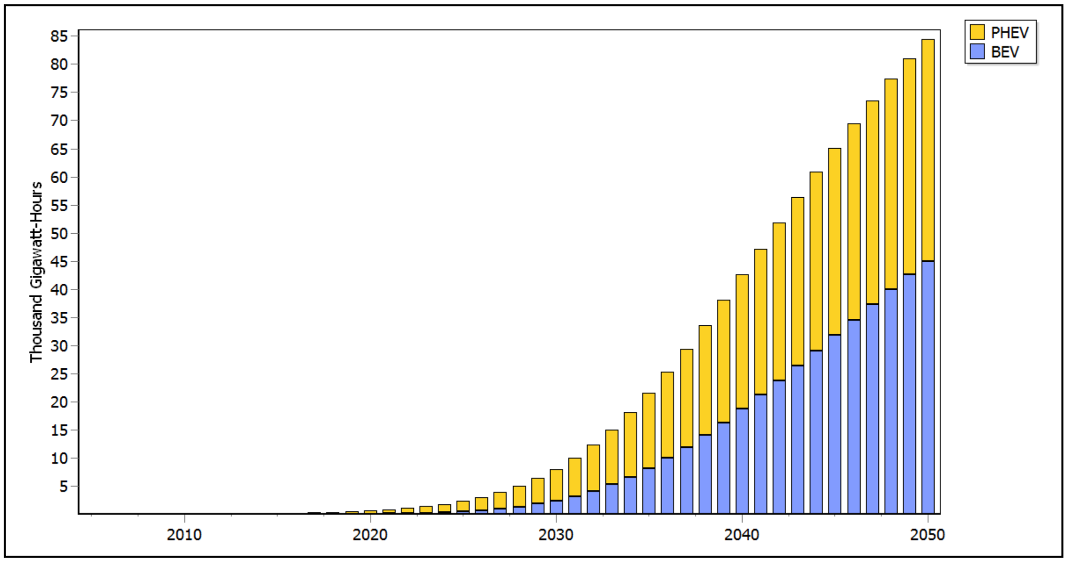


Figure S14. *Base case electricity demand for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*

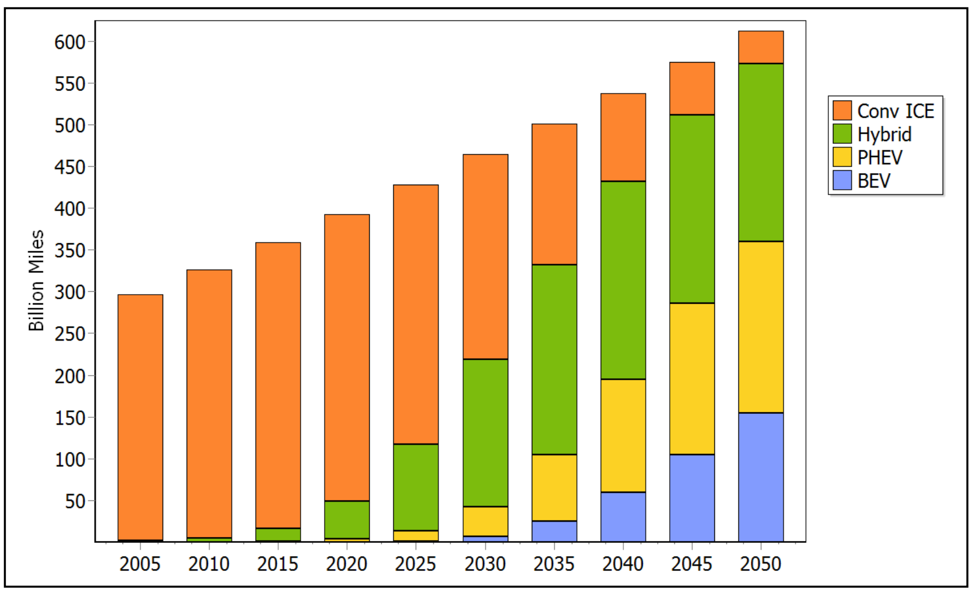


Figure S15. *Vehicle electrification LDV mix 2050 . Electricity powers about 45% of vehicle miles in 2050 (BEV plus about half of PHEV miles)*

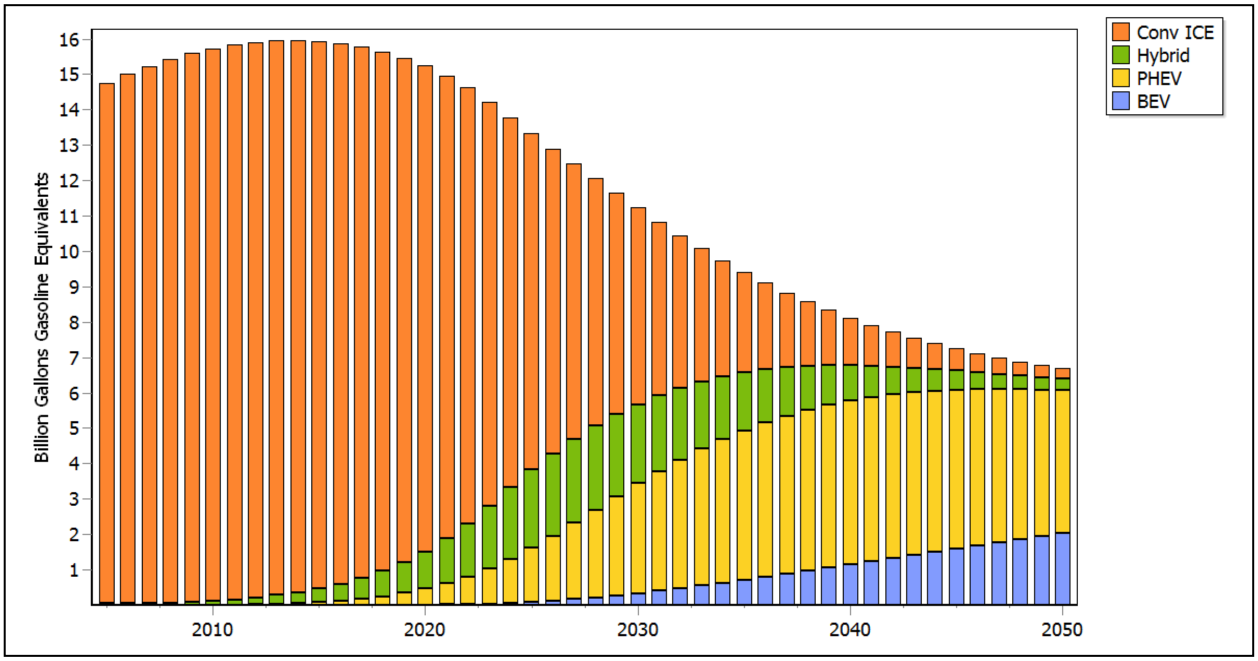


Figure S16. *Fuel use by type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles for high electrification case. Here end use electricity demand is included but in units of Bgge.*

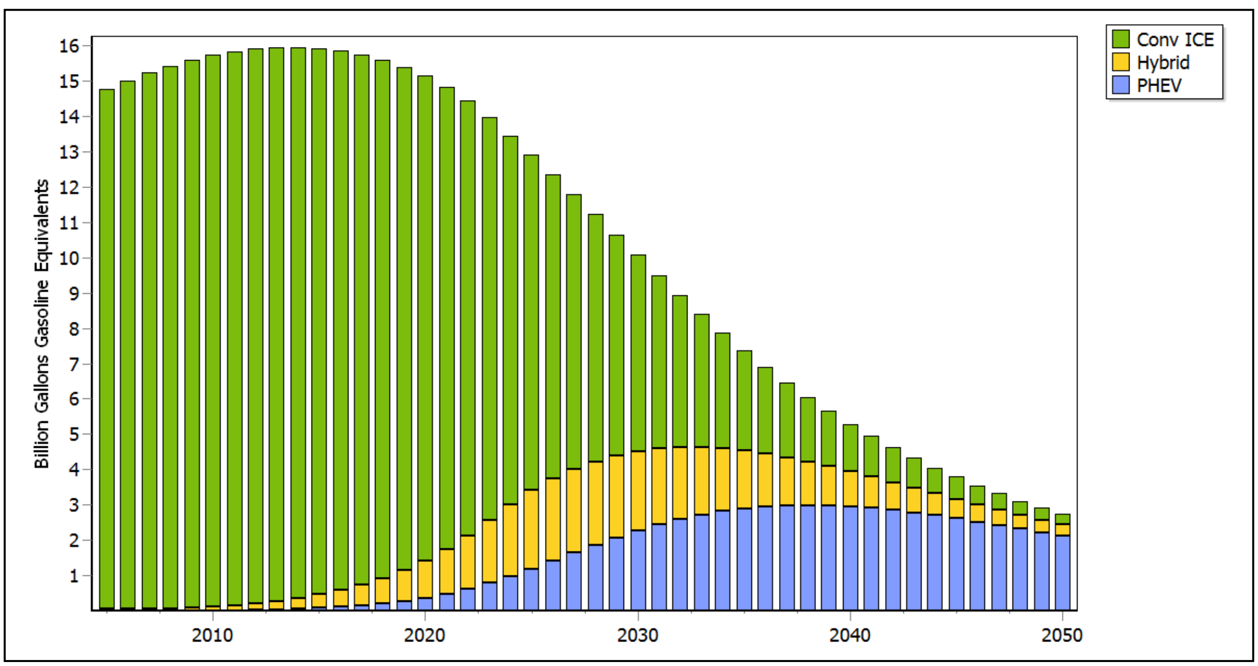


Figure S17. *High electrification case liquid fuel use by vehicle type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*

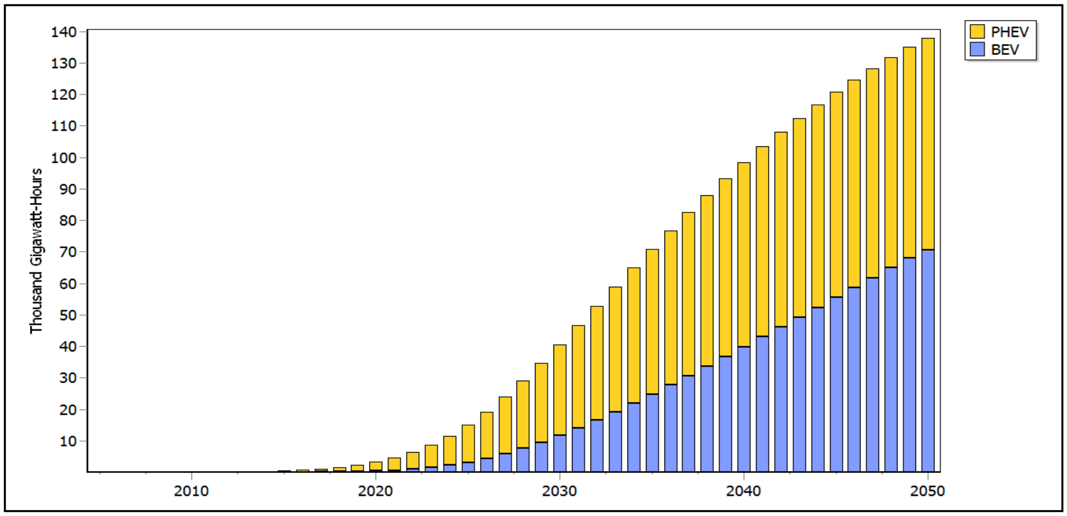


Figure S18. *High electrification case electricity demand for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*

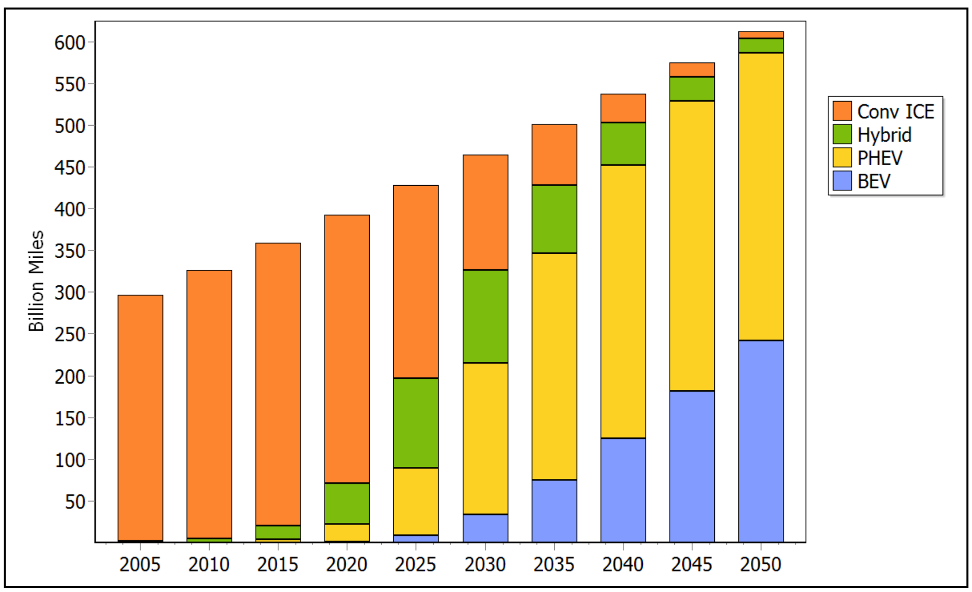


Figure S19. *Vehicle electrification mix in high electrification case. Electricity powers about 72% of vehicle miles in 2050 (BEV plus about half of PHEV miles).*

4.4 Medium and heavy duty trucks

Medium and heavy-duty vehicles mostly consist of large trucks with diesel engines that are designed to carry goods and freight and can come in a variety of sizes (up to 75 feet long and 100 tons). These vehicles and their engines receive a great deal of wear because they are driven several hundred thousand miles in their lifetime, carrying large and heavy loads. Consequently, durability, efficiency, and fuel costs are important considerations. These trucks have primarily used efficient diesel engines for energy conversion, because of their efficiency, durability and high power output. The challenge for lowering emissions from the medium and heavy duty truck sector is that alternative fuels and drive trains may not be acceptable for the demanding applications that use these vehicles.

One of the major barriers for the use of electricity and hydrogen as alternative fuels is in energy storage. The energy density of electricity storage in batteries or hydrogen in compressed gas tanks (as are being discussed for light-duty EVs and FCVs) are much lower than diesel fuel on a gravimetric and volumetric basis (See Figure S20). This energy storage challenge would negatively impact the vehicle cargo capacity and range. Long-haul trucks typically have fuel capacity over 200 gallons of fuel and get between 5-7 miles per gallon. This means that they typically can drive over 1000 miles between refuelings (46).

Storing enough energy in the form of batteries or compressed hydrogen to get an adequate range would significantly impinge on the cargo space, reducing the potential value of cargo as well as add significant weight to the vehicle, hurting fuel economy. Also critical is the issue of power density for fuel cells and batteries relative to diesel engines. Diesel engines are quite efficient with peak efficiencies around 45% though average efficiency over a drive cycle would be lower (<40%). Thus, they would not see as much of an improvement in fuel economy with a switch to electrification as LDVs do.

Medium duty trucks that are used for short-haul deliveries do not travel as far between refueling and could potentially benefit from some of these alternative power trains.

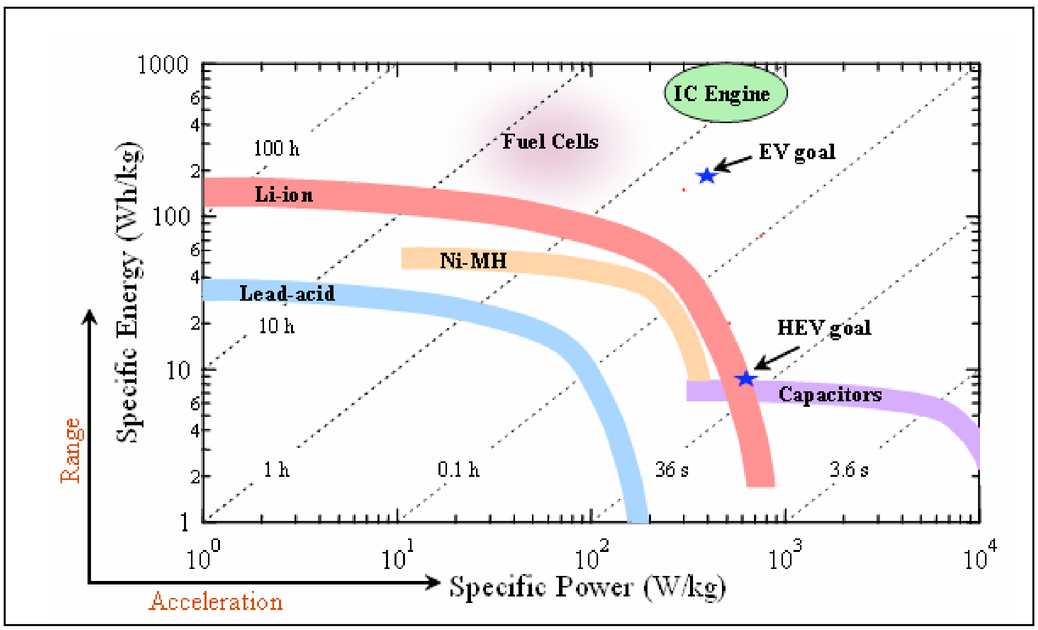


Figure S20. *Power and energy density for batteries, fuel cells and IC engines.*

The main approaches to reducing energy use and GHG emissions from long-haul heavy-trucks will come from further improvements to the engine and drivetrain efficiency, other vehicle based efficiency measures (weight, aerodynamics and rolling) and logistics, rather than from adopting advanced electric or fuel cell drivetrains. Use of compressed natural gas fuel was not considered for heavy duty transport, but may offer further potential to incrementally reduce CO2 emissions.

4.4.1 Approach and Data sources

A spreadsheet model is used to develop scenarios for energy/fuel use for several classes of trucks. Data for truck activity in California is derived from the California Department of Transportation's MVSTAFF model report (43). This analysis projects VMT, fuel usage and fuel economy for different truck classes to 2030. It breaks vehicles into several different categories (automobiles, motorcycles and 4 classes of trucks). Trucks considered in this section are in the 3rd and 4th categories, which will be called medium and heavy duty trucks. Medium duty trucks are those between 10,000 and 33,000 lbs and heavy duty are those above 33,000 lbs.

The EMFAC program from the California Air Resources Board also breaks down trucks into several categories and tracks miles, fuel consumption and emissions. It contains five categories of trucks (medium duty trucks, light heavy duty 1, light heavy duty 2, medium heavy duty and heavy heavy duty). The last three categories correspond with categories 3 and 4 from the MVSTAFF, which cover trucks heavier than 10,000 lbs. It is presumed that trucks below 10,000 lbs are passenger vehicles and used for personal and light commercial use.

4.4.2 Vehicle efficiency

Caltrans MVSTAFF model provided the fuel economy of each of the 4 types of trucks in 2010. Projections for efficiency improvements from a number of different mitigation options were considered with respect to each vehicle type. The main improvements resulted from improving the vehicle drivetrain (including engine, transmission, hybridization, and idle reduction), road load reductions (improvements in aerodynamics, rolling resistance, reduced weight) and operations (speed reduction and driver training).

All large long-haul trucks are assumed to continue to operate with diesel engines and liquid fuels while many of the smaller short-haul trucks are assumed to be able to electrify to some extent. For those vehicles that continue to run on diesel-like liquid fuels, they are able to reduce their energy intensity by 29% and 57% from the 2010 truck fleet for long and short-haul trucks respectively. The greater improvement in short-haul efficiency results from a greater benefit to hybridization, since short-haul trucks travel shorter distances and do more city driving. Long-haul trucks benefit more than short-haul trucks with respect to aerodynamics and speed reduction but these lead to much smaller improvements than hybridization.

Finally, nearly half of short-haul trucks are assumed to be able to switch to electric drive trains and operation on grid electricity. They are more likely to be found in smaller trucks (i.e. medium duty). These trucks achieve a reduction in energy intensity of 77% (i.e. they use about 1/5 the amount of energy to go one mile) compared to 2010 truck fleet.

This scenario assumes that electrified trucks make up 47% of class 3 trucks and 0% of the larger class 4 trucks. Of these electrified vehicles it is assumed that half of the miles are powered by electricity in 2050. Thus, approximately 24% of class 3 truck miles are powered by electricity in 2050.

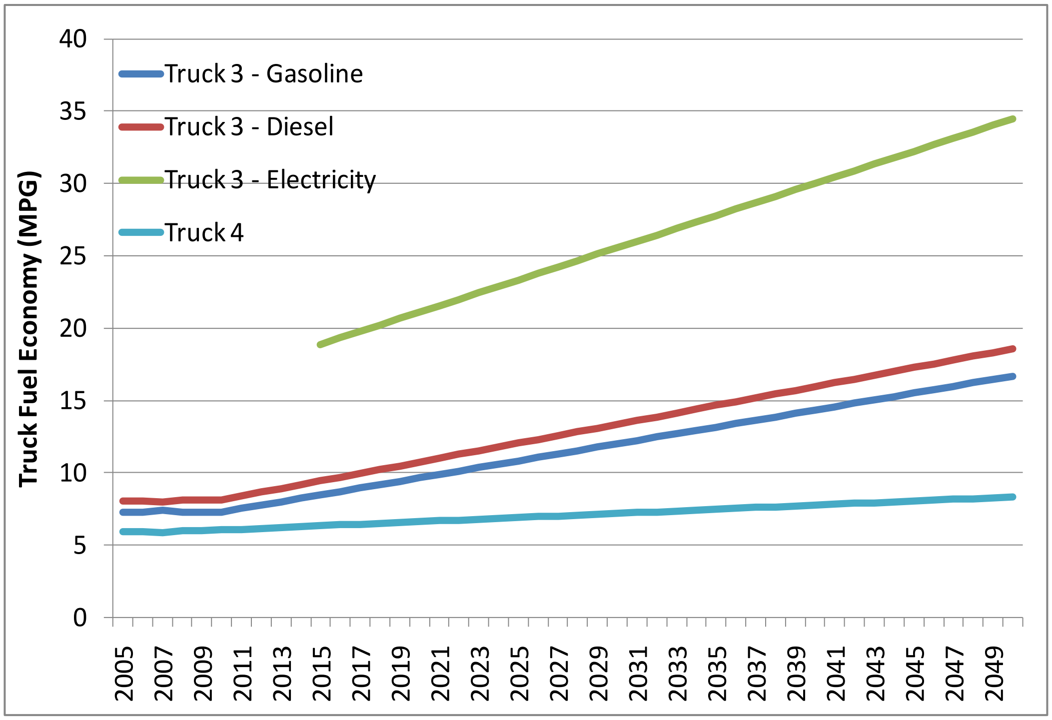


Figure S21. *Fuel economy of heavy duty trucks*

4.4.3 Travel demand

Projections for truck vehicle miles traveled were taken from the Caltrans MVSTAFF model out to 2030 and were normalized on a per capita basis. The model breaks down each class of trucks into gasoline and diesel versions, each with a separate travel demand. So the model essentially tracks four different vehicle classes. The trend in per capita travel demand for each of the different truck classes were linearly extended to 2050. These values were multiplied by the state forecast for population to get the total VMT for each truck class to 2050.

From 2010 to 2050, total truck VMT is expected to increase significantly, essentially doubling - class 3 trucks increase by 96% and class 4 trucks increase by 123%. Total miles for both classes of trucks increase 108%, from 23.6 billion VMT to 49.16 billion VMT. This results from a 37% increase in per capita truck miles and a 52% increase in population from 2010 to 2050.

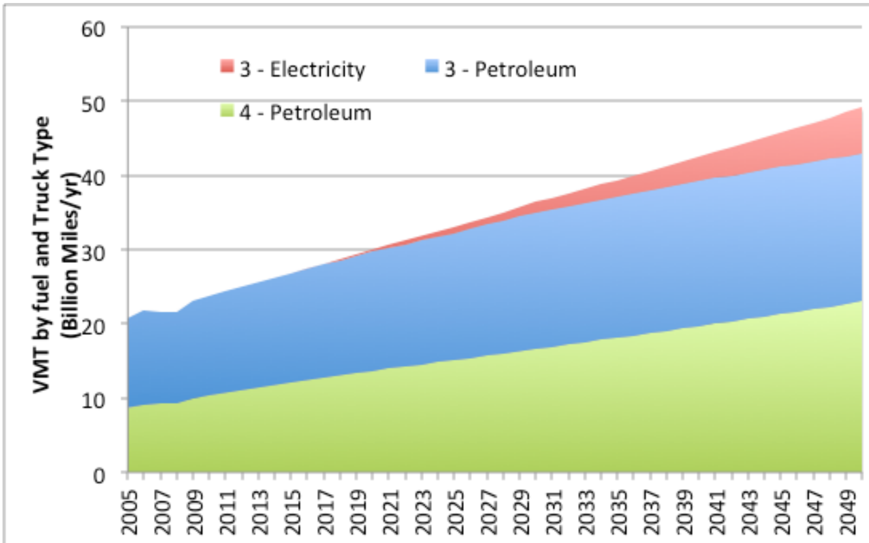


Figure S22. *Statewide travel demand for medium and heavy-duty trucks.*

4.4.4 Fuel Use

Based upon the increase in VMT and reduction in energy intensity of trucks, total fuel use is increases about 35% from 2010 to 2050.

The make-up of fuels is slightly different. Gasoline usage is reduced somewhat while electricity usage is increased to about 6000GWh, but diesel-like fuels remain the largest share of fuel consumption (~90%).

4.5 Aviation

Passenger and freight aviation is a growing transportation subsector. Of the major transportation subsectors, travel demand is the most uncertain in this subsector because of the high elasticity of aviation travel.

This analysis categorizes three types of passenger travel – intrastate, interstate and international flights and two types of freight travel – instate and out-of-state flights. Projections for demand are made in each of the travel categories. An estimate was made by the author for the mix of planes that is used in each of the three categories of travel. Aircraft fall into three categories: narrow-body aircraft, wide-body aircraft and regional jets. Each type of plane has a different efficiency (in terms of seat-miles per gallon) and thus the three categories of travel will vary in terms of their efficiency based upon the mix of aircraft that are used (e.g. international flights typically use larger planes that hold more passengers than shorter in-state flights).

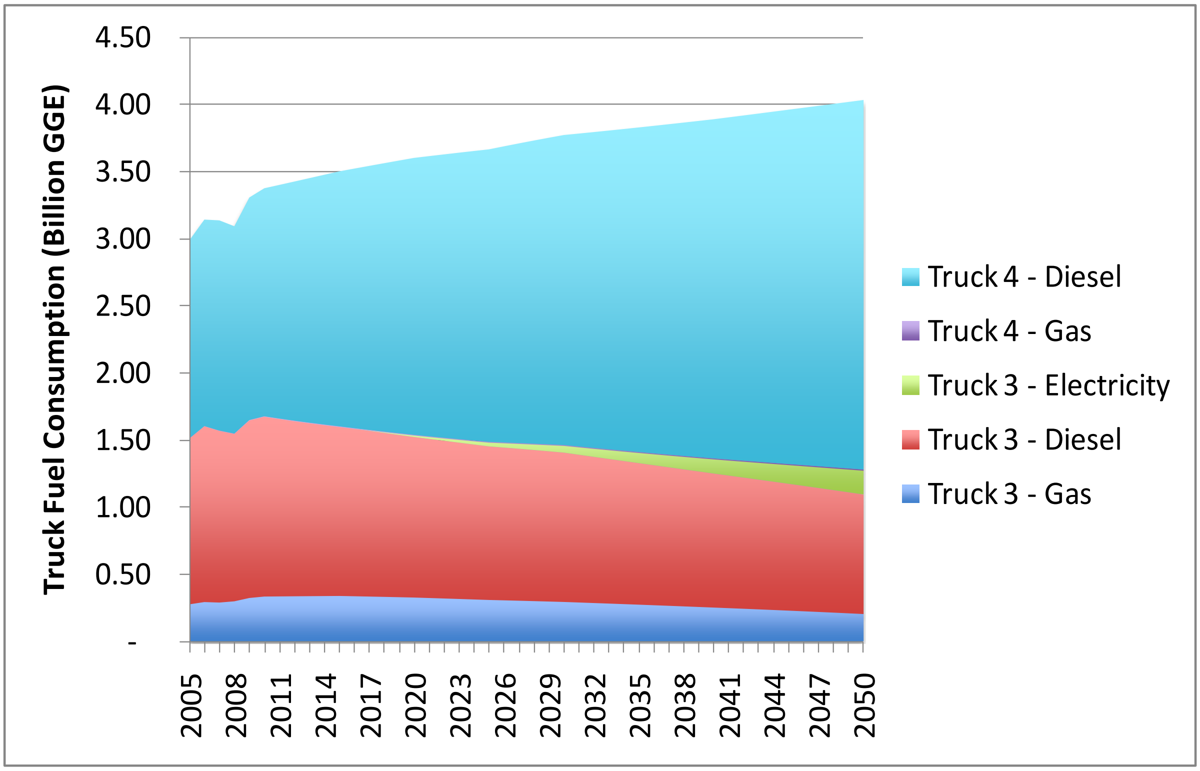


Figure S23. *Fuel usage for medium and heavy-duty trucks.*

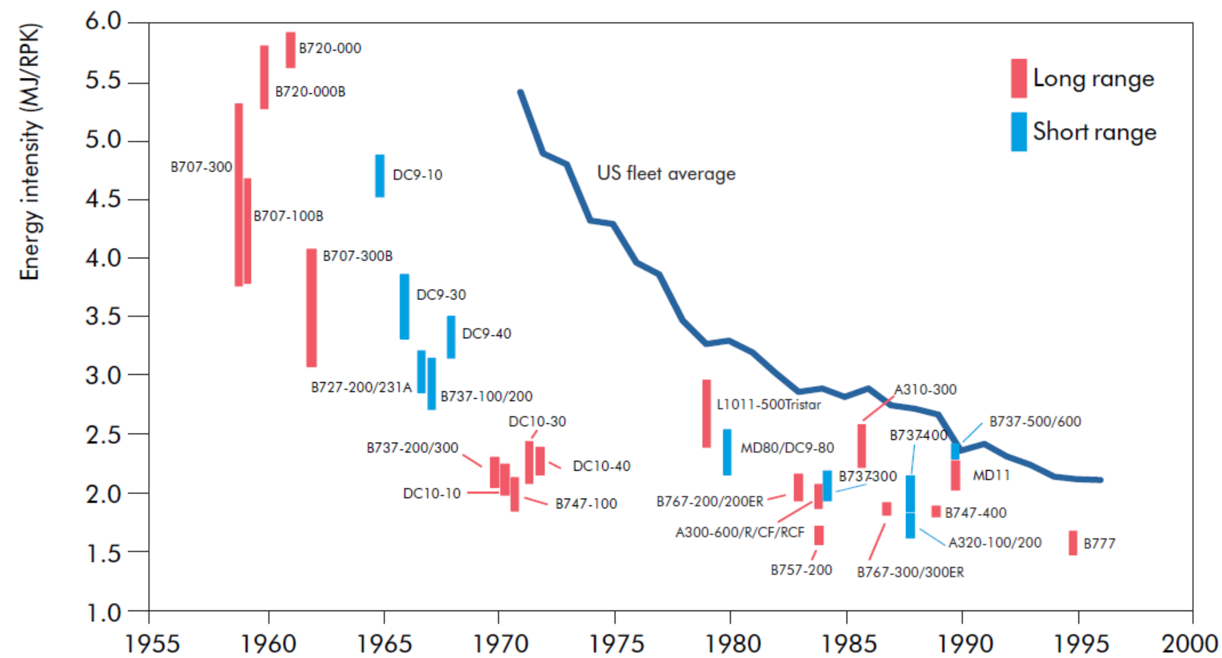
4.5.1 Approach and Data Sources

Scenarios are developed for the vehicle efficiency of new planes of each type and their travel demands over time. These assumptions are then input into a stock turnover model for California aviation that tracks the types of planes that are used, their mileage and efficiency. The output of this model is fuel demand for each travel category.

Data for aviation travel demands include DOE's Annual Energy Outlook (47), USDOT's Bureau of Transportation Statistics and the California Air Resources Board's emissions inventory (48). The potential for aviation efficiency improvements is obtained from several sources, including McCollum 2009 (34), and IEA 2008 (49).

4.5.2 Vehicle efficiency

Fuel consumption can be reduced by improving propulsion efficiency, improving aerodynamics, lightening the aircraft and operational improvements. Figure S24 shows the fuel consumption per passenger kilometer for different aircraft and the US fleet average over time.



Notes: 1) The bar for each aircraft reflects varying configurations; the line shows estimated fleet average for the United States across all existing aircraft. 2) RPK = revenue passenger kilometre = number of passengers carried x distance flown (in km).

Figure S24. *Historical aircraft energy intensity, new aircraft and U.S. fleet average (49)*

Fuel efficiency of conventional aircraft have been improving continuously for many years and the rate of improvement has slowed. Fleet turnover, which retires older, less efficient aircraft will also continue to bring down the energy consumption in the fleet. Because fuel is a major cost element for airlines, there is a strong incentive for fuel efficiency improvements and it is expected, even in the absence of significant policy, new aircraft energy intensity (energy/passenger mile) will continue to decrease by about 1-2% per year and a total reduction in fleet average energy intensity by 30% by 2050. This level of reduction is expected from the use of more efficient jet engines, advanced lightweight materials, and improved aerodynamics (e.g., winglets and longer wingspans) (49, 50). These technologies have already been demonstrated and employed on existing state-of-the-art aircraft, (Airbus A380, and the future Airbus A350 and Boeing 787).

Beyond these expected changes, additional improvements can be made to increase fuel efficiency. These include advanced jet engines, laminar flow control and more substantial changes/redesigns such as blended wing aircraft designs and these options have the combined potential to decrease energy intensity by an additional 35%. With these aggressive changes, it has been estimated that fleetwide energy intensity could be 70-80% lower (34). However, it is expected that these more aggressive changes could lead to an abatement cost of more than \$110/tonne CO_2 and as a result may not be cost effective unless very strong carbon policies are put in place.

Operational changes to how aircraft are operated include improved air traffic management and optimized flight paths, communications and navigation systems, and changes in aircraft descent patterns.

Improvements in these operational elements are expected to reduce global aircraft energy use by 10% in 2050.

This analysis assumes that aggressive changes to new aircraft lead to improvements in fuel efficiency such that new planes in 2050 achieve a 60% reduction in fuel consumption per seat mile relative to planes in 2000. Because of the lag in fleet fuel economy, this translates to a 47% reduction in fleet fuel consumption per seat mile from 2008 to 2050.

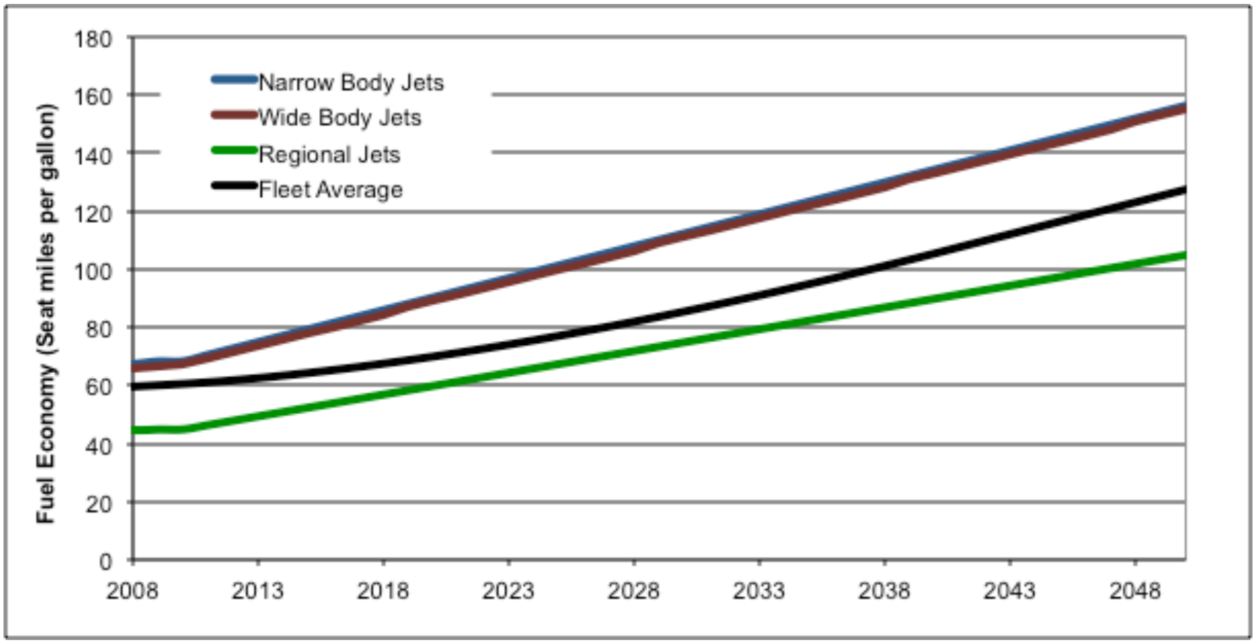


Figure S25. *Fuel economy of new planes over time and fleet average.*

4.5.3 Travel demand

Travel demand for aviation is highly uncertain as it is fairly elastic. Elasticity is higher for short flights because of substitutability, with other modes of transport. Business travel is relatively inelastic ($E_d > -1$), while most other types of flights tend to be relatively elastic ($E_d < -1$). Because of the price-sensitivity of air travelers, there is significant uncertainty about the future growth of air travel, especially in the face of uncertain economic growth, future oil prices, fuel and carbon policies and other factors. The projected annual growth rate for passenger travel in AEO projections, which extend 20-25 years into the future, has declined significantly over the last decade, mainly because of macroeconomic factors including oil prices.

	Passenger seat miles annual growth rate (%)	End Year
AEO 1999	3.8%	2020
AEO 2004	2.3%	2025
AEO 2007	1.6%	2030

AEO 2010	1.35%	2035

Table S4. *Passenger seat mile growth rate projections.*

This analysis uses the relatively conservative projections of per-capita air travel growth from the reference case in AEO 2010 to 2035, which are then extended out to 2050. The annual growth of per capita travel for the US from AEO is applied per-capita air travel data from California. However, because the reference case does not assume significant policies to reduce carbon emissions, projected demand could vary significantly due to high price elasticity from rising air travel prices.

From the 2008 ARB emissions inventory and an estimate of the breakdown of plane types used to meet the three different types of passenger travel, an estimate for the number of miles flown in each category of travel is made.

Intrastate travel (flights originating and ending in California) makes up a small percentage of total aviation travel (~7%). Interstate travel (flights that have an origin or destination, but not both, in California, and are domestic) make up about half of total aviation miles (~51%) and 43% of miles comes from international flights with an origin or destination in California. Regional jets are estimated to make up about 4% of total seat miles, narrow body jets, 64%, and wide-body jets about 32% of total seat miles for California.

Breakdown of Seat Miles (Billions) into Distance and Jet-type Categories					
	Regional Jets	**Narrow Body**	**Wide Body**	**Totals**	**Percentage**
Intrastate	3.5	10.5	0.0	14.0	6.9%
Interstate	5.2	93.0	5.2	103.3	50.6%
International	0.0	26.0	60.7	86.7	42.5%
Totals	8.7	129.5	65.9	204.0	
Percentage	4.2%	63.5%	32.3%		

Table S5. *2008 Breakdown of Miles for three categories by type of jet.*

ARB only counts emissions from intrastate travel (which makes up 7% of seat-miles). Because out-of-state travel (i.e. interstate and international trips) have an origin or destination in another location, only half of the miles and fuel use is attributable to California. The table above and the ARB emissions inventory reflects this. Thus, there can be a factor of around 17 in aviation seat miles (and a similar factor for energy usage and emissions) between considering only intrastate travel and considering all aviation travel related to California travel.

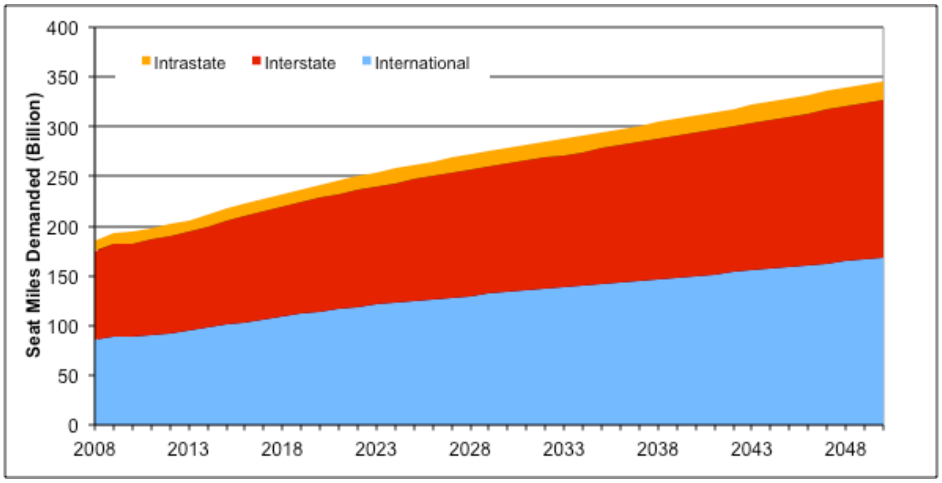


Figure S26. *Projected passenger seat miles demanded for three travel categories in California.*

4.5.4 Freight

Freight shipping is another key contributor to energy use in aviation and is tracked in terms of ton-miles traveled. However, there is some overlap in energy use between freight and passenger aviation since cargo is sometimes carried on commercial passenger flights. According to BTS statistics about half of passenger flights carry some cargo as well. It is assumed that energy use for passenger flights that also include cargo is entirely attributed to the passengers. Thus, only a fraction of freight shipments (ton miles) are counted when tracking freight energy usage, estimated to be around 50%.

Demand for freight shipping is assumed to grow on a per capita basis out to 2035 according to the AEO2010. This per capita growth rate is extrapolated to 2050 and applied to California's projected population to 2050. This leads to a growth in total ton miles shipped of 120% from 2008 levels in 2050. Out-of-state freight shipping makes up about 99% of total freight ton-miles shipped. Freight cargo planes are also assumed to improve in efficiency at the rate of passenger planes.

4.5.5 Total fuel consumption

Significant increases in aircraft passenger travel demand (86% increase) and freight transport demand (120% increase) from 2008 levels to 2050 and significant decreases in fuel consumption per passenger mile and per ton-mile (47% decrease) leads to slight decreases in overall fuel use over the 2008 to 2050 time period. Passenger aircraft fuel demand decreases from 3.1 to 2.7 billion gallons per year while freight fuel demand remains relatively constant at 0.7 billion gallons per year.

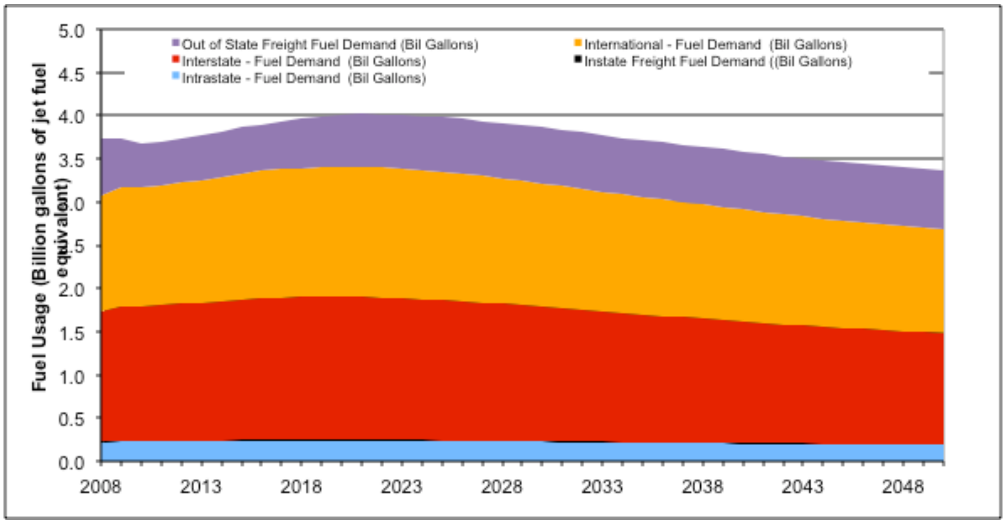


Figure S27. *Fuel consumption for different categories of passenger and freight aviation transport.*

4.6 Marine

The marine subsector encompasses several categories of vessels including large ships for the movement of freight, commercial fishing, and passengers, as well as smaller harbor craft such as work or tug/tow boats, ferries and personal recreational boats. Large marine vessels are an integral part of the global supply chain for goods and freight movement. Nearly all large ships are powered by diesel engines running on marine diesel oil or heavy residual fuel oil. Large ships account for most of the marine miles and energy usage, compared to harbor craft and personal boats. Smaller boats, particularly personal boats, can run on gasoline as well. Like aviation and heavy duty trucks, it is expected that the marine subsector will continue to run primarily on liquid fuels in various types of combustion engines.

As with aviation, marine travel can fall into several categories based upon travel in relation to state boundaries; intrastate, interstate and international.

Marine accounts for nearly 13% of total energy use and GHG emissions from transportation in California.

4.6.1 Data sources and approach

The California Air Resources Board's emissions inventory breaks up fuel usage in state by type of fuel used and into three travel categories. International marine fuel usage is the largest component of total marine fuel usage (87%), while intrastate and interstate marine shipping makes up 11% and 1% of total fuel use respectively. Thus like aviation, most of marine fuel usage and greenhouse gas emissions are "excluded" from a state emissions perspective. However, these sources can contribute a great deal to total statewide fuel usage and require fuel production and delivery infrastructure.

This analysis breaks these marine vehicles into two categories, Ocean going vessels and harbor craft. Given the fraction of fuel used for international shipping, ocean going vessels make up most of the fuel consumption. The potential efficiency improvement from these two vehicle types is estimated and applied to the fleet out to 2050.

4.6.2 Vehicle efficiency

Marintek (51) and McCollum (52) provide a good review of potential options for reducing GHG emissions from marine travel, focused mainly on ocean going vessels. Ship efficiency can be significantly increased by increasing ship sizes, hull and propeller optimization, engine efficiency improvements and low resistance hull coatings. Doubling the size of a ship has the potential to reduce drag forces by 30%, though practical limitations exist, which prevent ships from becoming too large. Optimization of hull, propeller and engines can improve efficiency by 40%. Additionally, operational changes, including speed reduction, and optimized routing can reduce fuel usage up to 50%. Based upon these potentials, ocean going vessels were assumed to be able to reduce fuel consumption per ton-mile carried by about 55%.

It was assumed that harbor craft have fewer options for reducing energy usage since they are not traveling long distances and have irregular duty cycles. By 2050, harbor craft energy usage per mile is assumed to decline by 25%, which would be representative of standard engine improvements.

4.6.3 Travel demand

The DOE's Annual Energy Outlook and DOT's Bureau of Transportation Statistics were used to calculate US ton-miles of marine shipping. A per capita value (ton-miles per person) was calculated from the AEO projection to 2035, which was extrapolated to 2050. Per capita ton miles are expected to decline 21% from 2008 to 2050, which when coupled with population growth amounts to a 23% increase in total ton-miles in California over the same time period. Harbor craft activity is expected to increase proportional to total ocean-going traffic.

4.6.4 Total fuel consumption

Greatly improved marine vessel efficiency and a slight increase in total ton-miles and harbor craft activity lead to a substantial reduction (36%) in total marine fuel demand in 2050 relative to 2008. The vast majority of fuel demanded is related to out of state travel (87%).

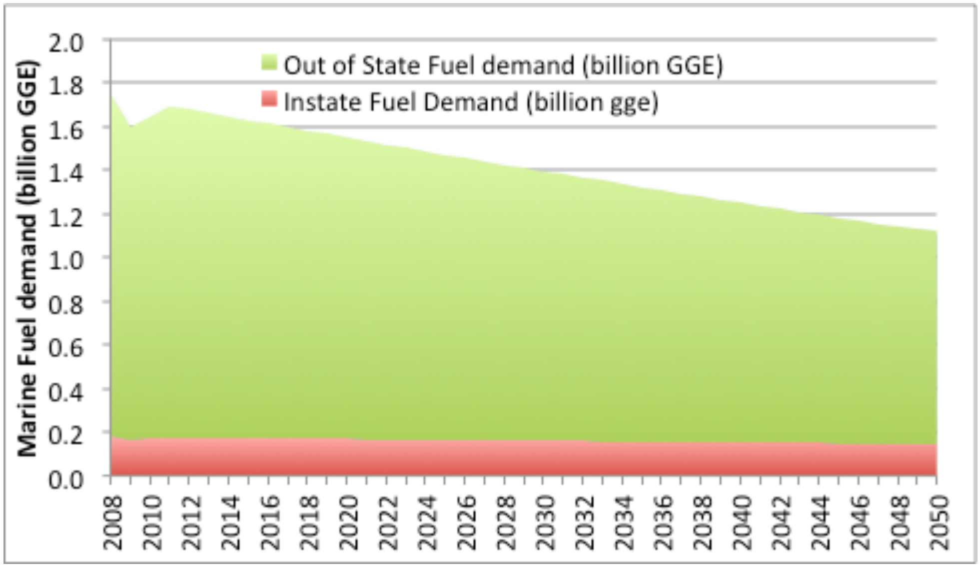


Figure S28. *Marine fuel demand projection to 2050.*

4.7 Bus

Buses are passenger vehicles, typically organized as a public transportation system either as city transit, intercity service or school buses. Buses and their engines receive a great deal of wear because they are often driven continuously over the course of the day with significant starts and stops. Consequently, durability, efficiency, and fuel costs are important considerations. Buses have primarily used diesel engines in the past, though air quality concerns have induced some municipalities to switch over a portion of their bus fleets to cleaner alternatives, such as natural gas.

Buses account for a small fraction of total energy and GHG emissions in California (~3%).

4.7.1 Data sources and approach

Data on US based bus travel is found from the American Public Transportation Association (APTA 2011), which provides information on energy efficiency, load factors and travel demand. This data is scaled to California. A scenario is developed regarding bus efficiency and fleet share from different drivetrains, and is used to calculate fuel usage. Figure S29 shows the assumed fleet share of each bus drivetrain type in California. Electric buses achieve approximately a 50% fleetshare, while diesel hybrid buses make up the remainder of the fleet.

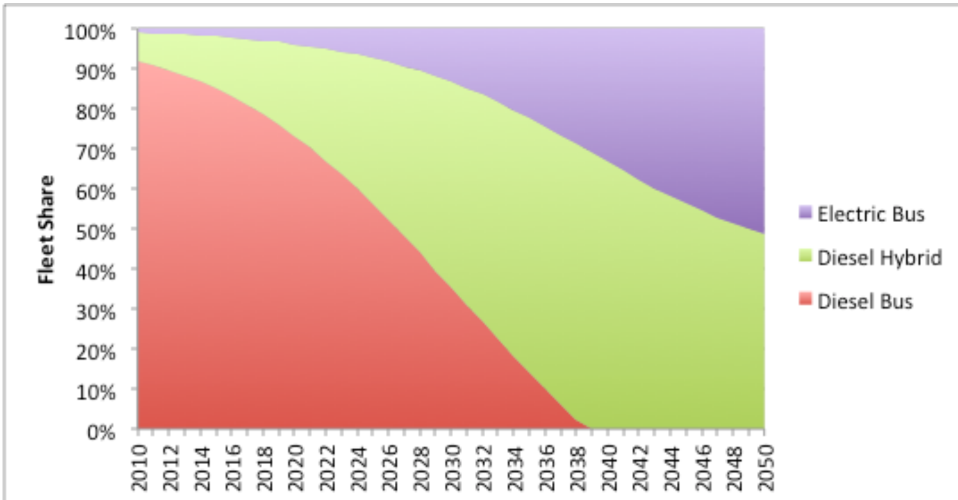


Figure S29. *Fleet share by bus drive train type.*

4.7.2 Vehicle efficiency

Buses, like heavy trucks and light-duty vehicles, can improve efficiency via advanced propulsion systems (hybridization, plug-in hybrids, fuel cells, and all electric drivetrains), reducing weight, aerodynamic drag and rolling resistance.

The fuel economy of diesel buses is expected to increase from 3.6 mpg to 4.6 mpg (28% improvement) from 2010 to 2050 while diesel hybrids are expected to increase from 4.7 to 5.9 mpg, and electric buses can achieve 8.3 mpgge in 2050. The switch from diesel buses to a combination of diesel hybrids and electric buses leads to a significant improvement in bus fuel economy, from 3.7 mpg in 2010 to about 7 mpgge in 2050 (89% improvement).

4.7.3 Travel demand

Travel demand, in terms of vehicle miles traveled by bus, is dependent upon two factors: population, passenger miles traveled per capita and load factor[6]. The latter two of these factors (passenger miles per capita and load factor) are assumed to be constant in this analysis, such that the main driver for overall travel demand growth is population growth. Total passenger miles grow from 19.5 billion passenger miles in 2010 to 29.7 billion passenger miles in 2050.

While not included in this scenario, the demand for buses could increase significantly if significant personal automobile traffic were shifted to transit modes (including rail and buses). This would be especially true in higher density urban areas where congestion and parking issues make single occupant car travel less convenient and expensive and transit more attractive.

[6] Load factor represents the number of passengers on a vehicle and thus represents the number of passenger miles that can be served based upon a vehicle mile traveled.

4.7.4 Fuel usage

Overall fuel use by buses declines in this scenario about 20%, though the amount of diesel (i.e. liquid fuel) declines by 54%. Electricity grows to be a major energy use in bus transportation accounting for 200 million gge (or 6618 GWh), which is approximately 2% of total electricity demand in California in 2010.

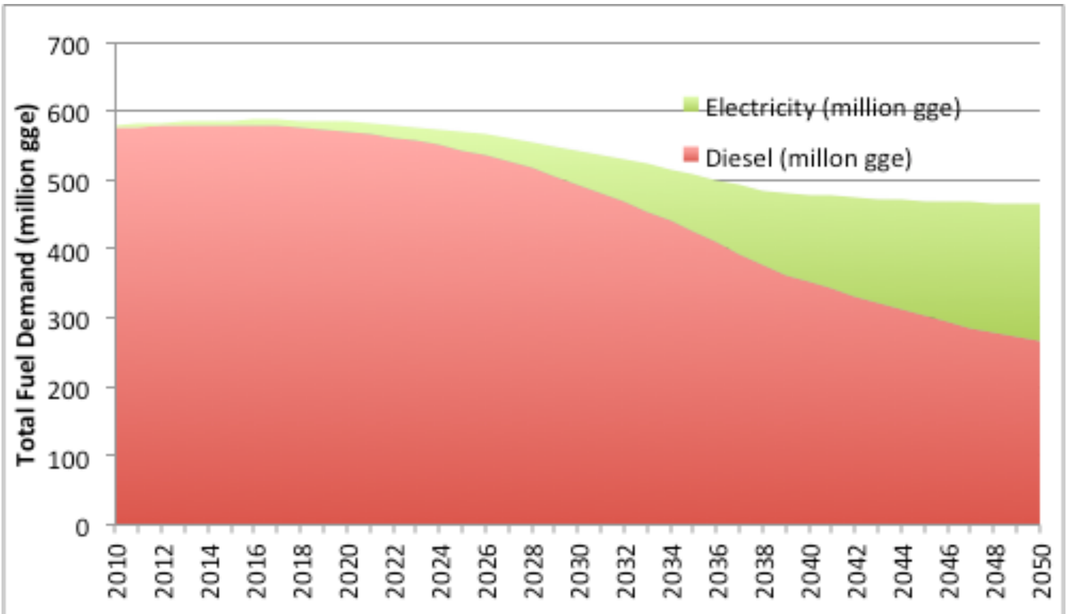


Figure S30. *Fuel usage by fuel type for buses.*

4.8 Rail

Rail transport consists of trains that are typically powered by diesel or electric locomotives and carry passengers and freight. The majority of rail energy usage results from the movement of freight, but passenger travel also accounts for a significant portion of rail energy use. Passenger rail is broken into several categories including intercity, commuter, light, and heavy rail. Current passenger rail usage is relatively small, but because passenger rail is one form of public transportation, a significant shift in personal mobility from automobiles to rail could lead to a rapid increase in the usage and energy requirements of rail transport. Freight transport is expected to increase in the future even without mode shifting.

Passenger and freight rail make up about 0.3% and 0.7% of energy use and GHG emissions of the California transportation sector.

4.8.1 Data sources and approach

Data for US rail transport are primarily derived from Oak Ridge National Lab's Transportation Energy Data Book (ORNL 2011), which provides information on passenger and freight rail miles, energy use and vehicle miles. This data is then scaled for California's share of rail transport.

Similar to the approach from other sectors, total fuel demands for rail transport will be a function of the passenger and freight rail travel demand, passenger car load factors, changes in rail engine efficiency, and switches in rail propulsion systems/fuels.

In this analysis rail transport is broken into four categories: Amtrak/intercity, commuter, transit and freight rail.

4.8.2 Vehicle efficiency

A number of strategies exist for improving freight and passenger rail efficiency, including reducing train weight, reducing aerodynamic drag, lubrication, traffic management, better power and traction management and regenerative braking. These technologies can improve the efficiency of the passenger rail fleet by about 50% from 2010 to 2050 while switching from conventional diesel locomotives to electric locomotives can approximately double the energy efficiency of train travel depending on the category of travel. Transit rail is primarily run on electricity already so there is less efficiency improvement potential. All trains in California are assumed to be able to switch to electric locomotives powered by overhead lines or a third rail.

4.8.3 Travel demand

Like bus travel, travel demand for rail is dependent on population, passenger and freight demands per capita, and load factors. As with buses, per capita miles and load factors are held constant in this analysis, so rail travel demand is assumed to scale proportionally with population growth.

While not explicitly included in this scenario, the construction and utilization of a high-speed rail system in California could significantly increase the amount of intercity rail usage by an order of magnitude or more.

4.8.4 Fuel usage

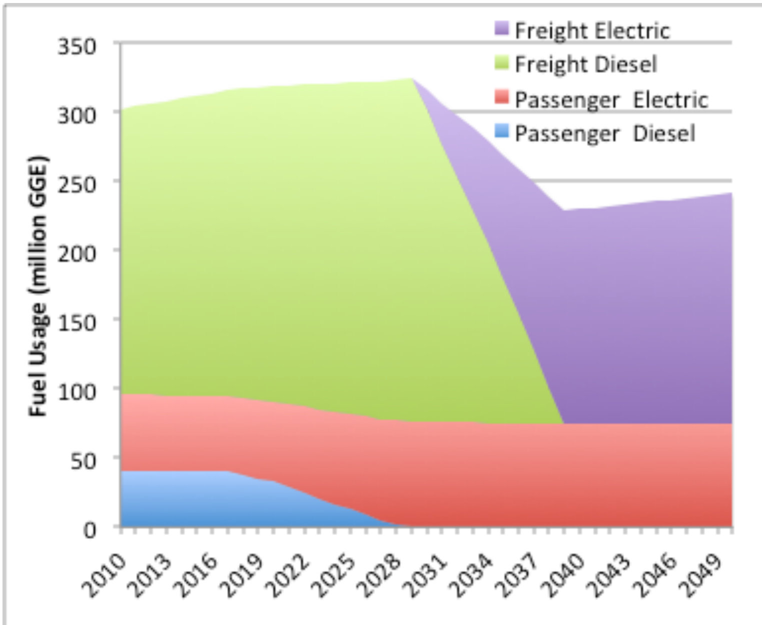


Figure S31. *Fuel used for rail travel in California.*

Overall fuel demand from rail transport declines about 20% from 2010 to 2050, though it switches from primarily diesel fuel to entirely electricity. The switch to electrified trains is expected to happen a little bit earlier for passenger rail than for freight rail.

5. BUILDING EFFICIENCY

5.1 Demand Sectors and Projections

5.2 Macroeconomic Assumptions

We assume the population grows to 59.5 million residents in 2050 per California Department of finance projections (33). Industry fuel energy growth is assumed to be 0.6% per year and industry electricity growth 1.4% annually as described below in the industry demand discussion. Other key macroeconomic drivers and sensitivities are adopted from a related PIER study (21) and discussed in great detail there, so the reader is directed to that report for the assumptions made regarding housing stock and commercial floor stock growth to 2050. Our approach is to take the "medium-growth" assumptions based on that study.

5.3 Buildings Sector

In this section we present and describe the methodology, data, and assumptions used to forecast total electricity demand from the buildings sector in California. We then present the two primary demand scenarios developed for this study – a "maximum energy efficiency" scenario based on current estimates of long-term technical potential and a "maximum energy efficiency and electrification" (base case) scenario based on both technical potential for energy savings and fuel-switching away from natural gas towards electricity in the buildings sector. We first present the overriding policy assumptions represented in these scenarios and then summarize the key characteristics of the resulting electric load forecasts for the buildings sector.

Natural gas demand in the building sector, fuel usage, energy efficiency and residential/commercial growth estimates were also adopted from the 2011 PIER study. Natural gas demand by end use and sector is tracked in LEAP. For the maximum energy efficiency and electrification (base case) scenario, end use saturations are adjusted to follow the electrification assumptions described below to calculate remaining fuel demand. The focus of this chapter, however, is on the electricity sector.

5.4 Load forecasting approach

The load forecasting approach for buildings seeks to leverage the methods, data, and findings from the latest bottom-up and long-term potential studies conducted for the buildings sector in California. To do this, the research team built upon a spreadsheet modeling tool developed previously for a related PIER study (21) that assessed energy savings potential in California's buildings sector to year 2050. This spreadsheet tool, referred to as the Scenario-based Energy Savings Assessment Tool (SESAT), builds directly upon the detailed data, analysis, and results of Itron's most recent bottom-up assessment of energy efficiency potential in California's buildings sector over the mid-term (i.e. through 2025) and allows exploration of a variety of longer-term outcomes driven by technological change, structural change, and changes in end-use energy service demand that are often beyond the scope of shorter-term load forecasts.

Below we provide an overview of the scope, methods, data, and assumptions used in the 2011 PIER study and summarize the modifications and additions to that analysis that were made for this study.

Overview of 2011 PIER study

The goal of the 2011 PIER study was to develop and apply modeling frameworks to estimate energy efficiency potentials for electricity and natural gas end uses in California's residential buildings, commercial buildings, and industry through the year 2050. To do this, the study team developed separate end use efficiency potential models for California buildings and industry using best-available information and data. The buildings and industrial sector models were constructed using a hybrid modeling approach, which coupled bottom-up, technology rich end use models for the mid-term analysis period (defined in this project as the period 2007-2025) with more aggregate and stylistic models of end use efficiency for the long-term analysis period (defined as the period 2026-2050). These models were designed to estimate the technical potential for energy efficiency improvements, which can be thought of as a theoretical benchmark of the upper bound of energy efficiency potential in a technical feasibility sense, regardless of cost or acceptability to customers.

SESAT modeling framework

One of the primary objectives in developing a forecasting tool for the 2011 PIER study was to leverage, to the furthest extent possible, the detailed data, analysis, and results of California Energy Efficiency Potential Study (referred to hereafter as the 2008 Itron potential update study) – see Itron 2008(23).[7] The 2008 Itron update study incorporated the latest estimates of baseline end-use equipment ownership and end-use load profiles, along with the latest estimates of efficiency measure costs, savings, and saturation across the service territories of California's four IOUs in order to assess the potential savings, cost-effectiveness (from both a utility and customer perspective), and likely adoption via utility rebate programs of over 200 energy efficiency measures commercially available in California.

An important modeling assumption embedded in the results of the 2008 Itron update study is that there are no significant changes in the suite of energy efficiency measures currently available over the short- and mid-term. Over the short-term, this assumption is reasonable. However, the validity of this assumption decreases significantly over the mid-term (e.g. 2025) and long-term (e.g. 2050) analysis periods. To this end, the approach developed for the 2011 PIER study built directly upon, but was not limited to, the results of the 2008 Itron update study.

Specifically, the research team developed a spreadsheet modeling tool, referred to as the Scenario-based Energy Savings Assessment Tool (SESAT), that uses the results of the 2008 Itron update study as the primary starting points for exploring alternative technology scenarios as well as scenarios that explore the

[7] The Itron 2008 potential update study was funded by California's four IOUs with the primary objective of forecasting the short-term (defined as 2016) and mid-term (defined as 2026) gross and net achievable market potential resulting from the installation of energy efficiency measures rebated through publicly-funded energy efficiency programs.

impact of macroeconomic and structural changes on long-term energy efficiency potential in California's buildings sector. The research team designed SESAT to introduce the following dimensions into the analysis of efficiency potential over the long-term:

- Interaction and comparison of the impacts of different sets of assumptions (i.e. scenario analysis) in a systematic, transparent, and internally-consistent fashion;
- Exploration of the impact of alternative baseline assumptions (e.g. relative increases or decreases in energy service demand); and
- Assessment of efficiency potential that may exist outside of the current suite of technologies commercially available in California.

Another important aspect of SESAT is that the inputs, outputs, and principle calculations are organized at the end-use level by building type, vintage (i.e. existing vs. new construction), and climate zone (residential only) as shown in Table S6 below. The research team chose this level of detail in order to explicitly frame the analysis in terms of end-use market segments for which electricity and natural gas consumption are reasonably well understood. This approach avoids the uncertainties associated with forecasting measure-specific characteristics over time, while maintaining a level of technology detail that is meaningful and relevant for policy and planning.

In SESAT, total energy use is calculated in a bottom-up fashion as the product of end-use energy intensities (e.g. kWh/household or kWh/ft2), end-use equipment saturations, and the number of households (residential) or floor area (commercial) by building type. The primary calculations for total residential and commercial energy use are shown below:

$$\text{Total residential energy use} = \sum_{ij} UEC_{ij} * SAT_{ij} * HH_{j}$$

$$\text{Total commercial energy use} = \sum_{ik} EUI_{ik} * SAT_{ik} * FloorArea_{k}$$

where:

i = end use
j = residential building type
k = commercial building type
UEC = unit energy consumption by end use i in building type j (kWh/household)
SAT = end-use saturation (%)
HH = total number of building type j
EUI = unit energy intensity by end use i in building type k (kWh/ft2)
$FloorArea$ = floor area of building type k (ft2)

Segment Name	**Segment Definitions**	
Sector	Residential	Commercial
Geographic region	16 standards climate zones	Statewide

Building type	Single-family dwelling Multi-family dwelling	College Food Store Health Large Office Lodging Miscellaneous Refrigerated Warehouse Restaurant Retail School Small Office Unrefrigerated Warehouse
Building vintage	Existing construction New construction	Existing construction New construction
End use	Space Cooling Space Heating Furnace Fan Water Heating Cooking Refrigerator Freezer Clothes Dryer Lighting Pool Pump Miscellaneous	Space Cooling Space Heating Ventilation Water Heating Commercial Cooking Refrigeration Exterior Lighting Interior Lighting Office Equipment Miscellaneous

Table S6. *Summary of SESAT analysis segmentation*

To allow explicit analysis of energy efficiency potential, the research team further disaggregated the UEC and EUI variables so that the impact of changes in technical efficiency due to the installation of efficiency measures can be examined and tracked separately from impacts due to changes in energy service demand (e.g. hours of use). To do this, the team introduced two dimensionless factors that represent the technical efficiency and energy service demand components, respectively, of end-use energy consumption into the principle energy use identity. This relationship is shown below, using residential UEC as an example:

$$UEC_{ijy} = UEC_{ijbase} * EffAdj_{ijy} * UseAdj_{ijy}$$

where:

UEC_{ijy} = unit energy consumption for end-use i in building type j in year y
UEC_{ijbase} = unit energy consumption for end-use i in building type j in the base year
$EffAdj_{ijy}$ = technical efficiency for end-use i in year y relative to technical efficiency in base year (defined as 1.0 in the reference scenario)
$UseAdj_{ijy}$ = energy service demand for end-use i in year y relative to energy service demand in base year (defined as 1.0 in the reference scenario)

In this analytic framework, any of the variables described above could be treated as parameters in a scenario analysis.

In the 2011 PIER study, the base-year (i.e. 2006) values for end-use saturations, UECs, EUIs, and end-use load shapes by building type were derived from the most recently available statewide building end-use studies conducted in California, namely the *California Statewide Residential Appliance Saturation Study* (53), and the *California Commercial Building End-Use Survey* (26). The base-year values for residential building stock and commercial floor stock by building type were derived from the most recently available building and floor stock estimates developed by CEC staff for use in the *California Energy Demand 2008-2018, Staff Revised Forecast* (54).[8] The bottom-up estimates of total electricity consumption and natural gas consumption were then calibrated to the respective base-year values published by the CEC.

Assessment of technical potential over the mid- and long-term

To develop the end-use energy savings inputs for the assessment of technical potential over the mid-term (through 2025), the study team primarily leveraged the detailed analyses of over 200 unique efficiency measures reflected in the 2008 Itron potential update study. [9] These detailed, measure-level results were then aggregated to the end-use level in order to calculate the technical efficiency factors described above. Over the 2050 timeframe of the long-term analysis, however, the amount of information available on emerging and future technologies is too limited to extend this level of measure-specific detail and analysis.

In order to effectively leverage the more limited amount of information available on future technologies, the study team developed an approach that first decomposed end-use energy intensities (e.g. kWh/household or kWh/ft2) into multiple discrete, multiplicative components. The generalized form of these end-use energy intensity decompositions is presented below (commercial electric example).

*End-use intensity (kWh/ft2) = (kW/energy service delivered) * (energy service required/ft2) * (hours of operation)*

In this decomposition, the first term (kW/energy service delivered) describes the efficiency of the end-use equipment, e.g. fluorescent lights, chillers, or water heaters. The second term (energy service required/ft2) describes the amount of energy service (e.g. lumens of light or tons of cooling) required per square foot of commercial building space or per residential home. The third term (hours) describes the operational

[8] In order to develop housing and floor stock estimates through 2025 and 2050 (which is beyond the CEC's load forecasting horizon), the research team developed an algorithm to project housing stock and commercial floor stock that leverages the long-term population forecasts produced by the California Department of Finance (33). In this algorithm, the historical relationship between population growth and annual housing stock additions is combined with the CADOF population projections to produce long-term housing stock forecasts. In the case of commercial buildings, the historical relationship between total population and total commercial floor stock by building type is combined with the CADOF population projections to produce long-term commercial floor stock forecasts.

[9] The full list and descriptions of the energy efficiency measures included in the 2008 Itron potential update study are available at: http://www.calmac.org/startDownload.asp?Name=PGE0264_Final_Report.pdf&Size=5406KB

pattern of the end use equipment. Potential changes in end-use energy intensity can in turn be expressed as changes in the specific individual terms shown above.

For purposes of assessing technical potential, these changes in the individual components of end-use energy intensity reflect three distinct types of efficiency strategies:

- Changes in kW/energy service demand reflect improvements in the technical efficiency of end-use equipment (e.g. replacing fluorescent tubes with LEDs);
- Changes in energy service/ft2 reflect reductions in energy service requirements (e.g. reductions in cooling load from improvements to the building envelope);
- Changes in hours reflect reductions or optimization of operating hours (e.g. matching lighting operation to ambient light through advanced day lighting sensors and controls).

This decomposition approach allows savings estimates to be developed in a way that minimizes double counting of potential savings across multiple efficiency strategies that target the same end use. More importantly, however, this decomposition approach allows the study team to focus on developing savings estimates for more general (but still end-use specific) efficiency strategies and use the more limited information of specific future technologies as representative benchmarks for corresponding efficiency strategies.

Within this end-use intensity decomposition framework, the team developed high/mid/low ranges of plausible 2050 savings values for each efficiency strategy. These 2050 end-use savings estimates were designed to reflect savings that are incremental to the savings estimates developed for the 2025 analysis. These ranges were developed primarily from a series of interviews conducted with technology experts and supplemented with secondary data from technology-specific literature on long-term savings potentials. Once the study team had compiled a full set of strategy-specific savings estimates, the team used a simplified Delphi process to vet and revise the savings estimates among technology experts and team members.

5.5 *Modifications for Current Study*

For this study, the research team made a host of modifications and additions to the long-term technical potential analysis developed for the 2011 PIER study. These modifications were driven by both the efficiency-related research objectives of this study and the need to integrate the long-term demand forecast results with the supply-side planning model (SWITCH) in order to enable system-wide modeling of GHG emissions. Specifically, the modifications made to the 2011 PIER analysis included the following: 1) minor revisions to the baseline end-use data; 2) adding the temporal and spatial resolution in SESAT necessary to feed SWITCH (annual electric energy consumption, hourly load profiles, and climate zone-level segmentation); and, 3) adding a demand-side electrification scenario. Each of these modifications is described in more detail below.

<u>*Baseline data revisions*</u>

In the time since the 2011 PIER study was completed, the results of the *2009 California Residential Appliance Saturation Survey* (24) became publically available. The electric end-use UECs from the 2009

RASS were used to verify the baseline UECs in the SESAT model for this study. In two specific cases, this verification and comparison process resulted in the research team making adjustments to the baseline UECs in SESAT model based on the 2009 RASS results.

For residential electric space heating, the 2009 RASS results were used to adjust the previous baseline UEC estimates downward. The result of this downward adjustment is that the target year (i.e. 2050) UECs for electric space heating in the technical potential scenario are now consistent with super high-efficiency heat pumps (e.g. 17+ SEER) and tight building shells.

For residential electric water heating, the comparison of previous baseline UECs used in SESAT with the 2009 RASS results identified significant double-counting in the previous water heating UECs associated with clothes washers and dishwashers. After eliminating this double-counting, the revised UECs were then verified with both the 2009 RASS results and metered results from a recent survey of Florida homes (which are nearly all electric) conducted by Itron.

<u>*Add annual results*</u>

In the 2011 PIER study, the research team developed technical potential estimates for two specific points in time, 2025 and 2050. For this study, however, the research objectives required annual streams of results for electric energy consumption. The research team therefore modified SESAT to produce an annual stream of energy consumption results between the base year (2006) and the target year (2050).

This was accomplished by applying “implementation curves” at the end-use and building type level. These implementation curves reflect the annual changes in average end-use UECs from the adoption of energy efficiency measures. The assumptions and calculations that determined the shape of each implementation curve are described in section 4.5.

<u>*Add hourly load profiles*</u>

Perhaps the most significant addition to SESAT made for this study was the introduction of hourly load profile information into the model specification. This addition was necessary due to the need to integrate the long-term demand forecast results with the supply-side planning and dispatch model (SWITCH). Since SWITCH, like all planning and dispatch models, is sensitive to the temporal distribution of aggregate electricity demand, it was necessary to expand the temporal resolution of the SESAT analysis.

To do this, the research team expanded the SESAT modeling identity to include load shape information (i.e. the distribution of demand across the day, week, month, and year) as a baseline input at the end-use and building type level. Including load shape information at the end-use level allows changes in the mix of end-use demand (whether from increased energy efficiency or changes in end-use service demand or both) to be transparently reflected in the overall temporal distribution of total load.

For this study, end-use load shapes were developed for each residential and commercial end-use and building type specified in SESAT. For residential buildings, the research team derived end-use load shapes from a set of building simulations performed for prototypical California homes using Itron’s *SitePro* simulation software. The load shapes for residential HVAC were differentiated for each of

California's 16 forecasting climate zones based on the results of simulations using climate-zone specific weather data. The load shapes for residential electric space heating were further refined by blending the results of two separate sets of simulation results that reflected distinct technology choices – furnaces and heat pumps. The final load shape for residential space heating is intended to reflect the higher COP of heat pumps as well as the heating requirements of tight building shells.

For commercial buildings, the research team applied hourly end-use load shapes by building type from the latest CEUS study (26). Note that the research team made no attempt to differentiate commercial HVAC load shapes across climate zones. This decision was based on the fact that commercial HVAC demand tends to be dictated largely by internal gains (lights, people, office equipment, servers, etc.) rather than external conditions and is thus only weakly correlated to climate (e.g., heating and cooling degree days).

Add climate zone-level segmentation

In order to reconcile the spatial resolution of the SESAT and SWITCH models, the research team also modified SESAT to output results at the climate-zone level. For the residential sector, this was enabled simply by eliminating an aggregation step in the model's reporting function, since all of the inputs were already specified at the climate zone level. In the commercial sector, however, all of the inputs are specified at the statewide level (by building type). In order to generate results for commercial buildings at the climate-zone level, the research team used climate-zone specific floor area data from the 2006 CEUS to share out the building-type level statewide results produced by SESAT across climate zones. These climate-zone and building-type specific results were then re-aggregated across building types to produce climate-zone level total load forecasts for commercial buildings.

Add fuel switching scenario

Finally, the research team developed an additional scenario that was not explored previously in the 2011 PIER study – the effect of fully electrified buildings. To do this, the research team used the saturation variable in the SESAT modeling identity as a scenario parameter to simulate the load impacts of fuel switching away from gas and towards electricity in the buildings sector. The specific assumptions used to develop and implement the fuel-switching scenario are described further in section 4.6 below.

5.6 Maximum Energy Efficiency Scenario

For this study, the research team developed two primary long-term electricity demand scenarios for the buildings sector, the first of which was a "maximum energy efficiency" (max-EE) scenario. The max-EE scenario was based largely on recent estimates of long-term technical potential developed by Itron in the 2011 PIER study. This corresponds to the "Increased Efficiency" pathway in the main article.

Technical potential reflects the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency were taken.[10] In this sense, technical

[10] Applicability limits measure installation to situations where a qualifying end use or technology is present (e.g., water heater blankets for electric water heaters require an electric water heater to be present). Feasibility limits

potential is best interpreted as a theoretical benchmark, particularly over the short-term. For this study, however, the research team wanted to construct an electric load forecast that reflected a policy-driven pathway towards achieving technical potential savings over the long-term, i.e. by 2050. The key policy assumptions reflected in the final max-EE scenario developed for this study are described below.

Policy Assumptions

Over the near-term, the max-EE scenario reflects a regulatory environment similar to that in California today, with utility rebate programs accounting for the vast majority of programmatic activity statewide, and rebates levels assumed to be set very aggressively, i.e. approaching 100% of the incremental cost of each measure. Aggressive utility programs are assumed to dominate California's regulatory environment through 2025, after which statewide programmatic activity is assumed to become more and more dominated by mandatory codes and standards such that by 2050, all end-use equipment replacements would be required to be high-efficiency.

To reflect these policy assumptions, the research team developed near-term measure adoption rates based on the results of the "full market potential" scenario from the 2008 Itron potential update study from 2006 through 2025.[11] From 2025 forward, measure adoptions were assumed to be driven by the increasing scope and stringency of codes and standards such that 100% of all installed end-use equipment is high-efficiency by 2050. The key characteristics of the resulting measure adoption rates and electric load forecast are summarized below.

Construction rates for new building units are assumed to be 0.5% of population in the residential sector with 70% of new units assumed to be single family households and 30% multifamily. For new build rates in commercial sector, historical relationships between population growth and annual commercial square footage area by sector (college, food store, hospital, etc). were employed.

Results

Figures S32 and S33 show the final energy efficiency "implementation curves" developed for existing residential and commercial buildings by end use. These implementation curves reflect the annual improvement in average end-use UECs from the adoption of energy efficiency measures. Note that Figures S32 and S33 display these implementation curves in terms of an index that describes the relative rate of progression towards the long-term (i.e. 2050) technical potential for each end use.

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measure installation to situations where installation is physically practical (e.g., available space, noise considerations, and lighting level requirements are considered, among other things).

[11] The measure-specific adoption rates for all of the scenarios modeled in the 2008 Itron potential update study are available at: http://www.calmac.org/startDownload.asp?Name=PGE0264_Final_Report.pdf&Size=5406KB. Note that for this study, the measure-specific adoption rates were aggregated to the end-use level in order to match the level of analysis in the SESAT model. In order to produce meaningful indices of measure adoption at the end-use level, this aggregation was done in terms cumulative energy savings (rather than number of adoptions).

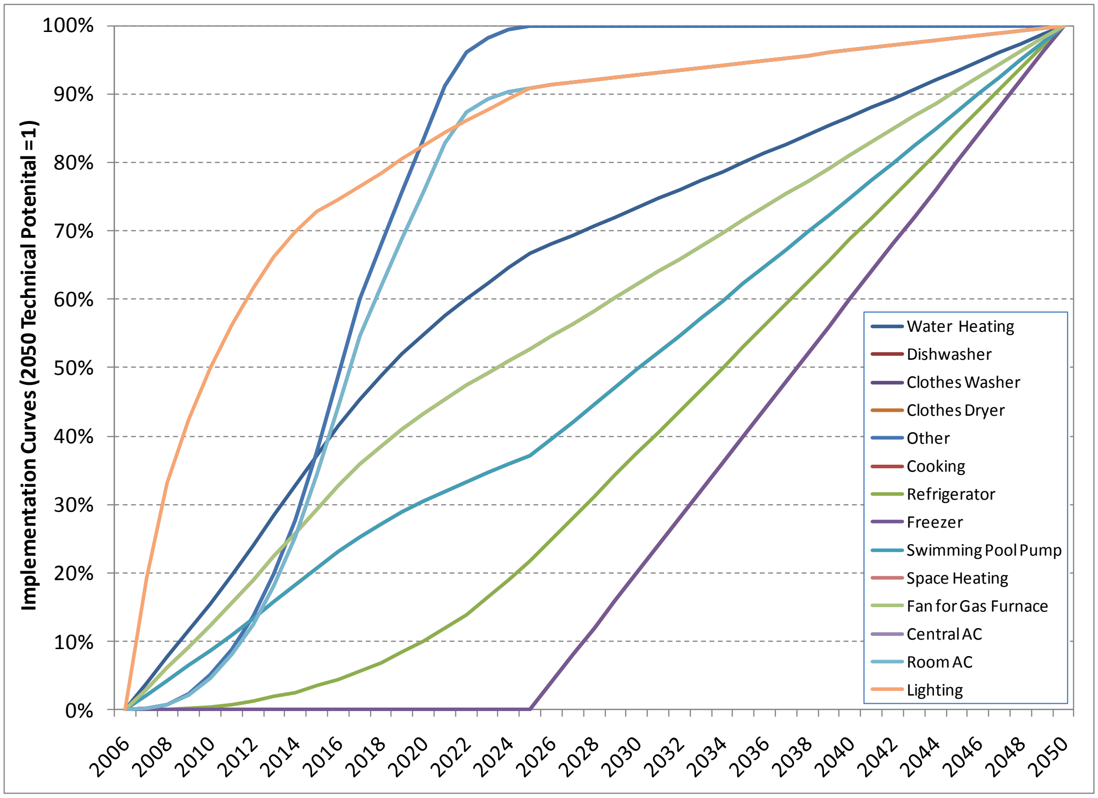


Figure S32. *Energy efficiency implementation curves for existing residential buildings.*

As Figure 4-1 shows, lighting measures are adopted very quickly relative to other types of residential measures under the utility-rebate paradigm, largely due to their cost-effectiveness to customers and the very short useful life and high turnover rate of standard efficiency lighting technologies (i.e. incandescent lamps). In contrast, adoption of longer-lived and more expensive measures such as high-efficiency refrigerators grow at a slower, more linear rate under the utility-rebate paradigm. From 2025 forward, however, measure adoptions for all end uses are assumed to be driven by the increasing scope and stringency of mandatory codes and standards and grow linearly until all 100% of all installed end-use equipment is high-efficiency by 2050.

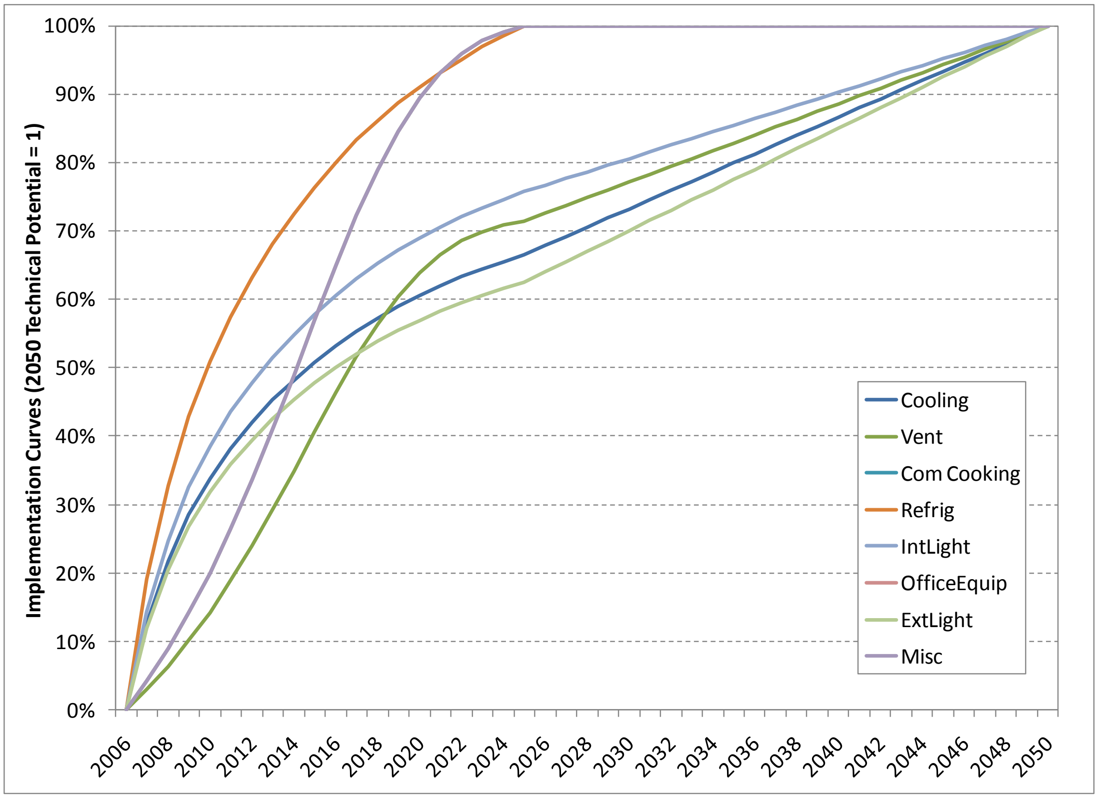


Figure S33. *Energy efficiency implementation curves for existing commercial buildings.*

Introducing these energy efficiency implementation curves into the SESAT model produces the total load forecast shown in Figures S34 and S35. As these figures show, the assumptions in the max-EE scenario yield a zero load growth forecast for the buildings sector, both in terms of annual electric energy consumption (GWh) and in terms of system coincident peak demand (GW). When compared to a long-term load forecast using "frozen efficiency" or baseline UECs throughout the forecast period, the max-EE scenario represents annual energy savings of roughly 1,700 GWh/year and system peak demand savings of roughly 500 MW/year.

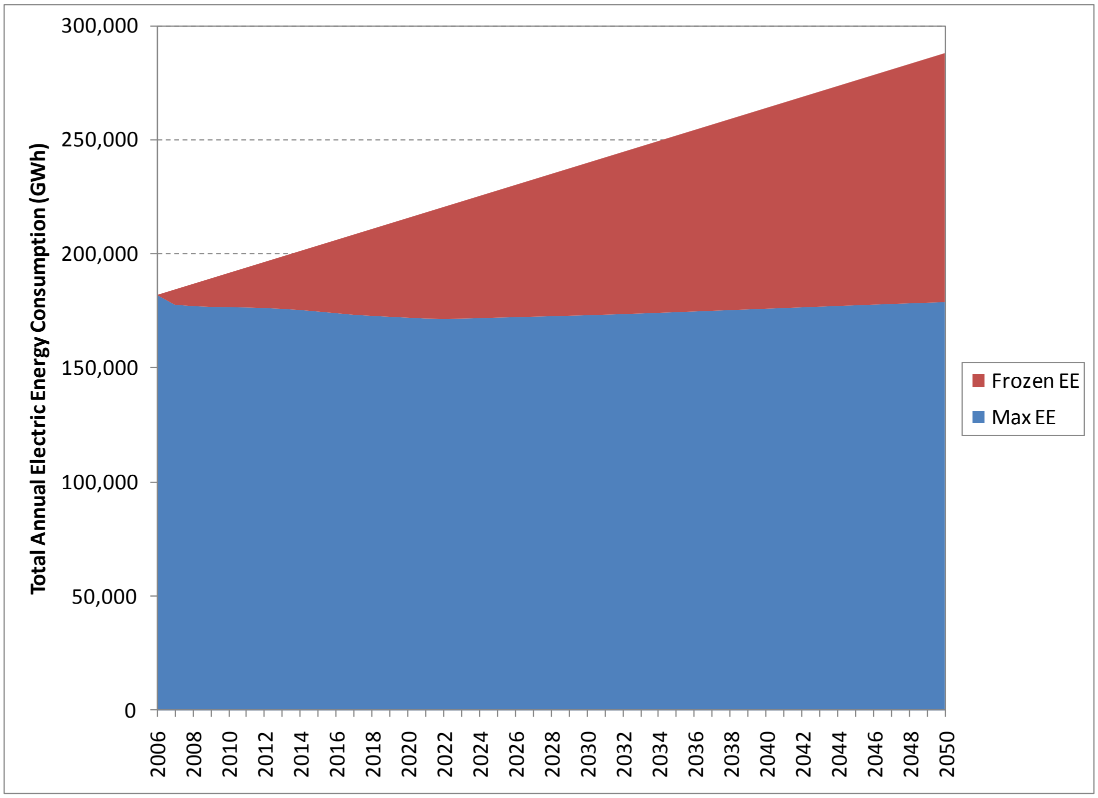


Figure S34. *Annual electric energy consumption in buildings in the max-EE scenario for California.*

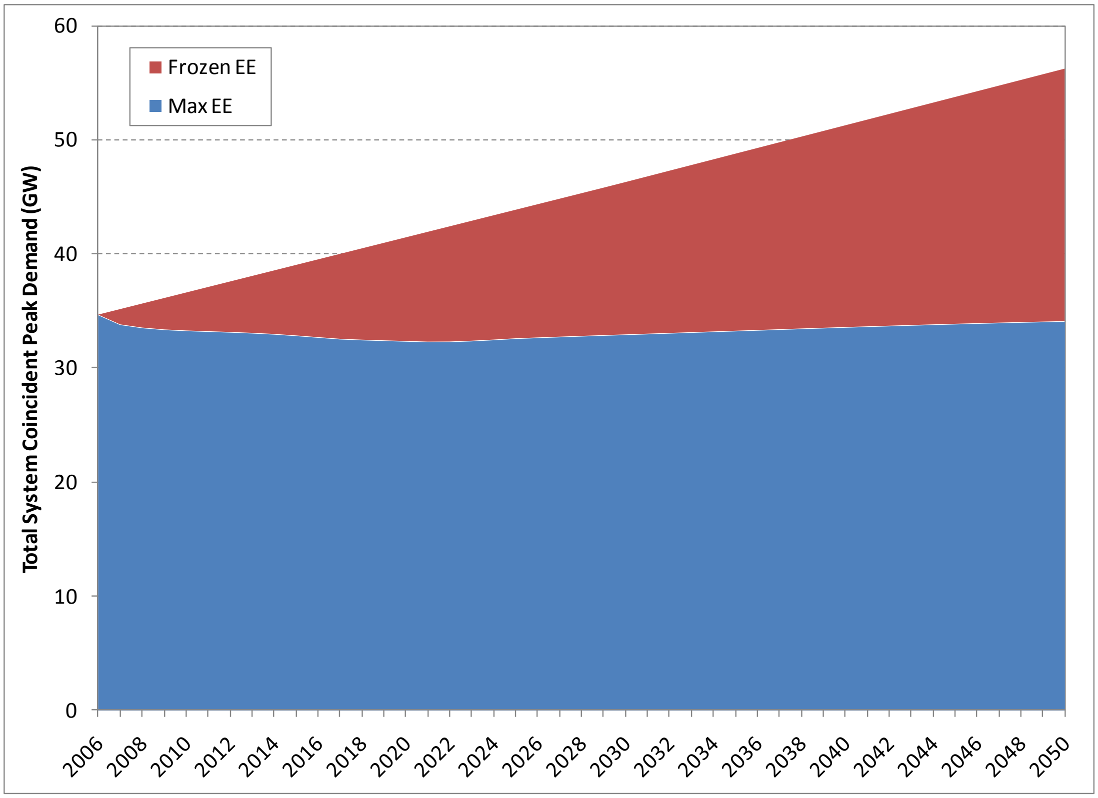


Figure S35. *Total system coincident peak demand from buildings in the max-EE scenario for California.*

The zero load growth forecasts shown in Figures 4-3 and 4-4 imply a relatively steady-state world under the max-EE scenario with about 38% overall savings relative to frozen-EE in 2050. However, both the relative and absolute level of technical potential savings vary significantly across measures and end uses in the buildings sector, and therefore the end-use composition of total load changes significantly in the max-EE scenario. Figure 4-5 compares the end-use breakdown of total load in the frozen efficiency forecast versus the max-EE forecast for the residential sector. As the figure shows, lighting accounts for one of the largest shares of total residential electricity consumption in the frozen efficiency case. In the max-EE case, however, lighting accounts for roughly the same share as electric cooking, reflecting the massive reductions in lighting UECs from the adoption of CFLs and LEDs. The decreased importance of lighting loads in turn increases the relative importance of miscellaneous plug loads (labeled as "other" in Figure S36) and refrigeration in total residential electricity demand in the max-EE case.

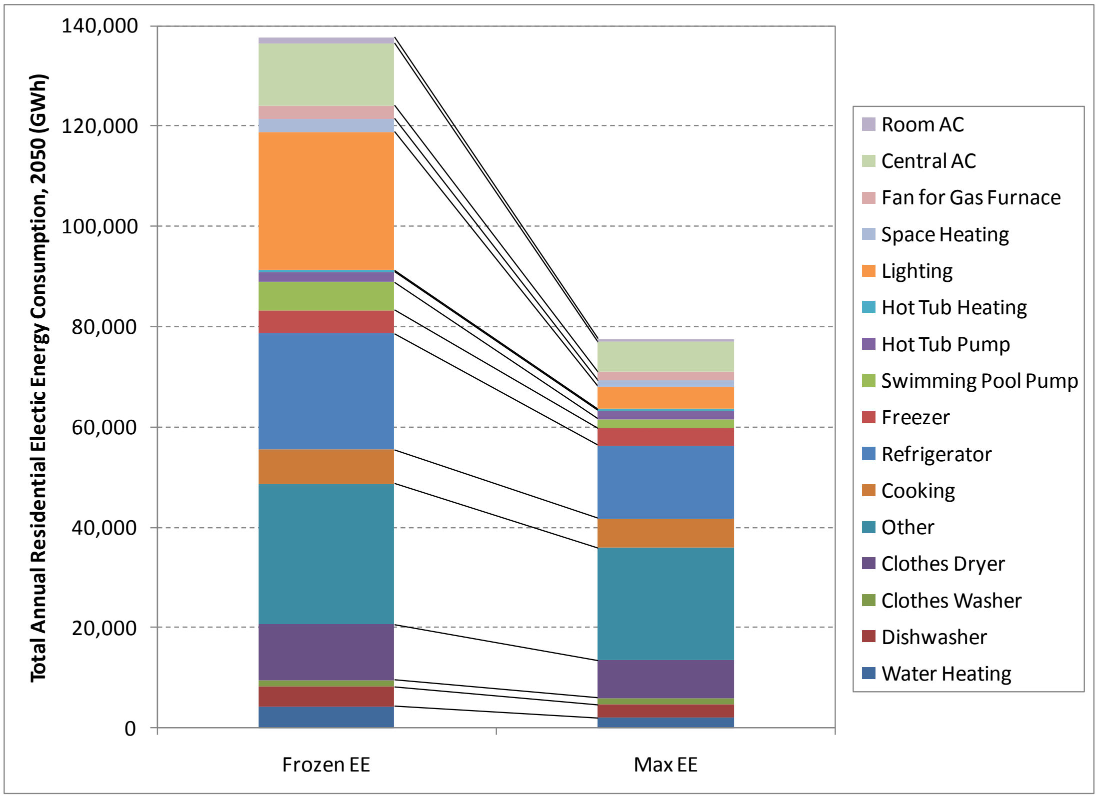


Figure S36. *End-use contributions to total load in the residential sector in 2050.*

Figure S37 compares the end-use breakdown of total load in the frozen efficiency forecast versus the max-EE forecast for the commercial sector. As in the residential sector, lighting accounts for one of the largest shares of total commercial electricity consumption in the frozen efficiency case but declines in relative importance in the max-EE case due to significant savings from advanced linear fluorescent lighting and control systems. The decreased importance of commercial lighting loads in turn increases the relative importance of office equipment, other miscellaneous plug loads (labeled as "misc" in Figure S37), commercial and refrigeration in total commercial electricity demand in the max-EE case.

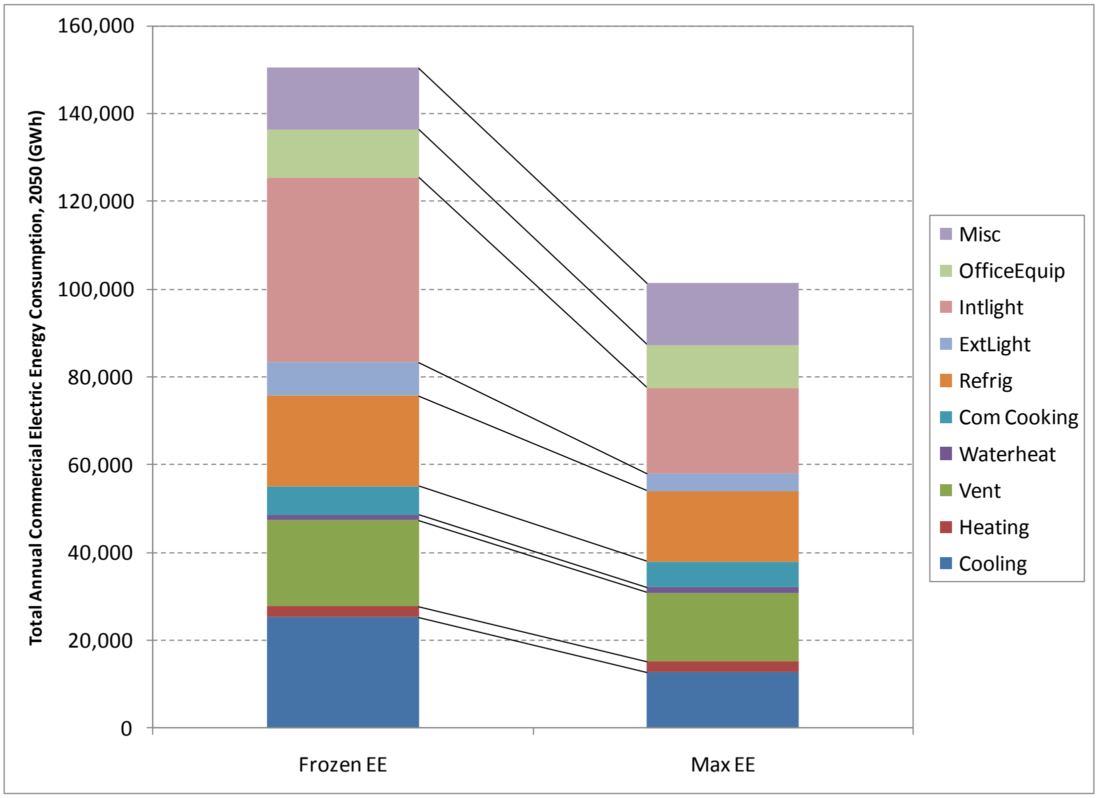


Figure S37. *End-use contributions to total load in the commercial sector in 2050.*

Because the distribution of electricity demand (across a day, week, month, and year) varies significantly across the various end uses in buildings, the changes in the end-use composition of total demand in the max-EE case therefore also change the relative temporal distribution of total demand. Figure S38 compares the daily system coincident peak demand for each day in the last year (2050) of the frozen-EE forecast and the max-EE forecast. As the figure shows, system peak demand in the max-EE case follows the same general pattern over the course of the year as in the frozen-EE case (albeit at a lower overall level due to overall increases in end-use efficiency) – i.e. a summer peaking system driven by space cooling demand. However, the overall load shape of the max-EE forecast is significantly flatter (particularly in the summer months) than that of the frozen-EE forecast, reflecting the reduced importance of highly dynamic loads from lighting and space cooling the increased importance of relatively flat loads from refrigeration and miscellaneous end uses in aggregate.

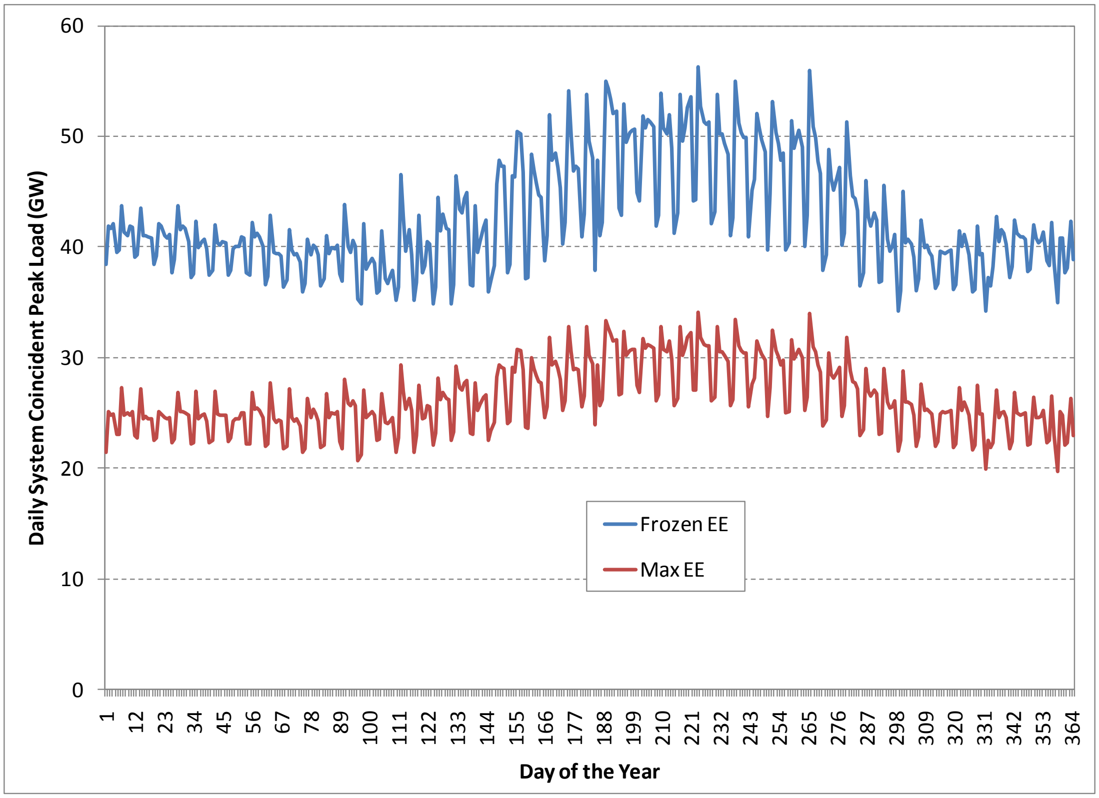


Figure S38. *Daily system coincident peak load from buildings in 2050 in California.*

5.7 Maximum Energy Efficiency and Electrification Scenario

The research team also developed a "maximum energy efficiency and electrification" (base case) scenario for this study based on both technical potential for energy savings and fuel-switching away from natural gas towards electricity in the buildings sector. This scenario builds directly upon the max-EE scenario presented above and simply adds assumptions describing a policy-driven shift away from natural gas and towards electricity for particular end uses in the buildings sector.

The key policy assumptions reflected in the final "max-EE + electrification" scenario developed for this study are described below ("max-EE" is equivalent to "technical potential energy efficiency").

Policy Assumptions

Over the near-term, end-use fuel shares are assumed to stay constant at baseline values. However, starting in 2015, codes and standards requiring fuel-switching away from natural gas and towards electricity are assumed to be phased in for key gas technologies and end uses in California in an effort to "electrify" the building sector and maximize the GHG emissions benefits of a de-carbonized electricity supply system.

In order to simulate the load impacts of such a fuel-switching policy, the research team assumed that codes and standards targeting residential and commercial water heating (gas-fired storage water heaters), residential space heating (gas-fired furnaces), and commercial space heating (gas-fired boilers) would be implemented at particular points in time during the forecast period that would mandate all new installations and end-of-life replacements to use electric-powered equivalent technologies.[12] These assumptions were then combined with average useful life estimates for the related gas technologies from the California Database for Energy Efficient Resources to develop annual fuel-switching rates based on stock turnover. The key characteristics of the resulting fuel-switching rates and electric load forecast are summarized below.

Results

Figure S39 shows the final fuel-switching rates developed for the water heating and space heating end uses in the "max-EE + electrification" scenario.

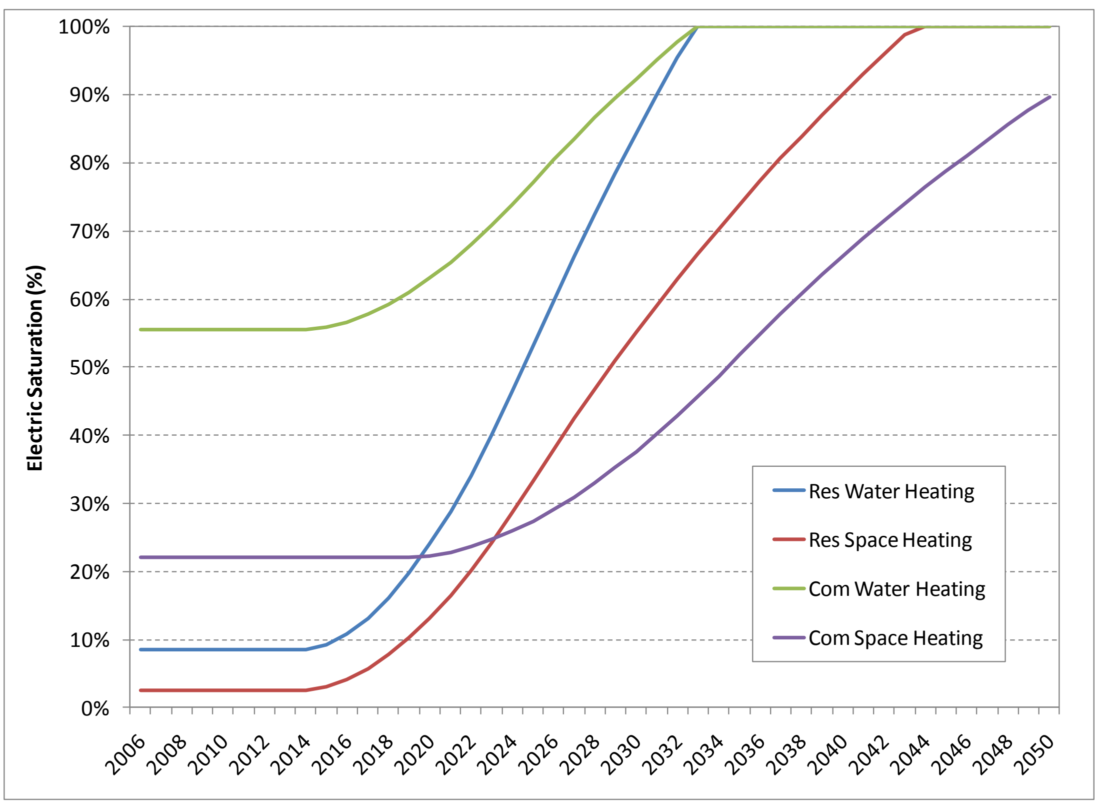


Figure S39. *Fuel-switching rates assumed in the max-EE + electrification scenario for California.*

[12] The specific assumptions used were the following: 1) phase-in of electric storage water heaters (commercial) and heat pump water heaters (residential) starting in 2015, with 100% penetration on the margin by 2025; 2) phase-in of air-source heat pumps starting in 2015, with 100% penetration on the margin by 2025; and 3) phase-in of electric boilers starting in 2020, with 100% penetration on the margin by 2035.

Note that Figure S39 shows the fuel-switching rates developed specifically for residential water heating in single family dwellings (SFD), residential space heating for SFDs in climate zone 5 (the SF Bay Area), and commercial water heating and space heating in retail buildings.[13]

As Figure S39 shows, the relative level of assumed fuel-switching is largest in the two residential end uses (from 5-10% penetration today to 100% by 2033 and 2044, respectively), whereas the relative level of assumed fuel-switching in the two commercial end uses is significantly more modest due to the significant baseline shares of electricity in commercial water heating and space heating systems.

Introducing these fuel-switching rates into the SESAT model produces the total load forecast shown below in Figures S40 and S41. As these figures show, complete electrification of water heating and space heating in the building sector over the forecast period has a significant impact on the resulting electric load forecast. In the case of annual electric energy consumption, Figure S40 shows that the electrification case produces annual average load growth of 0.4%/year.

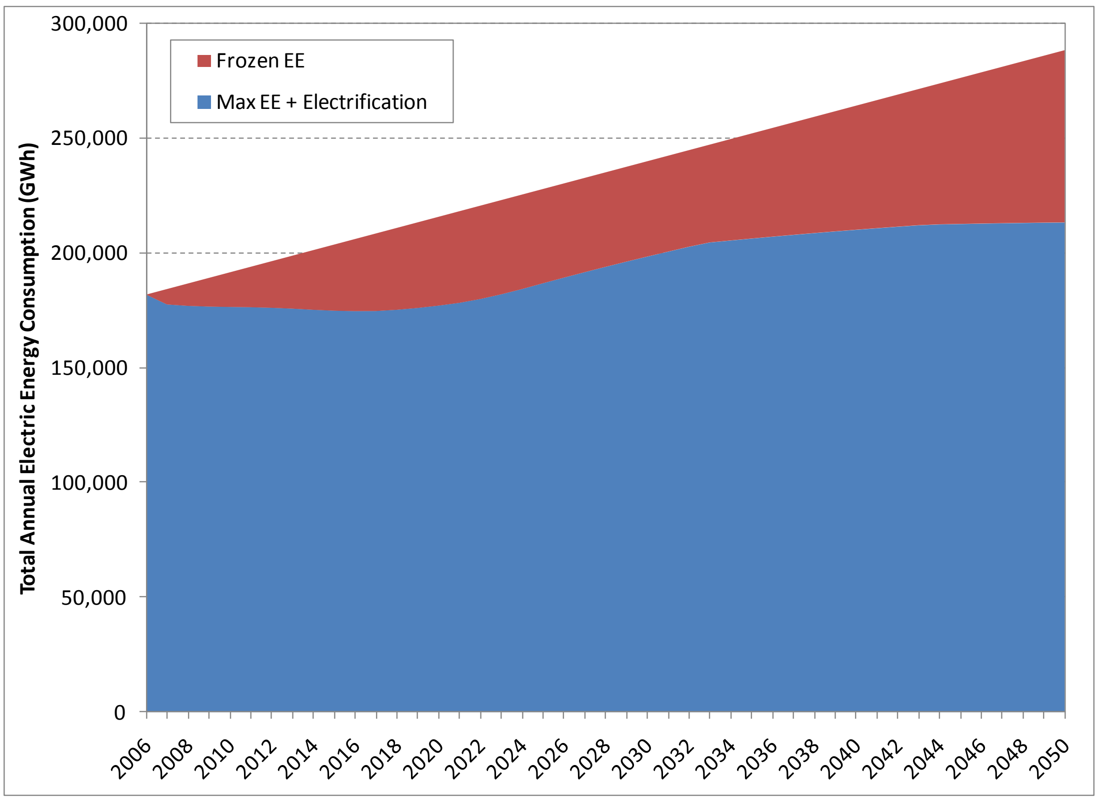


Figure S40. *Annual electric energy consumption in buildings in the max-EE + electrification scenario.*

It should be noted, however, that forecasted load growth in the electrification scenario is not uniform over the forecast period. Indeed, annual electric energy consumption remains flat through 2020 and then grows

[13] Fuel-switching rates were developed on a building-type specific basis (for residential and commercial water heating and space heating) and on a climate-zone specific basis (for residential space heating), but, for the sake of simplicity, are not all shown in Figure S39.

at 1.1%/year through 2033 and 0.2%/yr for the remainder of the forecast, reflecting the aggressive fuel-switching rates shown previously in Figure S39.

From a system peak demand perspective, the impact of the fuel-switching assumptions are even more pronounced, as shown in Figure S41 below. Indeed, Figure S41 shows that total system peak demand from the buildings sector in the "max-EE + electrification" scenario grows at nearly the same rate overall as in the frozen EE scenario. However, the most of the growth in system peak demand occurs in the latter half of the forecast period, averaging 1.7%/yr from 2025 to 2050.

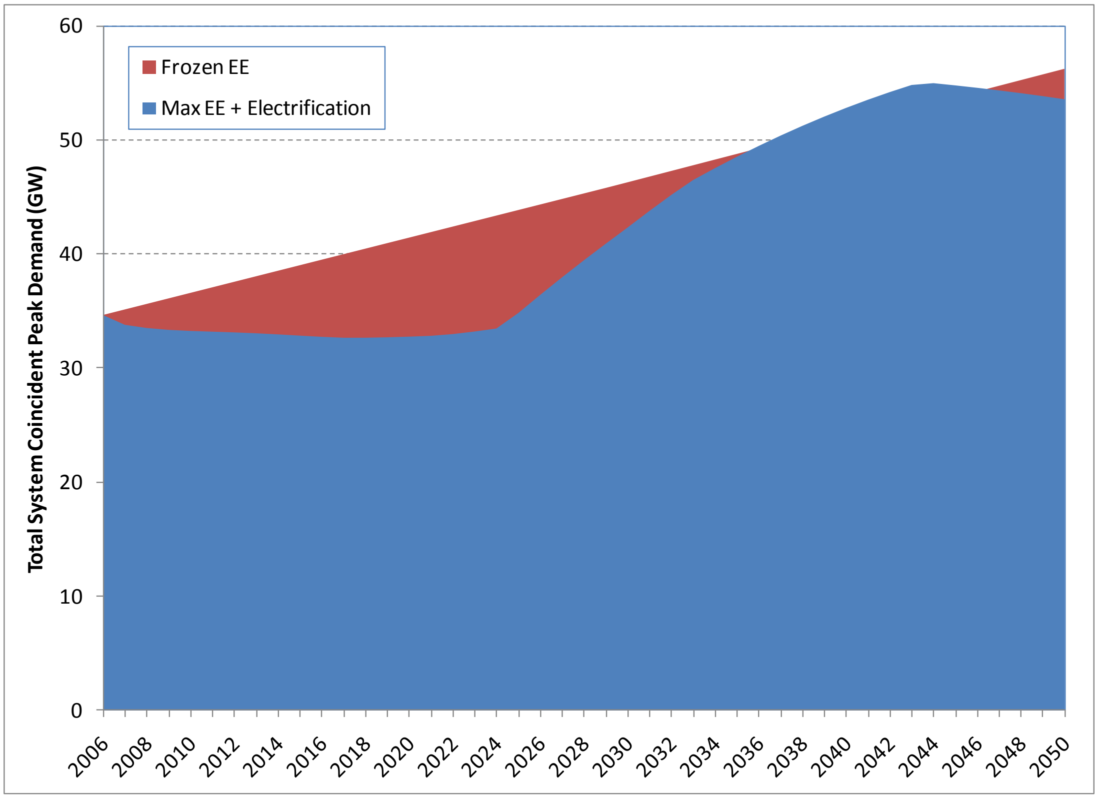


Figure S41. *Total system coincident peak demand from buildings in the max-EE scenario + electrification scenario.*

Figures S42 and S43 show the impact of the assumed fuel-switching rates on the end-use contributions to total forecasted load in the buildings sector. Figure S42 shows that electrifying water heating and space heating in the residential sector results in those two end uses accounting for roughly 30% of total residential electricity consumption – a dramatic shift from the max-EE and frozen-EE cases where those two end uses accounted for only 4% and 5% of total residential electricity consumption, respectively.

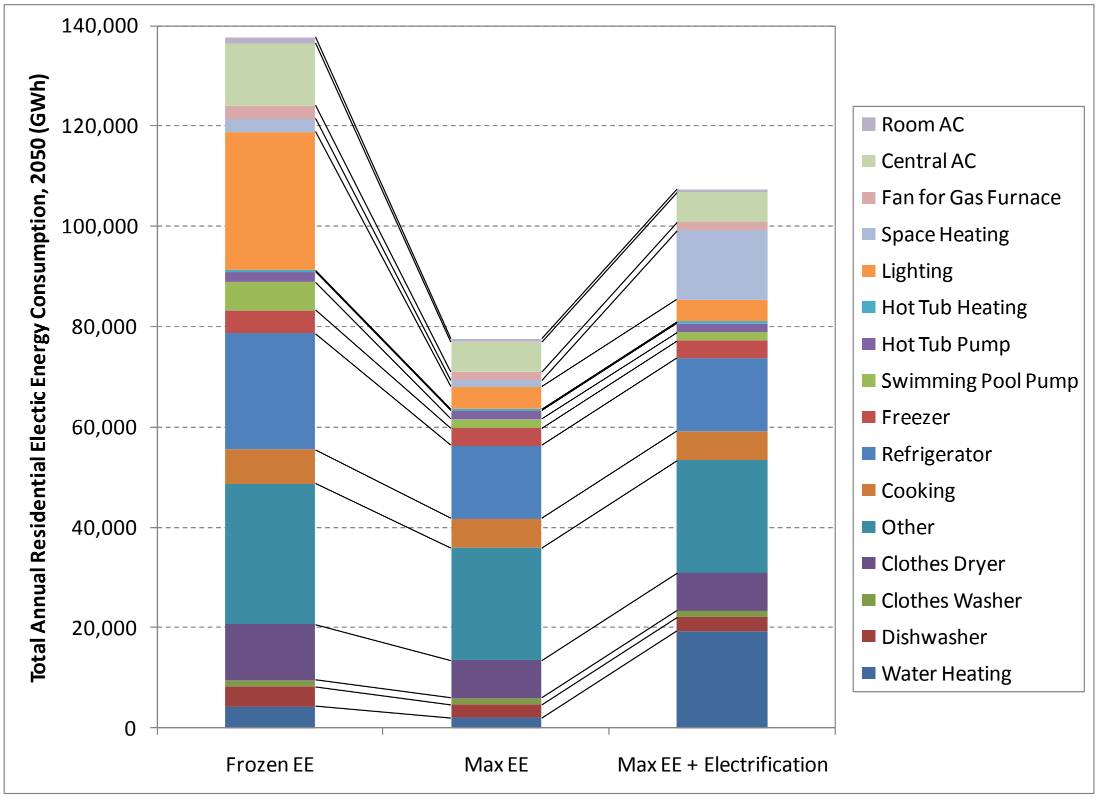


Figure S42. *End-use contributions to total load in the residential sector in 2050.*

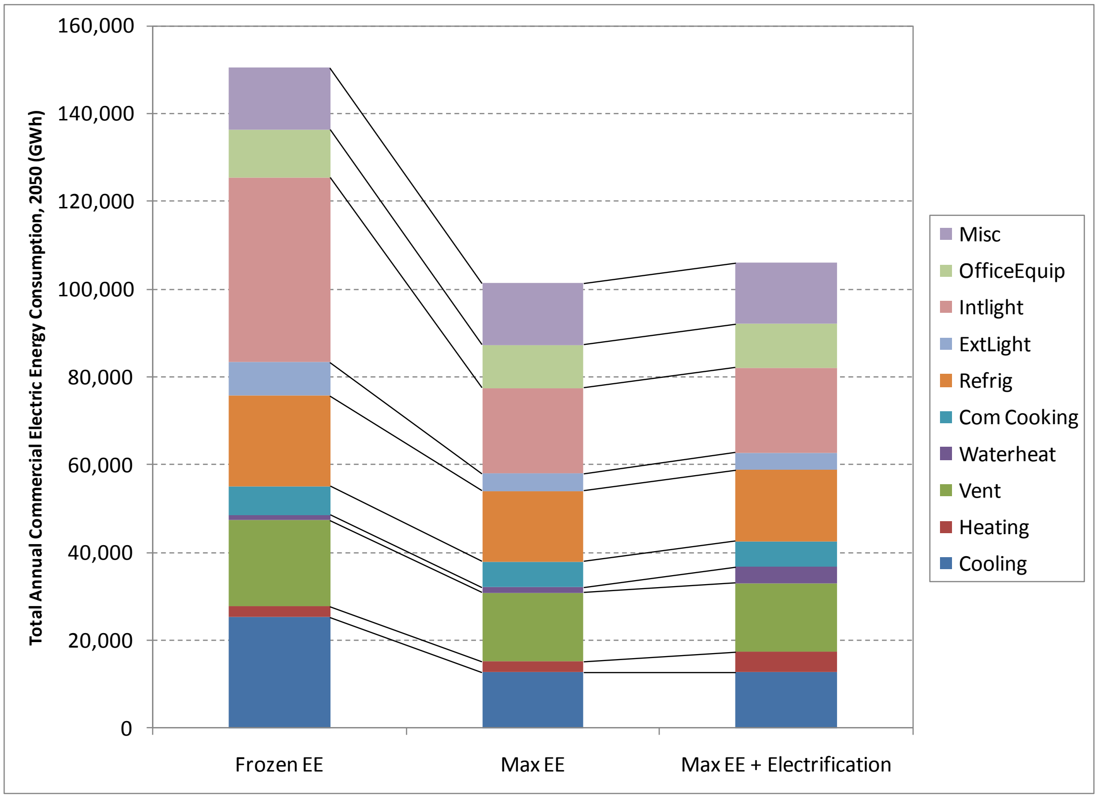


Figure S43. *End-use contributions to total load in the commercial sector in 2050.*

In contrast, Figure S43 shows that electrifying the heating end uses in commercial buildings results in only slight changes in their relative share of total commercial electricity consumption compared to those in the max-EE and frozen-EE scenarios. This result reflects both the relative insignificance of the heating end uses in commercial buildings and the fairly high baseline penetration of electric space heating and water heating technologies.

Given the dramatic changes in end-use contributions to total residential load shown in Figure S42 compared to the insignificant changes to total commercial load shown in Figure S43, it follows that the dynamics of total electricity demand from the buildings sector should be begin to follow those in the residential sector. Indeed, as Figure S44 shows below, total system coincident peak demand from buildings in the electrification scenario follows a very different pattern over the course the year compared to both the max-EE scenario and the frozen-EE scenario – the system shifts from being summer-peaking and driven by space cooling demand in both residential and commercial buildings to one that is winter-peaking and driven by space heating and water heating demand almost exclusively in residential buildings.

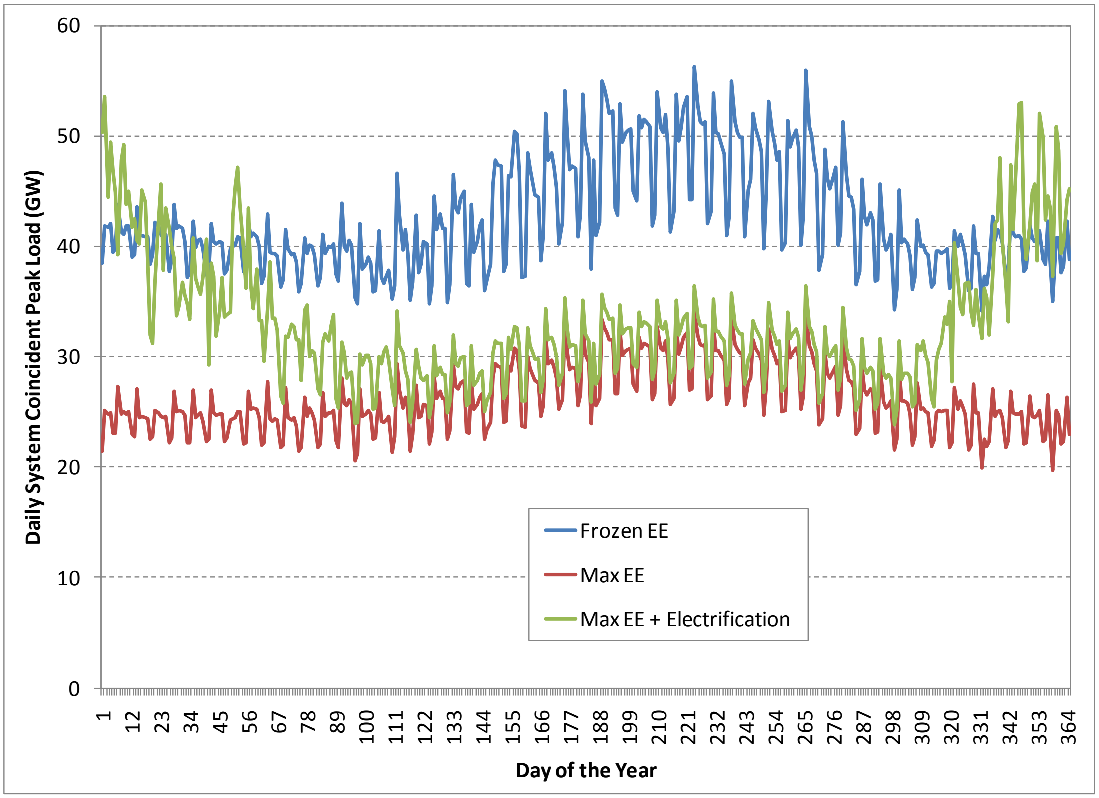


Figure S44. *Daily system coincident peak load from buildings in 2050 in California.*

Additionally, the importance of residential space heating and water loads in the electrification scenario also manifests itself in the hourly distribution of total demand during the system peak period. In the max-EE and frozen-EE cases, system peak demand occurs during the mid-afternoon, typically between 2pm and 4pm. As Figure S45 shows below, system peak demand in the electrification scenario occurs in the morning prior to the start of business hours and then experiences a secondary peak during the evening hours following the business day. This bi-modal distribution of hourly demand is a direct reflection of the load shapes associated with residential water heating and space heating and their relative importance in total residential electricity demand in the "max-EE + electrification" scenario.

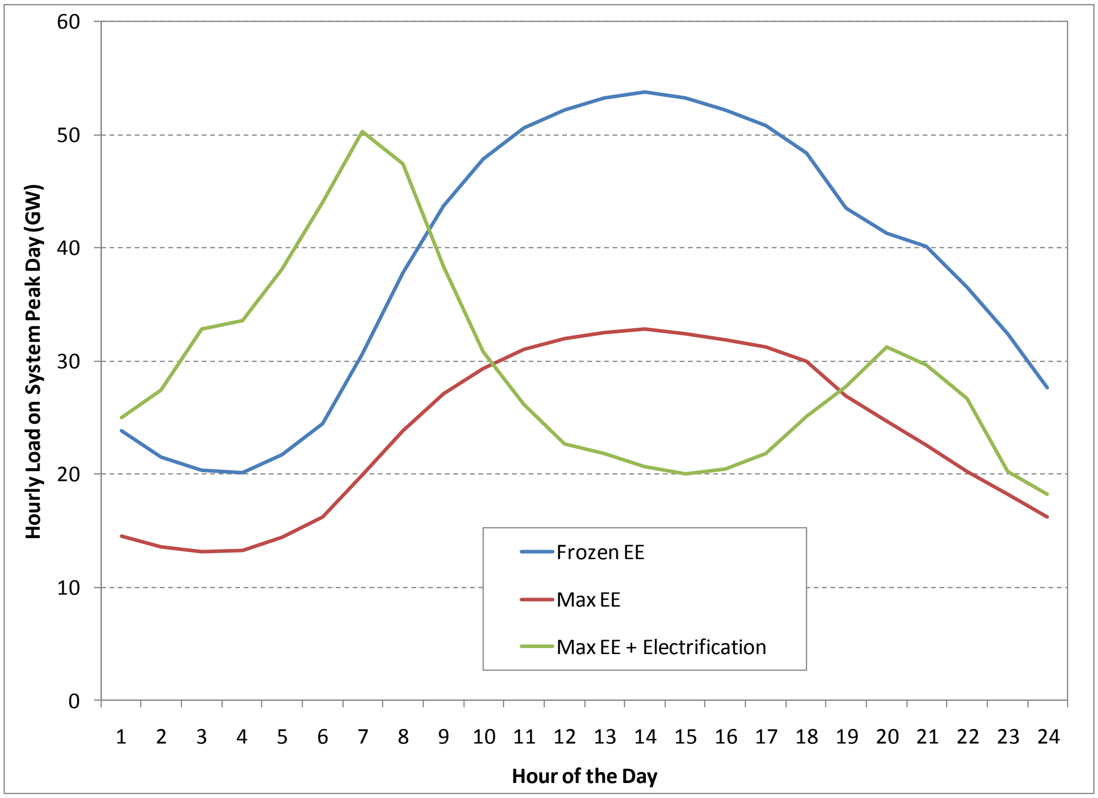


Figure S45. *Total hourly demand from buildings on the system peak day in 2050 in California . (Note: system peak day occurs on different calendar days for the three cases).*

6. INDUSTRY

6.1 Introduction

The treatment of long term industrial energy use is challenging because of the heterogeneity of industry sectors and applications and the dynamic nature of the economy. Overall there is a wide range of estimates for the U.S. in industry growth and concomitant energy consumption. For example, there is a wide range of estimates for long term (2035) industry electricity use by up to 50% between the most recent AEO 2011 projections and other long range studies. These differences stem from differing assumptions about overall GDP and industry sector growth, different energy efficiency assumptions, as well as different fuel switching assumptions. For example, AEO 2011 projections assume lower electricity demand from the previous year's projections due to growth in combined heat and power[14], whereas in this study we move in the opposite direction to minimize fossil fuel carbon emissions. Intra-industry sectoral change is also major contributor to overall industry energy use with a trend toward more off shoring of industrial activity and a shift to the less energy intensive service sector.

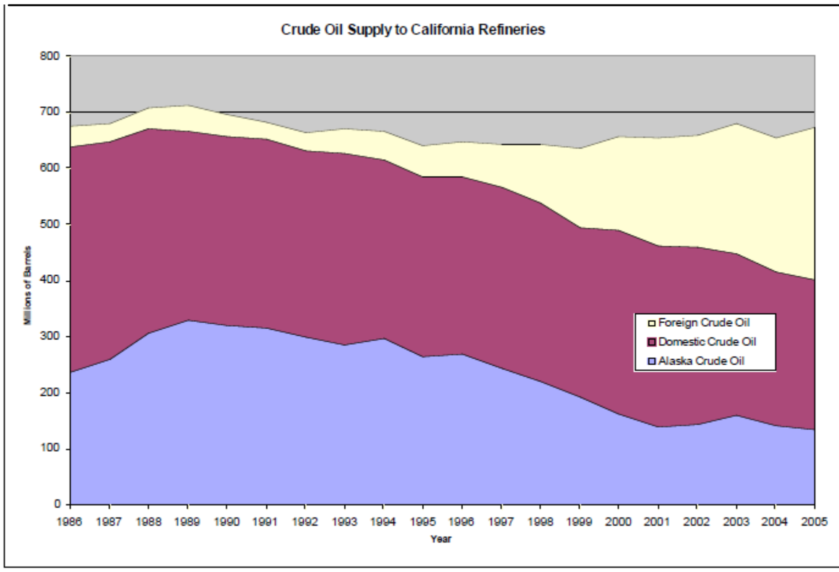
For industry, as opposed to the building sector, there is a large rate of "autonomous" energy efficiency (often assumed at 1% per year normalized to GDP growth), or natural growth of energy efficiency gains apart from policies and programs external to industry, since industry has a bottom line incentive to be more energy efficient.

The methodology for this report is to aggregate all the energy efficiency improvements that are technically possible relative to a frozen efficiency case to determine a technical potential case. This means that we are not counting items that could improve energy consumption like product design and continuous product improvement that can indirectly improve energy consumption, so our estimate may underestimate overall energy demand reduction. We follow this approach since it is possible to count the direct EE savings measures but less certain how to account for "indirect" EE savings.

For California, CO2 emissions in the state from industry have been flat to slightly falling (4% drop from 2000-2008), and are projected to be flat to 2020 in CARB state projections. Industrial activity and GHG emissions are dominated by the oil and gas industry: extraction and refining account for about 60% of overall energy consumption despite dropping in state crude oil production, with natural gas and refinery gases the primary fuels. Oil extraction is highly energy intensive with thermally enhanced oil recovery (TEOR) recovery techniques commonly practiced in the state. The oil and gas industry also represents about half of the states industry CHP and consumes oil refinery gases and petroleum coke in addition to large quantities of natural gas.

However, both in-state oil and gas extraction has been decreasing in California and expected to continue to decrease. 87% of natural gas is imported today and is expected to continue dropping to 2050 (CPUC 2010), and in state crude oil production has been decreasing by about 2% annually over the last 20 years, while foreign crude oil has increased sharply (Figure S46).

[14] Greater on-site combined heat and power would reduce grid electricity demand. In the case of natural gas fueled CHP, offsite electricity is typically replaced with on-site power generation and waste heat utilization and much higher efficiency is achieved. On-site gas usage would increase but total system wide energy would decrease.



Source: Petroleum Industry Information Reporting Act

Figure S46. *Domestic (in-state) crude oil supply to California refineries has been shrinking over the last 30 years. (55).*

Non-oil and gas manufacturing sector fuel usage is less than a third of oil and gas fuel usage. Overall energy consumption for electricity represents about 28% of overall energy consumption.

Other large energy consuming industries include the food industry (spanning food, beverages, sugar refining and fruits and vegetables), chemicals, and glass and clay products. The food industry represents 7% of overall energy or 17% of non-petroleum industry energy. Cement manufacturing is also a significant contributor to manufacturing emissions although a smaller relative fraction of energy consumption.

6.2 Short Term Energy Savings

Short term energy savings are projected to 20-30% over the next 10 years depending on the application, mainly from operational practices and improved maintenance and without high capital expense or a significant amount of equipment replacement. An example is provided for the process heating segment in Table S7 (56). "Low hanging fruit" includes air/fuel optimization, wall heat insulation and advanced controls as well as incorporating other best operations and best maintenance practices. Further retrofitting work can be done such as the installation of advanced burners, and preheating of combustion air or incoming load to bring cumulative savings above 30%.

Similar short term energy savings can be realized in steam and motor systems from maintenance, operational measures, and control measures without major capital investment. For boiler use and steam systems there are opportunities on the distribution side such as thermal recapture at the backend of steam systems while maintenance items such as faulty valves, and system related problems can also yield large savings. For motor systems, an estimated 20% savings can come from routine maintenance while for applications with variable loads, larger savings (up to 50%) can be realized with the adoption of variable speed motor systems.

Measure	Individual savings	Cumulative savings
Air/fuel ratio optimization	5%	5%
Wall heat losses	2%	7%
Furnace heat transfer	5%	12%
Advanced burners/ controls	5%	16%
Preheat combustion air	15%	29%
Fluid or load preheating	5%	32%

Table S7. *Process heating savings measures that can be implemented in the short term.*

A sampling of other energy efficiency examples in industry is given here to illustrate the wide nature of applications and opportunities:

- Existing plants in the pulp and paper industry feature waste heat recapture (e.g. increased heat recovery of steam used to dry the paper with closed hood heat exchanger for water pre-heating or air pre-heating for a 15-20% increase in energy efficiency)
- Mechanical vapor recompression in chemical distillation processes that are in production can give coefficients of performance from 3-5 versus fossil fuel efficiency without recompression ~ 80%.
- Membrane separation for various chemical, petroleum and food processes move production from high temperature thermal distillation processes or boiling/evaporation to electricity pump-driven membrane separation systems. Efficiency gains of up to 40% can be realized. This technology is starting to be utilized but not yet in wide scale manufacturing.
- Solar thermal concentration systems for low pressure steam are utilized in the food/beverage industry, for example at a Frito Lay plant in Modesto. Issues here include cost, seasonal variation of solar irradiation, and the need for backup boilers.
- Further out, process intensification in the chemical industry can yield 50-80% savings for selected processes but this may be a decade or more before reaching commercial application. By combining the chemical reaction and separation in one reactor, capital costs are reduced and energy efficiency is improved through better integration of these process steps and more compact reactors (e.g. reactive distillation).

6.3 Industry Electrification

We assume that there is a shift to electrified process heating in 2020. This is an area where more technology development is needed; while unit processes exist for electric heating (microwave, plasma, RF, induction techniques), large scale electrification requires design and development of integrated electric heating systems tailored to the industrial application. While some development has occurred in the past, it is currently not area of focus for R&D and pilot programs or increased funding would be needed to enable this.

Some industry sectors may also be more amenable to electrified heating especially those with lower temperature heating and drying requirements We studied two large sectors in some detail (food and beverages, plastics and rubber) to try to validate the assumption of large scale electrification technical potential (57). For example, food and beverages utilize fairly low process temperatures (230C bread oven, 175C boiler system) and food processing fuel-fired heating should be electrifiable (drying in dairy industry, ovens in baking, snack food, and meat industries, frying in the poultry and snack food industries). Currently electric process heating is just 3.3% of food and beverage heating and electric steam systems and less than 1% of the market nationwide. In the plastic and rubber sector, process heating electrification potential is similarly large. Fuel based thermal drying at 80C is an opportunity for many products (butyl, polybutadiene, polyisoprene, synthetic EP rubber, dipped latex fabricated rubber, molded latex fabricated rubber). High fuel consumption for curing (150C) is another opportunity for electric replacement.

It is critical to note that in industry, "technical potential" in end use energy efficiency or primary energy use is often insufficient when deciding the desirability of a proposed change and that one must include a systems perspective that can include product quality issues, throughput, process interactions, and other factors. Metal slab heating for forging provides an illustrative example. Electrical induction heating has lower overall cost despite three times the capital cost and 30% higher energy cost due to material savings with high quality output (less wasted output) and lower operational and maintenance costs than typical fuel-fired slab furnaces (19).

6.4 Growth Rate Assumptions

For industry-manufacturing growth of fuel, we take industry sector GDP growth assumptions from the recent 2011 PIER study on energy efficiency technical potential for California (21). Industry GDP is projected to grow 1.5% annually to 2050. Frozen efficiency natural gas demand projections are shown in Table S8, with projected GDP growth rate per sector and energy demand per unit GDP frozen for each sector. Overall this "frozen" growth in energy is projected to be just over 0.6% per year. Thus there is almost a 1% annual drop in energy per GDP due to sector change. The sectors in Table S8 are listed in terms of energy intensity per GSP and the last column provides the rank of each sector according to annual growth rate. The most energy intensive sectors are seen to have generally slower growth rates (petroleum manufacturing, pulp and paper mills, glass manufacturing), while less energy intensive sectors have faster growth rates (plastics and rubber product manufacturing, chemical manufacturing, and electrical equipment, appliance, and component manufacturing). Thus the overall energy intensity in Energy/GDP is seen to drop over time due to this shift to less energy intensive manufacturing. For the purposes of ARB GHG state accounting, this is favorable but may in effect be shifting emissions or exporting emissions from in-state to out of state.

For industry-manufacturing electricity, the frozen annual growth rate in GWh/year is about 1.4% in California (Table S9). As energy intensive industries are shrinking, higher growth for electricity than fuel is expected.

Description	2006 GSP	2006 Gas Demand [MTh]	2006 Mth/ GSP	Projected GSP ann. growth	2050 Projected GSP	2050 Projected Gas demand [MTh]	Rank by annual growth
Petroleum and Coal Products	3110	571	0.184	0.50%	3873	711	12
Pulp, Paper, and Paperboard Mills	366	52	0.142	-0.27%	325	46	16
Glass	984	115	0.117	-1.55%	495	58	22
Textile Mills	562	55	0.099	-0.82%	392	39	21
Sugar and Confectionary Products; Fruit and Vegetable Processing	3201	265	0.083	-0.76%	2286	189	20
Primary Metal	2561	79	0.031	-0.43%	2116	65	17
Food and Beverage	15812	359	0.023	0.05%	16157	367	15
Nonmetallic Mineral Product (ex. Glass and Cement)	5055	114	0.022	0.93%	7594	171	9
Textile Product Mills	659	13	0.019	-0.61%	503	10	18
Cement	2462	45	0.018	1.92%	5679	105	4
Paper (excluding Mills)	2504	42	0.017	0.61%	3266	55	11
Fabricated Metal Product	10158	89	0.009	0.73%	13989	123	10
Plastics and Rubber Products	4826	35	0.007	3.82%	25117	182	1
Logging and Wood Product	2254	12	0.006	-0.68%	1671	9	19
Chemical	21097	100	0.005	3.04%	78691	373	2
Transportation Equipment	12208	48	0.004	1.30%	21537	84	8
Printing and Related Support Activities	4378	14	0.003	0.46%	5347	18	13
Machinery	8723	26	0.003	1.73%	18526	56	5
Furniture and Related Product	3121	8	0.002	-1.59%	1543	4	23
Miscellaneous	11061	21	0.002	0.24%	12298	24	14
Electrical Equipment, Appliance, and Component	3216	5	0.002	2.63%	10080	16	3
Semiconductor and Other Electronic Component	21935	27	0.001	1.58%	43776	53	6
Apparel and Leather Product	4712	5	0.001	-1.61%	2309	3	24
Computer and Electronic Product (ex. Semiconductors)	69249	38	0.001	1.58%	137834	76	7
Total	214212	2139			415402	2835	
2050/2006 ratio					1.94	1.33	
Annual growth rate					1.52%	0.64%	

Table S8. *Industry sector GSP growth rate assumptions and frozen natural gas consumption with constant energy/GSP by sector. Industry sectors are ordered by energy consumption per GSP in 2006 (21).*

Description	2006 GSP	2006 Electricity Demand [GWh]	2006 GWh/ GSP	Projected GSP ann. growth	2050 Projected GSP	2050 Projected Electricity demand [GWh]	Rank by annual growth
Pulp, Paper, and Paperboard Mills	366	986	2.69	-0.27%	325	875	16
Petroleum and Coal Products	3110	7119	2.29	0.50%	3873	8866	12
Glass	984	695	0.71	-1.55%	495	350	22
Cement	2462	1624	0.66	1.92%	5679	3747	4
Plastics and Rubber Products	4826	2216	0.46	3.82%	25117	11532	1
Sugar and Confectionary Products; Fruit and Vegetable Processing	3201	1419	0.44	-0.76%	2286	1013	20
Textile Mills	562	224	0.40	-0.82%	392	156	21
Paper (excluding Mills)	2504	901	0.36	0.61%	3266	1175	11
Primary Metal	2561	899	0.35	-0.43%	2116	743	17
Food and Beverage	15812	5337	0.34	0.05%	16157	5453	15
Logging and Wood Product	2254	644	0.29	-0.68%	1671	477	19
Fabricated Metal Product	10158	2664	0.26	0.73%	13989	3669	10
Nonmetallic Mineral Product (ex. Glass and Cement)	5055	996	0.20	0.93%	7594	1496	9
Printing and Related Support Activities	4378	832	0.19	0.46%	5347	1016	13
Textile Product Mills	659	124	0.19	-0.61%	503	95	18
Chemical	21097	3907	0.19	3.04%	78691	14573	2
Transportation Equipment	12208	2231	0.18	1.30%	21537	3936	8
Machinery	8723	1387	0.16	1.73%	18526	2946	5
Electrical Equipment, Appliance, and Component	3216	487	0.15	2.63%	10080	1527	3
Furniture and Related Product	3121	432	0.14	-1.59%	1543	214	23
Semiconductor and Other Electronic Component	21935	2872	0.13	1.58%	43776	5732	6
Miscellaneous	11061	1012	0.09	0.24%	12298	1125	14
Apparel and Leather Product	4712	369	0.08	-1.61%	2309	181	24
Computer and Electronic Product (ex. Semiconductors)	69249	3702	0.05	1.58%	137834	7368	7
Total	214212	43079	0.20	1.52%	415402	78265	
2050/2006 ratio					**1.94**	**1.82**	
Annual growth rate					**1.52%**	**1.37%**	

Table S9. *Industry sector GSP growth rate assumptions and frozen end use electricity demand with constant energy/GSP by sector. Industry sectors are ordered by energy consumption per GSP in 2006 (Masanet 21).*

6.5 Analytical Approach and Results

Our analytical approach is as follows. We track the following three categories of energy consumption: industry electricity consumption, oil and gas industry fuel consumption, and non-oil and gas industry fuel consumption and use the growth rates as above for the frozen efficiency case. We adopt technical potential energy efficiency savings based on the PIER 2011 report on Long Term Energy Efficiency in California. This study projects about 28% savings from frozen efficiency in electricity in 2050 and about 44% in natural gas savings. Note that although this PIER study is limited to natural gas demand in the manufacturing sector only and thus represents only about 30% of overall fuel energy use, we still utilize this study as a benchmark for potential overall fuel savings.

We further assume that much higher levels of vehicle electrification and bio fuel production will sharply reduce the demand for in-state petroleum-based liquid fuels. Our scenarios assume a reduction in oil/gas extraction and refining activities by the same fraction that in-state fuel demand is displaced by vehicle electrification and bio fuel production, with no spillage from in-state gasoline production to out of state since we assume the world is sharply decarbonizing at the same time as California. In 2050 we project that 65% of the reference case oil and gas industry is replaced by electric vehicles and in-state or out of state bio-fuel supply consistent with the case of base case biomass supply availability. From the Biomass chapter, we assume that 2.8 billion gallons of gasoline-equivalent (Bgge) of bio fuels is produced in state for the base case. In the case of high biomass availability (7.5Bgge of biofuels produced in state), we project that 80% of the oil and gas industry is replaced.

From two biomass references (58,59) we assume the electricity generation requirements for a billion gge to be 13 TBtu currently improving to 9.4 TBtu per billion gge assuming 28% industry efficiency gains as above. For SWITCH electricity sector modeling, we include the electricity requirement for biofuels to comprehend the electricity impact of biorefineries. However, we do not account for additional fuel energy demand in other industry sectors in the production of biofuels and GHG emissions are accounted for by using a life-cycle analysis multiplier for biofuel emissions.

Finally after applying technical potential energy efficiency savings and reduction in oil and gas industry, we consider the electrification potential of remaining industry heat processes. Assuming 50% penetration of process heating starting in 2020, about 39% of industry fuel demand is projected to be electrified by 2050 in the base case with average savings of 50% in end use energy for electrified processes (20). This includes electrification of low and medium temperatures as well as utilization of heat pump technology but excludes high temperature thermal processing. In the high electrification case, about 53% of industry fuel demand is projected to be electrified by 2050 assuming a 75% electrification penetration of process heating starting in 2020.

In the base case this results in approximately the same electricity demand as the frozen case in 2050, or a near doubling of demand in 2050 from present levels from 47,000 GWh to 92,000 GWh. Of this, about 33,000 GWh is due to increased demand from industry electrification. Overall fuel reduction of 73% is achieved compared to the frozen case. Industry energy projections are shown for the reference case, technical potential efficiency case, and base case (energy efficiency plus electrification of process heating) in Figures S47 to S49.

Industry electricity demand is shown in Figure S50. The reference case increases by 1.4% a year to 81,000 GWh in 2050. Technical potential efficiency achieves 28% savings to 58,000 GWh. Fuel switching and additional demand from biorefinery production starts to ramp up in 2020 and adds about 33,000 GWh by 2050. This results in overall industry demand in the base case of 92,000 GWh or 13% higher than the reference case.

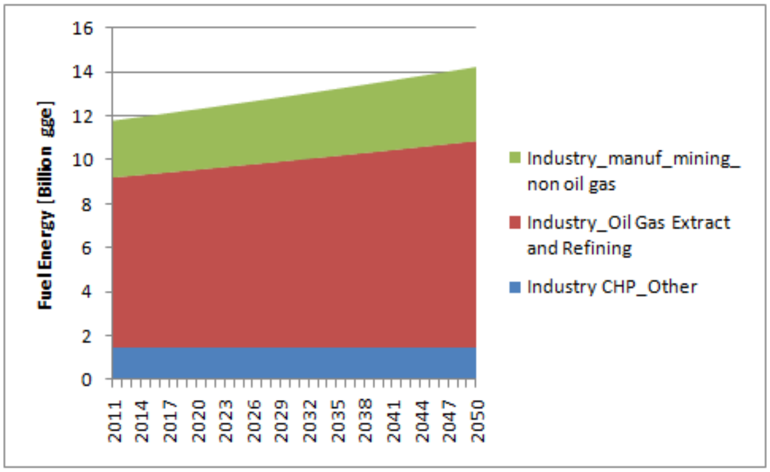


Figure S47. *Reference case (frozen energy efficiency) industry fuel demand split out into three sectors: non-oil and gas manufacturing and mining, oil and gas extraction and refining, and industry CHP and other.*

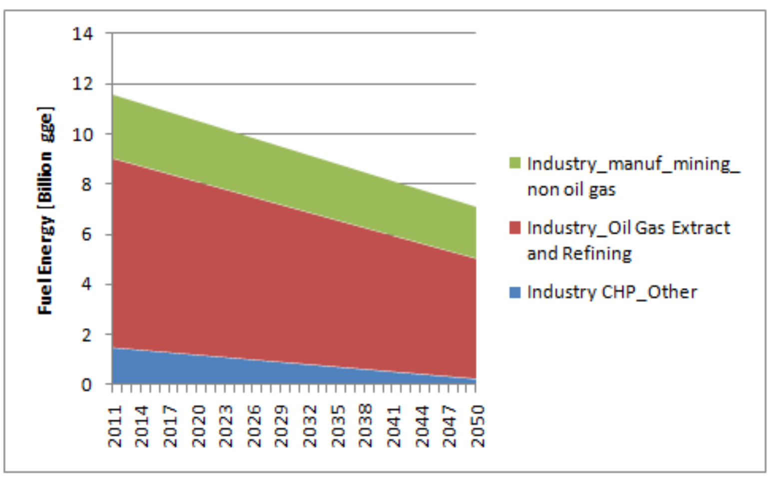


Figure S48. *Industry fuel demand with technical potential energy efficiency.*

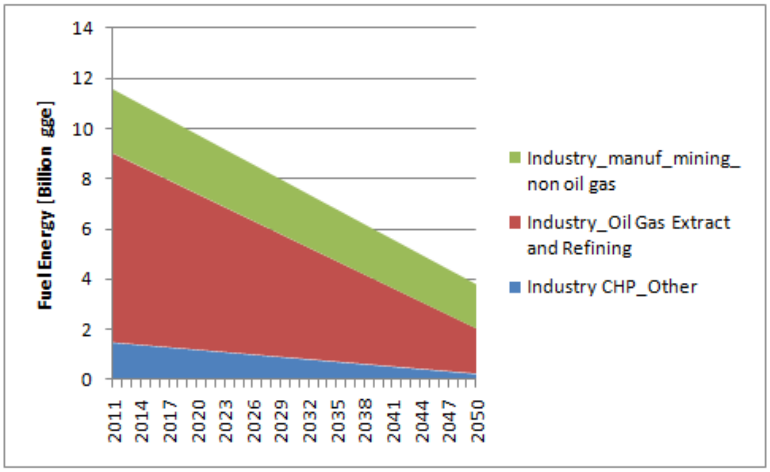


Figure S49. *Base case industry fuel demand (energy efficiency and electrification)*

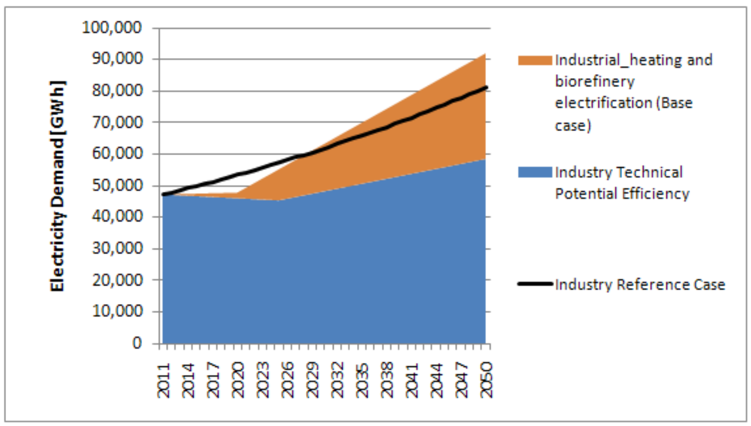


Figure S50. *Industry reference case electricity demand projection, technical potential efficiency, and technical potential efficiency with industry heating and biorefinery demand (base case).*

California industry electrification is utilized as a rough proxy for other regions in the West. We assume that industry electrification is delayed by 10 years for the rest of the WECC compared to California, starting in 2030, and take the incremental industry electrification demand increase in California in 2040 as a proxy for the rest of WECC in 2050 since it is assumed that California starts 10 years earlier in electrification. Based on relative regional growth rates differences in AEO2010, we take the Rocky Mountain and Pacific Northwest regional frozen growth rates to be higher at 1.6% and 1.8%, respectively. Industry growth rates in British Columbia and Alberta are based on 2007-2009 provincial utility projections. They average to be 2.6% annually to 2050 with a large contribution from the burgeoning mining, oil, and gas industry in Alberta. This may be an overly aggressive number for Canada in light of the recent recession of 2008-2009, but no further updated data projections were found.

Not treated under this framework is industry combined heat and power (CHP) and wastewater. We do not specifically treat CHP as a growing application area over time, since current CHP systems are largely natural gas and our general theme is to minimize fossil fuel use overall over time.

Industry growth is highly dependent on sectoral shifts and growth rates. It is possible that sectoral shifts could be significantly different from the projections taken here. New industries or new sources of industrial demand could potentially emerge increasing energy demand. In particular, interactions between supply and demand in electricity/transportation/buildings/agriculture are not comprehended in this study. For example our industry projections are "static" in the sense that a dramatic build out of renewable energy or electric vehicle purchasing and infrastructure does not have any feedback to industrial activity.

As noted above, we also do not include integrated design improvements or novel materials or other technology breakthroughs.

7. TREATMENT OF REST OF WECC AND OVERALL ELECTRICITY DEMAND

WECC regional electricity demands were disaggregated into four large sub-regions plus a small portion of Mexico for the analysis (Figure S51). The large sub-regions are: "CAN" (British Columbia and Alberta), "NW" (states in the Northwest), "CA" (California), and "RA" (Colorado, New Mexico, Arizona, and Southern Nevada). The Mexico region is relatively tiny portion of overall demand, and we assume baseline growth there throughout this work (1.5% annual growth in demand).

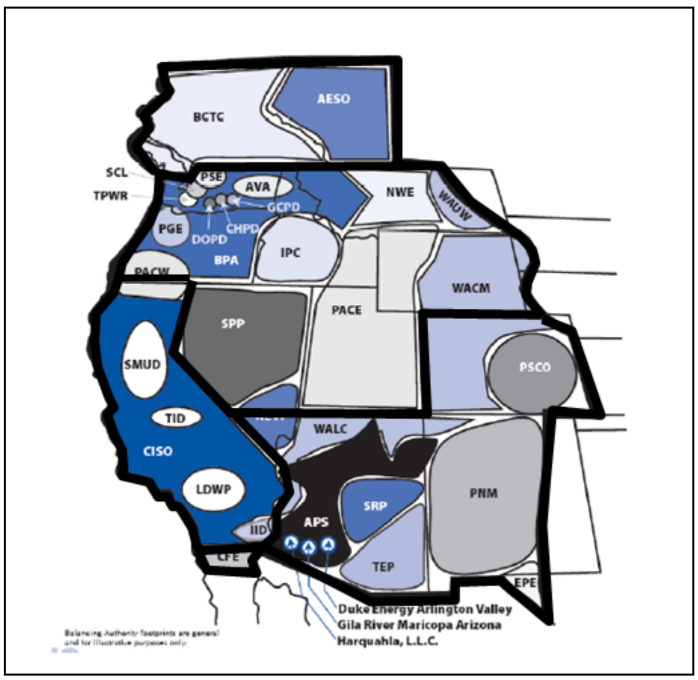


Figure S51. *Disaggregation of WECC Region into four sub-regions from top: "CAN" (Canada), "NW" (Northwest states), "CA" (California) and "RA" (Colorado, New Mexico, Arizona and S. Nevada.)*

We first describe baseline demand projections and then the technical potential efficiency and electrification scenarios.

Our general approach for modeling the rest of the WECC regions is to follow California demands as a proxy for the rest of the WECC (ROW). For the purposes of this study, we had access to a rich data set for California across the major sectors studied (buildings, industry, and transportation) and used this to generate "bottom up" electricity demands. However this type of data was not readily available for the ROW nor was it within the scope of the study to do similarly detailed ROW demand projections. As a simplification we assumed that the ROW would achieve same level of energy efficiency savings in all sectors, but that electrification of transport and building and industry heating is delayed by 10 years (Table S10). In other words if California EV sales start to surge in 2020, the ROW has the same sales adoption curves but pushed to 2030. Similarly, 2040 California incremental demands were used an approximate proxy for 2050 ROW in terms of degree of electrification and production of bio fuels. High level consistency checks were done in terms of overall starting electrification by WECC region and climate zone impacts to the degree of building and industry electrification. For example we examined what percentage of space and water heating is already electrified in the ROW and to what degree demand would be increased or decreased due to climate differences.

Region	End use	Start	Full adoption
California	Space heating	2015	2025
California	Water heating	2015	2025
California	Boilers	2025	2035
ROW	Space heating	2025	2035
ROW	Water heating	2025	2035
ROW	Boilers	2035	2045

Table S10. *Adoption assumptions of baseline case electrified building heating for CA and ROW.*

This approach oversimplifies the building, industry, and transportation details in the ROW, but still extends the modeling framework for California's electricity system to a more realistic framework beyond what has been done in the past. A detailed accounting of each WECC region's electricity demand in similar detail to California was not within the scope of this work and is an area for more detailed study in the future.

7.1 WECC electricity demand projections

Reference case demand projections for U.S regions in the WECC are based on AEO projections and are extrapolated to 2050. Our convention is that reference case demand is "frozen efficiency" demand, which is consistent with many climate studies and also consistent with the treatment of energy efficiency in the building and industry sectors.

We use the AEO 2011 (60) values as stating points and a synthesis of growth rates based on AEO and other sources for the frozen efficiency growth rates. We take the 2010 AEO growth rates for residential and commercial buildings since 2011 AEO growth rates are slightly lower based on future efficiency improvements in the residential sector (one round of energy efficiency standards are included). Similarly in industry, we take the 2010 AEO growth rates since an increased penetration of CHP is assumed in the 2011 projections. Furthermore, industry is expected to have greater self- generated or "autonomous" efficiency savings than the residential and commercial sectors and thus frozen efficiency is taken to be about 0.8% higher than AEO estimates, e.g. from 0.6% in California to 1.4%. These growth rates are then applied to each sector's starting demand estimate in 2011 to generate annual demands to 2050.

Region	Residential	Commercial/Other	Industrial
CA	0.7%	1.4%	1.4%
NW	0.9%	1.6%	1.6%
RA	1.2%	2%	1.8%
CAN	1.6%	2.2%	2.6%

Table S11. *Reference Case electricity growth rate assumptions by sector for the four WECC regions.*

Canada estimates were taken from the two recent utility studies (37,38). Canada growth rates are largely driven by high demand projections in Alberta and for the oil and gas industry in particular, but these estimates may be on the high side. Canada was not hit as hard by the 2008-2009 recession and their growth rates are high compared to the U.S. regions.

Energy efficiency technical potential savings (TP) for are based on a PIER study on California energy efficiency savings that are described in the building and industry chapters (21). Agriculture/Other energy consumption savings are assumed to be same as Industry savings. Similar levels of technical potential savings are assumed for the rest of the major WECC regions.

After TP demand is computed, we add electrification demand from vehicle electrification and electrification of building heat and industrial heat. Transportation, building, and industry assumptions are discussed above. Figures S52 and S53 show California and the ROW electricity demand projection to 2050 and Figure S54 shows the total for the entire WECC. Curves shown include the reference frozen efficiency case, demand after technical potential energy efficiency savings and demand after TP savings and vehicle and heating electrification (base case).

Both California and the ROW building heating electrification scenario assume marginal penetration of heat pump based space heating and water heating with a ten year phase in starting in 2015 to full penetration by 2025 at the margin and for new construction for California and starting in 2025 for the ROW. Boiler system penetration starts in 2025 in California and 2035 in Canada (Table S10).

California is seen to represent about a third of overall WECC demand, and post electrification demand in 2050 is about 70% greater than electricity demand in 2011 and about 7% higher than the frozen efficiency case. For the WECC overall, demand is seen to remain flat to about 2025 and then sharply increase thereafter due to increased electrification demand from buildings, industry, and transportation. With the energy efficiency plus electrification scenario one sees that the overall demand is very close to the projected frozen efficiency demand or about 70% higher than 2011 demand.

Electricity demand for the case of high electrification of vehicles and industry heat in shown in Figures S55-S57. For the case of California, electricity demand nearly doubles in 2050 from 2011 to 484,000 GWh, or about 22% higher than the frozen efficiency demand.

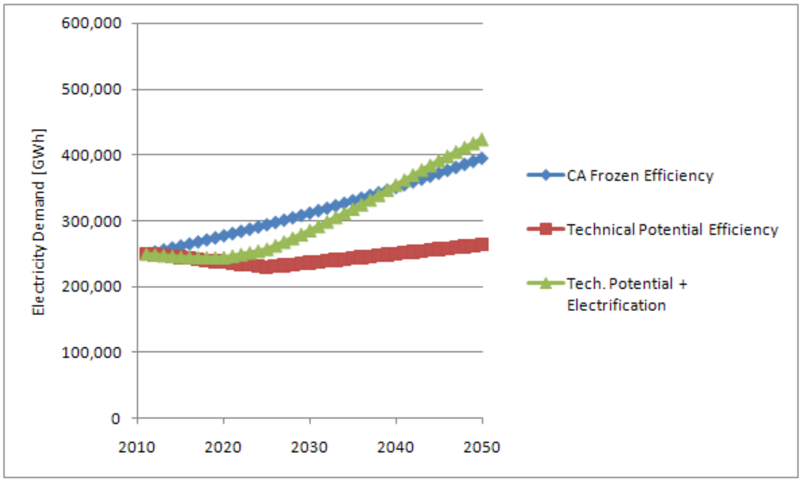


Figure S52. *California electricity demand showing frozen demand, demand after Technical potential efficiency improvements, and with electrification of building and industry heating (base case). Overall demand increases by about 70% from 2011.*

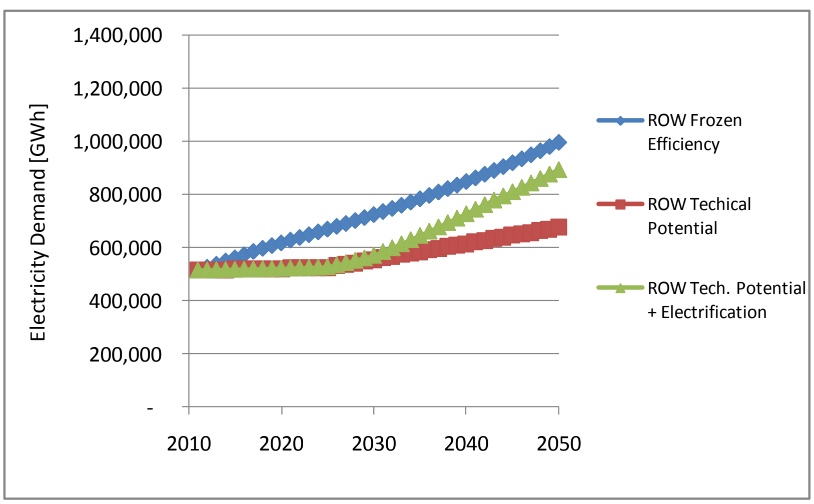


Figure S53. *Rest of WECC (ROW) electricity demand showing frozen demand, demand after Technical potential efficiency improvements, and with electrification of building and industry heating.*

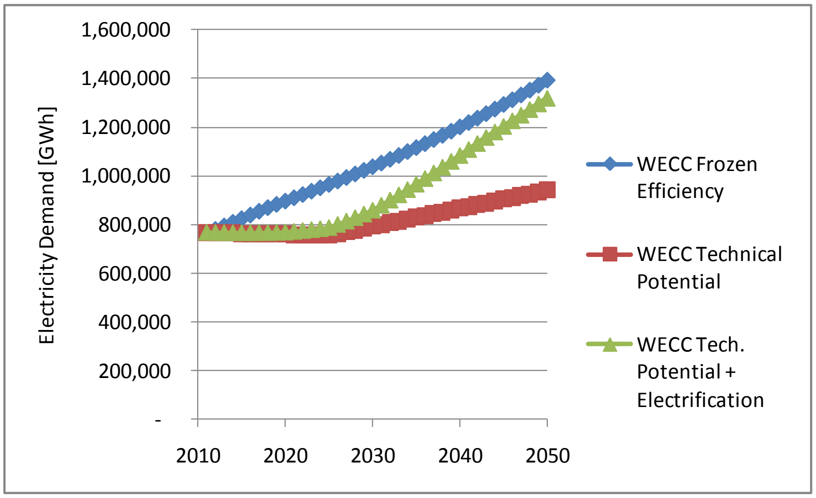


Figure S54. *Total WECC demand projection to 2050 showing frozen demand, demand after Technical potential efficiency improvements, and with electrification of building and industry heating.*

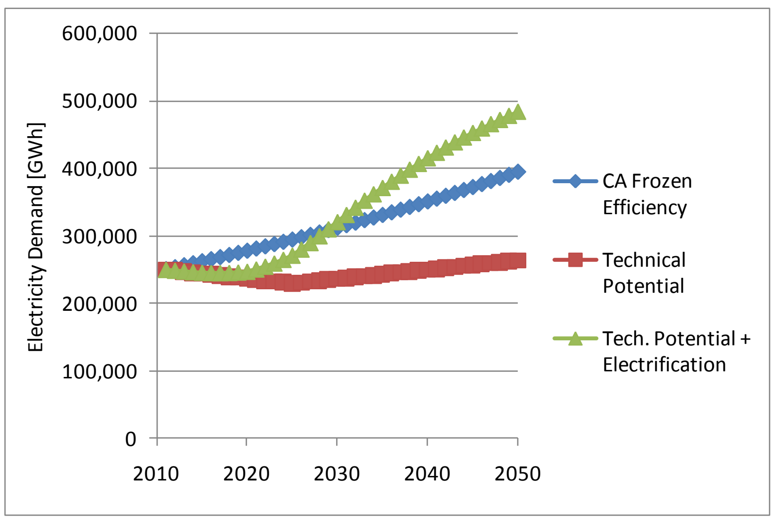


Figure S55. *California electricity demand showing frozen demand, demand after technical potential efficiency improvements, and with high electrification of transportation and industry eating. Overall demand is nearly doubled from 2011.*

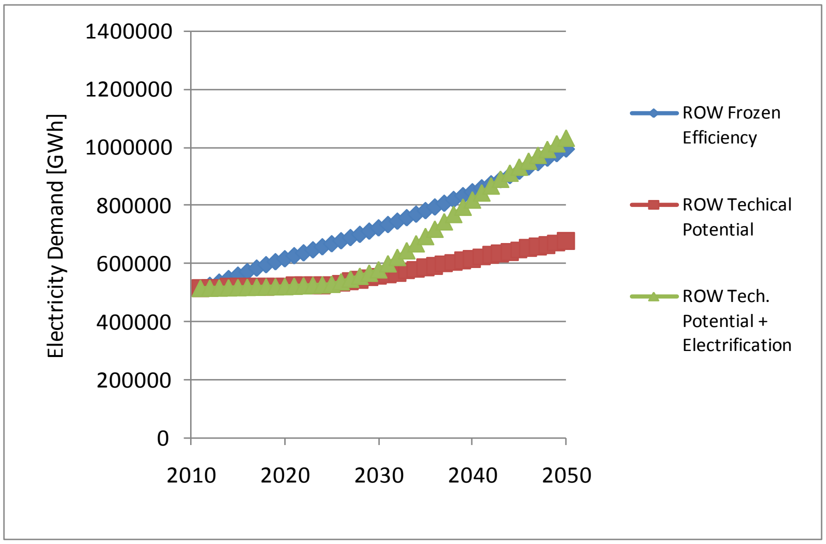


Figure S56. *Total WECC demand projection to 2050 showing frozen demand, demand after Technical potential efficiency improvements, and with high electrification of transportation and industry heating.*

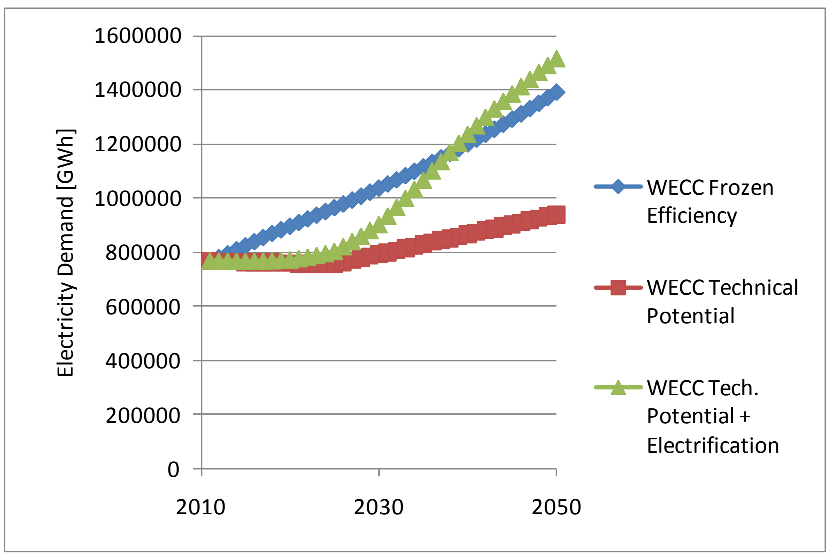


Figure S57. *Total WECC demand projection to 2050 showing frozen demand, demand after Technical potential efficiency improvements, and with high electrification of transportation and industry heating.*

8. ELECTRICITY SUPPLY MODELING RESULTS

8.1 Introduction

SWITCH (Figure S58) is a capacity-expansion and dispatch model of the electric power sector. In this study, SWITCH is used to model the entire geographic extent of the Western Electricity Coordinating Council (WECC). The model is a mixed-integer linear program whose objective function is to minimize the cost of delivering electricity from present day until 2050 with generation, transmission, and storage subject to policy, carbon emission, resource availability, and generator output constraints. SWITCH is well suited to project the optimal deployment of a low-carbon WECC power system as it models a large geographic region in detail at a high temporal resolution. It was created at the University of California, Berkeley by Dr. Matthias Fripp. The version of SWITCH used in this study is maintained and developed by Ph.D. students James Nelson, Ana Mileva, and Josiah Johnston in Professor Daniel Kammen's Renewable and Appropriate Energy Laboratory.

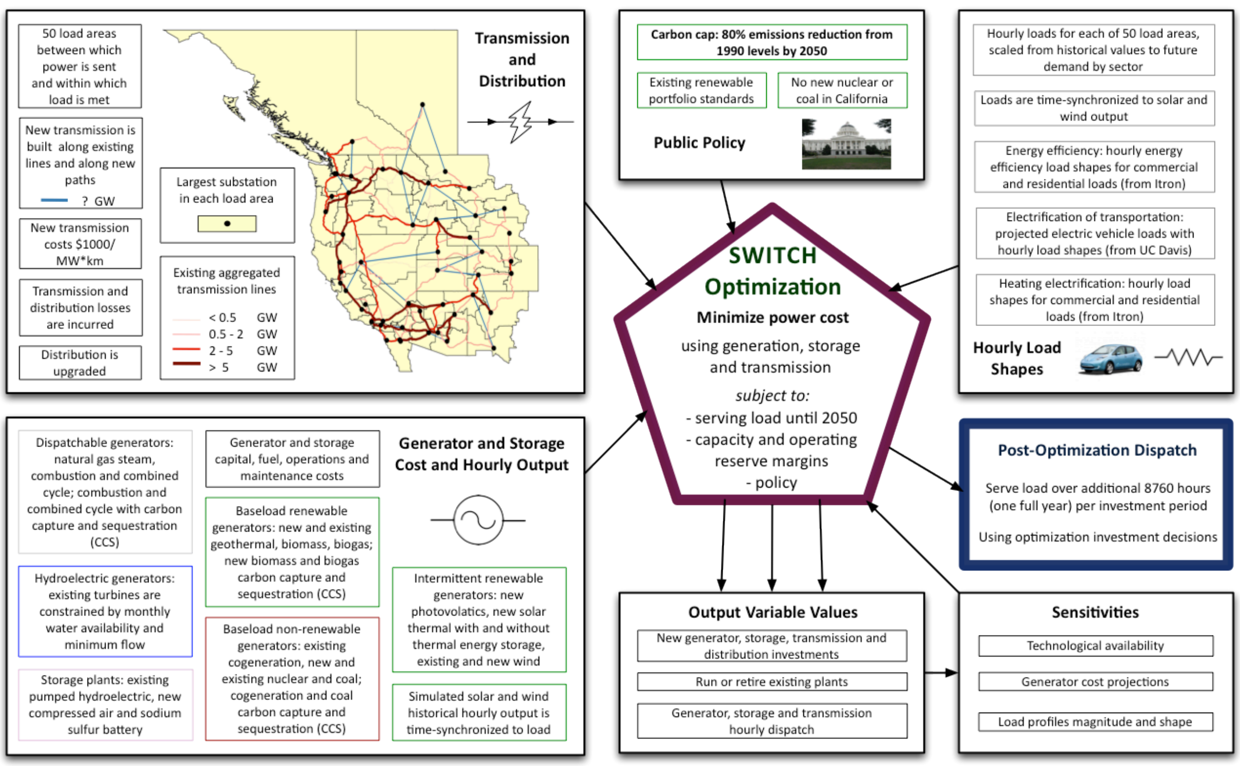


Figure S58: *Diagram of data inputs, optimization, and outputs of the SWITCH model.*

It is likely that future low-carbon electricity systems will rely on renewable generation sources such as solar and wind. However, the intermittency of solar and wind generation poses challenges for power grids in which a large fraction of power originates from these sources. Many capacity expansion models of the electricity grid encounter difficulties with the spatially and temporally complex nature of intermittent resources relative to conventional generators. To address these issues, SWITCH uses time-synchronized hourly load and renewable generation profiles in a capacity expansion model. SWITCH determines the contribution of baseload, dispatchable and intermittent generation options alongside storage and transmission capacity on a least-cost basis while ensuring that projected electricity load is met reliably subject to policy constraints. The model concurrently optimizes investment in and dispatch of power system infrastructure, an approach that allows for proper valuation of intermittent renewable capacity at varying levels of intermittent penetration.

While this study focuses on the state of California, it is important to consider regions outside California with respect to future electricity production. California currently makes up approximately one third of electricity load in the Western North American electric power interconnect, the area coordinated by the Western Electricity Coordinating Council (WECC). WECC is depicted in Figure S59. California currently imports hydroelectric power from the Pacific Northwest, and coal and nuclear power from the Desert Southwest. These imports may be subject to change in the 2050 timeframe, and it is therefore essential to explicitly model all of WECC in an integrated framework in order to account for interactions between California and the rest of the region.

In the version of SWITCH used in this study, WECC is divided into 50 'load areas,' within which power is generated and stored, and between which power is transmitted. Twelve of these 50 load areas are in California. Load areas represent nodes of electricity demand within WECC. In addition, load areas correspond to parts of the existing electric power system within which there is significant transmission and distribution infrastructure, but between which limited long-range, high-voltage transmission currently exists. Consequently, load areas are regions between which new transmission may be needed.

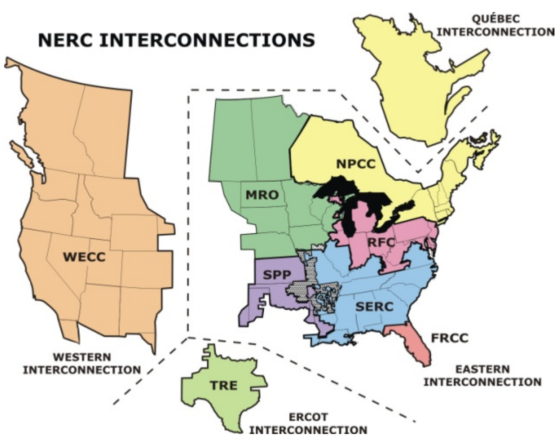


Figure S59: *North American Electricity Reliability Corporation (NERC) interconnections. Dashed lines represent divisions between wide area synchronous electric grids. The version of the SWITCH model used in this study encompasses the entirety of WECC, but does not include trading with other interconnects. Little power is currently transmitted between WECC and the other two North American interconnects. Figure reproduced from* http://www.nerc.com/page.php?cid=1%7C9%7C119.

In the model, four 'investment periods,' each ten years in length, span the time between the present day and 2050. The first of these investment periods represents 2015-2025 and the last represents 2045-2055. At the start of each investment period, SWITCH chooses which generation, storage and transmission projects to build. All investment periods are optimized simultaneously, so projects installation decisions in earlier investment periods affect decisions made in later periods, and vice versa. SWITCH is well suited to investigate a gradually decreasing cap on carbon emissions as near-term investments will be consistent with long-term emissions constraints.

SWITCH operates existing power system infrastructure and can build new generation, transmission and storage capacity in order to meet load cost-effectively. Each optimization is given the option to build over 7500 generation projects, 200 storage projects, and 100 transmission projects in each investment period. Installable generation and storage projects are shown in Figure S60 below. Existing power plants are operated individually and non-hydroelectric plants can be retired before the end of their projected operational lifetime. If not retired earlier for economic reasons, non-hydroelectric plants must retire at the end of their operation lifetime. Hydroelectric and pumped hydroelectric generators run indefinitely into the future, incurring concomitant operation and maintenance costs.

SWITCH makes power system investment and dispatch decisions simultaneously, thereby evaluating the present and future value of infrastructure investments within the context of their hourly value to the electric power system. Within each investment period modeled in this study, the available infrastructure (as determined by the investment decisions) is dispatched over 144 'study hours.' Study hours represent conditions from the middle of each investment period, so subsequent results will show the 2045-2055 investment period as '2050' for simplicity. Study hours are chosen such that the peak and median load days from each month are input to the optimization. Each of these days includes six hours, evenly spaced throughout the day at four hour intervals (12 months per investment period * 2 days per month * 6 hours per day = 144 hours per investment period). For each study hour and each load area, the model is constrained to meet projected hourly system load as well as a capacity reserve margin of 15% above load. Unlike operating reserves (spinning and quickstart reserves), the capacity reserve margin includes contribution from plants that are not required to have quickstart capability or to be online.

In all SWITCH scenarios presented here, operating reserve requirements similar to rules evaluated in the Western Wind and Solar Integration Study (28) are included. The study found that holding an amount of spinning reserves equal to 3% of load and 5% of intermittent generation was generally conservative and resulted in sufficient amount of reserves over large balancing areas. SWITCH employs similar balancing areas: California, Pacific Northwest, Rocky Mountains, Southwest, Western Canada, Baja Mexico. In each of the six SWITCH balancing areas, in each study hour, the model is constrained to keep an amount of both spinning and non-spinning reserve greater than or equal to 3% of load and 5% of intermittent renewable generation. Dispatchable natural gas, hydroelectric, and storage plants can provide operating reserves in the version of SWITCH used in this study. Operating reserves from demand-side flexibility have not yet been included.

Four different categories of generators are operated: baseload, intermittent, dispatchable and hydroelectric. Baseload generators (coal, biomass, biogas, geothermal, nuclear, cogenerators) are operated at the same level of output in every study hour. Intermittent generators (solar, wind) produce power corresponding to their hourly capacity factor in each study hour. Dispatchable generators (non-cogeneration natural gas and hydroelectric) can vary their level of energy output as a function of installed capacity and, for hydroelectric, the water availability conditions in each study hour. Dispatchable generators can also adjust how much capacity to keep in both spinning and non-spinning reserve within each study hour. Hydroelectric generators can vary hourly output subject to average historic generation and minimum flow requirements. Storage projects (compressed air, pumped hydroelectric, sodium sulfur battery) are similar to dispatchable generators, but are also subject to an energy balancing constraint within each day.

Generator capital cost projections are among the most important drivers of capacity expansion models because of their large contribution to the total cost of energy. Default generator and storage project overnight capital cost assumptions are shown in Figure S60. In SWITCH, learning and economies of scale from generator installation are modeled as an exponentially decreasing function over time. No generation technology is modeled as having increasing capital costs over time, though nuclear capital costs are assumed to stay constant. In the default cost assumptions, the capital cost of photovoltaics decreases fastest among technologies, at a rate of 4-5% per year, reflecting their large cost-reduction potential, a history of large cost decrease, and projected large-scale installation worldwide. Overnight capital costs are derived primarily from the California Energy Commission Cost of Generation Model (62) and the United States Energy Information Agency Updated Capital Cost Estimates for Electricity Generation Plants (47).

Fuel costs are another large cost in capacity expansion models. Natural gas and coal fuel costs are extrapolated to 2050 from the Reference Case of the United States Energy Information Agency's National Energy Modeling System (NEMS) Annual Energy Outlook (60). In California, natural gas and coal costs reach $9.27/MMBtu and $2.18/MMBtu in $2007 by 2050, respectively. Biomass fuel costs are included through a supply curve in each load area, as shown in Appendix 1, Table 1. Uranium cost projections are taken from California Energy Commission's 2007 Cost of Generation Model (64) and reach $2.16/MMBtu in $2007 by 2050.

Existing power transfer capacity between load areas is included, and new transmission capacity can be added at a cost of $1000/MW-km. New capacity is added along existing rights-of-way where possible, and incurs an additional $500/MW-km for creating new rights of way. Transmission between load areas is represented using a transportation network model and transmission lines are constrained to not exceed thermal limits. It should be noted that the current version of SWITCH does not include load flow transmission constraints, i.e. it does not strictly obey Kirchhoff's laws nor does it include stability limits for very long AC transmission lines. Similar transportation network models have been used successfully to plan power system capacity expansion, but future work will investigate SWITCH investment plans under more stringent load flow constraints.

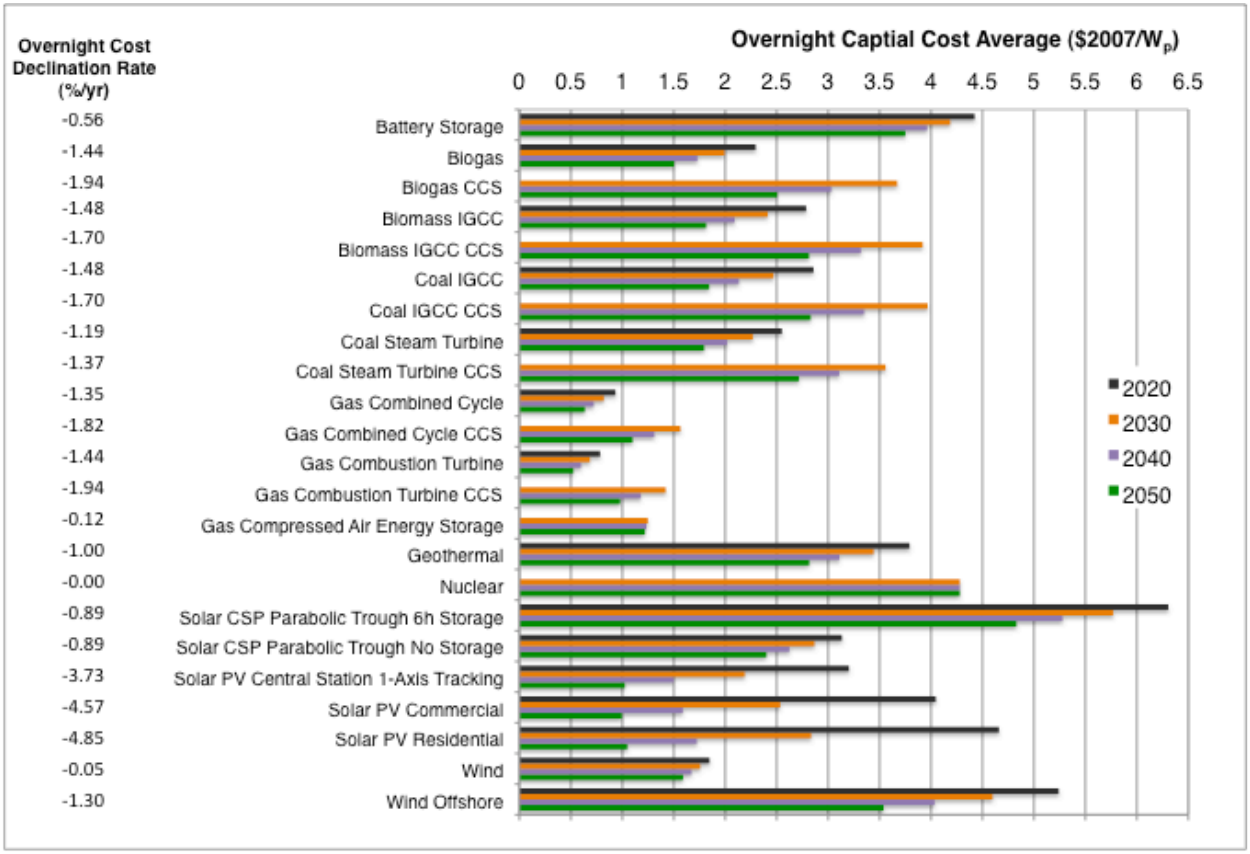


Figure S60: *Average generator and storage overnight capital costs in each investment period. Plants not eligible for construction in the 2020 investment period are excluded from this chart. The costs shown do not include expenses related to project development such as interest during construction, connection costs to the grid and upgrades to the local grid, though these costs are included in the optimization. In addition, costs incurred after construction such as fuel costs as well as operation and maintenance costs are input to each optimization but are not included here.*

8.2 Base Case Scenario Description

In this study, the SWITCH model is used to demonstrate a range of scenarios in which the electric power sector of Western North America (WECC) reaches deep carbon emission reduction targets by 2050. In the Base Case scenario, the optimal SWITCH power system is constrained to meet a target of 80% below 1990 CO_2 emission levels across all of WECC. This 80% reduction is consistent with economy-wide California emission targets, requiring the electric power sector to contribute to emission reductions in the same proportion as the rest of the economy.

In the Base Case scenario as well as all other scenarios investigated here, existing state-based renewable portfolio standard (RPS) targets are met in future years. In the model, RPS targets are met with renewable power produced locally or delivered via transmission lines – ‘unbundling’ of power produced from renewable energy credit is not allowed. In future years for which RPS targets are not explicitly specified, we assume a target equal to that in the latest year for which a target was specified. Renewable tax credits are not considered as their existence far into the future is uncertain. The California Solar Initiative is not currently modeled by SWITCH, but will be included in the future.

Generator capital costs in the Base Case scenario are as discussed in the previous section, but sensitivities of the optimal power system to variations in these costs are explored below.

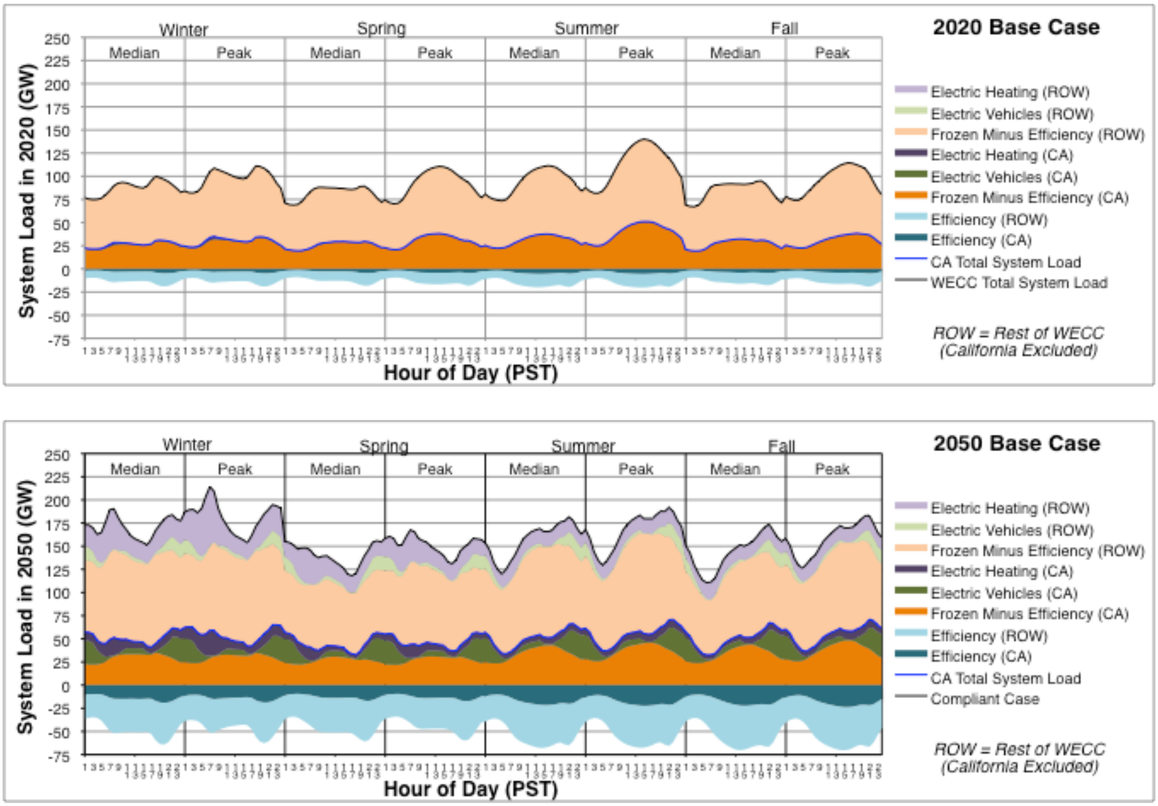


Figure S61*: Hourly load profiles by load type for the Base Case load profile in 2020 and 2050. For each season, the day with the peak load hour and the day with the median load are shown. 24 hours of data per day are plotted. Vertical gray lines divide distinct days. 'Frozen Minus Efficiency' represents the load profile after efficiency measures have been taken. 'Efficiency' is depicted here as negative load, representing the difference between the frozen efficiency load profile and the same load profile including energy efficiency reductions.*

Load profiles used in this study are derived from the Federal Energy Regulatory Commission's (FERC) Form 714 hourly load data reported by load-serving entities for the historical year 2006 (Federal Energy Regulatory Commission 2006). These profiles are allocated to the 50 SWITCH load areas and then scaled according to load projections. Hourly profiles for energy efficiency, vehicle electrification, and heating electrification are then added to the base load profile to obtain a full year of hourly load forecasts (8760 hours) for all 50 load areas. The Base Case scenario load profile includes substantial vehicle and heating electrification as well as aggressive energy efficiency measures. As a result, the WECC-wide 2050 load shape is transformed: instead of a load profile with a late-afternoon summer peak as in present day, in 2050, load peaks on winter nights as shown in Figure S61. California remains a summer-peaking system, but with the peak shifted to the late evening by electric vehicle load. The version of SWITCH presented here treats load as fixed and therefore does not allow load participation in the balancing of electricity supply and demand.

8.3 Base Case Scenario Results

The electric power system in the Base Case scenario changes dramatically between present day and 2050 (Figure S62) in order to adapt to changes in load profile resulting from efficiency, vehicle electrification, and heating electrification, as well as an ever more stringent constraint on carbon emissions.

As simulated in SWITCH, the present day (2011) electric power system is dominated by coal, natural gas, and hydroelectric generation, representing 29%, 24% and 31% of WECC-wide generation respectively. Nuclear, geothermal and wind make up the balance of generation. California relies heavily on imports, comprising 42% of its total power (Table S12). This level of imported power is high relative to recent reports that estimate imports to be roughly 1/3 of all California power (CEC 2007). As SWITCH does not honor current power purchase agreements between generators and utilities, this is likely due to unrealistically quick reorganization of power transfers within WECC. Projections into the future, especially in the 2050 timeframe, will have less of this discrepancy, as power contracts are generally on much shorter timescales. However, it should be noted that even without the explicit simulation of power purchase agreements, SWITCH qualitatively simulates present day power system dynamics correctly, with California importing a large fraction of its load from coal and nuclear power in the Southwest and hydroelectric power in the Pacific Northwest.

Wind, geothermal and biogas generation are added by 2020 to meet RPS demand for renewable power (Figure S62A and S62C), as well as to decrease the carbon intensity of power generation back to 1990 levels by 2020 as required by the carbon cap constraint. As is the case in the present day WECC power system, hydroelectric generation dominates in the Pacific Northwest and is transmitted to California (Figure S63). Coal generation dominates in the Rocky Mountains and Desert Southwest, with much coal electricity shipped to California. In the 2020 Base Case scenario, California relies heavily on out-of-state power imports (Table S12): in-state generation accounts for only 17% of WECC-wide generation while California accounts for 32% of WECC-wide load in 2020. Solar generation does not appear in the optimal 2020 generation portfolio as its high costs preclude installation. Future inclusion of the California Solar Initiative policy in the SWITCH model will bring solar into the generation mix before 2020 and likely reduce imports from out of state.

Investment Period	CA Average Net Transmission Imports [GW]	CA Average In-State Generation [GW]	CA Average Load [GW]	CA Import Percentage [%]
2011	12.7	17.8	28.3	42%
2020	13.7	16.2	27.9	46%
2030	16.1	17.9	31.8	47%
2040	14.6	27.6	39.5	35%
2050	18.7	31.9	46.8	37%

Table S12*: Average California power imports by investment period in the Base Case scenario. The 'Import Percentage' denotes the fraction of total power available to meet load that comes from imports, i.e. the net transmission imports into California divided by the sum of net transmission imports into California and total generator output within California. The difference between the total power available to meet load and the system load represents losses within the system from transmission, storage, distribution and spilling power.*

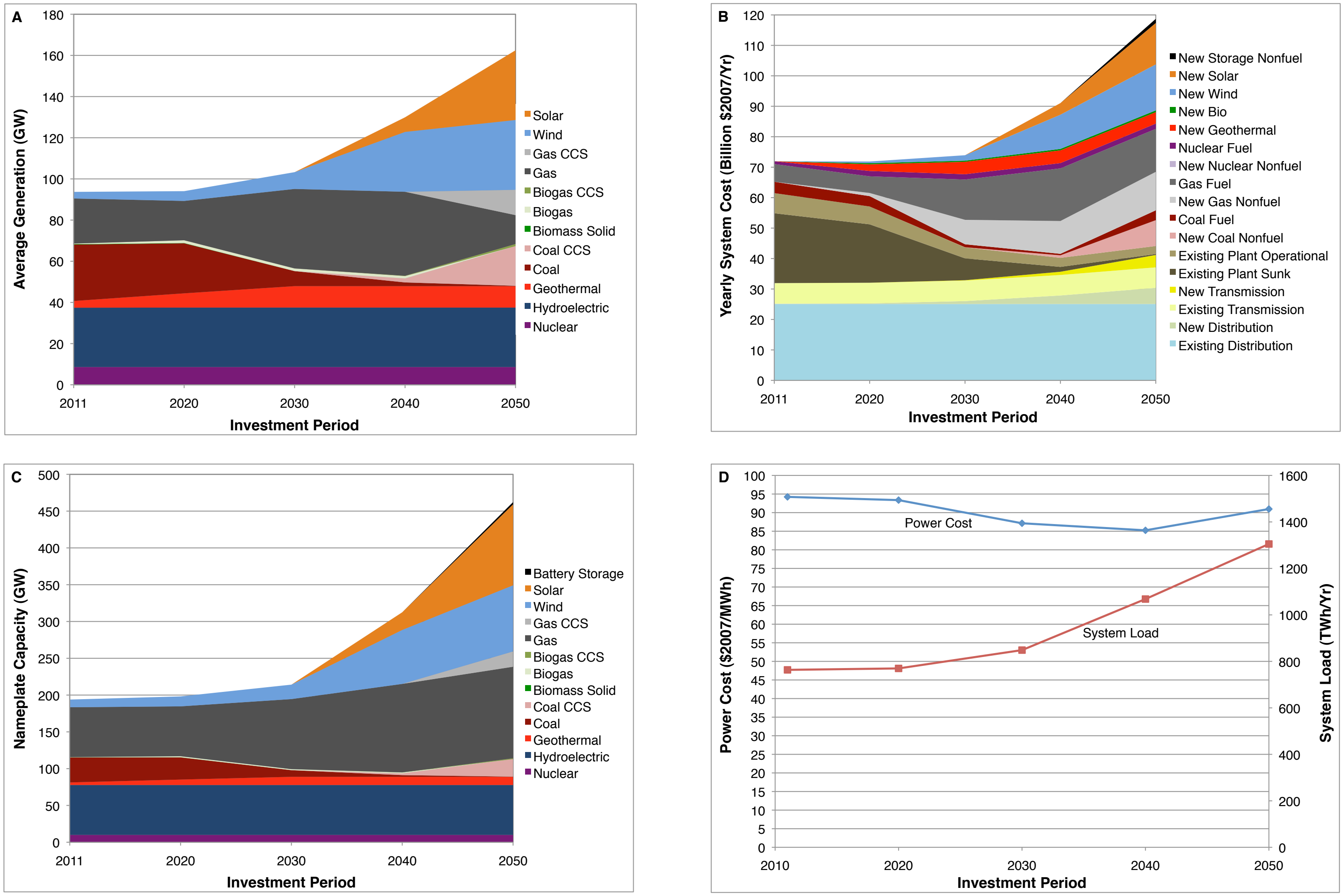
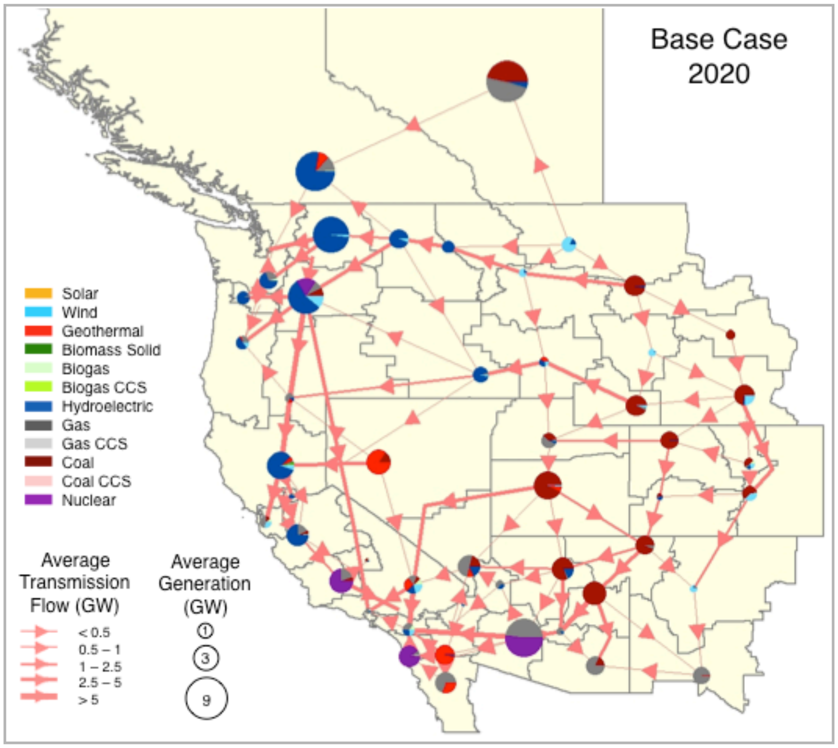


Figure S62*: Base Case scenario results as a function of investment period for all of WECC. All but the first investment period are modeled as ten year long periods starting five years before and ending five years after the year on the x-axis. The first investment period of 2011 represents a SWITCH simulation of the existing electric power system in which only investment in natural gas peaking turbines is allowed. (A) Average generation over each investment period (B) Yearly system cost breakdown (C) Installed nameplate generation and battery storage capacity. Pumped hydroelectric and compressed air storage projects are included with 'Hydroelectric' and 'Gas' respectively. (D) Power cost normalized to load, and total yearly system load.*



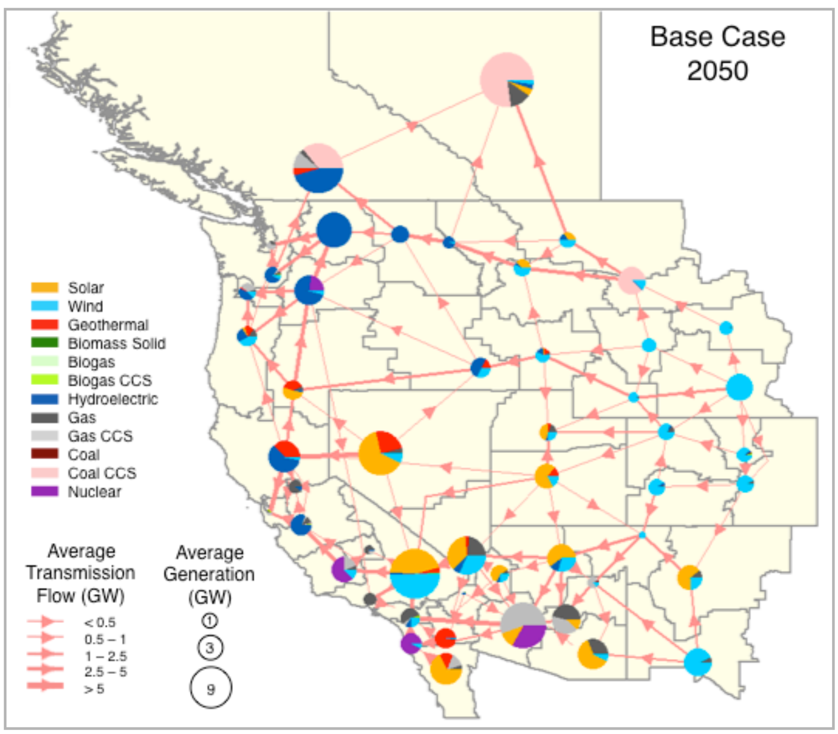


Figure S63*: Average generation by fuel within each SWITCH load area, and average transmission flow between load areas in 2020 (Top) and 2050 (Bottom). The size of each pie represents the amount of generation in the load area in which the pie resides. Transmission lines are modeled along existing transmission paths, but are depicted here as straight lines for clarity. Note that these maps portray <u>average</u> generation and transmission over the course of an investment period, and as such dispatch of the electric power system may vary greatly from these maps in some hours.*

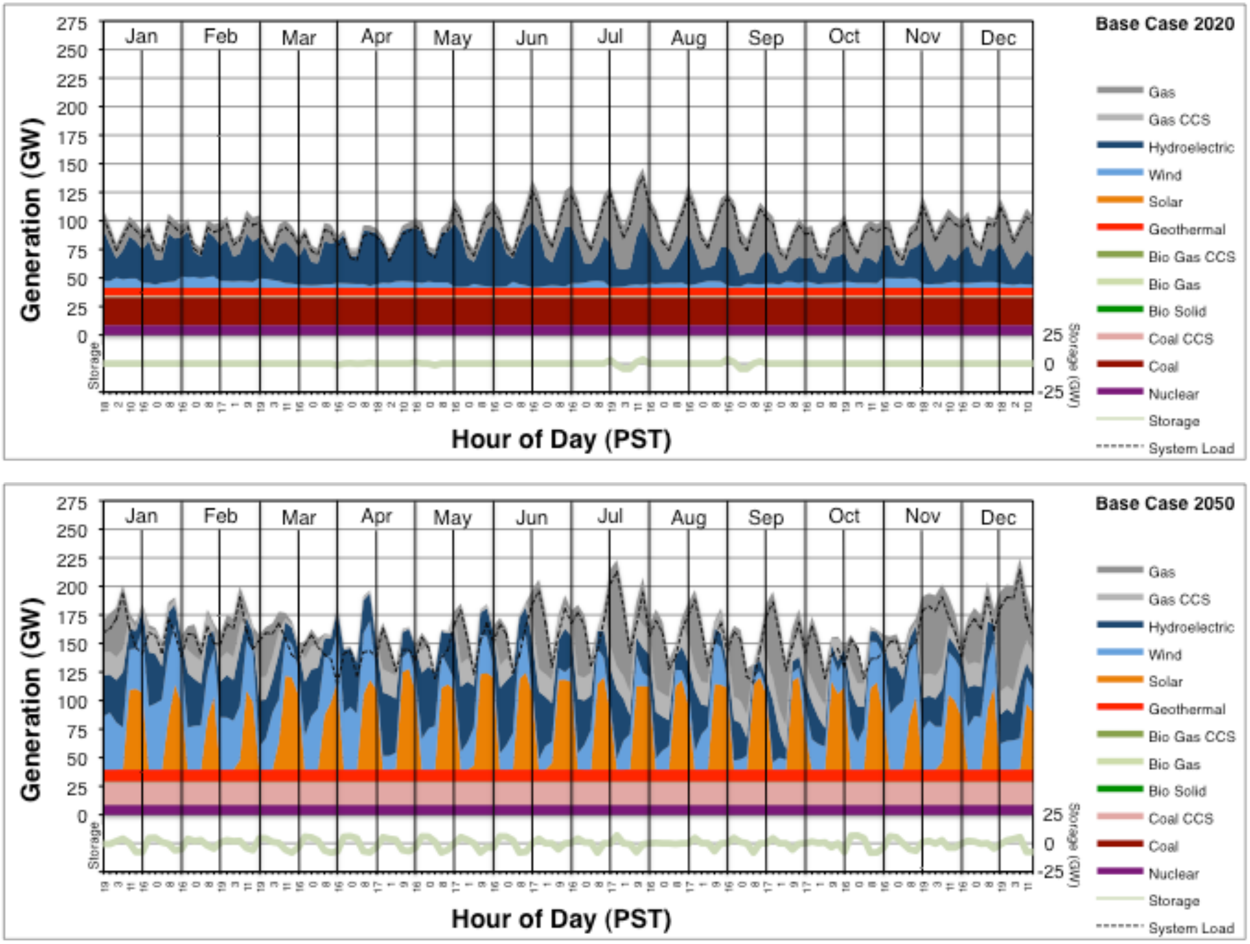


Figure S64: *Hourly dispatch of the Base Case scenario optimal electric power system for all of WECC in 2020 (Top) and 2050 (Bottom). Each plot depicts six hours per day, two days per month, and twelve months per year. Each vertical line divides different simulated days. Optimizations are offset eight hours from Pacific Standard Time (PST), and consequently start at between hour 16 and hour 19 of each day. The system load line does not equal the total generation in each hour due to energy storage and losses in transmission and distribution. The hourly dispatch of storage is shown in light green below each generation plot, with negative values corresponding to energy storage and positive values corresponding to energy release.*

As the power system evolves past 2020, the combination of increasing RPS targets and a more stringent carbon cap forces coal-fired generation out of the generation mix, in favor of primarily natural gas, but also wind and geothermal. By 2050, all existing coal-fired generation has been retired. Much of it is replaced by new coal plants equipped with carbon capture and sequestration (CCS), sited predominantly in Montana and Canada. About 10% of power comes from natural gas CCS, which is generally cycled diurnally (Figure S64), providing power during the night in order to charge electric vehicles and heat buildings. Heavy investment in new gas-fired generation starts in 2030 and continues through 2050, but this investment is largely to replace aging existing gas-fired generation. Investment in photovoltaics increases rapidly as capital costs fall to ~\$1/W_p by 2050, whereas the installation of wind is more gradual over time in large part due to its slower projected cost declination rate (Figure S60). Distributed rooftop photovoltaics are not installed in GW scale as their lower capacity factor and similar costs relative to central station photovoltaics make their deployment unattractive. No concentrating solar power (also known as 'solar thermal') is installed in the Base Case scenario or any other scenario investigated in this study due to high costs relative to central station photovoltaics.

Central-station solar is installed in the Desert Southwest, whereas wind power is installed primarily along the backbone of the Rocky Mountains as well as in California (Figure S63). Solar and wind generation are geographically separated from load, necessitating 14,000 GW-km of new long-distance, high-voltage transmission by 2050 throughout Western North America (Figure S66). The largest new transmission lines bring solar power from Nevada into California, increase power transfer capability between Canada and the United States, and ship Rocky Mountain wind power westward. In 2050, California is a net electricity importer (Table S12), generating 20% of WECC-wide power and consuming 33% of WECC-wide load.

Solar and wind generation complement each other temporally. A combination of gas, gas CCS, hydroelectric and storage are used to follow the load net generation from intermittent renewables and baseload resources. In addition to the existing WECC-wide 5 GW of existing pumped hydroelectric storage, 0.5 GW of compressed air energy storage and 3 GW of battery storage are installed by 2050 to provide spinning reserves (Figure S65) and to temporally shift solar generation to periods of high demand from electric vehicle loads and electric heating (Figure S64). Solar power is consumed in California and the Desert Southwest in the daytime, as well as sent out toward load centers in the Rocky Mountains and the Pacific Northwest. Wind power from the Rocky Mountains is consumed locally and also transmitted west at times of high demand. Throughout WECC, 42% of electricity originates from intermittent sources (solar and wind) in the Base Case in 2050. Despite the installation of storage, SWITCH finds the lowest cost power system spills 1.6% of total generated power. Should storage costs decrease faster than projected in this study, or if demand-response programs are deployed at scale, more of this power could be utilized instead of spilled.

The large-scale generation from intermittent renewables found in this scenario necessitates backup generation in case of weather forecasting errors. Spinning reserves, which are able to respond on the ten-minute timescale to compensate for unexpected variation in generation and load, are provided primarily by hydroelectric and storage technologies (Figure S65). Less gas-fired generation provides spinning reserves in 2050 because sub-optimal part-load efficiency penalties – and resultant carbon emission – make their use undesirable under a strong carbon constraint. In addition, the large balancing areas employed in this study enable the use of spinning reserves from hydroelectric and pumped hydroelectric generators over large geographic regions. "Quickstart" (also called non-spinning reserve) capacity, which is able respond to contingencies on the thirty-minute timescale, is provided almost exclusively from natural gas and natural gas CCS generation.

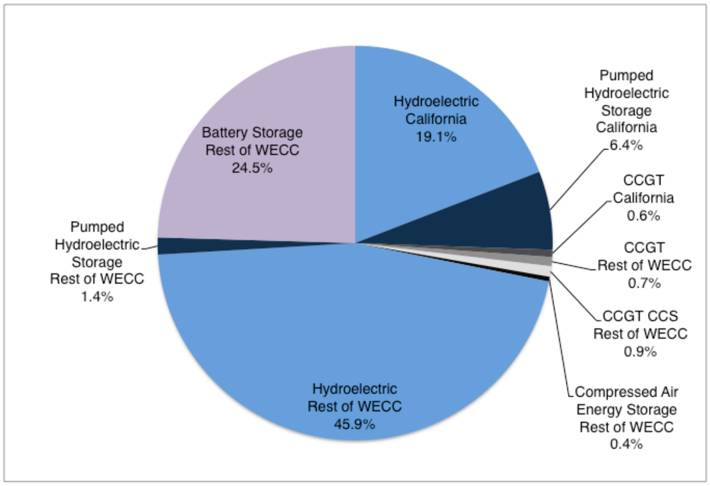


Figure S65. *Average spinning reserves in the Base Case scenario in 2050, broken down by technology and geographic area.*

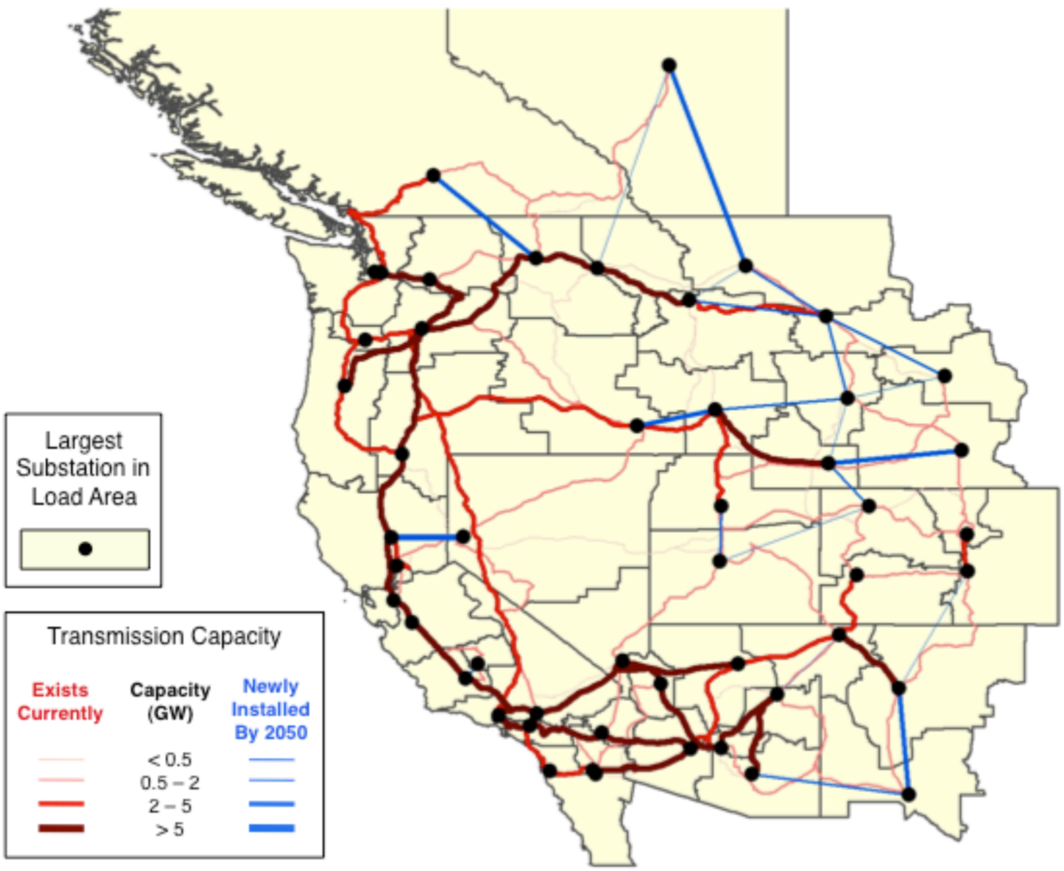


Figure S66*: Existing and new transmission capacity between load areas in 2050 for the Base Case scenario. New transmission is built along existing transmission corridors when possible, but is depicted here with straight lines for clarity. Note the addition of large amounts of new transmission capacity to bring predominantly solar power from Northern Nevada into the Central Valley and San Francisco Bay Area regions of Northern California. Also, note the new transmission additions in the upper right of this map that bring Rocky Mountain wind west.*

Our Base Case scenario results project that the cost of electricity per unit of energy stays relatively constant in real terms between present day and 2050, at between $85/MWh and $95/MWh (in $2007), as shown in Figure S62D. These findings are in contrast to some reports (e.g. AEF 2009) which project that the cost of electricity will increase steadily over time as carbon emission reductions are enforced. In the SWITCH results presented here, the added cost of decarbonizing the electric power system is largely offset by decreasing generator costs over time as well as structural reorganization of the grid to meet load cost-effectively. This result is robust within the SWITCH modeling framework, as similar cost conclusions can be drawn for the other nine carbon-constrained sensitivity cases we investigate subsequently. A larger exploration of the cost parameter space, as well as an in-depth comparison between the differences in cost assumptions between SWITCH and other models, is necessary to provide added confidence in the cost conclusions presented here.

8.4 Base Case Dispatch Verification

The decisions made by each SWITCH optimization use a limited number of sampled hours over which to dispatch the electric power system. While the model has state-of-the art hourly resolution for a large-scale capacity expansion model, each investment period in this study optimizes on 144 sampled hours – much less than a full year of load and intermittent renewable data. To verify that the model has in fact designed a power system that can function over a full year of hourly load and intermittent renewable output data, a dispatch verification check is included. In this check, performed after each optimization, investment decisions are held fixed and new, unseen hourly data are tested in batches of one week at a time. The results from each scenario simulated in this study are therefore checked using 8760 hours of data for each of the four future investment periods, making a total of 4 investment periods x 8760 hours per investment period = 35,040 hours simulated. If there is not sufficient generation capacity to meet demand and reserve constraints, more peaking gas combustion turbine capacity is added to the system to compensate. As is the case in the version of SWITCH used for this study, this dispatch check does not include generator ramping constraints, security constraints, and load flow transmission constraints.

In all but one single hour of the 35,040 total, the base case scenario is able to meet demand and reserve constraints. The single hour that fails necessitates installation of 155 MW of extra peaking capacity – an insignificant amount of capacity and concomitant cost with respect to the scale of the WECC power system. The success of this check adds validity to SWITCH's method of sampling median and peak load study hours as well as enforcing a 15% capacity reserve margin in each study hour of the investment optimization.

8.5 Generator and Cost Sensitivity Scenarios

The projected capital cost and availability of certain types of power generation is a source of substantial uncertainty, especially in the 2050 timeframe. We model these uncertainties using a scenario-based approach by varying the projected capital cost of generation technologies within a feasible range, or by adding/removing generation technologies from the array of technologies from which SWITCH can choose. The matrix of scenarios investigated in this study is found in Table S13.

Among the generation options investigated here, carbon capture and sequestration (CCS), nuclear, and solar capital cost projections are believed to be the most uncertain.

Photovoltaic capital cost projections vary widely, so we explore the sensitivity of the optimal power system to both higher and lower PV costs than in the Base Case scenario. In the Inexpensive Solar & Wind scenario, the costs of all intermittent generators – solar thermal, solar photovoltaic, onshore wind and offshore wind – decrease more rapidly than in the Base Case in order to demonstrate a power system dominated by intermittent renewable generation. The Expensive Photovoltaics scenario explores a future in which photovoltaics do not meet cost reduction targets in order to demonstrate a power system that does not rely extensively on inexpensive photovoltaic generation.

Scenario	Load Profile	California Load in 2050 [TWh/yr]	Total WECC load in 2050 [TWh/yr]	Carbon Cap [% reduction from 1990 Emission Levels]	Extra Capital Cost Declination Relative to Base Case [%/yr]	Generators Included or Excluded
Frozen, No Carbon Cap	Frozen Efficiency	395	1368	N/A	N/A	Biomass Solid CCS Excluded
Frozen Efficiency	Frozen Efficiency	395	1368	80%	N/A	Biomass Solid CCS Excluded
Base Case	Base Case	424	1310	80%	N/A	Biomass Solid CCS Excluded
Inexpensive Nuclear	Base Case	424	1310	80%	Nuclear: -2%/yr	Biomass Solid CCS Excluded
Inexpensive CCS	Base Case	424	1310	80%	CCS: -1.5%/yr	Biomass Solid CCS Excluded
No CCS Or New Nuclear	Base Case	424	1310	80%	N/A	All CCS and New Nuclear Excluded
No CCS	Base Case	424	1310	80%	N/A	All CCS Excluded
Inexpensive Solar And Wind	Base Case	424	1310	80%	Solar & Wind: -1%/yr	Biomass Solid CCS Excluded
Expensive Photovoltaics	Base Case	424	1310	80%	Photovoltaics: +1.5%/yr	Biomass Solid CCS Excluded
Biomass Solid CCS	Base Case	424	1310	100%	N/A	Biomass Solid CCS Included
Extra Electrification	Extra Electrification	484	1478	80%	N/A	Biomass Solid CCS Excluded

Table S13. *Electricity scenarios considered in this study.*

In the Inexpensive Nuclear and Inexpensive CCS scenarios, respectively, nuclear and CCS costs are reduced relative to the Base Case scenario in order to demonstrate power systems with large amounts of low-carbon baseload power.

In addition to the capital cost of generation, the viability of large-scale carbon capture and sequestration (CCS) deployment is also uncertain in the 2050 timeframe. CCS has been proven at demonstration scale only, and recent reports of carbon leakage bring into question the long-term viability of this technology. To model a possible future without large-scale CCS deployment, we include the No CCS scenario, in which all CCS options have been removed from the fleet of generators available to SWITCH. We also include the No CCS Or New Nuclear scenario, in which both CCS and new nuclear generations are not available

We also model a Biomass Solid CCS scenario, in which the electric power system is able to sequester carbon via biomass integrated gasification combined cycle (IGCC) CCS generators. For this scenario, the portion of solid biomass available at less than or equal to $100 per dry ton is unavailable as a feedstock for transportation fuel. We explore a scenario in which it is made available to the electricity sector instead. In the Biomass Solid CCS scenario, the electric power sector is constrained to be carbon-neutral (i.e. to have 100% emissions reductions from 1990), which would allow the electric power sector to offset additional emissions from the transportation sector.

We model one additional scenario, the Frozen, No Carbon Cap scenario, in order to assess the cost difference between a low-carbon and a high-carbon electric power system. The Frozen, No Carbon Cap scenario differs from the Base Case scenario in that carbon emissions from the electric power sector are unconstrained over time. The Frozen Efficiency load profile (discussed below) is used to represent a load profile similar to that which exists today. Current RPS targets are enforced in this scenario.

Figures S67 through S70 below show key metrics for each of the scenarios studied and are followed by descriptions of scenario-specific results.

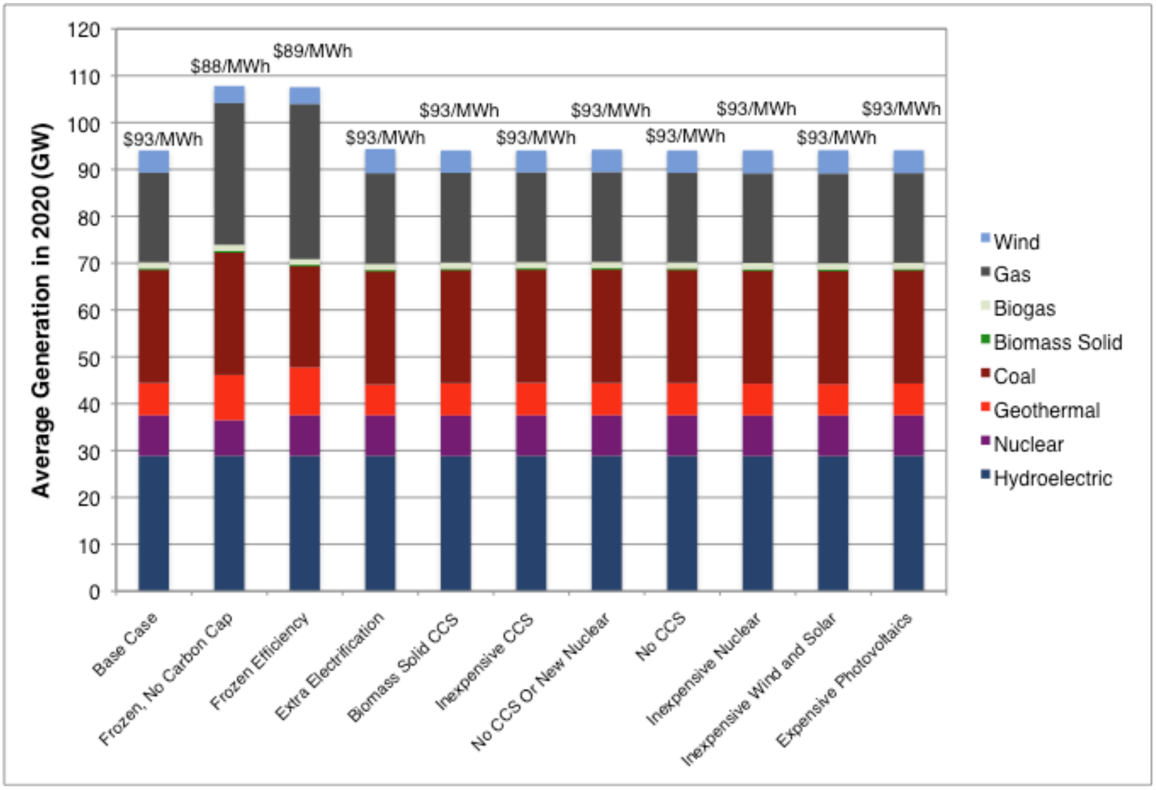


Figure S67. *Average generation by fuel (solid columns) and power cost (horizontal black lines) in 2020 for all scenarios. To convert into yearly energy totals in GWh per year, multiply average GW by 8760 hours per year. Note that the average generation and power cost are dominated by load profile rather than carbon policy or generator cost in the 2020 timeframe. Power cost per unit of electricity is lower in the frozen efficiency scenarios because sunk costs are spread over more units of electricity relative to scenarios with aggressive energy efficiency measures.*

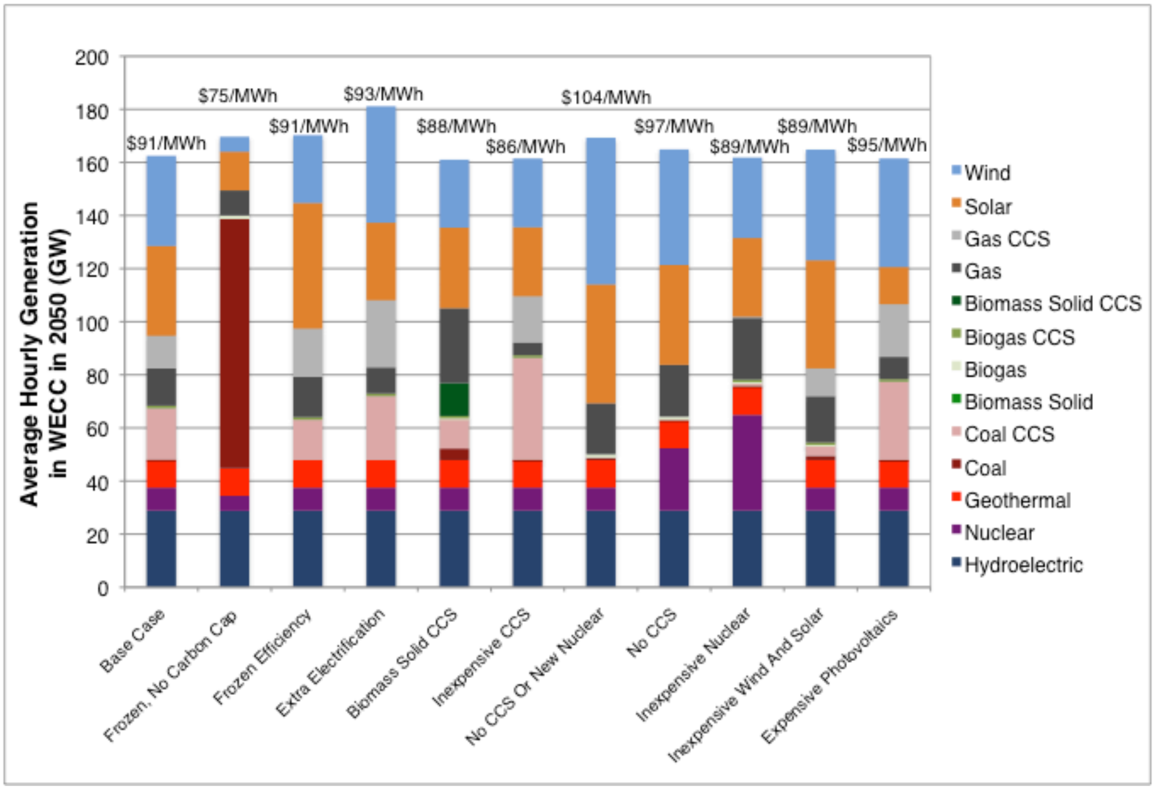


Figure S68*: Average generation by fuel (solid columns) and power cost (horizontal black lines) in 2050 for all scenarios. To convert into yearly energy totals in GWh per year, multiply average GW by 8760 hours per year. Note that the power cost is similar in all scenarios except for the Frozen, No Carbon Cap scenario.*

Scenario	Biogas	Biogas CCS	Biomass Solid CCS	Coal	Coal CCS	Gas	Gas CCS	Geothermal	Solar	Nuclear	Hydroelectric	Wind	Power Cost [$2007/MWh]
Base Case	0	1.0	0	0.2	19.3	14.0	12.3	10.4	33.9	8.6	28.9	33.9	91.0
Frozen, No Carbon Cap	1.3	0	0	93.9	0	9.4	0	10.4	14.6	5.6	28.8	5.6	75.1
Frozen Efficiency	0	1.0	0	0	15.2	15.1	18.2	10.4	47.4	8.6	28.8	25.5	90.9
Extra Electrification	0	1.0	0	0	24.1	9.8	25.3	10.4	29.2	8.6	28.9	43.9	92.6
Biomass Solid CCS	0.1	0.9	12. 4	4.3	11.3	28.2	0	10.4	30.3	8.6	28.9	25.6	88.4
Inexpensive CCS	0	1.0	0	0.1	38.4	4.8	17.4	10.4	26.0	8.6	28.9	25.9	86.8
No CCS Or New Nuclear	1.3	0	0	0.8	0	19.2	0	10.4	44.8	8.6	28.8	55.2	103.9
No CCS	1.3	0	0	0.1	0	19.5	0	10.4	37.6	23.5	28.9	43.5	96.8
Inexpensive Nuclear	0	1.0	0	0.4	1.5	23.4	0.2	10.4	29.6	36.0	28.9	30.3	88.9
Inexpensive Wind and Solar	0	1.0	0	1.6	4.1	17.4	10.5	10.4	40.7	8.6	28.9	41.7	88.6
Expensive Photovoltaics	0	1.0	0	0.1	29.4	8.4	19.8	10.4	14.0	8.6	28.9	40.9	95.1

Table S13*: Average WECC-wide generation by fuel in 2050 for all scenarios. This data is a tabular representation of Figure S68. All units are in average GW, except for the cost of power, which is in $2007/MWh. To convert into yearly energy totals in GWh per year, multiply average GW by 8760 hours per year.*

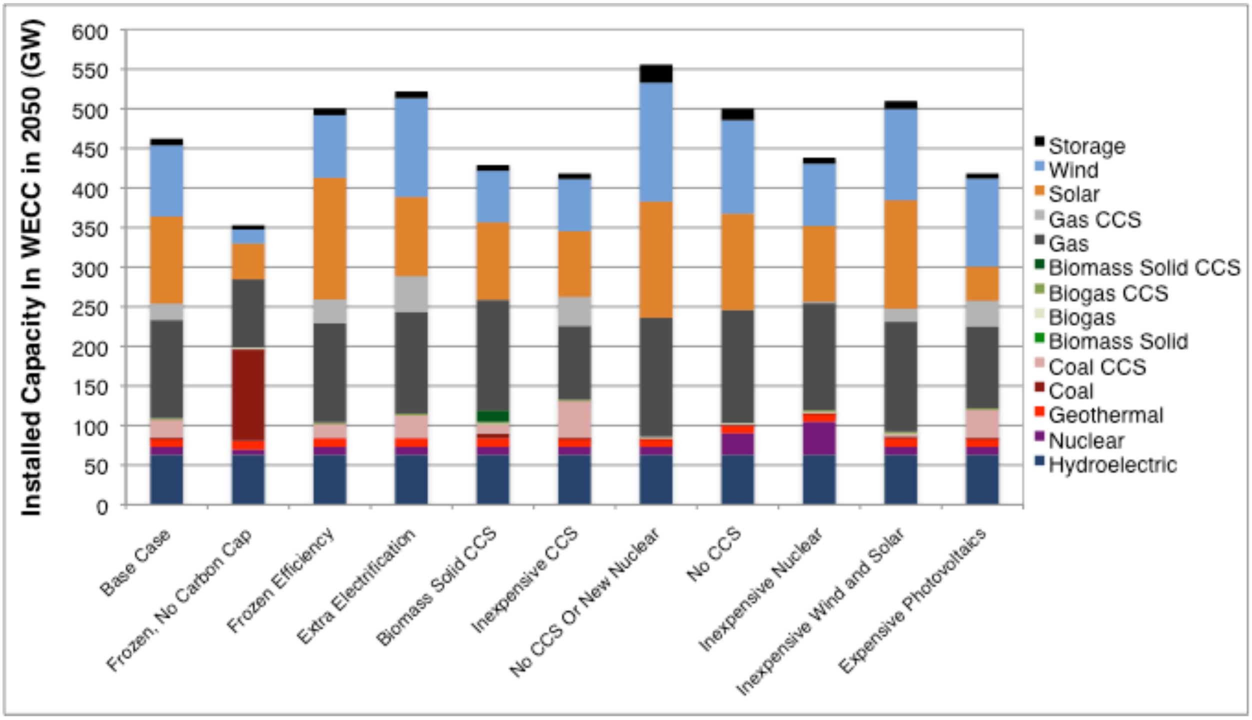


Figure S69*: Generator and storage capacity installed throughout WECC in 2050 for all scenarios considered in this study.*

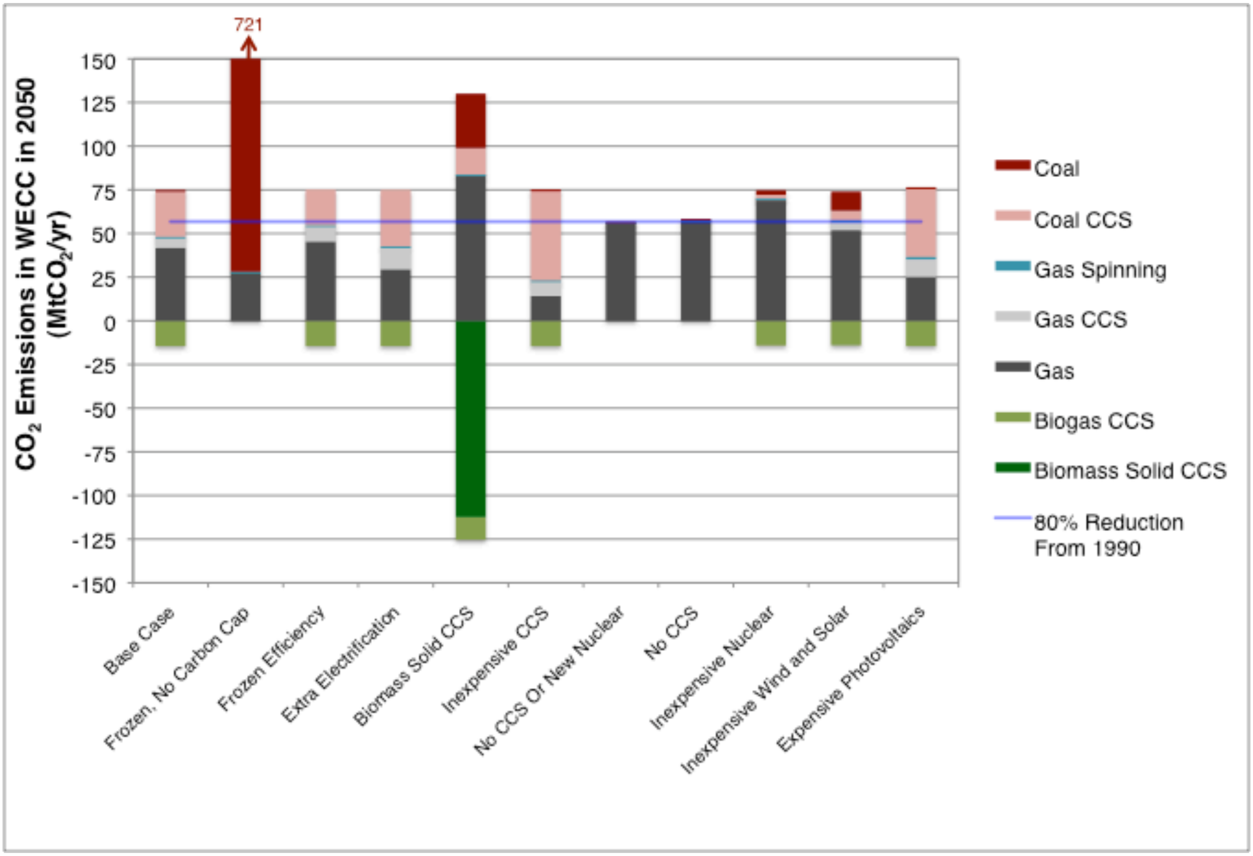


Figure S70: *Yearly CO_2 emissions across WECC in 2050 for all scenarios. The 2050 target of 80% emissions reduction relative to 1990 levels (61 $MtCO_2$) is shown for reference – this level of emissions is reached in all scenarios except for 'Frozen, No Carbon Cap' and 'Biomass Solid CCS' scenarios. CCS of biomass solid and biogas results in net negative emissions, thereby compensating for natural gas and coal emissions while remaining within the 80% emissions reduction cap. 'Gas Spinning' represents the additional emissions incurred from running gas-fired generation at part load, and is generally small owing in part to the extensive use of spinning reserves from hydroelectric and storage in 2050.*

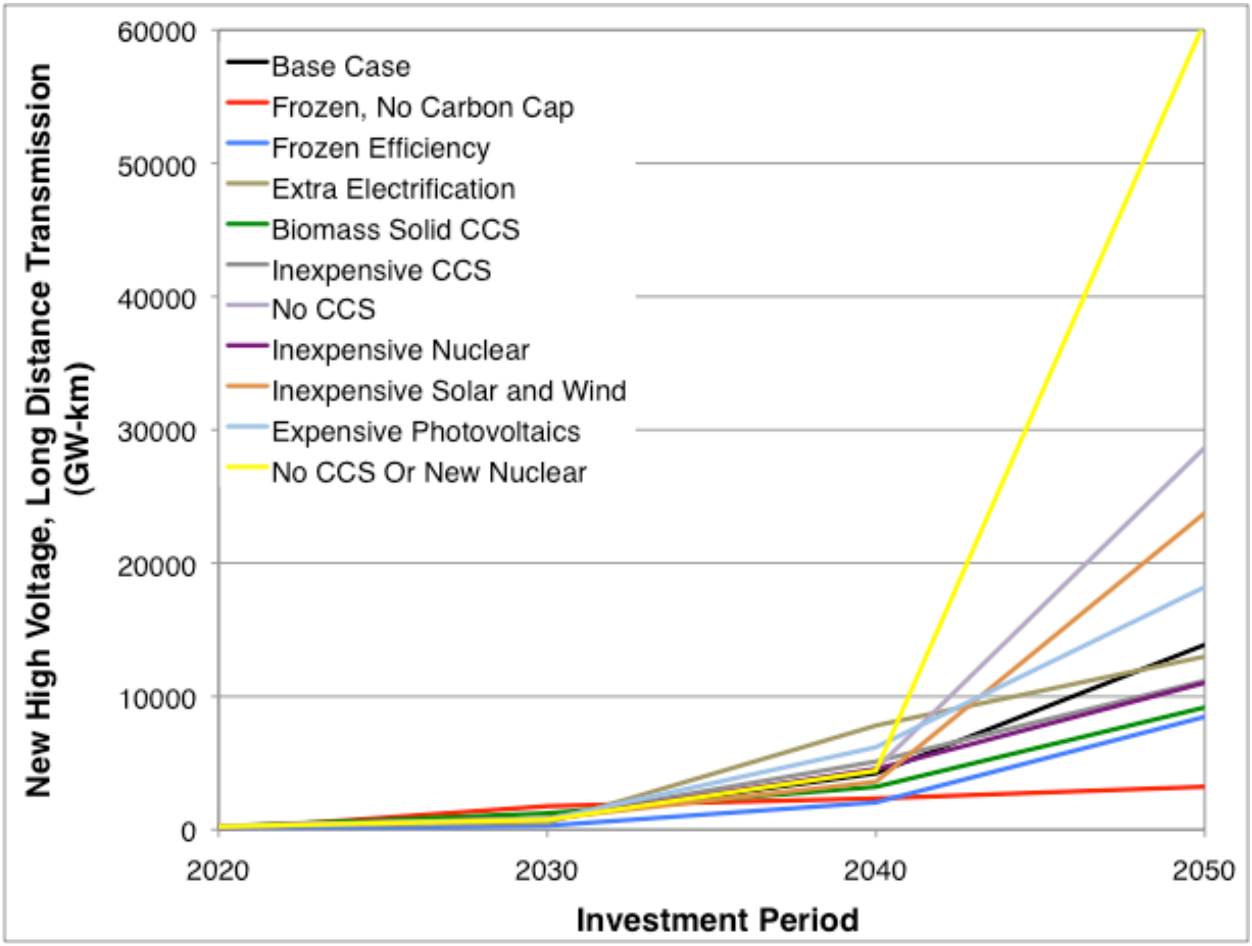


Figure S71: *New high-voltage, long-distance transmission built as a function of investment period, for all scenarios explored in this study. This figure does not include investment in smaller, local transmission and distribution lines, nor does it include small transmission lines that connect new generation projects to the larger transmission grid, although these costs are included in the SWITCH model.*

8.6 Biomass Solid CCS Scenario

The Biomass Solid CCS scenario is constrained to reduce carbon emissions to 100% below 1990 levels by 2050, making a carbon-neutral electricity grid. Biomass solid is sequestered via integrated gasification combined cycle CCS technology, a type of generator that is modeled to have a power conversion efficiency of 26%, which is relatively low with respect to gas-fired and coal-fired generation. The poor efficiency originates from extra energy consumed when using biomass as a feedstock and energy consumed in the carbon capture system. This low efficiency means that biomass solid CCS accounts for only 8% of the total WECC-wide energy produced in 2050. However, as shown in the dark green bar in Figure S70, another important role for bio CCS is in emission reduction: 112 $MtCO_2$/yr is sequestered from biomass solid and 13 $MtCO_2$/yr is sequestered from biogas. This total of 125 $MtCO_2$/yr sequestered from bio sources is double the carbon cap of 61 $MtCO_2$/yr in 2050. Of the total biomass solid fuel available to the electricity sector, 75% is sequestered by 2050.

Sequestering carbon from bio sources is a carbon-negative activity. By compensating for emissions from fossil fuel generation, bio sequestration enables significant generation from non-CCS natural gas (18%) and coal (3%) – the largest fraction of any scenario investigated in this study. The persistence of non-CCS fossil fuel generation in the Biomass Solid CCS scenario suggests that, if given the opportunity to sequester carbon from solid biomass, the electric power sector can accommodate further emission reductions beyond carbon neutrality. The power cost in 2050 for the Biomass Solid CCS scenario is 2.8% ($2.6/MWh) lower than the Base Case scenario (Figure S68), further corroborating the ability of the grid to go carbon negative.

8.7 High CCS Penetration: Inexpensive CCS and Expensive Photovoltaic Scenarios

In the Inexpensive CCS scenario in 2050, coal-fired CCS generation provides inexpensive low-carbon baseload power and replaces solar, wind and gas generation relative to the Base Case scenario. With 48 GW installed WECC-wide (Figure S69), coal CCS accounts for 24% of total energy (Figure S68), up from 12% in the Base Case scenario. Almost all of this coal CCS generation is built in load areas far from California, with 56% of new capacity installed in Canada. Gas-fired CCS generation is built in California, with 5 GW installed in the state out of a WECC-wide total of 37 GW. The Inexpensive CCS scenario produces power at a cost 5% lower than in the Base Case scenario due to the extensive deployment of low-cost CCS generation.

Similar results are obtained in the Expensive Photovoltaic scenario. Due to the high cost of photovoltaics, large amounts of wind power are installed in addition to coal-fired CCS generation to meet load. Only 9% of total electricity in 2050 is generated from photovoltaics in this scenario (Figure S68), the lowest amount of any scenario with a cap on carbon emissions. Despite the similar resource availability of solar thermal and central-station photovoltaics, no solar thermal generation is installed in this scenario by 2050. In this study, the projected cost of solar thermal with or without thermal energy storage is found to be prohibitively high relative to other low-carbon generation options. The Expensive Photovoltaic scenario produces power at a cost 4% higher than in the Base Case scenario.

The percentage of power from CCS generation exceeds 30% by 2050 in only two scenarios, reaching 31% in the Expensive Photovoltaics scenario and 35% in the Inexpensive CCS scenario. These scenarios demonstrate that CCS generation may contribute large amounts of electricity to the grid. However, widespread CCS availability and cost-effectiveness are highly uncertain in the 2050 timeframe. We do not explore the sensitivity of CCS deployment to fuel price in this study.

8.8 New Nuclear: Inexpensive Nuclear and No CCS Scenarios

While existing nuclear generation is kept running through 2050 in all carbon cap scenarios examined in this study, new nuclear is installed in only two cases: the Inexpensive Nuclear and No CCS scenarios. In both of these scenarios, the installation of nuclear power contributes greatly to meeting the 2050 carbon cap.

In the No CCS scenario, average all-in capital costs for new nuclear capacity remain at $4.92/W in 2050 as in the Base Case scenario. The removal of all CCS generation options forces the installation of 17 GW of new nuclear capacity, exclusively in Canada. A concomitant WECC-wide cost increase of 6%

($5.8/MWh) over the Base Case scenario is incurred (Figure S68). Five GW of additional compressed air energy storage capacity (Figure S69) is also deployed in the No CCS scenario to help replace CCS capacity present in the Base Case scenario. Non-CCS gas-fired generation produces 12% of power (Figure S68), and is responsible for virtually all WECC-wide electric power sector emissions (Figure S70) in the No CCS scenario in 2050.

In the Inexpensive Nuclear scenario, nuclear average all-in capital costs decline to $2.62/W by 2050, making it an economical option for low-carbon baseload power. In total, 42 GW of new nuclear capacity is installed across WECC (Figure S69) in order to meet rapidly rising demand, with 21 GW of this capacity installed in Canada. Little new nuclear capacity is installed in load areas near California and none is installed inside California itself due to the enforced ban on new nuclear within the state. In this scenario, nuclear outcompetes coal and gas CCS relative to the Base Case scenario. Non-CCS gas-fired generation produces 15% of power in 2050.

Using the cost and generator availability assumptions of the Base Case scenario, new nuclear capacity is not optimal to install, even in a carbon-constrained electricity grid, due to the availability of many other low-carbon supply options. The No CCS and Inexpensive Nuclear scenarios show nuclear power to act as a fail-safe for the cost and/or availability of other generation options. However, the lack of Canadian wind data in the current version of SWITCH may be one reason for large-scale installation of nuclear in Canada. We plan to obtain and integrate Canadian wind data for future studies.

8.9 Inexpensive Solar and Wind Scenario

The Inexpensive Solar and Wind scenario explores an electricity grid dominated by intermittent renewable generation. In this scenario in 2050, 25% of total WECC-wide generation originates from wind power and 25% originates from solar power, a total of 50% of generation from intermittent renewable sources.

The Inexpensive Solar and Wind scenario creates a power system that is reliant on new transmission (Figure S71) to move energy spatially, but is not as reliant on energy storage (Figure S69) to move energy temporally. It should be noted that storage does provide an important role in providing sub-hourly ancillary services to balance the large amounts of intermittent generation found in this scenario. Should storage costs decrease faster by 2050 than projected in this study, storage might participate more actively in inter-hourly energy arbitrage and enable deeper penetration of intermittent renewable energy.

8.10 No CCS Or New Nuclear Scenario

The No CCS or New Nuclear scenario represents the most extreme scenario of any presented here in terms of intermittent generation, with 33% of power from wind and 27% from solar in 2050. Relative to the Inexpensive Wind and Solar scenario, the lack of new nuclear power forces the installation of extra wind and solar capacity, along with additional transmission and storage capacity (Figures S69 and S71). The largest new transmission lines in this scenario are installed to bring Wyoming wind west to demand centers. Both battery storage and compressed air energy storage are installed to mitigate the intermittency of wind and solar, with 6 and 12 GW installed by 2050 respectively. The cost of power in 2050 is the highest of any investigated in this study at \$104/MWh, \$7/MWh higher than is found in the Inexpensive Solar and Wind scenario.

One of the potential weaknesses of the SWITCH model is that each optimization is based on a limited set of hourly intermittent renewable generation: 144 distinct hours per investment period in this study. As discussed above, the dispatch verification addresses this issue by testing the investment decisions on a full year of load and hourly intermittent renewable generation data after the completion of each optimization. The dispatch verification step checks whether SWITCH has installed sufficient capacity to successfully meet hourly load for a full year. As the No CCS Or New Nuclear scenario has the highest percentage of intermittent generation of any scenario investigated here, it represents the most difficult scenario to model with SWITCH. The dispatch verification shows that 1 GW of additional peaking capacity near to wind generation in Wyoming is required to meet load and reserve margins. This amount of capacity is small relative to the total installed capacity of the system (Figure S69), indicating that the optimization is producing a reliable electric power system. While the SWITCH model does not have the necessary capabilities to assess grid stability issues that may occur at large intermittent renewable penetration levels, it is an important step in renewable integration modeling with the goal of designing a power system that is able to integrate 60% intermittent renewable energy while successfully functioning on many timescales.

8.11 Frozen, No Carbon Cap Scenario

The Frozen, No Carbon Cap scenario assumes frozen energy efficiency and does not include a cap on carbon emissions. In this scenario, a large amount of new coal-fired generation is built by 2050 (Figure S69). This is the only case with substantially (17%) lower power cost than the Base Case scenario (Figure S68). CO_2 emissions in this scenario (Figure S70) are 721 $MtCO_2$/yr across WECC, 252% of 1990 WECC power sector emissions. This level of emissions is more than 12 times higher than the 2050 power sector emissions target of 80% below 1990 levels. This scenario demonstrates that under the Base Case cost assumptions present in the version of SWITCH model used here, coal is the least expensive form of generation in WECC. Inclusion of a carbon cap increases the cost of power, but external costs from global warming, criteria air pollutants, health impacts, and environmental and ecological degradation associated with coal mining, transport and combustion are likely to be very large (NRC 2010A), and are not reflected in the cost of power.

8.12 Load Profile Scenarios: Base Case, Frozen Efficiency, and Extra Electrification

The sensitivity of the optimal future power system to differences in energy efficiency, vehicle electrification and heating electrification is explored through three different load profiles. Load duration curves for these profiles can be found in Figure S72 and hourly plots by load type can be found in Figure S73. In the Frozen Efficiency and Extra Electrification scenarios the load profile is changed relative to the Base Case scenario but all other generator and carbon emission assumptions are held constant.

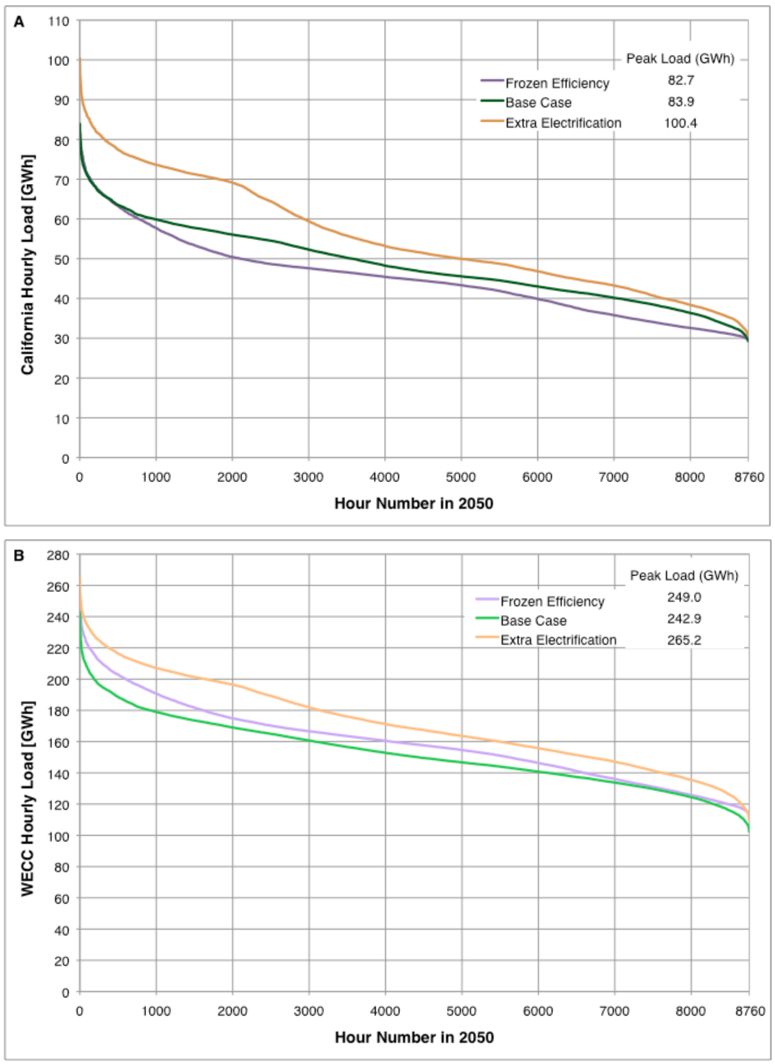


Figure S72: *Load duration curves for 2050 for (A) California (B) all of WECC, including California.*

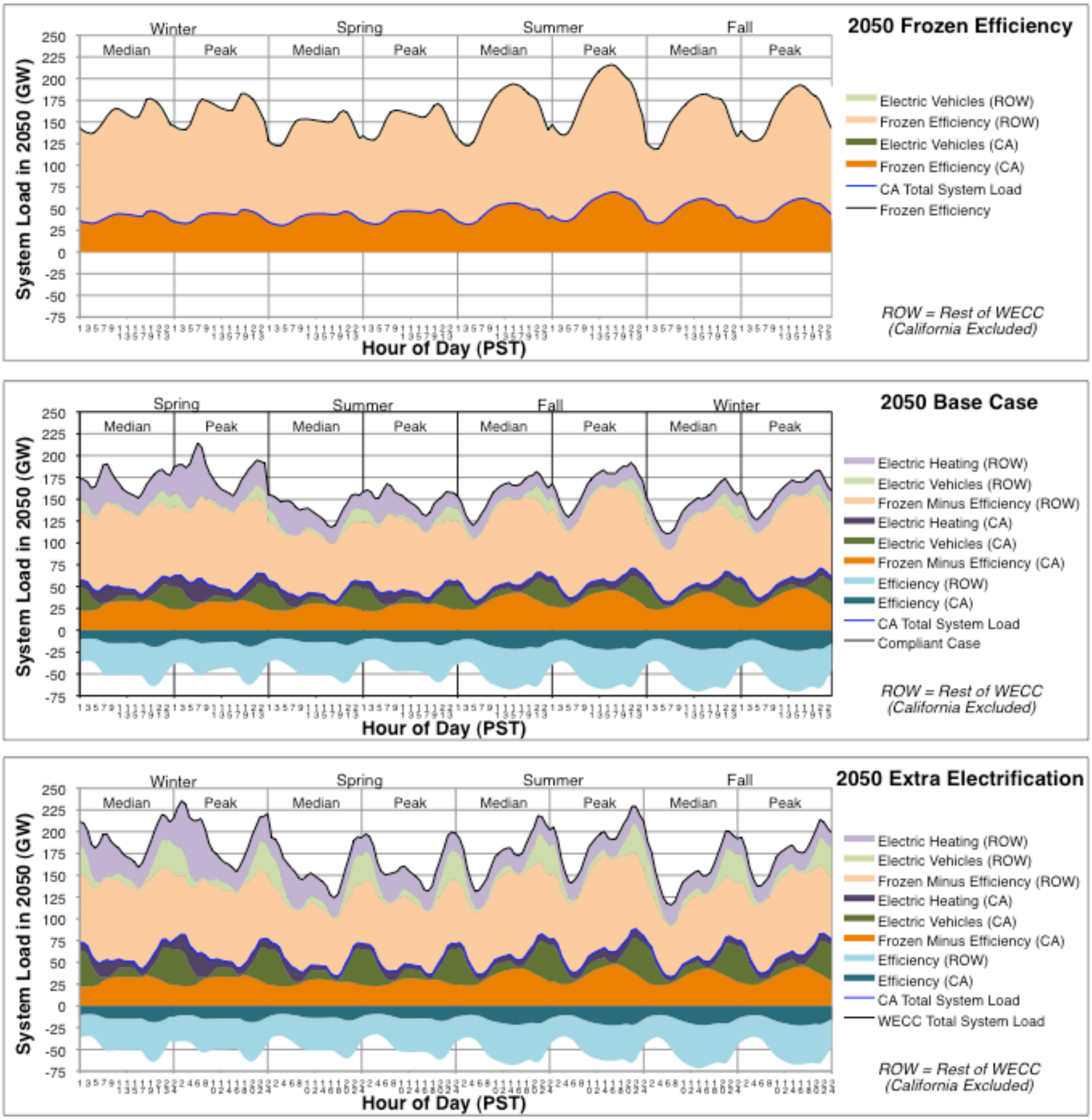


Figure S73*: Hourly load profiles by load type for the Frozen Efficiency, Base Case and Extra Electrification load profiles in 2050. For each season, the day with the peak load hour and the day with the median load are shown. 24 hours of data per day are plotted. Vertical gray lines divide distinct days. 'Frozen Minus Efficiency' represents the load profile after efficiency measures have been taken. 'Efficiency' is depicted here as negative load, representing the difference between the frozen efficiency load profile and the same load profile including energy efficiency reductions.*

The Base Case load profile includes substantial efficiency, vehicle electrification and heating electrification and, as a result, peaks at night. The Extra Electrification load profile includes aggressive amounts of vehicle and heating electrification above and beyond that which is found in the Base Case load profile. The night-peaking behavior of the Base Case profile is therefore amplified in the Extra Electrification profile.

For the Frozen Efficiency load profile, each hour from the 2006 load profile is scaled up by a uniform factor based on load projections. A small amount of electric vehicle load is included, but the EV demand does not significantly change the character of the load profile. This load profile therefore retains a diurnal shape similar to that found in present day, with the yearly peak coming in the early evening of hot summer months. The Frozen Efficiency load profile does not include aggressive energy efficiency measures.

The effect of projected load profile shape on the optimal temporal generation profile is shown for 2050 by comparing the plots in Figure S74. Relative to the Base Case load profile, the Frozen Efficiency load profile promotes solar generation due to the near-coincidence of peak load and peak solar generation. The Extra Electrification load profile has the opposite effect relative to the Base Case – electric vehicle and heating loads occur primarily at night and therefore favor wind generation over solar. Consequently, the Frozen Efficiency scenario has the second highest amount of generation from solar of any case explored here at 21% in 2050, whereas the Extra Electrification scenario has the second highest amount of generation from wind of any case explored here at 24% in 2050 (the Inexpensive Solar and Wind scenario has the most solar and wind generation, 25% for each). In all three load profiles cases, meeting load relies extensively on gas-fired generation with and without CCS to firm intermittent solar and wind generation. In all three scenarios, at least 40% of power is generated by intermittent sources: 42% in the Base Case scenario, 43% in the Frozen Efficiency scenario, and 40% in the Extra Electrification scenario.

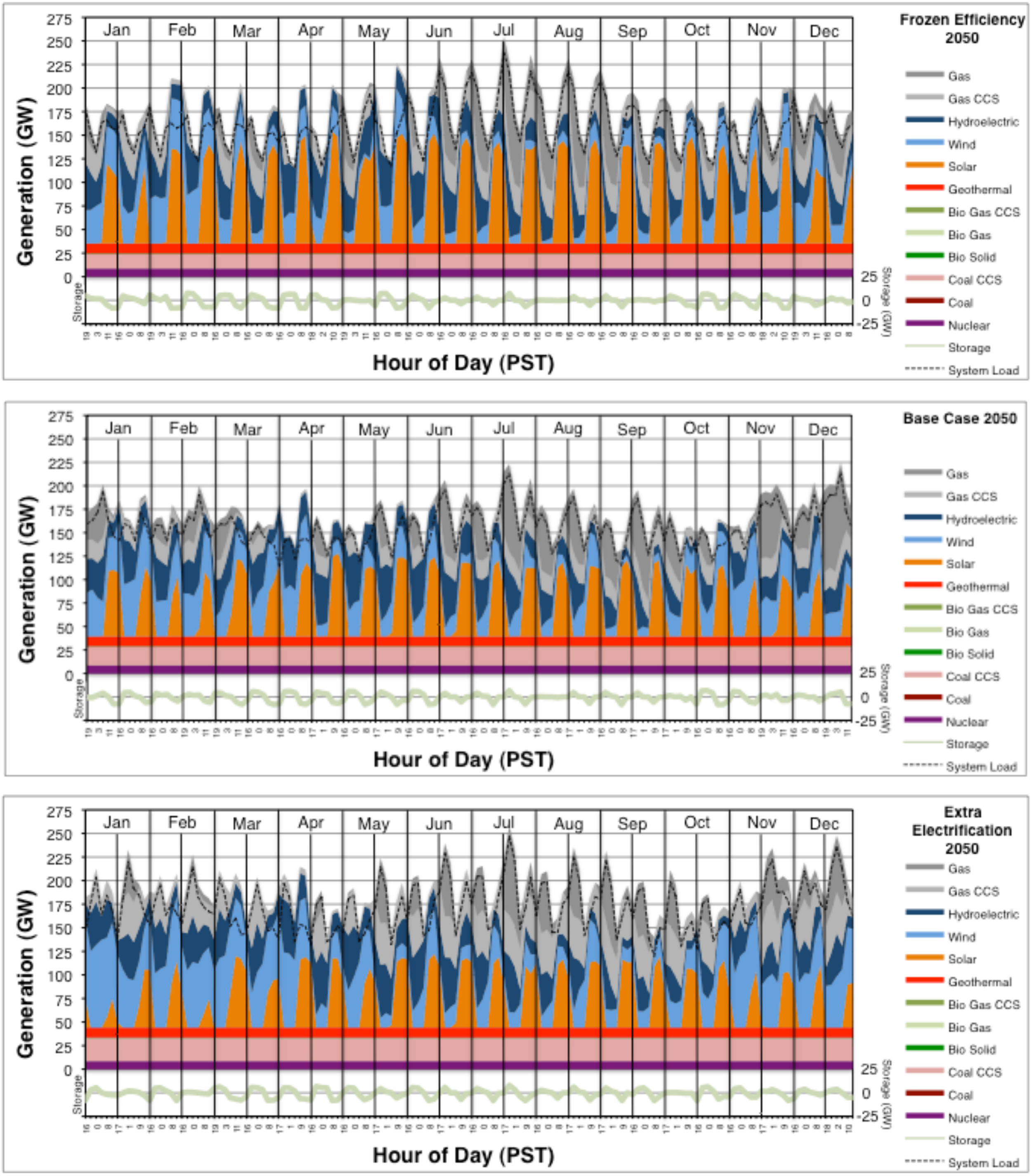


Figure S74: *Hourly dispatch of the for the Frozen Efficiency, Base Case and Extra Electrification load profiles for all of WECC in 2050. Each plot depicts six hours per day, two days per month, and twelve months per year. Each vertical line divides different simulated days.Optimizations are offset eight hours from Pacific Standard Time (PST), and consequently start at between hour 16 and hour 19 of each day.*

The system load line does not equal the total generation in each hour due to energy storage and losses in transmission and distribution. The hourly dispatch of storage is shown in light green below each generation plot, with negative values corresponding to energy storage and positive values corresponding to energy release.

9. ENERGY CONSERVATION MODEL

9.1 Introduction

Studies quantifying the potential for greenhouse gas emission reduction from behavior changes (or conservation) are often focused on the short term and include a wide range of behaviors. For example, Laitner 2009 (65) formulates his behaviors in a 2x2 matrix with purchasing/investment decisions on one axis and duration of behavior on the other axis. Dietz 2009 (66) considers the potential for GHG savings across a range of actions from weather stripping, one time set points, and ongoing behavior. Both studies estimate energy or GHG savings in the short term, i.e. less than 10 years into the future. This work focuses on long term potential for ongoing behavior change since habitual actions can be difficult to address, can take a long time to change, and their impacts on emissions will depend on the energy system. We focus on consumer actions since consumer purchases represent 70% of GDP. Future work should consider the role of businesses and industry and how they might interact with changes in consumer behavior in areas such as service oriented business models, integrative design, sustainable, metric based supply chains, closed cycle, closed loop design, etc.

Historical adoption rates in diet, recycling, and health are sufficient to suggest that long term behavior changes affecting energy consumption are possible. A detailed characterization matrix of attributes and barriers for many energy saving behaviors is described and long term adoption rates estimated based on correspondences with historical behaviors. Behaviors that reduce GHG emissions today may have less effect when future energy systems already have low GHG emissions. We quantify potential savings from behaviors in a future low-carbon energy system for California, using results from the energy system modeling work in this report. The 2050 energy system features deep energy efficiency, de-carbonization of electricity supply, electrification of building heating, and partial de-carbonization of transportation fuels from bio-fuels and/or electrification.

We have formulated a long-term residential consumer behavior model. It includes a mini-database of non-energy and energy-related historical behaviors such as smoking, seat belt usage, recycling, and dietary trends. We chose to focus on "habitual" behaviors that may be difficult to legislate or require by law, and do not include purchase decisions or actions such as weather stripping which will be modeled in the building energy efficiency and electrification areas of this report.

A core list of behaviors is listed in Table S15 and a detailed characterization matrix has been developed (Table S16). Each behavior -- both historical and energy related actions -- is characterized with this matrix and each measure is cross-compared for similar attributes and barriers. Estimation of behavior adoption in 2050 is informed by the following: extrapolation of existing trends, existing market segmentation and survey frameworks, and through utilization of historical behavior trends and our characterization matrix.   Finally GHG savings for each measure is estimated using a life cycle assessment decomposition into GHG savings components for California (29).

Long-term behavior changes can contribute GHG savings of 6-19% in 2050 and can make as large a difference as various high cost technology options. Greater GHG reduction is found from behavior related transportation fuel reduction than end-use electricity reduction, and behavior related energy savings constitute a key wedge toward meeting 80% GHG reduction targets relative to 1990. This long term perspective can hopefully lead to better alignment of behavior related policy considerations with overall energy policies.

An alternate view of the behavior model is to address the following question: given maximal effort at energy efficient technology deployment, clean electricity, and vehicle electrification, and low carbon biofuels, how much further behavior change is needed to meet long term climate change goals?

Area	Individual/Household Actions
Consumption	Recycle as much as possible - paper, plastic and metals
Consumption	Paper and packaging - purchase items with minimal packaging e.g bulk foods; 2-sided printing, less magazine subscriptions; no plastic water bottles
Consumption	Use rechargeable batteries
Consumption	Repair more, upgrade less; Extend life of PCs/electronics by 50%
Food/Diet	Healthier diet - less red meat and dairy, more plant based whole foods
Food/Diet	Waste less food by 25%
Food/Diet	Shift to more organic foods
Home Energy	Composting
Home Energy	Line dry clothes
Home Energy	Turn off lights/ unplug appliances, use smart power strips
Home Energy	Use oven less
Home Energy	Jog outside instead of treadmill
Home Energy	Cold water dish/clothes washing
Home Energy	Lower water tank temperature
Home Energy	Shorter showers
Home Energy	Tune up AC/ furnace filters
Home Energy	Lower thermostat in winter
Home Energy	Raise thermostat in summer
Home Energy	Unplug second refrigerator
Home Energy	Reduce security lighting, switch off outside decorative lighting
Transport	Drive less (Carpool, walking, biking, reduced distances, …)
Transport	Ecodriving: reduce max speed, hard stops and starts, driver training
Transport	Telecommute once a week
Transport	Proper tire inflation, regular auto maintenance
Transport	Increase public transit usage
Transport	Reduce number of air flights; through stay-cations, teleconferencing

Table S15. *List of Behaviors considered for this study.*

Characterization Feature	Description
Attributes	Visibility to Others
	Visibility of Benefits to consumer
	Ease of Substitution
	Ease of Behavior
	Feedback Visible?
	Enabling long term technologies?
	Enabling Policies, campaigns?
Barriers	Habit
	Indifference
	Info/Education
	Institutional/Cultural
	Risk Aversion/Safety
	Economic Cost
	Physical (Infrastructure)
	Labor/Inconvenience
	Lack of Incentive/Pleasure
	Climate/Weather
	Persistence/Stickiness

Table S16. *List of attributes and barriers for behavior characterization.*

9.2 Model scope

We make a distinction between energy service and "lifestyle" changes that is often made in behavior change potential studies (67). Behavior change can clearly occur on many different levels and the distinction here – which can clearly be blurred – is that behavior changes can either lead to no change in "energy service" delivery, or it could lead to lower energy service. The latter is typically associated with the "lifestyle change" denotation and is typically not included in behavior potential studies. Examples of the former could include items such as turning off your lights when you are not in the room or powering down your computer when not in use or using cold water dishwashing/clothes washing which implicitly deliver the same quality of service or results as the old behavior. But we do not include large ticket items such as buying smaller cars or moving from a single family 3000 square foot home to a smaller single family home or apartment with the implicit assumption that the level of service delivered is impinged in such cases or that "lifestyle" is changed. There is gray area here since we do include VMT reduction such as carpooling or biking and healthy diet. These items could also be argued to be lifestyle changes but on the other hand, VMT reduction could result in other co-benefits such as more time to rest or read the paper or conduct phone calls, and in the case of diet, one could argue that folks with healthy diet can consume similar number of calories in similar proportions of fats/carbohydrates/protein to less healthy diets.

We do not explicitly include the impact of technology, although that is embedded in behavior models and certainly in a wider perspective, behavior guides all our choice from purchasing of new technologies to habitual actions. It is within the framework of historical trends that technological improvements can abet greater adoption of what we call habitual behaviors. The historical trend toward eating more poultry for example may be helped by advances in food processing technology and the more ready availability of boneless chicken leading to greater consumption.

Similarly, aggressive policy measures can encourage energy saving behavior. For example, a much higher gasoline tax may induce people to drive less, but it may need to be coupled with offsetting tax reductions to avoid being regressive.

9.3 Historical Trends

A set of historical adoption curves for five historical behaviors are show in Figures S75 to S80. S-curve adoption curves are found to fit the data very well and follow the functional form:

$$A + \frac{B - A}{1 + \left(\frac{x}{C}\right)^{D}}$$

where A and B are the starting and ending adoption rates, respectively. For example, recycling has increased from 6.5% recovery rate 40 years ago to close to 35% in 2006 (EPA 2008). For the purposes of comparing and quantifying these behaviors, we parametrize these S-curves by 10%, 90% adoption percentages and 10-90 transition times in years in Table S17. With the exception of drunk driving fatalities, it can be seen that the time associated with behavior changes can take decades. Clearly these are not perfectly correlates to the energy space. In particular, public health and safety items can be mandated by laws and regulations and inspections – seat belt laws and drunk driving for example, that may not easily translate to energy related behaviors.

Several trends are abetted by a number of contributing factors such as increased awareness (smoking, recycling), authority figure awareness (physicians and smoking), labeling (smoking), policies (recycling and alcohol and tobacco “sin” taxes), improved infrastructure on varying scales (e.g. recycling bins), and improved technology (ease of purchasing boneless chicken versus whole chickens). Thus the final adoption rates are the result of many ongoing factors in information/awareness, infrastructure, and technology. Several energy behaviors can lend themselves to policy actions, education/awareness campaigns, labeling, and infrastructure to slowing increase adoption rates e.g. healthier diet, public transport, carpooling, etc.

Recycling has been on a steady upward climb in California for the past 20 years due to a number of factors and recently several communities have announced “Zero Waste” targets. On the other hand per capita generation of MSW is up 50% per capita in the U.S. since 1970 and we also note that VMT per capita is up 38% since 1970 in California.

Food calories per capita adjusted for losses and waste in the U.S is up 25% from 1970-2000, but the relative food loss and waste is down slightly from 30% to 27% of total food supply available for consumption.

We thus highlight four significant counter trends which have increased energy usage since 1970:

- Median size of new single family homes up 55% from 1970-2010.
- Food supply and calorie consumption up 26% per capita (68). From 1960 to 2006 the rate of obesity increased in U.S. adults from from 13.4 to 35.1 percent.
- VMT per capita up 38% in California since 1980.
- Higher generation of materials with per capita increase by 50%, especially plastics (69).

These are all significant trends but each has been influenced by state and national policies and each can be mitigated with policy as well. We assume that these factors do not increase further unless noted in the other demand sections of the report. This downward consumption trend is certainly plausible at least in the short term due to the ongoing recession and the need for private de-leveraging. Government policies can affect these trends as well such as tax policy which could be made more favorable to apartment renters, and USDA education policies which focus on less consumption rather than specific dietary guidelines which may be confusing (70).

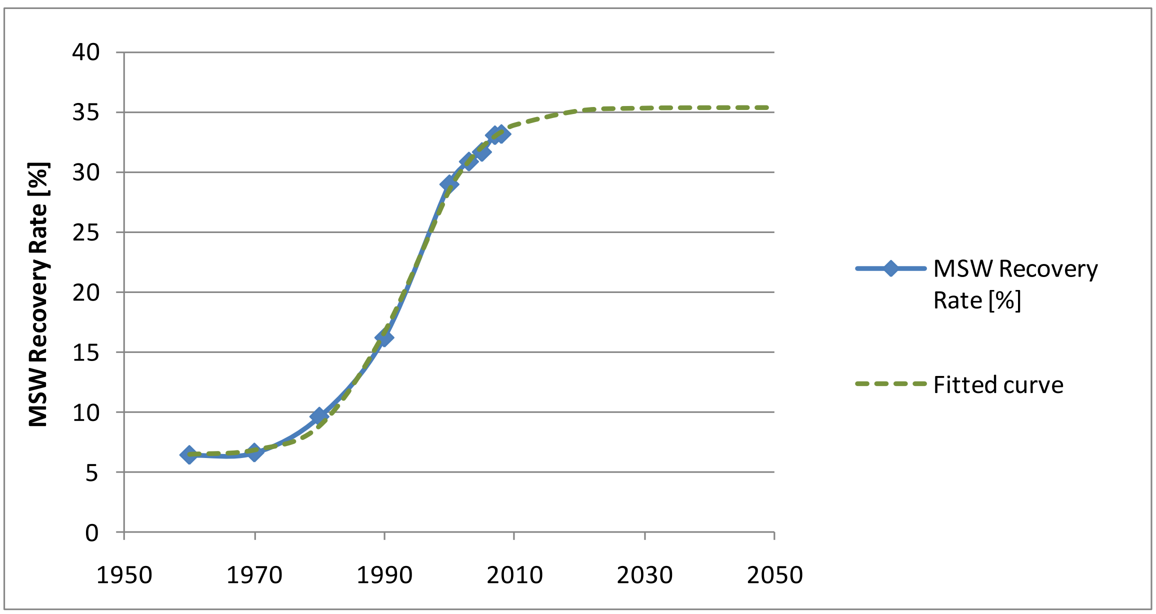


Figure S75. *Municipal solid waste (MSW) recovery rate for the United States (69). Data points are fit to adoption S-Curve.*

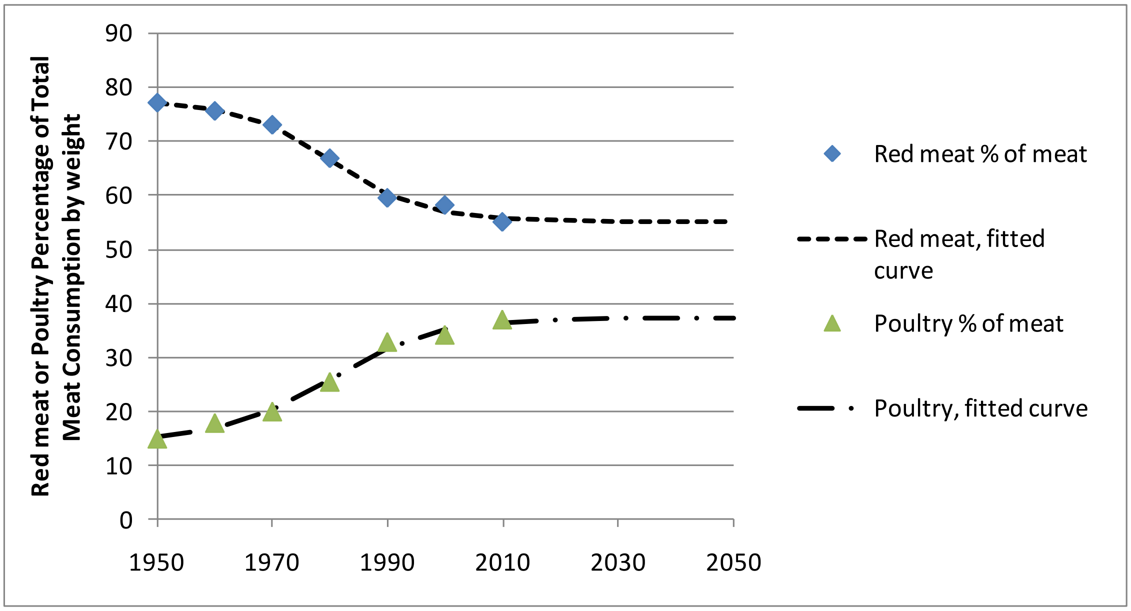


Figure S76. *Meat Consumption. (68) Data points are fit to adoption S-Curve.*

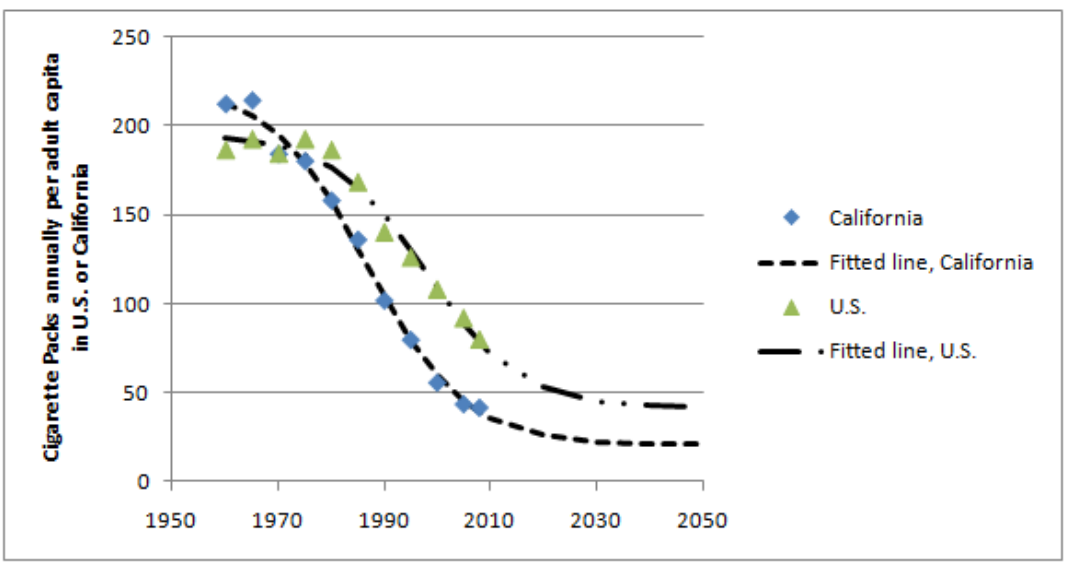


Figure S77. *Smoking – packs per adult capita for California (71) and the U.S. Data points are fit to adoption S-Curve.*

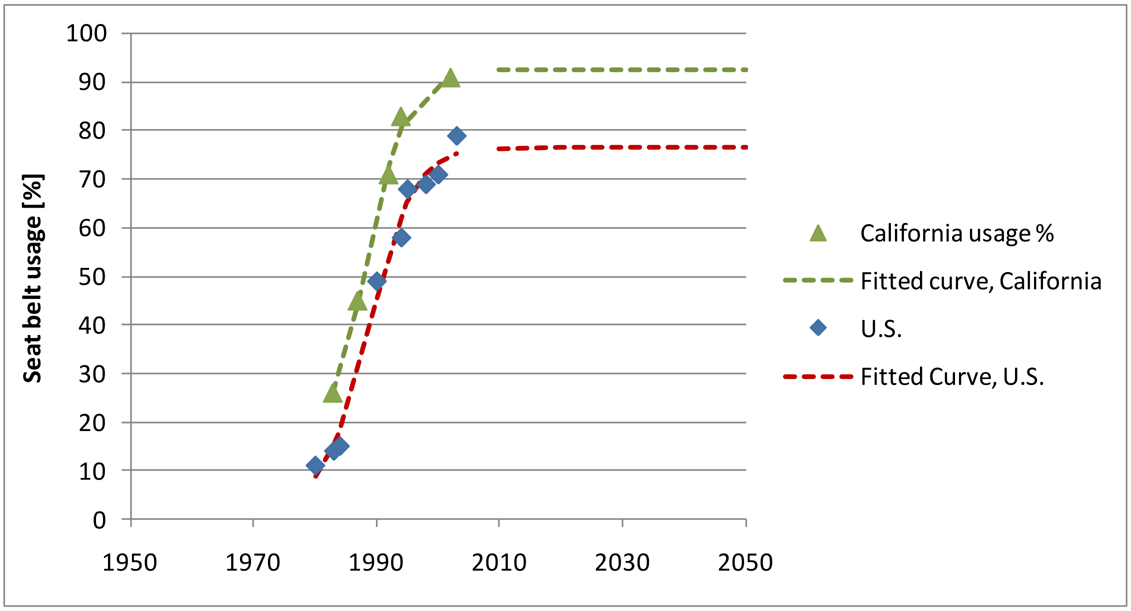


Figure S78 *Seat Belt Usage for U.S. (72) and California. Data points are fit to adoption S-Curve.*

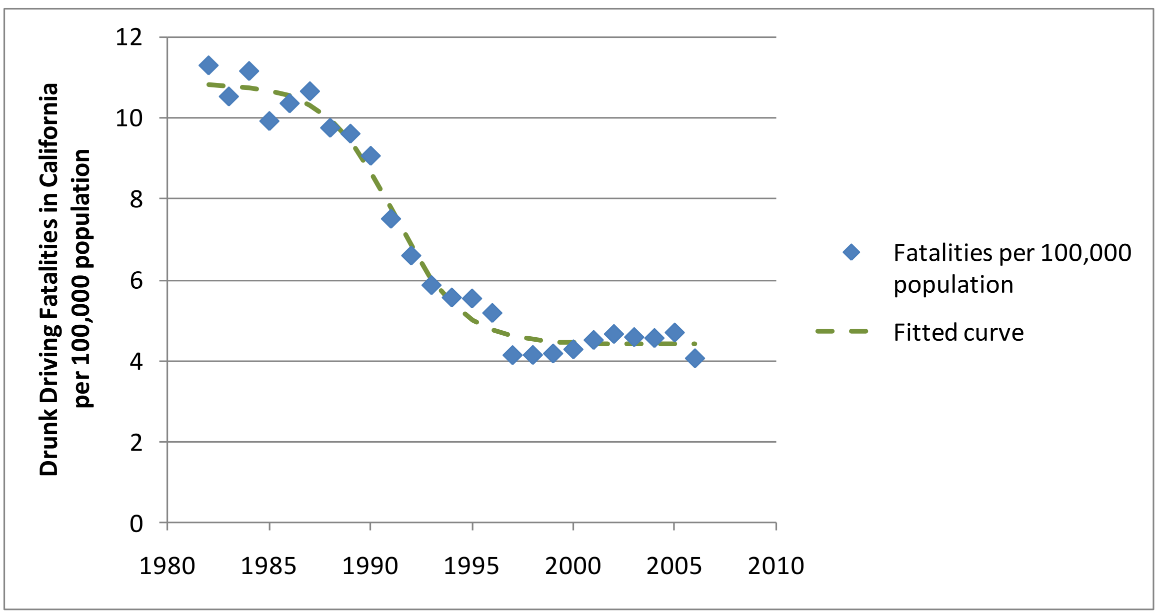


Figure S79 *Drunk driving fatality rate in California. Data points are fit to adoption S-Curve.*

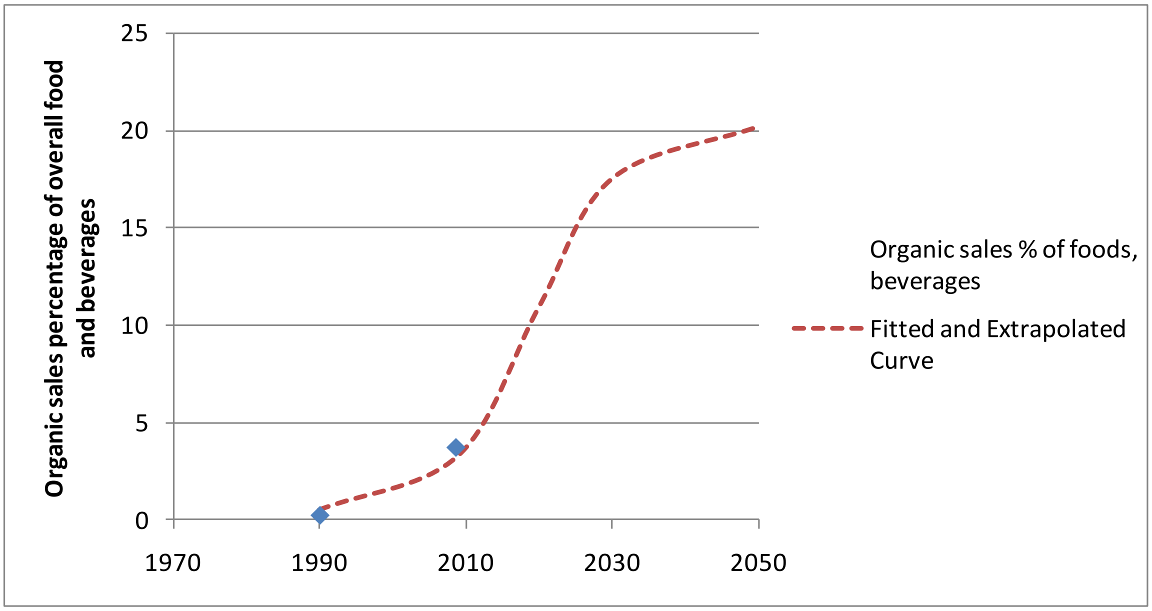


Figure S80. *Organic food percentage of total food and beverage sales. Data points to 2009. Fit curve extrapolated to 2050 to 20% adoption. In general, early adopters in a population are estimated at about 20% of population and this fraction of people expected to adopt organic food by 2050.*

Measure	10%	50%	90%	A	B	10-90% Time [years]
Recycling Rate, U.S.	1981	1993	2006	7%	35%	25
Seat Belt Usage, Calif.	1982	1989	1995	15%	93%	13
Seat Belt Usage, U.S.	1981	1989	1997	3%	77%	16
Drunk Driving, [fatalities per 100,000 pop.], Calif.	1987	1991	1995	10.9	4.4	8
Organic food, U.S. [1]	2006	2019	2032	0%	20%	26
Red Meat [% total meat wt], U.S.	1964	1980	1997	77%	55%	33
Poultry [% total meat wt], U.S.	1961	1980	2000	15%	37%	39
Smoking [annual packs per adult], Calif.	1967	1987	2007	223.0	20.7	40
Smoking [annual packs per adult], U.S.	1978	1998	2017	195.0	41.3	39
Yoga, U.S. [2]	2000	2010	2020	7%	7%	20
Vegetarian, U.S. [3]	1980	2000	2020	1%	10%	40

Table S17. *Characterization of historical behavior trends in recycling, diet and health.*

Notes:

[1] Organic food represents sales percentage of overall food and beverages and is projected to reach 20% in 2050.

[2] Recent results for yoga extrapolated to 2020

[3] Vegetarian rate extrapolated to 2020

9.4 Behavior Model

A core list of behaviors is listed in Table S15. They include "home energy conservation" measures, food/diet actions, and transportation measures. Home energy conservation measures include turning off or reducing end use electricity uses such as lighting and electronics, lower thermostat settings in winter, higher thermostats in summer, and reduced hot water usage through cold water dishwashing and clothes washing, and shorter showers. In general we focus on ongoing or habitual actions. Thus we do not include items such as home weather stripping, purchasing of more energy efficient vehicles or appliances, since both of these could in principle be mandated by building/housing regulations and/or appliance efficiency standards. There is gray area between actions which entail "lifestyle" changes. We include measures such as healthier diet and more use of public transit, but do not include smaller houses. The former certainly entail lifestyle change but could also be argued to enhance quality of life if co-benefits result such as improved health and well-being, or less unproductive time spent in congested traffic.

Some behaviors are difficult to maintain or may have a low terminal adoption. For example, line drying clothes may be too troublesome to be widely adopted. Vegetarianism seems slow to grow and we take 10% as an upper limit based on United Kingdom data. Similarly, limited data for regular activity such as yoga seems to suggest a flat or slightly decreasing trend.

Some measures have a take-back or rebound effect. For example, telecommuters may in fact use more home energy and take more trips of an errand nature while working at home, negating the energy savings that arise from less office energy use. We include a take-back reduction for telecommuting that is 25% of the GHG savings. No other take-back reductions are applied for other actions, however.

For each behavior a detailed characterization matrix has been developed (Table S16). Each behavior -- both historical and energy related actions -- is characterized with this matrix and each measure is cross-compared for similar attributes and barriers. Estimation of behavior adoption in 2050 can be informed by the following: extrapolation of existing trends including demographic trends, existing market segmentation and survey frameworks, and through utilization of historical behavior trends and our characterization matrix.

Here we utilize a survey framework to rate the attributes and behaviors of each behavior action . We use a committee of five behavior analysts within the LBNL/UC-Berkeley energy research community and take the average of their responses. Each behavior action, including historical behavior actions, are represented as an (i+j)th-dimensional vector with i entries for attributes, and j entries for barriers.

$$V_m = (a_1, a_2, a_3, \dots a_i, b_1, b_2, b_3, \dots b_j)$$

Attributes are rated on a scale of 1 to 5 for a low to high match to the attribute in question (e.g. ease of substitution, visibility of benefits). Similarly for barriers a high score indicates a more significant barrier (e.g. labor barriers, cultural barriers).

We then consider the vector distances between behavior vector V_m for action m and the set of historical vectors H_1, H_2, … H_n as an indicator for the correspondence between behaviors. A lower vector distance between V_m,H_i than between V_m,H_j indicates a greater correspondence with historical action i than with historical action j. Adoption rates in 2050 for action m are then estimated from weighted average of terminal adoption values for the three historical actions which best correspond with action m. Similarly, a high adoption rate in 2050 is found by either taking the maximum terminal value of the corresponding historical action.

Adoption rates are tabulated in Table S18. Additional actions were also considered but did not contribute significantly to overall GHG reduction are not shown here (composting, rechargeable batteries, wider scale organic food adoption, etc). We do not use detailed S-curves for adoption over time but basically take the terminal value as that at 2050 and a linear rate of increase from 2011 for simplicity.

Action	2050 Nominal Adoption rate	2050 High Adoption rate	Change in Behavior
Increase Recycling	80%	90%	90% overall recycling rate*
Reduce Municipal Solid Waste	22%	35%	33% less waste
Drive less (carpool, biking, reduced distances...)	16%	37%	30% lower VMT
Ecodriving (including trucks)	50%	80%	Lower top speed, reduce hard stops and starts
Take public transit	22%	35%	Overall public transit miles increase by 200%
Reduce air travel	29%	49%	Reduce air travel mile by 30%
Telecommute to work	20%	35%	Telecommute 4 days per month
Healthier diet	28%	37%	Less red meat and dairy, more plant based food
Waste less food	12%	20%	Waste 25% less food
Turning off electronics	57%	80%	Turn off electronics when not in use
Line dry clothes	13%	20%	Line dry clothes instead of dryer
Lower thermostat in winter	69%	80%	Turn down thermostat at night
Raise thermostat in summer	83%	87%	Higher daytime thermostat setting
Cold water dishwashing and clothes washing	36%	80%	Use cold water instead of hot water

Table S18. *Modeled adoption rates in 2050. *Recycling "adoption rates" are not adoption rates among the population but rather indicate overall recycling rate as percentage of available recoverable material.*

Estimated Conservation Savings

The calculation of GHG savings from behavior change has three important factors: (1) the energy associated with a given behavior; (2) the amount of potential energy efficiency savings associated with that behavior and (3) the carbon intensity associated with the fuels or electricity. For example, the production of a gallon of milk may have a given energy of production and distribution associated with it within the life cycle assessment boundary and this has associated GHG emissions with the current energy system. However over time, the energy associated with this consumption and production of milk may be reduced due to energy efficiency measures in the production of milk (production, pasteurization, bottling) and more efficient vehicles and concurrently carbon intensity may be reduced because of cleaner fuels (bio-based fuels for transport and/or cleaner electricity). Similarly for a reduction in vehicle miles travelled, there is improved vehicle efficiency over time coupled with cleaner fuels or vehicle electrification and cleaner electricity.

In addition, a fourth factor for CARB GHG accounting in the state is the boundary of energy expended or GHG emissions associated with the production of a product. Today imported emissions are not included in consumption or purchase of imported goods, so the LCA energy and emissions reduction would be reduced by the amount that is not currently counted in CARB GHG accounting conventions. Reduced consumption and recycling which leads to less energy and material inputs for production are two measures which are expected to have a relatively small California emissions fraction, as the trend has been for more imported goods from exporting countries such as China (Edwards 2010).

Thus a decomposition of GHG savings due to behavior changes can be written as:

$$GS(t) = ES_{LCA} * ES_{EEI} * CI(t) * BF(t)$$

where:

t = time
GS(t) = GHG savings
ES_{LCA} = LCA Energy Saved per unit of physical output (e.g. kg steel)
ES_{EEI} = Energy savings reduction due to continuous energy efficiency improvement
CI(t) = Carbon intensity [CO2-eq/ unit energy]
BF(t) = LCA boundary factor

It is worth emphasizing that current studies of GHG savings from actions e.g. recycling or diet quote GHG savings for a given snapshot in time, for a certain efficiency of production and distribution for the associated product, and for a certain carbon intensity associated with the energy of production.

We consider two energy system regimes for calculating the effects of long term behavior change:

(1) "RPS/LCFS" regime where more expensive clean energy requires regulation to achieve significant market share. In this case marginal demand reduction reduces both fossil and clean energy demand. For example, demand reduction of 20% translates into a 20% reduction in fossil based energy and clean energy production starting points. In this case, there can be diminishing returns to behavior changes as the overall energy system becomes cleaner e.g. through progressively higher RPS and LCFS standards.

(2) "Expensive" fossil fuel regime. Here marginal demand reduction is assumed to directly displace fossil fuel demand because clean energy supply sources are inexpensive relative to fossil fuels and/or because of a sufficiently high price of carbon. In contrast to the RPS/LCFS regime, there are constant returns to behavior change since behavior change energy savings translate one to one with reduced fossil fuel consumption, up to the point

where there is no fossil fuel remaining in the system. (Behavior model assumptions for both regimes are detailed in Appendix 4).

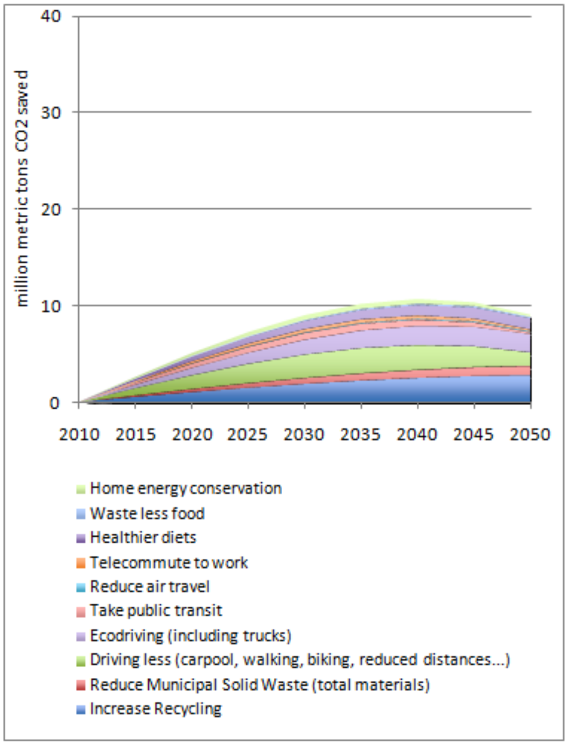
Figure S81 show the reduction to California CARB emissions under the nominal and high behavior adoption rates of Table S18 for the high in-state biofuels case in the “RPS/LCFS” regime. Several salient points can be made with this scenario for 2050. First CO2 reductions are 14.6Mt CO2eq for the high adoption case and 9.1 Mt for the nominal adoption case. This represents 9-15% emissions reduction from the high in-state biofuels starting point of 97Mt CO2. For the high adoption case, recycling contributes about a third of the behavior savings and the transportation measures (telecommuting, driving less, taking public transit, eco-driving and reduced air travel) contributes about one-half of the emission reductions. Note that these savings include both energy and non-energy savings (methane and nitrous oxide) but the bulk are from energy savings. Strictly speaking we could have split out these behavior savings into energy and non-energy sectors, but the team chose to keep these together to represent overall projected behavior savings.

Home energy conservation is a small contributor (<5% of total behavior emissions reduction) in our modeling. This is attributed to multiple factors in the future energy system: improving building shells and insulation will reduce the demand for space heating and space cooling while transitioning to highly efficient heat pump space heating and water heating will consume less energy; and finally the assumption that electricity is supplied by much cleaner sources.

In both nominal and higher adoption case, we observe that some behavior components bend downward over time (driving less) and overall behavior savings reaches a maximal value and then rolls off after that. This is because the rate of de-carbonization from the adoption of low carbon technologies (biofuels and electric vehicles) is greater than the rate of VMT reduction from behavior changes.

Behavior savings for the high in-state biofuels scenario with nominal adoption and high adoption savings in the “expensive fossil fuel” regime where all marginal demand savings translate into fossil fuel demand reduction are show in Figure S82. Here there are constant returns behavior change (up to the point at which all fossil fuels have been displaced) and much larger overall savings. CO2 reductions are 39.2Mt CO2eq for the high adoption case and 20.6Mt for the nominal adoption case. This represents 21-40% emissions reduction from the high in-state biofuels starting point of 97Mt CO2. As before, transportation measures dominate with almost 80% of the savings. We did not study the impact of food waste reduction and MSW reduction on in-state biofuel production but the reduction in waste is also offset by the increased recycling rate.

A matrix of output for each action will be presented in a separate analysis paper detailing the amount of energy savings or VMT reduction, the carbon-intensity reduction (CO2/unit energy or CO2/unit mile) and finally the amount of GHG savings. The energy savings is important to keep in mind as the energy system becomes decarbonized because there will be other non-carbon savings associated with continued energy savings such as physical investment/infrastructure costs, other non-CO2 emissions, and resource consumption.



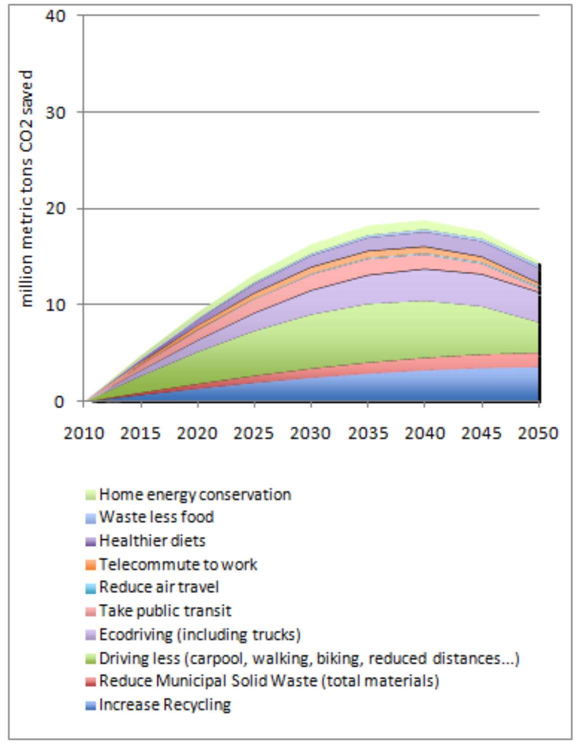


Figure S81. *Behavior change (conservation) savings for the high in-state biofuels scenario with nominal adoption (left) and high adoption (right) savings in "RPS/LCFS" regime of higher cost clean energy.*

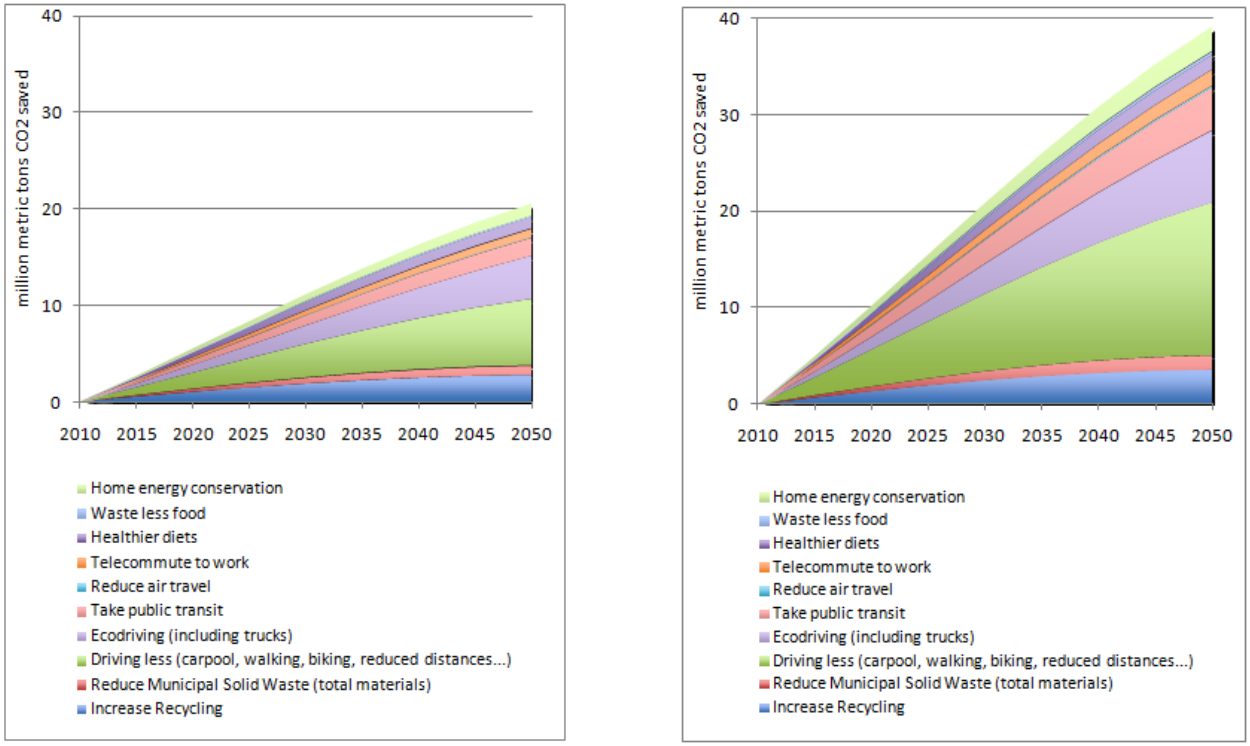


Figure S82. *Behavior change (conservation) savings for the high in-state biofuels scenario with nominal adoption (left) and high adoption (right) savings in the "expensive fossil fuel" regime where all marginal demand savings translate into fossil fuel demand reduction.*

Overall savings from behavior change in 2050 are depicted in Fig. 11-9, again starting from the high in-state biofuels case. Transportation measures are seen to be the main contributor. Recycling, reduction in municipal solid waste, healthier diet and home energy conservation measures contribute as well. We will see in the next chapter that most emissions remaining in our scenarios are from fuel combustion and here we have shown that behavior actions that reduce fuel usage and transportation fuel in particular have a large impact on reducing GHG emissions.

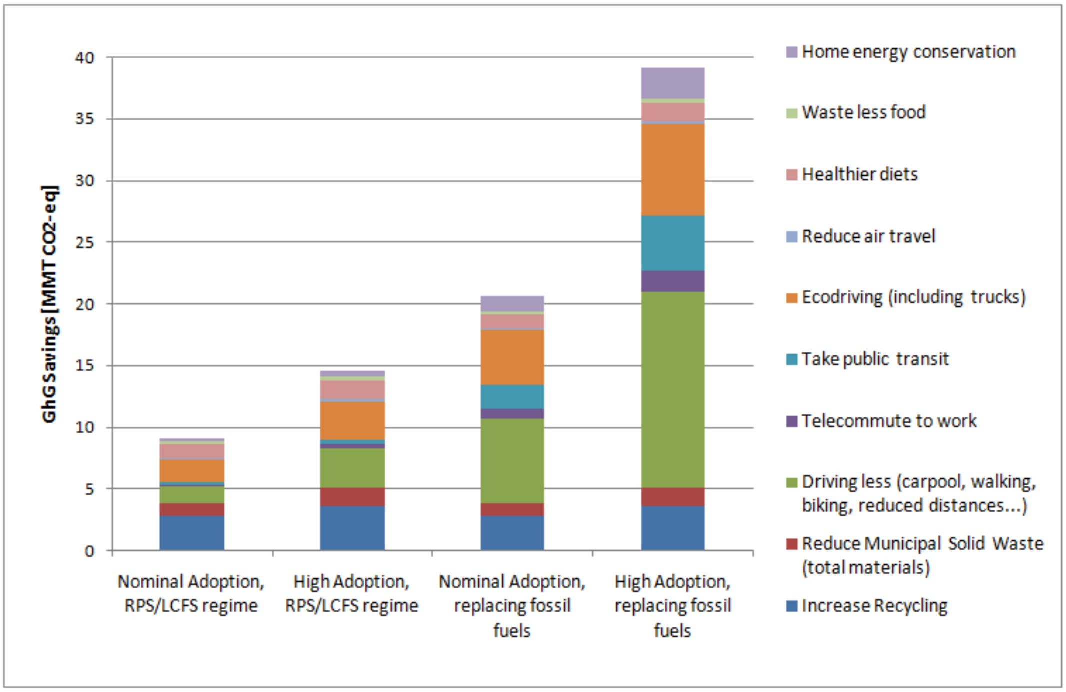


Figure S83. *2050 conservation savings from behavior change for nominal and high adoption for two treatment regimes, starting from high in-state biofuels case.*

Policy Implications

The largest impact items are transportation actions and increased recycling. Home energy conservation measures have smaller impact because of our assumptions regarding the evolution of the energy system. Transportation measures include smart growth policies (higher density developments with mixed use), traffic congestion charges to discourage use of passenger vehicles in central areas, increased funding for mass transit systems such as light rail and bus systems, incentives for carpooling, training programs for eco-driving and telecommuting energy savings optimization (Table S19). Clearly a large policy lever for transportation can be a higher gasoline tax and/or carbon charge for liquid fuel usage.

Here we would suggest that along with a concerted effort for long term energy system and supply changes as outlined in Sections 9 and 10 above, the state consider a set of policies focusing on reducing VMT, improving diets and increasing recycling/reducing solid waste. Reducing VMT can be done with measures that enable and encourage greater adoption of public transit, discourage use of automobiles, provide incentives for reduced single passenger vehicle use, etc. For recycling, strategies could focus on lower consumption and greater re-use, encouragement of zero waste programs, working with manufacturers to reduce packaging, encouraging re-use of products and re-use and recycle to be built into product design. Healthier diets can be encouraged by public information campaigns, increased food labeling, and junk food taxes.

Developing, testing, and implementing policies and technologies that can further abet the long adoption of these actions is an area for future study.

	Policy/Organization	Example Policies	Technology
Transportation			
Telecommute	Employers/ Companies	Flexible work policies; work at home protocols	Flexible office space; Improved software and hardware; improved commercial building controls
Reduced VMT	Smart growth (Integrated housing, transportation, commercial and land use planning), urban in-fill	SB375	Instant carpooling technology
	Employers/ Companies	Employer sponsored carpooling / shuttles	
	Federal, state or local taxation agency	Gasoline tax offset by reduced payroll tax or to provide alternate transit services	
	Various EU countries	Urban center higher parking fees, longer traffic lights, congestion charges (Rosenthal 2011)	
Public transit	Employer programs	Bus/rail subsidy through employer coupled with government incentives/rebates	
	Smart Growth policy	SB375	
Eco-driving	DMV, Driver's Education programs, Companies with large vehicle fleets	Eco-driving training and testing	Improved automotive feedback
Food and Diet			
Healthy diet	Federal, state and local jurisdictions	Public information campaign; Healthy food in schools; Food labeling; junk food tax	In-vitro meat
Reduced food waste	Federal, state and local jurisdictions	Public information campaign	
Recycling/ Less MSW generation	Zero waste Oakland	Zero Waste targets	
		Packaging charges	
		Rebates/ incentives for service and repair shops	

Table S19. *Policies, organizations, and technologies supporting long term behavior change.*

10. GHG EMISSIONS – SCENARIO RESULTS

10.1 2050 emissions

2050 California GHG emissions for the base case are shown in Figure S84. The impact of each of the four key elements taken by itself is shown and then the base case which combines all four elements. The important takeaway is that a portfolio of approaches is needed to meet the 2050 target (80MtCO2eq) and that any one element on its own is insufficient and very far from the target. The base case, which includes all four elements, is much closer to meeting the target but still above the target at 130MtCO2-eq.

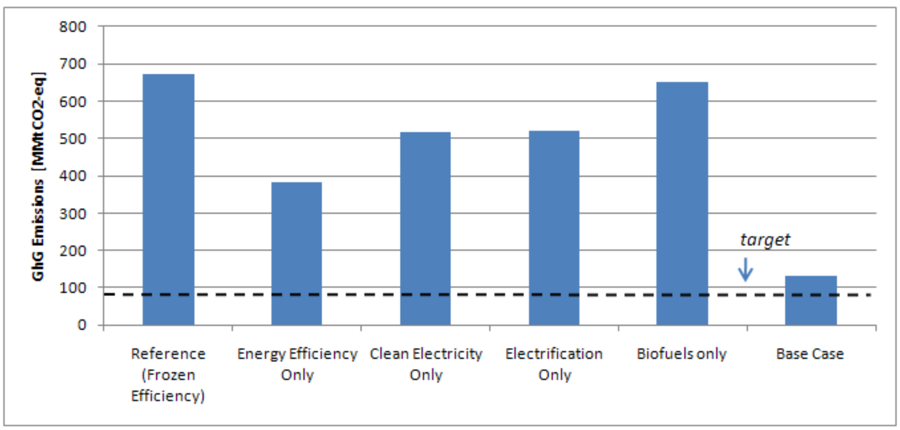


Figure S84. *2050 California GHG energy emissions. Base case include all four depicted elements (technical potential energy efficiency, clean electricity, electrification, biofuels).*

2050 California GHG emissions for all the modeled scenarios are shown in Table S20 and a subset of scenarios in Figure S85. All non-reference case scenarios assume technical potential efficiency and electrification of heating and vehicles, and all but the biomass CCS assume at least 3.7Bgge biofuel supply. All modeled scenarios include a carbon cap on electricity emissions in the WECC: 100% CO2 reduction from 1990 electricity emissions or carbon neutrality is assumed for the biomass CCS cases while all other cases require 80% CO2 reduction from 1990. Several scenarios can meet or come close to meeting the 2050 target of 80Mt CO2eq for energy emissions:

- high electrification with energy conservation savings (84 Mt);
- high in-state biofuels and energy conservation savings (81Mt);
- biomass CCS with high in-state biomass (79 Mt):
- high in-state biofuels and high biofuel imports (74Mt); and
- high in-state biofuels and high electrification (71Mt).

Scenario	Efficiency	Electrification of Heating and Vehicles	Electricity Supply (SWITCH)	2050 Carbon Cap for Electricity [% reduction from 1990 Emission Levels]	In-State Biomass	SWITCH biomass supply curve [Mdt]	Biomass for fuel [Mdt]	Instate Biofuel [Bgge]	Imported biofuel [Bgge]	California Energy Emissions [MMtCO2eq]	Emissions With Nominal Behavior Savings [MMtCO2 eq]	Emissions With High Behavior Savings [MMtCO2 eq]	Emissions with Nominal Behavior savings replacing fossil fuel	Emissions with High Behavior savings replacing fossil fuel
Frozen Efficiency	Frozen Efficiency	BAU	Without carbon cap	N/A	BAU					671	636	605	636	605
Frozen Efficiency + Electricity Cap	Frozen Efficiency	BAU	With carbon cap		BAU					512	479	450	477	446
Base case			Base case		Low, for liquid fuels					130	119	112	109	91
High Nuclear			Inexpensive nuclear		Low, for liquid fuel					130	119	112	109	91
High CCS			Inexpensive CCS		Low, for liquid fuel	0	35	2.8	0.93	130	119	112	109	91
No CCS			All CCS excluded	80%	Low, for liquid fuel					130	119	112	109	91
No CCS or New Nuclear			No CCS or New Nuclear		Low, for liquid fuel									
High Solar and Wind			Inexpensive solar and		Low, for liquid fuel					130	119	112	109	91
Expensive Photo-voltaics		Median (Base case level)	Expensive Photo-voltaics		Low, for liquid fuel					130	119	112	109	91
Biomass CCS	Tech. Potential		Biomass CCS	100%	Low, for electricity	23	12	1.0	0.3	124	113	106	103	85
Biomass CCS + Hi in-state biomass			Biomass CCS	100%	High, for electricity and liquid fuel	23	71	5.7	1.9	91	83	79	70	52
High in-state biofuels					High, for liquid fuel				2.5	97	88	81	76	58
Hi in-state & High imported biofuels					High in-state + High imports, for liquid fuel		94	7.5	7.5	74	66	62	66	62
High Electrif.		High	Base case	80%	Low, for liquid fuel	0	35	2.8	0.9	99	90	84	78	60
High Electrif. & High in-state biofuels		High			High, for liquid fuel		94	7.5	2.5	71	63	59	63	59

Table S20. *Summary of 2050 California GHG emissions for various modeled scenarios. All non-reference case scenarios assume technical potential energy efficiency, and electrification of heating and vehicles. Shaded boxes represent scenarios which meet the 81Mt target.*

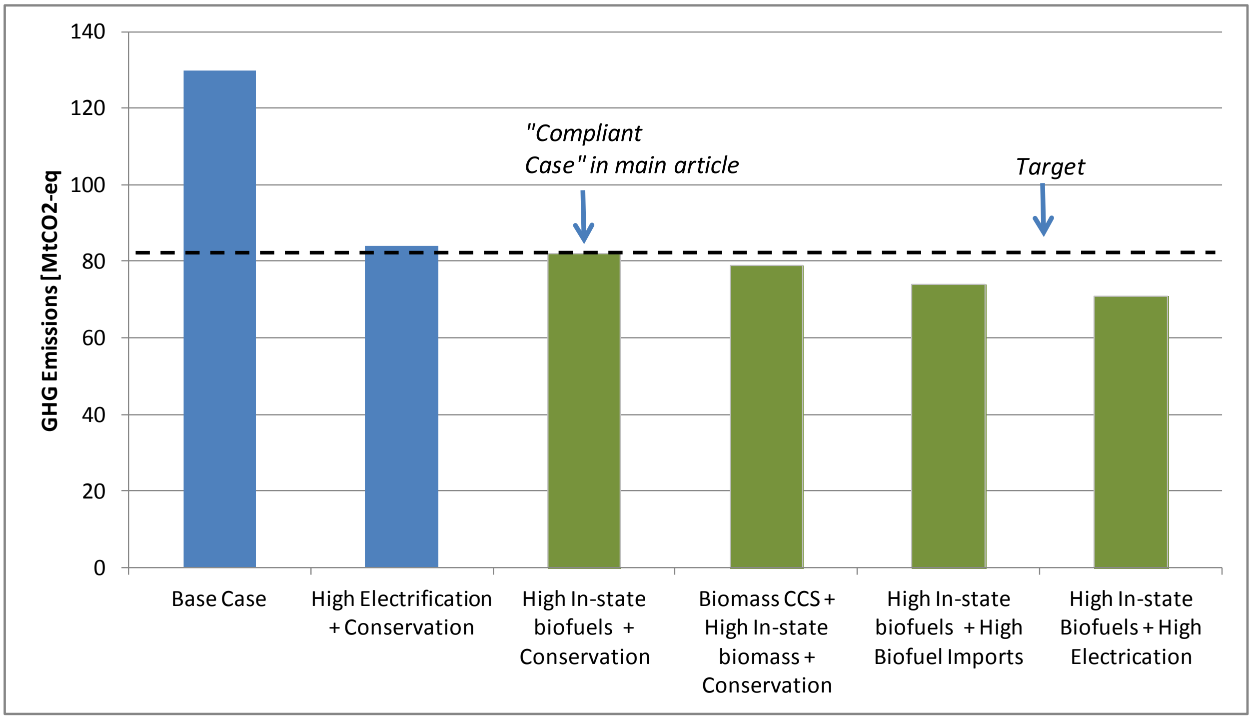


Figure S85. *2050 California GHG emissions for base case variants. Several scenarios meet or are very close to the 2050 target.*

The reference (frozen efficiency) case has 671Mt emission in 2050. Applying an 80% carbon cap to the electricity sector reduces this to 512 Mt (the "low-GHG electricity only" bar in Figure S84). The base case and electricity system variants have final overall emissions of 130Mt. (Fuller description of the electricity system cases is provided in Section 10). Here we note again that an external carbon cap was set on the electricity system and there is no feedback between the electricity sector and the non-electricity sector (e.g. no impact to industry or manufacturing energy demand as a function of electricity supply mix).

Moving from low in-state biofuel supply in the base case to high in-state supply reduces overall emissions from 130Mt to 97 Mt while moving from the base case to the high electrification case reduces emissions to 99Mt. Similar impacts of about 25% emissions reduction are observed for high in-state bio fuels or high electrification, versus the base case. It would be thus interesting to study the cost impacts of each variant to maximize benefit/cost impact to the state. We did not consider a case of even higher energy efficiency that would take into account out of paradigm technologies (e.g. non-compressive HVAC systems), system integration and integrated design approaches. Future work will also explore further cases of carbon neutrality or net negative emissions in the electricity sector.

Two cases are found to meet the 80 Mt target without any additional behavior change savings: the high in-state biofuels case with either high imported biofuels or with high electrification. Adding high adoption behavior can reduce energy emissions to around 60Mt or about 20Mt below the target.

However, in the former case, imported biofuels would exceed the 25% limit of overall supply (Executive order S-06-06, 2006) in 2050 and the latter case would require almost a complete phase-out of conventional internal combustion vehicles by 2050 and is probably best viewed as an illustrative bounding case for maximal EV penetration.

10.2 High In-state Biofuels Case

We consider the high in-state biofuels case in greater detail since this case has base case efficiency and electrification and meets the goal of 75% in-state produced biofuels. Moving from low in-state biofuels to high in-state biofuels reduces overall emission from 130MT to 97Mt CO2eq in 2050. The overall modeled GHG trend is show in Figure S86 showing a sharp reduction in emissions across most sectors. In particular, transportation sector emissions are reduced from vehicle electrification and biofuels and the oil and gas industry is reduced by about two-thirds. The electricity sector is also reduced about 80% from current levels due to shifting to clean power supply sources. The black solid line represents total emissions after assuming high behavior change adoption replacing fossil fuels and is seen to meet the 2050 target at 81 Mt ("Compliant Case"). Referring to Table S20, it can be seen that some combination of incrementally higher electrification, imported biofuels (albeit above the 25% import target) or behavior savings can further reduce emissions for this case to meet the 2050 target. If future policy or carbon economics move the state to a regime where behavior savings translate directly into fossil fuel savings, then high in-state biofuels with nominal behavior savings are sufficient to meet the target (76 Mt).

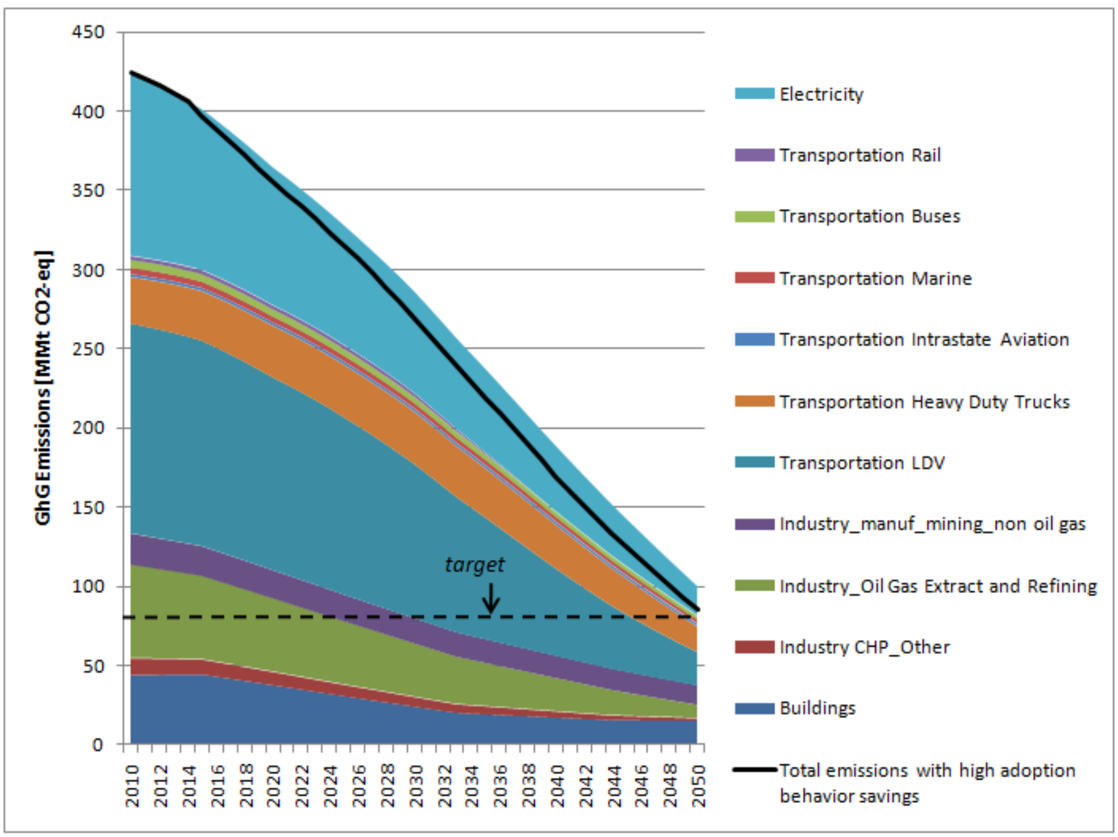


Figure S86. *High in-state biofuels case. The solid line represents total emissions after high behavior (conservation) savings and meets the target in 2050 (dashed line).*

10.3 Conservation Savings

Behavior change (conservation) savings are between 11 and 18 Mt for the base case for low and high adoption rates or 8-14% savings. Across the scenarios, behavior savings range from 8% to 17%. Savings are also calculated assuming that behavior savings translated directly into fossil fuel savings. In this case, savings become 21Mt and 39Mt (16% and 30% savings) respectively for the base case.

One can also ask how much behavior change savings would be required in a given scenario to meet the target. For example, the base case and high biofuel supply cases have overall emissions of 130Mt and 97Mt implying that behavior change savings of 38% and 18%, respectively, would be required to meet the target.

Behavior savings with our estimated high adoption rates allow several cases to either meet the target of come very close to meeting it: the biomass CCS, high in-state biofuels, and high electrification cases. As noted in the behavior section above much of the behavior savings are from reduced liquid fuel consumption from transportation measures and savings are reduced as the fuel system becomes cleaner.

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APPENDIX 1: SWITCH MODEL DATA DESCRIPTION FOR THE CALIFORNIA CARBON CHALLENGE

SWITCH was created at the University of California, Berkeley by Dr. Matthias Fripp (Fripp 2008). The version of SWITCH used in this study is maintained and developed by Ph.D. students James Nelson, Ana Mileva, and Josiah Johnston in Professor Daniel Kammen's Renewable and Appropriate Energy Laboratory at the University of California, Berkeley.

SWITCH Model Description

1. Study Years, Months, Dates and Hours

To simulate power system dynamics in WECC over the course of the next forty years, four levels of temporal resolution are employed by the SWITCH model: investment periods, months, days and hours. For this study, a single investment period contains historical data from 12 months, two days per month and six hours per day. There are four ten-year long investment periods: 2015-2025, 2025-2035, 2035-2045, and 2045-2055 in each optimization, resulting in (4 investment periods) x (12 months/investment period) x (2 days/month) x (6 hours/day) = 576 study hours over which the system is dispatched. The middle of each period is taken to represent the conditions within that period, e.g. results presented in this report for the year 2050 originate directly from the 2045-2055 investment period.

The peak and median day from each historical month are sampled to represent a large range of possible load and weather conditions over the course of each investment period. Each sampled day is assigned a weight: peak load days are given a weight of one day per month, while median days are given a weight of the number of days in a given month minus one. This weighting scheme ensures that the total number of days simulated in each investment period is equal to the number of days between the start and end of that investment period, emphasizes the economics of dispatching the system under 'average' load conditions, and forces the system to plan for capacity availability at times of high grid stress.

Weather conditions and the subsequent output of renewable generators dependent on these conditions can be correlated not only across renewable sites in space and time, but also correlated with electricity demand. A classic example of this type of correlation is the large magnitude of air conditioning load that is present on sunny, hot days. To include these correlations in SWITCH as much as possible, time-synchronized, historical hourly load and generation profiles for locations across WECC are employed. Dates in future investment periods correspond to a distinct historical date from 2006, for which historical data on hourly loads, simulated hourly wind capacity factors, and monthly hydroelectric availability over the Western United States, Western Canada, and Northern Baja Mexico are used. Solar capacity factors are calculated from hourly 2005 solar isolation data, as 2006 data was not available in the proper form. The day of year and hour of day is synchronized between the 2005 solar data and the 2006 wind and load data, thereby maintaining diurnal and seasonal correlations between load, wind, and solar. Hourly load data is scaled to projected future demand as is discussed in the description of the Base Case, Frozen Efficiency and Extra Electrification load profiles, while solar, wind and hydroelectric resource availability is used directly from historical data.

To make the optimization computationally feasible, each day is sampled every four hours, thereby including six distinct hours of load and resource data in each study date. For median days, hourly sampling begins at midnight Greenwich Mean Time (GMT) and includes hours 0, 4, 8, 12, 16, and 20. For peak days, hourly sampling is offset to ensure the peak hour is included, which may be at 14:00 Pacific Standard Time (PST) on some days and 15:00 PST on other days. These varying offsets can be seen upon close examination of hourly dispatch figures in the results section.

2. Important Indices

Important Sets and Indices		
Set	***Index***	***Description***
I	i	investment periods
M	m	months
D	d	dates
T	t	hours
$T_d \subset \mathrm{T}$	--	set of all hours on date d
$T_i \subset \mathrm{T}$	--	set of all hours in investment period i
A	a	load areas
LSE	lse	load-serving entities
BA	ba	balancing areas
F	f	fuel categories
$R \subset F$	r	set of RPS-eligible fuel categories
G	g	all generators
$C \subset G$	c	dispatchable generators
$VD \subset G$	vd	intermittent distributed generators
$VN \subset G$	vn	intermittent non-distributed generators
$B \subset G$	b	baseload generators
$S \subset G$	s	storage projects
$P \subset G$	p	pumped hydroelectric projects
$H \subset G$	h	non-pumped hydroelectric projects
$G_a \subset G$	--	set of generators in load area a
$C_a \subset C$	--	set of dispatchable generators in load area a
$VD_a \subset VD$	--	set of intermittent distributed generators in load area a
$VN_a \subset VN$	--	set of intermitted non-distributed generators in load area a
$B_a \subset B$	--	set of baseload generators in load area a

$S_a \subset S$	--		set of storage generators in load area *a*
$P_a \subset P$	--		set of pumped hydroelectric generators in load area *a*
$H_a \subset H$	--		set of hydroelectric generators in load area *a*
$G_{ba} \subset G$	--		set of generators in balancing area *ba*
$C_{ba} \subset C$	--		set of dispatchable generators in balancing area *ba*
$VD_{ba} \subset VD$	--		set of intermittent distributed generators in balancing area *ba*
$VN_{ba} \subset VN$	--		set of intermitted non-distributed generators in balancing area *ba*
$B_{ba} \subset B$	--		set of baseload generators in balancing area *ba*
$S_{ba} \subset S$	--		set of storage generators in balancing area *ba*
$P_{ba} \subset P$	--		set of pumped hydroelectric generators in balancing area *ba*
$H_{ba} \subset H$	--		set of hydroelectric generators in balancing area *ba*
$A_{lse} \subset A$	--		set of load areas in load-serving entity *lse*

3. Decision Variables: Capacity Investment

The model's first set of decision variables consists of the following infrastructure investment choices for the power system, which are made at the beginning of each ten-year investment period.

Capacity Investment Decision Variables:

1. Amount of new generation capacity to install of each generator type in each load area
2. Amount of transmission capacity to add between each pair of load areas
3. Whether to operate each existing power plant in each period

Investment Decision Variables	
$G_{g,i}$	Capacity installed in period *i* at plant *g* (further subdivided into generator types including dispatchable plants *c*, baseload plants *b*, storage plants *s*, hydroelectric plants *h*, and pumped hydroelectric plants *p*)
$CG_{c,i}$	Capacity installed in period *i* at dispatchable project *c*
$VDG_{vd,i}$	Capacity installed in period *i* at distributed intermittent project *vd*
$VNG_{vn,i}$	Capacity installed in period *i* at non-distributed intermittent project *vn*
$BG_{b,i}$	Capacity installed in period *i* at baseload project *b*
$T_{a,a',i}$	Capacity installed in period *i* between load area *a* and load area *a'*

$SG_{s,i}$	Capacity installed in period i at storage project *s*

Generation and storage projects can only be built if there is sufficient time to build the project between present day and the start of each investment period. This is only important for projects with long construction times such as nuclear plants and compressed air energy storage projects, which could not be finished by 2015, even if construction began today. Carbon Capture and Sequestration (CCS) generation cannot be built in the first investment period of 2015-2025, as this technology is not likely to be mature enough to able to be deployed at large (GW) scale before 2020. New nuclear plants must have a minimum capacity of 1 GW to reflect the minimum feasible nuclear plant size. Installation of resource-constrained generation and storage projects cannot exceed the maximum available resource for each project.

During each investment period, the model decides whether to operate or retire each of the ~800 existing power plants in WECC. All existing plants except for nuclear plants are forced to retire at the end of their operational lifetime. Nuclear plants can extend operation past their operational lifetime, but are required to pay operations and maintenance, as well as fuel costs for which any period in which they are operational. Hydroelectric facilities are required to operate throughout the whole study as, in addition to their value as electric generators, they also have much value in controlling stream flow.

New high-voltage transmission capacity is built along existing transmission corridors between the largest capacity substations of each load area. If no transmission corridor exists between two load areas, new transmission lines can be built at 1.5 times the straight-line transmission cost of \$1000 $MW^{-1}mi^{-1}$, reflecting the difficulty of transmission siting and permitting. Transmission can be built between adjacent load areas, non-adjacent load areas with primary substations less than 300 km from one another, and non-adjacent load areas that are already connected by existing transmission. Existing transmission links that are approximated well by two or more shorter links between load areas are removed from the new expansion decisions. Investment in transmission lines greater than 300 km in length is approximated by investment in a handful of shorter links.

Investment in new local transmission and distribution within a load area is included as a sunk cost and hence does not have associated decision variables.

4. Decision Variables: Dispatch

4.1. Generation Dispatch

The second set of decision variables includes choices made in every study hour about how to dispatch generation, storage, and transmission in order to meet load.

Dispatch Decision Variables:

1. Amount of power to generate from each dispatchable (hydroelectric or natural gas) generator in each load area in each hour
2. Amount of power to transfer along each transmission corridor in each hour
3. Amount of power to store and release at each storage facility (pumped hydroelectric, compressed

air energy storage, and sodium-sulfur battery plant) in each hour

Hourly dispatch decisions are not made for baseload generators because this type of generator, if kept running in an investment period, is assumed to produce the same amount of power in each hour of that period. Hourly dispatch decisions are also not made for intermittent renewable generators such as wind and solar because renewable facilities produce an amount of power that is exogenously calculated: an hourly capacity factor is specified based on the weather conditions on the corresponding historical hour at the location of each renewable plant. Excess renewable generation can occur in any hour - the excess is simply curtailed.

Dispatch Decision Variables	
$O_{g,t}$	Energy output of plant *g* in hour *t* (further subdivided into generator types including dispatchable plants *c*, baseload plants *b*, storage plants *s*, hydroelectric plants *h*, and pumped hydroelectric plants *p*)
$C_{c,t}$	Energy dispatched in hour *t* from dispatchable project *c*
$Tr_{a,a',t}$	Power dispatched in hour *t* along the transmission line between load area *a* and load area *a'*
$S_{s,t,f}$	Energy stored in hour *t* of fuel category *f* at storage project *s*
$R_{s,t,f}$	Energy released in hour *t* of fuel category *f* from storage project *s*
$H_{h,t}$	Energy dispatched in hour *t* from non-pumped hydroelectric project *h*
$PH_{p,t,f}$	Watershed energy dispatched in hour *t* of fuel category *f* from pumped-hydroelectric project *p*
$PHD_{p,t,f}$	Stored energy dispatched in hour *t* of fuel category *f* from pumped-hydroelectric project *p*
$PHS_{p,t,f}$	Energy stored in hour *t* of fuel category *f* at pumped-hydroelectric project *p*
$SP_{g,t}$	Spinning reserve provided by thermal dispatchable generator *g* in hour *t* (variable used only for dispatchable generators *c*)
$Q_{g,t}$	Quickstart capacity provided by thermal dispatchable generator *g* in hour *t* (variable used only for dispatchable generators *c*)
$OP_{g,t}$	Operating reserve (spinning and quickstart) provided by hydroelectric (*h*), pumped hydroelectric (*p*), and storage (*s*) plants in hour *t*

4.2. Dispatch of Operating Reserves

Operating reserves in the WECC are currently determined by the 'Regional Reliability Standard to Address the Operating Reserve Requirement of the Western Interconnection,'[15] This standard dictates that contingency reserves must be at least: "the sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation." At least half of those reserves must be spinning. In practice, this has usually meant a spinning reserve requirement of 3 percent of load and a quickstart reserve requirement of 3 percent of load. Similarly, the WECC version of SWITCH holds a base operating reserve requirement of 6 percent of load in each study hour, half of which is spinning. As operating reserves are a subhourly ancillary service, this represents the average amount necessary over the course of an hour. In addition, 'variability' reserves equal to 5 percent of the

[15] Available at: http://www.nerc.com/files/BAL-STD-002-0.pdf.

wind and solar output in each hour are held to cover the additional uncertainty imposed by generation intermittency.

SWITCH's operating reserve requirement is based on the "3+5 rule" developed in the Western Wind and Solar Integration Study as one possible heuristic for determining reserve requirements that is "usable" to system operators (GE Energy 2010). The 3+5 rule means that spinning reserves equal to 3 percent of load and 5 percent of wind generation are held. When keeping this amount of reserves, the report found, at the study footprint level there were no conditions under which insufficient reserves were carried to meet the implied $3\Delta\sigma$ requirement for net load variability. For most conditions, a considerably higher amount of reserves were carried than necessary to meet the $3\Delta\sigma$ requirement. Performance did vary at the individual area level, so in the future customized reserve rules may be implemented for different areas.

The size of the entity responsible for providing balancing services is important both in terms of ability to meet the reserve requirement and the cost of doing so. The sharing of generation resources, load, and reserves through interconnection and market mechanisms is one of the least-cost methods for dealing with load variability. Multiple renewable integration studies have now also demonstrated the benefits of increased balancing area size (through consolidation or cooperation) in managing the variability of intermittent renewable output. At present, WECC operates as 39 balancing areas (GE Energy 2010), but in light of the large benefits of increased balancing area size, their functions will likely be consolidated in the future. The Western Wind and Solar Integration Study assumes five regional balancing area in WECC for operating reserves – Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California – as their "statistical analysis showed, incorporating large amounts of intermittent renewable generation without consolidation of the smaller balancing areas in either a real or virtual sense could be difficult." Similarly, the WECC version of SWITCH assumes the primary NERC subregion as the balancing area in its optimization. Six balancing areas are modeled: Arizona-New Mexico (AZNMSNV), Rocky Mountain (RMPA), California (CA), Pacific Northwest (NWPP), Canada (NWPP Canada), and Mexico (MX).

Currently the model allows natural gas generators (including gas combustion turbines, combined-cycle natural gas plants, and stream turbine natural gas plants), hydro projects, and storage projects (including CAES, NaS batteries, and pumped hydro) to provide spinning and non-spinning reserves. It is assumed that natural gas generators back off from full load and operate with their valves partially closed when providing spinning reserves, so they incur a heat rate penalty, which is calculated from the generator's part-load efficiency curve (London Economics and Global Energy Decisions, 2007). Natural gas generators cannot provide more than their 10-min ramp rates in spinning reserves and must also be delivering useful energy when providing spinning reserves as backing off too far from full load quickly becomes uneconomical. Hydro projects are limited to providing no more than 20 percent of their turbine capacity as spinning reserves, in recognition of water availability limitations and possible environmental constraints on their ramp rates.

5. Objective Function and Economic Evaluation

The objective function includes the following system costs:

1. capital costs of existing and new power plants and storage projects
2. fixed operations and maintenance (O&M) costs incurred yearly by all active power plants

and storage projects

3. variable costs incurred for each MWh produced by each plant, including variable O&M costs, fuel costs to produce electricity, and any carbon costs of greenhouse gas emissions
4. capital costs of new and existing transmission lines and distribution infrastructure
5. annual O&M costs of new and existing transmission lines and distribution infrastructure

Objective function: minimize the total cost of meeting load			
Generation and Storage	Capital	$\sum_{g,i} G_{g,i} \cdot c_{g,i}$	The capital cost incurred for installing capacity at plant g in investment period i is calculated as the generator size in MW $G_{g,i}$ multiplied by the capital cost (including installation and connect costs) of that type of generator in \$2007 / MW $c_{g,i}$.
Generation and Storage	Fixed O&M	$+ (ep_g + \sum_{g,i} G_{g,i}) \cdot x_{g,i}$	The fixed operation and maintenance costs paid for plant g in investment period i are calculated as the total generation capacity of the plant in MW (the pre-existing capacity ep_g at plant g plus the capacity installed in all investment periods i) multiplied by the recurring fixed costs associated with that type of generator in \$2007 / MW $x_{g,i}$.
Generation and Storage	Variable	$+\sum_{g,t} O_{g,t} \cdot \left(m_{g,t} + f_{g,t} + c_{g,t}\right) \cdot hs_t$ $+\sum_{g,t} SP_{g,t} \cdot (spf_{g,t} + spc_{g,t}) \cdot hs_t$	The variable costs paid for operating plant g in time point t are calculated as the power output in MWh $O_{g,t}$ multiplied by the sum of the variable costs associated with that type of generator in \$2007 / MWh. The variable costs include maintenance $m_{g,t}$, fuel $f_{g,t}$, and a carbon cost $c_{g,t}$ (not included in this study), and are weighted by the number of hours each time point represents, hs_t. Variable costs also include the per unit fuel ($spf_{g,t}$) and carbon ($spc_{g,t}$) costs incurred by thermal dispatchable plants providing spinning reserve, $SP_{g,t}$.
Transmission	Capital	$+\sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot t_{a,a',i}$	The cost of building or upgrading transmission lines between two load areas a and a' in investment period i is calculated as the product of the rated transfer capacity of the new lines in MW $T_{a,a',i}$, the length of the new line $l_{a,a'}$, and the area-adjusted per-km cost of building new transmission in \$2007 / MW · km $t_{a,a',i}$. Transmission can only be built between load areas that already are connected or that are adjacent to each other.
Transmission	O&M	$+\sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot x_{a,a',i}$	The cost of maintaining new transmission lines between two load areas a and a' in investment period i is calculated as the product of the rated transfer capacity of the new lines in MW $T_{a,a',i}$, the length of the new line $l_{a,a'}$, and the area-adjusted per-km cost of maintaining new transmission in \$2007 / MW · km $x_{a,a',i}$.

Distribution		$+\sum_{a,i} d_{a,i}$	The cost of upgrading local transmission and distribution within a load area *a* in investment period *i* is calculated as the cost of building and maintaining the upgrade in \$2007 / MW, $d_{a,i}$. No decision variables are associated with these costs.
Sunk		$+ s$	Sunk costs include capital payments for existing plants, existing transmission networks, and existing distribution networks.

Capital costs are amortized over the expected lifetime of each generator or transmission line, and only those payments that occur during the length of the study – 2015 to 2055 – are included in the objective function. The present day capital cost of building each type of power plant or storage project is reduced via an exponential decay function using a capital cost declination rate (see the New Generators: Capital Costs section). The capital cost of each project is locked in at the first year of construction. Construction costs for power plants are tallied yearly, discounted to present value at the online year of the project, and then amortized over the operational lifetime of the project. The cost to connect new power plants to the grid is assumed to be incurred in the year before operation begins.

For optimization purposes, all costs during the study are discounted to a present-day value using a common real discount rate of 7% (White House Office of Management and Budget 2010), so that costs incurred later in the study have less impact than those incurred earlier. All costs are specified in real terms, indexed to the reference year 2007.

6. Constraints

The model includes five main sets of constraints: those that ensure that load is satisfied, those that maintain the capacity reserve margin, those that require that operating reserve be maintained, those that enforce Renewable Portfolio Standards (RPS), and those that impose a carbon cap.

The load-meeting constraints require that the power system is dispatched to meet load in every hour in every load area while providing the least expensive power based on expected generation, storage, and transmission availability. The nameplate capacity of these grid assets is de-rated by its forced outage rate to represent the amount of power generation capacity that is available on average in each hour of the study. Baseload generators are also de-rated by their scheduled outage rates.

The capacity reserve margin constraints require that the power system maintain a planning reserve margin at all times, i.e. that it would have sufficient capacity available to provide at least 15 percent extra power above load in every load area in every hour if all generators, storage projects and transmission lines are working properly. In calculating reserve margin, the outputs of these grid assets are therefore not de-rated by forced outage rates. SWITCH determines the reserve margin schedule concurrently with the load-satisfying dispatch schedule.

The operating reserve constraints ensure that an operating reserve equal to a percentage of load plus a percentage of intermittent generation is maintained in all hours, half of which must be spinning reserve.

The RPS constraints require that a certain percentage of load be met by renewable energy sources, consistent with state-based Renewable Portfolio Standards.

The carbon cap constraints limit the total amount of carbon emissions in each study period to a pre-defined level, e.g. 80% below 1990 carbon emissions levels for the investment period 2045-2055.

6.1. Load-Meeting Constraints

1. Natural gas dispatchable generators (combined cycle, combustion turbine, and steam turbine) can provide no more power, spinning reserve, and quickstart capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are therefore not included here. Spinning reserve can only be provided in hours when the plant is also producing useful generation and cannot exceed a pre-specified fraction of capacity.

$MAX\_DISPATCH_{c,t}$ $C_{c,t} + SP_{c,t} + Q_{c,t} \leq (1 - o_c) \cdot \sum_i CG_{c,i}$	For each dispatchable project c in every hour t, the expected amount of power $C_{c,t}$, spinning reserve $SP_{c,t,}$ and quickstart capacity $Q_{c,t}$ supplied by the dispatchable generator in that hour cannot exceed the sum, de-rated by the generator's forced outage rate o_c, of generator capacities $CG_{c,i}$ installed at generator c in the current and preceding periods i. The operational generator lifetime limits the extent of the sum over i to only periods in which the generator would still be operational.

$MAX\_SPIN_{c,t}$ $SP_{c,t} \leq \frac{spin\_frac_c}{1 - spin\_frac_c} \cdot C_{c,t}$	For each dispatchable project c in every hour t, the spinning reserve $SP_{c,t}$ supplied by the dispatchable generator in that hour cannot exceed a pre-specified fraction of capacity. This constraint is tied to the amount actually dispatched $C_{c,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing useful generation.

2. Intermittent generators (solar and wind) produce the amount of power corresponding to their simulated historical power output in each hour, de-rated by their forced outage rate. Intermittent generation is broken into non-distributed and distributed for use in the conservation of energy constraints below. These constraints define the derived variables $VD_{vd,t}$ and $VN_{vn,t}$, and as such do not appear in the compiled mixed-integer linear program.

DISTRIBUTED_VAR_GEN$_{vd,t}$ $VD_{vd,t} = cf_{vd,t} \cdot (1 - o_{vd}) \cdot \sum_i VDG_{vd,i}$	For each distributed intermittent project *vd* in every hour *t*, the expected amount of power, $VD_{vd,t}$, produced by the dispatchable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vd}, of generator capacities $VDG_{vd,i}$ installed at generator *vd* in the current and preceding periods *i*, multiplied by the generator's capacity factor in hour *t*, $cf_{vd,t}$. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.
NON_DISTRIBUTED_VAR_GEN$_{vn,t}$ $VN_{vn,t} = cf_{vn,t} \cdot (1 - o_{vn}) \cdot \sum_i VNG_{vn,i}$	For each distributed intermittent project *vn* in every hour *t*, the expected amount of power, $VN_{vn,t}$, produced by the dispatchable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vn}, of generator capacities $VNG_{vn,i}$ installed at generator *vn* in the current and preceding periods *i*, multiplied by the generator's capacity factor in hour *t*, $cf_{vn,t}$. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.

3. Baseload generators (nuclear, coal, geothermal, biomass solid, biogas and cogeneration) must produce an amount of power equal to their nameplate capacity, de-rated by their forced and scheduled outage rates. This constraint defines the derived variable $B_{b,t}$ and as such does not appear in the compiled mixed-integer linear program.

BASELOAD_GEN$_{b,t}$ $B_{b,t} = (1 - o_b) \cdot (1 - s_b) \cdot \sum_i BG_{b,i}$	For every baseload project *b* and every hour *t*, the expected amount of power, $B_{b,a,t}$, produced by each baseload generator *b* in each hour *t* cannot exceed the sum, de-rated by the generator's forced outage rate o_b and scheduled outage rate s_b, of generator capacities $BG_{b,i}$ installed at generator *b* in the current and preceding periods *i*. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational.

4. The amount of energy produced from all non-pumped hydroelectric facilities in a load area must equal or exceed 50% of the average non-pumped hydroelectric energy production for that load area in each hour, in order to maintain downstream water flow. The total amount of energy produced in each hour, on a load area basis, from all pumped and non-pumped hydroelectric facilities within a load area cannot exceed the load area's total turbine capacity, de-rated by the forced outage rate for hydroelectric generators.

HYDRO_MIN_DISP$_{h,t}$ $H_{h,t} \geq ah_{h,m_t} \cdot mf$	For every non-pumped hydroelectric project h in every hour t, the amount of energy $H_{h,t}$ dispatched by the non-pumped hydroelectric project must be greater than or equal to a pre-specified average flow rate for that project on the day of that hour, $ah_{h,m}$, times a pre-specified minimum dispatch fraction, mf, necessary to maintain stream flow.

HYDRO_MAX_DISP$_{h,t}$ $H_{h,t} + OP_{h,t} \leq (1 - o_h) \cdot hg_h$	For every non-pumped hydroelectric project h in every hour t, the amount of energy $H_{h,t}$ and operating reserve $OP_{h,t}$ dispatched by the non-pumped hydroelectric project h cannot exceed the project's capacity, hg_h de-rated by the hydroelectric project's forced outage rate o_h.

HYDRO_MAX_RESERVE$_{h,t}$ $OP_{h,t} \leq hydro\_op\_fraction \cdot hg_h$	For every hydroelectric project h in every hour t, the amount of operating reserve $OP_{h,t}$ dispatched cannot exceed a fraction *hydro_op_fraction* of the project's capacity, hg_h.

PUMPED_HYDRO_MAX_DISP$_{p,t}$ $PH_{p,t} + \sum_f PHD_{p,t,f} + OP_{p,t} \leq (1 - o_p) \cdot pg_p$	For pumped hydroelectric project p and every hour t, the sum of watershed energy, $PH_{p,t,f}$, dispatched stored energy, $PHD_{p,t,f}$, from all fuel categories f, and operating reserve $OP_{p,t}$ cannot exceed the pre-specified capacity of the pumped hydroelectric project, pg_p, de-rated by the pumped hydroelectric project's forced outage rate o_p.

5. The amount of energy produced from all hydroelectric facilities in a load area over the course of each study day must equal the historical average energy production for the month in which that day resides.

HYDRO_AVG_OUTPUT$_{h,t}$ $\sum_{t \in T_d} H_{h,t} = \sum_{t \in T_d} ah_{h,m_t}$	For every non-pumped hydroelectric project h and every day d, the historical monthly average flow must be met, i.e. the sum over all hours on day d of energy, $H_{h,t,}$ dispatched by the non-pumped hydroelectric project p must equal a pre-specified average daily level $ah_{h,m}$ for that month. T_d is the set of hours on day d.

PUMPED_HYDRO_AVG_WATERSHED$_{p,d}$ $\sum_{t \in T_d} PH_{p,t} = \sum_{t \in T_d} ah_{h,m_t}$	For every pumped hydroelectric project p and every day d, $PH_{p,t,f}$, the total watershed energy released by the pumped-hydroelectric project, must equal a pre-specified average daily level $ah_{h,m}$, for that month. T_d is the set of hours on day d.

6. A storage project can store no more power in each hour than its maximum hourly store rate, de-rated by its forced outage rate, and dispatch no more power in each hour than its capacity, de-rated by its forced outage rate. Compressed Air Energy Storage (CAES) projects must maintain the proper ratio between energy stored in the form of compressed air and energy dispatched in the form of natural gas.

MAX_STORAGE_RATE$_{s,t}$ $\sum_{f} S_{s,t,f} \le (1 - o_s) \cdot r_s \cdot \sum_{i} SG_{s,i}$	For every storage project s in every hour t, the expected amount of energy, $S_{s,t,f}$, stored at the storage project s in hour t from each fuel type f cannot exceed the product of a pre-specified store rate for that project, r_s, and the total capacity $SG_{s,t,f}$ installed at project s in the current and preceding periods i, de-rated by the storage project's forced outage rate o_s. The operational storage project lifetime limits the extent of the sum over i to only periods in which the storage project would still be operational.

MAX_STORAGE _DISPATCH$_{s \neq CAES,t}$ $\sum_{f} R_{s,t,f} + OP_{s,t} \le (1 - o_s) \cdot \sum_{i} SG_{s,i}$	For every non-CAES storage project s in every hour t, the expected amount of energy dispatched from the storage project in that hour from all fuel types f, $R_{s,t,f}$, plus the operating reserve provided $OP_{s,t}$ in that hour cannot exceed the sum, de-rated by the storage project's forced outage rate o_s, of the storage project power capacity $SG_{s,i}$ installed in the current and preceding periods i. The operational storage project lifetime limits the extent of the sum over i to only periods in which the storage project would still be operational.

MAX_CAES _DISPATCH$_{s=CAES,t}$ $\sum_{f} R_{s,t,f} + C_{s,t} + SP_{s,t} + Q_{s,t} + OP_{s,t}$ $\le (1 - o_s) \cdot \sum_{i} SG_{s,i}$	For every CAES storage project s in every hour t, the sum of the energy dispatched from all fuel types f, $R_{s,t,f}$, and the operating reserve $OP_{s,t}$ provided by the storage plant plus the energy dispatched $C_{s,t}$, spinning reserve $SP_{s,t}$ and quickstart reserve $Q_{s,t}$ provided from natural gas cannot exceed the sum, de-rated by the plant's forced outage rate o_s, of the plant's total power capacity $SG_{s,i}$ installed in the current and preceding periods i. The operational CAES project lifetime limits the extent of the sum over i to only

	periods in which the CAES project would still be operational.

CAES_COMBINED_DISPATCH$_{s=CAES,t}$ $\sum_{f} R_{s,t,f} = C_{s,t} \cdot caes\_ratio$	For every CAES project s in every hour t, the amount of energy dispatched from the CAES project in that hour from all fuel types f, $R_{s,t,f}$, must equal the amount of energy dispatched from natural gas $C_{s,t}$ multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

CAES_COMBINED_OR$_{s=CAES,t}$ $OR_{s,t} = (SP_{s,t} + Q_{s,t}) \cdot caes\_ratio$	For every CAES project s in every hour t, the amount of operating reserve dispatched from the CAES project in that hour must equal the operating reserve (spinning plus quickstart) dispatched from natural gas ($SP_{s,t}$+ $Q_{s,t}$) multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

PUMPED_HYDRO_MAX_STORE$_{p,t}$ $\sum_{f} PHS_{p,t,f} \leq pg_p \cdot (1 - o_p)$	For every hour t, the energy stored by a pumped hydroelectric project p, $PHS_{p,t,f}$, cannot exceed the pre-specified capacity of the hydroelectric project, de-rated for the project's forced outage rate o_p.

7. Because days are modeled as independent dispatch units, the energy dispatched by each storage project each day must equal the energy stored by the project on that day, adjusted for the storage project's round-trip efficiency losses.

STORAGE_ENERGY_BALANCE_BY_FUEL_CATEGO RY$_{s,d,f}$ $\sum_{t \in T_d} R_{s,t,f} = \sum_{t \in T_d} S_{s,t,f} \cdot e_s$	For each storage project s and each fuel category f on each day d, the energy from fuel category f dispatched by the storage project in all hours t on day d must equal the energy stored by the storage project in all hours t on day d, de-rated by the storage project's round-trip efficiency e_s.

STORAGE_ENERGY_BALANCE$_{s,d}$ $\sum_{t \in T_d} R_{s,t} + op\_fraction \cdot \sum_{t \in T_d} OR_{s,t} = \sum_{t \in T_d} S_{s,t} \cdot e_s$	For each storage project *s* on each day *d*, the energy dispatched by the storage project in all hours *t* on day *d* must equal the energy stored by the storage project in all hours *t* on day *d*, de-rated by the storage project's round-trip efficiency e_s. It is assumed that operating reserve is called upon to produce energy a fraction of the time, *op_fraction*, and this is included in the energy balance. T_d is the set of hours on day *d*.

PUMPED_HYDRO_ENERGY_BALANCE_BY_FUEL_CATEGORY$_{p,d,f}$ $\sum_{t \in T_d} PHD_{p,t,f} = \sum_{t \in T_d} PHS_{p,t,f} \cdot pe$	For every pumped hydroelectric project *p*, every day *d*, and every fuel category, $PHD_{p,t,f}$, the total amount of energy from fuel type *f* dispatched by the project in all hours *t* on day *d*, must equal $PHS_{p,t,f}$, the total amount of energy from fuel type f stored by the hydroelectric project in all hours t on day d, times a pre-specified pumped hydroelectric storage efficiency, *pe*. T_d is the set of hours on day *d*.

PUMPED_HYDRO_ENERGY_BALANCE$_{p,d}$ $\sum_{t \in T_d} PHD_{p,t,f} + op\_fraction \cdot \sum_{t \in T_d} OP_{p,t,f} = \sum_{t \in T_d} PHS_{p,t,f} \cdot pe$	For every pumped hydroelectric project *p*, every day *d*, the total amount of energy $PHD_{p,t}$ dispatched by the hydroelectric project in all hours *t* on day *d*, must equal $PHS_{p,t,f}$, the total amount of energy stored by the hydroelectric project in all hours t on day d, times a pre-specified pumped hydroelectric storage efficiency, *pe*. It is assumed that operating reserve is dispatched a fraction of the time, *op_fraction*, and this is included in the energy balance. T_d is the set of hours on day *d*.

8. The amount of power transferred in each direction through transmission lines in each hour between

each pair of connected load areas can be no more than the line's rated capacity, de-rated by its forced outage rate. Once a transmission line is installed, it is assumed to remain in operation for the remainder of the study.

MAX_TRANS$_{a,a1,t}$ $\sum_{f} Tr_{a,a',t,f} \leq (1 - o_{a,a'}) \cdot (et_{a,a'} + \sum_{i} T_{a,a',i})$	For each transmission line *(a, a')* in every hour *t*, the total amount of energy, $Tr_{a,a',t,f}$ from all fuel types *f* dispatched along the transmission line between load areas *a* and *a'* in each hour *t* cannot exceed the sum, de-rated by the transmission line's forced outage rate $o_{(a,a')}$, of the pre-existing transfer capacity $et_{(a,a')}$ and the sum of additional capacities $T_{a,a',i}$ installed between the two load areas in the current and all preceding periods *i*.

9. The total amount of power exported from the Mexican load area of Baja California Norte in each investment period cannot grow at more than of the historical electric power export growth rate between 2003 and 2008 of 3.2 %/yr (Secretaría de Energía 2010). This constraint ensures that Mexico can export power to United States load areas, but restricts the growth of exports to realistic levels.

MEX_EXPORT_LIMIT$_{a=MEX\_BAJA,i}$ $\sum_{a',t \in T_i, f} Tr_{a,a',t,f} \cdot hs_t - \sum_{a'',t \in T_i, f} Tr_{a'',a,t,f} \cdot hs_t \leq mexptlim_i$	For each investment period *i*, the sum of transmission capacity $Tr_{a,a',t,f}$ dispatched out of the load area *a=MEX_BAJA*, minus the sum of transmission capacity $Tr_{a'',a,t,f}$ dispatched into the load area *a=MEX_BAJA*, weighted by the number of sample hours hs_t represented by timepoint *t*, cannot exceed the specified export limit out of MEX_BAJA $mexptlim_i$.

10. The total expected supply of power from generation, storage, and transmission in each load area during each hour must equal or exceed the amount of power consumed in that load area and at that time. The total supply of power can exceed the demand for power to reflect the potential of spilling power or curtailment during certain hours.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED$_{a,t,f}$ $NP_{a,t,f} \cdot (1+dl) \le$		For every load area *a*, in each hour *t*, and for every fuel category *f*, the amount of non-distributed energy $NP_{a,t,f}$ consumed in the load area in that hour plus any distribution losses *dl* cannot exceed
Generation	$\sum_{vn\in VN_a} VN_{vn,t,f} + \sum_{c\in C_a} C_{c,t,f} + \sum_{b\in B_a} B_{b,t,f} + \sum_{h\in H_a} H_{h,t,f} +$	the total power generated in load area *a* in hour *t* by all intermittent non-distributed projects ($VN_{vn,t,f}$), all baseload projects ($B_{b,t,f}$), all dispatchable projects ($C_{c,t,f}$), and all non-pumped hydroelectric generators ($H_{h,t,f}$)
Transmission	$+\sum_{a,a'} Tr_{a,a',t,f} \cdot e_{a,a'} - \sum_{a'',a} Tr_{a'',a} +$	plus the total power supplied to load area *a* from other load areas *a'* via transmission, de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power exported from load area *a* to other load areas *a''* via transmission
Storage	$+\sum_{s\in S_a} R_{s,t,f} - \sum_{s\in S_a} S_{s,t,f} +$	plus the total energy, $R_{s,t,f}$, supplied to load area *a* in hour *t* by storage projects *s* minus the total energy, $S_{s,t,f}$, that is stored by storage projects *s*
Pumped Hydroelectric	$+\sum_{p\in P_a} PH_{p,t,f} + \sum_{p\in P_a} PHD_{p,t,f} - \sum_{p\in P_a} PHS_{p,t,f}$	plus the total power generated from pumped hydroelectric watershed energy, $PH_{p,a,t}$, and the total power dispatched from pumped hydroelectric storage, $PHD_{p,a,t,f}$, that is supplied to load area *a* in hour *t* by all pumped hydroelectric projects *p,* minus the total power, $PHS_{p,a,t,f}$, that is stored by pumped hydroelectric projects *p* in load area *a* in hour *t*.
Redirected	$+DR_{a,t,f}$	plus distributed energy , $DR_{a,t,f}$, that is exported through the distribution system to the transmission grid.

CONSERVATION_OF_ENERGY_DISTRIBUTED$_{a,t,f}$ $DP_{a,t,f} + DR_{a,t,f} \cdot (1+dl) \geq \sum_{vd \in VD_{a,f}} VD_{vd,t}$	In every load area a, in each hour t, and for every fuel category f, the amount of distributed energy $DP_{a,t,f}$ consumed in the load area plus any distributed power, $DR_{a,t,f}$, that is exported through the distribution system, adjusted for distribution losses dl, cannot exceed the total distributed generation available in load area a in hour t.

SATISFY_LOAD$_{a,t}$ $\sum_{f}(NP_{a,t,f} + DP_{a,t,f}) = l_{a,t}$	For every load area a in each hour t, the total energy consumed from distributed and non-distributed sources must equal the pre-defined system load $l_{a,t}$.

6.2. Reserve-Margin constraints

Power plants and transmission lines can experience outages and various mechanical failures, To address system risk, the model requires that enough power plant and transmission capacity be built to provide a 15% capacity reserve margin above load in each load area in all hours.

1. The total supply of reserve capacity in each load area during each hour must equal or exceed 115% of the power demand in each load area and in each study hour.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED_RESERVE$_{a,t}$ $NPR_{a,t} \cdot (1+dl) \leq$		In every load area a, in each hour t, the amount of non-distributed capacity $NPR_{a,f}$ available to meet the capacity reserve margin in the load area in that hour plus any distribution losses dl cannot exceed
Generation Capacity	$\sum_{vn \in VN_a}(cf_{vn,t} \cdot \sum_{i} VNG_{vn,i})$ $+ \sum_{c \in C_a}\sum_{i} CG_{c,i}$ $+ \sum_{b \in B_a}\sum_{i} BG_{b,i} \cdot (1-s_b)$	the total capacity of all intermittent non-distributed projects ($VNG_{vn,i}$) multiplied by their capacity factor $cf_{vn,t}$ in hour t, plus the total capacity of all dispatchable projects ($CG_{c,i}$), plus the total capacity, adjusted for scheduled outage rate s_b, of all baseload projects ($B_{b,i}$) in load area a in hour t,

Transmission Capacity	$+\sum_{a,a'}\sum_{f} Tr_{a,a',t,f}\cdot e_{a,a'} - \sum_{a'',a}\sum_{f} Tr_{a'',a,t,f}$	plus the total power transmitted to load area *a* from other load areas *a'* ($Tr_{a,a',t,f}$), de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power transmitted from load area *a* to other load areas *a''* ($Tr_{a'',a,t,f}$)
Storage Capacity	$+\sum_{s\in S_a}\sum_{f} R_{s,t,f} - \sum_{s\in S_a}\sum_{f} S_{s,t,f}$	plus the total output $R_{s,t,f}$, of storage projects *s* in load area *a* in hour *t* minus the energy stored, $S_{s,t,f}$, by storage projects *s* in load area *a* in hour *t*
Hydroelectric and Pumped Hydroelectric	$+\sum_{h\in H_a} H_{h,t} + \sum_{p\in P_a} PH_{p,t}$ $+\sum_{p\in P_a}\sum_{f} PHD_{p,t,f} - \sum_{p\in P_a}\sum_{f} PHS_{p,t,f}$	plus the total non-pumped hydroelectric ($H_{h,t}$) and pumped hydroelectric ($PHR_{p,a,t}$) watershed power supplied, and the total pumped hydroelectric stored power, $PHD_{p,a,t,f}$, supplied to load area *a* in hour *t* by all pumped hydroelectric projects *p* minus the total energy, $PHS_{p,a,t,f}$, that is stored by pumped hydroelectric projects *p*.
Redirecte d	$+DRR_{a,t}$	plus the distributed capacity, $DRR_{a,t}$, that is available to be exported through the distribution system.

$CONSERVATION\_OF\_ENERGY\_DISTRIBUTED\_RESERVE_{a,t,f}$ $DPR_{a,t} + DRR_{a,t}\cdot(1+dl) \geq \sum_{vn\in VN_a}(cf_{vd,t}\cdot\sum_{i} VDG_{vd,i})$	In every load area *a*, in each hour *t*, the amount of distributed energy $DPR_{a,t}$ consumed in the load area plus any distributed power, $DRR_{a,t}$, adjusted for distribution losses *dl*, that is exported through the distribution system cannot exceed the total distributed generation capacity available in load area *a* in hour *t*.

$SATISFY\_RESERVE\_MARGIN_{a,t}$ $DPR_{a,t} + NPR_{a,t} = (1+r)\cdot l_{a,t}$	For each load area *a*, in each hour *t*, the total distributed and non-distributed capacity available for consumption must equal the pre-defined system load $l_{a,t}$ for that load area for that hour plus a pre-specified reserve margin *r*.

6.4. Operating Reserve Constraints

SATISFY_SPINNING_RESERVE$_{ba,t}$ $\sum_{c \in C_{ba}} SP_{c,t} + \sum_{g \in S_{ba} \cup H_{ba} \cup P_{ba}} OP_{g,t} \geq spinning\_reserve\_reqt_{ba,t}$	In each balancing area *ba* in each hour *t*, the spinning reserve provided by dispatchable plants, $SP_{c,t}$, plus the operating reserve $OP_{g,t}$ provided by storage plants ($g \in S_a$), hydroelectric plants ($g \in H_a$), and pumped hydroelectric storage plants ($g \in P_a$) must equal or exceed the spinning reserve requirement in that balancing area in that hour. The spinning reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

SATISFY_OPERATING_RESERVE$_{ba,t}$ $\sum_{c \in C_{ba}} SP_{c,t} + \sum_{c \in C_{ba}} Q_{c,t} + \sum_{g \in S_{ba} \cup H_{ba} \cup P_{ba}} OP_{g,t} \geq operating\_reserve\_reqt_{ba,t}$	In each balancing area *ba* in each hour *t*, the spinning reserve provided by dispatchable plants, $SP_{c,t}$, plus the quickstart reserve provided by dispatchable plants, $Q_{c,t}$, plus the operating reserve $OP_{g,t}$ provided by storage plants ($g \in S_a$), hydroelectric plants ($g \in H_a$), and pumped hydroelectric storage plants ($g \in P_a$) must equal or exceed the total operating reserve requirement (spinning plus quickstart) in that balancing area in that hour. The operating reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

6.5. RPS Constraint

This constraint requires that, for each load-serving entity and for every period, the percentage of total consumed power delivered by qualifying renewable sources is greater than or equal to the fraction specified by existing RPS targets. The RPS constraint does not allow the use of unbundled, tradable Renewable Energy Credits (RECs).

MEET_RPS$_{lse,i}$ $\dfrac{\sum_{t \in T_i, f \in R, a \subset A_{lse}} (DP_{a,t,f} + NP_{a,t,f}) \cdot hs_t}{\sum_{t \in T_i, a \subset A_{lse}} l_{a,t} \cdot hs_t} \geq rps_{lse,i}$	For every load-serving entity *lse* in every period *i*, the proportion of the total power consumed in all hours of that period (the set T_i) from all RPS-eligible fuels (the set *R*) must be greater than or equal to the pre-defined RPS fraction, $rps_{lse,i}$, for that load area for that period. Each timepoint in the set T_i is weighted by the number of sample hours it represents, hs_t.

6.5. Carbon Cap Constraint

This constraint requires that, for every period, the total carbon dioxide emissions from generation and spinning reserve provision cannot exceed a pre-specified emissions cap.

CARBON_CAP$_i$ $$\sum_{g,t \in T_i} O_{g,t} \cdot hr_g \cdot co2\_fuel_g + \sum_{c,t \in T_i} SP_{c,t} \cdot hr\_penalty_g \cdot co2\_fuel_g \leq carbon\_cap_i$$	In every period *i*, the total carbon emissions from generation (calculated as the plant output $O_{g,t}$ times the plant heat rate hr_g times the carbon dioxide fuel content for that plant) plus the carbon emissions from spinning reserve (calculated as the plant output $O_{g,t}$ times the plant per unit heat rate penalty for providing spinning reserve $hr\_penalty_g$ times the carbon dioxide fuel content for that plant) cannot exceed a pre-specified carbon cap $carbon\_cap_i$ for that period.

<u>Data Description</u>

1. Load Areas: Geospatial Definition

The model divides the geographic region of WECC into 50 load areas. These areas represent sections of the grid within which there is significant existing local transmission and distribution, but between which there is limited long range, high-voltage existing transmission. Consequently, load areas are areas between which transmission investment may be beneficial.

Load areas are predominantly divided according to pre-existing administrative and geographic boundaries, including, in descending order of importance, state lines, North American Electric Reliability Corporation (NERC) control areas and utility service territory boundaries. Utility service territory boundaries are used instead of state lines where much high-voltage transmission connectivity is present between states within the same utility service territory. The location of mountain ranges is considered because of their role as natural boundaries to transmission networks. Major metropolitan areas are included because they represent localized areas of high electrical demand.

In addition, load area boundaries are defined to capture as many currently congested transmission corridors as possible (Western Electricity Coordinating Council 2009). These pathways are some of the first places that transmission is likely to be built, and exclusion of these pathways in definition of load areas would allow power to flow without penalty along overloaded transmission lines.

2. Cost Regionalization

Costs for constructing and operating generation and transmission vary significantly by region. To capture this variation, all costs in the model are multiplied by a regional economic multiplier derived from normalized average pay for major occupations in United States Metropolitan Statistical Areas (MSAs) (United States Department of Labor 2009). Counties that are not present in the listed MSAs are given the regional economic multiplier of the nearest MSA. These regional economic multipliers are then assigned to load areas weighted by the population within each county located within each load area.

Data for Canadian and Mexican economic multipliers are estimated and will be updated in future versions of the model.

3. Transmission Lines

The existing transmission capacity between load areas is found by matching geolocated Ventyx data (Ventyx EV Energy Map) with Federal Energy Regulatory Commission (FERC) data on the thermal limits of individual power lines (Federal Energy Regulatory Commission 2009). A small fraction of lines present in the Ventyx database could not be matched to lines found in the FERC database; these lines are ascribed a generic transfer capacity equal to the average transfer capacity of their voltage class. In total, 104 existing inter-load-area transmission corridors are represented in SWITCH.

The largest capacity substation in each load area is chosen by adding the transfer capacities of all lines into and out of each substation within each load area. It is assumed that all power transfer between load areas occurs between these largest capacity substations, using the corresponding distances along existing transmission lines between these substations. If no existing path is present, new transmission can be installed between adjacent load areas assuming a distance of 1.5 the distance between largest capacity substations of the two load areas.

The amount of power that can be transferred along each transmission line is set at the rated thermal limits of individual transmission lines. Additionally, transmission power losses are taken into account at 1 percent of power is lost for every 100 miles over which it is transmitted, with an upper limit of 98.5 % efficiency between any pair of load areas.

4. Local T&D and Transmission Costs

The costs for existing transmission and distribution are derived from the regional electricity tables of the United States Energy Information Agency's 2010 Annual Energy Outlook (United States Energy Information Agency 2010a). The $/MWh cost incurred in 2010 for each NERC subregion is apportioned by present day average load to each load area and is then assumed to be a sunk cost over the whole period of study. All existing transmission and distribution capacity is therefore implicitly assumed to be kept operational indefinitely, incurring concomitant operational costs.

It is further assumed that the distribution network is built to serve the peak load of 2011, and that in future investment periods this equivalence must be maintained. Investment in new local transmission and distribution is therefore a sunk cost as projected loads are exogenously calculated.

Distribution losses are assumed to be 5.3% of end-use demand; commercial and residential distributed PV technologies are assumed to experience zero distribution losses as they are sited inside the distribution network. In the case of surplus distributed generation, the model can send power from distributed generators out to other load areas, incurring a 5.3% power loss on the way out. This loss is in addition to subsequent transmission, storage and distribution losses, so power sent in this manner will incur distribution losses twice.

5. Load Profiles

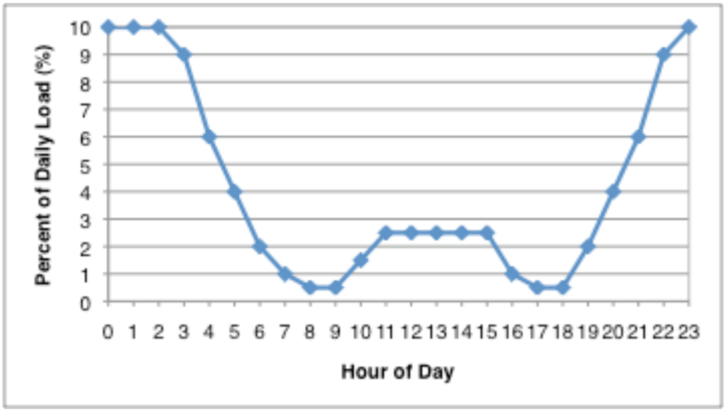
Planning Area hourly loads from the Federal Energy Regulatory Commission's (FERC) Annual Electric Balancing Authority Area and Planning Area Report (FERC Form 714) (Federal Energy Regulatory Commission 2006) are partitioned into SWITCH load areas by manually matching substations owned by each planning area to georeferenced substations (Platts Corporation 2009). As not all substations match between the two datasets, a map of each planning area is created by drawing boundaries around each of the substation areas. Existing geospatial layers of planning areas from Platts (Platts Corporation 2009) and Ventyx (Ventyx EV Energy Map) do not provide enough data to be used exclusively in this process because of overlapping territories, changes in planning areas over time, and the complexity of the electric power system at the distribution level. Rather, these planning area layers serve only as a guide to forming maps of planning area loads.

Many load areas are comprised of encompass single planning areas; for these regions, the planning area hourly load is used as the load of the corresponding load area. For planning areas that cross load area boundaries, the fraction of population within each load area is used to apportion planning area loads between SWITCH load areas. Finally, as the planning areas PacificCorp and Bonneville Power Administration span the Western and Central time zones but report a single hourly load, loads from areas located within these LSEs but in a different time zone from the reported load are shifted one hour to reflect the difference in timing of loads as a function of the hour of day.

Load on each hour in the model corresponds to the observed load on one historical hour from the year 2006. These hourly loads are then shaped using hourly load profiles for energy efficiency, electrification of heating, and electric vehicles. The magnitude of load added (or subtracted in the case of energy efficiency) to the 2006 load profile is dictated by electricity load projections discussed in the body of this report.

Hourly California load projections for energy efficiency and electrification of heating from present day to 2050 from were obtained from Itron for each of the three load profile cases (Frozen Efficiency, Base Case and Extra Electrification). These projections are made for each California forecast climate zone and are divided into load areas via the population fraction of each climate zone in each load area. For load areas outside California, the load profiles across all of California for energy efficiency and electrification of heating were used to shape demand. California load profiles were time-shifted by one hour for load areas in Mountain time to reflect dependence on the hour of day. In addition, as the adoption of heating electrification is assumed to occur ten years later in the rest of WECC than it does in California, the California heating electrification load profile was shifted ten years back when applied to load areas outside California.

Hourly electric vehicle loads are created from a daily charging profile shown below provided by UC Davis and scaled to projected demands. Historical monthly demand is also used to shape the magnitude of electric vehicle demand in each month.



Appendix Figure 1: *Electric Vehicle daily charging profile.*

6. Renewable Portfolio Standards

State-based Renewable Portfolio Standards (RPS) specify that a certain fraction of electricity consumed within a Load Serving Entity (LSE) that must be produced by qualified renewable generators. Targets follow a yearly schedule, increasing from low levels presently higher levels by the mid 2020s (North Carolina State University 2011). For example, California has RPS targets of 20% and 33% by 2010 and 2020, respectively. RPS targets are subject to the political structure of each state and are therefore heterogeneous in not only what resources qualify as renewable, but also when, where and how the qualifying renewable power is made and delivered. To maintain computational feasibility, RPS is modeled as a yearly target for each load area for the percentage of load that must be met by *delivered renewable* power.

In the version of SWITCH used in this study, renewable power is defined as power from geothermal, biomass solid, biomass liquid, biogas, solar or wind power plants. This is consistent with most of the state-specific definitions of qualifying resources in the western United States. Additionally, in most states, large hydroelectric power plants (> 50 MW) are not considered renewable power plants due to their high environmental impacts. Small hydroelectric power plants (< 50 MW) do not qualify as renewable power in the current version of the model.

Delivered power is power that is either generated within a load area and consumed immediately, or added to the power mix of the load area via transmission or storage, after accounting for efficiency losses. Power lost during distribution is not counted towards RPS targets. To ensure proper accounting, the stocks and flows of qualifying power is kept separate from non-qualifying power.

While most load areas are fully contained within a single LSE and a single state, targets for those load areas that span LSE and/or state lines are calculated as a weighted sum of the RPS goals on the two sides of the LSE and/or state border, with the weights based on the relative population levels within each load area within each LSE and/or state. RPS targets are averaged over each period for each load area. Canadian and Mexican load areas do not have RPS targets.

7. Fuel Prices

Coal, natural gas and fuel oil fuel price projections for electric power generation originate from the reference case of the United States Energy Information Agency's 2011 Annual Energy Outlook (United States Energy Information Agency 2011). These yearly projections are made for each North American Electric Reliability Corporation (NERC) subregion through 2035, and are extrapolated for years after 2035. Yearly fuel price projections are averaged over each study period. The fuel price for each load area is set by the NERC subregion with the greatest overlap with that load area. Canadian and Mexican coal, natural gas and fuel oil prices are assumed to be the same as the prices in the nearest United States NERC subregion. Fuel price elasticity is not currently included.

Uranium price projections are taken from the California Energy Commission's 2007 Cost of Generation Model (Klein 2007). These prices apply to all load areas as uranium has less regional price variation than other fuels.

Solid biomass fuel costs are discussed directly below.

8. Biomass Supply Curve

Fuel costs for solid biomass are input into the model as a piecewise linear supply curve for each load area. This piecewise linear supply curve is adjusted to include producer surplus from the solid biomass cost supply curve in order to represent market equilibrium of biomass prices in the electric power sector.

As no single data source is exhaustive in the types of biomass considered, solid biomass feedstock recovery costs and corresponding energy availability at each cost level originate from a variety of sources listed in the table below. This table does not represent the technical potential of recoverable solid biomass – instead it depicts the economically recoverable quantity of biomass solid feedstock. The definition of 'economically recoverable' is dependent on each dataset, but the maximum cost is generally less than or equal to \$100 per bone dry ton (BDT) of biomass. Feedstock prices range between \$0.2/MMBtu and \$13.3/MMBtu (in \$2007), with a quantity-weighted average price across WECC of \$2.7/MMBtu. While the energy content per BDT of biomass varies by feedstock, a factor of 15 MMBtu/BDT can be used for rough conversion between BDT and MMBtu. Note that, following standard biomass unit definitions, 1 MMBtu = 10^6 Btu.

Biomass Feedstock Type	California Availability [10^{12} Btu/Yr]	Rest of WECC Availability [10^{12} Btu/Yr]	California Availability [10^{12} BDT/Yr]	Rest of WECC Availability [10^{12} BDT/Yr]	Sources
Corn Stover	19.1	82.3	1.35	5.83	1
Forest Residue	41.3	408.8	2.74	27.13	1, 4
Forest Thinning	72.3	211.0	4.80	14.00	1
Mill Residue + Pulpwood	39.5	254.3	2.62	16.87	2, 3, 4
Municipal Solid Waste (MSW)	81.4	117.1	4.93	7.10	2, 4
Orchard and Vineyard Waste	66.1	10.5	4.39	0.70	2
Switchgrass	0	123.7	0	8.43	1, 4
Wheat Straw	8.1	70.0	0.60	5.16	1
Agricultural Residues (Canada Data Only)	0	183.2	0	13.51	4
Total	**327.8**	**1460.9**	**21.43**	**98.73**	

Appendix Table 1: *Biomass Supply in the SWITCH model for years 2030 and beyond. Sources: 1: de la Torre Ugarte 2000; University of Tennessee 2007; 2: Parker 2011; 3: Milbrandt 2005; 4: Kumarappan 2009 (Canada Data Only).*

9. Existing Generators

9.1. Existing Generator Data

Existing generators within the United States portion of WECC are geolocated into load areas using Ventyx EV Energy Map (Ventyx EV Energy Map 2009). Generators found in the United States Energy Information Agency's Annual Electric Generator Report (United States Energy Information Agency 2007a) but not in the Ventyx EV Energy Map database are geolocated by ZIP code. Canadian and Mexican generators are included using data in WECC's Transmission Expansion Planning Policy Committee database of generators (Western Electricity Coordinating Council 2009). Generators with the primary fuel of coal, natural gas, fuel oil, nuclear, water (hydroelectric, including pumped storage), geothermal, biomass solid, biomass liquid, biogas and wind are included. Existing synthetic crude oil, solar thermal, and solar photovoltaic generators, as well as biomass co-firing units on existing coal plants are not included in the current version of the model. These generators constitute less than 2% of the existing generating capacity in WECC.

Existing generators are assumed to use the fuel with which they generated the most electricity in 2007 as reported in the United States Energy Information Agency's Form 906 (United States Energy Information Agency 2007b). Generator-specific heat rates are derived by dividing each generator's fuel consumption by its total electricity output in 2007. Canadian and Mexican plants are assigned the heat rates given to their technology class (Western Electricity Coordinating Council 2009), except for cogeneration plants, which are assigned the average heat rate for United Stated generators with the same fuel and prime mover.

Capital and operating costs for existing coal and hydroelectric generators originate from present day costs found in the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010a). Costs for non-coal, non-hydroelectric generators originate from the California Energy Commission's Cost of Generation Model (California Energy Commission 2010). To reflect shared infrastructure costs, cogeneration plants are assumed to have 75% of the capital cost of pure electric plants. Capital costs of existing plants are included as sunk costs and therefore do not influence decision variables.

Existing plants are not allowed to operate past their expected lifetime with the exception of nuclear plants, which are given the choice to continue plant operation by paying all operational costs in investment periods past the expected lifetime of the plant in question.

In order to reduce the number of decision variables, non-hydroelectric generators are aggregated by prime mover for each plant and hydroelectric generators are aggregated by load area.

9.2. Existing Hydroelectric and Pumped Hydroelectric Plants

Hydroelectric and pumped hydroelectric generators include constraints derived from historical monthly generation data from 2006. For non-pumped hydroelectric generators in the United States, monthly net generation data from the United States Energy Information Agency's Form 906 (United States Energy Information Agency 2007b) is employed. The profile of Washington and Montana monthly net generation data is used to shape British Columbia and Albertan hydroelectric generation, respectively. Hydroelectric and pumped hydroelectric generators are aggregated to the load area level in order to reduce the number of decision variables.

For pumped hydroelectric generators, the use of net generation data is not sufficient, as it takes into account both electricity generated from in-stream flows and efficiency losses from the pumping process. The total electricity input to each pumped hydroelectric generator (United States Energy Information Agency 2007b) is used to correct this factor. By assuming a 74% round-trip efficiency (Electricity Storage Association 2010) and that monthly in-stream flows for pumped hydroelectric projects are similar to those from non-pumped projects, the monthly in-stream flow for pumped projects is derived. No pumped hydroelectric plants currently exist in Canadian or Mexican WECC territory (Ventyx EV Energy Map 2009).

New hydroelectric facilities are not built in the current version of the model. The high capital cost of these generators, especially pumped storage, would likely preclude installation.

9.3. Existing Wind Plants

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. The total capacity, number of turbines, and installation year of each wind farm in the United States that currently exists or is under construction is obtained from the American Wind Energy Association (AWEA) wind plant dataset (American Wind Energy Association 2010). The total existing wind farm capacity in WECC is 10 GW. Wind farms are geolocated by matching wind farms in the AWEA dataset with wind farms in the Ventyx EV Energy Map dataset (Ventyx EV Energy Map 2009). Existing Canadian wind farms are not currently included in the model. At present, the Mexican portion of WECC does not have operational utility-scale wind turbines (The Wind Power 2010).

Historical production from existing wind farms could not be used as many of these wind projects began operation after the historical study year of 2006. In addition, historical output would include forced outages, a phenomenon that is factored out of hourly power output in SWITCH.

In order to calculate hourly capacity factors for existing wind farms, the rated capacity of each wind turbine is used to find the turbine hub height and rotor diameter using averages by rated capacity from 'The Wind Power' wind turbines and wind farms database (The Wind Power 2010). Wind speeds are interpolated from wind points found in the 3TIER wind dataset (3TIER 2010) to the wind farm location using an inverse distance-weighted interpolation. The resultant speeds are scaled to turbine hub height using a friction coefficient of 1/7 (Masters 2004). These wind speeds are put through an ideal turbine power output curve (Westergaard 2009) to generate the hourly power output for each wind farm in the WECC.

10. New Generators

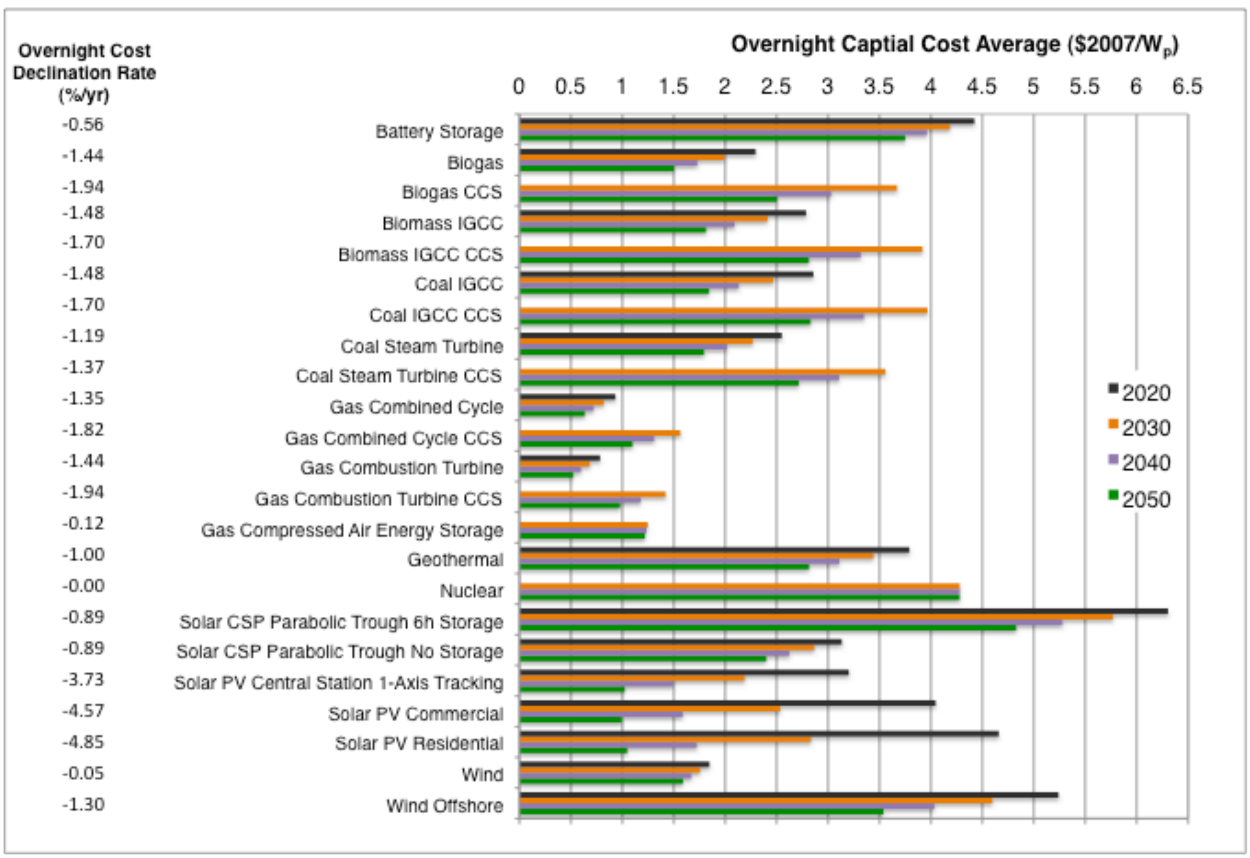
10.1. Capital and O&M Costs

The present day capital costs and operation and maintenance (O&M) costs for each power plant type originate primarily from the California Energy Commission Cost of Generation Model (California Energy Commission 2010). Present day costs for coal and carbon capture and sequestration generation originate from the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b). Costs for photovoltaic generators originate from the National Renewable Energy Laboratory's Solar Vision Study (United States Department of Energy 2010). Captial costs in SWITCH decrease over time via exponential decay using decay rates derived from (Black & Veatch 2010). O&M costs are assumed to remain constant over time.

Fuel	Technology	Overnight Cost in 2011 [$2007/W]	Overnight Cost Change [%/yr]	Fixed O&M [$2007/MW*yr]	Variable O&M [$2007/MWh]	Efficiency [%]	Carbon Emissions [tCO_2/MWh]
Bio Gas	Bio Gas	2.28	-1.44	114000	0.01	25	0
Bio Gas CCS	Bio Gas CCS	4.17	-1.94	156000	13.77	18.9	-1.633
Bio Solid	Biomass IGCC	2.7	-1.48	140000	3.71	32.5	0
Bio Solid CCS	Biomass IGCC CCS	4.61	-1.70	158000	5	26.4	-1.036
Coal	Coal Steam Turbine	2.57	-1.19	27000	3.89	38.8	0.841
Coal	Coal IGCC	2.91	-1.48	45000	6.29	39.2	0.831
Coal CCS	Coal Steam Turbine CCS	4.14	-1.37	58000	8.29	28.4	0.172
Coal CCS	Coal IGCC CCS	4.82	-1.70	63000	7.37	31.9	0.153
Gas	Gas Combustion Turbine	0.75	-1.35	15000	3.4	39.9	0.454
Gas	Compressed Air Energy Storage	1.1	-0.12	9000	2.84	77.6*	0.233
Gas	CCGT	0.9	-1.35	7000	2.46	52.8	0.343
Gas CCS	CCGT CCS	1.85	-1.82	28000	5.73	45.4	0.06
Gas CCS	Gas Combustion Turbine CCS	1.7	-1.94	36000	7.71	34.3	0.079
Geothermal	Geothermal	3.69	-1.00	44000	3.17		0
Solar	Central PV	3.63	-3.73	10000	0		0
Solar	Commercial PV	4.53	-4.57	10000	0		0
Solar	CSP Trough 6h Storage	5.74	-0.89	63000	0		0

Solar	Residential PV	5.27	-4.85	10000	0		0
Solar	CSP Trough No Storage	3.37	-0.89	63000	0		0
Storage	Battery Storage	4.11	-0.56	26000	0.52		0
Uranium	Nuclear	3.67	0.00	137000	4.82	32.8	0
Wind	Offshore Wind	5.06	-1.30	25000	9.47		0
Wind	Wind	1.83	-0.05	13000	4.73		0

Appendix Table 2: *New generator costs, heat rates and outage rates. The base overnight cost shown here represents the overnight cost incurred when starting construction in 2011. *The efficiency of Compressed Air Energy Storage quoted here contains only the natural gas part of energy generation – energy from the compressed air in the storage cavern is also needed, lowering the total efficiency.*



Appendix Figure 2: *Average generator and storage overnight capital costs in each investment period. Plants not eligible for construction in the 2020 investment period are excluded from this chart. The costs shown do not include expenses related to project development such as interest during construction, connection costs to the grid and upgrades to the local grid, though these costs are included in each optimization.*

10.2. Connection Costs

The cost to connect new generators to the existing electricity grid is derived from the United States Energy Information Agency's 2007 Annual Electric Generator Report (United States Energy Information Agency 2007a). Connection costs for different technologies are shown in Supplemental Table 4 below.

The generic connection cost category applies to projects that *are not* sited at specific geographic locations in SWITCH. For these projects, it is assumed that it is possible to find a project site near existing transmission in each load area, thereby not incurring significant costs to build new transmission lines to the grid. The average cost over the United States in 2007 to connect generators to the grid without a large transmission line was \$91,289 per MW (United States Energy Information Agency 2007a). Substation installation or upgrade and grid enhancement costs that are incurred by adding the generator to the grid account for \$65,639 per MW of the total connection cost. Constructing a small transmission line to the existing grid accounts for \$25,650 per MW of the total connection cost.

The site-specific connection cost category applies to projects that *are* sited in specific geographic locations but are not considered distributed generation in SWITCH. For these projects, the calculated cost to build a transmission line from the resource site to the nearest substation at or above 115 kV replaces the cost to build a small transmission line above. The cost to build this new line is \$1,000 per MW per km, the same as to the assumed cost of building transmission between load areas. Underwater transmission for offshore wind projects is assumed to be five times this cost, \$5000 per MW per km. The load area of each site-specific project is determined through connection to the nearest substation, as the grid connection point represents the part of the grid into which these projects will inject power.

Generic	Site Specific	Distributed
\$91,289/MW (\$2007)	\$65,639/MW (\$2007)	\$0/MW (\$2007)
No Additional Transmission	Additional Distance-Specific Transmission Costs Incurred	Interconnection Included In Capital Cost
Nuclear	Wind	Residential Photovoltaic
Gas Combined Cycle	Offshore Wind	Commercial Photovoltaic
Gas Combustion Turbine	Central Station Photovoltaic	
Coal Steam Turbine	Solar Thermal Trough, No Thermal Storage	
Coal Integrated Gasification Combined Cycle	Solar Thermal Trough, 6h Thermal Storage	
Biomass Integrated Gasification Combined Cycle		
Biogas		
Battery Storage		
Compressed Air Energy Storage		

Appendix Table 3: *Connection Cost Types in SWITCH. As these costs represent costs to connect a generator to the electricity grid, they are the same per unit of capacity for generation with or without cogeneration and/or carbon capture and sequestration.*

The distributed connection cost category currently applies only to residential and commercial photovoltaic projects. For these projects, the interconnection costs are included in project capital costs and are therefore not explicitly specified in other parts of the model.

The connection cost of existing generators is assumed to be included in the capital costs of each existing plant.

10.3. Non-Renewable Thermal Generators

10.3.1. Non-Renewable Non-CCS Thermal Generators

Nuclear steam turbines, coal steam turbines, and coal integrated gasification combined cycle plants (Coal IGCC) are modeled as baseload technologies. Their output remains constant in every study hour, de-rated by their forced and scheduled outage rates. These technologies are assumed to be buildable in any load area, which the exception of California load areas due to legal build restrictions on new nuclear and coal generation in California.

Natural gas combined cycle plants and combustion turbines are modeled as dispatchable technologies. The optimization chooses how much to dispatch from these generators in each study hour, limited by their installed capacity and de-rated by their forced outage rate. All thermal technologies in SWITCH have a fixed heat rate throughout all investment periods (see Supplemental Table 2).

All existing cogeneration plants are given the option to continue operation indefinitely at the existing plant's capacity, efficiency and cost. New cogeneration plants are not allowed to be installed in the current version of the model.

10.3.2. Non-Renewable Thermal Generators Equipped with Carbon Capture and Sequestration (CCS)

Generators equipped with carbon capture and sequestration (CCS) equipment are modeled similarlyto their non-CCS counterparts, but with different capital, fixed O&M and variable O&M costs, as well as different power conversion efficiencies. Newly installable non-renewable CCS technologies are: Gas Combined Cycle, Gas Combustion Turbine, Coal Steam Turbine, Coal Integrated Gasification Combined Cycle. In addition, all carbon-emitting existing cogeneration plants are given the option to replace the existing plant's turbine at the end of the turbine's operational lifetime with a new turbine of the same type equipped with CCS.

Costs for Gas Combined Cycle, Coal Steam Turbine and Coal Integrated Gasification Combined Cycle generators with CCS are used directly from the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b). In order to account for the additional cost of installing a CCS system into types of power plants for which consistent and up-to-date CCS cost data is not readily available, the capital cost difference between non-CCS and CCS generators with the same primemover is added to the capital cost of the non-CCS generator. For example, the capital cost of Gas Combustion Turbine CCS is assumed to be equal to the capital cost of non-CCS Gas Combustion Turbine plus the difference in capital costs between Gas Combined Cycle and Gas Combined Cycle CCS (all values in units of \$/W). The same method is used for fixed O&M costs. As is the case with non-CCS cogeneration technologies, CCS cogeneration plants incur 75 % of the capital cost of non-cogeneration plants to reflect shared infrastructure costs. Variable O&M costs for CCS generators increase relative to their non-CCS counterparts from costs incurred during O&M of the CCS equipment itself, as well as costs incurred from the decrease in efficiency of CCS power plants relative to non-CCS plants. Costs input into the model can be found in the table of generator costs and efficiencies above.

Large-scale deployment of CCS pipelines would require large interconnected pipeline networks from CO_2 sources to CO_2 sinks. While the cost of construction of short pipelines is included in the Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b), CCS generators that are not near a CO_2 sink would be forced to build longer pipelines, thereby incurring extra capital cost. If a load area does not does not contain an adequate CO_2 sink (National Energy Technology Laboratory, 2008) within its boundaries, a pipeline between the largest substation in that load area and the nearest CO_2 sink is built, incurring costs consistent with those found in Middleton et al., 2009.

CCS technology is in its infancy, with a handful of demonstration projects completed to date. This technology is therefore not allowed to be installed in the 2015-2025 investment period, as gigawatt scale deployment would not be feasible in this timeframe. Starting in 2025, CCS generation can be installed in unlimited quantities (except for bio projects that are limited by the amount of available biofuel).

10.4. Compressed Air Energy Storage

Conventional gas turbines expend much of their gross energy compressing the air/fuel mixture for the turbine intake. Compressed air energy storage (CAES) works in conjunction with a gas turbine, using underground reservoirs to store compressed air for the intake. During off-peak hours, CAES uses electricity from the grid to compress air. During peak hours, CAES adds natural gas to the compressed air and releases the mixture into the intake of a gas turbine. CAES projects in the WECC version of SWITCH are cited in aquifer geology. Geospatial aquifer layers are obtained from the United States Geological Survey (United States Geological Survey 2003) and all sandstone, carbonate, igneous, metamorphic, and unconsolidated sand and gravel aquifers are included (Succar and Williams 2008; Electric Power Research Institute 2003). A density of 83 MW/km^2 is assumed, following (Succar and Williams 2008), resulting in nearly unlimited CAES potential in almost all load areas.

A storage efficiency of 81.7% is used, in concert with a round trip efficiency of 1.4 (Succar and Williams 2008) to apportion generation between renewable and non-renewable fuel categories when RPS is enabled, as natural gas is burned in addition to the input electricity from the grid. In addition, a compressor to expander ratio of 1.2 (Greenblatt *et al.* 2007) is assumed.

10.5. Battery Storage

Sodium sulfur (NaS) batteries are modeled using performance data from (Electric Power Research Institute 2002) for load-leveling batteries. Storage is modeled using a daily energy balance – it is therefore assumed that NaS batteries have sufficient energy capacity to provide daily load-leveling. An AC-DC-AC storage efficiency of 76.7 % is used. NaS battery storage is available for construction in all load areas and investment periods.

10.6. Geothermal

New sites for geothermal steam turbine power projects are compiled from two separate datasets of geothermal projects under consideration from power plant developers (Ventyx EV Energy Map 2009, Western Governors' Association 2009b). The larger potential capacity of projects appearing in both datasets is taken. As new geothermal projects are located at specific sites within a load area, they incur the cost of building a transmission line to the existing electricity grid rather than a generic connection costs. These projects represent 7 GW of new geothermal capacity potential.

10.7. Biogas and Biomass Solid

County-level biogas availability (Milbrandt 2005) is divided into load areas by the fraction of land area overlap of each county in each load area. This resource includes landfill gas, methane from wastewater treatment plants and methane from manure. Canadian and Mexican biogas resource potentials are scaled from United States potentials by population and Gross Domestic Product (GDP). Biogas plants are not sited in specific geographic locations within each load area and therefore incur the generic connection cost for connection to the existing electricity. It is assumed that new biogas plants will use combustion turbine technology.

New biomass solid generation is assumed to use integrated gasification combined cycle technology. Installation of biomass solid generation is constrained by the resource availability if biomass solid fuel in each load area.

New biogas and biomass solid combined heat and power units (cogenerators) can be installed to replace existing plants, but cannot be expanded beyond the existing cogeneration potential.

CCS biogas generation is included in all scenarios discussed in this report, while biomass solid integrated gasification combined cycle generation is only available in the Biomass CCS scenario. Sequestration of biomass solid and biogas is modeled as carbon negative with 85% carbon capture efficiency. Biogas CCS is assumed to capture both pre- and post-combustion CO_2 (biogas is typically ~1:1 CH_4:CO_2).

10.8. Wind and Offshore Wind Resources

Hourly wind turbine output was obtained from the 3TIER wind power output dataset produced for the Western Wind and Solar Integration Study (WWSIS) (3TIER 2010). 3TIER modeled the historical 10-minute power output from Vestas V-90 3-MW turbines in a 2-km by 2-km grid cells across the western United States over the years 2004-2006 using the Weather Research and Forecasting (WRF) mesoscale weather model. Each of these grid cells was found to contain ten turbines, so each grid cell represents 30 MW of potential wind capacity. The Vestas V-90 3-MW turbine has a 100 m hub height.

Grid cells that were selected by the following criteria to create a final dataset of 32,043 wind points:

1) Wind projects that already exist or are under development
2) Sites with the high wind energy density at 100 m within 80 km of existing or planned transmission networks
3) Sites with high degree of temporal correlation to load profiles near the grid point
4) Sites with the highest wind energy density at 100 m (irrespective of location)

All of the wind points within WECC are aggregated into 3,362 wind farms. Many of the wind points were very near each other; adjacent wind points are aggregated if their area is within the corner-to-corner distance of each other, 2.8 km. Wind points with standard deviations in their average SCORE-lite power output (3TIER 2010) greater than 3 MW are aggregated into different wind farms. Offshore and onshore wind points are aggregated separately. The 10-minute SCORE-lite power output for each wind point is averaged over the hour before each timestamp, and then these hourly averages are again averaged over each group of aggregated wind points to create the hourly output of 3,314 onshore (875 GW) and 48 offshore (6 GW) wind farms.

Canadian hourly wind data will be integrated into future versions of the model.

10.9. Solar Resources

<u>*10.9.1. Weather file creation*</u>

Hourly weather and insolation files in the standard typical meteorological year 2 (TMY2) format for 41,000 sites for the historical years 2004 and 2005 were created by merging 10km-resolution gridded satellite insolation data from the State University of New York (SUNY) (Perez *et al*. 2002; National Renewable Energy Laboratory 2010b) and ~38km-resolution data from the National Center for Environmental Prediction's (NCEP) Climate Forecast System Reanalysis (CFSR) (Saha *et al*. 2010; National Climatic Data Center 2010).

The CFSR data are modified using standard approximations to conform to the TMY2 format. Wind velocity as reported by CFSR is at height of 10 meters – to convert to the TMY2 height of 2 meters, the friction coefficient of 1/7 is used (Masters 2004). Snow water equivalent is converted to snow depth using a 0.1 density conversion factor (Saha *et al*. 2010). Specific humidity is converted to relative humidity (Holton, Pyle, and Curry 2003) and the dew temperature is calculated (National Oceanic and Atmospheric Administration 2009). Wet bulb temperature is estimated from dry bulb temperature using the "1/3 rule" (Haby n.d.).

Time-shifted SUNY gridded insolation data as downloaded from the National Solar Radiation Database (National Renewable Energy Laboratory 2010b) was modified due to an error in time-shifting the direct normal insolation (DNI) values for a fraction of the sunset hours. In these hours, representing 0.1% of the hours, the DNI on a horizontal surface significantly exceeds the largest possible value of clear sky insolation, taking into account the air mass present at each grid cell (Meinel and Meinel 1976) and solar incidence angles (Duffie and Beckman 2006). When the SUNY value for DNI exceeded the largest possible value by more than 100 Wm^{-2}, the largest possible DNI value was used instead of the SUNY value. SUNY values for the diffuse and global radiation did not to have this problem, and as such were left unmodified.

The CFSR weather grid was combined with the SUNY grid by finding the CFSR grid cell centroid nearest to each SUNY grid cell centroid. For coastal SUNY grid cells, the centroid of the nearest land-based CFSR grid cell was used, as weather conditions change rapidly on the ocean-land boundary and all modeled solar projects are on land.

The weather files are used as inputs to the National Renewable Energy Laboratory's Solar Advisor Model (National Renewable Energy Laboratory 2010a) to calculate the simulated historical output of various types of solar projects.

<u>*10.9.2. Distributed Photovoltaics – Residential and Commercial*</u>

Residential and Commercial photovoltaic sites were chosen by overlaying a United States raster layer of population density with the SUNY grid cells and selecting any grid cell with a total population greater than 10,000 in the year 2000. Mexican and Canadian cities in WECC with a population greater than 10,000 were included if they were located within the SUNY insolation grid. This includes most major Mexican population centers in Baja California Norte, as well as many of the southern Canadian cities in WECC. This process produced 920 individual SUNY grid cells to simulate residential and commercial photovoltaic systems in WECC. These cells were aggregated to 222 sites by joining adjacent grid cells such that the standard deviation of average global horizontal radiation values within each aggregated site is less than 0.1 kWh/m^2/day. This is accomplished by sequestering grid cells with greater than +/- 0.2 kWh/m^2/day from the average global horizontal radiation value within each aggregated area into a smaller aggregated area.

In SAM, residential, commercial and central station photovoltaic systems are simulated using the California Energy Commission module model as 270 W multi-crystalline silicon Suntech STP270-24-Vb-1 modules.

For residential photovolatics, these modules are connected in a 10-module string to make a 2.7 kW array and are coupled with a 3 kW SMA America SB3000US 208 V inverter. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid derating factor is assumed to be 89%.

Commercial photovoltaic systems are simulated as a 100 kW array with a single point efficiency inverter at 95% efficiency and a DC capacity of 105 kW. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid de-rating factor is assumed to be 91%.

The roof area available for distributed photovoltaic development is estimated based on Navigant (Chaudhari, Frantzis, and Hoff 2004) and NREL (Denholm and Margolis 2007) reports. State-level roof area data (Chaudhari, Frantzis, and Hoff 2004) projected to 2025 is apportioned to load areas by population fraction. Twenty percent of all residential and 60% of all commercial roof area is assumed to be available for development. The rooftop spacing ratio for commercial photovoltaics is derived from the Department of Defense Unified Facilities Criteria (United States Department of Defense 2002). Canadian rooftop availability is assumed to be similar to that of the nearest U.S. state. Baja California Norte rooftop availability is scaled by GDP from California values. In total, 117 GW of residential and 88 GW of commercial photovoltaics are included.

10.9.3. Central Station Solar – Photovoltaics and CSP

Land suitable for large-scale solar development is derived using land exclusion criteria from Mehos and Perez (2005), but without a minimum insolation cutoff. Types of land excluded are: national parks, monuments, wildlife refuges, military land, urban areas, land with greater than 1% slope (at 1 km resolution), and parcels of land smaller than 1 km^2. In addition, only areas with land cover of wooded and non-wooded grassland, closed and open shrubland, and bare ground are assumed to be available for solar development.

The available solar land is aggregated on the basis of average global insolation and DNI. An iterative procedure that partitions available solar land polygons with standard deviations of greater than 0.05 kWh/m^2/day average global insolation or DNI into smaller polygons is employed to create the final solar farms.

In SAM, central station photovoltaics are modeled as 100 MW (AC) arrays using the same mulitcrystalline panels discussed above and mounted on a single axis tracker. The array is connected to a single point efficiency inverter with 95% efficiency. The tracker is modeled using SunPower specifications (SunPower Corporation 2009), and as such is southward facing at a 20° tilt on a one-axis tracker, with ground coverage ratios of 0.20 at low latitudes, increasing to 0.24 at high latitudes. A de-rating factor of 90% is used to convert from power produced at the module to power available to the grid. A total of 15 TW of central station photovoltaic systems are simulated; after site selection (see Section III.10.8.4) this is reduced to 4 TW.

CSP systems without thermal storage are modeled in SAM using the 'Physical Trough' model for CSP parabolic trough systems. In total, 100 MW nameplate systems using Solargenix SGX-1 collectors in an 'H' configuration with an evaporative cooling system are modeled with a total field aperture area calculated by minimizing the total levelized cost of energy with respect to aperture area. Costs for CSP systems are scaled to this aperture area from the base cost values. A total of 15 TW of CSP trough systems without storage are simulated; after site selection, this is reduced to 5 TW.

In the future, CSP trough systems with thermal storage will be simulated as above, but a bug in the storage dispatch of the latest available version of SAM makes this method impossible at present. Rather, the hourly output of 125 CSP trough sites (representing 272 GW of capacity) with six hours of thermal storage was obtained from the National Renewable Energy Laboratory. Dispatch of CSP storage is embedded in the hourly capacity factors – it is an input parameter rather than a variable.

10.10. Site Selection of Intermittent Projects

To decrease runtime, the number of solar and wind sites is reduced using criteria that retain the best quality resources, geographic diversity, and load-serving capability of each resource.

1) All sites with capacity factors that are at least 75% of the average capacity factor for their technology are included.
2) If more than five sites for the same technology are present in a load area, at least 10 of the highest average capacity factor projects are also retained.
3) Projects were selected such that the average generation (the capacity factor multiplied by the resource potential) of a technology, where sufficient resources exist, must be greater than or equal to three times the average 2010 load in each load area.

These criteria primarily filter out onshore wind, as well as central station photovoltaic and solar thermal sites, for which there is enormous potential in WECC. All distributed photovoltaic and offshore wind sites are retained.

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