Research Report – UCD-ITS-RR-11-20

Renewable Transportation Fuel for California's Electric-Drive Vehicles

March 2011

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Renewable Transportation Fuel for California's Electric-Drive Vehicles

By

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B.S. (University of California, Davis) 2008

THESIS

Submitted in partial satisfaction of the requirements for the degree of

MASTER OF SCIENCE

in

Transportation Technology and Policy

in the

OFFICE OF GRADUATE STUDIES

of the

UNIVERSITY OF CALIFORNIA
DAVIS

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2011

Abstract

California has enacted a number of policies that incentivize the use of advanced vehicle technologies and fuels to help reduce petroleum usage, air pollution and greenhouse gas emissions. These include the Pavley greenhouse gas emissions standards, the Low Carbon Fuel Standard (LCFS), the Zero Emission Vehicle (ZEV) and Low-Emission Vehicle (LEV) regulations and initiatives that support adoption of alternative fuels, such as the Air Quality Improvement Program (AQIP) and Alternative Fuel Incentive Program (AFIP). In addition, the state has set an economy-wide goal of reducing greenhouse gas (GHG) emissions 80% below 1990 levels by 2050. Greatly reducing GHG emissions from the transportation sector will likely require large-scale adoption of electric-drive – plug-in hybrid electric, battery-electric, or hydrogen fuel cell vehicles – powered by renewable, low carbon electricity or hydrogen. Under the Renewable Portfolio Standard (RPS) the contribution of renewable sources to California's electricity generation mix will increase from 20 percent in 2010 to 33 percent in 2020. Likewise, SB1505 requires hydrogen transportation fuel in California to achieve a 30% reduction in GHG emissions per mile and include a 33% renewable component. The mutual policy goals of decarbonized transportation fuels and electricity generation will lead to a "convergence" of these two previously disparate energy sectors. Any effort to assess California's ability to achieve deep GHG emissions cuts from transportation will therefore require an integrated approach that considers such a convergence, understanding how best to share energy supply resources among both sectors and meet the combined demand for low-carbon, renewable energy they represent.

In previous studies, Ryan McCarthy developed an hourly model of California's future electricity grid (LEDGE-CA) to investigate GHG emissions and cost impacts attributable to interactions between growing populations of electric-drive vehicles and the evolution of the electricity supply in California. This thesis aims to extend McCarthy's work in two key areas: quantifying renewable resources available for electricity and hydrogen fuel production in California and investigating the potential role of energy storage. Using geospatial and temporal analysis of planned and potential renewable electricity generation projects, this study develops a detailed assessment of the hourly renewable electricity supply in California that serves as an input into LEDGE-CA. Wind and solar energy are abundant renewable resources in California, yet their intermittency make them challenging to integrate into the electricity grid. Grid-energy storage options are evaluated to investigate how best to utilize wind and solar energy resources to meet electricity and hydrogen fuel demand.

This study assesses the total potential for using renewable resources to produce fuel for electric and hydrogen vehicles in California and identifies potential strategy differences in terms of where and when to produce electricity and hydrogen fuels. Alternative pathways are compared with respect to cost, GHG emissions, energy demand, and transition issues.

Acknowledgements

This research was funded by the U.S. Department of Energy Graduate Automotive Tehchnology Education Program and sponsors of the Sustainable Transportation Energy Pathways (STEPS) Program at the Institute of Transportation Studies at the University of California, Davis. I would like to express my gratitude to those organizations for providing financial support throughout my graduate research and education.

Appreciation is due to many others whose advice, wisdom, kindness and support have made for a rewarding graduate experience. Many thanks to Dr. Chris Yang and Professor Joan Ogden for their nurturing guidance and encouragement throughout the process of developing my research, and to Professor Dan Sperling, whose wisdom inspired and motivated me to select the graduate program at UC Davis for my studies. I am also grateful to Annemarie Schaaf and the rest of the staff at ITS-Davis for all the assistance they have provided to smooth the process as I completed my education.

The response from friends and family has also been overwhelming. I wish to thank Sumi and Art Tanabe and Richard and Carole Taniguchi for their encouragement and support throughout my education. Finally, and most importantly, I want to express my heartfelt gratitude to my lovely wife, Diane. Without her unwavering support, enthusiastic encouragement and personal sacrifice throughout my academic journey, none of this would have been possible.

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Abbreviations and Parameters

BEV	Battery-electric vehicle
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBC	California Biomass Collaborative
CCS	Carbon capture and sequestration
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
DNI	Direct Normal Insolation
EIA	U.S. Energy Information Administration
EPRI	Electric Power Research Institute
FCV	Fuel cell vehicle
GHG	Greenhouse gas
GWh	Gigawatt hour
HEV	Hybrid electric vehicle (gasoline-powered)
HHV	Higher heating value
ICEV	Internal combustion engine vehicle
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
LCFS	Low Carbon Fuel Standard
LCOE	Levelized cost of energy

LEDGE-CA	Long-Term Electricity Dispatch Model for Greenhouse Gas Emissions in California
LSE	Load serving entity
MW	Megawatt
MWh	Megawatt hour
NGCC	Natural gas combined cycle
NGCT	Natural gas combustion turbine
NRC	National Research Council
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OOS	Out-of-State
PHEV	Plug-in hybrid-electric vehicle
PHEVxx	Plug-in hybrid-electric vehicle with xx miles of all-electric range
RETI	Renewable Energy Transmission Initiative
RPS	Renewable Portfolio Standard
SAM	Solar Advisor Model
SMR	Steam-methane reformation
SSCHISM	Steady State City Hydrogen Infrastructure System Model
VMT	Vehicle-miles traveled
WREZ	Western Renewable Energy Zone
WWDS	Western Wind Data Set
ZEV	Zero emissions vehicle

1. Introduction

California has enacted a number of policies that incentivize the use of advanced vehicle technologies and fuels to help reduce petroleum usage, air pollution and greenhouse gas emissions. These include the Pavley greenhouse gas emissions standards, the Low Carbon Fuel Standard (LCFS), the Zero Emission Vehicle (ZEV) and Low-Emission Vehicle (LEV) regulations and initiatives that support adoption of alternative fuels, such as the Air Quality Improvement Program (AQIP) and Alternative Fuel Incentive Program (AFIP). In addition, the state has set an economy-wide goal of reducing greenhouse gas (GHG) emissions 80% below 1990 levels by 2050. In the near-term, increased use of liquid biofuels is the most likely renewable fuels strategy to reduce transportation-related GHG emissions as it requires only minor changes to the exisiting vehicle fleet and refueling infrastructure. However, concerns over resource constraints and GHG emissions attributable to indirect land use change make biofuels a less attractive long-term solution. Greatly reducing GHG emissions from the transportation sector over the long term will therefore likely require large-scale adoption of electric-drive – plug-in hybrid electric, battery-electric, or hydrogen fuel cell vehicles – powered by renewable, low carbon electricity or hydrogen. Under the Renewable Portfolio Standard (RPS) the contribution of renewable sources to California's electricity generation mix will increase from 20 percent in 2010 to 33 percent in 2020. Likewise, SB1505 requires hydrogen transportation fuel in California to achieve a 30 percent reduction in GHG emissions per mile and include a 33 percent renewable component. The mutual policy goals of decarbonized transportation fuels and electricity generation will lead to a “convergence” of these two previously disparate energy sectors. Any effort to assess California’s ability to achieve deep GHG emissions cuts from transportation will therefore require an integrated approach that considers such a convergence, understanding how best to share energy supply resources among both sectors and meet the combined demand for low-carbon, renewable energy they represent.

In previous studies, Ryan McCarthy developed an hourly model of California's future electricity grid (LEDGE-CA) to investigate GHG emissions and cost impacts attributable to interactions between growing populations of electric-drive vehicles and the evolution of the electricity supply in California. Using a modified version of LEDGE-CA and other modeling tools, this thesis aims to build upon McCarthy's work with the following key objectives in mind: (1) quantifying the availability and cost of low carbon, renewable resources for electricity and hydrogen fuel production in California, (2) investigating the potential role of energy storage to address temporal differences in the availability of renewable energy and the demand for electricity and hydrogen, and (3) understanding the GHG emissions impacts attributable to large numbers of electric-drive vehicles interacting with a de-carbonized electricity grid, by comparing emissions across various vehicle and fuel pathways with different renewable resource mixes.

This thesis is organized as follows. Chapter 2 provides an overview of California's energy and climate change policy initiatives that impact the evolution of both the state's electricity supply and the role of electric-drive vehicles in the light duty vehicle fleet. It also describes the factors that influence energy demand and GHG emissions from the transportation sector and elsewhere and establishes the energy demand framework to be investigated in this thesis. Non-vehicle electricity demand growth assumptions are defined, as are the various electric-drive vehicle and fuel pathway scenarios that will be compared in terms of energy demand, cost and GHG emissions impacts. Chapter 3 characterizes the magnitude and availability of renewable energy resources in California and elsewhere to meet the electricity and hydrogen demand scenarios outlined in Chapter 2. Using geospatial and temporal analysis of planned and potential renewable energy projects in California and neighboring states, detailed hourly renewable electricity supply portfolios are developed that are compared in terms of economic cost. These serve as hourly supply profiles for modeling grid-based electricity and hydrogen production in LEDGE-CA. Chapter 4 provides an overview of the modeling tools used to compare electricity and hydrogen fuel production pathways. The functionality and key outputs from LEDGE-CA are described. The chapter also describes grid-energy storage models I develop to investigate optimizing electricity production from intermittent wind and solar energy: they are the most abundant renewable resources available to California and dominate the renewable electricity supply profiles described in Chapter 3. The main results of analyzing grid-based electricity and hydrogen fuel production are presented in Chapter 5. Renewable energy supply portfolios described in Chapter 3, coupled with vehicle and fuel pathways described in Chapter 2 and energy storage options are compared with respect to energy demand, GHG emissions and cost. The thesis concludes in Chapter 6, which summarizes key findings from the analysis. It discusses the potential for using renewable resources to produce fuel for electric and hydrogen vehicles in California and identifies potential strategy differences in terms of where and when to produce those fuels.

2. Background

This section provides background information to frame the scope of the analysis in this thesis. It begins with a summary of key energy and climate change policy initiatives in California that will influence both the evolution of the state's electricity supply and the future composition of the light-duty vehicle fleet. Section 2.2 describes the factors that influence energy demand and GHG emissions in California and defines assumptions regarding electricity demand growth through year 2050: excluding demand from electric-drive vehicles. Next, Section 2.3 discusses vehicle demand in California and its relationship to energy use and GHG emissions. Assumptions regarding well-to-wheels (WTW) vehicle GHG emissions are defined, as are fuel economy, energy intensity and carbon intensity assumptions for a range of light-duty vehicle and transportation fuel combinations. Finally, Section 2.4 defines the range of vehicle and fuel combinations that will be compared in this thesis along with electricity demand and renewable electricity supply scenarios, based on the policy framework described in Section 2.1 and the assumptions outlined in Sections 2.2 and 2.3.

2.1 *Energy and Climate Change Policy in California*

California has a long history of providing leadership in the areas of environmental and energy policy: a trait that is reflected in the myriad policies and regulations that have been enacted in the state to help reduce fossil fuel energy usage, air pollution and greenhouse gas emissions from both vehicles and the electricity sector. Following is a summary of the key policy initiatives that are relevant to this thesis:

- Global Warming Solutions Act (AB 32) – This act requires the state's greenhouse gas emissions to be reduced to 1990 levels by 2020, a reduction of 25 percent under business as usual estimates [1]. In addition, the state established the more aggressive goal of reducing emissions 80% below 1990 levels by 2050 through Executive Order [2]. Early action items under AB32 include the Renewable Portfolio Standard and Low Carbon Fuel Standard, which are described below.
- Renewable Portfolio Standard (RPS) – This mandate requires 20 percent of the state's retail electricity sales to be generated from renewable resources by 2010 [3]. In addition, as a partial strategy for meeting the GHG emissions reduction goals of AB32, an Executive Order raised the renewable electricity target to 33 percent of the state electricity supply by 2020 [4].
- Emissions Performance Standard (SB 1368) – Enacted in 2006, this bill mandates that new long-term investments in "baseload" generation resources that supply California's electricity market meet a minimum GHG performance standard. The GHG emissions standard of 1,100 lbs CO_2/MWh is equivalent to that of a combined cycle natural gas power plant and applies to instate and out-of-state resources. This effectively prohibits conventional coal-power plants from supplying California's electricity market in the future [5].
- Fuel economy standards – In 2002, through the "Pavley Bill" (AB 1493) [6], California became the first state in the nation to establish aggressive GHG reduction targets for light-duty vehicles, which have recently been modified to conform to the federal Corporate Average Fuel Economy (CAFE) Standards for years 2012 to 2016 [7]. The standards require new passenger cars and light-duty trucks to have a

combined average fuel economy of 34.1 miles per gallon (mpg) by 2016. They also include two incentive mechanisms to encourage early commercialization of EVs, FCVs, and PHEVs: 1) All three vehicle classes will earn a zero GHG emission per mile credit when operated on grid electricity, and 2) they will be asigned a vehicle multiplier between 1.2 to 2.0 in determining the manufacturer's fleetwide fuel economy rating.

- Low Carbon Fuel Standard (LCFS) – The LCFS was established by Executive Order in 2007 [8] and has since been adopted as an early action item under AB 32. The regulation requires oil refiners and other fuel providers to reduce the carbon content of on-road transportation fuels in California by 10% in 2020, relative to conventional petroleum fuels [9]. As part of the LCFS implementation, the California Air Resources Board (ARB) has developed lifecycle GHG emissions estimates for various fuels. In the final regulation adopted in April, 2010, gasoline is attributed a lifecycle GHG intensity of 95.86 gCO2/MJ and marginal electricity for vehicle recharging is attributed a lifecycle GHG intensity of 104.71 gCO2/MJ [10]. Despite the higher GHG intensity of marginal electricity relative to gasoline, the LCFS also takes into account the higher energy efficiency of PHEVs, BEVs and FCVs by assigning an energy economy ratio (EER) to each vehicle technology. Relative to gasoline, whic has an EER of 1.0, ICEVs, PHEVs and BEVs are assigned an EER of 3.0 and FCVs are assigned an EER of 2.3. The lifecycle GHG intensities of marginal electricity and hydrogen are divided by the corresponding EER for comparison with gasoline

- Zero Emissions Vehicle Regulation (ZEV) – The Zero Emission Vehicle (ZEV) regulation was first adopted in 1990 as part of the Low Emission Vehicle Program to promote sales of zero-emission vehicles in California [11]. The regulation requires large automotive manufacturers to sell increasing percentages of zero-emission vehicles in California, however it has been revised several times to allow manufacturers greater flexibility in meeting the targets. In the most recent amendment adopted in December 2009, the minimum ZEV fleet sales requirements are: 11% for model years 2009-2011, 12% for model years 2012-2014, 14% for model years 2015-2017, and 16% for model years 2018 and beyond. [12].
- Low Emissions Vehicle (LEV) Regulations – First adopted in 1990, California's LEV regulations established emissions reduction standards for light-duty vehicles to advance the state's clean air goals. In an effort to achieve federally-mandated clean air goals, the regulations were amended by the more stringent LEV II standards in 2004 [13].
- Air Quality Improvement Program (AQIP, AB 118) – AB 118, is a voluntary incentive program administered by the Air Resources Board (ARB) to fund clean vehicle and fuel technologies [14] that incorporates many of the goals previously established in the State Alternative Fuels Plan (AB 1007) [15, 16] and California's Strategy to Reduce Petroleum Dependence (AB 2076) [17, 18]. AB 118 partially funds the California Hydrogen Highway [19], which develops a network of hydrogen refueling stations throughout the state.

- Alternative Fuel Incentive Program (AFIP, AB 1181) – Much like AB 118, the AFIP is designed to incentivise the adoption of alternative fuels by funding clean vehicle and fuel technology research and demonstration projects [20].
- Environmental Standards for Hydrogen Production (SB 1505) – Enacted in 2006, SB 1505 sets environmental limits in the production of hydrogen for transportation use. Under the regulation, hydrogen produced in California must include 33 percent renewable content and achieve a 30 percent reduction in GHG emissions per mile relative to conventional gasoline vehicles [21].
- The Federal and California state governments also provide incentives to consumers to promote sales of alternative fuel vehicles. Enacted under the Energy Policy Act of 2005, the Alternative Motor Vehicle Credit offers a federal income tax credit of up to $4,000 for qualifying alternative fueled vehicles, including hybrid-electric and FCVs, purchased by December 31, 2010 [22]. The American Recovery and Reinvestment Act of 2009 introduced tax credits of $2,500 to $7,500 for PHEV and BEV buyers [23], and the Fuel Cell Motor Vehicle Tax Credit offers a $4,000 federal income tax credit for qualifying FCVs purchased by December 31, 2014 [24]. Through the Clean Vehicle Rebate Project, The California Air Resources Board offers rebates of up to $5,000 for PHEVs, BEVs, and FCVs purchased or leased on or after March 15, 2010 [25].

2.2 *Electricity Demand and GHG Emissions in California*

Statewide, year 2008 annual electricity consumption in California reached an estimated 286,771 GWh [26] and was responsible for producing around 24 percent of the state’s

GHG emissions [27]. For the same year, California's light-duty vehicle (LDV) share of GHG emissions was around 128 million metric tones (MMTC02e) – 27 percent of the state total [27]. It is worth noting that in 1990, LDVs in the state emitted 109 MMTC02e [28]. Although electricity production represents a smaller share of the state's GHG emissions than transportation, electricity demand is projected to keep rising, fueled largely by population growth: statewide the population is estimated to grow from nearly 40 million in year 2010 to around 60 million in 2050 [29]. Achieving the deep cuts in GHG emissions required under AB 32 while electricity consumption continues to rise is a formidable challenge and is reflected in the aggressive renewable electricity generation targets adopted under the RPS. To analyze California's future electricity supply and model interactions between the electricity grid and electric-drive vehicles, assumptions about electricity demand growth must be made. This thesis uses electricity demand growth projections through year 2050 from a recent study by McCarthy et al. for the CEC's Advanced Energy Pathways project [30]. Figure 1 shows the range of projections, which vary from 217,000 GWh to 688,000 GWh in 2050 based on estimates of population growth, per-capita economic activity growth, and technology and efficiency assumptions. This thesis uses the baseline electricity consumption projection, which assumes annual electricity consumption of around 421,000 GWh in year 2050.

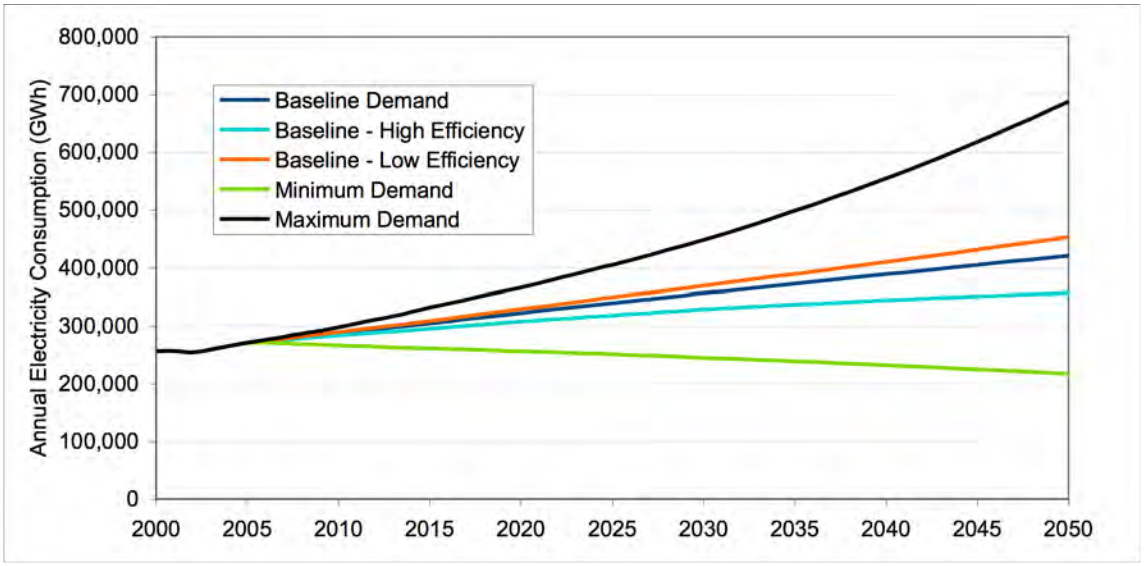


Figure 1: Annual Electricity Consumption in California Through 2050 [30]

2.3 *Vehicle Energy Demand and GHG Emissions in California*

As described in Section 2.2, California's light-duty vehicle fleet currently accounts for around 27 percent of the state's GHG emissions [27]. These emissions are attributable almost entirely to combustion of petroleum-based transportation fuels, but as the composition of the fleet evolves to include more electric-drive vehicles this is likely to change. The annual energy consumption and associated GHG emissions attributable to California's light-duty vehicle fleet depend on a number of factors: the size of the vehicle fleet, the number of passenger vehicle-miles traveled (VMT), average vehicle fuel economy, vehicle technology and transportation fuel. All of these factors must be taken into account when comparing energy use and GHG emissions from electric-drive vehicles with conventional petroleum-fueled vehicles.

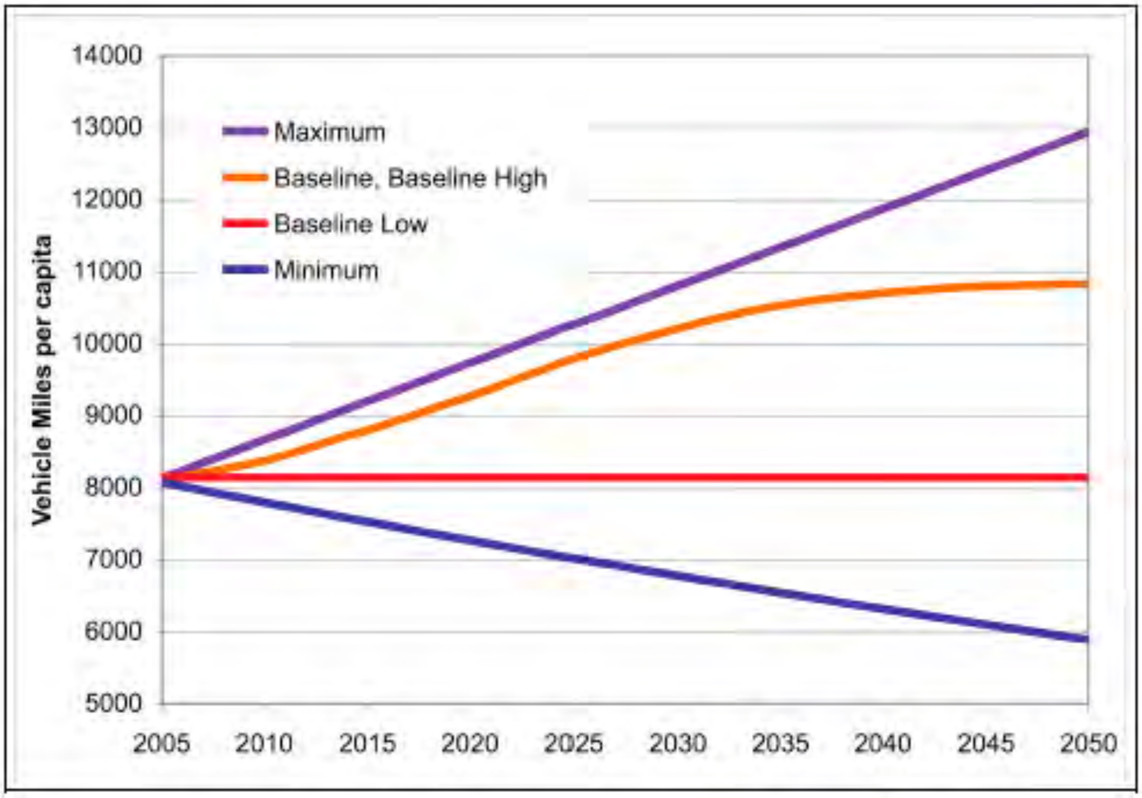


Figure 2: Per Capita Vehicle-Miles Traveled in California Through 2050 [30]

This thesis also uses VMT growth assumptions through year 2050 from the study by McCarthy et al. [30]. Figure 2 shows a range of per capita VMT projections through 2050 from the study. In this thesis, the baseline per capita VMT projection is assumed, which grows due to longer commute distances and increased individual travel demand, then levels off towards year 2050. Annual VMT is calculated for each year by multiplying per capita VMT by the estimated population. For example, in year 2050, an estimated state population of around 55 million with a per capita VMT of around 10,833 miles yields a total VMT of around 595 billion miles.

Table 1 summarizes estimated fuel economy and energy intensities of conventional internal combustion engine (ICE) and electric-drive vehicles fueled by gasoline, electricity or hydrogen. The fuel economy multiplier illustrates the energy efficiencies of electric-drive vehicles compared to conventional vehicles: PHEVs can be 1.5 to 2 times more efficient, BEVs can be 3 to 4 times more efficient, and FCVs can be 2 to 3 times more efficient.

Table 1: Fuel Economy and Energy Intensity of Light-Duty Vehicles

Vehicle Type	Fuel economy multiplier	mpgge[1]	All- electric fraction[2]	Gasoline intensity (gal/mi)[3]	Electricity intensity (kWh/mi)[4]	NG intensity (Btu/mi)[4,5]
ICEV	1	30.0	---	0.0333	---	---
HEV	1.53	45.9	---	0.0218	---	---
PHEV (ICE mode)	1.54	46.2	---	0.0216	---	---
PHEV (electric mode)	3	90.0	100%	---	0.357	---
PHEV10	1.78	53.3	27.5%	0.0190	0.098	---
PHEV20	1.91	57.4	40%	0.0130	0.143	---
PHEV40	2.18	65.3	60%	0.0087	0.214	---
BEV	3.5	105.0	---	---	0.306	---
FCV (electrolysis)	2.32	69.6	---	---	0.72	---
FCV (onsite SMR)	2.32	69.6	---	---	0.042	2443

BEV = Battery-electric vehicle; FCV = Fuel cell vehicle; HEV = Hybrid electric vehicle; ICEV = Internal combustion engine vehicle;

mpgge = miles per gasoline gallon equivalent; NG = Natural gas; PHEV = Plug-in hybrid electric vehicle; SMR = Steam-methane reformation

[1] Relative vehicle efficiencies based on scalars from [31], and assuming a new baseline vehicle gets 30 mpg.

[2] From [30], assuming 15,000 miles/vehicle/year

[3] The energy and lifecycle carbon content of California reformulated gasoline are assumed to be 115.63 MJ/gallon and 95.86 gCO_2/MJ, respectively [9]

[4] Hydrogen pathway electricity and natural gas intensity from DOE H2A analysis and EIA Annual Energy Outlook [33, 34]

[5] The carbon content of natural gas is assumed to be 64.3 gCO_2/MJ

Although EVs can be significantly more energy-efficient than conventional vehicles, GHG emissions attributable to EVs depend not only on fuel consumption, but also the carbon intensity of the fuel: for electricity or hydrogen, this varies greatly depending on the production and distribution method, or “fuel pathway”. Table 2, which is adapted from a recent study by Yang et al. on strategies to reduce California’s transportation GHG emissions 80 percent below 1990 levels by 2050, summarizes the GHG emissions attributable to various transportation fuel pathways expressed in terms of carbon intensity on an energy basis (g CO2e/MJ) or per gallon of gasoline equivalent (g CO2e/gge) [35]. Fuels listed include conventional gasoline and diesel, electricity and hydrogen. The reference fuel for the current light-duty vehicle fleet is reformulated California gasoline, which has an estimated carbon intensity of 96 g CO2e per MJ, or 10,877 g CO2e per gallon.

Table 2: Carbon Intensity of Transportation Fuels [35]

Fuel/Pathway	**Carbon Intensity**				**% Change from 1990 Gasoline**
	gCO2e/MJ		**gCO2e/gge**		
	1990	**2050**	1990	**2050**	
Gasoline and Diesel					
Conventional Crude Oil	96	96	10,877	10,877	0.00%
Unconventional Sources	---	101 to 210	---	12,073 to 25,101	+11 to 131%
Electricity					
Natural Gas Combined Cycle		134.6		16,083	+47.90%
Natural Gas Combined Cycle w/CCS		20.2		2,412	-77.80%
Coal,IGCC	---	345.3	---	41,274	
Coal,IGCC w/CCS	---	63.4	---	7,572	-30.40%
Wind, Solar, Biomass, Nuclear, Other Renewables	---	0 to 15	---	0 to 1,793	-100 to -84%
California average electricity grid mix	111.6	---	13,336	---	---
Hydrogen					

Natural Gas	---	90 to 112	---	10,757 to 13,387	-1 to 23%
Natural Gas w/CCS	---	90 to 112	---	1,793 to 2,032	-84 to -81%
Coal	---	15 to 17	---	22,125	103.4%
Coal w/CCS	---	45.7	---	5,463	-49.8%
Biomass	---	17.3	---	2,068	-81%
Electrolysis	---	0 to 138	---	0 to 16,495	-100 to -52%
CCS = Carbon Capture and Storage; IGCC = Integrated Gasification Combined Cycle					

2.4 *Electricity Demand, Vehicle and Fuel Pathway Scenarios*

In this thesis, a range of light-duty vehicle fleet mix and fuel pathways are compared, based on a range of assumed fuel demand, non-vehicle electricity demand and electricity supply scenarios. The scope of the analysis takes into account some of the policy initiatives discussed at the beginning of this chapter as well as assumptions outlined in Sections 2.2 and 2.3 regarding energy demand growth and vehicle and fuel characteristics. Three timeframes are considered in the analysis:

1. Year 2020, which represents a near-term scenario, with EVs representing 3 to 5 percent of the light-duty fleet and limited non-vehicle electricity demand and VMT growth.
2. Year 2035, which represents a medium-term transition, with EVs representing 20 percent of the light-duty fleet, as well as higher non-vehicle electricity demand and VMT growth.
3. Year 2050, which represents a long-term scenario, with EVs representing 50 percent of the light-duty fleet and significant non-vehicle electricity demand and VMT growth.

Table 3 summarizes the light-duty fleet mixes to be compared and the associated annual VMT. In all but one scenario, the fleet includes a combination of PHEVs and BEVs fueled with electricity, or FCVs fueled with hydrogen, but not both. While this may be a contrived scenario it enables electricity and hydrogen fuel pathways to be compared directly in terms of fuel cost and GHG emissions. All three EV technologies are included in the "Multi-Strategy" scenario for year 2050, which is adapted from the study by Yang et al. [35].

Table 3: Light-Duty Vehicle Fleet Scenarios

	2020: LDV Fleet Mix Comparisons		**2035: LDV Fleet Mix Comparisons**		**2050: LDV Fleet Mix Comparisons**		
	2020 PHEV/BEV	2020 FCV	2035 PHEV/BEV	2035 FCV	2050 PHEV/BEV	2050 FCV	2050 Multi-Strategy
PHEV	3.75%	0%	12%	0%	25%	0%	16%
BEV	1.25%	0%	8%	0%	25%	0%	34%
FCV	0%	3%	0%	20%	0%	50%	50%
ICE	95%	97%	80%	80%	50%	50%	0%
TOTAL	100%	100%	100%	100%	100%	100%	100%
PHEV / BEV Ratio	75% / 25%		60% / 40%		50% / 50%		32% / 68%
PHEV Type	PHEV 10		PHEV 20		PHEV 40		PHEV 40
PHEV (KWh/mile)	0.045		0.15		0.22		0.22
BEV (kWh/mile)	0.32		0.32		0.32		0.32
FCV (kWh/mile)		0.72		0.72		0.72	0.72
100% VMT (millions)	406,593	406,593	524,822	524,822	593,385	593,385	404,315

Market penetration assumptions for PHEVs, BEVs and FCVs for the three target years are based on likely estimates from two recent studies published by the National Research Council (NRC) [36, 37] and are expressed in terms of percentage of annual VMT. PHEV technology is assumed to improve over time as battery technology advances and costs decline, leading to an increase in all-electric driving range and higher vehicle energy intensity on a kWh/mile basis. A single PHEV technology is assumed for each of the target years: PHEV10 in 2020, PHEV20 in 2035, and PHEV40 in 2050, which represent all-electric driving ranges of 10, 20, and 40 miles respectively. This simplifying assumption is intended to represent the distribution of PHEV types in the fleet as the technology evolves over time.

Electricity demand from each fleet mix scenario, shown in Figure 3, is calculated by multiplying the corresponding electricity intensity (kWh/mile) and VMT share for each EV technology by the total annual VMT estimate for the fleet. For FCVs only 33 percent of the hydrogen demand is assumed to be produced via electrolysis, with the remainder being produced from natural gas via onsite steam methane reforming (SMR), so the electricity demand calculation for FCVs is multiplied by a factor of 0.33. Per the requirements of SB 5105 described in Section 2.1, the 33 percent share of hydrogen produced via electrolysis is assumed to come from 100 percent renewable electricity.

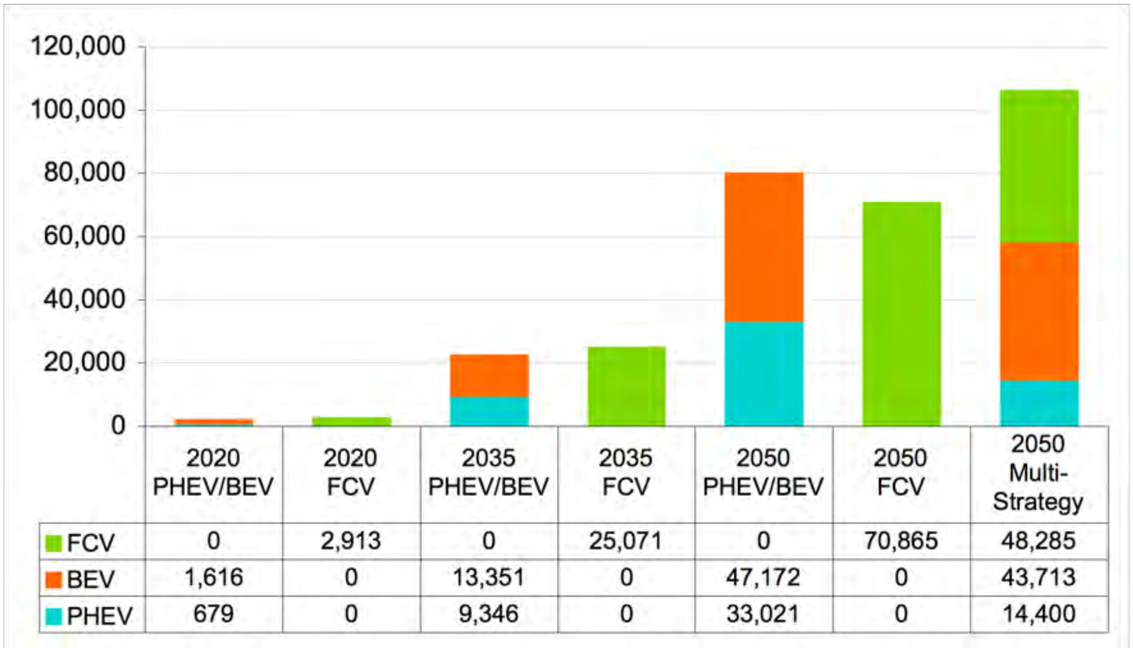


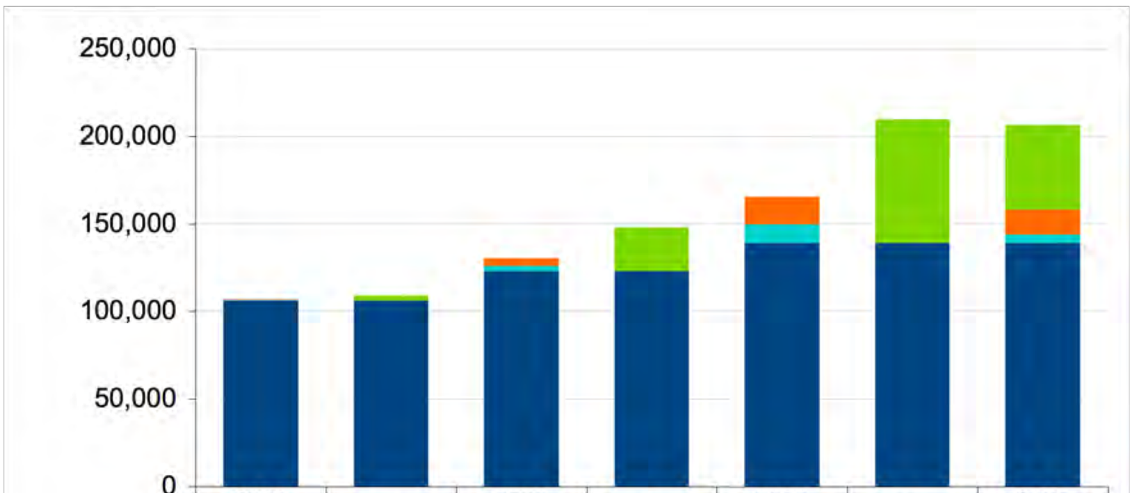
Figure 3: Electricity Demand (GWh/yr) for Light-Duty Vehicle Scenarios

Table 4 summarizes total statewide electricity demand, including non-vehicle demand based on the assumptions in Section 2.2, for all light-duty vehicle scenarios.

Table 4: Total Electricity Demand and Renewable Electricity Supply

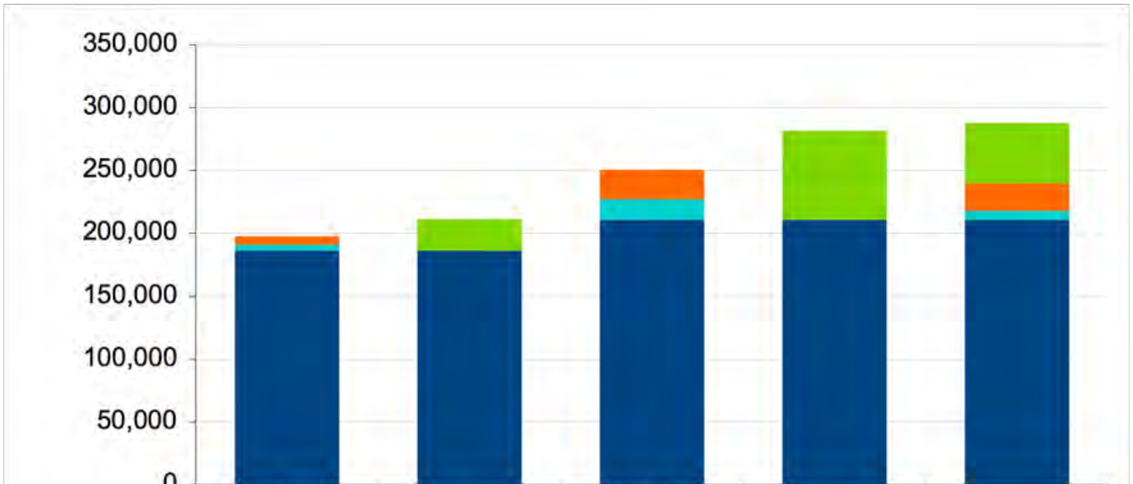
	2020: Electricity Demand (GWh)		**2035: Electricity Demand (GWh)**		**2050: Electricity Demand (GWh)**		
	2020 PHEV/BEV	2020 FCV	2035 PHEV/BEV	2035 FCV	2050 PHEV/BEV	2050 FCV	2050 Multi
PHEV	679	0	9,346	0	33,021	0	14,400
BEV	1,616	0	13,351	0	47,172	0	43,713
FCV	0	2,913	0	25,071	0	70,865	48,285
EV Demand	**2,295**	**2,913**	**22,697**	**25,071**	**80,193**	**70,865**	**106,398**
Non-Vehicle Demand	322,548	322,548	372,904	372,904	421,437	421,437	421,437
TOTAL Demand	**324,843**	**325,461**	**395,601**	**397,974**	**501,630**	**492,301**	**527,834**

Based on the electricity demand requirements from Table 4, Figures 4 and 5 illustrate the renewable electricity supply needed to satisfy two alternative RPS goals: 33 percent of electricity demand and 50 percent of electricity demand. With the exception of electricity demand attributable to hydrogen production, the electricity demand assumptions under each scenario are scaled by an appropriate RPS factor (0.33 or 0.5) to calculate the required amount of renewable electricity. As noted above, electricity for hydrogen production is assumed to be 100 percent renewable electricity, so the RPS scale factor is excluded from the calculation. The renewable electricity requirement to meet a 50 percent RPS goal is only considered for years 2035 and 2050. The total renewable electricity requirement across all scenarios ranges from 107,198 GWh in 2020 to a maximum of 288,060 GWh in 2050.



	2020 PHEV/ BEV	2020 FCV	2035 PHEV/ BEV	2035 FCV	2050 PHEV/ BEV	2050 FCV	2050 Multi-Strategy
FCV		2,913		25,071		70,865	48,285
BEV	533		4,406		15,567		14,425
PHEV	224		3,084		10,897		4,752
Non-Vehicle	106,441	106,441	123,058	123,058	139,074	139,074	139,074

Figure 4: Renewable Electricity Supply (GWh/yr) to Meet a 33% RPS Goal. It is assumed that 33% of hydrogen is produced via renewable powered electrolysis.



	2035 PHEV/ BEV	2035 FCV	2050 PHEV/ BEV	2050 FCV	2050 Multi-Strategy
FCV		25,071		70,865	48,285
BEV	6,675		23,586		21,856
PHEV	4,673		16,510		7,200
Non-Vehicle	186,452	186,452	210,718	210,718	210,718

Figure 5: Renewable Electricity Supply (GWh/yr) to Meet a 50% RPS Goal. It is assumed that 33% of hydrogen is produced via renewable powered electrolysis.

3. California's Renewable Energy Supply

There is an abundance of renewable resources available to meet California's renewable energy goals, yet many of those resources are located far from energy demand centers and must be transmitted: this is one of the biggest challenges to bringing renewable projects online. This section characterizes the magnitude, hourly availability and economic cost of renewable energy resources in California and neighboring states that might be utilized to meet the electricity and hydrogen demand scenarios outlined in Chapter 2. It begins with a broad assessment of the magnitude of renewable energy resources available within California based on a literature review of studies that have been undertaken in support of current RPS goals. Section 3.2 discusses the temporal variability of different types of renewable energy resources and highlights the challenges of integrating intermittent wind and solar energy projects into California's electricity supply. Next, Section 3.3 provides a detailed explanation of the methodology and assumptions I use to model a renewable electricity supply in this thesis. Using geospatial, temporal and economic modeling, I analyze renewable energy projects in California and neighboring states to develop a renewable electricity supply, ranked in order of lowest economic cost, that exceeds the RPS requirements described in Chapter 2. Finally, based on the modeled renewable electricity supply, Section 3.4 describes how I develop renewable electricity portfolios for each of the scenarios defined in Section 2.4. I develop three types of renewable electricity portfolios for each scenario: solar energy intensive, wind energy intensive, and balanced portfolios, which vary in terms of electricity cost and hourly availability. Each portfolio provides an hourly renewable electricity supply profile, which I use to model grid-based electricity and hydrogen production in LEDGE-

CA and hydrogen production from a standalone wind-hydrogen system model, as described in Chapter 4.

3.1 Magnitude of Renewable Energy Resources

Several studies have been undertaken to quantify renewable resources in California that might be utilized to help meet or exceed the current RPS requirement that 33 percent of the state's retail electricity sales must be generated from renewable resources by 2020. These assessments cover a range of renewable energy technologies that include biomass, biogas, geothermal, hydroelectric, marine energy, solar and wind energy. Table 5 summarizes a range of renewable energy capacity and generation estimates for the four most developed renewable energy resources – biomass, geothermal, solar and wind power – aggregated from studies by the California Energy Commission (CEC) [38, 39, 40, 41], the Western Governors' Association (WGA) [42, 43, 44], Black and Veatch [45], and the National Renewable Energy Laboratory (NREL) [46]. Here, technical potential is the amount of the power generation resource that is likely to be available, given environmental and land use restrictions and competing demands for those resources, but without considering the economic cost of developing those resources. As Table 5 illustrates, the estimates vary greatly. This is largely due to assumptions about the availability of the resource, but is also affected by performance assumptions for each generation technology, in particular, the maximum energy conversion potential.

Table 5: Magnitude of Renewable Resources in California by Technology

Technology	Technical Potential Capacity (MW)	Technical Potential Generation (GWh/yr)
Biomass	4,400 to 7,100	33,000 to 60,000
Geothermal	2,375 to 24,750	16,640 to 173,450
Solar Photovoltaic	16,822,180	36,550,800
Solar Thermal	16,069 to 1,061,360	37,241 to 2,717,540
Wind	34,110 to 126,560	105,646 to 479,360

Sources: [38, 39, 40, 41, 42, 43, 44, 45, 46]

3.2 Temporal Availability of Renewable Resources

While these studies suggest that there is an abundance of potential resources to produce renewable electricity in California, the magnitude of the resource is not the only consideration. One of the most important concerns for integrating large amounts of renewable resources into California's electricity grid is the reliability and availability of the resource when it is needed. Unlike other forms of energy, for example liquid transportation fuels, grid electricity is not produced and stored for later use – it is generated as needed, with a fluctuating supply responding to real-time demand or "system load". Currently, California's electricity grid is supplied by two broad categories of generation resources: "passive" and "active" generation. Passive, must-run generators supply electricity to the grid when it is available, regardless of the system load. This category includes predictable resources that meet baseload demand such as nuclear power, some hydropower, combined heat and power (CHP) facilities, biomass and geothermal power. Intermittent wind and solar power are also passive generation resources. Active, dispatchable generators, on the other hand, are brought online and go offline quickly to meet the fluctuating "net system load" over and above the electricity supplied from passive generation. In California, some of the dispatchable generation comes from hydropower, but the remainder comes from fossil-powered combustion turbine (CT) and combined cycle (CC) power plants, which are the main source of GHG emissions from California's electricity grid.

Compared to biomass and geothermal, solar and wind are potentially very large renewable generation resources, but their intermittent availability makes them challenging to integrate into the electricity grid. Both resources vary greatly depending on weather conditions and may not be available when needed. If the wind stops blowing or clouds block sunlight during periods of heavy demand, additional dispatchable generation resources need to be available to make up the shortfall. Current efforts to model the intermittency of wind and solar generation using meteorological data provide good insight into their availability, however this knowledge underscores why the timing is not ideal. Wind and solar generation varies throughout the day and seasonally in different ways, and their availability is not entirely in sync with electricity demand. Solar generation in California is somewhat better suited than wind to meet electricity demand as it follows a more predictable cycle and is typically available when electricity demand is higher: solar power peaks in the middle of the day, and provides longer periods of sustained generation during the day in the summer months. Wind generation in California fluctuates in a less cyclical way than solar generation, and varies with location as well as time of day and season. In general, wind energy is more abundant at night and during the winter months when electricity demand is lower, and can diminish during periods of peak electricity demand.

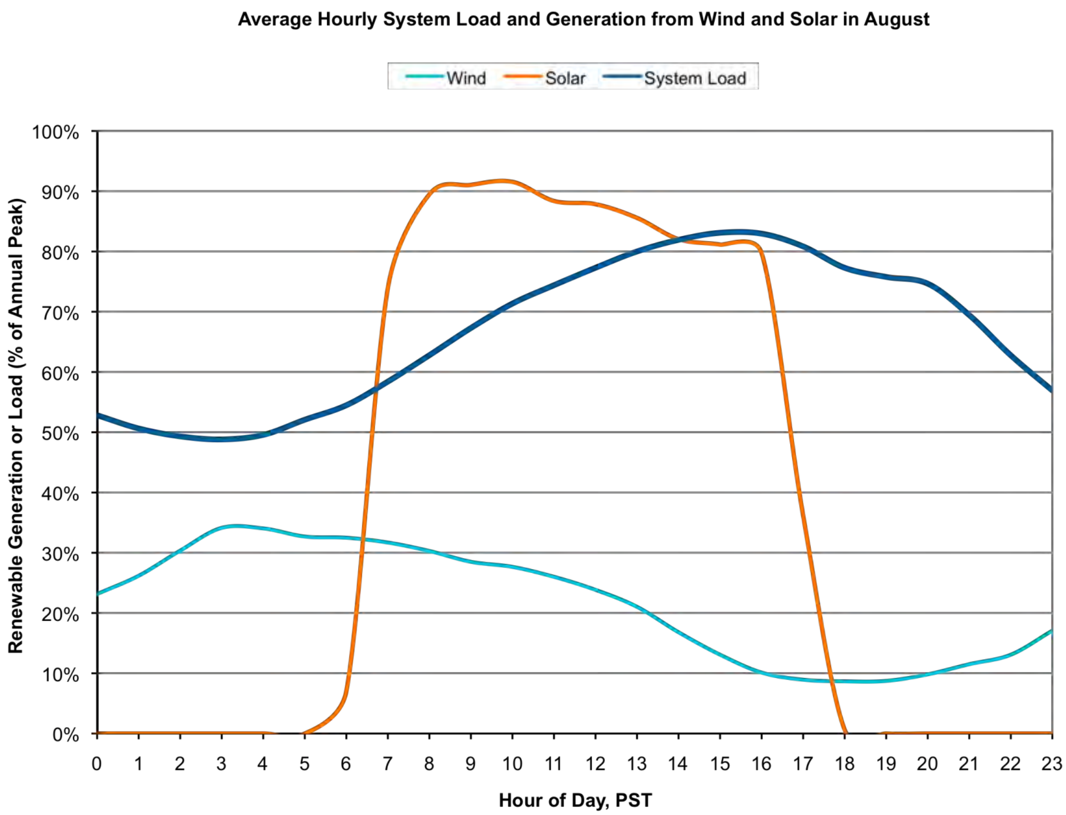


Figure 6: Median Hourly Demand, Wind and Solar Generation in August

Figure 6 illustrates the temporal availability of wind and solar generation compared to electricity demand: mean hourly wind and solar generation is compared to mean hourly demand in California during the month of August. (Hourly wind and solar generation are calculated in section 3.3.6 below. These graphs are based on results derived in that section.). The y-axis shows the August average hourly demand (or supply) divided by the peak annual demand (or supply). It is clear from Figure 6 that although wind generation does not vary to the same magnitude as solar generation, it is generally lowest during the hours of the day when electricity demand is highest – in this example, when demand reaches around 80 percent of its peak value. Solar generation varies more than wind – from zero to 90 percent of peak load – however, it is highest during the part of the day when electricity demand is growing.

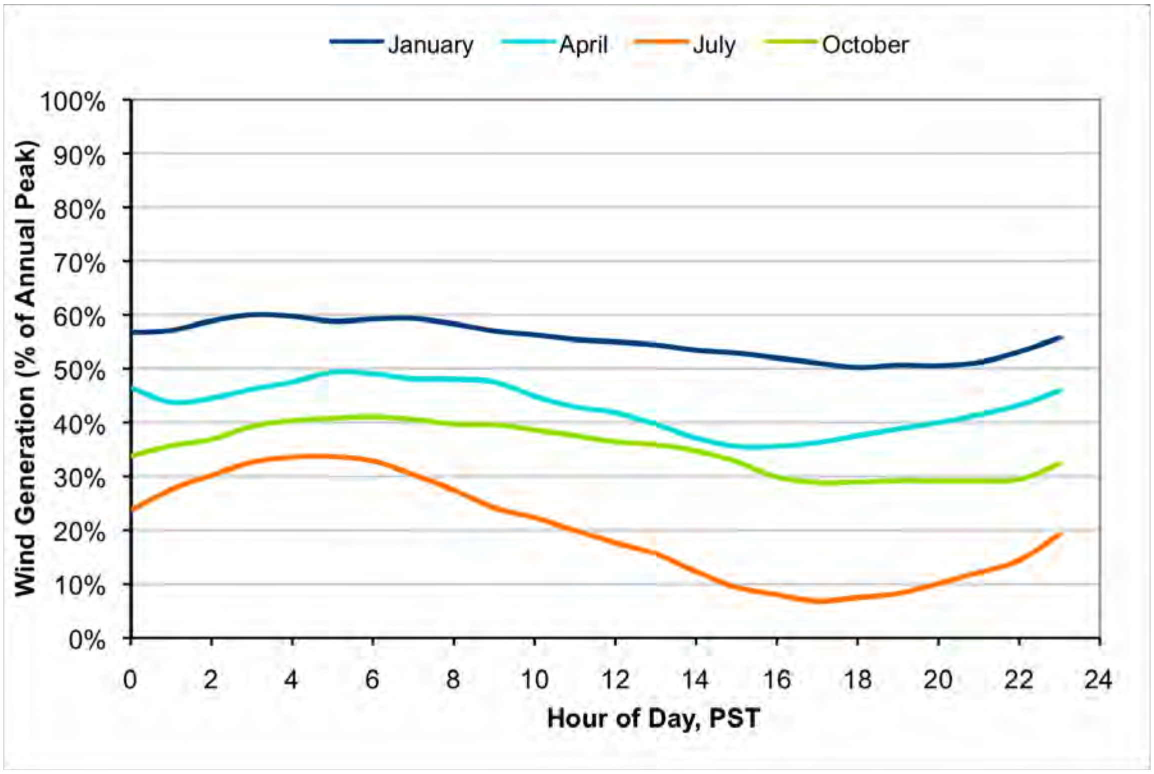


Figure 7: Hourly Average Wind Generation by Season

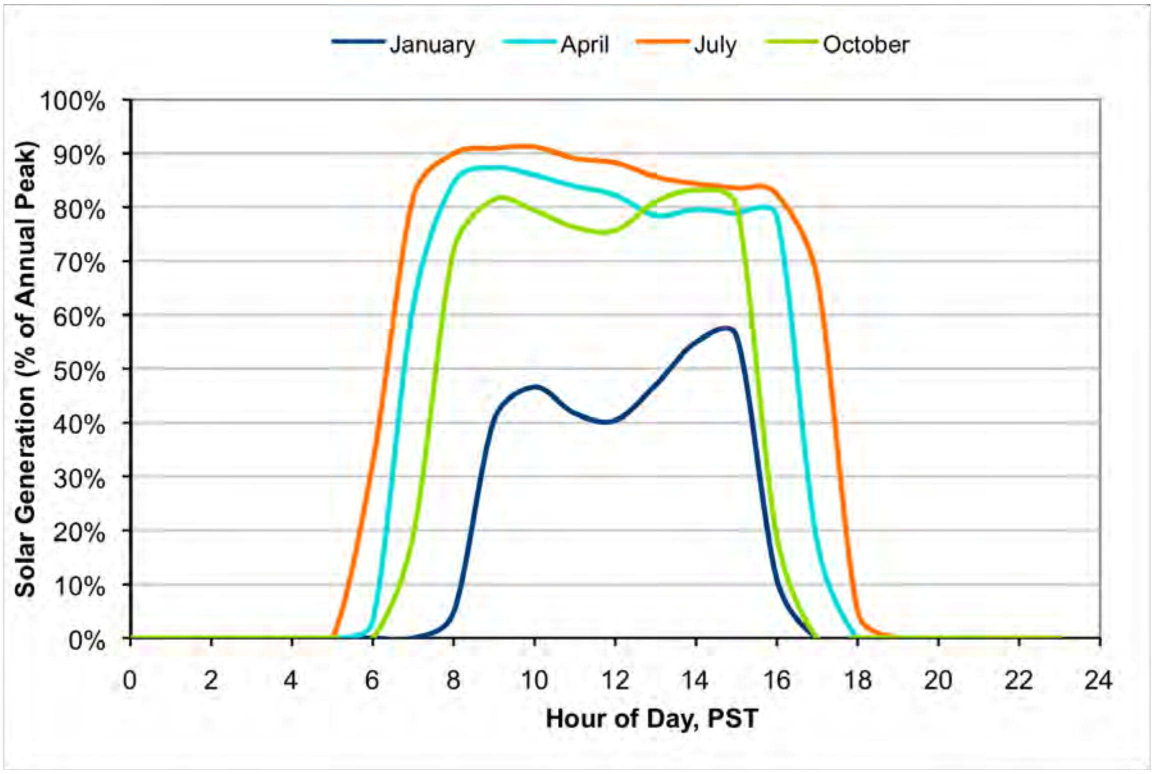


Figure 8: Hourly Average Solar Generation by Season

Figures 7 and 8 illustrate the seasonal differences between wind and solar generation. Both resources vary throughout the year, but in opposite ways. Wind generation is strongest during the winter months and weakest during the summer, whereas solar generation is the reverse. Based on the timing alone, solar generation is generally better suited to meeting California's electricity demand, however wind generation may be suitable for charging electric vehicles or producing hydrogen at night when solar generation is unavailable and demand for electricity is lower. Combining wind and solar generation may help to address the temporal issues and make them more suitable resources to meet electricity demand without large amounts of backup generation. Another potential solution is the addition of energy storage, which can be utilized to better align the availability of renewable generation and electricity demand. The economic cost and hourly availability of different types of renewable electricity mixes are explored in the next two sections, which discuss the renewable electricity supply modeled in this thesis. Section 3.3.6 provides a detailed explanation of how I calculate hourly values for wind and solar generation.

3.3 Model of California's Renewable Electricity Supply

Given the intermittent nature of wind and solar resources, which will likely play a significant role in any renewable electricity portfolio, a detailed renewable electricity supply must be modeled to enable comparison of the GHG and economic impacts of the vehicle fleet scenarios defined in Chapter 2. The renewable electricity supply modeled in this thesis is based on my analysis of studies by the Renewable Energy Transmission Initiative (RETI): a statewide stakeholder initiative tasked with identifying transmission projects to meet California's renewable energy goals, supporting future energy policy, and facilitating the implementation of transmission infrastructure and renewable energy generation projects [47]. In Sections 3.3.1 to 3.3.6, I describe how I quantify the estimated capacity and generation in the renewable electricity supply, and in Section 3.3.7, I discuss its economic cost. Section 3.4 explains how I develop a range of renewable portfolios to meet the energy demand scenarios described in Chapter 2, based on the economically-ranked supply.

3.3.1 Location and Magnitude of Renewable Energy Projects

RETI identifies new utility-scale renewable energy projects in California, and neighboring regions that can be developed to help meet California's RPS goals. Four renewable electricity technologies are included: biomass, geothermal, solar thermal, and wind energy. A key component of RETI's methodology is to identify planned and potential projects located in common areas that can be aggregated to connect to the transmission system at a shared interconnection point. RETI defines this level of aggregation as a Competitive Renewable Energy Zone (CREZ), and ranks CREZs by their cost-effectiveness based on their development potential, factoring in environmental restrictions, resource quality, development cost and cost of transmission to load centers. Figure 9 shows a simplified map of CREZ locations within California that I developed using GIS data from Phase 2B of the RETI project [48].

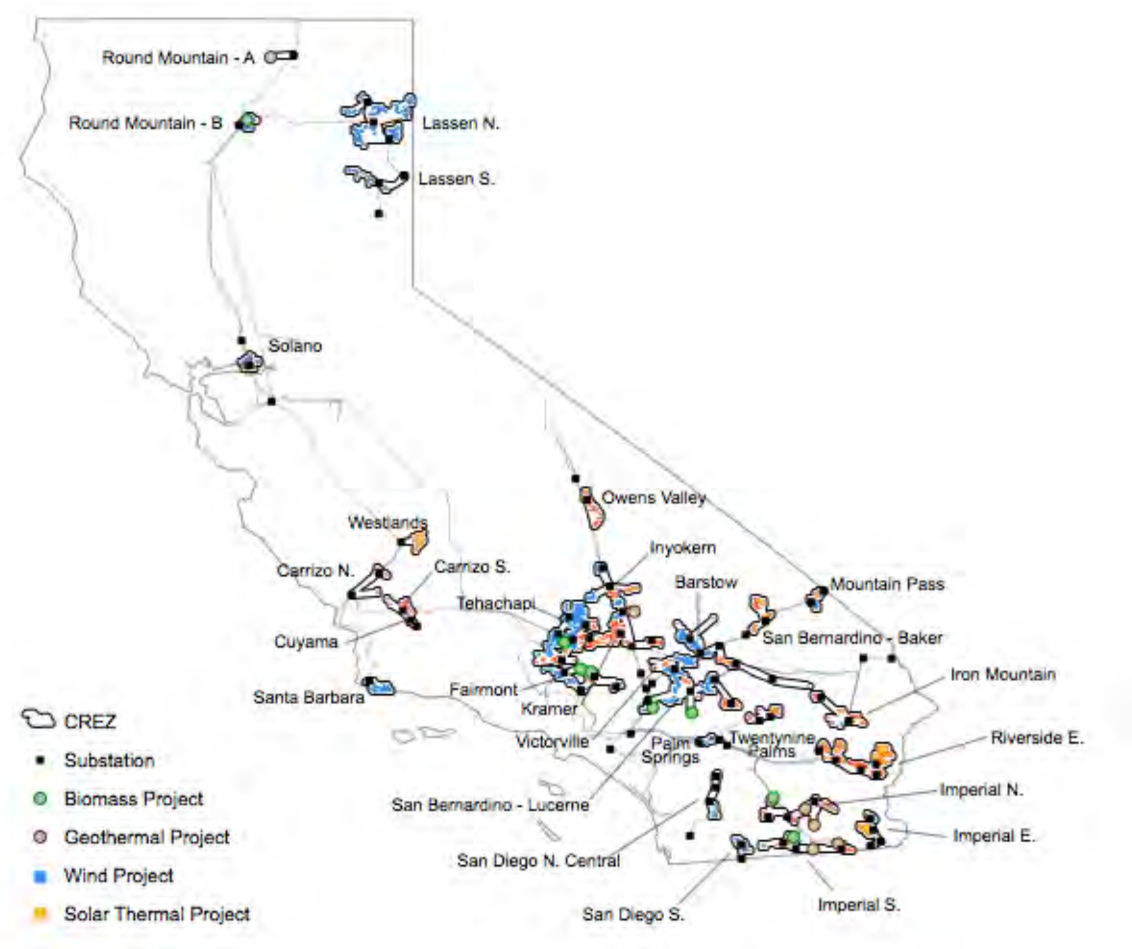
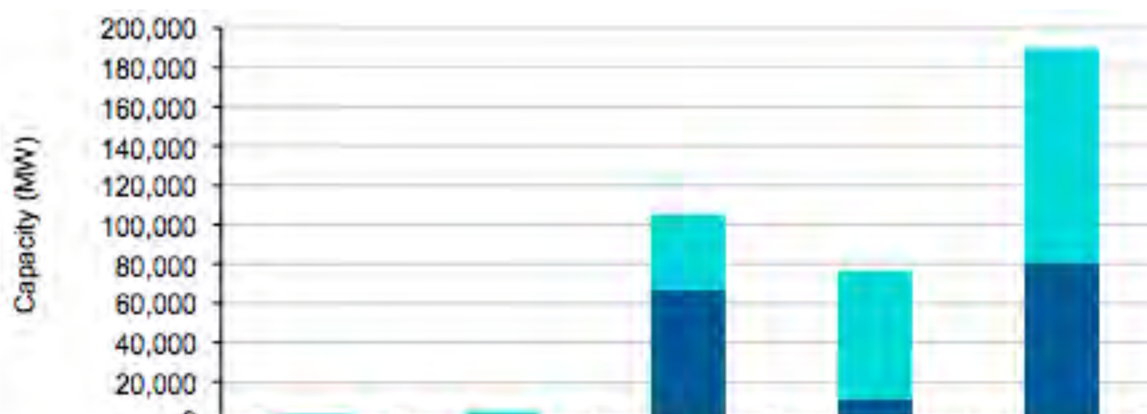


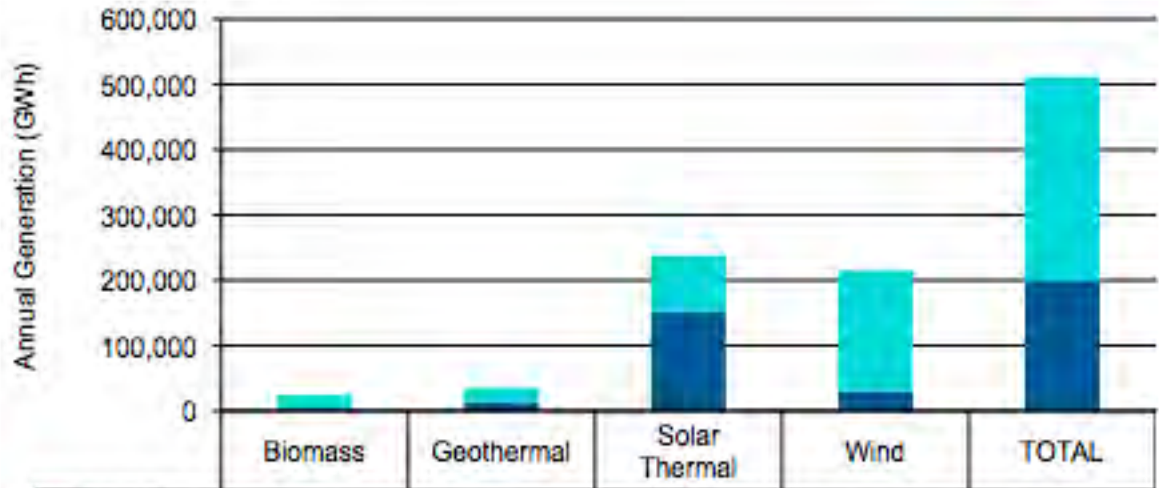
Figure 9: CREZ Map of California Renewable Energy Projects [48]

Although RETI identifies many economically competitive renewable resources within California, they also include a significant resource base from nearby out-of-state (OOS) locations, especially wind and biomass energy, and to a lesser extent, geothermal and solar thermal energy. The most recent RETI assessment identifies 665 individual renewable energy projects among 64 CREZs that represent a combined renewable energy capacity of 189,722 MW, and an estimated 511,605 GWh of annual electricity generation, shown in Figures 10 and 11 [49]. Roughly 42 percent of the capacity and 39 percent of the estimated generation is from projects in California, with the remainder coming from Arizona, Idaho, New Mexico, Nevada, Oregon, Utah, Washington, Wyoming, British Columbia, Canada, and Baja California, Mexico.



	Biomass	Geothermal	Solar Thermal	Wind	TOTAL
Out-Of-State	2,918	2,910	38,370	65,257	109,455
California	332	1,842	66,820	11,273	80,267

Figure 10: RETI Renewable Resource Capacity (MW) by Technology [49]



	Biomass	Geothermal	Solar Thermal	Wind	TOTAL
Out-Of-State	21,727	21,120	85,085	184,765	312,697
California	2,470	13,934	152,225	30,280	198,908

Figure 11: RETI Renewable Resource Generation (GWh) by Technology [49]

Unless specifically noted, I generally use RETI's assumptions regarding resource locations and magnitudes, and energy conversion technologies to calculate renewable energy capacity for all four renewable technologies and to calculate energy generation from biomass and geothermal resources. The assumptions are from a series of reports published by RETI between 2008 and 2010 [49, 50, 51, 52]. However, I use a different methodology to calculate generation from wind and solar resources, which is described and compared with RETI's generation estimates in Section 3.3.6. The renewable resource assumptions used in this thesis – both RETI's and my own – are discussed for each of the four technologies in the sections that follow.

3.3.2 Biomass Projects

The renewable electricity supply modeled in this thesis includes 61 biomass projects – seven in California – representing 3,250 MW of generating capacity and an estimated 24,197 GWh of annual generation [49]. For projects within California, RETI uses year

2010 county-level estimates from the California Energy Commission and California Biomass Collaborative (CBC) to identify the total amount of biomass that can be used as a combustible fuel feedstock: one-third of this fuel capacity is assumed to be available for power generation. RETI assumes all projects employ conventional direct-fired biomass electricity generation systems, with biomass combusted in a stoker or fluidized bed steam generator using a standard Rankine power cycle. Resource estimates are converted to equivalent generation capacity (MW) using higher heating value heat rates that range from 14,000 to 16,000 Btu/kWh, depending on the moisture content of the fuel. Individual "proxy" projects that range in capacity from 20 to 100 MW are modeled based on the feedstock availability, with an assumed capacity factor of 85 percent for all projects. All projects are assumed to have a constant generation rate (i.e. baseload power). Out-of-state (OOS) biomass projects are modeled in a similar way. I estimate generation capacity for OOS projects using NREL biomass resource data compiled for the Western Renewable Energy Zones (WREZ) Initiative [44], however I assume that no more than half of the total estimated generation capacity is available for export to California. This restriction is discussed further in Section 3.4.

3.3.3 Geothermal Projects

The renewable electricity supply includes 130 geothermal projects – seven in California – representing 4,752 MW of generating capacity and an estimated 35,053 GWh of annual generation [49]. RETI quantifies the geothermal resource using pre-identified projects in California and OOS areas, drawn from a range of data sources including geothermal potential resource assessments from government and academia, industry publications and responses to solicitations form geothermal developers. The list of projects includes existing geothermal plants with expansion potential, Known Geothermal Resource Areas (KGRAs) as published by the United States Geological Survey (USGS), geothermal leases as published by the BLM, and prospect areas with associated MW estimates published by the California Energy Commission (CEC) and the Western Governors Association (WGA). Undiscovered conventional resources and enhanced geothermal systems (EGS) resources are not considered.

For projects with sufficient resource data available, RETI uses the heat-in-place method to estimate the proportion of heat that can be recovered as electrical energy, based on estimates of the area, thickness, and average temperature of the geothermal resource. A probabilistic approach is applied to provide a range of generation estimates for each project, with the modal value of the probability distribution considered to be the “most likely value” of generation potential. For projects with limited resource data available, RETI derives estimates of annual generation from better-known projects in similar geologic environments. For those projects with limited resource data, capacity estimates range from 10 MW to 50 MW, based on potential geologic conditions and evidence of active development efforts. RETI assumes capacity factor estimates for geothermal projects are 90 percent for flash steam power plants and 80 percent for binary-cycle power plants. As with biomass generation, I assume that all geothermal plants included in this analysis have a constant generation rate.

3.3.4 Solar Thermal Projects

The renewable electricity supply includes 232 solar thermal projects – 216 in California – representing 105,190 MW of generating capacity and an estimated 237,310 GWh of annual generation. The solar thermal capacity estimate is from RETI's most recent analysis [49], and the annual generation estimate is from my calculations, described in Section 3.3.6. Due to the uniform and widely distributed nature of solar resources, RETI identifies large-scale solar projects using a grid that covers the entire state of California. Each grid square covers an area of two square miles and represents a single project parcel with a capacity of 200 MW. Grid squares containing land in exclusion zones are omitted from RETI's assessment, as are squares with a median land slope of more than two percent or an average annual direct normal insolation of less than 6 kWh/m^2/day. The list of solar thermal projects comprises both pre-identified and proxy projects. Grid squares are assigned to pre-identified projects based on evidence of development interest that include: Bureau of Land Management (BLM) applications, contracts for energy sales, information provided by developers, and known interest from military bases. To quantify OOS solar thermal resources, RETI models pre-identified projects in southern Nevada and Western Arizona based on BLM applications and information provided by developers.

3.3.5 Wind Projects

The renewable electricity supply includes 242 wind projects – 95 in California – representing 76,530 MW of generating capacity and an estimated 227,117 GWh of annual generation. As with solar thermal generation, the capacity estimate is from RETI's most recent analysis [49] and the generation estimate is from my calculations, described in the next section. RETI models wind project locations in California using a high resolution wind speed dataset produced by AWS Truewind for the California Energy Commissions's Intermittency Analysis Project [53]. The dataset includes wind speed, wind direction, and Weibull shape and scale parameters for a grid that covers the entire state of California. Grid squares covering an area of 40,000 square meters, are aggregated into ½ mile by ½ mile "quarter sections" to model individual project areas. Quarter sections that include environmentally sensitive areas, restricted air space, existing wind projects, proximity to airports or a median slope greater than 20 percent are excluded. Project capacity is calculated by estimating the number of turbines that can be placed in each quarter section, based on land terrain and wind class: turbines are placed more closely together in higher wind class areas. The list of wind projects comprises both pre-identified and proxy projects. Quarter sections are assigned to pre-identified projects based on evidence of development interest that include: Bureau of Land Management (BLM) applications, contracts for energy sales, and information provided by developers.

The method RETI uses to model OOS wind projects varies depending on the location. The capacity and location of wind projects in Southern Nevada, Oregon, Washington, and Northern Baja, Mexico are modeled using NREL wind GIS data. In Nevada, only pre-identified projects are included, based on BLM applications or information from developers. In Oregon and Washington, RETI assumes 25 percent of technically developable wind capacity is available for export to California, based on the current share of Oregon and Washington wind power being sold to California. RETI models wind projects in British Columbia, Canada based on a wind energy study by BC Hydro for Pacific Gas and Electric Company.

3.3.6. Hourly and Annual Generation Estimates

Biomass and Geothermal Projects

All biomass and geothermal projects are assumed to produce the same amount of energy at all times of day, therefore, calculating the estimated average hourly power output and annual generation are simply:

$$Hourly\ Power\ Output\ (MW) = Capacity\ (MW) \times Capacity\ Factor \tag{1}$$

$$Annual\ Generation\ (GWh) = \frac{Capacity\ (MW) \times Capacity\ Factor \times 8,760\ hours}{\frac{1,000\ MW}{GW}} \tag{2}$$

Solar Thermal Projects

I calculate estimated generation for each of the 232 solar thermal projects using tools from NREL that characterize hourly variations in solar power output throughout the year based on the solar resource at the plant's geographic location:

1. The Solar Power Prospector dataset, which provides eight years of satellite-derived hourly direct normal insolation (DNI) data throughout the United States, modeled on a 10km geospatial grid [54].
2. The Solar Advisor Model (SAM), which models the performance of solar thermal projects based on power plant design and location-specific DNI data [55].

I map each solar thermal project included in RETI’s analysis to the nearest location in the Solar Power Prospector dataset (Figure 12), based on the project’s longitude and latitude from RETI’s GIS project database [48].

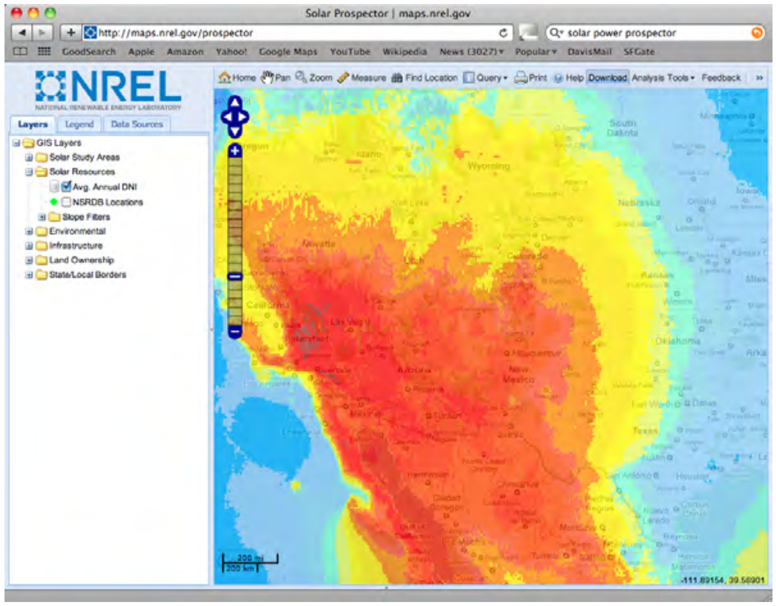


Figure 12: NREL Solar Power Prospector Dataset [54]

I input the corresponding eight-year average of hourly DNI data from the Solar Power Prospector dataset into SAM. I also define plant capacity, solar thermal technology, cooling method and storage assumptions in SAM for each project (Figure 13).

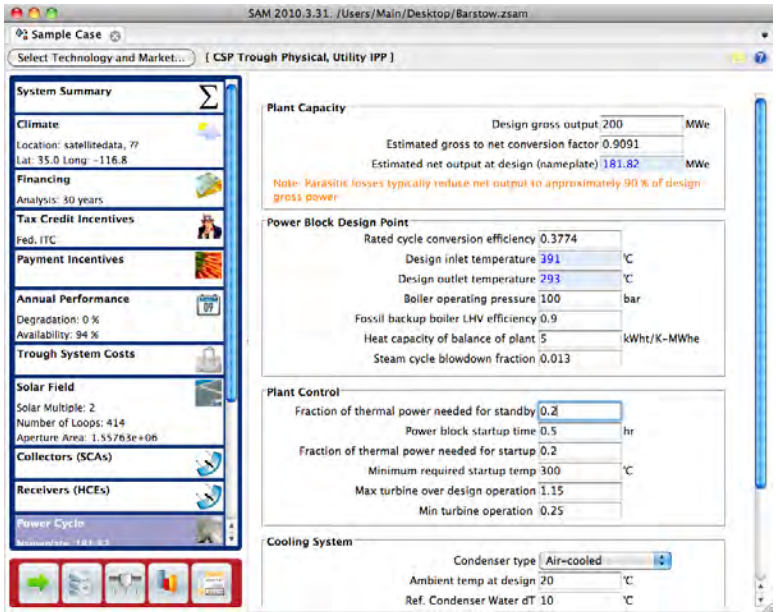


Figure 13: NREL Solar Advisor Model [55]

I model all solar thermal projects as parabolic trough plants, since this is the only utility-scale solar thermal technology that has operated commercially for several years. I assume projects use dry cooling, apart from specific projects that RETI identifies as having been granted permission to use water [51]. By default, SAM assumes six hours of thermal storage, which improves the performance and economics of solar thermal plants. However, few commercial solar thermal projects in development have opted to use storage, therefore I model solar thermal projects in SAM without storage. For each project, SAM estimates power output for every hour of the year, which are summed to provide an annual generation estimate. Modeling all solar thermal projects in SAM yields an aggregate annual generation estimate of 237,310 GWh. By comparison, RETI estimates an aggregate annual generation of 232,053 GWh [49], or approximately 2.2 percent lower.

Wind Projects

I calculate estimated generation for each of the 242 wind projects in RETI's analysis using NREL's Western Wind Dataset (WWDS) to characterize hourly variations in wind power output throughout the year based on the wind resource at the plant's geographic location [56].

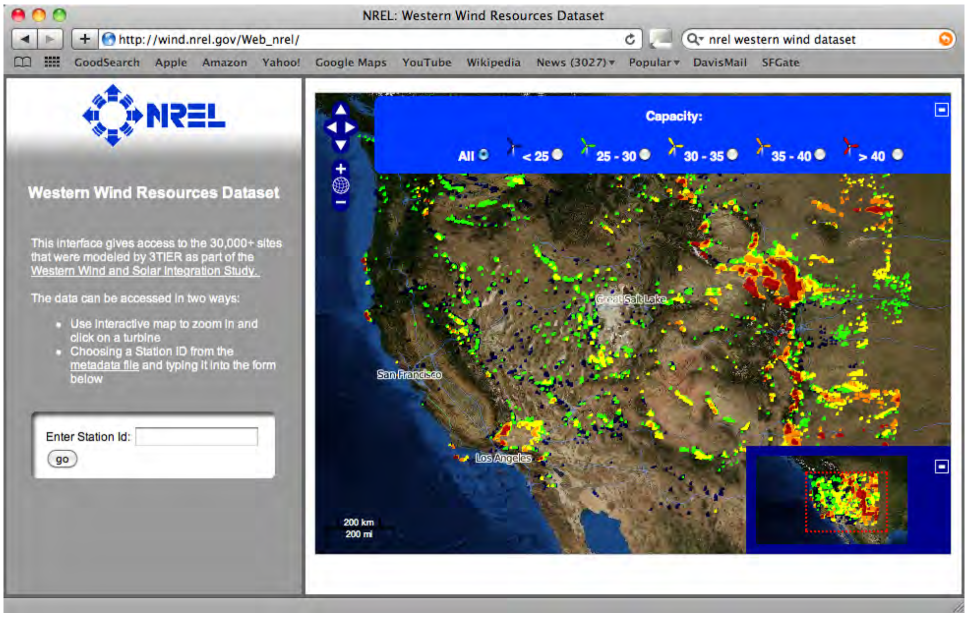


Figure 14: NREL Western Wind Dataset [56]

The WWDS is a high-resolution modeled GIS windspeed dataset, representing 32,043 wind power locations throughout the Western United States. Wind speed data at a turbine height of 100 m is modeled every 10-minutes throughout the year for years 2004, 2005 and 2006. In the dataset, raw wind speeds are converted to power output estimates using the power curve for a Vestas V90 3.0 MW wind turbine, with each data point in the WWDS representing a cluster of 10 turbines, or 30 MW of capacity. At 100 m turbine height, the Vestas V90 is among the more advanced turbine technologies currently available and is intended to represent both current and future turbine technology. To account for differences between real wind patterns and modeled wind speeds, NREL uses a probabilistic process to correct power output estimates from the WWDS. I map each wind project included in RETI's analysis to the nearest location in the WWDS, based on the project's longitude and latitude from RETI's GIS project database [48]. I convert the corresponding three-year average of 10-minute power output data from the WWDS to an hourly average power output for each hour of the year. I then scale the average hourly value, based on the ratio of the project capacity calculated by RETI to the 30 MW capacity assumed in the WWDS. For each project, I sum hourly power estimates to derive an annual generation estimate. Modeling all wind projects from RETI's analysis using the WWDS yields an aggregate annual generation estimate of 215,045 GWh. By comparison, RETI estimates an aggregate annual generation of 227,117 GWh, or approximately 5.6 percent higher.

3.3.7 Economic Ranking of Renewable Energy Projects

In the modeled supply, I rank renewable energy projects in order of lowest cost, expressed in \$/MWh of delivered energy, using constant year 2010 dollars. The rank cost of each project is the sum of two components: the cost of generation, representing the annualized cost to develop and operate the project over its lifetime, and the transmission cost to deliver electricity from the project to a load center. Projects within California incur instate transmission costs, whereas OOS projects incur both OOS and instate transmission costs, which are calculated separately. The rank cost calculation also factors in transmission losses for each project, which range from 5 percent to 14 percent of generation, depending on the resource location. Rank cost is calculated as follows:

$$Rank\ Cost\ \left(\$/_{MWh}\right) = \frac{LCOE + InState\ Transmission + OOS\ Transmission}{1 - Line\ Loss\ (\%)} \qquad (3)$$

Cost of Generation

The cost of generation, calculated at the plant site – commonly refered to as as the busbar cost – is calculated as a levelized cost of energy (LCOE) over the lifetime of each project on a $/MWh basis. This enables renewable energy projects to be compared on an economic basis, regardless of the project's expected economic life, generation technology or geographical location. I calculate the LCOE for each project using a simple spreadsheet-based financial model developed for RETI that considers the project from the perspective of a developer, including the direct costs, charges and incentives, and an expected rate of return on the equity [57]. Specifically, the model includes:

- Operations and maintenance costs
- Fuel costs (for biomass projects)
- Cost of equity investment in capital
- Cost of financing capital
- Taxes, including investment and production credits

Table 6 summarizes the project financing assumptions I use, which are based on the CEC's cost of generation model [58] and represent a typical structure for financing renewable energy projects: 60 percent debt financed over 15 years at a rate of 7.5 percent and 40 percent equity at a rate of 15 percent. This yields a weighted average cost of capital of 10.5 percent. The cost of equity is an approximation of the return on investment that a renewable energy project investor would require; taking into account the return they could receive on a similar investment. The tax life is the expected depreciation schedule for project assets.

Table 6: Renewable Energy Project Financing Assumptions [58]

Technology	Economic Life	Debt/Equity Ratio	Debt Term	Interest Rate	Cost of Equity	Tax Life
Biomass	20 years	60/40	15 years	7.5%	15%	7 years
Geothermal	20 years	60/40	15 years	7.5%	15%	5 years
Solar Thermal	20 years	60/40	15 years	7.5%	15%	5 years
Wind	20 years	60/40	15 years	7.5%	15%	5 years

The RETI financial model uses a revenue requirements approach to calculate a required LCOE for each project that will yield the desired cost of equity by generating income from electricity sales. All future cash flows associated with a project are discounted using the weighted average cost of capital rate to generate a net present value (NPV). The LCOE is chosen such that the NPV equals zero. In addition to the project financing assumptions, I assume a combined federal and state income tax rate of 40 percent and a general inflation rate of 2.5 percent to represent the escalation rate for fixed and variable operating and maintenance (O&M) costs and fuel costs.

Per the American Recovery and Reinvestment Act of 2009 (ARRA), described earlier in Chapter 2, all projects in the U.S. are assumed to be eligible for a 30 percent Investment Tax Credit (ITC), which permits 30 percent of the project capital costs to be depreciated during the first year of operation [23]. Projects in Canada and Baja Mexico are also eligible for investment tax credits that result in accelerated depreciation schedules. Canadian geothermal and wind projects are eligible for an incentive that is equivalent to the U.S. 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule [59], while wind projects in Mexico are eligible for incentives that are equivalent to a 26.6 percent ITC [60]. Although there is no guarantee that the ITC or similar incentives will be available for projects developed in future years, in this thesis, they are assumed to be available for all renewable energy projects, regardless of when they are completed.

Table 7: Capital, O&M and Fuel Costs by Generation Technology [49]

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Fuel Cost ($/MBtu)
Biomass	4,060 to 5,643	0 to 118	10 to 52	2 to 3
Geothermal	4,123 to 13,252	0	27 to 42	0
Solar Thermal	5,300	66	0	0
Wind	2,158 to 2,742	60	0	0

In addition to capital costs, projects are assumed to incur fixed and variable O&M costs and fuel costs that vary with the generation technology. Table 7 summarizes the range of capital, O&M and fuel cost assumptions used in the financial model [49].

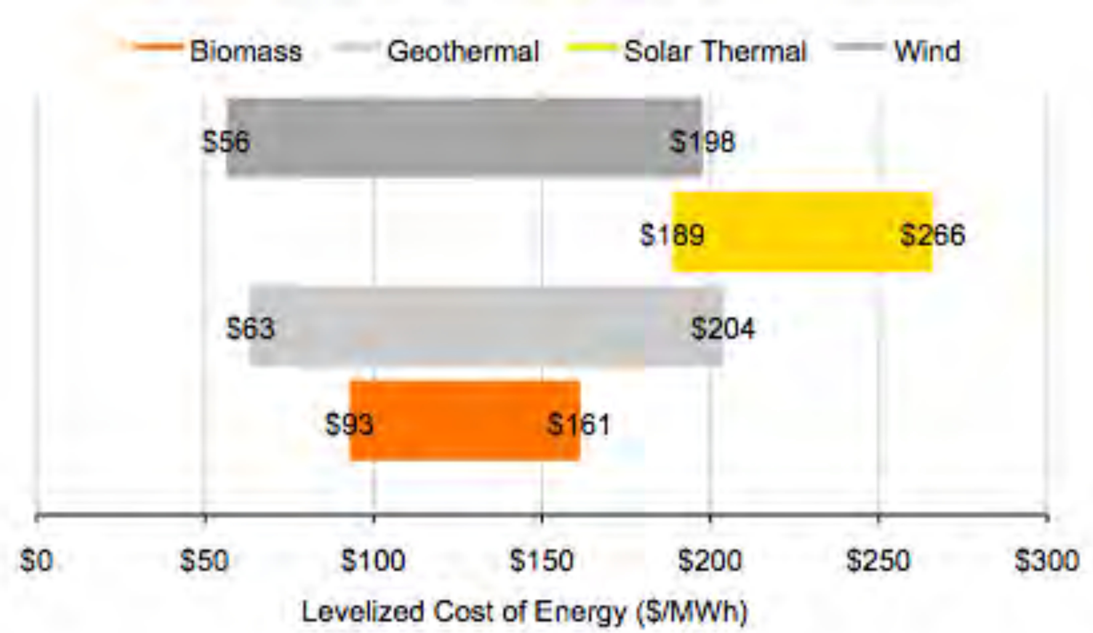


Figure 15: Levelized Cost of Energy by Technology

Figure 15 shows the range of generation cost estimates for all projects calculated with the financial model. The lowest cost generation comes from wind and geothermal projects, however the cost range for those technologies varies greatly: wind generation costs range from $56 to $198 per MWh while geothermal costs range from $63 to $204 per MWh. Biomass and solar thermal projects show a narrower cost range, however solar thermal is the most costly technology, with LCOE values ranging from $189 to $266 per MWh.

Out-of-state Transmission Costs

I use RETI's assumptions and estimates for OOS transmission costs. RETI assumes that new transmission lines must be built to deliver electricity from new renewable energy projects to California, i.e. no spare capacity is available in the existing transmission infrastructure. OOS transmissions costs are based on the following assumptions developed for the WREZ initiative [44]:

1. All new transmission lines are 500 kV single circuit ac lines.
2. The import path to California is determined based on the lowest cost or shortest path by region, using the WREZ transmission model.
3. Transmission lines are financed with a mix of 50 percent federal and private financing.
4. Generation is delivered to California through one of five gateway CREZs: Round Mountain, Owens Valley, Mountain Pass, Riverside East, or Imperial Valley.
5. Line utilization varies based on the mix of generation resources in a given geographical area.

6. Transmission losses are based on the line distance from the generation source to the California gateway CREZ.

Tables 8 and 9 summarize the capital and financing cost assumptions associated with new transmission capacity to deliver electricity to California.

Table 8: Capital Cost Assumptions for OOS Transmission Lines [49]

Nominal Capacity (MW)	Capital Cost ($/mile)	Substation Cost ($)	Right of Way (ROW) Width (ft)	ROW Cost ($/acre)
1,500	1,800,000	50,000,000	175	10,700

Table 9: Financing Assumptions for OOS Transmission Lines [49]

Economic Life	40 years
Debt Percentage	50%
Debt Term	30 years
Interest Rate	6%
Equity Cost	13%
Tax Life	15 years
Discount Rate	7.625%
Tax Rate	40%
Allowance for Funds Used During Construction	7.5% of capital cost
Annual Operation and Maintenance Costs	3% of initial cost

Figure 16 illustrates the range of OOS transmission costs for all 340 projects. The variation in cost is mainly attributable to transmission distance and assumed line utilization. Costs range from $3 to $4 per MWh for wind projects in Baja, Mexico and

Southwest Nevada, to as much as $69 per MWh for biomass, geothermal and wind projects in British Columbia, Canada.

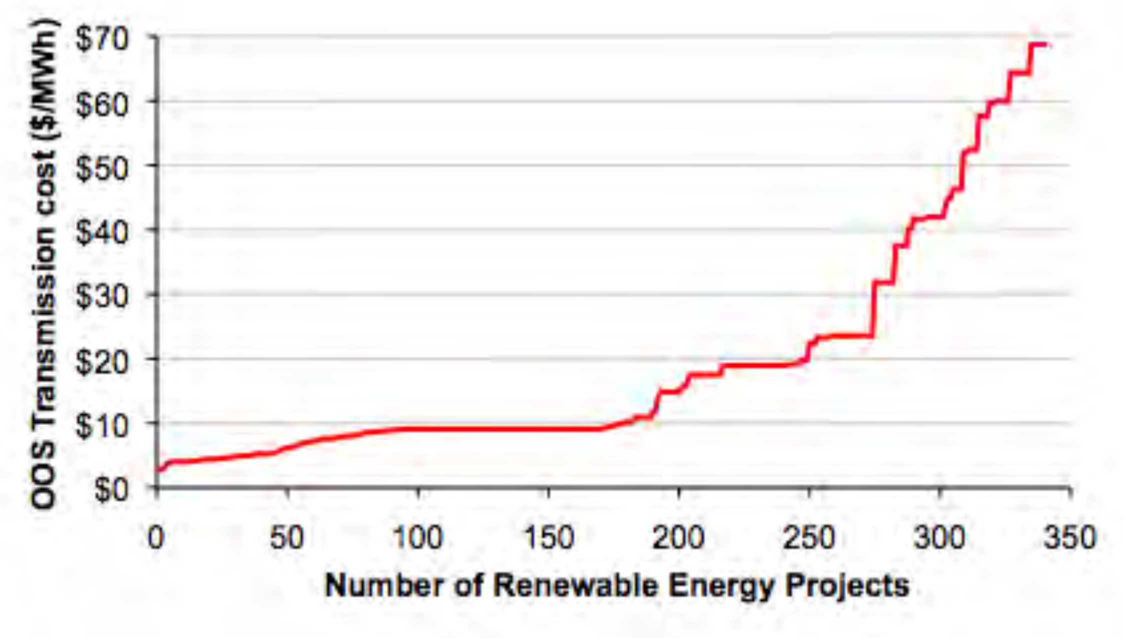


Figure 16: Range of Out-of-state Transmission Costs [49]

Instate Transmission Costs

Allocating instate transmission costs to individual generation projects is more complicated than allocating OOS transmission costs and requires a different approach. Integrating a large amount of renewable generation will require expansion of California's transmission infrastructure, however many of the links in the transmission network that will need to be built or upgraded will carry electricity from multiple renewable energy projects, making it difficult to directly allocate costs to individual projects. To simplify the calculation, I use the methodology developed by RETI's Conceptual Transmission Planning Work Group to calculate instate transmission costs for different amounts of renewable generation [52]. Under this methodology, instate transmission costs are allocated to an entire CREZ rather than to individual projects, so each project within a CREZ is assigned the same instate transmission cost ($/MWh). Instate transmission costs for OOS projects are based on the gateway CREZ used to deliver energy to California as shown in Table 10.

Table 10: Gateway CREZs and Allocated OOS Project Areas [49]

Gateway CREZ	**Allocated OOS Project Areas**
Imperial Valley	Baja North and Baja South
Mountain Pass	Northwestern Arizona, Eastern Nevada, Southwestern Nevada, Western Nevada, Utah, and Wyoming
Owens Valley	Northern Nevada
Riverside East	Northeastern Arizona, Southern Arizona, Western Arizona, and New Mexico
Round Mountain	Idaho, Oregon, Washington, and British Columbia

Instate transmission costs are allocated to each CREZ using a set of "shift factors" for all transmission line segments that need to be built or upgraded[1]. Shift factors represent the relative utility value of each transmission line segment to transmit renewable energy from each CREZ to load centers where the energy is needed. To calculate shift factors, renewable energy demand and designated delivery locations are identified based on the needs of each of California's load serving entities (LSE) to meet statewide RPS goals. The shift factor calculation process sequentially inserts one megawatt of power into the grid from each CREZ and computes the percentage of this additional power that flows in every line segment throughout the Western Interconnection to designated load locations.

[1] As part of its conceptual transmission plan, RETI identifies 104 required transmission line segments that need to be improved. These line segments and associated development costs are used to calculate instate transmission costs in this thesis. For additional information on the instate transmission cost methodology, see [52].

The percentages flowing in each of the line segments to be upgraded are tabulated in a matrix of 3,640 shift factors: 104 line segments proportionally allocated to 35 CREZs. To calculate instate transmission costs, the following assumptions are used:

1. Capital costs for transmission infrastructure improvements are based on RETI analysis of required line segment upgrades and additions.
2. 50 percent of the estimated capital costs for these line segments are arbitrarily allocated to renewable generation, since transmission improvements will be used for both renewable and conventional generation.
3. Collector lines from renewable projects bear 100 percent of the capital cost.
4. The allocated capital costs are annualized with a 10 percent fixed rate charge.

Using the above assumptions, instate transmission costs are calculated as follows:

1. The absolute value of each shift factor in the 35 x 104 matrix described above is weighted by the amount of renewable energy capacity from each CREZ needed to meet the RPS goal for a given year.
2. Using the weighted shift factor matrix, the estimated capital cost of each transmission line segment is proportionally assigned to each CREZ. The total transmission cost attributable to each CREZ is the sum of the weighted cost shares of all line segments for that CREZ.
3. The unit instate transmission cost ($/MWh) attributable to each CREZ is calculated by dividing the total transmission cost allocated to a CREZ by the estimated annual generation from that CREZ needed to meet the RPS goal.

In calculating instate transmission costs using the above method, I assume that the transmission upgrades are sufficient to meet a range of RPS scenarios. Based on this assumption, I calculate multiple sets of unit transmission costs to meet the range of renewable energy requirements described in Section 2.4. The unit instate transmission cost for each CREZ decreases as the amount of renewable energy needed increases. This occurs because the fixed capital costs attributable to transmission upgrades are shared by an increasing amount of renewable generation from each CREZ, resulting in higher transmission line utilization.

Rank Cost Economic Supply Curves

Combining generation costs and transmission costs and accounting for line losses, I develop rank cost supply curves for the modeled renewable supply in two ways:

1. By project: to show the incremental cost of developing each renewable project in order of lowest cost, regardless of where the project is located.
2. By CREZ: to show the incremental cost of developing each CREZ in order of lowest cost. In this approach, the cost associated with each CREZ is the weighted average rank cost of all generation resources within the CREZ.

Although individual projects will be developed incrementally to meet RPS goals, from a transmission planning perspective, it is more economically efficient and more feasible to develop and integrate all resources within an entire CREZ rather than simply choose the lowest cost resources. Since this approach is more realistic, this is the method I adopt in this thesis. For the sake of comparison, the two supply curves are shown in Figure 17. The results are similar, albeit with larger generation increments when calculated by

CREZ rather than by project. By project, rank costs range from $60/MWh to $300/MWh and by CREZ, weighted average rank costs range from $80/MWh to $280/MWh.

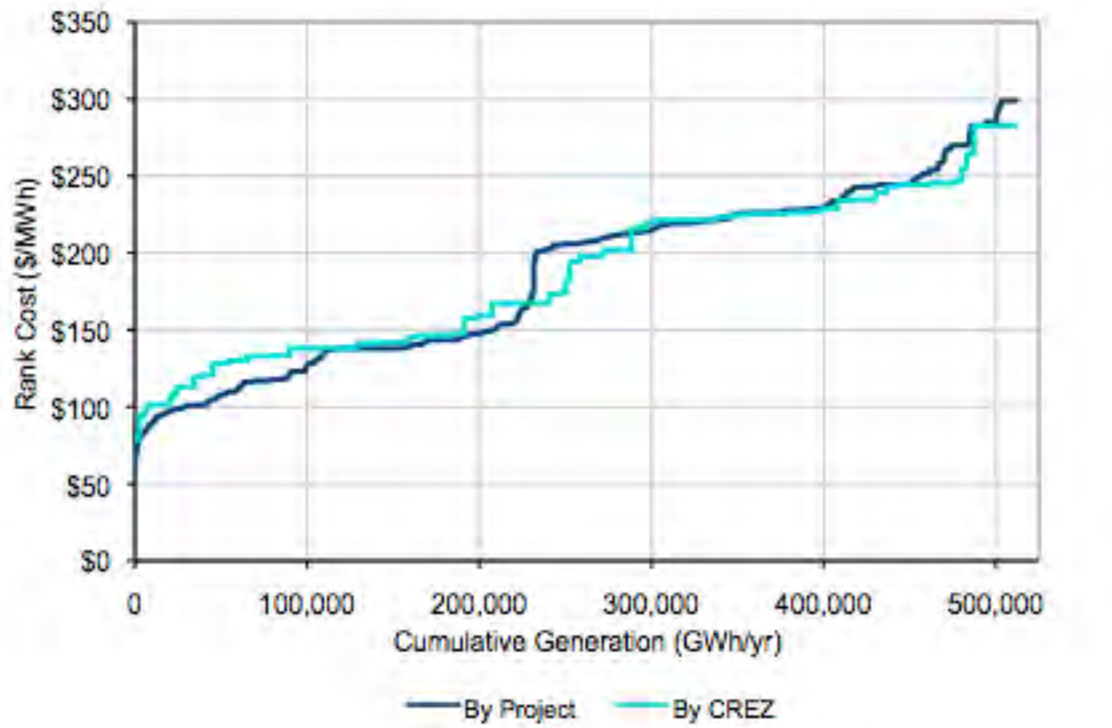


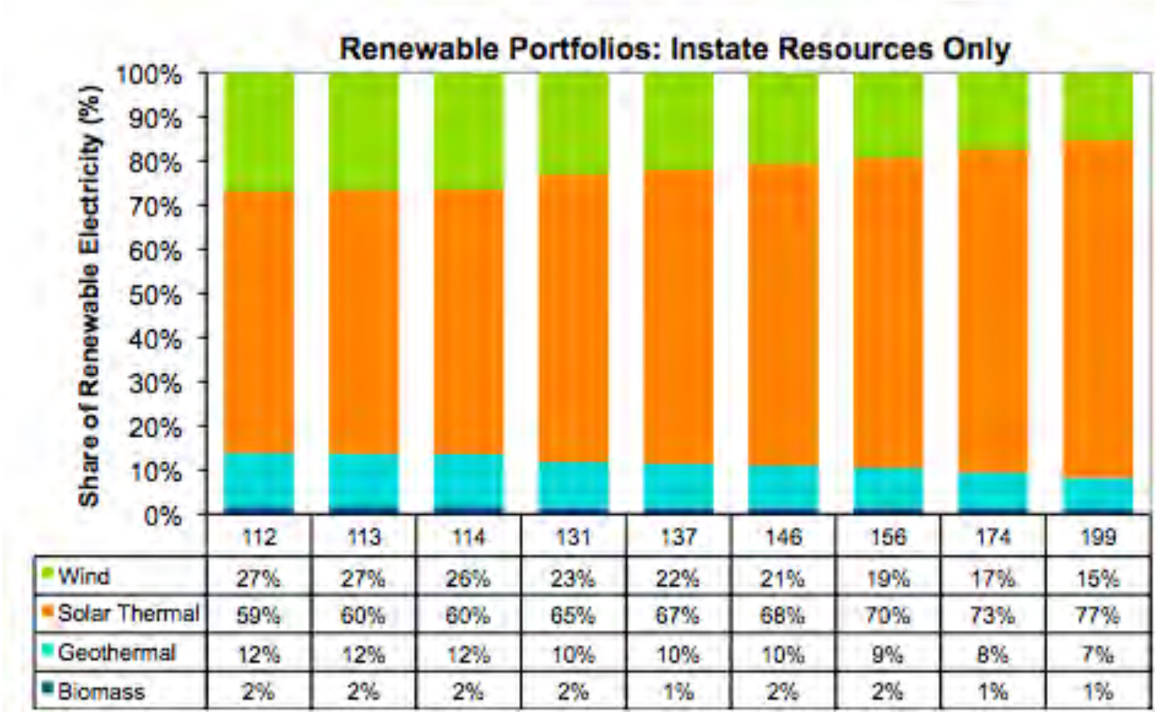
Figure 17: Rank Cost of Renewable Energy Supply

3.4 Renewable Electricity Portfolios

The electricity demand scenarios described in Section 2.4 require a renewable electricity supply that ranges from around 112 TWh in year 2020, with a 33 percent RPS goal to meet the baseline electricity demand with no demand from vehicles, to around 303 TWh in year 2050 for the mixed strategy scenario, in which the entire light-duty vehicle fleet is a mix of PHEVs, BEVs and FCVs and a 50 percent RPS goal is mandated. To meet this range of renewable supply scenarios, I develop three types of renewable electricity portfolios – based on the supply curve approach described above – that vary in resource mix, cost of generation, and intermittency:

1. **Instate resources only:** This type of portfolio might exist if California pursues an RPS policy focused on economic growth and job creation within the state.
2. **Out-of-state (OOS) resource heavy:** This type of portfolio is more likely to exist if utilities and other load-serving entities are permitted to meet RPS goals by using lower cost OOS resources and the most cost competitive instate resources.
3. **Limited OOS resources:** This type of portfolio might exist if the availability of lower cost OOS resources are restricted due to neighboring states implementing their own RPS goals.

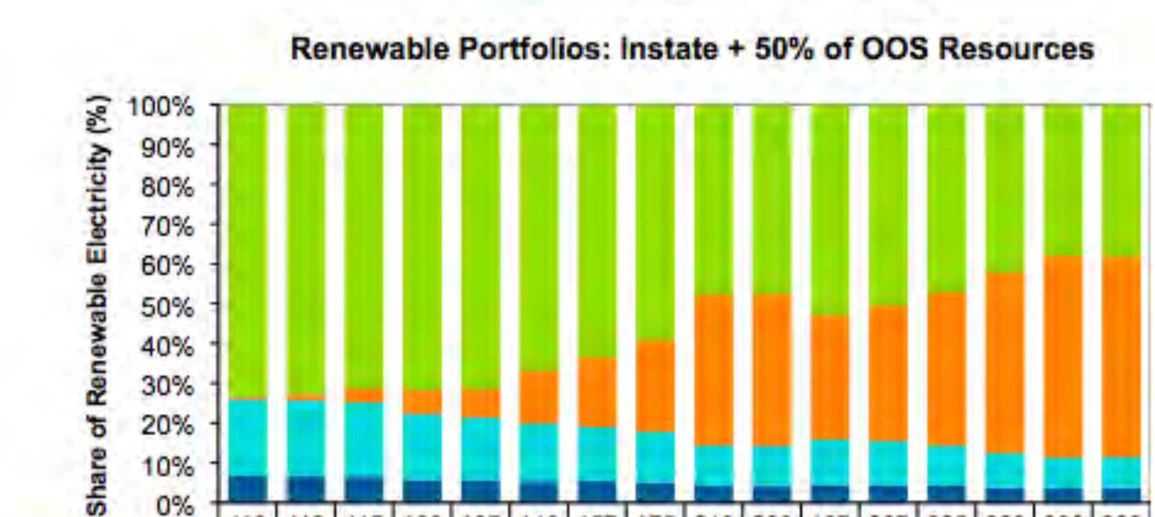
Figures 18, 19 and 20 show how the mix of resources varies by portfolio type and shifts to meet the required supply level, based on the rank cost of resources. The *instate resources* portfolios, shown in Figure 18, are dominated by solar thermal power, which ranges from 59 to 77 percent of the renewable mix, while wind power ranges from 15 to 27 percent. Geothermal contributes 7 to 12 percent, and biomass represents only 1 to 2 percent. It is worth noting that instate resources alone are insufficient to meet the highest renewable supply requirements and are the most expensive solution: the largest instate resources portfolio is less than 199 TWh, with an average generation cost of $195/MWh.



	112	113	114	131	137	146	156	174	199
Wind	27%	27%	26%	23%	22%	21%	19%	17%	15%
Solar Thermal	59%	60%	60%	65%	67%	68%	70%	73%	77%
Geothermal	12%	12%	12%	10%	10%	10%	9%	8%	7%
Biomass	2%	2%	2%	2%	1%	2%	2%	1%	1%

Figure 18: *Instate Resources* Renewable Electricity Portfolios

In the *OOS heavy* portfolios shown in Figure 19 I assume 50 percent of all OOS resources are available to California. These portfolios include a lot more wind resources, initially representing 73 percent of the renewable mix and decreasing to 38 percent as more solar thermal resources are added. Solar thermal power increases from 1 percent to 50 percent. Geothermal power ranges from 8 to 19 percent of the mix, while biomass is only 4 to 7 percent. The *OOS resources heavy* portfolio approach is the only mix that can meet the highest renewable supply requirement of 303 TWh. At this supply level the average generation cost is $177/MWh.

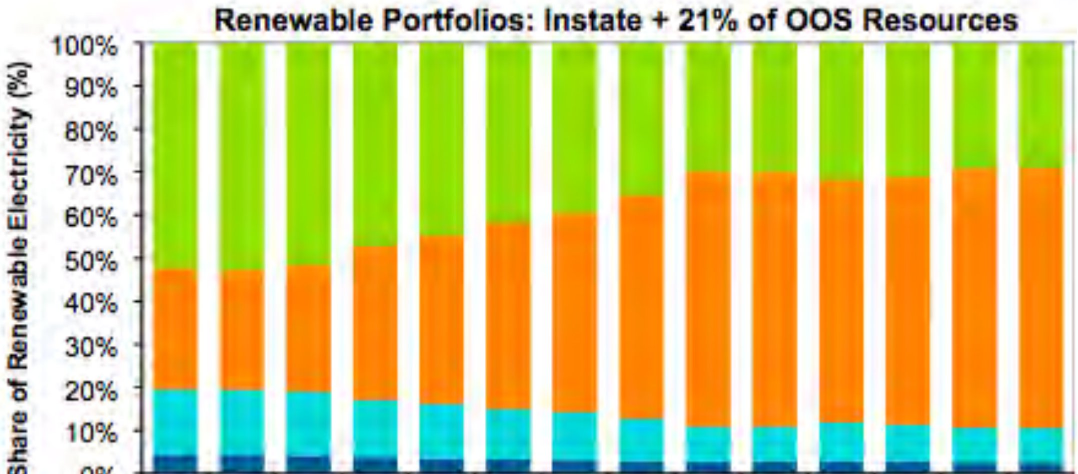


	112	113	115	130	137	146	157	175	219	220	197	207	225	263	296	303
Wind	73%	73%	71%	72%	71%	67%	63%	59%	48%	47%	53%	50%	47%	42%	38%	38%
Solar Thermal	1%	2%	4%	6%	7%	13%	18%	23%	38%	38%	31%	34%	39%	45%	51%	50%
Geothermal	19%	19%	19%	17%	16%	15%	14%	13%	10%	10%	11%	11%	10%	9%	8%	8%
Biomass	7%	7%	7%	6%	6%	5%	5%	5%	4%	4%	5%	5%	4%	4%	4%	4%

Figure 19: *OOS Resources Heavy* Renewable Electricity Portfolios

To calculate the *limited OOS resources* portfolios, I assume California's access to OOS resources is restricted based on relative population size – this serves as a proxy for OOS regions pursuing the same RPS goal as California. Based on recent census data, California represents 52 percent of the population of all resource areas included [61, 62, 63], but possesses only 39 percent of the renewable generation described in section 3.3. To allocate renewable resources proportionally between California and OOS areas based on population, I subtract California's resource share (39%) from its population share (52%) and divide by the percentage of all renewable resources that are in OOS areas (61%). This results in 21% of OOS generation resources being available to California.

$$\frac{CA\ population - CA\ resources}{OOS\ resources} = \frac{52\% - 39\%}{61\%} = 21$$



	112	113	115	129	137	147	155	174	217	221	196	208	222	223
Wind	52%	53%	52%	47%	45%	42%	39%	35%	30%	30%	32%	31%	29%	29%
Solar Thermal	28%	28%	29%	36%	39%	43%	46%	52%	59%	59%	56%	58%	60%	60%
Geothermal	15%	15%	15%	13%	13%	12%	11%	10%	8%	8%	9%	9%	8%	8%
Biomass	4%	4%	4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%

Figure 20: *Limited OOS Resources* Renewable Electricity Portfolios

Figure 20 shows the *limited OOS resources* portfolios calculated using this approach. Wind power ranges from 29 to 52 percent of the mix, while solar thermal ranges from 28 to 60 percent. Geothermal represents 8 to 15 percent and biomass is only 3 to 4 percent of the mix. The largest renewable supply with limited OOS access is around 223 TWh, with an average generation cost of $180/MWh.

4. Fuel Production Models

This section describes the modeling tools used to compare electricity and hydrogen fuel production pathways, based on the electricity demand scenarios defined in Chapter 2, and the renewable electricity supply scenarios defined in Chapter 3. It begins by describing the functionality, input assumptions and key outputs from LEDGE-CA: a spreadsheet-based dynamic hourly model of California's electricity grid, which is used to model grid-electricity for use in charging electric vehicles and producing hydrogen. Section 4.2 describes the modeling methodology used to investigate the addition of energy storage to optimize electricity and hydrogen production from intermittent wind and solar energy resources, since they are the largest sources of electricity generation in the renewable electricity portfolios defined in Chapter 3.

4.1 *Grid-Based Electricity and Hydrogen Production*

The main tool I use in this thesis to model interactions between the electric-drive vehicles and California's electricity grid is the Long-Term Electricity Dispatch Model for Greenhouse Gas Emissions in California (LEDGE-CA): a spreadsheet based dynamic hourly model of California's electricity grid developed by Ryan McCarthy at the University of California Davis[2] [64]. LEDGE-CA is a simplified model intended to simulate California's electricity supply and demand behavior on an hourly basis out to year 2050. In simulating the grid, LEDGE-CA includes a number of simplifying assumptions, however in the context of this thesis, these simplifications are reasonable,

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[2] This section provides a high level overview of the functionality and key outputs from LEDGE-CA. For complete documentation of the model, see *Assessing Vehicle Electricity Demand Impacts on California Electricity Supply* [64].

given the inherent uncertainties in the technology, demographic and energy policy assumptions I describe elsewhere in this thesis. Three key simplifications in LEDGE-CA used in this thesis and describe in [64] are:

1. California consists of a single electricity market. There are no physical or economic constraints to impede transmission of electricity between generation sites and load centers throughout the state's electricity supply infrastructure.
2. Power plants included in the model are dispatched by plant type and age, rather than on an individual plant-by-plant basis.
3. Electricity imports from other states are treated differently than the way California's electricity market currently operates. Fewer imports of hydropower from the Pacific Northwest are assumed to be available, due to population and demand growth in those states. The only electricity imports to California are those included in the renewable electricity portfolios defined in Chapter 3, with the assumption that California ratepayers bear the full cost of developing and transmitting electricity to California.

4.1.1 Must-Run Generation

LEDGE-CA uses hourly electricity supply profiles for hydro, nuclear and renewable power plants, which it treats as must-run "passive" generation. Hydro and nuclear profiles are based on current instate availability of those resources, with no retirements or additions of those types of power plants over the modeling period (to 2050). I assume that nuclear capacity is 4,390 MW, which is the current capacity in California [65]. Hydro capacity varies at specific points throughout the year based on seasonal availability, and has a peak summer capacity of around 7,000 MW [66]. I assume that the current instate hydro capacity will remain unchanged through year 2050. I assume that currently installed nuclear and large hydro-electric power plants will be upgraded over time. To reflect this, I use nuclear and hydropower generation cost assumptions for new technologies from the 2009 Annual Energy Outlook (AEO2009) [67, 68]. Nuclear and hydropower cost and efficiency assumptions, expressed in terms of heat rate, are summarized in Table 11. All costs are expressed in $ 2007.

Table 11: Cost Assumptions for Nuclear and Hydropower Plants [67]

Year	Technology	Capital Cost ($/kW)[1]	Fixed O&M ($/kW-yr)[2]	Var. O&M ($/MWh)[2]	Heat Rate (Btu/kWh)[3]
2020	Nuclear	3,213	90.00	0.49	10,434
	Hydropower	2,318	13.63	2.43	9,919
2035	Nuclear	2,372	90.00	0.49	10,434
	Hydropower	1,920	13.63	2.43	9,919
2050	Nuclear	1,653	90.00	0.49	10,434
	Hydropower	1,179	13.63	2.43	9,919

1. Capital costs are from the Assumptions to the AEO 2009 [67]. Costs in 2020 are based on the Reference Case costs in 2015; costs in 2035 are based on Reference Case costs in 2030; and costs in 2050 are based on the "Falling Costs" values in 2030.
2. Fixed and variable O&M costs are the same in all three years and are based on current values for new technology in AEO2009 [67].
3. Heat rates are from the Assumptions to the AEO 2009 [67]. In all three years, the heat rates are based on values for current new technology.

Renewable electricity supply profiles fall into two categories: baseload geothermal and biomass power plants that provide the same amount of power every hour throughout the year, and intermittent generation from wind and solar power plants. Hourly renewable electricity supply profiles based on the renewable portfolios described at the end of Chapter 3 are inputs onto LEDGE-CA for biomass, geothermal, solar and wind generation. These renewable supply profiles are assumed to represent all renewable generation in California, replacing any that is currently available.

4.1.2 Dispatchable Generation

Dispatchable “active” generation in LEDGE-CA comes from peaking hydro power plants and fossil-based power plants, which are dispatched in response to fluctuating demand levels above the “must-run” generation provided by passive nuclear, hydro and renewable power plants. Hydropower is dispatched first and any demand that exceeds the hourly availability of hydropower is met with generation from fossil-fired power plants. Fossil-fired power plants are dispatched in the order shown in Table 12 and by plant age. New natural gas combustion cycle (NGCC) power plants are dispatched first, followed by existing NGCC and combined heat and power (CHP) plants. Finally, peaking natural gas combustion turbine (NGCT) plants are dispatched in inverse age order. LEDGE-CA can also model conventional coal-fired power plants and new coal-fired integrated gasification combined cycle (IGCC) plants with carbon capture and sequestration (CCS), however, neither technology is included in the analysis. As discussed in Chapter 2, California’s Emissions Performance Standard prohibits conventional coal-fired power plants from supplying California’s electricity market in the future, and I assume that existing contracts with out-of-state conventional coal plants will have expired by 2020. I exclude IGCC plants with CCS since the commercial viability of this technology has not yet been proven. All of the dispatchable fossil-fuel power plants modeled in LEDGE-CA for my analysis are therefore fueled with natural gas.

Table 12: Types of Power Plants Represented in LEDGE-CA

Order	Power Plant Type	Operation
1	Nuclear Biomass Geothermal Solar Thermal Wind Baseload hydro	Must-run (passive)
2	Peaking hydro	Dispatchable (active)
3	NGCC with CCS (New plants)	
4	NGCC (New plants)	
5	NGCC + CHP (Existing plants)	
6	NGCT (New plants)	
7	NGCT (Existing plants)	

NGCC: Natural gas combined-cycle CHP: (Natural gas) Combined heat and power
NGCT: Natural gas combustion turbine

4.1.3 Screening Curve Analysis to Optimize Fossil Generation

LEDGE-CA uses a screening curve analysis to determine the most economically optimal mix of fossil power plant capacity needed to meet the level of demand beyond the supply of electricity from nuclear, hydro and renewable generation. In a screening curve analysis, total annual costs of different power plants are compared as a function of capacity factor. NGCC plants have higher fixed costs and lower variable costs, whereas peaking NGCT power plants have lower fixed costs and higher variable costs: NGCT plants are technologically simpler and cheaper to build than NGCC plants, but operate less efficiently and consume more fuel, which increases their variable operating costs. The screening curve analysis determines the capacity above which an NGCC plant generates electricity at lower cost than an NGCT plant. Figure 21 illustrates the idea behind screening curve analysis by comparing IGCC, NGCC and NGCT plants [64]. In the upper graph, IGCC plants are the least expensive to operate at a high capacity factor, whereas at a very low capacity factor, NGCT plants are the least costly to operate. The lower graph shows a load duration curve, the shape of which is determined by the system load factor, which represents the ratio of average to peak annual electricity demand. A higher load factor produces a flatter load duration curve, making it more economical to use larger amounts of generation from IGCC plants. A lower load factor produces a steeper load duration curve, making it more economical to increase the use of NGCT plants.

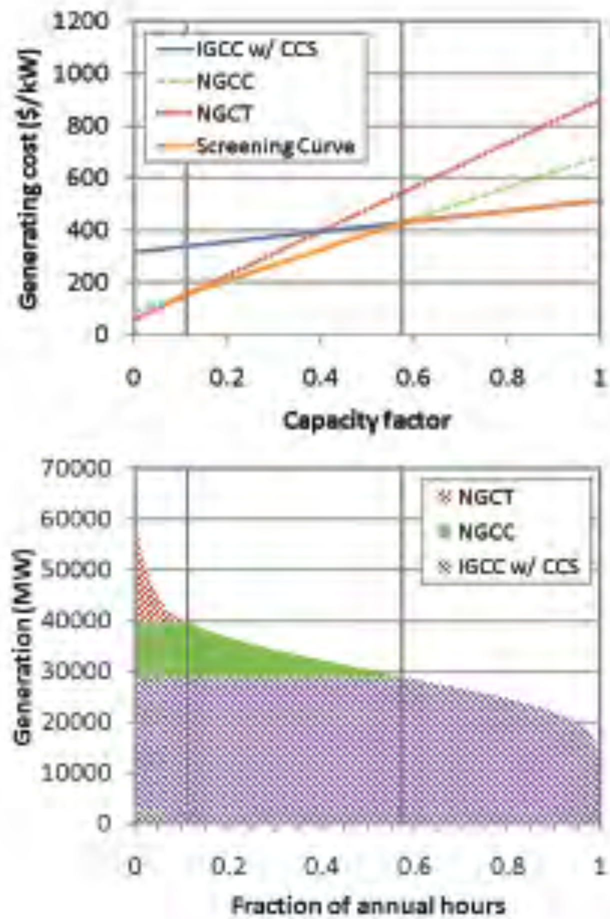

Figure 21: Example of Screening Curve Analysis [64]

To perform the screening curve analysis, LEDGE-CA uses new power plant cost assumptions adapted from the 2009 Annual Energy Outlook (AEO2009) [67, 68], which are summarized, along with efficiency assumptions, expressed in terms of heat rate, and GHG emissions for each plant technology in Table 13. All costs are expressed in $ 2007.

Table 13: Cost and GHG Emissions Assumptions for Fossil Power Plants [67]

Year	Technology	Capital Cost ($/kW)[1]	Fixed O&M ($/kW-yr)[2]	Var. O&M ($/MWh)[2]	Heat Rate (Btu/kWh)[3]	GHG Emissions (gC02-eq/kWh)[4]
2020	NGCC	929	11.70	2.00	6,752	403
	NGCT	619	10.53	3.17	9,289	556
2035	NGCC	717	11.70	2.00	6,333	378
	NGCT	460	10.53	3.17	8,550	511
2050	NGCC	507	11.70	2.00	5,725	342
	NGCT	325	10.53	3.17	8,109	485

1. Capital costs are from the Assumptions to the AEO 2009 [67]. Costs in 2020 are based on the Reference Case costs in 2015; costs in 2035 are based on Reference Case costs in 2030; and costs in 2050 are based on the "Falling Costs" values in 2030.
2. Fixed and variable O&M costs are the same in all three years and are based on current values for new technology in AEO2009 [67].
3. Heat rates are from the Assumptions to the AEO 2009 [67]. In 2020, the heat rates are based on values for current new technology; in 2035, heat rates are based on "nth-of-a-kind" plant technology from [67]; and heat rates in 2050 are from [32].
4. GHG intensities are assumed to be the same in all three years (16.7 gCO_2-eq/Btu for natural gas-fired plants) from [32] used to determine GHG emissions rates from heat rates.

4.1.4 Electric-Drive Vehicle Fuel Demand Profiles

Hourly demand for electricity to charge PHEVs or BEVs, or produce hydrogen for FCVs is modeled in LEDGE-CA separately from non-vehicle electricity demand. The hourly electricity demand for vehicle fuel is calculated based on the vehicle technology, energy intensity (kWh/mile) and assumed share of annual VMT as described in Chapter 2. This enables direct comparison of the grid impacts of PHEV/BEV charging with grid-based hydrogen fuel production for FCVs. LEDGE-CA includes three alternate charging profiles for PHEVs and BEVs that have varying impacts in terms of GHG emissions and electricity generation cost:

1. *Offpeak:* Ilustrated in Figure 22, this recharging profile was developed by EPRI [32], and is designed to take advantage of lower cost electricity during the night and in the middle of the day. In *offpeak* charging, overnight charging supplies 10 percent of daily vehicle electricity demand during each hour from 10 pm to 2 am, and daytime charging supplies 2.5 percent of daily vehicle electricity demand during each hour from 10 am to 3 pm. During morning and evening commutes, electricity demand for refueling drops to 0.5 percent of daily vehicle electricity demand.

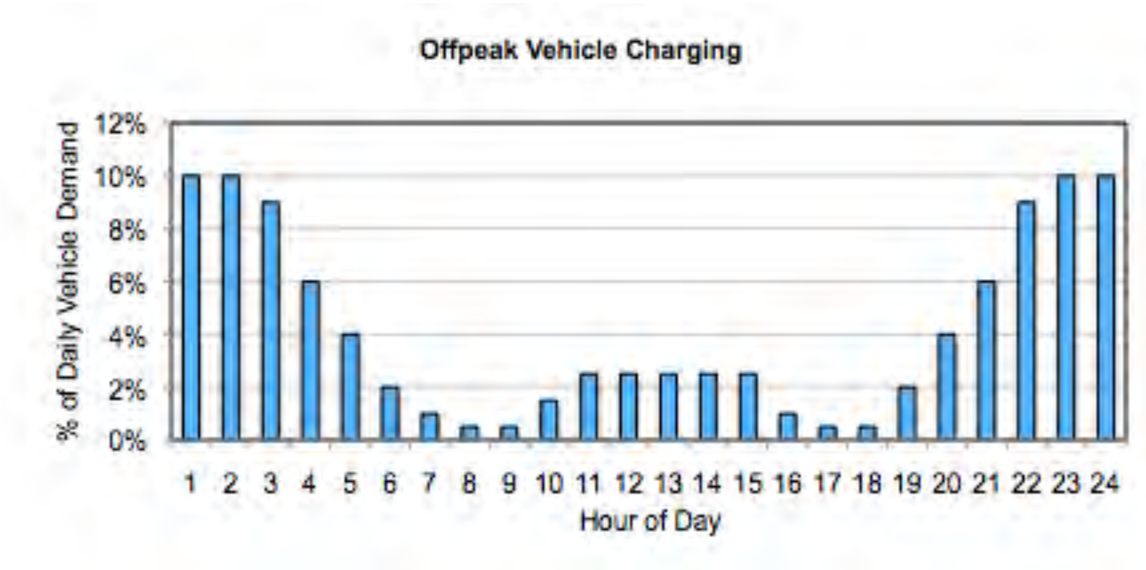

Figure 22: Offpeak Vehicle Charging Profile [32]

2. *Load-leveling*: This profile represents a scenario in which demand management is applied to the transportation sector to improve grid operations. LEDGE-CA iterates to determine a daily electricity demand threshold below which vehicle and

fuel demands are imposed, and distributes vehicle and fuel demand to increase minimum hourly electricity demand to reduce peak electricity demand.

3. *Minimize fossil supply*: This profile represents a scenario where vehicle refueling is coordinated to match generation from intermittent renewable power plants, to minimize dispatch of fossil-fueled power plants. From a generation perspective, this is the economically optimal vehicle-charging situation, and represents a future scenario where price incentives, coupled with "smart grid" technology, motivate consumers to recharge their vehicles when renewable generation is readily available, reducing the need for costly peaker power plants. In this profile, LEDGE-CA distributes daily vehicle electricity demand during hours when fossil generation is low, to fill in troughs in the fossil supply curve and reduce fossil generation requirements to the greatest possible extent. Vehicle electricity demand may vary daily, depending on the hourly distribution of non-vehicle demand and renewable generation. Based on the annual – and thus, daily – vehicle electricity demand scenario developed here, this profile never contributes to peak demand or fossil capacity requirements.

To model distributed onsite grid-based hydrogen production for FCVs in LEDGE-CA I develop three alternate time of day fuel production profiles that also have varying impacts in terms of GHG emissions and electricity generation cost:

1. *Constant electrolysis:* This production profile assumes that hydrogen is produced continuously at the same rate during each hour of the year and is stored, either offsite or onsite at a fueling station, and dispensed when needed. Continuous

hydrogen production will likely lead to lower infrastructure costs, since smaller, less expensive electrolyzers can be used, although a significant amount of hydrogen storage may be needed to meet time varying fueling demands.

2. *Offpeak electrolysis:* In this profile, electrolysis occurs at full capacity from midnight to 12 pm, shuts down completely between 12 pm and 8 pm, and operates at full capacity from 8 pm to midnight. Infrastructure costs for this scenario will likely be higher since larger, more expensive electrolyzers are needed to meet daily fuel production, however, electricity is less expensive during offpeak hours, reducing the variable cost of hydrogen production. As with constant electrolysis, hydrogen is stored for later dispensing at a fueling station. Since the fuel demand likely occurs during the day, more storage will be needed here compared to option 1.

3. *Refueling cycle electrolysis:* In this profile, adapted from a study by NREL [69], daily hydrogen production follows a cycle that is typical of conventional gasoline fueling, as shown in Figure 23. There are two fuel production peaks during morning and evening commute hours with a lower level of production during the day, and no production during late night and early morning. This profile is intended to represent a case where hydrogen is produced at a fueling station to meet real-time fuel demand, with no onsite storage. In this scenario, larger, more costly electrolyzers are needed to meet peak fuel demand during commute hours, and some production occurs during peak electricity demand hours, however the cost of fuel storage and transportation is avoided.

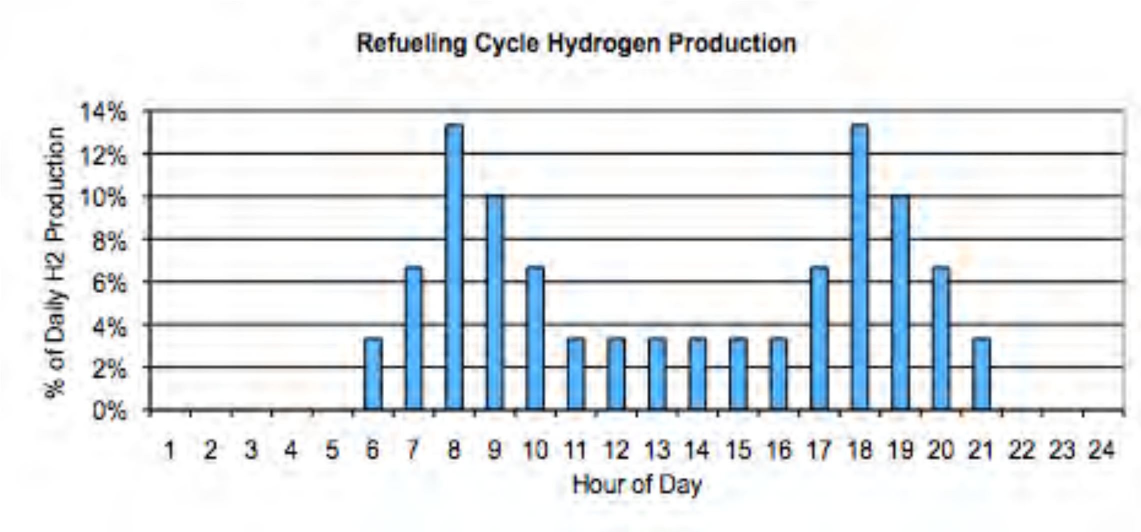

Figure 23: Refueling Cycle Hydrogen Production Profile [69]

The fuel demand, and non-fuel electricity demand scenarios described in Chapter 2 together with the renewable electricity portfolios described in Chapter 3 are input into LEDGE-CA and modeled using the six grid-electricity and hydrogen production scenarios described above to calculate GHG emissions attributable to each scenario. In Chapter 5, all grid-electricity-based fuel production scenarios are compared in terms of GHG emissions and fuel production cost.

4.2 Grid-Scale Energy Storage

One potential solution to address the challenge of integrating large amounts of intermittent wind and solar electricity generation on the grid is to add utility-scale energy storage to “shape” the electricity supply. The goal of adding energy storage is to shift the timing of the combined must-run supply from nuclear, hydropower, biomass and geothermal and intermittent renewables to produce a load-following supply. This results in more efficient utilization of dispatchable generators (natural gas power plants), potentially resulting in lower generation costs. Figure 24 provides a graphical representation from LEDGE-CA of what a load-following supply might look like to meet non-vehicle electricity demand during a week in August 2050. In this illustrative example, the must-run generation is time-shifted follow the load, and most of the dispatchable generation comes from more-efficient, lower emissions NGCC plants rather than NGCT plants. Because the must-run supply is shifted to follow load, this permits NGCC plants to operate at a higher capacity factor, as described earlier in section 4.1.3.

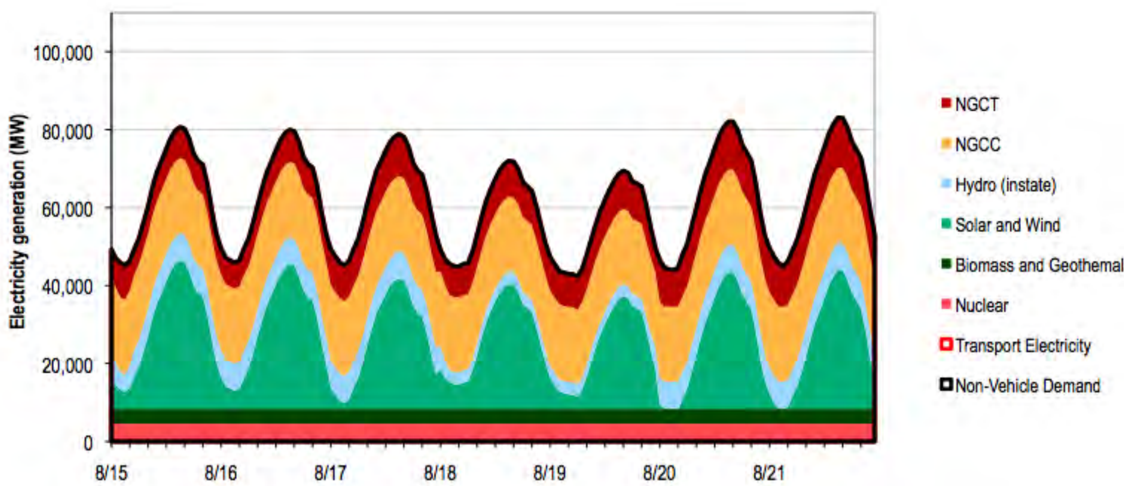

Figure 24: Load-Following Electricity Supply

To model the addition of grid energy storage, I use two spreadsheet-based models: a *load-following* model that produces an idealized load-following electricity supply, and a *storage simulation* model that adjusts the idealized load-following supply to take into account physical storage capacity constraints and energy conversion losses that arise in transferring electricity to and from storage. The *load-following* model produces an idealized load-following supply by first subtracting hourly baseload nuclear, hydropower, biomass and geothermal generation from hourly non-vehicle electricity demand to produce an hourly "net load". Through a series of iterations, the model then compares the intermittent hourly supply of wind and solar electricity throughout the year with the net load and adjusts the combined intermittent hourly wind and solar generation to match the hourly pattern of the net load. This results in an idealized non-dispatched electricity supply that follows the hourly demand pattern throughout the year.

To take into account the physical limitations of energy storage, I use a *storage simulation* model to adjust the idealized load-following supply. The following series of equations describes how the *storage simulation* model works.

$Actual_i$	Intermittent generation from wind and solar in hour *i*.
$Shaped_i$	Ideal load-following generation from wind and solar in hour *i*.
$E_{in,i}$	Generation in hour *i* diverted from the grid to storage.
$E_{out,i}$	Generation in hour *i* released from storage to the grid.
S_i	Stored energy at the end of hour *i*.
S_{MAX}	Maximum amount of energy that can be stored, i.e. storage capacity.
i	Hour of the year, $i = \{1, \ldots, 8760\}$.
$Shaped_{real,i}$	Real load-following generation from wind and solar in hour *i*.
$\eta_{storage}$	Round-trip efficiency of storage.

$$E_{in,i} = \begin{cases} (S_{MAX} - S_{i-1}) \times \eta_{storage};\ if\ (Actual_i - Shaped_i) + S_{i-1} > S_{MAX} \\ (Actual_i - Shaped_i) \times \eta_{storage};\ if\ 0 \le \left[(Actual_i - Shaped_i) + S_{i-1} \right] \le S_{MAX} \\ 0;\ if\ (Actual_i - Shaped_i) < 0 \end{cases}$$

$$E_{out,i} = \begin{cases} S_{i-1};\ if\ (Shaped_i - Actual_i) > S_{i-1} \\ (Shaped_i - Actual_i);\ if\ 0 \le (Shaped_i - Actual_i) \le S_{i-1} \\ 0;\ if\ (Shaped_i - Actual_i) < 0 \end{cases}$$

$$S_i = E_{in,i} - E_{out,i} + S_{i-1}$$

$$Shaped_{real,i} = \begin{cases} Actual_i + E_{out,i};\ if\ Shaped_i > Actual_i \\ Actual_i - \dfrac{E_{in.i}}{\eta_{storage}};\ if\ Shaped_i \le Actual_i \end{cases}$$

For each hour of the year, the *storage simulation* model calculates how much electricity goes into storage, passes through to the grid, or comes out of storage by comparing the actual hourly supply of wind and solar power with the idealized supply. It also takes into account the magnitude of available storage capacity, both in terms of the size of installed capacity, and how much electricity is already stored at a given hour of the year. If the idealized supply exceeds the actual supply, available energy comes out of storage; if the actual supply exceeds the idealized supply, energy either goes into storage or passes through to the grid if there is insufficient storage capacity available.

Currently there are several technologies being investigated for their commercial viability as grid storage solutions that vary in terms of cost, energy conversion efficiency and capacity: these include pumped hydro, compressed air, flow batteries, sodium sulphur batteries and hydrogen. However, for the purpose of investigating grid energy storage in this thesis, I consider a very optimistic scenario, namely: energy conversion losses of 10 percent, which might be achievable with battery storage, but would not be attainable with hydrogen or some other storage technologies; and an installed storage capacity of 50% of annual peak demand, with storage at full capacity at the beginning of the year. For example, to meet year 2050 non-vehicle demand, this would represent around 43 GW of stored energy. I do not attempt to estimate the cost of implementing grid-energy storage.

5. Results

This section describes the main modeling results using the electricity demand scenarios defined in Chapter 2, combined with the renewable electricity supply portfolios defined in Chapter 3. It begins by evaluating GHG emissions and generation costs attributable to grid-electricity and hydrogen production, modeled using LEDGE-CA, without the addition of utility-scale energy storage to address intermittent wind and solar generation. Results include direct comparison of electricity and hydrogen as alternate fuel choices for the three target years, using the PHEV/BEV and FCV scenarios defined in Chapter 2. The impact of different renewable electricity portfolios is illustrated by comparing the supply scenarios defined in Chapter 3 modeled with each electricity demand scenario. The results of modeling the multi-strategy scenario defined in Chapter 2 illustrate how much GHG emissions might be reduced by year 2050 using a mix of EV technologies, together with a renewables-intensive grid electricity supply and a reduction in statewide VMT. As a sensitivity analysis, Section 5.2 builds upon these initial results by evaluating the emissions impacts of adding utility-scale storage to the grid to produce a load-following electricity supply. Finally, Section 5.3 compares grid-electricity and hydrogen fuel production costs with conventional fuel production costs to illustrate some of the economic impacts of transitioning to electric-drive vehicles.

5.1 *Well-to-Wheels Greenhouse Gas Emissions Using Grid Electricity*

To characterize emissions from the grid attributable to vehicle charging or hydrogen fuel production, there are two potential approaches that yield significantly different emissions results. If one assumes that electric vehicle demand represents a *marginal* addition to overall electricity demand, then the *marginal mix* of power plants are the last plants that come online to serve electric vehicle demand that would not be running without electric vehicle demand. Defined this way, GHG emissions due to EV demand would be emissions from the *marginal mix* of power plants, which tend to be expensive, inefficient fossil-fired power plants, yielding higher emissions. This is an appropriate methodology for near-term analysis, and such a marginal approach is assumed in calculating emissions attributable to vehicle recharging in California's recently enacted Low Carbon Fuel Standard [9]. Over the longer-term, one might assume that EV demand is already part of overall expected electricity demand and use an *average* emissions approach. Under this approach, GHG emissions attributable to EV demand represent *average* emissions from the mix of power plants that are online when EV demand occurs, regardless of the order in which those plants are dispatched. Average emissions are generally lower than marginal emissions, because the overall mix of power plants during any hour of the year includes low-carbon baseload resources as well as fossil-fired power plants. In my analysis, I use an average emissions approach for EV demand, since I assume that by year 2020, EVs represent an increasing share of the light-duty vehicle fleet and will likely be represented in electricity demand forecasts as part of the overall expected load.

Unit Well-to-Wheels Greenhouse Gas Emissions from Light-Duty Vehicles

I first compare well-to-wheels (WTW) GHG emissions for the PHEV/BEV and FCV scenarios defined in Chapter 2 for years 2020, 2035 and 2050, which are summarized again in Table 3 below, across the range of vehicle charging and hydrogen production profiles described in Section 4.14, using the renewable electricity supply portfolios described in Chapter 3.

Table 3: Light-Duty Vehicle Fleet Scenarios

	2020: LDV Fleet Mix Comparisons		**2035: LDV Fleet Mix Comparisons**		**2050: LDV Fleet Mix Comparisons**		
	2020 PHEV/BEV	2020 FCV	2035 PHEV/BEV	2035 FCV	2050 PHEV/BEV	2050 FCV	2050 Multi-Strategy
PHEV	3.75%	0%	12%	0%	25%	0%	16%
BEV	1.25%	0%	8%	0%	25%	0%	34%
FCV	0%	3%	0%	20%	0%	50%	50%
ICE	95%	97%	80%	80%	50%	50%	0%
TOTAL	100%	100%	100%	100%	100%	100%	100%
PHEV / BEV Ratio	75% / 25%		60% / 40%		50% / 50%		32% / 68%
PHEV Type	PHEV 10		PHEV 20		PHEV 40		PHEV 40
PHEV (KWh/mile)	0.045		0.15		0.22		0.22
BEV (kWh/mile)	0.32		0.32		0.32		0.32
FCV (kWh/mile)		0.72		0.72		0.72	0.72
100% VMT (millions)	406,593	406,593	524,822	524,822	593,385	593,385	404,315

WTW emissions are expressed in g CO_2e/mile. To serve as a baseline for comparison, I include unit GHG emissions for gasoline-fueled ICEVs and conventional gasoline hybrid-electric vehicles (HEVs). For all vehicle technologies included in my analysis I assume efficiency improvements over time, which translates to higher fuel economy values: for ICEVs and HEVs I use fleet average fuel economy values from the efficient ICEV and HEV scenarios in the NRC PHEV study discussed in Chapter 2 [37]. The following example illustrates how I calculate unit GHG emissions for ICEVs and HEVs in each year of interest. Using an assumed fuel economy of 24.76 miles per gallon (mpg) and gasoline energy and carbon content assumptions from Table 1, unit GHG emissions of 447.65 g CO_2 per mile from ICEVs in year 2020 are calculated as follows:

$$115.63\ {}^{MJ}\!/_{gal} \times 95.86\ {}^{g\ CO_2}\!/_{MJ} \times \frac{1\ gal}{24.76\ miles} = 447.65\ {}^{g\ CO_2}\!/_{mile}$$

Higher fuel economy assumptions for ICEVs in years 2035 and 2050 of 34.63 and 40.64 mpg yield lower unit GHG emissions of 320.08 and 272.77 g CO_2 per mile respectively. The gasoline energy and carbon content assumptions from Table 1 are also included in the WTW GHG emissions calculations for PHEVs, since they are fueled partly by gasoline and electricity. Table 14 summarizes the electricity intensity, gasoline intensity and contribution of gasoline to WTW GHG emissions for ICEVs, HEVs and PHEVs in each year. Over time, as the assumed PHEV technology changes, more miles are fueled by electricity and fewer are fueled by gasoline, resulting in progressively lower unit GHG emissions from gasoline. GHG emissions from electricity depend on the grid-electricity generation mix during vehicle charging as described above.

Table 14: GHG Emissions from ICEVs and PHEVs Fueled with Gasoline

Year	Technology	Electricity Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Unit emissions from gasoline (g CO_2/mile)
2020	ICEV	---	0.0404	447.65
2035	ICEV	---	0.0289	320.08
2050	ICEV	---	0.0246	272.77
2020	HEV	---	0.02660	294.88
2035	HEV	---	0.01945	215.54
2050	HEV	---	0.01715	190.15
2020	PHEV10	0.0445	0.0190	211.13
2035	PHEV20	0.1484	0.0130	143.95
2050	PHEV40	0.2875	0.0087	95.97

Total WTW GHG emissions for PHEV/BEV scenarios include PHEV gasoline emissions, PHEV grid-electricity emissions, and BEV grid-electricity emissions. To calculate this total, the relative contributions of grid-electricity emissions for PHEVs and BEVs are weighted based on the fleet share of PHEVs and BEVs described in Table 3.

WTW GHG emissions for FCVs come from two sources: grid-electricity, which supplies 33% of hydrogen production and onsite SMR, which supplies 67% of hydrogen production, as discussed in Chapter 2. As with ICEVs and PHEVs, I assume the fuel economy of FCVs improves over time, based on fleet average fuel economy values from the NRC study [36]. I also assume progressive efficiency improvements in SMR hydrogen production, based on conversion efficiency assumptions from the most recent hydrogen production models used in the Department of Energy Hydrogen Program [33]. To calculate GHG emissions attributable to SMR-based hydrogen production, I also assume an energy equivalence value of 1.012 kg H_2 per gallon of gasoline equivalent (gge) [70]. Unit GHG emissions attributable to SMR-based hydrogen production are calculated using a combination of the assumed FCV fuel economy, GHG emissions attributable to fuel production, and the fuel energy equivalence. The following example illustrates how I calculate unit GHG emissions of 166.93 g CO_2/mile attributable to SMR-based hydrogen production for a year 2020 FCV:

$$9,256 \;{}^{g\ CO_2}\!\!\diagup_{kg\ H_2} \times \frac{1.012\ kg\ H_2}{1\ gge} \times \frac{1\ gge}{56.11\ miles} = 166.93 \;{}^{g\ CO_2}\!\!\diagup_{mile}$$

Table 15 summarizes FCV fuel economy assumptions, SMR-based hydrogen production GHG emissions assumptions and the resulting calculated unit GHG emissions attributable to FCVs fueled with SMR-based hydrogen for each of the target years. As with PHEVs and BEVs, emissions attributable to hydrogen produced via grid electrolysis depend on the generation mix at the time of hydrogen production.

Table 15: GHG Emissions from FCVs Fueled with SMR-Based Hydrogen

Year	SMR GHG emissions ($g\ CO_2$ per kg H_2)[1]	FCV fuel economy (miles per gge)[2]	Unit emissions from FCVs ($g\ CO_2$/mile)[3]
2020	9,256	56.11	166.93
2035	8,662	73.51	119.25
2050	8,662	82.70	105.99

[1] SMR-based hydrogen production emissions assumptions from DOE H2A analysis [33]
[2] FCV fleet average fuel economy assumptions from NRC hydrogen study [36]
[3] Calculated result using 1, 2 and assumed energy equivalency of 1.012 kg H2 per gge

Figures 25, 26, and 27 compare WTW emissions of PHEV/BEV and FCV fleets using grid-electricity and hydrogen assuming a 33% RPS goal. As described above, PHEVs are fueled partly with grid-electricity and partly with gasoline and FCVs are fueled with hydrogen, 33% of which is produced via grid-electrolysis and 67% is from SMR-based production. Figure 25 shows the results using the *instate resources* renewable electricity portfolio, whereas Figures 26 and 27 show, respectively, the results using the *OOS resources-heavy* renewable electricity portfolio and *limited OOS-resources* portfolios described in Section 3.4.

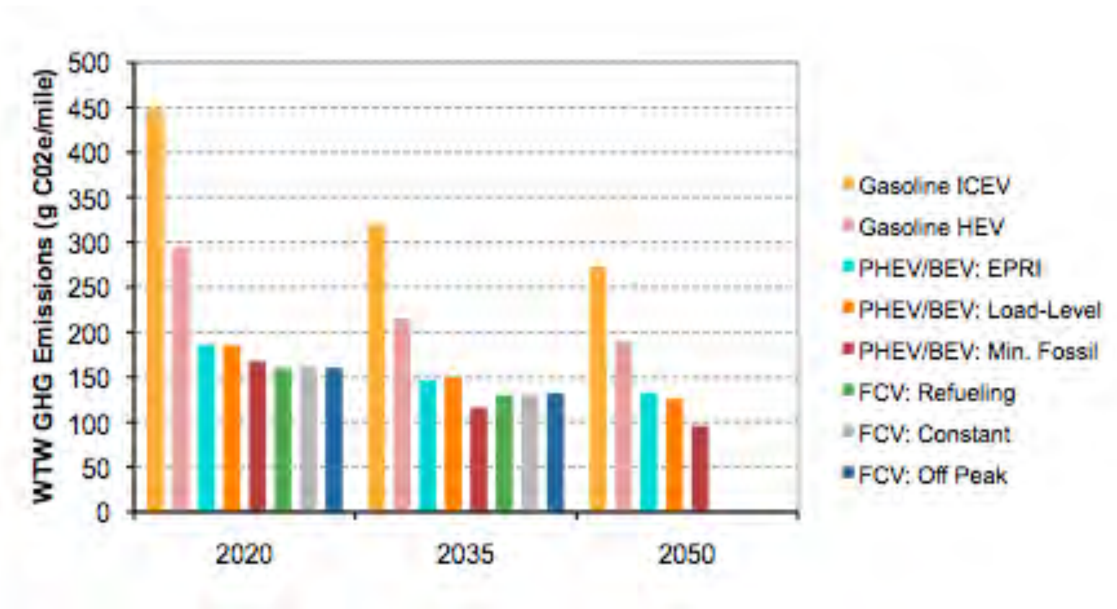

Figure 25: WTW GHG Emissions – ***Instate Resources*** **Renewable Portfolio**

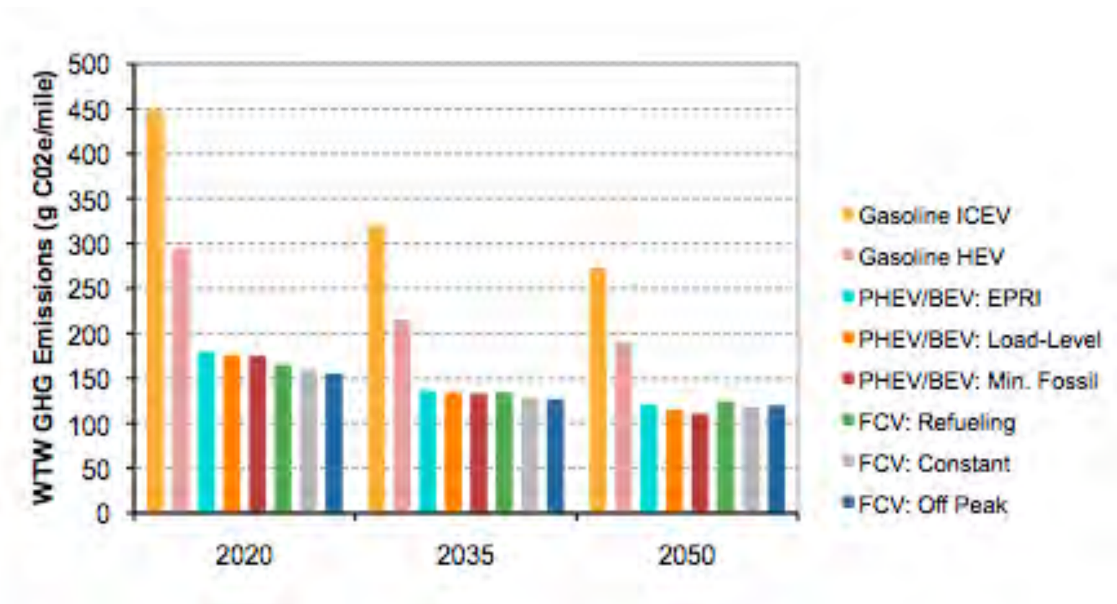

Figure 26: WTW GHG Emissions – ***OOS-Resources Heavy*** **Renewable Portfolio**

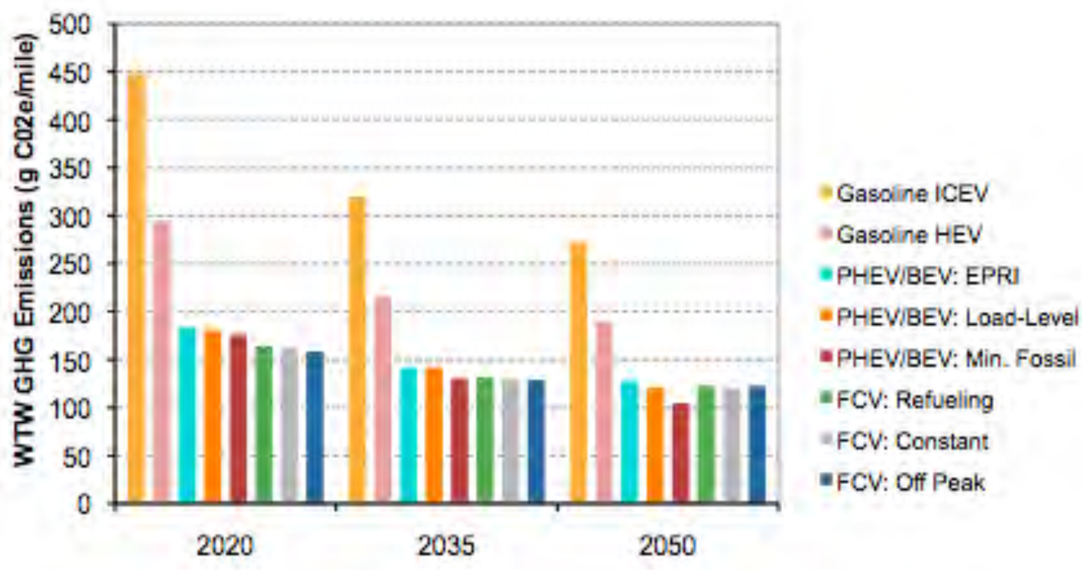

Figure 27: WTW GHG Emissions – *Limited OOS-Resources* Renewable Portfolio

Overall, the results are similar for all three renewable electricity portfolios. In all scenarios, WTW GHG emissions from PHEV/BEV and FCV fleets are significantly lower than the corresponding baseline ICEV values: results range from 96 to 186 g CO_2/mile, or in percentage terms, 35 to 42% of the corresponding baseline ICEV values and 50 to 63% of the corresponding HEV values. To some extent, there is also a downward trend in emissions over time. PHEV/BEVs show higher WTW emissions than FCVs in year 2020 because the assumed PHEV 10 technology is more gasoline intensive than PHEV 20 or PHEV 40 technologies assumed in later years. In year 2035 and 2050, PHEV/BEV and FCV scenarios show somewhat similar results, with neither technology consistently performing better than the other depending on the fueling profile and renewable energy portfolio combination. It is worth noting in Figure 25 that the *instate resources* renewable electricity supply is not large enough to meet the electricity demand for grid-electrolysis-based hydrogen production in year 2050. This implies that additional out-of-state resources will be needed to meet total electricity demand if FCVs represent as much as 50 percent of the light-duty vehicle fleet, and renewable hydrogen fuel is produced via grid-electrolysis.

To show the relative WTW GHG emisisions impacts of vehicle technology, electricity supply, and fueling profile, Appendix B provides a detailed breakdown of WTW GHG emissions for all scenarios. It includes the energy intensities and carbon intensities for each vehicle technology, and shows GHG emissions attributable to grid-electricity, grid-hydrogen, gasoline and SMR-based hydrogen.

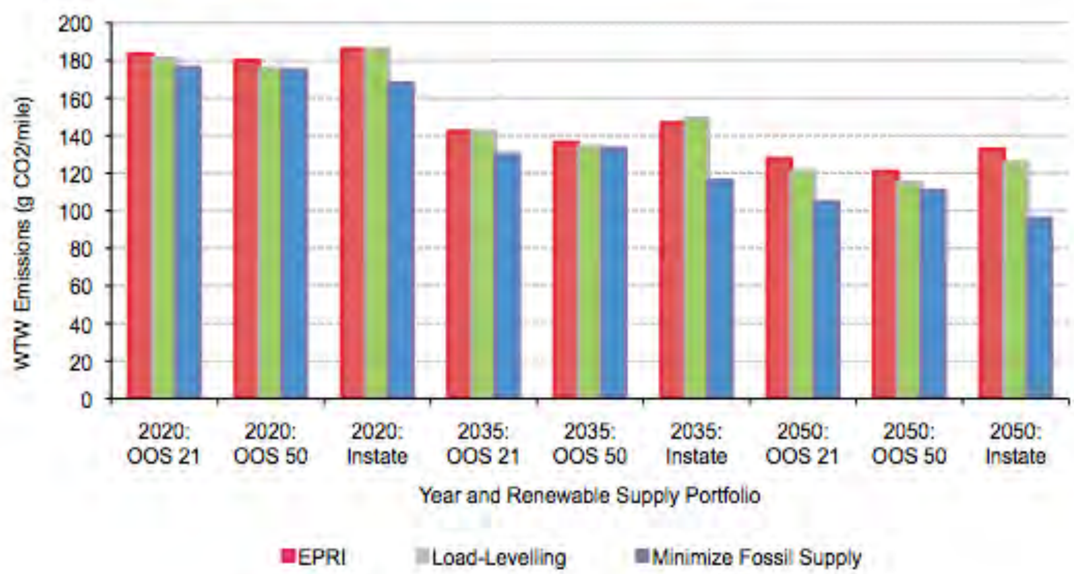

Figure 28: WTW GHG Emissions from PHEV/BEVs by Charging Profile

Figure 28 compares the impacts of PHEV/BEV charging profiles on WTW GHG emissions. For all three profiles, there is a clear downward trend in emissions over time: this occurs because the relative contribution of GHG emissions from gasoline declines as the fleet penetration of PHEVs and BEVs increases and the representative PHEV technology in each year is fueled increasingly by electricity rather than gasoline. Perhaps not surprisingly, the best PHEV/BEV charging profile from an emissions perspective is the *minimize fossil supply* profile, which consistently yields lower emissions than other scenarios in the same year, regardless of which renewable supply portfolio is used. However, with the *OOS resources-heavy* portfolio, the emissions results are similar for all three charging profiles. This is mainly due to the fact that the *OOS resources-heavy* portfolio has a higher percentage of wind resources than the other two portfolios: the *offpeak* and *load-leveling* charging profiles take advantage of the wind resources that are available at night, during non-peak demand hours. The other two supply portfolios have a larger percentage of solar resources, which are less available for *offpeak* and *load-leveling* charging profiles, resulting in higher GHG emissions.

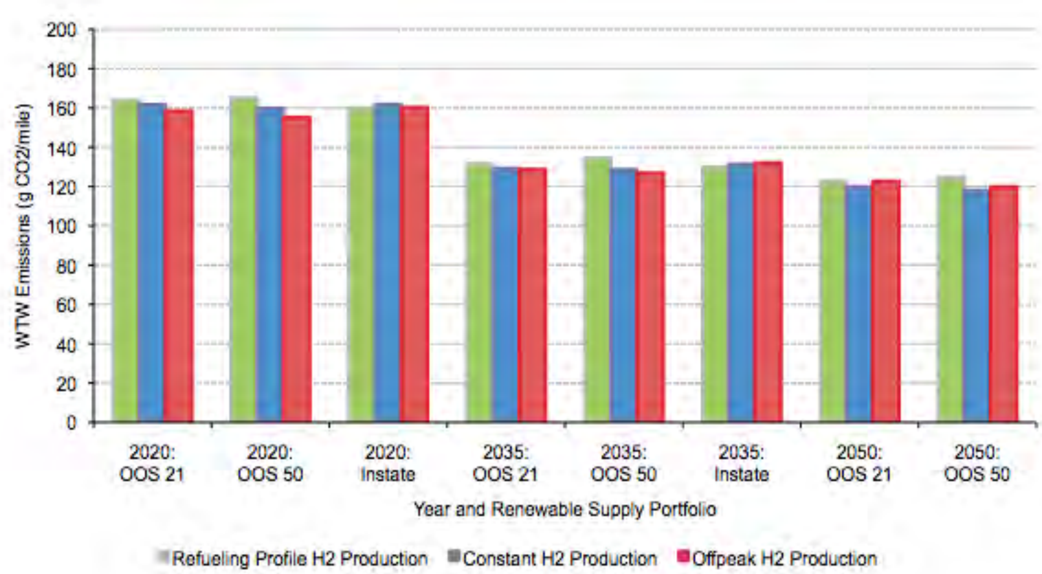

Figure 29: WTW GHG Emissions from FCVs by H_2 Production Profile

Figure 29 shows GHG emissions attributable to FCVs by hydrogen production profile and renewable portfolio. Although emissions decrease from year 2020 to 2035, there is little change between year 2035 and 2050. Also, the fuel production profile and renewable electricity supply selected in any given year has very little impact in terms of increasing or decreasing emissions. Although the fuel economy of FCVs are assumed to improve over time, as is the conversion efficiency of SMR-based hydrogen production, the GHG emissions benefits of these two effects are partially offset by the fact that grid-electrolysis is very energy intensive. As the FCV fleet penetration increases over time, electricity demand from grid-electrolysis increases. Although the renewable electricity supply increases to take into account the increased demand from grid-electrolysis, those renewable resources may not be available during the hours when grid-electrolysis occurs. As a result, hydrogen produced via the grid may not yield the same emissions benefits as PHEV or BEV charging because the timing of hydrogen production is not as well aligned with the availability of renewable generation. To help illustrate this, Table 16 shows GHG emissions contribution of grid-electricity with a 33% RPS target for vehicle charging or hydrogen production for all scenarios. Results are expressed in g CO_2 per kWh.

Table 16: GHG Emissions from Grid-electricity with a 33% RPS Target

Renewable Electricity Portfolio	Vehicle Technology	Fueling Profile	Unit Emissions from Grid-Electricity (g CO_2/kWh)		
			Year 2020	Year 2035	Year 2050
In State	PHEV/BEV	Minimize fossil supply	84	138	177
		Load-leveling	245	279	313
		EPRI	246	291	288
	FCV	Constant	209	215	---
		Offpeak	203	218	---
		Refueling cycle	201	209	---
Limited OOS	PHEV/BEV	Minimize fossil supply	158	202	210
		Load-leveling	222	258	295
		EPRI	201	258	271
	FCV	Constant	209	206	205
		Offpeak	195	205	216
		Refueling cycle	218	216	217

OOS-Heavy	PHEV/BEV	Minimize fossil supply	147	216	232
		Load-leveling	192	231	269
		EPRI	155	222	248
	FCV	Constant	201	204	197
		Offpeak	182	197	205
		Refueling cycle	223	229	224

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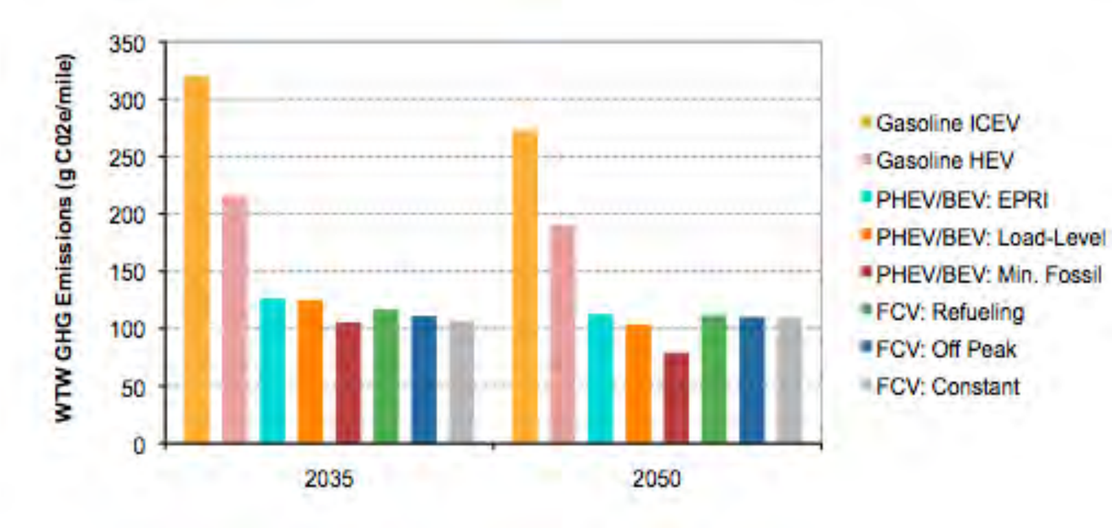

Figure 30: WTW GHG Emissions: *OOS Resources Heavy* Portfolio with a 50% RPS Target

Figure 30 shows WTW GHG emissions in years 2035 and 2050 with a more aggressive 50% RPS target. Although the *limited OOS resources* renewable supply portfolio is sufficient to meet the total renewable electricity demand in year 2035 for a 50% RPS target, it is insufficient to meet the requirement for year 2050. For this reason, Figure 30 shows only the results for the *OOS resources heavy* renewable supply to enable comparison of year 2035 and 2050 results. As might be expected, the higher 50% RPS target leads to lower WTW GHG emissions for PHEV/BEVs and FCVs. Emissions range from 79 to 126 g CO_2 per mile, or in percentage terms, 25 to 39% of the corresponding baseline ICEV value. With the *minimize fossil supply* charging profile, PHEV/BEVs yield slightly lower emissions than any of the other PHEV/BEV or FCV fueling profiles.

Total Well-to-Wheels Greenhouse Gas Emissions from Light-Duty Vehicles in Year 2050

The results above clearly illustrate that WTW GHG emissions attributable to EVs can be significantly lower than baseline emissions for conventional gasoline ICEVs, when measured on a unit GHG emissions basis of g CO_2 per mile. However, this does not take into account the total magnitude of GHG emissions associated with the electricity demand growth and increased VMT that will likely arise from population growth in California between 2010 and 2050, as described in Chapter 2. Figure 31 shows total GHG emissions in million metric tones (MMT) of CO_2 attributable to the *minimize fossil supply* PHEV/BEV charging profile as well as the *constant* and *offpeak* hydrogen production profiles, which show the best results above on a unit GHG emissions basis. For PHEV/BEVs, results are shown for all three renewable supply portfolios, given a 33% RPS target, plus the results for a 50% RPS target with the *OOS resources heavy* renewable supply. For FCVs, I show only the *OOS resources heavy* renewable supply with a 50% RPS target, since this is the only renewable supply portfolio with sufficient resources to meet year 2050 electricity demand for hydrogen production with the higher RPS target.

For comparison, I include a baseline value of 109 MMT CO_2, which represents total GHG emissions from California's light-duty vehicle fleet in 1990 [71]. I also include total emissions for efficient gasoline ICEVs and HEVs. From the figure, it is clear that even with a low-carbon electricity supply and a significant fleet share of energy-efficient PHEVs and BEVs or FCVs, total GHG emissions from the light-duty vehicle fleet are, at best, only slightly lower than 1990 levels, primarily due to the large increase in VMT. FCVs show the best result: with a 50% RPS target and a 50% fleet share, emissions drop to 100 MMT CO_2, or 8 percent below 1990 levels. The best PHEV/BEV result is 104 MMT CO_2, or 5 percent below 1990 levels. Interestingly, the results for conventional HEVs are not much higher than 1990 levels at 113 MMT CO_2, due to the assumed fuel economy improvements by 2050.

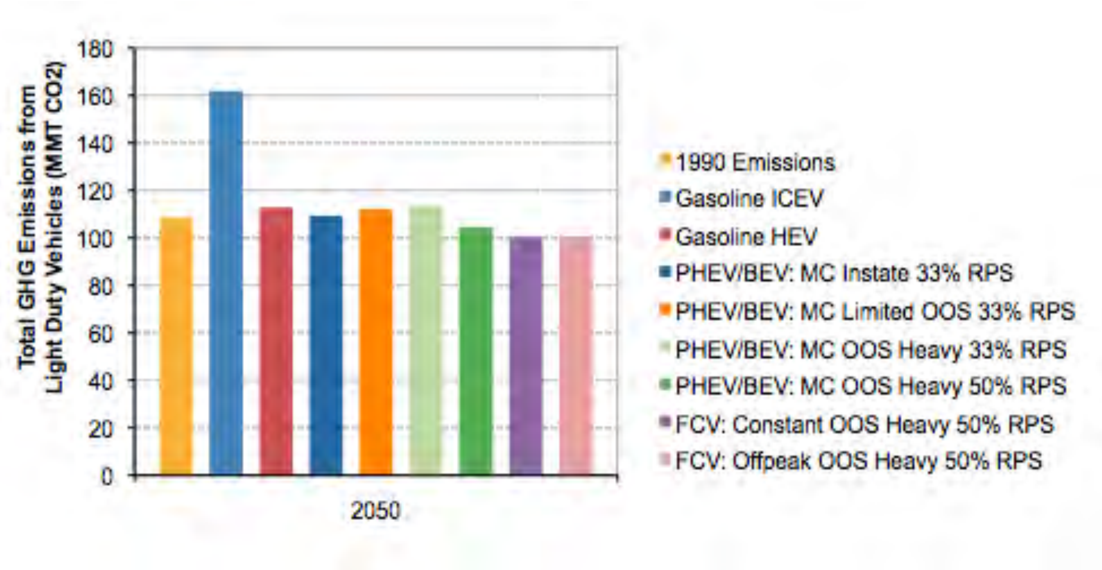

Figure 31: Year 2050 Total GHG Emissions from Light-Duty Vehicles

To realize AB 32's goal of reducing statewide GHG emissions to 1990 levels by 2020 and reducing them 80 percent below 1990 levels by 2050, more aggressive measures will likely be needed in the light-duty transportation sector. The *multi-strategy* scenario described in Chapter 2 is one such approach, in which the state's entire light-duty vehicle fleet is replaced with a mix of PHEVs, BEVs, and FCVs, and VMT decreases 32 percent through alternatives such as land use change to reduce travel demand and increased use of mass transit. Figure 32 shows year 2050 total GHG emissions using the *multi-strategy* scenario, with the range of vehicle charging and grid-hydrogen production scenarios. Results are shown using the *limited OOS* and *OOS-heavy* renewable supply portfolios with a 33% RPS target, and the *OOS-heavy* renewable supply portfolio with a 50% RPS target. In all cases, total emissions are much lower than the baseline 1990 level of 109 MMT CO_2. Results range from a high of 51 MMT CO_2 with a combination of PHEV/BEV charging with the *EPRI* charging profile and *constant* grid-hydrogen production, to as low as 32 MMT CO_2 with a combination of PHEV/BEV charging with the *minimize fossil supply* charging profile and *off-peak* grid-hydrogen production. In percentage terms, the GHG emissions results are 53 to 70 percent below 1990 levels. The emissions results from the *OOS heavy* and *limited OOS resources* renewable electricity supply portfolios are very similar, suggesting that the supply mixes are not sufficiently different from one another to have a big impact on emissions. Perhaps more surprisingly, moving from a 33% RPS target to a 50% RPS target with the *OOS heavy* supply portfolio does not significantly reduce GHG emissions from vehicles: emissions from PHEV/BEV charging with the *minimize fossil supply* charging profile and *off-peak* grid-hydrogen production drop from 43 to 32 MMT CO_2 with the higher RPS target.

Interestingly, if the entire light-duty fleet is replaced with conventional gasoline HEVs with a year 2050 average fuel economy of 58 mpg as assumed in the NRC study [37] instead of the EV fleet mix that I model, total emissions are comparably low, at around 44 MMT CO_2. Nevertheless, the results demonstrate that the AB32 goal of reducing emissions 80 percent below 1990 levels by 2050 is almost attainable in the light-duty vehicle sector with the appropriate mix of measures: aggressive reductions in vehicle demand, an all EV fleet and fuel production profiles designed to charge vehicles and produce hydrogen when renewable generation resources are most readily available. Appendix B includes more detailed results for all scenarios.

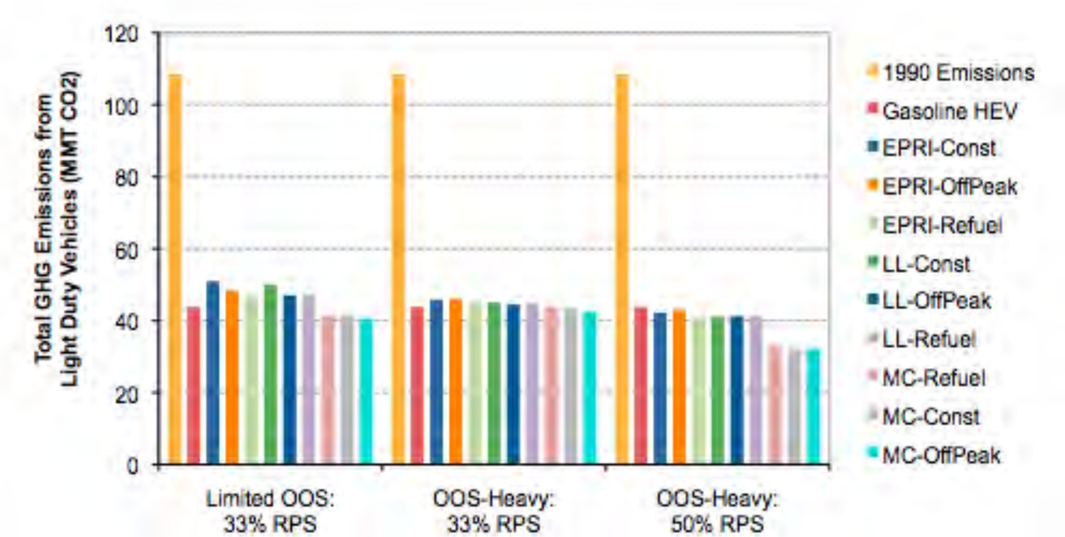

Figure 32: 2050 Total GHG Emissions from Multi-Strategy Scenario

5.2 *Emissions Reductions Using Grid-Energy Storage*

Although the multi-strategy scenario achieves significant GHG reductions from light-duty vehicles, the other scenarios are less beneficial in terms of total emissions. Using the *load-following* model and *storage simulation* model described in Chapter 4, I investigate the emissions impacts on PHEV/BEV charging by adding grid-scale energy storage to shape the electricity supply. Figure 33 shows average grid GHG emissions from PHEV/BEVs in year 2050 by renewable electricity supply and vehicle charging profile. The figure shows two sets of results: one with unshaped electricity supplies and a second, with electricity supplies shaped to follow non-vehicle demand, prior to modeling emissions in LEDGE-CA. The figure shows that for the *minimize fossil supply* charging profile, average grid emissions during vehicle charging increase after adding energy storage, whereas the other charging profiles show moderate reductions in emissions during vehicle charging. The EPRI profile benefits the most from the addition of grid-energy storage in terms of reducing GHG emissions from vehicle charging, but only with the *instate* renewable supply and the *OOS resources heavy* supply combined with a 50% RPS target.

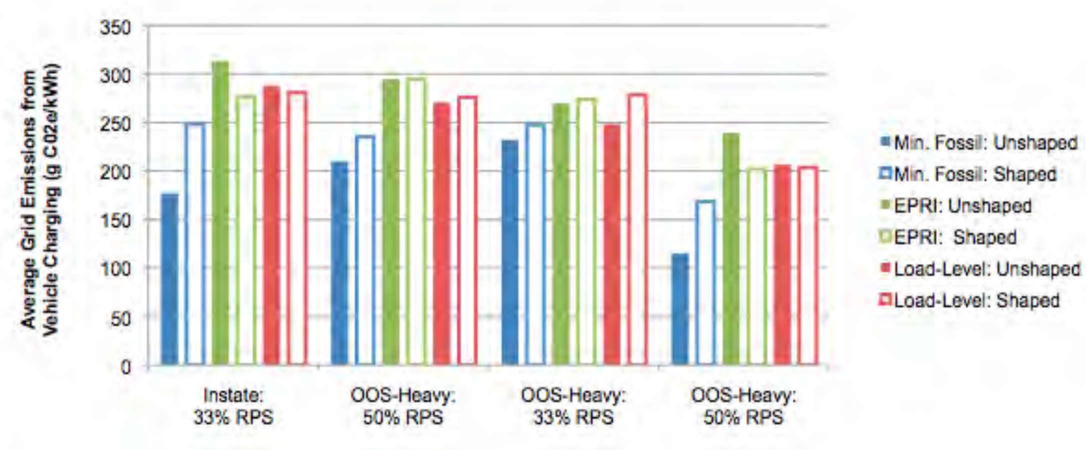

Figure 33: Impact of Grid-Energy Storage on PHEV/BEV Charging Emissions

Using energy storage to produce a load-following electricity supply does increase the utilization of more efficient NGCC power plants, and decreases the amount of NGCT plants dispatched. This results in lower average GHG emissions for the grid as a whole, including those attributable to non-vehicle electricity demand, but in some instances it increases emissions during those hours when vehicle charging occurs. For example, the *minimize fossil supply* profile is optimized to match vehicle charging with the availability of renewable generation. However, by shaping the intermittent renewable supply to follow non-vehicle demand, there are fewer hours in the year when there are large amounts of renewable generation available for vehicle charging. Figures 34 and 35 illustrate this effect. Figure 34 shows electricity generation and demand during August 2050 with PHEV/BEV charging using the *minimize fossil supply* profile with an unshaped electricity supply. Figure 35 shows the same vehicle charging scenario, but with electricity generation shaped to follow non-vehicle demand.

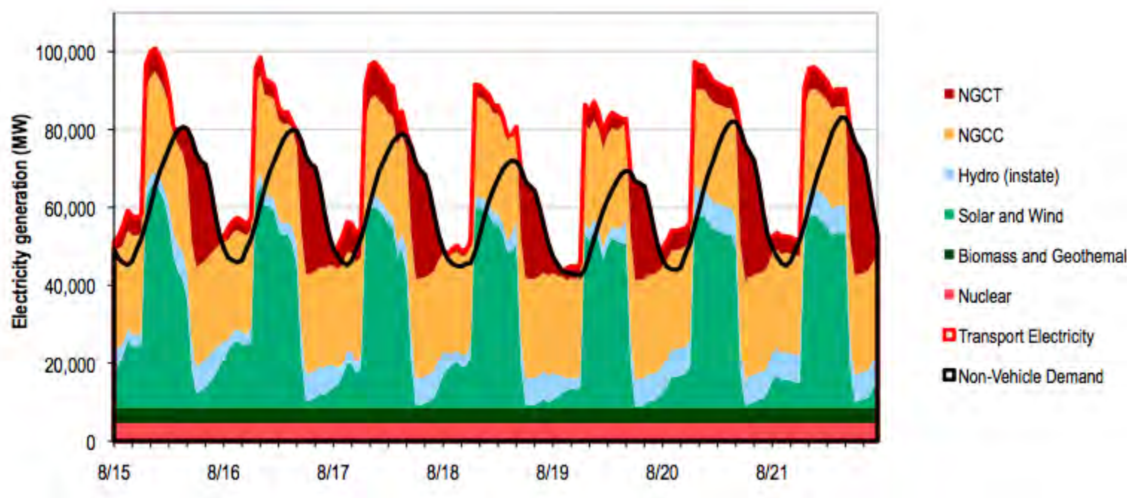

Figure 34: PHEV/BEV Charging with Unshaped Electricity Supply

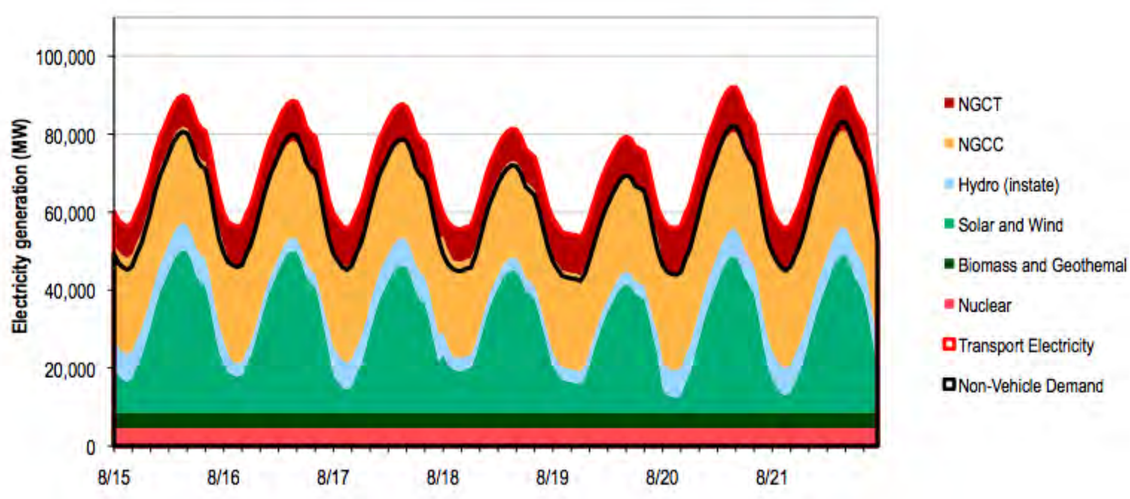

Figure 35: PHEV/BEV Charging with Load-Following Electricity Supply

With an unshaped renewable electricity supply, the *minimum fossil generation* charging profile takes advantage of those hours when there are large peaks in the solar and wind supply to recharge PHEVs and BEVs, minimizing the need for additional dispatchable generation, as shown in Figure 34. However, with a load-following supply, the “peaks” and “troughs” in the solar and wind electricity supply are shallower, resulting in fewer opportunities to recharge vehicles with low carbon electricity – this is shown in Figure 35. As I mentioned above, with the addition of energy storage, total GHG emissions from the grid are lower, however the emissions benefits are primarily attributable to non-vehicle electricity demand. To illustrate this, Figure 36 shows average GHG emissions for vehicle charging and average GHG emissions for the grid as a whole, i.e. for both vehicle charging and all other electricity demand. Results are shown with and without a load-following electricity supply.

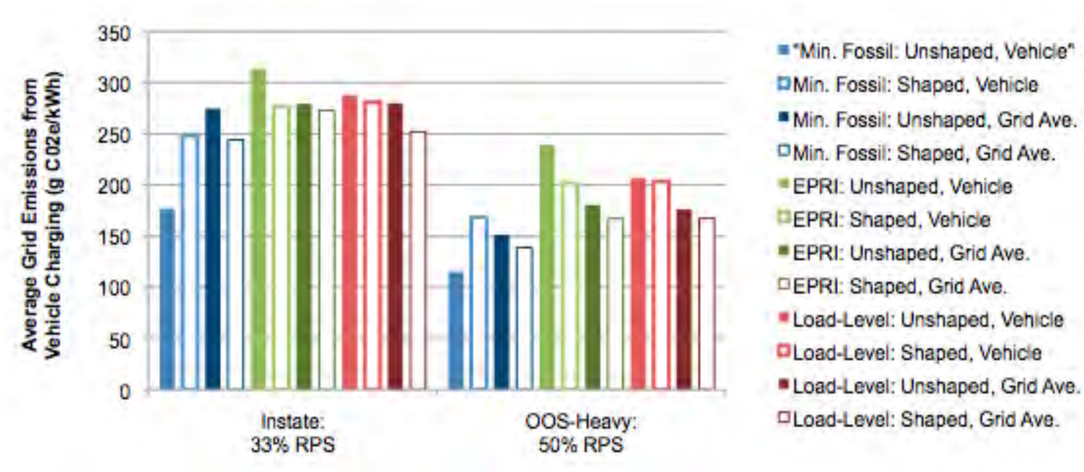

Figure 36: Impact of Grid-Energy Storage on PHEV/BEV Charging Emissions and Average Grid Emissions

5.3 *Fuel Production Costs*

The cost of electricity reflects the cost to produce and transmit renewable electricity as discussed in Chapter 3, as well as production and transmission costs attributable to all other generation technologies in the mix, namely large hydropower, nuclear power, and electricity from dispatchable natural gas-fired power plants. For PHEVs and BEVs the fuel cost is primarily the cost of producing electricity, since the energy is stored onboard the vehicle, whereas FCVs have the added capital cost burden of electricity to hydrogen conversion and fuel storage prior to dispensing the fuel. I compare the cost of producing grid-electricity and hydrogen fuel for all vehicle fleet scenarios modeled, combined with the renewable electricity supply scenarios needed to meet fuel demand for those fleet scenarios. To serve as a baseline for comparison, I include the statewide annual average production cost of California reformulated gasoline during 2010 [72]. Gasoline production costs include the cost to purchase crude oil as well as refining costs and profits and costs and profits attributable to fuel distribution and marketing. To enable comparison, all fuel costs are expressed in 2010 dollars per mile. The baseline gasoline cost is calculated by dividing the statewide average cost of $2.45 per gallon by the assumed average fleet economy of 24.76 mpg for year 2010 ICEVs and 32.10 mpg for year 2010 HEVs, yielding an average cost of nearly $0.010/mile for ICEVs and nearly $0.08/mile for HEVs. In comparing fuel costs, my assumptions are based on year 2010 production costs for gasoline, electricity and hydrogen, so although the scenarios modeled are for years 2020, 2035, and 2050, cost assumptions are primarily based on current estimates.

As mentioned above, fuel production costs for PHEVs and BEVs are the production and distribution costs of electricity. I calculate a levelized cost of electricity for PHEVs and BEVs from the generation and transmission costs for the renewable electricity supplies described in Chapter 3 along with costs for nuclear, large hydropower and NGCC and NGCT technologies, based on the assumptions outlined in Chapter 4. I calculate an average cost of electricity in \$/kWh, weighted by the mix of generation technologies during the hours in which fuel production occurs. To derive the fuel cost attributable to grid-electricity for PHEVs and BEVs, expressed in dollars per mile, the average generation cost (\$/kWh) is multiplied by the energy intensity of the vehicle technology (kWh/mile). In addition, since some PHEV miles are powered by gasoline, I calculate a weighted average fuel cost, based on the relative share of miles for PHEVs attributable to grid-electricity and gasoline.

Fuel production costs for grid-based hydrogen include the cost of grid-electricity, plus capital costs for electricity conversion and hydrogen storage. Modeling capital costs for electricity conversion and hydrogen storage are beyond the scope of this thesis. However, to account for this cost component, I use cost results from an ongoing hydrogen fuel production cost study at the University of California Davis, that uses my grid-electricity cost results and annual hydrogen demand assumptions for each scenario as inputs and outputs fuel production costs for each scenario in \$/kg H_2 [73]. I divide these results by the assumed FCV fuel economy value for each target year (miles/kg H_2) to derive a fuel cost in \$/mile. In addition, since I assume that only 33 percent of hydrogen demand is from grid-electricity, I use fuel cost assumptions from H2A analysis to estimate the cost of distributed SMR-based hydrogen production [33]. The most recent H2A modeling results estimate a levelized cost of \$1.591 \$/kg H_2 for future distributed SMR-based hydrogen production. As with grid-hydrogen costs, I divide these results by the assumed FCV fuel economy value for each target year (miles/kg H_2) to derive a fuel cost in \$/mile. I then calculate an average hydrogen fuel cost from the grid-hydrogen and SMR-based hydrogen costs, weighted by the corresponding percentage of each production method.

Figures 37 through 39 show the fuel costs for each fleet scenario by renewable electricity supply portfolio, assuming a 33 percent RPS target.

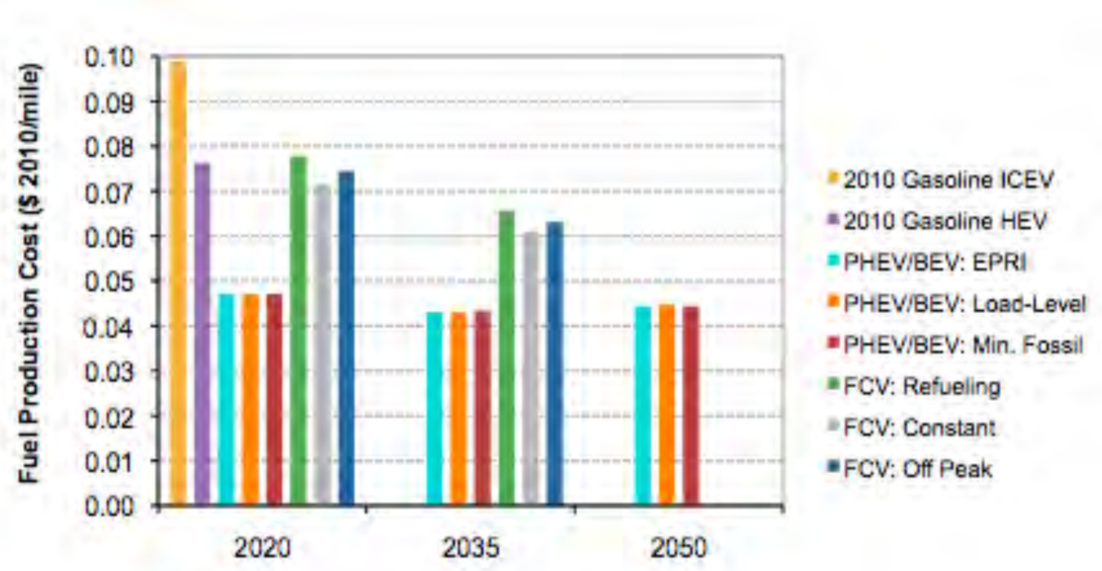

Figure 37: Fuel Production Costs – *Instate Resources* Renewable Portfolio

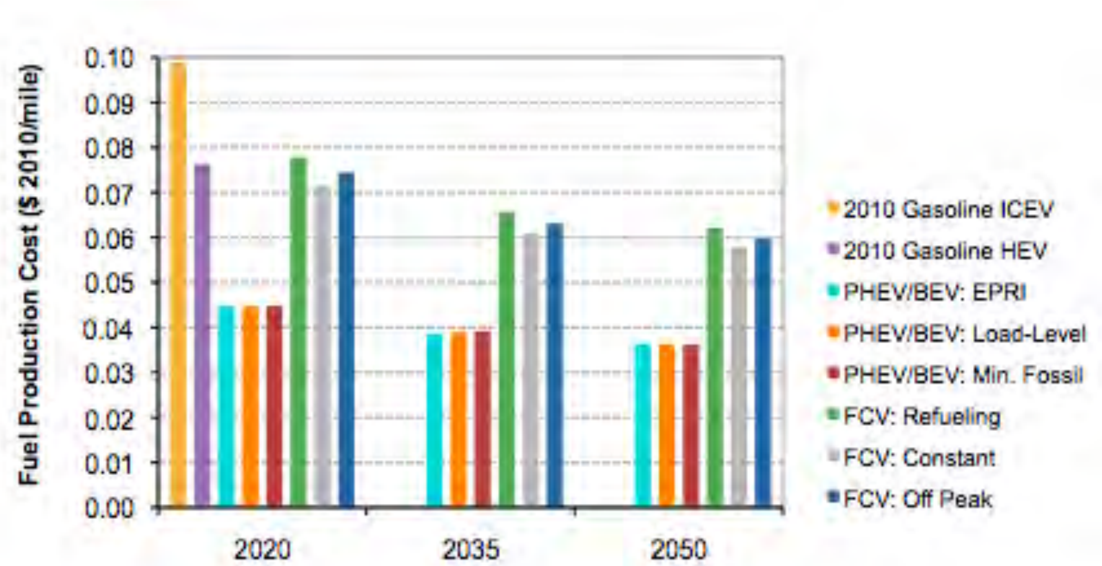

Figure 38: Fuel Production Costs – *OOS-Resources Heavy* Renewable Portfolio

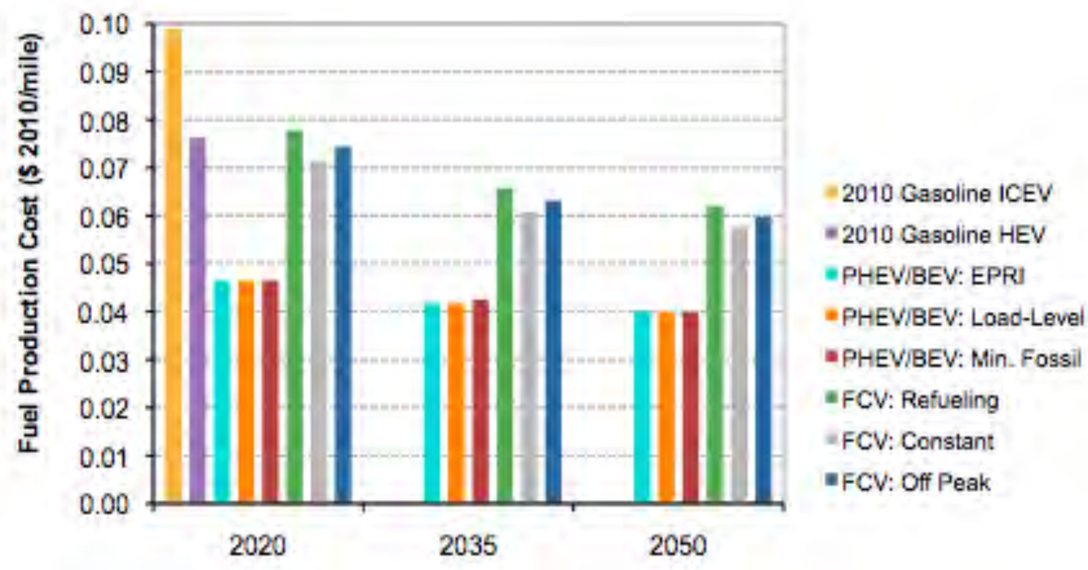

Figure 39: Fuel Production Costs – *Limited OOS-Resources* Renewable Portfolio

The results are very similar for all three renewable supply portfolios and vary little with each fueling profile, suggesting that the electricity generation mix during fuel production does not have a significant bearing on the resulting fuel cost. PHEV/BEV fuel costs range from around $0.04/mile to $.05/mile, while hydrogen fuel costs are slightly higher, ranging from around $0.06/mile to $.08/mile. It is worth noting that grid-hydrogen is more costly, in the range of $0.15/mile to $0.16/mile, however inexpensive SMR-based hydrogen production at around $0.02/mile to $0.03/mile lowers the average fuel cost to the range shown above. The results above show that fuel costs decrease over time for both PHEV/BEVs and FCVs, due largely to the assumed fuel economy improvements for each technology. In all scenarios, costs are lower than the baseline ICEV fuel cost of around $0.10/mile, however hydrogen costs are comparable to current HEV fuel costs of around $0.08/mile. Increasing the RPS target to 50 percent causes a slight increase in fuel costs, due to the higher cost of renewable generation, but the impact is less than 1 cent per mile. For the mixed-strategy scenario, the fuel costs are also basically the same as the other scenarios: PHEV/BEV fuel costs are around $0.04/mile, whereas FCV fuel costs are around $0.06/mile. A detailed breakdown of fuel costs for all scenarios is included in Appendix B.

6. Conclusions and Future Work

The results from Chapter 5 demonstrate that the combination of large-scale adoption of electric-drive vehicles and a low-carbon electricity supply are a promising strategy to help California achieve its aggressive GHG reduction goals in the light-duty transportation sector, even with likely growth in population and travel demand. On a unit emissions basis, both PHEV/BEV and FCV scenarios show significant GHG emissions reductions compared to conventional gasoline ICEVs – 35 to 42 percent of baseline ICEV emissions. The results are partly attributable to the increased energy efficiency of the vehicle technologies, and partly due to the lower carbon of the fuel, driven by large increases in renewable electricity. One key finding is that the mix of renewable energy resources does not greatly influence the results. In the scenarios considered, the renewable energy supply portfolios that rely more heavily on resources from neighboring states are more wind-intensive, whereas the *instate resources* portfolio is dominated by solar power. Despite the daily and seasonal difference in the availability of wind and solar power, on an annual basis, all three renewable portfolios yield fairly similar emissions results for the range of vehicle technology and fuel production profiles considered. Perhaps the most significant consideration in terms of the renewable electricity supply is that the *instate resources* portfolio is not large enough to meet the renewable energy requirements for large fleet penetrations of FCVs and perhaps PHEVs or BEVs if California were to pursue a more aggressive RPS target higher than 33 percent. Clearly, the decision to pursue a large fleet of electric-drive vehicles in California may have policy impacts with regards to how much of California's renewable energy can come from within California. Moreover, if neighboring states decide to pursue either more aggressive renewable energy goals, or pursue large fleets of EVs, California's access to a large low carbon fuel supply may be limited.

While the unit GHG emissions results attributable to PHEVs, BEVs and FCVs are attractive, perhaps a more important metric are total emissions from light-duty vehicles, which reflect the impacts of population growth and increases in VMT that California will likely face over the next few decades. The scenario results demonstrate that the AB 32 goal of reducing total GHG emissions 80 percent below 1990 levels may be attainable in the light-duty transportation sector if the right measures are put in place. My results show that a light-duty vehicle fleet comprised entirely of EVs combined with a 50 percent renewable electricity supply and a 32 percent reduction in VMT can yield total emissions that are as much as 70 percent below 1990 levels. While this does not quite reach the AB 32 goal it serves as a good indication of the magnitude of changes that might need to take place in the transportation sector to achieve this result. It also illustrates some of the policy choices and technologies that might be needed for this result to be achievable. The best emissions results involve PHEV and BEV charging using the *minimize fossil supply* and the *offpeak* and *constant* hydrogen fuel production profiles. All three of these fuel production profiles involve purposely producing electricity or hydrogen during hours when there is an abundance of renewable electricity available. Without targeted policy intervention and smart grid technology, there is no guarantee that vehicles will be charged or hydrogen fuel will be produced at the most optimal times from an emissions perspective.

The emissions benefits of grid energy storage in relation to fueling EVs are somewhat inconclusive and require further study. I model grid-energy storage in a relative simplistic way, and focus on using storage to produce an electricity supply that follows non-vehicle demand. This approach is beneficial in terms of investigating how to reduce emissions from the electricity grid as a whole, by optimizing the use of more efficient fossil generation resources, however a different approach is needed to better understand interactions with electricity demand from vehicles. A future analysis might involve shaping the electricity supply to reflect the timing of electricity demand from EVs as well as non-vehicle demand.

Another area that requires further study is hydrogen production. In my analysis, I focus on distributed onsite hydrogen production at a fueling station, using the electricity grid, but this is not the only option being considered for renewable hydrogen in California. Since hydrogen can be produced and stored in one location and transported to a fueling station for later use, an alternative option is to produce renewable hydrogen via electrolysis directly at a wind power plant. There are two potential advantages to this approach that are worth investigating:

1. Hydrogen can be produced whenever wind power is available, which often occurs during the night when electricity demand is low. In theory, this would increase the utilization of a wind power plant, making the investment more attractive and potentially lowering the cost of fuel production.
2. Unlike grid-electrolysis-based hydrogen production, all of the electricity used to produce and store hydrogen will be from a renewable resource with no GHG emissions, although there are some GHG emissions associated with delivering the hydrogen to a fueling station, if transported via truck rather than pipeline.

Another hydrogen production pathway that has already been investigated by others is biogasification of biomass waste, In a recent study, Parker et Al. investigate the benefits of using California's biomass resource to produce hydrogen fuel, with fuel cost estimates in the range of $3.50 to $5.50 per kg H2 and a 90 percent reduction in WTW GHG emissions, compared to conventional ICEVs [74]. An interesting study might involve comparing emissions, fuel costs and resource availability for all three hydrogen production pathways for the fuel demand scenarios explored in this thesis.

In terms of fuel production costs, the results shown in this thesis are encouraging. Both electricity and hydrogen show production cost estimates in the range of $0.04/mile to $0.08/mile that are cost-competitive with gasoline, especially for PHEVs and BEVs. In part, this is due to the fuel economy assumptions used for EVs, but it is also attributable to the fact that electricity is a less expensive energy resource than oil. Additional work remains in the area of cost analysis too. A more extensive cost analysis should include the cost of vehicle technologies to enable a complete lifecycle comparison of PHEVs, BEVs and FCVs as well as gasoline ICEVs and conventional gasoline HEVs. This would provide a more complete picture of the cost considerations to transition to a large EV fleet in California.

While further analysis is needed, this thesis does provide some key insights into the emissions and cost impacts of fueling electric-drive vehicles with low carbon electricity and hydrogen, which will likely play an increasingly important strategic role in helping to meet California's ambitious environmental goals in the transportation sector.

Appendix A – Renewable Electricity Capacity and Generation by CREZ

	Capacity (MW)				Annual Generation (GWh)			
	Biomass	Geothermal	Solar Thermal	Wind	Biomass	Geothermal	Solar Thermal	Wind
AZ NE	257		309	3,497	1,914	0	653	8,630
AZ NW	17		3,524	218	127	0	8,312	513
AZ SO	8		6,623		60	0	15,581	0
AZ WE	47		9,326		350	0	22,446	0
Barstow			1,400	936	0	0	3,289	2,641
BC CT	122			902	908	0	0	1,953
BC EA	34	32			253	224	0	0
BC NE	109	16		4,081	812	112	0	11,389
BC NO	78			2,176	581	0	0	5,730
BC NW	85	32		1,285	633	224	0	3,159
BC SE	60	32		138	447	224	0	252
BC SO	109	32		2,300	812	224	0	4,786
BC SW	162	16		1,744	1,206	112	0	3,630
BC WC	127	180			946	1,419	0	0
BC WE	53			1,317	395	0	0	3,205
BJ NO				5,655	0	0	0	14,753
BJ SO				2,650	0	0	0	7,007
Carrizo North			1,600		0	0	3,317	0
Carrizo South			3,000		0	0	6,279	0
Cuyama			400		0	0	851	0
Fairmont	138		1,800	712	1,028	0	4,253	2,319
ID EA	260	201		717	1,936	1,448	0	1,946
ID SW	98	128		932	730	897	0	2,384
Imperial East			1,500	74	0	0	3,616	120
Imperial North A		1,370			0	10,626	0	0
Imperial North B	30		1,800		223	0	4,261	0
Imperial South	36	64	3,570	45	266	449	8,159	120
Inyokern			2,145	287	0	0	5,086	776
IronMountain			4,800	62	0	0	11,233	105
Kramer		24	6,185	203	0	168	14,809	556
Lassen North				1,467	0	0	0	3,563
Lassen South				410	0	0	0	1,436
Mountain Pass			780	178	0	0	1,806	406
NM EA				11,292	0	0	0	39,246
NM SE				1,894	0	0	0	5,937
NV EA	133		7,817		990	0	14,567	0

NV NO	133	1,135			990	8,134	0	0
NV SW	12		3,475	1,555	89	0	7,954	4,104
NV WE	21	328	7,296	199	156	2,299	15,573	450
OR NE	41			2,048	305	0	0	4,900
OR SO	76	72		521	566	505	0	1,293
OR WE	296	331		343	2,204	2,596	0	781
Owens Valley			5,000		0	0	10,579	0
Palm Springs				333	0	0	0	915
Pisgah			2,200		0	0	5,126	0
Riverside East			10,550		0	0	24,931	0
Round Mountain A		384			0	2,691	0	0
Round Mountain B				132	0	0	0	344
San Bernardino Baker			3,350		0	0	7,774	0
San Bernardino Lucerne	91		1,540	599	678	0	3,700	1,475
San Diego North Central				200	0	0	0	409
San Diego South				678	0	0	0	1,835
Santa Barbara				433	0	0	0	993
Solano				894	0	0	0	1,470
Tehachapi	37		7,195	3,193	276	0	17,363	9,606
Twentynine Palms			1,805		0	0	4,316	0
UT WE	90	375		1,679	670	2,702	0	4,418
Victorville			1,200	436	0	0	2,691	1,190
WA SO	490			3,262	3,649	0	0	7,922
Westlands			5,000		0	0	8,786	0
WY EA				7,257	0	0	0	21,206
WY EC				2,595	0	0	0	8,642
WY NO				3,061	0	0	0	8,309
WY SO				1,940	0	0	0	6,719
TOTAL	**3,250**	**4,752**	**105,190**	**76,530**	**24,197**	**35,053**	**237,310**	**213,545**

Appendix B – GHG Emissions and Fuel Production Costs by Scenario

Year 2020 Results: PHEV/BEV (33% RPS Target)

Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
Instate Renewable Electricity Supply: 33% RPS Target									
PHEV 10	0.0445	0.01905	Min. Fossil	83.92	3.73	211.13	0.1076	0.0048	0.0467
PHEV 10	0.0445	0.01905	EPRI	244.54	10.88	211.13	0.1076	0.0048	0.0467
PHEV 10	0.0445	0.01905	Load-Level	246.07	10.95	211.13	0.1075	0.0048	0.0467
BEV	0.3180	---	Min. Fossil	83.92	26.69	---	0.1076	0.0342	---
BEV	0.3180	---	EPRI	244.54	77.76	---	0.1076	0.0342	---
BEV	0.3180	---	Load-Level	246.07	78.25	---	0.1075	0.0342	---
Limited OOS Renewable Electricity Supply: 33% RPS Target									
PHEV 10	0.0445	0.0190	Min. Fossil	158.06	7.03	211.13	0.1027	0.0046	0.0467
PHEV 10	0.0445	0.0190	EPRI	221.98	9.88	211.13	0.1022	0.0045	0.0467
PHEV 10	0.0445	0.0190	Load-Level	201.03	8.95	211.13	0.1022	0.0045	0.0467
BEV	0.3180	---	Min. Fossil	158.06	50.26	---	0.1027	0.0327	---
BEV	0.3180	---	EPRI	221.98	70.59	---	0.1022	0.0325	---
BEV	0.3180	---	Load-Level	201.03	63.93	---	0.1022	0.0325	---
OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
PHEV 10	0.0445	0.0190	Min. Fossil	146.94	6.54	211.13	0.0866	0.0039	0.0467
PHEV 10	0.0445	0.0190	EPRI	191.85	8.54	211.13	0.0862	0.0038	0.0467
PHEV 10	0.0445	0.0190	Load-Level	155.33	6.91	211.13	0.0864	0.0038	0.0467
BEV	0.3180	---	Min. Fossil	146.94	46.73	---	0.0866	0.0275	---
BEV	0.3180	---	EPRI	191.85	61.01	---	0.0862	0.0274	---
BEV	0.3180	---	Load-Level	155.33	49.39	---	0.0864	0.0275	---

Year 2035 Results: PHEV/BEV (33% RPS Target)

Instate Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
PHEV 20	0.1484	0.0190	Min. Fossil	137.86	20.46	211.13	0.1124	0.0167	0.0467
PHEV 20	0.1484	0.0190	EPRI	279.26	41.44	211.13	0.1112	0.0165	0.0467
PHEV 20	0.1484	0.0190	Load-Level	290.62	43.13	211.13	0.1106	0.0164	0.0467
BEV	0.3180	---	Min. Fossil	137.86	43.84	---	0.1124	0.0357	---
BEV	0.3180	---	EPRI	279.26	88.80	---	0.1112	0.0354	---
BEV	0.3180	---	Load-Level	290.62	92.41	---	0.1106	0.0352	---
Limited OOS Renewable Electricity Supply: 33% RPS Target									
PHEV 20	0.1484	0.0190	Min. Fossil	201.53	29.91	211.13	0.1085	0.0161	0.0467
PHEV 20	0.1484	0.0190	EPRI	258.32	38.33	211.13	0.1049	0.0156	0.0467
PHEV 20	0.1484	0.0190	Load-Level	258.09	38.30	211.13	0.1047	0.0155	0.0467
BEV	0.3180	---	Min. Fossil	201.53	64.08	---	0.1085	0.0345	---
BEV	0.3180	---	EPRI	258.32	82.14	---	0.1049	0.0334	---
BEV	0.3180	---	Load-Level	258.09	82.07	---	0.1047	0.0333	---
OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
PHEV 20	0.1484	0.0190	Min. Fossil	216.24	32.09	211.13	0.0928	0.0138	0.0467
PHEV 20	0.1484	0.0190	EPRI	230.56	34.21	211.13	0.0904	0.0134	0.0467
PHEV 20	0.1484	0.0190	Load-Level	221.61	32.89	211.13	0.0919	0.0136	0.0467
BEV	0.3180	---	Min. Fossil	216.24	68.76	---	0.0928	0.0295	---
BEV	0.3180	---	EPRI	230.56	73.32	---	0.0904	0.0287	---
BEV	0.3180	---	Load-Level	221.61	70.47	---	0.0919	0.0292	---

Year 2050 Results: PHEV/BEV (33% RPS Target)

Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
Instate Renewable Electricity Supply: 33% RPS Target									
PHEV 40	0.2226	0.0190	Min. Fossil	176.77	39.35	211.13	0.1249	0.0278	0.0467
PHEV 40	0.2226	0.0190	EPRI	313.24	69.72	211.13	0.1245	0.0277	0.0467
PHEV 40	0.2226	0.0190	Load-Level	287.93	64.09	211.13	0.1262	0.0281	0.0467
BEV	0.3180	---	Min. Fossil	176.77	56.21	---	0.1249	0.0397	---
BEV	0.3180	---	EPRI	313.24	99.61	---	0.1245	0.0396	---
BEV	0.3180	---	Load-Level	287.93	91.56	---	0.1262	0.0401	---
Limited OOS Renewable Electricity Supply: 33% RPS Target									
PHEV 40	0.2226	0.0190	Min. Fossil	210.04	46.75	211.13	0.1082	0.0241	0.0467
PHEV 40	0.2226	0.0190	EPRI	294.69	65.60	211.13	0.1090	0.0243	0.0467
PHEV 40	0.2226	0.0190	Load-Level	270.72	60.26	211.13	0.1084	0.0241	0.0467
BEV	0.3180	---	Min. Fossil	210.04	66.79	---	0.1082	0.0344	---
BEV	0.3180	---	EPRI	294.69	93.71	---	0.1090	0.0347	---
BEV	0.3180	---	Load-Level	270.72	86.09	---	0.1084	0.0345	---
OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
PHEV 40	0.2226	0.0190	Min. Fossil	232.01	51.64	211.13	0.0948	0.0211	0.0467
PHEV 40	0.2226	0.0190	EPRI	269.48	59.98	211.13	0.0954	0.0212	0.0467
PHEV 40	0.2226	0.0190	Load-Level	248.18	55.24	211.13	0.0949	0.0211	0.0467
BEV	0.3180	---	Min. Fossil	232.01	73.78	---	0.0948	0.0302	---
BEV	0.3180	---	EPRI	269.48	85.69	---	0.0954	0.0303	---
BEV	0.3180	---	Load-Level	248.18	78.92	---	0.0949	0.0302	---

Year 2035 Results: PHEV/BEV (50% RPS Target)

Limited OOS Renewable Electricity Supply: 50% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
PHEV 20	0.1484	0.0190	Min. Fossil	44.69	6.63	211.13	0.1272	0.0189	0.0467
PHEV 20	0.1484	0.0190	EPRI	223.99	33.24	211.13	0.1262	0.0187	0.0467
PHEV 20	0.1484	0.0190	Load-Level	232.17	34.45	211.13	0.1255	0.0186	0.0467
BEV	0.3180	---	Min. Fossil	44.69	14.21	---	0.1272	0.0405	---
BEV	0.3180	---	EPRI	223.99	71.23	---	0.1262	0.0401	---
BEV	0.3180	---	Load-Level	232.17	73.83	---	0.1255	0.0399	---
OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
PHEV 20	0.1484	0.0190	Min. Fossil	88.86	13.19	211.13	0.1166	0.0173	0.0467
PHEV 20	0.1484	0.0190	EPRI	185.00	27.45	211.13	0.1166	0.0173	0.0467
PHEV 20	0.1484	0.0190	Load-Level	178.68	26.52	211.13	0.1162	0.0172	0.0467
BEV	0.3180	---	Min. Fossil	88.86	28.26	---	0.1166	0.0371	---
BEV	0.3180	---	EPRI	185.00	58.83	---	0.1166	0.0371	---
BEV	0.3180	---	Load-Level	178.68	56.82	---	0.1162	0.0369	---

Year 2050 Results: PHEV/BEV (50% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
PHEV 40	0.2226	0.0190	Min. Fossil	115.41	25.69	211.13	0.1237	0.0275	0.0467
PHEV 40	0.2226	0.0190	EPRI	239.38	53.28	211.13	0.1236	0.0275	0.0467
PHEV 40	0.2226	0.0190	Load-Level	206.61	45.99	211.13	0.1233	0.0274	0.0467
BEV	0.3180	---	Min. Fossil	115.41	36.70	---	0.1237	0.0393	---
BEV	0.3180	---	EPRI	239.38	76.12	---	0.1236	0.0393	---
BEV	0.3180	---	Load-Level	206.61	65.70	---	0.1233	0.0392	---

Year 2050 Results: PHEV-Mixed Strategy (33% RPS Target)

Limited OOS Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
PHEV 40	0.2226	0.0190	Min. Fossil, Constant	154.40	34.37	211.13	0.1251	0.0278	0.0467
PHEV 40	0.2226	0.0190	EPRI, Constant	318.58	70.91	211.13	0.1274	0.0284	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Constant	301.33	67.07	211.13	0.1274	0.0283	0.0467
PHEV 40	0.2226	0.0190	Min. Fossil, Offpeak	143.37	31.91	211.13	0.1204	0.0268	0.0467
PHEV 40	0.2226	0.0190	EPRI, Offpeak	288.03	64.11	211.13	0.1190	0.0265	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Offpeak	265.35	59.06	211.13	0.1186	0.0264	0.0467
PHEV 40	0.2226	0.0190	Min. Fossil, Refuel	156.47	34.83	211.13	0.1222	0.0272	0.0467
PHEV 40	0.2226	0.0190	EPRI, Refuel	276.83	61.62	211.13	0.1200	0.0267	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Refuel	291.44	64.87	211.13	0.1190	0.0265	0.0467

Year 2050 Results: BEV-Mixed Strategy (33% RPS Target)

Limited OOS Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
BEV	0.3180	---	Min. Fossil, Constant	154.40	49.10	---	0.1251	0.0398	---
BEV	0.3180	---	EPRI, Constant	318.58	101.30	---	0.1274	0.0405	---
BEV	0.3180	---	Load-Level, Constant	301.33	95.82	---	0.1274	0.0405	---
BEV	0.3180	---	Min. Fossil, Offpeak	143.37	45.59	---	0.1204	0.0383	---
BEV	0.3180	---	EPRI, Offpeak	288.03	91.59	---	0.1190	0.0378	---
BEV	0.3180	---	Load-Level, Offpeak	265.35	84.38	---	0.1186	0.0377	---
BEV	0.3180	---	Min. Fossil, Refuel	156.47	49.76	---	0.1222	0.0389	---
BEV	0.3180	---	EPRI, Refuel	276.83	88.03	---	0.1200	0.0381	---
BEV	0.3180	---	Load-Level, Refuel	291.44	92.67	---	0.1190	0.0378	---

Year 2050 Results: PHEV-Mixed Strategy (33% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
PHEV 40	0.2226	0.0190	Min. Fossil, Constant	192.93	42.94	211.13	0.1091	0.0243	0.0467
PHEV 40	0.2226	0.0190	EPRI, Constant	259.21	57.70	211.13	0.1049	0.0233	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Constant	242.31	53.94	211.13	0.1045	0.0233	0.0467
PHEV 40	0.2226	0.0190	Min. Fossil, Offpeak	186.71	41.56	211.13	0.1067	0.0238	0.0467
PHEV 40	0.2226	0.0190	EPRI, Offpeak	260.82	58.06	211.13	0.1044	0.0232	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Offpeak	235.68	52.46	211.13	0.1037	0.0231	0.0467
PHEV 40	0.2226	0.0190	Min. Fossil, Refuel	194.00	43.18	211.13	0.1078	0.0240	0.0467
PHEV 40	0.2226	0.0190	EPRI, Refuel	243.41	54.18	211.13	0.1048	0.0233	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Refuel	244.15	54.35	211.13	0.1039	0.0231	0.0467

Year 2050 Results: BEV-Mixed Strategy (33% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
BEV	0.3180	---	Min. Fossil, Constant	192.93	61.35	---	0.1091	0.0347	---
BEV	0.3180	---	EPRI, Constant	259.21	82.43	---	0.1049	0.0333	---
BEV	0.3180	---	Load-Level, Constant	242.31	77.05	---	0.1045	0.0332	---
BEV	0.3180	---	Min. Fossil, Offpeak	186.71	59.37	---	0.1067	0.0339	---
BEV	0.3180	---	EPRI, Offpeak	260.82	82.94	---	0.1044	0.0332	---
BEV	0.3180	---	Load-Level, Offpeak	235.68	74.94	---	0.1037	0.0330	---
BEV	0.3180	---	Min. Fossil, Refuel	194.00	61.69	---	0.1078	0.0343	---
BEV	0.3180	---	EPRI, Refuel	243.41	77.40	---	0.1048	0.0333	---
BEV	0.3180	---	Load-Level, Refuel	244.15	77.64	---	0.1039	0.0330	---

Year 2050 Results: PHEV-Mixed Strategy (50% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
PHEV 40	0.2226	0.0190	Min. Fossil, Constant	65.51	14.58	211.13	0.1322	0.0294	0.0467
PHEV 40	0.2226	0.0190	EPRI, Constant	233.87	52.06	211.13	0.1307	0.0291	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Constant	215.09	47.88	211.13	0.1304	0.0290	0.0467
PHEV 40	0.2226	0.0190	Min. Fossil, Offpeak	64.18	14.28	211.13	0.1319	0.0293	0.0467
PHEV 40	0.2226	0.0190	EPRI, Offpeak	238.88	53.17	211.13	0.1306	0.0291	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Offpeak	211.28	47.03	211.13	0.1305	0.0290	0.0467
PHEV 40	0.2226	0.0190	Min. Fossil, Refuel	70.18	15.62	211.13	0.1330	0.0296	0.0467
PHEV 40	0.2226	0.0190	EPRI, Refuel	222.49	49.52	211.13	0.1317	0.0293	0.0467
PHEV 40	0.2226	0.0190	Load-Level, Refuel	232.20	51.69	211.13	0.1307	0.0291	0.0467

Year 2050 Results: BEV-Mixed Strategy (50% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	Gasoline Intensity (gal/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	Gasoline Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost - Gasoline ($/mile)
BEV	0.3180	---	Min. Fossil, Constant	65.51	20.83	---	0.1322	0.0420	---
BEV	0.3180	---	EPRI, Constant	233.87	74.37	---	0.1307	0.0416	---
BEV	0.3180	---	Load-Level, Constant	215.09	68.39	---	0.1304	0.0415	---
BEV	0.3180	---	Min. Fossil, Offpeak	64.18	20.41	---	0.1319	0.0419	---
BEV	0.3180	---	EPRI, Offpeak	238.88	75.96	---	0.1306	0.0415	---
BEV	0.3180	---	Load-Level, Offpeak	211.28	67.18	---	0.1305	0.0415	---
BEV	0.3180	---	Min. Fossil, Refuel	70.18	22.32	---	0.1330	0.0423	---
BEV	0.3180	---	EPRI, Refuel	222.49	70.75	---	0.1317	0.0419	---
BEV	0.3180	---	Load-Level, Refuel	232.20	73.84	---	0.1307	0.0415	---

Year 2020 Results: FCV (33% RPS Target)

Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
Instate Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.01804	Constant	209.09	151.33	166.93	0.10799	0.1580	0.0287
FCV	0.7238	0.01804	Offpeak	202.57	146.62	166.93	0.10793	0.1672	0.0287
FCV	0.7238	0.01804	Refueling	201.48	145.83	166.93	0.10810	0.1775	0.0287
Limited OOS Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.01804	Constant	208.88	151.18	166.93	0.10278	0.1580	0.0287
FCV	0.7238	0.01804	Offpeak	195.00	141.14	166.93	0.10278	0.1672	0.0287
FCV	0.7238	0.01804	Refueling	218.46	158.12	166.93	0.10283	0.1775	0.0287
OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.01804	Constant	200.58	145.18	166.93	0.08758	0.1580	0.0287
FCV	0.7238	0.01804	Offpeak	181.66	131.48	166.93	0.08762	0.1672	0.0287
FCV	0.7238	0.01804	Refueling	223.09	161.47	166.93	0.08743	0.1775	0.0287

Year 2035 Results: FCV (33% RPS Target)

Instate Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
FCV	0.7238	0.0138	Constant	215.29	155.82	119.25	0.1175	0.1399	0.0219
FCV	0.7238	0.0138	Offpeak	218.39	158.07	119.25	0.1171	0.1469	0.0219
FCV	0.7238	0.0138	Refueling	208.72	151.07	119.25	0.1184	0.1546	0.0219
Limited OOS Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.0138	Constant	206.49	149.46	119.25	0.1097	0.1399	0.0219
FCV	0.7238	0.0138	Offpeak	204.56	148.06	119.25	0.1094	0.1469	0.0219
FCV	0.7238	0.0138	Refueling	216.46	156.67	119.25	0.1104	0.1546	0.0219
OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.0138	Constant	204.21	147.80	119.25	0.0945	0.1399	0.0219
FCV	0.7238	0.0138	Offpeak	196.52	142.24	119.25	0.0945	0.1469	0.0219
FCV	0.7238	0.0138	Refueling	228.66	165.50	119.25	0.0945	0.1546	0.0219

Year 2050 Results: FCV (33% RPS Target)

Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
Instate Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.0122	Constant	---	---	105.99	---	---	0.0195
FCV	0.7238	0.0122	Offpeak	---	---	105.99	---	---	0.0195
FCV	0.7238	0.0122	Refueling	---	---	105.99	---	---	0.0195
Limited OOS Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.0122	Constant	204.57	148.06	105.99	0.1224	0.1353	0.0195
FCV	0.7238	0.0122	Offpeak	216.25	156.52	105.99	0.1219	0.1416	0.0195
FCV	0.7238	0.0122	Refueling	217.13	157.16	105.99	0.1245	0.1485	0.0195
OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
FCV	0.7238	0.0122	Constant	196.61	142.30	105.99	0.1062	0.1353	0.0195
FCV	0.7238	0.0122	Offpeak	204.64	148.12	105.99	0.1060	0.1416	0.0195
FCV	0.7238	0.0122	Refueling	224.48	162.47	105.99	0.1075	0.1485	0.0195

Year 2035 Results: FCV (50% RPS Target)

Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
Instate Renewable Electricity Supply: 50% RPS Target									
FCV	0.7238	0.0138	Constant	---	---	119.25	---	---	0.0219
FCV	0.7238	0.0138	Offpeak	---	---	119.25	---	---	0.0219
FCV	0.7238	0.0138	Refueling	---	---	119.25	---	---	0.0219
Limited OOS Renewable Electricity Supply: 50% RPS Target									
FCV	0.7238	0.0138	Constant	131.18	94.95	119.25	0.1304	0.1399	0.0219
FCV	0.7238	0.0138	Offpeak	164.26	118.89	119.25	0.1300	0.1469	0.0219
FCV	0.7238	0.0138	Refueling	161.71	117.04	119.25	0.1309	0.1546	0.0219
OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
FCV	0.7238	0.0138	Constant	111.61	80.78	119.25	0.1221	0.1399	0.0219
FCV	0.7238	0.0138	Offpeak	131.33	95.06	119.25	0.1219	0.1469	0.0219
FCV	0.7238	0.0138	Refueling	154.45	111.79	119.25	0.1227	0.1546	0.0219

Year 2050 Results: FCV (50% RPS Target)

Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
Instate Renewable Electricity Supply: 50% RPS Target									
FCV	0.7238	0.0122	Constant	---	---	105.99	---	---	0.0195
FCV	0.7238	0.0122	Offpeak	---	---	105.99	---	---	0.0195
FCV	0.7238	0.0122	Refueling	---	---	105.99	---	---	0.0195
Limited OOS Renewable Electricity Supply: 50% RPS Target									
FCV	0.7238	0.0122	Constant	---	---	105.99	---	---	0.0195
FCV	0.7238	0.0122	Offpeak	---	---	105.99	---	---	0.0195
FCV	0.7238	0.0122	Refueling	---	---	105.99	---	---	0.0195
OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
FCV	0.7238	0.0122	Constant	162.10	117.33	105.99	0.1321	0.1353	0.0195
FCV	0.7238	0.0122	Offpeak	164.19	118.84	105.99	0.1316	0.1416	0.0195
FCV	0.7238	0.0122	Refueling	171.26	123.96	105.99	0.1334	0.1485	0.0195

Year 2050 Results: FCV-Mixed Strategy (33% RPS Target)

Limited OOS Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
FCV	0.7238	0.0122	Min. Fossil, Constant	252.02	182.41	135.63	0.1251	0.1319	0.0195
FCV	0.7238	0.0122	EPRI, Constant	246.29	178.26	135.63	0.1274	0.1319	0.0195
FCV	0.7238	0.0122	Load-Level, Constant	246.95	178.74	135.63	0.1274	0.1319	0.0195
FCV	0.7238	0.0122	Min. Fossil, Offpeak	241.24	174.61	135.63	0.1204	0.1358	0.0195
FCV	0.7238	0.0122	EPRI, Offpeak	229.92	166.41	135.63	0.1190	0.1358	0.0195
FCV	0.7238	0.0122	Load-Level, Offpeak	228.95	165.71	135.63	0.1186	0.1358	0.0195
FCV	0.7238	0.0122	Min. Fossil, Refuel	244.86	177.23	135.63	0.1222	0.1457	0.0195
FCV	0.7238	0.0122	EPRI, Refuel	209.15	151.38	135.63	0.1200	0.1457	0.0195
FCV	0.7238	0.0122	Load-Level, Refuel	199.26	144.22	135.63	0.1190	0.1457	0.0195

Year 2050 Results: FCV-Mixed Strategy (33% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 33% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
FCV	0.7238	0.0122	Min. Fossil, Constant	242.00	175.15	135.63	0.1091	0.1319	0.0195
FCV	0.7238	0.0122	EPRI, Constant	212.09	153.50	135.63	0.1049	0.1319	0.0195
FCV	0.7238	0.0122	Load-Level, Constant	215.59	156.04	135.63	0.1045	0.1319	0.0195
FCV	0.7238	0.0122	Min. Fossil, Offpeak	229.88	166.38	135.63	0.1067	0.1358	0.0195
FCV	0.7238	0.0122	EPRI, Offpeak	215.69	156.11	135.63	0.1044	0.1358	0.0195
FCV	0.7238	0.0122	Load-Level, Offpeak	211.58	153.14	135.63	0.1037	0.1358	0.0195
FCV	0.7238	0.0122	Min. Fossil, Refuel	251.73	182.20	135.63	0.1078	0.1457	0.0195
FCV	0.7238	0.0122	EPRI, Refuel	217.66	157.54	135.63	0.1048	0.1457	0.0195
FCV	0.7238	0.0122	Load-Level, Refuel	207.74	150.36	135.63	0.1039	0.1457	0.0195

Year 2050 Results: FCV-Mixed Strategy (50% RPS Target)

OOS Resources Heavy Renewable Electricity Supply: 50% RPS Target									
Vehicle Technology	Energy Intensity (kWh/mile)	H_2 Intensity (Kg H_2/mile)	Fuel Production Profile	Grid-Electricity Emissions (g CO_2/kWh)	Grid-Electricity Emissions (g CO2/mile)	SMR-H_2 Emissions (g CO_2/mile)	Electricity Cost ($/kWh)	Fuel Cost - Electricity ($/mile)	Fuel Cost – SMR-H_2 ($/mile)
FCV	0.7238	0.0122	Min. Fossil, Constant	161.71	117.04	135.63	0.1322	0.1319	0.0195
FCV	0.7238	0.0122	EPRI, Constant	166.54	120.54	135.63	0.1307	0.1319	0.0195
FCV	0.7238	0.0122	Load-Level, Constant	168.45	121.92	135.63	0.1304	0.1319	0.0195
FCV	0.7238	0.0122	Min. Fossil, Offpeak	163.06	118.02	135.63	0.1319	0.1358	0.0195
FCV	0.7238	0.0122	EPRI, Offpeak	176.28	127.59	135.63	0.1306	0.1358	0.0195
FCV	0.7238	0.0122	Load-Level, Offpeak	175.08	126.72	135.63	0.1305	0.1358	0.0195
FCV	0.7238	0.0122	Min. Fossil, Refuel	175.60	127.10	135.63	0.1330	0.1457	0.0195
FCV	0.7238	0.0122	EPRI, Refuel	159.92	115.75	135.63	0.1317	0.1457	0.0195
FCV	0.7238	0.0122	Load-Level, Refuel	151.22	109.45	135.63	0.1307	0.1457	0.0195

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