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Attachment 2 of 2

Additional submitted attachment is included below.

Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal

November 2014

(Revised from June 2014 draft)



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Executive Summary

This study examines the potential role of decarbonized pipeline gas fuels, and the existing gas pipeline infrastructure, to help meet California’s long-term climate goals. The term “decarbonized gas” is used to refer to gaseous fuels with a net-zero, or very low, greenhouse gas impact on the climate. These include fuels such as biogas, hydrogen and renewable synthetic gases produced with low lifecycle GHG emission approaches. The term “pipeline gas” means any gaseous fuel that is transported and delivered through the natural gas distribution pipelines. Using a bottom-up model of California’s infrastructure and energy systems between today and 2050 known as PATHWAYS (v.2.1), we examine two “technology pathway” scenarios for meeting the state’s goal of reducing greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050:

- + **Electrification scenario**, where all energy end uses, to the extent feasible, are electrified and powered by renewable electricity by 2050;
- + **Mixed scenario**, where both electricity and decarbonized gas play significant roles in California’s energy supply by 2050.

Both scenarios meet California’s 2020 and 2050 GHG goals, to the extent feasible, accounting for constraints on energy resources, conversion efficiency, delivery systems, and end-use technology adoption. Across scenarios, we

compare total GHG emissions, costs, and gas pipeline utilization over time relative to a Reference scenario, which does not meet the 2050 GHG target.

The study concludes that a technology pathway for decarbonized gas could feasibly meet the state's GHG reduction goals and may be easier to implement in some sectors than a high electrification strategy. We find that the total costs of the decarbonized gas and electrification pathways to be comparable and within the range of uncertainty. A significant program of research and development, covering a range of areas from basic materials science to regulatory standards, would be needed to make decarbonized gas a reality.

The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

- + First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) heavy duty vehicles (HDVs), and (3) certain residential and commercial end uses, such as cooking, and existing space and water heating.
- + Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed.
- + Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, eliminating

the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen pipelines or additional electric transmission and distribution capacity.

- + Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a low-carbon energy system.

1 Introduction

California has embarked on a path to dramatically reduce its GHG emissions over the next four decades. In the nearer term, Assembly Bill 32 (AB 32) requires the state to reduce GHG emissions to 1990 levels by 2020. The state appears to be on track to meet this goal. In the longer term, Executive Order S-3-05 sets a target for California to reduce GHG emissions by 80% relative to 1990 levels by 2050. Achieving this target will require significant changes in the state's energy systems over the coming decades; the state's energy supply will need to be almost entirely carbon free by mid-century.

Natural gas and other gaseous fuels face an uncertain future in California's energy supply mix. The need to reduce the carbon intensity of the state's transportation fuels and industrial output to meet near- to medium-term GHG goals opens up opportunities for natural gas as a substitute for more carbon-intensive oil and coal. However, natural gas from traditional fossil fuel sources cannot represent a significant share of energy use by 2050 if the state is to meet its long-term GHG goal. By 2050, traditional uses of oil and natural gas, including transportation fuels, water and space heating, and industrial boilers and process heating, will need to be mostly, if not fully, decarbonized.

Solutions for achieving a deep decarbonization of California's energy supply have focused on extensive electrification using renewable energy sources, with

some liquid biofuel and hydrogen fuel use in the transportation sector. However, there are three principal challenges associated with this decarbonization “pathway.” First, there are practical limits to electrifying some energy end uses, such as HDVs and industrial process heating. Second, there are physical limits on sustainable biomass resources, which limit the amount of biomass that can be used as a primary energy source. Third, very high levels of renewable penetration require large-scale energy storage solutions, to integrate wind and solar generation on daily and seasonal timescales. Decarbonized¹ gas fuels distributed through the state’s extensive existing gas pipeline network offer a little-explored strategy for overcoming some of these challenges and meeting the state’s GHG goals.

To examine the roles of gas fuels in California and utilization of the state’s existing gas pipeline infrastructure from now until 2050, Southern California Gas Company (SCG) retained Energy and Environmental Economics (E3) to address four main questions:

1. Are there feasible technology pathways for achieving California’s nearer- and longer-term GHG targets where gaseous fuels continue to play a significant role?
2. If yes, how do these pathways compare against a reference case and a “high electrification” strategy in terms of GHG emissions and costs? How does the use of the state’s gas pipeline infrastructure differ under scenarios where more and less of the state’s energy supply is electrified?
3. In what key areas would research, development, and demonstration (RD&D) be needed to produce decarbonized gas on a commercial scale?

¹ Throughout this report, the term “decarbonized gas” refers to gases that have a net-zero, or very low, impact on the climate, accounting for both fuel production and combustion.

To provide an analytical framework for addressing these questions, we develop two “technology pathway” scenarios that represent different points along a spectrum between higher and lower levels of electrification of energy end uses by 2050:

- (1) “Electrification” scenario, where most of the state’s energy consumption is powered with renewable electricity by 2050;
- (2) “Mixed” scenario where decarbonized gas replaces existing natural gas demand and fuels HDVs, but renewable energy is used to produce electricity and to power most light-duty vehicles (LDVs).

The decarbonized gas technologies examined in this study were selected to represent a range of different options, but are not intended to be exhaustive. The focus in this study is on more generally examining the role of gas fuels over the longer term in a low-carbon energy system, not on comparing different emerging decarbonized gas options.² These scenarios are compared to a Reference scenario where current policies are unchanged through 2050 and the state’s GHG target is unmet. Table 1 shows a high-level summary of key differences among these three scenarios.

² A number of emerging technology options for low-carbon gas, such as artificial photosynthesis, are thus not included in the list of technology options examined in this study. Including these technologies would likely reinforce many of the main conclusions in this study.

Table 1. High-level summary of key differences among the three scenarios examined in this analysis

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply	Source and amount of decarbonized pipeline gas ³
Electrification	Mostly electric	Mostly electric LDVs, mostly hydrogen fuel cell HDVs	Renewable energy, some natural gas with CCS	Small amount of biogas
Mixed	Decarbonized gas for existing gas market share of end uses	Electric LDVs, Decarbonized gas in HDVs	Renewable energy, some natural gas with CCS	Large amount of biogas, smaller amounts of SNG, hydrogen, natural gas
Reference	Natural gas	Gasoline, diesel	Mostly natural gas	None

Both the Electrification and Mixed scenarios were designed to meet California’s 2020 and 2050 GHG targets. For each scenario we analyzed its technical feasibility and technology costs using a bottom-up model of the California economy. This model (California PATHWAYS v2.1), which includes a detailed “stock-rollover” representation of the state’s building, transportation, and energy infrastructure, allows for realistic depiction of infrastructure turnover and technology adoption; sector- and technology-based matching of energy demand and supply; and detailed energy system representation and technology coordination. The model includes hourly power system dispatch and realistic

³ Throughout this report, the term “pipeline gas” is used to encompass different mixes of gas in the pipeline, including conventional natural gas, gasified biomass, hydrogen (initially limited to 4% of pipeline gas volume, with up to 20% allowed by 2050), and gas produced from P2G methanation.

operating constraints. An earlier version of the model was peer reviewed as part of an article published in the journal *Science*.⁴

The identification of realistic sources of decarbonized gas is a critical piece of this analysis. We considered three energy carriers for decarbonized gas, each with different potential primary energy sources:

- + **Biogas**, which includes gas produced through biomass gasification (biomass synthetic gas) and anaerobic digestion of biomass;
- + **Hydrogen**, produced through electrolysis; and
- + **Synthetic natural gas (SNG)**, produced through electrolysis with renewables (mostly wind and solar “over-generation”) and further methanated into SNG in a process referred to as power-to-gas (P2G) throughout this report.⁵

By 2050, there are a limited number of primary energy sources available to supply decarbonized energy: renewable electricity, biomass, nuclear, or fossil fuels with carbon capture and sequestration (CCS). Each has different scaling constraints. For instance, wind and solar energy are intermittent and require energy storage at high penetration levels. Hydropower and geothermal energy are constrained by land and water use impacts and the availability of suitable

⁴ James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Sneller Price, Margaret S. Torn, “The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity,” *Science* 335: 53-59.

⁵ P2G, though often used generically to refer to any process that converts electricity to gas, refers specifically to electrolysis and hydrogen methanation in this report. The methanation reaction requires a source of CO₂, which we assume to be air capture in this study, although carbon capture from seawater is another promising, emerging technology. This extra methanation step, and the costs of seawater carbon capture, or air capture, makes P2G relatively expensive. We examined this technology in this study primarily for its electricity storage benefits. Other potential low-carbon gas production technologies, such as synthetic photosynthesis, are not examined within the scope of this study.

sites for development. Bioenergy is limited by the amount of feedstock that can be sustainably harvested. Nuclear is limited by public acceptance and the lack of long-term storage and disposal of spent fuel. Carbon capture and sequestration is also limited by public acceptance and generates higher emissions than the other options due to partial capture rates of CO₂. Choices of primary energy sources for a decarbonized energy supply require tradeoffs in costs, reliability, externalities, and public acceptance.

Similar limits and tradeoffs exist with conversion pathways from primary energy to secondary energy carriers, often with multiple interrelated options. Biomass, for instance, can be converted into a number of different energy carriers (e.g., liquid biofuels, biogas, hydrogen, electricity) through multiple energy conversion processes. P2G is only cost-effective from an energy system perspective when there is significant renewable over-generation. Fossil fuels can be converted into partially decarbonized energy with carbon capture and sequestration (CCS). Evaluating different decarbonized gas technology options — primary energy sources, energy conversion pathways, and energy carriers — thus requires realistic scaling constraints, an integrated energy system perspective, and strategies for managing uncertainty and complexity.

Our modeling framework addresses these requirements by: consistently constraining physical resources (e.g., biomass availability), conversion efficiencies (e.g., gasification efficiency), and gas distribution (e.g., limits on hydrogen gas volumes in pipelines); allowing for interrelationships among energy sources (e.g., electricity and gas); accounting for system costs and GHG emissions across a range of technologies; and exploring different potential options under a range of inputs and avoiding over-reliance on point estimate

assumptions as the driver of technology adoption. The results of this study confirm that the electricity sector will be pivotal to achieving a low-carbon future in California — in both the Electrification and Mixed scenarios the need for low-carbon electricity increases substantially. The results also suggest that decarbonized gases distributed through the state's existing pipeline network are complementary with a low-carbon electrification strategy by addressing four critical challenges to California's transition to a decarbonized energy supply.

- + First, decarbonized pipeline gas can help to reduce emissions in sectors that are otherwise difficult to electrify, either for technical or customer-acceptance reasons. These sectors include: (1) certain industrial end uses, such as process heating, (2) HDVs, and (3) certain residential and commercial end uses, such as cooking, existing space heating, and existing water heating.
- + Second, the production of decarbonized gas from electricity could play an important role in integrating variable renewable generation by producing gas when renewables are generating power, and then storing the gas in the pipeline distribution network for when it is needed. At high penetrations of variable renewable generation, long-term, seasonal electricity storage may be needed to balance demand and supply, in addition to daily storage. On these longer timescales, gas "storage" may be a more realistic and cost-effective load-resource balancing strategy than flexible loads and long-duration batteries.⁶
- + Third, a transition to decarbonized pipeline gas would enable continued use of the state's existing gas pipeline distribution network, reducing or

⁶ In this scenario, we assume that electrolysis for hydrogen production, powered by renewable electricity, can be ramped up and down on a daily basis as a dispatchable load in the medium-term. In the long-term, P2G methanation with air capture, or carbon capture from seawater to produce SNG could provide both a source of low-carbon gas and a grid balancing service.

eliminating the need for new energy delivery infrastructure to meet 2050 GHG targets, such as dedicated hydrogen delivery pipelines or additional electric transmission and distribution lines. Increased use of decarbonized gas in the coming decades would preserve the option of continued use of existing gas pipelines as a low-carbon energy delivery system over the longer term.

- + Fourth, pursuit of decarbonized gas technologies would help diversify the technology risk associated with heavy reliance on a limited number of decarbonized energy carriers, and would allow consumers, businesses and policymakers greater flexibility and choice in the transition to a decarbonized energy system.

All of the decarbonized gas energy carriers in this study make use of proven energy conversion processes — none require fundamental breakthroughs in science. Nonetheless, these processes remain relatively inefficient and expensive, and would need significant improvements in conversion efficiency and reductions in costs to be competitive in the medium- to long-term. Additionally, existing gas pipelines and end use equipment were not designed to transport and utilize hydrogen gas, and would require operational changes as the blend of decarbonized gas shifts over time.

Developing a supply of sustainably sourced biomass presents an additional challenge. Biomass resources have competing uses — food, fodder, and fiber — which may limit the amount of sustainably-sourced biomass available for energy production. The Electrification and Mixed scenarios both assume that a limited quantity of sustainably sourced biomass would be available to California in the 2030 and 2050 timeframe. The same quantity of biomass is assumed to produce electricity in the Electrification scenario, and biogas in the Mixed scenario.

However, it remains uncertain whether it will be possible to increase the production of biomass fuels to this scale, as would be needed to significantly reduce fossil fuel use, without negatively impacting food supply or increasing GHG emissions from changes in land use.

Furthermore, current RD&D efforts and policy initiatives have prioritized the production of liquid biofuels, particularly ethanol, over the production of biogas. More generally, the state does not appear to have a comprehensive decarbonized gas strategy, in contrast to low-carbon electricity which is promoted through the state's Renewables Portfolio Standard (RPS) and the decarbonized transportation fuels are encouraged through the state's Low Carbon Fuel Standard (LCFS). Overcoming these challenges would require prompt shifts in policy priorities and significant amounts of RD&D if biofuels, and particularly biogas, are to become an important part of the state's future energy mix.

The results suggest priority areas and time frames, outlined in Table 2, for a RD&D agenda that would be needed if California is to pursue decarbonized pipeline gas as a strategy to help meet the state's GHG reduction goals.

Table 2. RD&D timescales, priorities, and challenges for decarbonized gas fuels

Timeframe of RD&D payoff	RD&D Area	Challenge
Near-term	Energy efficiency	Achieving greater customer adoption and acceptance
	Reduction in methane leakage	Cost-effectively identifying and repairing methane leaks in natural gas mining, processing, and distribution
	Use of anaerobic digestion gas in the pipeline and pilot biomass gasification	Quality control on gas produced via anaerobic digestion for pipeline delivery
Medium-term	Agronomic and supply chain innovation for biomass feedstocks	Competition with liquid fuels, food, fodder, fiber may limit amount of biomass available as a source of decarbonized gas
	Pilot decarbonized SNG technology to improve conversion efficiency and cost	Gasification, electrolysis, and methanation need efficiency improvements, reductions in cost to be competitive; safety, scale, and location challenges must be addressed
	Limits on hydrogen volumes in existing pipelines	Need pipeline and operational changes to accommodate higher volumes
Long-term	Emerging technologies (e.g., P2G, artificial photosynthesis, CO ₂ capture from seawater for fuel production)	P2G must be scalable and available as a renewable resource balancing technology; in general, emerging technologies still require innovations in material science

The organization of the report is as follows: Section 2 develops the Reference case and two afore-mentioned scenarios. Section 3 describes the modeling approach and elaborates on the technology pathways for decarbonized gases. Section 4 presents the results. The final section, Section 5, distills key conclusions and discusses their policy and regulatory implications. Further details on methods and assumptions are provided in an appendix.

1.1 About this study

This study was commissioned by SCG to help the company consider their long-term business outlook under a low-carbon future, and to fill a gap in the existing literature regarding long-term GHG reduction strategies that include the use of decarbonized gas in the pipeline distribution network.

A number of studies have evaluated the options for states, countries and the world to achieve deep reductions in GHG emissions by 2050.⁷ These studies each make different assumptions about plausible technology pathways to achieve GHG reductions, with varying amounts of conservation and efficiency, CCS, hydrogen fuel cells, nuclear energy, and biofuel availability, to name a few key variables. However, few studies have undertaken an in-depth investigation of the role that decarbonized pipeline gas could play in achieving a decarbonized future.⁸

In our prior work, we highlighted the pivotal role of the electricity sector in achieving a low-carbon future for California.⁹ This study for SCG uses an

⁷ See for example: "Reducing Greenhouse Gas Emissions by 2050: California's Energy Future," California Council on Science and Technology, September 2012; "Roadmap 2050: A practical guide to a prosperous, low-carbon Europe," European Climate Foundation, April 2010; "EU Transport GHG: Road to 2050?," funded by the European Commission, June 2010; "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft," U.S. EPA, April 2009; "Energy Technology Perspectives, 2008: Scenarios & Strategies to 2050," International Energy Agency, 2008; "The Power to Reduce CO₂ Emissions: The Full Portfolio: 2008 Economic Sensitivity Studies," EPRI, Palo Alto, CA: 2008. 1018431; "Building a Low Carbon Economy: The U.K.'s Contribution to Tackling Climate Change," The First Report of the Committee on Climate Change, December 2008; "Making the Transition to a Secure and Low-Carbon Energy System: Synthesis Report," UK Energy Research Center, 2009.

⁸ For an example of a deep decarbonization study from Germany that employs both electrolysis and P2G (Sabatier), see Palzer, A. and Hans-Martin Henning, "A Future Germany Energy System with a Dominating Contribution from Renewable Energies: A Holistic Model Based on Hourly Simulation," *Energy Technol.* 2014, 2, 13 – 28.

⁹ James H. Williams, Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow III, Snuller Price, Margaret S. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335: 53-59.

updated version of the model (California PATHWAYS 2.1) employed in that prior work, relying on the same fundamental infrastructure-based stock roll-over modeling approach, and many of the same underlying input assumptions, such as energy efficiency potential. However, important updates to the analysis include:

- + Updated forecasts of macroeconomic drivers including population and economic growth;
- + Updated technology cost assumptions where new information has become available, including for solar photovoltaic (PV) and energy storage costs;
- + A more sophisticated treatment of electricity resource balancing, moving from a four time period model (summer/winter & high-load/low-load), to an hourly resource balancing exercise; and
- + Slightly higher biomass resource potential estimates, based on new data from the U.S. Department of Energy (DOE).¹⁰

The model results are driven by exogenous, scenario-defined technology adoption assumptions. Costs of technologies and fuels are exogenous, independent inputs which are tabulated to track total costs. The model does not use costs as an internal decision variable to drive the model results, rather the model is designed to evaluate technology-driven, user-defined scenarios.

¹⁰ U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.

2 Scenarios

2.1 Low-carbon scenarios

Two distinct low-carbon scenarios are developed and compared within this study. Both of these scenarios result in lower GHG emissions than required by California's mandate of reducing emissions to 1990 levels by 2020, and are designed to meet the 2050 goal of reducing GHG emissions 80% below 1990 levels. Each scenario is further constrained to achieve an approximately linear path in GHG reductions between today's emissions and the 2050 goal. The differences between the two scenarios are not in GHG reduction achievements, but between technology pathways, implied RD&D priorities, technology risks, and costs.

The two low-carbon scenarios evaluated include:

- + **Electrification Scenario:** This scenario meets the 2050 GHG reduction goal by electrifying most end-uses, including industrial end uses, space heating, hot water heating, cooking and a high proportion of light-duty vehicles. Low-carbon electricity is produced mostly from renewable generation, primarily solar PV and wind, combined with a limited amount of natural gas with carbon capture and storage (CCS) and 20 GW of electricity storage used for renewable integration. Low-carbon electricity is also used to produce hydrogen fuel for heavy-duty vehicles. California's limited supply of biomass is used largely to generate

renewable electricity in the form of biomass generation. In this scenario, the gas distribution pipeline network is effectively un-used by 2050. With very few remaining sales by 2050 and significant remaining fixed distribution costs, it seems unlikely that gas distribution companies would continue to operate under this scenario.

- + **Mixed Scenario: This scenario meets the 2050 GHG reduction goal with a blend of low-carbon electricity and decarbonized pipeline gas.** Existing uses for natural gas in California, such as industrial end uses (i.e. boilers and process heat), space heating, hot water heating and cooking are assumed to be supplied with decarbonized pipeline gas, such that the current market share for pipeline gas is maintained over time. California's limited supply of biomass is used to produce biogas which is injected into the pipeline. Over time, this scenario assumes that an increasing share of hydrogen is blended into the pipeline gas, which is assumed to be produced from renewable power (mostly solar and wind) using electrolysis. This scenario includes a significant increase in electric light-duty vehicles, while most heavy-duty vehicles are assumed to be powered with compressed or liquefied decarbonized gas and liquid hydrogen fuel. Electricity is produced mostly from renewable generation, primarily solar PV and wind, with a limited amount of natural gas with CCS and 5 GW of electricity storage used for renewable integration. Load balancing services are primarily provided by cycling the production of decarbonized gas to match the renewable generation profiles. In this way, the decarbonized pipeline gas provides both daily and seasonal energy storage. The Mixed scenario represents neither a significant expansion nor contraction of the gas pipeline distribution system. In this scenario, both the gas pipeline network and the electricity transmission and distribution system operate as conveyors of decarbonized energy.

The key parameters of these scenarios are summarized in Table 3 below.

Table 3. Summary of Low-Carbon Scenarios Based on Key Parameters in 2050

Scenario	Source of residential, commercial, industrial energy end uses	Source of transportation fuels	Source of electricity supply & resource balancing	Uses of biomass
Electrification	Mostly electric	Mostly electric light-duty vehicles, mostly hydrogen HDVs	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage and 15 GW of battery energy storage, some hydrogen production	Electricity generation, small amount of biogas
Mixed	Decarbonized gas (biogas, SNG & hydrogen) for existing gas market share of end uses	Decarbonized gas in HDVs; electric light duty vehicles (LDVs)	Renewable energy, limited natural gas with CCS, 5 GW of pumped hydro energy storage, plus P2G and hydrogen production assumed to provide resource balancing services	Biogas

Both of the low-carbon scenarios evaluated here entail different assumptions about the future feasibility and commercialization of key technologies to achieve an 80 percent reduction in GHGs relative to 1990. For the Electrification scenario to be viable, significant amounts of long-term electricity storage must be available on a daily and seasonal basis to balance intermittent renewable generation. The Electrification scenario also relies significantly on the production of low carbon liquid biofuels and hydrogen fuel cell vehicles in the transportation sector, for vehicles that are otherwise difficult to electrify. For the Mixed scenario to succeed, it must be possible to produce large quantities of biogas using sustainably-sourced biomass. Furthermore, the Mixed scenario

depends on eventual adoption of P2G methanation with carbon capture from sea water or air capture to produce SNG. All of the technologies that are applied in these scenarios are technically feasible; the science exists today. The challenge is commercializing and scaling these technologies to provide a significant energy service to California before 2050. In Table 4 below, the emerging technologies applied in the low-carbon scenarios are ranked based on their “risk” to the scenario’s success. Risk is determined by ranking the amount of energy that passes through each technology in 2050 for a given scenario (higher energy use implies higher reliance on the technology), combined with a measure of the technology’s current commercialization stage (lower availability implies higher risk).

Table 4. Ranking of emerging technology’s criticality to the Electrification and Mixed scenarios

Emerging Technologies	Overall Ranking of Technology Criticality by 2050 (maximum = 9 for most critical, minimum = 0 for least critical)	
	Electrification	Mixed
Availability of sustainably-sourced biomass	6	9
Power-to-gas methanation using carbon capture from seawater or air	0	6
Battery storage for load balancing	9	0
Carbon capture and storage	3	3
Cellulosic ethanol	6	0
Hydrogen production	4	4
Use of hydrogen in the distribution pipeline	0	4
Gasification to produce biogas	1	3
Fuel cells in transportation (HDVs)	6	3
Electrification of industrial end uses	2	0

2.2 Common strategies and assumptions across all low-carbon scenarios

Both of the low-carbon scenarios described above include a number of other carbon reduction efforts that must be implemented to achieve the state’s long-

term GHG reduction goal. These other assumptions do not vary between scenarios, and include low-carbon measures such as:

- + Significant levels of energy efficiency in all sectors, including transportation efficiency, industrial and building efficiency;
- + Significant reductions in non-CO₂ and non-energy GHG emissions, such as methane emissions and other high-global warming potential gases such as refrigerant gases;
- + Improvements in “smart growth” planning as per Senate Bill 375,¹¹ leading to reductions in vehicle miles traveled (VMT) and increased urban density leading to lower building square footage needs per person;
- + All scenarios include the use of sustainably-sourced biomass to produce decarbonized energy. The scenarios differ in how the biomass is used, to produce electricity, liquid or gas fuels.
- + All scenarios include an increase in electrification relative to today; the scenarios differ in how much additional electrification is assumed relative to other sources of low-carbon energy;
- + Flexible loads for renewable resource balancing, including limited use of controlled charging of electric vehicles and a limited share of certain residential and commercial electric thermal end uses.¹² Hydrogen and P2G production are assumed to provide fully dispatchable, perfectly flexible load-following services, helping to integrate variable renewable generation in the low-carbon scenarios.

¹¹ The Sustainable Communities and Climate Protection Act of 2008

¹² Up to 40 percent of electric vehicle charging load is assumed to be flexible within a 24-hour period to provide load-resource balancing services. Electric vehicles are not assumed to provide energy back to the electric grid, in a “vehicle-to-grid” configuration.

- + Imports of power over existing transmission lines are limited to a historical average and are assumed to maintain the same emissions intensity throughout the study period. New, dedicated transmission lines for out-of-state renewable resources are also tracked. Exports of electricity from California of up to 1500 MW are allowed.

2.3 Reference case

In addition to the low-carbon scenarios evaluated here, a Reference case is developed as a comparison point. The Reference case assumes a continuation of current policies and trends through the 2050 timeframe with no incremental effort beyond 2014 policies to reduce GHG emissions. This scenario is not constrained to achieve specific GHG reduction goals. As a result, this scenario misses the state's GHG reduction targets in 2050 by a wide margin, with 2050 emissions 9% above 1990 levels. In the Reference case current natural gas end uses, such as space heating and hot water heating, continue to be supplied with natural gas through 2050. With no future efforts, California achieves a 33% RPS by 2020 and maintains this share of renewable energy going forward. The transportation sector continues to be dominated by the use of fossil-fueled vehicles in the Reference case.

3 Analysis Approach

3.1 PATHWAYS model overview

This analysis employs a physical infrastructure model of California's energy economy through 2050. The model, known as PATHWAYS (v2.1), was developed by E3 to assess the GHG impacts of California's energy demand and supply choices over time. The model tracks energy service demand (i.e. VMT) to develop a projection of energy demand and the physical infrastructure stock utilized to provide that service (i.e. types and efficiency of different vehicles). End uses in the building sector, vehicles in the transportation sector, and power plants in the electricity sector are tracked by age and vintage, such that new technologies are adopted as older technologies and are replaced in a stock roll-over representation of market adoption rates.

Technology lifetimes, efficiency assumptions and cost data are generally drawn from the U.S. DOE National Energy Modeling System (NEMS), used to support development of the Annual Energy Outlook 2013. Assumptions about new technology adoption are highly uncertain, and are defined by E3 for each scenario. New technology adoption rate assumptions are selected to ensure that the low-carbon scenarios meet the state's 2050 GHG reduction goal.

The model can contextualize the impacts of different individual energy technology choices on energy supply systems (electricity grid, gas pipeline) and

energy demand sectors (residential, commercial, industrial) as well as more broadly examine disparate strategies designed to achieve deep de-carbonization targets. Below, Figure 1 details the basic modeling framework utilized in PATHWAYS to project results for energy demand, statewide GHG emissions, and costs for each scenario.

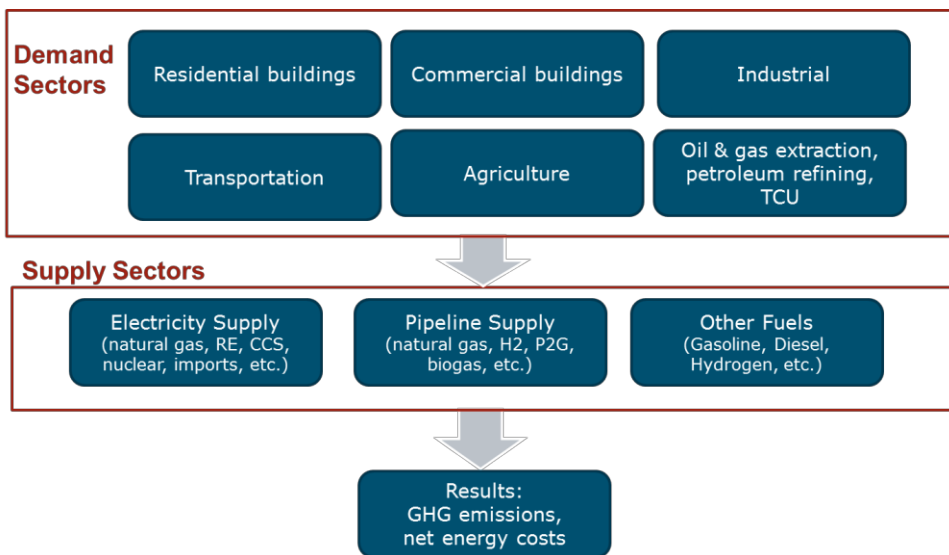


Figure 1. Basic PATHWAYS modeling framework

- + **Energy Demand:** projection of energy demand for ten final energy types. Projected either through stock roll-over or regression approach.
- + **Energy Supply:** informed by energy demand projections. Final energy supply can be provided by either conventional primary energy types (oil; natural gas; coal) or by decarbonized sources and processes (renewable electricity generation; biomass conversion processes; CCS). The energy supply module includes projections of costs and GHG emissions of all energy types.

- + **Summary Outputs:** calculation of total GHG emissions and costs (end-use stocks as well as energy costs). These summary outputs are used to compare economic and environmental impacts of scenarios.

PATHWAYS V2.1 projects energy demand in eight sectors, and eighty sub-sectors, as shown below in Table 5.

Table 5. PATHWAYS Energy Demand Sectors and Subsectors

Sector	Subsector
Residential	Water Heating, Space Heating, Central AC, Room AC, Lighting, Clothes Washing, Dish Washing, Freezers, Refrigeration, Misc: Electricity Only, Clothes Drying, Cooking, Pool Heating, Misc: Gas Only
Commercial	Water Heating, Space Heating, Space Cooling, Lighting, Cooking, Refrigeration, Office Equipment, Ventilation
Transportation	Light Duty Vehicles (LDVs), Medium Duty Trucking, Heavy Duty Trucking, Buses, Passenger Rail, Freight Rail, Commercial Passenger Aviation, Commercial Freight Aviation, General Aviation, Ocean Going Vessels, Harborcraft
Industrial	Mining, Construction, Food & Beverage, Food Processing, Textile Mills, Textile Product Mills, Apparel & Leather, Logging & Wood, Paper, Pulp & Paperboard Mills, Printing, Petroleum and Coal, Chemical Manufacturing, Plastics and Rubber, Nonmetallic Mineral, Glass, Cement, Primary Metal, Fabricated Metal, Machinery, Computer and Electronic, Semiconductor, Electrical Equipment & Appliance, Transportation Equipment, Furniture, Miscellaneous, Publishing
Agricultural	Sector-Level Only
Utilities (TCU)	Domestic Water Pumping, Streetlight, Electric and Gas Services Steam Supply, Local Transportation, National Security and International Affairs, Pipeline, Post Office, Radio and Television, Sanitary Service, Telephone, Water Transportation, Trucking and Warehousing, Transportation Service, Air Transportation
Petroleum Refining	Sector-Level Only
Oil & Gas Extraction	Sector-Level Only

For those sectors that can be represented at the stock level – residential, commercial, and transportation – we compute stock roll-over by individual subsector (i.e. air conditioners, LDVs, etc.). For all other sectors, a forecast of energy demand out to 2050 is developed based on historical trends using regression analysis. These two approaches are utilized to project eleven distinct final energy types (Table 6).

Table 6. PATHWAYS Final Energy Types and Sources of Energy

Final Energy Type	
Electricity <ul style="list-style-type: none"> many types of renewables, CCS, nuclear, fossil, large hydro. 	Gasoline <ul style="list-style-type: none"> ethanol & fossil gasoline
Pipeline Gas <ul style="list-style-type: none"> natural gas, hydrogen, biogas, SNG 	Liquefied petroleum gas (LPG)
Compressed Pipeline Gas <ul style="list-style-type: none"> natural gas, hydrogen, biogas, SNG 	Refinery and Process Gas
Liquefied Pipeline Gas <ul style="list-style-type: none"> natural gas, hydrogen, biogas, SNG 	Petroleum coke
Diesel <ul style="list-style-type: none"> biodiesel & fossil diesel 	Waste Heat
Kerosene-Jet Fuel	

These final energy types can be supplied by a variety of different resources. For example, pipeline gas can be supplied with combinations of natural gas, biogas, hydrogen, and SNG (produced through P2G processes). Electricity can be supplied by hydroelectric, nuclear, coal, natural gas combined cycles and combustion turbines, and a variety of renewable resources including utility-scale & distributed solar PV, wind, geothermal, biomass, etc. These supply composition choices affect the cost and emissions profile of each final energy type. Further methodology description can be found in the Technical Appendix.

3.2 Modeled energy delivery pathways

A decarbonized technology pathway can be thought of as consisting of three stages: (1) the provision of the primary energy itself, (2) the conversion of primary energy into the energy carrier, and (3) the delivery of an energy carrier

for final end use. In practice, there can be many variations on this theme, including multiple conversion process steps and the use of CCS. The primary decarbonized energy sources are biomass, renewable and nuclear generated electricity, and natural gas with CCS. The main options for energy carriers in a decarbonized system are electricity, liquid biofuels such as ethanol and biodiesel, and decarbonized gases including biogas, SNG, and hydrogen and decarbonized electricity.

Figure 2 illustrates the main decarbonized technology pathways for delivering energy to end uses represented in the model. In the remainder of this section, we sketch briefly the main low-carbon pathways considered in this study and how they are modeled.

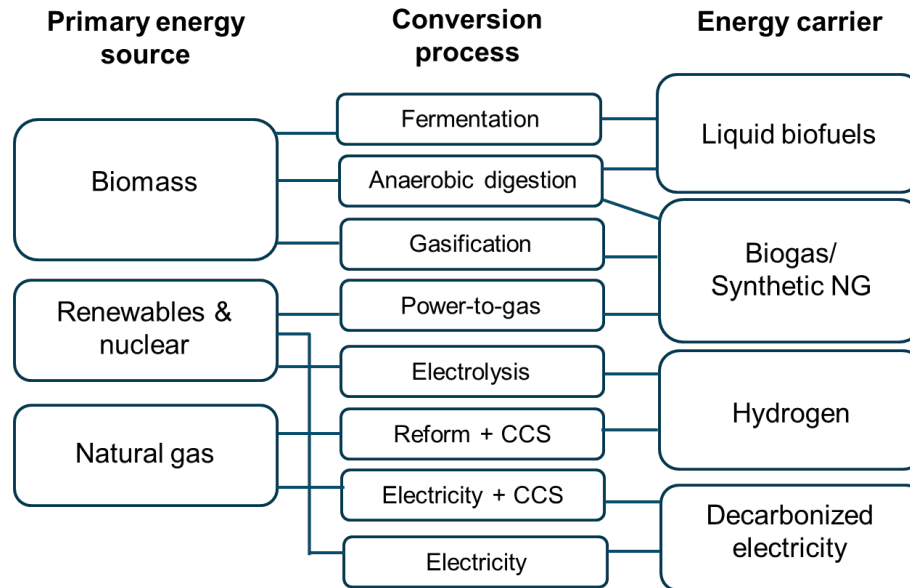


Figure 2. Major low-carbon pathways for delivered energy, from primary energy to conversion process to energy carriers

The technical opportunity for the gas distribution industry lies in providing an alternative to widespread electrification of end uses as an approach to deep decarbonization. The decarbonized gas technologies included in the Mixed scenario have been well-understood and some have been used in commercial applications for decades. For example, synthesized town gas, not natural gas, was the prevalent energy carrier for the first gas distribution companies over a century ago.

However, improvements in cost and efficiency will be required for decarbonized pipeline gas supplies to outcompete other forms of low-carbon delivered energy, such as electricity and liquid biofuels, and other issues require careful consideration and research, such as long-term biomass resource potential and carbon benefits. It is difficult at present to predict which pathways are the most

likely to take root and become the dominant forms of energy delivery in a deeply decarbonized world.

3.2.1 BIOMASS RESOURCE ASSUMPTIONS

The principal data source for biofuel feedstocks in our model is the DOE's *Billion Ton Study Update: Biomass Supply for a Bioenergy and Bioproducts Industry* led by Oak Ridge National Laboratory, the most comprehensive available study of long-term biomass potential in the U.S.¹³ This study, sometimes referred to as the BT2, updates the cost and potential estimates in the landmark 2005 *Billion Ton Study*, assessing dozens of potential biomass feedstocks in the U.S. out to the year 2030 at the county level (Figure 3).¹⁴

The estimated future supply of California produced biomass stocks is relatively small compared to the resource potential in the Eastern portion of the U.S., as shown in Figure 3. In this study, we have assumed that California can import up to its population-weighted proportional share of the U.S.-wide biomass feedstock resource potential, or 142 million tons per year by 2030. In the case of the Mixed scenario, where nearly all biomass is assumed to be gasified into biogas, this could be accomplished through production of biogas near the source of the feedstock, which would then be distributed through the national gas pipeline network. California would not necessarily need to physically import the biomass feedstock into the state in order to utilize, or purchase credits for, the biogas fuel. Under the emissions accounting

¹³ U.S. Department of Energy, "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," August 2011.

¹⁴ U.S. Department of Energy, "Biomass as a Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply," April 2005.

framework employed in this study, California would take credit for assumed emissions reductions associated with these biofuels, regardless of where the fuel is actually produced. This assumption may not reflect California’s long-term emissions accounting strategy. Furthermore, there remains significant uncertainty around the long-term GHG emissions impacts of land-use change associated with biofuels production.

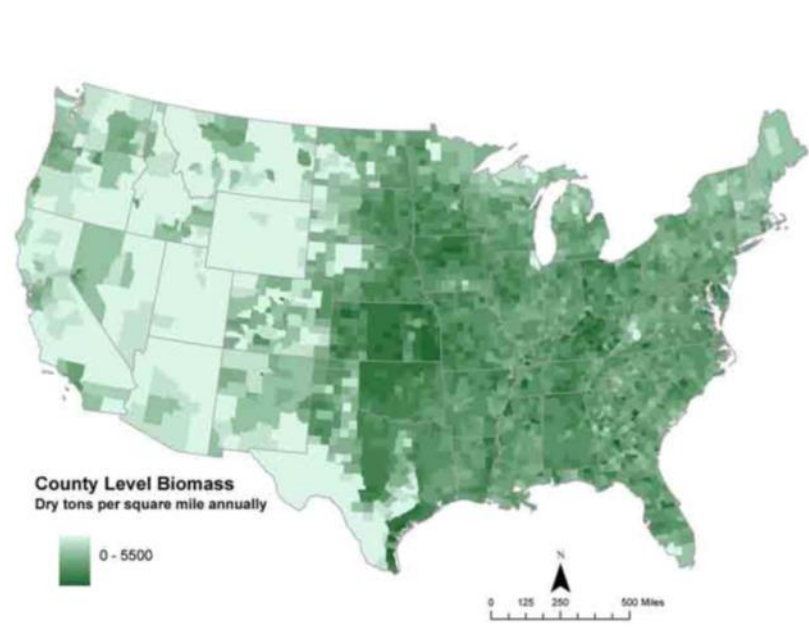


Figure 3. DOE Billions Tons Study Update Biomass Resource Potential (Source: DOE, 2011)

3.2.2 PIPELINE GAS AND LIQUID FUELS FROM BIOMASS

Biomass feedstocks ranging from purpose-grown fuel crops to a variety of agricultural, forestry, and municipal waste products can be converted into decarbonized gas. The main conversion method that is assumed in the Mixed

scenario is gasification, including thermal and biochemical variants, which break down complex biomass molecules through a series of steps into a stream of SNG, consisting primarily of hydrogen and carbon monoxide. In the modeled pathway, the SNG is cleaned, shifted, and methanated to produce a pipeline-ready biogas with a high methane content. The other main method for biomass conversion represented in the model is anaerobic digestion. In anaerobic digestion bacterial digestion of biomass in a low-oxygen environment produces a methane-rich biogas which, after the removal of impurities, can be injected into the pipeline. In addition to gas fuels, biomass can be turned into liquid fuels directly through fermentation and distillation, as in the case of ethanol, or through the transesterification of fats such as waste cooking oil to produce biodiesel. Biogas from gasification can also be turned into liquid fuels, for example through the Fischer-Tropsch process.

3.2.3 PIPELINE GAS AND LIQUID FUELS FROM ELECTRICITY AND NATURAL GAS

Renewable energy, fossil generation with CCS and nuclear energy produce low-carbon electricity that can either directly power end uses or be used to produce pipeline gas or liquefied gases for transportation fuels. There are two P2G pathways in the model. One pathway uses electricity for electrolysis to split water and produce hydrogen, which can be injected into the pipeline for distribution up to a certain mixing ratio, or can be compressed or liquefied for use in hydrogen fuel cell vehicles. The other pathway modeled also begins with electrolysis, followed by methanation to produce SNG, which is injected into the pipeline. The SNG pathway requires a source of CO₂, which can come from carbon capture from sea water, air capture or biomass, or under some

circumstances from CCS (e.g. situations in which the use of CCS implies no additional net carbon emissions, such as biomass power generation with CCS). The CO₂ and hydrogen are combined into methane through the Sabatier or related process.

Continued use of natural gas under a stringent carbon constraint requires that carbon be captured and stored. The low-carbon scenarios evaluated in this study assume a limited amount of natural gas with CCS is used for electricity generation in both of the low-carbon scenarios. There are two main types of CCS: (1) post-combustion capture of CO₂, and (2) pre-combustion capture of CO₂. In one pathway, CCS occurs after the natural gas has been combusted for electricity generation in a combined cycle gas turbine (CCGT), and the delivered energy remains in the form of decarbonized electricity. In the other pathway, natural gas is subjected to a reformation process to produce hydrogen and CO₂ streams. The CO₂ is captured and sequestered, and the hydrogen can be injected into the pipeline, liquefied for use in fuel cells, or combusted in a combustion turbine.

3.3 Modeling Technology and Energy Costs

3.3.1 GENERAL DESCRIPTION OF APPROACH

For long-term energy pathways scenarios, future costs are particularly uncertain. As a result, the PATHWAYS model does not use technology or energy cost estimates to drive energy demand or resource selection choices. Rather, total capital costs and variable costs of technologies are treated as input variables, which are summed up for each scenario as an indicator of the

scenario's total cost. The model does not include a least-cost optimization, nor does the model include price elasticity effects or feedback to macroeconomic outcomes. As such, the model should be understood as primarily a technology and infrastructure-driven model of energy use in California.

The model includes more resolution on cost for two key types of energy delivery: pipeline gas and electricity. These approaches are described in more detail below.

3.3.2 PIPELINE GAS DELIVERY COSTS

We model the California system of delivering pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates, which can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories.

Core service traditionally provides reliable bundled services of transportation and natural gas compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September 2013 the average U.S. delivered price of gas to an industrial customer was \$4.39/thousand cubic feet compared to

\$15.65/thousand cubic feet for residential customers.¹⁵ This difference is driven primarily by the difference in delivery costs and delivery charges for different customer classes at different pipeline pressures.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California investor owned utility (IOU). This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs of delivery services (to account for increasing prices of materials, labor, engineering, etc.), an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments.¹⁶

3.3.3 ELECTRICITY SECTOR AVERAGE RATES AND REVENUE REQUIREMENT

Electricity sector costs are built-up from estimates of the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. These costs are used to calculate an annual revenue requirement of total annualized electric utility investment in each year. These costs are then divided by total retail sales in order to estimate a statewide average electricity retail rates. These average electricity rates are applied to the annual electricity demand by subsector to allocate electricity costs between subsectors.

¹⁵ United States Energy Information Administration, 2013.

¹⁶ We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline approximately 1.7% per year without resulting in escalating delivery charges for remaining customers.

Transmission and distribution costs are also estimated in the model. Transmission costs are broken into three components: renewable procurement-driven transmission costs, sustaining transmission costs, and reliability upgrade costs. Distribution costs are broken into distributed renewable-driven costs and non-renewable costs. The revenue requirement also includes other electric utility costs which are escalated over time using simple growth assumptions, ("other" costs include nuclear decommissioning costs, energy efficiency program costs and customer incentives, and overhead and administration costs). These costs are approximated by calibrating to historical data. The methodology for calculating fixed generation costs in each year is described below, more details are provided in the Technical Appendix.

3.3.3.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and assumed capital cost and fixed operations and maintenance (O&M) cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the capital cost (which can vary by vintage year) times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. This methodology is also used to cost energy storage infrastructure and combined heat and power (CHP) infrastructure. Input cost assumptions for generation technologies are summarized below.¹⁷

¹⁷ Cost assumptions were informed by E3, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.
<http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf>

In general, cost assumptions for generation technologies, as for all technology assumptions in the model, are designed to be conservative, and avoid making uncertain predictions about how the relative costs of different technologies may change over the analysis period. Generation capital cost changes are driven by assumptions about technology learning. As a result, the cost of newer, less commercialized technologies are assumed to fall in real terms, while the costs of technologies that are widely commercialized are assumed to remain constant or to increase.

Table 7. Generation capital cost assumptions

Technology	Capital Cost from present - 2026 (2012\$/kW)	Assumed change in real capital cost by 2050 % change	Capital Cost from 2027 - 2050 (2012\$/kW)
Nuclear	9,406	0%	9,406
CHP	1,809	0%	1,809
Coal	4,209	0%	4,209
Combined Cycle Gas (CCGT)	1,243	16%	1,441
CCGT with CCS	3,860	-3%	3,750
Steam Turbine	1,245	0%	1,245
Combustion Turbine	996	44%	1,431
Conventional Hydro	3,709	0%	3,709
Geothermal	6,726	0%	6,726
Biomass	5,219	0%	5,219
Biogas	3,189	0%	3,189
Small Hydro	4,448	0%	4,448
Wind	2,236	-9%	2,045
Centralized PV	3,210	-31%	2,230
Distributed PV	5,912	-30%	4,110
CSP	5,811	-25%	4,358
CSP with Storage	7,100	-30%	5,000

3.3.4 COST ASSUMPTIONS FOR ENERGY STORAGE, DECARBONIZED GAS AND BIOMASS DERIVED FUELS

Cost and financing assumptions for energy storage technologies are summarized below. For this analysis, these costs are assumed to remain fixed in real terms over the analysis period.

Table 8. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012\$/kW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2,230	30	30
Batteries	4,300	15	15
Flow Batteries	4,300	15	15

The modeling assumptions for hydrogen production and SNG production are described in detail in Technical Appendix Sections 2.2.3 and 2.2.4, respectively. Below, Table 9 shows final product cost ranges, levelized capital costs, and conversion efficiencies for hydrogen and SNG pathways in the model.

Table 9. Renewable electricity-based pipeline gas final product cost, levelized capital cost, and conversion efficiencies in model

Product	Process	Levelized Capital Cost (\$/kg-year for hydrogen; \$/mmBTU-year for SNG)	Conversion Efficiency	Product Cost Range (\$/GJ)
SNG	Electrolysis plus methanation	\$7.60-\$18.50	52%-63%	\$30-\$138
Hydrogen	Electrolysis	\$0.65-\$1.53	65%-77%	\$24-\$112

The modeling assumptions for biofuels are described in detail in Technical Appendix Section 3. Below, Table 10 shows final product cost ranges, feedstock

and conversion cost ranges, and conversion efficiencies for all biomass conversion pathways in the model.

Table 10. Biomass final product cost, feedstock and conversion costs, and conversion efficiencies in model

Product	Process	Feedstock Cost Range (\$/ton)	Conversion Cost (\$/ton)	Conversion Efficiency (GJ/ton)	Product Cost Range (\$/GJ)
Biogas Electricity	Anaerobic digestion	\$40-\$80	\$96	6.5	\$21-\$27
Pipeline Biogas	Gasification	\$40-\$80	\$155	9.5	\$20-\$25
Ethanol	Fermentation	\$40-\$80	\$111	6.7	\$23-\$29
Diesel	Trans-Esterification	\$1000	\$160	36.4	\$32

4 Results

4.1 Summary of results

The two low-carbon scenarios evaluated in this study present unique technology pathways to achieve California's 2050 GHG reduction goals. Each scenario represents a different technically feasible, plausible strategy to decarbonize the state's energy system, resulting in different levels of energy consumption and different mixes of fuels providing energy services. This section presents energy demand by scenario and fuel type in 2050 for the Reference case and the two low-carbon scenarios. Energy system cost projections for each scenario are provided. The cost trajectories are highly uncertain and cannot be interpreted as definitive at this point in time. Each of the low-carbon scenarios shows a similar statewide GHG reduction trajectory.

4.2 Final energy demand

Figure 4 shows final energy demand by fuel type for each scenario in the year 2050. Of note, both the low-carbon scenarios have significantly lower total energy demand than the Reference case due to the impact of energy efficiency and conservation in the low-carbon scenarios.

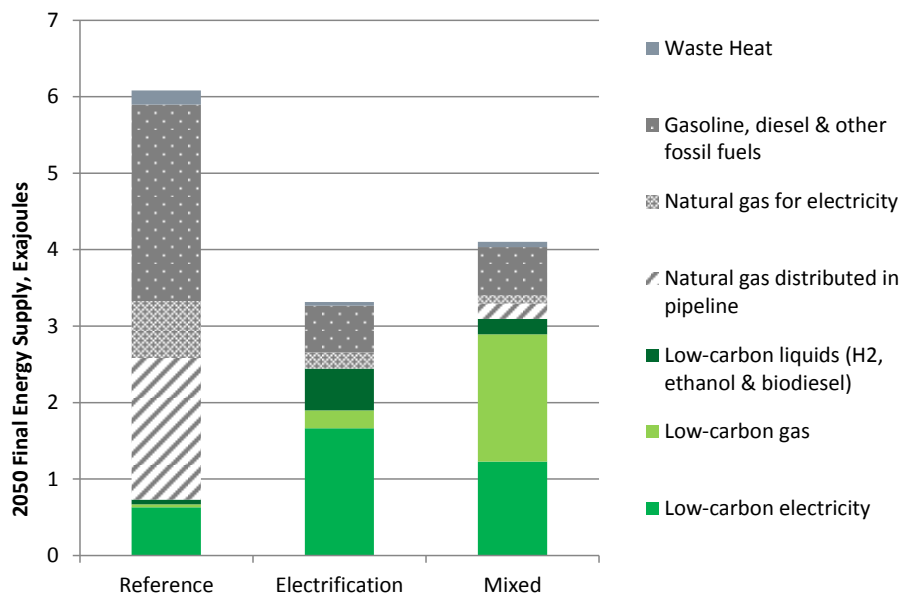


Figure 4. 2050 California economy-wide final energy demand by scenario and fuel type

Final energy consumption in 2050 is lower in the Electrification scenario than the Mixed Scenario due to the higher conversion efficiencies of electric batteries and motors compared to combustion engines and fuel cell vehicles.¹⁸

Low-carbon electricity is also used as an upstream energy source to produce decarbonized gas and liquid hydrogen, so it plays a larger role in meeting the state’s GHG reduction goals in the Mixed scenario than indicated by final energy demand alone. To gain a more complete picture of energy supply by fuel type, the next sections discuss the composition of the pipeline gas by scenario, the sources of electricity in each scenario, and the composition of the

¹⁸ Note that upstream efficiency losses associated with energy production: i.e. P2G methanation, hydrogen production and CCS, do not appear in the final energy supply numbers.

transportation vehicle fleet energy consumption. These results are not meant to be an exhaustive description of each assumption in each sector of the economy, but rather are selected to provide some insights into the biggest differences in energy use between the two low-carbon scenarios and the Reference case.

4.2.1 PIPELINE GAS FINAL ENERGY DEMAND

There are important differences between the two low-carbon scenarios. Pipeline infrastructure continues to be used extensively in the Mixed scenario, with decarbonized gas substituting for the natural gas that would otherwise be used in the pipeline. In the Electrification scenario, pipeline infrastructure is nearly unutilized by 2050. This corresponds to much more widespread electrification of industrial processes, vehicles, space heating, water heating, and cooking. The limited demand for pipeline gas in this scenario is assumed to be met with biogas (Figure 5).

The Mixed scenario includes a higher quantity of biogas, based on the assumption that all of the available sustainably sourced biomass are used to produce biogas. The remaining demand for decarbonized pipeline gas in this scenario is met with a mix of two technologies: 1) SNG produced using P2G methanation with air capture of CO₂¹⁹ and 2) hydrogen produced using electrolysis with renewable electricity.

¹⁹ Methanation using CO₂ capture from seawater is an alternative, potentially more efficient method to creating produced gases that have a net-carbon neutral climate impact.

In the Mixed Scenario, hydrogen use in the gas pipeline is limited by estimates of technical constraints. By 2050, the share of hydrogen gas in the pipeline is assumed to be limited to 20 percent of pipeline volume for reasons of safety as well as compatibility with end-use equipment.²⁰

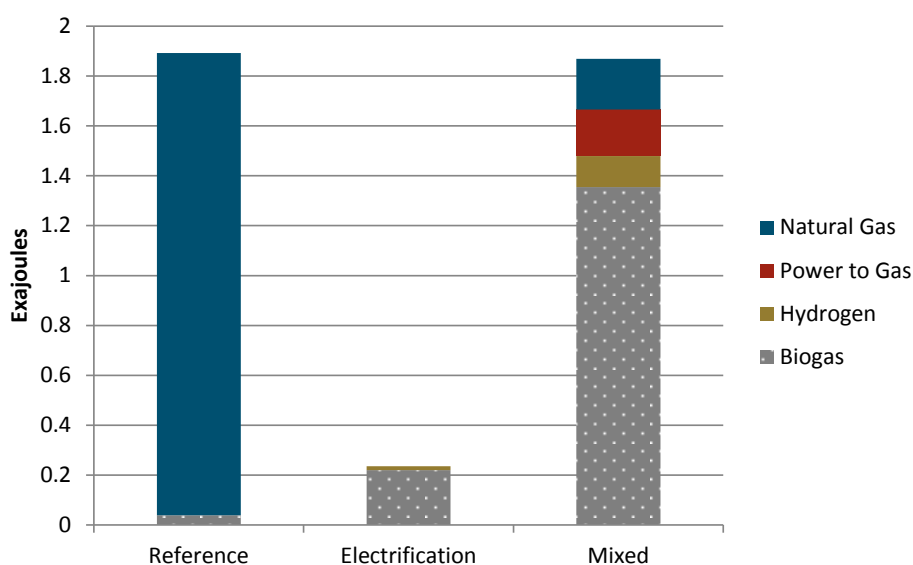


Figure 5. California pipeline gas final energy demand by fuel type by scenario, 2050

4.2.2 ELECTRICITY DEMAND

The 2050 electricity demand in each scenario tells a different part of the energy supply story. In the low-carbon scenarios, 2050 electricity demand is significantly higher in the Reference case due to the impact of electrification, particularly electric LDVs, and the electricity needs associated with P2G and

²⁰ Note that this limit is only a rough estimate of technical feasibility limits and the actual limit may be lower; additional research is needed to determine an appropriate limit for hydrogen gas in the pipeline.

hydrogen production. The expanding role of the electricity sector in achieving a low-carbon future is evident in each of these scenarios. Figure 6 shows the generation mix by fuel type utilized in each of the scenarios in 2050.

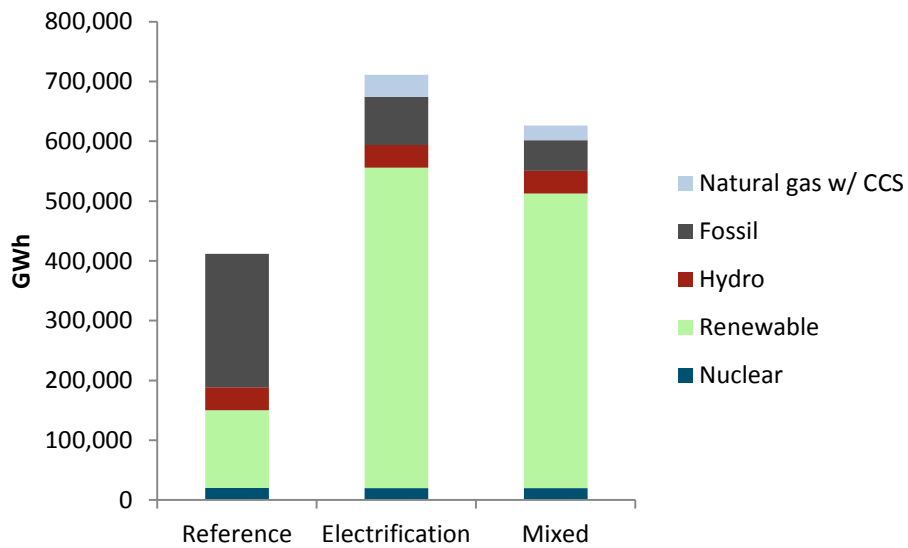


Figure 6. 2050 electricity sector energy demand by scenario and fuel type, GWh

4.2.2.1 Load resource balancing

Both of the low-carbon scenarios reflect a significant increase in intermittent wind and solar PV renewable generation by 2050 (Table 11). This results in new challenges that the grid faces to achieve load-resource balance.

Table 11. Share of 2050 California electricity generation provided by wind and solar PV

	Reference	Low-Carbon Scenarios
Intermittent renewables share of total electricity generation in 2050 (wind and solar PV)	30%	60 -70%

In the model, electricity supply and demand must be equal in each hour of each year. This load-resource balance is achieved using different strategies in each scenario, which contributes to the differences in technology costs and risks. As Table 12 indicates, the Electrification scenario relies heavily on the use of electric energy storage, in the form of flow batteries and pumped hydroelectric storage resources, while the Mixed scenario relies more heavily on P2G production as a load-following resource. Natural gas with CCS is assumed to be a load-following resource in both scenarios. Furthermore, both scenarios assume electric vehicles can provide limited load-resource balancing services through flexible charging of EVs over a 24-hour period, and that hydrogen production for fuel cell vehicles can be operated as a fully-dispatchable, flexible load.

Table 12. 2050 Load Resource Balancing Assumptions by Scenario

Load-resource balancing tool	Electrification	Mixed
Electric energy storage capacity	20 GW 75% 6-hour flow batteries, 25% 12-hour pumped hydro energy storage	5 GW 100% 12-hour pumped hydro energy storage
P2G capacity	None	40 GW P2G production cycles on during the daylight hours to utilize solar generation and cycles off at night, significant variation in production by season for load balancing
Electric vehicles & other flexible loads	40% of electric vehicle loads are considered “flexible” in both scenarios and can be shifted within a 24-hour period. Vehicle batteries are not assumed to provide power back onto the grid. Certain thermal electric commercial and residential end uses are also assumed to provide limited amounts of flexible loads to the grid. In both scenarios, hydrogen production is assumed to be a fully dispatchable, flexible load.	

4.2.3 ON-ROAD VEHICLE ENERGY CONSUMPTION BY FUEL TYPE

The decarbonization strategy pursued in the transportation sector differs by scenario, as illustrated in Figure 7 (LDV vehicle energy use) and Figure 8 (HDV energy use). Both of the low-carbon scenarios assume a significant reduction in VMT and vehicle efficiency improvements in the LDV fleet compared to the Reference scenario. This leads to a significant reduction in total energy demand by LDVs by 2050 in these scenarios. Among the HDV vehicle fleet, VMT reductions and vehicle efficiency improvements are assumed to be more difficult to achieve than in the LDV fleet. Furthermore, the Mixed scenario relies on a high proportion of fuel cell vehicles using hydrogen or liquefied pipeline gas, which have less efficient energy conversion processes than conventional

diesel engines, leading to higher energy demand. As a result, the HDV sector does not show a significant reduction in energy consumption by 2050 relative to the Reference case, although total carbon emissions are significantly lower.

Electricity is the largest source of fuel for the transportation sector among LDVs in both the Electrification and the Mixed scenarios. The HDV fleet is harder to electrify, so the Electrification scenario assumes HDV energy demand is largely met with hydrogen fuel and fuel cells. In the Mixed scenario, the majority of HDV energy demand is assumed to be met with liquefied pipeline gas (an equivalent to decarbonized LPG), with some compressed pipeline gas (the equivalent to decarbonized compressed natural gas), electrification and hydrogen fuel cell vehicles.

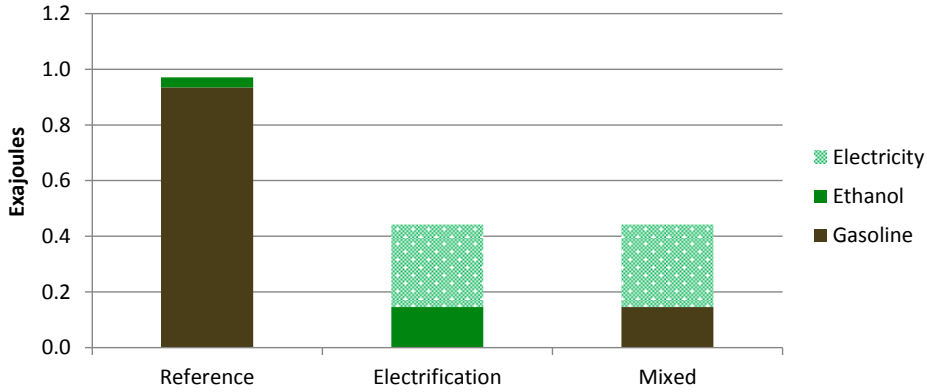


Figure 7. 2050 LDV energy share by fuel type by scenario

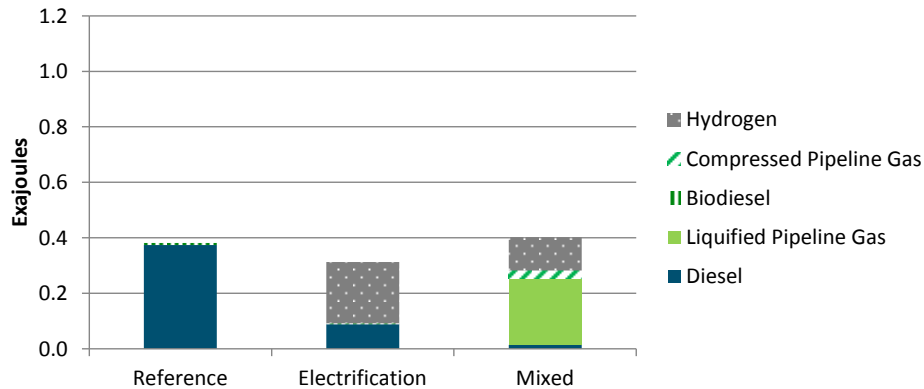


Figure 8. 2050 HDV energy share by fuel type by scenario

4.3 Greenhouse gas emissions

The Reference case shows GHG emissions that are relatively flat through 2030 before slightly increasing in the outer years through 2050. This increase occurs because population growth and increasing energy demand overwhelm the

emissions savings generated by current policies. The result is a 9 percent increase in Reference case emissions relative to 1990 levels by 2050.

The GHG emissions trajectories for the two low-carbon scenarios evaluated in this report are essentially the same. Both scenarios achieve the target of 80% reduction in GHG emissions by 2050 relative to 1990 levels, and both scenarios reflect a similar, approximately straight-line trajectory of emissions reductions between current emissions levels and 2050.

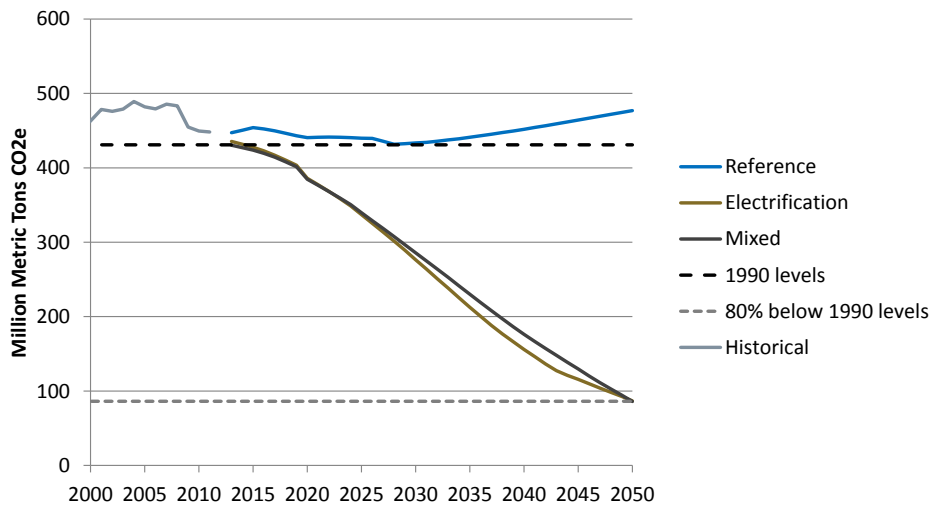


Figure 9. California GHG emissions by scenario, including historical emissions and policy targets (2000 – 2050)

4.4 Energy system cost comparison

The total energy system cost of each of the scenarios analyzed is one metric by which to evaluate different GHG scenarios. Total energy system cost is defined here as the annual statewide cost of fossil fuels and biofuels, plus the levelized cost of electricity and natural gas infrastructure, plus the cost of most energy-consuming customer products (e.g., clean vehicles in the transportation sector and energy efficiency and fuel-switching equipment in the buildings sector). The total energy system cost is calculated on a levelized basis in each analysis year, from 2015 – 2050. Further detail on cost assumptions and how costs are treated in the model is provided in the Technical Appendix.

While the Reference case is the lowest total cost scenario from an energy system perspective, it also does not succeed in meeting the state's GHG reduction goals. Of the two low-carbon scenarios, the Mixed scenario has approximately 10 percent lower cost than the Electrification scenario in 2050 using our base case assumptions. This difference is well within the range of uncertainty of projecting technology costs to 2050, and either scenario could be lower cost.

It is, however, useful to examine the differences in base case scenario costs that result from the modeling assumptions made in this analysis to identify the key drivers. Using the base case assumptions, the Mixed case results in lower total energy system costs in 2050 than the Electrification scenario for two main reasons (Figure 10). First, using the assumptions in this study, adding decarbonized gas in the Mixed case has a lower cost than adding the low-carbon electricity and end-use equipment necessary to electrify certain end-uses in the Electrification case. Therefore, the reduction of electricity-related capital costs between the Electrification and the Mixed scenario shown in Figure 10 is greater than the increase in pipeline gas capital costs and biogas fuel costs between these scenarios. Second, seasonal electricity storage needs are lower in the Mixed scenario than in the Electrification scenario. As a result, the electricity storage that is built in the Mixed scenario is utilized at a higher capacity factor than the electricity storage in the Electrification scenario. This means that the unit cost of electricity storage (\$/MWh) is higher in the Electrification scenario than in the Mixed scenario.

In order to evaluate the range of uncertainty, we define high and low cost Scenarios for the key input assumptions. These do not reflect the range of all of

the uncertainties in energy demands, population, or other key drivers embedded in the analysis, but serve to provide a boundary of possible high and low total costs given the same assumptions across the three cases. We then evaluate the total costs of each of the cases; Reference, Electrification Case, and Mixed Case with each cost scenario. Table 13, below, shows the range of the cost uncertainties in the analysis. Scenario 1 is purposefully designed to advantage the Mixed Case, and Scenario 2 is designed to advantage the Electrification Case.

Table 13 Cost sensitivity parameters

Cost Assumption	Scenario 1	Scenario 2
Renewable generation capital	+25%	-25%
Electrolysis capital equipment	-50%	+50%
SNG capital equipment	-50%	+50%
Fuel cell HDVs	+50%	-50%
Building electrification cost ²¹	+50%	-50%
Natural Gas Costs	-50%	+50%
Other Fossil Fuel Costs	+50%	-50%
Electricity storage costs	+50%	-50%
Biomass Availability ²²	+0%	-50%

The 2050 cost results shown below indicate that there are conditions under which either case is preferable from a cost standpoint. Given that, and given the

²¹ Costs of electrified water and space heating equipment

²² Biomass is replaced with addition P2G to maintain emissions levels +- 5MMT from base case.

additional uncertainties not analyzed in terms of other technology costs, energy demand drivers, etc., the preference for pursuing one mitigation case over the other should come down to other factors than narrow cost advantages displayed over these long term forecasts.

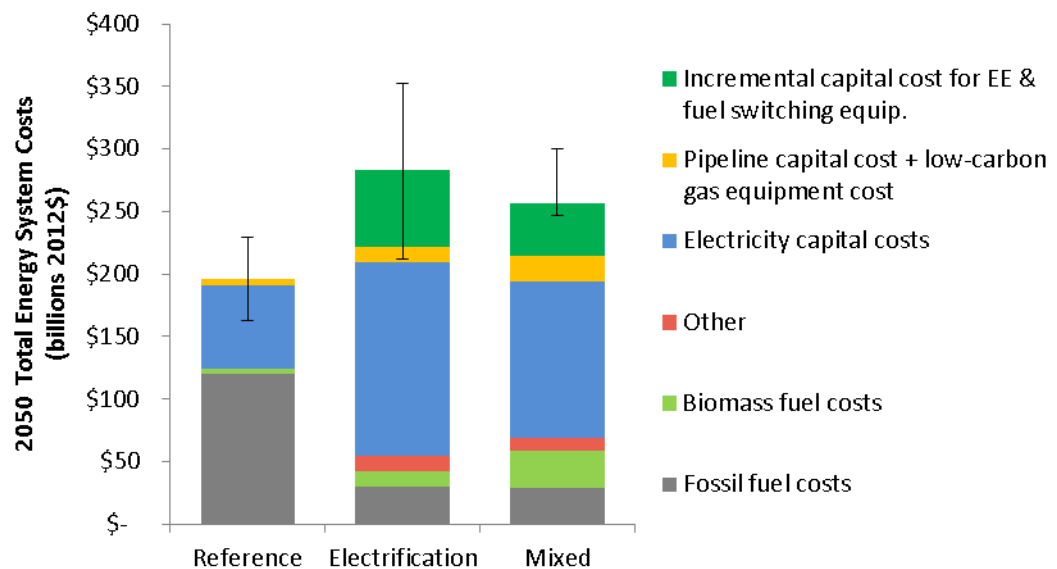


Figure 10. 2050 total energy system cost by scenario (levelized cost of fuel and levelized capital cost of energy infrastructure)

Figure 11, below, shows the base case total levelized energy system capital investment and fuel costs for each scenario along with the uncertainty range. Given the uncertainties associated with forecasting technology and commodity costs out to 2050, a difference in costs of approximately 10% (\$27 billion) between the two scenarios is not definitive.

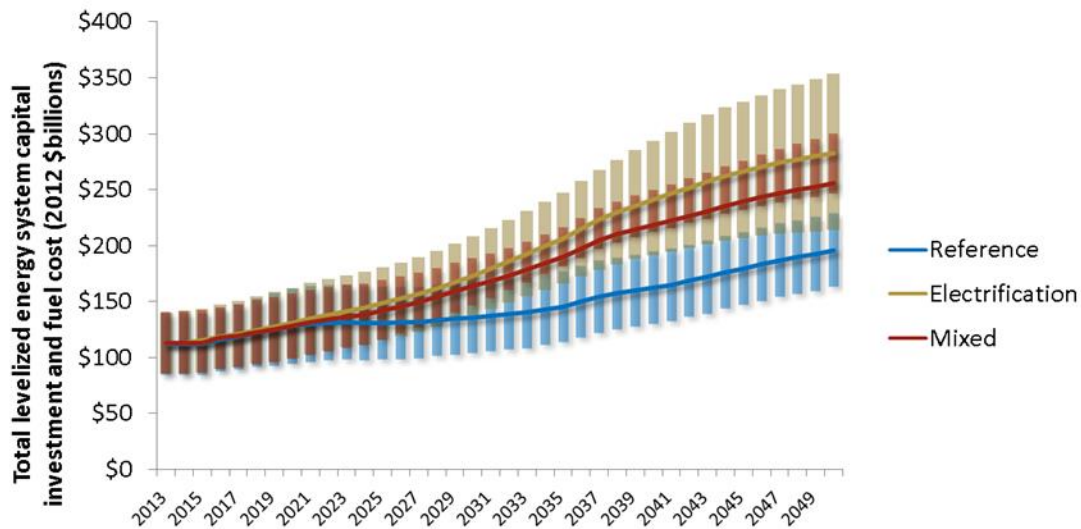


Figure 11. Total energy system cost by scenario, 2013 – 2050 (levelized cost of fuel and levelized capital cost of energy infrastructure, billions, 2012\$)

Figure 12, below, shows total electricity sector costs on an annualized basis, or equivalently, the statewide electricity sector revenue requirement, in 2050. Electricity costs are higher in the Electrification scenario both because total electricity demand is higher, and because the unit cost of electricity is higher. The cost of energy storage is highest in the Electrification scenario because more storage is needed to balance intermittent renewables, and because batteries are the primary means of storage. In the Mixed scenario, less energy storage is needed because the production of decarbonized gases (hydrogen and SNG) is dispatched to balance the grid, and because gas is a more cost-effective form of seasonal energy storage, given the assumptions here, than batteries. Again, however, cost forecasts for 2050 are highly uncertain and should be interpreted with caution.

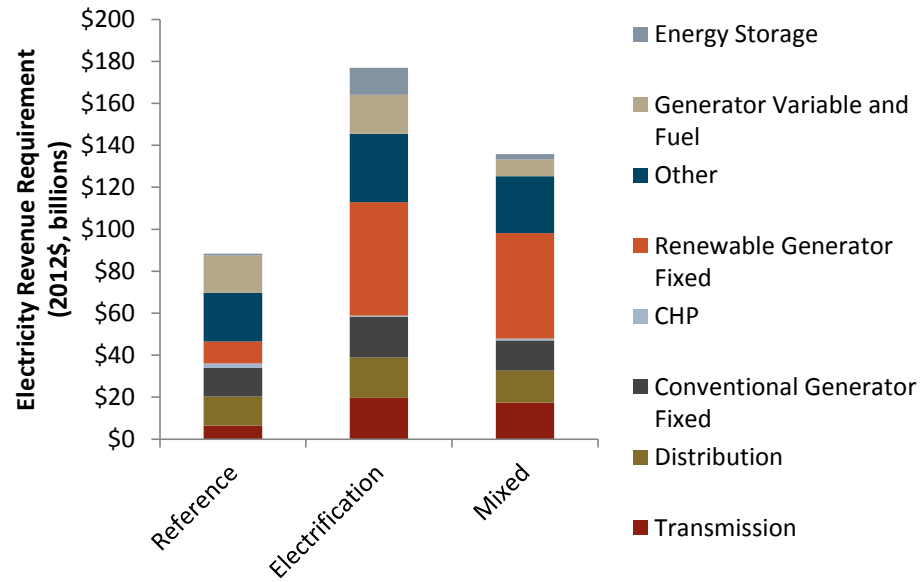


Figure 12. 2050 California total electricity sector revenue requirement by component and scenario (billions, 2012\$)

5 Discussion & Conclusions

California is committed to deeply reducing CO₂ and other GHG emissions across all sectors over the next several decades, as well as to sharply reducing ground-level ozone and particulate matter to protect public health. Both of these policies imply a dramatic transition of California's economy away from fossil fuel combustion as we know it, and indeed this transition is already underway. In some places where coal is the dominant form of energy supply, natural gas is often seen as a key transition fuel to a lower carbon system. In California, however, natural gas is the main incumbent fossil fuel in electricity generation, the building sector, and many industries, and is therefore the target of transition to a lower carbon economy rather than its vehicle; the problem of methane leakage in the natural gas production and supply chain, though not modeled in this analysis, only increases the policy pressure to hasten this transition.

It is possible for SCG and other gas distribution companies to be a contributor rather than an impediment to California's transition to a low carbon economy. This path of decarbonizing pipeline gas will require a major technological transformation in the coming years. On the demand side, the transition requires reducing demand in many existing applications and improving combustion processes to increase efficiency. On the supply side, it requires

developing decarbonized alternatives to conventional natural gas for delivering energy to end uses.

This study examined the role of gas fuels in California's energy supply from 2013 to 2050, using a bottom-up model of the California economy and its energy systems. We examined the feasibility and cost associated with two distinct technology pathways for achieving the state's 2050 GHG targets: (1) Electrification, and (2) Mixed (electricity and decarbonized gas).

To date, much of the literature on low-carbon strategies and policy strategies for achieving deep reductions in GHG emissions in California by 2050 has focused on extensive electrification. This study's results support our prior conclusions that the electricity sector must play an expanded and important role in achieving a low-carbon future in California. In both of the low-carbon scenarios, the need for low-carbon electricity increases significantly beyond the Reference case level: to power electric vehicles, electrification in buildings and as a fuel to produce decarbonized gases. We also demonstrate that, under reasonable assumptions, there are feasible technology pathways where gas continues to play an important role in California's energy supply.

The costs of technologies in the 2050 timeframe are highly uncertain, making it impossible to reach a definitive conclusion as to which of the low-carbon pathways evaluated here would be the lowest cost. However, we show that the Mixed scenario, where decarbonized gas meets existing natural gas market share in residential, commercial, and industrial end uses, and is used to power the heavy-duty vehicle fleet, could potentially be higher or lower cost depending on the technology and market transformation. A key driver of this

result is the ability to use the existing gas pipeline distribution network to store and distribute decarbonized gas, and to use the production of decarbonized gas as a means to integrate intermittent renewable energy production. Excess renewable energy in the middle of the day is absorbed by P2G production of SNG and hydrogen production in the Mixed scenario. The Electrification scenario, which does not utilize the P2G technology to produce decarbonized gas, decreases gas pipeline use out to 2050 (shown for SCG, Figure 13) and requires more relatively high-cost, long-duration batteries for energy storage.²³

²³ In Figure 13 the slight increase in natural gas used for electricity generation observed in 2020 is due to an existing coal generation contract being partially replaced with natural gas generation.

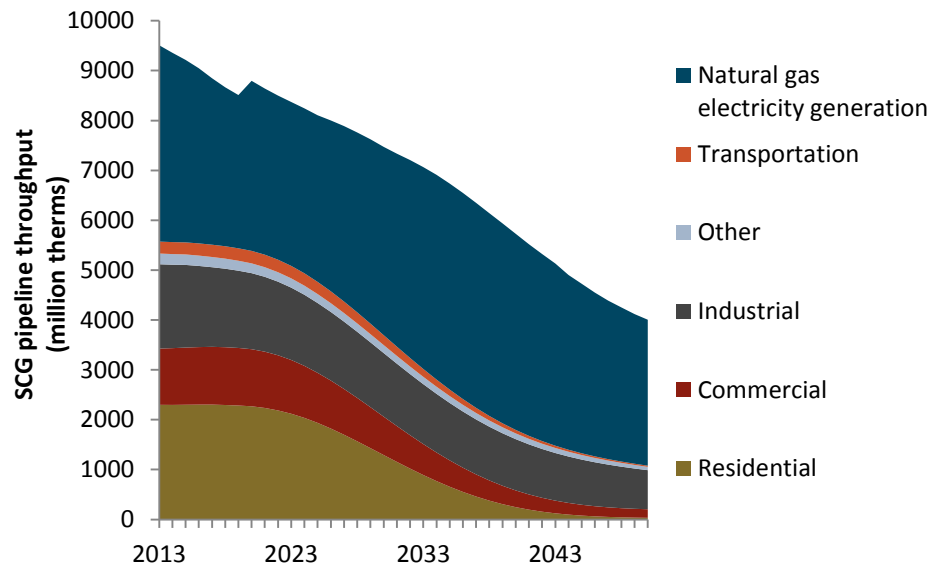


Figure 13. Electrification Scenario, SCG pipeline gas throughput (2013 – 2050)

Strategic use of decarbonized gas would additionally help to overcome four potential obstacles in California’s transition to a decarbonized energy system.

First, a number of current uses of natural gas and oil are difficult to electrify. These include certain industrial processes such as process heat, HDVs and certain end uses in the residential and commercial sectors such as cooking, where customers have historically preferred gas fuels. Using decarbonized gas for these end uses could avoid the need for economically and politically costly electrification strategies.

Second, under a high renewable generation future, long-term, seasonal load balancing may be needed in addition to daily load balancing. However, meeting these seasonal balancing needs under the Electrification scenario requires

uncertain technical progress in energy storage. Using the production of decarbonized gas to provide daily and seasonal load balancing services may be a more realistic and cost-effective strategy than flexible loads and long-duration batteries for electricity storage.

Third, using decarbonized gas takes advantage of the state's existing gas pipeline distribution system, and reduces the need for other low-carbon energy infrastructure such as transmission lines or a dedicated hydrogen pipeline network.

Fourth, and finally, the Mixed scenario, by employing a range of energy technologies, including electricity and decarbonized gas technologies, diversifies the risk that any one particular technology may not achieve commercial successes.

All of the decarbonized gas energy carriers examined in this analysis rely on century-old conversion processes; none require fusion-like innovations in science. However, these conversion processes — anaerobic digestion, gasification, electrolysis, and methanation — require improvements in efficiency and reductions in cost to be more competitive. Furthermore, existing pipelines were not designed to transport hydrogen, and innovations in pipeline materials and operations would be needed to accommodate a changing gas blend.

Sustainably-sourced biomass feedstock availability is another large source of uncertainty in both of the low-carbon strategies evaluated here. In the Mixed scenario, biogas plays a particularly important role in achieving the GHG emission

target. In the Electrification scenario, biomass is used to produce low-carbon electricity. However, biomass feedstocks are constrained by competing uses with energy supply, including food, fodder and fiber. The amount of biomass resources available as a feedstock for fuels, or for biogas production specifically, will depend on innovations in biosciences, biomass resource management, and supply chains. None of the above three challenges — conversion technology efficiency and cost, pipeline transport limits, and biomass feedstock availability — is inherently insurmountable. For decarbonized gas to begin to play an expanded role in California’s energy supply in the coming decades, however, a program of RD&D to overcome these challenges would need to begin very soon. This report identifies research priorities with near-term, medium-term and long-term payoff.

As a whole, California policy currently explicitly encourages the production of low-carbon electricity, through initiatives such as the RPS, and the production of decarbonized transportation fuels, through initiatives such as the LCFS. Biogas from landfill capture and dairy farms are encouraged, however, the state does not currently have a comprehensive policy around decarbonized gas production and distribution. This analysis has demonstrated that a technologically diverse, “mixed” strategy of electrification and decarbonized gas may be a promising route to explore on the pathway to a long-term, low-carbon future in California.