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Appendix A to Comment by Southern California Gas Company

Additional submitted attachment is included below.

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California Energy Commission

DRAFT STAFF REPORT

AB 1257 NATURAL GAS ACT REPORT: STRATEGIES TO MAXIMIZE THE BENEFITS OBTAINED FROM NATURAL GAS AS AN ENERGY SOURCE

Prepared Pursuant to Assembly Bill 1257 (Chapter 759, Statutes of 2014)

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

SEPTEMBER 2015

CEC-200-2015-XXX

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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ABSTRACT

Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013) requires the California Energy Commission, beginning November 1, 2015, and every four years thereafter, to identify strategies to maximize the benefits of natural gas as an energy source. The Energy Commission developed this report to explore the strategies and options for using natural gas, including biogas, in order to realize its environmental and societal benefits.

The report explores strategies and recommendations regarding natural gas including:

- Natural gas pipeline infrastructure, storage, and reliability
- Natural gas for electric generation
- Combined heat and power using natural gas
- Natural gas as a transportation fuel
- End-use efficiency applications using natural gas for heating and cooling, water heating, and appliances
- Natural gas and zero net energy buildings
- Other natural gas low emission resources, biogas, and biomethane
- Greenhouse gas emissions associated with the natural gas system

The amount of electricity generated using natural gas in California has increased in the past two decades. California consistently ranks as the second highest gas consuming state in the nation, further indicating that natural gas is an integral part of the state electricity and fuel portfolio. The report findings indicate that several improvements could be made to natural gas infrastructure in order to leverage the supply of existing biogas sources to satisfy market demand. In addition, research is necessary to balance state and federal greenhouse gas reduction and renewable generation policy, while providing grid stability.

Keywords: Natural gas, biomethane, transportation, fuel, generation, resource portfolio, combined heat and power, low emission, biogas, efficiency, heating, cooling, appliances, pipeline, infrastructure, reliability, zero net energy, greenhouse gas, benefits, Assembly Bill 1257

MacDonald, Rachel, Silas Bauer, Andre Freeman, Rey Gonzalez, Jason Harville, Melissa Jones, Chris Marxen, Brad Meister, Garry O'Neill, Bill Pennington, Charles Smith, David Vidaver. 2015. *Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Source*. California Energy Commission. CEC-200-2015-XXX

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EXECUTIVE SUMMARY

The California Energy Commission developed this report to explore the strategies and options for using natural gas, including biogas, in order to realize its environmental and societal benefits pursuant to Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013).

Energy Commission staff has addressed natural gas issues in the following areas:

- Natural gas pipeline infrastructure, storage, and reliability
- Natural gas for electric generation
- Combined heat and power using natural gas
- Natural gas as a transportation fuel
- End-use efficiency applications using natural gas for heating and cooling, water heating, and appliances
- Natural gas and zero net energy buildings
- Other natural gas low emission resources, biogas, and biomethane
- Greenhouse gas emissions associated with the natural gas system

In developing the report, the Energy Commission held public workshops seeking input from experts, industry stakeholders, the public, and various state agencies including the California Air Resources Board; California Public Utilities Commission; State Water Resources Control Board, the Department of Conservation; and the Division of Oil, Gas, and Geothermal Resources.

Natural Gas Infrastructure and Pipeline Safety

California consistently ranks as the second highest natural gas consuming state in the United States, with daily natural gas demand ranging from a little over 6 billion cubic feet per day to as high as 11 billion cubic feet per day depending on the time of year. Increased demand and the opening of new production areas in recent years have provided California with access to diverse natural gas sources. The immediate gas infrastructure challenges California faces relate to pipeline safety, infrastructure enhancements, gas-electric system coordination concerns, and renewables integration.

As a result of the pipeline explosion in San Bruno on September 9, 2010, the California Public Utilities Commission formed an Independent Review Panel of experts to gather and review facts and make recommendations to the California Public Utilities Commission. The panel developed recommendations that provided the cornerstone of a comprehensive effort launched by the California Public Utilities Commission to create a culture where safety permeates all of its regulatory activity.

California is improving its pipeline safety with research and analysis. The Energy Commission has funded research to help address natural gas safety after the San Bruno explosion. In addition, the Energy Commission awards research funds for natural gas system projects on an on-going basis. Current research is focused on developing new technologies, such as sensors and ultrasonic transducers, to monitor the integrity of gas pipelines. These projects are intended to reduce the cost and size of leak detection sensors and diagnostic tools, and improve accuracy of leak and defect detection. The Energy Commission will continue to support research that improves natural gas infrastructure and safety.

Natural Gas for Electric Generation

A number of proposed or adopted federal air and water quality regulations are expected to reduce the United States reliance on coal for generating electricity. These rules include the air toxics rule, the Clean Power Plan to reduce power plant emissions, the greenhouse gas new source performance standard, changes to water effluent rules, and others. Together, they may increase demand for natural gas-fired generation, depending on what choices utilities make when replacing electricity formerly generated by coal.

In California, roughly 40 percent of the natural gas is used to generate electricity. For the United States the amount of natural gas used for electric generation is 31 percent. As California electric utilities convert electricity generation portfolios away from carbon-intensive resources, the way natural gas is used will change. These changes will affect not only the quantity of natural gas used to generate electricity, but how and when natural gas-fired resources need to operate. These new operational profiles will require a higher degree of coordination between the gas and electric industries.

Keeping the gas system in balance could potentially become more challenging as the state further increases the portion of our electricity generated from renewable resources. In 2013, renewables in California produced approximately 21 percent of retail electricity sales. The electricity produced from renewables such as wind and solar—the largest sources of renewable electricity generation among California's Renewables Portfolio Standard-eligible technologies—vary depending on conditions each hour (or even minute to minute). Some of that variation in renewables' generation output is predictable (for example: solar only generates during daylight hours); some of it is not as predictable (for example: cloud cover reducing solar output or wind variations affecting wind generation).

Combined Heat and Power Systems and Natural Gas

Combined heat and power, also known as cogeneration, has the potential to provide many benefits and opportunities to California. Historically, the most important feature of combined heat and power has been fuel efficiency. A properly sized and operated combined heat and power facility can produce thermal, mechanical, and electrical energy using less fuel than would otherwise be used to acquire the same energy via a more traditional system of boilers and central-station grid electricity.

Despite the many advantages, the growth in combined heat and power development in California has been relatively flat in recent years. Many regulatory and economic barriers exist for a combined heat and power developer, and often these barriers result in a combination of cost and risk that is too high to justify the project. Economically, projects often face three major cost barriers including non-bypassable charges, grid interconnection, and contracting difficulties. Estimating the benefits of combined heat and power systems is currently a challenging and sometimes contentious issue.

The Energy Commission recognizes that the challenges facing combined heat and power today could be lessened by new regulatory and market frameworks. The Energy Commission should continue to develop and support new frameworks that will better value the true costs and benefits of combined heat and power generation and align utility incentives with those costs and benefits.

Natural Gas as a Transportation Fuel

Transportation accounts for nearly 40 percent of California's total energy consumption and roughly 36 percent of state greenhouse gas emissions. While petroleum accounts for more than 90 percent of California's transportation energy sources, there could be significant changes in the fuel mix by 2020 as a result of technological advances, market trends, consumer behavior, and government policies.

The range of alternatives to petroleum-based fuels is diverse, including biofuels, electricity, hydrogen, and natural gas. California has established programs and regulatory initiatives to ensure that the future transportation fuel supply reduces carbon intensity, tailpipe emissions, and adverse economic impacts, and utilizes a secure domestic fuel source when possible.

Natural gas is also playing an important role in the development of the emerging hydrogen vehicle industry. There are currently several options available for producing low-carbon intensity hydrogen fuel for transportation purposes. The majority of the existing hydrogen fueling stations currently use hydrogen made by a steam reformation process that converts natural gas or biomethane to hydrogen. This process and other technologies could allow hydrogen fueling stations and centralized fuel producers to utilize the existing natural gas infrastructure as a secure source of fuel for hydrogen production.

The Energy Commission Fuels and Transportation Division implements the Alternative and Renewable Fuel and Vehicle Technology Program that provides up to $100 million per year for projects that will transform California's fuel and vehicle types to help attain state climate change policies. To support natural gas related activities in California's transportation sector, funding is targeted at the major areas where public investment can help remove barriers to the adoption of alternative fuels. In addition, the *2014 Integrated Energy Policy Report* indicates that one key area showing improvement is transportation research. The Energy Commission Energy Research and Development Division transportation research program is focused on developing and advancing state-of-the-art electricity and natural gas-fueled transportation solutions that reduce fossil fuel consumption, greenhouse gas emissions, and air pollutants in the state.

This research program has accelerated the development of zero and near-zero emission technologies. In September 2015, Cummins Westport Innovations certified its first near-zero engine for buses, waste haulers and medium duty trucks. This engine will reduce NOx emissions by more than 90% from the current standard and will play an important role in improving air quality for Californians.

Many fleets in California have already converted petroleum-consumption vehicle fleets to operate on natural gas. At this time, however, the relative price advantage of natural gas vehicles has diminished, as natural gas vehicles have a greater incremental cost compared to similar gasoline and diesel vehicles. California fleets must weigh the benefits of the lower cost fuel prices against the increased purchase price of these vehicles. The Energy Commission should support research to help better understand the cost and societal benefits of natural gas as a transportation fuel.

In the short term (2016 through 2023), the most critical air policy issue the state must address is how to quickly accelerate the purchase and deployment of heavy-duty natural gas trucks to achieve NOx reductions in non-attainment areas. At the same time, the state must develop policies and programs to maximize the supply of renewable natural gas for transportation and other markets to achieve our 2030 and 2050 GHG reduction targets. The transportation sector can be an important catalyst for building the renewable natural gas market.

End-Use Efficiency Applications and Natural Gas Including Zero Net Energy Buildings

California households and businesses consume about one-third of the total state natural gas demand or about seven billion therms of natural gas annually. Residential natural gas consumption is driven mostly by space and water heating, followed distantly by cooking and miscellaneous residential uses, such as clothes dryers and pools. Similarly, commercial natural gas consumption is primarily from space and water heating, with cooking being a significant end use as well. Other uses in commercial buildings include process loads, such as commercial laundry or heated pools, and paint dryers in auto shops.

Residential and commercial natural gas consumption has remained relatively flat for the past two decades despite increases in population, jobs, and gross state product. During this period, the California Building Energy Efficiency Standards have increased stringency and investments in statewide utility energy efficiency programs have grown. This is contributing to the relative flattening of natural gas consumption. Maintaining this flat natural gas consumption trend over the next decade may be more challenging.

The industrial sector is a major energy consumer and one of the largest users of natural gas in the state, accounting for about 25 percent of total use in 2012. The largest users include petroleum and coal products manufacturing, oil and natural gas extraction, food processing, printing, and manufacture of electronics, transportation equipment, fabricated metals, furniture, chemicals, plastics, and machinery. These sectors represent prime areas of opportunity for reducing industrial natural gas use. Consequently, the industrial sector represents an important target for improving the efficiency of natural gas use through the adoption of new technologies and improved energy management practices.

There does not appear to be a clear-cut path for natural gas policy in end-use applications when considering zero net energy buildings. The Energy Commission adopted the following key recommendations in the *2011 Integrated Energy Policy Report* for achieving high levels of energy efficiency in the Building Energy Efficiency Standards updates between now and the 2020 zero net energy effective date:

- The Energy Commission, California Public Utilities Commission, local governments, utilities, and builders should collaborate to encourage the building industry to reach these advanced energy efficiency levels.
- The Energy Commission, California Public Utilities Commission, builders, and other stakeholders should collaborate to accomplish workforce development programs to impart the skills necessary to change building practice to accomplish zero net energy in newly constructed buildings.

The Energy Commission can use its regulatory authority in both building energy efficiency and appliance efficiency standards to require buildings and the equipment used in buildings to be more energy efficient. The timing between the Energy Commission's adoption of the zero net energy goal in 2007 and the 2020 effective date for newly constructed residential buildings is short. The Energy Commission made significant energy efficiency upgrades to the 2010 and 2013 California Energy Code, and the Commission expects to adopt the 2016 Building Energy Efficiency Standards in 2015.

Zero net energy buildings will need to have extensive energy efficiency measures, lowering the onsite electricity and natural gas use as much as possible. One way to address this situation would be to identify strategies to offset residual natural gas usage, such as through uses of waste heat, including combined heat and power, or potentially through the use of renewable gas resources at the building site or on a community basis.

Low-Emission Resources and Biogas

Biogas is the gas generally produced during the anaerobic decomposition of biomass and is principally composed of methane and carbon dioxide. Biomethane is the treated product of biogas where carbon dioxide and other contaminants are removed. Biomethane can supplement or directly replace the use of natural gas. In most cases, the potential for methane production is limited by immutable factors, such as "waste-in-place" at a landfill or the volumetric flow of water into a wastewater treatment plant. Production can be increased if there are opportunities to process additional biomass feedstocks within normal agricultural or industrial operations, such as diary digesters accepting food waste or wastewater treatment plants co-digesting fats, oils, and grease. Manure management, landfills, and wastewater treatment are three of California's largest anthropogenic methane-producing sources, and the capture and subsequent reduction of these methane emissions is arguably one of the greatest benefits for using biomethane.

The *2014 Integrated Energy Policy Report* indicated that biofuel data is needed to better understand its potential as a low-carbon resource. The Energy Commission should continue to provide information to the United States Environmental Protection Agency so that low-carbon biofuels are appropriately recognized and categorized in the annual Renewable Fuel Standard volumetric targets. The Energy Commission should work with the California Public Utilities Commission and the California Air Resources Board to overcome potential barriers impeding commercial biogas projects and explore the availability of potential funding or incentive programs to help bring additional low-carbon biogas projects online.

Some biomass-rich locations are relatively close to population centers and therefore utility pipelines, but interconnection to utility pipelines can still be difficult. The Energy Commission should continue to coordinate with the California Public Utilities Commission on their interconnection rulemaking, which includes biofuel interconnection. California should encourage increases in biomethane production and use to reduce methane emissions and decarbonize natural gas used in California.

Greenhouse Gas Emissions Associated With the Natural Gas System

Natural gas is composed of multiple chemical compounds, but methane is the main component comprising about 90 percent of the natural gas. Natural gas has the potential to reduce greenhouse gas emissions by shifting away from higher carbon dioxide emitting fuels like coal, gasoline, or diesel. Methane, however, is a highly potent, short-lived greenhouse gas that can reduce or potentially eliminate the climate change benefits of switching to natural gas. Methane emissions originate from the intentional operations of the natural gas system (venting of natural gas, pneumatic devices using natural gas, etc.) as well as from leakage throughout the natural gas supply chain from the production, processing, transportation, storage, distribution, and use of natural gas.

Estimating methane emissions from the natural gas system has proven challenging, with divergence in estimates of methane emissions from recent research studies. Additional research activities are underway at both the national and state level to reduce the uncertainty surrounding current estimates. These efforts will help to provide California policy makers with accurate and comprehensive assessments of the life-cycle emissions from natural gas to develop effective greenhouse gas reduction approaches.

~~The~~ **A** fundamental question regarding the climate benefits of using natural gas is how much methane is escaping from the natural gas system. Researchers estimate emissions **from the natural gas supply chain** using bottom-up, top-down, and hybrid methods. The "bottom-up" method is a straightforward summing up of emissions using emissions factors for the various components of the natural gas system. "Top-down" estimates use ambient measurements of methane and other compounds in the atmosphere to estimate emissions. Hybrid methods try to take advantage of both methods by reconciling the estimates from the top-down and bottom-up methods.

Methane emission estimates for California are uncertain. Recent work estimating methane emissions from California's natural gas system suggested emissions less than one percent of total throughput (or percent of production). Some studies indicate these may be underestimated. A comparison of the various study results is complicated by use of different methodologies, data, as well as difference in the different components of the natural gas system that are either excluded or included. This is an area of ongoing research.

The uncertainties and gaps in estimating methane emissions include:

- Most studies to date are not comprehensive life-cycle studies in that they typically do not capture all of the components of the natural gas system such as emissions downstream of the distribution system (for example, end use in homes) or from out-of-state natural gas production areas.
- Problems with measurement and sample bias may occur in the various studies because sample sizes are not large enough due to cost and practicality to be statistically representative of the population of various components of the natural gas system being measured and extrapolated.
- The presence of super-emitters that emit at significantly greater rates and volumes than other similar types of emitters may be missed in sampling, and, as a result, emissions may be underestimated. Several studies suggest that methane emissions are dominated by a small fraction of the emitters.
- Bottom-up and top-down estimates from oil and gas production in other states vary widely and are complicated by the lack of accepted methods to allocate the emissions between the natural gas and oil sectors, since many wells produce both oil and natural gas.

Despite the uncertainty in the emission estimates, there is adequate evidence that California needs to move forward aggressively to reduce methane emissions both inside and outside the state. Ongoing research is underway to better understand emissions from the natural gas system and identify actions to immediately reduce methane emissions. In addition, natural gas utilities are already taking steps to reduce emissions. The following examples highlight some of these activities:

- The Energy Commission is funding on-going research to assess methane emissions and support natural gas pipeline infrastructure and safety. This includes research to survey the main sources of emissions such as production and processing, transmission and distribution, underground storage units, abandoned wells, liquefied natural gas fueling stations, and end uses in homes.
- The Energy Commission is also supporting studies on safety issues to be able to detect leaks that may endanger public health and safety. For example, several ongoing projects focus on developing and testing cost-effective leak detection and pipeline integrity monitoring sensors and tools, as well as demonstrating them in the lab, under simulated field conditions, and at a few actual field sites.
- The California natural gas utilities are already taking actions to reduce methane emissions on their distribution system, many of which are being driven primarily by safety concerns following the San Bruno explosion. The investor-owned utilities have replaced old cast iron pipelines, which are notorious sources of emissions, and have plans to accelerate replacement of other pipes in their systems.
- The gas utilities are also actively engaged in research and development involving the leak detection technologies and real-time notification of leaks. For example, Pacific Gas and Electric is using a mobile platform to detect leaks in the distribution system and to immediately implement measures to eliminate these emissions. In another example, Southern California Gas, and San Diego Gas & Electric are installing smart gas meters to help with detecting leaks.
- The California Air Resources Board is developing a strategy to further reduce short-lived, climate pollutants including methane in accordance with Senate Bill 605 (Lara, Chapter 523, Statutes of 2014). In addition, the California Air Resources Board has already developed regulations for methane from municipal solid waste landfills and is in the process of developing regulations to reduce methane from oil and gas production, processing, and storage operations.
- The California Air Resources Board is also sponsoring several research efforts on methane including a study, to be complete by the end of the year, to develop California specific emission factors for distribution pipelines. Additionally, the California Air Resources Board continues to fund research taking measurements of greenhouse gases at towers located throughout the state.
- The California Public Utilities Commission, working in partnership with the California Air Resources Board, opened a rulemaking to reduce emissions from natural gas

transportation and distribution pipeline leaks pursuant to Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014). It requires the California Public Utilities Commission to establish and requires the use of best practices for leak surveys, patrols, leaks survey technology, leak prevention, and leak detection.

- The Environmental Defense Fund is coordinating a comprehensive study of methane leakage with more than 100 academics, natural gas utilities, research institutions, and others. The 16 projects include studies to measure and estimate methane emissions at natural gas production sites, utility distribution systems, and other components of the natural gas system. Ten of the studies have been completed, several others will be completed in the summer of 2015, and the synthesis project is expected in mid-to late-fall 2015.

- At the federal level, the Federal Energy Regulatory Commission has adopted a policy to allow pipeline owners to recover major capital investment costs that address pipeline safety or reduce greenhouse gas emissions. The U.S. Environmental Protection Agency has proposed regulations to reduce methane emissions from compressors, well completions and fracturing, and pneumatic devices.
- A number of federal agencies including the National Oceanic and Atmospheric Administration, the U.S. Department of Energy, the National Aeronautics and Space Administration, and others are actively engaged in research and development primarily focused on development of methane sensors and developing better ways to identify methane emissions.

Another important question is what role the existing natural gas infrastructure can play in reducing methane emissions from other sectors. The ARB GHG emissions database shows significant methane emissions from biological sources within the state. Additional research and policy focus should be directed to using our extensive natural gas infrastructure to deliver biomethane, reducing upstream methane leakage from fossil natural gas production and providing greater GHG reduction benefits to the state.

The results of the research that is currently underway, including the Environmental Defense Fund research effort, will be important in determining the role that natural gas should play in California climate change strategies. In addition, new research and development is likely to be initiated in the coming months to address the gaps and uncertainties identified above.

Conclusions

The Energy Commission prepared this report to address the comprehensive array of natural gas topic areas identified within Assembly Bill 1257. The report provides an overview of natural gas issues in the state, the current status of the natural gas system, and identifies opportunities for additional research and information gathering. The report is designed to be a beneficial tool to lawmakers and regulators as they face decisions on energy policy in California.

Making recommendations for the implementation strategies for all of the areas identified is premature at this time. Many ongoing regulatory initiatives are being undertaken by various agencies in the state (mostly relating to air pollution, greenhouse gases, and the increased use of renewable energy sources). Additionally, there is research underway that could provide additional information on several uncertainties including the impacts of methane emissions from the natural gas sector and the best use of biomethane. Because of current uncertainties, recommendations in this report are generally limited to monitoring and participating in regulatory initiatives and additional research in several key areas. There is, however, enough knowledge to continue to move forward with emission reduction strategies at the state level and encourage action at the federal level. Lastly, without implementation strategies, it is also premature to measure private sector job development.

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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CHAPTER 1:
Introduction

The Energy Commission prepared this report to address the comprehensive array of natural gas topic areas identified within Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013). Natural gas is an important fuel source in California, especially in the industrial and electric power sectors. **The natural gas energy sector continues to create jobs and grow our economy. In California, the existing natural gas energy sector supports (directly & indirectly) more than 250,000 jobs and adds over $36 billion to the state's economy. Additional natural gas infrastructure improvement projects offer additional significant jobs and contributions to the local and state economy. The manufacturing, industrial, and building sectors rely on natural gas as a low cost energy source to run profitable operations.**

Diversity in the state's energy portfolio is also important for prudent risk management to support resiliency in the energy infrastructure as a climate adaptation strategy. As weather becomes more extreme from droughts, hurricanes and El Nino(s), there have been too many lessons in the state's history and across the country that over reliance on a single energy source can create avoidable and unnecessary risks for the economy and public safety. For example, the Oakland firestorm of 1991 demonstrated why reliance upon electricity driven water pumps was disastrous. Hurricane Sandy provides another example where every system dependent on electricity was jeopardized from the refueling pumps at gasoline stations to the water pumps for putting out fires. Natural gas powered fuel cells that kept many facilities operating in the midst of surrounding blackouts in the aftermath of Hurricane Sandy provide real world examples of the importance of diversification of our state's energy portfolio. Indeed, the aggressive move to develop micro-grids which can operate for a limited timeframe separate from the grid, is further evidence that there is a need for a new, more dynamic model of the electric grid. Natural gas technologies like CHP and Fuel Cells are perfectly situated to support those developments. It is important to note that since the natural gas system is mostly underground it is very resilient to extreme weather events. The entire natural gas system was essentially intact after Hurricane Sandy allowing residents with natural gas service to support back-up generators, cook, and heat their homes.

Recent changes in California's regulatory policies, mostly related to renewable energy and greenhouse gas emissions, mean that the natural gas market will be evolving with the changing regulatory environment. The report provides an overview of natural gas issues in the state, the current status of the natural gas system, and identifies opportunities for additional research and information gathering. The report is designed to be a beneficial tool to lawmakers and regulators as they face decisions on energy policy in California.

Pursuant to Assembly Bill 1257, Energy Commission staff has addressed the following natural gas issues:

- Natural gas pipeline infrastructure, storage, and reliability

- Natural gas for electric generation
- Combined heat and power using natural gas
- Natural gas as a transportation fuel
- End-use efficiency applications using natural gas for heating and cooling, water heating, and appliances
- Natural gas and zero net energy buildings
- Other natural gas low emission resources, biogas, and biomethane
- Greenhouse gas emissions associated with the natural gas system

In developing the report, the Energy Commission held public workshops seeking input from experts, industry stakeholders, the public, and various state agencies including the California Air Resources Board; California Public Utilities Commission; State Water Resources Control Board; the Department of Conservation; and the Division of Oil, Gas, and Geothermal Resources.

AB 1257 seeks to identify strategies for job development in the private sector, particularly distressed areas, as well as evaluating economic cost and environmental impacts of greenhouse gas emissions from production, transportation, and use of natural gas. At this time there is not sufficient data to adequately address these requirements. Further, making recommendations for the implementation strategies for all of the areas identified is premature as many ongoing regulatory initiatives are being undertaken by various agencies in the state (mostly relating to air pollution, greenhouse gases, and the increased use of renewable energy sources) and data regarding the impacts of methane emissions from the natural gas sector is lacking.

Due to these uncertainties, recommendations in this report are generally limited to monitoring and participating in regulatory initiatives and additional research in several key areas. The Energy Commission may further pursue these issues in the future *2016 Integrated Energy Policy Report.*

CHAPTER 2:
Pipeline Safety and Natural Gas Infrastructure Improvements

Introduction

Adequate infrastructure consisting of transmission pipelines, storage, distribution mains, and related equipment must be maintained and operated safely to maximize the benefits of natural gas and meet California's future demand. This chapter reviews the safety and infrastructure-related steps could be taken to meet California's future demand for natural gas. This chapter also covers the immediate gas infrastructure challenges of pipeline safety, delivering sufficient gas into Southern California Gas Company's (SoCal Gas) southern system, potential exports to Mexico along the pipelines east of California that would reduce supply available for the state, gas-electric system coordination, and renewables integration.

California Pipeline Safety

The explosion of a Pacific Gas and Electric Company (PG&E) high pressure transmission pipeline in a residential neighborhood on September 9, 2010, killing eight people, injuring 58, and destroying or damaging more than 100 homes, has changed how citizens, energy regulators, and other public officials view natural gas pipeline safety. Lapses in pipeline safety led to that explosion. A natural gas system that does not protect the health and safety of Californians, by definition, does not satisfy the requirements of the Public Utilities Code and cannot meet California's future need for natural gas.

To accomplish this greater vigilance, the maintenance of infrastructure records and the continuous and rigorous enforcement of safety standards are essential. The passage of Senate Bill 705 (Leno, Chapter 522, Statutes of 2011), reinforces this by establishing that "[i]t is the policy of the state that the [California Public Utilities] Commission and each gas corporation place safety of the public and gas corporation employees as the top priority," and by requiring utilities to submit safety plans.

Within days of the pipeline explosion at San Bruno and with the National Transportation Safety Board (NTSB) investigation still underway, the California Public Utilities Commission (CPUC) directed the formation of an Independent Review Panel (the Panel) of experts to gather and review facts and make recommendations to the CPUC.[1] In June 2011, the Panel delivered eight recommendations for PG&E. Key among the recommendations was that PG&E review its integrity management threat assessment methodology, ensure capture of all relevant pipeline design data, improve and apply risk management including at the management level, improve its Supervisory Control and Data Acquisition (SCADA)

1 CPUC Resolution No. L-403.

systems, and modify its corporate culture so that safety is emphasized over financial performance.

The Panel also made 15 recommendations for the CPUC. These recommendations provide the cornerstone of a comprehensive effort launched by the CPUC to create a culture in which safety permeates all of its regulatory activity. Two major actions taken by the CPUC that exemplify this safety culture are the adoption of a safety policy statement on July 10, 2014, and the imposition of a $1.6 billion penalty on PG&E in April 2015.[2] CPUC President Picker noted this penalty was the largest ever imposed on a California utility and one of the largest in the United States.[3]

While the Panel work was still underway, the CPUC responded to San Bruno with a series of direct and sometimes pointed orders to California's gas utilities.[4] PG&E was ordered, on September 13, 2010, to lower the operating pressure of Line 132 and voluntarily reduced the pressure in several related lines that serve the San Francisco peninsula[5]. In December 2010, the CPUC Executive Director ordered PG&E to reduce operating pressures to 20 percent below maximum allowable operating pressure (MAOP) for various additional pipelines until assessments of the integrity of those lines were complete.[6] Roughly six weeks later, the Executive Director ordered further pressure reductions on PG&E pipelines that had experienced pressure excursions of greater than 10 percent of MAOP.[7]

Pipeline Safety Improvements

In early January 2011, the CPUC's Executive Director acted on recommendations from the NTSB and ordered not only PG&E, but all four of California's investor-owned natural gas utilities to produce "traceable, verifiable and complete records" to validate the MAOP on transmission pipelines located in Class 3 or 4 locations or in Class 1 or 2 locations in high

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2 The Safety Policy Statement was adopted as the report of Commissioner Michael Picker and does not have a unique Resolution number. The fine was imposed under Decision No. 15-04-024.

3 Opening remarks at April 9, 2015, CPUC voting meeting. (A copy is posted at http://www.cpuc.ca.gov/NR/rdonlyres/11A401C1-505A-4DF1-891D-688309FF478D/0/PresidentPickerCommentsonSanBrunoModifiedPresidingOfficerDecisionsandPresidentPickerDec.pdf).

4 The CPUC has a detailed timeline of events related to natural gas pipeline safety posted on its website at http://www.cpuc.ca.gov/PUC/events/timeline.htm.

5 CPUC, Paul Clanon 9/13/10 letter and Resolution L-403.

6 Order of the CPUC Executive Director dated December 16, 2010.

7 See Decision No. 11-09-006 describing the pressure reductions and approved steps for restoring pressure upon finding adequate documentation of appropriate MAOP.

consequence areas (HCA).[8] It further directed that segments without acceptable records either be subject to hydrostatic or other strength testing, or be replaced.

The initial responses from the utilities to the pipeline records search order revealed that only Southwest Gas (a Lake Tahoe area utility) believed it was in possession of records for all of the pipeline segments pertinent to the NTSB recommendation.[9] Subsequently, on June 9, 2011, the CPUC ordered all of the gas utilities to file by August 26, 2011, detailed plans to complete the pressure testing on the segments for which inadequate records were found.[10] Those plans are generally known as the Pipeline Safety Enhancement Plans (PSEPs). In later summarizing why it had ordered submission of the PSEPs, the CPUC stated:

> *"(t)hat the historic exemption and the utilities' record-keeping deficiencies had resulted in circumstances inconsistent with the safety, health, comfort, and convenience of utility patrons, employees, and the public. The Commission ordered all natural gas transmission pipelines in service in California to be brought into compliance with modern standards for safety, and all California natural gas system operators to file and serve a proposed Implementation Plan to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c)."*[11]

In December 2012, the CPUC approved PG&E's 2012 – 2014 PSEP, which outlined criteria and a timetable for PG&E to test or replace segments for which it had inadequate records or which had vintage seam welds not meeting modern standards. PG&E also had to add remote or automatic valves, retrofit some segments to allow the use of in-line inspection (ILI) techniques, and transition to a fully electronic asset management system.[12] Phase I of the plan, which went through 2014 alone, involved replacing 186 miles of pipe, strength testing more than 780 miles, retrofitting and then performing ILI on 200 miles, and then

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8 The NTSB letter can be found at http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf and the Executive Director's order was ratified by the Commission by resolution on January 13, 2011. HCA's are generally defined as an area within a specified distance of a pipeline that has 20 or more buildings intended for human occupancy or identified sites, such as beaches, playgrounds, and recreational facilities.

9 January 21, 2011, Letter of Southwest Gas Corporation's James F. Winderlin to CPUC Executive Director Paul Clannon. Southwest Gas serves a small area in Southern California.

10 D. 11-06-017.

11 D. 13-10-024, p. 4.

12 ILI provides pipeline condition data relating to "indentations, wall loss, pipe strain, metallurgical variations, and certain types of cracks. Finding of Fact 26, D. 12-12-030.

replacing some 228 gas shut-off valves along its pipelines.[13] PG&E estimated a cost of $2.2 billion for these changes, of which PG&E proposed shareholders bear slightly more than $0.5 billion.[14]

Sempra's (parent company of SoCal Gas and SDG&E) plan outlined a somewhat similar multiyear effort to replace 192 miles of transmission pipeline, but it would only have to strength test 407 miles of pipeline. It also proposed upgrading, replacing, or adding 487 valves on the SoCal Gas system and 74 on the San Diego Gas & Electric Company (SDG&E) system to provide remote control capability.[15] Sempra estimated Phase 1 of the plan to cost $1.5 billion for SoCal Gas and $236 million for SDG&E, with cost recovery extended over 10 years.[16] The CPUC moved consideration of the Sempra plan to its Triennial Cost Allocation Proceeding.[17]

Southwest Gas filed a plan to conduct pressure testing and found that approximately seven of its 15 miles of transmission pipeline did not have pressure test records. It also proposed replacing some pipeline to accommodate ILI tools as well as a remote control valve at one location. Southwest Gas estimated the work would cost $7.4 million, which the CPUC approved.[18] [19]

In approving PG&E's PESP the CPUC emphasized "why we must make the safety journey:"

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13 PG&E, "Natural Gas Transmission The Energy Commission projects the state's demand for natural gas for electric generation to remain flat over the early 2020's as growth in demand for electricity (for example, due to population growth) is likely to be met with distributed renewable resources. Pipeline Replacement or Testing Implementation Plan," submitted August 26, 2011 pursuant to D. 11-06-017 in R. 11-02-019, p. 3.

14 PG&E's Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan, p. 5.

15 The safety discussions post-San Bruno focus significantly on the benefits to be attained by greater use of automated and/or remotely-controlled valves given the frustration over it taking PG&E 90 minutes to close off gas to the San Bruno blast and the heroic efforts by two PG&E employees to fight the right values and close them manually. See "Report of the Independent Review Panel San Bruno Explosion" June 24, 2011, p. 75 and the Consumer Protection and Safety Division's Incident Investigation Report "September 9, 2010 PG&E Pipeline Rupture in San Bruno, California," pp. 119 to 121 and152.

16 "Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas and Electric Company," submitted August 26, 2011 pursuant to D. 11-06-017 in R. 11-02-019, pp. 48 – 52.

17 A. 11-11-002.

18 Southwest Gas Corporation, "Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan." Submitted in response to D. 11-06-07 in R. 11-02-019, August 26, 2011.

19 D. 13-10-024.

> *"Among all the public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. … gas pipelines carry flammable gas under pressure in transmission lines, often at high pressure – and these pipelines are typically located in public right of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems including the pace at which death and life-altering injuries can occur, are far more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.*[20]*"*

While the CPUC approved PG&E's PSEP, it approved rate recovery of significantly less at only $1.3 billion of the total cost of $2.2 billion, disallowing portions of the costs such as a contingency reserve and increasing the amount borne by shareholders.[21] It also reemphasized the continuing need for PG&E to develop a "safety culture."

Similarly, in approving the SoCal Gas/SDG&E PESP, the CPUC ruled that there was "an identified need to enhance the safety and reliability of the natural gas pipeline transmission systems operated by SDG&E and SoCal Gas."[22] It also ruled that shareholders should "absorb the portion of the Safety Enhancement costs that were caused by any prior imprudent management," the costs of pressure testing where the company cannot produce records, and for pipelines it chooses to replace rather than test.[23]

Implementation of the PSEPs continues. As of August 2014, PG&E completed MAOP validation of its 6,750-mile transmission pipeline system and hydrostatically tested over 565 miles of pipeline. It also replaced approximately 90 miles of pipeline and expects its PESP to be complete in 2017.[24] SoCal Gas has reported that it was able to find records for approximately 245 miles of the 385 miles of pipeline it initially thought it would have to

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20 D. 12-12-030, p. 43 and see Finding of Fact 4.

21 D. 12-12-030, Table E-4.

22 D. 14-06-007, Finding of Fact 4.

23 D. 14-06-007, Findings of Fact 13 and 14. There apparently remains some dispute about whether the cut-off date for ratepayers versus shareholders bearing pressure test costs is 1961 or 1956. See D. 15-03-049.

24 August 14, 2014 letter from Paul Clanon, Executive Director CPUC, to NTSB Acting Chairman Christopher A. Hart.

strength test or replace.[25] The PSEP work for SoCal Gas and SDG&E is scheduled to be completed by the end of ~~2015~~ 2018.~~,~~ **PSEP work to address** ~~though work~~ on the mainline into San Diego (Line 1600) will be delayed until the CPUC acts on an application to loop that line so that the existing line can be taken out of service without creating reliability problems.[26] **An application to address Line 1600 was filed on September 30, 2015. (see Pipeline Safety and Reliability Project section).**

In issuing its more general April 9, 2015, rulings and decision on penalties for the San Bruno explosion and fire, the CPUC documented 2,425 violations of federal and state codes, standards and orders, noting "some of the violations lasted for nearly 60 years."[27] The violations include failure to keep adequate records, various incorrect operating procedures relating to changing pressures, and failure to update pipeline class location designations (which can then affect MAOPs) as local populations grew. No other utilities have been assessed penalties relating to pipeline safety violations, though the CPUC has required shareholder funding of some of the records finding, strength testing, and replacement costs for the Sempra utilities and for Southwest Gas.[28] In addition to fining PG&E for its San Bruno-related violations, the CPUC ordered PG&E to also correct all of the deficiencies found by the NTSB. In his remarks, CPUC President Picker also emphasized the need to see action translate into seeing a safety culture fully take hold.

In the ensuing years, the energy agencies, including the Energy Commission and the California Independent System Operator (California ISO) have worked together with the utilities to manage pipeline outages required for safety testing or replacement to minimize impacts to power plants and electric reliability.

Pipeline Safety and Reliability Project

SDG&E and SoCalGas submitted an Application for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project (Proposed Project) on September 30, 2015. The Pipeline Safety & Reliability Project involves the construction of a new approximately 47-mile-long, 36-inch-diameter natural gas transmission pipeline in San Diego County. The new pipeline will carry natural gas from SDG&E's existing

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25 A. 14-12-015, "Chapter III Description of PSRMA Costs Prepared Direct Testimony of Richard D. Phillips," p. 3 and p. 11.

26 December 5, 2014, Letter of Sempra's Tamara Rasberry in Docket No. 15-IEPR-04 – "AB1257 Natural Gas Act Report."

27 D. 15-04-024, p. 2.

28 In approving the Sempra utilities' PSEP, the CPUC noted there is a difference between disallowing shareholder recovery versus imposing a penalty. D. 15-04-025, pp. 31 – 36.

Rainbow Metering Station near the Riverside County line to Marine Corps Air Station (MCAS) Miramar. In addition to the pipeline, the Project will include natural gas facilities. These facilities will include mainline valves, metering equipment, pressure-limiting equipment, in-line inspection equipment, corrosion protection systems, and intrusion detection and leak monitoring systems. The Proposed Project will expand the capacity of the SDG&E gas transmission system by 200 MMcfd and will improve the system's reliability. Once the new line is constructed, the existing Line 1600 would be used for distribution and would operate at a lower pressure. The project will cost $596 million and take approximately 18 months to construct.

The Proposed Project is needed to meet three fundamental objectives:

1. **<u>Implement Pipeline Safety Requirements for Existing Line 1600 and Modernize the System with State-of-the-Art Materials</u>: Enable the Applicants to comply with the CPUC-approved Pipeline Safety Enhancement Plan (PSEP) by replacing Line 1600 with a new gas transmission pipeline as soon as is practicable. Construction of the new line will enable the use of Line 1600 for distribution while operating at a lower pressure. This replacement will not only comply with the PSEP, but it will also add a greater margin of safety by replacing Line 1600's transmission function with a new pipeline by using modern, state-of-the-art materials. In addition, replacement would avoid any potential customer impacts associated with pressure testing Line 1600.**

2. **<u>Improve System Reliability and Resiliency by Minimizing Dependence on a Single Pipeline</u>: Simultaneously improve the reliability and resiliency of the Gas System by replacing Line 1600 with a 36-inch-diameter gas transmission pipeline so that core and noncore customers will continue to receive gas service in San Diego in the event of a planned or unplanned service reduction or outage of the existing 30-inch-diameter Line 3010 or the Moreno Compressor Station. San Diego County is essentially completely reliant on the compressor station in the City of Moreno Valley and Line 3010, which together provide approximately 90 percent of SDG&E's capacity. A system outage on Line 3010 or the Moreno Compressor Station would constrain available capacity in San Diego, which may lead to gas curtailments. This would be alleviated with the new 36-inch-diameter line providing resiliency for both Line 3010 and the Moreno Compressor Station.**

3. **<u>Enhance Operational Flexibility to Manage Stress Conditions by Increasing System Capacity</u>: Simultaneously increase the transmission capacity of the Gas System in San Diego County by approximately 200 MMcfd as a result of the PSEP replacement line being 36 inches in diameter so that the Applicants can reliably manage the fluctuating peak demand of core and noncore customers, including electric generation (EG) and clean transportation. The new line would provide incremental pipeline capacity that would give flexibility to operate the SDG&E system by**

expanding the options available to handle stress conditions on a daily and hourly basis that put system integrity and customer service at risk

Other Safety Efforts

In addition to the policies and procedures at the CPUC, California can also enhance its pipeline safety with research and analysis. The Energy Commission offered research program funds to help address natural gas safety soon after the San Bruno explosion. In addition, the Energy Commission carefully examined whether natural gas capacity to serve all customers would be sufficient during the winter of 2011, when a portion of the PG&E system was limited to operate at lower pressures, and the Energy Commission stood prepared to help approve contingency plans and assist other policy makers.

Meeting California's future natural gas needs will require continuing research, development, and deployment funding for projects that explore new technologies to monitor and address pipeline safety and integrity assessment. The goals are to conduct research in natural gas infrastructure not adequately addressed by the regulatory and competitive markets and provide research that will result in tangible benefits to utility customers. The focus is on projects that have the potential to monitor pipeline integrity, improve damage prevention and detection, better detect defects and leaks, increase safety, and enhance the transmission and distribution capabilities of the natural gas system. Research projects focused on safety, which will also help to minimize methane leakage from the natural gas system, are discussed in Chapter 9.

Current demonstration and deployment support of pre-commercial pipeline integrity management and inspection technologies will provide additional field operational data and increase operator confidence. These technologies have not been adequately addressed by competitive and regulatory markets and will provide significant benefits to pipeline operators. Research is also focused on developing new technologies, such as micro electro-mechanical sensors, piezoelectric sensors, and ultrasonic transducers to monitor the integrity of gas pipelines and inspect girth welds and other defects in gas pipelines. Currently funded projects are developing and demonstrating low-cost, long-life reliable sensors for both inspection and continuous monitoring of pipelines.

The objectives of the current research projects are to reduce the cost and size of leak detection sensors and diagnostic tools, improve the accuracy of leak and defect detection, design and develop prototypes integrated with hardware and software for prototype systems, and test the prototypes in the lab under simulated field conditions.

One of the most common causes of pipeline failure is third-party excavation damage. Prevention can be accomplished through improved right-of-way (ROW) monitoring technologies and programs to promote public knowledge regarding pipeline safety. By providing operators with early notification of potential external threats and educating the public on its role in pipeline safety, the occurrence of failures in California's pipeline network can be reduced. For dig-in prevention programs to work: (1) excavators have to call 8-1-1 in advance of their activities and have the work site marked before they start work; (2)

the information in the utility database about the location of the lines must be accurate. Preserving the health and safety of Californians means these programs require more outreach and more attention to compliance.

The other area that must command greater attention is the distribution system. PG&E, for example, has 42,000 miles of distribution pipe and 3.3 million individual gas service connections and related assets.[29] In its 2014 General Rate Case, PG&E proposed a Distribution Pipeline Replacement program to replace aging assets based on a risk determination that includes the probability of a leak on each section of pipe. This will be augmented by the Gas Distribution Asset Management Project known as "Pathfinder[30]", which will enhance and convert PG&E's gas distribution asset data into an integrated geographic information system using software from the German multinational firm SAP SE (GIS/SAP system), and provide analytical and visualization tools to enhance gas distribution management. The CPUC approved funding for Pathfinder, noting its "integral importance" to robust integrity management.[31] Leak detection and repair also become higher priorities both in terms of maintaining safety and in order to eliminate methane leaks. PG&E is in the midst of deploying use of the Picarro Surveyor leak detection technology, which is a vehicle mounted leak sensor system. In addition, the CPUC Safety and Enforcement Division, in March 2015, released its "Survey of Natural Gas Leakage Abatement Best Practices," and a separate rulemaking is underway to consider ways to address leakage.[32]

SB 1371 (Leno, Chapter 525, Statutes of 2014) requires the CPUC to adopt rules and procedures that focus on minimizing and mitigating pipeline leaks as a hazard, while giving priority to the safety, reliability, and affordability of service relevant to the operation, maintenance, repair and replacement of commission regulated gas pipeline infrastructure. SB 1371 also requires that due consideration be given to reducing GHG emissions to the maximum extent feasible in accordance with the state's greenhouse gas reductions goals. The ARB is working in partnership with the CPUC on this effort

The Southern System Minimum Flow Requirement

The Southern System Minimum (SoSysMin) flow requirement refers to the requirement that enough gas is delivered through the El Paso Natural Gas (EPNG) South Mainline at the

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29 A. 12-11-009, Prepared testimony (Revised) Exhibit (PG&E-3) "Gas Distribution," p. 1-22.

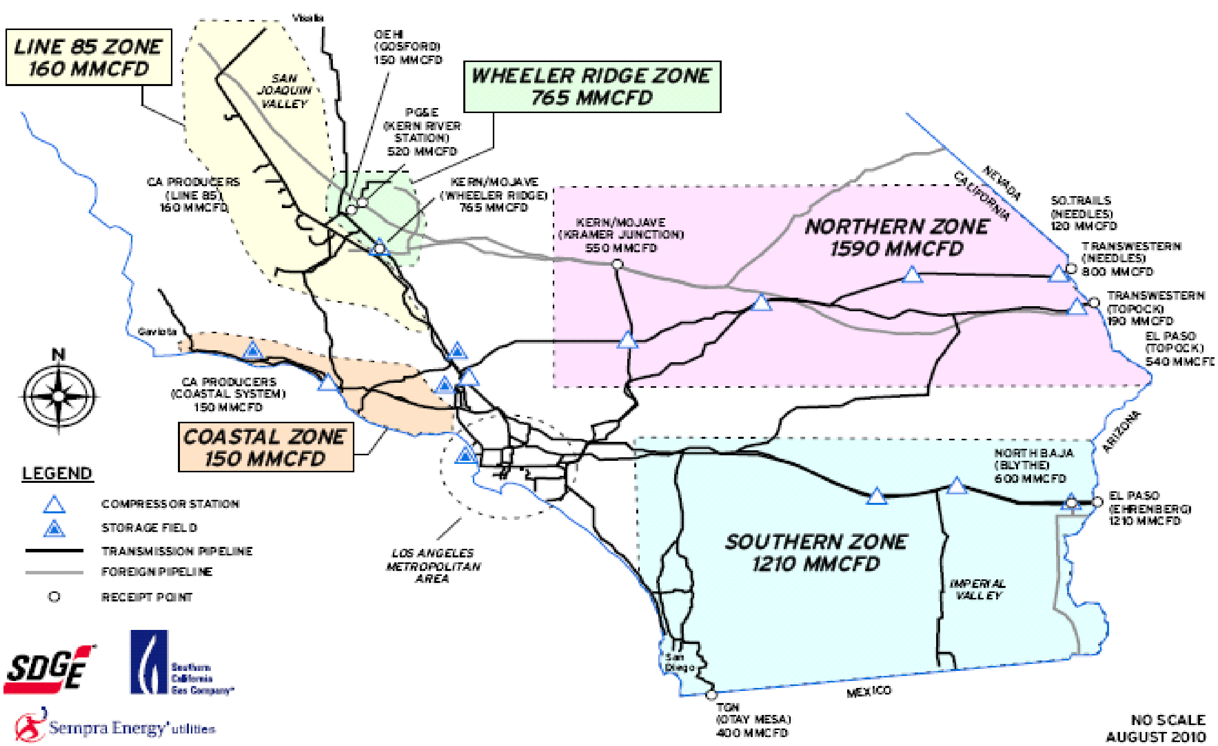
30 PG&E launched Pathfinder to improve the quality of and access to information in PG&E's distribution records.

31 D. 14-08-032, p. 112.

32 OIR 15-01-008.

Ehrenberg receipt point at the California border to meet the load in the SoCal Gas southern system, or zone. Southern California natural gas pipeline system is shown in **Figure 1**. The southern zone includes the SDG&E gas service area and territory east to the California/Arizona border.

Figure 1: SoCal Gas and SDG&E Pipeline System



Source: Sempra.

The flow requirements are necessary because the southern zone is relatively isolated, with limited interconnection to other gas receipt points in California. No gas storage is located within the southern zone and gas from So Cal Gas' storage facilities cannot reach it. Even when there is excess capacity on the EPNG South Mainline, it is not always in the economic interests of shippers along the pipeline to deliver supplies into the southern system when there are higher priced markets elsewhere. Nor is it in the interests of end-users to purchase out-of-state gas on the southern mainline when that gas is higher priced than supplies that are connected to pipelines delivering into So Cal Gas at receipt points other than the Ehrenberg hub.

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The CPUC has granted SoCal Gas permission to enter the market and purchase "make-up" gas to serve load. This short-term solution was meant to be for infrequent small amounts of gas to meet total demand in the southern system that is delivered at Ehrenberg.[33] Instead, So Cal Gas purchased make-up gas on about 80 days in the 12-month period from August 2013 to August 2014. In some cases, So Cal Gas' effort to purchase additional gas has occurred well after the "timely" or first nomination cycle of the gas day. This may push prices higher as liquidity drops off with fewer sellers having less gas available to sell than earlier in the gas day.

With the state's increasing interdependency between natural gas and electricity, concerns about possible curtailments have been raised by stakeholders. Until the recent event in the summer of 2015, winters were ~~2015-2016 was~~ generally identified as the periods in which possible curtailments may occur. However, the possibility of curtailment of electric generators in summer raises additional concerns. For example, on June 30 and July 1, 2015, SoCal Gas issued a general curtailment watch to noncore customers in the Los Angeles Basin. The aforementioned watch transformed into an actual curtailment of natural gas service to certain power plants in the Los Angeles Basin, causing the California Independent System Operator (California ISO) to issue a "Flex Alert" calling for electricity conservation.[34] ~~The curtailments lasted from five to six hours on each of the two days.~~ This curtailment episode resulted from the combination of several factors including:

- Low hydro-electric availability.
- Low ability to import electricity from out-of-state.
- Unusually high temperatures resulting in very high electricity demand and in turn, unusually high natural gas demand.
- A reduction in natural gas pipeline receipt capability caused by a pipeline being taken out-of-service to conduct important pipeline safety integrity work.

A review of SoCal Gas's maintenance schedule showed a storage inventory of 108 Bcf and withdrawals on those two days of as much as 1.3 Bcf/d. This is much lower than the

33 So Cal Gas has also used other tools, such as discounting access to the Ehrenberg receipt point, to try to make it more economically attractive, entering into agreements by which other suppliers deliver additional gas at Ehrenberg on a baseload basis, and buying the California portion of Questar's Southern Trails line and upgrading its interconnection to allow it to deliver a little more gas into the southern mainline.

34 Information on curtailments is posted in the "Critical Notices" section of So Cal Gas' Envoy System, at: https://scgenvoy.sempra.com/#nav=/Public/ViewExternalEbb.getMessageLedger%3FfolderId%3D1%26rand%3D19.

2.7 Bcf/d it withdrew during cold-day winter events discussed below. While SoCal Gas did not cite a limitation on storage withdrawals as a factor contributing to the curtailment, the gas utilities would not expect to pull such high volumes from storage in the summer. In fact, the maintenance schedule showed various summer maintenance activities occurring at SoCal Gas' gas storage facilities, which would have precluded such large withdrawals.

The combination of conditions that led to curtailments were high gas demand when gas infrastructure was down for planned maintenance, coupled with high temperatures causing high electricity demand when electricity supplies were limited by the lack of hydroelectricity and constraints on imports.

~~In response to this event,~~ **Before this summer curtailment event occurred** on June 26, 2015, SoCal Gas filed an application[35] at the CPUC to modify the gas curtailment rules and asked the CPUC to approve the new rules by August 2016. In A. 15-05-020, SoCal Gas and SDG&E seek to designate 10 local service zones. Curtailment within each zone would occur after directing all electric generators to hold their respective gas burns at their dispatched level throughout the duration of the curtailment episode, combined with a $50 per million British thermal units (MMBtu) penalty for taking gas above the hourly burn allowed during the curtailment. The sequence of curtailment to different customers would proceed as follows:

- Step 1: Dispatchable electric generation not currently operating
- Step 2: Up to 60 percent of currently dispatched operating electric generation load
- Step 3: Up to 100%, pro-rata cogeneration and non-electric generation noncore usage
- Step 4: Remaining dispatched and operating electric generation load
- Step 5: Large core (Priority 2A)
- Step 6: Small core nonresidential (Priority 1)
- Step 7: Residential (Priority 1)

~~SoCal Gas and SDG&E propose that the utility and customers be allowed to use a different curtailment order if they mutually agree to do so.~~ **To the extent operationally feasible, SoCalGas and SDG&E further propose to work with affected grid operators on a best efforts basis to reallocate the aggregate maximum allowed usage for the remaining dispatched electric generation load within the affected Local Service Zone(s) among all of the dispatchable electric generation facilities within the affected Local Service Zone(s) to maintain grid reliability.** The changes reflect formal recognition that the gas and electric utilities and California ISO need greater clarity and flexibility to work together to preserve electricity reliability when gas reliability is threatened.

35 A-15-05-020

In addition to recent summer 2015 events, the winter of 2013 – 2014, resulted in localized curtailments or near-curtailments, in which SoCal Gas did not receive sufficient gas supply at Ehrenberg.[36] The first occurred in early December 2013, when a winter storm caused very high natural gas demand on the West Coast that spread eastward to cause gas prices to not only rise in general, but to rise to relatively higher levels as areas east of California experienced even colder temperatures. Those prices exceeded the SoCal Gas Citygate price and not only reduced the incentive to sell gas for delivery at Ehrenburg but caused customers to prefer gas purchases at locations connected to receipt points other than Ehrenburg. On December 6, 2013, SoCal Gas and SDG&E curtailed standby service due to the reduced flows of gas into the SoCal Gas system.[37] On the following Monday, it issued a curtailment watch to customers in the Rainbow Corridor and SDG&E service area.[38] It also curtailed off-system service and later issued a curtailment watch for the area from El Segundo south to Huntington Beach.[39]

On February 6, 2014, a similar set of circumstances occurred. SoCal Gas and SDG&E first curtailed standby service, and then moved to emergency curtailment of electricity generation.[40] This curtailment initially affected only the southern zone but was later extended to cover its entire system, citing continued low system receipts and high electric generation demand. All generators were "instructed to hold their current load," meaning they could not increase their gas consumption.[41]

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36 Another event, in February 2011, also saw cold weather to the east of California cause curtailments throughout the Southwest.

37 CPUC Proceeding A14-06-021, Prepared Direct Testimony of Beth Musich, SoCal Gas, and SDG&E, June 27, 2014, page 3. The curtailment notice can be found at https://scgenvoy.sempra.com/#nav=/Public/ViewExternalEbb.getMessageLedger%3FledgerType%3Dmessage%26Page%3Dfilter%26datePosted_from%3D12%252F05%252F2013%26datePosted_to%3D12%252F10%252F2013%26keyword%3D%26folderId%3D1%26rand%3D167.

38 See https://scgenvoy.sempra.com/ebb/attachments/1386602045690_Curtailment_Watch_120913.pdf.

39 See: https://scgenvoy.sempra.com/#nav=/Public/ViewExternalEbb.getMessageLedger%3FledgerType%3Dmessage%26Page%3Dfilter%26datePosted_from%3D12%252F05%252F2013%26datePosted_to%3D12%252F10%252F2013%26keyword%3D%26folderId%3D1%26rand%3D167.

40 Ibid, page 4.

41 A copy of the curtailment notice can be found at https://scgenvoy.sempra.com/#nav=/Public/ViewExternalEbb.getMessageLedger%3FledgerType%3Dmessage%26Page%3Dfilter%26datePosted_from%3D02%252F05%252F2014%26datePosted_to%3D02%252F07%252F2014%26keyword%3D%26folderId%3D1%26rand%3D109.

Curtailments in the SDG&E gas service area are of particular concern for two reasons. First, there is virtually no industrial load in San Diego County, so there is little to curtail other than electric generation.[42] Second, much of the local area electricity generation was operating at higher levels to make up for power generation lost with the closure of the San Onofre Nuclear Generating Station (SONGS). SoCal Gas has calculated that the annual average SoSysMin requirement has increased by 100 Mdth/day (converts to 97.3 million cubic feet per day [MMcf/d]) and stated: "(t)he San Onofre outage has been a major contributor to this increase."[43] Meanwhile, deliveries into the southern zone have decreased from 2010 to 2012 by more than that amount.[44]

With the problem occurring much more frequently than anticipated, SoCal Gas developed a more comprehensive, physical solution to the SoSysMin issue by filing an application to build what is known as their North-South Pipeline.[45] The project would allow gas received at northern receipt points to flow into the southern zone by adding a new 60-mile, 36 inch diameter pipeline with a capacity of 800 MMcf/d from the Adelanto Compressor Station to the Moreno Pressure Limiting Station and rebuilding the Adelanto Compressor Station to 30,000 horsepower of compression.

SoCal Gas estimates that the total costs of the project will be $621.3 million. Several stakeholders have intervened in the case, which remains pending before the CPUC. Transw~~W~~estern Pipeline Company, LLC and TransCanada Pipelines Limited, and Kinder Morgan, owner of the EPNG line, proposed alternatives. Each argues their alternative costs less, and ~~would not result in direct increases in SoCal Gas rates. They also argue that their alternatives~~ can be permitted and constructed more quickly than SoCal Gas can build the

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42 Curtailments of small core customers is avoided at all costs because of the public safety danger as pilot lights go out and the very high cost to restore service, requiring high numbers of personnel going door-to-door. In restoring service following the February 2011 curtailments in New Mexico, the Governor called out the National Guard to assist police and fire departments, along with local contractors, plumbers and help from other local gas distribution companies. See "FERC/NERC Staff Report on the 2011 Southwest Cold Weather Event: Causes and Recommendations", August 2011, p. 132. See also, Elder, previous citation, pp. 75-76.

43 Ibid. Footnote 22, pg. 14.

44 Supplemental Direct Testimony of Beth Musich Regarding the Transfer of SoSysMin Flow Responsibility. SDG&E & SoCalGas. September 10, 2012, Pg. 13, Figure 1: http://socalgas.com/regulatory/documents/a-11-11-002/2010-1023/Musich%20TCAP%20Supplemental%20Testimony%20_091012.pdf.

45 A13-12-013, Application for Authority to Recover North-South Project Revenue Requirement in Customer Rates and for Approval of Related Cost Allocation and Rate Design Proposals. Though technically styled as seeking authority for cost recovery, SoCal Gas in practice would likely not build new infrastructure without permission to recover costs.

North-South Pipeline. Key elements of the SoCal Gas proposal and the three alternative proposals are summarized in **Table 1**. Evidentiary hearings on the proposals **took place** ~~should take place sometime~~ in **July and August** 2015, **which should** allow~~ing~~ CPUC action by year-end.

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Table 1: Proposed Pipeline Projects to Address the SoSysMin Issue

Options	Location	Estimated Cost	Cost to Ratepayers	Capacity	Est. Time Frame
SoCal Gas SDG&E	Adelanto, CA, to Moreno Pressure Limiting Station	$621.3 Million	Yes	800 MMcf/d	6 Years
Transwestern	Arizona side of border, Needles to Ehrenberg	$418 Million	No – Transwestern; indirect costs to ratepayers	800 MMcf/d	24-36 Months
TransCanada	Western Edge of the Rice Valley Wilderness, Needles to Blythe	$585.4 Million	No – TransCanada; indirect costs to ratepayers	775 MMcf/d	3 Years
Kinder Morgan[46]	Arizona side of border, Needles to Ehrenberg	Estimated 30% - 50% less than SoCal Gas' proposed project	No – Kinder Morgan; indirect costs to ratepayers	Scalable - 300 MMcf/d to 800 MMcf/d	3 Years

Source: Compilation by Energy Commission staff from information in CPUC Proceeding A13-12-013.

Gaps in Knowledge and Research

To achieve the public safety goals articulated in Public Utilities Code and recently amplified in Senate Bill 705, California needs to know the locations and condition of the pipelines. The gas utilities are making progress in this area, but as CPUC President Picker noted in his

46 Energy Commission, Direct testimony of Mr. Anthony Sanabria, Kinder Morgan during November 18, 2014, AB 1257 Staff Workshop on California's Natural Gas Infrastructure, Storage, and Supply. Workshop Transcript pp. 61-63. Docket 15-IEPR-04: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-04/TN203454_20141216T135019_Transcript.pdf.

April 8, 2015, comments explaining the San Bruno penalty decision, incidents continue to occur.[47]

In addition, ways to prevent unauthorized excavation need further attention. This includes exploring how to achieve better compliance with existing "Call Before You Dig" programs, as well as development and demonstration of technologies for right-of-way monitoring and prevention of damage due to unauthorized excavation.

Leak detection is also very important. PG&E's field-testing and deployment of the Picarro surveyor leak detection technology is a key step in demonstrating the accuracy and efficacy, as well as cost-effectiveness, for wide-scale acceptance, deployment, and use by gas pipeline operators and regulators. Even more robust, reliable, accurate, and large area capacity tools such as mobile and aerial (drones), could also be researched and developed.

Funding for pipeline safety research has been in the range of 1 to 2 million dollars per year. The kinds of programs described above require additional funds in the order of $10 million per year. The other infrastructure challenges certainly require regulatory and policy planning vigilance. Some further study could be conducted on whether it could be worthwhile to invest in additional line-packing capability in proximity to certain power plants and potentially comparing the cost of doing so to the other solutions identified above[48].

In addition, since studies conducted in the Western Region focused on short-term deliverability in the context of peak winter demand, it would be prudent to explore line pack conditions and document the velocity at which gas can be delivered to the rapid-fire gas units during the afternoon ramp-up.[49] It would also be important to look at other seasons like summer peak electric generation in light of the curtailment earlier this summer.

An issue is that the necessary detailed data is not available to the Energy Commission and other public agencies to conduct this kind of analysis.[50] The same issue arises in

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47 Written copies of comments are posted at http://www.cpuc.ca.gov/NR/rdonlyres/D8E5C7F1-A0A1-48C3-A80B-7FEDC84F9529/0/PresidentPickerCommentsonPGESafetyCultureandEnforcementTheory.pdf.

48 Line-packing is the introduction of new gas at a receipt point and "packs" or adds pressure to the line.

49 Schlag, Nick. *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective; Phase 1 and Phase 2 Reports*. Energy and Environmental Economics, Inc., March 2014 (Phase 1), July 2014 (Phase 2), prepared for the Western Interstate Energy Board and the State and Provincial Steering Committee.

50 The data set for the Western Interstate Energy Board work was purchased from a proprietary third-party vendor and did not have all the detail needed. SoCal Gas was very helpful in performing

understanding the system impacts of the proposed North-South pipeline or taking segments of lines out of service for hydrostatic testing or replacement. Only the gas utilities have the detailed data needed to perform hydraulic modeling that is specific enough to be accurate and reach conclusions. Notably, electricity system flow modeling is routinely performed by parties who sign non-disclosure agreements with FERC or the California ISO to get analogous data sets. Greater vigilance on public safety and the need for the gas system to operate more flexibly point to the need to develop an open planning process on the gas side, then explore how we might go about building that capability.

additional detailed hydraulic modeling, but the team could only watch and review SoCal Gas' results.

CHAPTER 3:
Natural Gas for Electric Generation

Introduction

This chapter reviews California's coordination efforts with federal regulations, the natural gas and the electric industry, and renewables integration. California will need to continue broad coordination efforts in order to: (1) achieve increasingly stringent federal air and water quality regulations; (2) improve natural gas and electricity market scheduling; and (3) adapt and support the system with the growing deployment of renewable generation resources.

Federal Regulations

A number of proposed or adopted federal air and water quality regulations are expected to reduce the United States reliance on coal for generating electricity. These rules include the Mercury and Air Toxics Standards (MATS) for power plants; the Clean Power Plan (111d) to reduce carbon pollution from existing power plants; the New Source Performance Standards addressing carbon dioxide for new, modified and reconstructed power plants; changes to water effluent rules and others. Together, they may increase demand for natural gas-fired generation, depending on what choices utilities make about how to replace the electricity formerly generated by coal.

As other states "decarbonize," they may use more natural gas. At some point, that higher natural gas demand may translate into a need for new pipeline and storage capacity. The lower natural gas prices in recent years have already resulted in some replacement of coal with natural gas, although gas use for electricity generation grew reasonably since 2001, as shown in **Figure 2**. The United States Environmental Protection Agency (U.S. EPA) analysis of how states could meet its Clean Power Plan also shows only 1.2 trillion cubic feet (Tcf) of additional increase in natural gas use by 2020, then declining into the future.[51]

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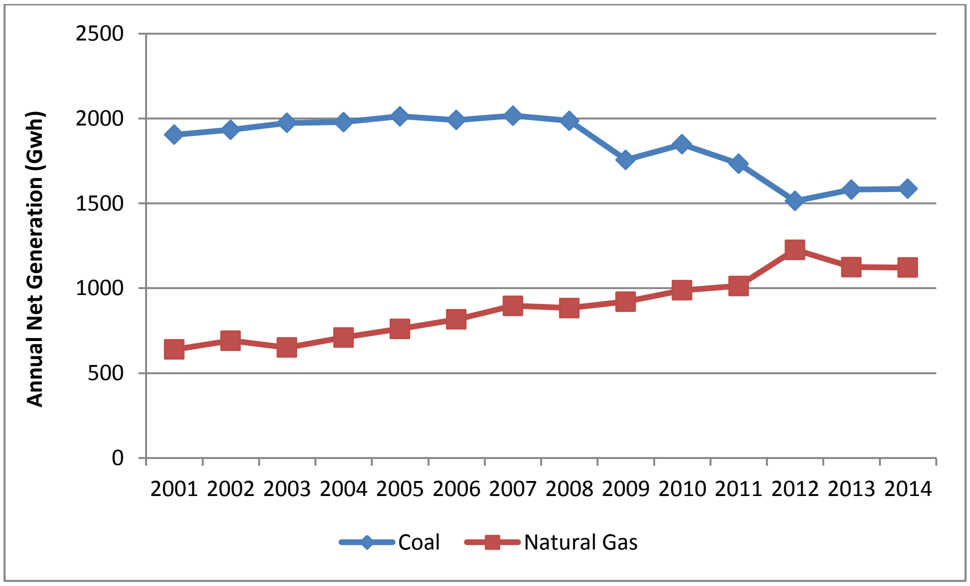
51 EPA Clean Power Plan *Regulatory Impact Analysis*, p. ES-24. Found at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

Figure 2: Net Generation of U.S. Electricity by Coal and Natural Gas (2001 to 2014)



Source: Energy Commission staff analysis of EIA net electricity generation data found at http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=91g&geo=g&sec=g&linechart=ELEC.GEN.COW-US-99.A&columnchart=ELEC.GEN.COW-US-99.A~ELEC.GEN.NG-US-99.A&map=ELEC.GEN.COW-US-99.A&freq=A&start=2001&end=2014&ctype=columnchart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

Other states located "upstream" of California, on the pipelines that interconnect to California gas utilities, use more natural gas to generate electricity. In the future, those pipelines may need to be expanded. Historically, building pipeline capacity has been a years-long but relatively straightforward exercise characterized by a "let the market decide" policy at the Federal Energy Regulatory Commission. As long as shippers commit to a project in sufficient numbers for a pipeline sponsor to justify taking the remaining risk of under-subscription, pipelines have been approved and built once construction-related environmental impacts were assessed.

Gas-Electric Coordination

In California, roughly 40 percent of the natural gas is used to generate electricity.[52] The thermal efficiency of natural gas-fired generation is typically described by measuring its heat rate. The heat rate of a power plant expresses how much fuel is necessary (measured in British thermal unit [Btu]) to produce one unit of energy (measured in kilowatt-hour [kWh]). The heat rate of California natural gas-fired generation is obtained by dividing the total fuel used by the total energy produced. A lower heat rate indicates a more efficient system. A recent Energy Commission paper noted that the thermal efficiency of natural gas-fired generation in California from 2001 through 2013 has improved more than 17 percent.[53]

For the United States the amount of natural gas used for electric generation is 31 percent.[54] As California electric utilities convert electricity generation portfolios away from carbon-intensive resources, the way natural gas is used will change. These changes will affect not only the quantity of natural gas used to generate electricity, but how and when natural gas-fired resources need to operate. These new operational profiles will require a higher degree of coordination between the gas and electric industries.

In light of this increased reliance on natural gas for electric generation, the need for more effective coordination between the natural gas and electric industry has been a topic of discussions and studies. Several events served to cement these concerns, including:

- The September 9, 2010, natural gas pipeline explosion at San Bruno and realization by the Energy Commission, California ISO, and CPUC of the need to coordinate continued service to generating facilities while pressure reductions, hydrostatic testing, and pipeline replacement activities were underway.
- The February 2011 cold event that caused curtailment of gas service to customers, including electric generators, in Texas, New Mexico, Arizona, and Southern California.
- The January 2012 closure of SONGS and the resulting need to generate from gas-fired facilities to meet demand and provide grid support in southern Orange and San Diego counties.
- The winter 2013 – 2014 polar vortex events that caused natural gas curtailments in Northern and Southern California on December 9-10, 2013, and February 6, 2014.

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52 *2014 California Gas Report*. California Gas and Electric Utilities. See: http://www.socalgas.com/regulatory/documents/cgr/2014-cgr.pdf, Page 15.

53 *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update* See: http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf .

54 In 2013 based on EIA *U.S. Natural Gas Consumption by End Use.* Found at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm .

- The summer 2015 gas curtailments incident~~s in~~ **on** SoCal Gas ~~& SDG&E~~ system~~s~~.

Partially in response to some of the above-mentioned events, on April 16, 2015, FERC issued a final rule to improve coordination of wholesale natural gas and electricity market scheduling.[55] The final rule adopted two proposals submitted by the North American Energy Standards Board (NAESB) to revise the interstate natural gas nomination timeline and make conforming changes to their standards by moving the Timely Nomination Cycle deadline for scheduling gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1 p.m. CCT. The rule also added a third intraday nomination cycle during the gas operating day to help shippers adjust their scheduling to reflect changes in demand.

Renewables Integration

Keeping the gas system in balance could potentially become more challenging as the state further increases the portion of electricity generated from renewables as part of its strategy to reduce greenhouse gas emissions[56] [57]. In 2013, California served about 21 percent of retail electricity sales from renewables.[58,59] The electricity produced from renewables such as wind and solar—the largest sources of renewable electricity generation among California Renewables Portfolio Standard (RPS)-eligible technologies—varies depending on conditions each hour (or even minute to minute). Some of that variation in renewables' generation output is predictable (for example, solar only generates during daylight hours); some of it is not as predictable (for example, cloud cover reducing solar output or wind variations affecting wind generation).

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55 http://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf.

56 Assembly Bill 32: http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html

57 Executive Order B-30-15: http://gov.ca.gov/news.php?id=18938

58 CPUC, RPS Quarterly Report, 3rd Quarter 2014, Pg. 3. http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf.

59 Renewable energy sources that are eligible for utility procurement under California's RPS program include: solar thermal electric, solar photovoltaics, landfill gas, wind, biomass, geothermal electric, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Database of State Incentives for Renewables and Efficiency (DSIRE): http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA25R&re=0&ee=0.

When generation from renewables declines but load does not, other generation sources must be called on to operate to maintain the grid. Certain natural gas-fired power plants are used to meet local reliability needs, to provide emergency system support, and to provide the range of ancillary services that are needed by the California ISO to keep the integrated electric system running reliably[60]. California ISO is the entity that gives operating instructions to the various generation units to ensure enough electricity is produced to meet demand for most of the state. Studies performed by the California ISO show that the predicted variation in renewables production mean that large numbers of remaining resources, namely those fired by natural gas, will need to ramp up production quickly, as the renewables generation falls off, and be turned down quickly as the renewables production increases.[61] The result is greater variation in gas load as well as large draws on the gas system, sometimes very quickly.

The timing, magnitude, and speed of these start-ups may create several potential issues. Any start-up risks using gas not properly scheduled for delivery on the gas system; which then becomes a source of a potential gas system imbalance. More imbalances are likely to cause more Operational Flow Orders (OFO) to be called and/or more OFO penalties issued to gas-fired generators. Other potential consequences include the possibility that an electric generator might also incur an additional cost by having to sell unused natural gas back to the market at a loss after the California ISO de-commits the facility from generating, or it might incur higher costs from needing gas storage service more frequently to help manage more frequent changes in load.

Another issue with relying on natural gas to backup renewables is magnitude: even when schedulers know the ramp-up is coming, it is possible for the associated draws on the gas system to be so large that over a short period there is not enough gas available in the pipeline when the generator fires. The gas line capacity is generally not an issue because that is studied by the gas utility when the generator signs up for gas service; the line is sized adequately at that time to meet projected gas load. Rather, the question is whether the gas will be there, especially if it was not scheduled in advance.

Gas system operators can prepare for this potential variable natural gas demand to some degree by packing gas into transmission pipelines during periods of low load, which are typically at night, with another low usually in early afternoon. "Line packing," as this is called, is the degree to which a gas line holds more gas than is being used at a given moment. In essence, an operator can use pressure to pack the gas molecules more closely

60 *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* See: http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF .

61 The California ISO, however, continues to monitor changes in the gas industry for any potential impact to its policies allowing market participants to recover additional start-up and minimum load costs.

together: one might imagine adding more people into an elevator car, for example, and how they squeeze closer together to allow more people on board. Line packing is ultimately limited by the Maximum Allowable Operating Pressure (MAOP) of the pipelines. "Drafting" is the opposite of line packing, and occurs when the rate of gas deliveries to end users exceeds the rate of gas receipts into the pipeline.[62] Too much drafting can lead to loss of pressure in the pipeline and difficulty delivering gas to end-users such as gas-fired flexible generation. Gas system operators routinely pack their systems at night and then draft a bit for the morning load as people warm their homes as they get up in the morning.

Line pack is a form of very short-term storage. Using gas from California's underground natural gas storage facilities may not always be able to quickly supply gas-fired generation. With a couple of exceptions, those storage facilities are simply not located close enough to most of the individual gas-fired power plants that will be called on to start up quickly.[63] Some amount of gas storage is reserved to provide balancing service, but it is too limited today to prevent the system getting out of balance and the consequent need for OFOs. It could be that reserving more gas storage for balancing service would reduce the number of OFOs. It could also be useful to increase the line-packing capability in proximity to key gas-fired plants.[64] ~~There is also the potential that the new California ISO energy imbalance market will help to reduce the need to rapidly fire up gas resources.~~ This, in addition to energy storage or even time of use rates, will modify the anticipated steepness of afternoon ramping and mitigate this operational concern. However, the California ISO continues to monitor changes in the gas industry for any potential impact to its policies allowing market participants to recover additional start-up and minimum load costs.

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62 Ibid. Pg. 42.

63 Those exceptions are the large gas-fired units located very near PG&E's Los Medanos gas storage facility but even those have not been independently verified.

64 For a description of how this could work see ICF International, "Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines" Submitted to the INGAA Foundation, March 2011, p. 77. See http://www.ingaa.org/File.aspx?id=12761. This study also contains a description of the general use of gas to back up variable renewable generation and the ability of the gas system to meet that rapid ramp-up. See also, Elder, previous citation, p. 73.

CHAPTER 4:
The Role of Natural Gas as a Fuel for Combined Heat and Power Systems

Introduction

This chapter discusses the benefits that California may receive from combined heat and power (CHP) systems using natural gas. This includes an overview of CHP policies and programs, as well as addressing the challenges and barriers to CHP deployment.

Opportunities

CHP has the potential to provide many benefits and opportunities to California. **CHP is one of the most efficient ways to generate power from fossil fuel with certain configurations achieving overall system efficiencies greater than 80%.[65] CHP can also utilize renewable fuel in the form of site sourced biogas or pipeline nominated renewable natural gas (RNG).** Historically, the most important feature of CHP has been fuel efficiency. A properly sized and operated CHP facility can produce thermal, mechanical, and electrical energy using less fuel than would otherwise be used to acquire the same energy via a more traditional system of boilers and central-station grid electricity. Additionally, some CHP systems are designed to collect waste heat from thermally intensive operations, such as manufacturing and industry, which is then used to generate electricity. While the efficiency of individual CHP facilities varies greatly depending on technologies used and the use of thermal energy, all forms of CHP are ultimately designed to decrease costs via increased fuel efficiency. Secondarily, they can also provide the energy consumer with greater price certainty, energy security and control over their business processes. On-site power, heating, and cooling can help shield a business from the costs associated with grid outages.

Today, the state recognizes the potential for CHP to provide benefits beyond the needs of those employing it. Greater fuel efficiency can directly result in a reduction of the greenhouse gas (GHG) emissions and criteria pollutants associated with the saved fuel, resulting in environmental benefits for the state. The distributed, local nature of most CHP systems results in many benefits to the electrical grid as a whole, including contribution to regional resource adequacy requirements, greater grid stability via reduced risk of major outages, reduction in net demand, and reduction in costs associated with power transmission and distribution infrastructure. When CHP is utilized at critical facilities (for example, hospitals, prisons, waste-water treatment plants, and data centers) the increased

[65] **http://www.businesswire.com/news/home/20120822005895/en/GE-Houweling%E2%80%99s-Tomatoes-Unveil-Greenhouse-Combined-Heat#.Vgn2A9JViko**

energy security enjoyed by these facilities also benefits members of the public who rely on their services. Broadly speaking, the cost savings a business can achieve through CHP also impacts the larger economy. Lower costs incentivize that business to operate in California and to operate more efficiently, thereby contributing to benefits associated with greater economic activity (for example: increased jobs and tax revenue).

Natural gas has an opportunity to play a key role in GHG reductions and fuel efficiency when used with onsite CHP. By using natural gas to deliver conventional heating and simultaneously generating onsite electricity without any transmission and distribution losses, the result is an increase in fuel efficiency. The goal of CHP is to simultaneously serve these two needs to the fullest extent of the overall fuel efficiency advantage that CHP offers. The technical potential for CHP in California can exceed 16 GW by 2030.[66] The food manufacturing segment has the most technical potential. The restaurant segment, a non-traditional CHP market, follows and a close third goes to another non-traditional CHP market, the food store segment. The health segment, a more traditional market for CHP given the 24/7 operation of hospitals and their demand for hot water and space conditioning, has over 2.5 GW and 10.6% of the total.

Existing Policies and Programs

California has a number of different policies, programs, and incentives in place for CHP procurement. In 2001, the Self Generation Incentive Program[67] was created in response to energy shortages during the California energy crisis of 2000 – 2001. Currently, the program provides rebates for the first three megawatts (MW) of capacity for qualifying distributed energy resources. The program, however, has changed many times since 2001. The program initially emphasized wind, solar, and fuel cells, but included a much smaller incentive for CHP. On January 1, 2008, solar, micro-turbines, internal combustion engines, and small gas turbines were removed from the program, which effectively removed CHP from the program (with the possible exception of fuel-cell CHP) pursuant to Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006).[68] In 2011, CHP technologies were restored and incentive rates were restructured by technology category, with the most emphasis on energy storage, biogas, and fuel cells.[69] Nonrenewable CHP is still included, but at a relatively low

66 "Combined Heat And Power: Policy Analysis and 2011-2030 Market Assessment," ICF International, prepared for the California Energy Commission, CEC-200-2012-002, February 2012

67 Assembly Bill 970 (Ducheny, Chapter 239, Statutes of 2000) http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html.

68 Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html.

69 CPUC Decision 11-09-015, September 8, 2011. http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf.

incentive rate compared to renewable CHP and other technologies. Today's Self Generation Incentive Program focuses more on incentivizing emerging distributed energy resources (DER) technologies than on CHP.

In December 2008, the ARB approved the *Climate Change Scoping Plan*, pursuant to Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), in which it set a target of an additional 4,000 megawatts (MW) of installed capacity from efficient CHP by 2020. This increase corresponded to a target reduction of 6.7 million metric tons carbon dioxide equivalent ($MMTCO_2e$) of GHG emissions. In its May 2014 *First Update to the Climate Change Scoping Plan*[70], the ARB maintained these goals.

In early 2010, the Energy Commission adopted guidelines for certification under a CHP feed-in tariff established by Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), the Waste Heat and Carbon Emissions Reduction Act.[71] Eligible projects are CHP installations of no more than 20 MW that meet specified fuel efficiency and nitrogen oxides (NOx) emission standards, in addition to meeting performance criteria. To date, the program has received little participation. Currently, only six projects are certified under Assembly Bill 1613, and of these, only two are fully interconnected with permanent utility contracts. Many developers claim that the exported electricity price of the tariff is too low to make a project economical, and the lack of participation seems to support this assertion.

In June 2010, Governor Jerry Brown's *Clean Energy Jobs Plan* called for an additional 6,500 MW of new CHP capacity by 2030.[72] At the time, California had approximately 8,500 MW of installed CHP capacity.[73]

Later in 2010, the CPUC adopted the qualifying facilities (QF) and CHP Program Settlement Agreement (D.10-12-035).[74] The QF and CHP Program Settlement Agreement ended numerous legal disputes between investor-owned utilities (IOUs), QF representatives, and

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70ARB, *First Update to the Climate Change Scoping Plan*, May 2014, p. 41; http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

71 Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) http://www.energy.ca.gov/wasteheat/documents/ab_1613_bill_20071014_chaptered.pdf.

72 Office of the Governor, Clean Energy Jobs Plan, 2011, p. 6 http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

73 Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc.,Combined Heat and Power: 2015 – 2030 Market Assessment, 2012, p. 1. http://energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf.

74 CPUC, CHP Program Settlement Agreement (D.10-12-035), 2010, p. 2; http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128624.pdf.

ratepayer advocacy groups, and mandated that California's three largest IOUs procure 3,000 MW of CHP and achieve 4.8 million metric tons of carbon dioxide (MMTCO$_2$e) of the 2008 *Climate Change Scoping Plan* GHG reduction target—proportional to the amount of electricity sales by the IOUs.

On June 11, 2015, the CPUC issued Decision 15-06-028[75] establishing procurement targets for the CHP's Second Program Period. The decision also revised the greenhouse gas Emissions Reduction Targets to collectively achieve 2.72 MMTCO$_2$e of emissions reductions from CHP facilities by 2020 and established a schedule of four competitive solicitations for CHP facilities between 2015 and 2020.

CHP also receives policy and financial support from the federal government, including President Barack Obama's August 30, 2012, Executive Order calling for an additional 40 gigawatts (GW) of CHP capacity nationwide.[76] Financially, CHP is primarily supported through the business energy investment tax credit, which provides a tax credit based on a percentage of the total expenditures of a CHP system. Additional federal support can be found through U.S. Department of Energy CHP Policies and Incentives Database.[77]

Despite these many ambitious goals and policies, California's total installed CHP capacity has changed very little since the ARB published its *Climate Change Scoping Plan*, maintaining a level of approximately 8,500 – 9,000 MW.[78]

Cost Benefit Analyses

Proper valuation of CHP systems is currently a challenging and sometimes contentious issue. Much of the existing body of analysis comes from, or is funded by, CHP stakeholders (primarily utilities and CHP organizations), and this work often focuses on specific costs or

75 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K559/152559026.PDF

76 President of the United States Executive Order, Accelerating Investment in Industrial Energy Efficiency, August 30, 2012. https://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency.

77 U.S. EPA, CHP Policies and incentives database, accessed May 5, 2015. http://www.epa.gov/chp/policies/database.html.

78 Range based on reported values from CHP Market Assessment page 11 and CHP: 2011 - 2030 Market Assessment page 1, reverenced below, as well as current values from the Energy Commission, *QFER* CEC-1304 Power Plant Owner Reporting Database. http://energyalmanac.ca.gov/electricity/web_qfer/source_files.

benefits. There is little analysis of the net benefits of CHP funded by neutral parties—a fact that has confused the issue.

Two frequently cited reports are from ICF International commissioned by the Energy Commission in 2009[79] and 2011[80]. While these reports do not attempt to fully quantify the net benefits of CHP, they do include detailed discussions of the market impacts of state policies on CHP and the impact of CHP on California's GHG goals.

Analysis and monetization of CHP costs and benefits is an ongoing area of research and debate.

Challenges

Despite the many benefits of CHP, its growth and development in California has been relatively flat in recent years. Many regulatory and economic barriers exist for a CHP developer, and often these barriers result in a combination of cost and risk that is too high to justify the project. Many of these challenges were recently discussed in greater detail in stakeholder comments to the Energy Commissions July 2014 CHP Workshop.[81]

Economically, projects often face three major cost barriers: non-bypassable charges, grid interconnection, and contract difficulties. Non-bypassable charges, a collection of energy surcharges that a consumer must pay for self-generated electricity that displaces their previous demand for grid electricity, can erode a large portion of the energy cost savings that a consumer would otherwise realize by installing a CHP system. While grid interconnection processes are frequently being revised, many CHP developers still claim that the interconnection process is unnecessarily complex, long, and costly. Additionally, the full cost of interconnection is often not known until after significant costs have already been incurred in the process. Uncertainty in interconnection time and cost can lead to much higher perceived risk for project developers.

Finally, many existing and potential CHP systems have difficulty obtaining adequate contract lengths and/or prices if they currently, or plan to, export power. Utilities have little incentive to contract with most CHP facilities, and the current regulatory system of tariffs and CHP procurement rarely results in contracts with terms greater than 12 years. These

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79 Darrow, Ken, Bruce Hedman, Anne Hampson. 2009. CHP Market Assessment. Energy Commission, PIER Program. CEC-500-2009-094-F,

80 Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. 2012. CHP: 2011-2030 Market Assessment. Energy Commission. CEC-200-2012-002-REV.

81 Stakeholder comments available at http://energy.ca.gov/chp/documents/2014-07-14_workshop/comments/.

short contract lengths require that a CHP facility receive a much higher price for energy than would otherwise be required to obtain an acceptable payback period, which in turn reduces their ability to compete in procurement processes.

CHP development also faces many regulatory challenges. While California has a variety of ambitious CHP procurement goals, regulatory efforts to achieve these results have so far been unsuccessful in developing new CHP and have left the future of the existing fleet in doubt. Economic incentives, such as feed-in tariffs and grants, have had little effect and appear to be too small or inconsistent to encourage developers. Procurement targets have also fallen short. In the case of the qualifying facilities (QFs), the CHP Program Settlement Agreement (see below for details), has failed to procure the kind of traditional, baseload CHP that was originally intended.

Fundamentally, the challenges to CHP development in California can be viewed as the byproduct of misaligned incentives. A business utilizing CHP is driven by their business process and usually cannot adjust their energy output without either affecting business operations or wasting thermal energy (and thereby losing the efficiency gains of the CHP system). Thus, such a business desires a contract where exported power is purchased on a must-take basis. On the other hand, an electric utility has little incentive to procure a non-dispatchable resource and can cite a number of potential costs associated with accommodating that resource. Additionally, a CHP system decreases the electric utility rate base, and so in a sense can be seen as a competitor. Economically, the costs and, in particular, the benefits of CHP are not fully monetized. For example, non-bypassable charges and demand/standby charges exist to compensate a utility for the costs that were incurred on behalf of the departing customer and to support customer load when their own generation is not operational. Many of the benefits, however, that arise from that departed load (for example, reduction in peak demand, reduced strain and outage risk for grid infrastructure, energy security for critical facilities) are not monetized and, therefore are essentially obtained for free by utilities and ratepayers. In short, many of the challenges facing CHP development today could be lessened, or at least made much clearer, by regulatory and market frameworks that better value the true costs and benefits of CHP generation and align utility incentives with those costs and benefits.

Gaps in Knowledge and Research

As discussed in the previous section, analysis and monetization of the costs and benefits of CHP needs much more research. As many CHP technologies are mature technologies, the challenges that additional research could address are as much economic and regulatory as they are engineering.

Within the broader subject of CHP costs and benefits, three areas stand out: displacement, GHG reductions, and the net impacts of departed load and distributed generation. When calculating what CHP and other forms of distributed generation displace when operated by a customer to meet their load, the impacts of that distributed generation are determined in large part by comparing the characteristics of the distributed generation to those of the traditional utility central generation it displaces. However, determining exactly what generation is displaced can be a difficult question. In an ideal situation, CHP is displacing the marginal generator—possibly an inefficient, fossil-fueled peaking plant. On the other hand, it is possible (although currently rare) that a must-take CHP resource could force renewable curtailment and effectively displace carbon-free generation. Determining an appropriate method to use in estimating the net or average characteristics of displaced generation is a key step towards answering many of the other questions regarding the net benefits of CHP, including GHG reductions.

As environmental policies and requirements change, CHP is capable of adapting to the requirements. However, strict emission requirements for generation technologies in California make on-site generation technologies significantly more expensive, especially in the LA Basin, which imports in excess of 40% of its power. Given this fact, development of emission control technologies to help reduce equipment, installation and monitoring costs is paramount. Eventually, the rest of the U.S. will have these same types of emissions requirements, so such investments will prove beneficial nationally.

Additionally, analyses is needed to help properly monetize the many benefits of CHP; these analyses should be detailed enough to consider the CHP system size and define in terms of kilowatts of nominal electric generating capacity, building type, floor area, climate region, and seasonal load variations. The magnitudes, shapes, and interplay of buildings' thermal and electric end-use loads over the course of a year form the landscape to which various CHP prime mover outputs are fit. Because these components drive CHP adoption, the analyses must take them into account.

Another key area of research is the effects of distributed generation, including CHP, on infrastructure cost and operations. Infrastructure investments, grid stability, and power quality all have serious implications for California's ratepayers, businesses, and economy. Determining the way that CHP affects these issues, and how it may be used to improve them, is critical toward understanding the role that CHP has to play in California's energy future.

CHAPTER 5: Natural Gas as a Transportation Fuel

Introduction

This chapter reviews current uses of natural gas as a vehicle fuel and the state of the fueling infrastructure in California. **It also identifies liquid natural gas (LNG) opportunities for rail and marine applications.** A discussion of upgrades to the state's infrastructure, specifically addressing fueling needs, potential new fleet use and the use of biomethane as an alternative to conventional natural gas follows. The chapter concludes with an overview the efforts of the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program and its support of natural gas-related activities in California's transportation sector.

Transportation Fuel in California

Transportation accounts for nearly 40 percent of total California energy consumption and roughly 36 percent of state GHG emissions.[82] While petroleum accounts for more than 90 percent of California transportation energy sources[83], there could be significant changes in the fuel mix by 2020 as a result of technology advances, market trends, consumer behavior, and government policies.

When looking at the viable alternatives to conventional fuels, many options have been considered as California works to develop cleaner and reliable fuel sources **and reduce dependency on petroleum.** The range of alternatives to petroleum-based fuels is diverse, including biofuels, electricity, hydrogen, and natural gas. **Since natural gas is not a petroleum product, the use of natural gas in transportation can play an important role in reducing the state's reliance on petroleum fuels. As an example, natural gas has been particularly successful in serving urban transit buses and currently is the fuel of choice for over 5,800 buses or 59% of California's urban transit bus population.**[84] California has established programs and regulations to ensure that the future transportation fuel supply lowers carbon intensity, lowers tailpipe emissions, reduces adverse economic impacts, and utilizes a secure domestic fuel source where possible. **To achieve these goals, it will be necessary for state and local agencies to set policies that "…encompasses the following**

82 Energy Commission, *2014 IEPR Update*, 2015, pp. 10-11. See http://energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF.pdf.

83 Energy Commission, *2013 IEPR*, 2013, p. 5. See http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf.

84 California Air Resources Board, "Advanced Clean Transit" slide deck, May 2015, page 15

attributes: addresses both the short and long term, harnesses market forces, is performance based, equitable (across geographical regions, socioeconomic groups and companies), transparent to all stakeholders, easy to administer, and efficient…"[85]

Natural gas vehicles (NGVs) ~~may~~ also offer the opportunity for lower criteria pollutant emissions. Historically, natural gas engines were cleaner than diesel engines and provided emissions benefits. Currently, diesel and natural gas engines must meet the same 0.20 grams of NOx per brake horsepower-hour emission standard. In December 2013, the ARB adopted an optional reduced NOx emission standard for heavy-duty vehicles, which can encourage engine manufacturers to demonstrate their emission reductions. Such standards include NOx levels that are 50, 75, and 90 percent lower than the current 0.2 gram NOx standard. **On September 10, 2015, the ARB certified a Cummins Westport (CWI) 8.9 liter natural gas engine at the 0.01 gram NOx standard or 95 percent lower than the prevailing standard.86 No other heavy-duty engine has been certified to such a low level. The SCAQMD refers to 0.02 gram NOX/bhp-hr engines as "power plant equivalent" emissions because electric vehicles may have zero tailpipe emissions but if full life cycle emissions are considered they are not zero emission. The "near zero" CWI engine actually certified to emissions of 0.01 gram NOX/bhp-hr, which means a natural gas truck or bus would have lower NOX emissions than an equivalent battery electric truck. The accelerated use of such engines can provide significant emissions benefits to non-attainment areas in the state suffering from regional air pollution.** The Initial Statement of Reasons for the voluntary standard suggests that heavy-duty natural gas engines may be the primary initial technology for meeting the more aggressive 75 and 90 percent NOx reduction targets. ~~Depending on the ability of~~ **Now that** natural gas engine manufacturers ~~to~~ **have** demonstrated such reductions, this ~~could~~ **will** further support the **need for significant** market deployment **and enabling state and local policies such as increased incentive funding, for** ~~of~~ heavy-duty natural gas trucks. [87]

The usage of natural gas and biomethane in the transportation sector offers significant opportunities to assist California in meeting its goals for reducing the environmental impact of fuels, reducing petroleum usage, and providing cost savings to fleets. When installed with low NOx engines, NGVs have benefits reducing NOx emissions which are a precursor for both ground level ozone and particulate matters. GHG benefit is provided by NGVs

[85] "California's Climate Policy Model for Transportation", GHG-TransPoRD invited expert paper, Daniel Sperling (UC Davis) and Mary Nichols (CARB), page 8

[86] California Air Resources Board Executive Order A-021-0630, http://www.arb.ca.gov/msprog/onroad/cert/mdehdehdv/2016/cummins_mhdd_a0210630_8d9_0d20-0d01_ng.pdf

87 ARB, "Staff Report: Initial Statement of Reasons for Proposed Rulemaking," October 23, 2013, p. 60. See http://www.arb.ca.gov/regact/2013/hdghg2013/hdghg2013isor.pdf.

with the use of renewable natural gas. With the wide variety of viable operational locations for NGVs, the tailpipe emissions reductions from use of these vehicles can be realized in many areas that are severely impacted by vehicle air pollution. **The last few years have seen the launch of commercial RNG products, such as Clean Energy's REDEEM program, currently providing RNG at a majority of Clean Energy NGV stations operating in California.[88] Major transit agencies, such as Big Blue Bus in Santa Monica, Los Angeles Metro in Los Angeles, Orange County Transportation Authority in Orange County, Riverside Transit Agency in Riverside, and Metropolitan Transit System in San Diego, are issuing RFPs for and/or already operating on up to 100% renewable natural gas.[89]** The development **and recent certification** of advanced low-emission natural gas engines, production **and use** of low-carbon intensity biomethane and expansion of the natural gas fueling infrastructure have been identified as other avenues **the state can focus on with enabling policies and regulations** to further expand the benefits of natural gas in the transportation sector over time.

The *2014 Integrated Energy Policy Report* (*IEPR*) provided support and recommendations for the use of natural gas in the transportation sector. One of the key areas showing improvement is transportation research. The Energy Commission Energy Research and Development Division transportation research program is focused on developing and advancing state-of-the-art electricity and natural gas-fueled transportation solutions that reduce fossil fuel consumption, greenhouse gas emissions, and air pollutants in the state. Many of California's fleets have already converted their petroleum-consumption vehicle fleets to operate on natural gas. California fleets must weigh the benefits of the lower cost fuel prices against the increased purchase price of these vehicles. The Energy Commission should support research to help understand the cost and societal benefits of natural gas as a transportation fuel.

Natural Gas Vehicles and Fuel

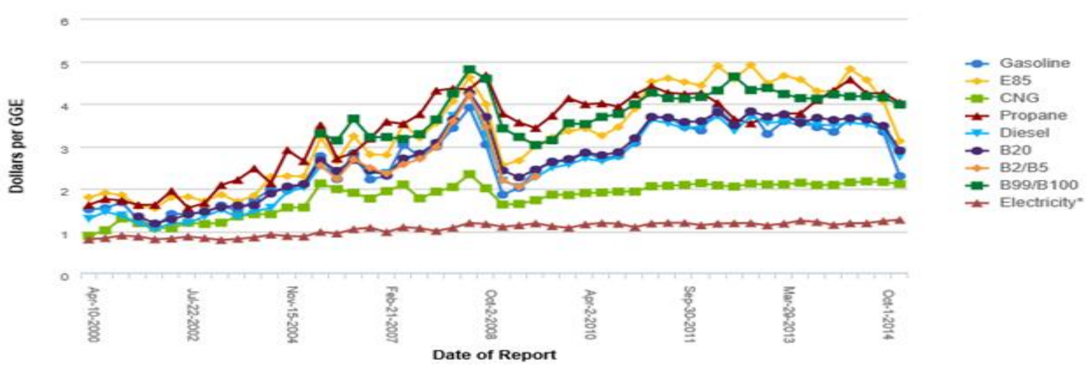
The primary driver for converting petroleum-consumption vehicle fleets over to operate on natural gas originally was the cost savings that can be realized by purchasing natural gas, which historically has been cheaper than gasoline and diesel as shown in **Figure 3**. Recently, however, the relative price advantage has diminished significantly. As NGVs have a greater

[88] https://redeem.cleanenergyfuels.com/

[89] http://ngvtoday.org/2015/07/23/santa-monica-transit-to-fuel-lng-buses-with-100-percent-renewable-natural-gas/, LAMTA Bid OP84203485, OCTA RFP 4-1964, RTA RFP 13-001, and MTS Executive Committee Meeting, Agenda Item C-2, February 14, 2013

incremental cost compared to similar gasoline and diesel vehicles, fleets must weigh the benefits of the lower cost fuel prices against the increased purchase price of these vehicles. When the spread between natural gas and diesel or gasoline is high, NGVs can provide a strong return on investment, with many high fuel-consumption vehicles in the heavy-duty sector paying back the incremental cost difference in as little as two years.

Figure 3: Alternative Fuel Prices[90]



Source: U.S. DOE Alternative Fuels Data Center.

When petroleum prices are low, natural gas prices are high (as is often the case for renewable natural gas), or the incremental cost of a natural gas vehicle is high, there is, however, less of a business case for fleet managers to convert to natural gas. To promote alternative fuel vehicles like NGVs, government entities have offered incentives to help reduce the incremental cost of these vehicles.

There are currently ~~only two~~ **at least four** 2015 model year light-duty vehicles that can utilize natural gas available directly from original equipment manufacturers[91] and **many more that are "gaseous prep" and can be easily converted to use natural gas using a retrofit kit.[92]** Honda recently announced the discontinuance of its natural gas Civic for the

90 U.S. DOE Alternative Fuels Data Center, (accessed on March 1, 2015). See http://www.afdc.energy.gov/fuels/prices.html. Electricity prices are reduced by a factor of 3.4 because electric motors are, on average, 3.4 times more efficient than internal combustion engines.

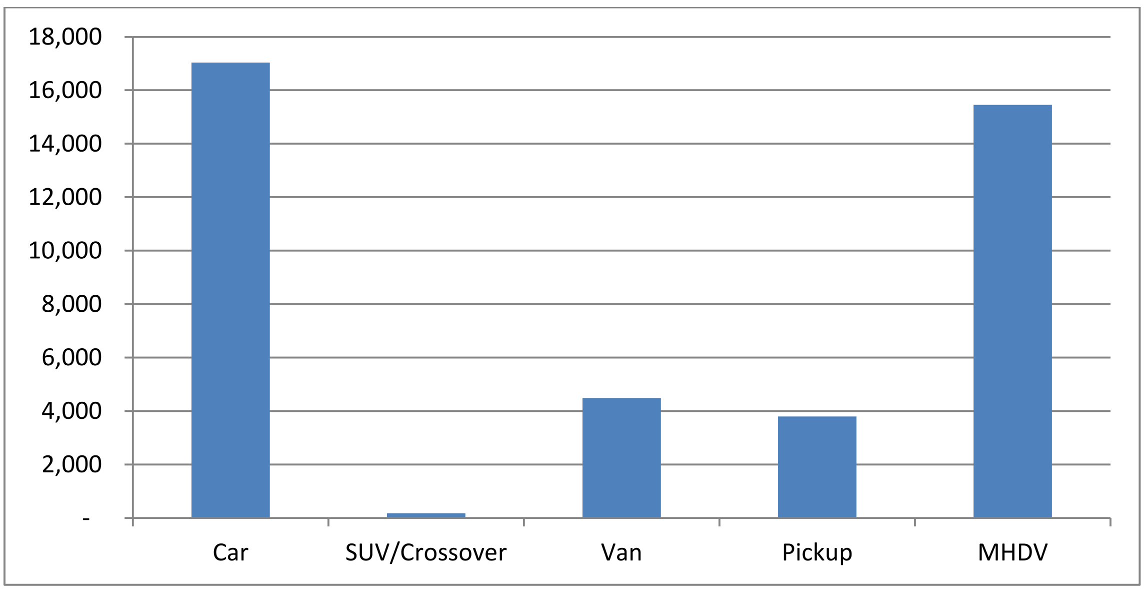
91 U.S. DOE, "Hybrids, Diesels, and Alternative Fuel Vehicles," (Accessed on April 1, 2015). See http://www.fueleconomy.gov/feg/alternatives.shtml.

92 http://www.ngvamerica.org/vehicles/vehicle-availability/

2016 model year. There are, however, many options available in the medium- and heavy-duty vehicle (MHDV) sector. There are also ~~many~~ **even more** options for vehicle upfit/retrofit available from ARB-certified engine manufacturers.

Since vehicles in the MHDV sector have significantly greater fuel costs than light-duty vehicles, there is a significant continuing interest in these vehicles from companies severely impacted by the rising costs of petroleum fuels. Some of the fleets currently making the transition to NGVs include municipal, transit bus, freight transport (for example: UPS or FedEx), waste disposal, and taxi fleets, as reflected in **Figure 4**. ~~Opportunities in the marine and rail sector are currently being investigated as alternatives for the off-road vehicle sector but will require additional research and development to be more widely adopted.~~

Figure 4: California Natural Gas Vehicle Registrations for 2013



Source: Energy Commission staff analysis of 2013 Department of Motor Vehicles vehicle registration database.

Marine and Rail Opportunities

Opportunities in the marine and rail sector are currently being investigated as alternatives for the off-road vehicle sector but will require additional research and development to be more widely adopted. Liquid natural gas (LNG) is an ideal choice to replace diesel fuels for the goods movement industry, especially rail and marine operators. This opportunity researched through Gladstein, Neandross and Associates' 2014 study, *LNG Opportunities for Marine and Rail*, is as follows:

"North American railroads used approximately 4.1 billion gallons of diesel in 2013, spending approximately $11.6 billion on fuel. Given the immense fuel volumes used, railroad companies dedicate significant resources to efficiency and fuel cost reduction strategies. If the railroads converted even one third of their operations to dual fuel natural gas operations, they would be able to save approximately $2.6 million each day. Given these numbers, it's no surprise that the majority of the large railroads are actively working with leading technology providers to take advantage of the cost-saving potential of natural gas. The two largest locomotive manufacturers—Electro Motive Diesel (EMD, a Caterpillar company) and General Electric (GE)—are developing natural gas products that could help shift the nation's rail system to natural gas, much as the railroads shifted from steam propulsion to diesel in the mid-1900s."[93]

"For marine, it is consistently less expensive on a diesel-gallon equivalency and is an intrinsically cleaner fuel in comparison with heavy fuel oils, marine diesel oil or marine gas oil. LNG represents a more apt, primary method of emissions reductions while providing an economic advantage to the end-user. Other technologies such as scrubbers raise questions such as difficulty in monitoring sulphur emissions and ecological risk to marine life, as noted by the German environmental organization Nature and Biodiversity Conservation Union (NABU).[94]

An April 2014 report by the Canadian Natural Gas Vehicle Alliance (CNGVA) evaluated the potential economic savings of using LNG as a means of compliance with the 2015 MARPOL SOx emission standard. The report evaluated several scenarios including, container ships, ferries, cruise ships, tankers, tugs, and bulk carriers. In all categories, it was found that the payback period for LNG-fueled vessels, in both new-build and conversion scenarios, was heavily dependent on the amount of time spent within the ECA, with significantly shorter payback periods achieved when vessels spend 30% or more of their time within an ECA. Of note, a container ship (new-build, dual-fuel, 6,500 container capacity), spending 20% of its time in the ECA (using LNG), is able to achieve a payback period ranging from 2-8 years depending on the "landed" price of LNG[95]."

[93] GNA, *LNG Opportunities for Marine and Rail*, October 2014, http://www.gladstein.org/pdfs/GNA-LNGOpportunitiesforMarineandRail.pdf, page 2.

[94] The Maritime Executive, *Scrubber Discharge Impacts Questioned*, http://www.maritime-executive.com/article/scrubber-discharge-impacts-questioned, March 2013

[95] CNGVA, *Liquefied Natural Gas: A Marine Fuel for Canada's West Coast*, April 2014, http://www.cngva.org/media/35832/04-2014_-_liquefied_natural_gas_-_a_marine_fuel_for_canada_s_west_coast__en_.pdf

The LNG market is rapidly developing:

- **03/05/13: BNSF, one of the biggest U.S. consumers of diesel fuel, started testing LNG as future source fuel**
- **11/06/13: Matson contracts with Philadelphia shipyard to build two new LNG powered containerships for delivery Q3-Q4 of 2018**
- **09/03/14: Puget Sound Energy (PSE) and Tote partner with Port of Tacoma to build LNG plant to fuel ships, locomotives, trucks, and vehicles; to be operational by 2018**
- **01/09/15: BNSF continues to test LNG as its future source fuel by moving LNG testing location from south to north to study operational effects based on climate conditions**
- **04/18/15: Tote launches world's first LNG powered containership**
- **03/17/15: Matson committed to LNG with USCG "SimOPs" bunkering method approval and looking for LNG supply**
- **05/30/15: Princess Cruise Lines is converting 2-4 of their 6 engines to be LNG dual fuel capable; AIDA (affiliate of Princess Cruise Lines) partners with Becker Marine Systems to create LNG hybrid barge system**
- **06/15/15: Carnival Cruise signs multi-billion dollar deal to build four new LNG ships**
- **08/31/15: Tote launches second LNG powered ship**
- **DNV-GL Report: 65 LNG fueled ships in operation worldwide**
- **DNV-GL Report: 79 Confirmed LNG fueled new builds worldwide**

State policy should also consider the advantages that switching from diesel to natural gas in the off-road and marine sectors will have for improvement of cancer risk in nearby communities affected by goods movement. The Office of Environmental Health Hazard Assessment (OEHHA) Air Toxics Hot Spots Program Risk Assessment Guidelines Version 8.0 published in March 2015, shows natural gas has a significant advantage over diesel. In the case of a marine engine transiting near a port terminal, calculation of the change in absolute residential cancer risk from just fuel switching (diesel to natural gas) shows that the diesel risk is 314 times the natural gas risk. In the case of locomotives using an example of arrival and departure trains (1 train/day; 4 hours/train at 50% load) calculation of the change in absolute residential cancer risk from just fuel switching (diesel to natural gas) shows that the diesel risk is 107 times the natural gas risk.

Natural Gas Fueling Infrastructure

To support NGV deployments, fleets and major fuel providers have established an early network of more than 45 liquid natural gas (LNG) and 500 compressed natural gas (CNG) fueling locations throughout the state.[96] The facilities are primarily located close to existing centralized fueling points for large vehicle fleets. These locations allow fueling stations to serve an established set of customers, while being available as a fueling option for local fleets that are considering the adoption of NGVs.

The further expansion of the California natural gas fueling infrastructure will be closely tied to the increase in the number of vehicles operating in the state. To be economically viable, a fuel provider must have a reliable stream of customers to warrant the significant investment to construct a fueling station. To enable fleets to purchase NGVs, there must be sufficient fueling infrastructure available locally to support their deployment. Fuel providers will often work with fleets and provide the infrastructure if fleets will commit to a certain amount of fuel purchases per year. This coordination allows fleets to have fueling infrastructure provided to them where it may otherwise be cost-prohibitive for them to build it.

In addition to the large public and private fueling facilities, there are also fueling options available for home use. Several units are currently sold that can be installed at a residence and connected to the local natural gas line. These options provide a fueling option for owners of NGVs that may not be closely located to a major NGV fleet. SoCal Gas also offers a special tariff for non-residential customers, which allows the utility to "plan, design, procure, construct, own, operate, and maintain compression equipment on customer premises."[97]

Additional opportunities for expanding the NGV infrastructure lie in the long-haul truck sector. The duty-cycle of these vehicles requires them to travel along the major transportation corridors in California and connected regions. To enable the deployment of these vehicles, a system of strategically located natural gas fueling stations must be developed. Development of such a system will require significant interest and investment from large fleets and fuel providers. Also, there are opportunities with smaller fleets, such as school districts and municipal fleets. These entities are primarily tethered to a single point and transition to alternative fuels based on an economic or environmental analysis of available options and often require outside funding supporting their transition to alternative fuels such as natural gas.

Natural gas is also playing an important role in the development of the emerging hydrogen vehicle industry. There are currently several options available for producing hydrogen fuel

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96 Energy Commission, *2015-2016 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, 2015, p. 49. See http://energy.ca.gov/2014publications/CEC-600-2014-009/CEC-600-2014-009-CMF.pdf.

97 SoCal Gas, "Compression Services Tariff." See http://www.SoCal Gas.com/innovation/natural-gas-vehicles/refueling/compression-services-tariff.shtml.

for transportation purposes. A majority of the existing hydrogen fueling stations utilize a steam reformation process that converts methane or natural gas to hydrogen. This process allows hydrogen fueling stations and centralized fuel producers to utilize the existing natural gas infrastructure as a secure source of fuel for hydrogen production. Based on the latest automaker survey by ARB, roughly 18,500 fuel cell electric vehicles utilizing hydrogen are expected by 2020.[98]

To date, the Energy Commission Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) has provided funding for 48 new or upgraded hydrogen refueling stations throughout the state.[99] Of these, 43 are currently expected to dispense hydrogen derived primarily or significantly from natural gas or renewable natural gas. The Energy Commission should continue to support natural gas fueling infrastructure research and development.

Biomethane Production Opportunities

As California works to increase its alternative fuel consumption, biomethane production has been identified as a source of transportation fuel that can help lower the overall carbon intensity of the fuel supply. When compared on a well-to-wheels basis, biomethane used in NGVs can provide significant GHG reductions when compared to gasoline and diesel. Certain types of biomethane production utilize organic waste stream feedstocks that would otherwise be disposed of in landfills or treated in anaerobic lagoons, resulting in significant emissions of methane and causing negative impacts to local air and water. Diversion of organic materials to anaerobic digestion facilities provides reduced land use, decreased methane emissions from material decomposition and produces both biomethane and secondary goods such as fertilizer.

The ARB has worked with the Argonne National Laboratory to refine the California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model which measures lifecycle GHG emissions on a well-to-wheel basis. The recently proposed carbon intensity values under the new preliminary model, CA-GREET 2.0, include updating the carbon intensity values for gasoline, diesel and alternative fuels. The resulting values show a neutral to modest GHG benefit comparing conventional natural

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98 ARB, *Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development*, June 2014, p. 18. See http://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_final_june2014.pdf.

99 Energy Commission, *2015-2016 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, 2015, p. 45. See http://energy.ca.gov/2014publications/CEC-600-2014-009/CEC-600-2014-009-CMF.pdf.

gas to gasoline and diesel, and a significant GHG benefit comparing biomethane and renewable natural gas to gasoline and diesel. Indeed, some of the biomethane and renewable natural gas pathways represent the lowest carbon pathways available under the low-carbon fuels standard (LCFS) as shown in **Table 2**. For instance, under the existing LCFS regulation, CNG from generic landfill gas offers carbon intensity roughly 80 percent lower than diesel, while CNG from biomethane derived from high solids anaerobic digestion is 125 percent lower than diesel.

The Energy Commission expects additional research that is currently underway to help to further refine this assessment. The Energy Commission should continue to coordinate with and support the ARB's research as well as develop research and development that expands biomethane integration and fueling infrastructure.

Table 2: Low-Carbon Fuel Standard Carbon Intensity Values[100]

Fuel Source	**Existing LCFS Regulation Using CA-GREET 1.8b** (Grams CO2-equivalent per megajoule, adjusted to baseline fuel equivalent using energy economy ratio = 0.9)	**Proposed LCFS Regulation Using CA-GREET 2.0** (Grams CO2-equivalent per megajoule, adjusted to baseline fuel equivalent using energy economy ratio = 0.9)
Ultra Low-Sulfur Diesel	98.03	102.01
California Reformulated Gasoline	98.95	98.47
North American Natural Gas (CNG)	75.56	88.29
North American Natural Gas (LNG, 90% liquefaction efficiency)	80.42	96.19
Landfill Gas (CNG)	12.51	21.34
Biomethane Derived from High Solids Anaerobic Digestion of Food and Green Wastes (CNG)	-13.59	--25.48

Source: ARB : http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm.

100 ARB, "CA-GREET 1.8b versus 2.0 CI Comparison Table", accessed on April 1, 2015, pp. 2-10. See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/040115_pathway_ci_comparison.pdf.

Sustainable Freight and Transport Sector Opportunities

To achieve California's public health, GHG reduction, energy security, and air quality improvement goals, the California freight transport sector has been identified as an area where significant near-term opportunities exist. Through ARB's *Sustainable Freight: Pathways to Zero and Near-Zero Emissions Discussion Document*[101]. California has identified several areas of promise to integrate greater quantities of natural gas technology into the freight transportation sector, to help achieve these goals. These opportunities are especially important to address the significant public health and air quality issues faced by California's most vulnerable populations in disadvantaged communities. **Natural gas can play a significant role in achieving these state-wide goals as described in the Gladstein, Neandross, and Associates' whitepaper entitled "Pathways to Near-Zero-Emission: Natural Gas Heavy-Duty Vehicles".**[102] **Policymakers can assist by encouraging the commercialization of near-zero, natural gas, heavy-duty vehicles through enabling regulation and incentives**.

For medium- and heavy-duty trucks operating in the freight transport sector, the adoption of low-NOx **natural gas** engines that are expected to be commercially available between 2015 – 2016, mixed with the use of low-carbon renewable natural gas, can be used to address the significant greenhouse gas and air quality issues that existing vehicles create.

In the off-road and marine sectors, the use of LNG in conjunction with advanced low emissions engines powered by low-carbon renewable natural gas show significant opportunities to reduce diesel particulate matter, NOx, and GHG emissions. With these vehicles operating in ports and freight hubs in high pollution areas, the introduction of these systems can assist California regions in meeting state and federal protective air quality standards.

Aligning Policies for Transportation and Fuel Development

In the short term (2016 through 2023), the most critical air policy issue the state must address is how to quickly accelerate the purchase and deployment of heavy-duty natural gas trucks to achieve NOx reductions in non-attainment areas. At the same time, the state

101 ARB, *Sustainable Freight: Pathways to Zero and Near-Zero Emissions Discussion Document*, April 2015, p. 4-5. See http://www.arb.ca.gov/gmp/sfti/sustainable-freight-pathways-to-zero-and-near-zero-emissions-discussion-document.pdf. http://www.arb.ca.gov/gmp/sfti/Sustainable_Freight_Draft_4-3-2015.pdf.

102 http://www.gladstein.org/pdfs/On-Road_Pathways.pdf

must develop policies and programs to maximize the supply of renewable natural gas for transportation and other markets to achieve our 2030 and 2050 GHG reduction targets. The transportation sector can be an important catalyst for building the renewable natural gas market.

The CEC is compelled to examine policies that will support the rapid deployment of the near-zero emissions engine technology in the on-road goods movement sector. This technology can play an important role in meeting California's petroleum reduction goal, GHG reduction goal and most importantly NOx emissions reductions that are vital to SCAQMD and SJVAPCD meeting the federal clean air standard. This technology and the resulting NOx emission reductions are achievable today. For example, CWI with the support of CEC, SCAQMD and SoCalGas has moved quickly to develop the first engine that can be used in transit, hauling and regional goods movement sectors. With a focused incentive and technology program, we can expand this technology to the heavier truck sectors and make a substantial improvement in air quality for the most at-risk members of our communities.

Alternative and Renewable Fuel and Vehicle Technology Program

The Energy Commission Fuels and Transportation Division implements the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). With funds collected from vehicle registration and smog fees, the ARFVTP provides up to $100 million per year for projects that will transform California fuel and vehicle types to help attain the state climate change policies. This includes projects that:

- Reduce Californian's use and dependence on petroleum transportation fuels and increase the use of alternative and renewable fuels and advanced vehicle technologies.
- Produce sustainable alternative and renewable low-carbon fuels in California.
- Expand alternative fueling infrastructure, and fueling stations.
- Improve the efficiency, performance, and market viability of alternative light-, medium-, and heavy-duty vehicle technologies.
- Retrofit medium- and heavy-duty on-road and off-road vehicle fleets to alternative technologies or fuel use.
- Expand the alternative fueling infrastructure available to existing fleets, public transit, and transportation corridors.
- Establish workforce training programs and conduct public outreach on the benefits of alternative transportation fuels and vehicle technologies.

To support natural gas related activities in California's transportation sector, the ARFVTP has targeted the major areas where public investment can help remove barriers to the adoption of this alternative fuel.

With the limited number of natural gas fueling stations being built currently, the equipment necessary for construction is often custom fabricated. Due to the lack of economies of scale, the costs for these facilities sometimes prevent interested fleets from switching over their aging diesel fleets to cleaner natural gas options. To help remove this barrier, the Energy Commission has provided funding for natural gas fueling infrastructure construction to entities that may not have access to the necessary capital for such long-term investments.

Similar to natural gas fueling infrastructure, the upfront capital necessary to purchase NGVs is sometimes cost prohibitive for interested parties. To reduce this upfront incremental cost, ARFVTP funds have been utilized to incentivize the purchase of NGVs throughout the state as shown in **Table 3**. Vehicles purchased with these incentives have ranged from light-duty passenger vehicles used for personal transportation to heavy-duty applications such as waste disposal trucks and large freight transport vehicles.

To further advance the MHDV sector beyond the existing vehicles options, the ARFVTP has funded the development of advanced natural gas vehicles including natural gas hybrid-electric drivetrains and low-NOx engine development. These technologies will help improve the overall emissions profiles for natural gas usage in this sector, while providing similar economic benefits as existing natural gas vehicles provide.

Table 3: Previous ARFVTP Awards as of March 9, 2015

Funded Activity	Cumulative Awards to Date (in millions)	# of Projects or Units
Biomethane Production	$51.0	15 Projects
Natural Gas Fueling Infrastructure	$16.1	59 Fueling Stations
Natural Gas Vehicle Deployment	$64.6	4,470 Cars and Trucks**
Natural Gas Engine Research, Development and Demonstration	$16.40	18 Projects

Source: Energy Commission. *Includes both completed and pending vehicle incentives, as well as encumbered funds for future incentives. **Does not yet include any vehicles funded under agreement with UC Irvine to administer future NGV incentives.

Public Interest Energy Research Natural Gas Program

The Energy Commission Energy Research and Development Division administers the Natural Gas Research Program. Transportation has the largest carbon footprint of any sector in California, making it a critical area for innovation. Energy Commission research and development (R&D) focuses on developing and advancing state-of-the-art electricity and natural gas-fueled transportation solutions that reduce fossil fuel consumption, GHG emissions, and air pollutants in the state transportation sector.

The Energy Commission research and development activities include:

- Accelerate the commercial viability of NGVs.
- Improve energy efficiency of NGVs.
- Advance the clean and cost effective production of renewable natural gas for transportation use.

With these goals in mind, the Energy Commission has identified major areas that can be impacted by R&D funding activities.

The market demand for natural gas-powered commercial vehicles has increased significantly in recent years. Natural gas market penetration, however, has been constrained by the unavailability of certain engine sizes and performance ratings. The range of medium- and heavy-duty natural gas engines available to the North American commercial vehicle market is not as comprehensive as the range of diesel engines, for which there is a product line of medium- and heavy-duty diesel engines over a broad range of engine displacement, power, and torque. Specifically, there is currently no natural gas engine available that is ideally suited for Class 3 through 6 commercial vehicle markets, including pickup and delivery trucks, utility trucks, school buses, shuttle buses, yard tractors, and specialized municipal works vehicles such as street sweepers. These market segments typically use 6 to 8 liter diesel engines, with a typical rating range from 200 to 300 horsepower and 500 to 750 lb-ft peak torque. In certain cases such as yard tractors and rear-engine, transit-bus style, Type D school buses, original equipment manufacturers and end users have elected to use larger engines such as Cummins Westport Inc.'s 8.9-liter ISL G engine to enable partial natural gas engine penetration. These engines, however, are typically larger and more expensive (and require heavier transmissions and driveline components) than those installed in the vehicle models typically used in Class 3 through 6 target markets. A smaller engine will be more cost-effective and will provide a better option for the majority of customers in the target markets. In many cases, installing larger engines is simply not an option due to physical constraints in the engine bays of the vehicles typically used in these applications.

Following development of 6 to 8 liter natural gas engines, the next phase in R&D is to perform integration and demonstration efforts to validate the functionality of the engine technology in an appropriate vehicle while evaluating the performance of this newly configured vehicle. The integration and demonstration effort will also help identify any performance or emissions issues that should be addressed prior to commercialization. This final phase will provide engine manufacturers additional insight into opportunities to optimize the performance of the engines and determine the needs of the Class 3 through 6 markets prior to commercialization. Without these additional steps, the newly developed engines could face technical and market barriers that hinder market deployment. The integration and demonstration effort are critical to the successful deployment of newly developed natural gas engines in the class 3 through 6 markets.

Fuel efficiency is a critical factor in determining engine performance, and operating efficiency can be a key enabler for the market transformation to natural gas engine technology in heavy-duty trucks. Natural gas engine fuel efficiency relative to diesel engine efficiency determines cost savings for prospective fleet customers, as well as criteria, toxic, and GHG emission benefits. The fuel efficiency of heavy-duty natural gas fueled trucks, however, varies widely among engine types and vehicle operations. While new engines, such as the un-throttled Westport Innovations high-pressure direct injection natural gas engines, offer efficiency comparable to diesel engines, the more common throttled and spark-ignited natural gas engines experience losses in fuel efficiency that vary widely between steady-speed highway operation and urban stop-and-go operation. Actual measurements of relative fuel efficiency between candidate heavy-duty natural gas engines and various diesel engines in representative fleet operations are needed to help prospective fleet customers evaluate potential fuel cost savings, to document public benefits, and to provide the appropriate incentives that will support market advancement and expansion.

Fuel efficiency can be monitored in actual day-to-day fleet operation, and emissions of pollutants and GHGs can be measured, both in the laboratory over driving cycles selected using data generated from actual day-to-day operation, as well as with an emission-instrumented trailer towed over actual daily routes. Such testing can also identify and measure any deterioration of performance. It is important to select and enlist representative fleets including those using ARFVTP incentives.

Areas for Further Research

Over the past five years, the Energy Commission R&D program has funded and partnered on significant R&D efforts related to advanced natural gas vehicles. **Table 4** provides an overview of the awarded R&D projects.

Table 4: Energy Commission's R&D Program Funding

Funding Topic	Cumulative Funding	No. of Projects
Natural Gas Engine Development *	$10.35M	8
Natural Gas Vehicle On-Board Storage	$2.20M	2
Fueling Infrastructure	$400K	1
Natural Gas Vehicle Systems (Hybridization)	$2.7M	3

Source: Energy Commission.

* Three engines have been successfully commercialized.

One of the highest priorities, as identified in the Natural Gas Vehicle Research Roadmap (CEC-500-2008-044-FN[103]), is the R&D of advanced natural gas engines for a broader range of engine sizes for more applications. The results of the research investments for this priority have yielded natural gas engines on the market that compete well with diesel engines by offering the comparable performance benefits. This is especially significant in the heavy-duty transportation sector where vehicles consume significant fuel, log high miles, and are the largest contributors to on-road emissions on a per vehicle basis. While the market for natural gas vehicles has expanded, and enabled by the R&D funds provided by the Energy Commission, the limits in funding force a narrow selection of engine sizes and vehicle applications resulting in a slow market transformation.

One of the final phases in the engine development process is the vehicle demonstration. Feedback from vehicle fleets indicates that the demonstration phase is one of the key factors to demonstrate functionality of developed vehicles and give fleets the opportunity to operate and gain confidence with the conversion to the new technology. In order to expand the vehicle demonstration effort, developed advanced natural gas engines must be integrated into a variety of different vehicle applications. A focused and aggressive effort to target key markets in the medium- to heavy-duty truck sector can accelerate the adoption of the developed technologies.

Funding to research and demonstrate advanced LNG technologies should be made available. There is currently no infrastructure to support the marine industry's use of LNG, but they are building multi-billion dollar vessels to be LNG-capable in anticipation of the infrastructure to support their fueling requirements. As for the rail sector, BNSF has been testing LNG applications since 2013. They are working with the EPA to conduct thorough tests on climate conditions, emissions levels, as well as engine technology to validate LNG can function without compromising productivity or efficiency.

Caterpillar, Electro-Motive Diesel, and Westport have developed technologies such as High Pressure Direct Injection and Dual Fuel for rail and mining operations, utilizing LNG as a fuel. Incentives for companies adopting technologies can help grow and sustain LNG as a primary fuel for the rail and mining industries.

Additional opportunities that exist but have not had adequate funding include the development and demonstration of large natural gas engines with advanced technology for railroad locomotives (starting with switch engines servicing the ports) that can also be utilized for large off-road vehicles such as earthmovers and mine trucks. These large

103 http://www.energy.ca.gov/2008publications/CEC-500-2008-044/CEC-500-2008-044-F.PDF.

engines constitute a major opportunity for significant NOx and particulate matter emission reductions as well as reducing dependence on petroleum and potentially reducing GHG emissions. Such engines will likely be LNG fueled, with an opportunity for CNG for local switch operation. There is also a related need for development of standards for LNG rail tenders to fuel railroad locomotives. There ~~is interest in supporting~~ **should be support for and a coordinate agency effort to** lower emission technology for these large engines, vehicles, and vessels from ARB and South Coast Air Quality Management District, the engine manufacturers General Electric and Caterpillar/EMD, and the class one railroads**, as well as marine engine and vessel manufacturers**.

The *2014 Integrated Energy Policy Report* indicates that NGVs can have a positive impact on California's transportation sector. These benefits will be enhanced by the further development of the biomethane production facilities and research, development, and deployment of natural gas engines. Continued efforts will be made by the Energy Commission, ARB, and other interested stakeholders to better quantify the impacts of natural gas vehicles on the environment:

- Low-NOx Engines: California faces challenging requirements for reducing criteria air pollutants by 2023 and 2032. Further development of low-NOx engines, both for NGVs and conventional vehicles, is needed to help achieve these goals for vehicle applications where introducing zero-emission technologies is not feasible.
- Expanding Engine Availability: The MHDV sector consists of many different vehicle types with unique service applications. R&D can help build a broader suite of natural gas engines, enabling NGVs to displace a greater number of gasoline and diesel trucks in the future.
- NGV Investment: Additional research may be needed into the factors that inform fleet owner decisions on when to invest in NGVs and how state policies can better influence that decision.
- Biomethane Production: Further research, development, and demonstration into biomethane production technologies and opportunities can contribute to lower carbon intensity for natural gas as a transportation fuel.
- Biomethane Distribution Needs: Integrating biomethane into the California natural gas distribution grid will expand the availability of biomethane producers to market their fuel. Further research may be needed into how to facilitate this process.

CHAPTER 6:
Natural Gas and End-Use Efficiency Applications

Introduction

This chapter addresses natural gas and end-use applications in California in both the residential and commercial building sectors. It covers a range of applications as well as existing policies and programs.

Building Sector

California households and businesses consume about one-third of the total state natural gas usage or about seven billion therms of natural gas annually.[104] Residential natural gas consumption is driven mostly by space and water heating, followed distantly by cooking and miscellaneous residential uses such as clothes dryers and pools. Similarly, commercial natural gas consumption is primarily from space heating and water heating, with cooking being a significant end use as well. Other end uses in commercial buildings include process loads, such as commercial laundry, heated pools, and other loads, such as paint dryers in auto shops.

Residential and commercial natural gas consumption has remained relatively flat for the past two decades despite increases in population, jobs, and gross state product.[105] During this period, the stringency of the California Building Energy Efficiency Standards (Title 24, Part 6 California Code of Regulation) has increased, as has investment in statewide utility energy-efficiency programs. This has contributed to the flattening of natural gas consumption. Maintaining this flat natural gas consumption trend over the next decade, however, may be more challenging. ~~Though natural gas burns relatively cleanly compared to other fossil fuels, opportunities for major improvements in natural gas energy efficiency and technology innovation are sparse.~~ Research on new technologies and reducing costs of proven high efficiency technologies is necessary to help reduce natural gas consumption in the face of forecasted increases in population and economic growth.

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104 Rosales, Jesselyn, Doris Yamamoto. March 2012. *The Natural Gas Research, Development and Demonstration Program: Proposed Program Plan and Funding Request for Fiscal Year 2012-13.* Energy Commission. Publication Number: CEC-500-2012-084, p. 17. Available at http://www.energy.ca.gov/2012publications/CEC-500-2012-084/CEC-500-2012-084.pdf.

105 Gross state product is a measurement of the economic output of a state or province. It is the sum of value added by all industries within the state and is the state counterpart to national gross domestic product.

Water Heating and Hot Water Delivery

About 49 percent of the natural gas used by residents and 32 percent of the natural gas used by commercial facilities (for example, restaurants) is for water heating.[106]

Natural gas water heating is used in more than 70 percent of California homes[107], and of this amount, more than 95 percent use storage (tank) water heaters.[108] Innovations over the past decade have resulted in advances in tankless systems, high efficiency condensing units, hot water distribution systems, reduced flow showerheads and faucets, and solar water heating systems. Implementation of these energy-efficient technologies and practices will result in reduced natural gas use. Additionally, training and design guides, better modeling tools, and building energy efficiency standards will further reduce natural gas use in buildings.[109]

For commercial buildings, the largest user of natural gas for water heating is in restaurants, lodging, and healthcare facilities. There are opportunities to address the large use in these occupancy types through higher efficiency equipment, such as condensing water heaters, and through heat recovery (and in some cases combined heat and power [CHP]), and solar water-heating applications.

Space Heating and Cooling

Natural gas is the main space-heating fuel for homes and businesses. More than 90 percent of households with gas service have gas heating.[110] Across all commercial building types, space heating remains the most dominant natural gas end use. Some commercial buildings also use natural gas for cooling through absorption chillers or gas-driven ~~engines~~ **chillers**.

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106 Seto, Betty, Jarred Metoyer, Rachel Schiff, Jon Taffel (DNV KEMA Energy & Sustainability). March 2014. *Natural Gas Energy Efficiency in Buildings: Roadmap for Future Research*. California Energy Commission. Publication number: CEC-500-2014-036-D, p. 2. Available at http://www.energy.ca.gov/2014publications/CEC-500-2014-036/CEC-500-2014-036-D.pdf.

107 Ibid, p. 19.

108 Ibid, p. 18.

109 2008 and 2013 Title 24 Building Energy Efficiency Standard now requires pipe insulation in all new residential construction.

110 Energy Commission. *California Energy Almanac: Overview of Natural Gas in California*. Available at http://energyalmanac.ca.gov/naturalgas/overview.html.

Absorption chillers or gas-driven engine chillers tend to have lower efficiencies[111,112] than their electric counterparts; therefore, the gas systems are often used primarily for load shifting and or reduction applications.[113]

Innovations over the past decade have resulted in increased energy efficiency of gas furnaces and new innovations in condensing gas units. These technological improvements have also been complemented with improvements to the building envelope and air delivery systems—primarily aimed at keeping buildings airtight and reducing heat loss. **In addition, low NOx residential central furnaces have been deployed and should enter the market in 2015.**

Cooking

About 23 percent of the natural gas used in the commercial sector in California, or approximately 580 million therms, is for commercial cooking.[114] There are 560,000 commercial cooking appliances installed and operating in California and about roughly 70 percent are powered by natural gas. The typical, full-load peak efficiency is the theoretical maximum efficiency for the cooking equipment. It ranges from 20 to 30 percent. Actual in-kitchen utilization efficiencies, which represent the total energy actually attributed to the food product over the cooking day, are in the 5 to 10 percent range.[115] As a result of recent research funded by the Energy Commission, new higher efficiency equipment can reduce

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111 Lizardos, Evans J. October 2011. American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. *Absorption vs. Electric Chiller Technologies*, p. 13. Available at http://www.ashraebistate.org/sites/all/files/events/Chill%20Technologies-101211.pdf.

112 American DG Energy Inc. *Natural Gas Chiller Cooling Systems*. Available at http://www.americandg.com/clean-energy-technology/natural-gas-cooling.

113 Arnold, Roger L. Jr, William P. Bahnfleth. September 1998. *Peak Shaving Using Natural Gas Engine-Driven Chillers,* pp. 56-59. *Heating/Piping/Air-Conditioning*, Vol. 70, Issue No. 9. Available at http://www.engr.psu.edu/ae/faculty/bahnfleth/peak_shaving.pdf.

114 Seto, Betty, Jarred Metoyer, Rachel Schiff, Jon Taffel (DNV KEMA Energy & Sustainability). March 2014**.** *Natural Gas Energy Efficiency in Buildings: Roadmap for Future Research*. California Energy Commission. Publication number: CEC-500-2014-036-D. Available at http://www.energy.ca.gov/2014publications/CEC-500-2014-036/CEC-500-2014-036-D.pdf.

115 Johnson, Frank, Don Fisher, Larry Brand, Eddie Huestis (Gas Technology Institute). July 2013. *Advanced Foodservice Appliances for California Restaurants*. California Energy Commission. Publication number: CEC-500-2014-021, p. 1. Available at http://www.energy.ca.gov/2014publications/CEC-500-2014-021/CEC-500-2014-021.pdf.

natural gas consumption by approximately 23 million therms annually, assuming a 30 to 50 percent penetration in the marketplace.[116]

Industrial Sector

The industrial sector is a major energy consumer and one of the largest users of natural gas in the state, accounting for about 25 percent of total use in 2012.[117] Nearly every industrial subsector in California relies in some way on natural gas. The bulk of natural gas consumption in California industry, however, is dominated by a relatively small set of industrial subsectors. The largest users include petroleum and coal products manufacturing, oil and natural gas extraction, food processing, printing, and the manufacturing of electronics, transportation equipment, fabricated metals, furniture, chemicals, plastics, and machinery. These sectors represent prime areas of opportunity for reducing industrial natural gas use. Consequently, industry represents an important target for improving the efficiency of natural gas use through the adoption of new technologies and improved energy management practices.

Specific operations and product segments within industries can also be identified as major natural gas users. Within food processing, for example, canned and dehydrated fruits and vegetables account for a significant share of natural gas use, due to drying and steam processing operations. Paper and paperboard mills account for a large share of natural gas use in the forest products industry, primarily due to heat used for drying and water evaporation.

Understanding how natural gas is used in California industry makes it possible to focus on opportunities and take advantage of ways to expand the potential benefits. While allocations differ across industrial sectors, process heating and steam generation represent the primary uses of natural gas in California industry. Together, these two uses account for about 85 percent of industrial natural gas use and represent a significant opportunity for realizing efficiency gains. Boilers (steam generation) account for about half of the natural gas used for process heating. The other half is used in a wide range of process heaters that serve a multitude of functions, from melting to forming to drying.[118]

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116 Ibid, p. 5.

117 Energy Commission. *California Energy Almanac: Overview of Natural Gas in California*. Available at http://energyalmanac.ca.gov/naturalgas/overview.html.

118 XENERGY, Inc., for Pacific Gas and Electric Company. December 2001. *California Industrial Energy Efficiency Market Characterization Study*. California Measurement Advisory Council. Study ID:

Existing Policies and Programs

In the past four decades, the state adopted several important new laws and policies that include aggressive goals for energy efficiency and environmental protection. These laws and policies established the appliance and building efficiency standards, and called for increased energy efficiency to meet carbon reduction goals pursuant to Assembly Bill 32, the California Global Warming Solutions Act of 2006 (Nuñez/Pavley, Chapter 488, Statutes of 2006)[119]. While these laws support and advocate for energy efficiency generally, including efficiency in the end-use of natural gas, this section summarizes programs that will have on-going specific impacts on natural gas as an end-use.

Natural Gas Research and Development Program: This program is funded by a ratepayer surcharge on all natural gas consumed in California.[120] The Energy Commission administers the program for the CPUC.[121] The purpose is to fund R&D projects in energy efficiency, renewable energy and advanced generation, transportation, natural gas-related environmental research, and natural gas infrastructure that advance science and technology and that benefit California natural gas ratepayers.[122]

Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009): Assembly Bill 758 requires the Energy Commission to collaborate with the CPUC and stakeholders to develop a comprehensive program to achieve greater energy efficiency in existing residential and nonresidential buildings. The Energy Commission developed the *Comprehensive Energy Efficiency Program for Existing Buildings Scoping Report* in 2012, and released its Final Draft *California's Existing Buildings Energy Efficiency Action Plan* in March 2015[123]. These plans prioritize strategies and approaches to achieve Governor Brown's recent goal and Executive Order direction to double the rate of efficiency savings in buildings in California through

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PGE0112.01; 4947, p. E-7. Available at http://www.calmac.org/publications/California%20Ind%20EE%20Mkt%20Characterization.pdf.

119 The state appliance standards are preempted by the federal appliance standards for nearly all gas fired appliances, thus the state is prohibited from setting more stringent efficiency requirements for these products.

120 Public Utilities Code, Section 890.

121 California Public Utilities Commission. August 2004. *Opinion Regarding Implementation of Assembly Bill 1002, Establishing a Natural Gas Surcharge*. Decision 04-08-010. Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/39314.PDF.

122 Ibid., p. 25 and p. 46.

123 The *California's Existing Buildings Energy Efficiency Action Plan* is on the agenda for adoption at the Energy Commission Business Meeting on September 9, 2015.

2030[124]. The Final Draft *California's Existing Buildings Energy Efficiency Action Plan* recognizes the importance of saving natural gas energy, through both past California efforts, as well as the massive energy efficiency improvement called for by the Governor's direction.

Cost Benefit and Effectiveness Analysis

The Energy Commission sponsored cost-effectiveness/cost-benefit analysis related to natural gas efficiency measures during development of the California Building Energy Efficiency Standards.

Research showed that it was cost effective to mandate hot-water pipe insulation, resulting in an estimated present value to cost ratio of 1.2 to 2.0. The 2008 and 2013 Building Energy Efficiency Standards included insulated kitchen pipes, insulated underground pipes, and pipe insulation for all hot water pipes greater than ¾ inch in diameter.[125]

2005 Flex Your Power Award recipient, Winesecrets, has created a low-energy tartrate removal system that was demonstrated in wineries in 2002 using a $300,000 grant from the Energy Commission.[126] The process, known as Selective Tartrate Removal System (STARS), applies electrodialysis to more efficiently remove tartrates from wine. With the support of the Energy Commission, the technology continues to advance. STARS units process 5 million gallons of wine a year in California, saving 4 million kilowatt hours (kWh) of electricity and 1 million gallons of water, as well as reducing waste sodium hydroxide, sulfuric acid, and salt in the effluent water. In addition, this process prevents 38,000 gallons of wine from being lost due to tartrate removal, and more than 12,000 therms of natural gas are saved because there is no need to warm the wine back up for bottle labeling.[127] If sales stopped today, the present value of operating existing STARS machines in California through 2020 is $8.7 million, 28 times the Energy Commission's investment. California jobs

124 January 5, 2015, Governor Brown's inaugural address http://gov.ca.gov/news.php?id=18828 .

125 Davis Energy Group, Inc. April 2006. *Measure Information Template: PEX Parallel Piping Hot Water Distribution Systems*. California Energy Commission, p. 6. Available at http://www.energy.ca.gov/title24/2008standards/prerulemaking/documents/2006-05-18_workshop/2006-05-11_PEX.PDF.

126 Mirviss, Lillian. March 2014. *Public Interest Energy Research 2013 Annual Report.* California Energy Commission. Publication Number: CEC-500-2014-035-CMF, p. 51. Available at http://www.energy.ca.gov/2014publications/CEC-500-2014-035/CEC-500-2014-035-CMF.pdf.

127 When wine undergoes cold stabilization, condensation from the cold temperatures builds up on the bottle, creating a challenge when adhering labels. After cold stabilization, many wineries have to warm wine bottles back up to near room temperature for labels to adhere properly.

have been created in sales, rental, installation services, and the increased competitiveness of the California wine industry. Currently, 20 Californians are directly employed as a result of Winesecret dissemination of STARS.

Challenges in California

This section discusses some of the major challenges with adopting new technologies and the regulatory constraints associated with natural gas use in buildings and industries.

Technology Considerations

Cost Effectiveness:

> High efficiency natural gas equipment is often more expensive than standard efficiency equipment. Combining the higher cost of equipment with the relatively low cost of natural gas ~~and equipment~~, payback time may be long or even exceed the life of the equipment, which makes it difficult to justify purchase based on energy savings alone. For instance, a solar water-heating system installed as a residential retrofit can cost upwards of $9,000 including collectors and storage tank, compared to the ~~$2,000~~ **$946** for a standard tank water heater.[128] The payback based on energy cost savings, however, can be more than 20 years, which exceeds the life of the solar water-heating components. **Additionally, the California Public Utilities Commission generally limits the Investor Owned Utilities to offering incentives to customers for above-code energy efficiency opportunities and precludes incentives to bring customer buildings and equipment to code.** The keys to making energy efficient equipment more affordable and attractive to California consumers is to reduce the equipment and installation cost**, allow for incentives to bring equipment to,** and above code, while also providing the same level of service as the standard equipment.

Proven/unproven track record of the technology:

> In order to create demand for high efficiency equipment, Californians must be assured that the promised energy savings and other benefits will be realized to justify the higher cost equipment. Demonstrations of advanced technologies in actual residential and commercial buildings, along with independent measured data that shows actual

128 Standard water heater cost is the estimated price of installation by a licensed contractor for a standard tank water heater (EF>0.61), including permits. Solar water heater cost estimate was based on the *June 2015 California Solar Initiative Annual Report*: http://www.cpuc.ca.gov/NR/rdonlyres/8E158382-9114-4756-B0C7-AA6CA1A110A4/0/CSI_2015AnnualReport_FINAL.pdf.

savings, benefits, and reliable performance, are needed to provide confidence that the savings are realistic. For example, research on new energy-efficient cooking equipment showed that it could reduce food service energy use by 23 to 40 percent, depending on the technology. Demonstrations of this equipment will happen in 2015 in several food service establishments in California to monitor energy savings and cooking performance.

Trained workforce:

In some cases, there is a shortfall of adequately trained contractors who can install high efficiency equipment correctly to maximize its efficiency. According to a study by Lawrence Berkeley National Laboratory (LBNL), it is important to educate and support the building and construction industries to make sure they are able to provide a trained workforce to support the growth in energy efficiency and to integrate building and industrial process system efficiency into existing building and construction, through apprenticeship and trades curricula.[129] This could be a cost-effective way to train large numbers of electricians; heating, ventilation, and air conditioning (HVAC) contractors; mechanical insulators; and homebuilders.

Environmental Considerations

Nitrogen Oxides (NOx):

One of the challenges facing natural gas use is air emissions. To meet the Federal Clean Air Act, specifically the 2023 and 2032 Ozone Standards for Extreme Non-Attainment Areas in California **(South Coast Air Quality Management District and the San Joaquin Valley Air Pollution Control District), NOx inventories must be reduced** ~~**natural gas-burning equipment will be required to reduce NOx emissions**~~ by 75 to 80 percent.[130] ~~This requirement greatly impacts natural gas use in the South Coast Air Quality Management District and the San Joaquin Valley Air Pollution Control District. More efficient burners may have about 10 to 15 percent higher NOx levels based on some limited testing done by the Gas Technology Institute (GTI) for food service equipment. Research by GTI, however, indicates that the level of NOx emissions in commercial food service appliances varies significantly based on the design and burner type.~~ **While the majority of the NOx inventory comes from mobile sources, further**

129 Goldman, Charles A., et. al. March 2010. *Energy Efficiency Services Sector: Workforce Education and Training Needs.* Lawrence Berkeley National Laboratory. LBNL-3163E, p. xvi. Available at http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-3163e.pdf.

130 Oral comments from SoCal Gas during *Proposed Natural Gas Research Initiatives Stakeholder Workshop for FY 2015/16*, January 2015.

reductions in NOx emissions from stationary gas-fired equipment will also be required. Over the last 20 years, industry has been very successful in reducing NOx emissions from the majority of gas fired equipment including residential water heaters, industrial boilers and process heaters, and engines to name a few.

Additional research is needed to better understand the relationship of equipment design and burner type, the impact on energy efficiency and NOx emissions, and the opportunities for **further** cost-effective improvements to **gas technologies**. ~~In certain geographical areas there may be measurable impact by end use electrification of space conditioning and cooking equipment.~~

Indoor Air Quality and Methane Leaks:

As buildings are better sealed against air leakage to improve energy efficiency, research is needed to correlate indoor air quality and potential health impacts associated with combustion of natural gas-fired appliances. Recently completed research indicates that combustion of natural gas in household ranges and cook tops results in emissions of NOx and carbon monoxide (CO). Recent research is also evaluating the potential of methane leaks in homes. Potential health hazards could result if these combustion products are inadequately exhausted from the building.[131] Research is needed to demonstrate new, energy-efficient technologies that minimize or eliminate impacts to indoor air quality.

Gaps in Knowledge and Research

This section will describe the knowledge gaps that require additional future research.[132] [133]

Currently, the Energy Commission does not have sufficient funding to support adequate scale-up of the successful technologies within the efficiency area of research. More funding to directly support the scale-up of a wide variety of successful technologies is needed. A

131 Mullen, Nasim A., Jina Li, Brett C. Singer. December 2012. *Impact of Natural Gas Appliances on Pollutant Levels in California Homes*. Lawrence Berkeley National Laboratory. LBNL-5970E, p. 3. Available at http://eetd.lbl.gov/sites/all/files/impact_of_natural_gas_appliances.pdf.

132 Seto, Betty, Jarred Metoyer, Rachel Schiff, Jon Taffel (DNV KEMA Energy & Sustainability). March 2014. *Natural Gas Energy Efficiency in Buildings: Roadmap for Future Research*. California Energy Commission. Publication number: CEC-500-2014-036-D. Available at http://www.energy.ca.gov/2014publications/CEC-500-2014-036/CEC-500-2014-036-D.pdf.

133 California Energy Commission. January 2015. "FY 2015/16 Natural Gas Research Initiatives." Available at http://www.energy.ca.gov/research/notices/2015-01-13_workshop/presentations/FY2015-2016_Natural_Gas_Research_Initiatives_Presentation.pdf.

properly crafted scale-up plan for new technologies would ultimately lead to increased adoption among new users.

Success and uptake of a new efficient product is not just tied to the availability, production and distribution of the new equipment from the manufacturer. Coordinated scale-up aimed at real penetration, integration, and long-term success requires interactions among a variety of groups, including utilities, trade organizations, manufacturers, and a host of other stakeholders. It also requires an understanding of each major customer's future equipment needs, their environment, and demonstrations of how the new efficient products can meet all their needs, without compromising customer satisfaction and quality, while saving energy, water, and money.

A recent example is the use of new, more efficient lines of cooking equipment to include: conveyor ovens, convection ovens, ranges, foodservice woks, under-fired broilers, **efficient grills** and over-fired broilers. While the new equipment is very efficient and is accepted among initial users, the reach of the new cook lines has been rather limited to a relatively small group of users. Expanding a scale-up component for these types of products could lead to much wider adoption across the industry resulting in significant future savings.

Research is needed to demonstrate cost-effective technologies and strategies for reducing natural gas use and cost for water heating and hot water delivery, such as designing and field testing new, efficient low-NOx burner technology and characterization of natural gas use across different building types.

Use of natural gas as a heating fuel may face challenges meeting state and local air quality requirements for NOx and particulate matter, especially in Southern California. Research is needed to improve space heating/cooling technology and delivery of efficiency to address technology cost and meeting local environmental air quality requirements.

Research is needed to develop smart appliances to improve technology efficiency while reducing equipment cost and air emissions.

In reviewing in-door air quality, the requirement as part of some programs to perform Natural Gas Appliance Testing (NGAT) to address safety considerations should be taken into account.

Research is needed to develop next-generation approaches for advanced hybrid systems, **including microCHP products,** that integrate multiple technologies and account for interactive effects of natural gas appliances for ZNE buildings.

A knowledge gap exists on the interaction between natural gas appliances and chemical constituents found in commercial and residential buildings and the need for improved, energy-efficient filtration systems. Research is needed to address data gaps on the interaction between natural gas appliances and indoor air pollution sources (such as moisture, combustion devices, plastics, fire retardants, products for cleaning or finishing surfaces) and improving air filter performance. Research is needed to evaluate the performance of mechanical ventilation systems in newly constructed California buildings to improve indoor air quality.

To advance energy-efficient emerging and under-utilized technologies in this risk-averse sector, demonstrations of technologies are needed to justify cost effectiveness. Additionally, research is needed to identify cost-effective opportunities for heat recovery from combustion systems and natural gas burners in the industrial sector.

Research is needed to address high product costs for condensing appliances. Technical approached should include development of protective coating or use of less expensive alternative materials as a substitute for expensive stainless steel typically used in condensing appliance design.

CHAPTER 7:
Natural Gas Use for Zero Net Energy Buildings

Introduction

The development of new energy production, energy efficiency, and construction technologies has made zero net energy consumption possible in many buildings. This chapter addresses natural gas use in zero net energy (ZNE) buildings, as well as opportunities for ZNE, existing ZNE policy and programs and the challenges that ZNE faces in California.

California and ZNE buildings

The simplest explanation of a ZNE building is that it uses only as much energy as it produces. The benefits of a ZNE building are that the consumer will have lower energy costs and the energy can be obtained from renewable resources. The California Energy Commission adopted the following ZNE goal in the *2007 Integrated Energy Policy Report*:

> Increase the efficiency levels of the building standards and combine them with on-site generation so that newly constructed buildings are ZNE by 2020 for residences and 2030 for commercial buildings.

In the *2013 Integrated Energy Policy Report*, the Energy Commission adopted the following definition for ZNE Code Building, developed in collaboration with the CPUC:

> A ZNE code building is one where the net amount of energy produced by on-site renewable energy resources is equal to the value of the energy consumed annually by the building, at the level of a single "project" seeking development entitlements and building code permits, measured using the Energy Commission time-dependent valuation metric. A ZNE code building meets an energy use intensity value designated in the building energy efficiency standards by building type and climate zone that reflects best practices for highly efficient buildings.[134]

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134 The *2016 Integrated Energy Policy Report* will propose a minor edit in the 2013 definition of ZNE: "A ZNE code building is one where the *value of the* net amount of energy produced by on-site renewable energy resources is equal to the value of the energy consumed annually by the building, at the level of a single "project" seeking development entitlements and building code permits, measured using the Energy Commission time-dependent valuation metric..."

The result could be accomplished through reducing the energy use (both electricity and natural gas) for the building to low levels through energy efficiency, improved energy use practices, and the greater use of renewable energy sources. The implementation of ZNE building concepts in California can have a tremendous impact on the state meeting its energy and environmental goals.

California utilities have offered many new construction programs, incentives, and project pilots to advance the state ZNE building goals. Thousands of homes have been built with increased building energy efficiency standards. The Energy Commission anticipates the 2019 Building Energy Efficiency Standards development to fully achieve the building efficiency measures necessary to enable ZNE realization.

Additionally, in September 2015, the U.S. Department of Energy released *A Common Definition for Zero Energy Buildings*:

> **An energy-efficient building where, on a source energy basis, the annual delivered energy is less than or equal to the on-site renewable exported energy."[135]**

The CEC should align the state's definition with this new federal definition.

Existing Policies and Programs

The Energy Commission ZNE goal has long been supported by the CPUC in the Long-Term Energy Efficiency Strategic Plan, through the development of action plans for both nonresidential and residential buildings and through studies to assess technical feasibility and to plan for implementation. Likewise, the ZNE goal has been supported by ARB in its Climate Change Scoping Plans. Governor Jerry Brown also has actively supported ZNE for newly constructed buildings through his original Clean Energy Jobs Plan, and in his Executive Order B-18-12, which calls for all newly constructed state buildings to be ZNE by 2025.

The Energy Commission is actively pursuing development of the 2016 Building Energy Efficiency Standards to make important energy efficiency upgrades to newly constructed residences in California. The Energy Commission, with support from the California utilities, developed and proposed the following upgrades to prescriptive standards, improving the performance standards by lowering the energy budget: high performance attics with emphasis on insulation at the roof deck, high performance walls with emphasis on advanced insulation methods, instantaneous water heating, and high-efficacy lighting,

135 US Department of Energy, A Common Definition for Zero Net Energy Buildings, available at: http://energy.gov/sites/prod/files/2015/09/f26/A%20Common%20Definition%20for%20Zero%20Energy%20Buildings_0.pdf

emphasizing light emitting diodes (LEDs). The first three measures will result in considerable natural gas savings.

In the *2011 Integrated Energy Policy Report*, the Energy Commission adopted the following key recommendations for achieving high levels of energy efficiency in the building energy efficiency standards updates between now and the 2020 ZNE effective date:

- The Energy Commission, CPUC, local governments, and builders should collaborate to encourage the building industry to reach these advanced energy efficiency levels in a substantial segment of the market through industry-specific training and financial incentives.
- The Energy Commission and CPUC should coordinate future investor owned utilities (IOUs) "new construction-related" programs with the Energy Commission's efforts to meet the ZNE goals through triennial updates of mandatory and reach standards. By offering incentives for achieving reach standards, providing technology demonstration and development, and conducting pilot programs for demonstrating ZNE solutions, new technologies and building practices can be integrated into upcoming triennial updates of the building standards quicker and with more success.
- The Energy Commission, CPUC, builders and other stakeholders should collaborate to accomplish workforce development programs to impart the skills necessary to change building practice to accomplish ZNE in newly constructed buildings.
- Starting in 2013, the California IOUs, in response to CPUC direction, have actively worked to focus attention of key programs—Codes and Standards Program, California Advanced Home Program (CAHP), Emerging Technology Program, and Workforce, Education and Training Program—on collaboration to deliver on the ZNE goals. The CAHP has redesigned its new construction incentive program to develop and put into place a revamped incentive structure that bases its incentives on target energy use intensity values, as anticipated by the *2013 Integrated Energy Policy Report*.

In the second half of 2014, the Energy Commission worked with the CPUC, California IOUs, Sacramento Municipal Utilities District, and the California Building Industry Association to establish the "High Performance Attics and High Performance Walls Code Readiness Initiative."

On June 10, 2015, the California Energy Commission unanimously approved building energy efficiency standards to reduce energy costs, save consumers money, and increase comfort in new and upgraded homes and other buildings.

Single family homes built with the Energy Commission 2016 Building Energy Efficiency Standards are expected to use about 28 percent less energy for lighting, heating, cooling, ventilation, and water heating than those built under the 2013 standards. The new standards, which take effect on January 1, 2017, focus on three key areas: updating residential requirements to move closer to California ZNE goals, updating nonresidential and high-rise residential requirements, and improving the clarity and consistency of existing regulations. Based on a 30-year mortgage, the Energy Commission estimates that standards will add about $11 per month for the average home but save consumers $31/month on monthly heating, cooling, and lighting bills.

Residential

Other major improvements in the 2016 Building Energy Efficiency Standards include:

- High performance attics: extra insulation at the roof deck in addition to ceiling insulation will reduce the attic temperature by 35 degrees or more during hot summer days.
- High performance walls: builders can choose from many different assemblages to reduce heating and cooling needs in the home year round.
- Lighting: installation of high quality lighting with controls that nearly halve the energy required for lights in new homes.
- Water heating: installation of tankless water heaters that reduce use by about 35 percent.

Nonresidential

- Envelope: revision of outer building, or envelope, requirements for all nonresidential and high-rise residential buildings.
- Lighting: update power allowances for lights to align with the American Society of Heating, Refrigerating, and Air-Conditioning Engineers standards.
- Elevators: require lights and fans to shut off when an elevator is empty.
- Escalators and moving walkways: require escalators and moving walkways in transit areas to run at a lower, less energy-consuming speed when not in use.
- Windows and doors: require lockout sensors that turn off cooling and heating systems if a door or window is left open for more than five minutes.

Cost Benefit Analyses

Estimates of the energy and GHG reductions, as well as cost effectiveness and other economic valuations of the role of ZNE in accomplishing California climate change goals, can be found in the ARB's *Climate Change Scoping Plan* (December 2008) and the *First Update* *to the Climate Change Scoping Plan* (May 2014).[136] It lays out a plan that will continue to further decrease GHG emissions and meet federal air quality requirements. But, in order to accomplish this, every major economic sector must play a role in the effort.

The Warren-Alquist Act, which created the Energy Commission in 1974, obligates the Energy Commission to meet specific cost-effectiveness requirements in the course of adopting energy efficiency standards for buildings and appliances. The Energy Commission, in collaboration with the CPUC, has made multiple updates of its building and appliance standards on the road to ZNE. For the latest round of standards, estimates of the energy savings and cost effectiveness, as well as GHG reductions of natural gas measures in contributing to further accomplishment of ZNE goals, can be found within Energy Commission rulemaking documents.[137]

Under the oversight of the CPUC, research has been conducted to support the development of specific Action Plans to meet the Long-Term Energy Efficiency Strategic Plans for ZNE. Estimates of energy savings and carbon reductions of ZNE buildings in California can be found in *The Technical Feasibility of ZNE Buildings in California*.[138] This study is a forward-looking stress test of the ZNE construction goals set forth by the CPUC and the Energy Commission. The goals establish both a 2020 and a 2030 goal. The 2020 goal sets a target for all low-rise residential new construction to reach ZNE, and the 2030 goal sets a target for all commercial new construction to reach ZNE. This study assesses the different possibilities for accomplishing these goals, and sets forth a list of recommendations. These recommendations include load reductions, use of passive systems such as natural ventilation, use of active systems for heat recovery, and further research to increase the efficiency of PV panels.

Challenges in California

The ZNE goals address the total energy that the building and its energy-using equipment and systems consume. ZNE buildings must have high levels of energy efficiency of both the

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136 Climate Change Scoping Plans http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf and http://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm .

137 2016 California Building Energy Efficiency Standards http://www.energy.ca.gov/title24/2016standards/rulemaking/ .

138 CALMAC Study ID—PGE0326.01 available at: http://www.cpuc.ca.gov/NR/rdonlyres/8DC39CB6-A29C-4789-B888-A9556F500BE5/0/CaliforniaZNETechnicalFeasibilityReport.pdf.

structure and energy-using appliances, combined with the addition of clean, renewable power generation, typically solar photovoltaic (PV).

ZNE could not be achieved without carefully addressing the natural gas energy use that is prominent in today's buildings. This is particularly true in residential buildings, where approximately 18.5 percent of the natural gas delivered to consumers in California is typically used for space or water heating, or cooking. [139] The Energy Commission can use its regulatory authority, both building energy efficiency standards (Title 24, Part 6 (California) Energy Code) and Part 11 (California Green Building Standards Code)) and appliance efficiency standards (Title 20, Chapter 4, Article 4), to require buildings and the equipment used in buildings to be energy efficient, and it has done so for both[140].

The time window between the Energy Commission adoption of the ZNE goal in 2007 and the 2020 effective date of the goal for newly constructed residential buildings is short. The Energy Commission made significant energy efficiency upgrades to the 2010 and 2013 California building energy efficiency standards and expects even more stringent standards in the 2016 and 2019 updates.

The Energy Commission is also pursuing some critical energy efficiency measures, which will require significant changes in building practice for residential building envelopes, the upgrading the efficiency of water heating and residential lighting. Consistent with the ZNE goal, these measures will save both electricity and natural gas. Finally, the Energy Commission is engaged in a multi-phase proceeding to upgrade appliance efficiency standards, which are expected to contribute to meeting the ZNE goals by saving electricity consumption from lighting and plug loads, and natural gas consumption for water heating resulting from the reduced water flow of plumbing fittings.

The residual electricity and natural gas consumption after these energy efficiency measures are implemented must be offset by rooftop solar photovoltaics (PV) or other renewable resources. Under current net energy metering rules, building owners are compensated at retail rates for onsite PV generation up to but not exceeding their annual energy usage. Any annual surplus generation is compensated at relatively low rates[141]. One way to address this situation would be to identify means of otherwise offsetting the residual natural gas usage,

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139 U.S. EIA, Natural Gas Consumption by End Use Database, accessed on June 1, 2015.

140 The state appliance standards are preempted by the federal appliance standards for nearly all gas fired appliances, thus the state is prohibited from setting more stringent efficiency requirements for these products.

141 Example of surplus generation rates: https://www.sce.com/wps/portal/home/regulatory/tariff-books/rates-pricing-choices/net-surplus-compensation.

such as through uses of waste heat, including CHP, or potentially through the use of renewable gas resources at the building site or on a community basis.

Some stakeholders suggest a ~~One~~ potential way to reduce emissions from end-use applications is to replace natural gas appliances, such as gas stoves, water heaters, and space conditioning units, with electric appliances. This fuel-switching is called "electrification," and at this time the greenhouse gas emission reduction benefits are not clear since a significant amount of electricity in the grid comes from natural gas combustion. Other things to consider are that end-use natural gas appliances typically have higher, very often much higher, efficiencies than power plants, and they also avoid losses in the electricity system. To the extent that California's generation mix and policy continues to advance more renewables versus natural gas generation, electrification would realize additional emission benefits. It is also not clear from a customer perspective how cost effective end-use electrification applications are. ~~Further research is necessary to better understand the trade-offs for electrification. For example, a recent July 2015 City of Palo Alto Utilities Advisory Commission Memo indicated that it may be cost effective for residential customers to switch from natural gas to electric heat pump technologies for water heating, and that space heating is close to being cost-effective.[142] The same memo indicated that the overall lifetime cost and operation of electric stoves and clothes dryers was more expensive versus natural gas.~~ **A recent study conducted by SoCalGas and Navigant Consulting, *Strategy and Impact Evaluation of ZNE Regulations on Gas-Fired Appliances Phase I Technology Report*[143], revealed areas where mixed-fuel homes have distinct advantages over electric-only ZNE homes when compared to a baseline electric-only home. Mixed-fuel homes have advantages in solar PV system size, incremental cost, simple payback, and TRC values compared to electric-only homes. Mixed-fuel ZNE homes typically offer an average 9% reduction ($2,200) in incremental cost compared to electric-only ZNE homes, based on the smaller required solar PV system size (reduction of 0.5 kW). On a utility programmatic perspective, mixed-fuel ZNE homes shows higher TRC values than electric-only ZNE homes when compared to baseline electric-only home for each location. On an incremental life-cycle cost basis, TRCs range from 0.42-0.46 for mixed-fuel and 0.33-0.38 for electric-only. When evaluated on an upfront incremental cost basis, TRCs range from 0.86-0.96 for mixed-fuel and 0.57-0.74 for electric-only ZNE homes. Beyond technical and economic advantages, new home-buyers overwhelmingly prefer natural gas appliances, further increasing the attractiveness for mixed-fuel ZNE homes.[144]**

142 July 2014 Utility Advisory Board Memo: https://www.cityofpaloalto.org/civicax/filebank/documents/47998.

[143] Navigant Consulting, Strategy and Impact Evaluation of ZNE Regulations on Gas-Fired Appliances Phase I Technology Report, March 2015

[144] SCG. 2015. "Visions 2014 Home Preference Study." Southern California Gas Company. Accessed March 2015. Available at: http://www.socalgas.com/for-your-business/builder-services/visions-home-survey.shtml

The South Coast Air Quality Management District (SCAQMD) indicated in their draft 2016 Management Plan, that while they have adopted the most stringent NOx emission regulations for new residential and commercial natural gas-fired water heaters and space heaters in the nation, residential natural gas combustion-related NOx emissions remain a significant source of emissions, ranked second highest among stationary NOx emission sources[145]. They recommend energy efficiency as an effective means to augment SCAQMD existing regulations to bring about further NOx reductions. The SCAQMD further recommends promoting energy efficient technologies in future SCAQMD regulatory or incentive programs.

The *2013 Integrated Energy Policy Report* recognized that as a practical matter, there will be a need to allow for meaningful flexibility as a significant number of buildings may be unable to meet the on-site renewable energy resources component of the ZNE code building definition. For example, a home may not meet ZNE building code due to rooftop shading. The ZNE building code definition anticipates the need for "development entitlements" for off-site renewable, such as community based renewable resources, to be a viable option for builders and developers. Any option for achieving compliance with ZNE requirements that relies on off-site renewable resources must provide a clear method for building department verification that ensures that the resources exist at the point in time that the building is being permitted. In addition, there should be no ambiguity regarding whether the building is properly offset by the community resource and that information concerning the development entitlement is reliably available without delay or significant additional work effort on the part of the building department at the point in time that compliance decisions are required.

It is possible that community based, renewable natural gas resources could be considered for these "development entitlements" if they could meet these building department reliability, verifiability, and enforceability needs.

Pande et al. 2015. "Residential ZNE Market Characterization." TRC Energy Services. CALMAC Study ID PGE0351.01. February 27, 2015.

145 South Coast AQMD Draft 2016 Management Plan White Paper: http://www.aqmd.gov/docs/default-source/Agendas/aqmp/white-paper-working-groups/preliminary-draft-residential-and-commercial-energy-white-paper.pdf?sfvrsn=2.

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Gaps in Knowledge and Research

An important area where additional knowledge and research is needed is on the costs of ZNE impacts to the electricity grid. A discussion of grid impacts can be found in the CPUC report *The Road to ZNE*.[146] This study identifies pathways to achieving ZNE for new construction low-rise residential buildings by 2020 and commercial buildings by 2030. It has three main objectives: (1) establish framework for ZNE research; (2) perform market assessment that identifies market intervention strategies; and (3) identify pathways to ZNE for residential and commercial new construction.

The study found that ZNE goals will help achieve California GHG reduction goals, and while they are not legally mandated, it would benefit the economy to meet them. The study also found that the ZNE market is still early in its development, and there remain significant uncertainties such as the potential impacts of the ZNE goals on the electrical grid, and whether the goals are cost-effective. It found that reducing the costs of renewables is necessary and identified the need for greater coordination amongst the regulatory agencies.

The Energy Commission should ~~continue to~~ explore the connection between end-use natural gas applications and ~~the increased electrification of buildings and electric appliances~~ **role they will play in reaching ZNE goals**. The joint CPUC and Energy Commission June 2015 *New Residential Zero Net Energy Action Plan 2015-2020* indicates that there is still uncertainty and lack of a clear path to achieving the vision of ZNE.[147] Further, the report doesn't address natural gas applications with ZNE.

146 P. 104, available at: http://www.cpuc.ca.gov/NR/rdonlyres/0474B6C9-2288-4EA0-B3B1-83ECBD4C70A4/0/TheRoadtoZNEReport.pdf.

147 http://www.cpuc.ca.gov/NR/rdonlyres/92F3497D-DC5C-4CCA-B4CB-05C58870E8B1/0/ZNERESACTIONPLAN_FINAL_060815.pdf.

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CHAPTER 8:
Natural Gas and Biogas as Low Emissions Resources

Introduction

This chapter provides an overview of **the opportunities, challenges, and opportunities for additional research in** California **to produce and use** biogas and biomethane ~~production opportunities as well as the challenges they face~~. **Opportunities to capitalize on biogas and biomethane resources from other states as well as opportunities for energy storage through electrolysis, (Power-to-Gas) are also included.**

Biogas and Biomethane Production

Biogas is the raw, untreated gas generally produced during the anaerobic decomposition of biomass and is principally composed of methane and carbon dioxide. Biomethane**, also known as renewable natural gas (RNG),** is the treated product of biogas where CO_2 and other contaminants are removed. Biogas is a byproduct of normal operations at many landfills (operating and closed), dairies, and wastewater treatment facilities. Biogas can also be produced by standalone facilities either directly through biochemical conversion processes (anaerobic digestion) or indirectly through gas reformation of ~~producer~~ **product** gas from thermochemical conversion processes. The Estimated Annual biomethane potential for California is shown in **Table 5**.

An important near-term opportunity for biomethane project development in California is being driven by California Department of Resources Recycling and Recovery's (CalRecycle) 75 percent diversion goal[148] and AB 1826 requirements for organic waste management.[149] In order to comply with these goals, anaerobic digestion is expected to be a major strategy used by waste handlers and municipalities to manage diverted organic waste. Tipping fees paid by waste haulers who dispose of organic waste at these facilities can provide a baseline revenue stream, which may be more consistent and reliable than revenue associated with the sale of product biomethane into current markets, providing more stability and significantly enabling the development of such facilities. With this

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[148] California has a legislative and executive goal of 75 percent recycling, composting or source reduction of solid waste by 2020. http://www.calrecycle.ca.gov/75percent/ and AB 341

[149] AB 1826 requires commercial facilities producing 8 cu yds or more weekly of organic waste on April 1, 2016, 4 cubic yards or more weekly of organic waste on January 1, 2017, 4 cubic yards or more weekly of commercial solid waste on January 1, 2019, and potentially 2 cubic yards or more weekly of commercial solid waste on January 1, 2020 to arrange for organic waste recycling services. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB1826

additional revenue source it is likely that a significant portion of the near-term biomethane projects in California may be developed in this market sector.

Some ~~E~~end-use opportunities for **biogas and biomethane** include electricity production, temperature control, and transportation fuel ~~production~~. In each of these cases, biogas (or biomethane) can supplement or directly replace the use of natural gas. Biomethane can also be injected into utility pipelines if quality standards are met. At this time there is not industry consensus on the best use of biomethane.

Table 5: Estimated Annual Biomethane Potential for California

	Gross Potential Bcf/yr[150 151]	Technical Resource Potential[152 153] Bcf/yr	Net Resource Potential Bcf/yr[154]
Dairy and Cattle Manure	33	17	17
Poultry Manure	6	3	0
Landfill Gas	71	53	34
Waste Water Treatment Plants	8	7	3
Municipal Solid Waste	18	13	8
Total	**136**	**93**	**62**

Compiled by: Rob Williams, UC Davis.

150 Compiled by Rob Williams, University of California, Davis. Source material: Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. See http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

Pages Cited: Landfill Gas: 44; Waste water treatment: 45; Dairy, cattle and poultry manure: 22, 40, 41, 46; MSW Page 28, 46.

151 Gross Potential based on recovering all available biomass and converting to biomethane.

152 Compiled by Rob Williams, University of California, Davis. Source material: Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

In addition to in-state biogas resources and feedstocks that may easily be converted to biogas via anaerobic digestion, the resource potential outside of California should be taken into consideration as it has already proven beneficial to the State in with regards to the Low Carbon Fuel Standard program, and other biomass feedstocks should be considered as an opportunity for use in longer-term technologies, such as pyrolysis. Below is a table comparing published data on biogas potential from several publicly available references.

Table 6: Comparison of Published Data on Biogas Potential

Technical Resource Potential	AB 1257 Draft Report Bcf/y	BAC Bcf/y [155]	AGF Bcf/y [156]		NPC Bcf/y [157]	DOE Bcf/y [158]	
	CA	CA	CA	US	US	CA	US
Agricultural Residue	N/A	31	4.2 - 10.6	401 - 1,002	1,300	30.7 - 33.7	327 - 1,872
Dairy and Cattle Manure	17	19.4	8.7 - 29	148 - 493	140	2.3 - 10.3	72 - 336
Poultry Manure	3						

Pages Cited: Landfill Gas: 44; Waste water treatment: 45; Dairy, cattle and poultry manure: 32, 40, 41, 46; MSW Page 28, 46.

153 Technical resource potential estimates the physical system constraints that limit utilization of the gross resource potential. Constraints limiting biomass resource potential include agronomic and ecological requirements, terrain limitations, inefficiencies in biomass collection and handling, among others. . For this report, the resource potential for waste water treatment plants was further constrained by staff to limit the technical viability to only facilities that have an average annual flow rate of 1 million gallons per day of waste water.

154 Net resources available for methane production assume the following constraints: Energy production from poultry manure has not been proposed or demonstrated at scale. In 2013, 19.7 million MMBTU of landfill gas (19.2 Bcf methane) was used to generate electricity (*QFER*). 3.8 million MMBTU of biogas (3.7 Bcf methane) was used to generate electricity in 2013 (*QFER*). Municipal solid waste diversion of organic materials were reduced from 5.8 million tons per year to 3.75 million tons per year to align with CalRecycle policy goals. See http://www.arb.ca.gov/cc/scopingplan/2013_update/waste.pdf. Energy conversion: 1,025 BTU = 1 standard cubic foot of methane.

155 **http://www.bioenergyca.org/wp-content/uploads/2015/03/BAC_RenewableGasStandard_2015.pdf**
156 **http://www.gasfoundation.org/researchstudies/agf-renewable-gas-assessment-report-110901.pdf**
157 **https://www.npc.org/FTF_Topic_papers/22-RNG.pdf**
158 **http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf**

Energy Crops	N/A	73.5	N/A	80 - 200	1,500	N/A	364 - 6,483
Fats, Oils, and Greases	N/A	6.4	N/A	N/A	N/A	N/A	N/A
Forestry and Forest Product Residue	N/A	80.9	4.9 - 12.2	82 - 206	1,100	9.2 - 15	293 - 569
Landfill Gas	53	52.1	28.4 - 56.8	182 - 365	340	N/A	N/A
WWTP	7	7.5	0.3 - 0.8	4 - 13	60	N/A	N/A
Municipal Solid Waste (food, leaves, and grass)	13	12.1	7.8 - 23.3	69 - 207	400	12.1 - 14.1	148 - 247
Municipal Solid Waste (lignocellulosic)	N/A	39.9				10.3 - 17.7	53 - 64
Total	**93**	**322.8**	**54.3 - 132.7**	**966 - 2,486**	**4,840**	**67.2 - 98.6**	**1,256 - 9,572**

Data from The Bioenergy Association of California Whitepaper (BAC),[159] The American Gas Foundation potential study (AGF),[160] The National Petroleum Council feedstock overview (NPC),[161] and the U.S. DOE Billion Ton update (DOE)[162]

Generally, facilities such as dairies, landfills, and wastewater treatment facilities produce biogas as a by-product of normal operation. In most cases, the potential for methane production is limited by immutable factors, such as the "waste-in-place" at a landfill or volumetric flow of water into a wastewater treatment plant. In some cases, production can be increased if there are opportunities to process additional biomass feedstocks within normal operations. Examples include dairy digesters accepting food waste and wastewater treatment plants co-digesting fats, oils, and grease.

Arguably one of the greatest benefits ~~for~~ of using biomethane is ~~through~~ the reduction of anthropogenic methane emissions. Manure management, landfills, and wastewater treatment are three of the largest anthropogenic methane-producing sources in California.

Landfill Waste Disposal

There are two distinct methods for collecting methane which would reduce the overall emissions of landfill waste disposal; the diversion of organics from landfill disposal and collection of landfill gas at existing landfills.

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159 http://www.bioenergyca.org/wp-content/uploads/2015/03/BAC_RenewableGasStandard_2015.pdf

160 http://www.gasfoundation.org/researchstudies/agf-renewable-gas-assessment-report-110901.pdf

161 https://www.npc.org/FTF_Topic_papers/22-RNG.pdf

162 http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf

Diverting Organic Solid Waste

Diversion of organic waste from landfills represents opportunities for methane collection and avoidance of anthropogenic methane emissions. In 2012, methane emissions from landfills were over 8 million metric tons of carbon dioxide **equivalent** (MMTCO$_2$e).[163] [164] Although most operating landfills are required to install gas collection systems, these systems cannot capture all of the gas produced and collection efficiency is a function of time, decay rate, moisture content, and management practices. During the first 10 years of gas collection in a landfill, the calculated gas collection efficiency can range from 25 to 75 percent of gas production.[165]

Assembly Bill 341 (Chesbro, Chapter 476, Statutes of 2011), requires that at least 75 percent of all solid waste generated in California be source reduced, recycled, or composted by 2020. California Department of Resources, Recycling, and Recovery (CalRecycle) estimates that diverting 75 percent of compostable materials to compost and anaerobic digestion can reduce landfill methane emissions by 4.5 to 5.6 MMTCO$_2$e per year and reduce the annual landfill disposal by 7.5 million tons annually.[166] Their analysis assumes that half (3.75 million tons) of the material will be available for energy production, while the remaining material will be composted. In some applications, biomass sent to anaerobic digesters could reduce methane emissions by an estimated 2 MMTCO$_2$e per year and could produce over 8 billion standard cubic feet (Bcf) of biomethane annually.[167]

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163 ARB, 2000 – 2012 Greenhouse Gas Inventory, see http://www.arb.ca.gov/cc/inventory/doc/doc.htm.

164 Calculation based upon the Intergovernmental Panel on Climate Change Fourth Assessment Report's Global Warming Potentials, Chapter 3, which accounts for methane collected by landfill gas collection systems. *2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 5, Chapter 3: Solid Waste Disposal.* Seehttp://www.ipcc-nggip.iges.or.jp/public/2006gl/vol5.html.

165 Morton A. Barlaz , Jeff P. Chanton & Roger B. Green (2009) Controls on Landfill Gas Collection Efficiency: Instantaneous and Lifetime Performance, Journal of the Air & Waste Management Association, pp. 1399-1404.

166 California Department of Resources Recycling and Recovery, AB 32 Scoping Plan Composting and Anaerobic Digestion Technical Paper. 2013. Table 2 Page 5.See http://www.calrecycle.ca.gov/Actions/Documents/77/20132013/935/Composting%20and%20Anaerobic%20Digestion%20FINAL.pdf.

167 This is a staff estimate assuming 25 percent volatile solids, methane production of approximately 5 standard cubic feet per pound of organic solid waste, and 50 percent methane production efficiency. Actual production will depend on a number of real-world factors such as technology, feedstock type, and so forth.

Collection of Landfill Gas

While diverting waste can ~~avoid new~~ **reduce growth of methane emissions** from landfills, existing waste-in-place is currently decomposing and ~~releasing~~ **producing** methane**, an estimated 25 percent of which is not collected, resulting in atmospheric methane** emissions. Since 1970, approximately 1.2 billion tons of waste has been buried in California landfills.[168] Total annual methane production is estimated to be 71 Bcf.[169] Assuming that collection systems are capable of collecting 75 percent of this gas, the adjusted potential for methane from landfill gas is 53 Bcf per year. In 2013, electricity generators reported using 19.7 million British thermal units (MMBtu) of landfill gas (approximately 19 Bcf of methane) to generate electricity.[170] Thus, the net resource potential for methane from landfills is about 34 billion cubic feet (Bcf per year, or about 1.5 percent of total California natural gas demand.[171]

The biomass decay rate in landfills is relatively inefficient compared to controlled processes such as anaerobic digestion, requiring decades of operation and maintenance of gas collection systems after landfills are closed. According to the latest waste characterization study from the CalRecycle, organic material (biomass) comprises more than 60 percent of solid waste disposed in landfills.[172] Nearly half of this material, or 30 percent **of all solid waste**, is compostable; that is, it is a suitable feedstock for anaerobic digestion. More than ten million tons of compostable material is disposed in landfills each year.[173] The California

168 Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020, p. 44, table 3.2.3.2. See http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

169 California Biomass Collaborative, University of California, Davis, An Assessment of Biomass Resources in California, 2013, March, 2015, Table 3.2.3.2. See http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

170 California Energy Commission, QFER CEC-1304 Power Plant Owner Reporting Database. (Data accessed 11/25/2014.) See http://energyalmanac.ca.gov/electricity/web_qfer/source_files.

171 PG&E, et, al. 2014. *2014 California Gas Report*, p. 30.

172 CalRecycle California 2008 Statewide Waste Characterization Study, November, 2009, Table ES-3 (paper, lumber, organics). See http://www.calrecycle.ca.gov/Publications/Detail.aspx?PublicationID=1346.

173 California Department of Resources Recycling and Recovery, Composting and Anaerobic Digestion, September, 2013. p.2. See http://www.calrecycle.ca.gov/Actions/Documents/77/20132013/935/Composting%20and%20Anaerobic%20Digestion%20FINAL.pdf.

biomass collaborative estimates that diverting 5.8 million tons per year of food, leaves, and grass to anaerobic digester systems can produce 13 Bcf of biomethane per year.[174]

Manure Management

Manure management represents the second largest source of methane emissions in California, accounting for over 10.6 $MMTCO_2e$ per year. Manure management at dairies account for over 10.2 $MMTCO_2e$ per year.[175] Dairies generate significant amounts of methane, primarily from manure storage lagoons. In certain application, these emissions can be collected using existing anaerobic digester technologies to enclose lagoons or by replacing lagoons with enclosed tanks.[176]

The California Biomass Collaborative estimates that dairies generate 6 million dry tons of manure each year[177] and that this manure, combined with other cattle manure, has the technical maximum potential to produce 17 Bcf (33 Bcf gross) of biomethane per year.[178] In certain applications, anaerobic digestion of dairy manure can provide non-energy benefits such as ~~increased~~ **improving** nutrient management, reducing dairy odors, and possibly improving groundwater quality. The process can also be designed to produce solids that are rich in ammonia and useful as a stable fertilizer or fiber for animal bedding.[179]

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174 Ibid, Table 3.2.4.1

175 California's Greenhouse Gas Inventory by Intergovernment Panel on Climate Change Category (filter for methane emissions from manure management). See http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_ipcc_00-12_2014-03-24.xlsx.

176 ARB, *First Update to the Climate Change Scoping Plan. Appendix C - Focus Group Working Papers Agriculture Working Paper.* May, 2014. p. 9. See http://www.arb.ca.gov/cc/scopingplan/2013_update/agriculture.pdf.

177 California Biomass Collaborative, University of California, Davis, *An Assessment of Biomass Resources in California*, 2013, March, 2015, Table 2.1.5.5. See http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

178 Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. *An Assessment of Biomass Resources in California, 2013 – DRAFT*. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. Staff calculation using Table 3.2.3.1.and Table 2.5.2.. http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

179 ARB, *First Update to the Climate Change Scoping Plan. Appendix C - Focus Group Working Papers Agriculture Working Paper*. May, 2014. pp. 9-10. See http://www.arb.ca.gov/cc/scopingplan/2013_update/agriculture.pdf.

Wastewater Treatment

As of 2013, California's wastewater treatment facilities account for 1.65 $MMTCO_2e$ of methane emissions per year. According to data collected by the California Association of Sanitation Agencies, there are 242 active water, wastewater, and sewage treatment facilities in California with an aggregate flow of over 3,000 million gallons per day. There are nearly 140 wastewater treatment plants with average daily flow rates above 1 million gallons per day and currently utilizing anaerobic digesters in their treatment process[180] with an aggregate flow rate of 2,800 million gallons per day.[181] These facilities are capable of producing approximately 7 Bcf of methane per year.[182] Electricity generated using biogas from wastewater treatment used 3.8 million MMBtu of biogas, or 4 Bcf of biomethane, in 2013.[183] Thus, the net available resource is 3 Bcf of methane per year.

Other Feedstock Opportunities

Other waste feedstock opportunities do exist to produce biomethane through anaerobic conversion **of organic waste**, such as cattle manure, and thermochemical conversion **of lignocellulosic organic wastes**, such as wood waste. These opportunities were not **specifically** included in this report because more research is needed to develop technologies and feedstock collection systems to make them a viable option for California**; however some feedstock potential numbers are included in Table 6 above**. These opportunities include thermochemical conversion under different temperatures, pressures, and using various thermal media—such a gasification, hydro-plasma gasification, plasma-arc gasification, pyrolysis, and so forth. Syngas, or other product gasses from these processes are rich in hydrogen, hydrocarbons, and/or carbon oxides. Chemical reformation processes can be

180 In general, it is assumed that flow rates below 1 million gallons per day would not lead to biogas yields high enough to make an energy project economically feasible.

181 California Biomass Collaborative, California Biomass Facilities, May, 2013. http://biomass.ucdavis.edu/files/2013/09/11-20-2013-cbc-facilities-database_1May_2013_update.xlsx.

182 Assuming 100 gallons of wastewater can produce 1.15 CF of biogas (65 percent methane content, 90 percent recoverable). Source: Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. *An Assessment of Biomass Resources in California, 2013 – DRAFT*.

Report to the Energy Commission. PIER Contract 500-11-020. p.43. See http://biomass.ucdavis.edu/files/2015/04/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf.

183 QFER CEC-1304 Power Plant Owner Reporting Database. Data accessed 11/25/2014. See http://energyalmanac.ca.gov/electricity/web_qfer/source_files.

applied to produce methane or other hydrocarbons. Chemical reformation, while possible, requires additional fuel processing, equipment, and on-site energy use.

These aforementioned factors~~,~~ however, increase the overall production cost of **biomethane from these** ~~a~~ feedstock. Therefore, generation projects utilizing biomethane **generated from these** ~~through~~ feedstock are **currently** generally limited to research and demonstration serving on-site energy use. These projects typically experience similar interconnection challenges as combined heat and power projects as many are not eligible for incentive programs. **Further study should be conducted to quantify the long term benefits of enabling biomethane production from these feedstock and incentive programs should be considered to enable these technologies.**

Opportunities for Biomethane Use in California

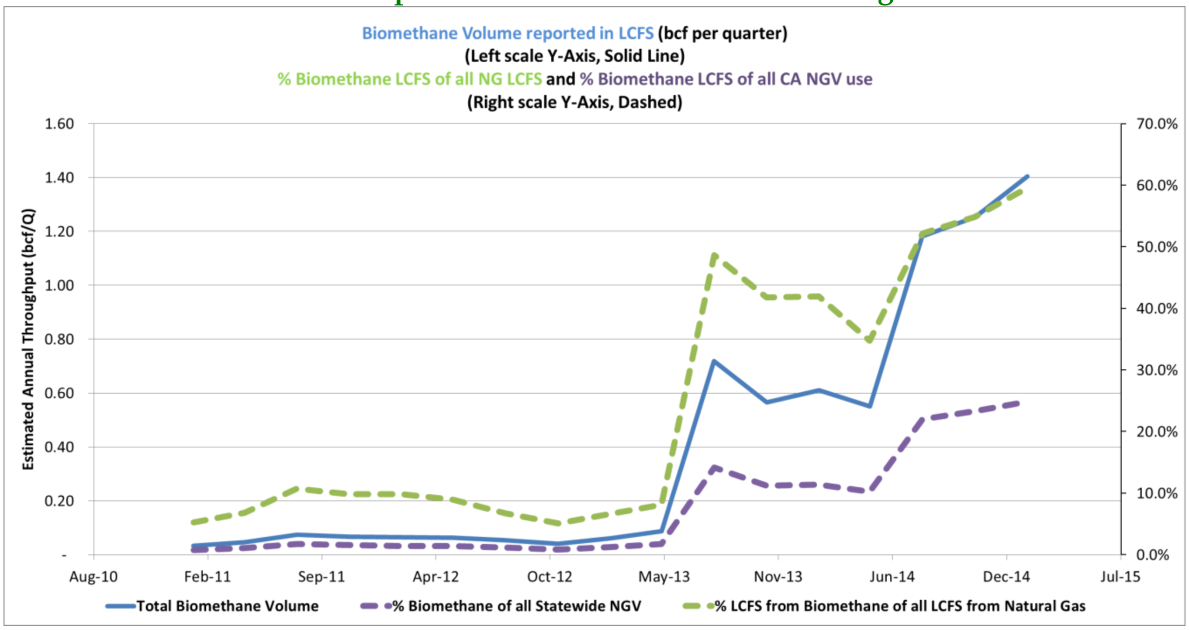
Biomethane can be used on-site to offset conventional natural gas or propane use, generate electricity, and/or fuel vehicles. Biomethane can also be transported offsite and used as a direct replacement for natural gas in ~~m~~any application~~s~~. Capturing and using biomethane from feedstock and waste sources is an additional greenhouse gas reduction strategy because it creates value and opportunity for a natural by-product of these processes.

Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) requires the CPUC to adopt pipeline access rules to ensure gas corporations provide nondiscriminatory open access to the pipeline system for biomethane, regardless of the type or source of the biogas. The issue being that biogas ~~typically~~ **may** contain~~s greater~~ levels of contaminates or constituents **that exceed** allow~~ed~~**able levels for health and safety** ~~in natural gas~~**.** These include: ammonia, biologicals, hydrogen, mercury, and siloxanes.

The chart below offers key statistics for the biomethane component of the LCFS program which demonstrates the value biomethane is already providing to the state's transportation sector.[184]

[184] **http://www.arb.ca.gov/fuels/lcfs/media_request_072015.xlsx**

Table 7: Impact of Biomethane on the LCFS Program



A rulemaking proceeding was opened on February 13, 2013, to implement the tasks in AB 1900. On January 16, 2014, the CPUC issued Decision 14-01-034 adopting concentration standards for the 17 Constituents of Concern, and the monitoring, testing, reporting, and recordkeeping protocols for biomethane to be injected into the gas utilities' pipelines.[185]

On April 9, 2014, the second phase of this proceeding was opened to consider who should bear the costs of meeting the standards and requirements that the CPUC adopted in D.14-01-034.[186] **On June 11, 2015, the CPUC issued Decision 15-06-029 adopting a monetary incentive program to encourage the in-state production and distribution of biomethane. This incentive provides 50 percent of qualified interconnection costs up to $1.5 million for biomethane projects that successfully interconnect with utilities' pipeline system and remain in operation for a minimum of 30 days.** The Energy Commission should continue to participate and monitor these proceedings. **Further consideration should be given to assess the need for additional incentives to encourage pipeline injection of biomethane, especially the opportunity to utilize GGRF dollars for this highly beneficial carbon reduction strategy.**

Renewable Natural Gas Jobs Creation

The Renewable Natural Gas Coalition (RNGC) has indicated that biomethane projects in California have resulted in the creation of more jobs per year average (11.5) than any

[185] See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF.

186 See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K642/89642428.PDF.

other renewable energy technology. Developing biomethane projects at the 200 candidate sites (located at landfills, wastewater recovery facilities and from the agricultural sector) more than 20,000 direct and indirect jobs would be created in the following 42 counties in California: Alameda, Butte, Contra Costa, Del Norte, El Dorado, Fresno, Humboldt, Imperial, Kern, Kings, Los Angeles, Madera, Manteca, Marin, Mariposa. Mendocino, Merced, Monterey, Napa, Nevada, Orange, Placer, Riverside, Sacramento, San Bernardino, San Diego, San Francisco, San Joaquin, San Luis Obispo, San Mateo, Santa Barbara, Santa Clara, Santa Cruz, Shasta, Solano, Sonoma, Stanislaus, Tulare, Tuolomne, Ventura, Yolo, Yuba. As many as 100 temporary construction jobs could be created as a result of each project as well.

Annual Biofuel Initiative Biomethane Impacts (assuming $70 million funding per year)

2016: Develop 13-26 Projects; Created 1300 - 2600 new jobs; 68,102,174 – 136,212,348 diesel gallon equivalent (DGE) biofuel produced in-State; Displace diesel for 11,350 – 22,701 Heavy Duty Trucks

2017: 26-39 Operating Projects; 2600 - 3900 jobs; 136,210,349 – 204,315,523 DGE biofuel produced in-State; Displace diesel for 22,701 – 34,051 Heavy Duty Trucks

2018: 39-52 Operating Projects: 3900 - 5200 jobs; 204,315,523 – 272,420,697 DGE biofuel produced in-State; diesel for 34,051 – 45,401 Heavy Duty Trucks

2019: 52-65 Operating Projects; 5200 - 6500 jobs; 272,420,697 – 340,525,871 DGE biofuel produced in-State; Displace diesel for 45,401 – 56,751 Heavy Duty Trucks)

2020: 65-78 Operating Projects; 6500 – 7800 jobs; 340,525,871 – 408,631,045 DGE biofuel produced in-State; Displace diesel for 56,751 - 68,101 Heavy Duty Trucks

Challenges in California

The primary barrier to biomethane project development is the lack of long-term demand and price stability. The current highest value use for biomethane in California is as a transport fuel generating LCFS credits and Renewable Fuel Standard Renewable Identification Numbers (RIN) in addition to baseline commodity value, but biomethane for this market is typically traded in short-term contracts and the market has been quite volatile with value varying nearly 100 percent within a year. This current policy is directing a large amount of North American biomethane to the transportation sector in California where it achieves some of the lowest carbon intensity transportation fuel pathways available. The electric generation market provides stable long-term demand for biomethane through 10 to 20 year term renewable power purchase agreements or fuel contracts, but the typical revenue provided to a biomethane project for this purpose will likely not provide enough incentive for most projects to move forward – especially not for small scale biogas producers. Biogas and biomethane projects serving the electric

generation market are also most often developed on-site rather than enabled through pipeline-delivery, resulting in investment in fixed assets which tie up this renewable resource long-term, eliminating the flexibility to deploy biomethane to serve a greater need as the state's energy and environmental requirements evolve. By developing policies that encourage the pipeline injection of biomethane, the state can leverage existing electric generation, combined heat and power, and CNG facilities as well as help to ensure efficient market-based deployment of this valuable resource, and improved reliability, flexibility, and sustainability of the state's energy portfolio.

Regulatory Issues

A common concern that many project developers~~, utilities,~~ and gas providers have cited is the effect of regulatory uncertainty and the effect of regulation changes on long-term contracts. Uncertainty creates development risk, which increases debt-financing costs. This uncertainty can jeopardize the viability of a project. ~~Recent changes in the regulation of biomethane pipeline injection will need to be tested by real development and demonstration of upgrading equipment that can produce biomethane gas of consistent quality before this uncertainty can be overcome.~~

Costs

A key challenge to biomethane distribution is the location of feedstock. In most cases, the highest concentrations of biomass feedstock are generally not located near natural gas pipelines. For locations that do not have feasible natural gas pipeline access, the gas must be used for onsite generation or for transportation biofuels. Feedstock for biomethane production is generally located in rural regions. Building the infrastructure necessary to access remote biomethane sources will be cost prohibitive, as developers are currently required to pay for pipeline extensions and upgrades.

Some biomass-rich locations are relatively close to population centers, and therefore **more likely to have better access to** utility pipelines, but **utility pipeline** interconnection costs ~~to utility pipelines~~ can still be an issue. According to a recent CPUC report[187], interconnection costs can range from $858,000 to $2.6 million dollars and depend on specifications unique to each project. Lengthy interconnection processes can further increase costs for project developers.

Excess costs are not easily absorbed because bioenergy projects are limited in size by the resources available. Generally, the production of biogas is a by-product of other processes, such as waste disposal. This limits the potential for methane production by unchangeable factors, such as the volume of a landfill or wastewater treatment plant. Increased production can be possible if the facility can process alternative feedstock within normal operation.

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187 http://www.cpuc.ca.gov/NR/rdonlyres/9ABE17A5-3633-4562-A6DA-A090EB3F6D07/0/SmallScaleBioenergy_DRAFT_04092013.pdf.

Examples can include dairy digesters accepting food waste and wastewater treatment plants co-digesting fats, oils, and grease. However, compared to natural gas, these projects will be relatively small and will have difficulty absorbing infrastructure capital costs.

Biomethane can be used as a direct replacement for natural gas in many applications. Because the heating value of biomethane is generally lower than fossil natural gas, blending with propane may be required to achieve heating values of greater than 990 British thermal unit (Btu) per standard cubic foot. Natural gas prices have been much lower than the production cost of biomethane. For example, the Point Loma Wastewater Plant produces biomethane at roughly $8.50 per MMBtu compared to an average cost of $4.00 per MMBtu for natural gas[188]. As a result, biomethane production is more expensive than natural gas extraction.

Despite these cost challenges, employing incentive structures like LCFS credits and RINs have shown promise in bringing the end-use cost of renewable natural gas to parity with fossil natural gas. However, due to price volatility and the concentration of a single end-use category, the renewable natural gas market impact of these transportation fuel incentives has been limited. Developing policies that create additional market incentives and promote more diverse end-use demand for renewable natural gas will reduce California's GHG emissions and help ensure a reliable, diverse, and sustainable energy future for the state.

Opportunity for Energy Storage: Power-to Gas (P2G)

One promising approach to reduced GHGs is the use of hydrogen and methane as an energy storage medium in an approach referred to as Power-to-Gas (or P2G). In this approach, hydrogen produced from electrical energy by water splitting (electrolysis) is used as an energy storage medium either directly or after further conversion to methane as the carrier.

P2G is not a concept or demonstration technology: it is being used commercially abroad. There are a total of 35 P2G projects in operation, being constructed, or planned in Europe, 23 of which are in Germany. While P2G is only at the early demonstration phase in California and is not as widely known as other energy storage approaches such as batteries, pumped hydro, and compressed air, clearly, it can serve as an important utility

188 Transcript of Staff Workshop Challenges to Procuring Biomethane in California, May 31, 2013, comments by Frank Mazanec (BioFuels Energy, LLC), p. 108. See http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-31_workshop/2013-05-31_transcript.pdf.

scale energy storage solution for California as well.

SoCalGas' facilities currently store over 135 Bcf of natural gas. If converted to electricity at an efficiency as low as 25 percent, it would represent over 12 tWh of electricity. The California Hydrogen Business Council's recent whitepaper on P2G[189] contains the following findings:

- **P2G provides unique storage functionality, offering a modular solution with long-duration storage capability and rapid response characteristics suitable to a variety of grid support functions, by way of example demand response**
- **The economic and environmental benefits of P2G technology can be maximized by tariffs and market structures that recognize storage use cases that convert energy from one form to another and that may store and later use energy at different locations**
- **Water consumption in the electrolysis process is modest and will not contribute to overall water demand even at high levels of penetration; the water is recoverable in some use cases**
- **Viewed as a combination fuel production system and grid resource, P2G can produce hydrogen at costs that are in line with U.S. Department of Energy long term hydrogen fuel cost targets and the grid-related benefits reduce overall cost by nearly 25 percent in the case analyzed**
- **P2G, as an electricity-to-electricity storage resource, uses the existing natural gas system to deliver electrolyzer produced hydrogen blends or synthetic methane to existing electrical generation resources. In this configuration, the cost of storage can be as low as $0.07/kWh (based on output energy net of conversion losses)**
- **P2G can provide the lowest cost solution for large scale, long-term energy storage and provides benefits to all sectors of the energy industry**
- **More detailed modeling of P2G economics under high renewable penetration is ongoing and will be available later in the year**

The major benefit of the P2G energy storage solution is that the renewable hydrogen or methane produced can be distributed, as needed, to all existing energy end-uses, including transportation applications such as fuel cell electric vehicles, with virtually no incremental environmental impacts.

A regulatory framework for monetizing the services that can be provided by P2G technologies and incentivizing the development of commercial P2G systems need to be developed.

[189] California Hydrogen Business Council, "Power-to-Gas: The Case for Hydrogen, Draft White Paper" 30 July, 2015.

Areas for Further Research

Pipeline biomethane can be very efficiently stored for long periods of time and flexibly deployed to existing natural gas fired generation assets or any other natural gas end-use of greatest need. Understanding and quantifying the benefits of increasing the availability of pipeline biomethane and other low carbon fuels should be a strategic priority for the efficient development of California's sustainable energy future. This research will be especially important to develop reliable and cost-efficient methods to comply with the 50 percent renewable electricity procurement target prescribed in SB 350.

Given that biomethane is a feedstock restricted, more research is required to understand the highest environmental and societal value applications for renewable natural gas, and how this value may be affected over time by regulatory, environmental, economic, and other conditions. This understanding will inform effective enablement strategies and policies—focused on optimal deployment of this resource to applications of the greatest need and benefits.

Additional primary and secondary research should be conducted to quantify the benefits of anaerobic digestion versus composting of organic materials. This research is especially pressing in order to inform policies that will impact the forthcoming operationalization of organic waste diversion plans driven by AB 341 and AB 1826.

The LCFS program custom pathway methodology could provide a mechanism to assign some value for the additional GHG benefits that biomethane can provide to the state; the CEC will assess additional grants and subsidies that could potentially be made available to enable these highly beneficial projects which directly address currently unmitigated anthropogenic methane emissions.

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CHAPTER 9:
Greenhouse Gas Emissions and the Natural Gas System

Introduction

Natural gas is a significant component of the California energy system and is both a potential fuel to reduce greenhouse gas (GHG) emissions and as a source of GHG emissions itself.

The primary focus of this chapter is on methane emissions associated with the natural gas system. This chapter starts with a discussion of the importance of methane emissions, a description of the natural gas system, and the associated sources of GHG emissions from that system. It then discusses the methods used to quantify methane emissions, estimates of methane from emission inventories, and findings from recent studies on lifecycle methane emissions.[190] The chapter identifies the uncertainties and gaps in estimating methane emissions and some areas where research is needed to guide California policy makers in determining the future role of natural gas in the state. Finally, it outlines what state and federal agencies, along with natural gas utilities and stakeholders, are doing to address methane emissions.

Natural Gas System Emissions

The primary source of carbon dioxide (CO_2) emissions is combustion of natural gas in power plants, appliances, industrial processes, and vehicles. Natural gas has the potential to reduce CO_2 emissions by shifting away from higher GHG emitting fuels like coal (in power plants) and gasoline or diesel (in vehicles). California has developed policy to reduce emissions of CO_2, which is the most abundant greenhouse gas and drives long-term climate change[191].

To the extent that unburned methane escapes or leaks anywhere along the natural gas supply chain, however, the GHG impact of using natural gas is higher than what it is measured solely at combustion. The fundamental question regarding the climate benefits of using natural gas is how much methane is escaping from the natural gas system. Estimates of methane emissions to date disagree. Some studies estimate methane emission levels that

190 Although many studies on methane emissions are characterized as life-cycle assessments the majority tend to focus on particular components of the natural gas system, such as production or processing, or on particular uses of natural gas, such as in power plants or as a transportation fuel, without providing the coherent and comprehensive view of life-cycle emissions that is needed.

191 Reducing Short-Lived Climate Pollutants in California, September 2014 : http://arb.ca.gov/cc/shortlived/slcp_booklet.pdf

are high enough to offset the benefits of burning natural gas in place of more carbon-intensive fuels. For this reason, it is critical that California policy makers have a clear understanding, as well as an accurate and comprehensive assessment, of the life-cycle GHG emissions associated with the natural gas system to develop effective GHG reduction strategies.

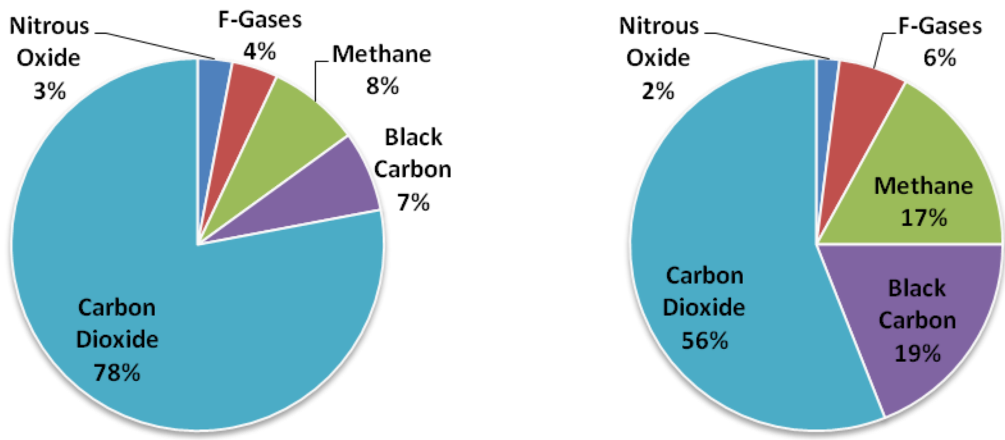
Methane Emissions and the Natural Gas System

Natural gas is primarily composed of methane and heavier alkanes (chains of multiple carbon and hydrogen atoms), with methane comprising about 90 percent or more of the total composition. Methane, a highly potent, short-lived GHG, is the second most prevalent GHG emitted in California, with CO_2 being the most dominant. The lifetime of methane in the atmosphere is much shorter than CO_2; however, it is more efficient at trapping radiation than CO_2. Atmospheric methane breaks down over time, so the global warming potential is highest when first emitted then declines.[192] As a result, one ton of methane is equal to 72 tons of CO_2 over a 20-year timeframe and 25 tons over a 100-year timeframe.[193] The ARB estimates that methane makes up approximately 17 percent of GHG emissions in the state on a 20-year basis and eight percent on a 100-year basis using the Intergovernmental Panel on Climate Change assessment on global warming potential, as shown in **Figure 5**.

192 LaCont, R., *Methane Emissions in the Natural Gas Life Cycle*, April 2015, p. 3. Available at http://westernenergyboard.org/2015/05/final-report-released-by-mj-bradley/.

193 Forster, P., V., *Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on ClimateChange,* Cambridge University Press, p.212. Available at: https://www.ipcc-wg1.unibe.ch/publications/wg1-ar4/ar4-wg1-chapter2.pdf

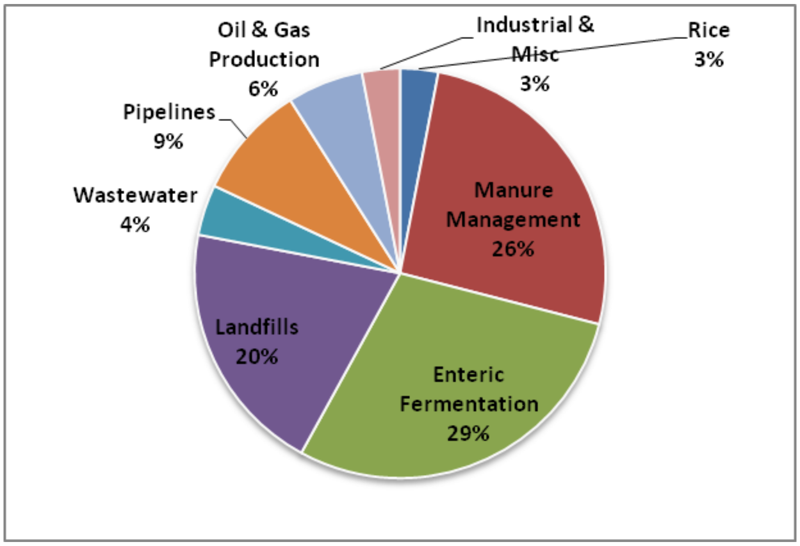
Figure 5: California's 2013 Greenhouse Gas Inventory Using 100-year (left pie chart) and 20- year (right pie chart) Global Warming Potential Values



Source: ARB, Short-Lived Climate Pollutant Reduction Strategy: Concept Paper, May, 2015, p. 11. http://www.arb.ca.gov/cc/shortlived/shortlived.htm.

In-state estimates of methane emissions from the oil and gas system, including pipelines account for about 15 percent of the total methane emitted in the state. Methane is also produced biologically in ruminant animals (such as dairy cattle), landfills and waste handling, from agricultural production, and other sources. Methane emissions from the major sources are difficult to measure due to the number of sources, area-wide nature of many sources, which often include complex biological processes, as shown in **Figure 6.**

Figure 6: California 2013 Methane Emission sources



Source: ARB, *Short-Lived Climate Pollutant Reduction Strategy: Concept Paper*, May, 2015, p. 17. See http://www.arb.ca.gov/cc/shortlived/shortlived.htm.

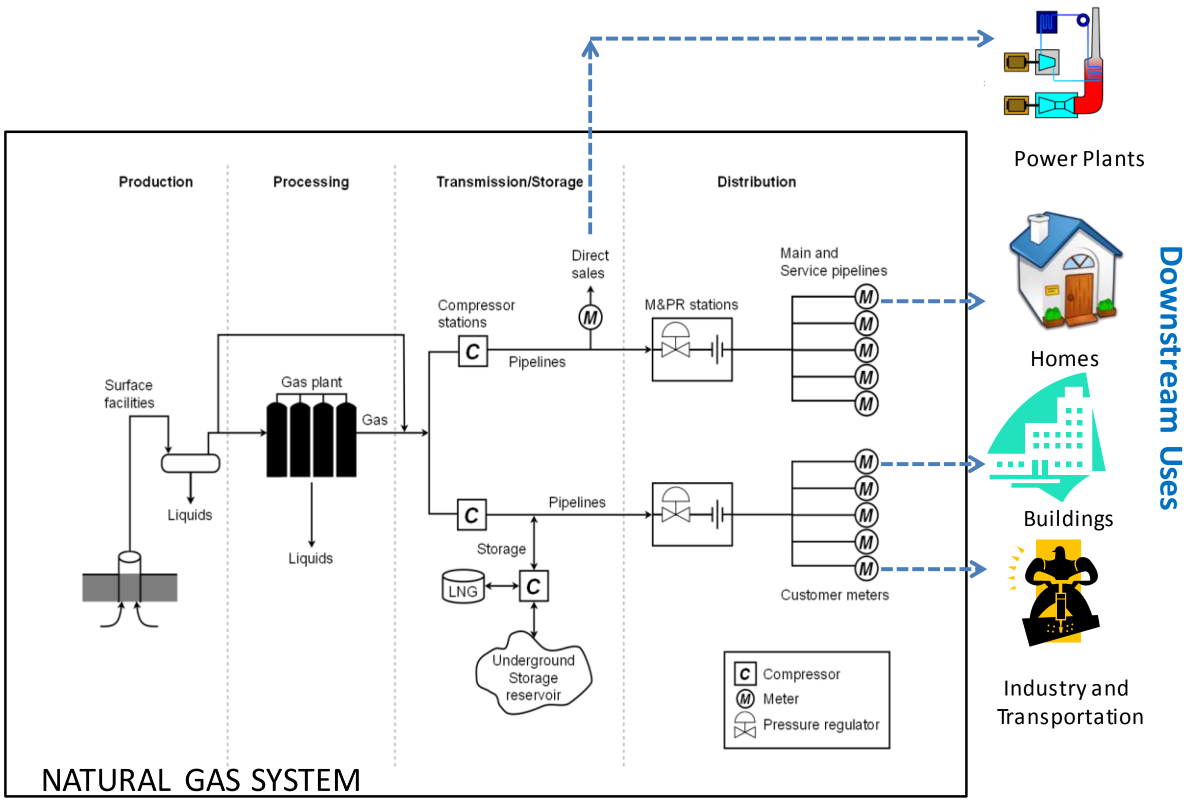
ARB 2015 Edition GHG Inventory: http://www.arb.ca.gov/cc/inventory/data/data.htm.

Methane emissions come from both intentional and unintentional releases of natural gas. Unintentional releases of methane, or fugitive emissions, can come from multiple sources and phases of the natural gas system, such as from leaking pipelines, abandoned wells, or inefficient combustion. Intentional releases are purposeful and known emissions that occur in the normal operations of the natural gas system. For example, safety dictates the venting of natural gas, when pressures reach levels where there could be a safety risk. Estimates of methane emissions from the natural gas system need to include both intentional releases and fugitive emissions across all phases of the natural gas system.

The Natural Gas System

The natural gas system includes a number of components or phases from production at wells through processing, transportation, storage, and distribution to final end user, as shown in **Figure 7**. Natural gas is produced from underground reservoirs by two types of wells; those that produce only natural gas, commonly referred to as dry wells, and wells that produce gas along with crude oil, commonly referred to as associated gas.

Figure 7: Schematic Representation of the Natural Gas System



Source: Modified from U.S. EPA Presentation[194].

Natural gas produced from wells is collected in gathering systems and then processed to remove impurities and separate out the other alkane by-products like propane or butane. The natural gas is then transported through a transmission pipeline system where compressors move gas through the pipe. Some, but not all, transmission pipeline systems include underground storage where there is favorable geology near-by, as shown in **Figure** .

The natural gas is delivered via a distribution system, where different lines or sections operate at various pressures controlled by regulating valves. In general, the closer the

194 See http://epa.gov/climatechange/Downloads/ghgemissions/2013Workshop/ghgrp-draft-summary.pdf.

natural gas is to a customer, the smaller the pipe diameter and the lower the pressure. In California, underground storage is a major feature of the gas distribution system, allowing gas utilities or large customers such as power plant owners to store gas during low-demand periods for withdrawal to supplement supplies during peak-demand periods.

From the distribution system, natural gas is then delivered to a customer's gas meter for use by residential, commercial, or industrial customers, and power plants. Once the natural gas is delivered to the customer meter, it is then used in appliances and equipment in homes, businesses, and industrial processes. These are shown as "downstream uses" in **Figure 7**.

Methods for Quantifying Methane Emissions

Estimates of methane emissions are developed using bottom-up, top-down, and hybrid methods. Each of these methods has its own limitations, which can cause uncertainty and variance in methane emission estimates. The major uncertainties associated with both bottom-up and top-down studies are discussed in more detail in a later section.

The "bottom-up" method applies emission factors (for example, grams of methane emitted per mile of transmission line), which are typically averages based on measured emissions from a device or facility that is part of the gas system. These emission factors are then multiplied by activity factors for different components of the natural gas system (for example, miles of pipeline). Estimating emissions is then a straightforward summing up of emissions from all components of the natural gas system. Both the ARB and U.S. EPA use bottom-up studies for their methane emission inventories.

One of the shortcomings of bottom- up studies is that emission factors involve key assumptions that may not be representative of the population being measured and extrapolated. For example, the samples may not accurately represent current technologies and practices. In addition, because measurements for use in developing emission factors are expensive, the sample sizes are typically small; as a result the estimates provide less certainty than would those produced by a larger sample size.[195]

"Top-down" studies use measurements of methane and other compounds in the atmosphere to estimate emissions. For example, emissions can be estimated by taking measurements with a research airplane upstream and downstream of a potential source or basin, while accounting for information such as wind velocity and the enhanced concentration of methane downwind of the source.

195 Brandt, A.R., et al., *Methane Leaks from North American Natural Gas Systems*, *Science*, 2014, 343(6172):733-735. Available at: http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

It appears that the greatest challenge for top-down studies is attributing observed methane concentrations among multiple sources, including both anthropogenic and natural sources.[196] There are other challenges to using ambient measurements for statewide emissions. For example, LBNL researchers used an aircraft to measure methane emissions around refineries and a mobile platform for measuring around wells where the only potential sources of methane were those individual facilities.[197] This technique is robust for measuring a snapshot of emissions from the entire facility, and is especially good for an area source like underground natural gas storage facility. However, for a more complex facility, measurement of emissions over a short time period of a few days cannot be assumed to be representative of all facilities across the state on an annual basis.

Unless tracers, or fingerprint compounds, can be identified and measured, top-down studies do not reveal which of the many sources of methane can be attributed to the natural gas system.[198] Not all top-down studies, however, suffer from the problem of disentangling the emissions that are attributed to the natural gas system from other sources of methane. However, there are other challenges such as the representativeness of the sample.

Regardless of the method employed, studies on methane emissions rely on numerous assumptions to estimate vented and fugitive emissions based on limited test data.[199] Complicating all three of the methods is the presence of "super-emitters," that emit methane at significantly greater rates and volumes than other similar types of emitters. The presence or absence of super-emitters means that the odds of missing that super-emitter when selecting a sample design is higher. If only a few sources are actually emitting large amounts and they are missed when selecting a random sample, the emissions will be underestimated. Several studies, in fact, suggest that emissions are dominated by a small fraction of these super-emitters at wells sites, gas-processing plants, coproduced liquids storage, compressors on transmission pipelines and distribution systems.[200] **Any methodology**

196 Ibid.

197 Fischer, Marc L., *Preliminary measurement from the natural gas system in California: from well to downstream of the meters*, Presentation from June 1, 2015 Energy Commission Workshop.

198 Allen, D.T., *Methane Emissions From Natural Gas Production and Use: Reconciling Bottom-Up and Top-Down Measurements, Current Opinion in Chemical Engineering*, 2014, 5(0):78-83, see http://www.sciencedirect.com/science/article/pii/S2211339814000525.

199 LaCont, R., et.al., *Methane Emissions in the Natural Gas Life Cycle*, April 2015, p. 6. Available at: http://westernenergyboard.org/2015/05/final-report-released-by-mj-bradley/

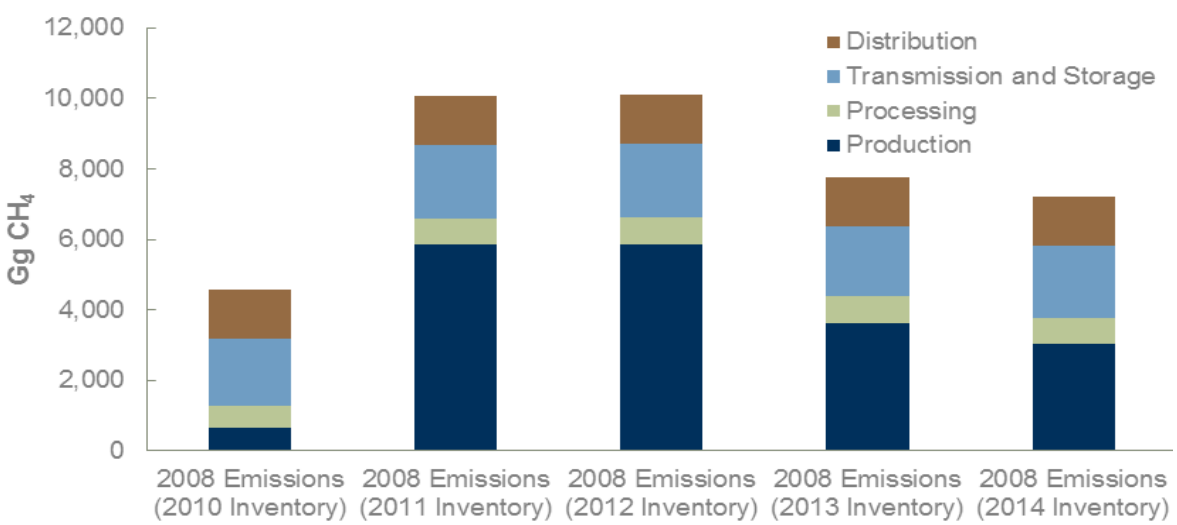
200 The source for the last sentence is: Brandt, A.R., et al., Methane Leaks from North American Natural Gas Systems, Science, 2014, 343(6172):733-735. Available at: http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf

should allow for a flexible selection process based on each utility's asset inventory, key activities, operational constraints and practices.

Methane Emission Estimates from State and Federal Inventories

U.S. EPA has seen wide variation in methane estimates presented in their GHG inventories over the last few years. **Figure** 8 shows U.S. EPA emission estimates for the same year (2008) across five consecutive inventories (2010 to 2014), illustrating the impact that methodology changes and new information can have on emissions estimates from a single year.[201] The largest changes in the U.S. EPA estimates are primarily associated with natural gas production. After the large jump in methane emissions related to the change in methodology for estimating emissions from production in the 2011 U.S. EPA GHG Inventory, a concerted effort by U.S. EPA, the natural gas industry, government and research organizations, environmental groups, and other stakeholders led to substantial changes in how emission estimates from certain activities were developed.

Figure 8: 2008 Natural Gas System Methane Emissions for Five Consecutive Inventories



Source: M.J. Bradley & Associates, *Methane Emissions in the Natural Gas Life Cycle*, April, 2015.

201 LaCont, R., *Draft Report of Methane Emissions in the Natural Gas Life Cycle*, October, 2014, p. 8. Available at: http://westernenergyboard.org/?s=Draft+Report+on+Methane+Emissions&submit.x=1&submit.y=12..

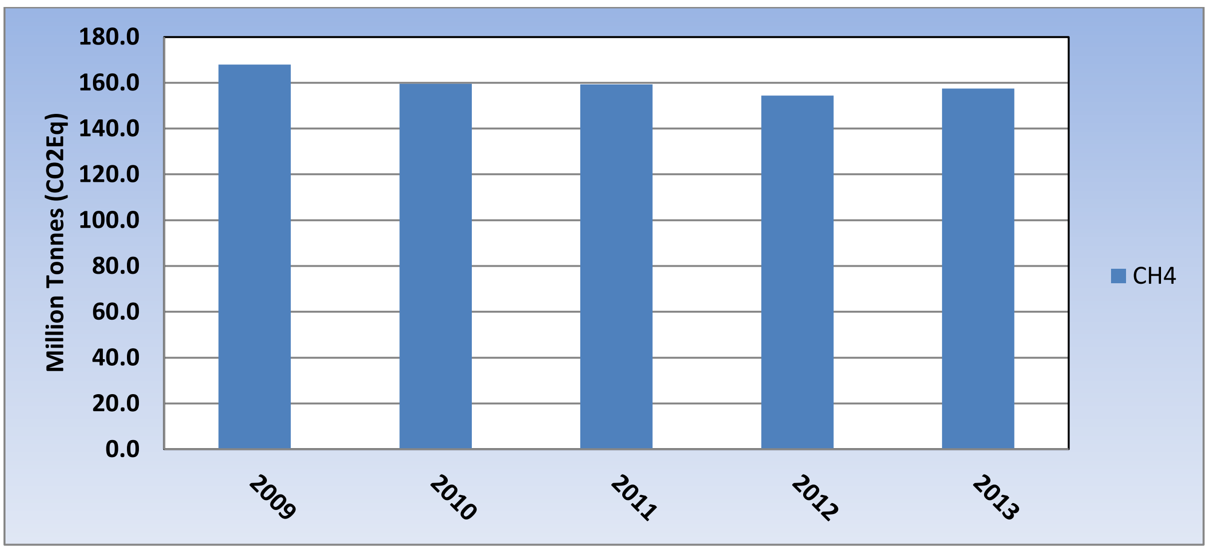
The U.S. EPA has undertaken updates of its methodologies to improve the accuracy of methane emissions estimates, especially for production of natural gas, and has made significant changes in approach over the last several years.[202]

ARB estimates that methane emissions in California have increased slightly, only about 5 percent, between 2009 and 2013.

Figure **9** shows the U.S. EPA inventory of total methane emissions associated with the natural gas system from 2008 to 2012, with methane emissions decreasing over the last few years, with a slight uptick in 2013.

ARB estimates that methane emissions in California have increased slightly, only about 5 percent, between 2009 and 2013.[203]

Figure 9: U.S. Methane Emissions from the U.S. Natural Gas System



Source: U.S. EPA, *U.S. Greenhouse Gas Inventory Report: 1990-2013*.

202 Ibid., pp.6-9.

203 ARB's emission inventory includes methane associated with in-state oil and gas production and natural gas pipeline fugitive emissions. California Air Resources Board, 2015 Edition of GHG Emission Inventory: 2000-2013. Available at: http://www.arb.ca.gov/cc/inventory/data/data.htm and http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_00-13_20150424.xlsx

Findings from Recent Assessments of Methane Emissions

Over the last few years, a number of studies have been conducted to estimate the climate impacts of switching to natural gas from high emitting fossil fuels such as coal for electricity generation and gasoline and diesel for transportation. For electricity production, it is fairly well understood that on a unit by unit basis, natural gas produces lower levels of CO_2 emissions than coal when combusted, due to its lower carbon content and because it burns relatively cleanly. Estimating methane emissions associated with natural gas electricity production, as well as for transportation, is a fairly recent and still emerging area of study. As a result, there is a significant controversy over the amount of methane that is emitted from the natural gas system and what this means for climate reduction policies.

Recent work estimating methane emissions from California's natural gas system suggested emissions were less than one percent of throughput.[204] Some peer-reviewed studies suggest, however, that these emissions may be underestimated, as discussed below. There is a large degree of uncertainty associated with methane emission estimates because the studies may use different methodologies, data, and device counts, as well as difference in the components of the natural gas system that are either included or excluded. This makes direct comparison of the various studies difficult. When these differences are combined with the other challenges discussed above, such as the presence of super-emitters and problems with attribution, there is variation among the different studies that have attempted to quantify methane emissions from natural gas. This is an area of ongoing research.

An important assessment of methane emissions published in the Proceedings of the National Academy of Science in 2012 and updated by the Environmental Defense Fund in 2014 concluded that in order to realize an immediate net climate benefit from the use of natural gas, the percent of methane emitted from the natural gas system should be lower than: 2.7 percent for coal-burning power plants; 1.4 percent for gasoline cars; and 0.8 percent for heavy-duty vehicles. [205] Also in 2012, another prominent study was conducted that compared a number of academic assessments of national upstream methane leakage,

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204 ARB, Transportation Fuels: ARB Technology Assessment, 2014. Presentation at the ARB Technology Assessment Workshop. Available at: http://www.arb.ca.gov/msprog/tech/presentation/fuels.pdf.

205 O'Connor, T., Environmental Defense Fund, Panel 2: Natural Gas Market Assessment and Methane Leakage, June 23, 2014, California Energy Commission Workshop, Slide 3. See: http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-23_workshop/presentations/13_O_Connor_EDF_IEPR-Presentation.pdf. EDF updated these estimates to account for new data. Original source: Alvarez, R., *Greater focus needed on methane leakage from natural gas infrastructure, Proceedings of the National Academy of Science*, April 24, 2012, vol. 109, no.17, pp. 6435-6440. Available at: http://www.pnas.org/content/109/17/6435.

excluding the distribution system, ranging from 0.7 – 2.7 percent of withdrawal for conventional natural gas, to 1.0 to 4.5 percent for shale gas.[206]

A 2014 meta-analysis compared the methane emissions estimates of 20 recent academic studies and concluded that the national normalized leakage rate for methane ranged from 1.87 to 2.62 and were 1.25 to 1.75 times the estimates in the U.S. EPA GHG inventory.[207] The study concludes that official inventories consistently underestimate actual emissions with the natural gas and oil sectors as important contributors. The study notes, however, that excess leakage above the U.S. EPA inventory were not attributed entirely to natural gas sources and infrastructure. Some methane leakage from other source like landfills and livestock could be underestimated and the leakage could include other sources not estimated, such as seepage and abandoned wells.[208] The study concluded that the very high leakage rates in some of the recent atmospheric studies are unlikely to be representative of typical natural gas system leakage rates and that hydraulic fracturing was unlikely to be a dominant contributor to total methane emissions.[209]

The 2014 meta-analysis study also notes that many independent experiments suggest that a small number of "super-emitters," could be responsible for a large percentage of leakage. The presence of super-emitters is noted in a number of studies. While it may prove difficult, and possibly expensive, to identify these super-emitters, the 2014 study notes that these emitters present an opportunity for large methane mitigation benefits.

California imports around 95 percent of its natural gas from productions areas located outside the state. Several studies have attempted to quantify methane emissions associated with U.S. production areas. One study estimates methane emissions from the Haynesville production region in Texas on the order of 1 to 2.1 percent of the total natural gas production.[210] The same study estimates methane emission of 1.0 to 2.8 percent for the

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206 Weber, C., et al., *Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications, Environmental Science & Implications*, 2012, 46, 5688-5695. Available at: http://pubs.acs.org/doi/abs/10.1021/es300375n. As presented by: ARB, Transportation Fuels: ARB Technology Assessment, Presented at the Technology Assessment Workshop, September 3, 2014, p. 54. Available at: http://www.arb.ca.gov/msprog/tech/presentation/fuels.pdf.

207 Ibid, p. 57. Based on data from: Brandt, A.R., et al., *Methane Leaks from North American Natural Gas Systems*, *Science*, 2014, 343(6172):733-735. Available at: http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

208 Ibid, p. 54.

209 Ibid, p. 57.

210 Peischl, J, et.al., Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions, Journal of Geophysical Science Research, March 2015. p. 1. Available at: http://onlinelibrary.wiley.com/doi/10.1002/2014JD022697/abstract.

Fayetteville region in Arkansas, and 0.18 to 0.41 percent for the Marcellus region in Pennsylvania. Another study estimates leakage rates (in terms of energy content), of 10.1 to for the Bakken production region in North Dakota and 9.1 percent for the Eagle Ford production area in South Texas.[211]

There are no similar reports for the San Juan Basin, but a study using satellite data suggests that this area may be a "hot spot" for methane emissions in the United States.[212] No information is available from the natural gas production region in Canada, but a related study seems to suggest that emissions may be higher than previously thought.[213] New top-down studies are under way to try to identify the main source of methane emissions in the San Juan region and other oil and gas producing basins. Even if better estimates are developed for the different producing areas, estimates will also need to account for emissions from the pipelines that bring the natural gas to California.

Uncertainties in Estimating Methane Emissions

Recent estimates of methane emissions from the natural gas system have varied widely due in part to the large population of sources throughout the natural gas system, differing measurements and estimation approaches, and the presence of super-emitters.[214] **However, one key consideration that must be taken into account is the distinction between "leaks" and "methane emissions" particularly for reporting purposes and in developing any estimation methodologies.** Researchers note that reconciling differences between top-down and bottom-up measurements of methane emissions will be critical to fully understanding methane emissions from the natural gas supply chain, and as a result, recommend a

211 Schneising, O., et.al., Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations, Earth's Future, 2014, 2(10). Available at: http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full.

212 Kort EA, et.al., *Four corners: The largest US methane anomaly viewed from space. Geophysical Research Letters,* 2014, 41(19):6898-6903. Available at: http://onlinelibrary.wiley.com/doi/10.1002/2014GL061503/abstract.

213 Tyner DR, et.al., *Emission Factors for Hydraulically Fractured Gas Wells Derived Using Well- and Battery-level Reported Data for Alberta, Canada. Environmental Science & Technology*, 2014, 48(24):14772-14781. Available at: http://pubs.acs.org/doi/abs/10.1021/es502815b.

214 Allen, D.T., *Methane emissions from natural gas production and use: reconciling bottom-up and top-down measurements, Current Opinion in Chemical Engineering*, 2014, 5(0):78-83, http://www.sciencedirect.com/science/article/pii/S2211339814000525.

combination of approaches for future studies. Several uncertainties inherent in these approaches will need to be addressed. These include:

- The need to be inclusive and comprehensive when establishing the boundaries of the natural gas system
- Understanding and addressing problems with measurement and sample bias
- The complexity in estimating emissions from oil and gas production.

After the reconciliation of the estimation models and the reduction of uncertainties, improved recommendations for approaches to be used in future studies can be developed.

Setting Boundaries of the Natural Gas System

There are several issues to consider when estimating life-cycle methane emissions related to the components that are included in the natural gas system. Leaving out emissions from certain aspects of the gas system can lead to uncertainties and gaps in quantifying them. Typically, the natural gas system has been characterized to include production, processing, transmission/storage, and distribution. Several additional elements related to natural gas have more recently been recognized as important to include in life-cycle methane emissions estimates, and it has been suggested that the boundaries of the system should be more broadly established.

Potential emissions downstream of the meters in homes, buildings, and industrial facilities are traditionally excluded from the boundaries of the natural gas system, but are an additional source of methane emissions that must be considered to produce full life-cycle emission estimates. For example, research underway by Lawrence Berkeley National Laboratory looking at methane emissions indicates that tankless water heaters may be a significant contributor of methane emissions behind the meter in homes.[215]

Since California imports the majority of its natural gas supplies from regions outside the state, it is important that these upstream methane emissions are included in life-cycle assessments. Quantifying methane emissions associated with oil and gas production has proven challenging and is an area with significant variance among studies and on-going research.

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215 Presentation by Marc L. Fischer, LBNL, *Preliminary measurements from the natural gas system in California: from well to downstream of the meters*, June 1, 2015. See also Transcript of June 1 ,2015 Commissioner Workshop on Fugitive Methane Emission, p.158. Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-04.

Another emerging issue related to life-cycle methane emissions from natural gas is the need to include infrastructure that is no longer in use but nonetheless may be emitting methane, such as abandoned wells. Researchers have concluded that abandoned oil and gas wells provide a potential pathway for methane leakage.[216] Abandoned wells within the state, as well as those located in regions from which California imports gas supplies, need to be considered. In California alone, the extensive history of oil development beginning in the 1930s and peaking in the mid-1980s, has resulted in tens of thousands to hundreds of thousands of abandoned wells.

At this point only preliminary results from limited measurements of methane emissions at abandoned wells in North American production basins show significant emissions levels.[217] For example, measurements of methane emissions taken at 19 abandoned wells in Pennsylvania were scaled, assuming they were representative of all abandoned wells in the state, to arrive at an estimate that abandoned wells constitute 4-7 percent of estimated total anthropogenic methane emissions in Pennsylvania.[218] The study notes that some wells were disproportionately high; three of the measured wells and flows rates were three orders of magnitude larger than median flows from the other wells. Other top-down research of North American so-called "tight" geologic formations using remote sensing suggests that emissions from oil and gas production are higher than estimates from bottom-up studies and inventories.[219] [220]

One difficulty in assessing emissions from abandoned oil and gas wells is that the number of these wells in the United States is highly uncertain and is complicated by the fact that many of the abandoned wells are "lost" with no evidence of their existence at the surface and/or via public records.[221] Because methane content and drilling and production practices vary across different production basins, little is known about methane emissions from the

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216 Bohlen, S., California Division of Oil, Gas and Geothermal Resources, Fugitive Methane Emissions: Natural Gas in CA and the Role of Hydraulic Fracturing, June 1, 2015. Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-04.

217 Kang, M., et al., *Direct measurement of methane emissions from abandoned oil and gas wells in Pennsylvania*, *Proceedings of the National Academy of Science*, 2014, 111(51):18173-18177. Available at: http://www.pnas.org/content/111/51/18173.abstract.

218 Ibid, p.18173.

219 Weber, C., et al., *Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications, Environmental Science & Implications*, 2012, 46, 5688-5695. Available at: http://pubs.acs.org/doi/abs/10.1021/es300375n.

220 Tight formations are those in which the pore spacing between molecules is very small; enhanced techniques often need to be used to produce gas from tight formations.

221 Ibid, p. 18176.

millions of abandoned wells in the United States. It is the subject of on-going research and more definitive studies on emissions from abandoned wells may be available over the next several years. The authors of this and other preliminary studies suggest that additional research is needed to accurately describe and include methane emissions in inventories.

Problems with Measurement and Sample Bias

Differences in sampling methodologies create complications in achieving legitimate and comparable estimates of methane leakage. Because constant measurement of all emissions is a nearly impossible task, methodologies are needed to sample emissions and then use those samples as representative of the whole population of components or processes. Top-down and bottom-up methodologies use different types of sampling at different points in the life-cycle of emissions sources, which leads to discrepancies between the results produced by the different methods.[222]

In bottom-up studies, there needs to be sufficient sample sizes for the very different components in the natural gas system to develop representative emission factors. The goal of this approach is to measure emissions from a statistically representative sample of sources, so they can be extrapolated to large populations.[223] There is also the potential of sampling bias for sampling at self-selected facilities.[224] Researchers for one study point out that activity and device counts for bottom-up estimates "…are contradictory, incomplete, and of unknown representativeness."[225] The EPA's inspector general notes that many of U.S. EPA emission factors for the oil and natural gas production sector are of questionable quality because they are based on limited and/or low-quality data.[226] Much more data and research is needed to develop more accurate and representative estimates for the different sources.

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222 Allen, D.T., *Methane emissions from natural gas production and use: reconciling bottom-up and top-down measurements, Current Opinion in Chemical Engineering*, 2014, 5(0):78-83, see http://www.sciencedirect.com/science/article/pii/S2211339814000525.

223 Ibid.

224 Ibid.

225 Brandt, A.R., et.al., *Methane Leaks from North American Natural Gas Systems, Science*, 2014, 343(6172):733-735 Available at: http://nature.berkeley.edu/er100/readings/Brandt_2014.pdf.

226 Office of the Inspector General, EPA, *EPA Needs to Improve Air Emission Data for the Oil and Natural Gas Production Sector*, 2013, p. 15. Available at: http://www.epa.gov/oig/reports/2013/20130220-13-P-0161.pdf.

As previously mentioned, it appears that total emissions are dominated by a small number of "super-emitters" and it may be impossible to identify these super-emitters.[227] [228] Bottom-up inventories rely on testing done on a small sample of components that most likely do not capture a representative sample of super-emitters. For example, in one study of natural gas infrastructure, 58 percent of emissions came from 0.06 percent of possible sources.[229] Since only a small fraction of leaks likely represents a high percentage of total emissions, this creates big challenges for bottom-up inventories because it requires testing of all components in the natural gas system to ensure that all super-emitters are identified and captured within the analysis.[230] Also, there are no standardized methods and protocols among the different studies for taking measurements at different sources.

Sample bias based on geography can introduce uncertainties in methane estimates. Emissions can vary between regions for several reasons. Potential causes for regional variation include societal differences, such as local policies or regulations, and differences in infrastructure, such as well types or well-completion procedures. In addition, the methane content of natural gas at wells varies depending on which production basin it comes from, for example, Colorado versus Texas. Natural gas coming into California from different regions have significantly different emissions profiles. When mixed in with other gas flowing through the pipeline system, the calculation of life-cycle emissions is further complicated. In addition, the composition of natural gas can vary significantly depending on where it is in the natural gas system. For example, methane leaks at the well head in the production phase typically have lower methane content (and higher propane and butane content) than from leaks in the transportation portions of the system.[231]

Top-down emission estimates also have data and sampling issues. For example, it can be difficult to attribute ambient measurements of emissions to a variety of sources of methane such as landfills, dairies, natural seeps, and wetlands in a region. Chemical fingerprints (for

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227 Brandt, A.R., et.al., *Methane Leaks from North American Natural Gas Systems, Science*, 2014, 343(6172):733-735. Available at: http://nature.berkeley.edu/er100/readings/Brandt_2014.pdf.

T Kuo, J., *Estimation of Methane Emissions From The California Natural Gas System*, California Energy Commissions, 2012, CEC-500-2014-072, Available at" http://www.energy.ca.gov/2014publications/CEC-500-2014-072/CEC-500-2014-072.pdf.

229 Brandt, A.R., et.al., *Methane Leaks from North American Natural Gas Systems, Science*, 2014, 343(6172):733-735. Available at: http://nature.berkeley.edu/er100/readings/Brandt_2014.pdf.

230 Allen, D.T., *Methane emissions from natural gas production and use: reconciling bottom-up and top-down measurements, Current Opinion in Chemical Engineering*, 2014, 5(0):78-83, http://www.sciencedirect.com/science/article/pii/S2211339814000525.

231 LaCont, R., et.al., *Methane Emissions in the Natural Gas Life Cycle*, April 2015, p. 15. Available at http://westernenergyboard.org/2015/05/final-report-released-by-mj-bradley/.

example, ethane is associated mostly with methane from petroleum-based sources such as well and natural seeps) can be used to help differentiate emissions sources, but some uncertainty in source attribution will still remain.[232] Ambient measurements can also rely on complex computations of weather conditions to link measured ambient concentrations to potential sources. These computations often have relatively high levels of uncertainty.[233]

An issue for both bottom-up and top-down methodologies is that emissions can be sporadic, and testing done at discrete times may or may not capture episodes that can dominate annual emissions. For example, before a well enters into full operation, some high emissions may take place during "well completion" when drilling finishes and a well is prepared for production.[234] Once it is connected to a gas gathering system and enters normal production, emissions from the well should decrease. These could be factors contributing to the widely divergent emissions levels from aerial testing performed at associated oil fields and underground natural gas storage facilities in California, which shows widely divergent emissions levels for testing done on different days. It is also difficult to estimate emissions per unit of natural gas produced or consumed for certain types of emissions.

Methane Emissions from Out-of-State Oil and Gas Production

Since California imports most of its natural gas from production basins located outside the state, it is important that methane emissions associated with these sources are accounted for in life-cycle methane emissions estimates. Despite a number of recent research efforts to address methane emissions from the oil and gas sector, this is a nascent area of study and as a result there is variability in the different estimates from these studies. As previously discussed, major revisions to U.S. EPA inventory of methane emissions from oil and gas production have been made over the last few years and indicate a large amount of uncertainty in this area. Several studies based on measurements of ambient methane at different production basins suggest that methane emissions from oil and gas production

232 Methane is CH_4; ethane is C_2H_6; butane is C_4H_{10} and propane is C_3H_8. More carbon atoms means higher carbon and GHG content.

233 Allen, D.T., *Methane emissions from natural gas production and use: reconciling bottom-up and top-down measurements, Current Opinion in Chemical Engineering*, 2014, 5(0):78-83. Available at: http://www.sciencedirect.com/science/article/pii/S2211339814000525.

234 The kinds of activities conducted to place a well into production include perforating the well lining in the production zone so that gas can flow into and up the well. It could also include hydraulic fracturing, and then generally includes hooking the well up to small diameter gas gathering pipelines that will move the gas from the well to processing facilities.

could be considerably higher than emission inventories and other bottom up studies.[235] A complicating factor in assessing methane emissions from oil and gas production is accurately allocating the emissions between the natural gas and petroleum systems since only a fraction of the methane emissions that occur during joint production are attributed to natural gas. For example, the production of natural gas and liquid products in combination with oil is common in most of the rapidly growing shale areas, such as the Eagle Ford region in Texas.[236] Because the hydrocarbon products and the emissions associated with extracting them from different reservoir types can differ, when estimating emissions from the natural gas supply chain, it is important to accurately allocate emissions to particular hydrocarbon products and reservoir types.[237]There is an ongoing effort to continue to improve estimates of emissions at both the national and state level. There is not yet, however, an accepted method for allocating emissions between natural gas and petroleum sectors.

Some studies use the same data, while in others the sources were from different production basins, making comparisons and efforts to come to convergence difficult.[238] Also, to estimate emissions per unit of natural gas extracted from a well, it is necessary to know beforehand the amount of gas that will be extracted from the well during the lifetime of the well, which is at best an uncertain estimation.[239]

Efforts to better understand methane leakage from the oil and gas sector, including methods for allocating methane emissions to natural gas, are being developed. At this point there are no accepted methods for allocating emissions between the oil production and the natural gas production sectors, which is a challenge for both top-down and bottom-up studies. Research in this area would help to narrow the divergence among the studies and lead to more accurate estimates of methane from out of state natural gas production.

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235 Schneising O., et al. *Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations, Earth's Future*, 2014, 2(10). Available at: http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full.

236 Zavala-Araiza, D., Allen D.T., Harrison, M., George, F.C., Jersey, G.R., Allocating Methane Emissions to Natural Gas and Oil Production from Shale Formations, ACS Sustainable Chemistry & Technology, 2015, 49(8):492-498, http://pubs.acs.org/doi/pdf/10.1021/sc500730x.

237 Ibid. p. 492.

238 Weber, C., *Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications, Environmental Science & Implications*, 2012, 46, 5688-5695. Available at: http://pubs.acs.org/doi/abs/10.1021/es300375n.

239 Heath, G. A., et al. *Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation. Proceedings of the National Academy of Sciences*, 2014, 111(31): E3167-E3176. Available at: http://www.pnas.org/content/111/31/E3167.full.pdf.

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State and Federal Efforts to Address Methane Leakage

Despite the uncertainty in quantifying methane emissions, there is, nonetheless, adequate evidence that California should move forward aggressively to reduce methane emissions, both within and outside of the state. Several state and federal efforts have or will be undertaken to address methane emissions and are discussed below.

The latest research on natural gas distribution system methane losses conducted by Washington State University (WSU),[240] utilizes research grade direct measurements from pipeline leaks and emissions from meter and regulation equipment. This is the most robust study to date and relied on extensive sampling and methods superior to the studies of twenty years ago that resulted in the emission factors used in mandatory reporting programs under ARB and EPA. The estimated emission losses using real leak data and these new factors are consistent with internal engineering lost and unaccounted for gas studies and reflect the modernization of the distribution systems over the last two decades. Other studies by the Gas Technology Institute (GTI) show similar results falling within the uncertainty ranges of the measurements.

State Efforts to Address Methane Emissions

California has taken significant steps in reducing short-lived climate pollutant (SLCP) emissions, especially black carbon from transportation; methane from oil and gas operations and landfill emissions; fluorinated-gas emissions from refrigerants, insulating foams, and aerosol propellants. Still, more remains to be done to reduce emissions from these and other sources.[241] Various efforts by state agencies will help in this regard.

ARB Activities

The ARB has taken a leadership role in working with other state agencies and stakeholders to develop strong planning and decisive action on the release of methane and other SLCPs, which they believe will deliver reduction in the short-term and will play an important role in achieving Governor Jerry Brown's goal of reducing California's GHG emissions by 40 percent below 1990 levels by 2030.[242]

The Legislature recognized the critical role that SLCPs must play in the state climate efforts with the passage of Senate Bill 605 (Lara, Chapter 523, Statutes of 2014), which requires the ARB to develop a strategy by the end of 2015 to further reduce SLCP emissions. In May of 2015, the ARB released a concept paper presenting initial ideas that will be considered and

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[240] **http://pubs.acs.org/doi/pdf/10.1021/es505116p**

241 ARB, *Short-Lived Climate Pollutant Reduction Strategy: Concept Paper*, May, 2015, p.19. Available at: http://www.arb.ca.gov/cc/shortlived/concept_paper.pdf.

242 Ibid.

evaluated in the coming months by ARB, in coordination with other agencies, as it develops a SLCP Strategy pursuant to Senate Bill 605 (author, chapter, statutes of year). The concept paper identifies scientific targets that align with levels of GHG emission reduction needed worldwide to stabilize climate, including reducing methane emission by at least 40 percent. A major focus of this effort is developing strategies that minimize methane emissions from all infrastructure and equipment in the natural gas sector. ARB has already established regulations for methane from municipal solid waste landfills. In addition, ARB is developing a regulation to reduce methane emissions from oil and gas production, processing and storage operations.

ARB has also supported research over the last several years to address methane and other SLCPs including:[243]

- Improving emissions estimates through atmospheric measuring and modeling of GHG emissions and impacts.
- Determining spatial distribution of ozone precursors and GHG concentrations for the Los Angeles Basin.
- Calibrating, validating, and implementing process models for agricultural GHG emissions.
- Inverse modeling to verify California's GHG inventory.

CPUC Activities

Pursuant to Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014) and in consultation with the ARB, the CPUC is developing rules to reduce emissions from gas transmission and distribution pipeline leaks throughout the state. Together, these rules should create a comprehensive approach to limit methane leaks from oil and gas operations. As previously discussed, however, the primary source of natural gas is from out-of-state suppliers, so the state should continue to advocate for strong national methane standards to ensure potential climate benefits from use of natural gas in the state.

Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014) requires the CPUC to minimize leaks as a hazard to be mitigated and to reduce emissions of natural gas "to the maximum extent possible" to advance goals of GHG emissions. It directs the CPUC to "establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak detection." SB 1371 also requires gas corporations to file reports about natural gas leaks, leak management practices, and "estimates of gas lost due to leaks" on an annual basis.

243 Methane Research Projects, available at http://www.arb.ca.gov/cc/shortlived/shortlived.htm.

SB 1371 also requires the CPUC to confer with the ARB and open a proceeding to adopt rules. A rulemaking (R. 15-01-008) was launched on January 15, 2015. On March 17, 2015, the CPUC released a report on best practices for surveys of natural gas leakage abatement. The CPUC proposed that for the purposes of SB 1371 GHG reductions all leaks should be considered hazardous to people, property, or the environment.[244] The report also recommends that "the best practice would be to repair all leaks immediately as they are found," but recognized that might not be practical and could be costly.

Energy Commission Activities

The Energy Commission has been active in funding research activities related to the natural gas system focused on assessing methane emissions and supporting natural gas pipeline infrastructure and safety.[245] The Energy Commission is supporting research to identify the main sources of emissions (for example, wells, distribution system) and to improve the calculation of how much methane is emitted from the natural gas system in California. Several research projects are already completed including: measuring and modeling long lived GHG emissions at two tall towers for methane emission estimates; and, developing California-specific methane emission factors.

In one of the on-going Energy Commission projects, LBNL researchers are surveying methane emissions from key subsectors of the natural gas system, including production and processing, transmission and distribution, underground storage units, abandoned wells, LNG fueling stations, and end uses in homes. It is expected that this work will identify the main sources of emissions from the natural gas system, but further work will be required to fully quantify total annual emissions. A complementary on-going project will improve capabilities of air-based identification of methane leaks from transmission pipelines.

The Energy Commission is also supporting studies on safety issues to be able to detect potential failure modes that may endanger public health and safety. For example, several ongoing projects focus on developing and testing cost-effective leak detection and pipeline integrity monitoring sensors and tools, as well as demonstrating them in the lab under simulated field conditions and at a few actual field sites. This also includes real-time monitoring of the pipeline defects and damage due to corrosion and improper girth welds, as well as damage to pipelines from encroachments and unauthorized right-of-way activities. These sensors and tools can be effective in monitoring the health and integrity of the pipelines, helping the pipeline operators to develop proper pipeline monitoring and

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244 http://www.cpuc.ca.gov/NR/rdonlyres/78171FC7-C5D9-44E5-A922-F49BF9C9D7F9/0/SEDSB1371LenoNaturalGasLeakageAbatementBestPracticesFinal.pdf.

245 Energy Commission, Presentation at 2015 IEPR Workshop on Fugitive Methane Emissions: Energy Commission Natural Gas Research Activities, June 1, 2015. Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-04.

maintenance practices, while properly operating and maintaining the pipelines. This is expected to improve pipeline safety and reduce danger to public health, as well as reduce chances of catastrophic events, such as the 2010 San Bruno pipeline explosion. Projects in this area of research include:

- Developing a mechanical pressure sensor and flow sensor for inspecting and monitoring natural gas pipelines.
- Demonstrating a multi-channel electromagnetic acoustic transducer sensor module for inline detection.
- Developing a real-time corrosion monitoring system for pipeline integrity detection.

Natural Gas Utility Activities

Natural gas utilities are already taking steps to reduce emissions. For example, the California natural gas utilities have replaced old, cast iron pipelines and some unprotected steel pipes, which typically have more leaks per mile than protected steel and plastic.[246] PG&E, SoCal Gas, and SDG&E note that their primary focus in reducing methane leakage is addressing distribution system leaks, which they also note have been heavily driven by safety concerns following the San Bruno explosion. PG&E, along with a number of partners, including National Aeronautics and Space Administration (NASA), the University of California, Jet Propulsion Lab (JPL), the Energy Commission, and others, are funding several research, development, and deployment projects. For example, one project demonstrated a stationary methane laser sensor that continuously monitors its line of sight above pipelines and provides rapid warning. PG&E tested a handheld methane detector that uses laser based technology and has superior sensitivity than other commercial handheld detectors. PG&E is also involved in using a Schlieren gas imaging technique that can observe leak flow remotely. In addition, PG&E is using a Picarro mobile platform system to detect leaks in the distribution system and immediately implementing measures to eliminate these emissions.[247] They are collaborating on a number of other research efforts. There is a concern that the effects of these measures may not be adequately documented in open literature to support further research, development, and demonstration (RD&D).

SoCal Gas and SDG&E are also active in RD&D efforts to reduce methane emissions on their gas systems, including many of the same technologies and programs being implemented by PG&E. Their Going Forward Plan to reduce methane emissions includes collaborating with the CPUC to cost-effectively enhance infrastructure safety, while yielding environmental

246 Lamb, B.K., *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*, *Environmental Science & Technology*, 2015, 49(8):5161-5169, http://pubs.acs.org/doi/full/10.1021/es505116p.

247 One of the reasons for the immediacy of fixing leaks is that the repair crew is deployed along with the platform, integrating the fixing into the leak detection.

benefits.[248] They are funding RD&D for new technologies and greater efficiencies. They are also partnering with academia, regulators, and industry on studies and programs.

All of SoCal Gas and SDG&E RD&D efforts are summarized in their Technology Plan, which is designed to provide near-term, real-time field data on large pipeline rights-of-way to prevent, mitigate, and manage pipeline incidents.[249] SoCal Gas and SDG&E are developing methane detectors that provide real-time notification of major leaks. For example, new mobile detection vehicles and un-manned aerial vehicles are being used to investigate possible events on the system. They are also looking at using fiber optic cabling along pipelines to provide early warning for events of digging, movement, and impact. In addition, SoCal Gas and SDG&E are installing smart gas meters that will help detect leaks by identifying excessive consumption and inefficient equipment, which will in turn, reduce methane emissions. They are also hoping to use smart meters to connect carbon monoxide monitoring, smoke alarms, or other sensors.

In addition to reducing methane emissions, SoCal Gas is preparing for the deep carbon reductions that will be required in California after 2020.[250] They are investigating ways to decarbonize natural gas with the use of hydrogen that would be generated from excess power produced by solar and wind, and by the use of bio-methane from the sustainable harvesting of biomass.[251]

EDF Comprehensive Study

The Environmental Defense Fund (EDF) commissioned an economic analysis of methane emission reduction opportunities for the oil and gas industries.[252] The study estimated that a

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248 SoCal Gas/SDG&E, Presentation: IEPR Staff Workshop, Fugitive Methane Emissions in California's Natural Gas System, June 1, 2015, p. 5. Available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-04/TN204783_20150529T154031_Intergrated_Energy_Policy_Report_IEPR_Staff_Workshop_Fugitive_M.pdf.

249 Ibid. pp. 8-9.

250 George Minter, SoCal Gas, *Natural Gas Pathways: Natural Gas Vehicles in California*, presentation at the June 23, 2014, *IEPR* workshop. Available at: http://www.energy.ca.gov/2014_energypolicy/documents/#06232014.

251 Biomethane is methane obtained from biogas after cleaning impurities and other processing to make it suitable quality for the natural gas system.

252 ICF International, *Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*, Prepared for EDF, March, 2014. Available at: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

40 percent reduction in onshore methane emissions was possible with existing technologies at a net total cost of $0.66 per thousand cubic feet (Mcf) of methane reduced, or less than $0.01/Mcf of methane produced. This analysis accounts for savings for companies implementing methane reduction; however, it assumes that there are easy ways to identify super-emitters, and it is unclear how realistic this assumption may be.

About 100 participants including academics, natural gas utilities, research institutions, and others, are funding research coordinated by the EDF. The EDF program is the most comprehensive set of studies trying to improve the characterization of emissions from the natural gas system. It includes 16 studies covering all the parts of the natural gas system.[253] Five common principles underlie this research effort: (1) Led by academic scientists; (2) Employ multiple methodologies where possible; (3) Input from independent scientific experts; (4) Make all data public to ensure transparency; and (5) Publish results in a peer-reviewed journal.

The studies include measuring and estimating methane emissions at natural gas production sites, including liquids loading and pneumatic controllers, gathering and processing facilities, and transmission and storage in interstate pipelines. On the distribution side, research projects include: better characterizing methane emissions in utility distribution system in various regions of the United States, tower based quantitative techniques for measuring methane in urban environments, and mapping methane leaks from local distribution systems. Other research includes fly-over studies on oil and gas production basins, investigating super-emitters, and various pilot projects. The final product is the project synthesis to gain an integrated understanding of what can be learned from the various research efforts. Ten of the studies have been completed, several others will be completed in late summer of 2015, and the synthesis project is expected in 2016.

Federal Efforts to Address Methane Emissions

At the national level, several federal agencies are addressing and supporting research on methane emissions from the natural gas system. The U.S. DOE, as well as natural gas utilities and the GTI are conducting further research to better identify methane emissions. For example, a branch of U.S. DOE recently awarded approximately $30 million for research developing accurate low-cost methane sensors. Once these sensors are developed, the goal is to deploy them in multiple locations to identify methane emissions and to be able to implement the necessary corrective actions.

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253 EDF, *Methane Research: The 16 Studies Series, An Unprecedented Look At Methane from the Natural Gas System*. Available at: https://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf.

The National Oceanic and Atmospheric Administration is also heavily involved in research using aircrafts and tall towers to characterize emissions from important basins including some work done in California, mostly in the Los Angeles region and the southern part of the San Joaquin Valley. The National Aeronautic and Space Administration (NASA) has made satellite information available to researchers that can be used to infer atmospheric concentrations. In addition, NASA is working very closely with the ARB and the Energy Commission using research-grade infrared cameras installed in aircraft that can detect methane leaks. This work promises to deliver very useful information in the near future.

The U.S. EPA recently released for peer review a number of technical white papers that proposes to address emissions from compressors, well completions and fracturing, liquids unloading, and pneumatic devices. [254] The white papers are in response to President Obama's Climate Action Plan: A Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent GHG, and outlines the Obama Administration efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

The Federal Energy Regulatory Commission (FERC) does not currently have any explicit GHG regulations in place or proposed for natural gas infrastructure. FERC, however, adopted a new policy statement in early 2015 that will be applied in upcoming gas infrastructure rate cases that would allow recovery of major capital investment costs when the investment addresses pipeline safety or reduces GHG emissions.[255] The primary driver of the policy statement is the set of directives issued by the NTSB and the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration, along with the 2011 Pipeline Safety Act to expand integrity management, reconfirm MAOP, replace cast iron pipeline, and a number of other activities to improve safety. The policy statement also refers to the U.S. EPA rule for mandatory reporting of GHG emissions including those from production, processing, transportation, and distribution of natural gas as another driver of the policy.

The policy statement adopts five thresholds that must be met to allow cost recovery under a "modernization cost surcharge:" including:

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254 The white papers were released by EPA on April 15, 2014. Available at: http://www.epa.gov/airquality/oilandgas/whitepapers.html.

255 The April 15, 2015 *Policy Statement: Cost Recovery for Modernization of Natural Gas Facilities*, goes into effect in October, 2015. Available at: http://www.ferc.gov/whats-new/comm-meet/2015/041615/G-1.pdf.

- Recent review of existing rates.[256]
- Costs must be one-time capital costs incurred to comply with safety or environmental regulations and each must be specifically identified.
- Cannot shift costs to captive customers.
- Must provide period review of the surcharge and base rates.
- Must work collaboratively to seek shipper support.

For the first time, FERC recently allowed, in a contested settlement for Columbia Gas Transmission, a tracking mechanism on "substantial pipeline modernization costs" of $300 million annually for five years.[257] The mechanism included a reduction in Columbia Gas Transmission base rates, and Columbia Gas Transmission also agreed to spend $100 million each year and not recover it through the tracking mechanism. Additional efforts to pursue recovery of safety or environmental costs for interstate pipelines are anticipated in the next few years.

These studies look at methane emissions from the delivery of fossil natural gas across the entire value chain. However, it is important to note the system wide leakage rate would be different for the delivery of biomethane. In fact, the existing natural gas delivery system can play an important role in total GHG emissions for California, if it is utilized to deliver methane captured from biological sources. The ARB's methane inventory, reflected in Table 6, shows there are significant biological sources of methane. Capture and utilization of these resources would directly reduce GHG emissions from the biological sources. It would also indirectly reduce methane emissions from the natural gas system by displacing the upstream methane emissions from the production and transmission of fossil natural gas. By applying Environmental Defense Fund (EDF)/WSU emission factors, the emissions from the utility system are approximately equivalent to four (4), 10,000 cow, commercial dairy farms' annual emissions. The state must prioritize its research and incentive funding to areas that can achieve the greatest GHG benefits to state.

256 A review of existing rates must be done in either an NGA Section 4 rate proceeding or a collaborative effort between the pipeline and its customers.

257 http://www.ferc.gov/EventCalendar/Files/20130124163733-RP12-1021-000.pdf

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Areas for Further Research

There are a number of areas where additional research could help to reduce the uncertainty in the current estimates of methane emissions. A few of these are listed below, including:[258]

- Continue efforts to bring convergence between bottom-up and top-down methods for estimating methane emissions.
- Continue to develop allocation methodologies to attribute emissions between the oil and gas systems.
- Collect additional data to develop better methane emission factors or other methodologies for use in inventories.
- Develop technologies for the early detection of gross methane emissions and for the identification of the source.
- Develop cost effective methane mitigation/recovery technologies to address known emission sources during pipeline operation and maintenance activities.
- Develop system and regional specific emission factors for pipeline facilities from actual system performance data.
- Develop a continuous integrity monitoring system (in-situ) that can continuously monitor the integrity of pipelines.
- **Develop cost-effective quantification methodologies that use a cap and trade price as a benchmark for a cost-effectiveness threshold**
- **Evaluate how utilization of existing natural gas infrastructure can reduce methane emissions from biological sources.**

258 Many of the recommendations for additional research were identified in: Comments of SoCal Gas on the June 1, 2015 *IEPR* Workshop, in Support of the Assembly Bill 1257 *Strategies to Maximize Benefits Obtained From Natural Gas as an Energy Source Draft Staff Report*, on Fugitive Methane Emissions in California's Natural Gas System Docket No. 15-IEPR-04, June 15, p. 4-5. Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-04.

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Acronyms

Acronym	Definition
ARFVTP	Alternative and Renewable Fuel and Vehicle Technology Program
Bcf (/d)	Billion cubic feet (per day)
Btu	British thermal unit
ARB	California Air Resources Board
CalRecycle	California Department of Resources, Recycling, and Recovery
California ISO	California Independent System Operator
CC	Combined cycle
CHP	Combined heat and power
CPUC	California Public Utilities Commission
CPUC SED	CPUC Safety and Enforcement Division
CO_2	Carbon dioxide
CO	Carbon monoxide
CHP	Combined heat and power
CNG	Compressed natural gas
EPNG	El Paso Natural Gas
EDF	Environmental Defense Fund
FERC	Federal Energy Regulatory Commission
GTI	Gas Technology Institute
GWh	Gigawatt hours
GW	Gigawatts
GHG	Greenhouse gas
HVAC	Heating, ventilation, and air conditioning
ILI	In-line inspection
IEPR	*Integrated Energy Policy Report*
IOUs	Investor owned utilities
kWh	Kilowatt hour
LADWP	Las Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LCFS	Least carbon fuel standards
LNG	Liquefied natural gas
LCA	Local Capacity Areas
LTPP	Long-Term Procurement Planning
MAOP	Maximum allowable operating pressure
MHDV	Medium and heavy duty vehicle
MW	Megawatts
MMBtu	Million British thermal units
MMcf(/d)	Million cubic feet (per day)

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Acronym	Definition
MMT	Million metric tons
$MMTCO_2e$	Million metric tons of carbon dioxide equivalent
NTSB	National Transportation Safety Board
NGV	Natural gas vehicle
NO_x	Nitrogen oxides
OFOs	Operational flow orders
PG&E	Pacific Gas and Electric Company
PV	Photovoltaic
PSEP	Pipeline safety enhancement plans
QF	Qualifying facility
QFER	*Quarterly Fuels and Energy Report*
RPS	Renewables Portfolio Standard
R&D	Research and development
SED GSRB	SED Gas Safety and Reliability Branch
SDG&E	San Diego Gas and Electric Company
SONGS	San Onofre Nuclear Generation Station
STARS	Selective Tartrate Removal System
SLCP	Short-lived climate pollutant
SoCal Gas	Southern California Gas Company
SoSysMin	Southern system minimum
SWRCB	State Water Resources Control Board
SCADA	Supervisory Control and Data Acquisition
Mcf	Thousand cubic feet
Tcf	Trillion cubic feet
The Panel	CPUC Independent Review Panel
U.S. DOE (/FE)	United States Department of Energy (Office of Fossil Energy)
U.S. EPA	United States Environmental Protection Agency
U.S. EIA	United Stated Energy Information Administration
WIEB	Western Interstate Energy Board
ZNE	Zero net energy

Appendix A- SoCalGas' Redlines to the Draft AB 1257 Report

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Appendix A

Table A-1: Interstate Natural Gas Pipelines Interconnecting to California as of April 2, 2015

Pipeline	Supply Source	Maximum Delivery Capacity	California Border Receipt Point/Receiving Utility System
Gas Transmission Northwest (GTN)	Western Canadian Sedimentary Basin	2.272 Bcf/d	Malin, OR/PG&E Redwood Path
Ruby Pipeline	Rocky Mountains	1.684 Bcf/d	Malin, OR/PG&E Redwood Path
Tuscarora Gas Transmission Company	Western Canadian Sedimentary Basin, Rocky Mountains	300 MMcf/d	Malin, OR/City of Susanville Natural Gas Department
Paiute Pipeline	Western Canadian Sedimentary Basin, Rocky Mountains	44 MMcf/d	North and South Lake Tahoe, CA/Southwest Gas
Kern River Gas Transmission Company	Rocky Mountains	1.900 Bcf/d	Daggett, CA/PG&E Baja Path
El Paso Natural Gas (EPNG) North Mainline	Anadarko, Permian, San Juan	2.145 Bcf/d	Topock, AZ: PG&E Baja Path, SoCalGas, Mojave Pipeline
El Paso Natural Gas (EPNG) South Mainline	Permian	1.410 Bcf/d	Ehrenberg, AZ/SoCalGas
Transwestern Pipeline Company	Anadarko, Permian, San Juan	1.210 Bcf/d	Topock, AZ; Needles, CA/ PG&E Baja Path, SoCalGas, Mojave Pipeline
Questar Southern Trails Pipeline	San Juan	240 MMcf/d	Mohave Valley, AZ/ SoCalGas, PG&E Baja Path
Mojave Pipeline Company	Anadarko, Permian, Rocky Mountains, San Juan	798 MMcf/d	Topock, AZ; Daggett, CA/SoCalGas
Transportadora de Gas Natural (TGN)	Costa Azul LNG Import Facility	413 MMcf/d	Otay Mesa, CA/SDG&E
North Baja Pipeline System	Permian	513 MMcf/d	Ehrenberg, AZ/ SoCalGas
Maximum California Delivery Capacity		**13.33 Bcf/d**	

Source: California Energy Commission with data from Regional Pipeline Flow Report #201, provided by PointLogic Energy LLC, an OPIS Company. Not all of these pipelines can deliver these maximum volumes into California concurrently due either to take-away constraints on the California side of the interconnection or the fact that North Baja, for example, is not designed to "serve" California but rather transports gas from Ehrenberg into Mexico's Baja Norte system that parallels the International Boundary to Costa Azul.